



RESOURCES  
*for the* FUTURE

# Options for EIA to Publish CO<sub>2</sub> Emissions Rates for Electricity

Karen Palmer, Brian Prest, Stuart Iler, and Seth Villanueva

Report 22-08  
August 2022

## About the Authors

**Karen Palmer** is a senior fellow at Resources for the Future and an expert on the economics of environmental, climate, and public utility regulation of the electric power sector. Her work seeks to improve the design of environmental and technology regulations in the sector and the development of new institutions to help guide the ongoing transition of the electricity sector.

**Brian Prest** is a fellow at Resources for the Future specializing in climate change, oil and gas, and energy economics. Prest uses economic theory and econometric models to improve energy and environmental policies by assessing their effects on markets and pollution outcomes. His recent work includes improving the scientific basis of the social cost of carbon (SCC) and economic modeling of federal oil and gas leasing policies that account for the SCC as part of royalties. He also uses machine learning techniques to improve understanding of household electricity demand and time-varying pricing. His past work includes econometric modeling of the US oil and gas industry, evaluating the effects of coal subsidies on emissions, understanding the economic effects of rising temperatures, and modeling the market dynamics of climate change policy under policy uncertainty. His work has appeared in the *Brookings Papers on Economic Activity*, the *Journal of the Association of Environmental and Resource Economists*, the *Journal of Environmental Economics and Management*, *Energy Economics*, and *The Energy Journal*, and other peer-reviewed journals.

**Stuart Iler** is an economist and computer scientist with experience in nonprofit, academic, private, and government settings. His previous research has focused on economic production networks, oil price episodes, green jobs, and projections of future energy production and use. He most recently worked as a data scientist at the Massachusetts Institute of Technology and was previously an analyst at the Bipartisan Policy Center and the Duke University Energy Initiative. He holds a master's degree in environmental management from Duke University and a PhD in public policy from Harvard University.

**Seth Villanueva** is a senior research analyst at Resources for the Future. His current work focuses on energy projection analysis for RFF's annual *Global Energy Outlook* as well as research on the regional and distributional effects of clean energy and climate policy. Villanueva graduated from UC Santa Barbara in 2019 with a BA in economics and a minor in mathematics. At UCSB, he was an undergraduate Gretler

Fellow research assistant studying the economic effect of scaled wind power generation.

## Acknowledgments

The authors would like to thank participants in the Clean Energy Buyers Association Data Harmonization Group, participants in the RFF stakeholders' workshop in March 2022 for helpful input and discussions, and Holly Lahd, Avi Allison, Hallie Cramer, and Savannah Goodman for comments on an earlier draft. This project was funded by Meta Platforms Inc., Apple Inc., Google LLC, and Microsoft Corporation in partnership with the Clean Energy Buyers Association.

## About RFF

Resources for the Future (RFF) is an independent, nonprofit research institution in Washington, DC. Its mission is to improve environmental, energy, and natural resource decisions through impartial economic research and policy engagement. RFF is committed to being the most widely trusted source of research insights and policy solutions leading to a healthy environment and a thriving economy.

Working papers are research materials circulated by their authors for purposes of information and discussion. They have not necessarily undergone formal peer review. The views expressed here are those of the individual authors and may differ from those of other RFF experts, its officers, or its directors.

## Sharing Our Work

Our work is available for sharing and adaptation under an Attribution-NonCommercial-NoDerivatives 4.0 International (CC BY-NC-ND 4.0) license. You can copy and redistribute our material in any medium or format; you must give appropriate credit, provide a link to the license, and indicate if changes were made, and you may not apply additional restrictions. You may do so in any reasonable manner, but not in any way that suggests the licensor endorses you or your use. You may not use the material for commercial purposes. If you remix, transform, or build upon the material, you may not distribute the modified material. For more information, visit <https://creativecommons.org/licenses/by-nc-nd/4.0/>.

# Abstract

Demand for data on the CO<sub>2</sub> intensity of US electricity consumption is growing as governments and private companies seek to understand the emissions effects of both their electricity consumption and their clean energy investment choices. The desire for transparent and consistent data on electricity emissions rates led the US Congress, in the Infrastructure Investment and Jobs Act, to call for the US Energy Information Administration (EIA) to publish spatially and temporally granular electricity emissions rate data, beginning in late 2022. This report reviews the use cases for emissions rate data and options available to EIA to publish data on both average and marginal emissions rates, and it presents relevant findings and recommendations for EIA to consider.

# Contents

<b>About the Authors</b>	ii
<b>Acknowledgments</b>	iii
<b>About RFF</b>	iii
<b>Sharing Our Work</b>	iii
<b>Abstract</b>	iv
<b>Contents</b>	v
<b>Executive Summary</b>	1
<b>Summary of Findings</b>	1
<b>Summary of Recommendations</b>	3
<b>Average Emissions Rates</b>	3
<b>Marginal Emissions Rates</b>	3
<b>All Emissions Rates</b>	4
<b>1. Introduction</b>	6
<b>Overview of Project</b>	8
<b>2. Emissions Rate Metrics and Their Use Cases</b>	10
<b>Retrospective Accounting Use Cases</b>	10
<b>Operational and Investment Decisionmaking Use Cases</b>	12
<b>Operational Decisionmaking Use Cases</b>	13
<b>Investment Decisionmaking Use Cases</b>	14
<b>Emissions Rate Metrics</b>	16
<b>Relevant Metrics in the IIJA</b>	19
<b>3. Evaluation of Existing Methods and Data Sources</b>	21
<b>PJM</b>	21
<b>ISO-NE</b>	22
<b>REsurety</b>	22
<b>electricityMap</b>	23
<b>WattTime</b>	24
<b>Singularity</b>	25
<b>Discussion and Evaluation</b>	25
<b>4. Data Standardization: Definitions, Formats, Methods of Transfer, and Potential Benefits</b>	31

<b>5. Barriers to Collecting and Reporting Residual Mix</b>	35
<b>6. Potential Pathways for EIA</b>	38
<b>Average Emissions Rates</b>	38
<b>Marginal Emissions Rates</b>	39
<b>EIA Collects Marginal Emissions Rate Data from Balancing Authorities</b>	40
<b>EIA Supplements Balancing Authority Data with Third-Party Sources</b>	42
<b>Anticipate Data Standards</b>	44
<b>7. Appendix A: Other Approaches to Emissions Rates</b>	45
<b>EPA AVERT</b>	45
<b>EPA eGRID</b>	45
<b>Kevala</b>	45
<b>NREL Cambium</b>	46
<b>8. References</b>	47

# Executive Summary

Decarbonization efforts in the US consist of a mix of government policies to promote clean sources of energy and improve energy efficiency and voluntary actions by private actors to reduce their CO<sub>2</sub> emissions. Understanding both the likely and actual benefits of both policies and private actions requires information about the carbon intensity of different sources of energy including electricity. Demand for data on the CO<sub>2</sub> intensity of US electricity production and consumption is growing as governments and private companies seek to understand the emissions effects of both their electricity consumption and their clean energy investment choices. Emissions rate information is also important for Scope 2 emissions accounting under the GHG Protocol Corporate Standard<sup>1</sup> that provides a way of tracking progress toward clean energy targets that many companies have declared.

The desire for transparent and consistent data on electricity emissions rates led the US Congress, in the Infrastructure Investment and Jobs Act (IIJA), to call for the US Energy Information Administration (EIA) to publish spatially and temporally granular electricity emissions rate data, beginning in late 2022. Specifically, the IIJA calls on EIA to report on hourly operating data, including “where available, the estimated marginal greenhouse gas emissions per megawatt hour of electricity generated” within each balancing authority and by pricing node. The law also calls on EIA to harmonize its electric system operating data with GHG and other relevant data collected by EPA or other federal agencies, as well as data collected by state or renewable energy credit registries. The resulting integrated data set should include net generation data and “where available, the average and marginal greenhouse gas emissions by megawatt hour of electricity generated within the boundaries of each balancing authority,” to be offered on a real-time basis through a publicly accessible application programming interface (API).

This report reviews the use cases for emissions rate data and options available to EIA to publish data on both average and marginal emissions rates. Our findings and recommendations for EIA’s consideration are listed below.

## Summary of Findings

- The emissions metrics requested of EIA in the IIJA are relevant to both retrospective emissions accounting (typically hourly average emissions

---

<sup>1</sup> For more information on the GHG Protocol Corporate Standard, see: <https://ghgprotocol.org/corporate-standard>.

rates) and near-term operating decisions (short-run, hourly marginal operating emissions, at the balancing authority or nodal level, and in real time). These are the most common applications, although in certain cases, average emissions rates can be used to inform operational decisions and marginal rates can be used for retrospective purposes.

