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Abstract

As a central element of its climate policy agenda, the Biden Administration has declared a goal to decarbonize the national power system by 2035. This ambitious goal will require an accelerated substitution of fossil fuel with renewable generation over the next decade. In this paper, we assess options for rapid decarbonization of the power system with a focus on coal-reliant states across the midcontinent, where a diversity of entities share responsibility for maintaining a reliable and affordable supply of electricity. In our analysis, we utilize a capacity expansion model to characterize the region and evaluate the impact of decarbonization policies such as carbon pricing and renewable energy mandates on prices, operations, costs, and emissions. We define decarbonization objectives in such a way that the most stringent scenarios, calling for emission reductions above 85% or more align with the Administration's carbon-free goal by 2035. Our detailed modeling allows us to estimate annual hourly profiles of relevant outputs: prices, power generation, renewable curtailments, and plant cycles. All decarbonization scenarios involve wind and solar generation displacing coal and fuel oil power plants to a greater or lesser extent, depending on the level of decarbonization and the type of policy. Natural gas generation remains in the system to support the integration of renewable generation, again to a greater or less extent, depending on the level of decarbonization and the type of policy. Nuclear generation remains central if the policy is to be cost efficient. Batteries remain a marginal technology. These levels of renewable penetration produce important challenges system managers will have to meet in order to maintain reliability. Decarbonization creates more volatility in system marginal cost, with more scarcity hours and more hours of zero or negative marginal cost. This suggests a need for implementation of capacity mechanisms to reduce perceived risks in financing capacity. Finally, we observe that a specific decarbonization policy can generate local distress for certain entities, e.g. cooperatives, suggesting a need for cooperation and agreement among all relevant stakeholders, potentially flanked by compensation payments.

1. Introduction

A variety of forces have been transforming generation supply stacks across the U.S. midcontinent over the last decade or more. Prime among these have been the persistently low price of natural gas and the falling cost of renewables, especially wind power. Continuing tax incentives and other public support for renewable investments has also played a part, as have tightened air pollution regulations. Stagnant power demand has kept wholesale prices low. Many coal and nuclear assets have taken hits to their valuations. Some have been retired early and more may be retired in the coming years.[1]

Going forward, a powerful driver of the transformation may be policies to reduce carbon emissions. On January 20, 2021, the U.S. is rejoining the Paris Agreement, and in April, President Biden updated the country's nationally determined contribution (NDC), pledging to reduce carbon emissions 50%-52% by

[1] Mills et al. (2021), Haratyk (2017), Jenkins (2018) and U.S. Department of Energy (2017). See also the annual State of the Market reports for SPP, MISO and PJM.

2030 as compared with 2005 levels.[2] The administration aims for a carbon-free electricity system by 2035.[3] Achieving that goal will be challenging, as 60% of the U.S. generation supply stack is fueled by coal, natural gas and petroleum, 1.66 TW of capacity in all.[4] New investments will be needed, whether in the form of new, zero-carbon generation that can substitute for retiring fossil assets, or by retrofitting fossil assets to capture and sequester the carbon. Of course, there is significant political conflict over these decarbonization goals and policies, and no one can reliably predict what policies may ultimately be implemented. Unsurprisingly, some states have already filed a lawsuit against the President's Executive Order setting out an ambitious agenda of further policies and regulations.

The decarbonization challenge will be especially great in the midcontinent where the share of coal-fired generation is significant. As Table 1 shows, coal generation exceeds 25% in the majority of these states, and in several it surpasses 50%. At the same time, wind potential is significant in many of these states. Where wind potential is lower, there is good solar potential. Some states are home to nuclear plants, which are zero-carbon, but financially challenged in the current market context. Many states have no nuclear plants. This stakeholder diversity may lead to resistance and slower adoption of decarbonization policies.

	Generation [GWh]	Coal share	Natural gas share	Carbon-free share	Wind potential [GW]	Solar potential
North Dakota	41,147	61%	4%	35%	296	Low
South Dakota	14,507	18%	8%	74%	418	Low
Nebraska	37,298	55%	3%	42%	465	Low to Fair
Kansas	50,888	34%	6%	60%	506	Fair
Oklahoma	85,217	9%	52%	39%	359	Fair
Minnesota	59,379	30%	21%	48%	183	Low
Iowa	62,650	35%	12%	52%	280	Low
Missouri	78,279	71%	10%	19%	279	Low to Fair
Arkansas	64,443	36%	34%	30%	162	Fair
Louisiana	100,175	7%	69%	18%	57	Fair to High
Mississippi	65,959	7%	74%	19%	115	Fair
Wisconsin	62,774	42%	32%	25%	114	Low
Illinois	184,470	26%	12%	62%	191	Low
Michigan	116,701	32%	30%	36%	81	Low
Indiana	102,505	59%	31%	7%	118	Low
Ohio	120,001	39%	43%	17%	119	Low
Kentucky	71,804	72%	21%	6%	151	Low
Tennessee	82,327	23%	21%	57%	116	Low to Fair

Table 1. Total generation [GWh]; coal, natural gas and carbon-free generation mix shares [%] (EIA); wind potential (NREL WINDEXCHANGE) and solar potential (own definition after NREL NSRDB).

A large number of studies have examined different aspects of decarbonization pathways, including the National Academies (2021), Larson et al. (2021), Farbes et al. (2020), Seel et al. (2018), and Wiser et al.

[2] https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/United%20States%20of%20America%20First/United%20States%20NDC%20April%2021%202021%20Final.pdf
[3] Executive Order 14008: Tackling the Climate Crisis at Home and Abroad, January 27, 2021.

https://www.federalregister.gov/documents/2021/02/01/2021-02177/tackling-the-climate-crisis-at-home-and-abroad
[4] The Energy Information Administration (EIA) quantified the amount of electricity originated from carbon-free sources at 40% in 2020, of which 20% are from nuclear plants and 20% from renewable generation. https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php

(2017). Unsurprisingly, a primary feature of most pathways is the closing of coal plants and large-scale investments in new wind and solar generation. Some studies identify the need to expand transmission capacity alongside the scale-up of renewable generation. A key challenge is how to finance the expansion of renewables as well as the needed balancing resources, such as peaking natural gas units. The changing mix of technologies alters the pattern of wholesale market prices, producing lower average wholesale energy prices, increased price volatility and many hours of very low prices. Flexible capacity is required, but utilization is low. Ancillary services become more valuable.

This study examines the situation across the U.S. midcontinent, encompassing a set of power systems stretching from Ohio in the east to the plain states in the west, and from Minnesota in the north to Louisiana in the south—full details are provided in the Methodology section below. We focus on a near-term horizon of 2030, where the tradeoffs are between already commercially available technologies utilizing the existing transmission grid. We use a capacity expansion and dispatch model configured to examine the task of serving the fluctuating hourly load throughout a full year given the fluctuating availability of renewable resources. With it, we explore the impact of decarbonization on the generation mix, operations, and costs, as well as the impact of different policies to achieve the same decarbonization goal.

Under our cost assumptions, we find that a $25/ton carbon price yields a 77% emission reduction relative to 2018 levels. The dramatic reduction comes from a large-scale closure of coal plants, investments in new wind and solar capacity, and from preservation of existing nuclear plants. Indeed, we simultaneously see some additions of natural gas capacity. The increase in the system cost required to achieve this emission reduction is $6 billion annually or $3.79/MWh of load, relative to the system cost without a carbon price. We also find that policies focused exclusively on expanding renewable generation are more costly because they preserve some coal plants while also displacing natural gas plants, and because they lead to the widespread closure of the nuclear fleet.

The next section on "Methodology", briefly describes the elements of the model, the input data, and the scenarios we selected for examination. The "Results" section presents and compares the results for the various scenarios with a particular focus on generation, capacity mix, prices, costs, and carbon emissions. We then discuss our modeling caveats in the "Limitations of the study" section, and, finally, we conclude with a policy discussion and enumerate areas for improvement to further refine the results and conclusions.

2. Methodology

We employed an open-source model[5] parameterized with widely used public data sources and with familiar policy scenarios. GenX is a configurable capacity expansion planning and hourly dispatch modeling tool. The model provides a mix of electricity generation and storage investments, and operational decisions to meet electricity demand in a representative year at the lowest cost subject to a variety of power system operational constraints and specified policies. The model can be configured with a variety of features and detail depending upon the modeler's needs for a particular problem. In what follows, we provide a basic description of our configuration and refer the reader to the more complete model description (Jenkins and Sepulveda, 2017).

[5] The model is available at https://energy.mit.edu/genx/#code

We apply GenX to a full hourly representation of the year, reflecting the variability of load and renewable resources. The model operates with perfect foresight to select a mix of capacity that can serve load in all hours.[6] We do not model uncertainty in this variability across years.

