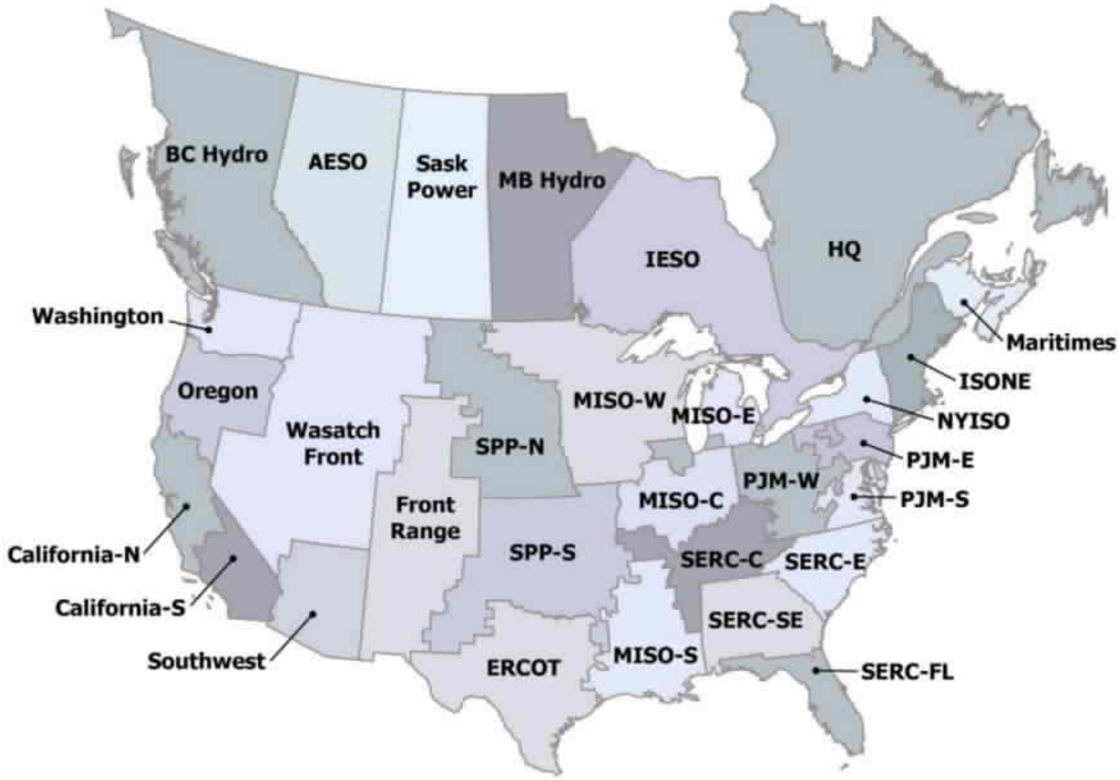

Figure D.2: Transmission Planning Regions

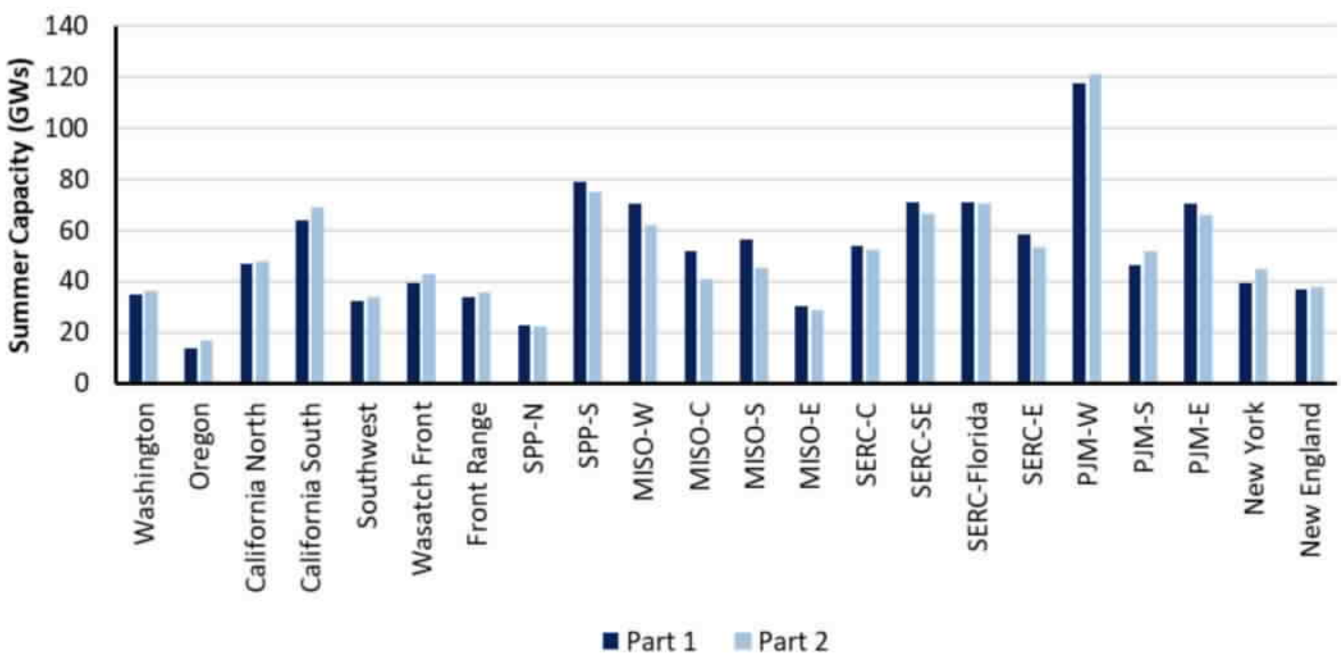

Figure D.3: Comparison of Capacity by TPR, Part 1 vs. Part 2 (2024)[105]

[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.

