A Supplemental Experimental Procedures: Input Data

A.1 Generators

Our model includes existing capacity generators as well as a set of new technologies that can be deployed. Existing generation capacity is sourced from EIA Form-860 and aggregated through PowerGenome (Schivley, 2023). Details can be found in Appendix A.1. Investment, operating, and maintenance costs for new generators can be found in Table 2. Fixed O&M costs for new capacity are sourced from NREL's Annual Technology Baseline (ATB) 2022 for the basis year 2035 assuming the moderate cost case and a market financial scenario except for Natural Gas with CCS for which we assume the conservative cost case (Vimmerstedt et al., 2022). CAPEX and WACC are taken as average values from NREL ATB 2022 from the years 2023 to 2035. Meanwhile, cost assumptions for existing plants use the basis year 2020, with variation assumptions from PowerGenome depending on the start year of operation. State-level offshore wind mandates as well as production and tax credits associated with the Inflation Reduction Act are also implemented in the model (Ho et al., 2021; Gagnon et al., 2023).

Table 2: New Technology Investment and Operation Costs in 2035

	Capex ($/MW)	Capital Recovery Period (years)	WACC	Investment Cost ($/MW-yr)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)
Natural Gas Combined Cycle	919,930	15	3.56%	80,609	28,000	2.00
Natural Gas Combined Cycle with CCS	2,292,360	20	3.56%	163,185	67,000	6.00
Natural Gas Combustion Turbine	792,572	15	3.56%	69,449	21,000	5.00
Nuclear	6,964,382	40	3.29%	318,166	145,960	2.84
Solar Photovoltaic	844,746	20	2.50%	54,330	14,721	-
Onshore Wind Turbine	1,052,987	20	3.06%	71,488	37,489	-
Offshore Wind Turbine	3,890,946	20	4.24%	294,739	61,370	-
Battery	252,126	15	2.50%	20,405	6,303	0.15

Table 3 summarizes the existing generating capacity per transmission planning region. We assume that there is a second-license extension for nuclear generators because of the passage of the Inflation Reduction Act (Gagnon et al., 2023).

Table 3: 2022 Existing Generating Capacity per Region (in GW)

	California	Central	Florida	Mid-Atlantic	Midwest	New York	Northeast	Northwest	Southeast	Southwest	Texas	Total
Batteries	11.33	0.23	0.54	0.34	0.08	0.20	0.36	1.08	0.44	1.28	4.40	20.28
Conventional Hydroelectric	8.86	4.58	0.04	2.83	1.42	3.63	1.08	35.14	11.04	3.24	0.48	72.35
Conventional Steam Coal	0.06	20.24	4.87	41.93	50.41	-	0.53	13.72	43.36	8.30	13.63	197.05
Hydroelectric Pumped Storage	3.94	0.47	-	5.21	2.49	1.41	1.80	0.31	6.41	0.80	-	22.84
Natural Gas Combined Cycle	21.18	12.21	37.54	60.94	39.01	12.32	16.03	15.85	44.70	15.72	41.75	317.25
Natural Gas Combustion Turbine	11.56	11.27	9.23	30.92	27.90	3.98	2.02	4.12	32.72	7.90	11.16	152.78
Natural Gas Steam Turbine	4.62	10.38	4.63	10.20	14.05	9.83	1.44	0.84	4.42	2.28	11.22	73.90
Nuclear	2.24	2.03	3.74	33.46	11.90	3.38	3.35	1.17	28.71	4.00	5.12	99.09
Offshore Wind Turbine	-	-	-	-	-	-	0.03	-	-	-	-	0.03
Onshore Wind Turbine	6.04	35.54	-	10.43	32.51	3.39	1.55	16.76	1.45	9.42	34.05	151.14
Small Hydroelectric	0.32	0.10	-	0.30	0.78	0.60	0.41	0.79	0.20	0.14	0.02	3.68
Solar Photovoltaic	19.89	0.81	9.45	11.10	9.48	1.87	2.65	9.79	16.42	8.58	20.83	110.88
	90.05	97.86	70.04	207.68	190.03	40.61	31.25	99.58	189.85	61.66	142.67	1,221.26

A.2 Fuel Costs

Fuel costs are sourced from EIA's Annual Energy Outlook (AEO) 2022 for the year 2035. The individual zones are matched to the AEO regions through PowerGenome. Fuel cost information can be found below in Table 4.

Table 4: Fuel Costs

Fuel	AEO Region	Model Region/s	Fuel Name	Price ($/MMBtu)
coal	pacific	California, Northwest	pacific_reference_coal	1.97
	mountain	Northwest, Southwest	mountain_reference_coal	1.32
	new_england	Northeast	new_england_reference_coal	2.00
	south_atlantic	Florida, Mid-Atlantic, Southeast	south_atlantic_reference_coal	2.39
	middle_atlantic	Mid-Atlantic	middle_atlantic_reference_coal	2.22
	west_south_central	Central, Midwest, Texas	west_south_central_reference_coal	1.73
	east_south_central	Southeast	east_south_central_reference_coal	1.83
	west_north_central	Central, Midwest, Southeast	west_north_central_reference_coal	1.57
	east_north_central	Mid-Atlantic, Midwest	east_north_central_reference_coal	1.80
natural gas	pacific	California, Northwest, Southwest	pacific_reference_naturalgas	4.01
	mountain	Northwest, Southwest	mountain_reference_naturalgas	4.33
	new_england	Northeast	new_england_reference_naturalgas	3.86
	south_atlantic	Florida, Mid-Atlantic, Southeast	south_atlantic_reference_naturalgas	4.21
	middle_atlantic	Mid-Atlantic, New York	middle_atlantic_reference_naturalgas	3.25
	west_south_central	Central, Midwest, Texas	west_south_central_reference_naturalgas	3.67
	east_south_central	Southeast	east_south_central_reference_naturalgas	3.91
	west_north_central	Central, Midwest, Southeast	west_north_central_reference_naturalgas	4.07
	east_north_central	Mid-Atlantic, Midwest	east_north_central_reference_naturalgas	3.51
uranium	pacific	California, Northwest, Southwest	pacific_reference_uranium	0.72
	mountain	Northwest, Southwest	mountain_reference_uranium	0.72
	new_england	Northeast	new_england_reference_uranium	0.72
	south_atlantic	Florida, Mid-Atlantic, Southeast	south_atlantic_reference_uranium	0.72
	middle_atlantic	Mid-Atlantic, New York	middle_atlantic_reference_uranium	0.72
	west_south_central	Central, Midwest, Texas	west_south_central_reference_uranium	0.72
	east_south_central	Southeast	east_south_central_reference_uranium	0.72
	west_north_central	Central, Midwest, Southeast	west_north_central_reference_uranium	0.72
	east_north_central	Mid-Atlantic, Midwest	east_north_central_reference_uranium	0.72

A.3 CO_2 Emissions Factors

Coal and Natural Gas are the two technologies that generate CO_2 emissions in the implementation of the GenX model. Emissions are generated for every MMbtu of coal and natural gas consumed by a generator. We assume 0.09552mtCO_2/MMBtu and 0.05306mtCO_2/MMBtu for coal and natural gas, respectively. Coal plants in the model have an average heat rate of 11.59 MMbtu/MWh and Natural Gas plants an average of 9.55 MMbtu/MWh.

A.4 Demand and Supply Curves

Load is sourced from NREL's EFS (Mai et al., 2018) through PowerGenome (Schivley, 2023) where we assume a high electrification scenario with moderate technology advancement. Total system load growth is 23.5% from 4,082 TWh in 2022 to 5,042 TWh in 2035. The load duration curves for each region can be found in Fig. 7. The total regional load is indicated in the Figure. The three regions with the highest total load are the Mid-Atlantic region at 20% of total load, followed by the Midwest at 16% and Northwest at 8%.

Solar and Wind Capacity Factors were obtained from Shi (2023), who follow the methodology provided by Brown and Botterud (2021). The capacity factors are processed from NREL's National Solar Radiation Database and the WIND Toolkit.

Due to the large scale of the optimization problem with 64 zones and more than 1000 generator clusters, we use a procedure called *Time Domain Reduction* (TDR). TDR creates a subset of representative periods for the operation of an entire year. GenX has a built-in TDR procedure that uses k-means clustering to determine the subset. A less computationally

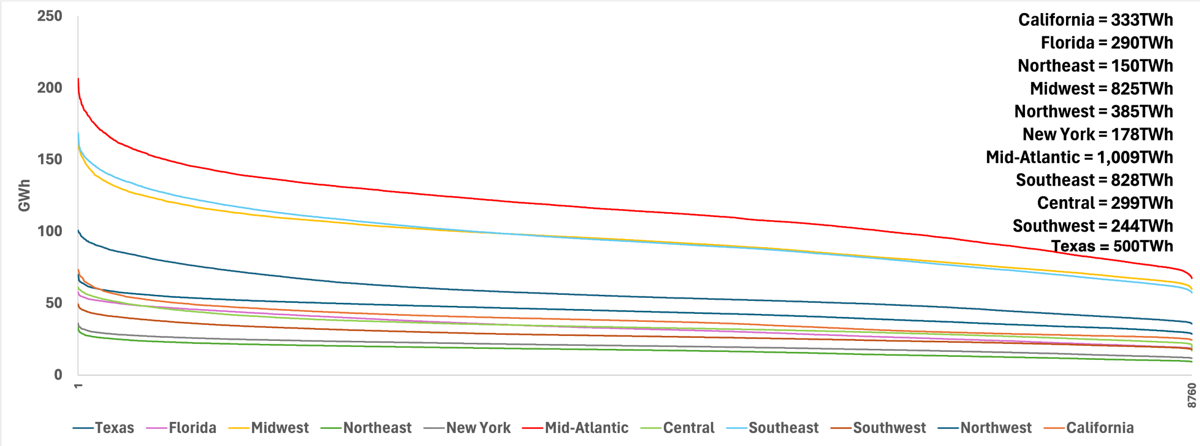

Figure 7: **Regional Load duration curves.** The load duration curve orders the load for each region from the largest value to the lowest value.

intensive dispatch model where we take the generation and transmission investments resulting from the TDR expansion case as input and do not allow any new investments in generation capacity (i.e., one where only dispatch decisions are made) was tested for a full year. We found that operational costs and dispatch results in this model were similar to the TDR case.

