NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interregional Transfer Capability Study (ITCS)

Strengthening Reliability Through the Energy Transformation

Final Report

RELIABILITY | RESILIENCE | SECURITY

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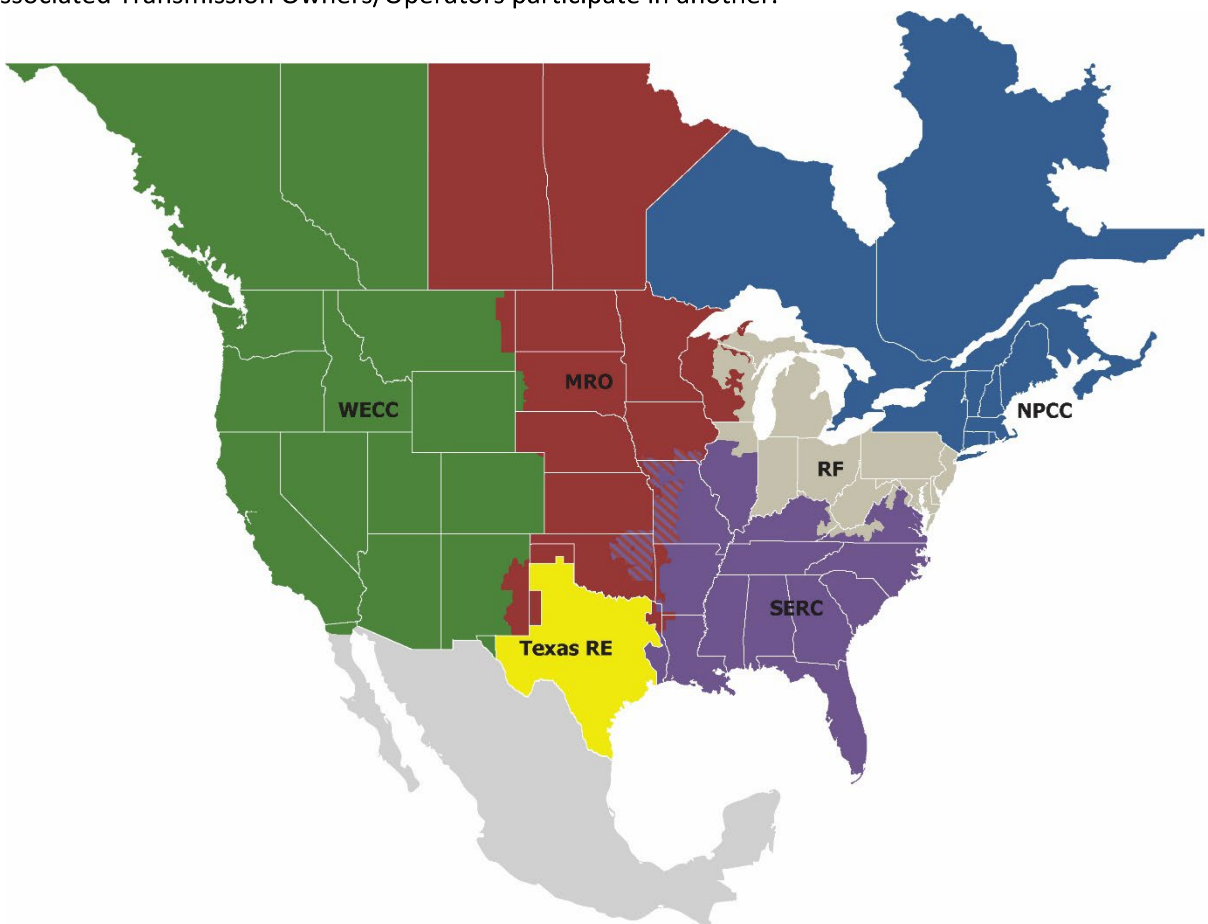
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American Bulk Power System (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Statement of Purpose

In June 2023, Congress enacted legislation – the Fiscal Responsibility Act of 2023[1] – that mandated NERC, as the ERO, to conduct the Interregional Transfer Capability Study (ITCS) to inform the potential need for more electric transmission transfer capability to enhance reliability:

> *The Electric Reliability Organization…in consultation with each regional entity…and each transmitting utility (as that term is defined in section 3(23) of such Act) that has facilities interconnected with a transmitting utility in a neighboring transmission planning region, shall conduct a study of total transfer capability as defined in section 37.6(b)(1)(vi) of title 18, Code of Federal Regulations, between transmission planning regions that contains the following:*
>
> *(1) Current total transfer capability, between each pair of neighboring transmission planning regions.*
> *(2) A recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions.*
> *(3) Recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions.*

This congressional directive falls within the scope of NERC's obligation under section 215 of the Federal Power Act,[2] to "conduct periodic assessments of the reliability and adequacy of the bulk power system in North America."[3] NERC and the six Regional Entities,[4] collectively called the ERO Enterprise, developed and executed the ITCS in collaboration with industry to address the congressional directive. This report details the inputs, processes, key findings, and recommendations of the ITCS.

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[1] H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress

[2] 16 U.S.C. § 824o [hereafter section 215]

[3] Section 215(g). Such reliability assessments include the Long-Term Reliability Assessment (LTRA), Summer Assessment, Winter Assessment, and special assessments.

[4] NERC's work with the Regional Entities is governed by Regional Delegation Agreements (RDA) on file with FERC and posted on NERC's website. See also section 215(e)(4).

Executive Summary

The North American grid is a complex machine that has evolved over many decades and integrates a network of generation, transmission, and distribution systems across vast geographic areas.[5] As a result of the changing resource mix[6] and extreme weather, interregional energy transfers play an increasingly pivotal role. More than ever, a strong, flexible, and resilient transmission system is essential for grid reliability. NERC, as the Electric Reliability Organization (ERO), remains focused on assuring reliability throughout this energy transformation. As evidenced during recent operational events,[7] more needs to be done to support energy adequacy[8] to be able to continuously meet customer demand. This is the reliability risk that the Interregional Transfer Capability Study (ITCS) seeks to identify and mitigate through additions to transfer capability[9] as directed in the Fiscal Responsibility Act of 2023.[10]

THE ITCS

In Scope

- ✓ A common modeling approach to study the North American grid independently and transparently
- ✓ Evaluation of the impact of extreme weather events on hourly energy adequacy using the calculated current transfer capability and 10-year resource and load futures
- ✓ Recommendations for additional transfer capability between neighboring regions to address energy deficits when surplus is available
- ✓ Extensive consultation and collaboration with industry
- ✓ Reliability improvement as the sole factor in determining prudence

Out of Scope

- ✘ Economic, siting, political, or environmental impacts
- ✘ Alternative modeling approaches – ITCS results may differ from other analyses
- ✘ Quantified impacts of planned projects
- ✘ Recommendations for specific projects, as additional planning by industry would be necessary to determine project feasibility
- ✘ Recent changes to load forecasts, renewable targets, or retirement announcements

A Critical Study

Previous NERC assessments[11] identified the need for more transmission transfer capability, as well as a strategically planned resource mix,[12] to address these changes and support the ongoing electrification of the economy including the growing transportation sector, industrial loads, and data centers. More frequent extreme weather events further compound the challenge. While always important, the need for a reliable energy supply – in the interest of public health, safety, and security – becomes most pronounced under these extreme conditions. These factors emphasize the criticality of adequate and informed planning at a broader interregional level that will support future grid reliability. For this reason, developing a common approach and consistent assumptions, with model development, validation, and results coordinated with industry, was key to the study's design. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions but is not a transmission plan or blueprint. Transmission assessments, like the

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5 An explanation of the grid can be found at *Electricity Explained – U.S. Energy Information Administration* (*April 2024*).

6 This phrase relates to the replacement of traditional dispatchable resources with a higher percentage of intermittent resources with non-stored fuel sources, such as wind and solar resources.

7 The ITCS Overview of Study Need and Approach includes examples of the role of transfer capability during the Western Interconnection Heatwave (2020), Winter Storm Uri (2021), and Winter Storm Elliott (2022).

8 While there are many facets to reliability, the ITCS focuses on energy adequacy, the ability of the bulk power system (BPS) to meet customer demand at all times.

9 Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions.

10 H.R.3746 - 118th Congress (2023-2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress

11 NERC's assessments can be found at nerc.com.

12 The terms "resource mix" and "resources" broadly include generators, storage, and demand response.

ITCS, are crucial to mitigating future risks; however, alternative approaches other than transmission can also mitigate future energy risks, such as local generation, or demand-side solutions.

The study specifically does not include:

- **Economic Assessments:** Economic analysis, cost-benefit evaluation, or financial modeling were not factors in determining prudent recommendations. The focus was strictly on improving energy adequacy.
- **Project-Specific Recommendations:** This report highlights areas where new capacity is desirable to improve reliability but does not endorse individual transmission projects.
- **Transmission Expansion Analysis:** The ITCS is not a replacement for existing or future transmission expansion planning efforts or interconnection studies nor does it represent a comprehensive transmission plan. Economic and project viability assessments are needed to fully understand cost implications, market impacts, siting and permitting challenges, and further technical considerations.
- **Operational Mitigation:** The ITCS used existing interconnection planning models developed annually by NERC and the Regional Entities. The analysis did not evaluate operational mitigations through re-dispatch or other actions.
- **Capacity Expansion Planning:** Transmission needs are heavily influenced by future resource assumptions. Significant changes to the underlying assumptions could impact the energy margin analysis and, consequently, the identified prudent additions. Due to gaps in firm resource plans for 2033 in many areas, the ITCS established a future resource mix assumption based on available plans, ranging from certain to speculative resources.[13]

The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and action in response to the opportunities identified. Therefore, the ITCS:

- **Acknowledges Anticipated Benefits of Projects Already in Progress:** NERC acknowledges that transmission projects in planning, permitting, or construction phases may reduce some needs identified in the ITCS. The existence of these projects supports the ITCS findings by highlighting their relevance to improving reliability. By underscoring these projects' critical roles, the study affirms the need for timely completion of these or similar efforts supporting overall grid resilience.
- **Leaves Implementation to Policymakers and Industry:** The ITCS does not prescribe "how" prudent additions to transfer capability should be achieved, rather provides information on what would be desirable to improve energy adequacy. While prudent additions are one approach to reducing vulnerability during extreme conditions, these needs can be addressed in various ways. The study's findings underscore the urgency of targeted, strategic actions but remain flexible in implementation. The directional guidance provided by the ITCS is foundational to ongoing planning, regulatory, and legislative efforts aimed at securing a resilient and reliable grid.

The ITCS demonstrates a significant opportunity to optimize reserve use during extreme weather events and shows how transmission can maximize the use of local resources, including storage and demand response. Further, the ITCS highlights the continuing importance of resource planning, as increasing transfer capability without surplus energy would be inefficient.

[13] The future resource mix assumptions are based on the 2023 Long-Term Reliability Assessment (LTRA), which projects new resources in three tier levels. In general, Tier 1 resources are in the final stages for connection, while Tier 2 resources are further from completion, and Tier 3 resources are even less certain.

Study Progression: Enhancing Reliability

As shown in **Figure ES.1**, the ITCS project consists of four parts.

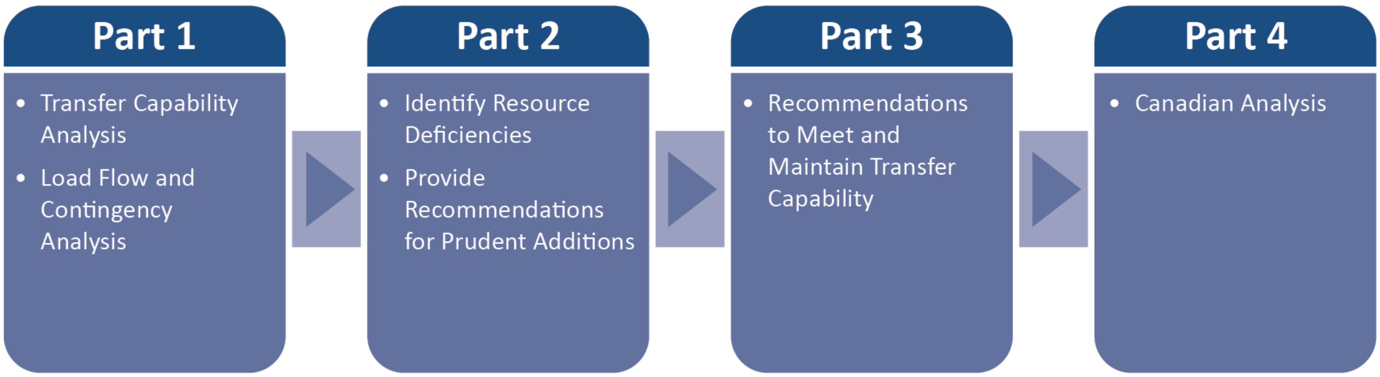

Figure ES.1: Study Parts

Overview of Study Need and Approach

The first ITCS document – *Overview of Study Need and Approach*[14] – was released in June 2024. It provides background and context on the study, including a brief discussion of recent operational events. It also includes details of transfer capability calculations and the approach for recommending additions to transfer capability, laying the foundation for the ITCS.

Transfer Capability Analysis (Part 1)

The second ITCS document – *Transfer Capability Analysis (Part 1)*[15] – was released in August 2024 and addressed the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring Transmission Planning Regions (TPR).[16] Transfer capability is the amount of power that can be reliably transported over a given interface under specific conditions. The Part 1 study report provided the calculation and limitations of current total transfer capability (TTC)[17] and informed Part 2 of the study.

Recommendations for Prudent Additions (Part 2) and to Achieve Transfer Capability (Part 3)

The third ITCS document – *Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)*[18] – was released in November 2024. It contained an energy margin analysis and resulting recommendations for prudent[19] additions[20] to the transfer capability between neighboring TPRs to improve energy adequacy during, for example, extreme weather events. It also discussed how to meet and maintain transfer capability as enhanced by these prudent additions.

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[14] The ITCS Overview of Study Need and Approach further explains transfer capability, calculation method, study assumptions, and other study information.

[15] The ITCS Transfer Capability Analysis (Part 1) report was published in August 2024.

[16] This is not a defined term in the NERC Glossary of Terms, but for the ITCS, this term refers to the study regions that are described in the ITCS Overview, the ITCS Transfer Capability Analysis (Part 1) report, and in **Chapter 1** of this report.

[17] The TTC method was used for consistency across the study area, and these values are distinct from the path limits used by some entities.

[18] The ITCS Parts 2 and 3 Report was published in November 2024.

[19] FERC defines prudence as the determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances at the relevant point in time. See, e.g., *New England Power Co*., 31 FERC ¶61,047 at p. 61,084 (1985); and *Potomac-Appalachian Transmission Highline, LLC,* 140 FERC ¶61,229 at P 82 2012 (Sept. 20, 2012).

[20] A discussion of the interpretation of technically prudent additions to transfer capability can be found in the ITCS Overview of Study Need and Approach. Hereafter, this is typically referred to interchangeably as "recommended additions" or "prudent additions."

Canadian Analysis

Due to the interconnected nature of the bulk power system (BPS),[21] NERC will extend the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces.[22] The Canadian analysis will be published in the first quarter of 2025.

Stakeholder Engagement During the ITCS

To ensure a comprehensive and inclusive study, an ITCS Advisory Group of stakeholders was formed including regulators, industry trade groups, and transmitting utilities across North America. Throughout the process, NERC and the Regional Entities undertook a comprehensive outreach program to keep industry and stakeholders informed through regular updates and to provide opportunities for input. The ITCS Advisory Group meetings, which are public, are posted on the ITCS web page, along with other project materials and supporting information. The involvement of these stakeholders is critical toward making the ITCS as effective as possible.

The ITCS is the beginning of an extensive process involving the evaluation of the recommended additions made in this report. NERC encourages all stakeholders to continue the constructive engagement and collaboration shown in this process to address the challenges facing our grid. NERC is committed to doing its part by integrating transmission adequacy into future Long-Term Reliability Assessments (LTRA) and continuing to highlight risks in its reliability assessments.

ANALYSIS: Transfer Capability (Part 1)

Part 1 (beginning in **Chapter 3**) addressed the first part of the congressional directive that mandated an analysis of the current transfer capability between each pair of neighboring TPRs. The results of the Part 1 analysis informed Part 2 of the study.

Key Findings – Part 1

- Transfer capability varies seasonally and under different system conditions that limit transmission loading – it cannot be represented by a single number.
- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.
- Observed transfer capabilities are generally higher in the West Coast, Great Lakes, and Mid-Atlantic areas, but relatively lower in the Mountain States, Great Plains, Southeast, and the Northeast regions. There is limited transfer capability between Interconnections.

The Part 1 current transfer capability analysis between each pair of neighboring TPRs focused on two different base cases[23] representing 2024 Summer and 2024/25 Winter, with results shown in **Figure ES.2** and **Figure ES.3**, respectively. A complete listing of the current TTC results can be found in **Chapter 4**.

[21] The Western Interconnection includes the Canadian provinces of Alberta and British Columbia. Similarly, the Eastern Interconnection contains numerous transmission lines between the United States and Manitoba, New Brunswick, Ontario, and Saskatchewan, plus direct current (dc) connections with Québec.

[22] The ITCS Part 1 evaluated transfer capability from Canada into the United States.

[23] Base cases are computer models that simulate the behavior of the electrical system under various conditions. The cases chosen were from readily available seasonal peak load models and updated by industry to reflect future conditions.

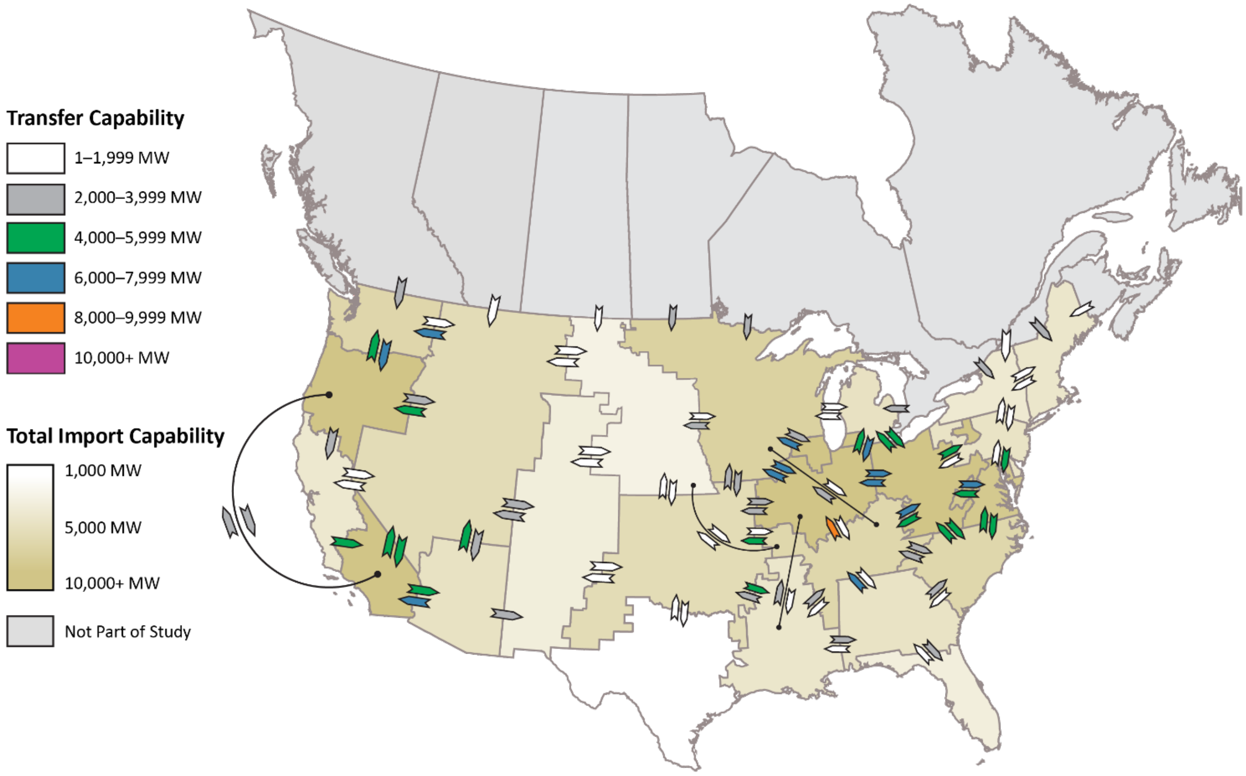

Figure ES.2: Transfer Capabilities (Summer)

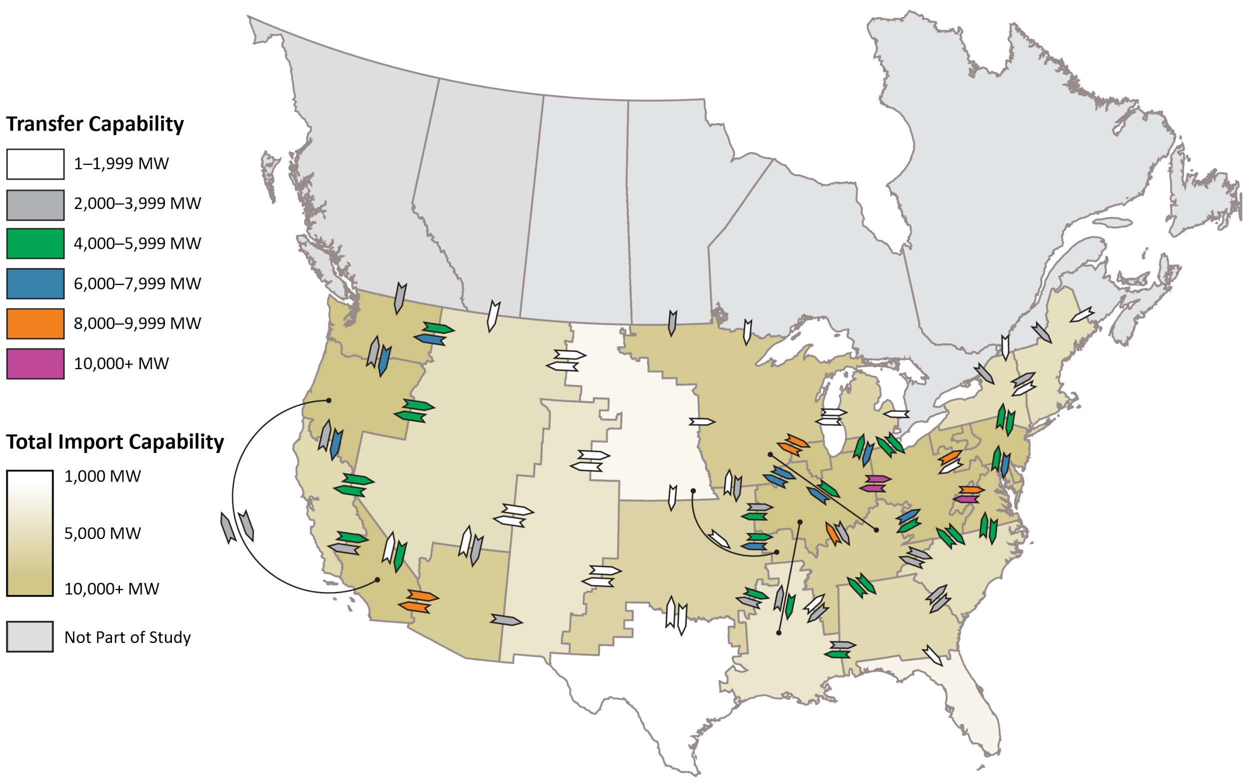

Figure ES.3: Transfer Capabilities (Winter)

The transfer capability results in this report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, both of which can vary significantly between seasons. For the same reasons, transfer capability can be different during non-peak periods than the peak conditions studied. This study used a set of cases representative of stressed system conditions most relevant for the Part 2 analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures. Consequently, higher transfer capabilities may be available under different conditions. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans have the potential to significantly alter the study results.

A holistic view of the interconnected system and a thorough understanding of its behavior are essential when calculating or increasing transfer capability. When neighboring TPRs transfer energy over a highly interconnected system, the energy flows over many different lines based on the electrical characteristics, or impedance, of traveling each route, unless there is specific equipment used to control flows. As a result, energy typically flows not only across the tie lines that directly connect the exporting (source) TPR to the importing (sink) TPR, but over many routes, some of which may be running through third-party systems. The way electrical energy flows has broad implications for calculating and using transfer capability in an interconnected system, especially when traveling over long distances. For example, maintaining and increasing transfer capability may be highly dependent on the system conditions within the source and sink TPRs as well as surrounding areas. Likewise, transfer capability does not correlate one-to-one with the rating of new or upgraded transmission facilities.

RECOMMENDATIONS: Prudent Additions to Transfer Capability (Part 2)

Part 2 (beginning in **Chapter 5**) addressed the second part of the congressional directive, which mandated a set of recommendations for prudent additions to transfer capability that would strengthen reliability.

Key Findings – Part 2 and 3

- The North American system is vulnerable to extreme weather. Transmission limitations, and the potential for energy inadequacy, were identified in all 12 weather years studied. Enhancing specific transmission interfaces could reduce the likelihood of energy deficits during extreme conditions.
- Reliability risks are highly dependent on regional conditions. The import capability needed during extreme conditions varied significantly across the country, indicating that a one-size-fits-all requirement may be ineffective. An additional 35 GW of transfer capability is recommended across the United States as a vehicle to strengthen energy adequacy under extreme conditions:
  - ERCOT faces large energy deficits under various summer and winter conditions, including Winter Storm Uri in 2021.
  - California North faces energy adequacy challenges during large-scale heat events in the Western Interconnection, such as the one that occurred in 2020.
  - Energy shortages in New York were observed during multiple events.
  - MISO-E, PJM-S, SERC-E, SERC-Florida, and SPP-S each have significant vulnerability to extreme weather (>1,000 MW).
  - Enhancing interfaces between Interconnections (Western, ERCOT, Eastern, and Québec) could provide considerable reliability benefits.
  - The inclusion of Canada highlights interdependence and opportunities to increase transfer capability.
- Interregional transmission could mitigate certain extreme conditions by distributing resources more effectively, underscoring the value of transmission as an important risk mitigation tool, if there is sufficient available generation in neighboring systems at the times of need. However, there are numerous barriers to realizing these benefits in a timely fashion.
- Some identified transmission needs could be alleviated by projects already in the planning, permitting, or construction phases. If completed, these projects could mitigate several risks highlighted by the ITCS, reinforcing their importance for grid resilience.
- The importance of maintaining sufficient generating resources underpins the study's assumptions. Higher than expected retirements (without replacement capacity) would lead to increased energy deficiencies and potentially more transfer capability needed than recommended in this study (if surplus energy is available from neighbors).
- The ITCS provides foundational insights for further study, discussion, and decisions. Transmission upgrades alone will not fully address all risks, and a broader set of solutions should be considered, emphasizing the need for local resources, energy efficiency, demand-side, and storage solutions. A diverse and flexible approach allows solutions tailored to each TPR's vulnerabilities, risk tolerance, economics, and policies.

Defining Prudent Additions in Context of Reliability

Prudent additions mitigate identified instances of energy deficiency without regard to economic considerations.

This study defined "prudent additions" as potential transmission enhancements identified to mitigate grid reliability risks under especially challenging conditions. The ITCS mandate requires NERC to develop these recommendations that "*demonstrably strengthen reliability;"* therefore recommendations are made that are beyond the existing reliability requirements and transmission needs supporting reliability and economic planning. Notably, the ITCS does not consider economic feasibility. The analysis excludes cost-benefit assessments, meaning no economic or financial modeling was used in determining prudent recommendations. Prudent additions are recommendations based on reducing energy deficits by transferring available excess energy from neighboring TPRs and have three primary objectives:

- **Strengthen Reliability:** Provides a potential solution that enables more flexibility between TPRs and access to resources that may be available during local energy deficits.
- **Serve Load Under Extreme Conditions:** Provides a solution that serves future demand during extreme conditions, which is a more restrictive design basis than current resource adequacy constructs.
- **Does Not Create Unintended Reliability Concerns:** Recommendations for larger connections between TPRs will require detailed system studies to assure system stability.

These recommendations are built upon rigorous modeling of extreme conditions where the BPS experiences stress due to factors such as elevated demand levels, limited generation availability (e.g., from weather-dependent renewables), and transmission limitations or contingencies impacting energy delivery. Across all TPRs evaluated, the estimated unserved load – the hours during which demand outstrips supply – varies from 0 to 135 hours, directly reflecting different levels of reliability risk. Recommended additions seek to reduce these potential load-shedding risks. In some cases, policymakers may choose to accept some risk as the likelihood of load loss is small, and other mitigation may be more acceptable.

The prudent additions to transfer capability represent directional guidance for strengthening reliability under extreme conditions and should not be misconstrued as mandatory construction directives but rather as directional insights for supporting system resilience.

Evaluating Prudent Additions to Transfer Capability

Part 2 of the ITCS evaluated the future energy adequacy of the BPS based on past weather conditions occurring again in 2033. Specifically, the study applied 12 past weather years to the 2033 load and resource mix using the current transfer capabilities as calculated in Part 1.[24] This future year (2033) was selected because interregional transmission projects typically require at least 10 years to plan and build but forecasting demand and resources beyond that timeframe becomes increasingly speculative and uncertain.

The study then evaluated the impact of additional transfer capability in mitigating the identified resource deficiencies during extreme events, thereby improving energy adequacy. The six-step process (see **Figure ES.4**) used in this evaluation is described in **Chapter 6**, culminating in a list of recommended additions. While there are several factors that transmission planners consider – including reliability, economics, and policy objectives – given NERC's role as the ERO, the ITCS focused solely on reliability, specifically in terms of energy adequacy and reserve optimization.

[24] Part 1 calculated current transfer capabilities for summer and winter based on 2024/25 projected system conditions using the area interchange method. Prudent additions do not account for any changes to the transmission network that are planned after winter 2024/25.

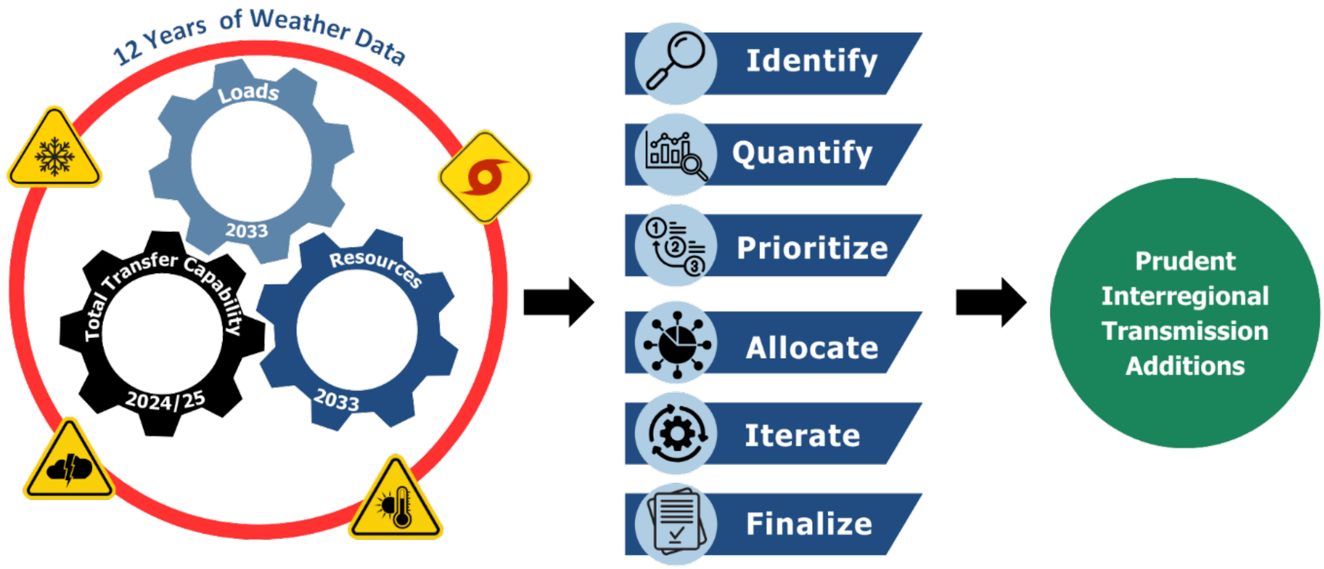

Figure ES.4: Part 2 Process Overview

Potential for energy deficiency[25] was identified in all 12 weather years evaluated and in 11 different TPRs, with a maximum resource deficiency of almost 19 gigawatts (GW) in ERCOT. Results from the energy margin analysis can be found in **Chapter 7**.

Potential for energy deficiency was identified in all 12 weather years evaluated.

These results were used to develop a list of recommended additions to transfer capability from neighboring TPRs, including geographic neighbors without existing electrical connections. As a result, 35 GW of additional transfer capability is recommended to improve energy adequacy under the studied extreme conditions throughout the United States.[26] **Figure ES.5** shows the existing and potential[27] new interfaces where additional transfer capability is recommended, and **Table ES.1** provides further detail. These additions are discussed in detail in **Chapter 7**.

35 GW of additional transfer capability is recommended to improve energy adequacy under extreme conditions.

[25] The terms "resource deficiency" and "energy deficiency" are used interchangeably throughout this report to describe instances in the study where available resources, including energy transfers from neighbors, are insufficient to meet the projected demand plus minimum margin level, described further in **Chapter 6**.

[26] The ITCS recommendations result from NERC working with the Regional Entities and in collaboration with the ITCS Advisory Group.

[27] The full list of potential new interfaces evaluated is shown in **Chapter 2**.

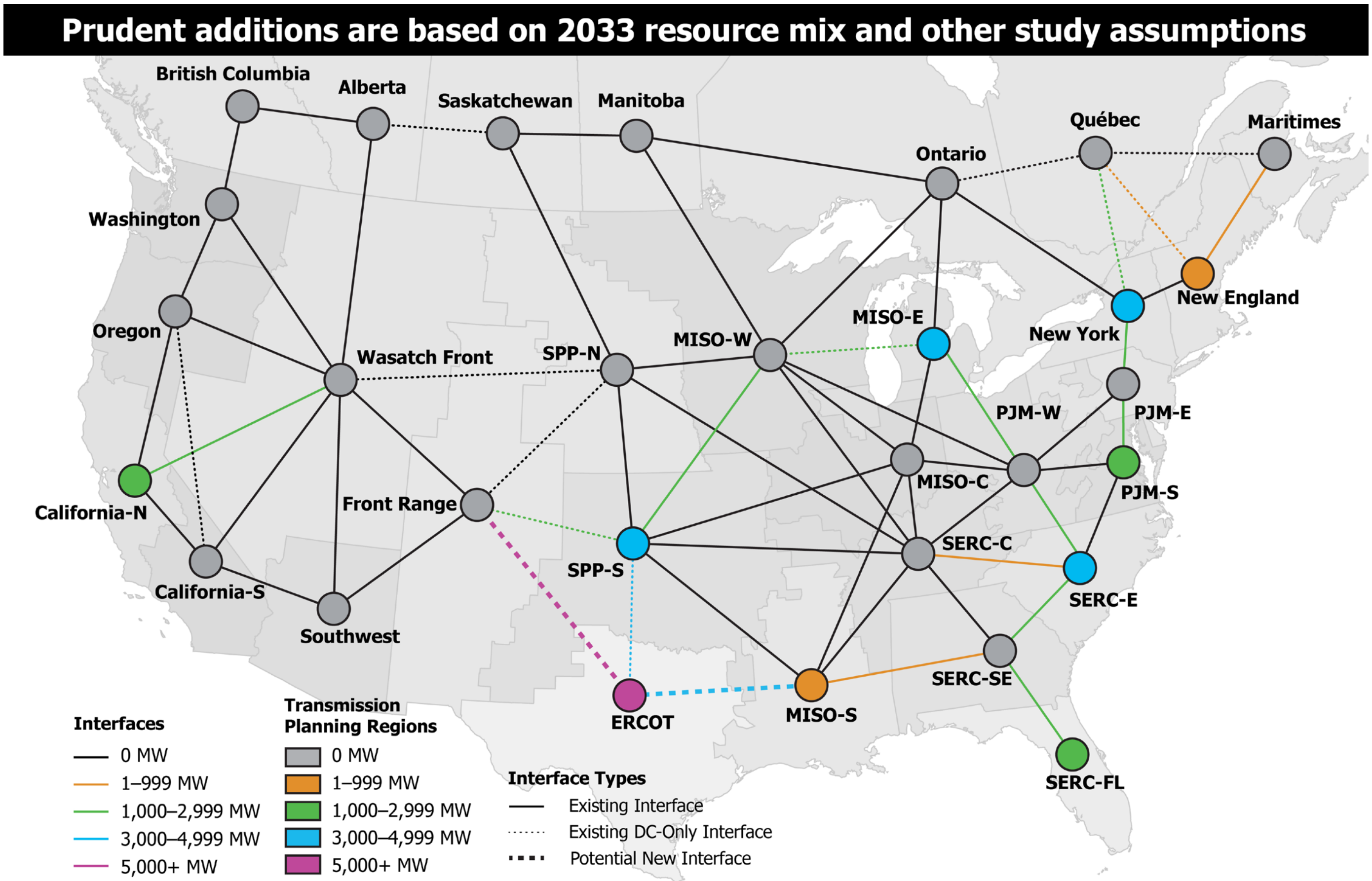

Figure ES.5: Prudent Additions to Transfer Capability

Increasing Energy Deficiency Hours

Table ES.1: Recommended Prudent Additions Detail					
Transmission Planning Region	**Weather Years (WY) / Events**	**Resource Deficiency Hours**	**Maximum Deficiency (MW)**	**Additional Transfer Capability (MW)**	**Interface Additions (MW)**
ERCOT	Winter Storm Uri (WY2021) and nine other events	135	18,926	14,100	Front Range (5,700) MISO-S (4,300) SPP-S (4,100)
MISO-E	WY2020 Heat Wave and two other events	58	5,715	3,000	MISO-W (2,000) PJM-W (1,000)
New York	WY2023 Heat Wave and seven other events	52	3,729	3,700	PJM-E (1,800) Québec (1,900)
SPP-S	Winter Storm Uri (WY2021)	34	4,137	3,700	Front Range (1,200) ERCOT (800) MISO-W (1,700)
PJM-S	Winter Storm Elliott (WY2022)	20	4,147	2,800	PJM-E (2,800)
California North	WY2022 Heat Wave	17	3,211	1,100	Wasatch Front (1,100)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
New England	WY2012 Heat Wave and two other events	5	984	700	Québec (400) Maritimes (300)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT (300) SERC-SE (300)
TOTAL				**35,000**	

In two cases, it was not possible to eliminate all energy deficiencies, even by increasing transfer capability, due to wide-area resource shortages. In ERCOT and California North, resource deficiencies remained even after increasing transfer capability by 14 GW and 1 GW, respectively.

The amount of transfer capability required to reliably serve customers during extreme conditions varied significantly, demonstrating that a one-size-fits-all requirement may be inefficient and ineffective.

The amount of transfer capability needed to mitigate energy adequacy risk varied significantly across the country. Specifically, some TPRs with relatively low transfer capability did not show resource deficiencies, such as SERC-SE and SERC-C with transfer capabilities of 11%-18% of peak load.[28] In contrast, other TPRs with relatively high transfer capability did show resource deficiencies. Examples include MISO-E and PJM-S, with transfer capabilities of 25%-44% of peak load. This is a direct result of the unique challenges that face each TPR, such as energy availability resulting from its resource mix, each neighbor's resource mix, and probable weather impacts. **Based on these findings, the ITCS concludes that a one-size-fits-all requirement for a minimum amount of transfer capability may be inefficient and potentially ineffective.**

[28] These TPRs did not show resource deficiency even in the higher margin sensitivity analysis, underscoring the importance of holistic transmission and resource planning.

The ERCOT system had the most significant energy deficiency and the greatest volume of recommendations for increased transfer capability. Recommendations for prudent increases to transfer capability total approximately 14 GW between the ERCOT-Front Range, ERCOT-SPP South, and ERCOT-MISO South interfaces. These additions address, in part, energy deficits across 135 total hours in the 2033 case, the most severe of which was a shortfall of 19 GW during extreme cold weather. The identified prudent additions also support and provide mutual benefits to resolve energy deficits in the SPP South and MISO South areas. While significant advancements have been made at the state-level and through new NERC winterization standards, better performance should be observed to gain confidence in the performance of natural gas generation during extreme cold weather.

Again, future resource assumptions are pivotal in ascertaining the amount of prudent additions needed. If fewer resources are assumed, many TPRs would exhibit energy deficiencies, as shown in the "Tier 1 Only Resource Mix" sensitivity in **Chapter 8**. This could limit the ability to support neighboring TPRs during extreme weather events. Conversely, if more resources are assumed, the need for prudent increases to transfer capability is reduced. The 2033 "Replace Retirements" case, which is derived from 2023 LTRA data, strikes a balance to appropriately assess energy adequacy risks and inform recommended additions. The specific resource assumptions can be found in **Appendix E**. Resource projections may shift over time with new technologies, market conditions, or policy directives. These dynamics, as well as changes to load growth forecasts, highlight the need for this type of analysis to be repeated in future LTRAs.

Various Options to Address Prudent Addition Recommendations

When it comes to addressing the identified risks, entities have various tools at their disposal. While the ITCS identifies prudent additions as one means of addressing extreme condition vulnerabilities, these needs can be addressed in a variety of ways:

Planners have multiple options to mitigate identified energy deficiencies and should consider the impacts of each option.

- **Internal Resource Development**: Adding internal resources, such as generation or storage, can reduce the need to rely on the transfer of energy from external resources. Importantly, these resources should not be subject to the same common-mode failures as extreme conditions may impact multiple parts of the system simultaneously. For example, adding solar resources may not reveal significant reliability benefits if energy deficits are expected in the early morning or evening hours of a wide-area cold weather event.
- **Transmission Enhancements to Neighboring TPRs**: Building new transmission lines or increasing transfer capability with, for example, grid enhancing technologies can provide critical access to external energy resources that may not be simultaneously impacted by the extreme conditions; however, this approach necessitates:
  - **Resource Evaluations**: Each neighboring TPR must be assessed to verify that sufficient, reliable generation resources are available to support the needed energy transfers during the critical periods. Building transfer capability between systems that are simultaneously resource-deficient will not improve energy adequacy during those extreme conditions.
  - **Permitting and Siting Requirements**: Transmission projects require extensive regulatory processes including permitting, siting, and often complex cross-jurisdictional agreements.
  - **Cost-Allocation Mechanisms**: Since transmission projects serve multiple stakeholders, clear and fair cost-allocation structures are essential to advance these projects efficiently.
- **Demand-Side Management and Resilience Initiatives**: In some cases, the need for additional transmission transfer capability can be mitigated by strategic demand-side solutions. Examples include:

- **Demand Shifting**: Encouraging shifts in demand to non-peak periods through rate structures or operational adjustments.
- **Energy Efficiency**: Achieving reduction in demand through implementation of new technologies.
- **Targeted Demand Response**: Designing programs specifically for extreme conditions, where demand reduction can alleviate stress on the grid.
- **Enhanced Storage Deployment**: Providing backup capacity in the form of storage that can release energy to the grid during peak demand, reducing reliance on external transmission sources.

Planners should consider all options and balance reliance on external resources vs. internal resources, noting that there may be better options than an overreliance on one or the other.

How to Use this Report

This report is a tool for envisioning and planning the future of a more resilient and reliable grid. While the ITCS offers critical insights, its findings should be considered as foundational insights for further study, discussion, and decisions on regulatory and legislative solutions. While the study highlights specific needs to improve resilience under extreme conditions, NERC encourages flexibility in meeting these needs through various approaches, including enhanced collaboration with regional planning entities, careful alignment with FERC and state policies, and consistent stakeholder engagement to effectively assess, refine, and execute strategies.

The ITCS is designed to explore reliability under extreme conditions, such as severe weather or peak demand. It is not a general assessment of routine operations or a prescription for addressing routine grid concerns. The study's conclusions are, therefore, relevant for identifying high-stress scenarios and should be used accordingly. Below is guidance for policymakers, planners, and stakeholders on how to best use this study's recommendations.

Like all reliability studies, understanding the study scope and future resource and transmission assumptions is critical.

Understand how best to interpret the recommendations for prudent additions. Before pursuing new transmission projects, system planners and stakeholders should first identify existing projects in the planning, permitting, or construction phases that could address some or all the transmission needs outlined in the ITCS. Once completed, these in-progress projects may reduce or eliminate the need for additional transmission capability in certain areas, reinforcing the value of these projects as part of the broader solution.

The findings identify directional, not prescriptive, guidance. The ITCS provides a roadmap for understanding where transmission may need enhancement but does not mandate specific projects or a minimum level of transfer capability. Instead, the findings are directional, helping stakeholders identify where improvements could be most impactful without imposing specific requirements. This flexibility enables industry stakeholders and policymakers to consider the best solutions for their unique needs and resources.

This study's recommendations should be considered as a starting point, prioritizing those areas where the study suggests significant reliability improvements. Policymakers should look at these areas with an open perspective toward potential solutions — whether that involves building additional resources, increasing transmission, or managing demand — to create a resilient approach that aligns with regional conditions and economic viability.

Policymakers should consider the barriers to achieving the prudent additions identified in the ITCS. Policy, regulations, and coordination considerations can create significant challenges in the development of transmission. The study reinforces the value of interregional transmission for managing extreme conditions and supporting an evolving energy mix. However, realizing these benefits requires coordinated policy support. Policymakers, in consultation with Planning Coordinators, should consider potential enhancements to current frameworks, such as establishing a process or forum for addressing large, multi-regional transmission projects. Such a forum would enable collaboration on cost-sharing, permitting, and regulatory hurdles, among other issues. Given the cost-intensive nature of transmission projects, policymakers should prioritize those solutions with the broadest benefits. Wide-area transmission planning could support a more equitable approach to cost allocation and decision-making, ensuring that investments are balanced with the collective resilience needs. Better valuation of the reliability benefits to all impacted parties can help identify the most impactful projects. Regulations including siting and permitting also need to be addressed. Finally, operational tie agreements need to be reviewed and considered by Transmission Planners and Transmission Operators. Market-to-market and seams issues must be resolved to enable flows at required critical times. Different regulatory environments can make achieving some of the recommendations difficult, but some TPRs are exposed to risks that require solutions.

A one-size-fits-all approach may not be effective in achieving the needed transfer capability. When considering a minimum transfer capability requirement, the study's findings do not support a universal minimum transfer capability. A blanket requirement could lead to inefficient investments in areas where transmission needs are already met or could fail to address the identified energy deficiency risks. For example:

- Some TPRs with high levels of transfer capability may require further enhancements due to high demand or significant renewable integration.
- Other TPRs with lower transfer capability may already have adequate resources to meet reliability needs, even under extreme conditions.
- Other TPRs may need additional energy, but transfer capability could be ineffective because neighboring TPRs do not have sufficient surplus energy during the times of need.

Each TPR's unique footprint should drive decision-making. The study's flexibility allows TPRs to identify and address specific vulnerabilities, ensuring that investments are efficient, targeted, and effective in achieving the desired level of reliability.

Use of the ITCS can foster collaboration between utilities, regional planning organizations, and state regulators and develop forward-thinking solutions for resource mix vulnerabilities. The study underscores that reliability challenges cannot be solved with a single approach. Rather, a combination of strategies — adapted to meet the needs of each TPR — will create a more resilient, adaptable grid for the future. Reliability planning is an ongoing process. As technology advances, transmission plans unfold, and the resource mix evolves, this study should be revisited, with findings used to refine and adapt future transmission and resilience strategies. Updates will be incorporated into future LTRAs.

The ITCS offers critical insights to help stakeholders understand and prepare for extreme scenarios. The findings emphasize a balanced, flexible approach to resilience, where transmission is an important but not exclusive solution. By considering these recommendations thoughtfully and holistically, stakeholders can make decisions that meet today's challenges and build a foundation for a reliable, adaptable energy system for the future.

Study Lessons

Increasing Need to Conduct Wide-Area Energy Assessment and Scenario Development

- ✓ Ensuring energy deliverability requires more than transfer capability and transmission tie-lines; resources must be readily available to provide surplus energy.
- ✓ Adding scenarios and probabilistic energy analysis can provide more robust results, introducing different sets of resource and demand assumptions. Assessing the results of various scenarios can provide a range of options and highlight areas of greatest need.
- ✓ A consistent approach to transfer capability studies and calculations advances industry’s ability to study the wide-area impacts induced by wide-area weather events. Most importantly, this consistency ensures that one area is not counting on excess generation from their neighbors when the neighbors are also experiencing the same weather impacts and are unable to share.

Increasing Need to Fully Incorporate Weather Impacts in Assessments

- ✓ Risks due to weather are becoming more significant. Weather impacts several TPRs simultaneously, so planning entities must collaborate to study the wide-area impacts on the system and plan accordingly.
- ✓ With an increasing wind, solar, and storage fleet, weather events may present greater impacts to resource availability unless solutions are put in place.

Changes in System Planning Evaluation

- ✓ In some instances, adding transfer capability was insufficient due to resource limitations. It is essential to plan transmission and resources together to prevent over-dependence on one versus the other.
- ✓ Wide-area system studies are essential to increase transfer capability without compromising reliability. Detailed studies must be conducted to identify reinforcements needed to meet reliability criteria before selecting solutions.

Barriers to Transmission Development Present Risk to Timely Solutions

- ✓ Appropriate projects and solutions must be included while considering all factors including reliability, cost, and policy objectives.
- ✓ Siting, permitting, and cost allocation and recovery present significant barriers to interregional transmission. Addressing these challenges will enable planning entities to implement effective solutions.
- ✓ Policy and planning processes need to be more adaptive. The ITCS underscores the importance of a more coordinated approach to regional and interregional planning, particularly as the resource mix changes and the grid faces increasing stress from extreme weather. While there are several examples of planned projects and emerging interregional planning efforts, existing planning structures may be insufficient for addressing broader transmission needs. Establishing a wide-area planning forum could facilitate more collaboration among stakeholders.

Common Data Sets, Case Development, and Consistent Metrics Are Essential Components of Future Assessment Strategy

- ✓ More data will be needed to assess system risks in the future.
- ✓ Future resource projections are highly uncertain and as underlying assumptions change, so do the results; therefore, it is essential to establish a cadence to study the system periodically and identify risks.
- ✓ The impact of Canadian systems is crucial for assessing the reliability of U.S. systems and vice versa.

Chapter 1: The Reliability Value of Transfer Capability

Recent Extreme Weather Events Show Reliance on Neighbors

Analyses of extreme weather events, such as Winter Storms Uri and Elliott and the heatwave experienced in the Western Interconnection in 2020, as summarized below, have reinforced the critical need for neighboring systems to exchange energy with one another when needed to minimize reliability impacts. During these events, transfer capability, or the lack thereof, had a direct impact on the magnitude and duration of firm load shed. These recent extreme weather events have highlighted the importance of the interregional transmission network in improving reliability by transferring surplus energy between TPRs to mitigate shortfalls. In short, these events underscore the types of challenging scenarios that system operators must be equipped to overcome:

- The **Western Interconnection Heatwave**, from August 14–19, 2020, affected much of the Western Interconnection as noted in the associated report.[29] Several Balancing Authorities declared energy emergencies and the California Independent System Operator (CAISO) shed more than 1,000 MW of firm load. In addition to the primary cause of extreme and widespread heat, this report notes two secondary causes related to interregional transfer capability limitations.
- **Winter Storm Uri** impacted the BPS in the Electric Reliability Council of Texas (ERCOT) and Eastern Interconnections during February 8–20, 2021. As noted in the associated report,[30] extreme cold temperatures, freezing precipitation, and generator outages led the ERCOT operators to order firm load shed for nearly three consecutive days, peaking at 20,000 MW on February 15.[31] The Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO) also declared transmission emergencies and shed firm load in lower quantities and for shorter durations. Firm load shed during this event was directly related to the transfer capability from TPRs with surplus energy into the TPRs with energy shortfalls, as the eastern portion of the continent was not experiencing extreme conditions and had surplus energy to provide.
- **Winter Storm Elliott** impacted the BPS in the Eastern Interconnection from December 21–26, 2022. As noted in the associated report,[32] several Balancing Authorities in the Southeast United States shed firm load during the event to maintain reliability. This firm load shed in total (at different points in time) exceeded 5,400 MW, the largest controlled firm load shed recorded in the history of the Eastern Interconnection. Even though interregional transfers were limited by availability of resources in neighboring TPRs, energy transfers from Florida, New York, and the Midwest into the most heavily affected TPRs almost certainly reduced the amount and duration of firm load shed that would otherwise have been required.

Setting the Stage for Transfer Capability Analysis

Recognizing the transforming grid and the reliability impacts of the extreme events summarized above, the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) have examined transfer capability, each considering a variety of factors. The DOE released the *National Transmission Needs Study* (October 2023)[33] as part of its State of the Grid report, which is required by Congress at least every three years to assess national electric transmission constraints and congestion. This DOE study assessed current and near-term transmission needs through 2040 across 13 geographic regions.

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[29] August 2020 Heatwave Event Report.pdf (wecc.org)

[30] The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission

[31] Ibid.

[32] Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022 | Federal Energy Regulatory Commission (ferc.gov)

[33] https://www.energy.gov/gdo/national-transmission-needs-study

In 2022, FERC initiated a proceeding regarding interregional transfer capability transmission planning and cost allocation and hosted a staff-led workshop on December 5–6, 2022.[34] The workshop considered whether a minimum requirement for interregional transfer capability should be established and, if so, how to identify the right levels of transfer capability. Some panelists spoke in favor of a minimum interregional transfer capability requirement for each planning region, such as a percentage of peak load, noting benefits of new transmission beyond pure reliability benefits. Other panelists encouraged a more deliberate approach that would study the needs of each area rather than a one-size-fits-all requirement. The ITCS team took this latter approach to ensure reasonableness of any recommendations, recognizing that a simple percentage requirement may not produce desired outcomes across all TPRs. For instance, some of the considerations lost in the former approach include ignoring dynamic transmission use patterns, varying resource mixes, regional network topology, size of the largest contingency, and periods of stress that do not always correlate to peak demand.

Recently, FERC issued Order No. 1920 "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation" to revise the *pro forma* Open Access Transmission Tariff.[35] In particular, FERC revised tariff requirements pertaining to regional and local transmission planning and cost allocation, including requiring long-term regional transmission planning as well as other reforms to improve the coordination of regional transmission planning and generator interconnection processes. NERC filed comments supporting FERC's examination of transmission planning under the changing resource mix and stated, "Transmission will be the key to support the resource transformation enabling delivery of energy from areas that have surplus energy to areas which are deficient. The frequency of such occurrences is increasing as extreme weather conditions resulting from climate change impact the fuel sources for variable energy resources. Regional transmission planning can ensure that sufficient amounts of transmission capacity will be needed to address these more frequent extreme weather conditions."[36]

Transfer capability is the amount of power that can be reliably transported over a given interface under specific conditions. Planning engineers model elements on the system and simulate how power flow will impact the transmission system under a series of reliability tests. These studies provide assurance that the system is stable and within predefined ranges. As stated in NERC's 2013 Adequate Level of Reliability (ALR)[37] filing, "[a] target to achieve adequate transmission transfer capability and resource capability to meet forecast demand is an inherent, fundamental objective for planning, designing, and operating the BES [Bulk Electric System]."[38]

Each Interconnection consists of a network of transmission lines for redundancy, avoiding reliance on a single path. Electricity transfers flow over parallel paths, introducing a variety of operating constraints. Consequently, planning studies must be performed to ensure that these transfers will not jeopardize the reliability of an Interconnection. Additional details regarding the ITCS evaluation of transfer capability can be found in **Chapter 2**.

The Part 2 recommendations to increase transfer capability are prudent to strengthen reliability but may go beyond what is required to meet current Reliability Standards. Additional transmission studies will be needed once specific projects or other actions are identified to address these recommended increases to transfer capability.

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[34] Staff-Led Workshop Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements, Docket No. AD23-3-000 (December 5-6, 2022)

[35] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, Order No. 1920, 187 FERC ¶ 61,068 (2024), at https://ferc.gov/media/e1-rm21-17-000.

[36] NERC Comments, Docket No. RM21-17-000; also Order No. 1920, at page 94 (discussing comments such as NERC's pertaining to transmission under the changing resource mix); and ibid., at page 586 (referencing NERC comments on potential studies pertaining to transmission)

[37] For more information regarding ALR, see the informational filing on the Definition of "Adequate Level of Reliability" (filed May 10, 2013), at https://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf.

[38] Ibid. at Exhibit A, page 3

Chapter 2: Overview of ITCS Scope and Terminology

The purpose of this study is to perform a U.S.- and Canada-wide assessment of the reliable transfer capability of electricity between neighboring Transmission Planning Regions. While the congressional mandate[39] applies to the United States, any analysis would be incomplete without a thorough understanding of the Canadian limits and available resources. The Western Interconnection includes the Canadian provinces of Alberta and British Columbia. Similarly, the Eastern Interconnection contains numerous transmission lines between the United States and Manitoba, New Brunswick, Ontario, and Saskatchewan, plus direct current (dc) connections with Québec.

The ITCS is the first comprehensive study of transfer capabilities between adjacent TPRs, including neighboring Interconnections, making it unique. Further, to perform the future-looking energy assessment to determine potential deficiencies, the study used 12 years of data to capture a wide variety of operating conditions and account for historical weather events. It is also unprecedented in scope, as it used internally consistent assumptions and modeling approaches for all neighboring interfaces and TPRs across interconnected North America. This broad view is key when evaluating the support that may be available to assist in meeting energy adequacy while considering transfer capability limitations. Ultimately, the goal is to incorporate this analysis into future LTRAs to provide a more comprehensive picture of each TPR's reliability risks.

Within this strategic context, the key objectives of the ITCS are the following:

- Conduct a comprehensive, repeatable study of existing interregional transfer capability across the contiguous United States and Canada between each TPR to assess currently available transfer capability (Part 1) and the future need for additional transfer capability (Part 2) to ensure reliability under various system conditions, including extreme weather.
- Provide analysis-driven recommendations for additions to the amount of energy that can be transferred between neighboring TPRs (Part 2).
- Recommend approaches to achieve and maintain an adequate level of transfer capability (Part 3).
- Actively engage stakeholders and gather inputs, assumptions, and conditions from Regional Entities, industry, and the Advisory Group to ensure a comprehensive and inclusive study.
- Identify expectations for next steps and continuing analysis of transfer capability to reinforce future NERC assessments, including trends.

Study Scope

Part 1 consists of transfer capability analysis for forecasted 2024 summer and 2024/25 winter conditions. This transfer capability analysis produced a set of transfer capability limits between neighboring TPRs. More information can be found in the Part 1 scoping document.[40]

As shown in **Figure 2.1**, the Part 1 results were vital inputs to Part 2, which identified TPRs that are deficient under the study scenarios, including extreme weather events. TPRs with an energy deficiency were first evaluated to determine if there is sufficient transfer capability to cover the deficiency, then prudent additions to transfer capability were recommended. Part 3 identified various actions that could be taken by policy makers, industry leaders, and the ERO Enterprise to meet and maintain transfer capability.