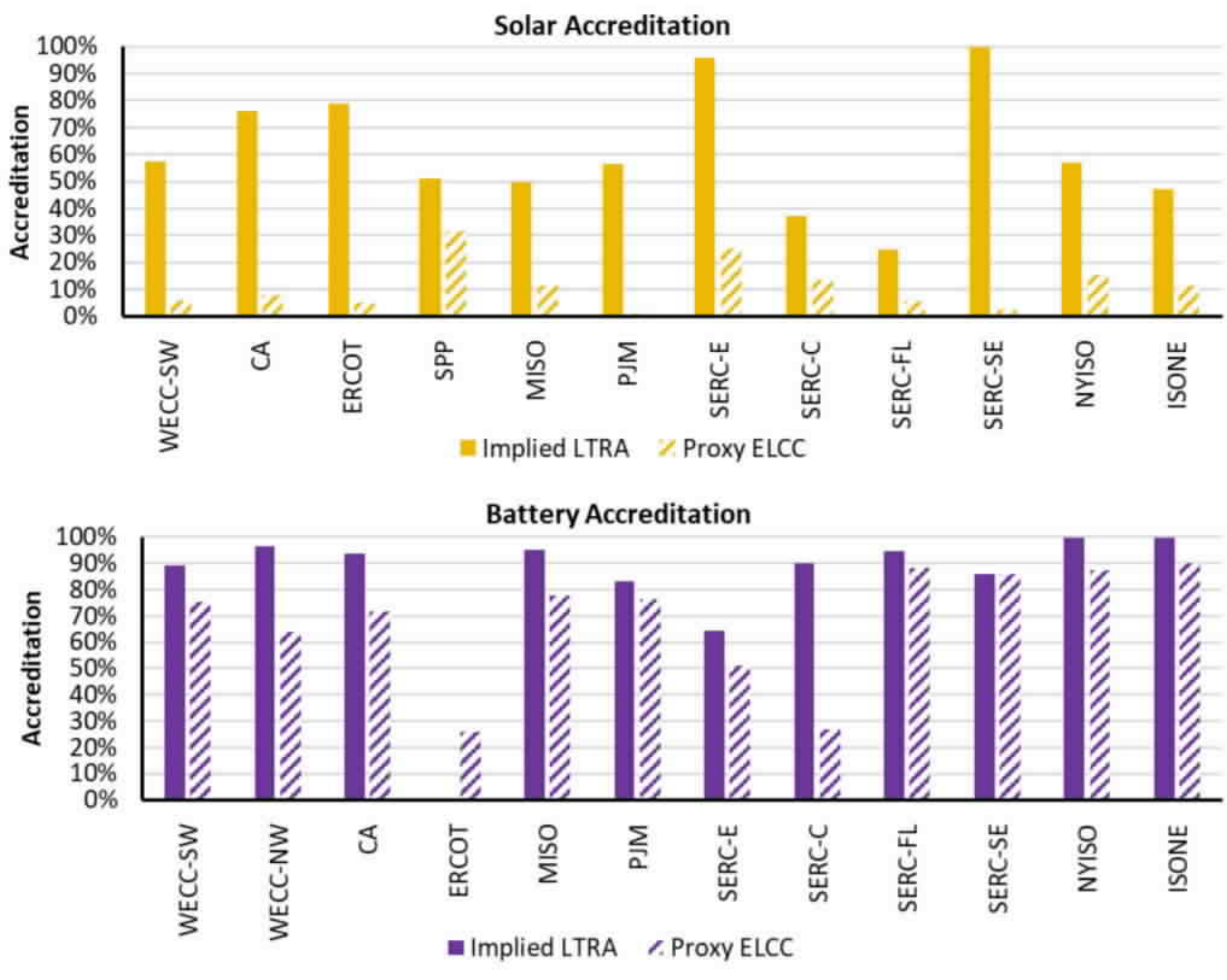

Figure E.1: Proxy Accreditation and Implied LTRA Values for Solar and Battery

[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

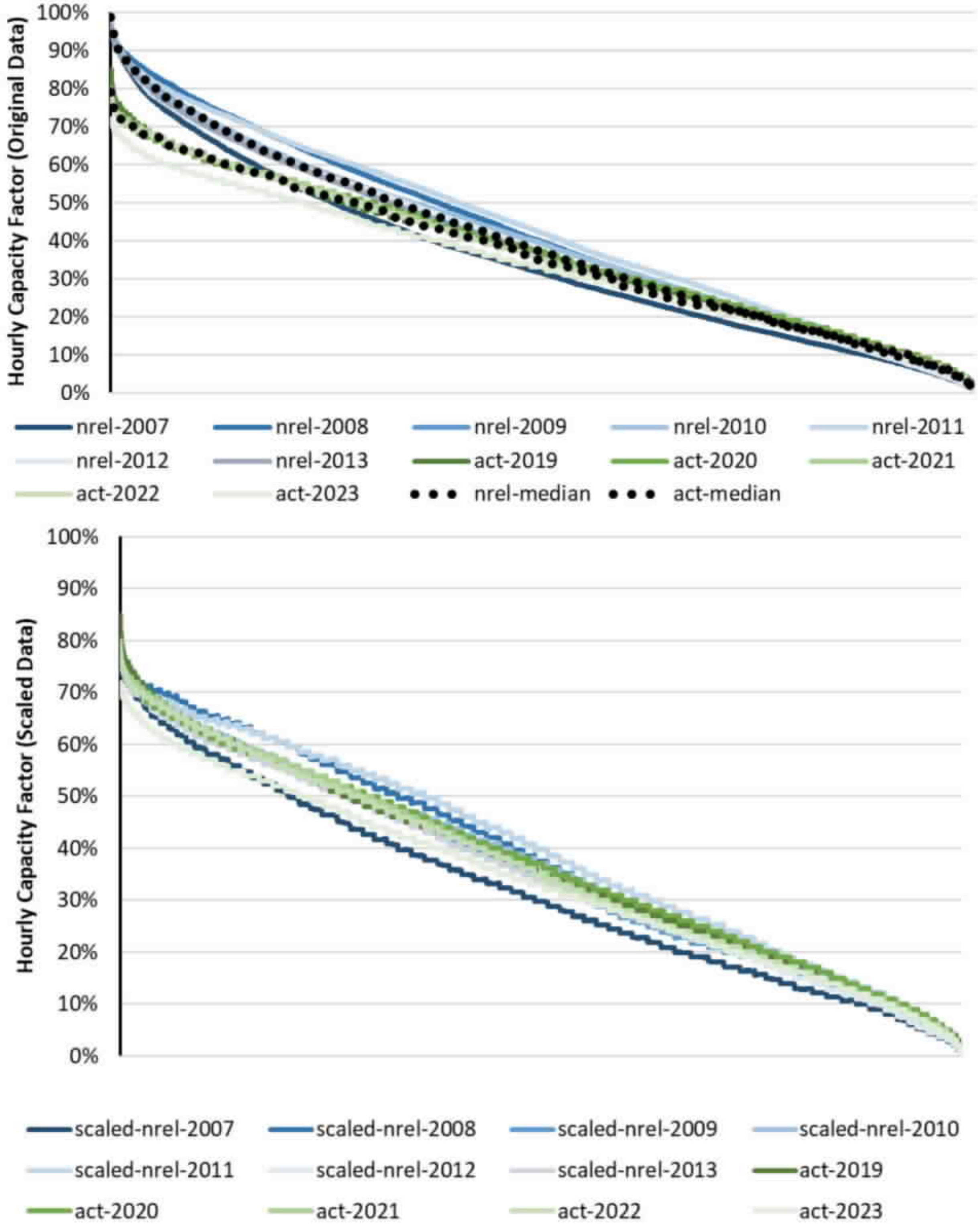

Figure F.1: Example of Scaling Synthetic Weather Data to Align with Historical Actual Data (ERCOT Land-Based Wind)

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.