A.5 Transmission

A.5.1 Calculating Interregional transfer capability

The transfer capability between two zones z and z' (where $z \neq z'$) is represented by a non-negative number $c_{zz'}$ that constrains the maximum amount of electricity that can flow between zones. The combination of zones z and z' where there is existing or where we allow potentially new built transfer capability is the number of possible *lines* L. We then have $L = 142$, with each line represented by a line number $l = 1, 2, \ldots, L$. Line transfer capability between zones can be found in Supplementary Table 7. The origin zone of line l is $l_o = z$ and the destination zone is $l_d = z'$. Transmission lines between zones within the same region are called *intraregional*, and transmission lines between zones from different regions are *interregional*.[1] That is, l is intraregional if $l_o, l_d \in Z_r$ for the same r and interregional otherwise. Note that $c_{zz'} = c_{z'z}$ and both are denoted by the same l. We can also then define the capacity of line l as $\hat{c}_l = c_{zz'}$. Given these definitions, the transfer capability $TC_{rr'}$ between regions r and r' is the sum of transfer capabilities between zones located in r and r'. More specifically:

$$TC_{rr'} = \sum_{l \in \mathcal{L}_{rr'}} \hat{c}_l, \tag{2}$$

where $\mathcal{L}_{rr'} = \{l | l_o = z \in Z_r; l_d = z' \in Z_{r'}\}$ is the set of lines where the origin zone z is in region r and the destination zone z' is in region r'. The overall interregional transfer capability $\hat{TC}_r$

[1] Another type of transmission that can be built is transmission lines within each zone. We call these *intra-zonal* transmission lines but do not model them explicitly. The cost of lines that connect new generators to the grid is also not included explicitly, but the cost is embedded in the investment in new generators

of a region r is the sum of its transfer capability to all other regions:

$$\hat{TC}_r = \sum_{\forall r' \neq r} TC_{rr'}. \tag{3}$$

It will also be convenient for calculations to define $\hat{\mathcal{L}}_r = \bigcup_{\forall r'} \mathcal{L}_{rr'}$ which is the set of all interregional lines of region r (i.e., the union of the sets of lines that connect from region r to another region r').

From the above calculation, Table 5 shows the number of zones per region and the current interregional and intraregional transfer capabilities. Table 10 shows the current interregional transfer capability between regional corridors.

Table 5: Zones and Transfer Capability per Region

		Transfer Capability (in GW)	
Region	Number of Zones	Intraregional	Interregional ($\hat{TC}_r$)
California	5	11.45	19.08
Florida	1	0.00	3.60
Northeast	3	4.95	2.16
Midwest	14	19.02	35.92
Northwest	7	10.49	22.17
New York	8	19.62	4.08
Mid-Atlantic	9	39.18	24.01
Southeast	5	5.58	23.32
Central	5	7.53	10.42
Southwest	4	3.27	12.40
Texas	3	8.86	0.82

A.5.2 Minimum Interregional Transfer Capability Requirements

The BIG WIRES Act specifies that each FERC Order No. 1000 region should achieve a Minimum Interregional Transfer Capability (MITC). The MITC is calculated as the minimum between 30% of regional coincident peak load and 15% of regional coincident peak load plus the current transfer capability. The requirement is designed to give regions with lower current transfer capability relative to its peak load a lower MITC than regions with higher current transfer capabilities. The 30% value is what we call the MITC % represented by the variable p. We generalize this calculation for varying p using the following formula (also found in the main text):

$$MITC_r(p) = \min(p\bar{D}_r, \frac{p}{2}\bar{D}_r + \hat{TC}_r), \tag{4}$$

The MITC formula in (4) relies on two values: the coincident peak load of a region and its current transfer capability. For the purposes of this analysis, we use the EPA's transfer capability (specified in the Suppplementary Note A.5.3 and consolidated using the methodology described in Supplementary Note A.5.1). Table 6 shows the calculation for MITC across different p values. Texas is not required to build interregional transmission in our model as it is not typically included in federal proposals.

Table 6: Minimum Interregional Transfer Capability values per MITC % (in GW)

			MITC									
Region	Peak Load	Current Transfer Capability	p =10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
California	70.93	19.08	7.09	14.19	21.28	28.37	35.47	40.36	43.91	47.46	51.00	54.55
Florida	55.80	3.60	5.58	9.18	11.97	14.76	17.55	20.34	23.13	25.92	28.71	31.50
Northeast	30.47	2.16	3.05	5.21	6.73	8.25	9.78	11.30	12.82	14.35	15.87	17.39
Midwest	157.51	35.92	15.75	31.50	47.25	63.00	75.30	83.18	91.05	98.93	106.80	114.68
Northwest	65.75	22.17	6.57	13.15	19.72	26.30	32.87	39.45	45.18	48.46	51.75	55.04
New York	33.64	4.08	3.36	6.73	9.12	10.80	12.49	14.17	15.85	17.53	19.21	20.90
Mid-Atlantic	195.35	24.01	19.53	39.07	53.32	63.08	72.85	82.62	92.39	102.15	111.92	121.69
Southeast	160.27	23.32	16.03	32.05	47.36	55.38	63.39	71.40	79.42	87.43	95.44	103.46
Central	59.67	10.42	5.97	11.93	17.90	22.36	25.34	28.32	31.31	34.29	37.27	40.26
Southwest	47.17	12.40	4.72	9.43	14.15	18.87	23.58	26.55	28.91	31.27	33.62	35.98

A.5.3 Line Transfer Capabilities and Transmission Line Investment Cost

Currently, there is no consistent methodology for determining what the transfer capability is between two zones and regions. In 2006, the North American Electric Reliability Corporation (NERC) required each reliability coordinator and planning authority to provide methodologies for determining transfer capability (NERC, 2006).[2] Inevitably, although regularly updated, these methodologies varied from region to region and usually required complex simulations (see, for example, CAISO (CAISO, 2024) and PJM's (PJM, 2024) methodologies). To address these differences, NERC more recently initiated a nation-wide Interregional Transfer Capability Study (ITCS) that quantifies transfer capability between regions with the hope that it unifies the varying definitions (NERC, 2024). This study is set to be completed by December 2024. The BIG WIRES Act proposes that transfer capability should be the actual observed maximum flow between two zones rather than the combined transmission line ratings. In our case, we use the EPA's transfer capability in our model.

Current transfer capabilities per line (Capacity column) and the investment cost per MW-yr ($/MW-yr column) for expanding the line can be found in Table 7. These are sourced from the EPA's Power Sector Modeling Platform v6 – 2021 Summer Reference Case (EPA, 2021). Transmission investment costs per MW-yr were sourced from Shi (2023). Shi's methodology involves using NREL REeDS' definition of zones called "p-regions" (Fig. 8). Each NREL REeDS p-region has a base cost ($/MW/mile) of building a transmission line that starts/ends in the p-region (see https://github.com/NREL/ReEDS-2.0; Ho et al., 2021). The p-region is converted to the zones in our model by the weighted area of overlap between the two. Distance between zones is measured by a straight line between the centroids of two zones. Line loss is 0.01 per 100 miles. Transmission cost ($/MW/mile) between zones is the average of the two zones, then multiplied by the distance (miles) between the zones. Transmission cost is then annualized (4.4% WACC, 60-year capital recovery period (Gorman et al., 2019)).

The costs of transmission between p-regions are calculated as follows: For interregional transmission lines, an assumed voltage of either 345kV, 500kV, or 765kV is used based on the highest line voltage in the p-region from the Homeland Security Infrastructure project (HSIP, 2012). Each voltage class corresponds to a base capital cost of $2333/MW/mile, $1347/MW/mile, and $1400/MW/mile for 345kV, 500kV, and 765kV, respectively. The cost is scaled according to regional multipliers. The base cost and regional multipliers are taken from the Phase II Eastern

[2]Transfer Capabilities are also sometimes called transfer capacities or transmission capabilities.

Interconnection Planning Collaborative (EIPC) report (EIPC, 2015): (Vol 2, pp. 5-1 to 5-5: https://eipconline.com/phase-ii-documents).

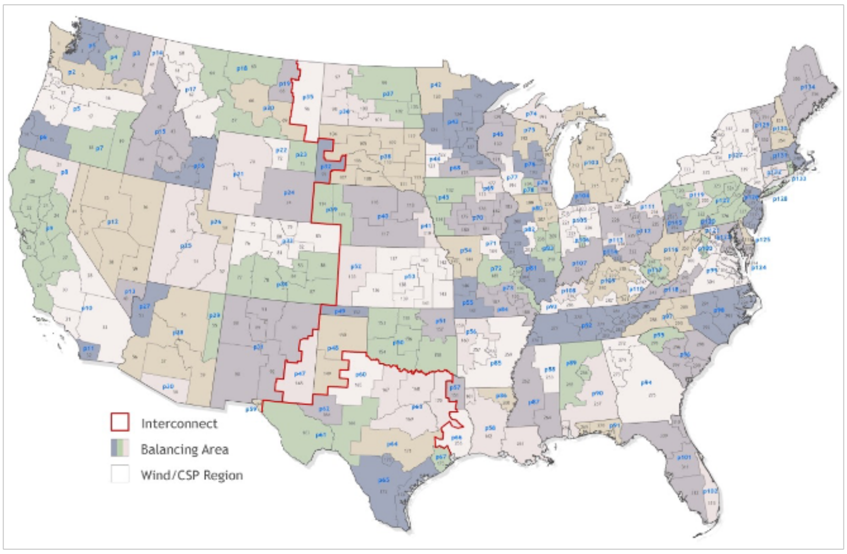

Figure 8: **NREL REeDS p-regions (taken from Ho et al. (2021))**

Table 7: Lines and Transfer Capability (in MW)