Regional structure and transmission

The system we model is made up of 18 regions. Figure 1 locates them geographically.

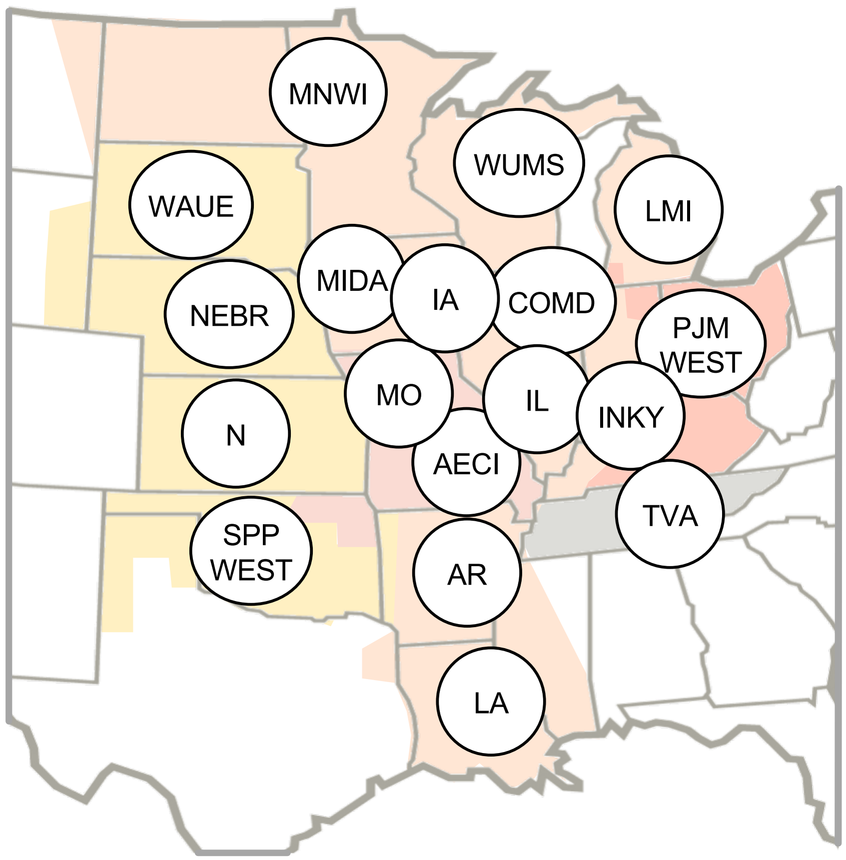


Figure 1: Geographical scope and balancing areas.

These regions will be how we organize the location of generation and load, and the transmission links. As shown in Table 2, we build them from 61 regions in the National Renewable Energy Laboratory's (NREL) Regional Energy Development System (ReEDS) model. The aggregation of ReEDS regions is chosen so that our 18 regions approximately align with regions in the Integrated Planning Model (IPM) used by the U.S. Environmental Protection Agency.[7] In a few cases, that alignment is with an aggregation of two or four IPM regions.

The ReEDS regional boundaries do not conform precisely with the boundaries of the different wholesale markets, such as SPP, MISO or PJM. In a few cases we adjusted the regional data so that all generators

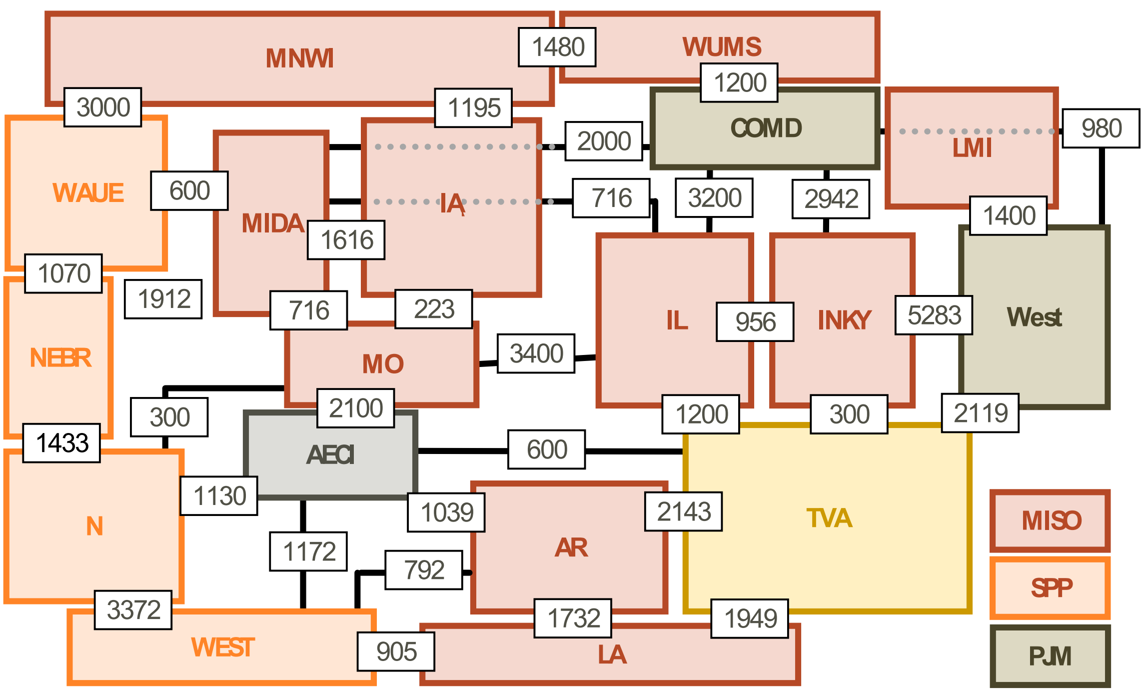
[6] The model allows for non-served energy at a penalty. Our parameterization results in very few hours of non-served energy.
[7] https://www.epa.gov/airmarkets/integrated-planning-model-ipm-results-viewer

within each region are dispatched into the same wholesale market. We detail these adjustments in supplementary materials.

GenX Model Region Number	Label	Building Block ReEDS Regions	Approximately aligned with IPM Regions
1	MIS_INKY	105, 106, 107, 108	MIS_INKY
2	MIS_MNWI	42, 43, 44, 46, 68, 19, 35, 36, 37	MIS_MNWI + MIS_MAPP
3	MIS_LMI	103	MIS_LMI
4	MIS_AR	85	MIS_AR
5	MIS_LA	58, 86, 66, 87	MIS_LA + MIS_AMSO + MIS_D_MS + MIS_WOTA
6	MIS_IA	69, 70	MIS_IA
7	MIS_WUMS	74, 75, 76, 77, 78, 79	MIS_WUMS
8	MIS_IL	81, 82, 83	MIS_IL
9	MIS_MIDA	45	MIS_MIDA
10	MIS_MO	71, 72, 73	MIS_MO
11	SPP_WEST	50, 51, 56, 57, 47, 49	SPP_WEST + SPP_SPS
12	SPP_N	52, 53, 55	SPP_N
13	SPP_NEBR	39, 40, 41	SPP_NEBR
14	SPP_WAUE	38	SPP_WAUE
15	S_C_TVA	88, 89, 92, 93	S_C_TVA
16	S_C_AECI	54, 84	S_C_AECI
17	PJM_WEST	104, 110, 112, 113, 114, 117, 118	PJM_WEST
18	PJM_COMD	80	PJM_COMD

Table 2: Correspondence Between our System Regions and ReEDS and IPM Regions.

We model the transmission capacity between regions as shown in Figure 2. The transfer capacity values are taken from the IPM[8].



[8] https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-november-2018-reference-case

Figure 2: Transmission transfer capacity (MW) between regions.

We assume these capacities are fixed. We do not explore expanding the transmission network.

This study is based on a single load balancing area for each region, which means that there is enough transmission capacity to accommodate intra-regional power flows in each region. Our stylized and simplified (N-1) representation of the network reasonably captures the amount of energy that can flow in reality, although fails in characterizing the challenges of operating the real network, as we do not represent real-time operations to respond to unexpected load conditions, supply or transmission contingency events.

Generation technologies

We model seven major categories of generation technologies, distinguished by fuel: coal, natural gas, fuel oil, nuclear, hydro, wind and solar. We also include the small quantity of legacy bio fueled generation in the model, but since it is a trivial factor in the calculations we do not mention it again. We model two types of storage technologies: pumped hydro and lithium-ion batteries. We do not capture the storage value of existing reservoir hydro, treating it the same as run-of-river hydro. We do not model any demand response.