- The primary two types of approaches used by providers of real-time operating marginal emissions rate data are (1) economic dispatch-based approaches that reveal the characteristics of the marginal generator(s) at specific locations to which estimated emissions rates can be applied; and (2) statistical and machine learning models that predict marginal generator type(s) at a point in time based on how generation (and hence emissions) will change in response to changes in load under different grid conditions, including load levels, prices, and weather.
- The two approaches to calculating marginal emissions rates—economic dispatch-based and statistical—have trade-offs. Economic dispatch-based approaches reflect the algorithms used by grid operators and can yield granular nodal estimates, but they require access to detailed data often known only to grid operators. Statistical approaches are more scalable to new regions because they rely primarily on publicly available data, but they can struggle to produce reliable estimates at the very disaggregated nodal level.
- All marginal emissions rate estimation methodologies are imperfect for one reason or another. For example, marginal emissions estimates produced by economic dispatch-based approaches are strictly valid only for small changes in load (say, 1 MW or less). A change in load large enough to change which generator is marginal will lead to a different marginal emissions rate, and the magnitude and direction of this difference are not necessarily known without more detailed information on the dispatch stack and transmission constraints (or reduced-form representations of them by fuel type). Estimates produced by statistical models inevitably involve assumptions and approximations that also lead to imperfect estimates.
- Approaches to calculating marginal emissions rates that yield geographically and temporally detailed data require aggregation to create hourly estimates and estimates at broader spatial resolutions, such as at the balancing authority or sub-balancing-authority level. When transmission is constrained, multiple generators will be on the margin; in those cases, one approach to spatial aggregation (used by ISO New England (ISO-NE)) would be taking weighted averages, weighing the emissions rate estimates for those generators by the amount of load served by each. Translating sub-hourly values into hourly could be done using different approaches. ISO-NE uses both a time-based approach and a marginal load-based approach to weighting five-minute estimates to provide two different estimates of hourly marginal emissions rates.

- Providing information on the emissions rates for the residual mix is challenging for EIA in the near term because information on privately procured clean energy (outside the transactions directly involving the utilities from which it typically collects information) is limited.

## Summary of Recommendations

### Average Emissions Rates

- EIA has a clear path forward for producing average emissions rates (both production- and consumption-based) through an extension of the methodology underlying its recently released hourly national average emissions rate estimates.<sup>2</sup> EIA is already producing production-based average emissions estimates at the national level, and the same methodology could be applied at the balancing authority level, with appropriate adjustments to assumed emissions factors. In extending those methods to produce consumption-based average emissions rate estimates at the balancing authority (rather than national) level, EIA should account for interchange between regions—for example, by using flow-tracing algorithms, as mentioned in this report. Other improvements can be made on an ongoing basis—for example, by using more regionally (e.g., balancing authority level instead of national) and temporally (e.g., seasonal or monthly instead of annual) granular and representative estimated emissions factors.

### Marginal Emissions Rates

- For marginal emissions rates, EIA has several reasonable options that we would endorse. Our preferred approach would be to request that the data be reported by the balancing authorities, from which EIA routinely collects grid operating data in real time. PJM and ISO-NE are balancing authorities that are already producing marginal emissions rate estimates, and some others could produce analogous estimates. Below are three potential approaches that a balancing authority could take to produce such estimates, listed in order of preference, contingent on implementability, which may vary by balancing authority.
  1. Adopt a methodology similar to that of PJM and ISO-NE, which use their economic dispatch algorithms to identify marginal generators.
  2. Extend the balancing authority's existing methodologies that identify marginal sources of generation (e.g., MISO reports data on marginal fuel types) and then apply emissions factors. In some instances, EIA could perform such calculations in house—for example, by taking MISO's reported fuel on the margin dataset and

---

<sup>2</sup> Currently available at [https://www.eia.gov/electricity/gridmonitor/knownissues/xls/Region\\_US48.xlsx](https://www.eia.gov/electricity/gridmonitor/knownissues/xls/Region_US48.xlsx); a link is on EIA's main electricity landing page, <https://www.eia.gov/electricity/>.

applying emissions factors, just as EIA does in its calculation of average emissions rates.

3. Partner with existing data providers to develop such estimates (e.g., the model used by the [California Self-Generation Incentive Program](#)).
- It is unlikely that all balancing authorities will be able to produce marginal emissions rate estimates right away; therefore, EIA would need additional sources to publish nationally comprehensive data on marginal emissions. Although some existing methods (such as the statistical methods discussed in this report) can produce geographically comprehensive estimates of marginal emissions rates for all balancing authorities in the contiguous 48 states, quantitative comparisons of their estimates are insufficient. Thus, we recommend that an independent organization work with third-party providers of emissions rate data and compile a comprehensive set of marginal emissions rate estimates, then use those data to quantify their similarities and differences and assess their relative reliability. This compilation and quantitative comparison of data would allow data users to better understand the differences among alternative estimates. It would also enable data providers and other analysts to improve, compare, validate, stress-test, and harmonize their methods and data products.
  - Such a public quantitative comparison would inform EIA's task of providing marginal emissions rate information in regions where balancing authorities may not yet be able to produce the necessary data. With a public data comparison in place, EIA could then consider publishing data provided by third-party organizations, such as those discussed in this report, with clear and appropriate data definitions, descriptions, and caveats.
  - If multiple approaches to estimating a particular emissions rate metric are available and deemed reliable, EIA should consider presenting more than one set of estimates so that data users and researchers, at EIA or elsewhere, can compare the various methods to understand their differences. When presenting multiple estimates for the same metric, EIA should include clear definitions of the data, include caveats, and note the underlying methodology (e.g., economic dispatch, statistical). These recommendations would apply regardless of the entity—EIA or an independent third party—presenting the standardized estimates.

### **All Emissions Rates**

- Although there are not yet standards for emissions-related data, balancing authorities, utilities, private companies, and government agencies can work now to build flexibility into their data publishing systems (e.g., the static files they publish and the APIs they maintain) so that they can more easily adapt those systems to any future data standards. This is relevant both for data that are used as inputs to the estimation of emissions rates (e.g.,

information on dispatch) and for the publication of emissions rate estimates themselves (e.g., average and marginal emissions rates). EIA should consider making its emissions rates and other data conform, as applicable, to any future standards. That would facilitate the transferability and scalability of data and applications among regions and promote data transparency and reliability.

- For emissions rate data specifically, data publishers should be transparent and provide documentation for their metrics, including the conceptual basis for each metric and the underlying methodologies and data sources. Such documentation ensures that users understand what the data mean and how they should be used, while also setting the stage for future standardized data definitions that might incorporate (and differentiate) the metrics provided by different entities.
- As part of the IIJA's required interagency data harmonization process, EIA should coordinate with EPA, including the Green Power Partnership, which has expertise in voluntary renewable procurement, to ensure common understanding of the scope of data collection necessary to develop estimates of residual mix emissions rates.

# 1. Introduction

The path toward decarbonization in the United States entails not only a mix of federal, state, and local government policies promoting clean energy, but also voluntary efforts by private actors to reduce their CO<sub>2</sub> emissions. Understanding both the likely and the actual benefits of such actions requires information about the carbon emissions intensity of different sources of energy. Given its major role as a source of both CO<sub>2</sub> emissions and low-cost emissions reductions, the electricity sector features prominently in discussions about emissions rates and the importance of emissions rate information. And the expectation of greater electrification of buildings and transport means that interest in electricity emissions rate information is likely to grow over time.

Currently, emissions rate information is being used by governments to inform new building codes and building performance standards, to guide energy efficiency investments, to undergird electrification policies, and to monitor progress toward climate goals. Private companies and other organizations are using emissions rate information to inform investment and operating decisions and to monitor progress toward their own decarbonization goals. Many firms are also undertaking various forms of voluntary carbon accounting, which requires access to reliable data on electric grid emissions for Scope 2 accounting under greenhouse gas (GHG) reporting protocols (Sotos 2015). Moreover, under recently proposed rules from the Securities and Exchange Commission to increase transparency about climate risks and their effects on business activity, all publicly traded companies would be required to report their direct greenhouse gas emissions as well as the carbon emissions associated with their purchased electricity as a part of their 10-K financial disclosures (Securities and Exchange Commission 2022).

Hence, demand for publicly available and transparent data on the GHG emissions intensity of electricity developed using a common methodology is also growing. As the statistical and analytical agency in the US Department of Energy, the Energy Information Administration (EIA) is the natural candidate to collect and publish these data. By law, EIA's data, analyses, and forecasts are independent and not subject to approval by any other government agency or employee, which makes EIA a trusted source of quality data. Under authority granted by US law, most recently the Department of Energy Organization Act of 1977, EIA conducts a comprehensive data collection program that covers the full spectrum of energy sources, end uses, and energy flows. EIA disseminates its data and other products primarily through its website, EIA.gov.

