Assessing the evolution of power sector carbon intensity in the United States

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Abstract

In the United States, the electricity sector is a major focus for implementing policies to meet national, state, or local mandatory or voluntary CO2 emissions reductions goals. Thus, it is important to have timely and available information on greenhouse gas emissions generated by the power sector to ensure that the policies implemented achieve intended emissions reductions. This work is the first to develop a transparent method to compute the emissions intensity for the US electricity section from 2001 through 2017 at different temporal (annual, quarterly, monthly) and regional (US, NERC, and state) levels. We find that between 2001 and 2017 the average annual CO2 emissions intensity of electricity production in the United States decreased by 30%, from 630 g CO2 kWh−1 to 439 g CO2 kWh−1. This change in CO2 intensity is attributable to an increase in generation from natural gas and wind accompanied by a reduction in coal-fired power generation. The decline in carbon intensity varies across regions, with the largest reduction between 2001 and 2017 from power plants in the Northeast (58%) and the smallest reduction from power plants in the Texas region (27%). In absolute terms the South-central region saw the largest decrease in emissions intensity (358 g CO2 kWh−1) and Texas saw the smallest (164 g CO2 kWh−1). We also find that replacing coal generation with natural gas or renewables has increased the monthly correlation of CO2 intensity between regions. At the state level, Delaware saw the largest decrease in CO2 intensity (466 g CO2 kWh−1), and Idaho is the only state that has not decreased CO2 intensity since 2001.

Introduction

Deep decarbonization of the electricity sector is required to meet climate stabilization targets (IPCC 2014), and thus it is important to have timely and available information on greenhouse gas emissions generated by the power sector to ensure that the policies implemented achieve intended emissions reductions. In the United States (US), electricity generation comprised 29% of greenhouse gas emissions in 2015 (US EPA 2017b), and estimating how the CO2 intensity of electricity generation changes over time is important for national, regional, and local decision-making. Stakeholders can use this information to benchmark performance and progress, to estimate how electricity uses contribute to CO2 emissions, to design new products and policies, and to understand how the changing generation mix has affected the carbon intensity of electricity. When lower-emitting electricity sources become a larger share of generation, the overall CO2 intensity of electricity decreases. Conversely, when low-carbon generation decreases, CO2 intensity increases. Given the relatively flat demand for electricity in the US (US EIA 2017c), changes in the CO2 intensity are proportional to changes in total CO2 emissions. Using direct emissions intensity as an indicator has the advantage that values are generally bounded between 0 g CO2 kWh−1 and around...
1000 g CO$_2$ kWh$^{-1}$, representing the range of generation from sources with no direct CO$_2$ emissions and older coal-fired power plants. This bounded range makes comparisons between regions and over time easier.

The electricity fuel and technology mix in the US from 2001 through 2008 was fairly stable: about half of all electricity was generated from coal, while natural gas and nuclear each contributed about 20%. This period of stability led the Energy Information Administration (EIA) of the US Department of Energy to project that the electricity sector would be similar well into the future, with coal continuing to supply more than half of all electricity (US EIA 2008). As we now know, 2008 was at the start of a massive transformation caused by the drop in natural gas prices and increased generation from renewables (Houser et al. 2017, Knittel et al. 2015, Lu et al. 2012, Venkatesh et al. 2011, Davis et al. 2016). Generation from natural gas surpassed that of coal in 2016, and wind now generates nearly as much electricity as conventional hydroelectric sources (US EIA 2017b). There is also evidence that state policies encouraging renewable generation have lowered CO$_2$ emissions (Lyon 2016, Prasad and Munch 2012, Shrimali and Kniefel 2011).

Data on electricity generation in the US is collected and made available by several different government agencies. The US Environmental Protection Agency (EPA) collects hourly air and CO$_2$ emissions data from the Continuous Emissions Monitoring Systems (CEMS) installed on power plants larger than 25 MW as part of the Air Markets Program Data (US EPA 2017a). EPA also generates regional and national estimates of conventional air pollutants and CO$_2$ emissions from every electricity generating unit in their eGRID program (US EPA 2018). The Energy Information Administration (EIA) of the US Department of Energy also provides monthly unit-level operating data and characteristics for the electricity sector. Previous work by P´etron et al. (2008) used CEMS data and eGRID to examine temporal and locational trends in average CO$_2$ emissions from power generation in the US, and de Gouw et al. (2014) used CEMS data to calculate CO$_2$ emissions and intensity from reporting power plants between 1995 and 2012. As part of their analysis of the Clean Power Plan, Davis et al. (2016) used EIA generation and fuel consumption data to examine monthly CO$_2$ emissions and intensity from electricity generation. Other studies have looked at regional differences in average (Weber et al. 2015) and marginal (Siler-Evans et al. 2012, Graff Zivin et al. 2014, Archsmith et al. 2015) emission rates at different geographic levels across the US for a single year.