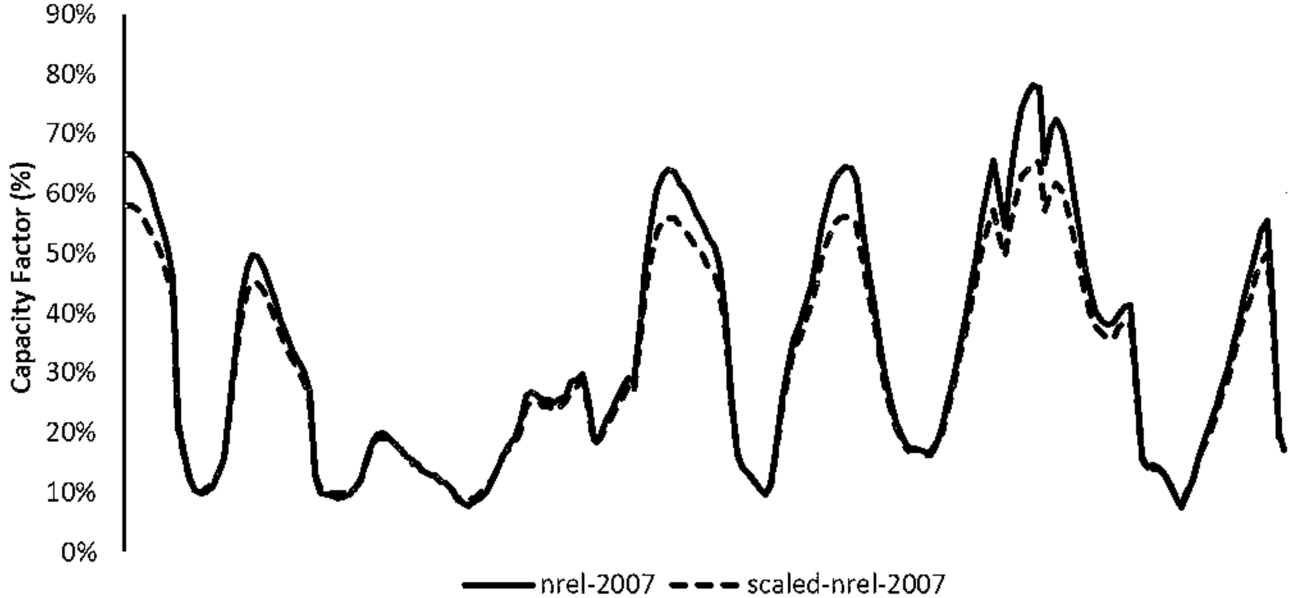

Figure F.2: Example of Chronological Variability in Synthetic Renewable Profile After Scaling to Match Historical Actuals (ERCOT Land-Based Wind)

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.

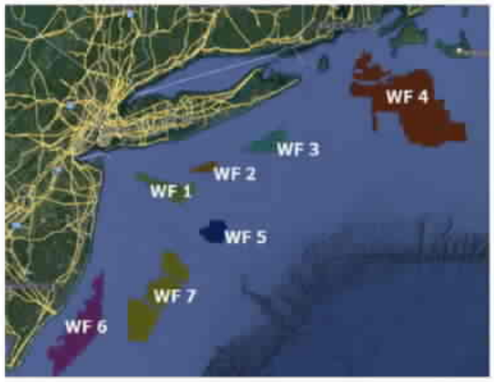

Figure F.3: Locations of Available East Coast Offshore Wind Profiles from DNV Used for Representative Shapes

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.

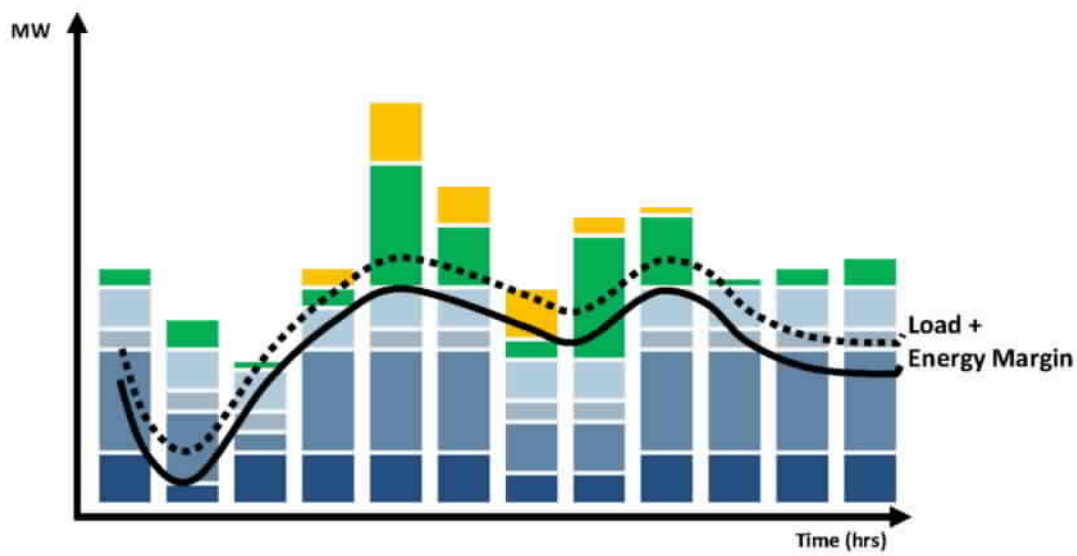

Figure H.1: Illustrative Example of the Available Capacity and Load on an Hourly Basis

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.

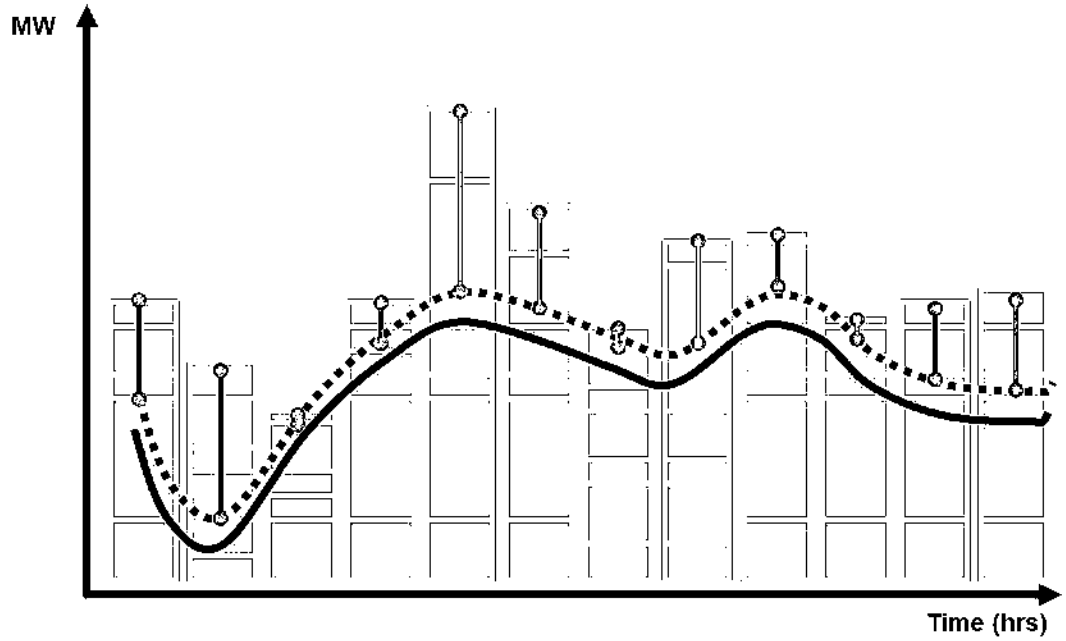

Figure H.2: Illustrative Example of the Hourly Energy Margin

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.