For the electricity sector, EIA regularly collects data from generators on their operations and fuel use and from utilities on sales to customers and revenues, among other variables. In 2015, EIA added to its website an hourly grid monitor with detailed data on electricity demand, net electricity generation by fuel source, and

electricity interchange by balancing authority for every hour of the day, as requested in form EIA-930. There is roughly a 75-minute lag between when the data for the hourly grid monitor is provided to EIA and when it appears on the website. EIA also reports annual estimates of emissions of CO<sub>2</sub>, sulfur dioxide (SO<sub>2</sub>), and nitrogen oxides (NO<sub>x</sub>) by generator and by geographic region.<sup>3</sup>

However, having estimates of emissions by generator on an annual basis is not sufficient for GHG accounting or understanding how decisions about electricity use will affect emissions from the grid. Those applications require an association between emissions and end use, information not currently reported by EIA. That data gap is addressed in a new requirement found in the Infrastructure Investment and Jobs Act,<sup>4</sup> which was signed into law by President Biden in November 2021. Section 40412 of the IJJA calls on EIA to report on hourly operating data, including “where available, the estimated marginal greenhouse gas emissions per megawatt hour of electricity generated” within each balancing authority and by pricing node.<sup>5</sup> Sections 40412 and 40419 of the law also call on EIA to harmonize its electric system operating data with GHG and other pollutant emissions data collected by EPA, other relevant data collected by EPA or other federal agencies, and data collected by state or regional energy credit (REC) registries. The resulting integrated data set should include net generation data and “where available, the average and marginal greenhouse gas emissions by megawatt hour of electricity generated within the boundaries of each balancing authority,” to be offered on a real-time basis through a publicly accessible application programming interface.<sup>6</sup>

As EIA works to respond to this request, it is important to recognize the parameters that shape the agency’s approach to new data collection efforts. As a government agency, EIA is subject to oversight by the Office of Management and Budget (OMB), which under the Paperwork Reduction Act of 1995 rules on the appropriateness of all

---

<sup>3</sup> EIA’s estimates of CO<sub>2</sub> emissions from generators are derived from information on fuel-specific emissions factors from the Environmental Protection Agency’s *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019* and *Greenhouse Gas Emissions Factor Hub*, applied to data on fuel consumption and heat content of fuel collected on form EIA-923. EPA also collects hourly data on emissions of various air pollutants, including CO<sub>2</sub>, from all generators with 25 MW or more of generating capacity required to install continuous emissions monitors, which are used to measure compliance with emissions regulations. These data are supplemented with data on gross generation. The data are made available to the public by EPA with an approximately quarterly lag.

<sup>4</sup> See Infrastructure Investment and Jobs Act (2021).

<sup>5</sup> Collection of data by pricing node is relevant for those independent system operators or regional transmission operators that run day-ahead or real-time electricity markets, which determine prices based on marginal bids by generators that offer to sell energy into the market and the presence or absence of congestion on the transmission grid.

<sup>6</sup> The IJJA also calls on EIA to collect additional data on integration of distribution grids and the bulk power system and on distribution system operations within a year of enactment and to expand the types of information on energy end use and other variables collected as part of the Manufacturing Energy Consumption Survey, the Commercial Building Energy Consumption Survey, and the Residential Energy Consumption Survey. EIA is also called on to expand the collection of international data and to develop a plan to update the capabilities of the National Energy Modeling System along several dimensions.

government-sponsored surveys that collect data from 10 or more respondents. When it proposes to implement a new survey or augment or update an existing one, EIA must demonstrate that the sought-after data are relevant, that the data collection method is efficient, and that there is a strong likelihood of statistical success. As a part of that process, EIA must also issue a notice in the *Federal Register* of its intentions to augment or modify existing survey instruments and allow time for public comment on both the initial proposal and the final revised proposal submitted to OMB.<sup>7</sup> Relevance of emissions rate and generation mix data to both private and public decisionmaking is well demonstrated (and discussed in more detail in this report). Efficiency depends on whether the data are already collected by the target entities and over what time frame the data are requested. Efficiency is also related to the effort associated with reporting the data to EIA; in keeping with US law, EIA seeks to use data collection methods that provide useful information while minimizing the burden on respondents. Likelihood of statistical success is related to the ability to communicate the data request in a way that all respondents interpret similarly so that the collected data are comparable across respondents.

Before publishing survey results on its website, EIA typically conducts quality checks on its data to ensure accuracy and provides notice when data are preliminary and subject to revision, as well as when data have been revised.<sup>8</sup> There is a trade-off between the speed with which collected data are made available to the public and EIA's ability to conduct thorough reviews of the quality of submitted data. Timing can also lead to inconsistencies between EIA's hourly real-time data, reported by balancing authorities in form EIA-930, and its monthly data, reported by power plants in form EIA-923; EIA has recognized this issue and is working on it.<sup>9</sup>

To ensure continuing relevance of its information and data collection efforts, EIA monitors information needs on an ongoing basis and develops new data sources or revises existing surveys when appropriate.

## Overview of Project

The purpose of this project is to identify pathways that EIA could take to collect and provide information necessary to meet the electricity grid mix and detailed emissions rate data reporting requirements of the IIJA. Producing these detailed data sets on CO<sub>2</sub> emissions rates is a new endeavor and just one among several requests of EIA in the IIJA, in addition to the agency's other ongoing obligations. In this report, we provide background on data uses of emissions rate data and why

---

<sup>7</sup> The process for obtaining approval from OMB for a new information collection request (outlined here: <https://pra.digital.gov/clearance-process/>) is said to typically take six to nine months.

<sup>8</sup> For more information on EIA's information quality guidelines and several of the issues discussed in this paragraph, see [https://www.eia.gov/about/information\\_quality\\_guidelines.php](https://www.eia.gov/about/information_quality_guidelines.php)

<sup>9</sup> See this recent request to add questions to form EIA-930 to help reconcile the data sets: <https://www.federalregister.gov/documents/2022/05/23/2022-11012/agency-information-collection-proposed-extension>.

such data are important. We then describe and assess emissions rate concepts, sources, and estimation methodologies, and we evaluate how alternative sources and methodologies align with different use cases and with the metrics required by the IJJA. We also describe the trade-offs EIA faces among the timeliness, quality, and comprehensiveness of the data. The goal is to inform and help advance EIA's data collection efforts.

The information provided in this report is drawn from many sources, including meetings and interviews with both private and public data providers to learn more about their approaches to estimating emissions rates, the temporal and geographic characteristics of their estimates, the information they use as inputs to their estimation methods, and how their estimates might be of help to EIA. We also met with data users, including many firms with ambitious clean energy goals, experts in standards for clean energy information, and other stakeholders in the emissions rate data process, such as those leading efforts to establish common approaches to data definitions and provision across the globe. We met monthly with the Data Harmonization Working Group of the Clean Energy Buyers Association (CEBA) to get input on project progress. We also met with representatives of EIA to discuss what types of information would be useful and learn about their potential constraints and opportunities.

In addition, we held a half-day virtual workshop that included presentations on various uses of emissions rate data, presentations from several private companies and nonprofits that provide these data, and presentations from representatives of EIA. This event allowed EIA to learn about a range of use cases for emissions rate data and to hear from private sector data providers about their approaches and other users about how they use energy and emissions data. EIA also shared information on past efforts in response to a similar request by Congress to estimate emissions from city-level electricity consumption and on the OMB process for approving new data requests from EIA. In addition to the panelists, participants included representatives from EPA, academic experts in electricity markets, and staff from independent system operators (ISOs) and other utilities that act as balancing authorities.<sup>10</sup>

---

<sup>10</sup> Throughout this document we use the term *independent system operator* to refer to both ISOs and regional transmission organizations (RTOs).

## 2. Emissions Rate Metrics and Their Use Cases

The many potential use cases for greenhouse gas emissions data can be classified into three high-level categories: retrospective accounting, operational decisionmaking, and investment decisionmaking.

Use cases in the first category are concerned with accounting for the emissions associated with the past activities or operations of an organization. What drives these use cases is the need to understand where and when emissions were produced, who consumed the associated energy, and who can claim credit for the generation of clean energy.

In contrast, use cases in the latter two categories are focused on understanding the potential consequences of an action that has not yet been taken. These are decisionmaking uses, oriented toward the future rather than the past. The operational and investment uses differ in time horizon and, in turn, degree of evolution and/or response that they expect to see in the energy system.

As discussed below, specific use cases both across and within the three categories often have different needs for spatial and temporal resolution and publishing frequency.