In this paper, we present an open method for estimating national or regional CO$_2$ intensity and emissions from US electricity generation. Our method uses publicly available EPA and EIA data sources to determine CO$_2$ intensity of electricity generation at monthly, quarterly, and annual levels as detailed in figure 1 and the methods below. The goal is to have a method that is easily reproducible, temporally relevant, and usable by different decision makers. A continuous time series of CO$_2$ intensity from 2001–2017, at sub-annual resolution, is a new resource for researchers and policy makers. Our emissions index results, open data, and code are freely available at the Power Sector Carbon Index website (Scott Institute for Energy Innovation 2017). The closest available data sources are eGRID, which provides detailed annual data every few years, and EIA’s estimates of CO$_2$ emissions from electricity in section 12 of the Monthly Energy Review (US EIA 2017c). EIA’s estimates only use fuel consumption and emission factors to calculate CO$_2$ emissions, and eGRID results—even if connected together correctly—represent annual data from two years before they were published.

This paper is organized as follows: first, using monthly CO$_2$ intensity data from 2001–2017, we examine trends in CO$_2$ intensity and generation sources over time at national, North American Reliability Council (NERC) regions covering the US lower-48 states, and state levels. The eight NERC regions that cover the lower-48 states are shown in figure 2. They represent an intermediate level of aggregation between state and national levels, and are often used when determining environmental emissions from electricity production (Tamayo et al. 2015, Siler-Evans et al. 2012, Graff Zivin et al. 2014, Archsmith et al. 2015, US EPA 2017c). Understanding the CO$_2$ emissions from electricity generation at multiple spatial scales can also illustrate uncertainty around the emissions from electricity (Weber et al. 2010). We find that seasonal generation patterns in several NERC regions have changed substantially at the same time generation from natural gas and wind has increased. Renewable generation has increased, partly due to policies such as Renewable Portfolio Standards (RPS), currently implemented in twenty-nine states and Washington, D.C. (Barbose 2017). These RPS policies usually mandate that some fraction of electricity production provided by retail suppliers within the state come from renewable sources, although most programs do not restrict the location of generation to within state lines. Several other states have voluntary renewable energy goals, which are not part of RPS policies. We examine the annual CO$_2$ intensity of electricity for each state in 2001, 2008, and 2017, indicating which states had or had not implemented mandated RPS programs.

Finally, we look at the correlation in monthly CO$_2$ intensity between NERC regions to determine if low-carbon power is generated at the same intra-annual periods across regions. Moving electricity generated from renewable sources via high-voltage direct-current (HVDC) transmission has been proposed as one path to substantially lower electricity CO$_2$ emissions (MacDonald et al. 2016). Negative seasonal correlations between two regions would mean that additional
low-carbon power generated in each region could be shared, lowering the CO₂ intensity across regions. Conversely, positive correlations between each region would mean that they both generate low-carbon power at the same times of the year.