Within the categories of thermal technologies, there are finer distinctions, such as between pulverized coal and gasification or between combustion turbines and combined cycle, and between plants of varying efficiency. Ultimately, these distinctions are reduced to differences in heat rates, minimum turndown ratios, and non-fuel operating costs, including start-up costs. Within the categories of renewable technologies, there are finer distinctions reflecting the varying quality of the renewable resource.[9] For each category of technology in each region, we choose the number of buckets (or clusters) in order to balance the numerical complexity of the model while maintaining realistic granularity in results.

The system is endowed with a set of legacy assets, and the model will determine a set of additions and retirements. For retirements, we focus on coal, natural gas, fuel oil and nuclear plants. For additions, we focus on natural gas (both combined cycle and combustion turbine), wind, solar and batteries. We keep hydro assets fixed.

Data sources

We first use the model parameterized for 2018, and then we run a number of scenarios parameterized for 2030. For 2018, the data sources are as follows:

- The set of legacy assets in each region, and their operating characteristics and costs are taken from ReEDS which, in turn, sources this material from the EIA's National Energy Modeling System (NEMS). This data is already organized into clusters by region. In some cases, we created a coarser clustering as detailed in supplementary materials.
- The hourly load profiles by region are based on the regional hourly profiles reported in the IPM, updated to match FERC data on 2018 annual load.[10]

[9] All of our solar assets are utility scale PV. We do not include distributed solar.

[10] https://www.epa.gov/sites/production/files/2019-03/table_2-2_load_duration_curves_used_in_epa_platform_v6.xlsx

- The hourly wind and solar resource profiles by region are taken from IPM.[11] For hydro, we use the monthly generation data in ReEDS.
- The hourly fuel cost profiles are constructed to match the average annual fuel costs in each region as reported in ReEDS and to mimic the calendar patterns reported in S&P Global Market Intelligence. Although the profiles are hourly, the calendar patterns are available on a weekly basis for natural gas and a monthly basis for coal.
- The CO_2 emission rates for fossil fuels taken from the EIA are natural gas: 53.07 kg/MMBtu, coal-bit: 93.30 kg/MMBtu, coal-sub: 97.20 kg/MMBtu, and fuel oil: 73.16 kg/MMBtu. We assume the coal plants in the PJM-WEST region use bituminous coal while all others use sub-bituminous.

For 2030, the data sources are as follows:

- The set of legacy assets in each region is updated to 2030 per ReEDS.
- The investment and non-fuel operating costs for new assets are from NREL's 2020 Annual Technology Baseline (ATB). We then create regional ranges based on the EIA's 2021 Annual Energy Outlook. The investment costs range for natural gas combined cycles, 815-1115 \$/kW, and combustion turbines, 609-818 \$/kW; wind turbines, 1044-1601 \$/kW; solar panels, 729-821 \$/kW; and batteries, 627-658 \$/kW.
- The load profiles are updated to match the EIA's Reference Case projection for load in each region: MISO-E: 7.20%; MISO-C: 8.04%; MISO-W: 7.68%; MISO-S: 11.04%; PJM-E: 4.32%; PJM-W: 8.40%; SPP-S: 11.40%; SPP-C: 6.96%; SPP-N: 7.80%; SERC: 10.56%. We retain the same hourly profile patterns used for 2018.
- The levels of the fuel cost profiles are updated to reflect the EIA's Reference Case projection: for natural gas, 3.60 \$/MMBtu (+5.9% increase with respect to 2018); coal, 1.88 \$/MMBtu (–8.0%); and fuel oil, 11.24 \$/MMBtu (–31.3%).

Notably, comparing the legacy assets for 2018 and 2030, ReEDS shows 23.3 GW of expected retirements in coal, fuel oil, nuclear and gas power plants and 12.5 GW of expected additions of wind and solar assets. Coal accounts for about 73% of the fossil-fuel retirements, while wind represents over 95% of the additions.

With respect to renewable resources, we included several wind profiles within each region with different hourly capacity factors in order to reflect the diversity in resource quality and variability. We also imposed an upper limit on the potential wind deployment following the U.S. DOE assessment that, for example, reflects a potential several orders of magnitude greater than our estimates. Moreover, the capacity factors play a key role in determining which renewable resource will be economical. Although diverse, the number of hourly renewable profiles is still reduced. This may lead the model to opt for additions to a single technology in a region, when common sense may expect deployments of more than a renewable technology, even if in a minor amount. This effect is diluted systemwide, however.

[11] https://www.epa.gov/sites/production/files/2019-03/table_4-39_wind_generation_profiles_in_epa_platform_v6.zip
https://www.epa.gov/sites/production/files/2019-03/table_4-43_solar_photovoltaic_generation_profiles_in_epa_platform_v6.xlsx

Policy scenarios

Across such a large region encompassing many state governments and even more electric utilities, there are innumerable combinations of policies that could be pursued. We use our model to highlight a couple of key insights across a couple of dimensions.

One dimension is the depth of decarbonization. We explore this dimension in three steps. First, we analyze a 2030 Reference Case which includes existing state-level renewable and clean energy targets but does not include any further decarbonization policies. The contrast between this 2030 Reference Case and the 2018 Case helps to calibrate the decarbonization impetus already embedded in our cost assumptions and in existing policies. Second, we analyze a 2030 Low Cost case, in which we further reduce the forecasted capital cost of renewables: wind (regionally, between –28% and –38%) and solar (–18%) generation, as well as the cost of Li-Ion batteries (–31%). This helps to calibrate the impact of further changes in costs without any further policy drivers. Third, we analyze three levels of further decarbonization driven by policy.

Our initial analysis of policy-driven decarbonization assumes the policy is cost efficient. That is, we search for capacity substitutions and redispatches that produce the largest reductions in emissions at the least cost—i.e., we start with the lowest marginal abatement cost. This is also equivalent to running our cost minimizing model with a uniform carbon price throughout the entire region and calculating optimal investment and dispatch in the face of this carbon price. In point of fact, this is how we implement the cost efficient decarbonization scenario. However, the scenario need not be realized through use of a carbon price. These scenarios represent economic baselines against which to understand other, more likely, mosaics of state and federal policies which attempt to achieve comparable levels of decarbonization at reasonable cost.

The three levels of decarbonization are described by the percent decrease in emissions and by the corresponding carbon price level.

- An approximately 75% emissions reduction corresponds to a $25/t carbon price. This lies midway between the California-Québec Auction Reserve Price—about 36 $/ton in 2030[12]—and the Regional Greenhouse Gas Initiative expected carbon price in 2030—in the range of 11 $/ton (Emission Containment Reserve trigger price) and 24 $/ton (Cost Containment Reserve trigger price)[13].
- An approximately 80% emissions reduction corresponds to a $50/t carbon price. This scenario is the proposed U.S. social cost of carbon for regulatory impact analysis under the Biden administration's Executive Order 12866 as projected to 2030. This price also coincides with the credit for carbon sequestration by 2026, as set in the Internal Revenue Code, Section 45Q(b).
- An approximately 90% emissions reduction corresponds to a $100/t carbon price. This scenario represents the 2C pathway as suggested by the High-Level Commission on Carbon Prices for 2030 in the OECD regions (CPLC, 2017)

The second dimension is the technology focus. Different decarbonization policies impact various technologies differently. A uniform carbon price is sometimes called technology neutral: carbon

[12] https://icapcarbonaction.com/en/?option=com_etsmap&task=export&format=pdf&layout=list&systems[]=73
[13] https://icapcarbonaction.com/en/?option=com_etsmap&task=export&format=pdf&layout=list&systems[]=50

emissions are the only metric. However, in practice, we know that some technologies vary by their carbon intensity, so a uniform carbon price is rightly targeting those technologies that have the greatest carbon intensity. Other policies pursue a different technology focus. A renewable portfolio standard, for example, treats equally all fossil fuel technologies with no regard for their differing carbon intensity. A renewable portfolio standard also favors certain zero-carbon technologies, such as wind and solar, but not others, such as nuclear.

As with the uniform carbon price, a uniform renewable portfolio standard is unlikely to be applied across the entire region. These two cases produce economic baselines against which to understand other mosaics of state and federal policies which may produce similar results. For example, uniform federal subsidies to renewables produce similar supply-side effects of a regionwide renewable portfolio standard.[14] A collection of state-based renewable portfolio standards and utility renewable pledges will have some similar results, but with important differences for embedding different standards geographically.

To draw out the consequences of this type of technology focus, we analyze two levels of renewable portfolio standards applied across the entire system: Intense Renewable Mandate, 60%; and Extreme Renewable Mandate, 75%. We also examine the 60% renewable mandate combined with a policy to preserve the nuclear fleet.