Line (Zone z_to_Zone z')	Region From	Region To	Capacity	$/MW-yr	Line (Zone z_to_Zone z')	Region From	Region To	Capacity	$/MW-yr
ERC_REST_to_ERC_WEST	Texas	Texas	5,529	12,493	NY_Z_A_to_PJM_PENE	New York	Mid-Atlantic	500	16,410
ERC_REST_to_SPP_WEST	Texas	Central	600	18,005	PJM_WMAC_to_PJM_EMAC	Mid-Atlantic	Mid-Atlantic	6,900	23,014
ERC_WEST_to_ERC_PHDL	Texas	Texas	3,332	9,413	PJM_WMAC_to_PJM_SMAC	Mid-Atlantic	Mid-Atlantic	780	31,679
ERC_WEST_to_SPP_WEST	Texas	Central	220	20,194	PJM_WMAC_to_PJM_AP	Mid-Atlantic	Mid-Atlantic	-	23,837
FRCC_to_S_SOU	Florida	Southeast	3,600	23,751	PJM_WMAC_to_PJM_PENE	Mid-Atlantic	Mid-Atlantic	3,565	17,985
MIS_MAPP_to_MIS_MNWI	Midwest	Midwest	2,150	18,833	PJM_EMAC_to_PJM_SMAC	Mid-Atlantic	Mid-Atlantic	300	26,591
MIS_MAPP_to_SPP_WAUE	Midwest	Central	1,000	7,545	PJM_SMAC_to_PJM_AP	Mid-Atlantic	Mid-Atlantic	1,100	27,217
MIS_IL_to_MIS_INKY	Midwest	Midwest	956	6,559	PJM_SMAC_to_PJM_Dom	Mid-Atlantic	Mid-Atlantic	1,200	23,363
MIS_IL_to_MIS_IA	Midwest	Midwest	-	12,072	PJM_West_to_PJM_AP	Mid-Atlantic	Mid-Atlantic	4,800	15,665
MIS_IL_to_MIS_MIDA	Midwest	Midwest	716	14,149	PJM_West_to_PJM_COMD	Mid-Atlantic	Mid-Atlantic	980	23,488
MIS_IL_to_MIS_MO	Midwest	Midwest	3,400	6,153	PJM_West_to_PJM_ATSI	Mid-Atlantic	Mid-Atlantic	7,400	11,330
MIS_IL_to_PJM_West	Midwest	Mid-Atlantic	-	18,739	PJM_West_to_PJM_Dom	Mid-Atlantic	Mid-Atlantic	1,530	19,121
MIS_IL_to_PJM_COMD	Midwest	Mid-Atlantic	3,200	7,894	PJM_West_to_S_VACA	Mid-Atlantic	Southeast	1,219	17,700
MIS_IL_to_S_C_TVA	Midwest	Southeast	1,200	15,556	PJM_West_to_S_C_KY	Mid-Atlantic	Southeast	1,214	7,411
MIS_INKY_to_MIS_LMI	Midwest	Midwest	-	16,225	PJM_West_to_S_C_TVA	Mid-Atlantic	Southeast	2,119	19,794
MIS_INKY_to_PJM_West	Midwest	Mid-Atlantic	5,441	11,689	PJM_AP_to_PJM_ATSI	Mid-Atlantic	Mid-Atlantic	2,444	15,326
MIS_INKY_to_PJM_COMD	Midwest	Mid-Atlantic	2,044	10,763	PJM_AP_to_PJM_Dom	Mid-Atlantic	Mid-Atlantic	5,400	13,659
MIS_INKY_to_S_C_KY	Midwest	Southeast	2,245	8,583	PJM_AP_to_PJM_PENE	Mid-Atlantic	Mid-Atlantic	2,785	15,360
MIS_INKY_to_S_C_TVA	Midwest	Southeast	300	14,703	PJM_ATSI_to_PJM_PENE	Mid-Atlantic	Mid-Atlantic	-	23,806
MIS_IA_to_MIS_MIDA	Midwest	Midwest	1,616	2,765	PJM_Dom_to_S_VACA	Mid-Atlantic	Southeast	1,000	11,977
MIS_IA_to_MIS_MO	Midwest	Midwest	223	10,900	S_VACA_to_S_C_TVA	Southeast	Southeast	216	20,101
MIS_IA_to_MIS_WUMS	Midwest	Midwest	-	13,902	S_VACA_to_S_SOU	Southeast	Southeast	1,400	19,089
MIS_IA_to_MIS_MNWI	Midwest	Midwest	1,195	12,148	S_C_KY_to_S_C_TVA	Southeast	Southeast	764	13,332
MIS_IA_to_PJM_COMD	Midwest	Mid-Atlantic	-	10,729	S_D_AECI_to_S_C_TVA	Southeast	Southeast	-	23,120
MIS_IA_to_S_D_AECI	Midwest	Southeast	-	14,366	S_D_AECI_to_SPP_NEBR	Southeast	Central	-	25,834
MIS_IA_to_SPP_WAUE	Midwest	Central	-	18,503	S_D_AECI_to_SPP_N	Southeast	Central	1,130	16,108
MIS_MIDA_to_MIS_MO	Midwest	Midwest	716	11,934	S_D_AECI_to_SPP_WEST	Southeast	Central	1,172	18,363
MIS_MIDA_to_MIS_MNWI	Midwest	Midwest	-	12,200	S_D_AECI_to_SPP_WAUE	Southeast	Central	-	34,486
MIS_MIDA_to_PJM_COMD	Midwest	Mid-Atlantic	2,000	13,948	S_C_TVA_to_S_SOU	Southeast	Southeast	3,196	15,346
MIS_MIDA_to_S_D_AECI	Midwest	Southeast	-	15,237	SPP_NEBR_to_SPP_N	Central	Central	1,433	12,055
MIS_MIDA_to_SPP_NEBR	Midwest	Central	1,912	13,080	SPP_NEBR_to_SPP_WEST	Central	Central	-	24,082
MIS_MIDA_to_SPP_N	Midwest	Central	-	14,160	SPP_NEBR_to_SPP_WAUE	Central	Central	1,440	11,420
MIS_MIDA_to_SPP_WAUE	Midwest	Central	600	16,266	SPP_N_to_SPP_WEST	Central	Central	2,903	11,645
MIS_LMI_to_MIS_WUMS	Midwest	Midwest	-	12,033	SPP_N_to_SPP_SPS	Central	Central	469	19,046
MIS_LMI_to_PJM_West	Midwest	Mid-Atlantic	1,400	20,415	SPP_WEST_to_SPP_SPS	Central	Central	1,289	19,011
MIS_LMI_to_PJM_ATSI	Midwest	Mid-Atlantic	1,262	14,742	SPP_SPS_to_WECC_NM	Central	Southwest	610	12,448
MIS_MO_to_S_D_AECI	Midwest	Southeast	2,100	1,927	WEC_CALN_to_WECC_SCE	California	California	3,675	52,126
MIS_MO_to_SPP_N	Midwest	Central	300	14,417	WEC_CALN_to_WEC_BANC	California	California	2,750	11,013
MIS_WUMS_to_MIS_MNWI	Midwest	Midwest	1,480	12,639	WEC_CALN_to_WECC_NNV	California	Northwest	100	28,453
MIS_WUMS_to_PJM_COMD	Midwest	Mid-Atlantic	1,200	13,131	WEC_CALN_to_WECC_PNW	California	Northwest	3,675	54,715
MIS_MNWI_to_SPP_WAUE	Midwest	Central	2,000	14,648	WEC_LADW_to_WECC_SCE	California	California	3,750	13,977
MIS_WOTA_to_MIS_LA	Midwest	Midwest	1,200	11,717	WEC_LADW_to_WECC_SNV	California	Northwest	3,883	22,452
MIS_WOTA_to_SPP_WEST	Midwest	Central	-	26,035	WEC_LADW_to_WECC_UT	California	Northwest	1,400	50,774
MIS_AMSO_to_MIS_D_MS	Midwest	Midwest	200	14,794	WEC_LADW_to_WECC_PNW	California	Northwest	2,858	78,676
MIS_AMSO_to_MIS_LA	Midwest	Midwest	1,699	14,404	WEC_LADW_to_WECC_AZ	California	Southwest	468	46,156
MIS_AR_to_MIS_LA	Midwest	Midwest	1,732	21,170	WEC_SDGE_to_WECC_SCE	California	California	1,273	24,746
MIS_AR_to_S_D_AECI	Midwest	Southeast	1,039	19,737	WEC_SDGE_to_WECC_AZ	California	Southwest	1,168	34,905
MIS_AR_to_S_C_TVA	Midwest	Southeast	2,143	21,225	WEC_SDGE_to_WECC_IID	California	Southwest	150	13,016
MIS_AR_to_SPP_N	Midwest	Central	-	27,619	WECC_SCE_to_WECC_SNV	California	Northwest	2,814	16,731
MIS_AR_to_SPP_WEST	Midwest	Central	792	17,680	WECC_SCE_to_WECC_AZ	California	Southwest	1,968	37,252
MIS_D_MS_to_MIS_LA	Midwest	Midwest	1,732	13,498	WECC_SCE_to_WECC_IID	California	Southwest	600	30,099
MIS_D_MS_to_S_C_TVA	Midwest	Southeast	1,949	21,318	WECC_MT_to_WECC_ID	Northwest	Northwest	325	17,413
MIS_D_MS_to_S_SOU	Midwest	Southeast	94	23,067	WECC_MT_to_WECC_PNW	Northwest	Northwest	2,000	31,882
MIS_LA_to_S_SOU	Midwest	Southeast	797	34,673	WECC_MT_to_WECC_WY	Northwest	Northwest	400	22,311
MIS_LA_to_SPP_WEST	Midwest	Central	905	24,409	WECC_ID_to_WECC_NNV	Northwest	Northwest	350	20,628
NENG_CT_to_NENGREST	Northeast	Northeast	2,950	35,071	WECC_ID_to_WECC_UT	Northwest	Northwest	680	22,132
NENG_CT_to_NY_Z_G-I	Northeast	New York	600	17,030	WECC_ID_to_WECC_PNW	Northwest	Northwest	2,850	22,020
NENG_CT_to_NY_Z_K	Northeast	New York	760	19,019	WECC_ID_to_WECC_WY	Northwest	Northwest	1,500	23,989
NENGREST_to_NENG_ME	Northeast	Northeast	2,000	56,012	WECC_NNV_to_WECC_UT	Northwest	Northwest	235	17,742
NENGREST_to_NY_Z_F	Northeast	New York	800	22,290	WECC_NNV_to_WECC_PNW	Northwest	Northwest	300	30,536
NENGREST_to_NY_Z_D	Northeast	New York	-	34,272	WECC_SNV_to_WECC_UT	Northwest	Northwest	250	18,343
NY_Z_C&E_to_NY_Z_F	New York	New York	3,250	16,549	WECC_SNV_to_WECC_AZ	Northwest	Southwest	4,785	15,079
NY_Z_C&E_to_NY_Z_G-I	New York	New York	2,150	20,475	WECC_UT_to_WECC_CO	Northwest	Southwest	650	21,833
NY_Z_C&E_to_NY_Z_B	New York	New York	1,300	15,411	WECC_UT_to_WECC_WY	Northwest	Northwest	1,600	23,085
NY_Z_C&E_to_NY_Z_D	New York	New York	1,600	22,002	WECC_UT_to_WECC_AZ	Northwest	Southwest	250	22,653
NY_Z_C&E_to_PJM_PENE	New York	Mid-Atlantic	755	28,946	WECC_UT_to_WECC_NM	Northwest	Southwest	350	28,515
NY_Z_F_to_NY_Z_G-I	New York	New York	3,475	18,327	WECC_CO_to_WECC_WY	Southwest	Northwest	1,400	19,611
NY_Z_G-I_to_NY_Z_J	New York	New York	4,450	18,393	WECC_CO_to_WECC_NM	Southwest	Southwest	614	21,063
NY_Z_G-I_to_NY_Z_K	New York	New York	1,290	22,730	WECC_AZ_to_WECC_NM	Southwest	Southwest	2,400	18,922
NY_Z_J_to_NY_Z_K	New York	New York	175	19,249	WECC_AZ_to_WECC_IID	Southwest	Southwest	255	26,366
NY_Z_K_to_PJM_EMAC	New York	Mid-Atlantic	660	49,594					
NY_Z_A_to_NY_Z_B	New York	New York	1,930	8,844					

A.6 Policies

A.6.1 Inflation Reduction Act

Supplementary Table 8 shows our assumption on IRA (Inflation Reduction Act) Tax Credits per applicable technology. The Tax Credit Amounts/Percentages are obtained by getting the average of the lowest possible and highest possible tax credits that can be obtained. These values are taken from https://www.whitehouse.gov/cleanenergy/clean-energy-tax-provisions/. The tax monetization penalty is taken from the same assumptions in NREL's 2022 Standard Scenarios Report. These values are lower than the typical 33% tax monetization penalties assumed in existing models because of provisions in the IRA that make it easier to monetize tax credits (Gagnon et al., 2023).