**Data and method**

The CO₂ intensity of electricity generation (g CO₂ kWh⁻¹) is estimated using a simple approach of dividing total CO₂ emissions from producing electricity by the net amount of electricity generated. Monthly net electricity generation data and fuel consumption is reported by facilities on form EIA-923 (US EIA 2017a). EIA uses these data to estimate the amount of fuel that was consumed specifically to generate electricity at facilities that cogenertate heat and electricity (CHP) (US EIA 2015). Final EIA-923 data, which is released late in the year following the year of data collection, includes nearly every facility in the US. Data for a subset of larger facilities—representing 91% of capacity and 95% of generation in 2015—is available after only a few months delay from when the data are collected (US EIA 2017b, 2017f). EIA supplements these data from monthly reporting facilities with their own estimates of generation and fuel consumption at annual reporting facilities, and releases an estimate of total generation/fuel consumption at the state level as part of their Electric Power Monthly (US EIA 2017c). The difference between the sum of facility data within a state and the state level total represents an estimate by EIA of generation/fuel consumption by facilities that have not yet reported for that month. We obtain both facility EIA-923 data and state level estimates of total net generation/fuel consumption through EIA’s Open Data portal (US EIA 2017b).
CO₂ emissions from fuel combustion at power plant facilities larger than 25 MW are measured hourly as part of CEMS, and reported to the EPA. These data include both fossil and non-fossil CO₂ emissions from production of electricity and cogeneration of heat. CEMS data for total non-CHP fossil fuel CO₂ emissions are, on average, less than 1% larger than expected emissions calculated from fuel consumption, although average absolute discrepancies can be much larger (Ackerman and Sundquist 2008, Gurney et al 2016). We use CEMS as the primary data source for CO₂ emissions from reporting facilities. These data are adjusted to exclude cogeneration of heat and biomass consumption using EPA fuel consumption data and emission factors from EPA and IPCC (see supporting information (SI) tables S3 and S4 available at stacks.iop.org/ERL/13/064018/mmmedia for emission factors and a sample calculation). Total monthly CO₂ emissions from each facility in CEMS are multiplied by the ratio of calculated fossil CO₂ for electricity production over total calculated CO₂. The few instances where unadjusted fossil CO₂ emissions yield an intensity of less than 300 g kWh⁻¹ (gross) over a monthly period are considered too low to be reliable, and are replaced with CO₂ emissions calculated from fuel consumption. This threshold is well below the expected CO₂ emissions intensity (350 g kWh⁻¹) of an advanced natural gas combined cycle power plant (NETL 2015). Monthly CO₂ emissions from facilities that do not report to CEMS are estimated using fuel consumption and emission factors.

While we use CO₂ emissions reported to CEMS, we have not investigated if methods used by power plants to measure their emissions have changed over time. Facilities can use a number of different methods to determine their CO₂ emissions, and there is some evidence that the accuracy of data varies between methods (Quick 2014).

Although estimating marginal carbon intensity would likely better characterize the effects of near-term interventions in the power sector (Siler-Evans et al 2012, Graff Zivin et al 2014, Archsmith et al 2015, Weis et al 2016), not all hourly generation is reported in CEMS, and thus it is not feasible to undertake that strategy. Thus, in this paper we compute the average carbon intensity at different regional and temporal time frames, rather than the marginal.

The smaller fraction of monthly CO₂ emissions from facilities that are not represented in EIA-923 or CEMS are calculated by multiplying fossil fuel consumption for electricity production by the corresponding emission factor. EIA reports total fuel consumption and generation by fuel type at the state level. We subtract fuel consumed in a state by the set of responding emission factor. EIA reports total fuel consumption for electricity production by the category (x) as their primary fuel source. Potential generation is calculated using the net summer capacity (Cap) of all units from EIA-860 that have not been retired (e.g. operating, standby and out of service) and the number of hours (h) in a month or year (t) (US EIA 2017d).

\[
\text{CF}_{x,t} = \frac{\text{Gen}_{x,t}}{\text{Cap}_x \times h_t} \quad (1)
\]

Calculating CO₂ intensity for NERC regions, which cross state boundaries, is challenging because our method relies on EIA estimates of non-reported net generation and fuel consumption at the state level. The missing generation and fuel consumption is small enough to ignore in most years where final EIA data has been released. In more recent months it is necessary to allocate generation and fuel consumption from EIA’s state level estimates to NERC regions. We use the most recent final EIA-923 data (representing operations in 2016) for each state to calculate the fraction of generation and consumption from each fuel type that occurred at annually reporting facilities in each NERC region within a state. Generation and fuel consumption for more recent months in states that cross NERC boundaries and are not accounted for by EIA-923 facility data are then allocated to each NERC region based on the proportion at annual reporting facilities that took place within each NERC region.

Each NERC acronym or initialism corresponds to a specific region in the US, as illustrated in figure 2 and defined in the SI. NERC regions have changed over time, but we use currently defined NERC regions for all years between 2001 and 2017. Power plants that were retired before the current NERC regions came into existence, or that began operations after 2016, are assigned to a NERC region using a RandomForest classification algorithm as described in the supporting information.