### Retrospective Accounting Use Cases

Use cases in the retrospective accounting category are concerned with measuring the greenhouse gas emissions produced in a particular location for a given time period and assigning those emissions to different entities—without double-counting, to the extent possible. This approach is retrospective in that it aims to account for past emissions, though the time periods for the estimates can vary.

As it relates to the consumption of electricity, the primary use case in this category is Scope 2 emissions accounting. Scope 2 fits within the corporate-level standard of the GHG Protocol, which aims to provide an internationally accepted set of methods for GHG accounting and reporting.<sup>11</sup> Organizations use the Scope 2 Guidance on a voluntary basis to quantify the emissions from the generation of electricity<sup>12</sup> that they purchase and consume. In this way, Scope 2 accounting supports organizational climate action and renewable energy investment. The reporting period for Scope 2 emissions—that is, the time over which emissions are measured and reported—is typically one year. Depending on availability, the resolution of the

---

<sup>11</sup> For more information, see the Scope 2 Guidance on the GHG Protocol website: [https://ghgprotocol.org/scope\\_2\\_guidance](https://ghgprotocol.org/scope_2_guidance).

<sup>12</sup> Scope 2 accounting also covers the emissions associated with the purchase and consumption of steam, heat, and cooling. See Sotos (2015).

underlying data may match the reporting period or, in some cases, be more granular (see below).

The Scope 2 Guidance codifies two methods for Scope 2 accounting: location-based and market-based. The location-based method relies on the average emissions intensity of the grid on which electricity consumption occurs, whereas the market-based method relies on the emissions associated with the electricity that an organization has procured by contractual agreement. Each method requires its own set of emissions rate data (at the grid-wide level and at the electricity-supplier level, respectively), and both require organizations to track their energy consumption over the course of the reporting period. As the reporting period for organizations is often a single year, the required consumption and emissions rate data can typically be aggregated to the annual level, and some amount of publishing lag can be accommodated. However, Scope 2 accounting can benefit from the use of hourly data even within an annual reporting period because annual-average grid emissions factors may over- or under-estimate carbon inventories by as much as 35 percent, depending on variation in both grid carbon intensity and energy consumption over the year (Miller et al. 2022).

Closely related to Scope 2 accounting is the residual mix, which represents the emissions produced in a geography over a given time period, excluding generation by units that has already been claimed by consuming entities. The Scope 2 Guidance specifies that, under the market-based method, consumers should use the residual mix to calculate emissions for the portion of their consumption not associated with the purchase of certificates or with a contract, or where supplier-specific information is unavailable. In this way, the residual mix aims to avoid double-counting: it allows a given amount of clean energy generation to be credited to a single consuming entity only. Calculation of the residual mix, in turn, requires detailed data about energy that has already been claimed, such as renewable energy certificates (RECs) created by generators and information about power purchase agreements and other contractual instruments. The residual mix is discussed in more detail below and in Section 5.

A second use case in the retrospective accounting category is tracking progress toward organizations' "24/7" goals, which require the continuous use of clean energy. A key stipulation of such commitments is that the entity's electricity demand must match, on a near-real-time basis, with the clean source of electricity serving that demand. Tracking 24/7 goals therefore requires data with a relatively high level of time granularity (as the name implies, at least hourly) for both production and consumption. In contrast, as discussed above, current Scope 2 accounting often leverages data at the annual level and typically relies on grid-wide emissions factors in the absence of source-specific information.

In addition to 24/7 goals, some organizations are interested in calculating the avoided emissions from the renewable clean energy for which they contract. This

“avoided emissions approach,” which is separate from Scope 2 accounting,<sup>13</sup> often looks to estimate the emissions displaced by a clean energy generator in the economic dispatch stack. It requires spatially and temporally disaggregated data, including information about the production of clean energy generators as well as the emissions rates of the generation that they displace.

Finally, granular emissions data may also be used to demonstrate compliance with local laws. For instance, as part of New York City’s Climate Mobilization Act of 2019,<sup>14</sup> most buildings larger than 25,000 square feet will be required to meet greenhouse gas emissions limits that begin in 2024 and become more stringent over time. A technical amendment to the law<sup>15</sup> allows emissions factors for electricity to be based on time of consumption (rather than annual averages), which suggests another potential use case for high-resolution emissions data.

All the use cases in this category are related in that they are retrospective and seek to measure, and then assign, the emissions (or lack thereof) from electricity generation to energy consumers.

### **Operational and Investment Decisionmaking Use Cases**

Use cases in the operational and investment decisionmaking categories are forward looking: their main goal is to understand the consequence of a present or future action. These use cases often require a business-as-usual baseline: what would happen if the action in question is not taken. From this perspective, the aim is to understand the difference in outcomes between a baseline (i.e., no action) case and an alternative (i.e., action) case.

What distinguishes the use cases in the operational category from those in the investment category is the time horizon under consideration: for the first, the future may be the five-minute interval following the action, whereas for the second, the future may be as distant as a decade or more.

Given that the effect of an action may differ with the time horizon, a distinction is often drawn between the “operating margin” and the “build margin.” The operating margin considers the day-to-day functioning of the energy system while leaving structural factors as they are. For electricity, structural factors include installed

---

<sup>13</sup> Specifically, the GHG Protocol’s Scope 2 Guidance notes that organizations “can report the estimated grid emissions avoided by low-carbon energy generation and use, separately from the scopes” (p. 52; see [https://ghgprotocol.org/scope\\_2\\_guidance](https://ghgprotocol.org/scope_2_guidance)). The guidance states that such estimation should follow the project-level methodology outlined in the GHG Protocol for Project Accounting (“Project Protocol”) and the supplementary Guidelines for Grid-Connected Electricity Projects (see <https://ghgprotocol.org/standards/project-protocol>).

<sup>14</sup> These requirements for buildings were enacted through Local Law 97, which was part of the Climate Mobilization Act. For more information on Local Law 97, see <https://www1.nyc.gov/site/sustainablebuildings/ll97/local-law-97.page> and <https://www.urbangreencouncil.org/content/projects/all-about-local-law-97>.

<sup>15</sup> For more information, see the text of Local Law 147 of 2019: [https://www1.nyc.gov/assets/buildings/local\\_laws/ll147of2019.pdf](https://www1.nyc.gov/assets/buildings/local_laws/ll147of2019.pdf).

capacity, transmission constraints, and patterns of demand anticipated by regional balancing authorities. The operating margin takes these factors as fixed; the build margin assumes the possibility of longer-term changes in the overall system, such as the construction or retirement of generators, changes in the transmission and distribution networks, and the addition of load to the grid that is factored into the balancing authority's planning processes.

Use cases in the operational decisionmaking category typically consider effects on the operating margin, whereas use cases in the investment decision-making category may consider effects on both the operating and the build margins. The data requirements for both are described in more detail below and summarized in Table 1.

### **Operational Decisionmaking Use Cases**

Use cases in the operational decisionmaking category range from demand response, scheduling of large loads, and energy storage dispatch to electric vehicle charging. The common theme across the varied cases is the need to decide when to use—or not to use—energy to maximize environmental and other objectives.

Consider electric vehicle charging. A car parked during the day may not need to be continuously charging to be at full capacity for the end-of-day commute. Rather, charging can opportunistically start and stop to take advantage of periods when electricity is being supplied with clean energy, thereby helping reduce the overall emissions of the grid.<sup>16</sup>

Such operational decisionmaking use cases seek to leverage data that are temporally granular and published at the highest frequency. Other use cases where consumption can be adjusted without much lag are certain kinds of demand response and energy storage dispatch—uses that take advantage of data published on a real-time or near-real-time basis and at a subhourly level of granularity (e.g., five- or 15-minute intervals), as well as near-term forecasts of emissions intensity.

These cases are also likely to benefit from standardized and machine-readable data transfer, such as through an API. This benefit is partly due to the data themselves, since high-granularity, high-frequency data are often easier to access and process when they can be integrated into automated computer systems. Data transfer is also highly valuable for load shifting for energy-using durables, such as appliances and cars. In these instances, consumers often rely on third-party software and hardware to retrieve data and make energy consumption adjustments automatically.

Finally, some case may have flexibility in scheduling a load but the decision can be made with a lead time of hours or days rather than seconds or minutes. The benefits of these decisions will still be experienced on the operating margin, though the decisionmaking process requires projecting conditions in the near-term future (such as a day-ahead forecast) rather than the current moment.

---

<sup>16</sup> For a more detailed discussion of electric vehicle charging and emissions, see Daniels et al. (2022).