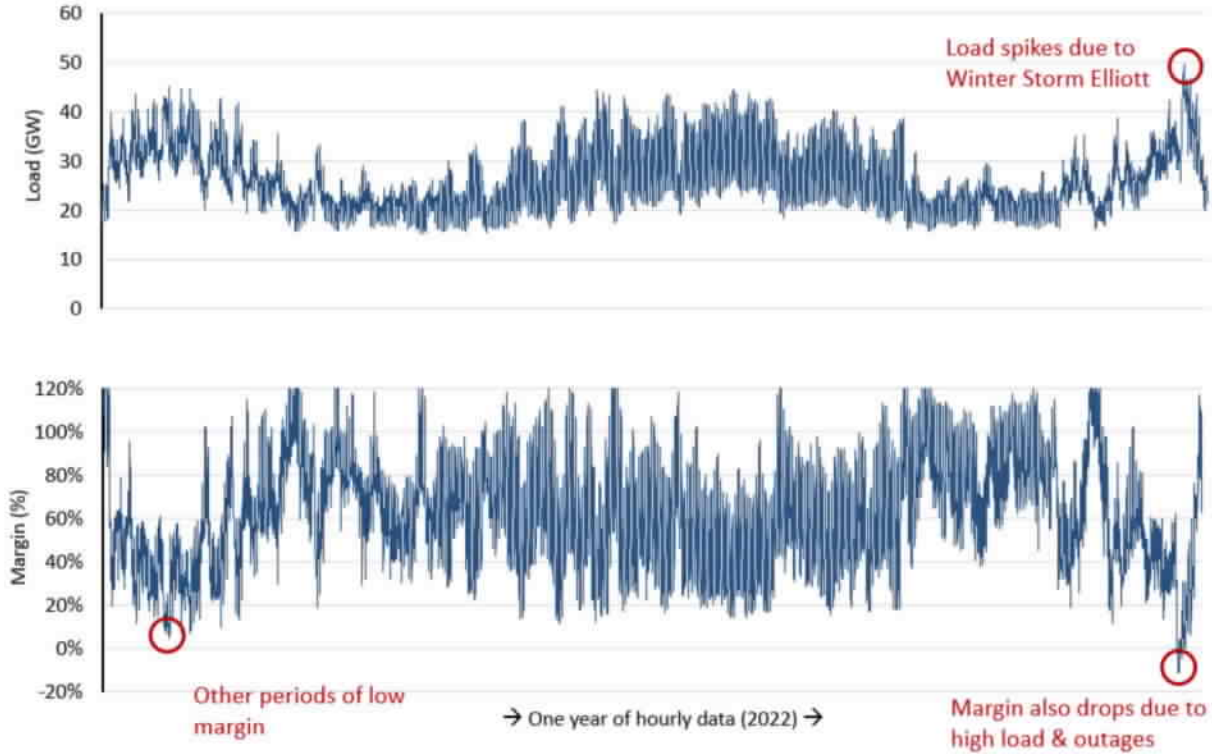

Figure H.3: Load (top) and Energy Margin (bottom) for SERC-E, Weather Year 2022

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.

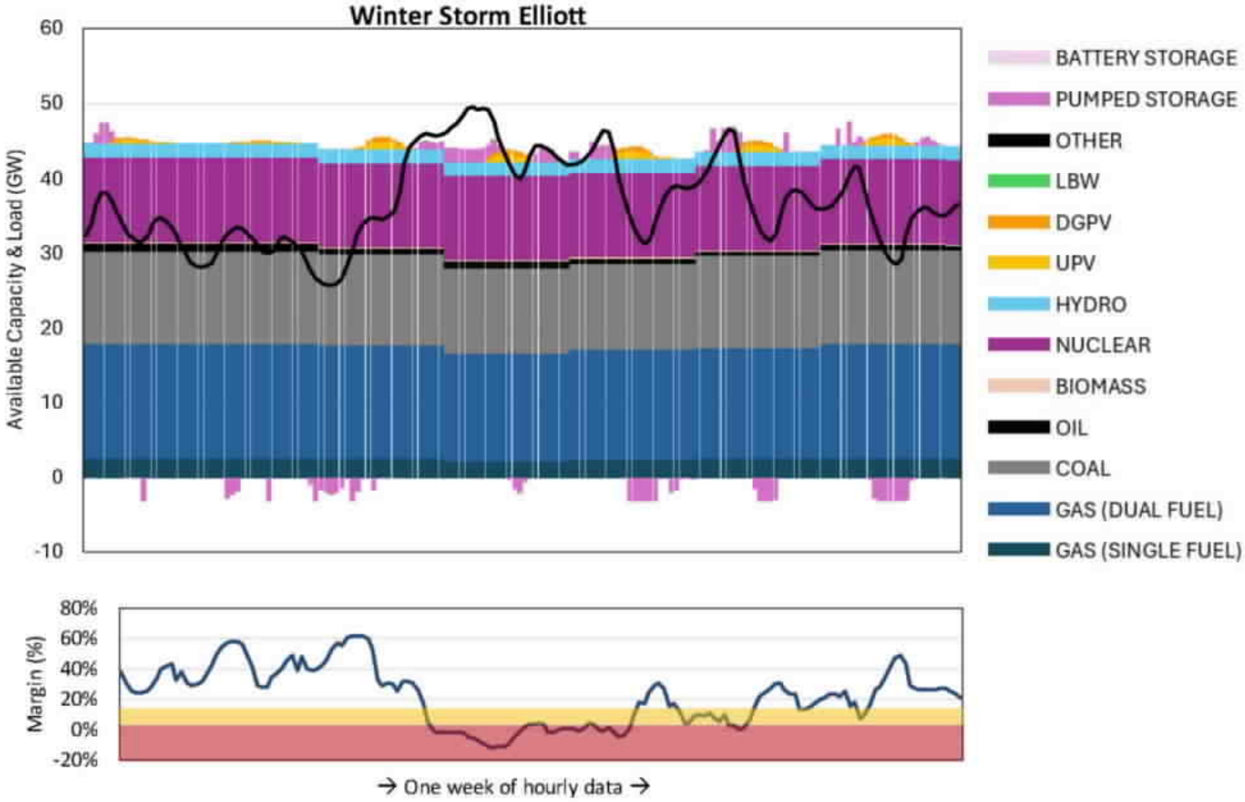

Figure H.4: Illustrative Example of Available Resources, Load, and Hourly Energy Margin

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.

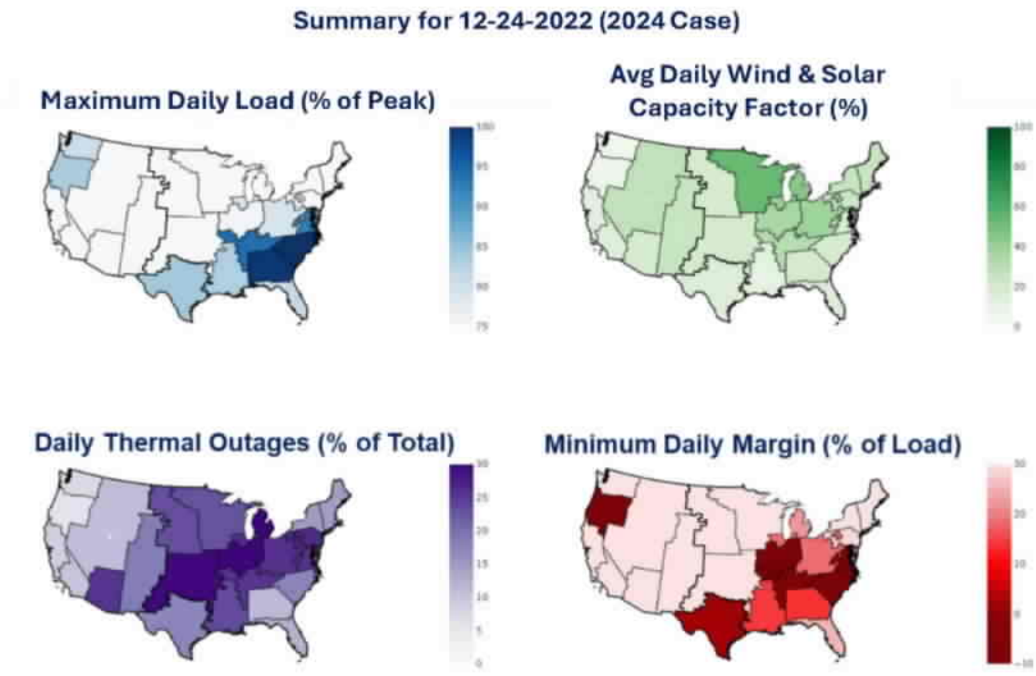

Figure H.5: National Illustration of Energy Margins and Contributing Factors

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.