When reporting generation, fuel consumption, or capacity factor by fuel category we aggregate fuels to coal, natural gas, nuclear, wind, hydro, solar, other renewables, and other. The specific fuels included in each of these categories are described in tables S1 and S2 of the SI. Capacity factors (CF) for each fuel category (x) are defined as the ratio of total generation (Gen) from fuel category x over potential generation at generators with fuel category x as their primary fuel source. Potential generation is calculated using the net summer capacity (Cap) of all units from EIA-860 that have not been retired (e.g. operating, standby and out of service) and the number of hours (h) in a month or year (t) (US EIA 2017d).

\[
\text{CF}_{x,t} = \frac{\text{Gen}_{x,t}}{\text{Cap}_x \times h_t} \quad (1)
\]

Correlations between monthly CO₂ intensity in each pair of adjacent NERC regions show the extent to which they share seasonal patterns over a period of time. We use a rolling 48 month window to calculate a time series of correlations between adjacent NERC regions. The monthly CO₂ intensity in each region is detrended by subtracting the 1 year centered rolling mean before correlations are calculated.

**Results**

Carbon intensity of the electricity sector in the US and for each NERC region: The monthly CO₂ intensity of
electricity generation, shown in figure 3, has declined in all US NERC regions examined since 2001, with the highest annual average rates of decline in SPP (22 g CO₂ kWh⁻¹ year) and MRO (20 g CO₂ kWh⁻¹ year) regions. These NERC regions started with the highest CO₂ intensity of electricity generation and largest fraction of generation from coal. NPCC declined at a rate of 15 g CO₂ kWh⁻¹ year, which still represented a total reduction of 58%—the largest for any region. TRE saw both the slowest decline (10 g CO₂ kWh⁻¹ year), and smallest reduction (27%). Annual CO₂ intensity values for each NERC region in 2001 and 2017 are provided in figure 3 and table 1.

One reason why all regions show at least some decline in intensity is that they all produced less electricity from coal and more electricity from natural gas and/or wind (Mohlin et al. 2018), which can be seen in figure 4. Additional figures showing the change in generation by fuel category are provided in the SI (figures S3 through S9). Electricity from natural gas has less than half of the direct CO₂ emissions as from coal (Farquharson et al. 2016) and wind generation has zero direct CO₂ emissions. Reduced coal generation has coincided with the retirement of 112 GW of coal generation capacity since 2008 (US EIA 2017). However, it is possible for coal generation to increase when natural gas prices rise, as seen in the first half of 2017 when the US natural gas price at Henry Hub increased from under S2 GJ⁻¹ to over S3 GJ⁻¹ (US EIA 2017c).

Both total demand within a region and electricity generation from each fuel source display seasonal trends. Demand is usually highest in the summer, has a secondary peak in the winter, and is lowest in the spring and fall. Monthly total generation in the US and each NERC region are included in figure S2 of the SI. These seasonal trends are driven largely by variations in residential demand factors such as space conditioning (heating and cooling) and lighting (US EIA 2017). The regional share of generation

Table 1. Annual CO₂ intensity of electricity generation for the US and each NERC region in 2001 and 2017, with the absolute and percent reduction over that timeframe. Values for 2017 are calculated using preliminary data and may be subject to revision once final data are available.

| Region | 2001 | 2017 | Reduction | Percent reduction |
|--------|------|------|-----------|------------------|
| TRE    | 610  | 439  | 170       | 28%              |
| WECC   | 532  | 346  | 174       | 33%              |
| USA    | 630  | 439  | 191       | 30%              |
| SPP    | 854  | 546  | 309       | 36%              |
| SPP    | 491  | 363  | 128       | 26%              |

Figure 3. CO₂ intensity (g CO₂ kWh⁻¹) of electricity generation in the United States (USA), and each NERC region in the continental US Values for 2017 are calculated using preliminary data and may be subject to revision.
from each fuel category in a season will depend on available capacity, how quickly demand changes over the course of a day, and the cost of generating electricity from that fuel.

Natural gas generation peaks in the summer because demand is high and natural gas combustion turbines are able to react quickly to changing demand. Electricity from those combustion turbines is expensive because they have low heat rates, and they are generally only used when other resources are either already generating at their maximum or cannot respond quickly enough to increased demand. MRO has the highest share of natural combustion turbines and the lowest share of natural gas combined cycle plants of any NERC region. MRO also has a lower share of generation from natural gas than any other NERC region. Combined cycle plants have comprised at least 50% of the natural gas capacity in FRCC, TRE, WECC and NPCC since 2006 and is still below 50% in all other regions. Figure S10 in the SI shows the capacity share of different natural gas generator types over time in each NERC region.