[39] H.R.3746 - 118th Congress (2023-2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress
[40] ITCS Transfer Study Scope Part 1 (nerc.com)

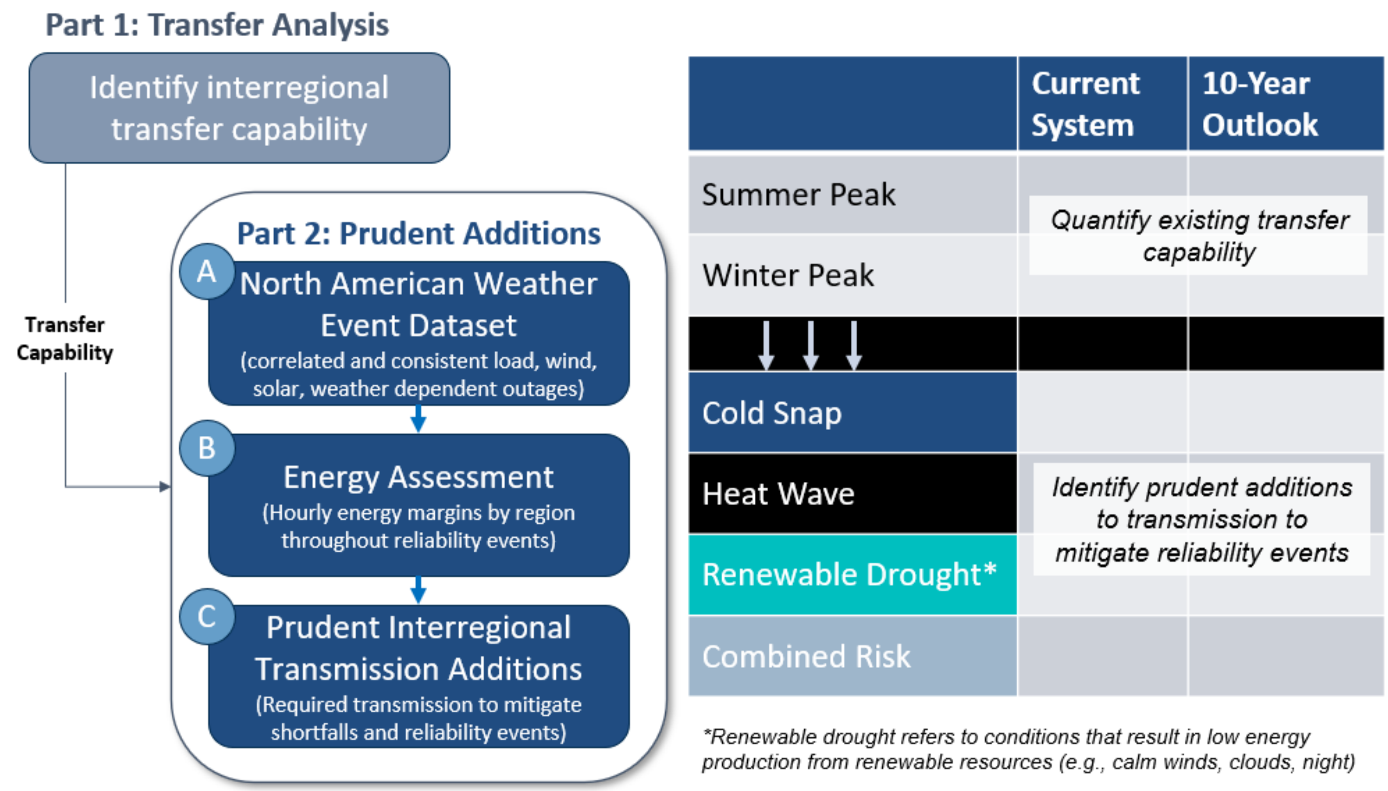


Figure 2.1: Additional Part 2 Details

Part 2 was divided into four tasks to further develop these recommendations:

1. Develop a North American dataset of consistent, correlated, time-synchronized load, wind and solar generation output, and weather-dependent outages.
2. Conduct an energy margin analysis to identify periods of tight supply conditions and potential resource deficiencies to be further evaluated.
3. Develop metrics and methods to identify which TPRs would benefit from increased transfer capability.
4. Quantify the amount of additional transfer capability recommended as prudent between each pair of TPRs to mitigate the resource deficiencies, deliberately evaluating whether neighboring TPRs had surplus energy available to transfer.

The following items were intentionally out of scope for this analysis:

- Probabilistic resource adequacy analysis was not conducted. While 12 years of weather conditions were considered, the study did not attempt to sample hundreds or thousands of potential generator outages and load conditions, nor did it assign probabilities to potential loss of load events. In short, the ITCS should not be considered a North American resource adequacy assessment.
- The relative merits of additional transfer capability versus local resource additions were not considered. Per the congressional directive, the ITCS focused on transfer capability as a mitigation for energy deficiencies. In practice, strengthening the energy adequacy of the BPS should consider a multi-faceted approach that can include adding new local resources (generation or storage), improving load flexibility (demand response), and/or increasing transfer capability.

- Part 2 used a simplified transmission model – often referred to as a "pipe and bubble" model – and did not perform a full nodal, security-constrained economic dispatch or power flow analysis. Instead, it leveraged the TTC values from the power flow analysis conducted in Part 1.

The Part 2 study used large hourly datasets, both publicly available and NERC proprietary, to quantify and visualize energy adequacy for each TPR across North America. These datasets were used to conduct an energy margin analysis that was used as part of the prudent additions process. Data was compiled to create a multi-year, hourly, time-synchronized dataset of load, wind, solar, hydro, and weather-dependent outages of thermal resources that collectively determine energy margins. The Part 2 scope[41] document contains additional details.

Stakeholder Participation

The Fiscal Responsibility Act of 2023 required that NERC, working with the full ERO Enterprise in the performance of the ITCS, consult with each transmitting utility that has facilities interconnected with another transmitting utility in a neighboring TPR. The Federal Power Act defines a transmitting utility as follows:

> *The term ''transmitting utility'' means an entity (including an entity described in section 201(f)) that owns, operates, or controls facilities used for the transmission of electric energy—*
> *(A) in interstate commerce*
> *(B) for the sale of electric energy at wholesale*

Even though a subset of utilities classified as transmitting utilities were required to be consulted, NERC has adopted a broader approach to consult with and inform all stakeholders, such as Transmission Planners, Planning Coordinators, Transmission Operators, Transmission Owners, state/provincial/federal regulators, and industry trade groups. Due to the sheer size and number of stakeholders involved, as shown in **Figure 2.2**, a comprehensive stakeholder management plan was developed to keep each stakeholder informed and engaged.

[41] ITCS SAMA Study Scope - Part 2 (nerc.com)

Figure 2.2: ITCS Stakeholder Engagement

An ITCS Advisory Group was assembled with functional and geographic diversity to gather industry input and ensure a comprehensive study. Participants represented stakeholders including FERC, DOE, National Resources Canada, the Electric Power Research Institute (EPRI), Independent System Operators, and a variety of utilities.[42] The monthly meetings were open with meeting schedules and materials posted publicly. The ITCS Advisory Group's role is to provide input to the ERO Enterprise regarding ITCS design, execution, and recommendations.[43] This group provided insights, expertise, and inputs to the study approach, scope, and results.

In addition, an ITCS letter was broadly distributed to the industry on February 9, 2024, to provide direct outreach to all transmitting utilities. A second letter was distributed on September 24, 2024, to remind entities of the study results available. Each Regional Entity also worked closely with Planning Coordinators and other industry technical groups in their respective regions.

Throughout the ITCS process, NERC reviewed stakeholder comments and incorporated input where appropriate.

[42] A full roster is posted at ITCS_Advisory_Group_Roster.pdf (nerc.com).
[43] ITCS_Advisory_Group_Scope.pdf (nerc.com)

Transmission Model

The TPRs used for this study are shown in **Figure 2.3**. In some cases, traditional planning areas defined in FERC's Order No. 1000,[44] which generally do not follow state boundaries, were sub-divided to provide more granular analysis of potential transfer capability limitations, especially under specific weather scenarios. For example, SPP has an expansive geographic footprint stretching from the border of Saskatchewan into parts of Texas. Weather and other operating conditions vary widely over this extended region. Further, construction practices can vary based on expected temperatures, as noted in the Winter Storm Uri report. Significant transmission constraints exist within these larger planning areas, some of which have played a major factor in weather events, and it is important for the ITCS to reflect such limitations to interregional transfer capability. Additionally, this more granular approach allows recommendations at more precise locations. The studied TPRs were large enough to analyze interregional reliability issues while avoiding an overly granular analysis of local constraints.

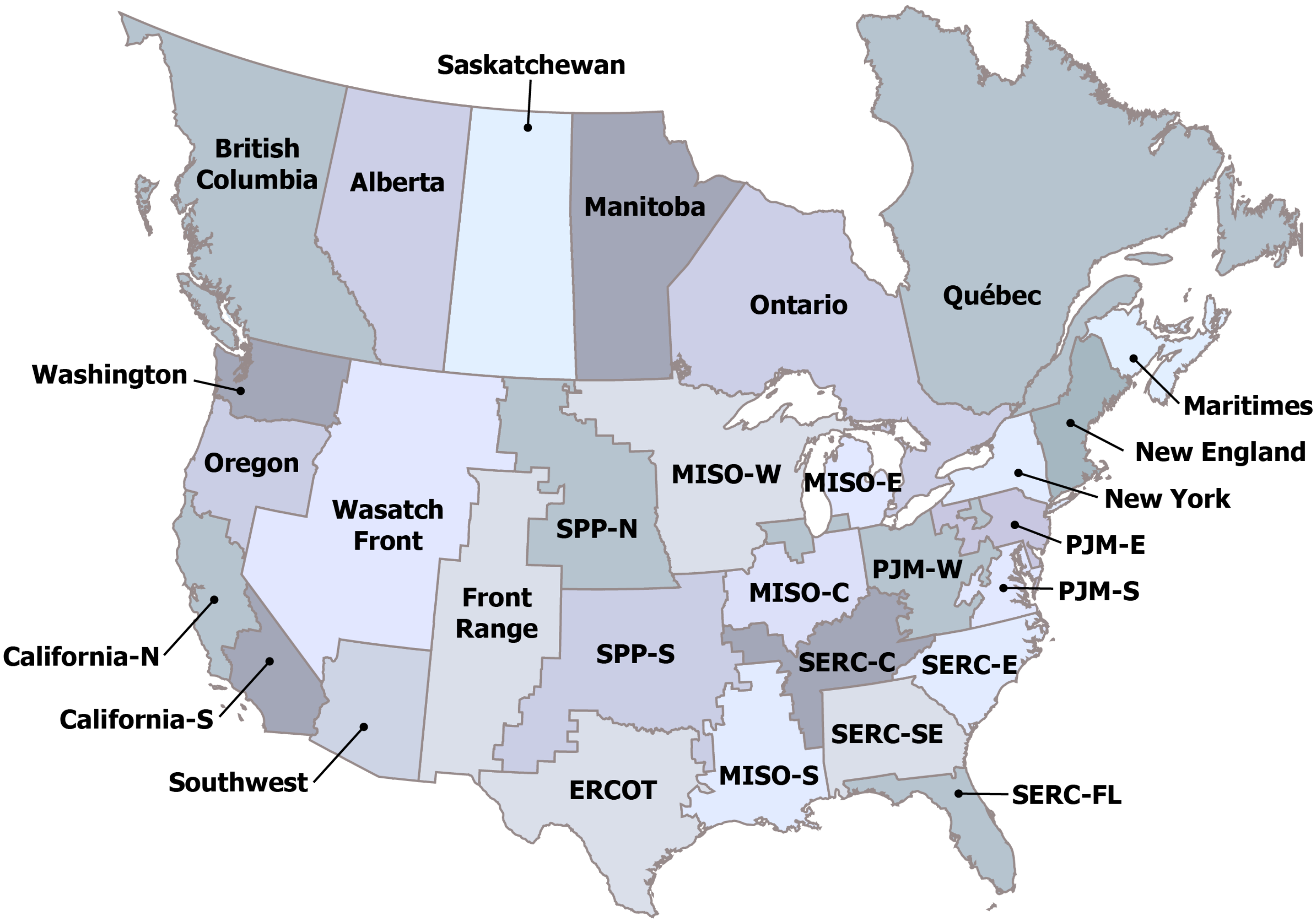


Figure 2.3: Transmission Planning Regions

In Part 1, a set of interfaces was identified that included all pairs of neighboring TPRs so that transfer analysis from source (exporting) TPR to sink (importing) TPR and vice versa could be performed. In this context, only electrically connected neighboring systems were evaluated.

To more accurately reflect the ability of a TPR to simultaneously import energy from multiple neighbors, Part 1 also analyzed total import capabilities of each TPR. Though not part of the mandate, which directed evaluation of transfer

[44] More information can be found on FERC's website at www.ferc.gov.

capability between neighboring TPRs, this evaluation is technically necessary to appropriately model system capability in Part 2 of the ITCS.

For Part 2, a representation of the transmission system was created, with transfer capability limits applied to each interface and a total import interface constraint for each TPR. These transfer capability limits were calculated in Part 1, which analyzed 2024 summer and 2024/25 winter conditions. The Part 2 model is not intended to represent actual energy flows, nor does it calculate generation shift factors, line impedances, individual line loadings or ratings, or other transmission considerations.

A visual representation of the transmission topology is provided in **Figure 2.4**, which shows each of the existing transmission interfaces represented as a solid line. Dotted lines represent existing dc-only interfaces between TPRs, including connections between Interconnections, the Oregon to California South dc tie (Path 65), and between MISO West and MISO East near the Straits of Mackinac.

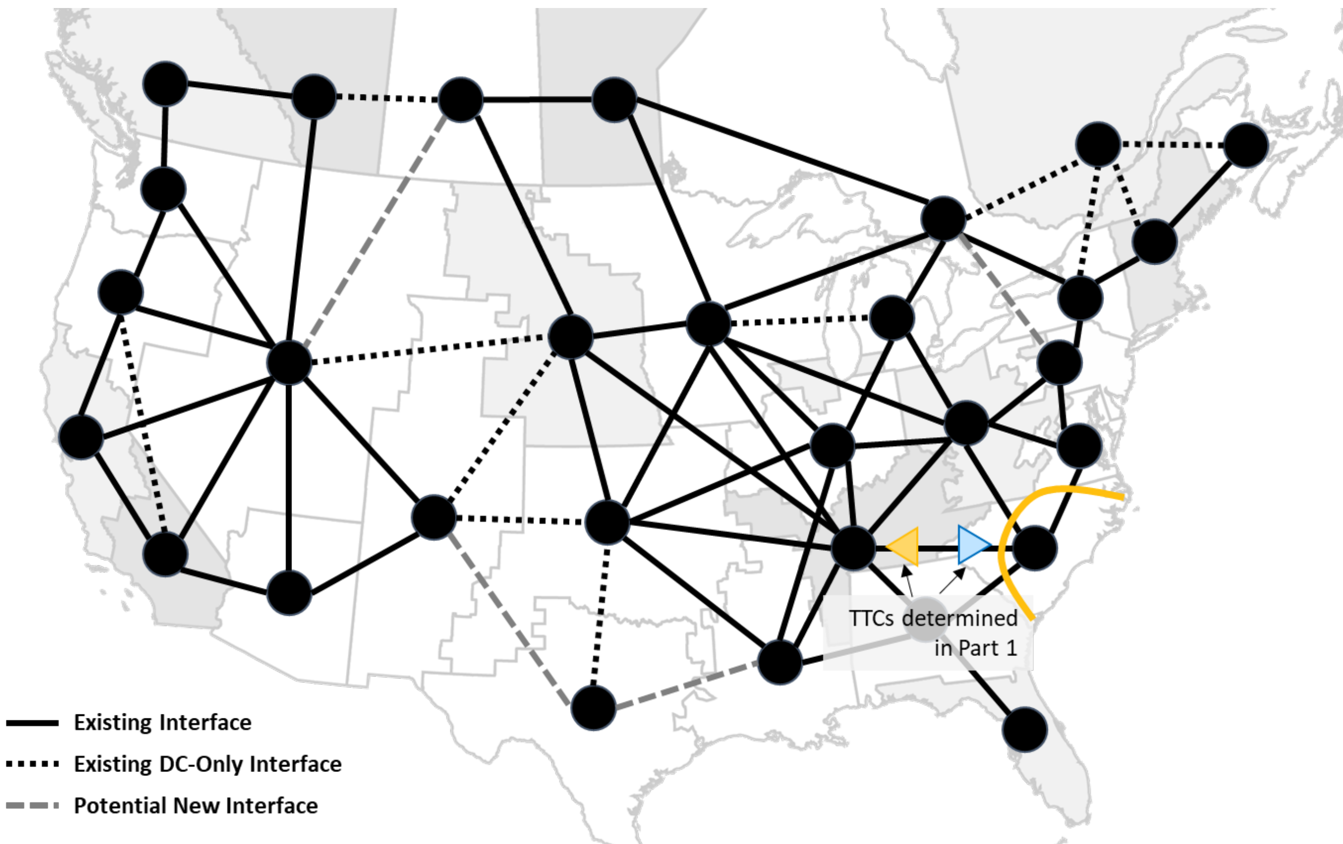


Figure 2.4: Transmission Interfaces

The model also included potential new transmission interfaces between geographically adjacent TPRs even if no transmission linkage currently exists. These candidates for prudent additions are represented as dashed grey lines in **Figure 2.4**.

In the Part 2 model, each interface has a transfer limit in the forward flow direction (e.g., from SERC-C to SERC-E) and a potentially different limit in the reverse flow direction (e.g., from SERC-E to SERC-C). A total import interface was also included in the model, represented by the yellow arc in **Figure 2.4**. In addition to the limits across individual interfaces, this total import interface limited the simultaneous imports from all neighboring TPRs. This limit was also calculated in the Part 1 Transfer Analysis by decreasing generation in each sink (importing TPR) and increasing generation proportionally across all neighboring sources (exporting TPRs). Since the Part 2 model does not consider the physics of energy flows across the transmission network, this interface was necessary to reflect limitations to simultaneous transfer capability.

Transfer Capability

Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions. The units of transfer capability are in terms of electric power, generally expressed in MW. In this context, area refers to the configuration of generating stations, switching stations, substations, and connecting transmission lines that may define an individual electric system, power pool, control area, subregion, or region, or a portion thereof.[45]

However, while the transfer capability is a measured amount in MW, it does not have a one-to-one correspondence with what new transmission facility (or facilities) could be added. For example, to increase transfer capability by 200 MW between two areas, the areas may evaluate and find that a single new line with a rating of 200 MW would not be the sole change to the network and a combination of facilities may need to be added or improved to support the increase in energy transfers between areas. Determining a solution is complex and may involve additions or modifications to multiple transmission facilities, while taking into account the other planning considerations.

In both the planning and operation of electric systems, transfer capability is one of several performance measures used to assess the reliability of the interconnected transmission systems and has been used as such for many years. System planners use transfer capability as a measure or indicator of transmission strength in assessing interconnected transmission system performance. It is often used to compare and evaluate alternative transmission system configurations. System operators use transfer capability to evaluate the real-time ability of the interconnected transmission system to transfer electric power from one portion of the network to another or between control areas. In the operation of interconnected systems, “transfer” is synonymous with “interchange.”[46]

The intent of a transfer capability calculation is to determine a transfer value with the following general characteristics:

- Represents a realistic operating condition or expected future operating condition
- Conforms with the requirements of the transfer capability definitions
- Typically considers single contingency facility outages that result in conditions most restrictive to electric power transfers[47]

Transfer capability is calculated using computer network simulation software to represent anticipated system operating conditions. Each such simulation reflects a snapshot of one specific combination of system conditions. Transfers between two areas are determined by increasing transfers from a normal base transfer level until a system limit is reached.[48]

The ITCS calculated TTC by determining the amount of additional energy transfers that can be added to base transfers already modeled while respecting contingency limits. Reliable operation insists that the grid must be operated to withstand the worst single contingency while remaining within system operating limits, noting that the most severe

[45] NERC Transmission Transfer Capability Whitepaper, 1995, at Transmission Transfer Capability May 1995.pdf (nerc.com)
[46] Ibid.
[47] Ibid.
[48] Ibid.

single contingency may be in a neighboring area. Category P-1 single contingencies were used in this study, as defined in NERC Reliability Standard TPL-001-5.1.[49]

TTC is the total amount of power that can be transferred between two areas. TTC is made up of two parts, as shown in **Figure 2.5**:

- Base Transfer Level (BTL): Typically, scheduled power flows between areas in the starting case. These are usually referred to as base flows.
- First Contingency Incremental Transfer Capability (FCITC): FCITC simulates an incremental transfer between areas under a single contingency until a system limitation is reached. In other words, it is the amount of energy that can be reliably transferred.

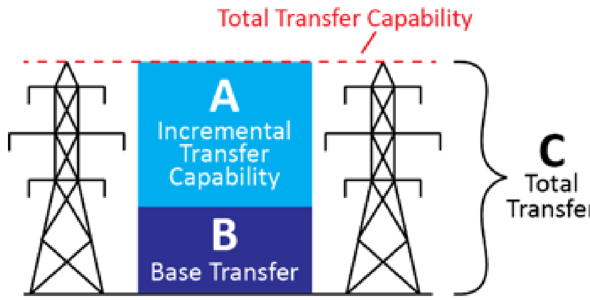


Figure 2.5: Total Transfer Capability

In simple terms, **TTC = BTL + FCITC**. The TTC method enables a consistent calculation across the entire study footprint, although these calculations are different than path limits which are used by some entities.

In Part 1, the BTL for each interface was derived, where available, from the scheduled interchange tables provided with each of the study cases. This was compared to the desired interchange provided in the study cases to cross-check. Where required, adjustments were made to account for additional schedules and market re-dispatch based on load ratio where a Balancing Authority spanned multiple TPRs. Where the detailed scheduled interchange tables were unavailable, BTL was approximated using the actual line flow across each interface and cross-checked against the scheduled interchange. This approach was endorsed by the ITCS Advisory Group.

The transfer analysis, which calculates the FCITC, involves simulating an incremental increase in transfers from source to sink while applying relevant contingencies and monitoring criteria (both described in **Chapter 3**), until a criteria violation is found. The last incremental step prior to finding a criteria violation is reported as the FCITC. A voltage screening was performed for each transfer analysis to validate the FCITC limit found. Models reflecting this transfer amount were created and screened for voltage violations using applicable contingencies. If a voltage violation was found, the FCITC was reduced, and the process repeated until the voltage violation was resolved. All results were vetted by the Regional Entities through the respective Planning Coordinators.

Prudent Additions to Strengthen Reliability

The Fiscal Responsibility Act of 2023 requires a recommendation of technically prudent additions to transfer capability between neighboring TPRs that would demonstrably strengthen reliability. Reliability is a broad concept, and significant aspects of required reliability are defined by NERC Reliability Standards and continually implemented through entities' planning, investment, and compliance processes. The ITCS examines transfer capabilities between adjacent TPRs under a variety of weather scenarios and operating conditions that reflect potential extreme conditions, such as those observed during recent events. For this reason, the ITCS goes beyond existing reliability studies and is an avenue to improve the delivery of energy under extreme conditions. In fact, when NERC assesses system reliability, it often reviews capacity and energy scenarios to identify system risk. This is a foundational activity at NERC, as a part of its mandate as the ERO, to assess risks to the BPS in the coming seasons and years.

[49] TPL-001-5 (nerc.com)

Determining exactly how much additional transfer capability is "prudent" can depend on the totality of factors and circumstances. FERC precedent[50] reflects that prudence means a determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances and at the relevant point in time. FERC has considered prudence in the context of specific, fact-based scenarios involving rates. For example, as part of examining the totality of circumstances, FERC has considered matters such as whether activities have enhanced the ability to restore service, achieved significant efficiencies, reduced costs or time delays, and/or made efficient use of resources to ensure reliability.

The ITCS identified where there are reasonable additions to transfer capability that would be expected to improve energy adequacy and thereby strengthen reliability. This is not intended to preclude entities from considering other factors, such as cost allocation or economic advantages.

To determine prudent additions to transfer capability and maintain focus on strengthening reliability, NERC, working with the Regional Entities, developed an approach so that consistent, objective, reasonable criteria could be applied. This process is described in **Chapter 6**.

Important Study Considerations

While the ITCS used engineering study approaches deployed within industry planning processes, it is not a planning study. Reliability, in the form of energy adequacy and operating reliability, is the sole focus of the ITCS and aligns with the ERO Enterprise scope and obligations, as well as the parameters defined in the Fiscal Responsibility Act. Unlike the ITCS, planning studies ensure that electricity is generated, transmitted, and distributed in a cost-effective, reliable, and sustainable manner, while meeting environmental and regulatory requirements.

Similarly, this reliability-focused study did not provide economic justification for new and/or upgraded transmission facilities. Rather, the study identified increases in transfer capability that can improve energy adequacy during extreme conditions. NERC recognizes that additional transmission has more quantifiable benefits than purely the reliability benefits referenced in this study. For example, these benefits may include factors such as cost savings by providing access to lower-cost sources of generation, voltage support, blackstart, and policy goal implementation. Nothing in the study is intended to preclude stakeholders and governmental authorities at federal, state, and local levels from evaluating those additional considerations.

The Fiscal Responsibility Act specifically required that prudent additions to transfer capability be recommended. Local solutions, such as additional resources in an energy-deficient TPR, were not considered in the ITCS. This study also does not recommend any particular transmission or generation projects, which may take the form of, but are not limited to, new ac or dc transmission facilities, upgrades to enable higher ratings, grid-enhancing technologies,[51] or a combination thereof.

The ITCS considered a range of scenarios to ensure robust study results. Sensitivity analysis was also performed to programmatically explore underlying risks. However, the ITCS is not an exhaustive study of all transmission limitations that may occur during real-time operations or under simultaneous transfers across multiple TPRs.

Due to the unprecedented scope of this study, Part 1 efforts were limited to steady-state power flow analysis using P-0 (no contingency) and P-1 (single contingency) scenarios as defined in NERC Reliability Standard TPL-001-5.1.[52] This approach is consistent with many other similar studies and was reasonable to meet the ITCS study needs and timeframe. In addition to the contingency analysis, a voltage screening was performed for each transfer at the valid

[50] See, e.g., *New England Power Co*., 31 FERC ¶61,047 at p. 61,084 (1985); and *Potomac-Appalachian Transmission Highline, LLC,* 140 FERC ¶61,229 at P 82 2012 (Sept. 20, 2012).

[51] This term references advanced technologies that include dynamic line ratings, power-flow control devices, and analytical tools.

[52] TPL-001-5 (nerc.com)

limit found using category P-1 contingencies. Notably, while known stability limits were included, the team did not complete short-circuit or stability analysis (i.e., voltage, transient, frequency). These limitations can be more restrictive than the results presented, which focus primarily on thermal and voltage limits. Further analysis is recommended in the future to determine appropriate solutions after a more comprehensive analysis is performed.

Similarly, in Part 2, a deterministic energy assessment of challenging weather conditions was chosen, rather than a probabilistic resource adequacy assessment. This industry-supported approach enables holistic evaluation of the impacts of actual extreme weather events.

This study does not satisfy any registered entity's obligation to perform studies under enforceable NERC Reliability Standards. This report also does not attempt to determine load or generator deliverability, available transfer capability (ATC), available flowgate capacity (AFC), the availability of transmission service, or to provide a forecast of anticipated dispatch patterns.

Finally, the ITCS represents a point-in-time analysis using the best available time-synchronized data. Changes to future resource additions, resource retirements, and/or transmission expansion plans have the potential to significantly alter the study results. As such, the study team recommends performing this study, documented in NERC's future LTRA reports, on a periodic basis to identify trends.

Chapter 3: Transfer Capability (Part 1) Study Process

This section details the study design, tools, case development, and analysis parameters for calculating current transfer capability. The study details were reviewed by various industry groups, including the ITCS Advisory Group and Regional Entities' technical groups and committees.

Base Case Development

The current transfer capability calculation was performed using relevant Eastern Interconnection and Western Interconnection base cases with consistent criteria and assumptions. System models representing Eastern and Western Interconnections were created to perform the analysis via base cases created through the MOD-032[53] process as a starting point for the following seasons:

- 2024 Summer
- 2024/25 Winter

Base cases are not required for the ERCOT and Québec Interconnections for this study, as they are only tied with the Eastern Interconnection via dc ties. Also, the dc ties from the Electric Reliability Council of Texas (ERCOT) to Mexico are treated as static, and the ERCOT-Mexico interface is not included in the scope of this analysis.

NERC issued data requests in November 2023 to all Planning Coordinators in the Eastern and Western Interconnections to provide base case updates. Planning Coordinators and Transmission Planners were requested to review these cases and to supply updates, including:

- New generation – At a minimum, generation with a signed Interconnection Service Agreement was included in the applicable cases.
- Planned retirements – Generation that has retired or has announced retirement was removed from the applicable cases.
- Load forecast adjustments – Cases were updated to use the most current load forecasts.
- Resource dispatch – Changes to reflect the most current resource plans were included.
- Facility ratings – Rating changes received, including enhancements since the cases were built, were included in the cases.
- Expected long-term facility outages – Facilities expected to be out of service were removed from the applicable cases.
- Transmission system topology updates – Changes to topology, including new facility construction, were included in the cases.
- Base transfers (interchange) – New or updated firm transfers were accounted for in the cases.

Contingencies

The transfer analysis simulated contingencies, namely the unplanned outage of system elements, to ensure that the system would remain reliable during the energy transfer. The following NERC Reliability Standard TPL-001-5.1[54] category P1 contingencies (100kV and above) were used for the transfer studies, namely:

- P1-1: Loss of individual generators,
- P1-2: Loss of a single transmission line operating at 100 kV or above, and

[53] MOD-032-1 (nerc.com)
[54] TPL-001-5.1 (nerc.com)

- P1-3: Loss of a single transformer with a low-side voltage of 100 kV or above

All contingencies meeting the above criteria within the source and sink TPRs were included in each transfer study, along with all contingencies within five buses from either the source or sink TPR.

Monitored Facilities and Thresholds

Facility monitoring criteria and thresholds were established to prevent undue limitation of transfer capability results based on heavily loaded, electrically distant elements. These practices followed industry-accepted methods to ensure that transmission facilities only minimally participating in an interregional transfer do not artificially constrain the transfer limits. Additional detail regarding these criteria can be found in the Part 1 scoping document.[55] Some entities performed additional studies while monitoring lower voltage facilities to ensure there were no significant differences.

Modeling of Transfer Participation

Transfers were simulated by scaling up the available generation in the source TPR in proportion to each unit's remaining availability, namely the difference between maximum generating capacity (P_{MAX}) and its modeled output (P_{GEN}), while scaling down the generation in the sink TPR proportional to its modeled output. Each transfer was simulated until a valid thermal limit was reached while enforcing the source system's maximum generation capacity. If the transfer did not report any transfer limits, meaning that the source TPR was resource-limited, the transfer was repeated without enforcing the source TPR's maximum generation capacity. Invalid limits, such as overloads on generating plant outlets due to not respecting these P_{MAX} values, were ignored.

Special Interface Considerations

Several interfaces have known operating procedures or other special circumstances. In many cases, these are remedial action schemes and/or flow control devices (e.g., phase angle regulators (PAR) or dc lines). The project team worked closely with industry subject matter experts to ensure that these situations were fully understood and properly reflected in the study results.

Power flows over dc lines do not change during transfer analysis; however, these lines are typically designed to carry large quantities of energy over long distances and across asynchronous Interconnections. Where an interface consists solely of dc tie lines, the TTC was calculated as the sum of the dc tie line ratings except where limitations on the ac system near the dc terminals were known to be more restrictive. Where an interface includes one or more dc tie lines as well as ac tie lines, the transfer analysis was conducted with the dc lines at the flow levels in the base cases.

Similarly, many interfaces include one or more PARs. For example, the PJM East to New York Interface is partially controlled by several PARs. Operating manuals describe how transfers across this interface are controlled, including the target percentage of flows across each line. This flow distribution was modeled in the base case development and transfer analysis to reflect the operating agreements between PJM and the New York Independent System Operator (NYISO).

Finally, there are several situations where one or more units at a power plant can connect to two different Interconnections. These units were modeled as provided in the base cases. The associated capacity was not added to the interface TTC, as this could lead to an overstatement of transfer capability, such as when the units are offline.

[55] ITCS Transfer Study Scope Part 1 (nerc.com)

Chapter 4: Transfer Capability (Part 1) Study Results

TTC results are highly dependent on the precise operating conditions, including dispatch, topology, load patterns, and facility ratings. This study did not attempt to optimize dispatch or topology to maximize TTC values. Observed transfer capability may be higher or lower depending on the operational conditions.

Results are presented by Interconnection for each season, proceeding from west to east as follows:

Western Interconnection Results

Western – Eastern Interconnection Results

ERCOT – Eastern Interconnection Results

Eastern Interconnection Results

Québec – Eastern Interconnection Results

Within the Western and Eastern Interconnections, results are generally presented from west to east, then north to south. A list of the interfaces and their ordering is included at the outset of each section.

The ITCS also analyzed an additional set of transfers into each TPR. These **Total Import Interface Results** reflect the simultaneous transfer limits into a TPR from all its neighbors.

Finally, the ITCS analyzed an additional set of transfers between areas defined in FERC's Order 1000. While these larger geographic areas were not used for the purpose of determining prudent additions, the **Supplemental Results Between Order 1000 Areas** are provided for completeness.

Western Interconnection Results

TTC results for the following interfaces are presented in this section:

Interface W1: British Columbia -> Washington

Interface W2: Washington <-> Oregon

Interface W3: Washington <-> Wasatch Front

Interface W4: Oregon <-> California North

Interface W5: Oregon <-> Wasatch Front

Interface W6: California North <-> California South

Interface W7: California North <-> Wasatch Front

Interface W8: California South <-> Wasatch Front

Interface W9: California South <-> Southwest

Interface W10: Alberta -> Wasatch Front

Interface W11: Wasatch Front <-> Southwest

Interface W12: Wasatch Front <-> Front Range

Interface W13: Southwest <-> Front Range

Interface W14: Oregon <-> California South (dc-only)

The interface between British Columbia and Alberta will be covered in the Canadian Analysis.

The TTC results in this study, which are based on a combination of source and sink TPRs, may differ from the path ratings that have been established throughout the Western Interconnection. Path ratings examine a specific subset of facilities, whereas this study method considers all facilities connecting the source and sink TPRs, including third-party connections.

Figure 4.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 4.2** similarly depicts the results from the 2024/25 Winter case.

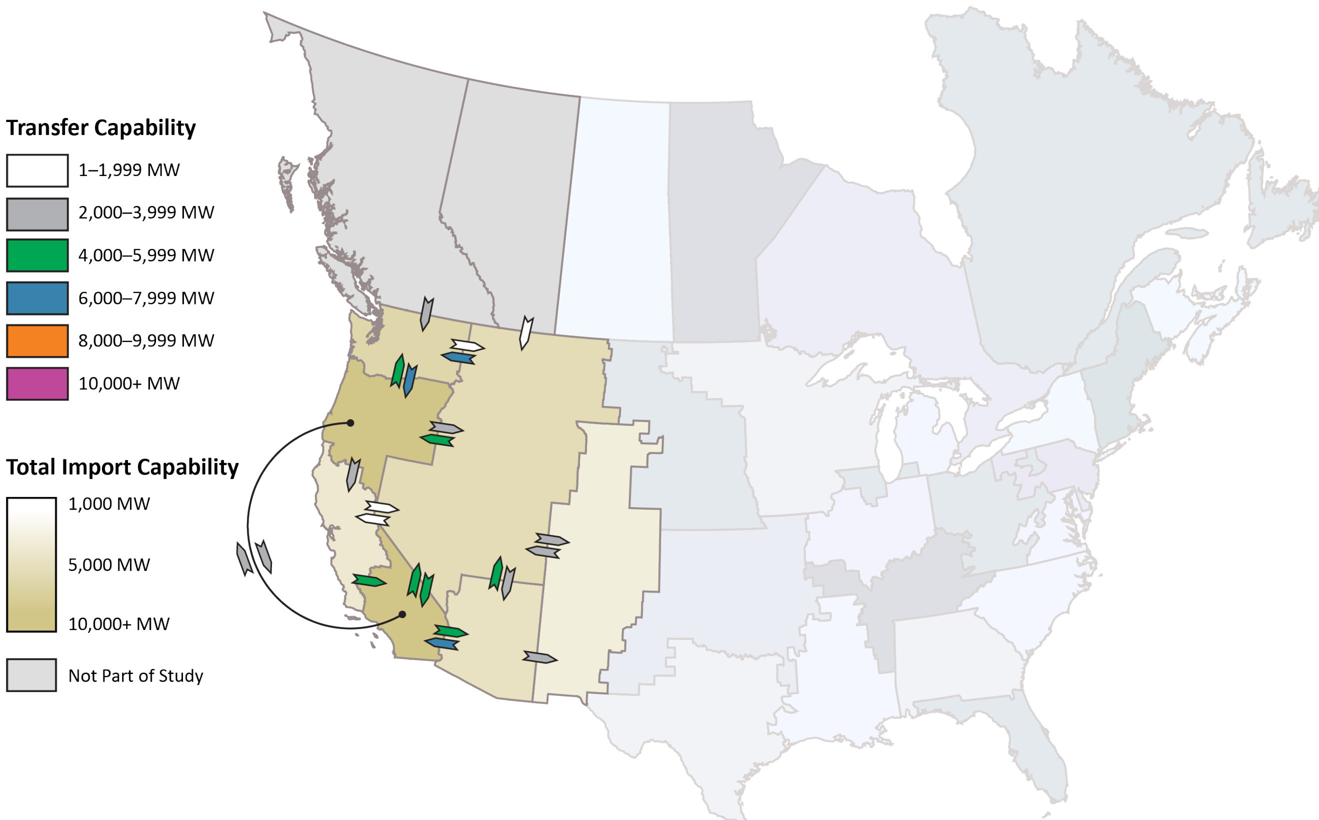


Figure 4.1: Transfer Capabilities for Western Interconnection Interfaces (Summer)

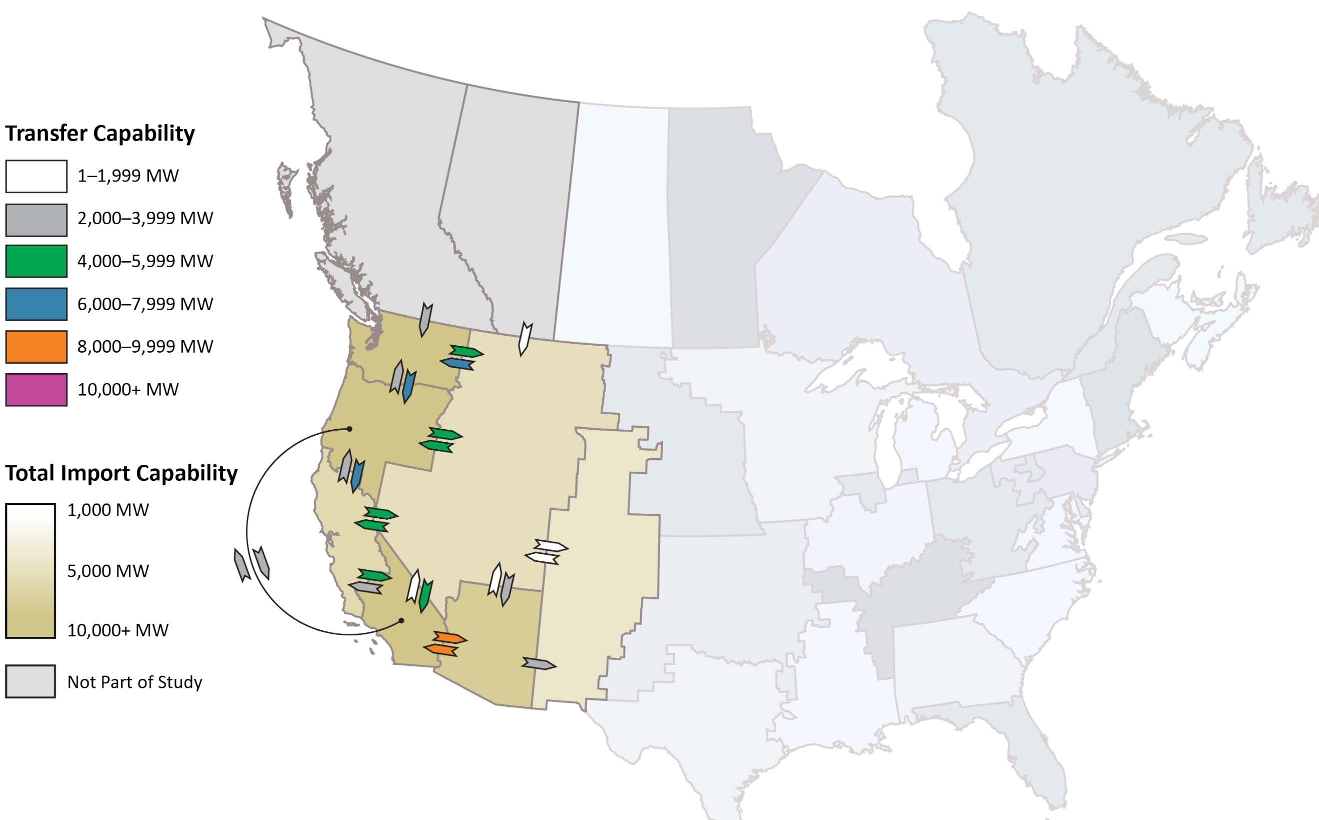
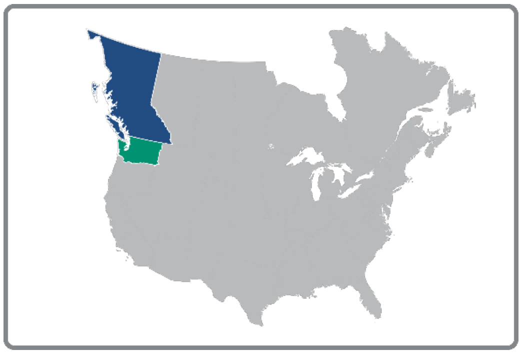


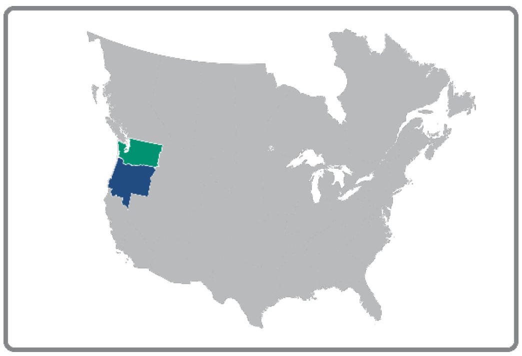
Figure 4.2: Transfer Capabilities for Western Interconnection Interfaces (Winter)

Interface W1: British Columbia -> Washington



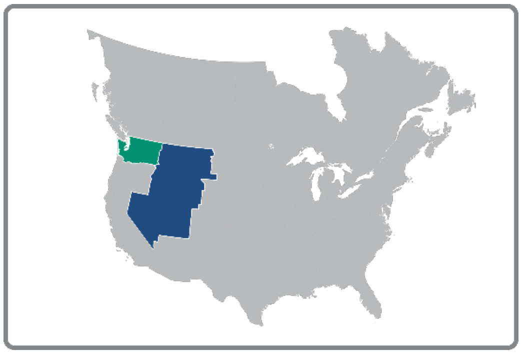
Interface Direction	2024 Summer	2024/25 Winter
British Columbia -> Washington	2,358 MW	2,170 MW

Interface W2: Washington <-> Oregon



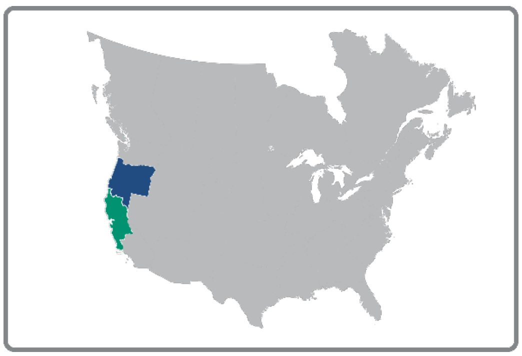
Interface Direction	2024 Summer	2024/25 Winter
Washington -> Oregon	7,085 MW	7,496 MW
Oregon -> Washington	4,103 MW	2,713 MW

Interface W3: Washington <-> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Washington -> Wasatch Front	1,925 MW	4,498 MW
Wasatch Front -> Washington	7,377 MW	7,030 MW

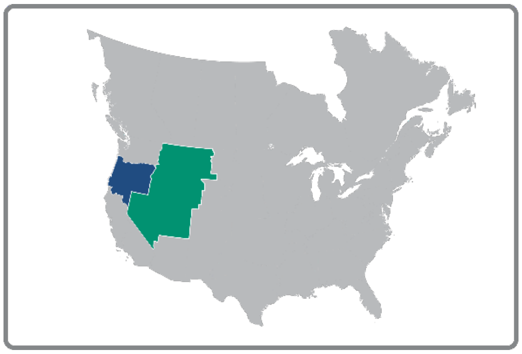
Interface W4: Oregon <-> California North



Interface Direction	2024 Summer	2024/25 Winter
Oregon -> California North	3,972 MW	6,175 MW
California North -> Oregon	0 MW	2,548 MW

Explanatory Note: Flows from south to north (California North to Oregon) are not typical under summer peak conditions, and generation dispatch optimization would be required to reverse the flows. Previous studies have shown a south to north transfer of ~3,675 MW.

Interface W5: Oregon <-> Wasatch Front



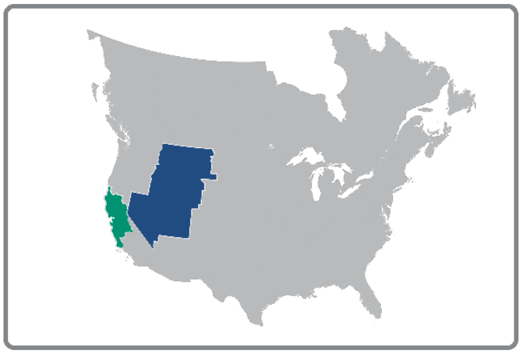
Interface Direction	2024 Summer	2024/25 Winter
Oregon -> Wasatch Front	2,525 MW	5,339 MW
Wasatch Front -> Oregon	4,748 MW	5,079 MW

Interface W6: California North <-> California South

Interface Direction	2024 Summer	2024/25 Winter
California North -> California South	4,647 MW	5,676 MW
California South -> California North	0 MW	3,861 MW

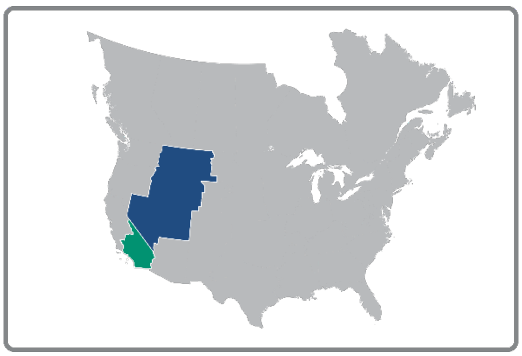
Explanatory Note: Flows from south to north (California South to California North) are not typical under summer peak conditions, and generation dispatch optimization would be required to reverse the flows. Previous studies have shown a south to north transfer of ~3,000 MW.

Interface W7: California North <-> Wasatch Front



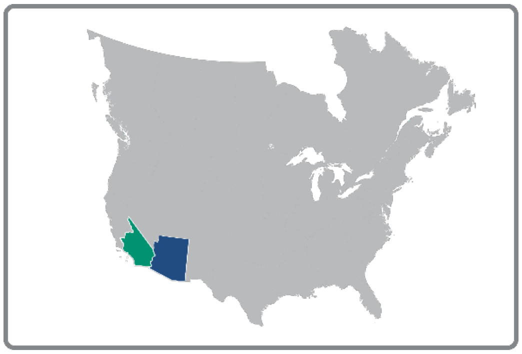
Interface Direction	2024 Summer	2024/25 Winter
California North -> Wasatch Front	1,961 MW	4,980 MW
Wasatch Front -> California North	116 MW	5,388 MW

Interface W8: California South <-> Wasatch Front



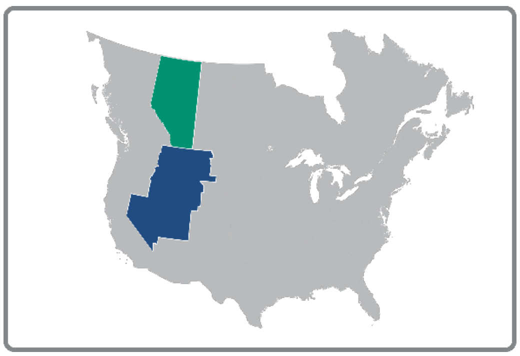
Interface Direction	2024 Summer	2024/25 Winter
California South -> Wasatch Front	5,965 MW	984 MW
Wasatch Front -> California South	5,419 MW	5,568 MW

Interface W9: California South <-> Southwest



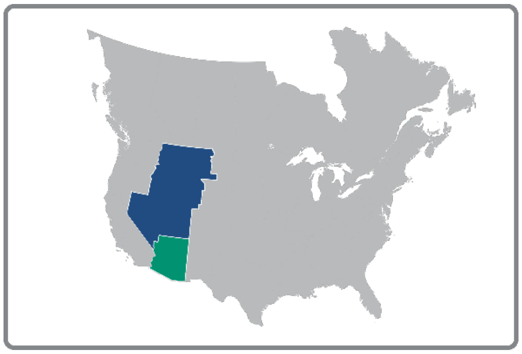
Interface Direction	2024 Summer	2024/25 Winter
California South -> Southwest	5,247 MW	8,470 MW
Southwest -> California South	7,667 MW	8,752 MW

Interface W10: Alberta -> Wasatch Front



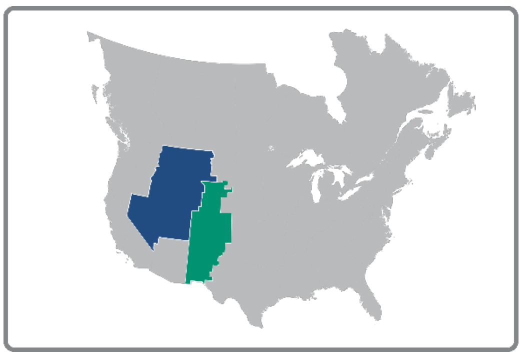
Interface Direction	2024 Summer	2024/25 Winter
Alberta -> Wasatch Front	957 MW	1,280 MW

Interface W11: Wasatch Front <-> Southwest



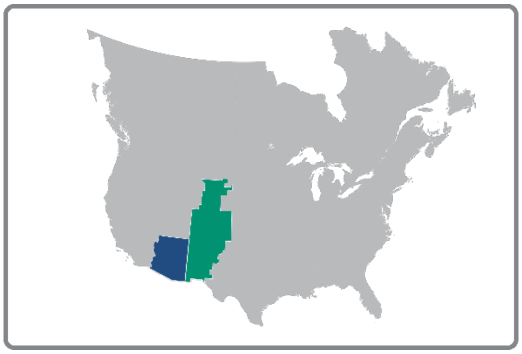
Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> Southwest	2,351 MW	2,095 MW
Southwest -> Wasatch Front	5,821 MW	1,295 MW

Interface W12: Wasatch Front <-> Front Range



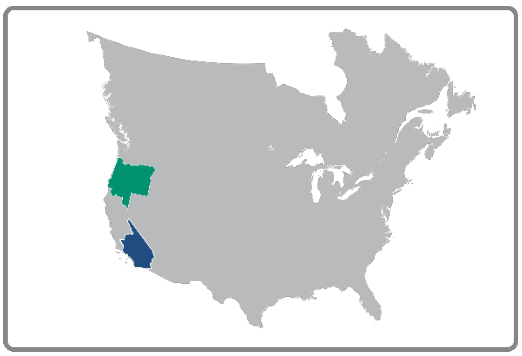
Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> Front Range	2,032 MW	1,984 MW
Front Range -> Wasatch Front	2,437 MW	477 MW

Interface W13: Southwest <-> Front Range



Interface Direction	2024 Summer	2024/25 Winter
Southwest -> Front Range	3,284 MW	3,751 MW
Front Range -> Southwest	0 MW	0 MW

Interface W14: Oregon <-> California South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Oregon -> California South	3,220 MW	3,220 MW
California South -> Oregon	3,100 MW	3,100 MW

Western – Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

Interface WE1: Wasatch Front <-> SPP North (dc-only)

Interface WE2: Front Range <-> SPP North (dc-only)

Interface WE3: Front Range <-> SPP South (dc-only)

The interface between Alberta and Saskatchewan will be covered in the Canadian Analysis.

Figure 4.3 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 4.4** similarly depicts the results from the 2024/25 Winter case.

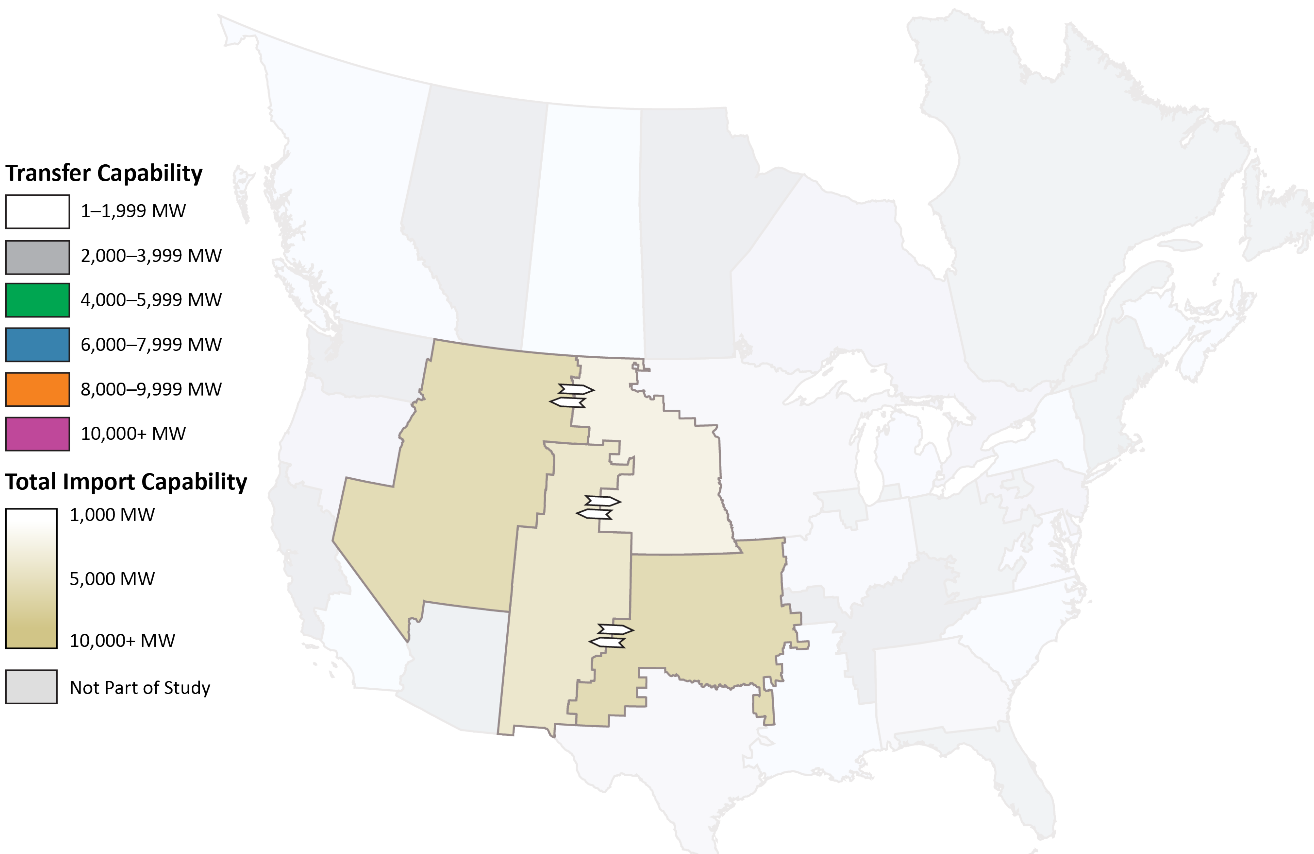


Figure 4.3: Transfer Capability Between Western and Eastern Interconnections (Summer)

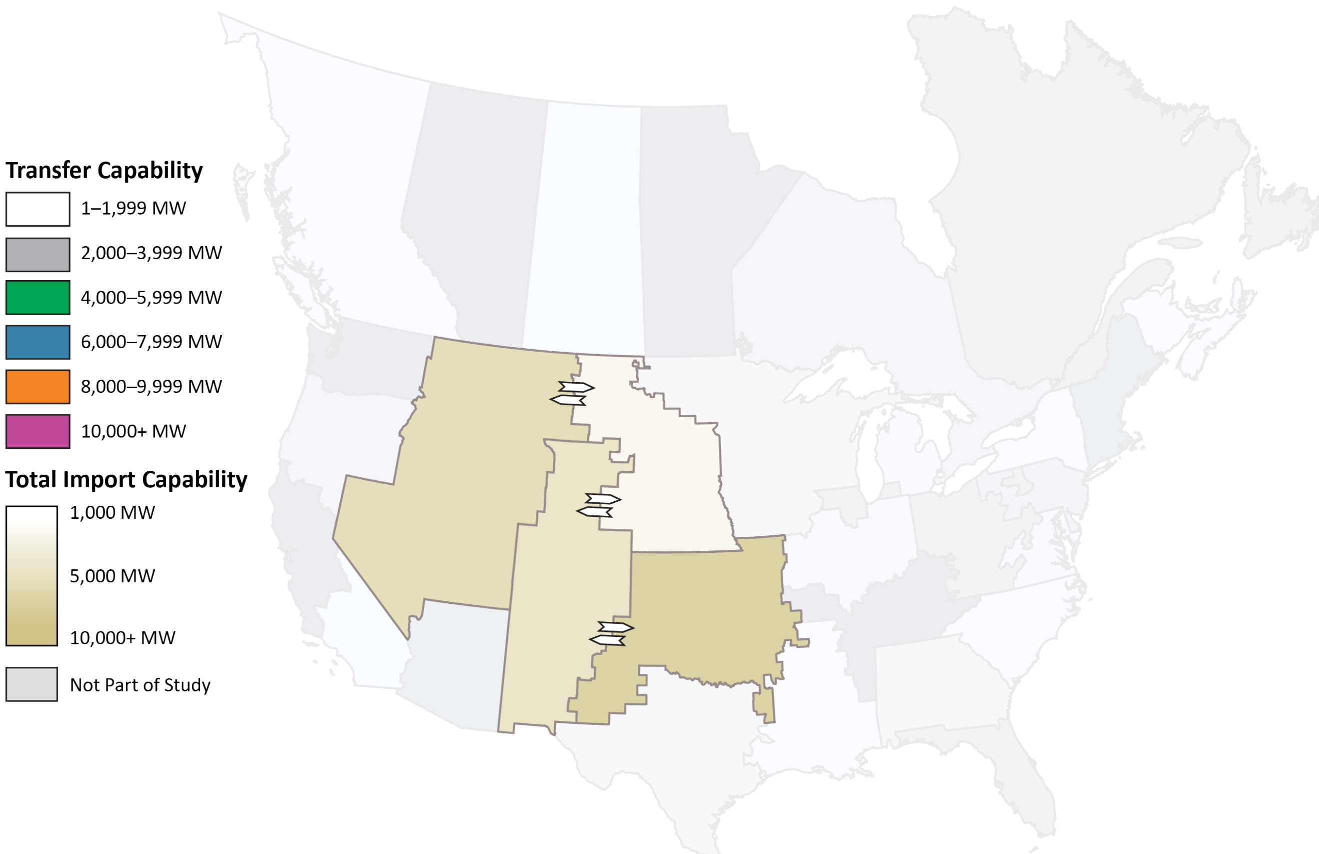
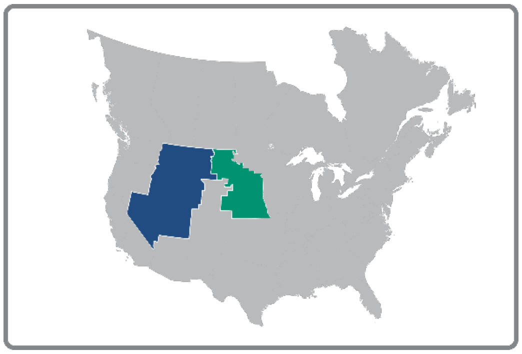


Figure 4.4: Transfer Capability Between Western and Eastern Interconnections (Winter)

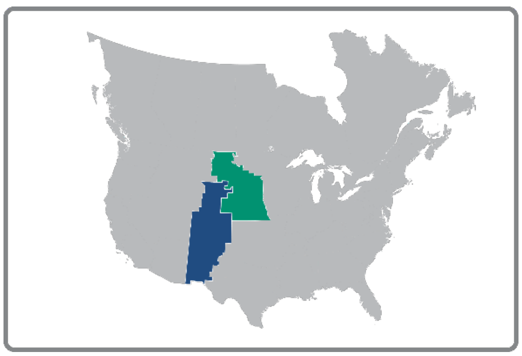
Interface WE1: Wasatch Front <-> SPP North



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> SPP North	150 MW	150 MW
SPP North -> Wasatch Front	200 MW	200 MW

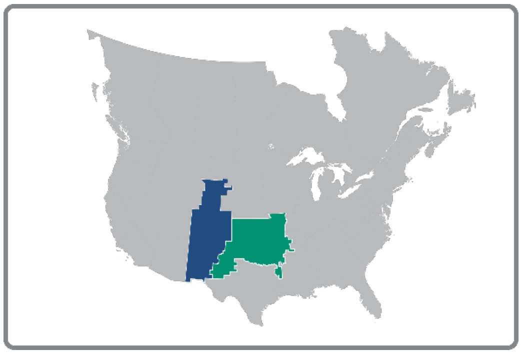
Interface WE2: Front Range <-> SPP North



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Front Range -> SPP North	510 MW	510 MW
SPP North -> Front Range	510 MW	510 MW

Interface WE3: Front Range <-> SPP South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Front Range -> SPP South	410 MW	410 MW
SPP South -> Front Range	410 MW	410 MW

ERCOT – Eastern Interconnection Results

TTC results for the following interface are presented in this section:

Interface TE1: ERCOT <-> SPP South (dc-only)

Figure 4.5 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 4.6** similarly depicts the results from the 2024/25 Winter case.