To summarize, for 2030 we produce eight main scenarios:

- 2030 Reference Case
- 2030 Low-Cost Renewables Case
- 2030 Carbon Price (uniform)
    - 75% emission reduction / $25 per ton
    - 85% emission reduction / $50 per ton
    - 90% emission reduction / $100 per ton
- 2030 Renewable Portfolio Standard (regionwide)
    - 42% emission reduction / RPS = 60%
    - 64% emission reduction / RPS = 75%
    - RPS = 60% plus preservation of nuclear fleet

Model

The objective function minimizes the annualized capital cost and fixed O&M costs, the fuel and other variable O&M and start-up costs, and the (undesired) non-served energy cost:

[14] The GenX model is primarily a supply-side model which takes load as given and does not account for how increasing the price of electricity moves the system along the demand curve to lower load. Even when GenX includes demand response it is shifting demand between periods. One of the benefits of carbon pricing is its effects on the demand side. See, for example, Holland et al. (2009). Our calculations do not include these cost savings for a carbon tax.

$$\min \sum_{z,g} \left(C^{I}_{g,z} \cdot Q^{U}_{g,z} \cdot \Delta x_{g,z} + CF^{O\&M}_{g,z} \cdot \left(X_{g,z} + Q^{U}_{g,z} \cdot \left(\Delta x_{g,z} - \nabla x_{g,z} \right) \right) \right)$$
$$+ \sum_{z,g,t} \left(\left(C^{Fuel}_{g,z} + CV^{O\&M}_{g,z} \right) \cdot q^{+}_{g,t,z} \right) + \left(CV^{O\&M}_{g,z} \cdot q^{-}_{g,t,z} \right) + \left(C^{SU}_{g,z} \cdot v_{g,t,z} \right)$$
$$+ \sum_{z,t} \left(C^{NSE} \cdot q^{NSE}_{t,z} \right) + \sum_{t} \left(C^{NSR} \cdot \left(\hat{r}^{+}_{t} + \hat{r}^{-}_{t} \right) \right)$$

The demand balance constraint guarantees that the sum of thermal, battery, renewable and hydro generation satisfies the withdrawals from hydro pumping units and batteries, power flows leaving the reference zone, and the electricity demand. When both terms are unequal, the non-served energy reduces the electricity demand:

$$\sum_{g} q^{+}_{g,t,z} = \sum_{g} q^{-}_{g,t,z} + \sum_{l} \varphi^{map}_{l,z} \cdot f_{l,t} + D_{t,z} - q^{NSE}_{t,z} \quad \forall t, z$$

The unit commitment and cycling—startup and shutdown—of thermal generators replicates the integer clustering technique developed in Palmintier and Webster (2014). This clustering implies that the state variable for each commitment varies from zero to the number of existing units in the cluster. Although the computational efficiency improves, it simplifies all units within the same cluster to feature uniform characteristics—capacity size, heat rate or ramping rates—, and identical power output.

The net installed thermal capacity in a cluster limits the number of plants that are committed, started up, and shut down at any given time:

$$u_{g,t,z} \leq \frac{X_{g,z}}{Q^{U}_{g,z}} + \Delta x_{g,z} - \nabla x_{g,z} \quad \forall g \in \mathcal{UC}, t, z$$
$$v_{g,t,z} \leq \frac{X_{g,z}}{Q^{U}_{g,z}} + \Delta x_{g,z} - \nabla x_{g,z} \quad \forall g \in \mathcal{UC}, t, z$$
$$w_{g,t,z} \leq \frac{X_{g,z}}{Q^{U}_{g,z}} + \Delta x_{g,z} - \nabla x_{g,z} \quad \forall g \in \mathcal{UC}, t, z$$
$$u_{g,t,z} = u_{g,t-1,z} + v_{g,t,z} - w_{g,t,z} \quad \forall g \in \mathcal{UC}, t, z$$

The maximum and minimum (stable) output levels are equally limited for all clustered thermal generators. The ramping down (up) limit—calculated as the difference of power output between two consecutive hours—must be less than or equal to the feasible ramp-down (-up) rate from the committed units in the time step. This term hence subtracts the additional units within the cluster that may start during the time step. In fact, the effect on the ramping constraints of the non-committed—starting-up or shutting-down—units at the beginning or end of the period, respectively, must be accounted for individually. This effect is opposite since starting-up (shutting-down) units entail an additional effort from the ramping-down (-up) units within the cluster. Whereas the effect is favorable when shutting-down (starting-up) units collaborate in the ramping-down (-up) operation.

$$q^{+}_{g,t-1,z} - q^{+}_{g,t,z} \leq \quad Q^{U}_{g,z} \cdot \begin{pmatrix} R^{down}_{g,z} \cdot \left(u_{g,t,z} - v_{g,t,z}\right) - \underline{\rho}_{g,z} \cdot v_{g,t,z} \\ + \max\left(\underline{\rho}_{g,z}, R^{down}_{g,z}\right) \cdot w_{g,t,z} \end{pmatrix} \quad \forall g \in \mathcal{UC}, t, z$$

$$q^{+}_{g,t,z} - q^{+}_{g,t-1,z} \leq \quad Q^{U}_{g,z} \cdot \begin{pmatrix} R^{up}_{g,z} \cdot \left(u_{g,t,z} - v_{g,t,z}\right) - \underline{\rho}_{g,z} \cdot w_{g,t,z} \\ + \max\left(\underline{\rho}_{g,z}, R^{up}_{g,z}\right) \cdot v_{g,t,z} \end{pmatrix} \quad \forall g \in \mathcal{UC}, t, z$$

The thermal clustered units must also respect the minimum up- and down-time, that limits the time steps before one unit can start up (shut down) after shutting down (starting up):

$$u_{g,t,z} \geq \sum\nolimits_{\hat{t}=t-T^{up}_{g,z}}^{t} v_{g,t,z} \quad \forall g \in \mathcal{UC}, t, z$$

$$\left(\frac{X_{g,z}}{Q^{U}_{g,z}} + \Delta x_{g,z} - \nabla x_{g,z}\right) - u_{g,t,z} \geq \sum\nolimits_{\hat{t}=t-T^{down}_{g,z}}^{t} w_{g,t,z} \quad \forall g \in \mathcal{UC}, t, z$$

The renewable power production, which includes solar, wind and run-of-river hydro energy, is a function of the availability factor and the installed capacity, allowing curtailments to guarantee the balance between the generation and demand:

$$q^{+}_{g,t,z} \leq \overline{\rho}_{g,t,z}\left(X_{g,z} + \Delta x_{g,z} - \nabla x_{g,z}\right) \quad \forall g \in \mathcal{R}, t, z$$

A simple inventory model characterizes the operation of storage technologies: pumped-hydro plants and electrochemical storage devices. These are parametrized by the charging and discharging efficiencies, and a fixed power-to-energy ratio. Because GenX is an hourly model, the inverse of this ratio represents the number of hours to discharge completely the storage unit from full state of charge.

The following set of equations models the storage operation. The storage level at the end of the time step depends on the previous storage level plus the injections minus the withdrawals. Both are corrected by the charging and discharging efficiency. The maximum storage level, in MWh, is constrained by the maximum installed capacity, in MW, after applying the power-to-energy ratio. The maximum installed capacity also limits the charging and discharging rate. In addition, the injection and withdrawal rates cannot exceed the available storage capacity and storage level during the time step, respectively.

$$s_{g,t,z} - s_{g,t-1,z} = \eta^{up}_{g,z} \cdot q^{-}_{g,t,z} - \frac{q^{+}_{g,t,z}}{\eta^{down}_{g,z}} \quad \forall g \epsilon \mathcal{S}, t, z$$

$$s_{g,t,z} \leq \frac{1}{\eta^{P2E}_{g,z}} \cdot \left(X_{g,z} + Q^{U}_{g,z} \cdot \left(\Delta x_{g,z} - \nabla x_{g,z}\right)\right) \quad \forall g \epsilon \mathcal{S}, t, z$$

$$q^{-}_{g,t,z} \leq \frac{1}{\eta^{up}_{g,z}} \cdot \left(X_{g,z} + Q^{U}_{g,z} \cdot \left(\Delta x_{g,z} - \nabla x_{g,z}\right)\right) \quad \forall g \epsilon \mathcal{S}, t, z$$

$$q^{+}_{g,t,z} \leq \eta^{down}_{g,z} \cdot \left(X_{g,z} + Q^{U}_{g,z} \cdot \left(\Delta x_{g,z} - \nabla x_{g,z}\right)\right) \quad \forall g \epsilon \mathcal{S}, t, z$$

$$q^{-}_{g,t,z} \leq \frac{1}{\eta^{P2E}_{g,z}} \cdot \left(X_{g,z} + Q^{U}_{g,z} \cdot \left(\Delta x_{g,z} - \nabla x_{g,z}\right)\right) - s_{g,t,z} \quad \forall g \epsilon \mathcal{S}, t, z$$

$$q^{+}_{g,t,z} \leq s_{g,t,z} \quad \forall g \epsilon \mathcal{S}, t, z$$

The carbon-pricing scenarios increase the operation cost of those technologies that emit CO_2: coal, natural gas and fuel oil; while the renewable mandates introduce a new constraint that must guarantee that the renewable production is higher than the established threshold:

$$\sum_{g\in\mathcal{R},t,z} q^{+}_{g,t,z} \geq RPS \cdot \sum_{t,z} D_{t,z} - q^{NSE}_{t,z}$$