Coal generation generally follows total generation within a region, peaking in both the summer and winter. During these peaks coal power plants within each region historically (before 2008) operated at 70%–80% of their net summer capacity. Coal capacity factors have been decreasing since 2008, especially in the spring and fall months. At the national level they went as low as 35% in March 2016 and 45% in November 2016. Annual average coal capacity factors at the national level were 52% in both 2016 and 2017. Monthly coal and natural gas capacity factors for the US and each NERC region are included in the SI as figures S11 and S12.

Three NERC regions—SPP, TRE, and MRO—have seen large increases in wind generation. The growth of wind power has disrupted previous thermal generation patterns. In SPP and TRE, which had both growing wind generation and high generation from natural gas, seasonal trends show a disconnect starting in 2012–13 (see figure 4). Figure 5 shows the seasonal generation of coal, natural gas, and wind over time in these three NERC regions. The change in seasonal variation over time is shown in figure 6. In all three regions the seasonal variability of coal generation has increased while total coal generation declined, driven by less generation in the spring.

As wind generation grew in SPP and TRE, the summer peak of natural gas generation in SPP got flatter and the winter generation from natural gas grew in TRE. The higher share of natural gas capacity from lower operating cost combined cycle units in TRE could have played a role in maintaining summer natural gas generation levels. In contrast, more than 60% of the natural gas capacity in SPP is from higher cost combustion turbines, steam boilers, and internal combustion engines.

Despite this difference in natural gas generator types, the normalized variability of natural gas generation in these two regions—which increased slightly from the 2005–2008 to the 2009–2012 timeframe—decreased after 2012 while wind generation increased. SPP saw a sharp decrease in normalized variability.
of both wind and natural gas that coincided with the shift to a new day-ahead Integrated Marketplace in early 2014 (Southwest Power Pool 2016). This move to a market-based dispatch approach and transmission upgrades also helped the region handle increasing amounts of wind generation (Bird et al 2016, Southwest Power Pool 2016).

MRO, where more than 50% of natural gas generation capacity is from combustion turbines, saw a large increase in the normalized variability of natural gas generation from about 2010 through 2013. Several warm summers during these years (National Centers for Environmental Information 2013) led to spikes in natural gas generation. The largest spike occurred in July of 2012, when monthly generation from natural gas was 3.2 million MWh. The previous record for monthly natural gas generation in MRO was July of 2011 (2.0 million MWh), followed by August of 2010 (1.7 million MWh). For comparison, natural gas generation in November of 2011 fell to 0.25 million MWh.

Correlation of CO$_2$ intensity time series across regions: the seasonal patterns of fuel type share, which affect the CO$_2$ intensity of electricity generation at different times of the year, have changed as natural gas prices fell and renewable generation increased. These
changes have increased the correlation of monthly CO\textsubscript{2} intensity across most regions. Negative correlations between two regions would mean that additional generation of lower CO\textsubscript{2} electricity happens at different times of year in each region. This temporal difference could be exploited with increased long-distance transmission of electricity, lowering CO\textsubscript{2} emissions in both regions.

Figure 7 shows the rolling correlation of detrended CO\textsubscript{2} intensity between adjacent NERC regions (see figure 2 for a map of NERC regions). Some periods have low or negative correlation, but the trend is upward in almost all pairings. WECC, which has the highest proportion of generation from hydro, tends to have the least change in correlation with other regions. Correlations with SERC and RFC have historically been the lowest—sometimes at or below 0—but since 2010 these correlations have increased and are now above 0.5. This increase in correlation occurred at the same time that generation from natural gas started to displace coal generation in both regions.

NERC regions vary in size and may contain sub-regions with significantly different generation mixes and seasonal CO\textsubscript{2} intensity profiles. This is especially true in WECC, where the approximately equal shares of hydro, natural gas, and coal generation are geographically separated. Hydro generation is mostly in Washington, Oregon, and California; most natural gas generation is in California; and coal generation is distributed across Wyoming, Arizona, Colorado, New Mexico, and Montana (US EIA 2017b).