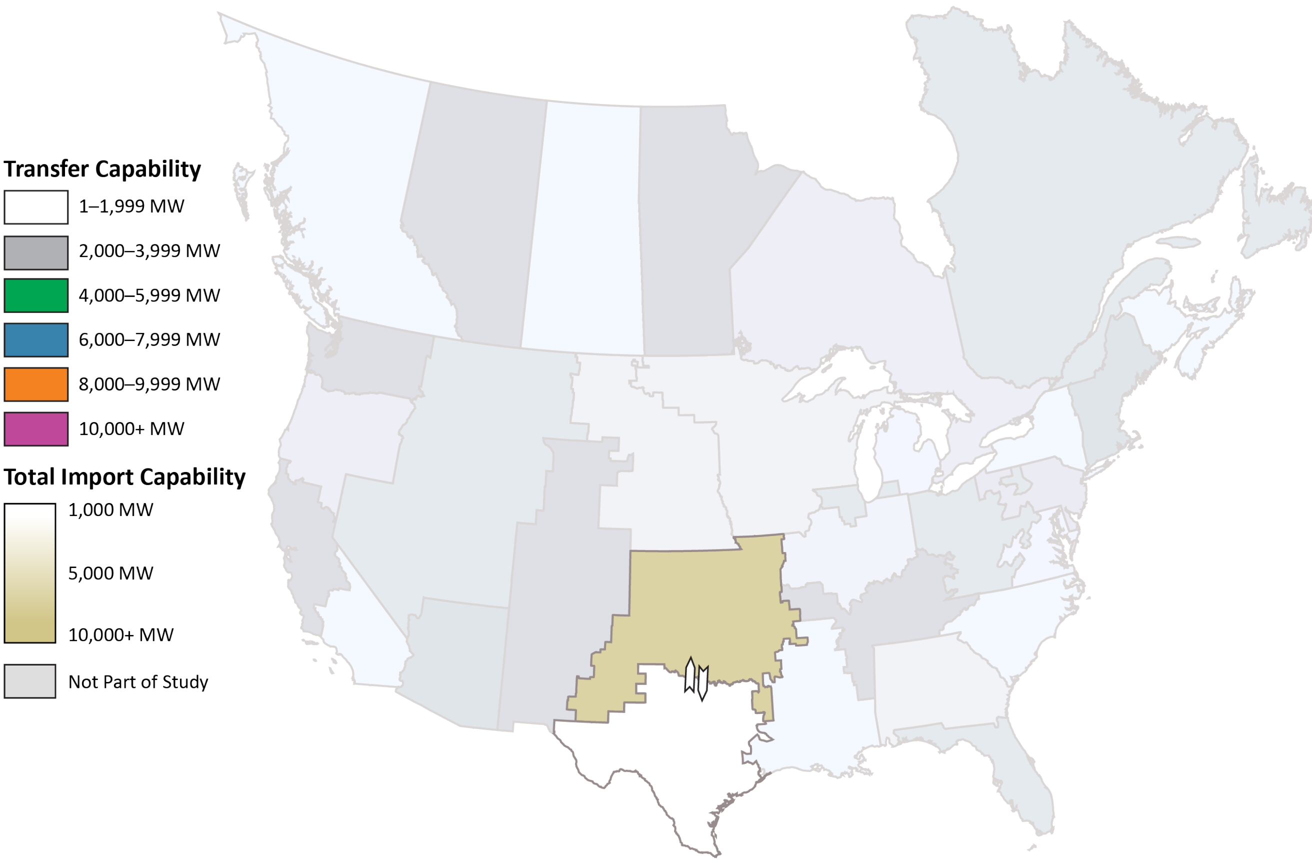


Figure 4.5: Transfer Capability Between ERCOT and Eastern Interconnections (Summer)

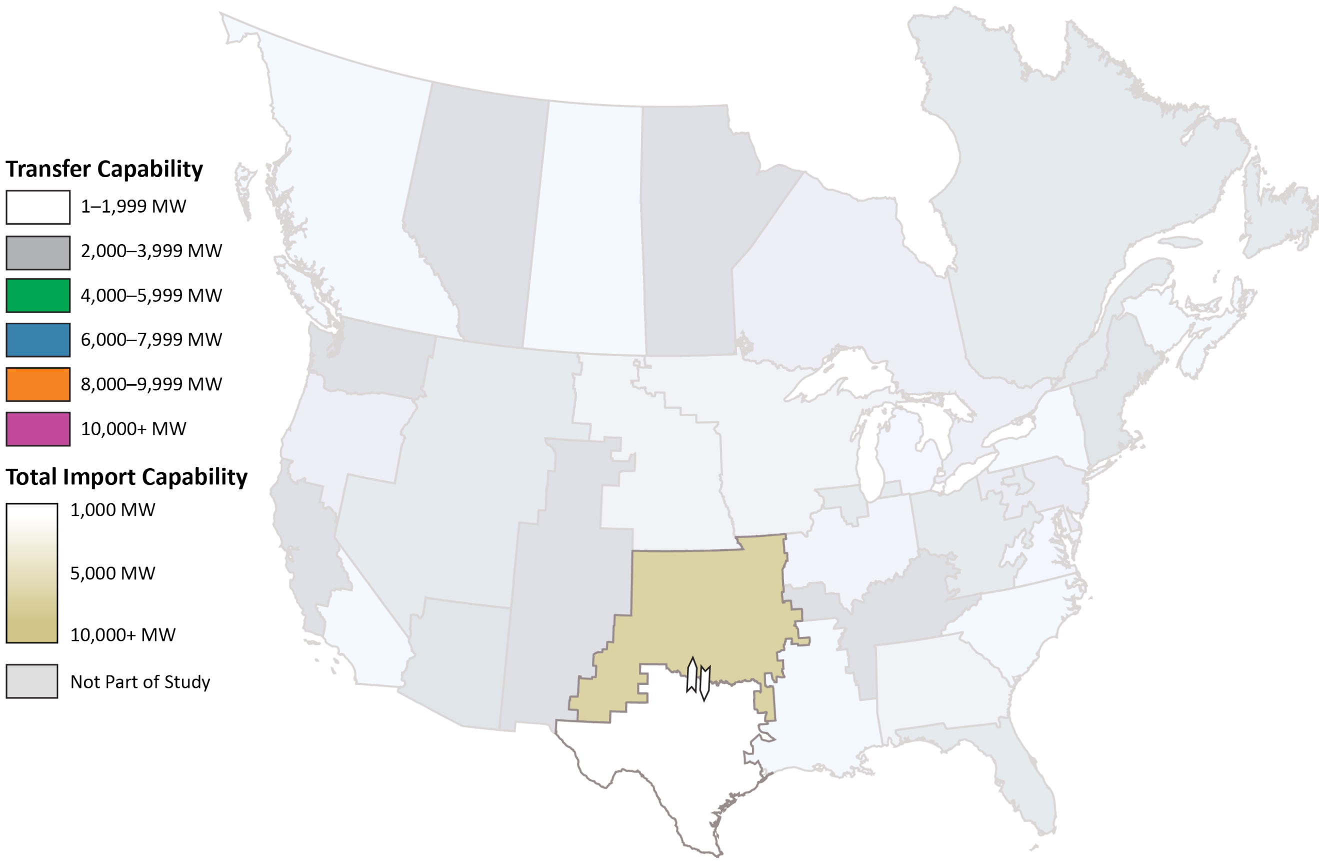
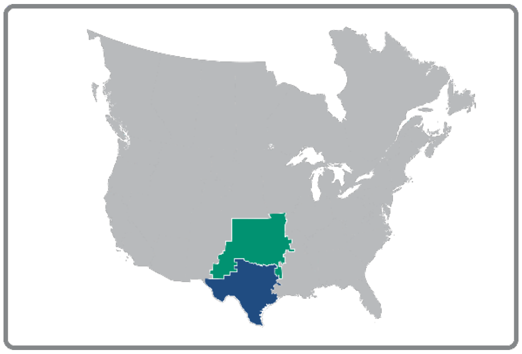


Figure 4.6: Transfer Capability Between ERCOT and Eastern Interconnections (Winter)

Interface TE1: ERCOT <-> SPP South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
ERCOT -> SPP South	820 MW	820 MW
SPP South -> ERCOT	820 MW	820 MW

Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

Interface E1: Saskatchewan -> SPP North

Interface E2: SPP North <-> SPP South

Interface E3: SPP North <-> SERC Central

Interface E4: SPP North <-> MISO West

Interface E5: SPP South <-> MISO West

Interface E6: SPP South <-> MISO Central

Interface E7: SPP South <-> SERC Central

Interface E8: SPP South <-> MISO South

Interface E9: Manitoba -> MISO West

Interface E10: Ontario -> MISO West

Interface E11: MISO West <-> MISO East (dc-only)

Interface E12: MISO West <-> PJM West

Interface E13: MISO West <-> MISO Central

Interface E14: MISO West <-> SERC Central

Interface E15: MISO Central <-> MISO East

Interface E16: MISO Central <-> PJM West

Interface E17: MISO Central <-> SERC Central

Interface E18: MISO Central <-> MISO South

Interface E19: MISO South <-> SERC Central

Interface E20: MISO South <-> SERC Southeast

Interface E21: Ontario -> MISO East

Interface E22: MISO East <-> PJM West

Interface E23: SERC Central <-> PJM West

Interface E24: SERC Central <-> SERC East

Interface E25: SERC Central <-> SERC Southeast

Interface E26: SERC Southeast <-> SERC Florida

Interface E27: SERC Southeast <-> SERC East

Interface E28: SERC East <-> PJM West

Interface E29: SERC East <-> PJM South

Interface E30: PJM West <-> PJM East

Interface E31: PJM West <-> PJM South

Interface E32: PJM East <-> PJM South

Interface E33: PJM East <-> New York

Interface E34: Ontario -> New York

Interface E35: New York <-> New England

Interface E36: Maritimes -> New England

Interfaces between Saskatchewan and Manitoba and between Manitoba and Ontario will be covered in the Canadian Analysis.

Figure 4.7 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 4.8** similarly depicts the results from the 2024/25 Winter case.

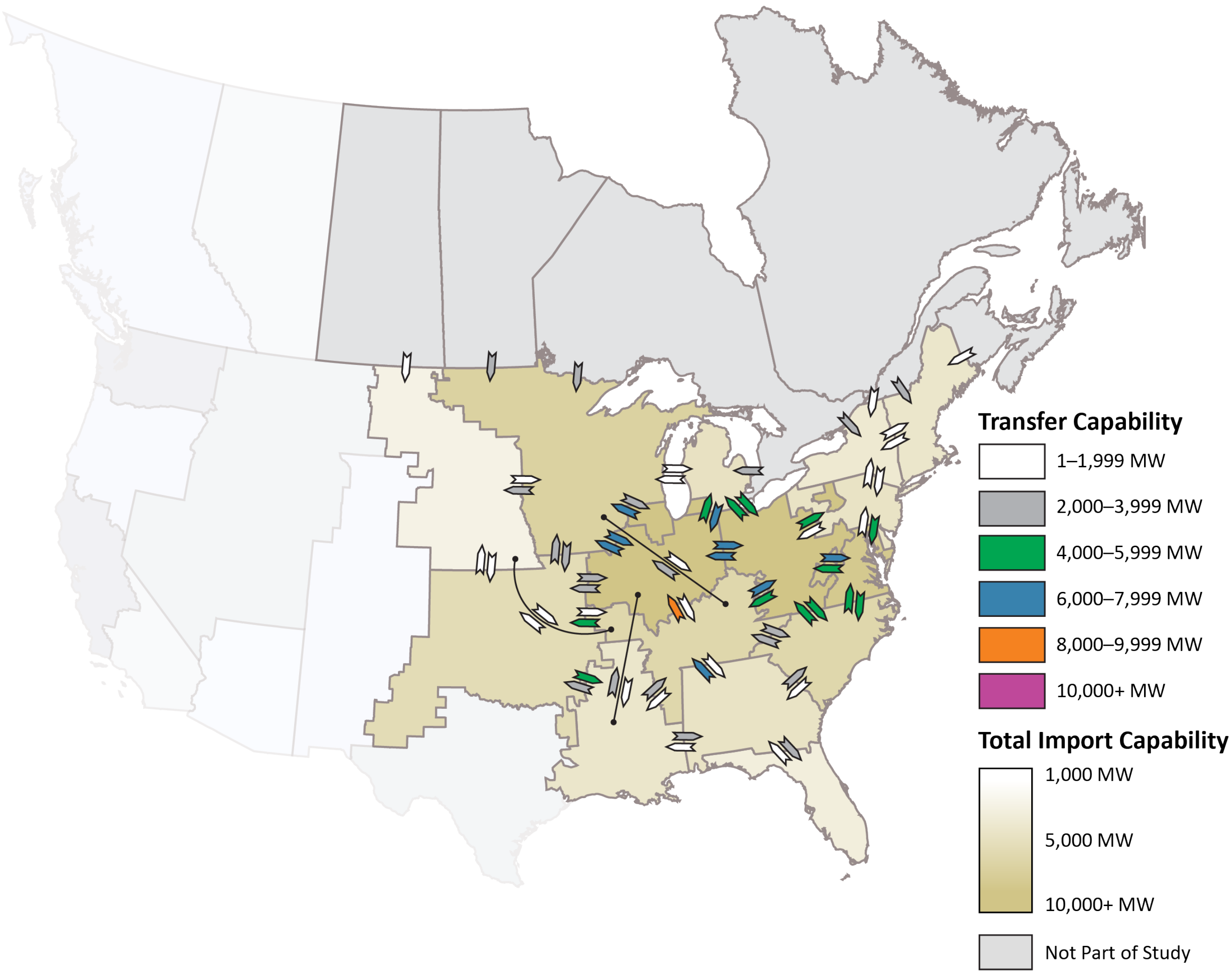


Figure 4.7: Transfer Capabilities of Eastern Interconnection Interfaces (Summer)

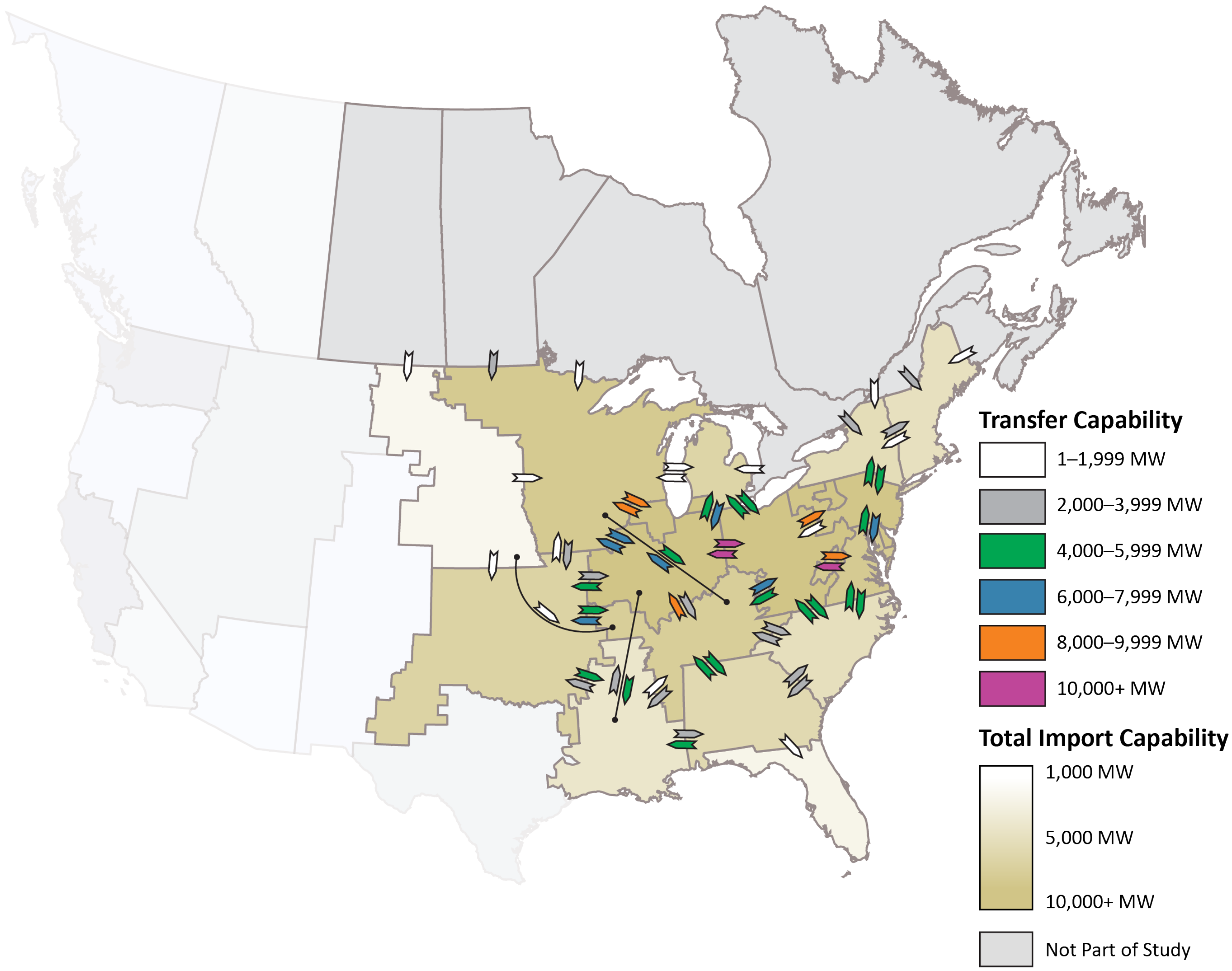
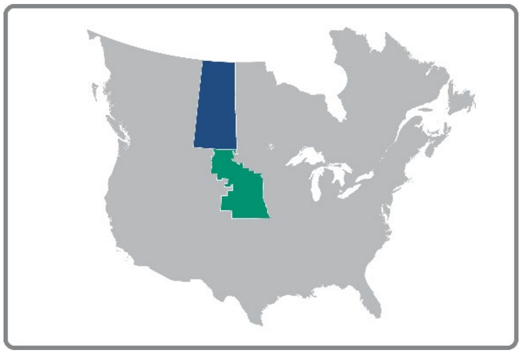


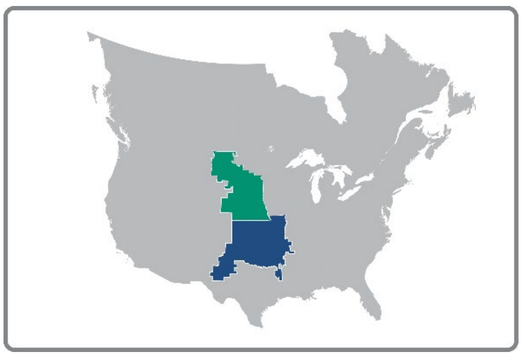
Figure 4.8: Transfer Capabilities of Eastern Interconnection Interfaces (Winter)

Interface E1: Saskatchewan -> SPP North



Interface Direction	2024 Summer	2024/25 Winter
Saskatchewan -> SPP North	165 MW	663 MW

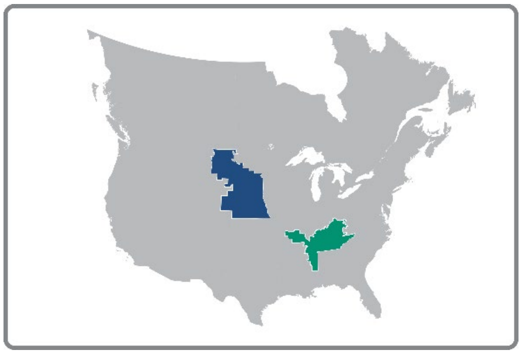
Interface E2: SPP North <-> SPP South



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> SPP South	1,501 MW	1,785 MW
SPP South -> SPP North	1,705 MW	0 MW

Explanatory Note: Under the studied winter peak conditions, transfers from SPP South to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

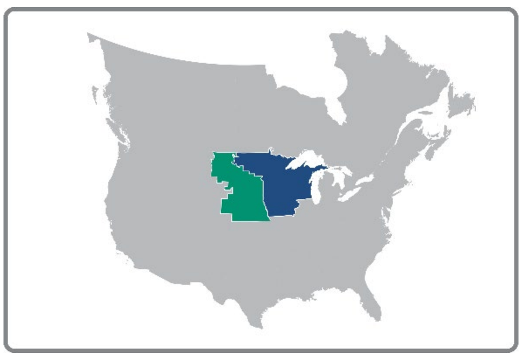
Interface E3: SPP North <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> SERC Central	128 MW	1,102 MW
SERC Central -> SPP North	1,183 MW	0 MW

Explanatory Note: Under the studied winter peak conditions, transfers from SERC Central to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

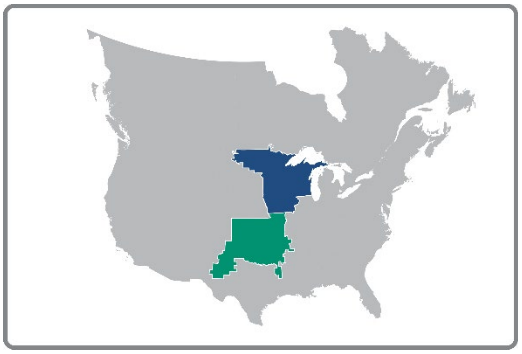
Interface E4: SPP North <-> MISO West



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> MISO West	623 MW	778 MW
MISO West -> SPP North	2,209 MW	0 MW

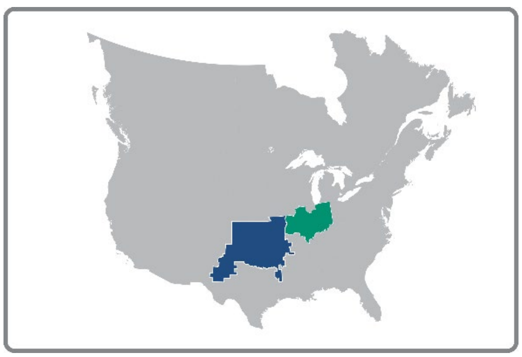
Explanatory Note: Under the studied winter peak conditions, transfers from MISO West to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

Interface E5: SPP South <-> MISO West



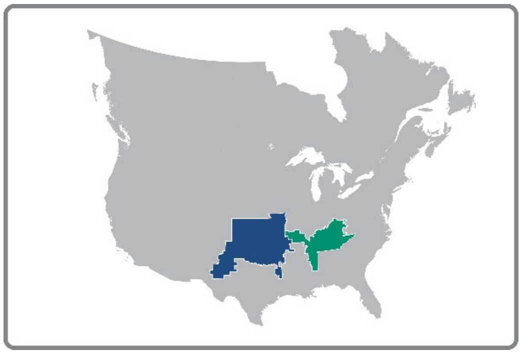
Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO West	3,323 MW	1,196 MW
MISO West -> SPP South	2,086 MW	3,801 MW

Interface E6: SPP South <-> MISO Central



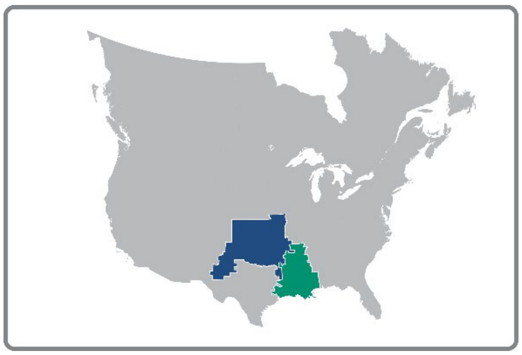
Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO Central	2,481 MW	2,420 MW
MISO Central -> SPP South	3,873 MW	5,635 MW

Interface E7: SPP South <-> SERC Central



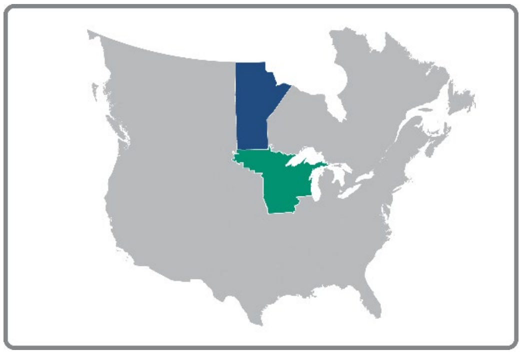
Interface Direction	2024 Summer	2024/25 Winter
SPP South -> SERC Central	859 MW	5,591 MW
SERC Central -> SPP South	5,042 MW	6,445 MW

Interface E8: SPP South <-> MISO South



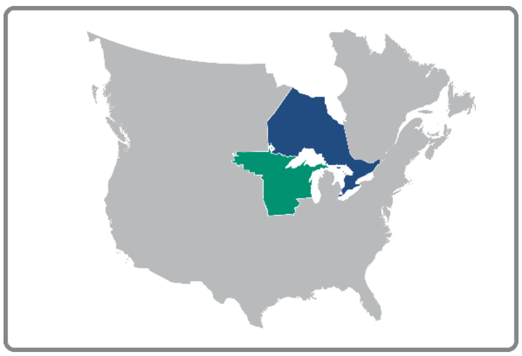
Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO South	4,295 MW	4,336 MW
MISO South -> SPP South	3,033 MW	3,878 MW

Interface E9: Manitoba -> MISO West



Interface Direction	2024 Summer	2024/25 Winter
Manitoba -> MISO West	3,772 MW	3,633 MW

Interface E10: Ontario -> MISO West



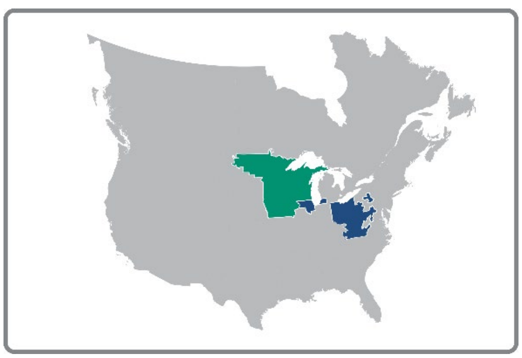
Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO West	2,424 MW	1,862 MW

Interface E11: MISO West <-> MISO East

Special Information: dc-only interface

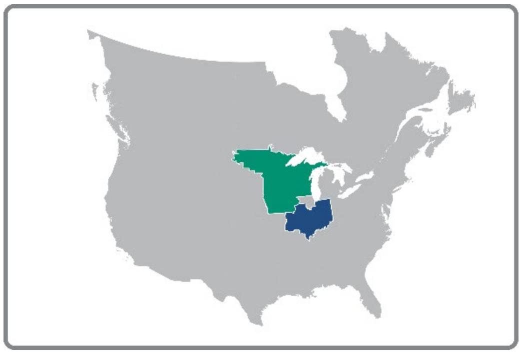
Interface Direction	2024 Summer	2024/25 Winter
MISO West -> MISO East	160 MW	160 MW
MISO East -> MISO West	160 MW	160 MW

Interface E12: MISO West <-> PJM West



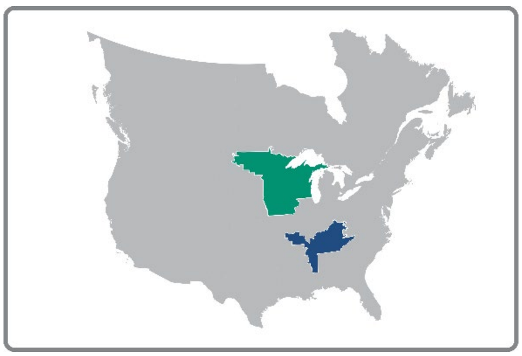
Interface Direction	2024 Summer	2024/25 Winter
MISO West -> PJM West	2,518 MW	8,011 MW
PJM West -> MISO West	7,791 MW	9,086 MW

Interface E13: MISO West <-> MISO Central



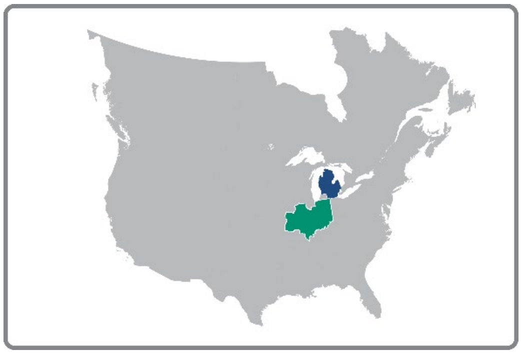
Interface Direction	2024 Summer	2024/25 Winter
MISO West -> MISO Central	6,199 MW	7,306 MW
MISO Central -> MISO West	7,602 MW	7,341 MW

Interface E14: MISO West <-> SERC Central



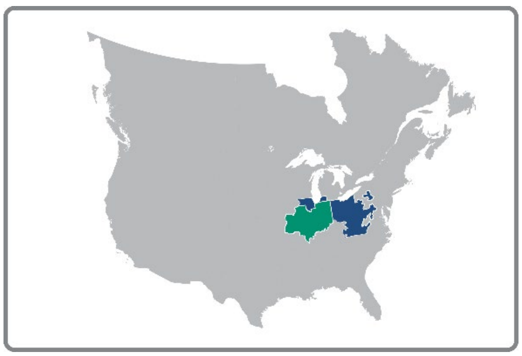
Interface Direction	2024 Summer	2024/25 Winter
MISO West -> SERC Central	150 MW	4,141 MW
SERC Central -> MISO West	3,671 MW	6,877 MW

Interface E15: MISO Central <-> MISO East



Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> MISO East	4,864 MW	5,585 MW
MISO East -> MISO Central	6,344 MW	6,531 MW

Interface E16: MISO Central <-> PJM West

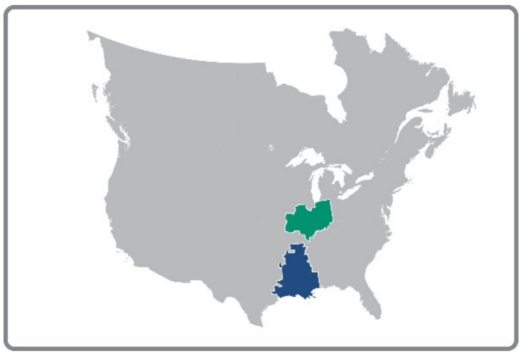


Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> PJM West	6,572 MW	10,790 MW
PJM West -> MISO Central	6,986 MW	20,449 MW

Interface E17: MISO Central <-> SERC Central

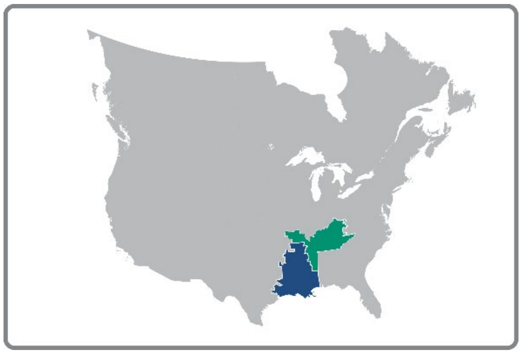
Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> SERC Central	235 MW	3,903 MW
SERC Central -> MISO Central	8,288 MW	8,441 MW

Interface E18: MISO Central <-> MISO South



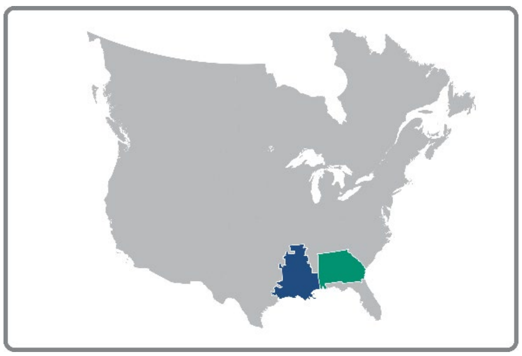
Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> MISO South	1,797 MW	4,067 MW
MISO South -> MISO Central	2,117 MW	1,093 MW

Interface E19: MISO South <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
MISO South -> SERC Central	2,468 MW	1,361 MW
SERC Central -> MISO South	1,457 MW	3,342 MW

Interface E20: MISO South <-> SERC Southeast

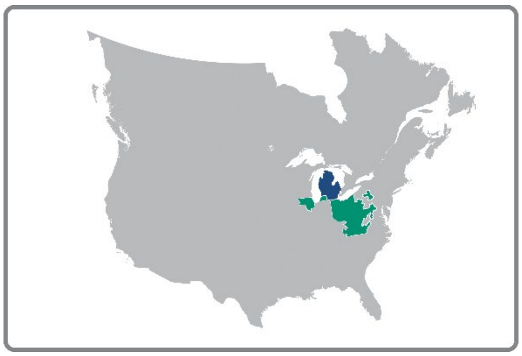


Interface Direction	2024 Summer	2024/25 Winter
MISO South -> SERC Southeast	3,600 MW	3,392 MW
SERC Southeast -> MISO South	1,638 MW	4,028 MW

Interface E21: Ontario -> MISO East

Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO East	2,348 MW	1,649 MW

Interface E22: MISO East <-> PJM West

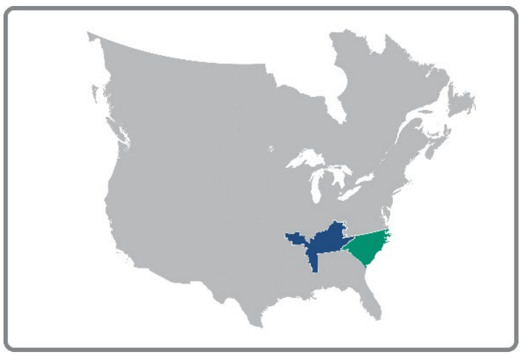


Interface Direction	2024 Summer	2024/25 Winter
MISO East -> PJM West	5,603 MW	5,940 MW
PJM West -> MISO East	4,345 MW	5,608 MW

Interface E23: SERC Central <-> PJM West

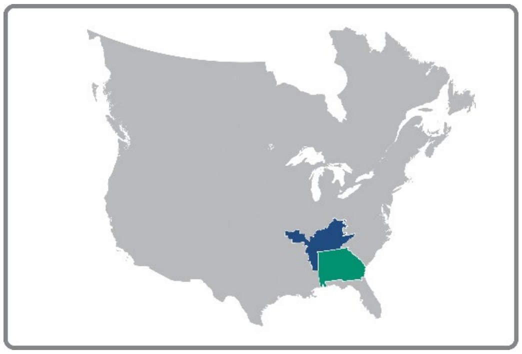
Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> PJM West	6,646 MW	6,710 MW
PJM West -> SERC Central	5,444 MW	5,786 MW

Interface E24: SERC Central <-> SERC East



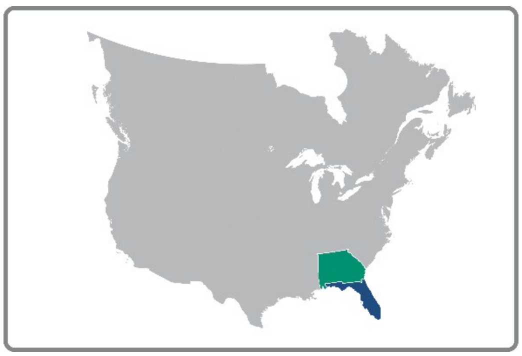
Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> SERC East	2,419 MW	3,311 MW
SERC East -> SERC Central	3,257 MW	2,675 MW

Interface E25: SERC Central <-> SERC Southeast



Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> SERC Southeast	1,095 MW	5,387 MW
SERC Southeast -> SERC Central	6,579 MW	4,639 MW

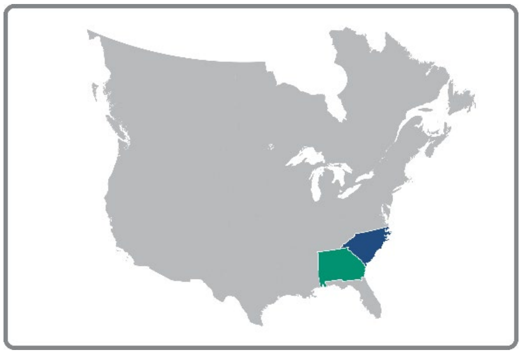
Interface E26: SERC Southeast <-> SERC Florida



Interface Direction	2024 Summer	2024/25 Winter
SERC Southeast -> SERC Florida	2,958 MW	1,807 MW
SERC Florida -> SERC Southeast	1,322 MW	0 MW

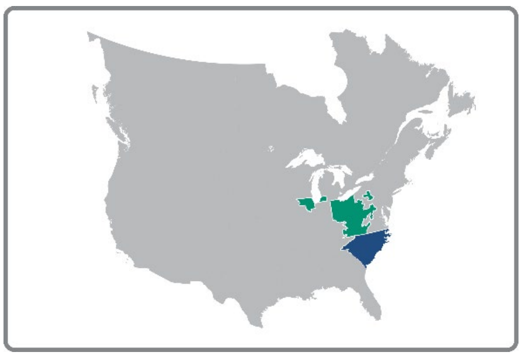
Explanatory Note: Flows from South to North (SERC Florida to SERC Southeast) are not typical under winter peak conditions.

Interface E27: SERC Southeast <-> SERC East



Interface Direction	2024 Summer	2024/25 Winter
SERC Southeast -> SERC East	2,397 MW	3,669 MW
SERC East -> SERC Southeast	1,703 MW	3,536 MW

Interface E28: SERC East <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
SERC East -> PJM West	5,185 MW	4,448 MW
PJM West -> SERC East	5,318 MW	4,286 MW

Interface E29: SERC East <-> PJM South

Interface Direction	2024 Summer	2024/25 Winter
SERC East -> PJM South	4,596 MW	4,963 MW
PJM South -> SERC East	4,665 MW	5,463 MW

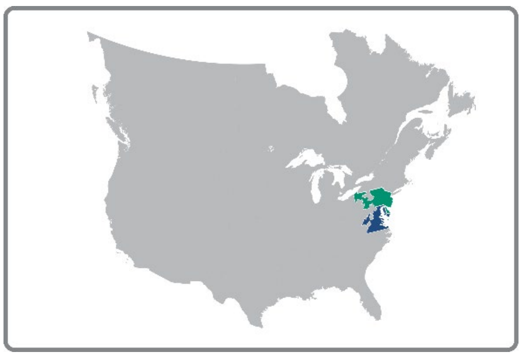
Interface E30: PJM West <-> PJM East

Interface Direction	2024 Summer	2024/25 Winter
PJM West -> PJM East	4,762 MW	9,815 MW
PJM East -> PJM West	1,443 MW	166 MW

Interface E31: PJM West <-> PJM South

Interface Direction	2024 Summer	2024/25 Winter
PJM West -> PJM South	7,041 MW	9,035 MW
PJM South -> PJM West	5,347 MW	10,942 MW

Interface E32: PJM East <-> PJM South

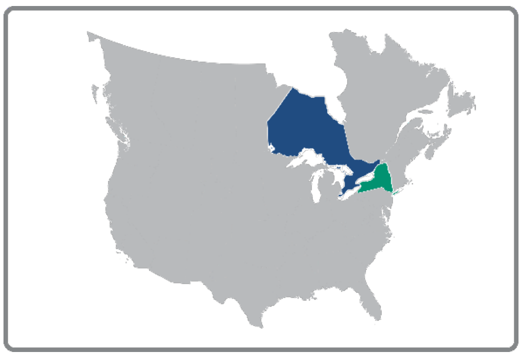


Interface Direction	2024 Summer	2024/25 Winter
PJM East -> PJM South	5,094 MW	6,770 MW
PJM South -> PJM East	1,605 MW	4,166 MW

Interface E33: PJM East <-> New York[56]

Interface Direction	2024 Summer	2024/25 Winter
PJM East -> New York	1,356 MW	4,814 MW
New York -> PJM East	913 MW	4,019 MW

Interface E34: Ontario -> New York



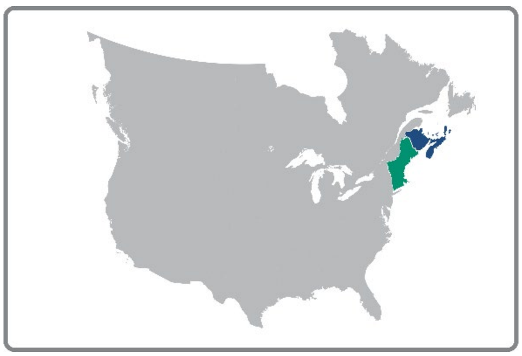
Interface Direction	2024 Summer	2024/25 Winter
Ontario -> New York	2,286 MW	2,719 MW

[56] Power flow cases used to calculate these TTC values reflected the operating agreements between PJM and the New York Independent System Operator (NYISO).

Interface E35: New York <-> New England

Interface Direction	2024 Summer	2024/25 Winter
New York -> New England	1,303 MW	2,432 MW
New England -> New York	1,660 MW	1,359 MW

Interface E36: Maritimes -> New England



Interface Direction	2024 Summer	2024/25 Winter
Maritimes -> New England	1,127 MW	1,265 MW

Québec – Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

Interface QE1: Québec -> New York (dc-only)

Interface QE2: Québec -> New England (dc-only)

Interfaces between Québec and Ontario and between Québec and the Maritimes will be covered in the Canadian Analysis.

Figure 4.9 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 4.10** similarly depicts the results from the 2024/25 Winter case.

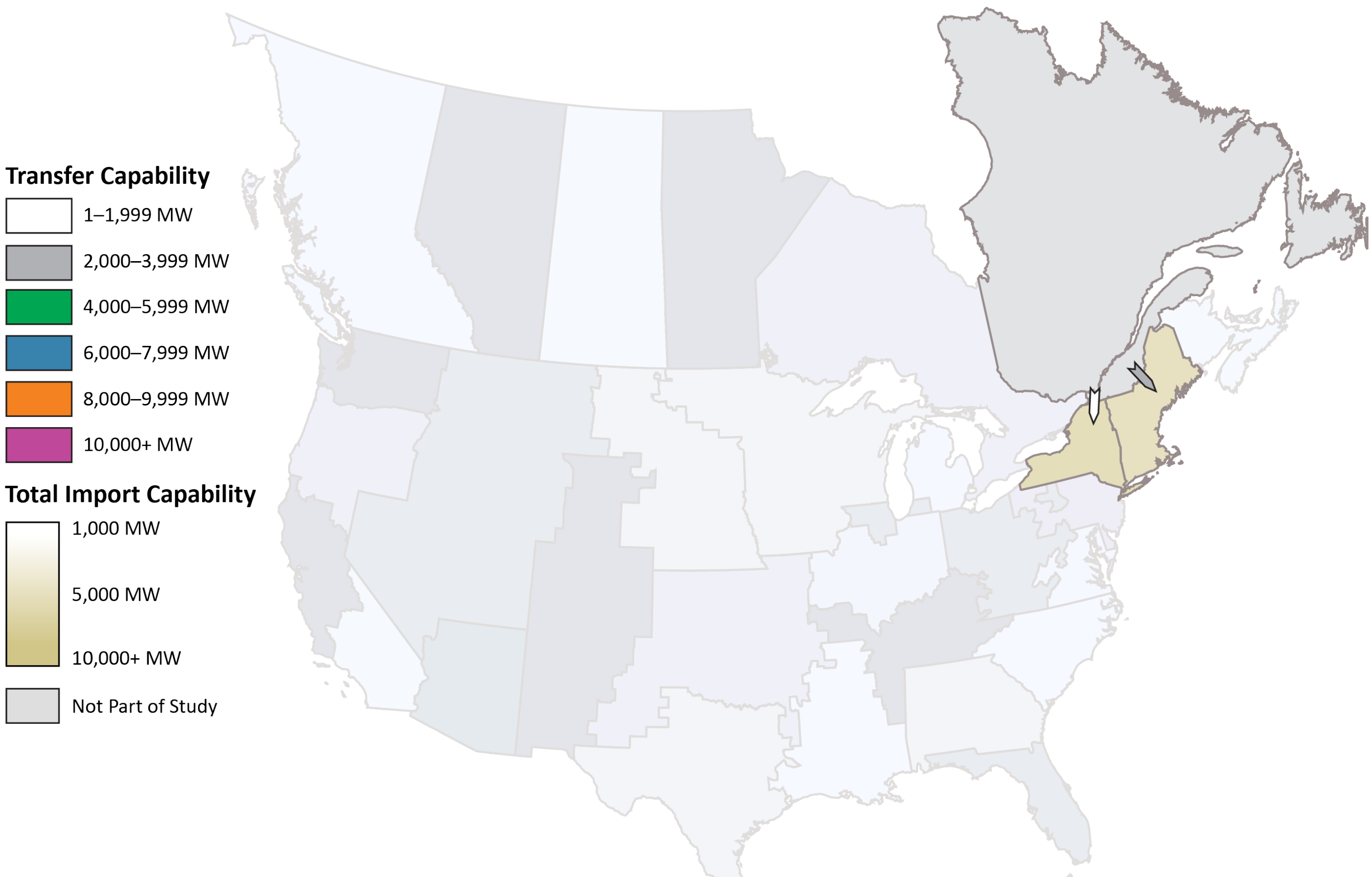


Figure 4.9: Transfer Capability Between Québec and Eastern Interconnections (Summer)

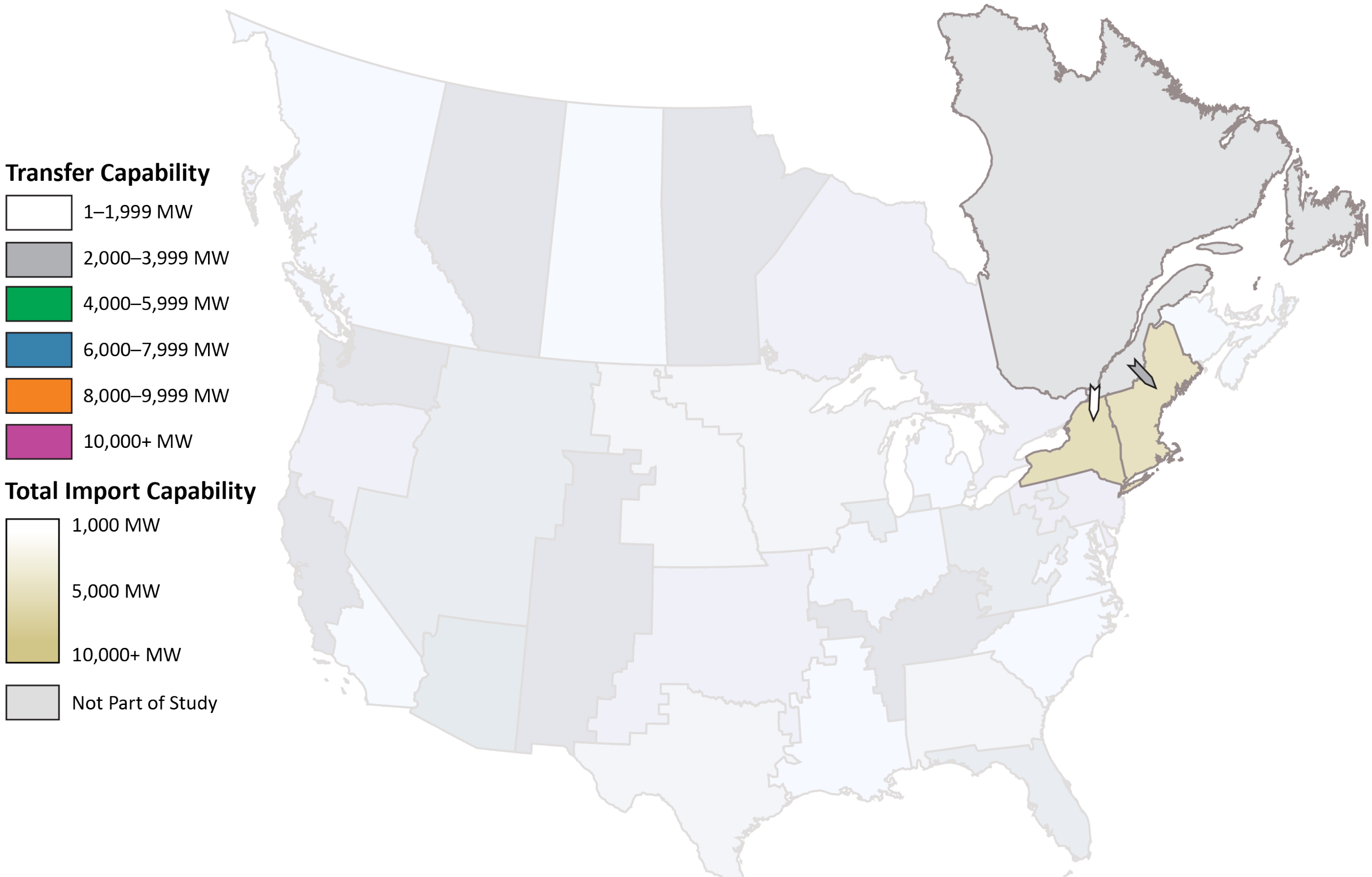
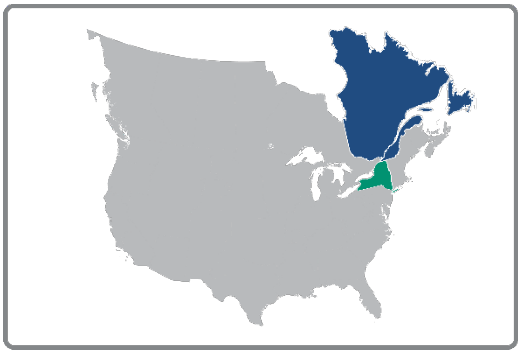


Figure 4.10: Transfer Capability Between Québec and Eastern Interconnections (Winter)

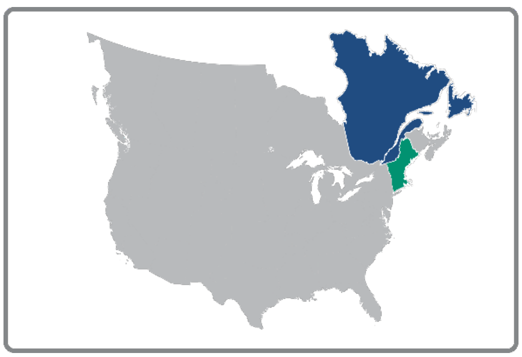
Interface QE1: Québec -> New York



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> New York	1,000 MW	1,000 MW

Interface QE2: Québec -> New England



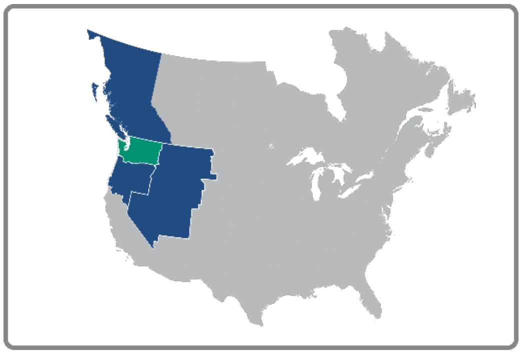
Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> New England	2,225 MW	2,225 MW

Total Import Interface Results

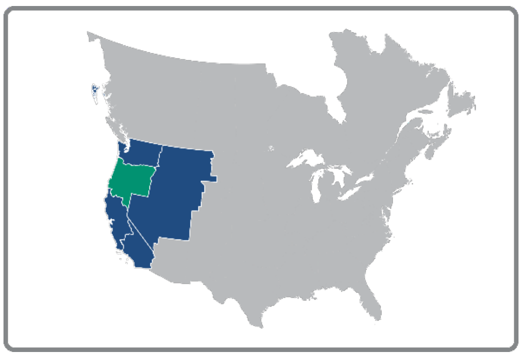
The ITCS also analyzed an additional set of transfers into each TPR. These total import interfaces analyze the simultaneous transfers into a TPR from all its neighbors. In instances where the calculated total import interface transfer capability was lower than that from any neighboring TPR, the highest neighbor-to-neighbor results were reported to avoid understating the total import capability. The definitions of these interfaces exclude connections via dc-only interfaces, which can typically be scheduled independently. TTC results for the following interfaces are presented in this section:

Interface WTI01: Into Washington



Interface Direction	2024 Summer	2024/25 Winter
Into Washington TTC	7,377 MW[57]	10,297 MW
Percentage of Peak Load	43%	50%

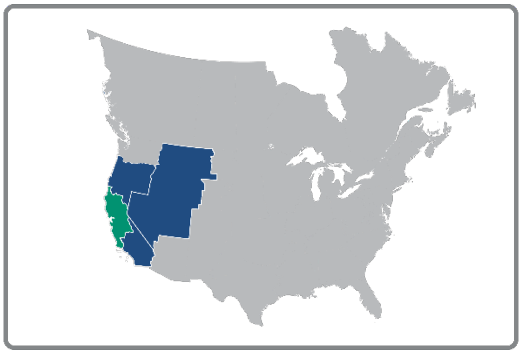
Interface WTI02: Into Oregon



Interface Direction	2024 Summer	2024/25 Winter
Into Oregon TTC	8,004 MW	7,534 MW
dc-only interfaces	3,100 MW	3,100 MW
Total of TTC and dc-only interfaces	11,104 MW	10,634 MW
Percentage of Peak Load	92%	89%

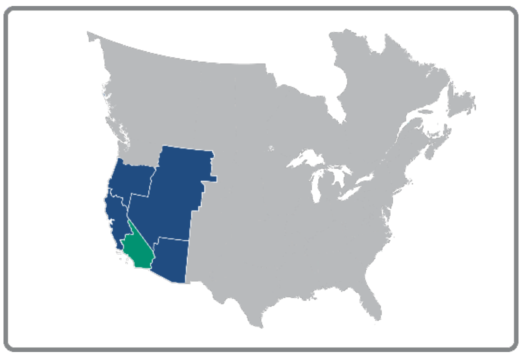
[57] Value is from the Wasatch Front to Washington interface, as the total import interface calculation was more limiting.

Interface WTI03: Into California North



Interface Direction	2024 Summer	2024/25 Winter
Into California North TTC	3,972 MW[58]	6,631 MW
Percentage of Peak Load	14%	29%

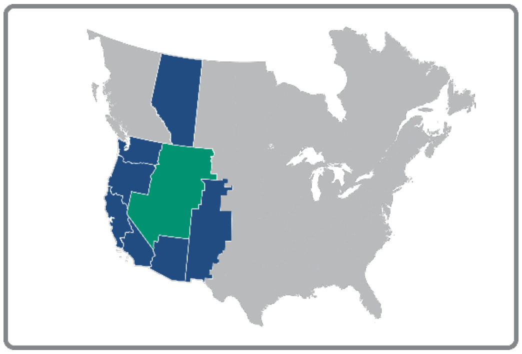
Interface WTI04: Into California South



Interface Direction	2024 Summer	2024/25 Winter
Into California South TTC	7,829 MW	11,288 MW
dc-only interfaces	3,220 MW	3,220 MW
Total of TTC and dc-only interfaces	11,049 MW	14,508 MW
Percentage of Peak Load	28%	69%

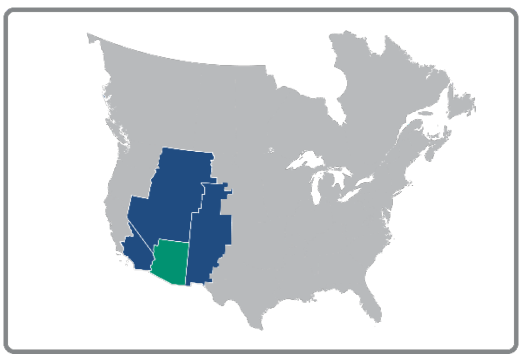
[58] Value is from the Oregon to California North interface, as the total import interface calculation was more limiting.

Interface WTI05: Into Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Into Wasatch Front TTC	5,965 MW[59]	5,558 MW
dc-only interfaces	200 MW	200 MW
Total of TTC and dc-only interfaces	6,165 MW	5,758 MW
Percentage of Peak Load	23%	35%

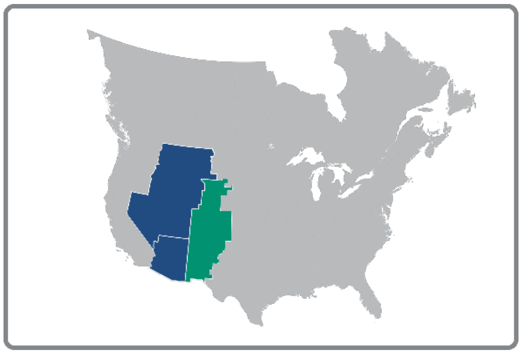
Interface WTI06: Into Southwest



Interface Direction	2024 Summer	2024/25 Winter
Into Southwest TTC	5,247 MW[60]	8,470 MW[61]
Percentage of Peak Load	22%	66%

[59] Value is from the California South to Wasatch Front interface, as the total import interface calculation was more limiting.
[60] Value is from the California South to Southwest interface, as the total import interface calculation was more limiting.
[61] Value is from the California South to Southwest interface, as the total import interface calculation was more limiting.

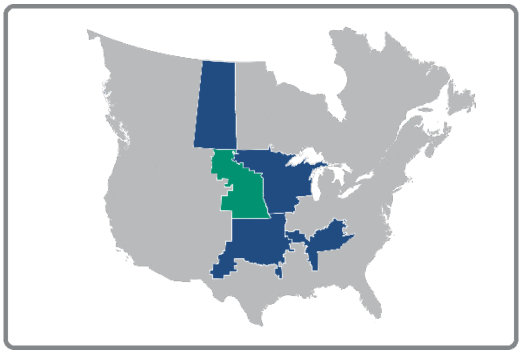
Interface WTI07: Into Front Range



Interface Direction	2024 Summer	2024/25 Winter
Into Front Range TTC	3,284 MW[62]	3,751 MW [63]
dc-only interfaces	920 MW	920 MW
Total of TTC and dc-only interfaces	4,204 MW	4,671 MW
Percentage of Peak Load	21%	30%

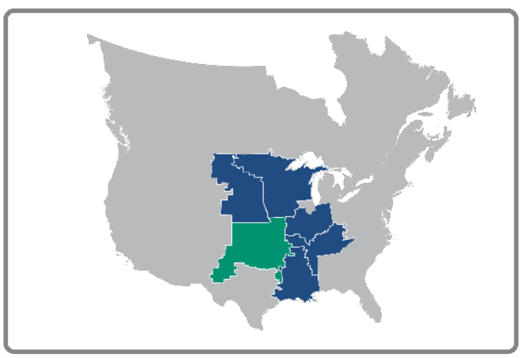
[62] Value is from the Southwest to Front Range interface, as the total import interface calculation was more limiting.
[63] Value is from the Southwest to Front Range interface, as the total import interface calculation was more limiting.

Interface ETI01: Into SPP North



Interface Direction	2024 Summer	2024/25 Winter
Into SPP North TTC	2,209 MW[64]	663 MW[65]
dc-only interfaces	660 MW	660 MW
Total of TTC and dc-only interfaces	2,869 MW	1,323 MW
Percentage of Peak Load	21%	11%

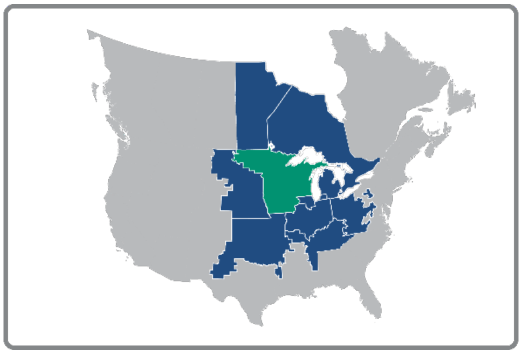
Interface ETI02: Into SPP South



Interface Direction	2024 Summer	2024/25 Winter
Into SPP South TTC	5,042 MW[66]	6,445 MW[67]
dc-only interfaces	1,230 MW	1,230 MW
Total of TTC and dc-only interfaces	6,272 MW	7,675 MW
Percentage of Peak Load	13%	20%

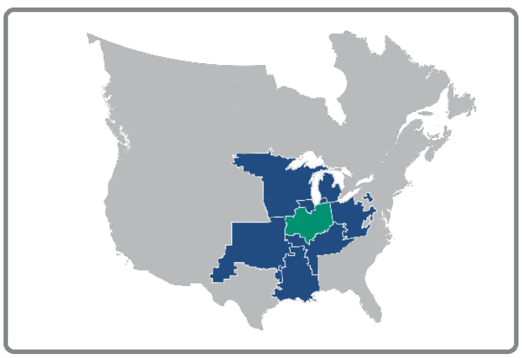
[64] Value is from the MISO West to SPP North interface, as the total import interface calculation was more limiting.
[65] Value is from the Saskatchewan to SPP North interface, as the total import interface calculation was more limiting.
[66] Value is from the SERC Central to SPP South interface, as the total import interface calculation was more limiting.
[67] Value is from the SERC Central to SPP South interface, as the total import interface calculation was more limiting.