3. Results: Decarbonization, the Mix of Capacity and Generation, and System Cost

Reproducing the present: the 2018 Case

Table 3, on the following page, shows some systemwide summary statistics for 2018 including the generation dispatch. They capture a generation mix dominated by coal (53%), followed by nuclear (19%), and gas (15%). However, there are clear regional differences. The MISO, SPP and AECI regions rely heavily on coal, and nuclear is significant in the PJM portion and TVA areas. The current penetration of wind is larger than 20% in regions within MISO (MNWI, MIDA, IA) and SPP. Solar deployment is negligible across the region. Power generally flows from North to South throughout the year, with large amounts of energy being directed towards the areas of MISO-LA and SPP-WEST, where more expensive combustion turbines represent a significant share of the capacity mix. In addition, corridors connecting MISO-LA, TVA, MISO-AR and MISO-MO are often congested.

Table 3 also reports the system cost. This number includes all new investment costs, as well as any fixed and variable operating and maintenance costs, including fuel costs. It does not include any of the sunk costs, which is the investment cost for any legacy assets. This is an annual cost, so the investment costs are amortized.

Looking to the future – the 2030 Reference Case

Table 3 also reports the systemwide summary statistics for the 2030 Reference Case which we can contrast with the 2018 Case to understand the expected pathway of the various regions being modeled given our assumptions on future load, technology costs and fuel prices, and scheduled additions and retirements in the region. It shows a continuation of recent trends mentioned earlier. At the system level, fossil fuel-fired capacity of all types decline, but coal and natural gas-fired plants remain the two largest categories of capacity. A small amount of nuclear capacity is retired, too. New investments are large in both wind and solar capacity with solar accounting for more than 2/3 of the added capacity. Emissions in this 2030 Reference Case are 11% below the 2018 case.

Interestingly, natural gas-fired generation increases even as capacity decreases. However, we also expect regional differences. In particular, all areas within SPP observe around 50% of generation coming from renewables with SPP-WAUE reaching up to 83%, and areas within MISO—MNWI, IA and MIDA—foresee 63%, 42% and 42% renewable generation. In contrast, MISO-MO, MISO-WUMS, and PJM-COMD areas only accommodate less than 7% penetration of renewables, followed by areas located in the East such as PJM-West, MISO-INKY, and MISO-LMI with around 10%. Nuclear is important in the PJM and TVA areas, while coal is still relevant across all the regions, except MISO-LA and SPP-WAUE.

		2030 Cases				
				Cost Efficient Decarbonization Scenarios		
	2018			-77%	-84%	-90%
	Case	Reference	Low Cost	$25/ton	$50/ton	$100/ton
Emissions (kton CO2)	878.4	783.6	673.5	200.3	141.5	91.8
% change from 2018		-11%	-23%	-77%	-84%	-90%
Capacity (GW)						
Coal	117.9	98.5	95.6	6.5	0.0	0.0
Natural Gas	132.2	109.0	104.8	174.8	171.5	155.5
Fuel Oil	5.7	0.7	0.7	1.2	1.4	1.3
Nuclear	35.5	30.4	28.1	33.2	33.2	34.0
Hydro	11.4	10.9	10.9	10.9	10.9	10.9
Wind	39.2	61.3	100.4	141.9	175.8	219.5
Solar	1.5	60.2	82.0	116.3	140.6	174.4
Pumped hydro	4.9	4.9	4.9	4.9	4.9	4.9
Battery	0.0	0.1	0.1	0.1	2.0	8.9
Total	348.3	376.0	427.5	489.8	540.3	609.4
Generation (TWh)						
Coal	771	663	589	12	0	0
Natural Gas	220	288	191	523	394	254
Fuel Oil	0	0	0	0	0	0
Nuclear	275	235	217	256	256	263
Hydro	38	35	35	35	35	35
Wind	126	215	361	501	600	697
Solar	3	130	173	239	283	323
Pumped hydro	7	8	9	8	9	11
Battery	0	0	0	0	3	14
Total	1,440	1,574	1,575	1,574	1,580	1,597
System Costs ($B)						
Fixed	13.4	17.4	20.6	31.4	36.7	44.1
Variable	27.5	25.2	20.8	17.1	13.8	10.1
Total	41.0	42.6	41.3	48.5	50.5	54.2
Per Unit Load ($/MWh)	28.57	27.19	26.41	30.97	32.28	34.65

Table 3. System-wide emission levels, capacity and generation portfolio mix, and system costs for the 2018 Case, 2030 Reference and Low-Cost Cases, and the 2030 Cost Efficient Decarbonization Scenarios.

The system cost increases slightly, but declines per unit of generation relative to 2018. The share of fixed costs increases and the share of variable costs decreases as the system invests more in capital intensive generation and avoids fuel costs. This, too, is a trend we will see more of as we look to deeper decarbonization scenarios.

We explored expected curtailments across the various areas. Solar curtailments are significant, 465 GWh, and occur mainly in SPP (325 GWh happen in SPP-N) and MISO-LA. In addition, wind curtailments are also quite relevant, 657 GWh, and located especially in MISO-MNWI (three quarters of the total) followed by MISO-IA and SPP-WAUE. More specifically, we detected solar curtailments mainly February through May. These curtailments happen mostly by midday (12pm to 3pm). Regarding wind curtailments, these are quite relevant in May, June, September and October. Hourly wind curtailment mostly occurs at night until early morning (11pm to 6am) across all regions.

Low-cost renewable scenario

Table 3 also reports systemwide summary statistics for the 2030 Low-Cost Case which we can contrast with the Reference Case. This additional reduction in renewables costs by 2030 leads to more wind and solar capacity and generation, as compared to the Reference Case, and a reduction in capacity and generation from coal, natural gas, and nuclear. Despite the drop in the cost of storage investments, we only see a modest addition of capacity. Emissions are reduced by 23% relative to the 2018 case, which is a doubling of emission reductions over the Reference Case. Regionally, we observe four effects: 1) coal is substituted by gas in PJM-West (–2.4 GW by +1.1 GW) to help to integrate additional wind (+6.7 GW) and solar (+5.5 GW) resources; 2) additional nuclear capacity is retired in MISO-IL (–1.1 GW) and SPP-N (–1.2 GW); 3) gas is substituted by wind and/or solar in AECI, MISO-WUMS, MISO-LMI, SPP-NEBR and SPP-WEST; and 4) wind (+17.4 GW) substitutes solar (–4.5 GW) and thermal technologies (–2.8 GW) in SPP-N, SPP-NEBR and SPP-WEST.

Of course, since the assumption of the case is lower investment costs for renewables, it is not surprising that the system cost is lower relative to the Reference Case.

Cost-efficient decarbonization scenarios

Finally, Table 3 also provides the summary statistics for our three levels of cost efficient decarbonization. A large reduction in emissions—77% relative to 2018—is accomplished at a $25/ton marginal abatement cost. The source of emission reductions is an enormous substitution of coal generation with a mix of natural gas, wind and solar generation, as well as a small amount of nuclear. Note that natural gas capacity and generation are higher in this cost efficient decarbonization scenario than in the Reference Case. Even at this low marginal abatement cost, most of the coal capacity is retired.

Deeper decarbonization scenarios of 84% and 90% emission reductions require marching up a steepening marginal cost of abatement curve—at, respectively, $50 and $100/ton CO_2 for these two scenarios. Already to achieve an 84% abatement outcome, coal-fired generation is zeroed out completely. As the level of decarbonization increases to 84% and 90%, natural gas-fired capacity is successively decreased. Natural gas-fired generation decreases even more. However, both natural gas-fired capacity and generation are greater than in the Reference Case even as decarbonization increases to 90%. Deeper decarbonization is enabled by successively greater investments in wind and solar. It also involves preserving some nuclear units that would have been retired in the Reference Case, and utilizing the nuclear a little more. Even at the decarbonization level of 77%, investment in battery capacity remains negligible. However, at 84% and 90% we see a sizable increase in investments in batteries. Still, the overall quantity is small.[15]

Table 3 reports the system cost for each scenario. It does not include any carbon charge. The annual system cost for the 77% decarbonization scenario is $48.5 billion, as compared against $42.6 billion for the 2030 Reference Case, a 14% increase. This is an increase of $3.79/MWh to obtain the extra 66 percentage point reduction in emissions. A 90% reduction has an annual system cost of $54.2 billion, which is a 27% increase over the Reference Case.