CO\textsubscript{2} intensity by state over time: we calculate state-level CO\textsubscript{2} intensity using only electricity gen-

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**Figure 7.** Rolling, centered, 48 month Pearson correlation of CO\textsubscript{2} intensity between adjacent NERC regions from 2001–2017. Correlations in each facet are between the titled NERC region and the NERC region shown in the legend. Regression lines are included with shaded 95% confidence intervals.
Idaho, where nearly all power generation is from hydro, added some natural gas generation and hence is the only state that did not see a decline in CO₂ intensity between 2001 and 2017. Figure 8(a) shows the annual CO₂ intensity of generation within each state in 2001, 2008, and 2017. Hollow circle markers indicate that the state had requirements for renewable generation as part of a renewable portfolio standard (RPS) in that year (Barbose 2017). RPS programs are varied in their design and implementation, and we do not distinguish between different aspects here. States with large declines in CO₂ intensity are not limited to those that implemented RPS policies. Delaware and Iowa—with the largest declines—do have RPS policies, but Oklahoma, North Dakota, and South Dakota—with the third, fourth, and sixth largest declines—do not have RPS programs but do have voluntary renewable energy goals. These three states have all taken advantage of their excellent wind generation resources to reduce electricity CO₂ intensity, and they even export power to help other states meet their RPS goals (Barbose 2017, US EIA 2017b). South Dakota, for example, went from annual wind generation of 145 GWh in 2008 to 3154 GWh in 2017. Meanwhile, North Dakota increased wind generation from 1693 GWh to 10,987 GWh, and Oklahoma went from 2358 GWh to 24,404 GWh (US EIA 2017b).

States without RPS standards or wind generation have also seen declines in their electricity CO₂ intensity. Florida, Arkansas, Georgia, and Tennessee, which ended 2017 close to the national average, all increased generation from natural gas and decreased generation from coal. This coal-to-gas switch explain how states without RPS policies or large renewable resources have been able to reduce CO₂ intensity. A shift to generation with natural gas can lower emissions, but fossil CO₂ emissions from natural gas combustion will still be at least 350 g kWh⁻¹ without carbon capture and storage (CCS) (NETL 2015). Retaining substantial amounts of fossil generation while also achieving a very low-carbon electricity grid will require deployment of CCS or negative emissions technologies.

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4 Accounting for inter-state electricity transfers makes it difficult to perform this analysis using consumption rather than generation data.
Using data from (US Census Bureau 2012, 2017b), we produce an additional measure of environmental efficiency by dividing total CO₂ emissions from electricity production by state population. These values are shown in figure 8(b). Because electricity flows across state boundaries, electricity CO₂ emissions normalized by population may be skewed in states that produce significantly more electricity than they consume. Figure S6 in the SI shows that a small number of states—including Wyoming, West Virginia, and North Dakota—generate a substantial amount of electricity for export. But some states with high CO₂ intensity, such as Kentucky and Indiana, have close to zero net imports or exports of electricity. CO₂ emissions from electricity generation per capita in those states are relatively high compared to the rest of the country.

Discussion and conclusion

We use publicly available data from EIA and EPA to construct a continuous dataset of US electricity production CO₂ intensity at state, NERC region, and national levels from 2001 onward. Our assembled index results, open data and code are freely available for use by researchers and stakeholders at the Power Sector Carbon Index website (Scott Institute for Energy Innovation 2017). We find that the CO₂ intensity of US electricity production has decreased from 630 g CO₂ kWh⁻¹ in 2001 to 439 g CO₂ kWh⁻¹ in 2017 (30%). This downward trend is evident at every geographic level we examine, except for Idaho. Declining generation from coal, and increased generation from natural gas and wind are the primary drivers for the CO₂ intensity decrease.

A continuous time-series at a monthly resolution allows us to show how the seasonal variation in CO₂ intensity has changed across states and NERC regions while generation from wind and natural gas has increased. These changes have tended to align low and high points of CO₂ intensity—lows are generally in the spring and fall and highs are generally in the summer and winter. This leads to an increased correlation in monthly CO₂ intensity between regions. Exporting excess low-CO₂ electricity from one part of the US to another might be a viable strategy for lowering CO₂ intensity throughout the year, but it will be most effective if nearby regions low or negative correlations. Future research should focus on the implications of seasonal correlation in CO₂ intensity for system-wide deep decarbonization of CO₂ emissions.

This analysis and open dataset can serve as the foundation for other work on electricity CO₂ emissions and emissions intensity. Organizing and using EIA and EPA data to estimate CO₂ intensity has previously been time consuming and often subject to tacit assumptions. This paper makes these assumptions explicit and provides a transparent, clean, and curated dataset for stakeholders to analyze and understand these changes. As the power sector continues to evolve, these data can serve as performance benchmarks and innovation targets for researchers, governments, and firms.

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