Table 8: Inflation Reduction Act Tax Credit Assumptions

Technology	Tax Credit Type	Units	Amount	Tax Monetization Penalty	Final Tax Credit
Solar Photovoltaic	Production Tax Credit	$/MWh	9	10%	8.1
Onshore Wind Turbine	Production Tax Credit	$/MWh	9	10%	8.1
Batteries	Investment Tax Credit	Percentage	18%	10%	16.20%
Offshore Wind Turbine	Investment Tax Credit	Percentage	18%	10%	16.20%
Nuclear	Investment Tax Credit	Percentage	18%	10%	16.20%
Natural Gas CCS	Captured CO2 Incentive	$/MT	85	7.50%	78.63

A.6.2 Offshore Wind Mandates

We incorporate offshore wind mandates based on existing Bills/Acts in applicable states. These were obtained from NREL REeDS Assumptions in Table 3-21 (Ho et al., 2021) and from the California Energy Commission (CEC, 2022) and then assigned to the GenX zones based on the overlap of the zone with the state/s. The summarized information on the offshore wind mandates used in our model is found in Table 9. Any difference between the Mandate and the GenX minimum builds is due to the specified calculation in PowerGenome, which determines the maximum possible capacity of offshore wind in a zone. For California, the mandate is for 3.5GW of offshore wind generation capacity to be built by 2030 and 25GW by 2045. The 2035 mandate in the table is the linear extrapolation between these two values. The total minimum amount of offshore wind capacity is then 35GW by 2035.

Table 9: Offshore Wind Mandates

State	Bill/Act	Mandate (MW)	Implementation Year	GenX Zones	GenX Min Builds (MW)
Maryland	Senate Bill 516	1,200	2030		
	Maryland Offshore Wind Energy Act of 2013	368	2023	PJM_DOM	4,801
Virginia	Virginia Clean Economy Act	5,200	2035		
California	California Assembly Bill 525	10,200	2030	WECC_PNW WEC BANC WEC_CALN WEC_LADW	10,200
New Jersey	Executive Order No. 92	7,500	2035	PJM_EMAC	7,332
Connecticut	House Bill 7156	2,000	2030	NENG_REST	6,000
Massachusetts	Massachusets Energy Diversity Act	4,000	2027		
New York	Climate Leadership and Community Protection Act	9,000	2035	NY_Z_J	6,236

B Supplemental Experimental Procedures: Algorithms

B.1 Transmission Build Algorithms

B.1.1 Proportional Dual Algorithm

Within GenX, additional transfer capability can be built between two zones up to a set maximum value R_l for transmission line l.[3] In the Status Quo, R_l is set to 0 for all lines that connect zones

[3] R is used because adding transfer capability is also called "reinforcing" transmission.

located in different regions (i.e., $R_l = 0$ if $l_o \neq l_d$; consistent with the definition of the Status Quo). To satisfy the MITC requirement in the Fixed ITC scenario, R_l should be greater than 0 for some but not all interregional lines. That is, the maximum increase in transfer capability should be high enough such that the MITC requirements are met. However, since GenX is a cost optimization model, allowing $R_l > 0$ for all lines results in the model possibly building more than what the Fixed ITC requires. Maintaining our assumption that only enough transmission is built to satisfy the MITC requirement for each region necessitates a procedure to determine what R_l should be. The Proportional Dual Algorithm addresses this.

The Proportional Dual Algorithm is a procedure that increases R_l for all lines connected to a region proportional to the dual of each transmission constraint. This is done until MITC requirements for all regions can be met. Increasing R_l proportionally at the line with the *most negative dual* reflects a system cost optimizing preference that is consistent with the objective function of GenX. More concretely, the procedure is as follows:

Algorithm 1. *Proportional Dual Algorithm*

Let δ_r be the gap between the MITC of the region r and the model's current ability to meet the requirement. It is initialized as $\delta_r = MITC_r - \sum_{l \in \hat{\mathcal{L}}_r} (\hat{c}_l + R_l)$ for all r. Define the dual of the transmission constraint on line l in model Status Quo as d_l.

1. *Obtain $\delta_r^* = \max\{\delta_r\}$*
2. *Set $R_l' = R_l + \frac{|d_l|\delta_r^*}{\sum_{l \in \hat{\mathcal{L}}_r} |d_l|}$ for each $l \in \hat{\mathcal{L}}_r$*
3. *Set $R_l = R_l'$ for each $l \in \hat{\mathcal{L}}_r$*
4. *Recalculate $\delta_r = MITC_r - \sum_{l \in \hat{\mathcal{L}}_r} (\hat{c}_l + R_l)$ for all r*
5. *If $\exists \delta_r > 0$, go back to step 1. Otherwise, stop.*

The alternative to the Proportional Dual algorithm is to use the *Iterative Dual Algorithm.* The Iterative Dual Algorithm iteratively increases the maximum line reinforcement of a line with the most negative dual by a small amount each time and re-evaluates the solution. The heuristic stops once all regions meet the MITC.

Algorithm 2. *Iterative Dual Algorithm*

Let $\epsilon > 0$ be a user input on how much each line will be increased for every iteration

1. *Solve the problem and obtain the duals d_l of each line*
2. *Obtain $l^* = \arg\max(l | d_l$ and $\delta_r > 0$ for $l \in \hat{\mathcal{L}}_r)$*
3. *Set $R_l' = R_l + \epsilon$*
4. *If $\exists \delta_r > 0$, go back to step 1. Otherwise, stop.*

We note that the Proportional Dual algorithm can lead to non-cost optimal transmission build outs. This is because dual values change at every increment of the right-hand side in a linear programming model, but the algorithm makes the maximum line reinforcements increase simultaneously. To get the cost-optimal build-outs, the Iterative Dual algorithm can be used such that it increases R_l for the line with the most negative dual by a small amount, one line at a time. The optimization problem is then re-evaluated with the slightly larger R_l, and the procedure is repeated until all MITC requirements are met. It is computationally intensive, however, because of the re-evaluation that happens at each iteration. For higher MITC values, the calculation time extends to several days and in some cases several weeks. Comparing the two approaches, we contend that the Proportional Dual algorithm reflects a more realistic scenario of how regions decide to build and satisfy the MITC requirements. It reflects the regions' strategic decisions to simultaneously build transmission given economic signals (i.e., the duals). The only action that it will consider is that other regions will also be building transmission, but they will not wait for each transmission line to be built before building their own. On the other hand, the iterative dual algorithm assumes regions have perfect information on the impact of transmission builds between regions and that each one will wait for specific lines to be built before making their own decision. This unrealistic assumption and the computational complexity of the Iterative Dual algorithm shifted our preference to the Proportional Dual algorithm. As a comparison, we show the transmission builds between the Proportional Dual and the Iterative Dual algorithms in Fig. 9

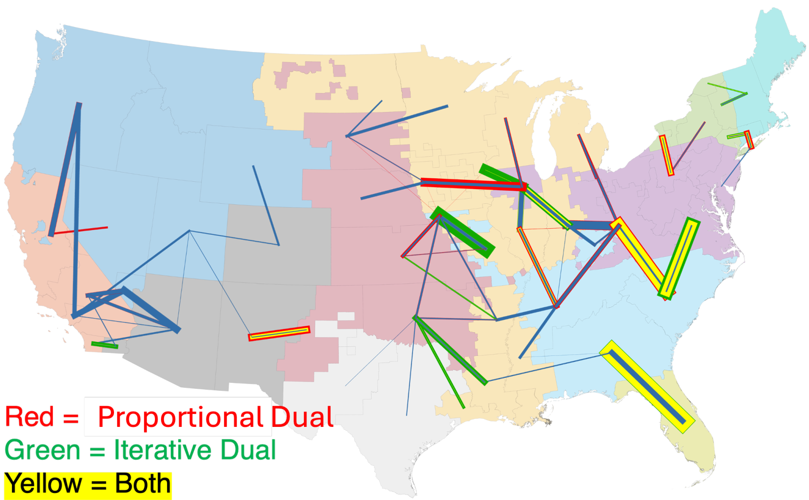

Figure 9: **Map of existing and new interregional transfer capability between zones based on transmission build algorithm.** Both algorithms build in the Southeast-Florida and Southeast-Mid-Atlantic connections. Some portion of the Southwest-Central and Mid-Atlantic-New York connections are also captured.

Another alternative algorithm is the *Greedy Algorithm*. The Greedy Algorithm works in the same way as the Proportional Dual Algorithm, except it uses the current interregional transmission capacity ($\hat{c}_l$) between regions instead of the dual as the basis for calculating the proportion of additional transmission capacity that gets allocated to a line. Since this is obviously going to lead to a poorer solution, we opt to not show comparisons with the Proportional Dual nor the Iterative Dual algorithms.