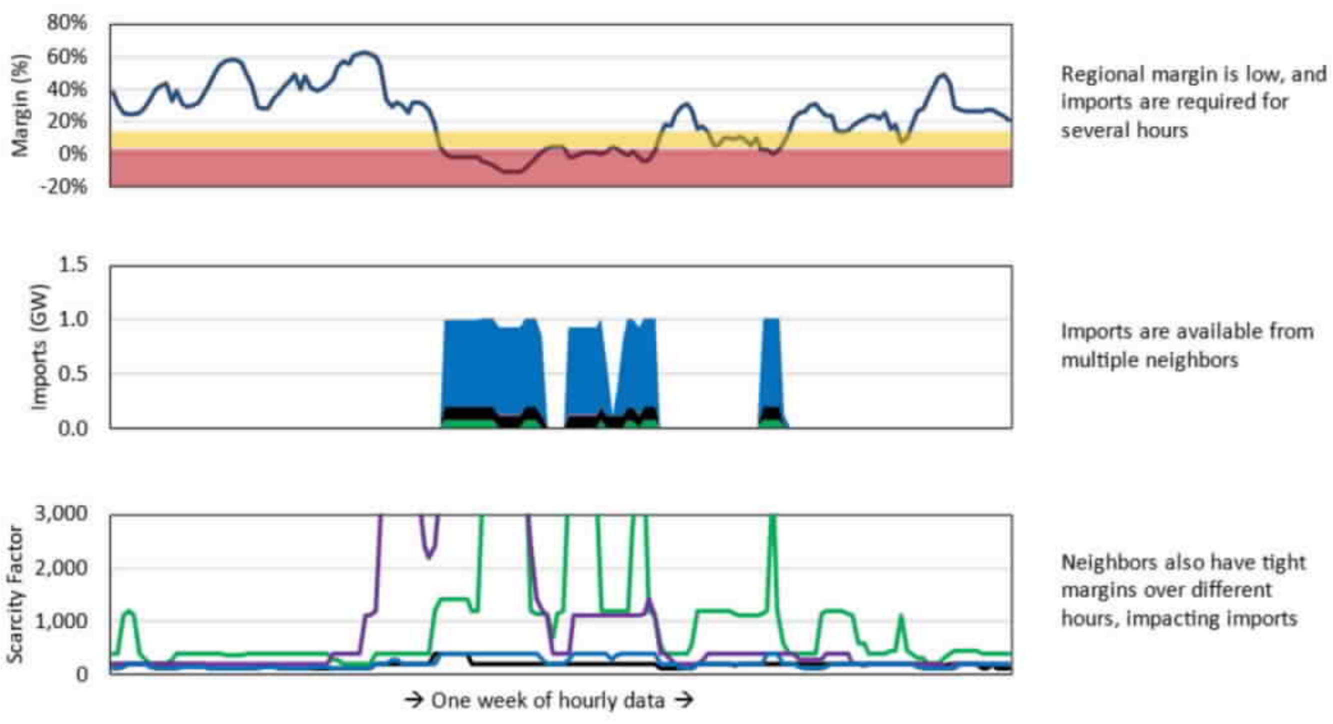

Figure H.6: Hourly Energy Margin Example and Corresponding Imports

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.

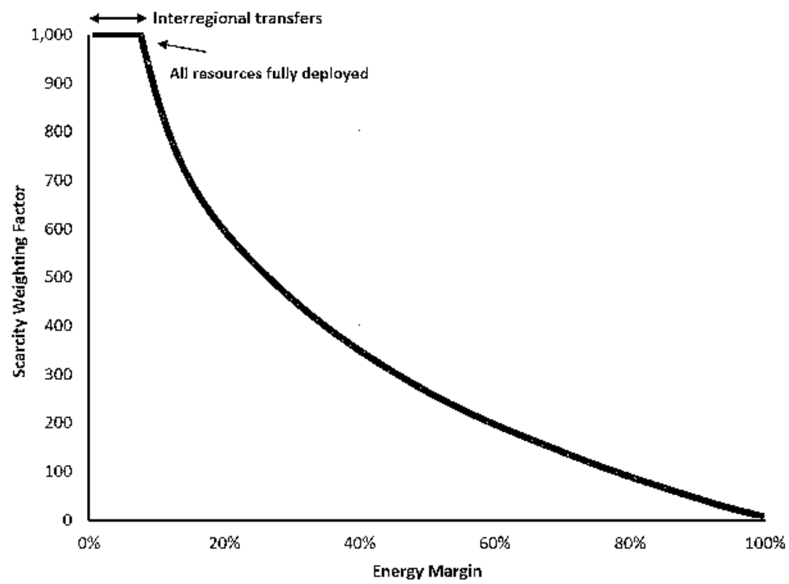

Figure I.1: Scarcity Weighting Factor Used in the Dispatch Model

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.

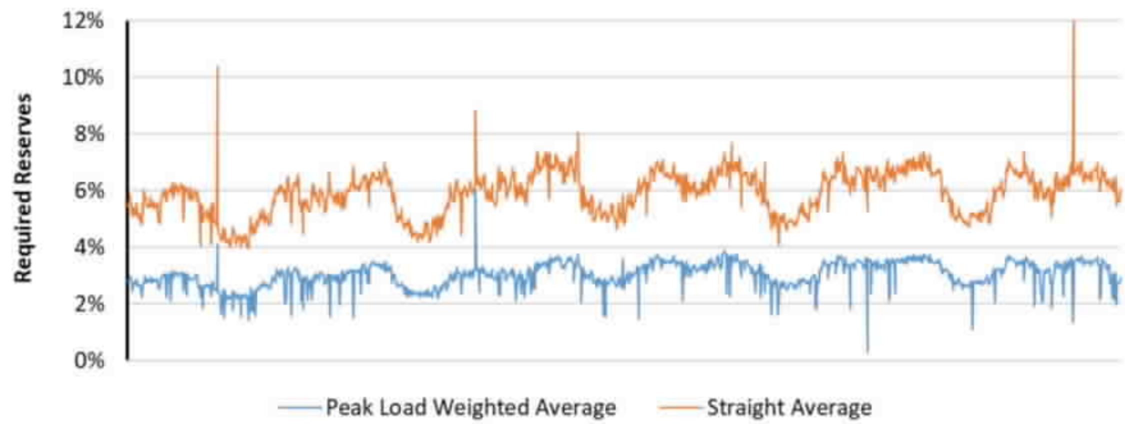

Figure J.1 Average Daily Required Reserves (as a Percentage of Daily Peak)