Interface ETI03: Into MISO West



Interface Direction	2024 Summer	2024/25 Winter
Into MISO West TTC	7,791 MW[68]	9,086 MW[69]
dc-only interfaces	160 MW	160 MW
Total of TTC and dc-only interfaces	7,951 MW	9,246 MW
Percentage of Peak Load	19%	26%

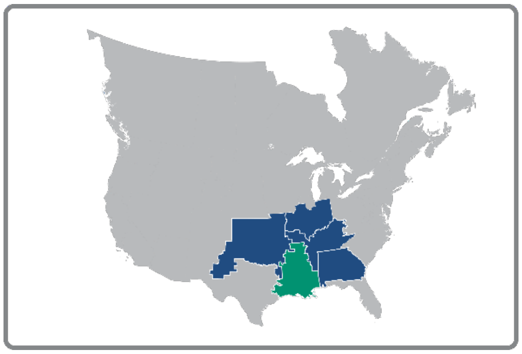
Interface ETI04: Into MISO Central



Interface Direction	2024 Summer	2024/25 Winter
Into MISO Central TTC	12,714 MW	20,449 MW[70]
Percentage of Peak Load	35%	63%

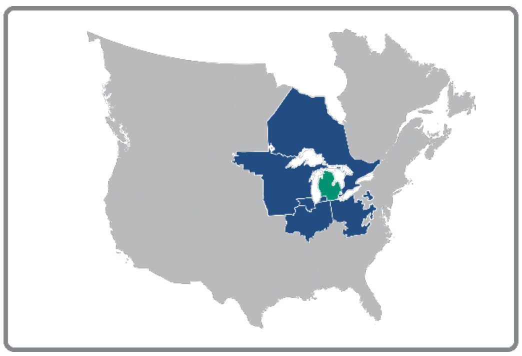
[68] Value is from the PJM West to MISO West interface, as the total import interface calculation was more limiting.
[69] Value is from the PJM West to MISO West interface, as the total import interface calculation was more limiting.
[70] Value is from the PJM West to MISO Central interface, as the total import interface calculation was more limiting.

Interface ETI05: Into MISO South



Interface Direction	2024 Summer	2024/25 Winter
Into MISO South TTC	4,295 MW[71]	4,336 MW[72]
Percentage of Peak Load	12%	13%

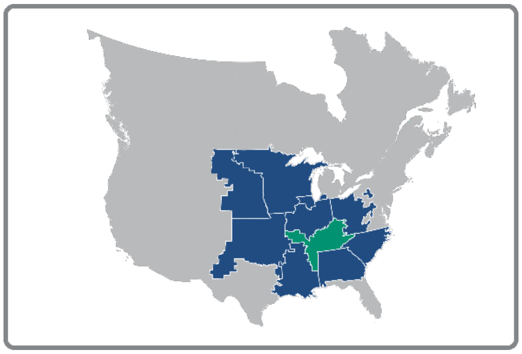
Interface ETI06: Into MISO East



Interface Direction	2024 Summer	2024/25 Winter
Into MISO East TTC	5,139 MW	7,019 MW
dc-only interfaces	160 MW	160 MW
Total of TTC and dc-only interfaces	5,299 MW	7,179 MW
Percentage of Peak Load	25%	44%

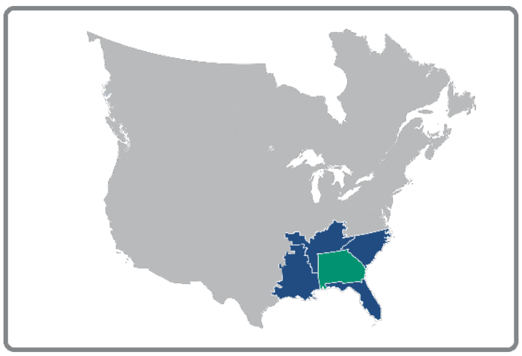
[71] Value is from the SPP South to MISO South interface, as the total import interface calculation was more limiting.
[72] Value is from the SPP South to MISO South interface, as the total import interface calculation was more limiting.

Interface ETI07: Into SERC Central



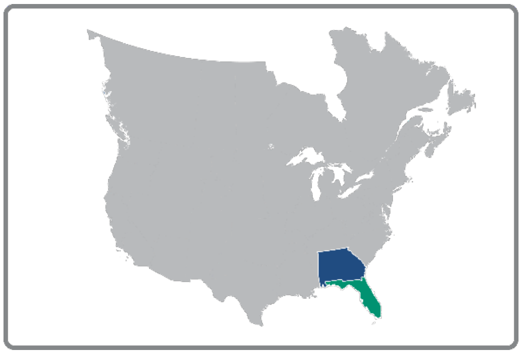
Interface Direction	2024 Summer	2024/25 Winter
Into SERC Central TTC	6,878 MW	8,443 MW
Percentage of Peak Load	15%	18%

Interface ETI08: Into SERC Southeast



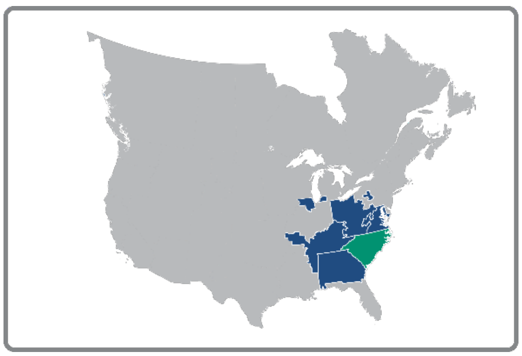
Interface Direction	2024 Summer	2024/25 Winter
Into SERC Southeast TTC	4,900 MW	6,525 MW
Percentage of Peak Load	11%	15%

Interface ETI09: Into SERC Florida



Interface Direction	2024 Summer	2024/25 Winter
Into SERC Florida TTC	2,958 MW	1,807 MW
Percentage of Peak Load	6%	4%

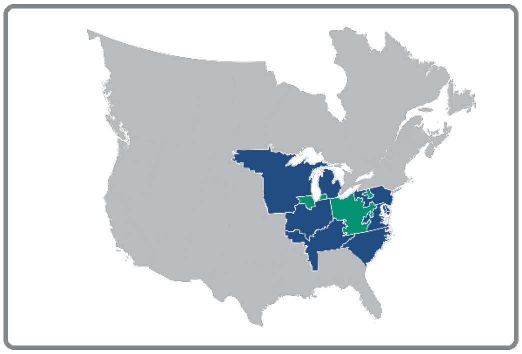
Interface ETI10: Into SERC East



Interface Direction	2024 Summer	2024/25 Winter
Into SERC East TTC	6,959 MW	5,463 MW[73]
Percentage of Peak Load	16%	12%

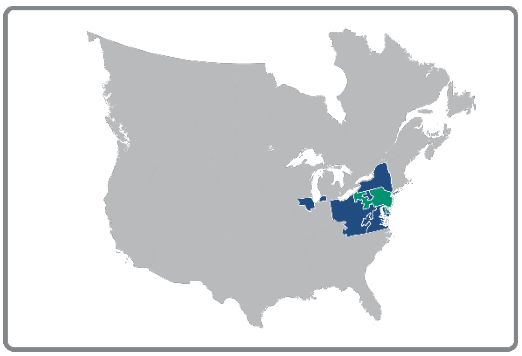
[73] Value is from PJM South to SERC East interface, as the total import interface calculation was more limiting.

Interface ETI11: Into PJM West



Interface Direction	2024 Summer	2024/25 Winter
Into PJM West TTC	21,773 MW	10,942 MW[74]
Percentage of Peak Load	28%	16%

Interface ETI12: Into PJM East



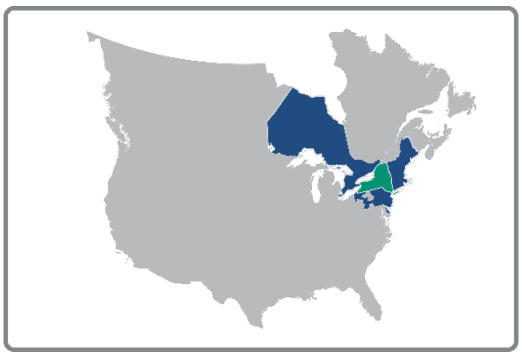
Interface Direction	2024 Summer	2024/25 Winter
Into PJM East TTC	4,762 MW[75]	9,815 MW[76]
Percentage of Peak Load	11%	28%

[74] Value is from the PJM South to PJM West interface, as the total import interface calculation was more limiting.
[75] Value is from the PJM West to PJM East interface, as the total import interface calculation was more limiting.
[76] Value is from the PJM West to PJM East interface, as the total import interface calculation was more limiting.

Interface ETI13: Into PJM South

Interface Direction	2024 Summer	2024/25 Winter
Into PJM South TTC	9,578 MW	9,035 MW[77]
Percentage of Peak Load	28%	27%

Interface ETI14: Into New York



Interface Direction	2024 Summer	2024/25 Winter
Into New York TTC	2,802 MW	4,814 MW[78]
dc-only interfaces	1,000 MW	1,000 MW
Total of TTC and dc-only interfaces	3,802 MW	5,814 MW
Percentage of Peak Load	12%	24%

[77] Value is from the PJM West to PJM South interface, as the total import interface calculation was more limiting.
[78] Value is from the PJM East to New York interface, as the total import interface calculation was more limiting.

Interface ETI15: Into New England

Interface Direction	2024 Summer	2024/25 Winter
Into New England TTC	2,313 MW	3,033 MW
dc-only interfaces	2,225 MW	2,225 MW
Total of TTC and dc-only interfaces	4,538 MW	5,258 MW
Percentage of Peak Load	19%	25%

Supplemental Results Between Order 1000 Areas

The ITCS analyzed an additional set of transfers between areas defined in FERC's Order 1000 (see **Figure 4.11**). While these larger geographic areas were not be used for the purpose of determining prudent additions, the current transfer capability results are provided for completeness. While the Los Angeles Department of Water & Power (LADWP) is part of WestConnect, for the purposes of this study, LADWP was included as part of CAISO due to its geographic location within California. Where results were previously presented, they are not repeated here. TTC results for the following interfaces are presented in this section:

Interface W1001: British Columbia -> Northern Grid

Interface W1002: Alberta -> Northern Grid

Interface W1003: Northern Grid <-> California ISO

Interface W1004: Northern Grid <-> West Connect

Interface W1005: California ISO <-> West Connect

Interface E1001: Saskatchewan -> SPP

Interface E1002: SPP <-> MISO

Interface E1003: SPP <-> SERTP

Interface E1004: Manitoba -> MISO

Interface E1005: Ontario -> MISO

Interface E1006: MISO <-> PJM

Interface E1007: MISO <-> SERTP

Interface E1008: SERTP <-> PJM

Interface E1009: SERTP <-> SCRTP

Interface E1010: SERTP <-> FRCC

Interface E1011: PJM <-> New York

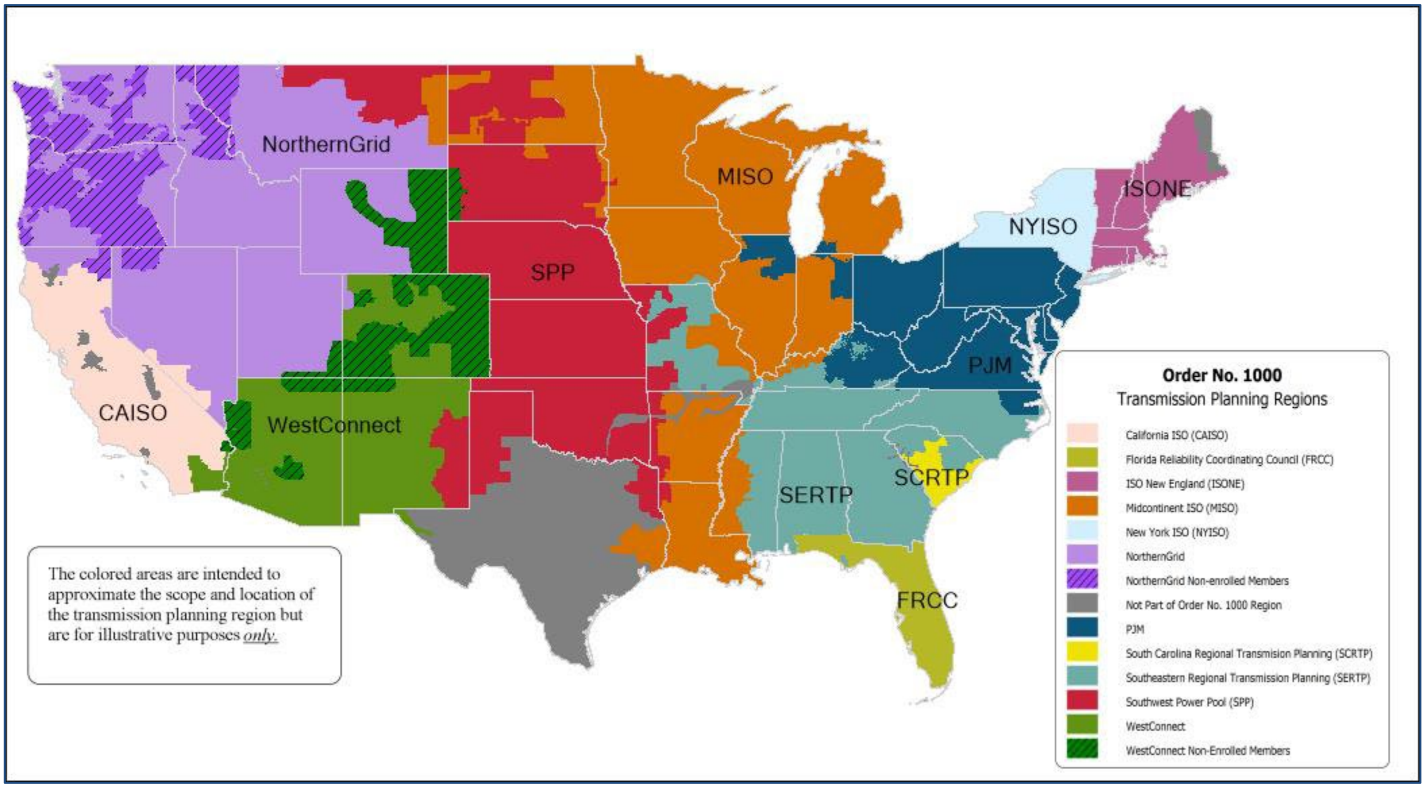


Figure 4.11: Areas Defined in FERC Order 1000[79]

[79] An electronic version of this map can be found [here](ferc.gov) (ferc.gov)

Interface W1001: British Columbia -> Northern Grid

Interface Direction	2024 Summer	2024/25 Winter
British Columbia -> Northern Grid	2,435 MW	2,164 MW

Interface W1002: Alberta -> Northern Grid

Interface Direction	2024 Summer	2024/25 Winter
Alberta -> Northern Grid	981 MW	1,286 MW

Interface W1003: Northern Grid <-> California ISO

Interface Direction	2024 Summer	2024/25 Winter
Northern Grid -> California ISO	4,140 MW	8,705 MW
California ISO -> Northern Grid	1,985 MW	5,208 MW

Interface W1004: Northern Grid <-> West Connect

Interface Direction	2024 Summer	2024/25 Winter
Northern Grid -> West Connect	2,842 MW	3,326 MW
West Connect -> Northern Grid	5,710 MW	1,865 MW

Interface W1005: California ISO <-> West Connect

Interface Direction	2024 Summer	2024/25 Winter
California ISO -> West Connect	2,534 MW	2,375 MW
West Connect -> California ISO	2,967 MW	3,912 MW

Interface E1001: Saskatchewan -> SPP

Interface Direction	2024 Summer	2024/25 Winter
Saskatchewan -> SPP	0 MW	665 MW

Interface E1002: SPP <-> MISO

Interface Direction	2024 Summer	2024/25 Winter
SPP -> MISO	7,058 MW	1,513 MW
MISO -> SPP	5,308 MW	6,403 MW

Interface E1003: SPP <-> SERTP

Interface Direction	2024 Summer	2024/25 Winter
SPP -> SERTP	4,857 MW	2,814 MW
SERTP -> SPP	2,822 MW	6,324 MW

Interface E1004: Manitoba -> MISO

Interface Direction	2024 Summer	2024/25 Winter
Manitoba -> MISO	3,058 MW	3,058 MW

Interface E1005: Ontario -> MISO

Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO	2,419 MW	1,834 MW

Interface E1006: MISO <-> PJM

Interface Direction	2024 Summer	2024/25 Winter
MISO -> PJM	5,593 MW	12,552 MW
PJM -> MISO	9,146 MW	10,771 MW

Interface E1007: MISO <-> SERTP

Interface Direction	2024 Summer	2024/25 Winter
MISO -> SERTP	6,976 MW	9,543 MW
SERTP -> MISO	0 MW	9,801 MW

Interface E1008: SERTP <-> PJM

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> PJM	8,609 MW	9,782 MW
PJM -> SERTP	7,704 MW	7,905 MW

Interface E1009: SERTP <-> SCRTP

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> SCRTP	1,767 MW	1,948 MW
SCRTP -> SERTP	2,415 MW	2,335 MW

Interface E1010: SERTP <-> FRCC

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> FRCC	2,918 MW	1,803 MW
FRCC -> SERTP	1,058 MW	0 MW

Interface E1011: PJM <-> New York[80]

Interface Direction	2024 Summer	2024/25 Winter
PJM -> New York	635 MW	858 MW
New York -> PJM	3,136 MW	3,394 MW

[80] Power flow cases used to calculate these TTC values reflected the operating agreements between PJM and the New York Independent System Operator (NYISO).

Chapter 5: Prudent Additions (Part 2) Inputs

Selected Weather Years

Part 2 used a two-pronged approach for inputs and assumptions to study a variety of conditions across 12 different weather years. This approach combined synthetic, modeled datasets from 2007 to 2013[81] with historical, actual data from 2019[82] to 2023, as shown in **Figure 5.1**. This combination increased the number of weather years available for analysis and helped overcome the limitations in both types of datasets.

Figure 5.1: Two-Pronged Approach for Historical Weather Data

Note: The hourly energy margin analysis did not simulate historical operations, but rather applied historical weather year data to simulate future grid operations under similar conditions.

The synthetic approach used historical weather data to estimate load and resource availability if those same weather conditions were to occur again in the future. The historic approach used historical measured data for load, as well as wind and solar resource output, from recent years and scaled it appropriately to represent future conditions. More detail on these approaches is shown in **Appendix A**, including sources from the National Renewable Energy Laboratory (NREL), the Energy Information Administration (EIA), and FERC forms.

By evaluating all hours of the year across 12 weather years, Part 2 inherently evaluates resource availability, load, and opportunities for energy transfers between TPRs during both normal and extreme weather over more than 105,000 hours. A list of known extreme weather events embedded in the Part 2 analysis include:

- Intense Florida Cold Wave, 2010
- Intense Southern Cold Wave, 2011
- Western Wide Area Heat Domes, 2020-2022
- Winter Storm Uri, 2021
- Winter Storm Elliott, 2022
- Midwest Wind Drought, 2023
- Western and Midwest Heat Waves, 2023
- Northeast Heat Wave, 2023

While using 12 weather years provides a diverse set of extreme weather conditions to evaluate, it should not be interpreted as representative of all possible conditions. If, for example, one TPR does not show a resource deficiency in the 12 weather years evaluated, it does not mean that it is robust against all weather conditions. This is important when considering when and where resource deficiencies arise and when additional transfer capability can mitigate these risks.

The studied weather years should not be interpreted as representative of all possible extreme weather conditions.

[81] 2013 is the last year with available National Renewable Energy Laboratory (NREL) Wind Toolkit data.
[82] 2019 is the first full calendar year with available Energy Information Administration (EIA) Form EIA-930 data.

Load Assumptions

A range of load conditions across the grid was studied, time-synchronized and correlated with respect to weather. Of particular interest is the load, which may be much higher during extreme weather conditions than forecasted in the 2023 LTRA data submissions.[83] A combination of historical load (2019-2023) and synthetic load (2007-2013) was used to capture a range of hourly variability in load for each TPR. Recent historical loads were used to capture recent weather events and associated load behavior as they occurred, using the EIA 930 hourly demand data. Synthetic loads were used to supplement the range of load behavior during weather conditions that may not be represented in the recent five-year history, with the further benefit of isolating electrification impacts and economic growth in the load profiles. The hourly profiles were then scaled to the LTRA forecasted load on both an energy and seasonal peak basis. Additional detail on the data source and load scaling done for the load profiles is available in **Appendix B**.

The overall goal of scaling the weather year profiles was to provide hourly profiles that reflect the varying magnitude and timing of peak load across each TPR that were scaled to forecasted annual energy and peak demand targets. The result of the scaling effort maintains the underlying weather variability but increases the overall peak and energy values to align with the LTRA, maintaining variations in seasonal peak load across weather years. This approach was reviewed by the ITCS Advisory Group. Tables that show the resulting peak loads are available in **Appendix C**.

Resource Mix

Resource portfolios for the Part 2 analysis, aligned with the 2023 LTRA, included existing generators, retirements, Tier 1 resources, and a portion of Tier 2 resource additions to create portfolios for 2024 and 2033.

The LTRA is a NERC assessment of supply and demand on a peak-hour basis, evaluating the winter and summer seasonal reserve margins for North American areas, considering the expected contribution of each resource type during the peak load hours. In Part 2 of the ITCS, however, the LTRA resource mix was evaluated across all hours of the year, and multiple weather years by varying hourly loads and resource supply.

Two study years were the starting points for evaluation in Part 2:

- **2024 Case:** Included all existing resources, plus certain retirements and Tier 1 resource additions online by the summer season, the 2024 peak load, and the annual energy forecast from the LTRA.
- **2033 Case:** Included all existing resources, plus certain retirements and Tier 1 resource additions expected by 2033, the 2033 peak load, and the annual energy forecast from the LTRA. Further, new resources were added to TPRs that retired capacity in the LTRA by also adding a portion of Tier 2 and Tier 3 resources.

Unit-level information was used to distinguish between fuel types and to map generation capacity to each TPR from the larger LTRA assessment areas. The analysis considered resource availability across aggregated fuel types, including natural gas (single fuel and dual-fuel), coal, oil, nuclear, hydro, land-based wind, offshore wind, utility-scale solar, behind-the-meter solar, pumped storage hydro, and battery storage. It did not perform any unit-specific modeling but captured variability in resource availability at the aggregate level based on historical performance and synthetic weather conditions.

Winter and summer seasonal capacity ratings were used to represent installed capacity for each TPR by fuel type, except for solar and wind resources, where nameplate capacity was used. Using the LTRA winter and summer capacity ratings for 2024 and 2033 ensures that capacity mixes in Part 2 include retirements and units unavailable for other reasons in a manner consistent with the LTRA.

[83] The 2023 LTRA can be found here.

Resources were assigned to TPRs based on their geographic locations. Contractual obligations between generation units and load in a different TPR were not considered. This is an appropriate modeling choice for determining the amount of transfer capability needed to transfer energy from one TPR to another. As such, energy deficiency as modeled does not imply that an entity is failing to meet its resource adequacy obligations.

The LTRA generator and load data was aligned to the TPRs used in Part 1 for both existing and future resource additions. For example, the SPP LTRA assessment area was divided into SPP-N and SPP-S TPRs so that the energy analysis used the same breakdown as Part 1. Given the differences between resource and transmission planning, some resource differences between Part 1 and Part 2 analysis were expected. Additional detail can be found in **Appendix D**.

2024 Resource Mix

Figure 5.2 shows the winter capacity of the 2024 resource mix by TPR and type based on the LTRA data forms. Additional details, including summer resource capacity values, can be found in the TPR-specific tables in **Chapter 9**.

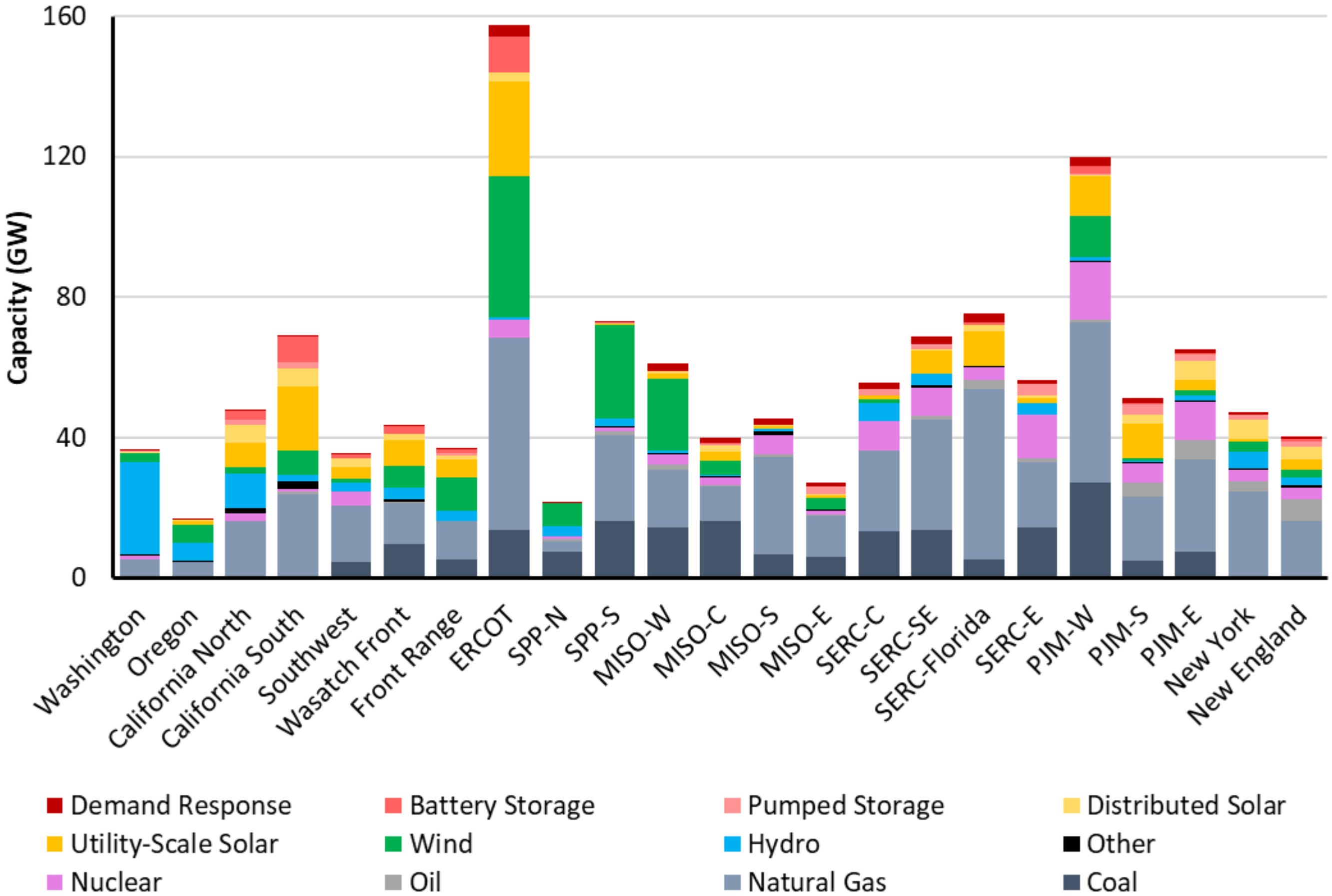


Figure 5.2: Capacity, Existing + Tier 1 Resources (2024 Case)

2033 Resource Mix

The capacity mix for the 2033 study year required adjustments relative to using the existing plus Tier 1 resources provided in the LTRA data forms. Tier 1 resources generally represent plants that are under construction or have high confidence to be online. An initial review revealed that Tier 1 additions are insufficient alone to meet 2033 load growth expectations because Tier 1 resources are inherently more near-term than the 10-year-out case. However, review of the Tier 2 and Tier 3 resources, which include less certain and more speculative resource additions, revealed different application of these tiers across the country. In some cases, the entire generator interconnection queue is included in these tiers, whereas in other cases, no resources were identified as Tier 2 or 3. This disparity necessitated a different approach to ensure that the future capacity mix was reasonable and applied in a consistent manner.

To this end, 2033 capacity mixes were developed based on the reported retirements in that TPR and the types of resources identified in its Tier 2 and 3 lists. If no Tier 2 or 3 resources existed, then Tier 1 was used. The Part 2 study used this "Replace Retirements" scenario. For every MW of retired certain capacity, an equivalent amount of accredited capacity was added. Additional detail regarding the 2033 "Replace Retirements" scenario, including the resulting resource additions, can be found in **Appendix E**. This approach was reviewed by the ITCS Advisory Group.

Figure 5.3 shows the 2033 winter capacity mix by TPR and technology type based on the LTRA data forms.

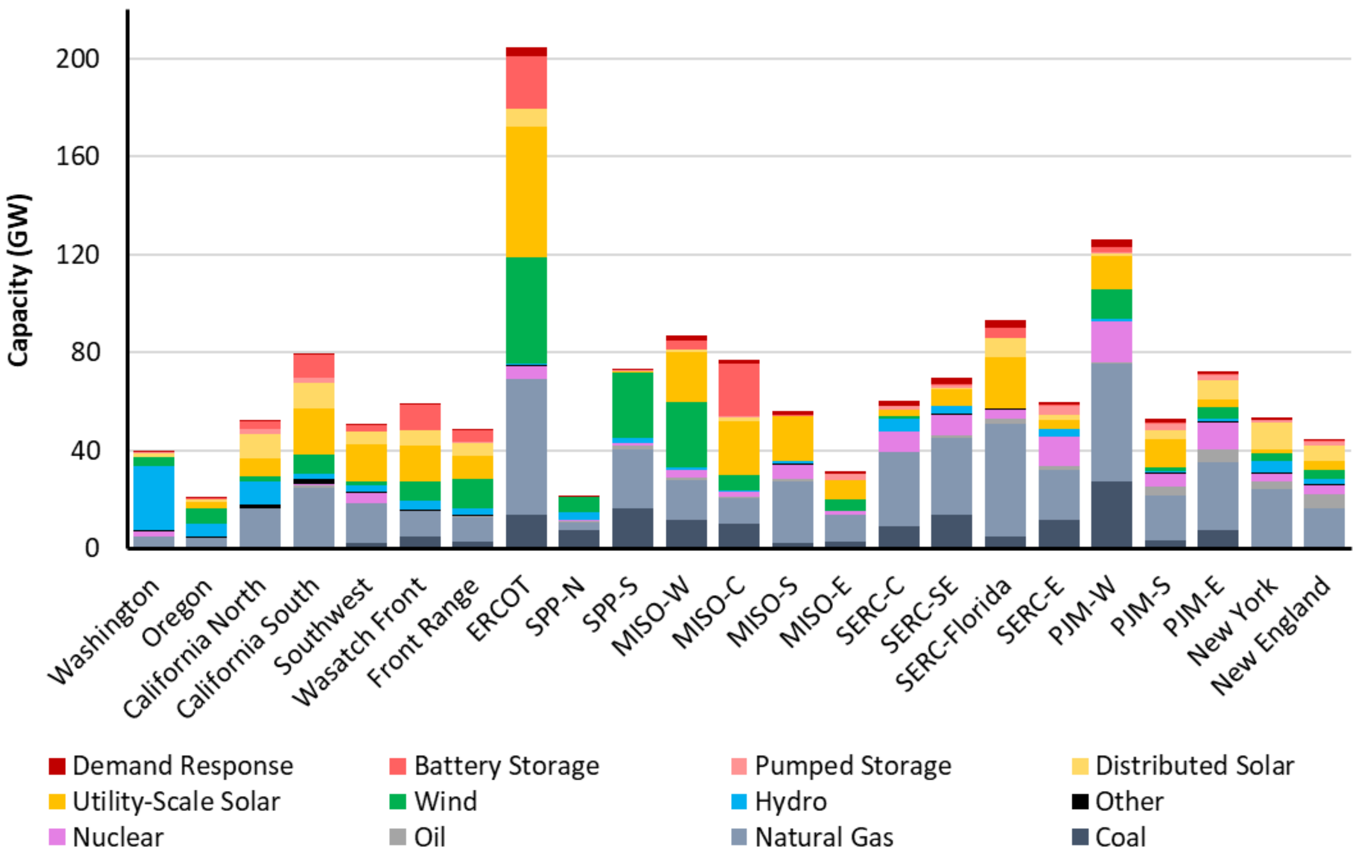


Figure 5.3: Capacity, Existing + Tier 1 + Replace Retirements (2033 Case)

Resource Modeling

Additional detail regarding modeling of certain resource types is noted below. These modeling details were reviewed by the ITCS Advisory Group.

Wind and Solar Modeling

Wind and solar resources were modeled using a combination of historical and synthetic weather year data to represent the hourly energy variability within each TPR. Both datasets described in this section result in hourly capacity factor values for utility scale solar (UPV), distributed behind-the-meter solar (BTM PV), land-based wind (LBW), and offshore wind (OSW). While the underlying datasets for the historical and synthetic weather years are different, as discussed in **Appendix A**, both produced a capacity-weighted profile for each resource type within each TPR, normalized to the installed capacity. As a result, this capacity-weighted profile can be used for different levels of renewable resource capacity. In a few cases, historical data was supplemented with synthetic data for the same weather years, or historical and synthetic data was used to recreate weather years not covered directly by the historical or synthetic record based on temperature and wind-speed relationships. The steps taken to create each set of profiles and descriptions of the underlying data for each weather year profile are provided in **Appendix F**.

Hydro Resource Availability

Hydro resources were modeled with monthly maximum availability factors based on historical observations. While they are renewable resources, the availability of hydro is relatively uncorrelated with wind, solar, and load conditions and affected by longer inter-annual cycles in water availability. Also, hydro resources may be limited in generating at maximum capacity for several reasons in addition to typical generator maintenance and forced outages. These factors include water levels on rivers and constraints due to reservoir levels. To account for these factors on hydro generating potential, a monthly maximum availability was created for each TPR based on historical data, thereby limiting the maximum generation that hydro resources could contribute. No limitations on monthly or annual energy production were applied and it was assumed that the maximum output seen in historical records was the limiting factor for hydro resources.

In Canadian TPRs, like Hydro Québec, where hydro generation regularly serves most or all of the demand throughout much of the year, historical generation data does not fully represent the actual availability of hydro resources, especially during lower load months. Discussion with these entities, where needed, resulted in modifications to the monthly hydro capacity used in the simulations to better reflect resource availability.

Thermal Generator Outage Modeling

Thermal generators were aggregated by TPR and fuel type to account for daily fluctuations in available capacity. Thermal capacity was aggregated by up to eight fuel types in each TPR, resulting in 290 unique capacity aggregations across the North American BPS. These aggregations were done to represent the total, fleet-wide resource availability, rather than individual generator outage sampling traditionally done in resource adequacy modeling.

Each of the 290 aggregated resource types was then modeled to reflect daily fluctuations in available capacity, accounting for fleet-wide maintenance and forced outages, weather-dependent forced outages, and seasonal maintenance schedules. Ambient derates were reflected for summer and winter based on the associated capacity values provided in the 2023 LTRA data forms.

Forced Outages and Derates

Figure 5.4 shows the aggregated capacity of forced outages across the United States on a daily basis from 2016 to 2023, derived from available GADS[84] data. Additional detail regarding these calculations and application can be found in **Appendix G**. The analysis shows daily and seasonal variation in forced outages, but most importantly, extreme spikes in forced outages observed during the January 2018 winter event, Winter Storm Uri (February 2021) and Winter Storm Elliott (December 2022). Generator outage modeling was intentionally done on an aggregated fleet-wide basis to capture correlated outages across large areas.

[84] Generating Availability Data System, a NERC database that includes outages and derates

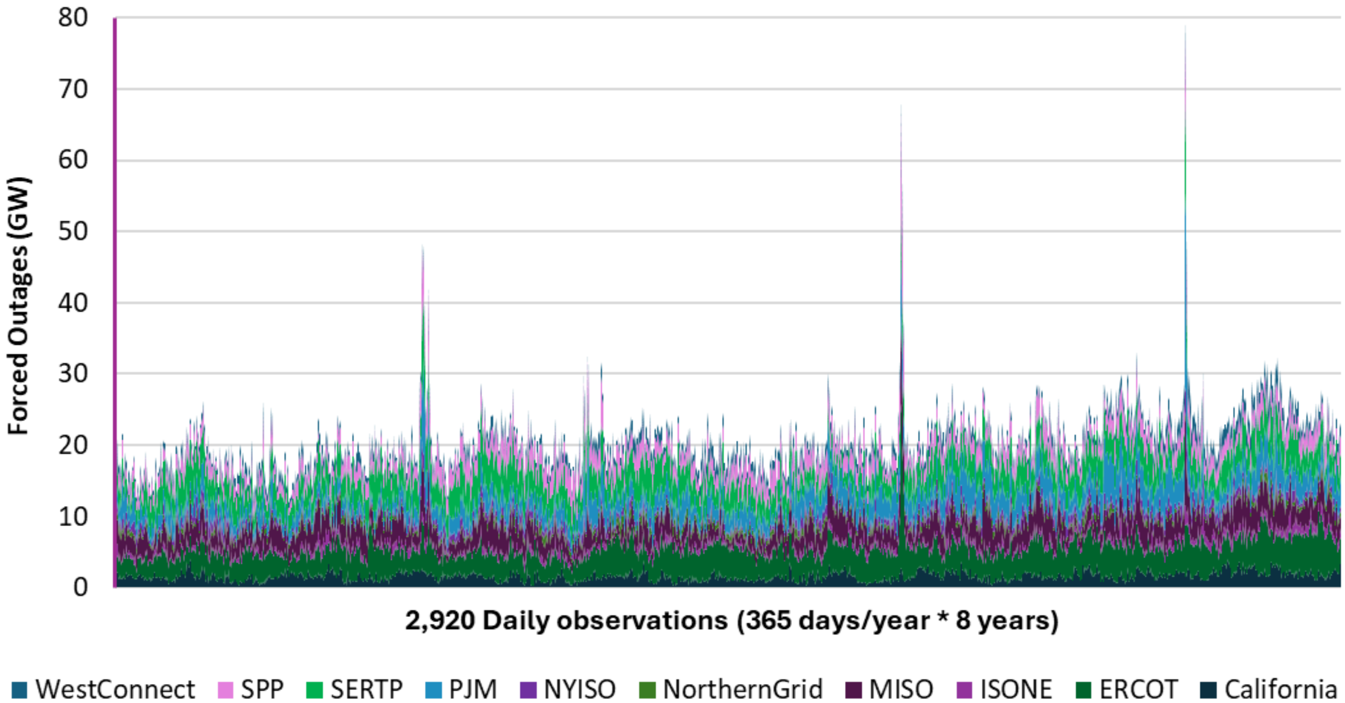


Figure 5.4: Total Daily U.S. Forced Outages and Derates (in GW)

Planned and Maintenance Outages and Derates

Similar to the forced outage rate modeling, planned and maintenance outages and derates were modeled based on historical GADS data, by day, by TPR, and by fuel type. This data in aggregate was converted to an average capacity on outage per day, as a percentage of Net Maximum Capacity.

An example of the combined capacity on outage (Forced Outages and Maintenance) is provided in **Figure 5.5** for a single TPR and single fuel type (natural gas, single fuel). This figure clearly shows the seasonal increases in maintenance during the shoulder seasons (spring and fall) and the potential for increased capacity on outage during extreme weather events (e.g., Winter Storm Uri). While the forced outages were higher during this event, less capacity was on planned maintenance because it occurred during the winter season.

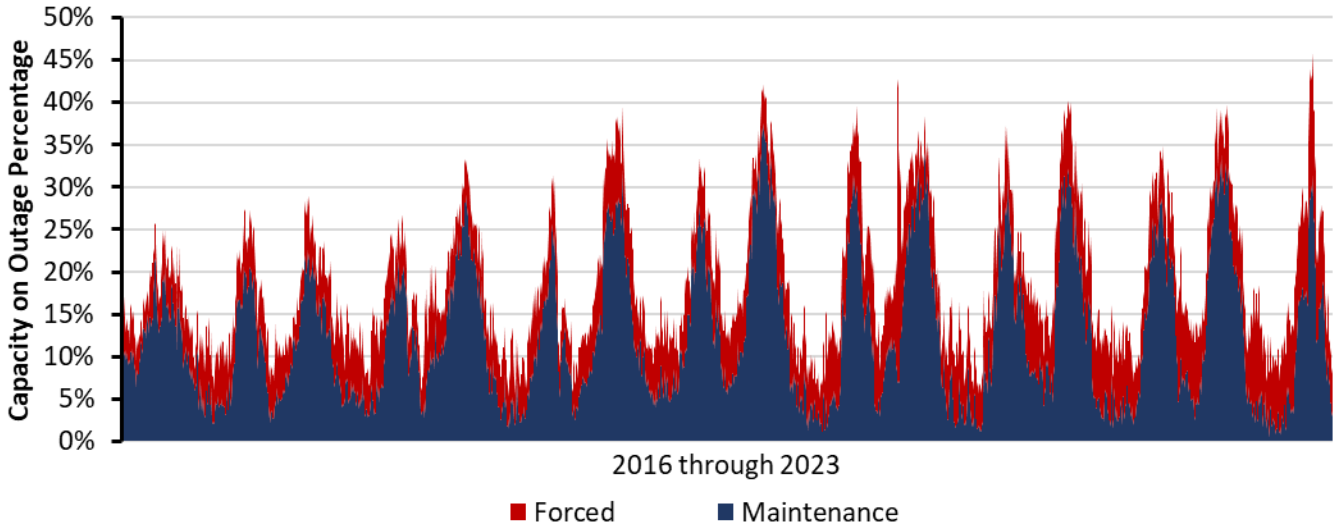


Figure 5.5: Forced and Planned Outages for Single Fuel Natural Gas (% of Capacity)

ERCOT Winterization Mandate

Due to the statewide mandate[85] in Texas directing winterization measures to be implemented across the generation fleet, discussion with the Regional Entity (Texas RE) resulted in a modification to ERCOT resource availability relative to the historical GADS data. Efforts resulting from the winterization mandate are expected to improve thermal resource availability during extreme cold weather events to be no less than 85% of the winter rating. This adjustment was made to the input data for the months of December, January, and February. The winterization case is used as the starting point for ERCOT and is reflected in the energy margin analysis and recommended additions in **Chapter 7**. A comparison of the results with and without the winterization mandate are shown for ERCOT as a sensitivity in **Chapter 8**.

Storage Modeling

Storage resources, both pumped storage hydro and battery storage, were modeled as two distinct units for each TPR. Information regarding installed capacity for each resource type for existing and future capacity builds was taken from the 2023 LTRA. Since information on the duration of each storage plant was limited or not available, it was assumed that pumped storage hydro would have 12 hours of duration and battery storage was four hours[86] based on trends and available battery storage information from the EIA Form 860.

Storage resources were allowed to charge dynamically within the model to create hourly profiles of charging (adding load) and discharging (generation), subject to round-trip efficiency losses of 30% for pumped storage hydro and 13% for battery storage resources. Storage resources were scheduled to arbitrage hourly energy margins, based on the resource scheduling method described in **Chapter 6**. In doing so, storage was charged during periods of high energy margins (surplus resources) and discharged during periods of lower energy margins. Furthermore, the storage resources did not optimize imports/exports between TPRs, although during grid stress events, storage resources were allowed to recharge via imports if available.

Demand Response Modeling

Demand response resources were also included in the model as a supply-side resource that could be dynamically scheduled by the model to mitigate resource deficiency events. Similar to storage resources, demand response was

[85] Texas Public Utilities Commission Weather Emergency Preparedness (adopted September 29, 2022) standards can be found here and here (2 documents).

[86] Three hours was used for ERCOT due to lower duration of existing and planned resources.

modeled assuming both capacity (MW) and energy (MWh) limitations but did not assume any round-trip energy losses or payback required. Demand response was modeled only after energy transfers between TPRs.

Demand response capacity was based on the LTRA Form A data submissions, "Controllable and Dispatchable Demand Response – Available," which represents the estimated demand response available during seasonal peak demand periods. While both "Total" and "Available" demand response capacity values were reported, the "Available" resource potential, shown in **Figure 5.6**, was used to represent any assumed derates due to non-performance when called on. For LTRA assessment areas with multiple TPRs, demand response was allocated proportionally to load.

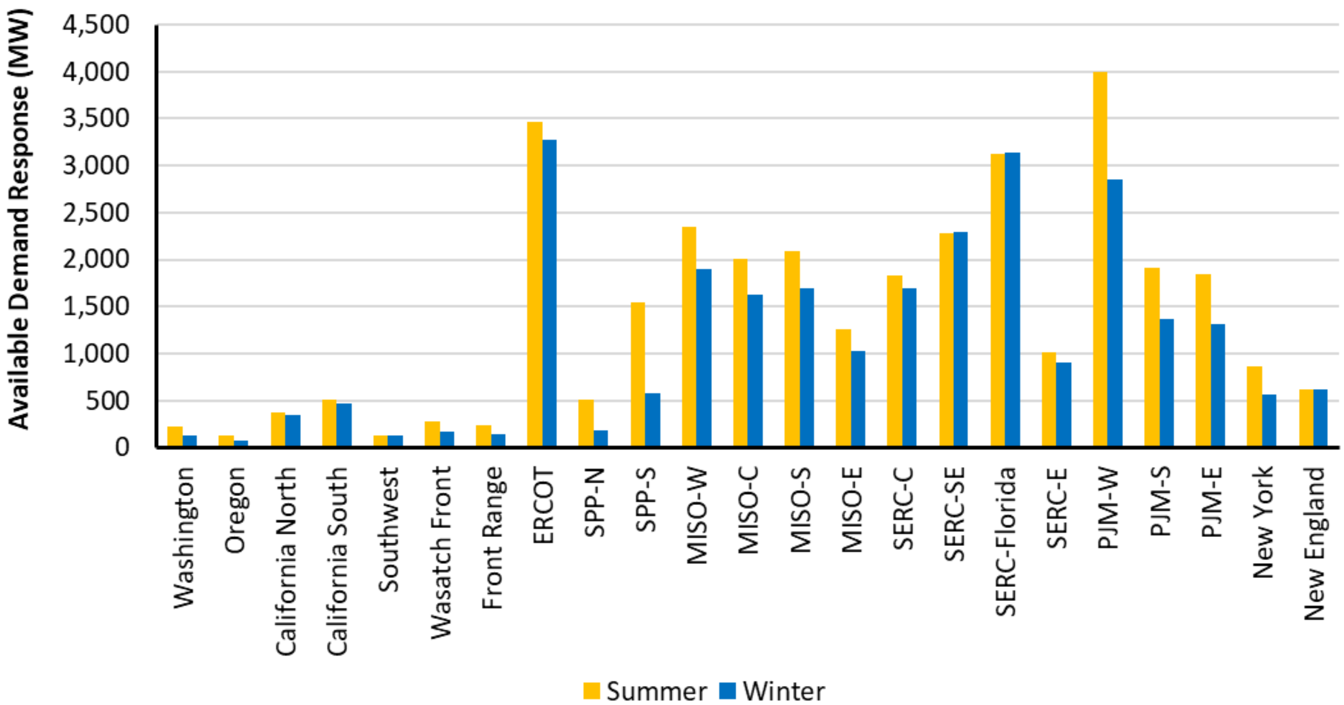


Figure 5.6: Available Demand Response by TPR

Energy constraints were also assumed for demand response resources to ensure that they were deployed sparingly. All demand response resources were modeled with a maximum of three hours per day up to the seasonal capacity. These hourly "per call" constraints were converted into energy constraints, meaning a demand response resource could choose to spread its capacity over six hours in a day, if needed, but would have to do so by deploying only a portion of the total capacity. Lastly, demand response resources were considered the resource of last resort to avoid load shedding, deploying only after all local resources and imports were fully exhausted.

Chapter 6: Prudent Additions (Part 2) Process

Using the multi-year, hourly, correlated, time-synchronized dataset for load, wind, solar, and thermal resource availability described in **Chapter 5**, the prudent additions process identified instances of resource deficiency and evaluated where additional transfer capability would improve energy adequacy. This data-driven process evaluated specific time periods where extreme weather may impact loads and resource availability in one TPR, but neighboring TPRs may have surplus energy available, thus capturing geographic diversity. This approach considered where resource deficiencies occurred, which interfaces were at their limits, and which adjacent TPRs had available energy to export. Specifically, a six-step process was used to identify and quantify prudent additions to transfer capability, each of which is discussed further in this section:

1. Identify hours of resource deficiency
2. Quantify the maximum resource deficiency
3. Prioritize constrained interfaces
4. Allocate additional transfer capability
5. Iterate until resource deficiencies are mitigated
6. Finalize prudent level of transfer capability

Step 1: Identify Hours of Resource Deficiency

The prudent additions process begins with the calculation of the hourly energy margin for each TPR. Unlike traditional planning reserve margins that evaluate the supply and demand during expected peak load conditions, the energy margin analysis is an 8,760-hour chronological assessment of each TPR's load and availability of resources. The energy margin analysis, therefore, provides an assessment of a TPR's potential surplus or deficit across each hour of the year. In addition, the energy margin analysis was conducted over 12 weather years, allowing for fluctuations in load, wind, solar, and thermal resources based on weather conditions, along with seasonal hydro availability.

The energy margin analysis captures the impacts of variable renewables, scheduling of storage resources, expected outage conditions, and load levels associated with specific weather conditions. The formula in **Figure 6.1** below further characterizes the hourly energy margin, followed by an explanation of each property. All properties vary hourly except for available thermal capacity (daily variation) and hydro capacity (monthly variation).

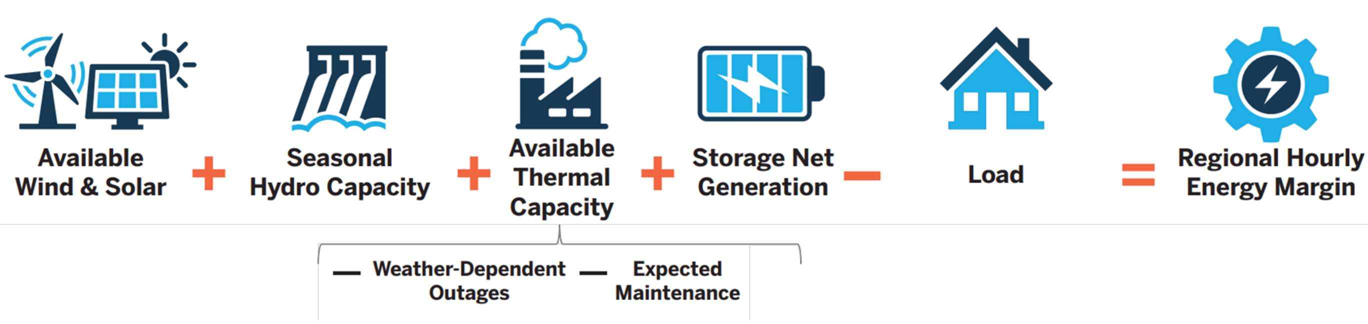


Figure 6.1: Hourly Energy Margin Calculation
Source: Energy Systems Integration Group, 2024

The results of the energy margin analysis provide an *hourly, time-synchronized, locational, and consistent dataset*, allowing for direct comparisons between TPRs. When one TPR has a low hourly energy margin (i.e., a low supply of resources relative to demand), the analysis considers the availability of resources and load in all neighboring TPRs simultaneously. Additional detail regarding the energy margin analysis can be found in **Appendix H**. Below, **Figure 6.2** shows an example of the time-synchronized load, renewable output, weather-dependent outages, and hourly energy margin.

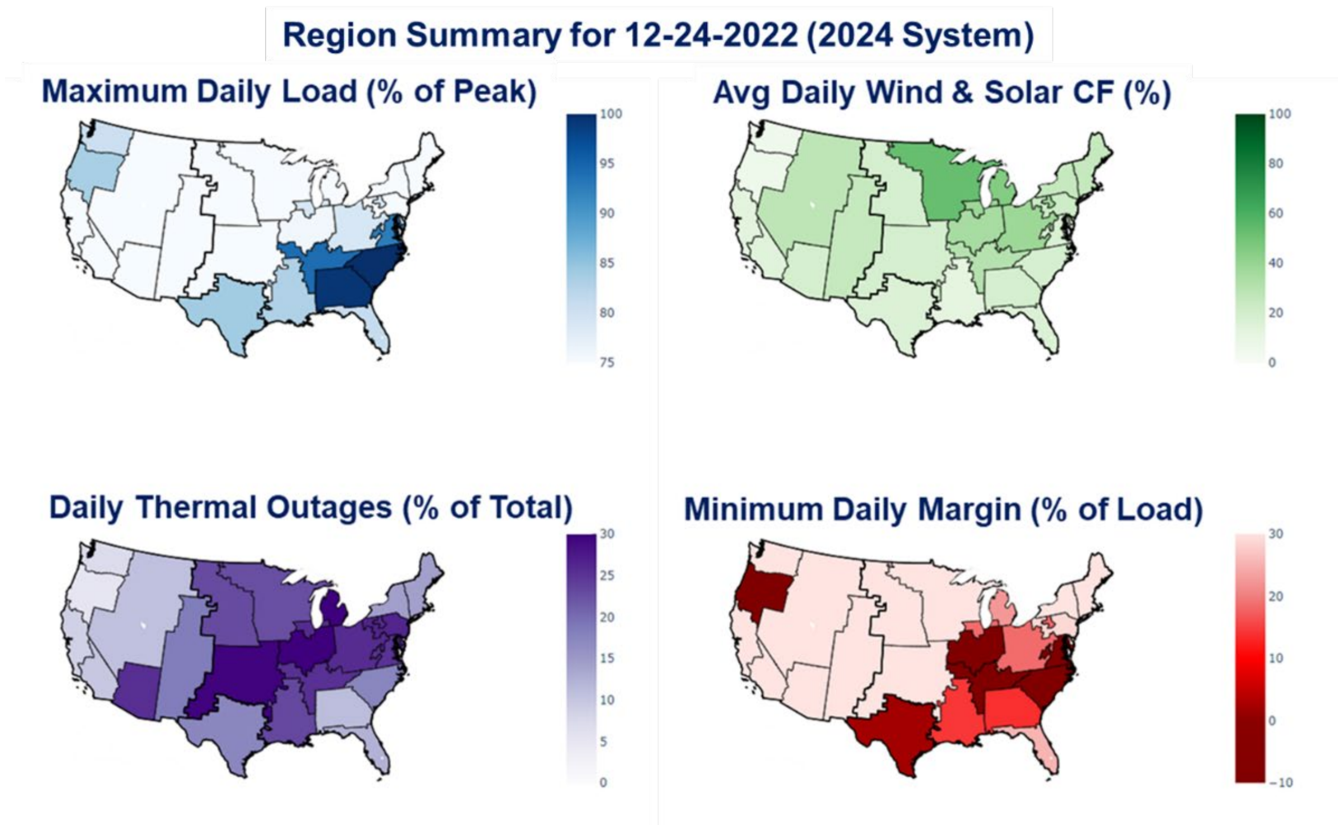


Figure 6.2: Example of Correlated Load, Renewable Output, Weather-Dependent Outages, and Hourly Energy Margin

Resource Scheduling Method

The hourly energy margin is then used to model the available energy across the entire North American BPS for all 12 weather years. This is done to consider the energy adequacy in each TPR, with and without transfers from neighboring TPRs. To isolate reliability needs, resources are first scheduled within a TPR to serve its load before relying on neighboring TPRs. This method allowed for appropriate charge and discharge patterns for energy-limited resources like storage and demand response. The primary reason for using this dispatch model was to ensure that any recommended additions to transfer capability are to improve energy adequacy, and thereby strengthen reliability, rather than for policy or economic objectives, such as minimizing overall production cost. Operating costs are intentionally not considered for resources in this model. Instead, an operating constraint will increase the scarcity weighting factor in a TPR as the margin between supply and demand becomes tighter. This ensures that the dispatch decisions are driven by relative surplus or scarcity rather than resource dispatch costs. Additional information regarding the dispatch model and scarcity weighting factor calculations can be found in **Appendix I**.

Margin Levels

Margins were applied to each TPR's hourly load to account for study uncertainty and operational practices. Unlike a planning reserve margin, which is often denoted in terms of peak demand, these margins are applied to all hours of the year, in an equal percentage of demand.

The first threshold, the **tight margin level**, determines when a TPR will seek to import energy. This threshold, applied across all hours, was set at 10% of the TPR's load based on observed projected daily reserves. This level was discussed and endorsed by the ITCS Advisory Group.

The second margin, the **minimum margin level**, determines when a TPR will incur unserved energy (load reduction) if additional resources or imports are unavailable. Following multiple discussions with, and feedback from, the ITCS Advisory Group, this value was set at 3% of the TPR's load. An additional sensitivity was conducted using a 6% minimum margin level.

A more detailed rationale for these levels is provided in **Appendix J**.

Energy Transfers

Figure 6.3 illustrates the relationship between the hourly energy margin and the conditions under which a TPR may import or export energy. This is crucial for understanding how energy transfers are modeled.

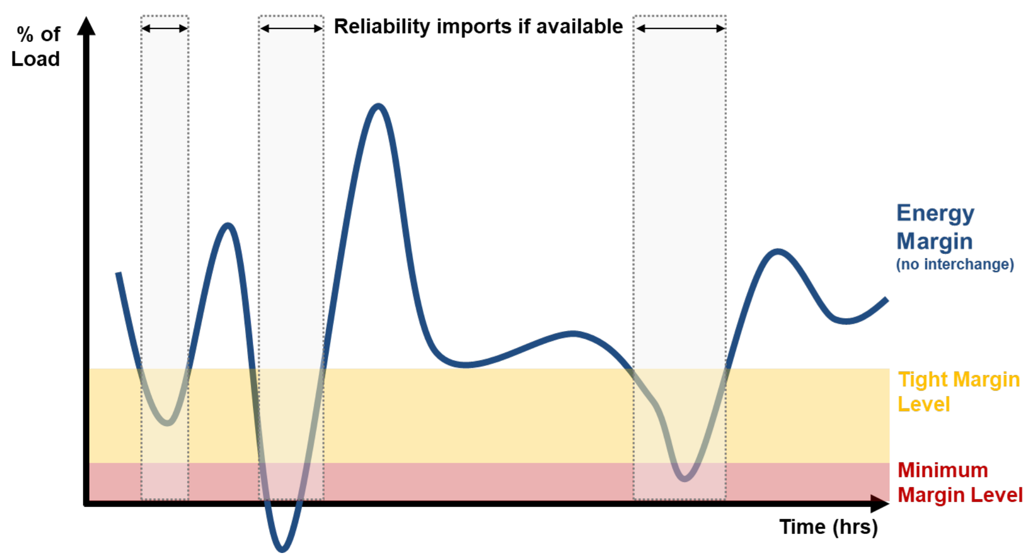


Figure 6.3: Illustrative Example of the Hourly Energy Margin and Reserve Levels

The line represents the hourly energy margin for a TPR, showing the difference between available energy supply and the TPR's load, fluctuating due to changes in supply and demand discussed previously. Two different threshold levels are also shown:

- The **tight margin level** (yellow zone) indicates the desired margin under normal conditions. When the energy margin is above this zone, the TPR is in surplus and is a good candidate to export energy to other TPRs that may need additional energy. When the energy margin is within this level, the TPR has enough capacity to meet its load, but uncertainty in the forecast (resource mix, load levels, weather impacts, outages, etc.) may warrant additional energy imports if available. The tight margin level dictates **when** TPRs will import energy from their neighbors, if it is available.
- The **minimum margin level** (red zone) marks the minimum permissible threshold, below which the TPR faces a resource deficiency. In this red zone, it is assumed that the TPR may experience load reduction if energy

imports from neighbors are unavailable. This retention of reserves is consistent with normal operating practices, where a Balancing Authority will continue to hold reserves even if involuntary load shed is underway to safeguard the system from cascading or widespread outages that would adversely affect overall BPS reliability. The minimum margin level determines **when**, and to **what extent**, new transfer capability is considered to mitigate the energy deficiency.

Visualized another way, **Figure 6.4** shows how the model will attempt to import energy any time that a TPR's energy margin drops below the tight margin level.