Algorithm 3. ***Greedy Algorithm***

1. *Obtain* $\delta_r^* = \max\{\delta_r\}$

2. *Set* $R_l' = R_l + \frac{|\hat{c}_l|\delta_r^*}{\sum_{l\in\hat{\mathcal{L}}_r}|\hat{c}_l|}$ *for each* $l \in \hat{\mathcal{L}}_r$

3. *Set* $R_l = R_l'$ *for each* $l \in \hat{\mathcal{L}}_r$

4. *Recalculate* $\delta_r = MITC_r - \sum_{l\in\hat{\mathcal{L}}_r}(\hat{c}_l + R_l)$ *for all* r

5. *If* $\exists\delta_r > 0$*, go back to step 1. Otherwise, stop.*

B.2 Extreme Event Simulation Methodology

We model an extreme weather event's impact on a power system as a $q_{y,r}$ percentage of capacity outages for technology type y at region r. While we assume that outages occur in a region, the methodology can be easily adjusted to apply to zones (i.e. instead of $q_{y,r}$ the percentage of outages will be $q_{y,z}$, where z is a zone. We implemented it to simulate outages similar in scale to Winter Storm Uri with all generation technologies in Texas experience outages at a level of 43% for coal, 21% nuclear, 7% PV, 46% wind, and 50% natural gas (Levin et al., 2022; Busby et al., 2021; FERC, 2021). We isolated each region and simulated each at an outage level at the percentages indicated. The outage amount is based on the final capacity of each technology in the region following optimization using GenX. This is done across MITC % values: $p \in \{0\%, 30\%, 65\%\}$ for the Fixed and Optimal ITC cases to enable comparisons across scenarios. We then run GenX as a dispatch model 1,000 times while including these random outages for each region and MITC % combination from Feb 13 to 17 of the model year (i.e., 120 hours – the duration and dates of Winter Storm Uri). The random outages were present in each simulated dispatch, and the average non-served energy across the 120 hours and 1,000 simulations was calculated. The hourly percentage increase in load varies and is based on the method used by Botterud et al. (2024). Fig. 10 shows the hourly increase.

The aim of this methodology is to create a distribution of the region's average non-served energy during extreme weather events and obtain the overall average non-served energy across the entire distribution. This distribution is obtained by repeatedly simulating random generator outages in the region. In each simulation iteration, outages are assigned based on uniform, random draws from the set of eligible generators. The capacity of this generator is reduced by a set percentage, and the process is repeated until the specified total capacity experiencing an outage is met. This process is rigorously illustrated using the following heuristic:

Algorithm 4. ***Generator Outage Allocation Algorithm***

Let $\hat{C}_{y,r}$ *be the total capacity of technology* y *that experiences an extreme weather event outage in region* r*. It is calculated as* $\hat{C}_{y,r} = a_{y,r}q_{y,r}$ *where* $a_{y,r}$ *is the total generation capacity of* y *in* r*. In the heuristic, this will also be used to track the amount of capacity outages that has already been allocated to generators. Let* $\mathcal{G}_{y,r}$ *be the set of all generator units of type* y *found in* r*. This set contains unique generator IDs,* g*. Let* $\psi \in (0, 1)$ *be a fixed capacity percentage that remains from a chosen generator. Finally, let* C_g *be the remaining, unaffected capacity of generator* g*. It is initialized as the existing capacity of* g*.*

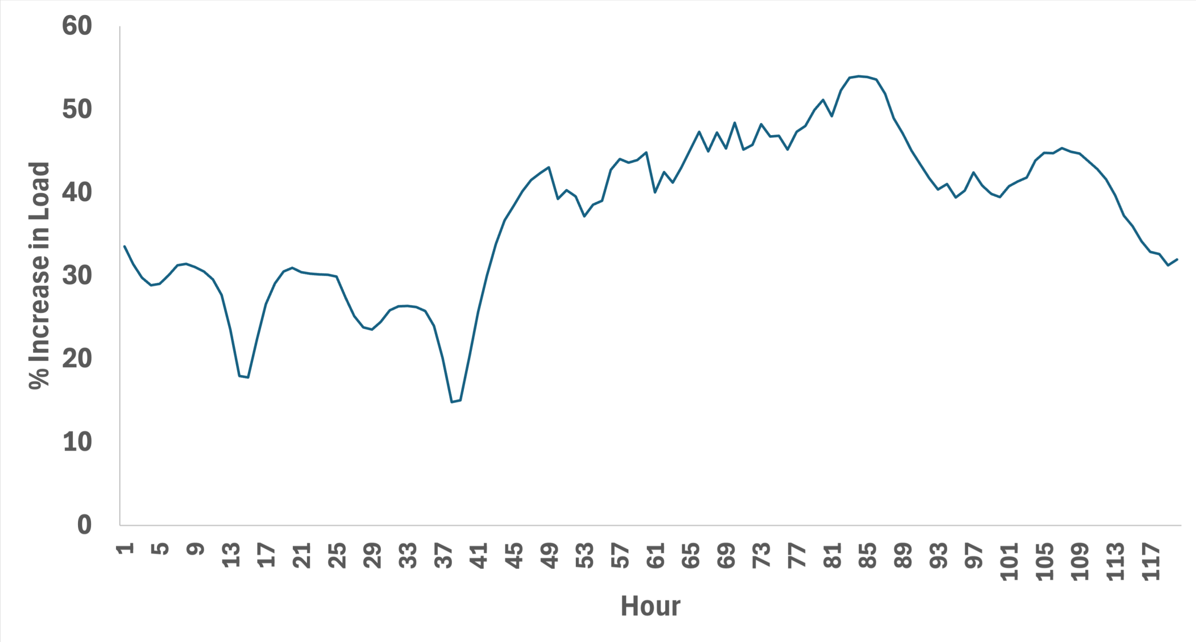

Figure 10: **Hourly Percent increase in load for the Extreme Event Simulation Methodology.** The average increase in load is 37%. The methodology of Botterud et al. (2024) scales the Texas load data in 2035 according to the increase that it would have experienced in Winter Storm Uri. For each hour from Feb 13 – 17, 2021, we divided the Winter Storm Uri load by the average load of the same hour in 2019, 2020, and 2022. In the hours where load shed occurred, we used forecasted load as the denominator.

1. *If $\hat{C}_{y,r} > 0$, proceed to Step 2. Otherwise, stop.*

2. *Draw a generator $g \in \mathcal{G}_{y,r}$ according to a uniform distribution.*

3. *Set $C'_g = \min(\psi C_g, \hat{C}_{y,r})$ and $\hat{C}'_{y,r} = \hat{C}_{y,r} - (C'_g - \min(\psi C_g, \hat{C}_{y,r}))$*

4. *Set $C_g = C'_g$ and $\hat{C}_{y,r} = \hat{C}'_{y,r}$. If $C_g = 0$, remove g from $\mathcal{G}_{y,r}$ (i.e. $\mathcal{G}_{y,r} = \mathcal{G}_{y,r}/\{g\}$). Go back to Step 1.*

The output of an iteration i of Algorithm 4 is a set $\mathcal{C}_{y,r,i} = \{(g, C_g)|g \in \mathcal{G}_{y,r}\}$ where each element is a vector of the generator and its remaining capacity. C_g replaces the original capacity for g in GenX. A dispatch model over a specified time interval denoted by $\mathcal{T} = [t^{\text{start}}, t^{\text{end}}]$ is then run, where t^{start} and t^{end} denote the start and end hours of the extreme event simulation. We calculate the mean of the non-served energy $N\bar{S}E_i$ resulting from this dispatch model as $N\bar{S}E_i = \frac{\sum_{t \in \mathcal{T}} NSE_{t,i}}{t^{\text{end}} - t^{\text{start}} + 1}$, where $NSE_{t,i}$ is the non-served energy in t at iteration i. Algorithm 4 is then repeated across an I number of iterations and the overall average non-served energy is calculated as $N\bar{\bar{S}}E = \frac{N\bar{S}E_i}{I}$.

C Proposed Transmission Infrastructure Bills from 2023 to 2024

In this section, we briefly describe the proposed transmission infrastructure bills in the U.S. Congress from 2023 to 2024. We note that The BIG WIRES Act (S.2827 - 118th Congress), CETA Act (H.R.6747 - 118th Congress), and Connect the Grid Act (H.R.7348 - 118th Congress)

– three out of the six proposed transmission infrastructure bills from 2023 to 2024 – all include transfer capability requirements as provisions. Two – the Energy Permitting Reform Act (S.4753 - 118th Congress) and the Reinforcing the Grid Against Extreme Weather Act (H.R.9362 - 118th Congress) – require that transfer capability requirements be determined by a centralized entity. While some proposed bills cover a wide-array of energy-related topics such as offshore wind mandates, natural gas permits, and rate-making, we focus the descriptions on the components that are related to interregional transmission.

The BIG WIRES Act (S.2827 - 118th Congress): The Building Integrated Grids With Inter-Regional Energy Supply (BIG WIRES) Act is a bill that was introduced in 2023 and co-sponsored by Senator John Hickenlooper (D-CO) and Rep. Scott Peters (D-CA). It requires every FERC Order No. 1000 region to increase its interregional transfer capability to the minimum between 30% of a region's peak load and 15% of a region's peak load plus its current transfer capability. The BIG WIRES Act included provisions to describe how to measure current transfer capability in order to standardize across all regions. (https://www.congress.gov/bill/118th-congress/house-bill/5551)

CETA Act (H.R.6747 - 118th Congress): The Clean Electricity and Transmission Acceleration (CETA) Act was introduced in 2024 by Rep. Sean Casten (D-IL) and Rep. Mike Levin (D-CA). It requires every FERC Order No. 1000 region to increase its interregional transfer capability to 30% of a region's peak load if it borders two or more other regions, and 15% if it borders only one. That means that all regions except the Northeast and Florida will have an MITC of 30% which will have 15% MITC. CETA also provides Transmission Tax Credits ranging from 6 to 30% to eligible transmission lines. (https://www.congress.gov/bill/118th-congress/house-bill/6747)

Connect the Grid Act (H.R.7348 - 118th Congress:) The Connect the Grid Act was proposed by Rep. Greg Casar (D-TX) in 2024. It requires ERCOT to meet a pre-defined range of interregional transfer capabilities with its three neighbors. Namely, between 4.3 to 12.6GW with SPP, 2.5 to 16.2GW with MISO, and 2.6 to 7.9GW with the Western Interconnect. (https://www.congress.gov/bill/118th-congress/house-bill/6747)

Reinforcing the Grid Against Extreme Weather Act (H.R.9362 - 118th Congress): The Reinforcing the Grid Against Extreme Weather Act was proposed by Rep. Sean Casten (D-IL) in 2024. It gives authority to FERC to determine the required amount of interregional transmission to be built between neighboring regions. The required amount should be set such that *transmission benefits* are obtained. These transmission benefits range from cost, reliability, emissions, and security improvements among others. (https://www.congress.gov/bill/118th-congress/house-bill/9362)

Energy Permitting Reform Act (S.4753 - 118th Congress): The Energy Permitting Reform Act was proposed by Sen. Joe Manchin (I-WV) and Sen. John Barrasso (R-WY) in 2024. It gives FERC more authority in approving transmission projects. For example, it proposes to give FERC the authority to approve proposed transmission builds even without a NIETC designation. (https://www.congress.gov/bill/118th-congress/senate-bill/4753)

D Supplemental Results

D.1 Transmission Builds

Tables 10 and 11 show the transmission builds per pair-wise regional corridor while Tables 12 and 13 show the transfer capability per region. We assume that the MITC is met if 99% of the requirement is met. This was done to avoid rounding and feasibility errors in the programming language used. We see that in some cases, the regions build more transfer capability than what the MITC requires. To illustrate, consider Florida, which is connected solely to the Southeast. To meet Florida's MITC requirement, the Southeast may need to build more transfer capability than its own MITC would require. This demonstrates that a uniform MITC percentage across regions does not imply uniform transmission expansions, as interregional transmission inherently involves two regions. Building capacity across a corridor increases transfer capability for both regions, necessitating overbuilding in some cases.