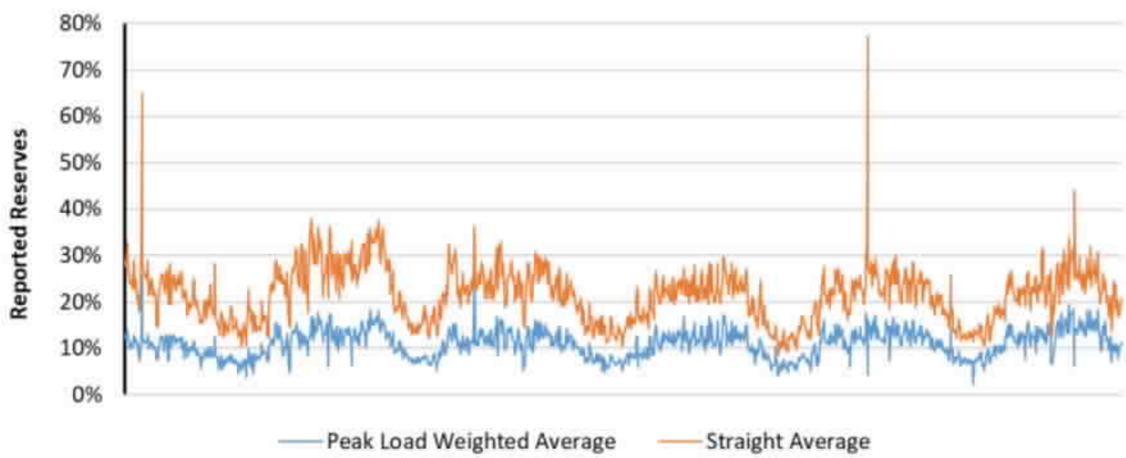

Figure J.2: Average Daily Reserves (as a Percentage of Daily Peak)

[110] NERC, System Awareness Daily Report, Forecasted Loads and Reserves Table, 2019-2024

Appendix B

List of Stakeholder Engagement Activities

Appendix B - List of Stakeholder Engagement Activities

Interregional Transfer Capability Study – As of Nov. 19, 2024

The following list summarizes the list of more than 130 stakeholder engagement activities held by the ERO Enterprise in connection with preparation of the Interregional Transfer Capability Study

June 2, 2023	Touchpoint	NERC News
September 14, 2023	Board / Committee Meeting	WECC Board of Directors Meeting
October 3, 2023	Board / Committee Meeting	WECC Advisory Group meeting
October 17, 2023	Board / Committee Meeting	NERC Board of Directors Meeting - Quarterly Technical Session
October 24, 2023	Touchpoint	NERC News
October 25, 2023	Touchpoint	WECC Reliability Assessment Committee
October 30, 2023	Touchpoint	WECC: Western Power Pool
October 31, 2023	Touchpoint	WECC: WestConnect
October 31, 2023	Board / Committee Meeting	WECC Advisory Group
November 13, 2023	Touchpoint	WECC: California ISO
November 13, 2023	Touchpoint	RF Tech-Talk
November 14, 2023	Board / Committee Meeting	WECC Advisory Group meeting
November-23	Touchpoint	Mentions of ITCS in Texas Review monthly newsletter
November 28, 2023	Board / Committee Meeting	ITCS Advisory

December 6, 2023	Board / Committee Meeting	WECC Board of Directors Meeting
December 7, 2023	Touchpoint	WECC: ITCS Data Request webinar
December 12, 2023	Touchpoint	WECC Weekly Update - mentions the Data Request Letter
December 12, 2023	Board / Committee Meeting	WECC Advisory Group meeting
December 14, 2023	Board / Committee Meeting	ITCS Advisory
January 4, 2023	Touchpoint	WECC Weekly Update - Status update webinar and Data Request letter
January 11, 2024	Touchpoint	WECC Weekly Update - Status update webinar and Data Request letter
January 16, 2024	Board / Committee Meeting	WECC Advisory Group meetings
January 18, 2024	Touchpoint	WECC Weekly Update - Status update webinar
January-24	Touchpoint	Mentions of ITCS in Texas Review monthly newsletter (2 paragraphs with link to Q4 update)
January 25, 2024	Touchpoint	WECC Weekly Update - Status update webinar
January 25, 2024	Board / Committee Meeting	ITCS Advisory
February 6, 2024	Board / Committee Meeting	WECC Advisory Group meeting
February 7, 2024	Board / Committee Meeting	NERC Reliability Assessment Subcommittee (RAS)
February 7, 2024	Touchpoint	Illinois Commerce Commission
February 7, 2024	Touchpoint	State Policymakers
February 8, 2024	Touchpoint	WECC Weekly Update - ITCS update message
February 8, 2024	Board / Committee Meeting	MRO Board of Directors
February 9, 2024	Feedback Request	Letters to Transmitting Utilities Requesting Feedback - sent to entities with the following roles: PA/PC, RC, RP, TO, TOP, TP
February 14, 2024	Board / Committee Meeting	NERC Board Quarterly Technical Session
February 21, 2024	Board / Committee Meeting	Reliability First (RF) Transmission Subcommittee

February 21, 2024	Board / Committee Meeting	Texas RE Board in Chief Engineers report
February 22, 2024	Board / Committee Meeting	NPCC Reliability Coordinating Committee Meeting
February 22, 2024	Board / Committee Meeting	Midwest Reliability Organization (MRO) Reliability Advisory Council
February 27, 2024	Touchpoint	(SERC briefed the Organization of MISO States Board of Directors during the) National Association of Regulatory Utility Commissioners
February 27, 2024	Board / Committee Meeting	WECC Reliability Assessment Committee
February 27, 2024	Board / Committee Meeting	ITCS Advisory
Q1	Touchpoint	Northeast Power Coordinating Council (NPCC) conducted several ITCS case development meetings with the New York ISO
Q1	Board / Committee Meeting	NPCC shared activities with stakeholders at their committee and task force meetings
March 5, 2024	Board / Committee Meeting	WECC Advisory Group meeting
March 13, 2024	Board / Committee Meeting	Reliability and Security Technical Committee (RSTC)
March 13, 2024	Board / Committee Meeting	WECC Board of Directors Meeting
March 19, 2024	Board / Committee Meeting	NPCC Task Force on System Studies meeting
March 26, 2024	Touchpoint	Edison Electric Institute (EEI) meeting
March 26, 2024	Board / Committee Meeting	ITCS Advisory
March-24	Touchpoint	Mentions of ITCS in Texas Review monthly newsletter (2 paragraphs with link to ITCS site)
March 27, 2024	Board / Committee Meeting	SERC Reliability Corporation (SERC) Board of Directors
March 28, 2024	Touchpoint	WECC Weekly Update - ITCS update message
April 4, 2024	Touchpoint	WECC Weekly Update - ITCS update message
April 9, 2024	Board / Committee Meeting	NERC RAS

April 10, 2024	Touchpoint	Eastern Interconnection Planning Collaborative (EIPC)
April-24	Touchpoint	Mentions of ITCS in Texas Review monthly newsletter
April 30, 2024	Board / Committee Meeting	ITCS Advisory
May 2, 2024	Board / Committee Meeting	ERO Executive Leadership
May 2, 2024	Board / Committee Meeting	ReliabilityFirst (RF) Board of Directors
May 3, 2024	Board / Committee Meeting	SERC Planning Coordination Subcommittee
May 8, 2024	Touchpoint	WECC Chief Dispatchers Meeting
May 8, 2024	Board / Committee Meeting	NERC Board Quarterly Technical Session
May 14, 2024	Board / Committee Meeting	WECC Advisory Group meeting
May 15, 2024	Feedback Request	ITCS Study Overview Report Review by Advisory Group
May 15, 2024	Board / Committee Meeting	Texas RE Board in Chief Engineers report
May 16, 2024	Board / Committee Meeting	Midwest Reliability Organization (MRO) Reliability Advisory Council
May 20, 2024	Board / Committee Meeting	RF Transmission Performance Committee
May 28, 2024	Board / Committee Meeting	WECC Advisory Group meeting
May-24	Touchpoint	Mentions of ITCS in Texas Review monthly newsletter
June 4, 2024	Board / Committee Meeting	ITCS Advisory
June 11, 2024	Board / Committee Meeting	RSTC
June 12, 2024	Board / Committee Meeting	WECC Board of Directors Meeting
June 12, 2024	Board / Committee Meeting	SERC Board
June 25, 2024	Board / Committee Meeting	ITCS Advisory Group