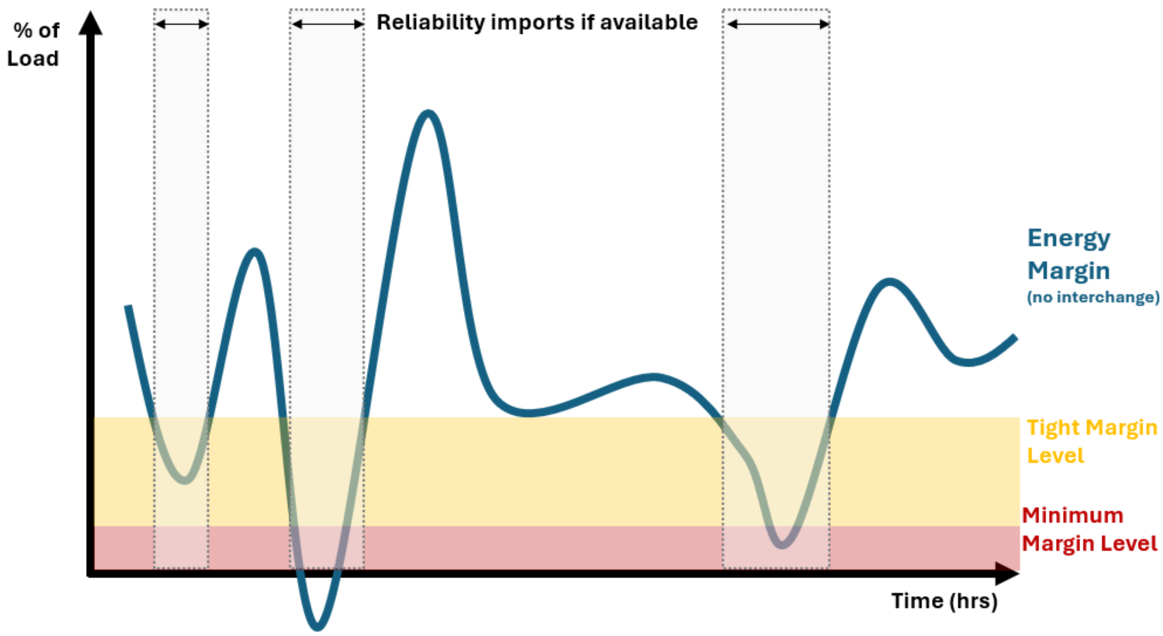


Figure 6.4: Illustrative Example when Imports Occur in the Model

The method for determining transfers between TPRs relies heavily on the tight margin level and minimum margin level. While each TPR initially uses its available resources to meet demand and associated margin, as the energy margin tightens, its scarcity weighting factor increases to reflect the growing need for additional resources.

When a TPR falls below the tight margin level, it begins to import energy from neighboring TPRs. The decision on which neighbor to import from is based on the respective scarcity weighting factors of those neighbors. This ensures that imports are sourced from neighbors with the most surplus capacity (i.e., the lowest scarcity weighting factor). If sufficient imports are unavailable due to transmission interface limits and/or lack of available resources, the TPR may temporarily violate the tight margin level but will still maintain a minimum margin level. This is referred to as a tight margin hour.

If a TPR's energy margin drops to the minimum margin level after exhausting available imports and demand response, the model will decrease the load served, resulting in unserved energy. This is referred to as a resource deficiency hour.

Figure 6.5 shows the hourly energy margin after interchange is scheduled (light blue line). Exports to neighbors are shown as a reduction in the hourly energy margin when a TPR has relative surplus, while imports are shown as an increase in the hourly energy margin when a TPR drops below the tight margin level.

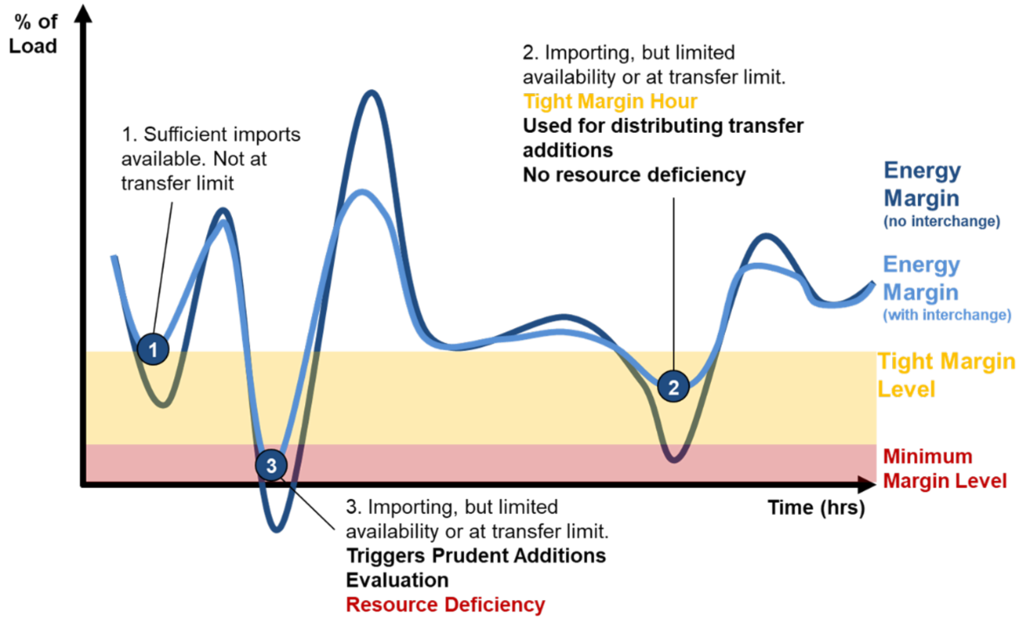


Figure 6.5: Illustrative Example Showing Impacts of Imported Energy

Metrics

Three important points can be considered in Figure 6.5 above:

- **Point 1** indicates that a TPR, in isolation, is below the tight margin level but there is sufficient transfer capability to import energy from its neighbors to maintain the tight margin level. This represents an **interchange hour.** Because the imports allow the TPR to get back to its tight margin level, transfer capability is sufficient and not limiting.
- **Point 2** indicates that a TPR is unable to get back to the tight margin level even with imports. At this point, the transfer capability is insufficient and limited and/or neighboring TPRs do not have sufficient resources to share. This point is referred to as a **tight margin hour**.
- **Point 3** indicates that a TPR is unable to get back to the minimum margin level even with imports from its neighbors. In this example the model will reduce load in the TPR rather than dropping below the minimum margin level, resulting in unserved energy. This is referred to as a **resource deficiency hour** and is used to trigger prudent additions evaluation as described in later steps.

The model performed the above analysis for all TPRs across all hours over 12 weather years. The calculated metrics, which include the hourly energy margin, are shown in Table 6.1.

Table 6.1: Calculated Metrics		
Metric	**Units**	**Description**
Energy Margin	MW or %	Tracks the hourly energy margin of available capacity relative to load over the course of the year. Quantified in both MW and percent and summarized to show average, minimum, or number of times below a threshold.
Interchange Hour	Hours, MW, or MWh	Quantifies the number of hours, maximum flow, or total energy when a TPR imports to keep its hourly energy margin at the tight margin level. This metric calculates the frequency and quantity of imports for each TPR.
Tight Margin Hour	Hours, MW, or MWh	Quantifies the number of hours in a year, maximum deficit (MW), or total deficit (MWh) when a TPR is below the tight margin level (10%).[87] This metric quantifies how often the transfer capability is insufficient due to interface limit **or** due to lack of resources.
Resource Deficiency Hour	Hours, MW, or MWh	Quantifies the number of hours in a year, maximum deficit (MW), or total deficit (MWh) when a TPR is at the minimum margin level (3%)[88] and experiences unserved energy.
Hours Congested	Hours	Quantifies the number of hours in a year where the transfer capability is at the maximum import capacity. This metric quantifies how often an interface's transfer capability is insufficient.

Step 2: Quantify Maximum Resource Deficiency

In Step 1, the energy margin analysis quantified the frequency, magnitude, and duration of energy deficiency for each TPR. To illustrate the output of this process, a portion of the 2033 energy margin analysis results are shown in Table 6.2 below. Specifically, this table shows the yearly maximum resource deficiency (in MW) for each of the 12 weather years, with winter deficiencies highlighted in blue and summer deficiencies shown in orange. The full set of energy margin analysis results can be found in Chapter 7.

Table 6.2: Maximum Resource Deficiency (MW) for Select TPRs by Weather Year (2033 Case)													
Transmission Planning Region	**WY2007**	**WY2008**	**WY2009**	**WY2010**	**WY2011**	**WY2012**	**WY2013**	**WY2019**	**WY2020**	**WY2021**	**WY2022**	**WY2023**	**Max Resource Deficiency**
California North	0	0	0	0	0	0	0	0	0	0	3,211	0	3,211
ERCOT	1,361	0	0	9,400	0	0	0	8,977	14,853	18,926	14,321	12,108	18,926
SPP-N	0	0	0	0	0	0	0	0	0	155	0	0	155
SPP-S	0	0	0	0	0	0	0	0	0	4,137	0	0	4,137
MISO-S	0	0	560	0	629	0	0	0	0	0	0	0	629
MISO-E	0	0	0	0	1,676	0	0	0	5,715	979	0	0	5,715
SERC-Florida	0	0	1,030	1,152	0	0	0	0	0	0	0	0	1,152
SERC-E	0	0	0	0	0	0	0	0	0	0	5,849	0	5,849
PJM-S	0	0	0	0	0	0	0	0	0	0	4,147	0	4,147
New York	0	81	0	3,244	1,748	2,631	1,229	0	0	0	0	3,729	3,729
New England	0	0	0	85	0	984	68	0	0	0	0	0	984

The largest yearly maximum resource deficiency identified across all 12 weather years is known as the maximum resource deficiency. This value is a critical input to Step 4, described later.

[87] As a reminder, further discussion on the tight margin level can be found in Appendix J.
[88] As a reminder, further discussion on the minimum margin level can be found in Appendix J.

Step 3: Prioritize Constrained Interfaces

Step 3 focuses on identifying constrained interfaces. After determining which TPRs are in deficit (Step 1) and to what extent (Step 2), the third step is to determine which specific interfaces are constrained during tight margin hours by calculating the number of hours that individual interfaces, including total import interfaces, are transferring energy at their TTC. This is quantified as hours congested across each interface. Additionally, the model calculates the difference between the scarcity weighting factors of each TPR when imports occur and the transmission interface is at its limit. This measures the relative resource surplus between potential sending (exporting) TPRs that could help the receiving (importing) TPR.

The difference between the scarcity weighting factors of the importing and exporting TPRs helps quantify the best candidates for increased transfer capability. In cases where the total import interface is constrained, the difference between the scarcity weighting factor between each pair of TPRs is still quantified and is used as the measure to increase *both* the individual interface capability and the total import interface limit.

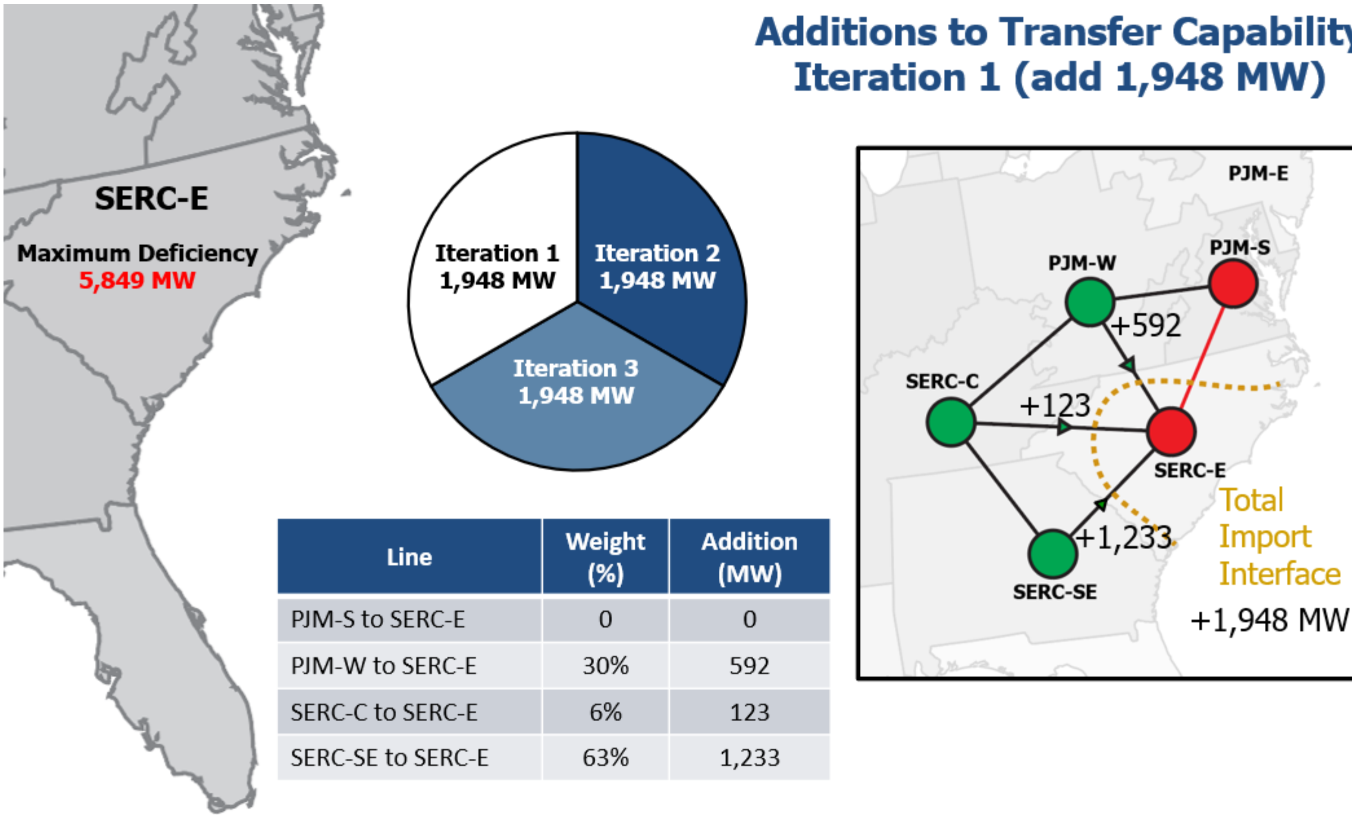
As an example, the 2033 energy margin analysis showed SERC-E in a resource deficiency during WY2022 (Winter Storm Elliott). Neighbors PJM-W, SERC-C, and SERC-SE are already exporting resources to SERC-E, which has reached its transfer capability. During this event, SERC-SE has the lowest scarcity weighting factor, followed by PJM-W, then SERC-C. The scarcity weighting factors indicate that transfer capability should be prioritized from SERC-SE, followed by PJM-W, then SERC-C. The interface from PJM-S, which is not at its limit, would not benefit from additional transfer capability during this event, as it has no surplus resources available.

This calculation is repeated for all TPRs for all tight margin hours.

Step 4: Allocate Additional Transfer Capability

Step 4 focuses on programmatically allocating transfer capability increases to constrained interfaces to address the Maximum Resource Deficiencies (identified in Step 2), using the scarcity weighting factors (calculated in Step 3). Specifically, the model initially allocates transfer capability increases of one third (33.3%) of the maximum resource deficiency proportionally to interfaces based on the relative difference in scarcity weighting factors, thereby prioritizing neighboring TPRs with relatively more surplus energy available. This partial increase allows the modeling method to capture interactive effects between TPRs and iterative effects as resources are re-dispatched, including exhaustion of surplus resources.

Continuing with the SERC-E example from the previous steps, the maximum resource deficiency observed in the 2024 energy margin analysis is 5,849 MW. The initial increase to transfer capability is 1,948 MW, one third of that amount. Using the difference in the scarcity weighting factors between the exporting TPR and importing TPR from Step 3, this additional transfer capability is allocated 30% to PJM-W (592 MW), 6% to SERC-C (123 MW), and 63% to SERC-SE (1,233 MW), as shown in **Figure 6.6.**



Line	Weight (%)	Addition (MW)
PJM-S to SERC-E	0	0
PJM-W to SERC-E	30%	592
SERC-C to SERC-E	6%	123
SERC-SE to SERC-E	63%	1,233

Figure 6.6: SERC-E Iteration 1 Allocation of Additional Transfer Capability (2033 Case)

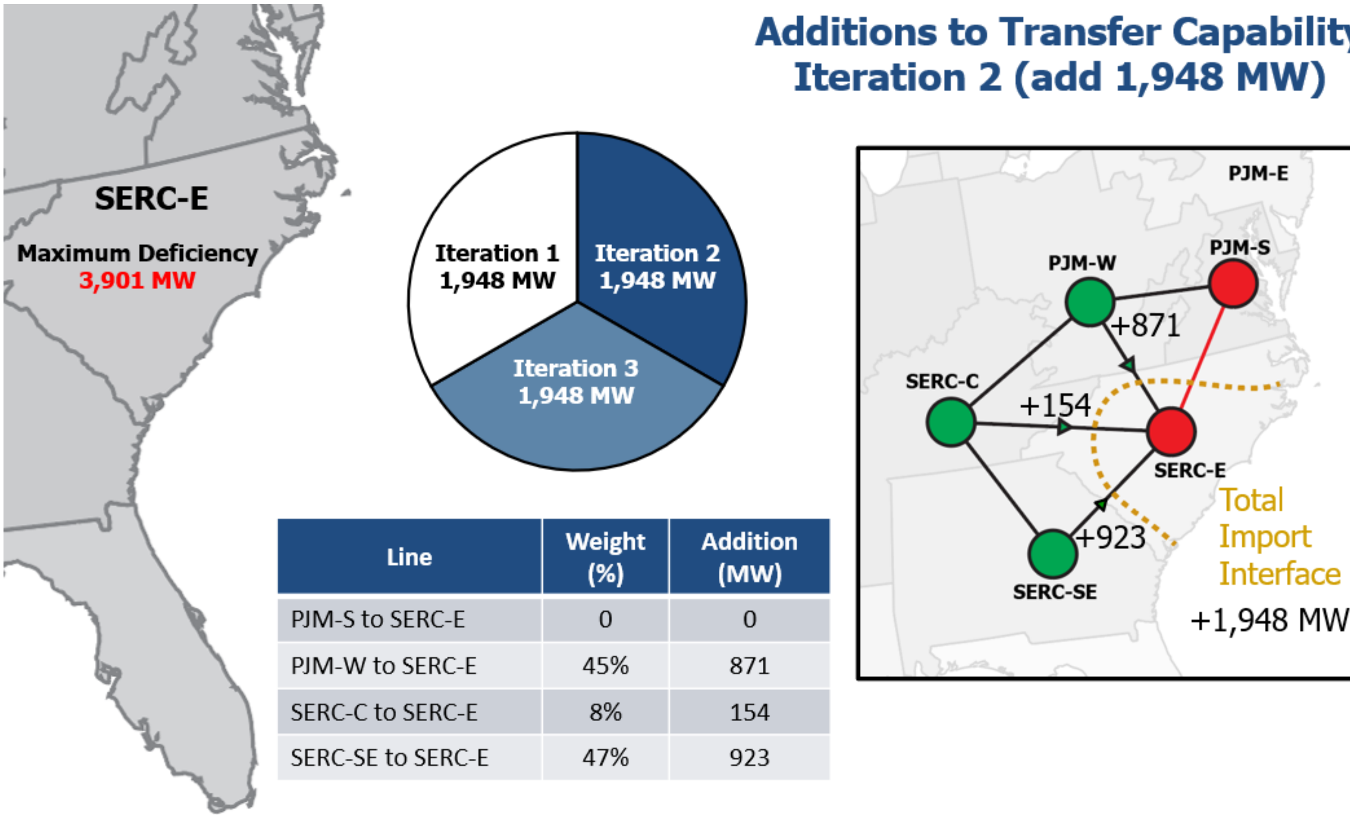
Iterate

Step 5: Iterate Until Resource Deficiencies are Resolved

Step 5 employs an iterative approach to incremental additions to transfer capability until all resource deficiencies are mitigated (if possible). The modeling method employed in Steps 1-4, including the energy margin analysis, is repeated with the increased transfer capability included.

The study repeated the process of adding transfer capability to constrained interfaces in blocks set at one third of the original maximum resource deficiency amount until all resource deficiency events were mitigated or until improvements stopped because there were no available resources from neighboring TPRs. This iterative approach ensures that the model accurately reflects the impact of each incremental change on the overall system, captures interactive effects, and allows for the finalization of prudent additions to be conducted after all modeling is complete rather than directly in the modeling process.

As shown in **Figure 6.7**, after one iteration of additional transfer capability, the maximum resource deficiency decreased to 3,901 MW, a reduction of 1,948 MW. The second increase to transfer capability is again 1,948 MW (one third of the original maximum resource deficiency), but this time the allocation is 45% to PJM-W (871 MW), 8% to SERC-C (154 MW), and 47% to SERC-SE (923 MW), again based on the differences in scarcity weighting factors. This reflects tightening conditions in SERC-SE and is an intentional result of the iterative process.

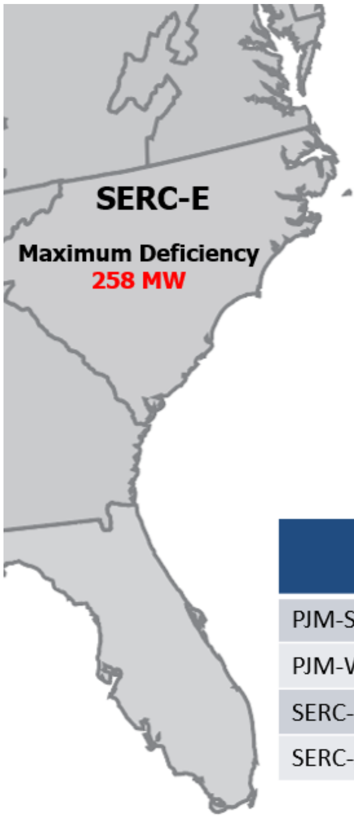


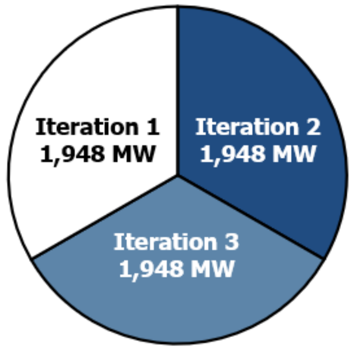
Line	Weight (%)	Addition (MW)
PJM-S to SERC-E	0	0
PJM-W to SERC-E	45%	871
SERC-C to SERC-E	8%	154
SERC-SE to SERC-E	47%	923

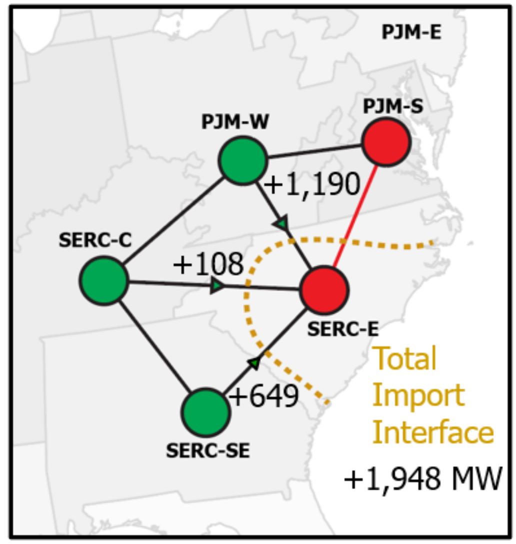
Figure 6.7: SERC-E Iteration 2 Allocation of Additional Transfer Capability (2033 Case)

As shown in **Figure 6.8**, after two iterations of additional transfer capability, the maximum resource deficiency decreased to 258 MW, a further reduction of 3,643 MW, or 187% of the transfer capability added in Iteration 2, which is due to multiplier effects described in **Chapter 7**. Despite the highly effective second iteration, there are still resource deficiency hours observed, so the process is repeated a third time. The third increase to transfer capability is again 1,948 MW (one third of the original maximum resource deficiency), and this time the allocation is 61% to PJM-W (1,190 MW), 6% to SERC-C (108 MW), and 33% to SERC-SE (649 MW) as surplus resources tighten in SERC-SE. Because of the highly effective second iteration, the programmatic third iteration size (1,948 MW) is larger than the remaining resource deficiency, and this will be adjusted proportionally in Step 6. After the third iteration, all maximum resource deficiency hours have been mitigated.

Additions to Transfer Capability
Iteration 3 (add 1,948 MW)







Line	Weight (%)	Addition (MW)
PJM-S to SERC-E	0	0
PJM-W to SERC-E	61%	1,190
SERC-C to SERC-E	6%	108
SERC-SE to SERC-E	33%	649

Figure 6.8: SERC-E Iteration 3 Allocation of Additional Transfer Capability (2033 Case)

Finalize

Step 6: Finalize Prudent Levels of Transfer Capability

Step 6 uses the results from the multiple iterations of Steps 1-5 described above. After completing all incremental modeling runs, the outputs were used to determine the recommended additions to transfer capability. This final step ensures that the recommendations are right-sized and effective, including identification of scenarios where additional transfer capability would not mitigate identified resource deficiencies. As a reminder, these recommended additions were based off the calculated 2024/25 current transfer capability values from Part 1, applied to the projected 2033 load and resource mix.

Prudent Additions Criteria

The following criteria[89] were applied when finalizing recommendations for prudent additions:

- Recommended additions were made to maintain a 3% minimum margin level,[90] if possible.
- Where practical, all resource deficiency hours were mitigated (i.e., there was no minimum threshold for the number of resource deficiency hours).
- While all resource deficiency hours were reported for each TPR, recommendations were only made to address resource deficiencies greater than 300 MW.[91]
- Recommended additions were rounded to the nearest 100 MW increment.
- Recommended additions address limiting interfaces and total import interfaces for the applicable season(s) where resource deficiency was identified.

[89] These criteria served as mechanisms to guide the application of sound engineering judgment so that prudent addition recommendations are reasonable. Since ITCS is a reliability study, economic and policy objectives were not considered when making recommendations.

[90] This level was established based on an evaluation of average reserve requirements where load shed may occur.

[91] This criterion was derived from EOP-004-4.pdf (nerc.com) which prescribes thresholds for disturbance reporting.

- Where additions to transfer capability did not significantly reduce the resource deficiency, it was indicative of a lack of surplus energy in the source TPRs such that continued additions to transfer capability would have minimal benefit – additional transfer capability was considered prudent if it:
  - Reduced the maximum resource deficiency by at least 75% of the additional transfer capability, or
  - Reduced the resource deficiency by at least 100% of the additional transfer capability in at least four hours.

Other Considerations for Prudent Additions

In addition to the criteria above, the following factors were considered:

- Recommended additions were only considered between neighboring TPRs.
  - Transfer capability additions that solely benefit a "neighbor's neighbor" are outside the scope of this study, including the Part 1 analysis.
  - In cases where surplus energy in neighboring TPRs is insufficient to address the deficiency, supplemental reporting is included in **Chapter 7** regarding the nearest non-neighbor TPRs that could assist during resource-deficient hours.
- Recommended additions were prioritized from neighboring TPRs with relatively higher resource surplus, as measured by the difference in scarcity weighting factor discussed in Step 4.
- A 6% minimum margin level sensitivity was also reviewed.[92]
- Changes not reflected in the LTRA data, such as an announcement of delayed retirements, were not considered.
- Several generating units can connect to multiple Interconnections (non-simultaneously) without using the associated interface tie lines, thus they do not deplete the associated transfer capability. This capability should be considered as a potential reduction to the recommended additions and is noted where applicable.

Example of Prudent Additions

Continuing with the 2033 SERC-E example, **Table 6.3** below shows the cumulative iterations of increases to transfer capability. Recalling that the remaining resource deficiency after Iteration 2 was only 258 MW, Iteration 3 was prorated to right-size the additional transfer capability. In accordance with the criteria above, these values were rounded to the nearest 100 MW. As a result, in this example, the prudent additions are 1,600 MW from PJM-W, 300 MW from SERC-C, and 2,200 MW from SERC-SE.

Table 6.3: SERC-E Finalizing Transfer Capability Additions (2033 Case)

Iteration	Transfer Capability Additions (MW)				Max Resource Deficiency (MW)
	PJM-S	PJM-W	SERC-C	SERC-SE	
Base					5,849
Iteration 1	0	592	123	1,233	3,901
Iteration 2	0	871	154	923	258
Iteration 3*	0	155	14	84	0
Total	0	1,618	291	2,240	
Prudent**	0	**1,600**	**300**	**2,200**	

**Prorated Based on Maximum Resource Deficiency* ***Rounded to Nearest 100 MW*

[92] This sensitivity helped inform, for instance, if a TPR was very close to resource deficiency at 3% for a significant number of hours.

Chapter 7: Prudent Additions (Part 2) Recommendations

2024 Energy Margin Analysis Results

The results of the energy margin analysis for the 2024 case are summarized in Table 7.1, which provides an overview of the maximum resource deficiencies observed across various TPRs and weather years. This table illustrates how different TPRs perform using the 3% minimum margin level and identifying where resource shortfalls may occur under specific weather conditions. Note that these results include the ability of TPRs to share resources among each other, subject to resource availability and the current transfer capabilities quantified in Part 1. Blue highlighting indicates that the maximum deficiency occurred in the winter, while orange highlighting represents summer.

Table 7.1: Maximum Resource Deficiency (MW) by TPR and Weather Year (2024 Case)

Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Max Resource Deficiency
Washington	0	0	0	0	0	0	0	0	0	0	0	0	0
Oregon	0	0	0	0	0	0	0	0	0	0	0	0	0
California North	0	0	0	0	0	0	0	0	0	0	0	0	0
California South	0	0	0	0	0	0	0	0	0	0	0	0	0
Southwest	0	0	0	0	0	0	0	0	0	0	0	0	0
Wasatch Front	0	0	0	0	0	0	0	0	0	0	0	0	0
Front Range	0	0	0	0	0	0	0	0	0	0	0	0	0
ERCOT	0	0	0	0	0	0	0	0	2,669	10,699	7,585	8,354	10,699
SPP-N	0	0	0	0	0	0	0	0	0	0	0	0	0
SPP-S	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-W	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-C	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-S	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-E	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-C	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-SE	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-Florida	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-E	0	0	0	0	0	0	0	0	0	0	2,894	0	2,894
PJM-W	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM-S	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM-E	0	0	0	0	0	0	0	0	0	0	0	0	0
New York	0	0	0	0	0	0	0	0	0	0	0	1,242	1,242
New England	0	0	0	0	0	0	0	0	0	0	0	0	0

The analysis reveals that the 2024 case has relatively few resource deficiencies across most TPRs, indicating that, under the current system, there are sufficient resources and transfer capability in place to serve the load under the weather conditions and load levels evaluated. This outcome is significant because it suggests that the existing infrastructure is largely capable of maintaining energy adequacy across diverse scenarios except under especially challenging conditions. As such, the 2024 case serves as a valuable reference point for future comparisons, particularly when evaluating the 10-year out (2033) case. By establishing a baseline using the 2024 resource mix and load, the study can better assess how future changes in resource mixes, load growth, and extreme weather conditions might be impactful over the next decade. As a reminder, the simulations did not attempt to recreate actual operations or the resource mix from previous years. Instead, they applied the historical weather conditions from those years to the projected 2024 resource mix, providing insights into how the future system might respond to similar extreme events.

The 2024 case was used for benchmarking, but the simulations did not attempt to recreate actual operations.

One notable exception is that ERCOT exhibits resource deficiencies across multiple weather years. The most severe deficiency is observed during WY2021, coinciding with the extreme conditions of Winter Storm Uri. ERCOT faced a maximum resource deficiency of approximately 10,700 MW after assuming improvements from winterization efforts.[93]

While Winter Storm Uri can be considered an outlier, the fact that ERCOT also experiences deficiencies in other weather years highlights a broader challenge. The ERCOT system, on average, reaches lower margin levels on a more regular basis than other TPRs. This vulnerability is partly attributable to ERCOT's limited transfer capability, which restricts its ability to import energy from neighboring TPRs during periods of high demand or supply shortages. This limited transfer capability underscores the importance of considering strategic enhancements to ERCOT's interregional connections to bolster its resilience against a variety of conditions. While ERCOT must be prepared to handle extreme conditions like Winter Storm Uri, this study highlights potential for increased transfer capability to address capacity deficiencies and avoid emergency measures, as an additional option along with internal resource additions and demand response.

In addition to ERCOT, other TPRs also show resource deficiencies, albeit on a smaller scale. For instance, New York experienced a deficiency during an early September heatwave in WY2023, while SERC-E encountered challenges during Winter Storm Elliott in WY2022. These instances highlight the potential vulnerabilities under specific extreme weather scenarios. Further details on the timing, size, and magnitude of these individual events are provided in **Chapter 9**, which provides a more granular, TPR-specific analysis.

While Canadian TPRs were included in the overall study, their results are not presented in this table. Instead, these findings will be detailed in a separate Canadian Report, ensuring that the unique characteristics and challenges of those TPRs are appropriately addressed.

In addition to the maximum resource deficiency, the total energy deficiency (GWh) and number of hours of deficiency provide insight into the 2024 case results. **Table 7.2** quantifies the total amount of resource deficiency on an energy basis (GWh) and **Table 7.3** provides the number of resource deficiency hours in each weather year, thus providing additional information on the size, frequency, and duration of events.

[93] In the sensitivity case without winterization efforts, ERCOT's maximum resource deficiency reached approximately 25 GW, a shortfall that mirrors the scale of the actual Winter Storm Uri event.

Table 7.2: Total Resource Deficiency (GWh) by TPR and Weather Year (2024 Case)

Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Avg
Washington	0	0	0	0	0	0	0	0	0	0	0	0	0
Oregon	0	0	0	0	0	0	0	0	0	0	0	0	0
California North	0	0	0	0	0	0	0	0	0	0	0	0	0
California South	0	0	0	0	0	0	0	0	0	0	0	0	0
Southwest	0	0	0	0	0	0	0	0	0	0	0	0	0
Wasatch Front	0	0	0	0	0	0	0	0	0	0	0	0	0
Front Range	0	0	0	0	0	0	0	0	0	0	0	0	0
ERCOT	0	0	0	0	0	0	0	0	4	167	19	44	20
SPP-N	0	0	0	0	0	0	0	0	0	0	0	0	0
SPP-S	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-W	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-C	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-S	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-E	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-C	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-SE	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-Florida	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-E	0	0	0	0	0	0	0	0	0	0	6	0	<1
PJM-W	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM-S	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM-E	0	0	0	0	0	0	0	0	0	0	0	0	0
New York	0	0	0	0	0	0	0	0	0	0	0	4	<1
New England	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 7.3: Annual Hours of Resource Deficiency by TPR and Weather Year (2024 Case)

Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Avg
Washington	0	0	0	0	0	0	0	0	0	0	0	0	0
Oregon	0	0	0	0	0	0	0	0	0	0	0	0	0
California North	0	0	0	0	0	0	0	0	0	0	0	0	0
California South	0	0	0	0	0	0	0	0	0	0	0	0	0
Southwest	0	0	0	0	0	0	0	0	0	0	0	0	0
Wasatch Front	0	0	0	0	0	0	0	0	0	0	0	0	0
Front Range	0	0	0	0	0	0	0	0	0	0	0	0	0
ERCOT	0	0	0	0	0	0	0	0	2	36	4	12	5
SPP-N	0	0	0	0	0	0	0	0	0	0	0	0	0
SPP-S	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-W	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-C	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-S	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-E	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-C	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-SE	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-Florida	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-E	0	0	0	0	0	0	0	0	0	0	5	0	<1
PJM-W	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM-S	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM-E	0	0	0	0	0	0	0	0	0	0	0	0	0
New York	0	0	0	0	0	0	0	0	0	0	0	7	<1
New England	0	0	0	0	0	0	0	0	0	0	0	0	0

The 2024 results provide a useful test case for the analysis, but ultimately are not used to recommend prudent additions. Instead, these recommendations were made based on the 10-year-out analysis, evaluating potential future resource mix and load levels in 2033.

2033 Energy Margin Analysis Results

The 2033 case analysis mirrors the 2024 analysis, but accounts for continued load growth, retirements, and new resource additions. The assumptions for load growth, retirements, and resource additions were based on projections from the 2023 LTRA. Specifically in this case, all Tier 1 resources were added, plus additional Tier 2 resources where necessary to backfill retirements on an effective (accredited) capacity basis as described further in **Appendix E**.

Table 7.4 provides a detailed summary of the maximum resource deficiencies observed across different TPRs and weather years for the 2033 case. Like the 2024 results, the table quantifies the maximum resource deficiency observed in each TPR during each weather year, with the last column highlighting the maximum resource deficiency across all weather years. One difference between **Table 7.1** and **Table 7.4** is that purple highlighting indicates a weather year where resource deficiency hours were observed in both summer and winter.

Table 7.4: Maximum Resource Deficiency (MW) by TPR and Weather Year (2033 Case)

Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Max Resource Deficiency
Washington	0	0	0	0	0	0	0	0	0	0	0	0	0
Oregon	0	0	0	0	0	0	0	0	0	0	0	0	0
California North	0	0	0	0	0	0	0	0	0	0	3,211	0	3,211
California South	0	0	0	0	0	0	0	0	0	0	0	0	0
Southwest	0	0	0	0	0	0	0	0	0	0	0	0	0
Wasatch Front	0	0	0	0	0	0	0	0	0	0	0	0	0
Front Range	0	0	0	0	0	0	0	0	0	0	0	0	0
ERCOT	1,361	0	0	9,400	0	0	0	8,977	14,853	18,926	14,321	12,108	18,926
SPP-N	0	0	0	0	0	0	0	0	0	155	0	0	155
SPP-S	0	0	0	0	0	0	0	0	0	4,137	0	0	4,137
MISO-W	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-C	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-S	0	0	560	0	629	0	0	0	0	0	0	0	629
MISO-E	0	0	0	0	1,676	0	0	0	5,715	979	0	0	5,715
SERC-C	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-SE	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-Florida	0	0	1,030	1,152	0	0	0	0	0	0	0	0	1,152
SERC-E	0	0	0	0	0	0	0	0	0	0	5,849	0	5,849
PJM-W	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM-S	0	0	0	0	0	0	0	0	0	0	4,147	0	4,147
PJM-E	0	0	0	0	0	0	0	0	0	0	0	0	0
New York	0	81	0	3,244	1,748	2,631	1,229	0	0	0	0	3,729	3,729
New England	0	0	0	85	0	984	68	0	0	0	0	0	984

In contrast to the 2024 case, the 2033 results indicate a more widespread challenge to energy adequacy, with additional TPRs exhibiting resource deficiencies and more weather years posing challenges. This is primarily due to tightening energy margins driven by load growth, the changing resource mix, and the application of current transfer capability to the future case.

In the 2033 case, 11 out of 23 TPRs are affected by resource deficiencies in at least one weather year, and in many cases, across multiple weather years. Eight of these TPRs had no deficiencies in the 2024 case.

Similar to the 2024 results, **Table 7.5** quantifies the total amount of resource deficiency on an energy basis (GWh) and **Table 7.6** provides the number of hours of deficiency in each weather year, thus providing additional information on the size, frequency, and duration of events.

Table 7.5: Total Resource Deficiency (GWh) by TPR and Weather Year (2033 Case)													
Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Avg
Washington	0	0	0	0	0	0	0	0	0	0	0	0	0
Oregon	0	0	0	0	0	0	0	0	0	0	0	0	0
California North	0	0	0	0	0	0	0	0	0	0	22	0	2
California South	0	0	0	0	0	0	0	0	0	0	0	0	0
Southwest	0	0	0	0	0	0	0	0	0	0	0	0	0
Wasatch Front	0	0	0	0	0	0	0	0	0	0	0	0	0
Front Range	0	0	0	0	0	0	0	0	0	0	0	0	0
ERCOT	2	0	0	19	0	0	0	37	201	668	91	57	90
SPP-N	0	0	0	0	0	0	0	0	0	<1	0	0	<1
SPP-S	0	0	0	0	0	0	0	0	0	55	0	0	5
MISO-W	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-C	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-S	0	0	1	0	1	0	0	0	0	0	0	0	<1
MISO-E	0	0	0	0	4	0	0	0	128	2	0	0	11
SERC-C	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-SE	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-Florida	0	0	2	2	0	0	0	0	0	0	0	0	<1
SERC-E	0	0	0	0	0	0	0	0	0	0	30	0	3
PJM-W	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM-S	0	0	0	0	0	0	0	0	0	0	45	0	4
PJM-E	0	0	0	0	0	0	0	0	0	0	0	0	0
New York	0	<1	0	18	7	15	3	0	0	0	0	31	6
New England	0	0	0	<1	0	2	<1	0	0	0	0	0	<1

Table 7.6: Annual Hours of Resource Deficiency by TPR and Weather Year (2033 Case)													
Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Avg
Washington	0	0	0	0	0	0	0	0	0	0	0	0	0
Oregon	0	0	0	0	0	0	0	0	0	0	0	0	0
California North	0	0	0	0	0	0	0	0	0	0	17	0	1
California South	0	0	0	0	0	0	0	0	0	0	0	0	0
Southwest	0	0	0	0	0	0	0	0	0	0	0	0	0
Wasatch Front	0	0	0	0	0	0	0	0	0	0	0	0	0
Front Range	0	0	0	0	0	0	0	0	0	0	0	0	0
ERCOT	2	0	0	3	0	0	0	10	24	72	10	14	11
SPP-N	0	0	0	0	0	0	0	0	0	4	0	0	<1
SPP-S	0	0	0	0	0	0	0	0	0	34	0	0	3
MISO-W	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-C	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-S	0	0	2	0	2	0	0	0	0	0	0	0	<1
MISO-E	0	0	0	0	5	0	0	0	50	3	0	0	5
SERC-C	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-SE	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-Florida	0	0	4	2	0	0	0	0	0	0	0	0	<1
SERC-E	0	0	0	0	0	0	0	0	0	0	9	0	<1
PJM-W	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM-S	0	0	0	0	0	0	0	0	0	0	20	0	2
PJM-E	0	0	0	0	0	0	0	0	0	0	0	0	0
New York	0	2	0	12	7	12	4	0	0	0	0	15	4.3
New England	0	0	0	1	0	3	1	0	0	0	0	0	<1

Recommendations for Prudent Additions

As a result of the above analysis, additions to transfer capability are recommended as prudent for 10 TPRs as summarized in **Table 7.7** after following the six-step process described in **Chapter 6**. The table is ordered from highest to lowest number of resource deficiency hours as observed in the study. Additional TPR-specific information can be found in **Chapter 9**. Transfer capability additions did not fully resolve the identified resource deficiencies in California North and ERCOT.

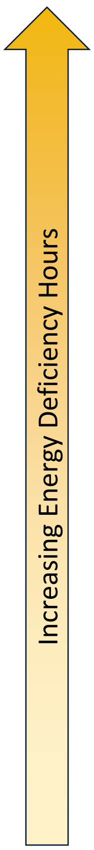


Table 7.7: Recommended Prudent Additions Detail

Transmission Planning Region	Weather Years (WY) / Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
ERCOT*	Winter Storm Uri (WY2021) and nine other events	135	18,926	14,100	Front Range*** (5,700) MISO-S*** (4,300) SPP-S** (4,100)
MISO-E	WY2020 Heat Wave and two other events	58	5,715	3,000	MISO-W** (2,000) PJM-W (1,000)
New York	WY2023 Heat Wave and seven other events	52	3,729	3,700	PJM-E (1,800) Québec** (1,900)
SPP-S	Winter Storm Uri (WY2021)	34	4,137	3,700	Front Range** (1,200) ERCOT** (800) MISO-W (1,700)
PJM-S	Winter Storm Elliott (WY2022)	20	4,147	2,800	PJM-E (2,800)
California North*	WY2022 Heat Wave	17	3,211	1,100	Wasatch Front (1,100)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
New England	WY2012 Heat Wave and two other events	5	984	700	Québec** (400) Maritimes (300)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT*** (300) SERC-SE (300)
TOTAL				**35,000**	

** Transfer capability additions did not fully address identified resource deficiencies*

Existing interface is dc-only* * Proposed new interface*

A further discussion of each TPR with prudent additions is provided below. Since these recommendations are based on current transfer capability (2024/25) as analyzed in Part 1, known planned projects likely to increase transfer capability are noted where applicable, and reviewed by the ITCS Advisory Group. This is not intended as an exhaustive list,[94] nor does it constitute an endorsement of any particular project; nevertheless, it illustrates that existing industry plans may be responsive to the recommended transfer capability increases.

California North: Recommendations are attributed to the 2022 heat dome that affected much of the Western U.S. where the energy margin analysis for California North showed resource deficiencies for a total of 17 hours over a

[94] Readers are encouraged to review available regional transmission expansion plans for a more complete list of planned projects.

four-day period. A prudent addition of 1,100 MW from Wasatch Front is recommended to help alleviate the resource deficiency. The proposed Greenlink project could help meet this transfer capability increase. However, during this same time, most of the Western Interconnection has low energy margins and all of California North's neighbors quickly reach their 3% minimum margin level, indicating that further increases in transfer capability would be ineffective in reducing resource deficiencies. In other words, there was a large-scale resource deficiency as shown in **Figure 7.1**, such that neighboring TPRs could not mitigate the deficit. Additional transfer capability would be needed from non-neighboring systems further away, namely from Canada.

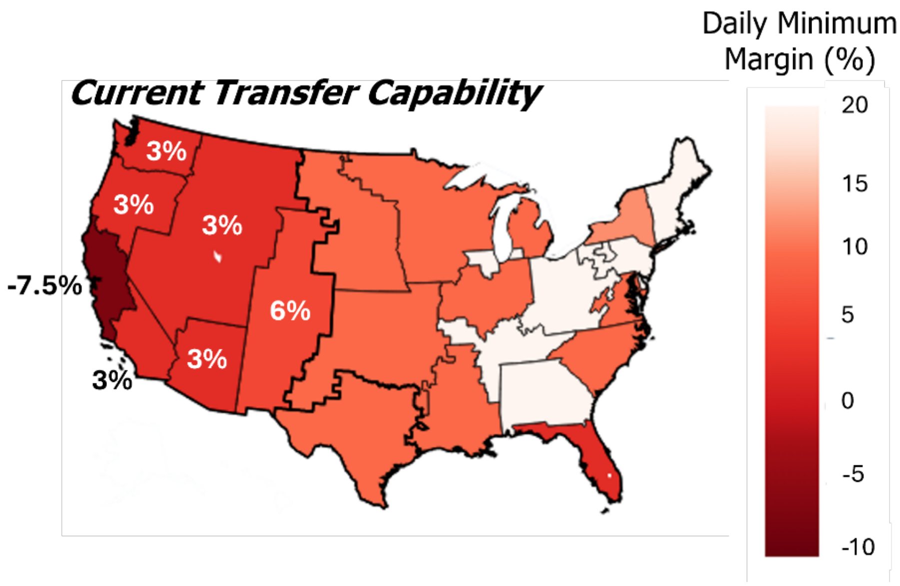


Figure 7.1: Resource Saturation in the Western Interconnection, September 6, WY2022 (2033 Case)

ERCOT: As noted in **Chapter 5**, the energy margin analysis for ERCOT reflects a high level of plant winterization due to mandated improvements and compliance programs instituted by the state of Texas.[95] Notwithstanding, several instances of resource deficiency were also observed in both summer and winter seasons, the most severe of which was observed during WY2021 (Winter Storm Uri).

Even though neighboring TPRs (in particular, SPP-S and MISO-S) were also stressed during some of the same events, the study found that some surplus energy was available and additional transfer capability of 14 GW would be effective in resolving most of the identified resource deficiencies. Specifically, prudent additions from Front Range (5,700 MW), MISO-S (4,300 MW), and SPP-S (4,100 MW) are recommended, noting that connections to Front Range and MISO-S would be entirely new. Two substantial dc line projects have been proposed to increase transfer capability to and from ERCOT. One could transfer additional energy between Eastern Texas with the Eastern Interconnection, while the other would connect Western Texas with the Western Interconnection. Neither has reached the status to include in regional planning models but significant progress has been made.

SPP-S: Recommended additions for SPP-S were driven by WY2021 (Winter Storm Uri). Currently, simultaneous imports are limited to 6,400 MW. The prudent additions for SPP-S are for both individual lines and for the total import interface. The increases for individual transfer capabilities were from Front Range (1,200 MW), ERCOT (800 MW), and MISO-W (1,700 MW). The ability of generating stations to switch between SPP-S and ERCOT may at times address a portion of the need. Multiple projects approved in SPP's past Integrated Transmission Plans (ITP) have potential to increase transfer capability between SPP-N and SPP-S. In addition, SPP's 2024 ITP includes a proposal for two new

[95] A sensitivity analysis without this winterization assumption can be found in **Chapter 8**.

345kV lines to address issues observed in its winter weather model which could further increase transfer capability across this interface.

MISO-E: Recommended additions for MISO-E were driven by three summer events in July and August for the 2011, 2020, and 2021 weather years. Summer events represent a high load risk due to extreme temperatures and potential low resource availability. Prudent additions are recommended for the summer months to increase transfer capability by 3,000 MW (2,000 MW from MISO-W and 1,000 MW from PJM-W), which would resolve the identified resource deficiencies. This increased transfer capability from MISO-W to MISO-E (2,000 MW) represents a substantial increase relative to the current transfer capability from MISO-W to MISO-E (160 MW). Some approved Tranche 1 projects in the MISO Transmission Expansion Plan have the potential to increase the transfer capability into lower Michigan.

MISO-S: Prudent additions for MISO-S were driven by two summer events in WY2009 and WY2011. Based on the energy margin analysis, additional transfer capability from ERCOT (300 MW) and SERC-SE (300 MW) would allow for access to surplus resources, resulting in part from load diversity during extreme summer heat events. The ability of the Frontier generating station to switch between MISO-S and ERCOT may address a portion of the need.

SERC-Florida: Prudent additions are driven by both summer (WY2009) and winter (WY2010) events. Since SERC-Florida is only a neighbor to SERC-SE, all recommended additions are between these two TPRs. The existing transfer capability to SERC-Florida from SERC-SE is 3,000 MW in the summer and 1,800 MW in the winter. An increase of 1,200 MW of transfer capability in both seasons resolves all resource deficiencies identified in the energy margin analysis. A planned relocation and reconductoring project may increase transfer capability somewhat, but stability limits will need to also be addressed to achieve the full 1,200 MW increase recommended.

SERC-E: Recommended additions for SERC-E are driven by WY2022 (Winter Storm Elliott) when the southeast United States saw extremely cold temperatures, high winter load, and decreased plant availability. Increased transfer capability of 4,100 MW from PJM-W (1,600 MW), SERC-SE (2,200 MW), and SERC-C (300 MW) would provide access to more resources during periods of high stress as Winter Storm Elliott moved across the southeast. These prudent additions resolve all resource deficiencies identified for SERC-E in the energy margin analysis.

PJM-S: Prudent additions for PJM-S are driven by WY2022 (Winter Storm Elliott) when the southeast United States experienced extremely cold temperatures, high winter load, and decreased plant availability. Additional transfer capability from PJM-E of 2,800 MW allowed for access to more resources in a TPR experiencing less severe extreme cold than PJM-S and resolved all PJM-S resource deficiencies.

New York: Prudent additions are driven by multiple summer events across weather years 2008, 2010, 2011, 2013, and 2023. The WY2023 event was the most severe, with several hours of resource deficiency across a three-day period while much of the northeast also experienced reduced energy margins. Additional transfer capability totaling 3,700 MW from PJM-E (1,800 MW) and Québec (1,900 MW) resolved all identified resource deficiencies. The planned Champlain Hudson Power Express is likely to address a significant portion of this need. The ability of the Beauharnois generating station to switch between Québec and New York may also address a portion of the need.

New England: Recommended additions for New England are driven by three summer events during weather years 2010, 2012, and 2013. Additional transfer capability of 700 MW, split between Québec (400 MW) and the Maritimes (300 MW), would provide access to TPRs not experiencing the same levels of high temperature and high load. The prudent additions for New England resolve all resource deficiencies identified in the energy margin analysis. The planned New England Clean Energy Connect project is likely to address a significant portion of this need.

Other Key Insights

This section provides an in-depth analysis of the critical insights and conclusions drawn from Part 2 of the ITCS. These observations highlight several key topics that are essential for understanding the role of transfer capability in mitigating resource deficiencies. These include the following topics, each of which are explored in more detail below:

- Multiplier effects that may enhance the benefits of additional transfer capability
- Saturation effects observed when surplus resources in neighboring TPRs are exhausted
- The intricate relationship between generation and transmission planning
- Pronounced benefits of transfer capability across Interconnections
- Additional benefits that could be realized through "neighbor's neighbor" transfer capability

Multiplier Effects

Another key finding of the study is that increasing transfer capability can, at times, reduce the maximum resource deficiency by more than the transfer capability addition. For instance, a 1,000 MW increase in transfer capability can reduce resource deficiencies by more than 1,000 MW, as illustrated by the SERC-E example in Chapter 6. While not immediately intuitive, this can occur for several reasons:

- **Storage Resource Optimization:** The additional transfer capability allows for pre-charging of storage resources, such as batteries and pumped storage hydro, that might not have been able to charge without the imports. This ensures that these resources, which otherwise would have been depleted, are available during future hours of resource deficiency. This is illustrated in Figure 7.2.

Additional transfer capability can optimize the effectiveness of existing storage resources.

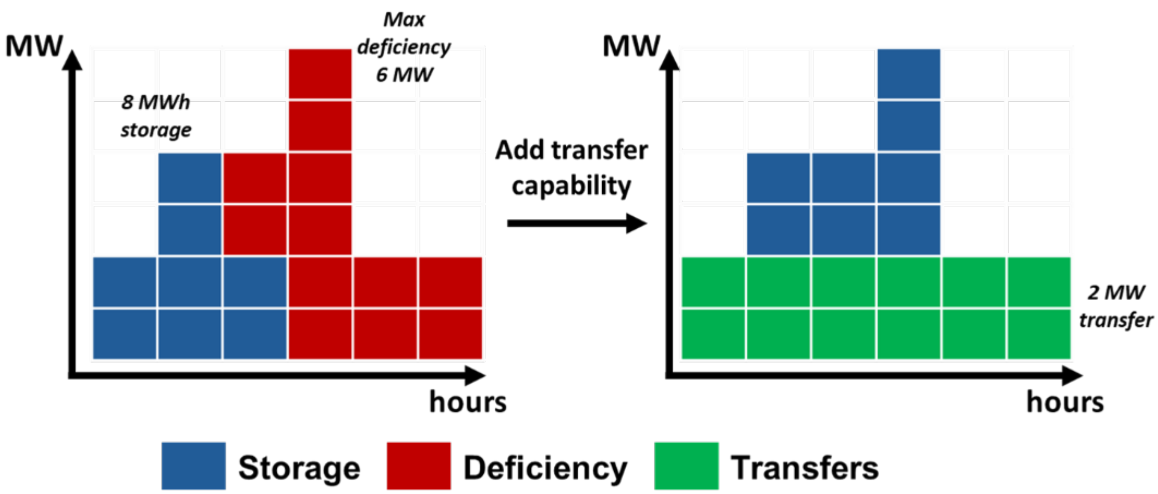


Figure 7.2: Interactive Effects of Transfer Capability and Energy-Limited Resources

- **Shortened Deficiency Windows:** Increased transfer capability can shorten the duration of resource deficiencies, by reducing the window from, for example, six hours to two hours. This enables energy-limited resources like batteries, pumped storage hydro, and demand response to manage the remaining hours more effectively.
- **Interactive Effects:** Transfer capability additions in one TPR can have cascading benefits for others. For example, an increase to transfer capability can help one TPR mitigate its own resource deficiency at one time but may also be used at other times to support a nearby TPR. Additionally, while the study primarily evaluated

transfer capability in one direction, new transmission lines or upgrades could increase transfer capability in both directions, providing benefits to both sides of the transfer.

Resource Saturation Effects

As discussed for the recommended additions for California North, the analysis demonstrated that increasing transfer capability can reduce observed resource deficiencies. However, it also revealed a point of saturation when the wider area exhausts its available resources. As neighboring TPRs run out of surplus energy to share, the benefits of additional transfer capability diminish. In such cases, the ability of additional transfer capability to mitigate resource deficiencies becomes limited, indicating that further mitigation would require different solutions, such as the introduction of new local resources or possibly a "neighbor's neighbor" to access surplus energy. This saturation effect highlights the need for a more comprehensive approach to addressing resource deficiencies.

This saturation effect is most notable in ERCOT during Winter Storm Uri. **Figure 7.3** depicts the progressions of iterations of the 2033 case for one hour. In the starting case, some neighboring TPRs have surplus resources to share with ERCOT (hourly energy margins above the 3% minimum margin level). However, as transfer capability is added iteratively, these surpluses are exhausted. Eventually, additional transfer capability no longer substantially reduces resource deficiencies and is not deemed prudent.

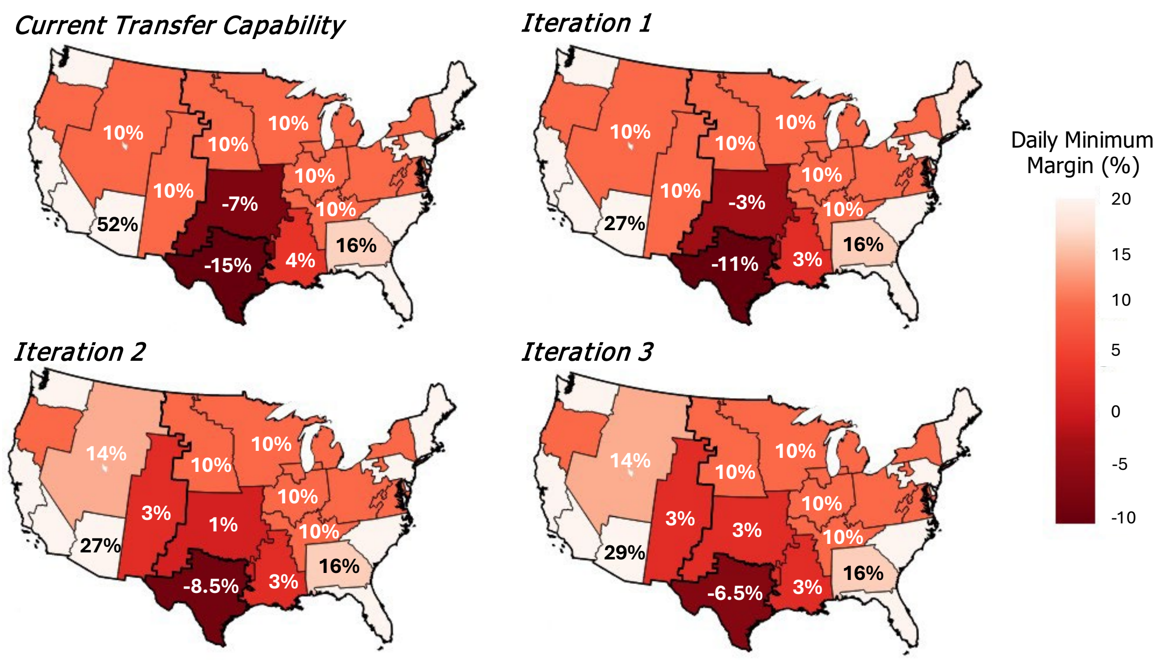


Figure 7.3: Resource Saturation Around ERCOT, February 16, WY2021 (2033 Case)

Relationship Between Generation and Transmission

The study found a nuanced but crucial relationship between generation and transmission. If multiple neighboring TPRs lack resources, additional transfer capability offers limited help because there is not enough surplus energy to share. Conversely, if TPRs each have surplus resources, the benefits of additional transfer capability are diminished, as each TPR can meet its own demands locally. Striking the right balance between generation and transmission to meet each TPR's load is essential. However, it is important to consider that adding local resources to mitigate deficiencies may also have drawbacks as these new resources could be subject to the same constraints that caused the initial challenge, such as fuel supply restrictions or low renewable availability, leading to correlated risks. This finding points to the increased importance of holistic generation and transmission planning. This is particularly important as the resource mix changes and accelerated load growth is expected relative to the past decade. The ITCS evaluated the role of interregional transfer capability to improve energy adequacy reliability across different resource mixes and study years and did not evaluate trade-offs between resource and transmission options. This is identified as an area of interest in the Future Work section later.

Pronounced Benefits of Transfer Capability Across Interconnections

The study highlighted the significant benefits of transfer capability across Interconnections, where geographic diversity in resource availability and load proved advantageous. For example, the ties between SPP and the Western Interconnection demonstrated substantial benefits during extreme weather events. Similarly, transfer capability between ERCOT and both the Western and Eastern Interconnections provided crucial support, as does increasing transfer capability from Québec to New York and New England. Neighboring Planning Coordinators and Transmission Planners across Interconnections should continue to work toward a wider area planning approach.

"Neighbor's Neighbor" Transfer Capability Could Provide Additional Benefits

While the study focused on evaluating transfer capability between neighboring TPRs, the analysis suggests that additional benefits could be realized by improving transfer capability with a "neighbor's neighbor" in two instances. Specifically, increasing transfer capability from ERCOT to SERC-SE or from British Columbia to California North could unlock access to even greater load and resource diversity, particularly during extreme events like Winter Storm Uri. TPRs two or more steps away from ERCOT had surplus energy available, as shown in **Table 7.8**, even when ERCOT's immediate neighbors were operating at their 3% minimum margin level.

Table 7.8: Energy Margins of Nearest TPRs During Resource Saturation (ERCOT)

Transmission Planning Region	Average Energy Margin
SERC-SE	46%
Southwest	45%
Wasatch Front	22%
SERC-C	11%

Similarly, California North's neighbors quickly depleted their surplus energy during the 2022 Western Heat Wave, but more distant TPRs still had surplus energy available, as shown in **Table 7.9**. In particular, the Canadian provinces of British Columbia and Alberta had significant surplus during this event.