Table 10: Interregional Transmission builds for the Current Policies Scenario (in GW)

		30% MITC				65% MITC			
		Fixed ITC		Optimal ITC		Fixed ITC		Optimal ITC	
Regions	Existing	Additional	Total	Additional	Total	Additional	Total	Additional	Total
California-Northwest	14.73	1.73	16.46	0.00	14.73	19.98	34.71	0.00	14.73
California-Southwest	4.35	0.25	4.60	0.43	4.79	2.66	7.01	0.85	5.21
Northwest-Southwest	7.44	-	7.44	0.63	8.07	0.57	8.00	8.16	15.60
Southwest-Central	0.61	4.48	5.09	10.01	10.62	11.83	12.44	15.95	16.56
Southeast-Central	2.30	1.68	3.98	0.00	2.30	1.58	3.89	1.84	4.14
Florida-Southeast	3.60	8.25	11.85	0.00	3.60	17.92	21.52	1.90	5.50
Mid-Atlantic-Midwest	16.55	9.52	26.06	6.86	23.41	29.87	46.42	36.09	52.64
Mid-Atlantic-New York	1.92	4.34	6.25	0.00	1.92	10.09	12.01	0.39	2.31
Mid-Atlantic-Southeast	5.55	14.91	20.46	3.67	9.23	22.65	28.20	9.48	15.04
Midwest-Central	7.51	1.07	8.58	21.60	29.10	6.68	14.19	40.92	48.43
Midwest-Southeast	11.87	2.80	14.66	10.33	22.20	13.76	25.63	31.64	43.51
Northeast-New York	2.16	4.50	6.66	0.00	2.16	9.78	11.94	0.14	2.30
	78.58	53.53	132.11	53.53	132.11	147.37	225.95	147.37	225.95

Table 11: Interregional Transmission builds for the 95% CO_2 Reduction Scenario (in GW)

		30% MITC				100% MITC			
		Fixed ITC		Optimal ITC		Fixed ITC		Optimal ITC	
Regions	Existing	Additional	Total	Additional	Total	Additional	Total	Additional	Total
California-Northwest	14.73	1.51	16.24	0.00	14.73	29.10	43.83	0.06	14.79
California-Southwest	4.35	0.47	4.83	0.02	4.37	6.52	10.88	0.58	4.93
Northwest-Southwest	7.44	-	7.44	0.26	7.70	3.22	10.65	12.74	20.18
Southwest-Central	0.61	3.25	3.86	8.21	8.82	13.48	14.09	17.77	18.38
Southeast-Central	2.30	2.36	4.66	0.00	2.30	7.39	9.69	4.32	6.62
Florida-Southeast	3.60	8.25	11.85	3.59	7.19	27.59	31.19	9.20	12.80
Mid-Atlantic-Midwest	16.55	7.46	24.01	17.99	34.54	24.88	41.43	76.81	93.36
Mid-Atlantic-New York	1.92	12.85	14.76	1.54	3.46	43.39	45.30	2.21	4.12
Mid-Atlantic-Southeast	5.55	8.46	14.01	2.18	7.73	28.19	33.74	9.71	15.26
Midwest-Central	7.51	1.87	9.38	18.68	26.19	7.74	15.25	70.69	78.20
Midwest-Southeast	11.87	13.92	25.79	11.97	23.83	44.98	56.85	45.22	57.09
Northeast-New York	2.16	4.50	6.66	0.48	2.64	15.06	17.22	2.24	4.40
	78.58	64.91	143.49	64.91	143.49	251.54	330.13	251.54	330.13

Table 12: Transfer Capability per region for the Current Policies Scenario (in GW)

			30% MITC					65% MITC				
				Fixed ITC		Optimal ITC			Fixed ITC		Optimal ITC	
	Peak Load	Existing	MITC	Additional	Total	Additional	Total	MITC	Additional	Total	Additional	Total
California	70.93	19.08	21.28	1.98	21.07	0.43	19.52	42.14	22.63	41.72	0.85	19.94
Florida	55.80	3.60	11.97	8.25	11.85	0.00	3.60	21.74	17.92	21.52	1.90	5.50
Northeast	30.47	2.16	6.73	4.50	6.66	0.00	2.16	12.06	9.78	11.94	0.14	2.30
Midwest	157.51	35.92	47.25	13.39	49.31	38.79	74.71	87.11	50.32	86.24	108.65	144.58
Northwest	65.75	22.17	19.72	1.73	23.90	0.63	22.80	42.74	20.55	42.71	8.16	30.33
New York	33.64	4.08	9.12	8.84	12.92	0.00	4.08	15.01	19.87	23.95	0.53	4.60
Mid-Atlantic	195.35	24.01	53.32	28.77	52.78	10.54	34.55	87.50	62.61	86.63	45.97	69.98
Southeast	160.27	23.32	47.36	27.64	50.96	14.00	37.33	75.41	55.91	79.23	44.86	68.18
Central	59.67	10.42	17.90	7.23	17.65	31.60	42.02	29.81	20.09	30.51	58.71	69.13
Southwest	47.17	12.40	14.15	4.73	17.13	11.07	23.47	27.73	15.05	27.45	24.97	37.37

Table 13: Transfer Capability per region for the 95% CO_2 Reduction Scenario (in GW)

			30% MITC					100% MITC				
				Fixed ITC		Optimal ITC			Fixed ITC		Optimal ITC	
	Peak Load	Existing	MITC	Additional	Total	Additional	Total	MITC	Additional	Total	Additional	Total
California	70.93	19.08	21.28	1.98	21.07	0.02	19.10	54.55	35.63	54.71	0.63	19.72
Florida	55.80	3.60	11.97	8.25	11.85	3.59	7.19	31.50	27.59	31.19	9.20	12.80
Northeast	30.47	2.16	6.73	4.50	6.66	0.48	2.64	17.39	15.06	17.22	2.24	4.40
Midwest	157.51	35.92	47.25	23.26	59.18	48.64	84.56	114.68	77.61	113.53	192.72	228.64
Northwest	65.75	22.17	19.72	1.51	23.68	0.26	22.43	55.04	32.32	54.49	12.80	34.96
New York	33.64	4.08	9.12	17.35	21.43	2.02	6.09	20.90	58.45	62.52	4.44	8.52
Mid-Atlantic	195.35	24.01	53.32	28.77	52.78	21.71	45.73	121.69	96.46	120.47	88.73	112.74
Southeast	160.27	23.32	47.36	32.99	56.31	17.73	41.05	103.46	108.14	131.47	68.46	91.78
Central	59.67	10.42	17.90	7.48	17.90	26.88	37.30	40.26	28.61	39.03	92.78	103.20
Southwest	47.17	12.40	14.15	3.73	16.12	8.49	20.89	35.98	23.22	35.62	31.09	43.49

D.2 Additional Cost Results

D.2.1 System Cost Sensitivity Analysis

We test the sensitivity of the system cost to varying Transmission and Policy Assumptions. Fig. 11 shows the results. We find that across the different assumptions, the shape of the Fixed ITC cost curve relative to the Optimal ITC cost curve remains the same. That is, the Optimal ITC consistently results in lower cost proportional to the cost that was assumed in the base case. This shows that our results are robust to these assumptions.