## Investment Decisionmaking Use Cases

Use cases in the investment decisionmaking category consider effects to the energy system from changes that will persist more than several years in the future.<sup>17</sup> Such use cases include where to build new clean energy generation, where to site new energy-consuming facilities, where to invest in energy storage, how to develop transmission capacity to connect generation to demand, and more generally, how to design power markets to facilitate environmental and other goals.<sup>18</sup>

The primary distinction between operational and investment decisionmaking cases is that the latter case considers effects on both the operating margin (in the nearer term) and the build margin (in the longer term). Take the siting of a large new data center—an energy-consuming facility. In its first several years of operation, the center may induce operational changes on the electricity grid, including which generating units are dispatched and for how long. In the longer term, the regional utility, balancing authority, independent power producers, and/or transmission operator—knowing that the data center is permanent—may implement changes to the grid to better serve the new baseline load, which could include new clean energy capacity and changes to the transmission network.

In this way, use cases in this category require modeling that goes well beyond a day-ahead forecast. By understanding how the energy system may evolve over the course of several years or more, investors can choose the timing and location of their projects to maximize their climate and other goals, such as building additional clean energy capacity based on the siting of large loads.

---

<sup>17</sup> For additional discussion in the context of short-run and long-run marginal emissions rates, see Gagnon et al. (2021).

<sup>18</sup> For an example of how to incorporate marginal emissions rates into electricity market design to encourage investment in clean generation capacity where it is most beneficial, see Spees et al. (2017).

**Table 1. Summary of Uses for Emissions Rate Data**

Category	Time Horizon	Example Use Cases	Data Needs
Retrospective accounting	Backward looking	Scope 2 accounting	Annual (or more granular) electric energy consumption data; annual (or more granular) emissions rate data (including residual mix)
		24/7 accounting	Hourly energy consumption data; hourly production data by fuel type; emissions rate assumptions by fuel type for full mix
		Avoided emissions	Hourly production data by contracted generator; emissions rate assumptions for displaced energy by node, region, and/or balancing authority
Operational decisionmaking	Forward looking (operating margin)	Demand response, electric vehicle charging, energy storage dispatch	Emissions rate data with high time granularity and published with high frequency
		Large load scheduling	Short-term forecasts of emissions rates
Investment decisionmaking	Forward looking (both operating and build margins)	New clean energy generation, new load siting, transmission changes, market design	Long-term projections of grid structure and operations

The specific data needs of use cases in this category may vary. For some, including where to build new clean energy generation and where to site new energy-consuming facilities, it is valuable to understand the future emissions intensity of the electricity grid at a spatially granular level. Given that local factors, such as transmission constraints, can affect how energy flows from producers to consumers, such detailed information can help decisionmakers site their energy projects to achieve their objectives. Other use cases, such as where to invest in energy storage,

could also find value in temporally granular estimates, since the emissions effects of such projects depend in large part on how they respond to fluctuations in the emissions intensity of the grid over time (e.g., for energy storage, through strategically timing its charging and discharging to reduce overall emissions).

We note that many of the data needs listed in Table 1 for retrospective accounting and operational and investment decisionmaking use cases are not currently being met.

## Emissions Rate Metrics

The use cases described above call for different types of emissions rate metrics. Average and marginal emissions rates are both explicitly requested in the IIJA. The residual mix is a type of average. All these emissions rates are tied to a particular location or region (e.g., eGRID region, balancing authority, or node) and time interval (e.g., hour, five-minute interval).

The **average emissions rate** is the simplest category: it is total CO<sub>2</sub> emissions divided by total MWh generated or consumed. Average emissions rates vary along several dimensions. **Production-based averages** reflect only generation and emissions within the location or region in question; **consumption-based averages** reflect the emissions intensity of electricity delivered to a particular location or region, accounting for any emissions associated with imported or exported electricity.<sup>19</sup>

Whether production- or consumption-based, average emissions rates are often used for retrospective accounting, though they may be applicable for decisionmaking use cases as well.

---

<sup>19</sup> As previously discussed, emissions rates used for Scope 2 accounting can be location-based values, representing physical emissions impacts, or market-based, representing contractual relationships. Here, we discuss location-based measures because market-based ones are not the focus of the IIJA.

### The Math behind the Metrics

Mathematical definitions for the three main kinds of emissions rate metrics follow. The values for each metric can be calculated for a given region (e.g., eGRID region, BA, node) and time interval (e.g., hour, five-minute period).

- Average emissions rate:  $\frac{\text{total } CO_2}{\text{total } MWh}$
- Marginal emissions rate:  $\frac{dCO_2}{dMWh}$
- Residual mix emissions rate:  $\frac{\text{total } CO_2}{\text{total } MWh - \text{claimed clean } MWh}$

There are also both production-based and consumption-based concepts of some of these metrics, such as production-based averages (where the total CO<sub>2</sub> value only reflects generation within a region) versus consumption-based averages (which account for emissions associated imported electricity from neighboring regions).

The second category of emissions metric is a **marginal emissions rate**, defined as the change in CO<sub>2</sub> emissions that results from a very small increase in electricity consumption at a particular location and time. The focus is on causal effects: How many tons of emissions are caused by a given change in electricity use?

The **residual mix emissions rate** resembles an average emissions rate, but where the MWh value in the denominator removes energy for which the environmental attribute has been retained, or “claimed.” This adjustment avoids the potential for double-counting: it prevents multiple entities from laying claim to the environmental attributes of the same clean energy generation.

### How the residual mix metric avoids double-counting

The residual mix emissions rate is a type of average emissions rate in which “claimed” clean generation is removed from the denominator. A simple example shows how this metric avoids double-counting of emissions under Scope 2 protocols.

Suppose there are two companies, A and B, purchasing energy in a market of 100 MWh, of which 40 MWh come from carbon-free wind and 60 MWh are generated by coal with an emissions rate of 1 ton CO<sub>2</sub>/MWh. This results 60 tons of CO<sub>2</sub> emissions, for an average emissions intensity of 0.6 tons/MWh. Company A purchases the 40 MWh of wind and thereby claims credit for zero tons of electricity emissions. At the same time, company B purchases 60 MWh of undifferentiated power. Using the grid average emissions rate to estimate its emissions, company B would calculate only 60 MWh \* (0.6 tons/MWh) = 36 tons CO<sub>2</sub>, resulting in a combined accounting of 36 tons of emissions for the market as a whole (0 tons for company A plus 36 tons for company B). This accounting understates the actual total of 60 tons. To reach the correct accounting, company B would have to use the residual mix, as recommended by **Scope 2 GHG Protocols**, which would be calculated as (60 tons)/(100 total MWh – 40 claimed MWh) = (60 tons)/(60 MWh) = 1 ton/MWh. Under the residual mix, the total accounting of 60 tons (0 tons for company A plus 60 tons for company B) accurately reflects total emissions.

Another dimension of variation for emissions metrics is the time horizon. Average and marginal emissions rates can both be conceptualized as an average over either **short or long time horizons**. As with the operating margin versus the build margin (above), averages over short time horizons generally take the structure of the grid as fixed, whereas long time horizons account for future changes in generation mix, transmission, and other factors. There are further refinements for short and long time horizons,<sup>20,21</sup> but a common short-run metric is the “operational” emissions rate, which considers only the immediate operation of the grid as it currently exists. This is most relevant for use cases in the operational decisionmaking category, like the timing for charging an electric vehicle, whereas long-run rates are more relevant for actions with sustained or long-term consequences over years. Note, however, that continually repeated short-run actions (e.g., shifting intraday load from peak to off-peak periods) can also have long-run consequences (Gagnon and Cole 2022).

<sup>20</sup> For more detail, see Miller (2022), who distinguishes among operational margin, short-run, build margin, and long-run emissions rates.

<sup>21</sup> The term “short run” can be used in multiple ways. One involves the time horizon, where short run refers to an hour, a day, a month, or a year or two, and long run means five, 10, or 20 years. The terms can also be used in the economic sense: short-run emissions metrics reflect the immediate operation of the grid, without accounting for potential for structural changes in the mix of generating resources, and long-run rates reflect the potential for those changes, such as additional clean electricity, built either independently or as a result of an intervention that affects load or generation. See Gagnon and Cole (2022) for more discussion.

Metrics also vary in their **spatial and temporal resolution**. The degree of spatial aggregation can be nationwide, eGRID region, balancing authority, or pricing node. Greater spatial resolution can better reflect transmission constraints, which can limit the deliverability of clean energy and hence cause emissions intensities to diverge across space. Temporal resolution can also vary, from highly resolved (five minutes) to hourly to highly aggregated (a year). If an emissions metric is provided at finer time granularity than necessary (e.g., in five-minute intervals when hourly data are needed), the data can be aggregated to the coarser resolution by taking a weighted average over the longer time period. The appropriate weights would vary by use case and would correspond to the load profile over the aggregated period. A constant load over the time period would imply using equal weights, whereas a varying load profile would place greater or lesser weights on the subintervals in proportion to periods of higher or lower energy consumption, respectively.