Table 7.9: Energy Margins of Nearest TPRs During Resource Saturation (California North)

Transmission Planning Region	Average Energy Margin
British Columbia	57%
Alberta	46%
SPP-N	24%
Saskatchewan	16%

In summary, these results indicate that exploring and investing in "neighbor's neighbor" transfer capability could provide a critical buffer during challenging grid conditions. However, the potential benefits of expanding connectivity to more distant TPRs must also be balanced with the associated costs and risks. These key findings underscore the importance of a balanced and strategic approach to enhancing transfer capability, recognizing both the strengths and limitations of existing infrastructure and the potential benefits of expanding connectivity to more distant TPRs.

Chapter 8: Sensitivity Analysis

In addition to the 2024 and 2033 cases discussed in the previous sections, a series of sensitivity analyses were conducted to evaluate the impact of varying specific assumptions on the overall results. These sensitivities were designed to isolate the effects of individual factors and quantify their influence on resource deficiencies and the need for increased transfer capability. By examining these factors in isolation, the sensitivity analysis provides a clearer understanding of how changes in assumptions might alter the outcomes of the study. Each sensitivity was analyzed under both the current transfer capability and in scenarios with increased transfer capability to determine how recommendations might change.

The sensitivity analyses provide valuable insights into how different assumptions can influence study outcomes, including the necessity for enhanced transfer capability. By understanding these dynamics, future planning can be more responsive to a range of potential scenarios.

ERCOT Winterization Effects

This section summarizes the effects of winterization on resource deficiencies in ERCOT. As discussed in **Chapter 7**, the energy margin analysis included the anticipated effects of mandated winterization efforts in ERCOT to mitigate the impact of cold weather on thermal resource availability. **Table 8.1** through **Table 8.3** show the comparison between energy margin analysis results for ERCOT with and without these winterization assumptions.

Table 8.1: ERCOT Maximum Resource Deficiency (MW) by Weather Year (2033 Case)

Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Max Resource Deficiency
ERCOT without Winterization	5,742	0	0	10,874	23,886	0	8,775	8,977	14,853	34,383	16,279	12,108	34,383
ERCOT with Winterization	1,361	0	0	9,400	0	0	0	8,977	14,853	18,926	14,321	12,108	18,926

Table 8.2: ERCOT Total Resource Deficiency (GWh) by Weather Year (2033 Case)

Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Avg
ERCOT without Winterization	9	0	0	42	131	0	21	37	201	2129	102	62	228
ERCOT with Winterization	2	0	0	19	0	0	0	37	201	668	91	57	90

Table 8.3: ERCOT Annual Hours of Resource Deficiency by Weather Year (2033 Case)

Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Avg
ERCOT without Winterization	3	0	0	7	11	0	3	10	24	148	11	15	19
ERCOT with Winterization	2	0	0	3	0	0	0	10	24	72	10	14	11

6% Minimum Margin Level Sensitivity

In this sensitivity analysis, the minimum margin level was increased from 3% to 6%, effectively reducing the surplus energy in all TPRs simultaneously. This adjustment led to an increase in the size, frequency, and duration of resource deficiencies, the number of TPRs experiencing these deficiencies, and the magnitude of transfer additions evaluated. **Table 8.4** compares the maximum resource deficiency between the 3% and 6% minimum margin levels. The 6% minimum margin level sensitivity introduces greater levels and frequency of resource deficiency for the 11 TPRs that showed resource deficiency in the 3% case and introduces resource deficiency in five additional TPRs. In particular, large portions of the Western Interconnection are simultaneously deficient, limiting the usefulness of additional transfer capability.

Table 8.4: Comparison of Maximum Resource Deficiency (in MW)			
Transmission Planning Region	Max Resource Deficiency (3% Margin)	Max Resource Deficiency (6% Margin)	Change in Max Resource Deficiency
Washington	0	0	0
Oregon	0	1,626	1,626
California North	3,211	6,765	3,554
California South	0	7,984	7,984
Southwest	0	1,638	1,638
Wasatch Front	0	3,734	3,734
Front Range	0	2,190	2,190
ERCOT	18,926	21,391	2,465
SPP-N	155	639	483
SPP-S	4,137	5,362	1,225
MISO-W	0	0	0
MISO-C	0	0	0
MISO-S	629	1,677	1,049
MISO-E	5,715	6,410	694
SERC-C	0	0	0
SERC-SE	0	0	0
SERC-Florida	1,152	9,098	7,946
SERC-E	5,849	10,689	4,840
PJM-W	0	0	0
PJM-S	4,147	7,807	3,660
PJM-E	0	0	0
New York	3,729	5,953	2,224
New England	984	1,892	909

The iteration method described in **Chapter 6** was performed for the 6% minimum margin level sensitivity. While recommendations for prudent additions were not made based on this sensitivity, it highlights the importance of considering generation and transmission planning holistically along with benefits of potential "neighbor's neighbor" transfers to mitigate resource deficiencies. This is because the more restrictive minimum margin level simultaneously reduces surplus resources for all TPRs, exacerbating resource deficiencies and reducing the effectiveness of existing and additional transfer capability. The results of the iterations for the 6% minimum margin level sensitivity in **Figure 8.1** reflect either where all deficiencies were resolved for a TPR, or where additional transfer capability was no longer beneficial due to saturation effects or lack of resources. No prudent recommendations were made based on these results and they should be viewed as exploratory only.

The cumulative additions across the United States increased from 35 GW of prudent additions to 58 GW in the case with a 6% minimum margin level. Notably, much of the Western U.S. now shows additions to transfer capability.

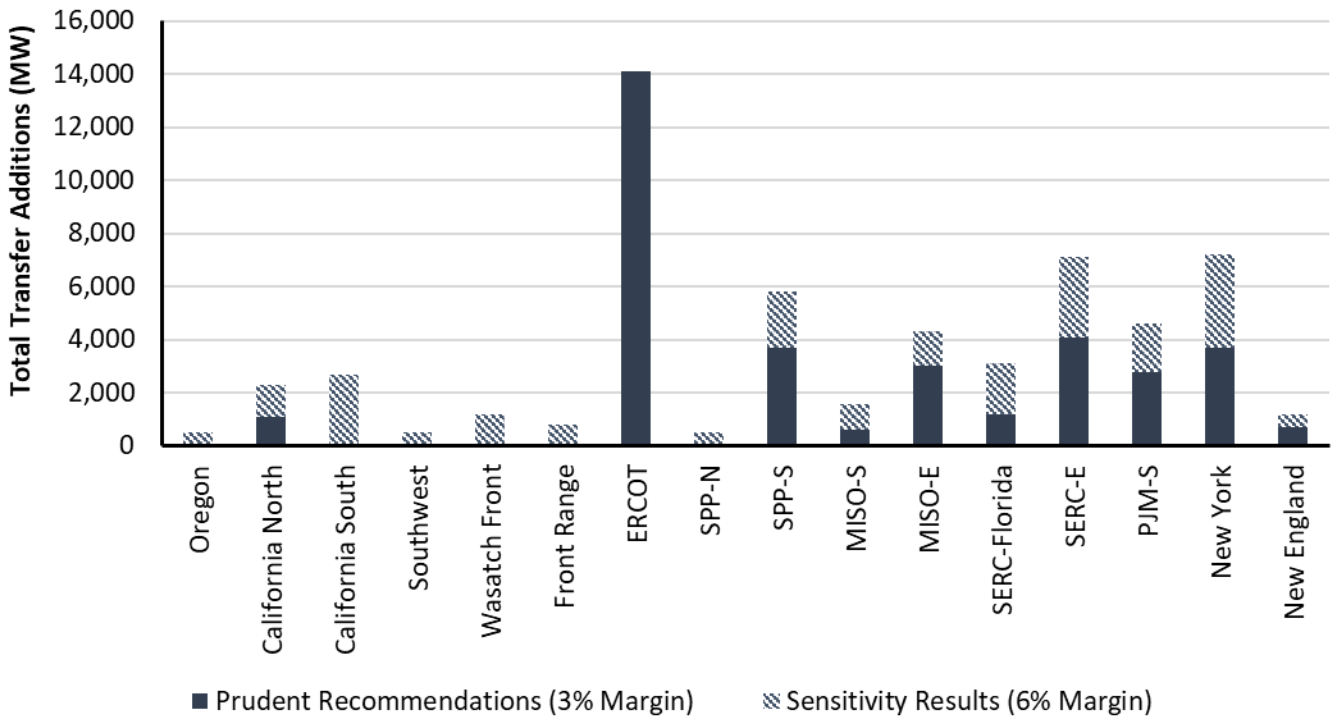


Figure 8.1: Change to Transfer Capability Additions

Tier 1-Only Resource Mix Sensitivity

The analysis for the 2033 case included all announced retirements, Tier 1 resource additions, and a portion of additional Tier 2 resources if necessary to replace retiring capacity. In this sensitivity, no additional resources to replace retirements were included. In other words, this scenario reflected only the addition of Tier 1 resources, so significantly fewer resources were available to provide energy to serve existing load or support neighboring TPRs. As expected, this adjustment increased the frequency, duration, magnitude, and geographic distribution of resource deficiencies. **Table 8.5** shows the energy margin analysis by weather year results from this sensitivity, and **Table 8.6** shows the change in the maximum resource deficiency between the 2033 case and the 2033 Tier 1 Only case.

These results show that the buildout assumptions predominantly affect the Western Interconnection, where LTRA reporting included a large number of coal plant retirements, but the Tier 1 resources are insufficient, in isolation, to replace the capacity. These results also highlight that the risk is a clear resource adequacy issue, as each year in the historical record shows resource deficiencies, all of which are in the summer season. In this example, additional transfer capability between western TPRs will not improve energy margins as resource deficiency events often coincided across multiple TPRs.

Table 8.5: Maximum Resource Deficiency by Weather Year (2033 Tier 1 Only Case)													
Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Max Resource Deficiency
Washington	0	0	0	0	0	0	0	0	0	0	0	0	0
Oregon	0	0	2,550	1,114	144	1,022	1,534	1,666	1,573	398	1,864	3,959	3,959
California North	3,801	447	2,870	5,245	4,337	3,659	2,331	1,076	6,297	3,131	9,336	6,221	9,336
California South	9,791	1,520	6,622	10,387	8,664	11,690	5,562	7,549	6,301	509	11,768	5,408	11,768
Southwest	2,926	3,068	3,911	4,497	3,358	4,866	3,175	2,310	2,477	1,614	701	4,656	4,866
Wasatch Front	5,586	4,559	9,120	9,423	9,667	9,566	12,401	6,156	7,418	3,996	7,611	6,806	12,401
Front Range	2,584	2,086	3,940	5,353	6,054	4,686	4,298	4,087	2,987	3,180	3,231	5,728	6,054
ERCOT	9,964	0	7,158	10,088	0	0	0	13,628	15,431	19,511	16,171	16,519	19,511
SPP-N	0	0	0	0	0	0	0	0	0	155	0	0	155
SPP-S	0	0	0	0	0	0	0	0	0	4,137	0	0	4,137
MISO-W	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-C	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO-S	0	0	3,637	0	3,910	1,800	2,550	0	0	0	1,237	93	3,910
MISO-E	2,533	0	3,173	3,815	5,046	3,479	0	3,626	6,924	5,363	1,392	779	6,924
SERC-C	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-SE	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-Florida	849	0	1,932	2,098	468	0	0	0	0	0	0	0	2,098
SERC-E	0	0	0	0	0	0	0	0	0	0	10,353	0	10,353
PJM-W	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM-S	0	0	0	0	0	0	0	0	0	0	4,147	0	4,147
PJM-E	0	0	0	0	0	0	0	0	0	0	0	0	0
New York	0	81	0	3,244	1,748	2,631	1,229	0	0	0	0	3,729	3,729
New England	0	0	0	141	0	1,043	125	0	0	0	0	0	1,043

Table 8.6: Comparison of Maximum Resource Deficiency in 2033 (in MW)			
Transmission Planning Region	Max Resource Deficiency (Rep. Retirements)	Max Resource Deficiency (Tier 1 Only)	Change in Max Resource Deficiency
Washington	0	0	0
Oregon	0	3,959	3,959
California North	3,211	9,336	6,126
California South	0	11,768	11,768
Southwest	0	4,866	4,866
Wasatch Front	0	12,401	12,401
Front Range	0	6,054	6,054
ERCOT	18,926	19,511	585
SPP-N	155	155	0
SPP-S	4,137	4,137	0
MISO-W	0	0	0
MISO-C	0	0	0
MISO-S	629	3,910	3,282
MISO-E	5,715	6,924	1,209
SERC-C	0	0	0
SERC-SE	0	0	0
SERC-Florida	1,152	2,098	946
SERC-E	5,849	10,353	4,504
PJM-W	0	0	0
PJM-S	4,147	4,147	0
PJM-E	0	0	0
New York	3,729	3,729	0
New England	984	1,043	60

By comparing the results of the 2033 case and the Tier 1 Only case the connection between resource and transmission planning is made apparent. When only considering Tier 1 resources, resource deficiencies worsen and affect larger portions of the country, often limiting the effectiveness of additional transfer capability. The "Replace Retirements" scenario was selected to represent an anticipated resource mix and highlight the role that transfer capability can play in improving energy adequacy.

As time progresses, the nature and severity of energy adequacy risks will evolve, thereby changing the effectiveness of transfer capability. This highlights the opportunities of periodic studies that evaluate future resource mixes across many hours of chronological load and resource availability as is done in this report.

Chapter 9: TPR-Specific Results

The following pages provide detailed results for each TPR, including information on each interface transfer capability, recommended prudent additions, information on each model iteration, assumed resource mix and peak load data, and details on resource deficiency events. Summary maps of transfer capability are also provided, with current transfer capability presented on the top, and recommended prudent additions highlighted in blue on the bottom. The map is provided for the season when transfer capability is required or for the peak demand season if there are no prudent recommendations. All data is provided for 2033 unless otherwise noted. Each of the following pages is organized as follows:

Transfer Capability Summary Section

- Current summer and winter transfer capability columns include each of the interface names importing to the TPR summarized along with the summer and winter transfer capability quantified in Part 1.
- The prudent additions column provides the results of the simulations and the recommended additions to transfer capability for each interface.
- Recommended summer and winter transfer capability columns provide the TTC for each interface with prudent additions to the current transfer capability. Prudent additions are only added in the season(s) that they are needed to mitigate resource deficiencies.
- The total import interface limit represents the simultaneous import transfer capability determined in Part 1, excluding any transfer capability on dc-only interfaces, which is added to the following line if applicable.
- The total import interface + dc-only interfaces limit is provided both in MW and normalized as a percentage of the TPR's 2033 peak demand.

Energy Adequacy by Iteration Section

- This section provides information on each iteration of the simulation, whether or not transfer capability was added for the respective TPR. In general, the energy adequacy metrics will improve in each iteration.
- Interchange hours represent the number of hours that the TPR imports from its neighbors in order to meet the 10% tight margin level. It is normalized by the total number of hours evaluated.
- Tight margin hours and resource deficiency hours quantify the total number of hours with tight margins (<10%) and resource deficiencies, respectively, after accounting for available transfers from neighbors. This is the total number of hours for all 12 weather years.
- Max resource deficiency represents the largest resource deficiency during the 12 weather years.
- Total deficiency is the total GWh of resource deficiency across the 12 weather years.

Capacity and Load Data Section

- Resource capacity is presented for 2024 and 2033 by resource type. Thermal capacity includes coal, nuclear, single-fuel gas, dual-fuel gas, oil, biomass, geothermal, and other fuels. Variable renewable resources includes land-based wind, offshore wind, utility-scale solar, and behind-the-meter solar. Energy limited resources include pumped storage hydro, battery storage, and demand response.
- Winter capacities are provided for all thermal and hydro capacities. Nameplate capacity is provided for variable renewable and energy limited resources.
- Summer and winter peak demand is provided for 2024 and 2033 and represents the median peak demand, inclusive of behind-the-meter solar resources, but prior to demand response.

Resource Deficiency Events Section

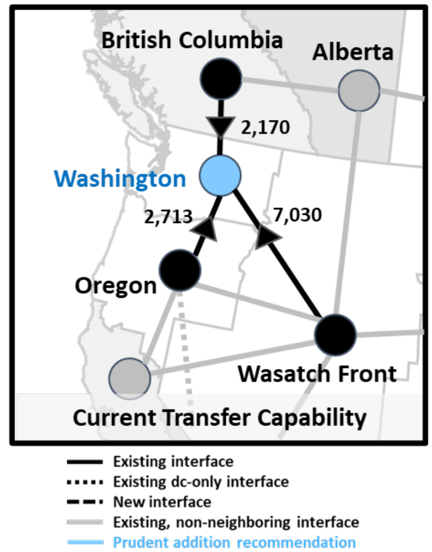
- The summary statistics for each day of resource deficiency in the base 2033 case is provided if applicable.
- Daily peak demand represents the day's highest load, regardless of when it occurs. Resource deficiency hours may occur before or after the peak demand hour due to variable renewable resources and energy limited resources having changing availability throughout the day.

Results for the following interfaces are presented in this chapter:

Washington

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Prudent Additions (MW)**	**Recommended Summer (MW)**	**Recommended Winter (MW)**
Oregon to Washington	4,103	2,713	N/A	N/A	N/A
Wasatch Front to Washington	7,377	7,030	N/A	N/A	N/A
British Columbia to Washington	2,358	2,170	N/A	N/A	N/A
Total Import Interface Limit	**7,377**	**10,297**			
Total Import Interface Limit + dc-only Interfaces Limit	**7,377**	**10,297**			
(as % of 2033 Peak Demand)	**33%**	**47%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	43	0	0	0.0
Iteration 1	N/A	42	0	0	0.0
Iteration 2	N/A	41	0	0	0.0
Iteration 3	N/A	42	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	6,874	7,550
Hydro	25,957	26,336
Variable Renewable	3,254	5,099
Energy Limited	472	469
Total	36,557	39,454

Note: Thermal and hydro values represent winter ratings

Summer Peak	16,280	19,199
Winter Peak	19,357	22,136

Note: Median peak demand across all weather years

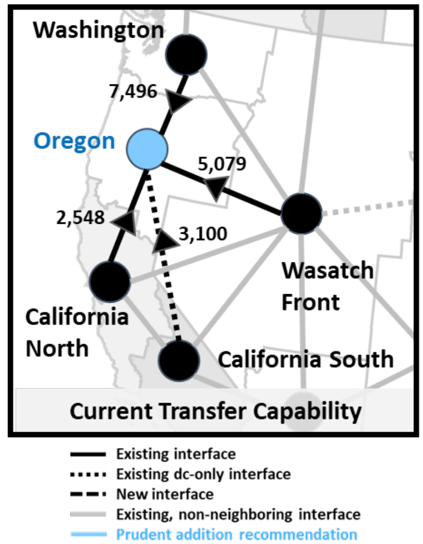
Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
No identified resource deficiency events					

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

Oregon

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
California North to Oregon	0	2,548	N/A	N/A	N/A
California South to Oregon	3,100	3,100	N/A	N/A	N/A
Wasatch Front to Oregon	4,748	5,079	N/A	N/A	N/A
Washington to Oregon	7,085	7,496	N/A	N/A	N/A
Total Import Interface Limit	**8,004**	**7,534**			
Total Import Interface Limit + dc-only Interfaces Limit	**11,104**	**10,634**			
(as % of 2033 Peak Demand)	**91%**	**87%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	142	0	0	0.0
Iteration 1	N/A	139	0	0	0.0
Iteration 2	N/A	139	0	0	0.0
Iteration 3	N/A	137	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	4,786	4,688
Hydro	5,228	5,314
Variable Renewable	6,724	10,334
Energy Limited	93	96
Total	16,831	20,432

Note: Thermal and hydro values represent winter ratings

Summer Peak	10,516	12,237
Winter Peak	10,437	11,942

Note: Median peak demand across all weather years

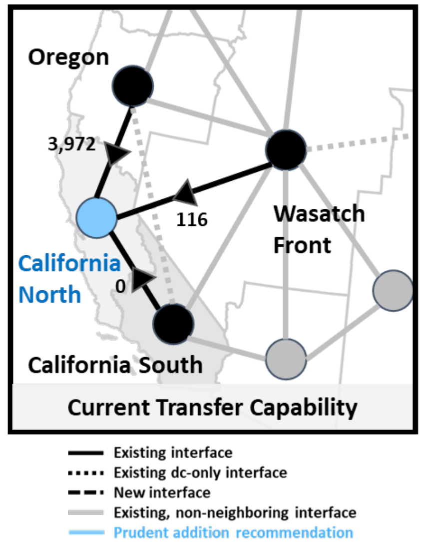
Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
No identified resource deficiency events					

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

California North[96]

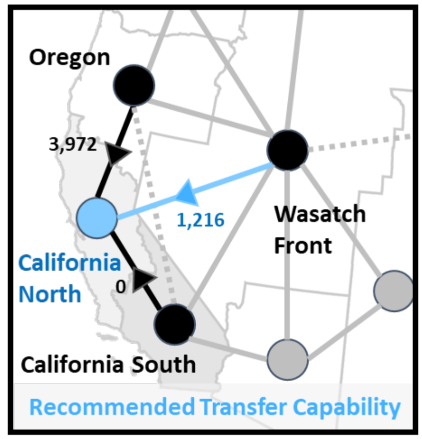
Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
Oregon to California North	3,972	6,175	0	3,972	N/A
California South to California North	0	3,861	0	0	N/A
Wasatch Front to California North	116	5,388	1,100	1,216	N/A
Total Import Interface Limit	**3,972**	**6,631**	**1,100**	**5,072**	
Total Import Interface Limit + dc-only Interfaces Limit	**3,972**	**6,631**	**1,100**	**5,072**	
(as % of 2033 Peak Demand)	**14%**	**23%**	**4%**	**17%**	

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	331	17	3,211	22.4
Iteration 1	1,069	296	8	2,140	7.3
Iteration 2	1,069	281	3	2,140	5.9
Iteration 3	1,069	276	3	2,140	5.6

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years



Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	20,003	17,969
Hydro	9,625	9,625
Variable Renewable	13,846	19,379
Energy Limited	4,322	5,109
Total	47,796	52,082

Note: Thermal and hydro values represent winter ratings

Summer Peak	24,542	29,368
Winter Peak	15,917	18,332

Note: Median peak demand across all weather years

Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
9/5 WY2022	Summer	31,047	4	1.8	740
9/6 WY2022	Summer	33,493	6	12.4	3,211
9/7 WY2022	Summer	31,229	2	0.6	382
9/8 WY2022	Summer	32,019	5	7.7	2,290

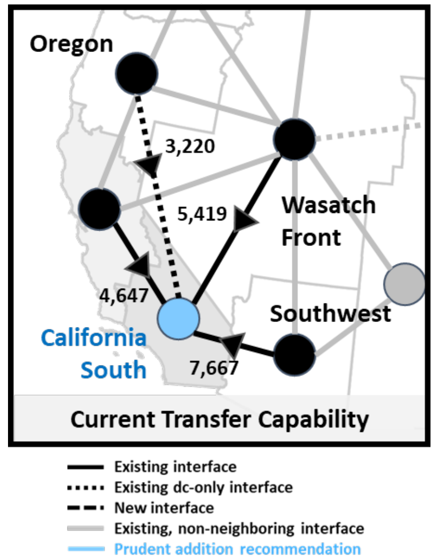
Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

[96] Prudent additions include only iteration 1 due to resource saturation in neighboring TPRs. As a result, some resource deficiency hours were not resolved.

California South

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
California North to California South	4,647	5,676	N/A	N/A	N/A
Oregon to California South	3,220	3,220	N/A	N/A	N/A
Southwest to California South	7,667	8,752	N/A	N/A	N/A
Wasatch Front to California South	5,419	5,568	N/A	N/A	N/A
Total Import Interface Limit	**7,829**	**11,288**			
Total Import Interface Limit + dc-only Interfaces Limit	**11,049**	**14,508**			
(as % of 2033 Peak Demand)	**26%**	**34%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	272	0	0	0.0
Iteration 1	N/A	270	0	0	0.0
Iteration 2	N/A	278	0	0	0.0
Iteration 3	N/A	269	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	27,462	28,624
Hydro	1,839	1,839
Variable Renewable	30,356	37,068
Energy Limited	9,609	12,190
Total	69,266	79,721

Note: Thermal and hydro values represent winter ratings

Summer Peak	34,691	42,602
Winter Peak	22,495	26,767

Note: Median peak demand across all weather years

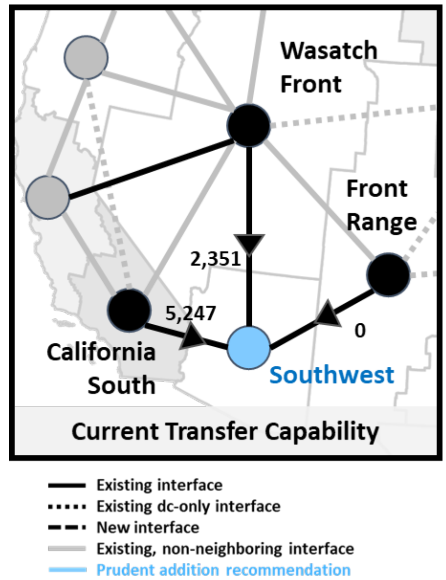
Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
No identified resource deficiency events					

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

Southwest

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Prudent Additions (MW)**	**Recommended Summer (MW)**	**Recommended Winter (MW)**
Front Range to Southwest	0	0	N/A	N/A	N/A
California South to Southwest	5,247	8,470	N/A	N/A	N/A
Wasatch Front to Southwest	2,351	2,095	N/A	N/A	N/A
Total Import Interface Limit	**5,247**	**8,470**			
Total Import Interface Limit + dc-only Interfaces Limit	**5,247**	**8,470**			
(as % of 2033 Peak Demand)	**20%**	**33%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	170	0	0	0.0
Iteration 1	N/A	177	0	0	0.0
Iteration 2	N/A	176	0	0	0.0
Iteration 3	N/A	175	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	24,634	23,099
Hydro	2,568	2,568
Variable Renewable	6,845	21,959
Energy Limited	1,320	3,170
Total	35,367	50,796

Note: Thermal and hydro values represent winter ratings

Summer Peak	21,320	25,909
Winter Peak	12,104	14,071

Note: Median peak demand across all weather years

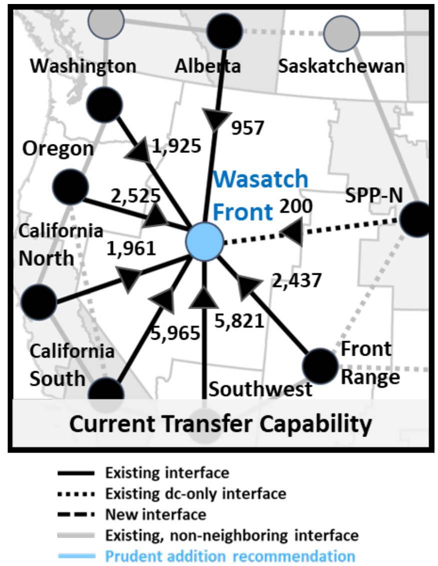
Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
No identified resource deficiency events					

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

Wasatch Front

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Prudent Additions (MW)**	**Recommended Summer (MW)**	**Recommended Winter (MW)**
Front Range to Wasatch Front	2,437	477	N/A	N/A	N/A
California North to Wasatch Front	1,961	4,980	N/A	N/A	N/A
Oregon to Wasatch Front	2,525	5,339	N/A	N/A	N/A
Saskatchewan to Wasatch Front	Candidate	Candidate	N/A	N/A	N/A
California South to Wasatch Front	5,965	984	N/A	N/A	N/A
Southwest to Wasatch Front	5,821	1,295	N/A	N/A	N/A
SPP-N to Wasatch Front	200	200	N/A	N/A	N/A
Washington to Wasatch Front	1,925	4,498	N/A	N/A	N/A
Alberta to Wasatch Front	957	1,280	N/A	N/A	N/A
Total Import Interface Limit	**5,965**	**5,558**			
Total Import Interface Limit + dc-only Interfaces Limit	**6,165**	**5,758**			
(as % of 2033 Peak Demand)	**19%**	**18%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	202	0	0	0.0
Iteration 1	N/A	202	0	0	0.0
Iteration 2	N/A	200	0	0	0.0
Iteration 3	N/A	204	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	22,540	15,970
Hydro	3,325	3,362
Variable Renewable	15,126	28,891
Energy Limited	2,403	10,888
Total	43,394	59,111

Note: Thermal and hydro values represent winter ratings

Summer Peak	25,410	31,733
Winter Peak	18,452	22,178

Note: Median peak demand across all weather years

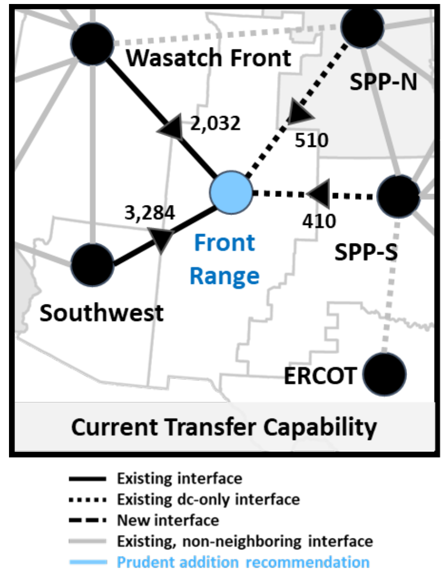
Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
No identified resource deficiency events					

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

Front Range

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Prudent Additions (MW)**	**Recommended Summer (MW)**	**Recommended Winter (MW)**
ERCOT to Front Range	Candidate	Candidate	N/A	N/A	N/A
Southwest to Front Range	3,284	3,751	N/A	N/A	N/A
SPP-N to Front Range	510	510	N/A	N/A	N/A
SPP-S to Front Range	410	410	N/A	N/A	N/A
Wasatch Front to Front Range	2,032	1,984	N/A	N/A	N/A
Total Import Interface Limit	**3,284**	**3,751**			
Total Import Interface Limit + dc-only Interfaces Limit	**4,204**	**4,671**			
(as % of 2033 Peak Demand)	**19%**	**21%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	117	0	0	0.0
Iteration 1	N/A	138	0	0	0.0
Iteration 2	N/A	171	0	0	0.0
Iteration 3	N/A	179	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	16,383	13,625
Hydro	2,795	2,819
Variable Renewable	15,738	26,621
Energy Limited	1,731	5,380
Total	36,647	48,445

Note: Thermal and hydro values represent winter ratings

Summer Peak	18,634	22,273
Winter Peak	15,293	18,468

Note: Median peak demand across all weather years

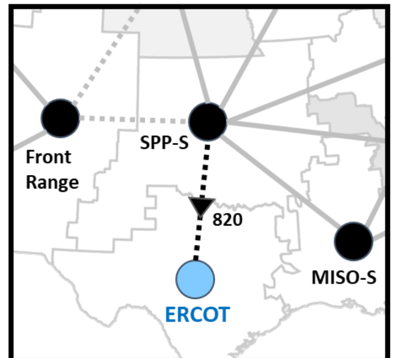
Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
No identified resource deficiency events					

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

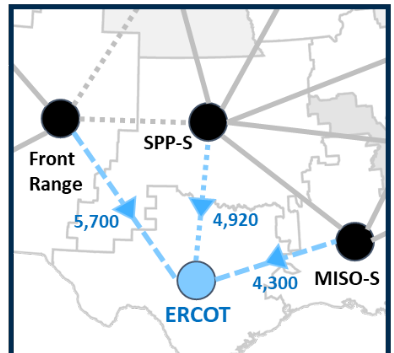
ERCOT[97]

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
Front Range to ERCOT	Candidate	Candidate	5,700	5,700	5,700
MISO-S to ERCOT	Candidate	Candidate	4,300	4,300	4,300
SPP-S to ERCOT	820	820	4,100	4,920	4,920
Total Import Interface Limit	**820**	**820**	**14,100**	**14,920**	**14,920**
Total Import Interface Limit + dc-only Interfaces Limit	**820**	**820**	**14,100**	**14,920**	**14,920**
(as % of 2033 Peak Demand)	**1%**	**1%**	**15%**	**16%**	**16%**

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Current Transfer Capability



Recommended Transfer Capability

Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	1520	135	18,926	1,074.7
Iteration 1	6300	271	30	13,976	192.5
Iteration 2	6300	116	12	9,486	53.0
Iteration 3	6300	66	3	7,828	17.1

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	73,557	74,750
Hydro	549	549
Variable Renewable	69,673	104,290
Energy Limited	13,586	24,951
Total	157,365	204,540

Note: Thermal and hydro values represent winter ratings

Summer Peak	84,059	92,214
Winter Peak	69,495	79,832

Note: Median peak demand across all weather years

Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
1/17 WY2007	Winter	78,063	2	1.9	1,361
1/9 WY2010	Winter	79,813	3	18.6	9,400
7/11 WY2019	Summer	90,223	3	16.8	8,977
7/12 WY2019	Summer	88,454	2	5.3	2,727
8/14 WY2019	Summer	93,169	2	6.4	5,150
9/22 WY2019	Summer	83,308	3	8.9	4,178
10/27 WY2020	Summer	67,078	20	177.3	14,853
10/28 WY2020	Summer	65,046	4	23.9	8,394
2/12 WY2021	Winter	81,982	6	63.2	12,556
2/13 WY2021	Winter	81,691	20	111.8	9,065
2/14 WY2021	Winter	88,567	11	96.6	14,513
2/15 WY2021	Winter	85,552	14	180.4	18,926
2/16 WY2021	Winter	83,137	13	142.2	14,198
2/17 WY2021	Winter	76,314	8	73.4	12,847
12/23 WY2022	Winter	88,897	3	38.3	14,321
12/24 WY2022	Winter	80,337	7	52.7	9,966
2/1 WY2023	Winter	76,242	5	17.9	6,305
8/24 WY2023	Summer	94,639	1	0.4	371
8/25 WY2023	Summer	94,402	4	22.7	12,108
8/26 WY2023	Summer	93,186	3	15.5	6,763
8/30 WY2023	Summer	87,334	1	0.5	481

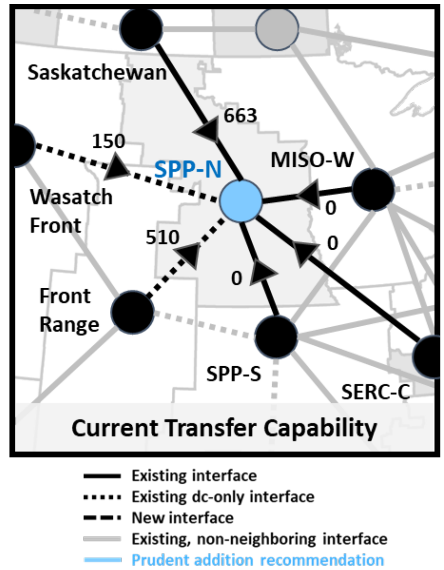
Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

[97] Prudent additions include only iterations 1 and 2, plus a portion of iteration 3, due to resource saturation in neighboring TPRs. As a result, some resource deficiency hours were not resolved.

SPP-N[98]

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Prudent Additions (MW)**	**Recommended Summer (MW)**	**Recommended Winter (MW)**
Front Range to SPP-N	510	510	N/A	N/A	N/A
MISO-W to SPP-N	2,209	0	N/A	N/A	N/A
Saskatchewan to SPP-N	165	663	N/A	N/A	N/A
SERC-C to SPP-N	1,183	0	N/A	N/A	N/A
SPP-S to SPP-N	1,705	0	N/A	N/A	N/A
Wasatch Front to SPP-N	150	150	N/A	N/A	N/A
Total Import Interface Limit	**2,209**	**663**			
Total Import Interface Limit + dc-only Interfaces Limit	**2,869**	**1,323**			
(as % of 2033 Peak Demand)	**21%**	**10%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	54	4	155	0.5
Iteration 1	52	48	4	104	0.3
Iteration 2	52	48	2	53	0.1
Iteration 3	52	37	1	2	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	11,929	11,929
Hydro	2,904	2,904
Variable Renewable	6,509	6,509
Energy Limited	81	187
Total	21,423	21,529

Note: Thermal and hydro values represent winter ratings

Summer Peak	12,231	13,517
Winter Peak	10,732	12,189

Note: Median peak demand across all weather years

Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
2/11 WY2021	Winter	12,122	4	0.5	155

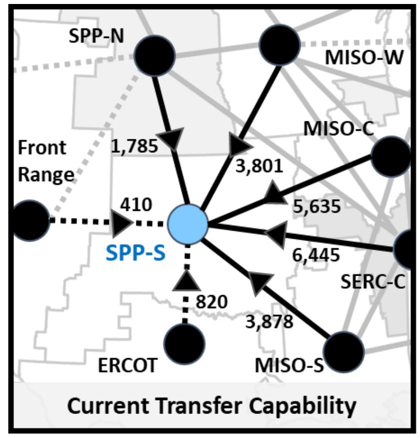
Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

98 Prudent additions were not recommended because the maximum deficiency was under 300 MW.

SPP-S

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Prudent Additions (MW)**	**Recommended Summer (MW)**	**Recommended Winter (MW)**
ERCOT to SPP-S	820	820	800	N/A	1,620
Front Range to SPP-S	410	410	1,200	N/A	1,610
MISO-C to SPP-S	3,873	5,635	0	N/A	5,635
MISO-S to SPP-S	3,033	3,878	0	N/A	3,878
MISO-W to SPP-S	2,086	3,801	1,700	N/A	5,501
SERC-C to SPP-S	5,042	6,445	0	N/A	6,445
SPP-N to SPP-S	1,501	1,785	0	N/A	1,785
Total Import Interface Limit	**5,042**	**6,445**	**1,700**		**8,145**
Total Import Interface Limit + dc-only Interfaces Limit	**6,272**	**7,675**	**3,700**		**10,145**
(as % of 2033 Peak Demand)	**14%**	**17%**	**8%**		**22%**

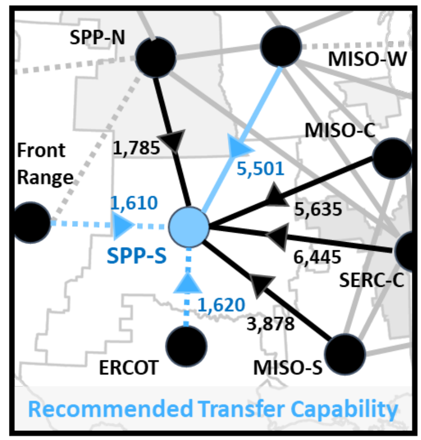
Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Existing interface
Existing dc-only interface
New interface
Existing, non-neighboring interface
Prudent addition recommendation

Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	177	34	4,137	54.7
Iteration 1	1,378	102	20	2,464	16.0
Iteration 2	1,378	75	3	817	1.8
Iteration 3	1,378	69	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years



Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	43,323	43,275
Hydro	2,101	2,101
Variable Renewable	27,007	27,007
Energy Limited	709	1,032
Total	73,140	73,415

Note: Thermal and hydro values represent winter ratings

Summer Peak	41,758	46,105
Winter Peak	32,037	36,562

Note: Median peak demand across all weather years

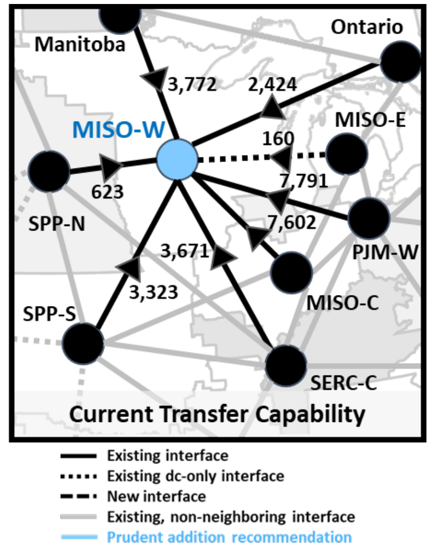
Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
2/15 WY2021	Winter	40,353	16	22.3	2,914
2/16 WY2021	Winter	40,832	7	15.4	4,137
2/17 WY2021	Winter	35,808	11	17.0	3,257

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

MISO-W

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Prudent Additions (MW)**	**Recommended Summer (MW)**	**Recommended Winter (MW)**
Ontario to MISO-W	2,424	1,862	N/A	N/A	N/A
Manitoba to MISO-W	3,772	3,633	N/A	N/A	N/A
MISO-C to MISO-W	7,602	7,341	N/A	N/A	N/A
MISO-E to MISO-W	160	160	N/A	N/A	N/A
PJM-W to MISO-W	7,791	9,086	N/A	N/A	N/A
SERC-C to MISO-W	3,671	6,877	N/A	N/A	N/A
SPP-N to MISO-W	623	778	N/A	N/A	N/A
SPP-S to MISO-W	3,323	1,196	N/A	N/A	N/A
Total Import Interface Limit	**7,791**	**9,086**			
Total Import Interface Limit + dc-only Interfaces Limit	**7,951**	**9,246**			
(as % of 2033 Peak Demand)	**21%**	**25%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	0	0	0	0.0
Iteration 1	N/A	0	0	0	0.0
Iteration 2	N/A	0	0	0	0.0
Iteration 3	N/A	0	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	35,680	32,247
Hydro	719	732
Variable Renewable	22,686	48,217
Energy Limited	1,953	5,647
Total	61,038	86,843

Note: Thermal and hydro values represent winter ratings

Summer Peak	35,702	37,127
Winter Peak	31,265	32,450

Note: Median peak demand across all weather years

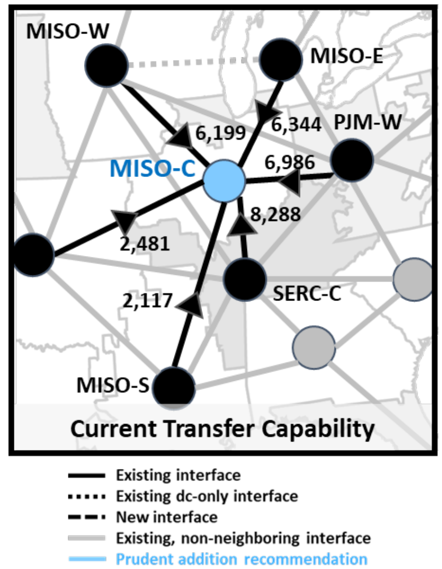
Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
No identified resource deficiency events					

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

MISO-C

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
MISO-E to MISO-C	6,344	6,531	N/A	N/A	N/A
MISO-S to MISO-C	2,117	1,093	N/A	N/A	N/A
MISO-W to MISO-C	6,199	7,306	N/A	N/A	N/A
PJM-W to MISO-C	6,986	20,449	N/A	N/A	N/A
SERC-C to MISO-C	8,288	8,441	N/A	N/A	N/A
SPP-S to MISO-C	2,481	2,420	N/A	N/A	N/A
Total Import Interface Limit	**12,714**	**20,449**			
Total Import Interface Limit + dc-only Interfaces Limit	**12,714**	**20,449**			
(as % of 2033 Peak Demand)	**37%**	**60%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	0	0	0	0.0
Iteration 1	N/A	15	0	0	0.0
Iteration 2	N/A	15	0	0	0.0
Iteration 3	N/A	15	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	28,986	23,418
Hydro	468	477
Variable Renewable	8,232	29,712
Energy Limited	2,306	23,632
Total	39,992	77,239

Note: Thermal and hydro values represent winter ratings

Summer Peak	32,967	34,278
Winter Peak	28,573	29,665

Note: Median peak demand across all weather years

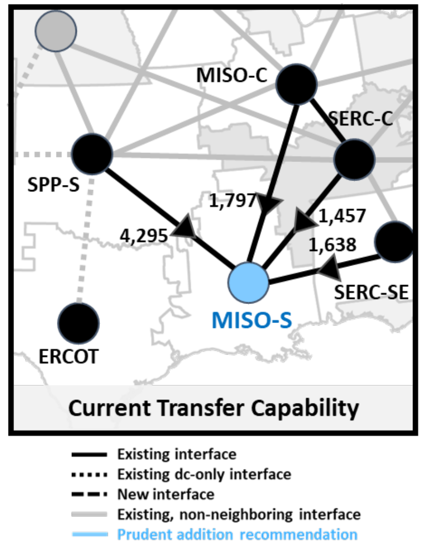
Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
No identified resource deficiency events					

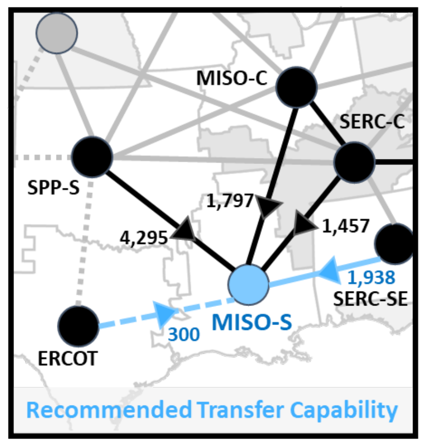
Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

MISO-S

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
ERCOT to MISO-S	Candidate	Candidate	300	300	N/A
MISO-C to MISO-S	1,797	4,067	0	1,797	N/A
SERC-C to MISO-S	1,457	3,342	0	1,457	N/A
SERC-SE to MISO-S	1,638	4,028	300	1,938	N/A
SPP-S to MISO-S	4,295	4,336	0	4,295	N/A
Total Import Interface Limit	**4,295**	**4,336**	**300**	**4,595**	
Total Import Interface Limit + dc-only Interfaces Limit	**4,295**	**4,336**	**600**	**4,895**	
(as % of 2033 Peak Demand)	**12%**	**12%**	**2%**	**14%**	

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values





Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	297	4	629	1.5
Iteration 1	209	278	2	420	0.8
Iteration 2	209	241	2	211	0.4
Iteration 3	209	205	1	2	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	41,748	34,904
Hydro	704	717
Variable Renewable	1,250	18,671
Energy Limited	1,773	2,038
Total	45,475	56,330

Note: Thermal and hydro values represent winter ratings

Summer Peak	33,676	34,980
Winter Peak	26,054	27,034

Note: Median peak demand across all weather years

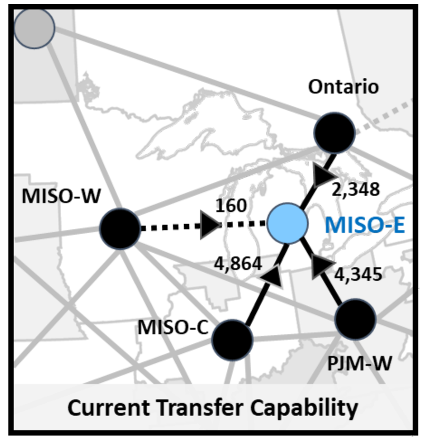
Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
6/22 WY2009	Summer	34,503	2	0.7	560
7/20 WY2011	Summer	36,724	2	0.8	629

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

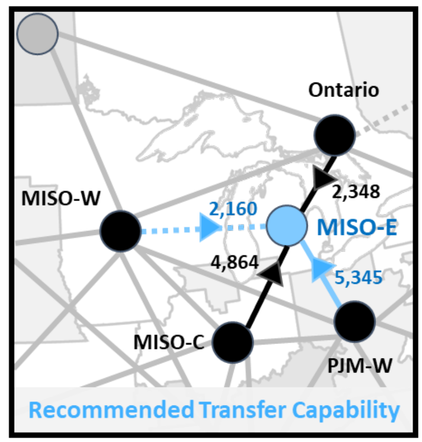
MISO-E

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
Ontario to MISO-E	2,348	1,649	0	2,348	N/A
MISO-C to MISO-E	4,864	5,585	0	4,864	N/A
MISO-W to MISO-E	160	160	2,000	2,160	N/A
PJM-W to MISO-E	4,345	5,608	1,000	5,345	N/A
Total Import Interface Limit	**5,139**	**7,019**	**1,000**	**6,139**	
Total Import Interface Limit + dc-only Interfaces Limit	**5,299**	**7,179**	**3,000**	**8,299**	
(as % of 2033 Peak Demand)	**24%**	**32%**	**13%**	**37%**	

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Existing interface
Existing dc-only interface
New interface
Existing, non-neighboring interface
Prudent addition recommendation



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	672	58	5,715	132.7
Iteration 1	1,903	116	5	977	1.9
Iteration 2	1,903	10	0	0	0.0
Iteration 3	1,903	10	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	19,332	15,262
Hydro	88	90
Variable Renewable	4,502	12,740
Energy Limited	3,345	3,317
Total	27,267	31,409

Note: Thermal and hydro values represent winter ratings

Summer Peak	21,536	22,370
Winter Peak	15,622	16,241

Note: Median peak demand across all weather years

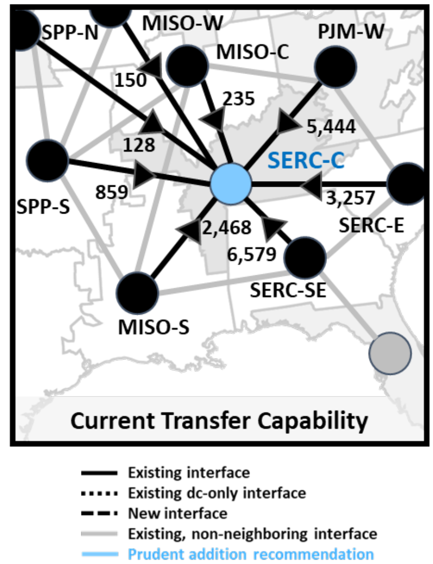
Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
8/2 WY2011	Summer	22,516	5	3.7	1,676
7/2 WY2020	Summer	21,926	3	1.9	982
7/3 WY2020	Summer	21,584	4	2.0	650
7/5 WY2020	Summer	20,700	4	0.8	380
7/6 WY2020	Summer	23,403	11	41.6	5,715
7/7 WY2020	Summer	23,850	11	38.3	5,353
7/8 WY2020	Summer	23,209	7	12.8	3,718
7/9 WY2020	Summer	23,522	10	30.1	4,206
8/25 WY2021	Summer	23,093	3	1.5	979

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

SERC-C

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
MISO-C to SERC-C	235	3,903	N/A	N/A	N/A
MISO-S to SERC-C	2,468	1,361	N/A	N/A	N/A
MISO-W to SERC-C	150	4,141	N/A	N/A	N/A
PJM-W to SERC-C	5,444	5,786	N/A	N/A	N/A
SERC-E to SERC-C	3,257	2,675	N/A	N/A	N/A
SERC-SE to SERC-C	6,579	4,639	N/A	N/A	N/A
SPP-N to SERC-C	128	1,102	N/A	N/A	N/A
SPP-S to SERC-C	859	5,591	N/A	N/A	N/A
Total Import Interface Limit	**6,878**	**8,443**			
Total Import Interface Limit + dc-only Interfaces Limit	**6,878**	**8,443**			
(as % of 2033 Peak Demand)	**16%**	**20%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	18	0	0	0.0
Iteration 1	N/A	19	0	0	0.0
Iteration 2	N/A	19	0	0	0.0
Iteration 3	N/A	18	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	44,841	47,921
Hydro	4,971	4,971
Variable Renewable	2,342	3,580
Energy Limited	3,506	3,667
Total	55,660	60,139

Note: Thermal and hydro values represent winter ratings

Summer Peak	42,203	43,083
Winter Peak	42,226	42,700

Note: Median peak demand across all weather years

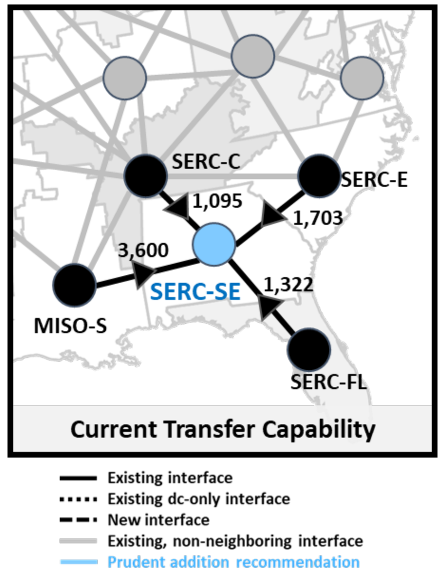
Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
No identified resource deficiency events					

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

SERC-SE

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
MISO-S to SERC-SE	3,600	3,392	N/A	N/A	N/A
SERC-C to SERC-SE	1,095	5,387	N/A	N/A	N/A
SERC-E to SERC-SE	1,703	3,536	N/A	N/A	N/A
SERC-FL to SERC-SE	1,322	0	N/A	N/A	N/A
Total Import Interface Limit	**4,900**	**6,525**			
Total Import Interface Limit + dc-only Interfaces Limit	**4,900**	**6,525**			
(as % of 2033 Peak Demand)	**10%**	**14%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	12	0	0	0.0
Iteration 1	N/A	11	0	0	0.0
Iteration 2	N/A	12	0	0	0.0
Iteration 3	N/A	7	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	54,953	55,016
Hydro	3,242	3,242
Variable Renewable	6,787	7,076
Energy Limited	3,698	4,227
Total	68,680	69,561

Note: Thermal and hydro values represent winter ratings

Summer Peak	46,322	47,849
Winter Peak	45,127	47,680

Note: Median peak demand across all weather years

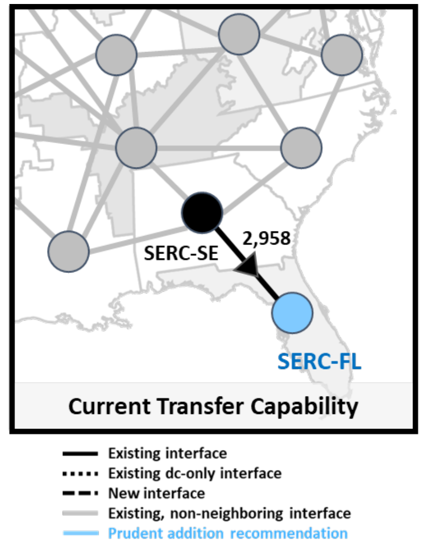
Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
No identified resource deficiency events					

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

SERC-Florida

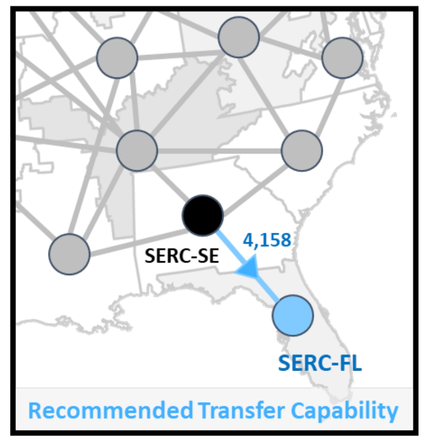
Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
SERC-SE to SERC-FL	2,958	1,807	1,200	4,158	3,007
Total Import Interface Limit	**2,958**	**1,807**	**1,200**	**4,158**	**3,007**
Total Import Interface Limit + dc-only Interfaces Limit	**2,958**	**1,807**	**1,200**	**4,158**	**3,007**
(as % of 2033 Peak Demand)	**5%**	**3%**	**2%**	**7%**	**5%**

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	618	6	1,152	3.7
Iteration 1	384	540	4	768	2.0
Iteration 2	384	450	3	384	0.7
Iteration 3	384	358	1	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years



Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	60,349	56,952
Hydro	0	0
Variable Renewable	11,770	28,984
Energy Limited	3,299	7,388
Total	75,418	93,324

Note: Thermal and hydro values represent winter ratings

Summer Peak	53,219	58,977
Winter Peak	48,260	52,952

Note: Median peak demand across all weather years

Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
6/22 WY2009	Summer	61,414	1	0.5	533
10/8 WY2009	Summer	55,305	3	1.2	1,030
1/11 WY2010	Winter	63,312	2	2.0	1,152

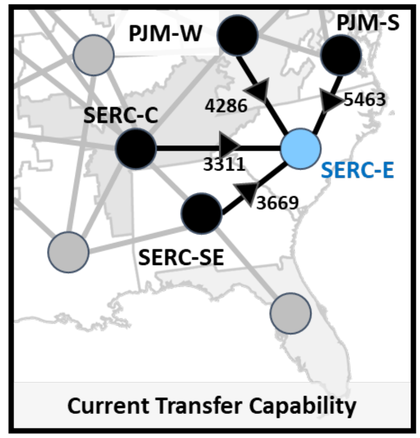
Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

SERC-E

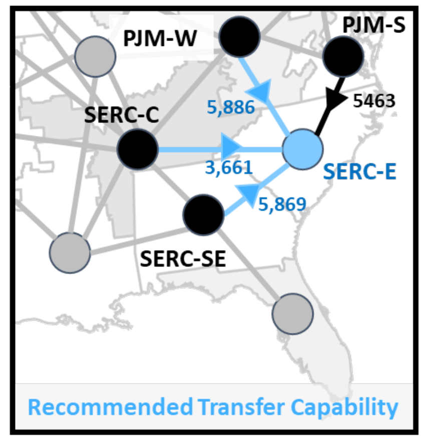
Total Transfer Capability (TTC) Summary

Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
PJM-S to SERC-E	4,665	5,463	0	N/A	5,463
PJM-W to SERC-E	5,318	4,286	1,600	N/A	5,886
SERC-C to SERC-E	2,419	3,311	300	N/A	3,611
SERC-SE to SERC-E	2,397	3,669	2,200	N/A	5,869
Total Import Interface Limit	**6,959**	**5,463**	**4,100**		**9,563**
Total Import Interface Limit + dc-only Interfaces Limit	**6,959**	**5,463**	**4,100**		**9,563**
(as % of 2033 Peak Demand)	**15%**	**11%**	**9%**		**20%**

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Existing interface
Existing dc-only interface
New interface
Existing, non-neighboring interface
Prudent addition recommendation



Energy Adequacy by Iteration

Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	74	9	5,849	30.2
Iteration 1	1,948	44	5	3,901	9.8
Iteration 2	1,948	22	2	258	0.4
Iteration 3	1,948	21	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)

Resource Type	2024	2033
Thermal	46,552	45,796
Hydro	3,164	3,164
Variable Renewable	2,363	5,862
Energy Limited	4,112	4,892
Total	56,191	59,714

Note: Thermal and hydro values represent winter ratings

Summer Peak	43,963	47,329
Winter Peak	45,015	47,591

Note: Median peak demand across all weather years

Resource Deficiency Events

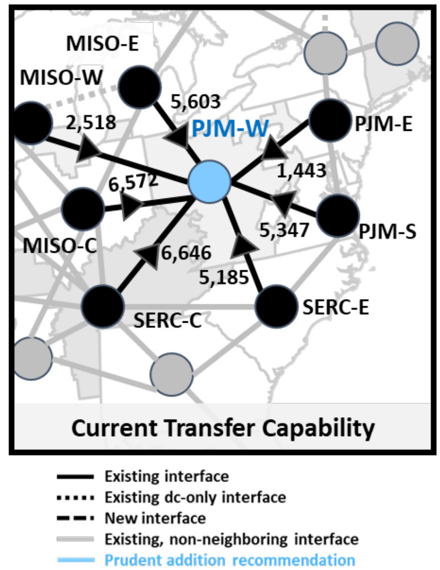
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
12/24 WY2022	Winter	54,603	8	28.8	5,849
12/25 WY2022	Winter	49,414	1	1.4	1,432

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

PJM-W

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Prudent Additions (MW)**	**Recommended Summer (MW)**	**Recommended Winter (MW)**
MISO-C to PJM-W	6,572	10,790	N/A	N/A	N/A
MISO-E to PJM-W	5,603	5,940	N/A	N/A	N/A
MISO-W to PJM-W	2,518	8,011	N/A	N/A	N/A
PJM-E to PJM-W	1,443	166	N/A	N/A	N/A
PJM-S to PJM-W	5,347	10,942	N/A	N/A	N/A
SERC-C to PJM-W	6,646	6,710	N/A	N/A	N/A
SERC-E to PJM-W	5,185	4,448	N/A	N/A	N/A
Total Import Interface Limit	**21,773**	**10,942**			
Total Import Interface Limit + dc-only Interfaces Limit	**21,773**	**10,942**			
(as % of 2033 Peak Demand)	**26%**	**13%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	3	0	0	0.0
Iteration 1	N/A	7	0	0	0.0
Iteration 2	N/A	10	0	0	0.0
Iteration 3	N/A	8	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	90,190	92,700
Hydro	1,177	1,194
Variable Renewable	23,454	26,652
Energy Limited	5,151	5,494
Total	119,972	126,040