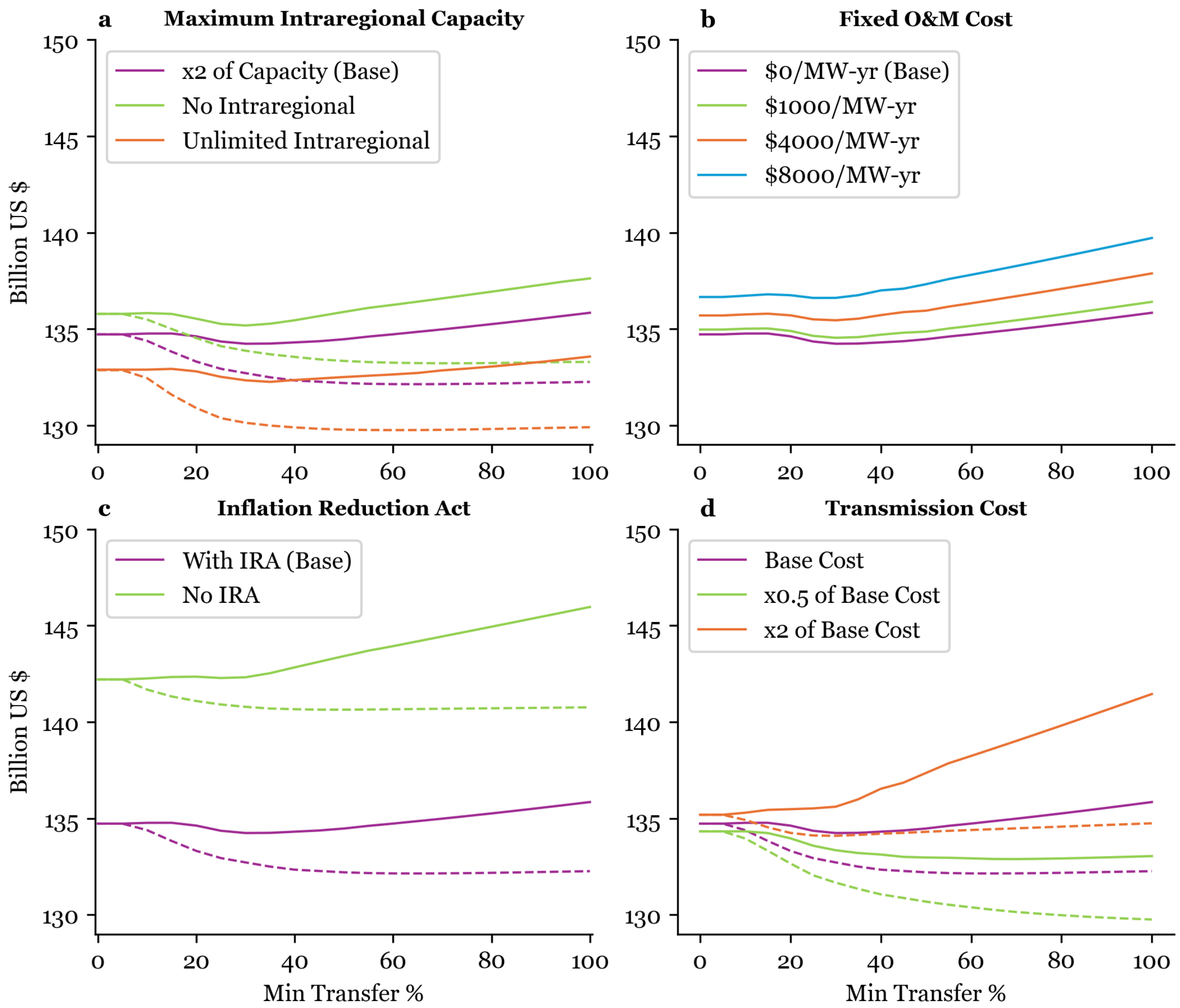

Figure 11: **a – d, Total system cost for the Current Policies Scenario at varying assumptions for Transmission Cost and Policies.** The solid lines represent the Fixed ITC and the dashed lines represent the Optimal ITC. The purple line represents the base case and what is used and referenced in the main text. **(a)** shows the results when changing the assumption on how much intraregional transmission can be built between each zone. **(b)** shows the results if a fixed O&M costs for existing and new transmission lines are incurred. **(c)** shows the impact of not implementing the IRA in the model. **(d)** shows the results for various assumptions on the cost of building transmission.

D.2.2 Cost Differences

This section shows the cost differences for the 65% and 100% scenarios per cost component in Fig. 12. The insights remain the same as in the 30% scenario, however, the magnitude of where savings or additional spending occur is larger. This is because more transmission is built both in the Fixed and Optimal ITC scenarios at higher MITC requirement levels.

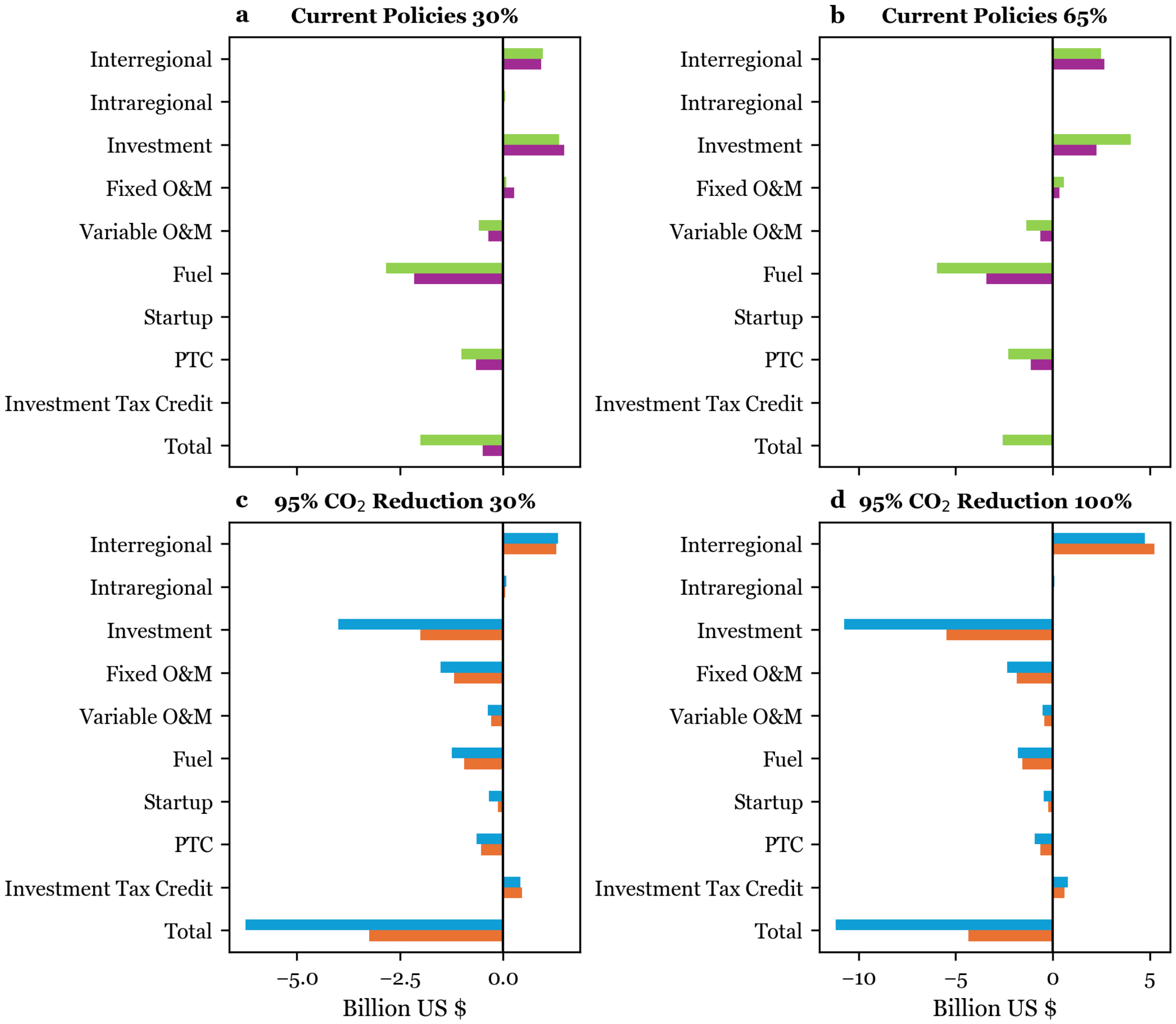

Figure 12: **a – d, Cost Difference between the Status Quo and the Fixed and Optimal ITC scenarios at the specified MITC % per cost component for each decarbonization scenario.** The insights for the 65 % and 100% MITC scenarios are similar to the 30% MITC scenario. **(a)** and **(c)** are the same as the graphs in Fig. 2 in the Main text.

D.3 Electricity Flows

Next, we will provide an analysis of the changing regional import and export interactions between regions in the Current Policies, Fixed ITC Scenario. Fig. 13 shows the net exports and imports for varying MITC %. In the Current Policies setting, we find that all regions retain their status as a net exporter or net importer. Regions stay at relatively similar magnitudes of net exports and imports than compared to the Status Quo. However, some notable exceptions can be observed. The Southeast relies more on imports from neighboring regions, increasing its net import of electricity from 29.25 TWh to 82.47 TWh. The Central and Midwest regions – with their quality wind resources – export more to other regions in the Fixed ITC scenario. Both see net exports increasing from 31.67 TWh and 3.09 TWh to 63.30 TWh and 25.98 TWh, respectively, when $p = 30\%$. The Northwest, while still a net exporter, is the only net exporting region that sees its exports decline because of the MITC.

We also report the net export and import in each corridor in Tables 14 and 15 for the Current

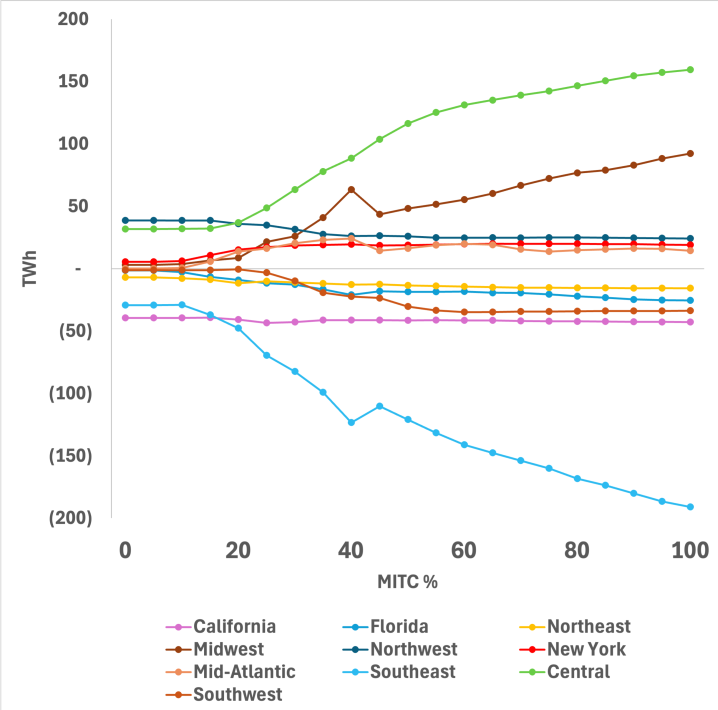

Figure 13: **Total Electricity Net Export (Import) per Region in the Current Policies, Fixed ITC scenario.**

Policies and 95% CO_2 Reduction Scenarios, respectively. In the Current Policies scenario, the Southeast imports triple the amount from the Mid-Atlantic in the Fixed ITC scenario from 19.66 TWh to 61.83 TWh. This is also the case with the Midwest, where imports increase from 8.85 TWh to 25.07 TWh. The Southeast further imports more power from Central at 8.41 TWh compared to the Status Quo scenario of 2.03 TWh. New York becomes a net exporter to the Mid-Atlantic, where previously it was a net importer. The added transfer capability between Central and the Southwest results in a more than ten-fold increase in Central's electricity exports to the Southwest from 1.97 TWh to 21.17 TWh.

Comparing this with the Optimal ITC cases, we see that even at the 30% MITC requirement, the Midwest imports 177TWh from Central and exports 71TWh to the Southeast. This highlights how transmission is able to access Central's wind resources.