Finally, emissions rate metrics can be either **retrospective** or **prospective** values. Retrospective estimates, such as the emissions intensity of electricity generation yesterday, last month, or last year, are directly and indirectly useful for several purposes, including emissions accounting (see below). Prospective estimates, such as day-ahead forecasts of emissions intensity today and tomorrow, are useful for operational decisions by entities wishing to shift their load to low-carbon periods of the day. Prospective estimates over longer time horizons, such as years, are primarily useful for long-term investment decisions. As forecasts, prospective values are, by definition, estimates that rely on historical data (from EIA or elsewhere) and/or modeling to calculate. This highlights one valuable use of EIA emissions rate data—as inputs to inform emissions rate forecasts generated by others. EIA data on emissions rates can also be used for Scope 2 accounting purposes (retrospective data) and for real-time operational decisions (to the extent its Hourly Electric Grid Monitor represents real-time operations).

## Relevant Metrics in the IIJA

For the remainder of this report, we focus on the emissions rate metrics most relevant to EIA under the IIJA. The law directs EIA to augment the data collected from balancing authorities for the Hourly Electric Grid Monitor. The types of data to be included are as follows (emphasis added in bold):

- (B) *Types of data.—The **hourly** operating data collected under subparagraph (A) may include data relating to—*
- (i) *total electricity demand;*
  - (ii) *electricity demand by subregion;*
  - (iii) *short-term electricity demand forecasts;*
  - (iv) *total electricity generation;*
  - (v) *net electricity generation by fuel type, including renewables;*
  - (vi) *electricity stored and discharged;*
  - (vii) *total net electricity interchange;*
  - (viii) *electricity interchange with directly interconnected balancing authorities; and*

- (ix) **where available, the estimated marginal greenhouse gas emissions per megawatt hour of electricity generated—**  
(I) **within the metered boundaries of each balancing authority; and**  
(II) **for each pricing node.**

The law also requires EIA to establish a data set that harmonizes data from EPA, other relevant federal agencies, and data collected by state or regional energy credit registries, covering the following information (emphasis added in bold):

- (A) *the net generation of electricity by megawatt hour within the metered boundaries of each balancing authority; and*  
(B) **where available, the average and marginal greenhouse gas emissions by megawatt hour of electricity generated within the metered boundaries of each balancing authority.**  
(3) *Real-time data dissemination.—To the maximum extent practicable, the system established under paragraph (1) shall disseminate data—*  
(A) *on a real-time basis; and*  
(B) *through an application programming interface that is publicly accessible.*

The text indicates that EIA is tasked with extending its existing Hourly Electric Grid Monitor to include both average and marginal hourly emissions rates, measured at both the balancing authority level (for average and marginal) and the pricing node level (for marginal). This corresponds with the temporal and geographic distribution of the Hourly Electric Grid Monitor, which shows retrospective data on the real-time operation of the US electricity grid at the balancing authority level (although not the pricing node level).

Therefore, in this report we focus on **short-run, hourly operating average and marginal metrics, at the balancing authority or nodal level**, corresponding to the structure of EIA's Hourly Grid Monitor and the IIJA language.

### 3. Evaluation of Existing Methods and Data Sources

We begin with a summary of the methods and data sources used by existing providers of marginal and average emissions rate information that is consistent with the IJA reporting requirements for short-run, hourly operating average and marginal metrics. (See the Appendix for other sources of emissions rate information that are not particularly suited to the request of EIA but could be useful in informing some of the use cases described in Section 2.) We then discuss their advantages and disadvantages.

#### PJM

PJM calculates marginal emissions rates for each load-serving node in its territory using data on the marginal unit(s) multiplied by historical average emissions factors for those units.<sup>22</sup> It leverages the detailed outputs from its economic dispatch algorithm (sometimes referred to as “security constrained economic dispatch,” or SCED) to determine plant operations and locational marginal prices (LMPs). That output includes, for each node and five-minute period, which generators are marginal and to what degree.<sup>23</sup> PJM applies generator-specific historical average emissions factors to marginal generation from those units, and then sums those marginal emissions across the marginal generators to arrive at an overall marginal emissions intensity value. The PJM approach treats imports as having zero emissions because, even though imports can be marginal, PJM “has no detailed information on the generation sources for such imports.”<sup>24</sup>

The data are accessible through the free Data Miner tool<sup>25</sup> or through an API.<sup>26</sup> PJM provides a short documentation primer for its data,<sup>27</sup> with many cautions about how the data should and should not be used. Currently, PJM does not provide public information on a data validation process.

---

<sup>22</sup> PJM does not plan to publish information on marginal emissions rates at nodes that do not serve load, since doing so could reveal the identity of the marginal unit and violate PJM’s commitment to confidentiality. Of the 13,000-plus pricing nodes in PJM, 79 percent are load-serving nodes for which PJM reports marginal emissions rates.

<sup>23</sup> For example, unit A might meet 50 percent of a marginal increase in demand, unit B might meet 35 percent, and unit C would meet the remainder. Some units may also need to ramp down because of transmission constraints, implying negative marginal generation for that unit.

<sup>24</sup> <https://pjm.com/-/media/etools/data-miner-2/marginal-emissions-primer.ashx>

<sup>25</sup> [https://dataminer2.pjm.com/feed/fivemin\\_marginal\\_emissions/definition](https://dataminer2.pjm.com/feed/fivemin_marginal_emissions/definition)

<sup>26</sup> <https://apiportal.pjm.com/>

<sup>27</sup> <https://pjm.com/-/media/etools/data-miner-2/marginal-emissions-primer.ashx>

## ISO-NE

ISO-NE reports marginal emissions rates for the balancing authority as a whole at five-minute intervals also using the identities of marginal units. The raw data in spreadsheet form<sup>28</sup> and a report summarizing them<sup>29</sup> are available with a one- to two-year delay. Akin to PJM's approach, ISO-NE uses the identities of the marginal unit(s) from its dispatch, paired with unit-specific emissions rates derived using EPA's Clean Air Markets Division (CAMD) Continuous Emissions Monitoring System (CEMS) data (or NEPOOL GIS data for units not in the CAMD data<sup>30</sup>). Those unit-specific emissions rates are also permitted to vary by month and on-peak versus off-peak, capturing seasonality and some variation in operating efficiencies at different load levels. As with PJM, imports and exports are treated as having zero emissions because of the lack of data.

The resulting marginal emissions rates are aggregated to produce load-weighted marginal emissions rates by fuel type for each five-minute interval for the ISO-NE region as a whole, which are the most disaggregated values ISO-NE reports publicly. Along with time interval, fuel type, and marginal emissions rate, ISO-NE reports the amount of load (in MW) for which the fuel type was setting the LMP. For example, if two fuels are marginal at a given time—say natural gas at location A and wind at location B—how much load is served by the marginal generator at location A (gas) versus location B (wind) provides important context. ISO-NE aggregates from five-minute intervals to hourly intervals using two approaches: a load-weighted average and a time-weighted average. For more detail, see the above-mentioned annual reports.<sup>31</sup> PJM and ISO-NE use closely related approaches, with two differences: (1) ISO-NE reports balancing authority-wide values, whereas PJM reports values at the nodal level; and (2) ISO-NE releases its values after a one- to two-year delay, whereas PJM releases them with a five-minute delay. ISO-NE's reporting lag is due in part to its use of realized air emissions data from CAMD to calculate unit-specific emissions rates, and CAMD CEMS data are released with an approximately quarterly lag.<sup>32</sup>

## REsurety

REsurety produces hourly, nodal marginal emissions rate estimates using data from ISOs' market operations, including generator offers, LMPs, and information on binding transmission constraints. Their algorithm, an approach consistent with the

---

<sup>28</sup> See <https://www.iso-ne.com/search/?file-type=XLS&file-type=XLSX&file-type=CSV&file-type=xls&file-type=xlsx&file-type=csv&query=emission%20rates>

<sup>29</sup> See the 2020 report here: [https://www.iso-ne.com/static-assets/documents/2022/05/2020\\_air\\_emissions\\_report.pdf](https://www.iso-ne.com/static-assets/documents/2022/05/2020_air_emissions_report.pdf)

<sup>30</sup> For a small number of cases where emissions data are not available from CAMD or NEPOOL, ISO-NE uses an eGRID average.