Note: Thermal and hydro values represent winter ratings

Summer Peak	78,112	84,656
Winter Peak	68,845	75,667

Note: Median peak demand across all weather years

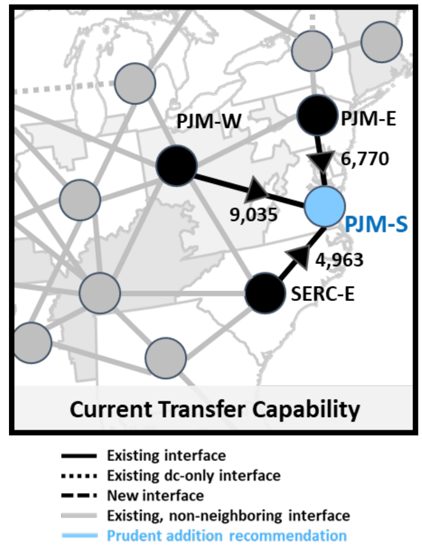
Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
No identified resource deficiency events					

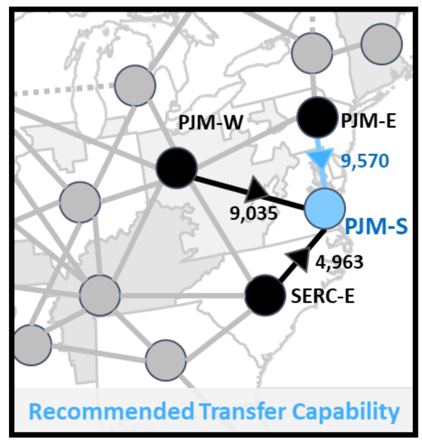
Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

PJM-S

Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
PJM-E to PJM-S	5,094	6,770	2,800	N/A	9,570
PJM-W to PJM-S	7,041	9,035	0	N/A	9,035
SERC-E to PJM-S	4,596	4,963	0	N/A	4,963
Total Import Interface Limit	**9,578**	**9,035**	**2,800**		**11,835**
Total Import Interface Limit + dc-only Interfaces Limit	**9,578**	**9,035**	**2,800**		**11,835**
(as % of 2033 Peak Demand)	**24%**	**23%**	**7%**		**30%**

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values





Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	185	20	4,147	45.3
Iteration 1	1,381	58	2	2,026	2.7
Iteration 2	1,381	39	0	0	0.0
Iteration 3	0	39	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	32,899	31,049
Hydro	552	552
Variable Renewable	12,967	16,511
Energy Limited	4,690	4,918
Total	51,108	53,030

Note: Thermal and hydro values represent winter ratings

Summer Peak	36,813	39,510
Winter Peak	32,927	36,002

Note: Median peak demand across all weather years

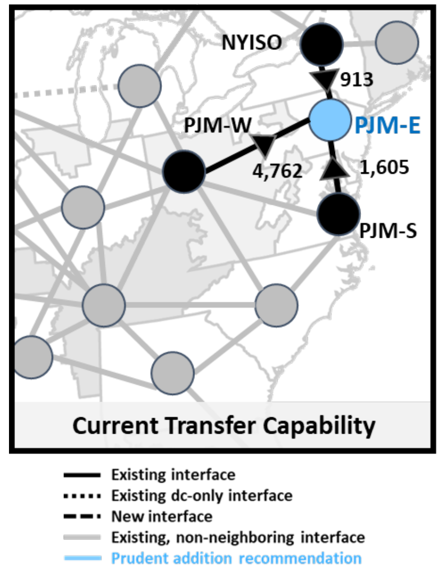
Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
12/24 WY2022	Winter	42,924	13	31.6	4,147
12/25 WY2022	Winter	39,928	7	13.7	3,874

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

PJM-E

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Prudent Additions (MW)**	**Recommended Summer (MW)**	**Recommended Winter (MW)**
Ontario to PJM-E	Candidate	Candidate	N/A	N/A	N/A
New York to PJM-E	913	4,019	N/A	N/A	N/A
PJM-S to PJM-E	1,605	4,166	N/A	N/A	N/A
PJM-W to PJM-E	4,762	9,815	N/A	N/A	N/A
Total Import Interface Limit	**4,762**	**9,815**			
Total Import Interface Limit + dc-only Interfaces Limit	**4,762**	**9,815**			
(as % of 2033 Peak Demand)	**12%**	**24%**			

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	0	0	0	0.0
Iteration 1	N/A	0	0	0	0.0
Iteration 2	N/A	1	0	0	0.0
Iteration 3	N/A	0	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	50,502	51,861
Hydro	1,366	1,366
Variable Renewable	9,947	15,507
Energy Limited	3,426	3,719
Total	65,241	72,453

Note: Thermal and hydro values represent winter ratings

Summer Peak	37,865	40,566
Winter Peak	31,522	34,488

Note: Median peak demand across all weather years

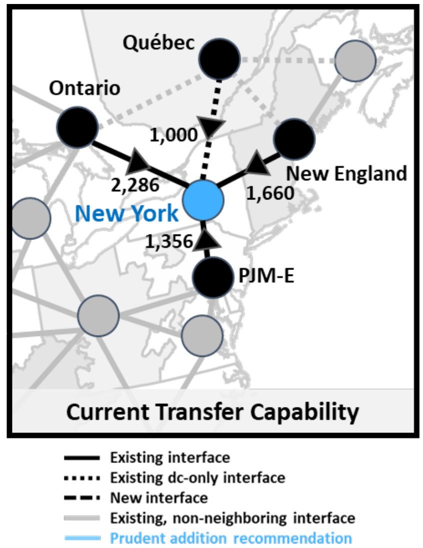
Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
No identified resource deficiency events					

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

New York

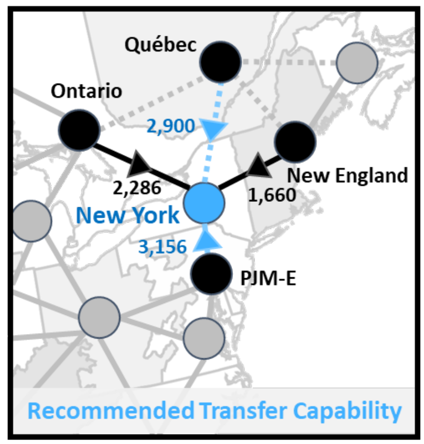
Total Transfer Capability (TTC) Summary					
Interface Name	Current Summer (MW)	Current Winter (MW)	Prudent Additions (MW)	Recommended Summer (MW)	Recommended Winter (MW)
Québec to New York	1,000	1,000	1,900	2,900	N/A
Ontario to New York	2,286	2,719	0	2,286	N/A
New England to New York	1,660	1,359	0	1,660	N/A
PJM-E to New York	1,356	4,814	1,800	3,156	N/A
Total Import Interface Limit	**2,802**	**4,814**	**1,800**	**4,602**	
Total Import Interface Limit + dc-only Interfaces Limit	**3,802**	**5,814**	**3,700**	**7,502**	
(as % of 2033 Peak Demand)	**11%**	**17%**	**11%**	**22%**	

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Energy Adequacy by Iteration					
Iteration Number	Iteration Size (MW)	Tight Margin Hours (h)	Resource Deficiency Hours (h)	Max Resource Deficiency (MW)	Total Deficiency (GWh)
Base	N/A	302	52	3,729	75.0
Iteration 1	1,242	149	20	2,431	22.5
Iteration 2	1,242	86	9	1,189	4.5
Iteration 3	1,242	58	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years



Capacity and Load Data (in MW)		
Resource Type	2024	2033
Thermal	31,114	31,079
Hydro	4,921	4,921
Variable Renewable	9,114	15,322
Energy Limited	1,983	1,983
Total	47,132	53,305

Note: Thermal and hydro values represent winter ratings

Summer Peak	31,496	34,345
Winter Peak	24,161	31,467

Note: Median peak demand across all weather years

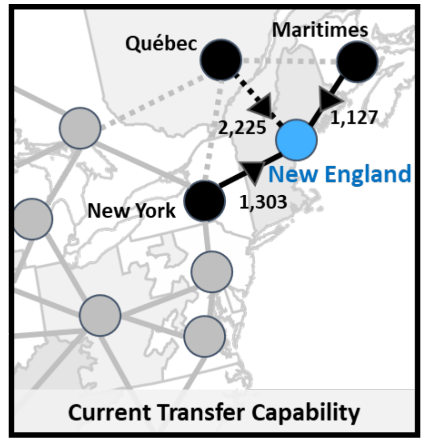
Resource Deficiency Events					
Event Date	Season	Daily Peak Demand (MW)	Max Deficiency Hours (h)	Total Deficiency (GWh)	Max Resource Deficiency (MW)
6/10 WY2008	Summer	35,149	2	0.1	81
7/6 WY2010	Summer	36,429	3	2.7	929
7/7 WY2010	Summer	35,389	5	10.9	3,244
8/31 WY2010	Summer	33,777	4	4.0	1,534
7/21 WY2011	Summer	36,672	3	1.9	754
7/22 WY2011	Summer	36,792	4	5.6	1,748
6/22 WY2012	Summer	35,963	6	6.3	1,998
7/18 WY2012	Summer	36,725	6	8.9	2,631
7/18 WY2013	Summer	36,798	4	3.3	1,229
9/5 WY2023	Summer	33,473	6	13.3	3,502
9/6 WY2023	Summer	34,679	6	15.7	3,729
9/7 WY2023	Summer	33,716	3	2.4	1,491

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

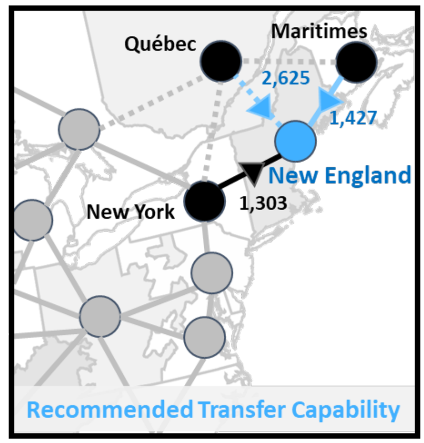
New England

Total Transfer Capability (TTC) Summary					
Interface Name	**Current Summer (MW)**	**Current Winter (MW)**	**Prudent Additions (MW)**	**Recommended Summer (MW)**	**Recommended Winter (MW)**
Québec to New England	2,225	2,225	400	2,625	N/A
Maritimes to New England	1,127	1,265	300	1,427	N/A
New York to New England	1,303	2,432	0	1,303	N/A
Total Import Interface Limit	**2,313**	**3,033**	**300**	**2,613**	
Total Import Interface Limit + dc-only Interfaces Limit	**4,538**	**5,258**	**700**	**5,238**	
(as % of 2033 Peak Demand)	**16%**	**18%**	**2%**	**18%**	

Note: The percentage of peak demand uses the higher of summer and winter 2033 peak load values



Existing interface
Existing dc-only interface
New interface
Existing, non-neighboring interface
Prudent addition recommendation



Energy Adequacy by Iteration					
Iteration Number	**Iteration Size (MW)**	**Tight Margin Hours (h)**	**Resource Deficiency Hours (h)**	**Max Resource Deficiency (MW)**	**Total Deficiency (GWh)**
Base	N/A	146	5	984	2.4
Iteration 1	328	113	2	547	1.0
Iteration 2	328	80	0	0	0.0
Iteration 3	0	73	0	0	0.0

Note: Tight margin hours and resource deficiency hours are the total across 12 weather years

Capacity and Load Data (in MW)		
Resource Type	**2024**	**2033**
Thermal	26,567	26,377
Hydro	1,894	1,893
Variable Renewable	8,903	13,804
Energy Limited	2,784	2,796
Total	40,148	44,870

Note: Thermal and hydro values represent winter ratings

Summer Peak	25,140	29,168
Winter Peak	20,552	26,829

Note: Median peak demand across all weather years

Resource Deficiency Events					
Event Date	**Season**	**Daily Peak Demand (MW)**	**Max Deficiency Hours (h)**	**Total Deficiency (GWh)**	**Max Resource Deficiency (MW)**
7/6 WY2010	Summer	30,683	1	0.1	85
6/22 WY2012	Summer	30,384	3	2.2	984
7/16 WY2013	Summer	29,828	1	0.1	68

Note: Daily peak demand does not necessarily reflect demand during resource deficiency hours

Chapter 10: Meeting and Maintaining Transfer Capability (Part 3)

The third requirement in the Fiscal Responsibility Act of 2023 is to make recommendations to meet and maintain current transfer capability as well as the recommended additions.

Increased transfer capability is one of many options for addressing the identified energy deficiencies.

As noted above, Part 2 of the ITCS recommended increases to transfer capability on particular interfaces as directed by the congressional mandate, but intentionally did not specify a particular set of projects or approach. This was intentional, as planners have multiple options for mitigating the identified energy adequacy risks. At a high level, these are:

- Increase transfer capability to neighbors with surplus resources
- Construct local generation
- Increase demand response resources
- Accept the identified risks during extreme events (assuming other reliability thresholds are met).

The implementation time for these enhancements vary considerably, so depending on the options selected, grid operators must be prepared to maintain the reliability of the BPS through emergency measures, including rotating outages if necessary.

Meeting Transfer Capability

If planners elect to increase transfer capability, there are multiple options to consider, including:

- Upgraded transmission infrastructure
- Remedial action schemes (RAS)
- Dynamic line ratings (DLR)
- Power flow control devices

The last two of these, along with advanced conductors, are frequently referred to as grid enhancing technologies. Grid enhancing technology projects are typically less expensive and require less lead time than building a new transmission line.

Regardless of the options chosen, planners need to perform detailed studies[99] to select projects and implement enhancements that will not result in other reliability issues. Increased transfers between TPRs can improve energy adequacy in some situations, but large transfers also have reliability implications that must be considered. When a large amount of energy is transferred, certain aspects of reliable system operations – such as system stability, voltage control, and minimizing the potential for cascading outages – must also be considered and mitigated, including the ability to withstand unplanned facility outages. This evaluation is crucial as an increased transfer capability may benefit neighboring TPRs under stressed conditions, but it can also potentially create reliability issues at other times if not mitigated.

Planners recognize that the thermal ratings of transmission lines may not be the most limiting constraint. Substation equipment may be more limiting than the transmission wires, so DLR or advanced conductors would not be effective without also upgrading the limiting elements. There may also be voltage limitations that can be remediated through

[99] Transmission Planners and Planning Coordinators should consider both TPL-001 studies plus other study methods to review potential solutions to identified deficiencies.

capacitors or other reactive compensation devices. Finally, in some instances, there may also be stability constraints that need to be appropriately addressed. All solutions must be carefully coordinated between neighboring planners to avoid unforeseen third-party impacts.

Upgraded Transmission Infrastructure

Building new and reconductoring existing transmission lines between TPRs are often effective options to increase transfer capability. Building new lines, either ac or dc,[100] between TPRs increases the ability to transfer energy, but this is typically a lengthy process, especially if new right-of-way is required.

Another way to increase transfer capability is to reconductor existing transmission lines with conductors having higher ratings. Advanced high-temperature low-sag (HTLS) conductors use new materials and designs to increase the current-carrying capacity of transmission lines without significant sag, even at high temperatures. The operational characteristics of these conductors should be fully considered when evaluating potential applications.

In some cases, existing tower structures can be raised to provide additional ground clearance and thereby allow operation at a higher conductor temperature.

Remedial Action Schemes (RAS)

In certain circumstances, it may be possible to increase transfer capability using a RAS. These schemes automatically respond to unplanned equipment outages when necessary to maintain operation within reliability criteria. The use of RAS must be planned, coordinated, and monitored to avoid unintended consequences. The use of RAS is generally discouraged as a long-term solution, as these schemes introduce higher levels of operational complexity, but may be helpful in the short term while other solutions are being implemented.

Dynamic Line Ratings (DLR)

This technology uses real-time and forecasted weather conditions to continuously calculate the thermal capacity of transmission lines, typically based on a variety of factors.[101] At times it is possible to increase transfer capability by using higher facility ratings given lower temperatures and/or higher wind speeds. During favorable weather conditions, DLR can increase the transmission rating by 10-30%.[102] DLR can provide improved real-time visibility and customized equipment rating profiles.

However, DLR may not be suitable for addressing recommended additions in all situations, such as if the driving weather event was a summer event where temperatures are high and wind speeds are generally lower. Localized weather conditions are difficult to predict more than a day or two in advance, so planning studies beyond the operational time horizon may still need to rely on seasonal weather conditions to determine the facility ratings.

Power Flow Control Devices

Power flow control devices, such as Flexible AC Transmission Systems (FACTS), Phase-Shifting Transformers (PST), and series compensation devices, are used to control and redirect the flow of electricity. This typically involves routing energy flows away from limiting constraints to optimize the use of existing transmission facilities without making changes to generator dispatch or topology. In general, FACTS have been in place for many years, but newer digital control technology allows for faster responses to system needs. This is especially of benefit in a loss of transmission or other contingency situation where these devices can quickly re-distribute power to maximize TTC. These devices could also be helpful in the integration of new renewable energy resources by using the existing capacity of the transmission system. Considering power flow control devices during the transmission planning process could allow for more options outside of transmission system expansion.

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[100] Because the Interconnections operate asynchronously, traditional ac solutions are unable to transfer energy between Interconnections.

[101] ERO Enterprise comments on FERC's advance notice of proposed rulemaking (ANOPR) were filed on October 15, 2024. See also Reliability Insights for more information on dynamic line ratings.

[102] https://www.energy.gov/oe/articles/dynamic-line-rating-report-congress-june-2019

Maintaining Transfer Capability

The actual transfer capability available during real-time operations may be different from the calculated transfer capability, because system conditions during actual operation may be different from the studied conditions. A certain level of transfer capability cannot always be maintained due to changing system conditions, including planned maintenance and forced outages. Since it is not possible to always maintain a particular level of transfer capability in the operations horizon, this section focuses primarily on what can be done in the planning horizon.

Future Studies

The data used in this study – including load forecasts, transmission topology, and resource mix – are constantly changing. NERC and the Regional Entities, working with industry, are planning to conduct regular assessments, rolled into future LTRA reports, that will consider the latest developments in resource mixes, transmission infrastructure, new load projections, and changing weather and climate patterns.

Planners can also evaluate changes in transfer capability as a part of regular planning processes, generator interconnection evaluations, and resource retirement studies. NERC encourages wide-area studies that holistically integrate transmission and resource planning.

Collectively, these studies can identify trends in interregional transfer capability and inform energy adequacy risk.

Coordination Agreements

Strong coordination is important under normal and emergency operating conditions, but is particularly vital when the grid is stressed, such as during extreme weather events. Entities should ensure that coordination procedures are in place to maximize the support that can be reliably provided to help promote energy adequacy. This has been an important factor in minimizing the impact of recent events.

Effective interregional coordination of maintenance is also critical. The transmission system must be maintained, including rigorous operations and maintenance procedures, such as tree trimming and insulator washing, so that transmission lines are protected from some of the external factors that can contribute to faults which remove equipment from service on an unplanned basis, usually reducing transfer capability. Equipment maintenance must be planned to be performed outside of periods of increased system stress and coordinated with neighbors to avoid impacts to other systems. This applies to the interregional tie lines as well as many facilities internal to a region where an outage can impact neighboring systems.

Regulatory or Policy Mechanisms and NERC Reliability Standards

The Fiscal Responsibility Act of 2023 requires FERC to post the ITCS report for public comments and subsequently submit a report to Congress including any recommended statutory changes. Such statutory changes could require entities to plan for recommended levels of transfer capability. As seen in the Part 2 analysis, a uniform minimum transfer capability requirement may not be necessary for some TPRs, nor a sufficient mechanism for others to ensure energy adequacy. Any statutory recommendations must ensure that the mandates result in actual transfer capability being available for entities to use under stressed system conditions.

Achieving the recommended levels of transfer capability may require upgrades to existing transmission facilities, as well as construction of new transmission facilities on new rights-of-way. ITCS recommends that policymakers consider implementing mechanisms to address current challenges with siting and permit approval processes, cost allocation methods, and multi-party operating and maintenance agreements, to accelerate the associated timelines where needed for reliability.[103]

[103] A National Renewable Energy Laboratory (NREL) paper *Barriers and Opportunities to Realize the System Value of Interregional Transmission* can be found here.

Currently, it is not NERC's intent to create a reliability standard for entities to establish a certain transfer capability. However, if events continue to occur or risks warrant such action, NERC may consider enacting reliability standards requiring certain assessments to be performed for planning transfer capability and appropriate mitigation measures put in place when risks to reliability warrant such action.

While there are no standards around transfer capability, there are standard development projects in progress around energy assurance. Project 2022-03 Energy Assurance with Energy-Constrained Resources and 2024-02 Planning Energy Assurance are meant to enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy adequacy and develop corrective action plans to address any identified risks. These assessments will evaluate energy adequacy across multiple time horizons by analyzing the expected resource mix availability (flexibility) and the expected fuel availability during the study period. This standard is meant to address resource deficiencies that can result in insufficient amounts of energy on the system to serve electrical demand and impact BPS reliability.

The ERO Enterprise is also taking steps to help address this risk with its Energy Assessment Strategy that was developed in 2023. The purpose of this strategy is to enable assessments of reliability risk through the transition from a capacity-limited system to a more energy-limited system reliant on variable energy resources and natural gas-fired generators. The first major step in this strategy is implementing an annual probabilistic assessment with additional data, such as hourly demand and resource data and improved variable energy resource modeling.

Chapter 11: Future Work

While this study represents a pioneering and comprehensive effort to evaluate transfer capability and its impact on energy adequacy, it also had limitations due to the study's timeframe and there were lessons learned throughout the process. These factors highlight the need for additional future work to build on the findings and address areas that were not fully explored in this initial analysis. The following sections outline key areas for future work that will help refine and expand the understanding of transfer capability and its role in strengthening grid reliability.

Explore Alternative Resource Mixes

One of the key areas for future work involves exploring alternative resource mixes to better understand the tradeoffs between generation and transmission options. By analyzing different combinations of generation types, such as varying levels of renewable energy integration and retirement of fossil fuel resources, a comparison can be made regarding the need for additional transmission infrastructure and generation resources. Future studies can offer more nuanced insights into how to optimally balance local generation with transfer capability. This exploration could help identify comprehensive strategies that also consider cost-effectiveness, policy objectives, and utility plans.

Evaluate Transfer Capability Between "Neighbor's Neighbor"

Another area for further study is the evaluation of transfer capability between non-neighboring TPRs, or "neighbor's neighbors," to capture additional reliability benefits and enhance geographic diversity. Connections such as ERCOT to SERC-SE and Front Range to California North, among others, represent opportunities to mitigate the resource saturation effects observed with immediately neighboring TPRs. While these connections may be more costly to build, they could provide significant benefits by extending the reach of surplus resources during extreme events, reducing the overall vulnerability of the grid, and may also access other benefits beyond reliability, like congestion savings or access to lower cost resources. Studies of this nature would require a wide area planning approach and cost allocation mechanism for any resulting system additions.

Expand Weather Datasets

This study developed a consistent, time-synchronized weather dataset across wind, solar, load, and generator outages over 12 weather years. Some TPRs might not have shown deficits only because they did not experience a challenging weather event during the years that were evaluated. Similarly, another TPR may have experienced a resource deficit in the weather events analyzed, but there is no information regarding the future likelihood of these events. Expanding the analysis to include a more extensive dataset, including decades of historical and/or projected future weather data, would provide a more robust basis for evaluating investments.

Evaluate Stability and Transfer Capability During Extreme Weather Events

Part 1 studies included power flow analysis, voltage screening, and known stability limits. Future studies should include more expansive stability analysis to identify potentially more restrictive limits, especially because stability limitations can become more prominent when there is increased reliance on heavy transfers across large areas.

Future work should also focus on evaluating transfer capability during extreme weather events. Part 1 results were based on summer and winter peak demand cases, but did not account for the specific weather conditions that led to resource deficiencies identified in Part 2. In subsequent studies, the power flow analysis should be dispatched based on the extreme weather events highlighted in the energy margin analysis. This approach will help determine whether the existing transfer capabilities calculated in Part 1 and assumed in Part 2 are practical and sufficient under real-world conditions and determine what, if any, additional mitigation may be needed to transfer energy up to the levels evaluated in this study.

Incorporate Probabilistic Resource Adequacy Analysis

The methods and analysis in this study evaluated a single outage pattern for each weather year, incorporating weather-dependent outages and fuel supply disruptions. However, future work could expand this analysis to be fully probabilistic, considering hundreds or even thousands of outage scenarios rather than just 12 weather years. This expansion would allow for the estimation of probabilities and the introduction of typical resource adequacy metrics such as Loss of Load Expectation (LOLE), Loss of Load Probability (LOLP), and Expected Unserved Energy (EUE). These metrics would facilitate easier comparisons between transmission enhancements and generation resource additions, offering a more comprehensive view.

Establish Study Periodicity and Parameters

To ensure that the findings and recommendations from this study remain relevant and adaptive to the evolving industry landscape, it is recommended that this type of evaluation be conducted on a regular basis. NERC and the Regional Entities, working with industry, are planning to conduct regular assessments, rolled into future LTRA reports, that will consider the latest developments in resource mixes, transmission infrastructure, new load projections, and changing weather and climate patterns. It is also recommended that NERC, working with industry, should promote consistency in how queue resources are categorized in reliability assessments. Additional sensitivities and alternative criteria may be explored.

Some differences in load forecasts and resource assumptions were noted when comparing study power flow cases to LTRA data. Standardizing case-building processes and associated content could ensure consistency and improve the efficiency of future studies.

There is also an opportunity to develop guidance for subdividing large areas and standardizing data sources for future studies. As the BPS evolves, the TPRs should be reviewed and modified as appropriate to identify significant limitations of interregional transfers. In a few instances where Balancing Authorities are split into multiple TPRs, there are opportunities to enhance available data to more efficiently account for each TPR, improving the data quality in future studies.

Chapter 12: Acknowledgements

NERC appreciates the people across the industry who provided technical support and identified areas for improvement throughout the ongoing ITCS project.

Table 12.1: NERC Industry Group Acknowledgements	
Group	**Members**
ITCS Executive Committee	Dave Angell (Industry Expert), Richard Burt (MRO), Charles Dickerson (NPCC), Tim Gallagher (RF), Fritz Hirst (NERC), Robert Kondziolka (Industry Expert), Mark Lauby (NERC), Gary Leidich (Industry Expert), Kimberly Mielcarek (NERC), Tim Ponseti (SERC), Sonia Rocha (NERC), Branden Sudduth (WECC), Joseph Younger (Texas RE)
ITCS Advisory Group	Gabriel Adam (IESO), Aaron Berner (PJM), Adria Brooks (DOE), Daniel Brooks (EPRI), Jessica Cockrell (FERC), Vandan Divatia (Eversource), Edison Elizeh (BPA), Robert Entriken (EPRI), Vincent Fihey (Hydro Québec), Greg Ford (Georgia System Operations), Tom Galloway (NATF), Jeffrey Gindling (Duke Energy Midwest), Prabhu Gnanam (ERCOT), Biju Gopi (California ISO), Wayne Guttormson (SaskPower), Hassan Hayat (AEP), Matt Holtz (Invenergy), Larre Hozempa (FirstEnergy), Faheem Ibrahim (ISO New England), David Jacobson (Manitoba Hydro), Aubrey Johnson (MISO), David Kelley (SPP), Brett Kruse (Calpine), Darryl Lawrence (Pennsylvania Office of Consumer Advocate), Charles Long (Entergy), Chelsea Loomis (Northern Grid), Thanh Luong (FERC), Charles Marshall (ITC), Daryl McGee (Southern), Gayle Nansel (WAPA), Heidi Pacini (WestConnect), Colton Pankhurst (Natural Resources Canada), Nate Schweighart (TVA), Zachary Smith (NYISO), Lance Spross (ONCOR), Aidan Tuohy (EPRI), John Twitty (MJMEUC), Miguel Yanes (FP&L)
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Appendix A: Data Sources

The data sources used for the Part 2 analysis are shown in **Table A.1** below.

Table A.1: Overview of the Two-Pronged Approach for Historical Weather Data		
	Synthetic Weather Data Weather Years 2007 - 2013	**Scaled Historic Actuals Weather Years 2019-2023**
Data Source	North American meteorological datasets – often developed by National Labs, including National Solar Radiation Database (NSRDB), Wind Toolkit, etc.	Reported data from Balancing Authorities, including EIA-930 and FERC-714
Historical Record	Can span several weather years, typically 10-40 years, but current data gaps (specifically for wind resources) can limit years of analysis	Must use a shorter historical record, i.e., last three to five years, to make sure it is representative of current system
Outlier Events	Can get a longer history of outlier events (i.e., cold snaps in the 1980s) but estimates may be less accurate than recent observations	Fewer outlier events will be in the sample size (i.e., Winter Storm Uri, Elliott, heat domes) but may be more accurate than synthetic data
Wind and solar profiles	Captures geographic diversity based on new site selection and allows user to make assumptions on technology developments	Scaling historical generation amplifies correlation of resources and assumes technology remains constant
Load Growth Trends	Load data can be developed by end use to introduce changes from electric vehicles and building electrification	Embedded in the underlying load data, cannot be easily introduced
Climate Trends	Climate trends can be applied to underlying meteorological datasets	Embedded in the underlying data, cannot be easily introduced
Application	Better for analyzing future power systems and/or screening across a wider range of potential events	Better for analyzing near-term power systems during specific events

Appendix B: Scaling Weather Year Load Profiles

Differences in the Synthetic and Historical Weather Year Data

Both the synthetic and historical weather year data have advantages and disadvantages, which is why two different datasets were used to extend the available weather years for analysis and to provide comparisons. The synthetic load supplements the fact that historical load may not capture changes in the underlying load shapes due to economic changes. Historical data supplements the need for reflecting actual conditions as they transpired and helps overcome challenges in acceptance for using purely synthetic data which relies on many assumptions. Both are useful for conducting the energy margin analysis and provide a wider picture of possible grid conditions.

Historical Load

Before using the historical data in the study, it was necessary to clean and adjust it in the following ways:

- Clean data using data engineering practices:
  - Replace outlier load spikes (defined as load that is 4x median demand) with preceding or following hour demand.
  - Replace zero load reporting with interpolation or previous day's demand depending on duration of the events in EIA data.
  - Supplement EIA data with ISO-reported load for prolonged (multi-day) periods of reported zero or flat load in EIA 930 data.
- Add unserved energy (USE) back in for known events using the FERC, NERC, and Regional Entity Staff Reports for Elliott, Uri, and CAISO's report on their 2020 event.
- Add estimates for behind-the-meter (BTM) generation that masks load.

Synthetic Load

The synthetic load from NREL and EER represented "End Use Load" prior to reductions due to behind-the-meter solar (BTM PV) generation and does not include line losses. This means that the load factor of the synthetic weather year load is not altered by BTM PV, and no adjustments needed to be made to the hourly weather year profiles prior to scaling them to the LTRA forecasts.

Target Forecast (2023 LTRA Annual Energy, Summer and Winter Peak Loads)

The target forecast for the study used the 2023 LTRA seasonal peak load and annual energy forecasts for 2024 and 2033 and assumed that these values represent the median forecast (P50). Based on this assumption, each set of weather year (synthetic and historical) loads were scaled so that the median peak and energy values of those datasets matched the values for each LTRA assessment area. The data provided in the LTRA forecast represents net energy for load which excludes the impacts of behind-the-meter PV. BTM PV was modeled as a supply side resource for the energy margin analysis, so the LTRA forecast was adjusted to gross load derived from BTM PV assumptions in the LTRA. The target peak and energy forecasts for each LTRA assessment area used in this study are shown in **Table B.1.**

Table B.1: Adjusted LTRA Forecast Target Annual Energy and Summer/Winter Peak Loads														
Year	**Period**	**ERCOT**	**MISO**	**New England**	**New York**	**PJM**	**SERC C**	**SERC E**	**SERC FL**	**SERC SE**	**SPP**	**WECC CA/MX**	**WECC NW**	**WECC SW**
2024	Summer Peak (MW)	85,717	123,609	26,675	34,561	152,931	42,266	44,323	53,952	46,472	53,626	61,587	64,449	27,552
	Winter Peak (MW)	69,495	102,287	20,528	24,231	132,758	42,282	45,053	48,492	45,104	42,661	38,778	57,546	15,792
	Annual Energy (GWh)	469,383	682,261	128,773	160,663	814,833	225,229	231,307	261,337	243,058	299,150	287,384	381,958	127,379
2033	Summer Peak (MW)	96,163	128,270	31,202	37,834	165,476	43,122	48,333	61,396	48,055	59,265	74,285	79,232	32,878
	Winter Peak (MW)	79,946	105,562	26,723	31,552	145,120	42,764	47,549	52,954	47,523	48,383	45,638	68,103	19,731
	Annual Energy (GWh)	554,676	711,081	162,933	183,337	927,808	233,060	250,382	292,486	257,758	337,976	346,458	461,524	158,534

For the historical load, the EIA Form 930 served as the foundational dataset as it provides hourly loads at the Balancing Authority level along with sub-regional load for some ISO/RTOs. This sub-regional data was key for allocating load across the TPRs. EIA 930 provides demand as net generation for load values, the same as is reported in the LTRA.

For the synthetic load, data prepared for the National Renewable Energy Laboratory (NREL) Regional Energy Deployment System (ReEDS) model was used as the foundation for creating the 2007-2013 weather year load profiles for the TPRs. The underlying weather year dataset was prepared by Evolved Energy Research (EER) and purchased by NREL for several load growth scenarios. EER performs bottom-up load modeling and forecasts future loads based on building stock characteristics, industrial growth, electrification, etc.

The synthetic load scenario chosen for the study was the “EER_Baseline_AEO2022” dataset available on the NREL ReEDS-2.0 GitHub repository.[104] This load forecast represents business as usual load growth conditions based on projections from the Energy Information Administration's (EIA) 2022 Annual Energy Outlook. The load forecast was produced by Evolved Energy Research for the 2007 - 2013 weather years but represents consistent future economic years. This study used the forecasted load data for 2024 and 2033 and then adjusted peak and energy targets for the forecasts to align projections with the 2023 LTRA load forecast data.

Both the synthetic and historical load profiles were scaled to align the median energy and peak loads from the weather years to the targets at the LTRA assessment area level. Adjusting just for energy targets can cause the peak load values to differ significantly from the target values in the LTRA forecast. This was accounted for by incrementally adjusting the hourly profiles so that the summer and winter median peak loads aligned with the forecast targets without changing the annual energy. This maintains variability in timing and magnitude of peak loads based on the weather and ensures that annual energy targets are maintained. The general steps taken to scale the load profiles are detailed below.

1. Add energy to each hour in a Weather Year so that the annual energy aligns with the LTRA forecast.
2. Adjust the energy shifted profiles to align the median weather year summer and winter peak loads with the LTRA forecast.
3. While maintaining the load shape, align scaled load with LTRA annual load factors.
4. Perform process for both 2024 and 2033 LTRA Forecast Years.

[104] NREL ReEDS-2.0, 2007-2013 weather year, see EER_Baseline_AEO2022, GitHub - NREL/ReEDS-2.0

This process is portrayed graphically below as a historical data example. Step 0 for the historical data shows the cleaning and addition of BTM PV to the load profile (see **Figure B.1**).

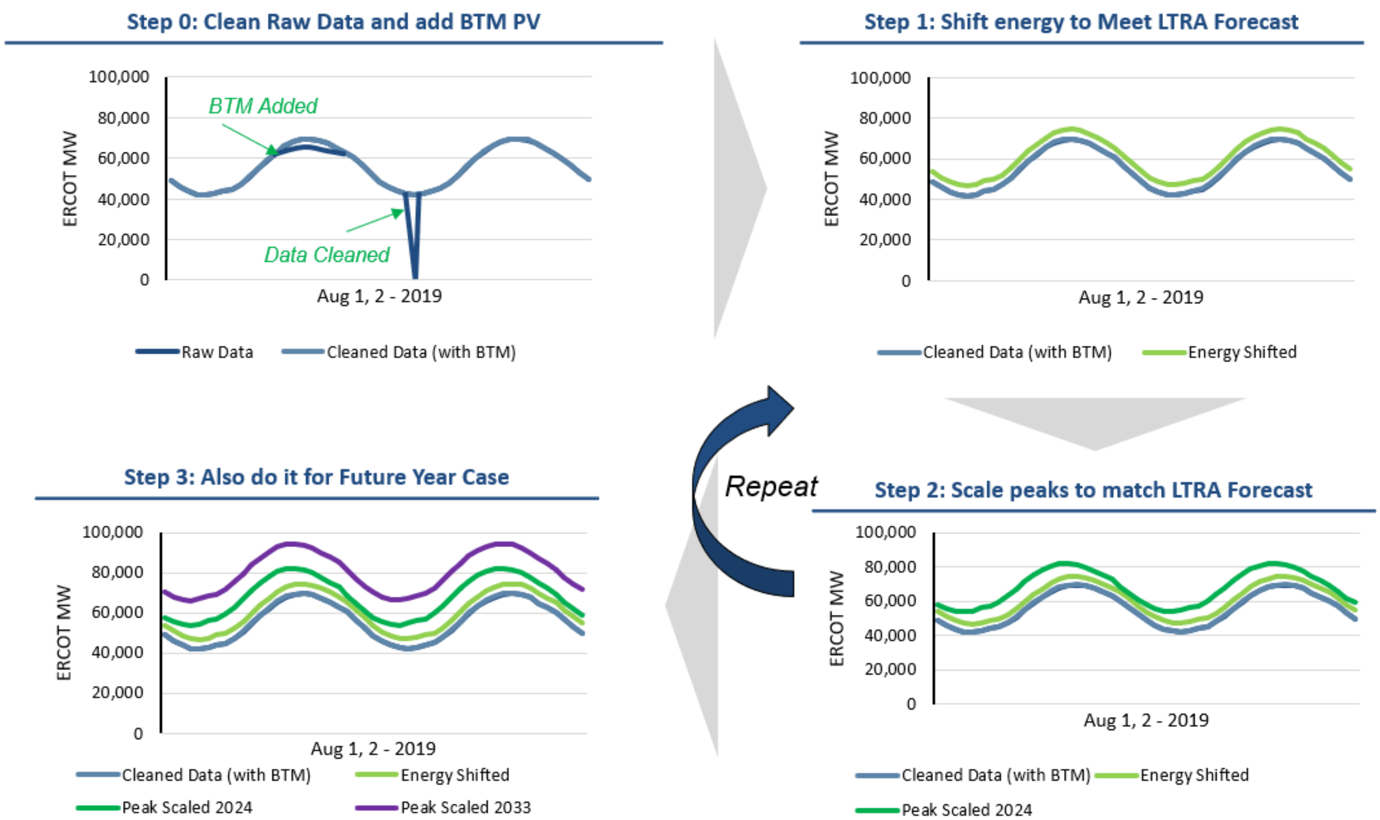

Figure B.1: Example of Load Scaling Process to Scale Weather Year Load Profiles to LTRA Forecast Years

The load scaling step was done in reference to the LTRA assessment areas because these are the areas available in the LTRA forecast. After scaling the load data, each LTRA assessment area was disaggregated from an hourly LTRA profile into a TPR profile.

Figure B.2 illustrates the variability in peak loads for three TPRs, namely California South, ERCOT, and SERC-C.

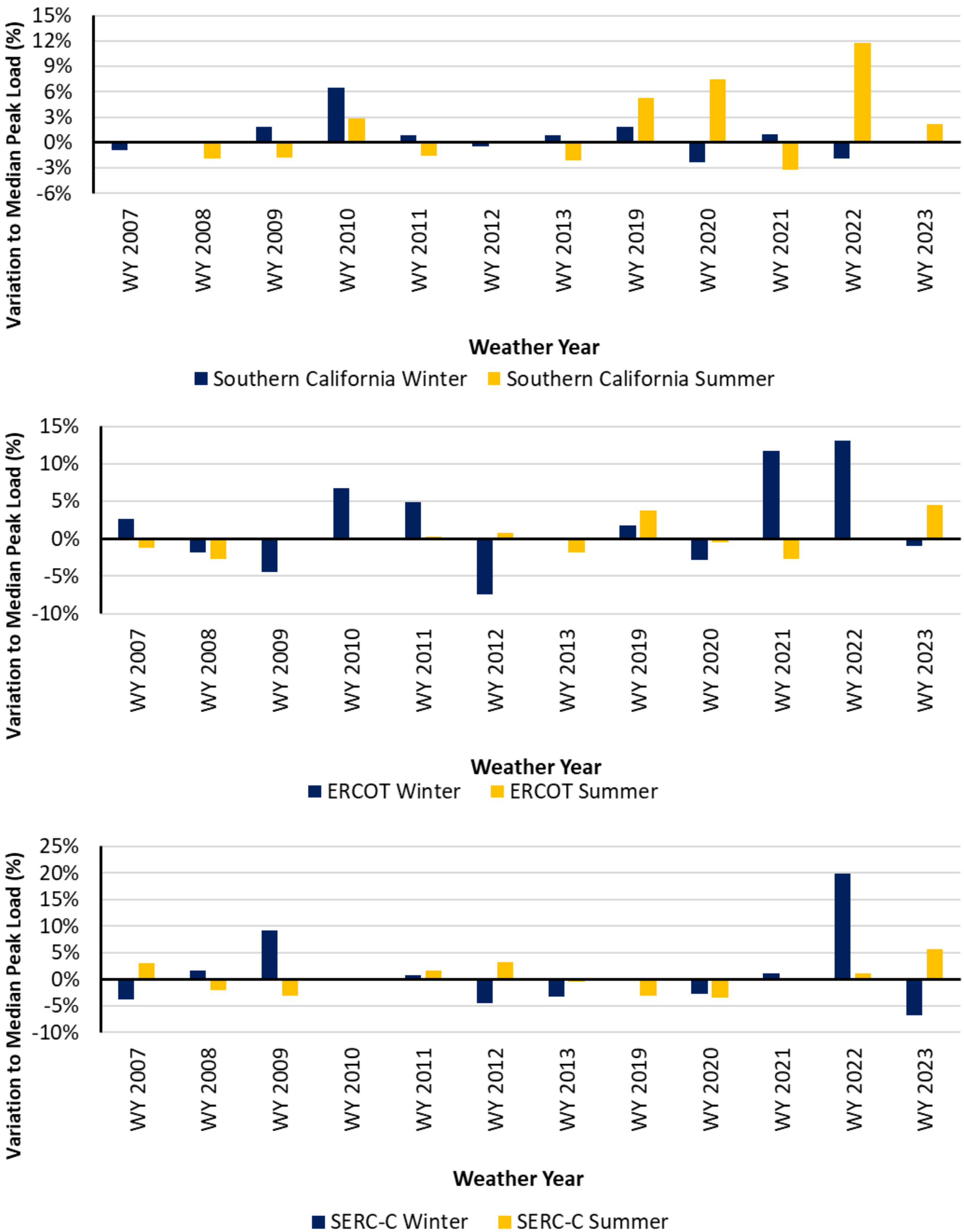

Figure B.2: Weather Year Variation Relative to Median Peak Load for Selected TPRs

Appendix C: Annual Peak Load Tables by TPR

Annual peak loads for each TPR by weather year are shown in Table C.1 and Table C.2 below for the 2024 and 2033 cases, respectively. Annual peak loads vary due to the underlying weather conditions present for each TPR in each weather year. Minimum, median, and maximum annual peak load values are provided as a summary. Load reflects the net energy for load which excludes BTM PV.

Table C.1: Annual Peak Load by Weather Year (2024 Case)

Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Min	Median	Max
Washington	18,294	19,358	20,226	19,178	17,835	17,371	19,356	20,071	18,390	19,370	20,674	19,379	17,371	19,356	20,674
Oregon	10,447	10,400	10,954	10,585	10,057	10,412	10,633	10,725	10,224	11,085	11,194	10,955	10,057	10,585	11,194
California North	23,972	23,468	23,913	25,219	24,281	24,910	24,000	25,658	25,067	24,174	28,324	25,016	23,468	24,281	28,324
California South	34,780	34,183	34,837	36,750	35,285	35,556	34,603	36,738	37,273	32,961	40,605	36,283	32,961	35,285	40,605
Southwest	21,085	21,295	21,965	21,814	21,066	21,260	21,194	20,613	21,856	22,317	21,345	22,345	20,613	21,295	22,345
Wasatch Front	26,109	25,178	25,135	25,515	25,304	25,982	26,774	23,815	24,798	25,625	25,750	25,089	23,815	25,304	26,774
Front Range	18,935	18,723	18,151	18,047	19,022	19,271	18,546	18,279	17,864	18,295	18,794	19,699	17,864	18,546	19,699
ERCOT	83,263	82,416	84,280	84,125	83,992	84,454	82,416	85,964	83,872	81,806	84,522	88,683	81,806	83,992	88,683
SPP-N	12,242	12,220	11,920	12,346	12,664	12,587	12,021	11,366	11,993	12,309	12,008	12,582	11,366	12,220	12,664
SPP-S	41,334	41,257	40,857	41,681	42,753	42,510	40,584	42,717	40,967	41,834	42,956	44,880	40,584	41,681	44,880
MISO-W	35,072	34,319	35,537	35,237	37,488	36,936	35,387	36,082	35,886	35,640	35,763	37,471	34,319	35,640	37,488
MISO-C	31,174	31,104	31,470	31,596	33,411	32,990	31,500	33,274	32,943	33,551	33,499	34,459	31,104	32,943	34,459
MISO-S	34,001	32,352	34,402	34,203	35,299	35,394	33,352	32,773	33,158	33,263	33,323	36,260	32,352	33,352	36,260
MISO-E	21,076	20,481	20,631	21,133	22,346	21,938	21,131	22,387	23,012	22,480	22,921	21,986	20,481	21,938	23,012
SERC-C	43,492	42,980	46,262	42,278	42,957	43,499	42,149	42,175	41,022	42,650	50,787	44,583	41,022	42,957	50,787
SERC-SE	47,799	46,567	48,226	47,197	47,713	47,020	43,314	46,017	46,226	46,346	47,944	46,749	43,314	46,749	48,226
SERC-Florida	53,968	53,277	55,269	58,856	53,131	52,986	53,161	51,820	51,262	53,636	53,893	55,964	51,262	53,277	58,856
SERC-E	45,051	44,926	46,882	45,247	45,856	45,091	42,604	46,337	44,978	44,062	51,628	44,922	42,604	45,051	51,628
PJM-W	77,282	75,819	74,440	75,468	81,135	78,745	78,649	77,980	78,920	79,319	78,243	76,039	74,440	77,980	81,135
PJM-S	35,670	33,929	34,262	35,559	38,358	38,173	37,520	38,703	37,162	36,542	39,664	38,831	33,929	37,162	39,664
PJM-E	35,390	34,043	33,781	35,455	38,432	38,821	37,307	39,076	38,153	38,719	37,868	38,843	33,781	37,868	39,076
New York	31,464	32,111	31,467	33,278	33,721	33,982	33,656	30,708	31,525	31,349	31,277	32,753	30,708	31,525	33,982
New England	24,490	25,102	24,830	26,286	26,928	26,423	26,700	24,143	25,179	25,562	24,919	24,843	24,143	25,102	26,928

Table C.2: Annual Peak Load by Weather Year (2033 Case)															
Transmission Planning Region	WY2007	WY2008	WY2009	WY2010	WY2011	WY2012	WY2013	WY2019	WY2020	WY2021	WY2022	WY2023	Min	Median	Max
Washington	21,006	22,137	22,949	21,966	20,567	20,174	22,135	23,034	21,190	22,230	23,425	22,246	20,174	22,135	23,425
Oregon	12,144	12,028	12,671	12,329	11,658	12,093	12,384	12,333	12,124	13,254	12,922	13,237	11,658	12,329	13,254
California North	29,063	28,339	28,157	30,157	28,760	29,565	28,932	30,825	30,069	29,172	33,493	30,235	28,157	29,172	33,493
California South	42,969	42,235	42,911	44,947	43,221	43,740	43,126	42,866	43,647	39,401	48,448	43,430	39,401	43,126	48,448
Southwest	26,111	25,657	26,755	26,125	25,704	26,079	25,798	24,205	25,424	26,113	25,189	26,020	24,205	25,798	26,755
Wasatch Front	33,020	31,671	31,795	32,094	31,975	32,976	33,820	28,452	29,602	30,683	30,901	29,509	28,452	31,671	33,820
Front Range	22,371	22,365	21,466	21,635	22,864	23,381	22,347	21,681	20,853	21,266	22,199	23,101	20,853	22,199	23,381
ERCOT	90,619	90,490	92,160	91,393	92,268	92,619	90,062	96,792	92,312	90,391	92,947	96,638	90,062	92,160	96,792
SPP-N	13,531	13,502	13,157	13,632	14,010	13,909	13,280	12,638	13,308	13,660	13,343	13,959	12,638	13,502	14,010
SPP-S	45,686	45,587	45,099	46,027	47,301	46,980	44,839	47,153	45,285	46,182	47,369	49,362	44,839	46,027	49,362
MISO-W	36,466	35,616	36,912	36,576	39,013	38,396	36,738	37,513	37,310	37,063	37,191	38,934	35,616	37,063	39,013
MISO-C	32,453	32,279	32,742	32,838	34,811	34,312	32,756	34,597	34,243	34,869	34,803	35,757	32,279	34,243	35,757
MISO-S	35,345	33,564	35,720	35,493	36,724	36,845	34,615	34,038	34,421	34,532	34,613	37,606	33,564	34,615	37,606
MISO-E	21,908	21,250	21,422	21,936	23,250	22,804	21,932	23,215	23,850	23,311	23,754	22,800	21,250	22,800	23,850
SERC-C	44,374	43,338	46,580	43,105	43,796	44,475	42,872	42,643	41,557	43,116	51,141	45,481	41,557	43,338	51,141
SERC-SE	49,518	48,085	50,538	49,477	50,020	48,794	44,496	47,490	47,843	47,913	50,706	48,222	44,496	48,222	50,706
SERC-Florida	60,084	59,337	61,414	63,312	58,928	58,177	58,469	56,410	56,106	61,325	59,027	61,138	56,106	59,027	63,312
SERC-E	48,661	47,766	49,308	47,632	48,310	48,585	45,158	49,249	47,831	46,894	54,603	48,360	45,158	48,310	54,603
PJM-W	83,512	82,072	80,426	81,775	87,588	85,230	84,920	84,580	85,500	85,869	84,732	82,492	80,426	84,580	87,588
PJM-S	38,346	36,542	36,662	38,306	41,207	41,223	40,406	41,839	39,842	39,276	42,924	41,661	36,542	39,842	42,924
PJM-E	38,468	36,536	36,691	38,294	41,506	41,970	40,389	42,377	40,785	41,359	40,122	41,585	36,536	40,389	42,377
New York	34,285	35,149	34,406	36,429	36,792	36,725	36,798	33,270	33,624	33,088	32,223	34,679	32,223	34,406	36,798
New England	28,588	29,224	28,781	30,683	31,368	30,758	30,890	29,288	29,113	29,357	28,196	28,403	28,196	29,224	31,368

Appendix D: Sub-regional Mapping

All the data used for the energy margin analysis was reported or developed at one of three levels, the LTRA assessment areas, the EIA Balancing Authority and sub-regional topology, or the NREL ReEDS topology. To reconcile data that was not aligned with the TPR topology, mapping between the different topologies was done. The figures in this section present the different topologies that were mapped to align data to both the LTRA assessment areas and TPRs, which are shown in **Figure D.1** and **Figure D.2**, respectively.

Generators provided in the LTRA data form were mapped from LTRA assessment area to TPR based on several mapping rules listed in order of hierarchy below.

- LTRA maps one-to-one with the TPR. Examples are SERC-C, SERC-SE, SERC-E.
- Specific mappings based on supplemental data submitted in the LTRA such as Balancing Authority, data submitter, State, or Regional Entity review of select plants.
- Manual mapping for generators that could not be assigned using the first two approaches. Generator names, or interconnection numbers, were mapped to a TPR using EIA or interconnection queue data.

The results of this mapping exercise compared against the capacities in the power flows used in the Part 1 analysis is shown in **Figure D.3**.

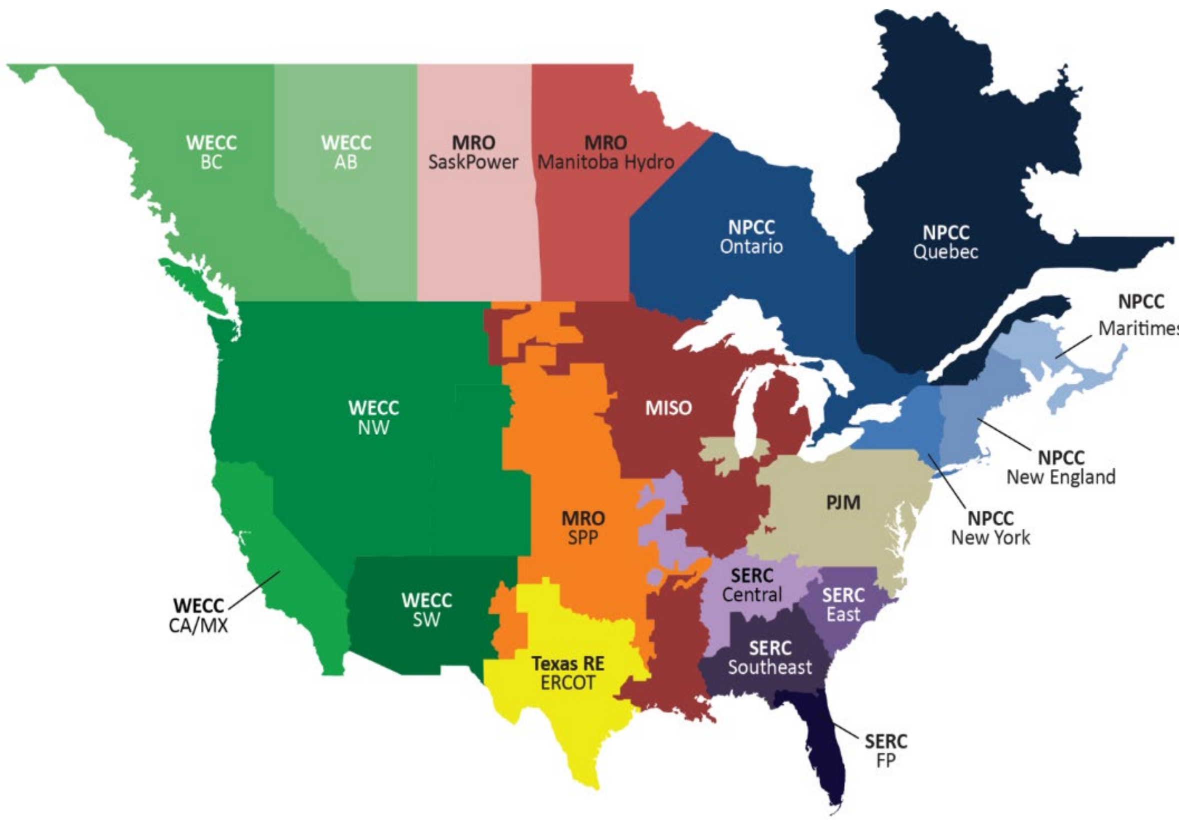

Figure D.1: LTRA Assessment Areas (Resource Mix and Load Scaling Topology)

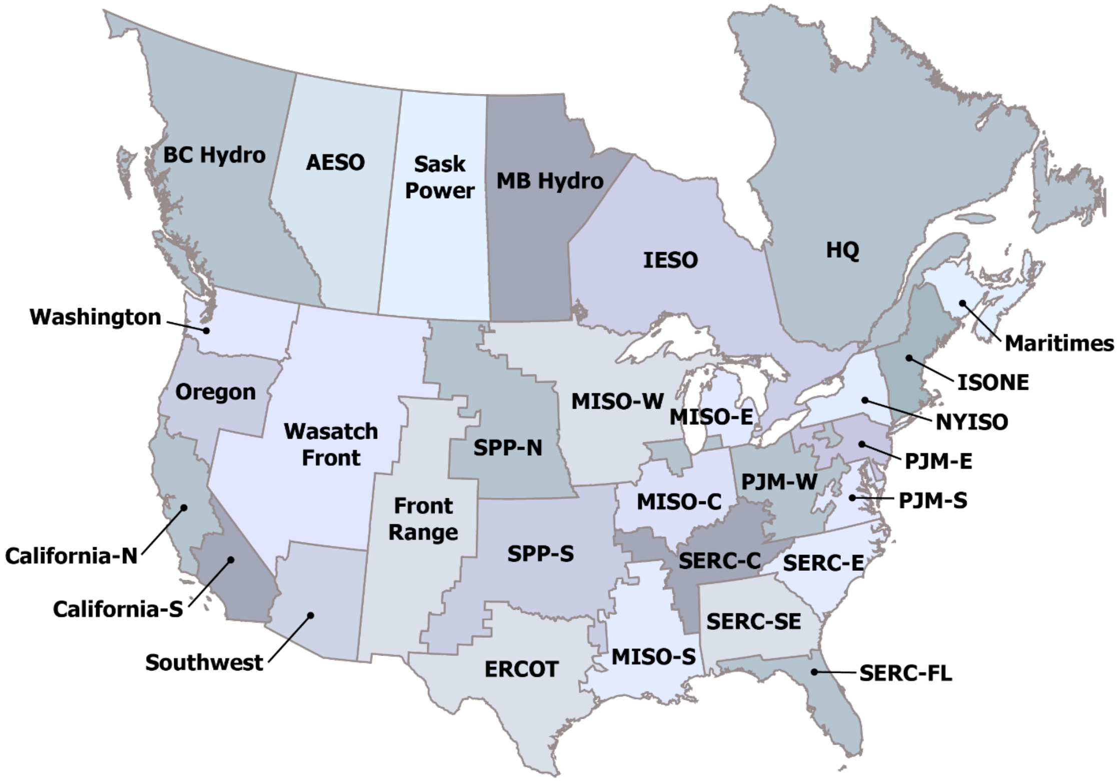

Figure D.2: Transmission Planning Regions

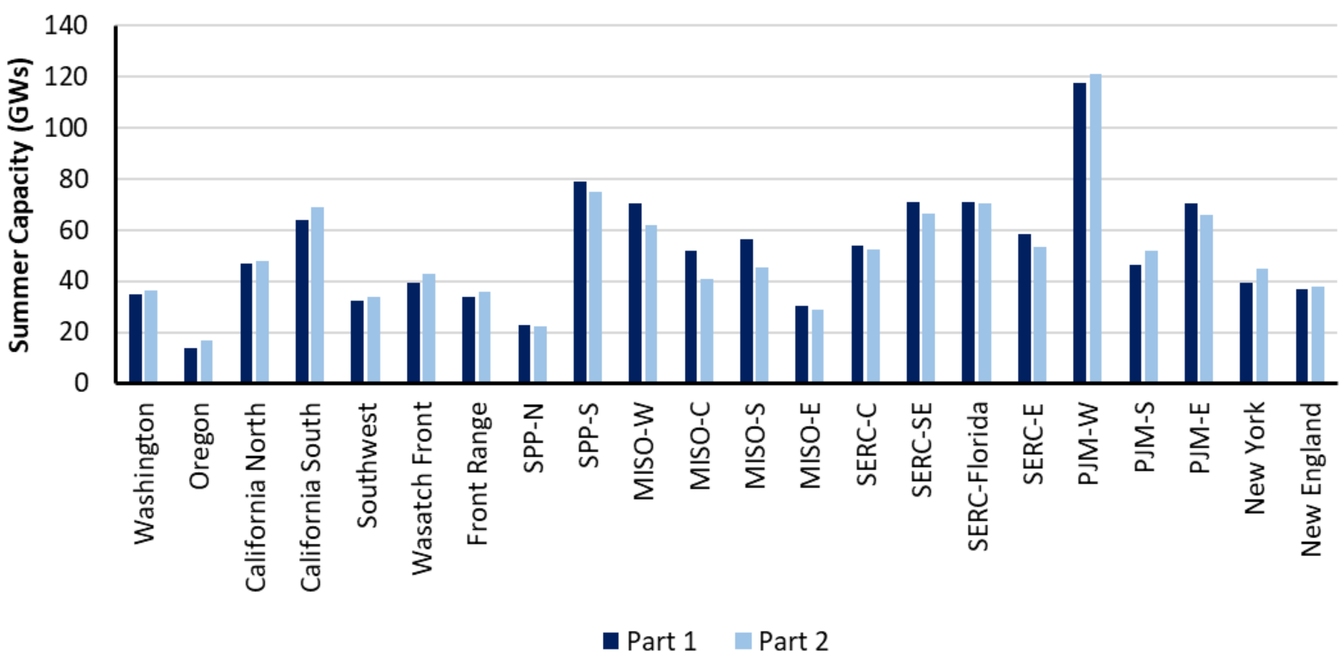

Figure D.3: Comparison of Capacity by TPR, Part 1 vs. Part 2 (2024)[105]

[105] ERCOT is not included in this chart because no power flow models were developed for the ERCOT Interconnection in Part 1.