Table 14: Net Export (Import) per corridor for the Current Policies Scenario (in TWh)

From	To	Status Quo	30% Fixed ITC	30% Optimal ITC	65% Fixed ITC	65% Optimal ITC
California	Northwest	(27.86)	(26.42)	(25.99)	(24.17)	(26.87)
California	Southwest	(11.54)	(16.44)	(17.40)	(17.39)	(19.37)
Northwest	Southwest	10.73	5.08	(1.43)	0.68	(27.34)
Central	Southwest	1.98	21.17	50.76	51.54	87.40
Southeast	Central	(2.04)	(8.41)	(4.71)	(11.93)	(10.54)
Florida	Southeast	(1.30)	(12.84)	(6.75)	(19.33)	(18.33)
Midwest	Mid-Atlantic	20.99	33.79	31.59	50.28	97.37
New York	Mid-Atlantic	(1.49)	7.70	(1.65)	5.07	(1.67)
Mid-Atlantic	Southeast	19.66	61.83	32.55	74.52	50.10
Midwest	Central	(26.75)	(32.87)	(177.22)	(70.65)	(310.08)
Midwest	Southeast	8.85	25.07	71.05	80.51	181.96
Northeast	New York	(6.97)	(10.99)	(7.00)	(14.88)	(7.91)
Central	Texas	0.94	0.85	0.81	1.02	0.66

Table 15: Net Export (Import) per corridor for the 95% CO_2 Reduction Scenario (in TWh)

From	To	Status Quo	30% Fixed ITC	30% Optimal ITC	100% Fixed ITC	100% Optimal ITC
California	Northwest	(61.46)	(59.44)	(58.43)	(52.43)	(41.89)
California	Southwest	(7.09)	(4.52)	(7.29)	0.63	(15.34)
Northwest	Southwest	22.92	21.15	19.31	11.86	(20.80)
Central	Southwest	2.27	18.21	50.07	60.81	106.43
Southeast	Central	(8.98)	(20.24)	(10.13)	(38.80)	(16.93)
Florida	Southeast	(10.62)	(51.76)	(26.33)	(124.69)	(67.65)
Midwest	Mid-Atlantic	20.07	20.59	64.33	20.06	187.21
New York	Mid-Atlantic	3.47	25.58	8.32	18.42	5.93
Mid-Atlantic	Southeast	(0.83)	14.62	12.36	(7.36)	31.51
Midwest	Central	(20.73)	(30.93)	(138.12)	(74.11)	(489.79)
Midwest	Southeast	5.59	52.64	71.93	164.29	255.66
Northeast	New York	(3.16)	(6.12)	(6.39)	(25.48)	(16.58)
Central	Texas	(0.12)	(0.19)	0.38	0.09	0.08

D.4 Capacity and Generation Mix

Figures 14 and 15 show the total ending capacity and generation, respectively for each region and decarbonization scenario.

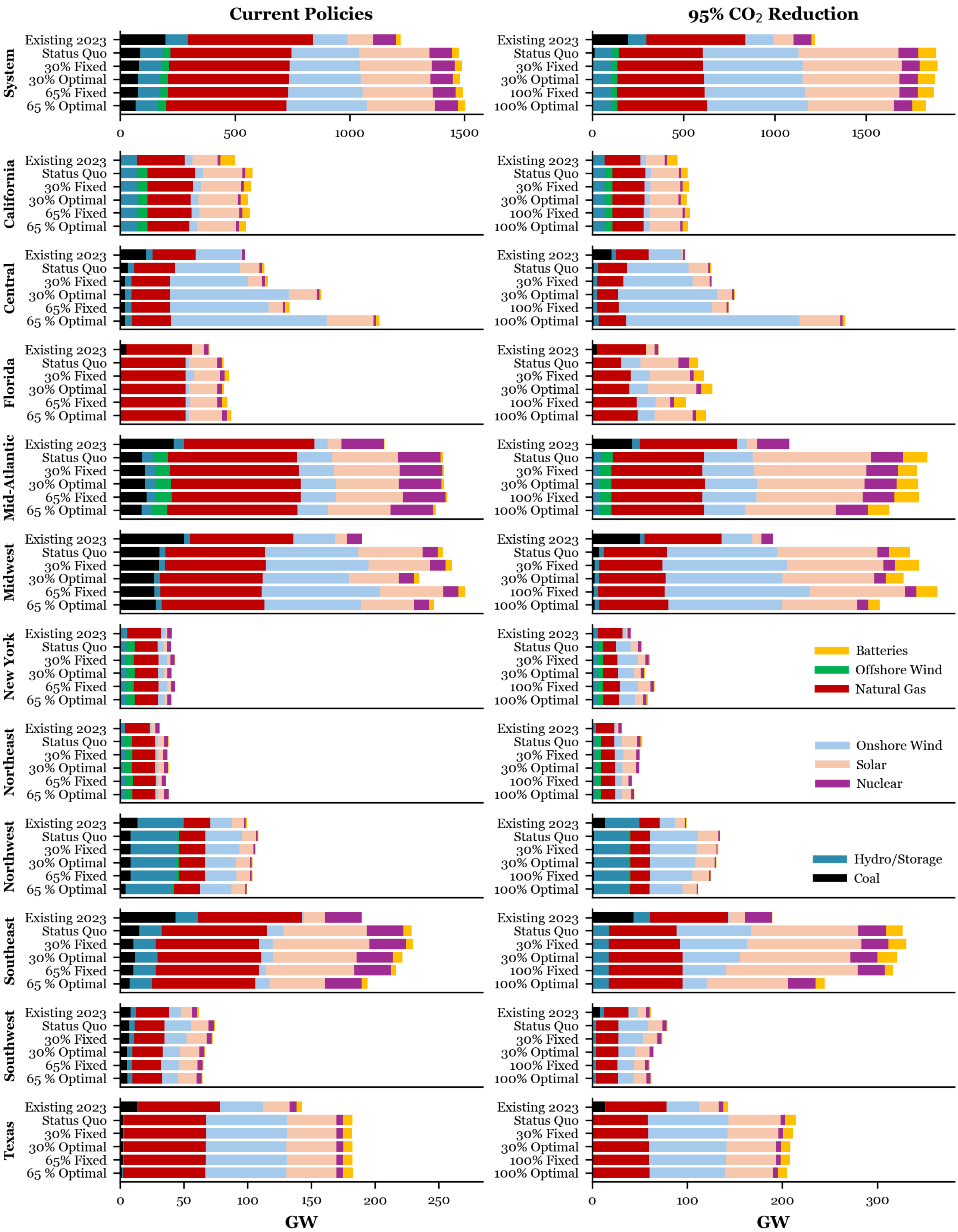

Figure 14: **Capacity Mix per ITC and Decarbonization Scenario.** Existing 2023 capacity is the starting capacity input in GenX. System is the sum of all regions. Note the difference in scale for System and the regional breakdown.

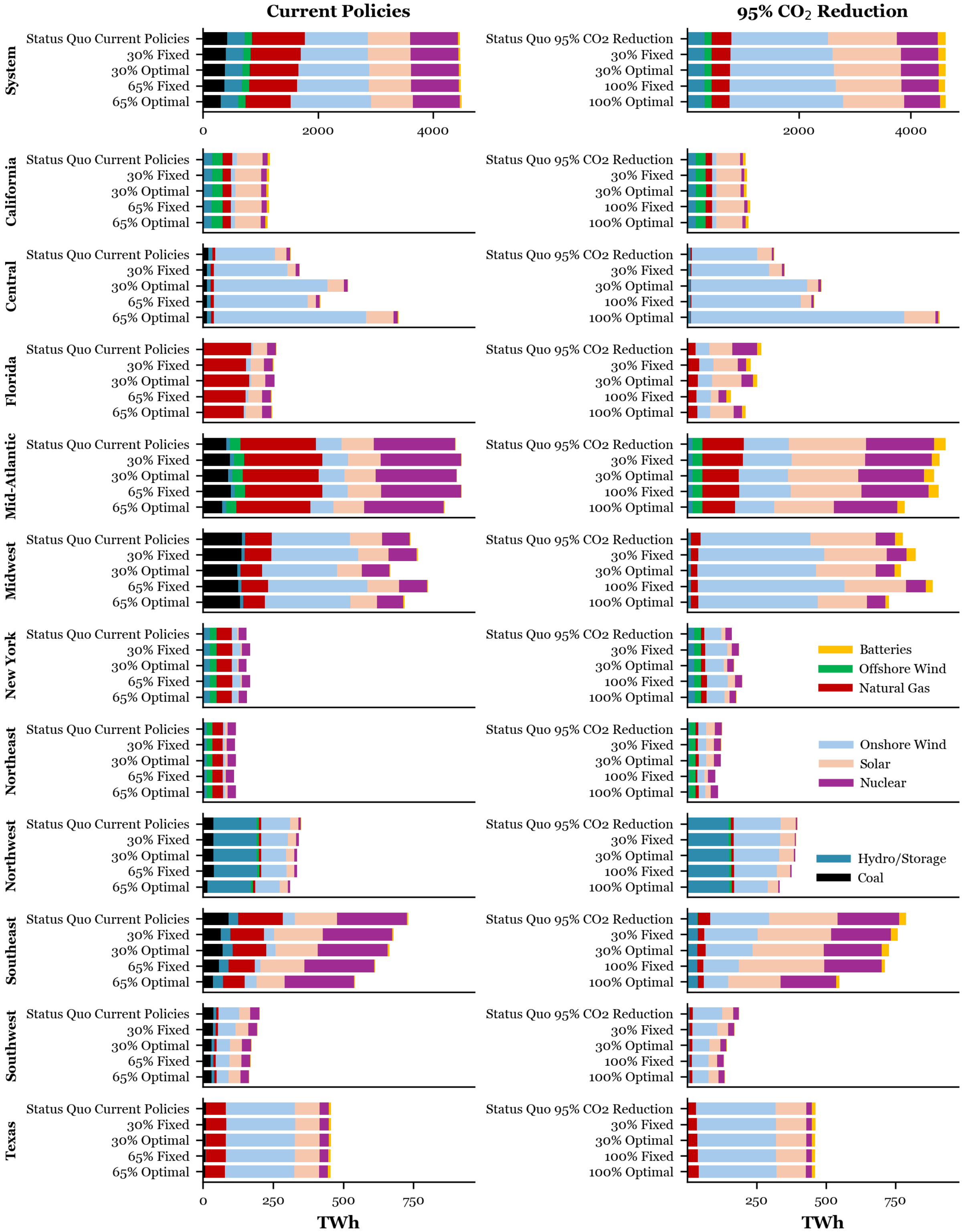

Figure 15: **Generation Mix per ITC and Decarbonization Scenario.** Note the difference in scale for System and the regional breakdown.