<sup>31</sup> In addition, see the technical presentation found here: [https://www.iso-ne.com/static-assets/documents/2021/11/20211102\\_real\\_time\\_marginal\\_emissions.pdf](https://www.iso-ne.com/static-assets/documents/2021/11/20211102_real_time_marginal_emissions.pdf)

<sup>32</sup> In principle, using more dated emissions factors (as PJM does) could allow ISO-NE to produce marginal emissions estimates more quickly, at the cost of decreased accuracy.

method documented in Rudkevich et al. (2011), begins with shift factor matrices that translate changes in nodal load into changes in line flows.<sup>33</sup> This translation is then combined with the identities of marginal generator(s) (estimated using data on LMPs and generator offer prices) to calculate a redispatch matrix, which translates changes in nodal load to changes in unit-level generation. The final step is to convert those changes in unit-level generation to changes in emissions. RESurety's approach here is similar to PJM's: it applies generator-specific historical average emissions factors based on form EIA-923 data. It currently covers ERCOT and PJM and plans to add CAISO/WECC in 2022. Lags in the release of necessary inputs result in publication delays of 60 to 90 days.

RESurety has internally validated its methodology by comparing its estimates of marginal emissions rates with those from other organizations, but it has not published the validation process.

## **electricityMap**

electricityMap produces average and marginal emissions rate estimates that subscribers can access through a web platform, an API, or in comma-separated-values (csv) and Excel form.

Average emissions rate estimates in the United States are based on statistical models of generation by fuel type, using input data from ISOs, balancing authorities, and EIA.<sup>34</sup> These estimates account for imports and exports between zones using a flow-tracing algorithm that leverages accounting identities regarding conservation of energy and emissions equations, based on the flow-tracing methods developed in Bialek (1996), Bialek and Kattuman (2004), and Tranberg et al. (2019).<sup>35</sup> Estimates of generation by fuel type are converted to emissions rates using carbon intensity estimates by fuel type, based primarily on Schlömer et al. (2014),<sup>36</sup> although electricityMap plans to incorporate regional and possibly power plant-level emissions factors by the end of 2022. In cases of delayed or incomplete source data, the above estimates are complemented with estimates using several alternative methods.<sup>37</sup>

For marginal emissions rates, electricityMap uses a “statistical dispatch” model that estimates how load affects generation by fuel type, which is then converted into emissions using the above-mentioned emissions factors (primarily IPCC 2014). Specifically, it uses statistical and machine learning-based modeling approaches to estimate how changes in local load affect local generation by fuel type and imports or exports, and how this effect varies with market prices, weather, demand

---

<sup>33</sup> In ERCOT, shift factor matrices are available directly from the system operator; elsewhere, they must be estimated using data on LMPs and binding transmission constraints.

<sup>34</sup> [https://github.com/electricitymap/electricitymap-contrib/blob/master/DATA\\_SOURCES.md#real-time-electricity-data-sources](https://github.com/electricitymap/electricitymap-contrib/blob/master/DATA_SOURCES.md#real-time-electricity-data-sources)

<sup>35</sup> See <https://electricitymap.org/blog/flow-tracing/>

<sup>36</sup> See <https://github.com/electricityMap/electricitymap-contrib/wiki/Emission-factors>

<sup>37</sup> <https://github.com/electricityMap/electricitymap-contrib/wiki/Estimation-methods>

predictions, third-party forecasts, and other conditions.<sup>38</sup> Its data lag depends primarily on the lag in the availability of input data, which can range from hourly to 24 hours (the latter applies to EIA data).

electricityMap currently provides estimates for more than 120 zones worldwide,<sup>39</sup> including the contiguous United States at the balancing authority level on an hourly basis. It has plans to increase this spatial and temporal granularity by the end of 2022. It does not currently publish information on its data validation methodology for the marginal emissions rate estimates; its goodness-of-fit tests are confidential but available from electricityMap upon request.

## **WattTime**

WattTime employs empirical statistical and econometric methods to estimate marginal operating emissions and average emissions across the contiguous United States using data from real-time APIs, such as <https://www.eia.gov/opendata/>, on grid conditions, interchange, and weather, and from EPA CAMD CEMS data on power plant emissions.

It uses a combination of three models that separately estimate (1) marginal nonrenewable sources (including both fossil fuel generation and imports); (2) carbon intensities of each fuel source; and (3) marginal (i.e., curtailed) renewable resources.<sup>40</sup> The first model estimates regressions of generation by nonrenewable sources on load, separately for bins of grid-relevant variables to avoid introducing noncausal variation (such as diurnal patterns) that would lead to biased estimates. The second model estimates carbon intensity by fuel type using regressions of emissions from CEMS data on generation, again for bins of relevant variables on grid conditions.<sup>41</sup> These carbon intensities by fuel type are combined with marginal generation to calculate marginal nonrenewable emissions.

Finally, the third model estimates marginal renewable generation using a supervised learning model that predicts curtailment of renewable generation (which is therefore responsive to marginal changes in load) as a function of grid conditions. The models for renewable generation are tailored to individual ISOs to reflect regional differences in drivers of curtailment. The nonrenewable and renewable marginal emissions rates are then combined to obtain an overall marginal emissions rate.

WattTime's estimates are available at the balancing authority and sub-balancing authority levels. The estimates are available at a five-minute timescale, and with a one-month delay for historical data.

---

<sup>38</sup> <https://electricitymap.org/blog/marginal-carbon-intensity-of-electricity-with-machine-learning/>

<sup>39</sup> Covering North America, Europe, Australia, and parts of South America, Asia, and Africa.

<sup>40</sup> See <https://www.watttime.org/marginal-emissions-methodology/>.

<sup>41</sup> In addition, adjustments are made for other cases, such as reservoir hydro, that require idiosyncratic treatment.

Although WattTime emphasizes ongoing improvement of its methodology by comparing the results of alternative estimation approaches, including those based on regression-based approaches, and inference of heat rates via LMPs, experiment-based estimates, a data validation process is not made public at this time.

For California, WattTime publicly shares real-time and forecasted marginal emissions data based on a simpler model<sup>42</sup> via the California Self-Generation Incentive Program (SGIP).<sup>43</sup>

## Singularity

Singularity takes a model-agnostic approach to emissions rates and focuses on consolidating, comparing, and improving the granularity of other methods discussed in this section. For operating margin emissions rates specifically, Singularity considers the following approaches, listed in what it deems increasing order of sophistication but decreasing order of transparency: EPA eGRID nonbaseload rates, ISO-reported marginal emissions data, EPA AVERT, WattTime, RESurety, and NREL Cambium.<sup>44</sup> Singularity's methodology is also mixed, and it varies by region, including both dispatch based and statistical and machine learning modeling.

Singularity uses form EIA-860 and Hourly Electric Grid Monitor data, as well as EPA AVERT and ISO-provided data. Temporal resolution of the data is between five minutes and one hour, depending on region. The data release lag also varies by region and ranges from five minutes to 24 hours.

Singularity offers 2,000 API requests per month for free before a subscription is required. It has performed internal validation of its modeling against ISO reported data but has not published a methodology.

## Discussion and Evaluation

Given the relative difficulty of estimating marginal emissions rates, it is important to consider the advantages and disadvantages of the alternative methodologies that estimate them.<sup>45</sup>

Our review (above) found six organizations deploying methodologies that provide operational marginal emissions rate estimates, reported in real time, as requested by the IJJA: electricityMap, ISO-NE, PJM, RESurety, Singularity, and WattTime.

---

<sup>42</sup> This simpler model infers the heat rate of marginal units—which are assumed to be gas units in CAISO—using reported LMPs. This model is likely to be very incorrect outside CAISO, where nongas generators, such as coal, can often be marginal.

<sup>43</sup> For more information, see <https://sgipsignal.com/>

<sup>44</sup> Note that NREL's Cambium model includes estimates of operating marginal emissions rates for internal modeling purposes but discourages users from employing these estimates because, they say, long-run marginal emissions are a more meaningful metric (Gagnon and Cole 2022).

<sup>45</sup> This section focuses on methodologies for estimating marginal emissions rates; we return to approaches for estimating average emissions rates in Section 6.

We also identified other organizations that produce emissions rate estimates: EPA's AVERT and eGRID teams, Kevala, and NREL's Cambium team.<sup>46</sup> Although those organizations produce valuable data, their products are, for one reason or another, less directly relevant to or not fully responsive to the IJJA request, which pertain to the operational marginal emissions estimates, reported in real-time.<sup>47</sup> Because of the EIA Hourly Electric Grid Monitor's established role in reporting real-time operational data on the grid and the IJJA's focus on operational emissions rates, it would be inappropriate and potentially misleading for EIA to report other kinds of emissions rate metrics (such as long-run marginal rates, or "total" emissions intensity values) as if they represented operating marginal emissions rates.

We focus on the following features of the six most relevant approaches:

- data requirements and limitations;
- extent to which the approach can scale geographically, such as to other (or all) balancing authorities;
- treatment of imports and exports; and
- data validation process.

Table 2 summarizes each organization's methodology.