[15] The results in Table 3 only pertain to hourly energy demand and do not include operating reserves and frequency regulation which batteries may be well suited to provide.

Our results highlight again relevant regional differences. With a low carbon price, levels of fossil fuel generation are below 25% in areas in MISO (MO, MNWI, IL), AECI, PJM-COMD and SPP. As the carbon price becomes more expensive, more areas move away from fossil fuels, although regions like MISO-WUMS, MISO-LA, MISO-AR and MISO-INKY still have over 40% of their generation coming from fossil fuels. With a price of 100 $/ton, all areas experience pronounced growth in the renewable generation portfolio, with SPP and the Western regions in MISO presenting negligible percentages of fossil fuel generation, but two areas (MISO-LA and MISO-INKY) maintaining more than 30% of fossil fuel generation.

With respect to the installed capacity, the major wind additions occur in SPP and northern MISO and MISO-IL across all price scenarios. Solar is widespread, but mostly concentrated in southern areas within TVA, MISO and SPP, while battery installations appear across all regions up to a total capacity of 8.9 GW, which is a reduced capacity in comparison with the 394 GW of intermittent renewable generation.

Alternative decarbonization scenarios — Renewable mandates

Table 4 provides the summary statistics for our alternative decarbonization scenarios, beginning with the 60% and 75% renewable portfolio standards. These achieve emission reductions of 42% and 64%, respectively, relative to 2018 emissions.

	2030 Cases		
	Alternative Decarbonization Scenarios		
	RPS		RPS(60%)
	60%	75%	+Nuclear
Emissions (kton CO2)	510.5	312.7	313.4
% change from 2018	-42%	-64%	-64%
Capacity (GW)			
Coal	76.7	58.3	61.7
Natural Gas	138.1	135.0	112.6
Fuel Oil	2.7	2.7	0.7
Nuclear	0.0	0.0	34.0
Hydro	10.9	10.9	10.9
Wind	163.0	226.0	177.9
Solar	158.2	199.6	140.9
Pumped hydro	4.9	4.9	4.9
Battery	0.1	10.8	3.2
Total	554.6	648.2	546.8
Generation (TWh)			
Coal	408	228	254
Natural Gas	241	192	135
Fuel Oil	0	0	0
Nuclear	0	0	263
Hydro	35	35	35
Wind	562	725	598
Solar	323	395	287
Pumped hydro	19	19	19
Battery	0	26	8
Total	1,588	1,620	1,599
System Costs ($B)			
Fixed	30.1	40.7	35.7
Variable	17.8	12.8	12.9
Total	47.9	53.5	48.6
Per Unit Load ($/MWh)	30.58	34.14	31.04

Table 4. System-wide emission levels, capacity and generation portfolio mix, and system costs for the 2030 Alternative Decarbonization Scenarios.

The annual system cost for achieving a 42% decarbonization using a 60% renewable mandate is $47.9 billion, as compared against $42.6 billion for the 2030 Reference Case, a 12% increase. Note that this almost matches the cost of achieving a much deeper 77% decarbonization with cost efficient policies. The annual system cost for achieving a 64% decarbonization using a 75% renewable mandate is $53.5 billion. That is more than the cost of achieving a greater level of decarbonization with cost efficient policies. The explanation for this fact becomes clear when we look at how a renewable mandate shapes the stack of generation capacity.

Obviously, system-wide renewable mandates increase wind and solar capacity and generation, which helps decarbonization. This increased renewable generation displaces some fossil fuel-fired generation. However, instead of targeting coal generation specifically, it displaces both coal and natural gas generation. The 60% RPS produces 255 fewer GWh of coal generation and 47 fewer GWh of natural gas generation relative to the Reference Case. Therefore, the intensity of the emission reduction is less per MWh of renewable generation than if it had displaced coal only, as the cost efficient decarbonization policies do. The intensity even declines as we move to the higher 75% RPS. It produces 180 fewer GWh of coal generation and 48 fewer GWh of natural gas generation relative to the 60% RPS Scenario.

A second factor in the costly nature of the RPS is its impact on nuclear generation. Under both RPS scenarios, the entire nuclear fleet is retired, eliminating 235 GWh of zero-carbon generation, relative to the Reference Case. So, while the 60% RPS increases renewable generation by 540 GWh relative to the Reference Case, it only displaces 302 GWh of fossil fuel-fired generation.

In the third column of Table 4, we show a variation on renewable mandates. In addition to mandating 60% renewable generation, we preserve the nuclear fleet. This achieves the same 64% decarbonization produced by the larger 75% renewable mandate. It also has a much lower system cost than the larger 75% renewable mandate, saving nearly $5 billion annually. The cost of this more efficient decarbonization is $3.10/MWh less than the exclusive renewable mandate.

4. The Changing Operating Profile

The changing supply stack across the midcontinent—especially the penetration of wind in the western regions—has already produced changes in the operating profiles and market outcomes. For example, the Market Monitoring Unit of the Southwest Power Pool has documented the increased frequency of negative prices and of scarcity events (when system load approaches total capacity and prices peak), the shifting location of transmission congestion, and the increased cycling of fossil plants.[16] MISO, and to a lesser extent PJM, have also experienced changes of this sort. Each of the market operators in these regions anticipates further penetration of both wind and solar, and are studying ways to adapt their operations in order to accommodate the changes while maintaining the reliability of the system—see for example, MISO (2021). Related studies have been made at the national level, too—see for example, US Department of Energy (2017) and the many Variable Renewable Energy Integration Studies cited there.

Our model focuses on optimizing the capacity mix and generation dispatch schedules that minimize the cost of serving the hourly load through the course of a representative year in the face of variable

[16] Market Monitoring Unit, SPP (2020) and (2021).

renewable resources. With it, we can see changes in the utilization of the system during that year. However, the model does not incorporate uncertainty about interannual variability and how to assure reliability in the face of extreme events. Nevertheless, the utilization during the year is instructive. We focus our attention on comparing results for the 2018 simulation, the 2030 Reference Case, the 2030 - 77% cost efficient decarbonization (\$25/t CO_2) and the 2030 Renewable Mandate at 75%.

Looking back at Table 3, we can see that our modeling shows the share of generation from wind and solar increasing from 9% in 2018 to 22% in 2030 without any further policies. The share of fossil generation declines from 69% to 60%. In the deeper decarbonization scenarios, the share of wind and solar generation increases further. For our scenario with a 77% emission reduction (\$25/t CO2 price), the wind and solar share increases to 47% while the fossil generation declines to 50%. For our scenario with a renewable mandate of 75% (of load), wind and solar increase to 69% (of generation) with the fossil generation at 26%. As documented in the studies cited above, these levels of renewable penetration produce important challenges system managers will have to meet in order to maintain frequency and voltage, among other aspects of reliability. They also produce challenges to the financial models for remunerating capacity investments.

Figure 3 shows a set of duration curves for the aggregate fossil capacity factor across the entire system.

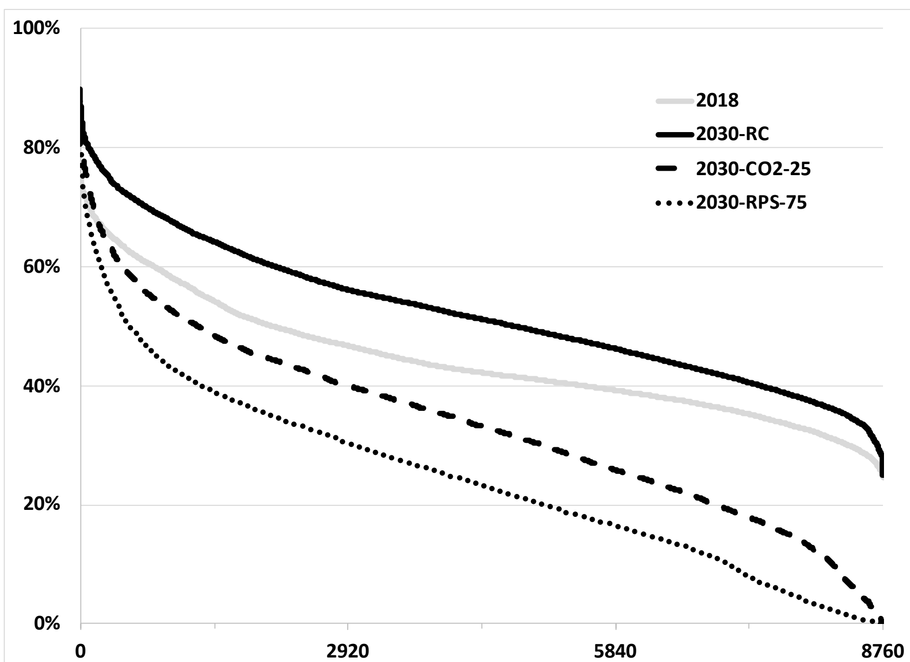


Figure 3. System-wide generation duration curves for aggregate fossil plants.