Appendix E: 2033 Replace Retirements Scenario

Replacing retired capacity based on expected resource additions and Tier 2 and 3 LTRA resources required accounting for the effective capacity of the future resource types. While the LTRA reports include resource peak hour capacity by season, this implied accreditation needed to be expanded to assess all hours to fit the energy assessment framework and account for the changing resource mix. Additionally, the implied accreditation varied across different LTRA assessment areas. This section discusses the consistent approach applied to all resource types for calculating additional resources by TPR.

Accreditation of each resource type was based on the resource's availability during periods of tight margin for each TPR. For example, if a TPR's highest risk of deficiency occurs at 9:00 p.m., a solar resource would get discounted in its accredited capacity.[106] In this way, the interconnection queues were used to replace retiring capacity but ensured that resources were weighted according to their *effective capacity* rather than nameplate. Two of the most important examples of why the proxy accreditation was required for this ITCS study is apparent when comparing results of the solar and battery accreditation. **Figure E.1** below shows these results relative to the implied accreditation in the LTRA.

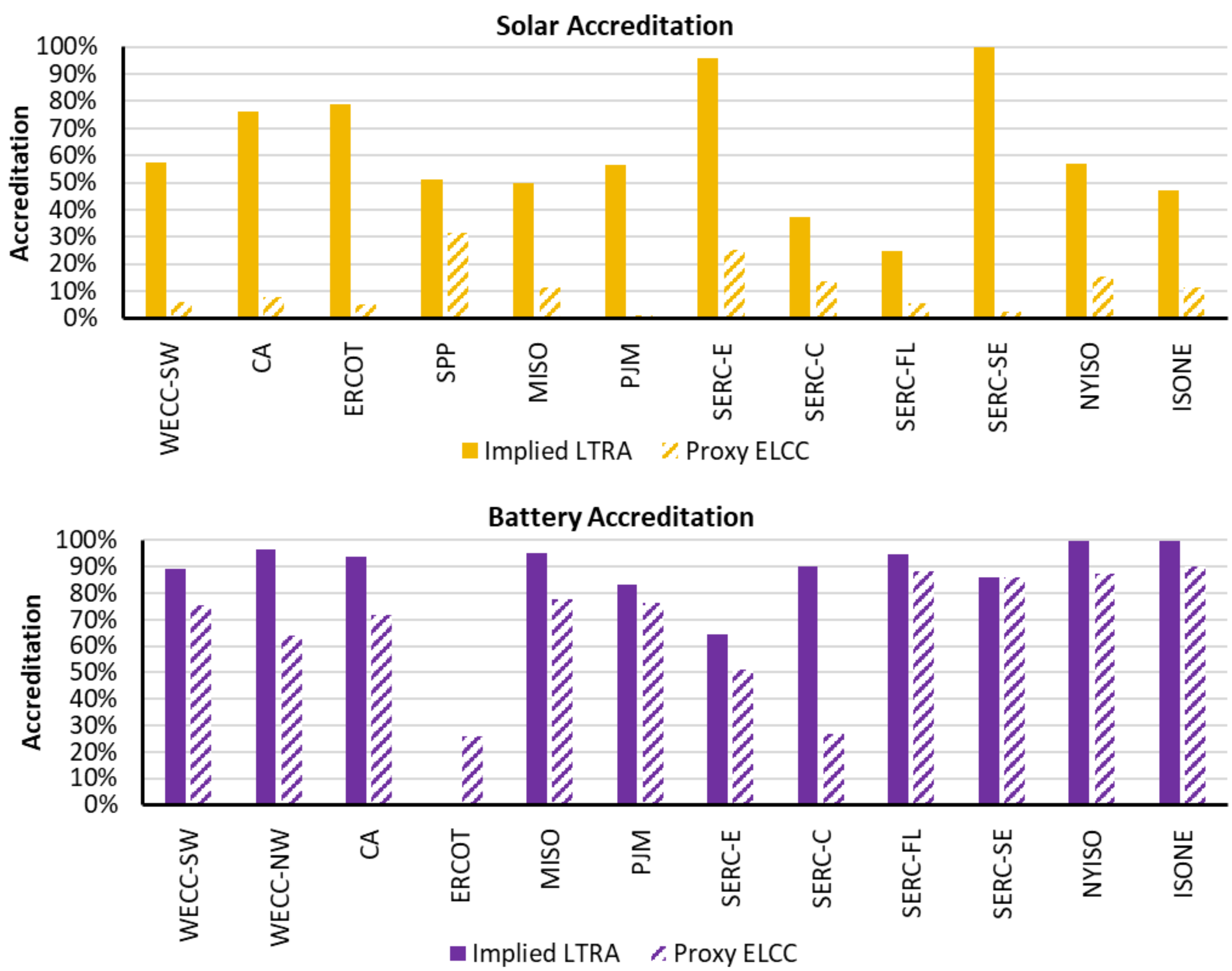

Figure E.1: Proxy Accreditation and Implied LTRA Values for Solar and Battery

[106] This accreditation approach is best akin to an Equivalent Load Carrying Capability (ELCC) approach used throughout the industry. Although it is not a full probabilistic ELCC assessment, it assesses the availability of each thermal, renewable, and energy storage resource based on its availability during periods of tight margin for each TPR, which informs how effective each MW of capacity is at replacing retired resources.

The proportion of resources such as new gas, wind, solar, battery storage, etc., reflected the proportion each resource type has in the Tier 2 and 3 data from the 2023 LTRA. **Table E.1** details the capacity in each TPR by resource type in the 2024 case. **Table E.2** shows the capacity of certain retirements and Tier 1 additions that were applied to the 2033 case. **Table E.3** provides the additional resources that were added to the 2033 case using the replace retirements method. Finally, **Table E.4** lists the total capacity by resource type and TPR in the 2033 case. In each of these four tables, the winter capacity is shown for thermal and hydro resources, and the installed capacity for wind, solar, and storage resources.

Table E.1: 2024 Capacity by Resource Type and TPR (in MW)

Transmission Planning Region	Coal	Natural Gas	Oil	Nuclear	Other	Hydro	Wind	Utility-Scale Solar	Distrib. Solar	Pumped Storage	Battery Storage	Demand Response
Washington	670	4,645	35	1,145	379	25,957	2,795	73	386	314	6	152
Oregon	0	4,523	0	0	263	5,228	5,055	1,297	372	0	5	88
California North	14	16,057	110	2,280	1,542	9,625	1,858	6,952	5,036	1,592	2,407	323
California South	5	23,798	972	635	2,052	1,839	7,088	18,257	5,011	1,922	7,242	445
Southwest	4,660	15,802	80	3,936	156	2,568	1,062	3,331	2,452	176	1,021	123
Wasatch Front	9,635	11,816	93	0	996	3,325	5,883	7,569	1,674	0	2,211	192
Front Range	5,179	10,924	206	0	74	2,795	9,611	4,787	1,340	540	1,025	166
ERCOT	13,630	54,611	0	5,153	163	549	40,291	26,851	2,531	0	10,311	3,275
SPP-N	7,546	2,941	624	769	49	2,904	6,496	6	7	0	0	81
SPP-S	16,260	24,474	1,134	1,176	279	2,101	26,589	354	64	449	11	249
MISO-W	14,522	16,280	1,408	3,013	457	719	20,198	1,747	741	0	0	1,953
MISO-C	16,332	9,882	291	2,247	234	468	3,967	2,491	1,774	450	184	1,672
MISO-S	6,591	27,867	856	5,473	961	704	0	959	291	32	0	1,741
MISO-E	5,826	11,869	300	1,167	170	88	3,370	889	243	2,294	0	1,051
SERC-C	13,440	22,684	148	8,525	44	4,971	1,202	1,120	20	1,762	50	1,694
SERC-SE	13,770	31,395	1,122	8,018	648	3,242	0	6,470	317	1,548	75	2,075
SERC-Florida	5,184	48,807	2,313	3,588	457	0	0	9,719	2,051	0	534	2,765
SERC-E	14,515	18,367	1,393	12,104	173	3,164	0	1,530	833	3,197	24	891
PJM-W	27,207	45,603	654	16,623	103	1,177	11,885	10,970	599	247	2,218	2,686
PJM-S	5,075	18,075	4,026	5,321	402	552	814	9,655	2,498	2,862	544	1,284
PJM-E	7,639	26,153	5,521	10,742	447	1,366	1,464	2,977	5,506	1,953	235	1,238
New York	0	24,533	2,890	3,356	335	4,921	2,720	684	5,710	1,400	20	563
New England	487	15,798	6,161	3,352	769	1,894	2,320	2,870	3,713	1,571	547	666

Table E.2: Tier 1 Additions and Certain Retirements by Resource Type and TPR (in MW)

Transmission Planning Region	Coal	Natural Gas	Oil	Nuclear	Other	Hydro	Wind	Utility-Scale Solar	Distrib. Solar	Pumped Storage	Battery Storage	Demand Response
Washington	-670					-184			1,059			-20
Oregon					-98	-28	-74	319	1,018			-11
California North				-2,280					5,269			19
California South		844	-80					485	5,243		300	26
Southwest	-2,608	-238			-14		29	180	2,638		300	
Wasatch Front	-4,899	-1,571	-6		-457	-35	412	1,389	4,589		680	-26
Front Range	-2,403	-1,142				-36		987	3,674		240	-18
ERCOT		538					2,411	21,556	5,000		6,193	
SPP-N												106
SPP-S			-48									323
MISO-W	-2,550	-1,242	-232		-73		1,528	4,535			240	-51
MISO-C	-5,982	440	-120				1,150	4,100			1,197	-44
MISO-S	-4,209	-3,287					180	4,580			20	-47
MISO-E	-2,958	-1,363			-139		374	1,510				-28
SERC-C	-4,471	7,551						1,224	14		166	-5
SERC-SE		63						289			311	218
SERC-Florida	-438	-2,688	-386		-15			10,584	5,721		2,980	378
SERC-E	-2,629	779	-48					995	1,274		350	20
PJM-W		2,510				17	279	2,674	245		175	168
PJM-S	-1,683		-167				548	1,971	1,025		148	80
PJM-E		1,359					2,874	427	2,259		215	78
New York		-35					238	744	5,226			
New England		-75	-86		-29	-1	1,680	327	2,840			-41

Table E.3: 2033 Replace Retirements Additions by Resource Type and TPR (in MW)												
Transmission Planning Region	Coal	Natural Gas	Oil	Nuclear	Other	Hydro	Wind	Utility-Scale Solar	Distrib. Solar	Pumped Storage	Battery Storage	Demand Response
Washington		309		1,037		563	739	47			17	
Oregon						114	1,317	1,030			14	
California North		184			62		241	23		78	690	
California South		282			116		921	63		94	2,161	
Southwest		988			337		561	11,706			1,550	
Wasatch Front		214			149	72	1,665	5,710			7,831	
Front Range		450			337	60	2,541	3,681			3,427	
ERCOT		652			3		780	4,870			5,172	
SPP-N												
SPP-S												
MISO-W		664				13	5,157	14,311			3,505	
MISO-C		89			5	9	1,215	15,015			20,173	
MISO-S		652				13	43	12,618			292	
MISO-E		390				2	889	5,465				
SERC-C												
SERC-SE												
SERC-Florida		130						909			731	
SERC-E		1,142						1,230			410	
PJM-W												
PJM-S												
PJM-E												
New York												
New England							47	7			53	

Table E.4: 2033 Capacity by Resource Type and TPR (in MW)												
Transmission Planning Region	Coal	Natural Gas	Oil	Nuclear	Other	Hydro	Wind	Utility-Scale Solar	Distrib. Solar	Pumped Storage	Battery Storage	Demand Response
Washington	0	4,954	35	2,182	379	26,336	3,534	120	1,445	314	23	132
Oregon	0	4,523	0	0	165	5,314	6,298	2,646	1,390	0	19	77
California North	14	16,241	110	0	1,604	9,625	2,099	6,975	10,305	1,670	3,097	342
California South	5	24,924	892	635	2,168	1,839	8,009	18,805	10,254	2,016	9,703	471
Southwest	2,052	16,552	80	3,936	479	2,568	1,652	15,217	5,090	176	2,871	123
Wasatch Front	4,736	10,459	87	0	688	3,362	7,960	14,668	6,263	0	10,722	166
Front Range	2,776	10,232	206	0	411	2,819	12,152	9,455	5,014	540	4,692	148
ERCOT	13,630	55,801	0	5,153	166	549	43,482	53,277	7,531	0	21,676	3,275
SPP-N	7,546	2,941	624	769	49	2,904	6,496	6	7	0	0	187
SPP-S	16,260	24,474	1,086	1,176	279	2,101	26,589	354	64	449	11	572
MISO-W	11,972	15,702	1,176	3,013	384	732	26,883	20,593	741	0	3,745	1,902
MISO-C	10,350	10,411	171	2,247	239	477	6,332	21,606	1,774	450	21,554	1,628
MISO-S	2,382	25,232	856	5,473	961	717	223	18,157	291	32	312	1,694
MISO-E	2,868	10,896	300	1,167	31	90	4,633	7,864	243	2,294	0	1,023
SERC-C	8,969	30,235	148	8,525	44	4,971	1,202	2,344	34	1,762	216	1,689
SERC-SE	13,770	31,458	1,122	8,018	648	3,242	0	6,759	317	1,548	386	2,293
SERC-Florida	4,746	46,249	1,927	3,588	442	0	0	21,212	7,772	0	4,245	3,143
SERC-E	11,886	20,288	1,345	12,104	173	3,164	0	3,755	2,107	3,197	784	911
PJM-W	27,207	48,113	654	16,623	103	1,194	12,164	13,644	844	247	2,393	2,854
PJM-S	3,392	18,075	3,859	5,321	402	552	1,362	11,626	3,523	2,862	692	1,364
PJM-E	7,639	27,512	5,521	10,742	447	1,366	4,338	3,404	7,765	1,953	450	1,316
New York	0	24,498	2,890	3,356	335	4,921	2,958	1,428	10,936	1,400	20	563
New England	487	15,723	6,075	3,352	740	1,893	4,047	3,204	6,553	1,571	600	625

Appendix F: Synthetic Wind and Solar Profiles

Like the synthetic load data, the synthetic profiles for renewable energy production represent the weather conditions during the 2007 to 2013 weather years and included additional synthetic data for behind-the-meter solar and resources like offshore wind with no historical data as shown in **Table F.1**. The datasets used to create these profiles were all based on the NREL WindToolKit data (2007 to 2013), the NREL NSRDB data (1998 to 2022), and publicly available offshore wind profiles for the Northeast (2007 to 2020).

Table F.1: Overview of the Two-Pronged Approach for Hourly Wind and Solar Production Data

	Synthetic Weather Data	Historical Weather Data
Data Source	National Solar Radiation Database (NSRDB), Wind Toolkit, Det Norske Veritas (DNV) Northeast Offshore Wind Profiles, scaled-down historical utility-scale, etc.	Reported data from Balancing Authorities, including EIA-930
Weather Years Applicable	2007 to 2013 and select resource types for 2022 and 2023 (BTM-PV and Offshore Wind)	2019 to 2023
Resource Types Applicable	Utility-scale solar, behind-the-meter solar, land-based wind, offshore wind	Utility-scale solar and land-based wind
Notable Adjustments	Synthetic profiles scaled down to match historical data median capacity factors (controls for technology improvements)	Regions without sufficient historical data, such as utility-scale solar for New York, were matched with nearby regions' profiles
Profile Format	8,760 profiles based on CST time zone	8,760 profiles based on CST time zone

Synthetic Utility-Scale PV and Land-Based Wind

This data was provided in collaboration with NREL based on 2018 technology characteristics for both solar PV and wind resources. Hourly data was provided by NREL for each ReEDS region for solar or wind resources. Each ReEDS region was mapped to a TPR and the magnitude of different renewable resource capacity (e.g., poor, moderate, excellent solar locations) for UPV and LBW. This data was provided by NREL based on their Renewable Energy Potential (reV) model and used to create a capacity weighted profile for every TPR.[107]

While this dataset provides a robust foundation for capturing the hourly variability in solar and wind energy production, it required some additional calibration to ensure that overall capacity factors for UPV and LBW align with historical production. This calibration helps account for the effects of curtailment, suboptimal plant designs, and older technologies and plant configurations, particularly where older renewable energy facilities exist. To calibrate each TPR's UPV and LBW profiles, the historical data for 2019-2023 was used to scale the 2007-2013 UPV and LBW profiles for every hour to align the median capacity factor from synthetic data to the median of the historical data. To maintain the variability in production, as well as the high and low periods, this was done by rank-ordered scaling. An example is depicted for ERCOT LBW in **Figure F.1** below.

[107] NREL, reV: The Renewable Energy Potential Model, https://www.nrel.gov/gis/renewable-energy-potential.html

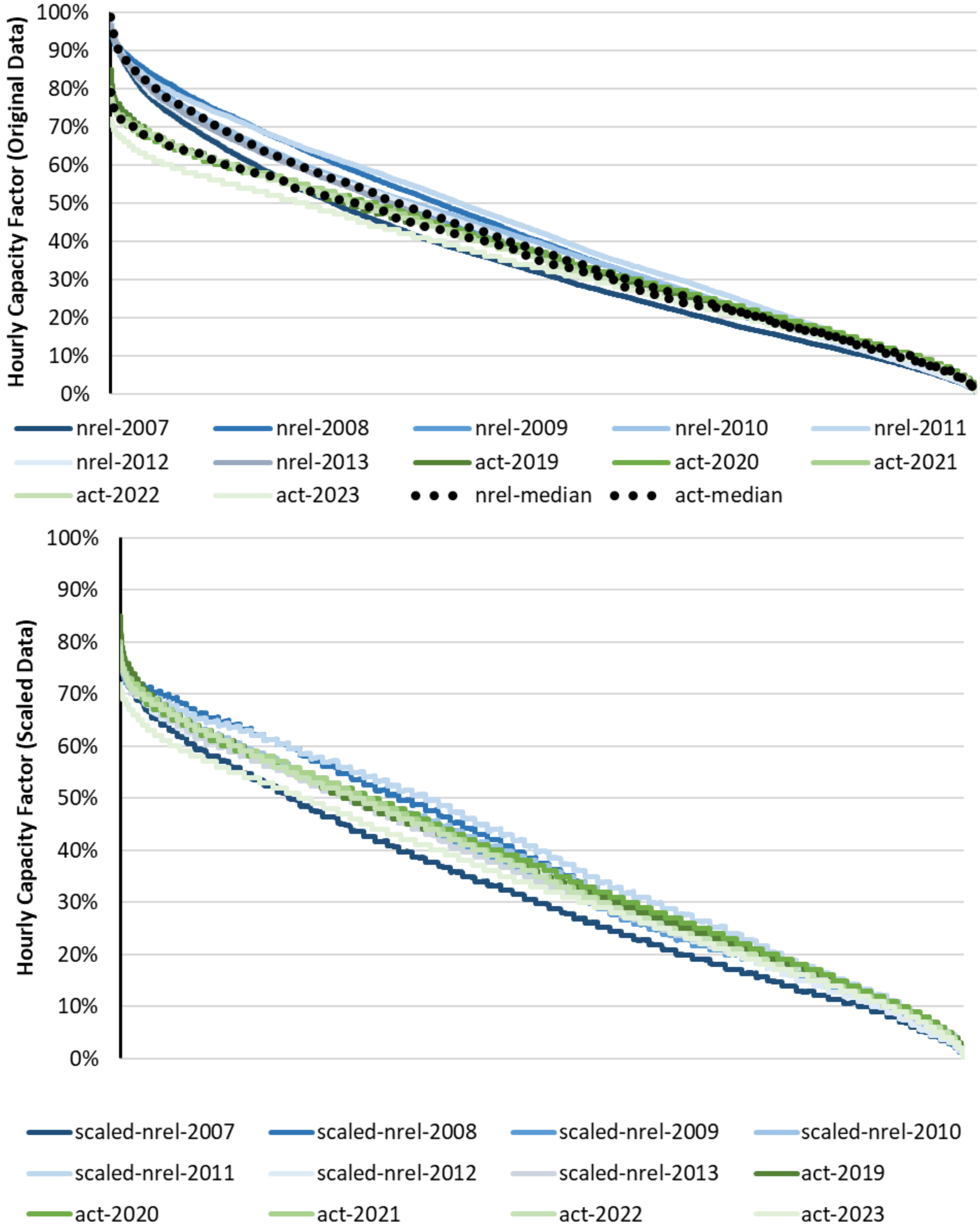

Figure F.1: Example of Scaling Synthetic Weather Data to Align with Historical Actual Data (ERCOT Land-Based Wind)

This scaling has the effect of maintaining chronology and hourly variability but reduces overall production output for the profiles. While renewable technology is improving, it was deemed important to ensure that the synthetic profiles aligned well with the historical actuals on an annual energy basis. This is a conservative assumption due to the reliance on observed historical data, but the effects of improved plant designs, new capacity additions, and technological advancements will eventually come through historical records for future studies. **Figure F.2** presents the same ERCOT LBW case but shows how the original variability is maintained while the annual energy is reduced to align with historical values.

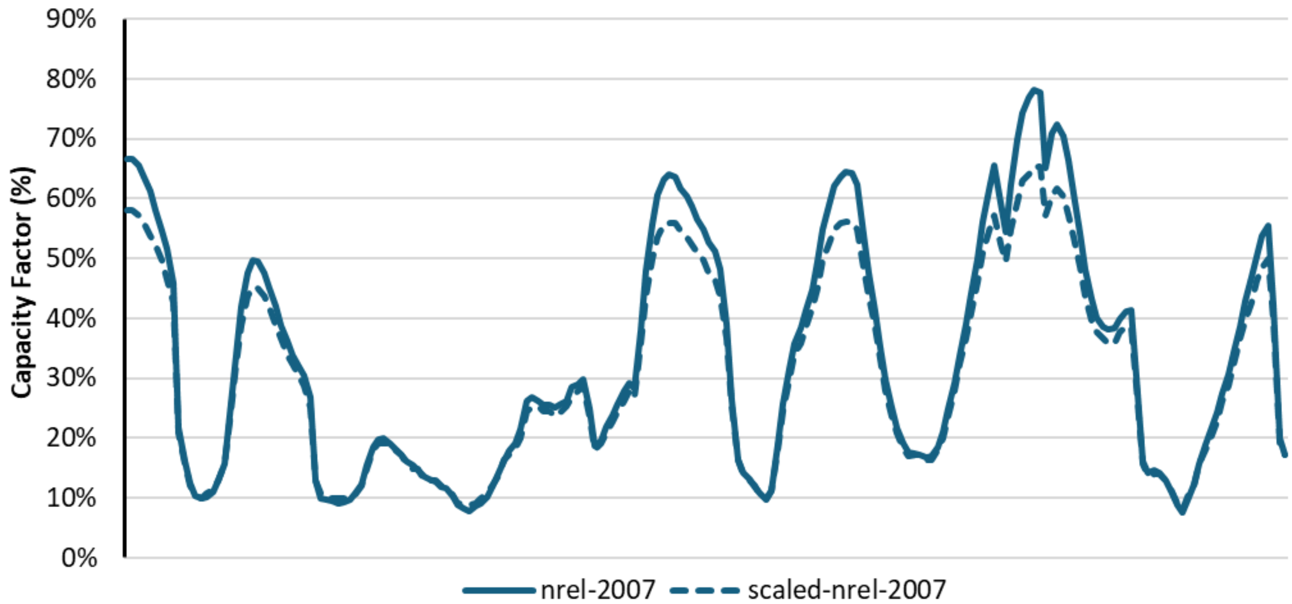

Figure F.2: Example of Chronological Variability in Synthetic Renewable Profile After Scaling to Match Historical Actuals (ERCOT Land-Based Wind)

Synthetic Behind-the-Meter PV (BTM PV)

Rooftop solar data was developed using an alternative process to the UPV and LBW data, but still used the NREL NSRDB data for underlying weather data. In this case, power production was modeled using a standard rooftop solar configuration. A capacity-weighted profile was developed across 1,209 irradiance locations across North America. The locations were spread across counties and cover 96% of the total installed rooftop capacity locations. For each county, a capacity weighting was determined using Google Project Sunroof data on existing installations. Data was then downloaded from the NSRDB for every county profile using the center point latitude and longitude for each county as the solar site. County locations were then assigned a TPR, and a capacity-weighted profile was created for the 2007-2013 and 2019-2022 weather years. No data was available from the NSRDB for the 2023 weather year, so historical UPV production profiles were scaled down to match the median DGPV profile from the synthetic weather years. Where rooftop solar capacity was not listed in the LTRA data form, it was assumed that BTM PV installations matched data for small-scale solar reported in the EIA 861M small-scale solar form and kept constant to 2033.

Synthetic Offshore Wind (OSW)

Due to the nascent nature of offshore wind in North America, the hourly production profiles for offshore wind were developed using synthetic data. All the offshore wind included in the LTRA as Tier 1 resources were on the East Coast. This study used data produced for New York by DNV for three offshore wind lease areas to represent the hourly profile for future offshore wind capacity based on Tier 1 in PJM-E (WF 6, 2,875 MW), New York (WF 3, 136 MW), and New England (WF 4, 2,324 MW). **Figure F.3** shows the location of the wind farm profiles developed by DNV. These profiles are intended to be representative of potential offshore wind projects on the East Coast and provide data for 2007-2021.

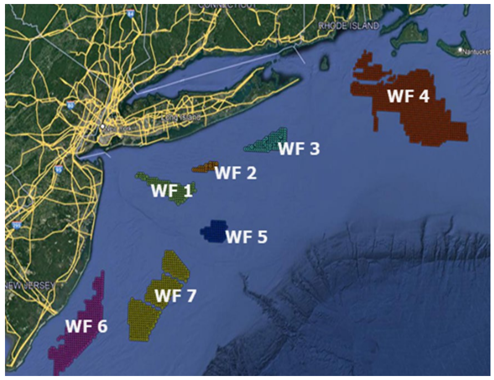

Figure F.3: Locations of Available East Coast Offshore Wind Profiles from DNV Used for Representative Shapes

To supplement the range of weather years so that they include 2022 and 2023 data, wind speed observations along the coast near the wind farms were used to relate offshore wind capacity factors to measured wind speeds and sampling daily wind profiles based on a relationship of measured wind speed to plant output for the 2022 and 2023 weather years.

Historical Wind and Solar Profiles

Historical wind and solar capacity factor profiles were created by TPR for weather years 2019-2023 using reported generation data from EIA 930 and reported capacity data from EIA 860-M (a monthly version of the EIA 860 dataset). In general, data processing followed the steps detailed below.

- Gather hourly renewable generation for each Balancing Authority from the EIA 930.
- Adjust raw data due to anomalies such as negative generation, solar production overnight, or outliers in output due to reporting errors.
- Gather Balancing Authority installed resource capacity by month using the EIA 860-M for 2019-2023.
- Create hourly capacity factor profiles using monthly installed capacity and hourly generation by Balancing Authority.
- Adjust capacity factor profiles for discrepancies in hourly generation or installed capacity due to reporting delays or errors in the EIA 860-M form.

Ensuring Reasonable Capacity Factors

Delays in reporting from EIA 860-M as well as differences in the number of generators reporting to the EIA 930 and 860 datasets resulted in the need for additional adjustments to monthly capacities to obtain reasonable capacity factor profiles (avoiding capacity factors >100%, or capacity factors that were very low relative to the technology class or historical annual average). In some instances, generation increased significantly in EIA 930 but was not reflected in the EIA 860-M dataset until a few months later; this capacity was pulled backwards to create more reasonable capacity factors. In other instances, the EIA 860-M data was not used due to it showing significantly more or less capacity than the generation shown in EIA 930 over an extended period. In these cases, capacity was estimated by using EIA 930 data only. The 99th percentile generation over a given year was calculated to estimate a nameplate capacity.

After creating the Balancing Authority capacity factor profiles, and adjusting as necessary, the profiles were aggregated together by hour into TPR profiles using a capacity weighted average of the Balancing Authorities within that TPR. One exception was the solar profile for New York where EIA 930 data was not available but solar generation was expected in the LTRA forecast. For New York, the average of the PJM and New England profiles were used.

Appendix G: Outages and Derates

Forced Outages and Derates

To develop daily forced outage information by TPR, forced outages were aggregated across all reporting thermal plants and the average MW on forced outage for each day was noted, as shown in **Table G.1**. This quantity was divided by the total Net Maximum Capacity (NMC) for the TPR to convert the outage data into a percentage that could be applied to future resource mixes. Due to limited locational information on GADS plant data, each plant was assigned to a state, and subsequently to the appropriate TPR. For states that are split across two or more TPRs (e.g., Illinois is included in both MISO-C and PJM-W reporting), the total NMC and forced outage capacity was split proportionally to the TPR based on capacity reported in EIA Form 860. The forced outage aggregation was done on a daily basis to reflect correlations with extreme weather, including increased mechanical failures and fuel supply disruptions during extreme cold periods.

Table G.1: Types of Derates and Outages Used to Represent Daily Thermal Resource Availability[108]

Capacity Derate	Description
Seasonal Derates	Summer and winter seasonal capacities were based on LTRA Form B submissions by generator, aggregated to TPR and fuel type
Historical Forced Outages	GADS forced outages and deratings (GADS Codes D1, D2, D3, U1, U2, U3, SF) aggregated by day from 2016-2023, by TPR
Synthetic Forced Outages	Sampled data from GADS historical forced outages for outage rates by plant type in each TPR. Sampling done randomly based on temperature and outage rate relationships for each resource type
Planned Maintenance Outages & Derates	GADS maintenance outages (MO) and planned outages (PO) aggregated by day from 2016-2023, by TPR

While the GADS data was evaluated across 2016-2023 weather years, 2016-2018 were not used directly in Part 2 to ensure weather years were synchronized across load, wind, solar, and thermal availability. To extend the forced outage data set to cover weather years 2007-2013 while continuing to represent correlation to weather and load, a method was developed to resample the 2016-2023 dataset. The resampling was done based on daily minimum and maximum temperature observations. To perform this analysis, daily regional airport temperature observations were used. This approach enabled the determination of forced outage rates across all TPRs and fuel types, incorporating the weather dependence of each fuel type. The method involved three key steps:

1. Using regional airport temperature readings from 1981-2023 to ascertain average, minimum, and maximum temperatures in each TPR. This involved calculating the minimum, average, and maximum daily temperatures based on temperature readings from all regional airports within a specific TPR for a given day.
2. Grouping daily temperature observations for each TPR into categorized temperature ranges. Temperature groups ranged from -28°C to 52°C in increments of 4°C, with temperatures outside this range forming separate groups (below -28 and above 52). Days with average temperatures above 16°C were categorized based on their maximum temperature, while those below 16°C were grouped according to their minimum temperature.

[108] GADS cause codes can be found here

3. Creating a daily forced outage rate dataset for 2007-2013 by randomly sampling a day from the associated temperature and forced outage rate dataset within the same temperature group for each TPR. For instance, if the temperature in ERCOT on a specific date fell within the 32-36°C range, one of the temperature observations from that range between 2016-2023 is randomly sampled to determine the forced outage rates for each ERCOT fuel type.

This process resulted in a weather-dependent dataset that reflects the varying forced outage rates by fuel type and TPR that could be resampled for any historical year. Note that this method did not consider any extrapolation of outage rates beyond the temperature range observed during the 2016-2023 weather years. For example, if a TPR's minimum and maximum daily temperatures observed in 2016-2023 were -20°C and 48°C respectively, but temperatures in the longer historical record fell above/below that range, no extrapolation of increased severity in forced outages was assumed. Furthermore, if the historical record in the 2016-2023 weather years (representing 2,920 daily observations) had limited observations in one of the extreme heat or cold bins, those days were resampled repeatedly to represent the 2007-2013 weather years.

Planned Outages and Derates

For 2019-2023 weather years, the planned outage data was kept time-synchronized with the forced outage dataset, reflecting the fact that during periods of high planned outage rates, there is less capacity that can simultaneously go on forced outage and some planned outages can be recalled from maintenance during events and periods of higher-than-expected forced outages.

Unlike the forced outage modeling, planned and maintenance outages were not resampled as a function of temperature to fill in data for the 2007-2013 weather years. Instead, the average capacity on outage by month, by fuel type, and by TPR was assumed. This intentionally smoothed out the amount of capacity on planned maintenance in the 2007-2013 weather years, assuming that some maintenance is recalled during tight margin time periods.

Appendix H: Explanation of the Hourly Energy Margin

Figure H.1 illustrates a sample analysis of the hourly energy margin, demonstrating how the dispatch method operates under various conditions. The bar chart shows different types of available capacity (e.g., wind, solar, thermal, and hydro) stacked to reflect their contribution to the overall energy supply. The solid black line represents the hourly demand (load) for the TPR, while the dotted line indicates the threshold for tight margins, highlighting hours where the energy supply is just sufficient to meet the demand or where there is a deficit.

The bars in the illustrative chart are color-coded to distinguish between different sources of energy. For instance, green could represent wind capacity, with blue for thermal capacity, and yellow for solar capacity. This segmentation allows for a representative visualization of the contribution of each resource type to the total available capacity. Each bar's height represents the total capacity available for each hour, with fluctuations reflecting changes in resource availability due to factors like weather conditions or scheduled maintenance.

The solid black line tracks the TPR's hourly demand. The points where this line intersects or exceeds the top of the bars indicate hours when the demand meets or surpasses the available capacity located within the TPR. The dotted line serves as an indicator for additional margin that is required. This threshold helps identify periods where the TPR is at risk of energy shortfalls and may need to rely on imports from its neighbors.

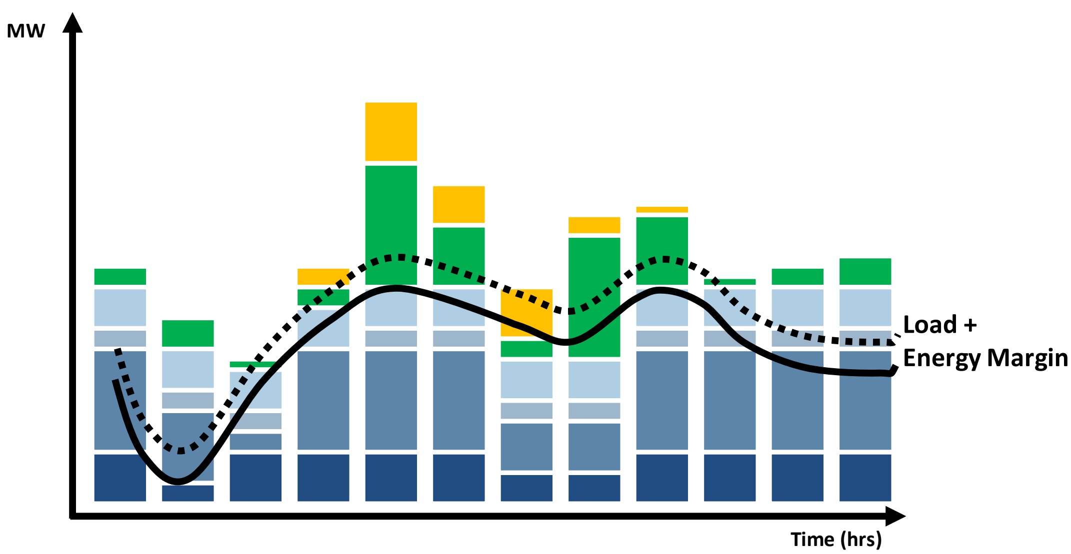

Figure H.1: Illustrative Example of the Available Capacity and Load on an Hourly Basis

While the previous figure shows the hourly fluctuations of available capacity and load, particular attention is given to the hourly energy margin, or the difference between the total available capacity and the load and associated margin. Figure H.2 specifically highlights the difference between the available energy supply and the combined load plus margin requirements for each hour. The green markers and lines emphasize the hourly energy margin, which is the difference between the top of each bar (total available capacity) and the dotted black line (load plus margin). When the top of a bar exceeds the dotted black line, the green markers indicate a positive energy margin, meaning there is surplus energy. Conversely, when the top of a bar is below the dotted black line, it shows a negative margin, indicating where a TPR's internal available capacity is insufficient to meet the load plus margin.

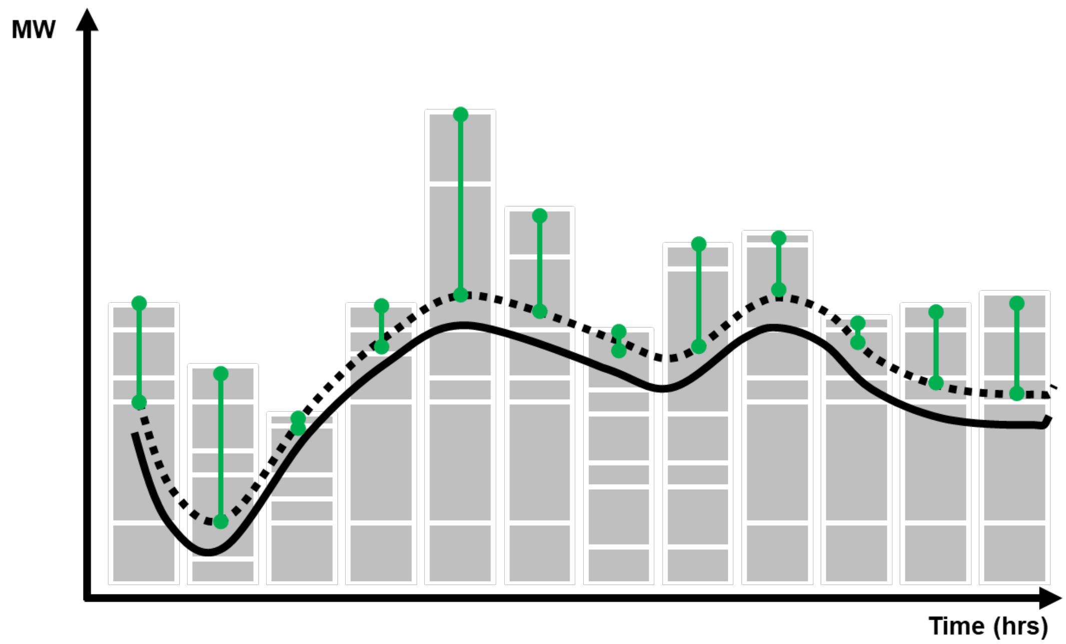

Figure H.2: Illustrative Example of the Hourly Energy Margin

Hours with a significant gap between the top of the bars and the dotted black line (green markers) indicate periods of comfortable surplus. These are periods when the value of the scarcity weighting factor will be low. Hours where the bars are close to or below the dotted black line are periods when the value of the TPR's scarcity weighting factor will be high. These are critical times when the TPR might need to rely on imports from neighbors to ensure energy adequacy.

To illustrate the process of the energy margin analysis, a deep dive of Winter Storm Elliott (December 2022) is shown in this section for the SERC-E and neighboring TPRs. It should be noted that the results of this analysis are shown on a simulation of a 2024 BPS, assuming the weather conditions observed during Winter Storm Elliott were repeated. Thus, the load levels, resource mix, and specific operation conditions are expected to be different from the actual December 2022 event.

Figure H.3 provides the hourly load (top) and hourly energy margin (bottom) for SERC-E in the 2024 scenario, assuming 2022 weather year conditions. The top chart shows load deviating between ~15 GW during spring and fall shoulder conditions, to a high of ~50 GW during Winter Storm Elliott, with other high load events occurring in the summer and winter.

The bottom chart shows the corresponding energy margins, which in most cases show an inverse relationship to load, with low, and at times negative, energy margins during winter storm Elliott and other winter peak demand periods. Other times of the year have relatively low margins, but they rarely drop to the 10% tight margin level. These results are shown prior to energy transfers, demand response, or involuntary load shed required to maintain the minimum margin level.

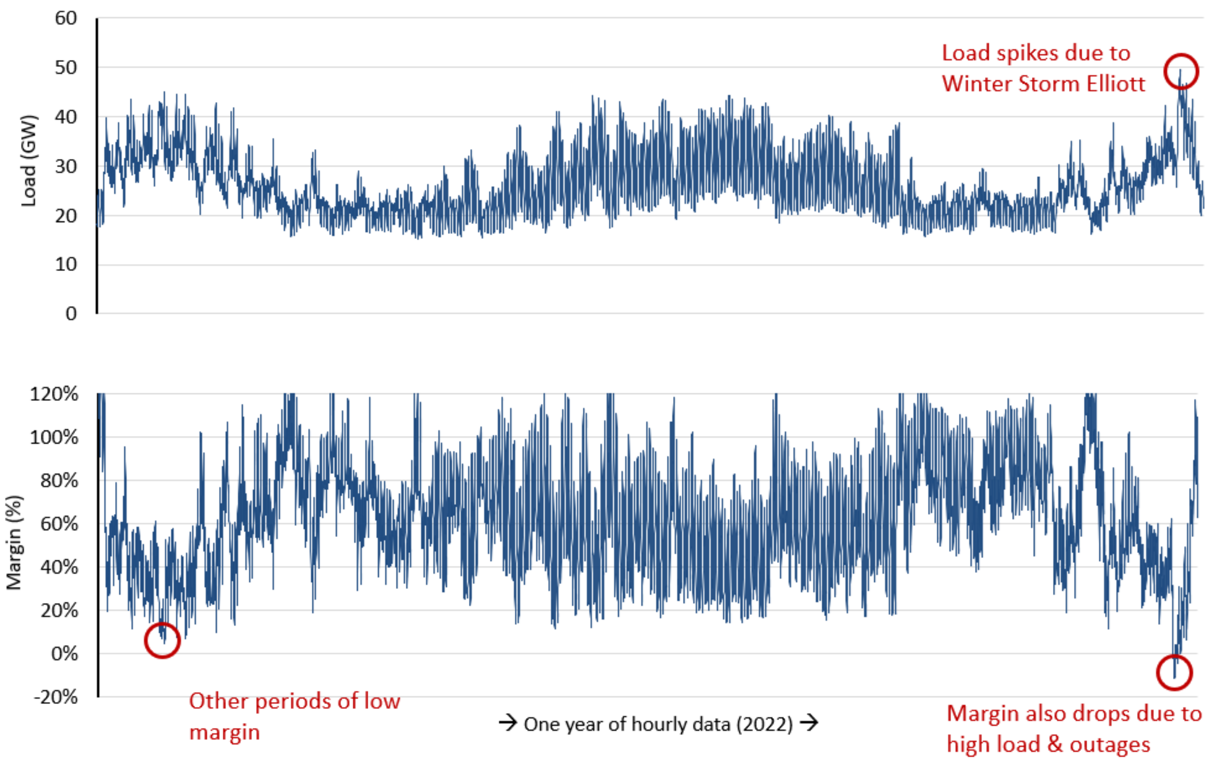

Figure H.3: Load (top) and Energy Margin (bottom) for SERC-E, Weather Year 2022

Zooming in on the conditions during the end of December, **Figure H.4** shows the available capacity during a week of challenging conditions for SERC-E. Available resources (colored columns) fluctuate across the week due to maintenance and/or forced outages, as well as fluctuations in the variable renewable resource, and the charge (negative) and discharge (positive) contributions of energy storage resources. The solid black line shows the load levels across the week, also fluctuating due to hour of day, day of week, and weather conditions. The peak demand occurs on the third day, reaching ~50 GW.

The figure shows a gap between the load level (black line) and the top of the available capacity stack, thus indicating negative energy margins if no imports are available. The corresponding energy margins are shown on the bottom trace in **Figure H.4**, showing times dropping below both the tight margin level and the minimum margin level. This indicates time periods when energy imports are needed.

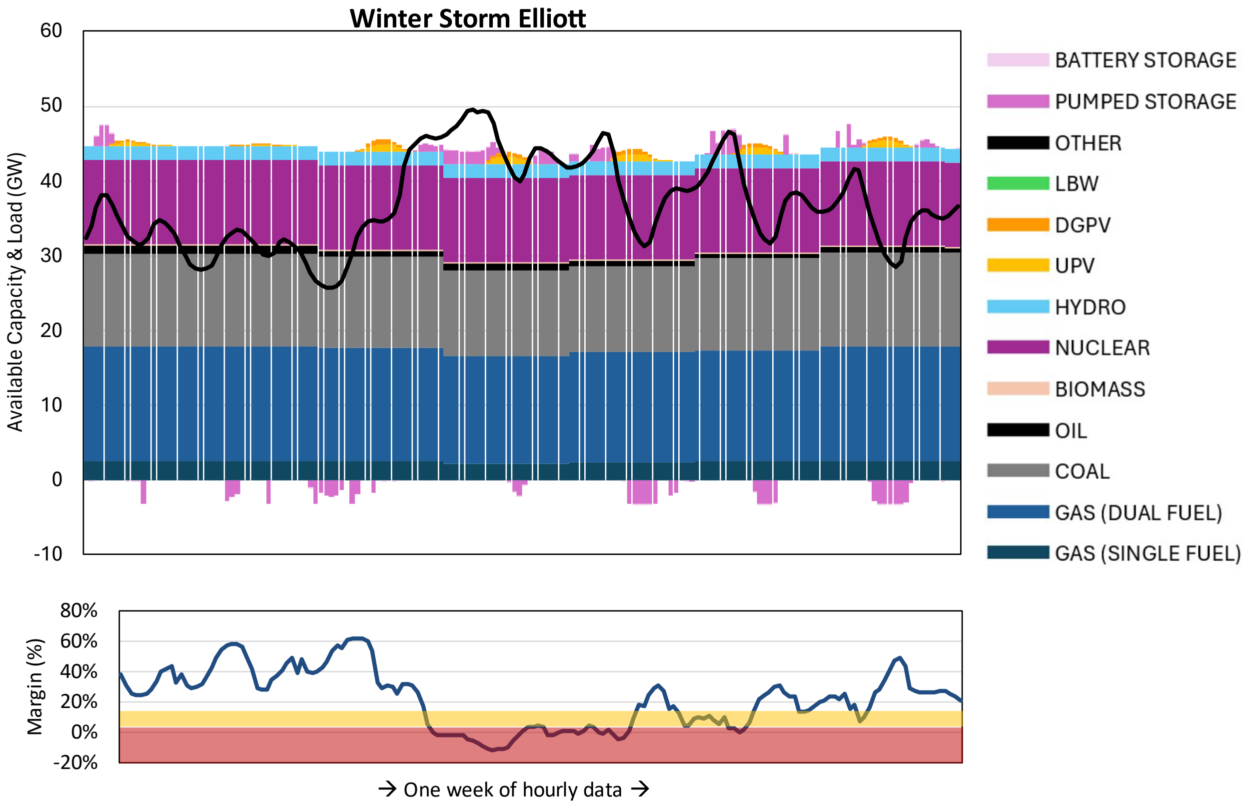

Figure H.4: Illustrative Example of Available Resources, Load, and Hourly Energy Margin

In the previous plots, SERC-E was evaluated without interregional transfers from neighboring TPRs. The periods of low energy margins represent time periods when imports are needed. **Figure H.5** shows four maps of the United States during the same time period (12/24, weather year 2022). The top left plot shows maximum load as a percentage of annual peak, the top right shows average daily wind and solar capacity factor, the bottom left plot shows the percentage of thermal resources on outage due to maintenance or forced outages, and the bottom right plot shows the summary of all factors – the minimum energy margin as a percentage of load in each TPR seen on that day.

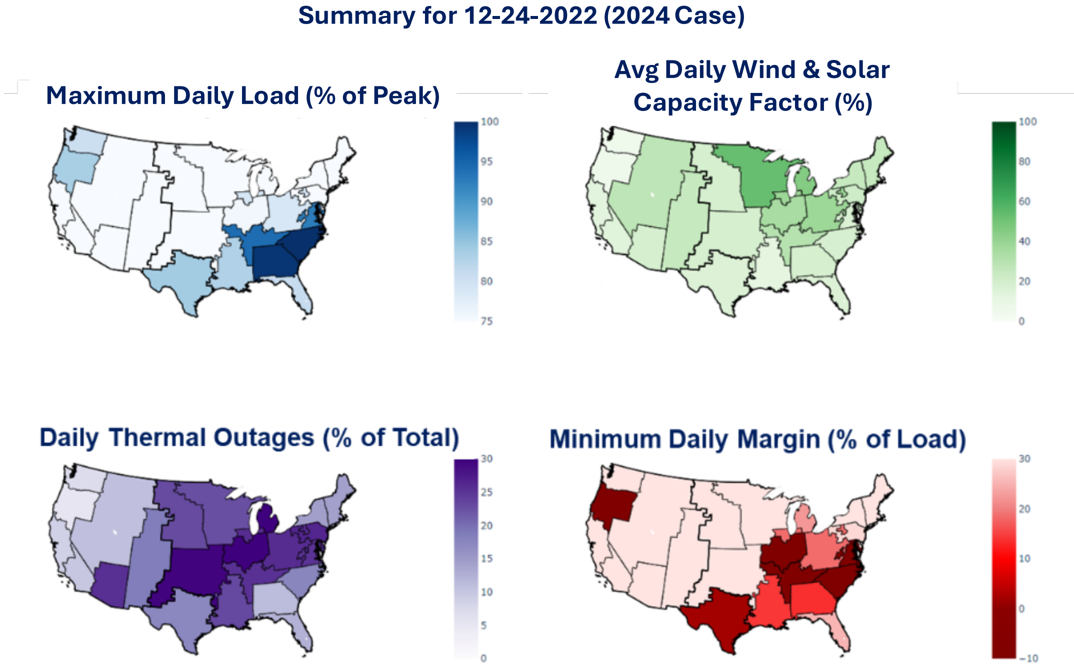

Figure H.5: National Illustration of Energy Margins and Contributing Factors

Taking these relative comparisons into account, the energy margin for SERC-E is provided in **Figure H.6**, along with the imports from neighbors colored in the middle pane and the scarcity weighting factor in the neighboring TPRs shown in the bottom pane. This illustrates that when SERC-E hits a tight margin level, it imports from neighboring TPRs to help bring the hourly energy margin back to the tight margin level but can only do so if neighboring TPRs have surplus energy to share and transmission limits allow for the interchange.

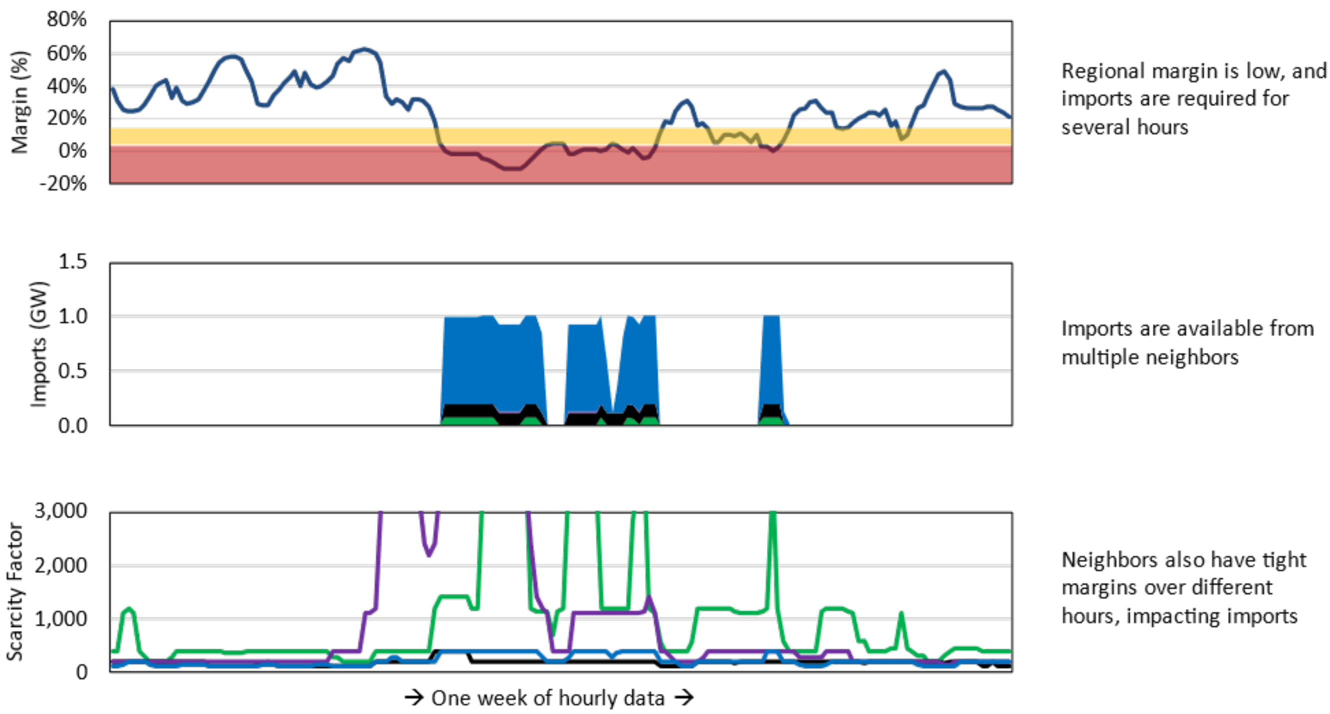

Figure H.6: Hourly Energy Margin Example and Corresponding Imports

Appendix I: Explanation of Scarcity Weighting Factor

The scarcity weighting factor is akin to the operating reserve demand curve (ORDC) implemented in ERCOT, which employs a market mechanism that values operating reserves in the wholesale electric market based on the scarcity of those reserves and reflects that value in energy prices.[109] In this case, however, the scarcity weighting factor is not a price, but rather a numerical quantity, for comparison of the hourly energy margin in each TPR. As reserves on the system get tighter, the scarcity weighting factor increases, indicating that the TPR is getting tighter on its hourly energy margin. An example of the scarcity weighting factor is provided in **Figure I.1**, which shows an increasing scarcity weighting factor at lower hourly energy margins.

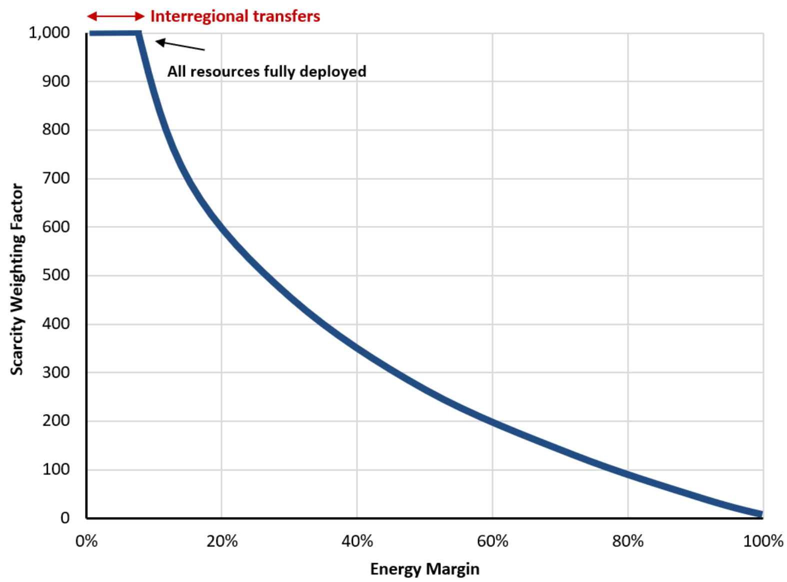

Figure I.1: Scarcity Weighting Factor Used in the Dispatch Model

The scarcity weighting factor is used in the model for two reasons, 1) to schedule storage resources to arbitrage net load and the hourly energy margin, and 2) to indicate and prioritize which interfaces should be used for energy transfers.

If a TPR cannot serve its own load, it will seek to import energy from a neighboring TPR with a relatively higher surplus (indicated by a lower scarcity weighting factor), if transfer capability is available. This method allows the model to track the daily and hourly availability of all resource types and calculate the relative surplus and deficit in each TPR simultaneously, and ultimately prioritize additions to transfer capability. Consequently, this dispatch approach supports the ability for a TPR to import from one neighbor while exporting to another, facilitating balanced energy interchange across the network.

This approach intentionally focuses on the aggregate availability of energy within each TPR with respect to internal resources as the primary focus. This deliberately excludes economic and policy objectives when considering prudent additions to transfer capability as they are not within the scope of the study. By incorporating the Part 1 results in the Part 2 analysis, a more simplified transfer model could be used to enable a simultaneous hourly assessment of resource availability and transfers to support energy adequacy for reliability. Assessing the timing and location of resource availability during chronological representations of system conditions for the entire North American BPS is a substantial endeavor and this approach enabled systematic assessment of the entire system in a consistent manner.

[109] ERCOT, *2022 Biennial ERCOT Report on the Operating Reserve Demand Curve*, https://www.ercot.com/files/docs/2022/10/31/2022%20Biennial%20ERCOT%20Report%20on%20the%20ORDC%20-%20Final_corr.pdf

Appendix J: Details on Minimum and Tight Margin Levels

The minimum and tight margin levels used in Part 2 are intended to constrain TPR resources and set a limit for when a TPR will no longer share additional energy with its neighbors. This is in recognition that Balancing Authorities do hold resources in reserves. However, the margin levels specified in this study are not intended to exactly replicate operating reserves as these differ by TPR and even by utility, but rather to seek to represent some level of withheld capacity and energy.

In practice, a Balancing Authority holds a portion of operating reserves (i.e., contingency and regulation reserves) even if entering involuntary load shed. The 3% threshold for minimum margin level was determined after reviewing required daily reserve margin reports[110] and taking a load-weighted average of the required reserves, as a percentage of daily peak load, by TPR across the country. This aggregated data is shown in **Figure J.1**. The tight margin level was set at 10% based on discussion with the ITCS Advisory Group. **Figure J.2** shows the actual average daily reserves held, which informed the 10% tight margin level.

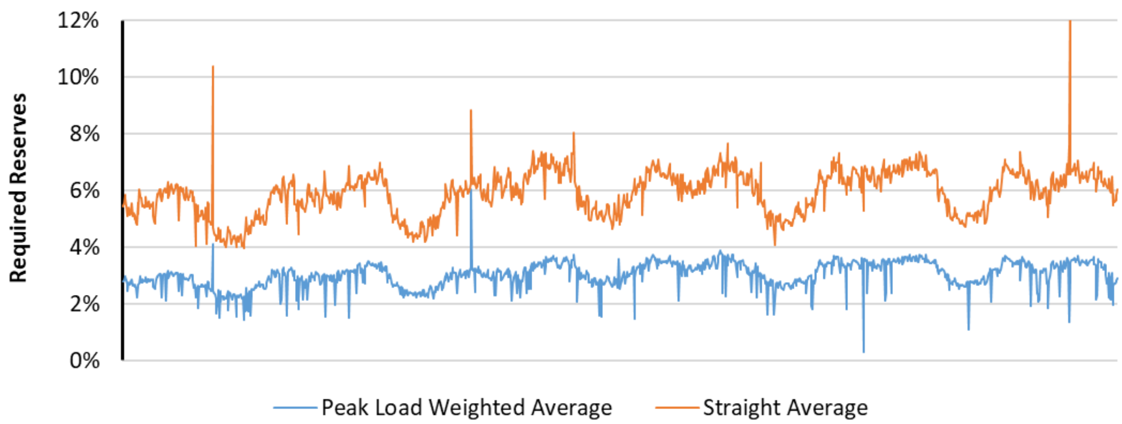

Figure J.1 Average Daily Required Reserves (as a Percentage of Daily Peak)

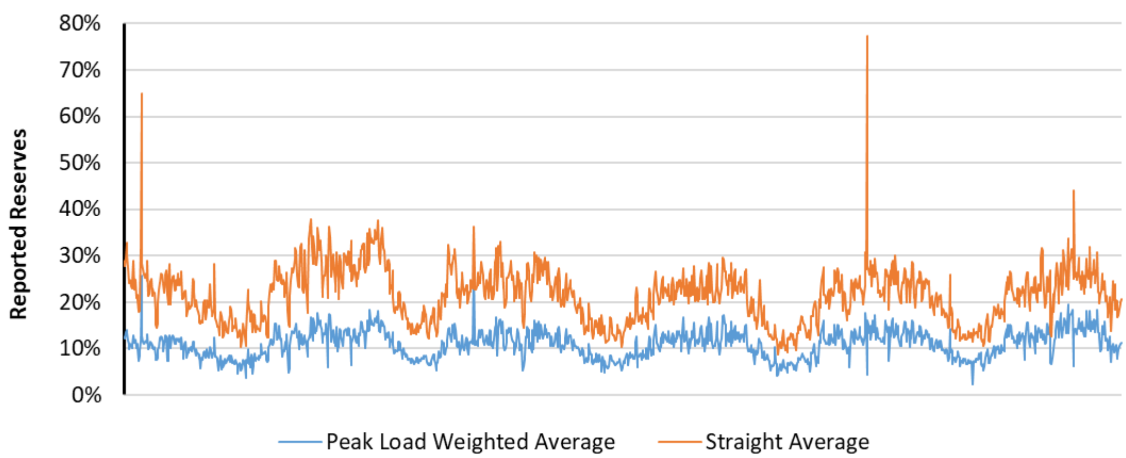

Figure J.2: Average Daily Reserves (as a Percentage of Daily Peak)

[110] NERC, System Awareness Daily Report, Forecasted Loads and Reserves Table, 2019-2024