June 19, 2024	Feedback Request	Advisory Group Survey Responses
June 27, 2024	Board / Committee Meeting	ERO Executive Leadership
June 27, 2024	Touchpoint	NERC News
June 27, 2024	Touchpoint	Electric Power Research Institute (EPRI) Workshop?
July 8, 2024	Feedback Request	ITCS Study Part I Report Review by Advisory Group
July 11, 2024	Board / Committee Meeting	WECC Reliability Assessment Committee
July 11, 2024	Board / Committee Meeting	NERC Reliability Assessment Subcommittee
July 18, 2024	Board / Committee Meeting	SERC Technical Committee
July 22, 2024	Touchpoint	Q3 Trades and Forum
July 30, 2024	Board / Committee Meeting	SERC Technical Committee
July 30, 2024	Board / Committee Meeting	ITCS Advisory
July-24	Touchpoint	Mentions of ITCS in Texas Review monthly newsletter (articles with links to the NERC site)
August 2, 2024	Board / Committee Meeting	NPCC Reliability Coordinating Committee Meeting
August 5, 2024	Feedback Request	ITCS Study Part I Report Review by Advisory Group
August 8, 2024	Board / Committee Meeting	Midwest Reliability Organization (MRO) Reliability Advisory Council
August 8, 2024	Board / Committee Meeting	ERO Executive Leadership
August 14, 2024	Board / Committee Meeting	NERC Board Quarterly Technical Session
August 23, 2024	Feedback Request	ITCS Study Parts 2 & 3 Report Review by Advisory Group
August 26, 2024	Board / Committee Meeting	ERO Executive Leadership
August 27, 2024	Touchpoint	NERC News
August 27, 2024	Board / Committee Meeting	ITCS Advisory
September 10, 2024	Board / Committee Meeting	NPCC Task Force on System Studies meeting

September 11, 2024	Board / Committee Meeting	RSTC
September 17, 2024	Board / Committee Meeting	WECC Board of Directors Meeting
September 17, 2024	Touchpoint	RF Reliability and Security Summit - ITCS
September 18, 2024	Board / Committee Meeting	SERC Board of Directors
September 18, 2024	Board / Committee Meeting	Texas RE Board in Chief Engineers report
September 20, 2024	Touchpoint	EEI ITCS - Part 1 and Part 2 Transfer Capability Analysis
September 23, 2024	Board / Committee Meeting	ITCS Advisory
September 23, 2024	Board / Committee Meeting	ITCS Executive Committee
September 24, 2024	Touchpoint	Letter to Transmitting Utilities Requesting Feedback - sent to entities with the following roles: PA/PC, RC, RP, TO, TOP, TP
September-24	Touchpoint	Mentions of ITCS in Texas Review monthly newsletter (link to June 27th NERC announcement of ITCS Part 1 report)
September 26, 2024	Touchpoint	ACEG (Americans for a Clean Energy Grid)
September 30, 2024	Touchpoint	WECC: EEI Transmission, Distribution, Metering & Mutual Assistance Conference
October 1, 2024	Touchpoint	Interregional Transfer Capability Study 2024 Q3 Update Posted
October 2, 2024	Board / Committee Meeting	SERC Technical Committee
October 3, 2024	Board / Committee Meeting	Midwest Reliability Organization (MRO) Reliability Advisory Council
October 16, 2024	Board / Committee Meeting	WECC Reliability Assessment Committee (RAC)
October 22, 2024	Board / Committee Meeting	ITCS Advisory
October 25, 2024	Board / Committee Meeting	WECC Reliability Assessment Committee
October 28, 2024	Board / Committee Meeting	RF Transmission Performance Subcommittee
October 29, 2024	Touchpoint	Transmission Access Policy Study Group (TAPS)

October 31, 2024	Touchpoint	Q4 Trades and Forum
October 2024	Touchpoint	Texas RE - summary to ERCOT technical subject matter expert group
October, 2024	Touchpoint	Mentions of ITCS in Texas Review monthly newsletter
November 4, 2024	Touchpoint	Letter requesting feedback to all TOs, TOPs, PCs, and TPs
November 4, 2024	Touchpoint	Announcement: Third ITCS Document Recommends Technically Prudent Additions to Bolster Transfer Capability
November 5, 2024	Touchpoint	ITCS Webinar
November 6, 2024	Board / Committee Meeting	SERC Board of Directors
November 7, 2024	Board / Committee Meeting	MRO Board
November 7, 2024	Touchpoint	NPCC: Fall Reliability and Compliance conference
November 13, 2024	Board / Committee Meeting	NERC Reliability Assessment Subcommittee (RAS)
November 13, 2024	Board / Committee Meeting	NERC Board Informational Session
November 13, 2024	Touchpoint	NERC ITCS: Implications for New York
November 13, 2024	Touchpoint	Minnesota Power Systems Conference
November 18, 2024	Touchpoint	Midwestern Governors Association (MGA)
In addition to these presentations consulting with industry stakeholders, NERC engaged in outreach with governmental authorities, such as the Department of Energy, Federal Energy Regulatory Commission, and U.S. Congress. In addition, there were more informal touchpoints with stakeholders throughout development of the ITCS which would be too numerous to include.		

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Appendix C

Letters to Transmitting Utilities
Regarding Interregional Transfer Capability Study

February 9, 2024

Subject: Collaborative Study on Interregional Power Transfer - Seeking Your Input

Dear Registered Entity,

We are reaching out to highlight a critical initiative that the North American Electric Reliability Corporation (NERC), in consultation with our six Regional Entities, is currently undertaking and to invite your participation in a comprehensive study of interregional transfer capability across North America's interconnected transmission systems. This study, the Interregional Transfer Capability Study (ITCS) was congressionally mandated in the Fiscal Responsibility Act of 2023. The study must be submitted to the Federal Energy Regulatory Commission (FERC) by December 2, 2024.

The study focuses on three primary goals:

1. Evaluating the current power transfer capability between each pair of neighboring transmission planning regions.
2. Recommending prudent additions to the total transfer capability that are reasonably expected to help maintain reliability in the future.
3. Proposing recommendations to meet and maintain the current total transfer capability as well as total transfer capability enhanced by prudent additional recommendations.

Active engagement with our stakeholders is key to the success of this project, which is why we are inviting you – transmitting utilities and interested stakeholders – to share your insights, feedback, and inquiries related to the study. You may provide input at any time through your Regional Entity – Midwest Reliability Organization, Northeast Power Coordinating Council, WECC , SERC Regional Corporation, Texas RE and ReliabilityFirst as well as directly to NERC via email.

Your active participation and insights will be invaluable in ensuring the reliability and resiliency of North America's transfer capabilities. For more information on the study and study timeline, you can access the NERC ITCS webpage.

To date, we have made considerable progress. The team has outlined the study's framework and scope, engaged technical consultants to support the planning and execution, initiated the process of data collection, and collected input and feedback on various aspects of the study with the ITCS Advisory Group, which consists of industry leaders and experts from public and private organizations across the United States and Canada to provide their valuable insights and expertise in guiding our efforts.

We have also engaged with technical staff from the Department of Energy and selected a software vendor for data analysis. Currently, we are in the process of collecting data to calculate the current total transfer capability between each pair of neighboring transmission planning regions. The next steps include identifying system conditions that might lead to energy shortfalls and determining prudent additions to interregional transfer capability.