The gray curve shows the modeled duration curve in 2018. Our focus is on the three other curves, which are for 2030 under alternative policy scenarios. The highest one, the solid black curve, is for the Reference Case. It is higher than the curve in 2018 because in moving from 2018 to 2030, the system retires some units that are located in low use regions and builds new units in other regions where they will be most needed. The two lower curves are for two of our deeper decarbonization scenarios—our scenario with a 77% emission reduction (\$25/t CO_2 price) and our scenario with a renewable mandate of 75%. Both curves show a large reduction in the capacity factor over most hours, with the reduction highest for the renewable mandate. In a few hours, the capacity factor for the entire fleet of fossil plants approaches zero. However, as we can see on the left side of the chart, there are a few hours when most of the entire fleet is needed to be running full out. This illustrates the fact that in our model these fossil units are the main tool for balancing the fluctuating renewable resources. As renewable penetration increases, it places an increasing demand for flexibility from the fossil units. For example, as we move from the 2030 Reference Case to the two deeper decarbonization scenarios shown in the figure, we see the number of starts of the fossil units dramatically increase. In our model, investments in new fossil units are made in light of this need for flexibility—for example in the mix of combined-cycle or combustion turbine units added to each region.

Table 5 shows the role of transmission in balancing fluctuations in net load. The table shows information on two statistics. The top panel shows the share of load served by imports to each region. In 2030, the role of regional imports increases from a systemwide hourly average of 8% in the Reference Case to 12% and 13% in our two deeper decarbonization scenarios. The role varies greatly across regions as can be seen in both the standard deviation and the difference between the maximum share across regions and the minimum. The standard deviation drops between 2018 and the 2030 Reference Case, but increased again in our two deeper decarbonization scenarios. Imports may be used because they are the cheapest option available for balancing load, or they may be used because they are the only option. The bottom panel in Table 5 focuses on this second situation, when imports are essential to balancing load because the region's own unutilized thermal capacity is less than the hour's change in net load. The average number of hours increases between 2018 and 2030. It increases very dramatically for the first of our two deep decarbonization scenarios—our scenario with a 77% emission reduction (\$25/t CO_2 price). However, for the alternative deep decarbonization scenario—our scenario with a renewable mandate of 75%--the share of hours in which imports are essential falls. This is because this scenario involves a large volume of renewable capacity which is curtailed in many hours. Therefore, much of the variability of renewables does not translate into variability in generation.

		2030 Cases		
			Decarb Scenarios	
	2018 Case	Reference Case	\$25/t CO2 price	RPS 75%
Regional Import Share				
Average Across Regions	9%	8%	12%	13%
St.Dev. Across Regions	12%	7%	13%	11%
Maximum	46%	24%	50%	49%
Minimum	0%	0%	2%	5%
Share of Hours Reliant on Imports				
Average Across Regions	1%	6%	13%	3%
St.Dev. Across Regions	1%	9%	16%	3%
Maximum	4%	33%	44%	11%
Minimum	0%	0%	0%	0%

Table 5. Statistical Metrics on the Import Share Across Regions, and on the Share of Hours in which Imports are Essential to Balancing Regional Load

These changes in operating profiles also translate into a different profile of marginal cost across the system. Figure 4 shows a set of duration curves for the load-weighted average system marginal cost. This parameter is often treated as a proxy for a wholesale market price, although that depends upon the market structure—for example, whether there is a capacity market and whether there are other, out-of-market payments such as tax incentives for renewables. Under certain circumstances this marginal cost is likely to approximate the wholesale market price. The gray curve in Figure 4 shows the modeled duration curve in 2018, and the solid black curve is for the Reference Case. Comparing and contrasting these two curves is instructive. On the right-hand-side of the chart the 2030 curve lies a little bit below the 2018 curve. This reflects the fact zero-marginal cost renewable resources have penetrated enough in certain regions to occasionally be the marginal resource.

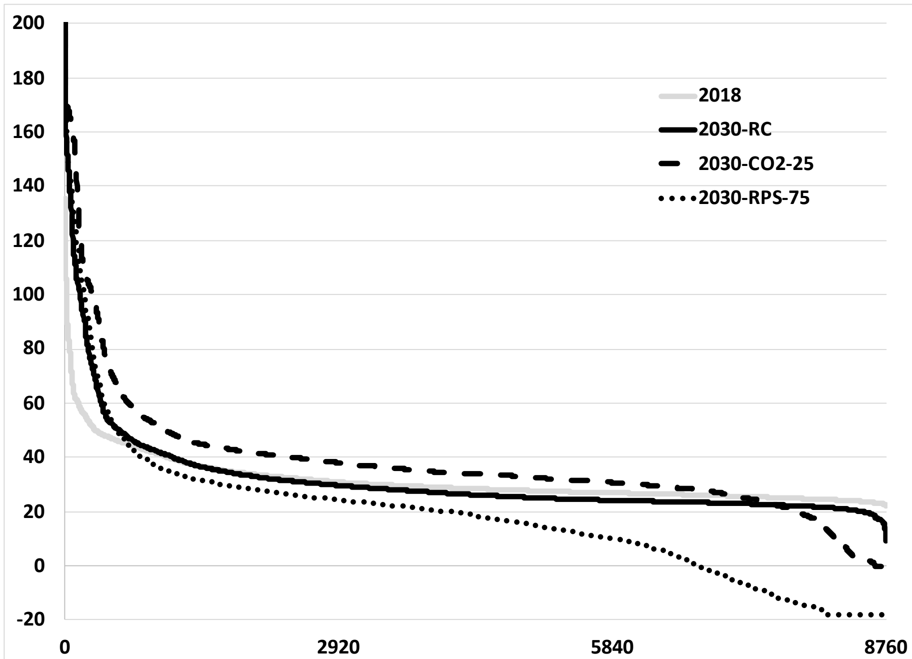


Figure 3. System-wide average marginal cost duration curves.

Table 6 reports a few statistics on the marginal cost of energy across all regions and hours by scenario, including statistics on the two tails of the distribution—benchmarked by $0/MWh at the low end and $100/MWh at the high end. For 2018, our results show a load weighted average marginal cost of about $31/MWh with regional averages that vary between $29/MWh and $38/MWh. Southwest regions (MISO-LA, SPP-WEST and SPP-N) exhibit particularly high average marginal cost, followed by regions in the North. Regions exhibit different volatility in the standard deviation of hourly marginal cost, with the volatility being higher in those regions where wind generation is located. Nevertheless, no region exhibits a significant volume of extreme values.

		2030 Cases		
			Decarb Scenarios	
	2018 Case	Reference	-77% $25/t	RPS 75%
Marg Cost of Energy ($/MWh)				
Average (Load Weighted)	32.87	33.96	42.60	34.49
% zero	0%	1%	14%	0%
% negative	0%	0%	0%	35%
% > 100	0%	2%	4%	3%

Table 6. System-wide marginal cost statistics.

In the 2030 Reference Case, we observe higher hourly marginal costs in areas located in the South and East driven by congestion on the main corridors connecting those areas with the rest of the system—specifically, SPP-N, SPP-WEST, MISO-LMI, and MISO-LA. with the increasing penetration of renewables. Lower prices occur in MISO and SPP areas in comparison to 2018, where significant wind or solar resources are located and being deployed. The areas with non-negligible increases in average hourly marginal costs are those experiencing transmission constraints where the pooling of additional renewable resources becomes a challenge.

Table 6 also shows that the average hourly marginal cost becomes more volatile. There is some modest growth in the number of hours when the marginal cost is zero and in the number of hours when the marginal cost spikes above \$100/MWh. The trend is already more marked in those regions with the higher concentration of renewables: in this Reference Case there are two regions in which the hourly marginal cost is zero in 7% of the hours, while in many other regions it does not happen at all.