We look forward to your participation and plan on contacting you again in Quarter 3 to keep you apprised of the project's progress and as a reminder that your input is valuable.

Thank you in advance for your time and input.

Regards,

John Moura
Director, Reliability Assessments and Performance Analysis

September 24, 2024

Subject: Collaborative Study on Interregional Power Transfer - Seeking Your Input

Dear Registered Entity,

Following our initial outreach letter on February 9, 2024. We're reaching out again to request your input on the North American Electric Reliability Corporation's (NERC) Interregional Transfer Capability Study (ITCS). This study was Congressionally mandated by the Fiscal Responsibility Act of 2023, and the report must be submitted to the Federal Energy Regulatory Commission (FERC) by December 2, 2024.

The ITCS focuses on three primary goals:

1. Evaluating the current power transfer capability between each pair of neighboring transmission planning regions.
2. Recommending prudent additions to the total transfer capability to help maintain reliability in the future.
3. Proposing recommendations to meet and maintain the current total transfer capability and total transfer capability enhanced by the prudent addition recommendations.

The ITCS is being released in three draft parts and posted on NERC's ITCS initiative webpage:

- ITCS Overview of Study Need and Approach (published June 2024)
- ITCS Part 1 Transfer Capability Analysis (published August 2024)
- ITCS Parts 2 and 3 Prudent Addition Recommendations (to be published November 2024)

The Advisory Group materials posted on the webpage also provide presentations on study design and assumptions, such as considerations and criteria when evaluating potential prudent additions to total transfer capability.

Since the initial February letter, the project team has made considerable progress as reflected on NERC's ITCS webpage with the draft reports and other posted materials. Since then, the team has gathered data, performed analysis, reviewed results with planning entities, and published two of the three reports on our ITCS webpage. The team also updated the Parts 1[1] and 2[2] scope documents, also posted on our ITCS initiative webpage.

[1] https://www.nerc.com/pa/RAPA/Documents/ITCS_Transfer_Study_Scope_Part_1_Final.pdf
[2] https://www.nerc.com/pa/RAPA/Documents/ITCS_SAMA_Study_Scope_Part_2.pdf

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Atlanta, GA 30326
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Your input is highly valued and we encourage you to review the aforementioned published reports and scope documents and provide your input directly to NERC via email at itcs@nerc.net as well as through your region's respective Regional Entities:

- Midwest Reliability Organization: reliabilityanalysis@mro.net
- Northeast Power Coordinating Council: support@npcc.org
- ReliabilityFirst: ITCSSupport@rfirst.org
- SERC Reliability Corporation: support@serc1.org
- Texas Reliability Entity: information@texasre.org
- WECC: engage@wecc.org

The ITCS is a collaborative effort and the team has been providing regular updates to the ITCS Advisory Group, which is comprised of industry leaders and experts from both public and private organizations across the U.S. and Canada. Their valuable feedback and guidance have been instrumental in our progress, and we look forward to your contributions as well.

Currently, we are in the process of finalizing our prudent addition recommendations and drafting the ITCS Parts 2 and 3 report. The next steps include the publication of Parts 2 and 3 report, and a final compilation of all parts of the report into a final consolidated report to be filed with FERC on or before Dec 2, 2024.

We look forward to your input. Your insights will be invaluable in ensuring the reliability and resiliency of our electric power transfer capabilities.

Once we publish the Parts 2 and 3 report, we will contact you again to seek your input.

Thank you in advance for your time and input.

Regards,

John Moura
Director, Reliability Assessments and Performance Analysis

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

November 4, 2024

To: Registered Entities

From: ITCS Project Team

Re: Letter 3 - Collaborative Study on Interregional Power Transfer - Seeking Your Input

The North American Electric Reliability Corporation (NERC) would like your input on NERC's *Interregional Transfer Capability Study* (ITCS). This study was congressionally mandated in the Fiscal Responsibility Act of 2023 and focuses on three primary goals:

1. Evaluating the current transfer capability between each pair of neighboring transmission planning regions.
2. Recommending prudent additions to the total transfer capability to help maintain reliability in the future.
3. Proposing recommendations to meet and maintain the current total transfer capability and total transfer capability enhanced by the prudent addition recommendations.

Throughout this past year of development, NERC has incorporated transmitting utility and other stakeholder feedback into the study documents, where applicable, which were gathered from letter responses – additional letters were sent on February 9 and September 24, ITCS Advisory Group public meetings, and other stakeholder outreach.

Three draft ITCS documents have been released and can be found on the ITCS web page. Consistent with prior letter requests, please review these documents and provide any feedback:

- ITCS Overview of Study Need and Approach (published June 2024)
- ITCS Part 1 Transfer Capability Analysis (published August 2024)
- ITCS Parts 2 and 3 Prudent Addition Recommendations (published November 2024)

These three drafts will be consolidated into a final report that must be filed with the Federal Energy Regulatory Commission no later than December 2. A FERC comment period will follow. Any feedback is kindly requested by November 12, 2024 to facilitate timely consideration for the final report.

While no action or comments are required in response to this letter, we encourage you to review and provide any input through your respective Regional Entity or via NERC.

- **North American Electric Reliability Corporation**: itcs@nerc.net

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- **Midwest Reliability Organization**: reliabilityanalysis@mro.net
- **Northeast Power Coordinating Council**: support@npcc.org
- **ReliabilityFirst**: ITCSSupport@rfirst.org
- **SERC Reliability Corporation**: support@serc1.org
- **Texas Reliability Entity**: information@texasre.org
- **WECC**: engage@wecc.org

Since the start of the ITCS project in June 2023, the project team shared documents and updates, hosted public meetings and provided opportunities for stakeholder input into the ITCS. All documents have been posted on the ITCS web page, including those of the ITCS Advisory Group, which is comprised of industry leaders and experts from both public and private organizations across the United States and Canada.

We hope you will take advantage of this opportunity to share your insights, which are invaluable in ensuring the reliability and resiliency of our bulk power system. Thank you in advance for your time and input.

Regards,

John Moura
Director, Reliability Assessments and Performance Analysis

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Appendix D

Advisory Group Roster, ITCS Study Team Roster,
and Schedule of Monthly Public Advisory Group Meetings

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ITCS Advisory Group Roster

November 2024

Name	Title	Organization
Adam, Gabriel	Senior Manager, Engineering Studies	Independent Electricity System Operator
Berner, Aaron	Sr. Manager, System Planning Process Reform and Development	PJM
Brooks, Adria	Senior Technical Advisor	U.S. Department of Energy
Brooks, Daniel	Director, Grid Operations and Planning	EPRI
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Interregional Transfer Capability Study Advisory Group Meeting Schedule

Meeting Name	Dates	Description	Goals	Type
Overview				
ITCS Progress Review	Monthly through September Last Tuesday* of each month. 2:00 -4:00 p.m. Eastern. *Exception: September 23 meeting is on Monday	NERC Project Team provides update on ITCS project and a status update on milestone deliverables	Update Advisory Group on progress. Q&A with NERC project staff	Remote
Major Study Milestone Completion	January 25 – NERC DC June 4 – WECC SLC	Review deliverables following milestone activity completion	Advisory Group provides comments and recommendations on milestone deliverables	In Person
ITCS Report Review	September 2-13, 2024	Advisory Group reviews draft ITCS report	Advisory Group members edits, comments, and recommendations of the draft ITCS report	Remote
ITCS Report Review	October 22 – NERC DC	Consolidation of edits and concurrence of Advisory Group on ITCS Report	Concurrence of Advisory Group on ITCS Report	In Person