The marginal cost of energy for these decarbonization scenarios will include the impact of a carbon price in those hours when fossil units are the marginal generator. Therefore, it is not surprising that the average hourly marginal cost of energy for the 77% decarbonization scenario increases to \$42.60/MWh, as compared against \$33.96/MWh for the 2030 Reference Case, a 25% increase. Higher cost-efficient decarbonization scenarios, not displayed in the table, show an increasing share of hours in which the marginal cost is zero. At the 90% decarbonization level the marginal cost is zero in nearly 40% of the hours. These are mostly hours when renewable generation is larger than load and some renewable capacity is being curtailed. Simultaneously, the number of hours in which the marginal cost spikes above \$100/MWh is also increasing slightly.

For the 75% renewable mandate, the average marginal cost is \$34.49, which is much lower than in any of the cost-efficient decarbonization scenarios. This could erroneously lead one to imagine that the renewable mandate policy should be cheaper than for the cost-efficient scenarios. We already reviewed the total system costs and saw that the renewable mandate is more expensive. The hourly marginal energy cost is not the total picture. A renewable mandate works by compensating renewables for capacity outside of the wholesale energy market. It pushes capacity with a low marginal cost onto the system, with the investment cost partially remunerated outside of the energy market. So the marginal cost of energy is low, while the total cost can be high.

A consequence of driving so much renewable generation onto the system, while also allowing nuclear generation to be removed, is a dramatic increase in the number of hours of very low extreme values for the hourly marginal cost. The 75% RPS has 35% of the hours when the hourly marginal cost is negative!

We also examined how decarbonization impacted the regional distribution of generation and the utilization of the transmission system. The top panel of Table 7 shows two metrics on this. First, it shows the average hourly utilization of transmission capacity, using an average that is weighted by each link's share of total interregional transfer capacity. Second, it shows the fraction of hours in which capacity is congested. Going from the 2018 simulation to the 2030 Reference Case, we see utilization increase slightly and congestion decrease slightly. This is not surprising because the location of new generation investments are made to avoid congestion or even to relieve it. The \$25/t CO_2 decarbonization scenario sees a slightly reduced utilization and slightly reduced congestion. The 75% renewable mandate, however sees both higher utilization and higher congestion. Keep in mind that the model optimizes the placement of generation given the transmission system and the carbon policy. So, if a given mix of assets leads to too much congestion, then the model looks for an alternative mix that can deliver power where it is needed. The model confronts a tradeoff between selecting the most advantageous locations for new wind and solar investments, for example, and the limited transmission capacity for exporting the cheap power from those regions. The results shown in Table 7 reflect this tradeoff.

		2030 Cases		
			Decarb Scenarios	
	2018 Case	Reference Case	$25/t CO2 price	RPS 75%
Utilization of Transm. Links				
Hourly Average (T.C. Weighted)	71%	73%	70%	78%
Hours Congested (T.C. weighted)	50%	48%	46%	58%
Congestion Value ($B)				
Increase in System Cost	0.2	0.2	0.5	2.0
Congestion Rents	0.7	0.2	0.3	1.1

Table 7. Utilization of the transmission links, frequency of congestion, and the impact of congestion on system cost and on congestion rents.

The bottom panel of Table 7 shows how the limited transfer capacity increases system costs. This increase is calculated as the difference between the modeled system cost and a counterfactual system cost calculated assuming away the transmission constraints. In the counterfactual, all generation across the entire system is sorted into a single supply stack for dispatch. The table shows that transmission constraints play a large role in producing the higher system costs for the decarbonization scenarios. This effect is especially true for the 75% renewable mandate scenario. Finally, the bottom panel also calculates congestion rents. This is calculated assuming that the regional hourly wholesale price equals the marginal cost of energy in that region. Under that assumption, in a model with locational pricing, load pays more than generation receives, with the difference being the congestion rent. This is an aggregate measure of the marginal value of investments in new transmission. The congestion rent is smaller in the 2030 Reference Case than in the 2018 simulation—again, because new generation investments have been deployed in response to existing transmission constraints. The congestion rent increases in the decarbonization scenarios, especially in the 75% renewable mandate scenario.

5. Conclusions

In this paper, we simulated plausible transition scenarios for the power system within a decarbonizing process, assuming the latest U.S. administration plans. We studied the regional generation landscape under various scenarios that explored better economic conditions for renewables, and tighter decarbonization policies. This study incorporates a stylized representation of SPP, MISO, part of PJM, TVA and AECI power systems, characterized by a fossil fuel fleet that accounts for over 85% of its electricity mix.

Our results suggest that by 2030, based on widely used price forecasts, demand projections and planned electricity resources, gas- and coal-based technologies still prevail in the system. Coal and fuel oil are expected to be displaced by wind and solar as long as decarbonization is stimulated through further policies. Gas resources are still needed to help to accommodate the significant amount of renewable generation. Regionally, SPP and Northern MISO are more prone to hosting massive renewable generation. In contrast, areas in Southern and Eastern MISO, PJM, or TVA will still heavily rely on fossil fuels. With respect to electricity prices, prices will become more uniform on average across the regions, more volatile within each region, and with an increasing frequency of zero-price events as compared to the year 2018. Wind curtailments are significant in Northern MISO and SPP. On the other hand, solar curtailments are minor and only observed in Southern MISO and SPP.

The decarbonization trend is happening even without implementing any decarbonization policies as observed when comparing the CO_2 emissions of our simulated 2018, 878.4 kton, and the 2030 Reference Case, 783.6 kton. We expect a reduction of 11% of CO_2 emissions from market forces and existing policies: many coal assets are reaching the end of their useful life or are becoming uneconomical due to lower natural gas prices and falling wind capital costs. However, this trend is limited. Even assuming lower renewable costs in our Low Cost scenario, the emissions could just drop 23%, clearly insufficient to comply with the U.S. pledge under the Paris Agreement, and the current U.S. administration goal of a carbon-free power system by 2035.

Decarbonization policies are then needed if these goals are to be achieved. The study explored the implications of three carbon-pricing and three renewable-mandate policies primarily in terms of operations, emissions and costs. From their analysis, we can conclude:

- All decarbonization pathways require mobilizing capital resources to invest in new zero carbon capacity. We document the cost at different levels of decarbonization and along alternative pathways pushed by different policies. Policymakers need to choose among policies with an eye to these costs, and address who should pay them—taking into consideration, for example the impact on low-income households, on industrial competitiveness, among other things.
- At the same time, a key feature of grids with a large penetration of renewables is the volatility in the marginal cost of energy and thereby in the market price. There are more hours when the price is zero or negative, and more scarcity pricing hours where the price spikes. The flip side of this is the increasing responsibility placed on fossil-fueled generators to balance load. This presents important challenges for assuring a return on investment in capacity. To accelerate decarbonization may require additional mechanisms to reduce the long-term uncertainty and guarantee enough capacity (e.g., capacity payments).
- Renewable mandates displace fossil capacity generally, without targeting the most carbon intensive coal plants. They also displace the nuclear fleet, which sacrifices a major source of zero-carbon generation.
- The impact of decarbonization varies greatly across the many regions and localities, depending upon the legacy assets and the availability of renewable resources, among other things. This argues for cooperation and discussion among policymakers and stakeholders: RTO/ISOs, cooperatives, utilities, federal agencies, state commissions, consumers, etc. Some compensation payments should be expected.
- We have not included any transmission reinforcement in our study, but recognize the key role that transmission plays to support high shares of renewable generation. Our simulations show curtailments and congestions in specific corridors whose alleviation could reduce operation costs, or offer new opportunities for renewable deployment in resource-endowed wind and solar areas. Transmission expansion also contributes to improving system reliability, which is also needed, as revealed by the decreased ramping requirements as long as more renewable energy capacity is installed. Any transmission expansion would require doing a cost-benefit analysis.

We recognize that this line of research can be extended to address some of the limitations we previously identified. These include:

1) Incorporating internal and local dispatch rules or technical constraints normally found in single balancing areas or regional ISO/RTOs.
2) Including a more disaggregated resource estimate and a renewable supply curve that accounts for the increasing costs associated with higher quality resources.
3) Considering limitations to deployment of renewable resources that include not only technical potential, but also local realities in terms of costs, deployment rates, and uncertainty related to resource long-term energy estimates.
4) Evaluating other technologies that can contribute to the decarbonization process and that are not necessarily off the table: new nuclear, carbon capture and sequestration or hydrogen.
5) Valuing the provision of ancillary services with generation and demand resources.

We could also explore a more in-depth analysis of how reliability and resiliency challenges brought about by renewables could still be addressed by traditional fossil-fuel baseload resources even as they experience decreasing capacity factors—in the case of gas—, and phasing-out—in the case of coal.

Decarbonization of the power system is undoubtedly of the utmost importance, and while the challenge of doing so is daunting, particularly in areas where coal has been the prevailing technology, through technological innovation and policy we are also on the cutting edge of transforming this challenge into opportunity.

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