The first category of methodologies includes those based on **economic dispatch models** that either directly use or closely mimic the actual security-constrained economic dispatch models used by grid operators to coordinate grid operations and meet electricity demand at lowest cost. These methods, used by PJM, ISO-NE, and RESurety, identify the marginal generator(s) and estimate locational marginal emissions (LME) using some estimate of a generator-specific emissions factor. The process for calculating LMEs is analogous to that for LMPs and is familiar to grid operators and market participants in organized wholesale markets operated by ISOs.

The main advantage of economic dispatch-based methods is that they are closely tied to actual economic dispatch used in grid operations and therefore reflect the marginal generator(s) as actually dispatched. Although the close association of these approaches with actual grid operations is an advantage, PJM clearly warns that locational marginal emissions rates can be sensitive to small changes in load in a way that locational marginal prices are not. This is because a sufficiently large change in load can change which unit is the marginal generator. Such a change would have little effect on LMP values because units are dispatched in order of marginal cost, but it could have substantial effects on LME values because units are *not* dispatched in order of marginal emissions. All these factors imply that LME estimates produced by dispatch model-based approaches, while perhaps very

---

<sup>46</sup> See Appendix A for a description of these organizations and their metrics.

<sup>47</sup> Specifically, both EPA's AVERT and NREL's Cambium models produce marginal emissions rate estimates on an annual basis, not a real-time basis. EPA's eGRID data set is at annual resolution, not hourly. Kevala's preferred metric, called total carbon accounting, differs from marginal rates.

accurate for small changes in load, may not accurately reflect the effects of nontrivial changes in load.

A disadvantage of dispatch-based methods is that they require detailed operating data that are often available only to grid operators. As a result, these detailed approaches have thus far been deployed in only a small number of ISOs: in PJM and ISO-NE by those ISOs themselves and in ERCOT by REsurety, which leverages the large amount of public data provided by ERCOT.<sup>48</sup> Scaling economic dispatch-based approaches to many other balancing authorities, including those without ISOs, could be difficult because it would require each balancing authority to replicate a PJM-like analysis or be willing to share potentially confidential or sensitive data with outside analysts. In some cases, sharing that information might be prohibited under rules designed to prevent market manipulation, though there are ways to reduce this risk. In addition, balancing authorities that do not operate wholesale markets may not routinely retain the information on system operations necessary to reveal the identity of the marginal generator.

Another disadvantage is that these approaches must make assumptions about the emissions intensity of the identified marginal generators. PJM does this using historical generator-level annual averages for units in its territory. This simplification does not capture variation in generators' emissions intensity, such as across seasons or when ramping up or down instead of operating at maximum output. ISO-NE's approach approximates those factors by using emissions factors that vary by month and peak or off-peak periods. Relatedly, it is difficult to assign an emissions intensity to imports from other grids where an individual grid operator has little visibility on operations outside its territory. For example, PJM's and ISO-NE's methodologies treat imports as having zero emissions, which means their estimates understate the true marginal emissions rate to the extent that imported fossil fuel generation is on the margin.<sup>49</sup> REsurety's approach also has difficulty accounting for imports due to limited data on their carbon intensity, so it does not treat imports as potentially on the margin; the direction of the bias from this approach is ambiguous.

Empirical approaches used by electricityMap and WattTime leverage **statistical and machine learning models** to estimate how historical generation (and hence emissions) rises and falls when load changes, using solely publicly available historical data on grid conditions and emissions. These approaches use statistical models trained on historical relationships between generation (by fuel) and load to predict generation levels associated with a particular level of or change in electricity demand, which are then converted to emissions using emissions factors.

These statistical approaches avoid the need for complex dispatch models or access to potentially confidential or sensitive data. Their major advantage is that they are easy to scale to produce marginal emissions estimates comprehensively across the country (and in other countries). This feature means that unlike the power dispatch

---

<sup>48</sup> REsurety reports being on the verge of releasing information for PJM and plans to expand its coverage to CAISO later in 2022.

<sup>49</sup> PJM, "Marginal Emissions Rate—A Primer," <https://pjm.com/-/media/etools/data-miner-2/marginal-emissions-primer.ashx>

models used by PJM, ISO-NE, and REsurety, these methods can be extended to regions without ISOs. In addition, statistical methods can be deployed to produce estimates in real time, which is important for use cases like short-run operational decisions. Indeed, both WattTime and electricityMap produce real-time emissions rate estimates and forecasts across the contiguous United States.<sup>50</sup>

Statistical approaches have other advantages as well. So long as the data sets comprehensively cover all relevant sources of generation and load, they can correctly reflect emissions from imports, which power dispatch models can struggle to do (see PJM’s primer, which notes that emissions associated with imports are not accounted for). In addition, these methods permit one to estimate changes in emissions resulting from nonmarginal changes in load, to the extent that this information can be teased out from observed historical data.

Those advantages come with disadvantages, however. First, to the extent that statistical approaches reflect the physics underlying grid operations, it is through reduced-form statistical models, and all such models involve simplifications and therefore represent approximations based on historical patterns at times and locations that look statistically similar. Second, statistical approaches, if not properly designed, can be vulnerable to mistaking correlation for causation, leading to faulty learned relationships. For example, historical data may reveal that when demand increases in the morning as the sun rises, solar generation also increases. It would be easy for a naïve statistical algorithm to then mistakenly predict that an increase in demand “causes” an increase in solar generation. Avoiding such errors requires that statistical models be carefully designed to ensure that the estimated relationships are truly causal, not simply correlational. Third, whereas dispatch model-based approaches are well placed to produce estimates at the nodal level, such disaggregated estimates produced by statistical methods are likely less reliable because of decreased statistical power and variability at finer degrees of disaggregation. Indeed, WattTime and electricityMap tend to produce marginal emissions rate estimates at the balancing authority level rather than the more disaggregated nodal level because of the difficulty of empirically validating such estimates.

Finally, despite the substantial amount of publicly available data on the US electricity grid, the information is nonetheless incomplete. The main source of generator-level CO<sub>2</sub> emissions information is EPA’s CAMD data from its CEMS network of monitors at power plant smokestacks across the country. Data from CEMS monitors are standardized and largely comprehensive. However, CEMS monitors are required only at fossil fuel generators larger than 25 MW; the network does not include small units or nonfossil generation—nuclear, hydro, wind, or solar. CO<sub>2</sub> emissions from units not included are estimated to represent 10 to 20 percent of all CO<sub>2</sub> emissions from US generation.<sup>51</sup> Calculations requiring data on nonfossil

---

<sup>50</sup> See, for example, <https://www.watttime.org/explorer/> and <https://app.electricitymap.org/>

<sup>51</sup> See US Environmental Protection Agency (2022).

generation may then require finding other sources of data, which can vary in accessibility and format from region to region.

Perhaps most important feature is the ability to scale beyond individual regions. Balancing authorities that don't use the kind of economic dispatch algorithms used by ISOs such as PJM and ISO-NE could not easily deploy dispatch model approaches. In those cases, statistical approaches may currently be the only option. Thus, statistical model-based approaches can be pursued in the short and medium term, alongside the development of dispatch model-based approaches in various ISOs.

If data developed through multiple approaches are available, it would be valuable to compare the results and methods to determine how much they actually differ, and why. Further, presenting multiple estimates for the same metric would enable analysts to improve, validate, stress-test, and harmonize their methods and data products. Importantly, multiple estimates should be accompanied by clear data definitions, caveats, and information about the methodology (e.g., dispatch, statistical) underlying each estimate. These recommendations would apply regardless of the entity—EIA or an independent third party—presenting the standardized estimates.

**Table 2. Summary of Existing Methodologies for Estimating Operational Marginal Emissions Rates and Other Metrics**

Organization	Approach	Key metrics	Data type	Data cost, access, format	Temporal resolution	Data release lag	Geographic coverage	Geographic resolution
PJM	Economic dispatch model	Operating margin	Historical, real time	Free, API, csv	5-minute	5-minute	PJM	Wholesale pricing node
ISO-NE	Economic dispatch model	Operating margin	Historical	Free, xlsx	5-minute, hourly	1–2 years	ISO-NE	Balancing authority
REsurety	Economic dispatch model	Operating margin	Historical	Paid, API, Excel	Hourly	60–90 days	ERCOT and PJM, (CAISO/WECC planned 2022)	Wholesale pricing node
electricityMap	Statistical and machine learning models	Operating margin	Historical, real time	Paid, API, csv, Excel	Hourly	Unknown/1 day	On-demand global	Balancing authority
WattTime	Statistical and machine learning models	Operating margin	Historical, real time	Paid, API	5-minute	1 month/5-minute	Contiguous US, Canada (partial), more	Balancing authority
Singularity	Combined approaches	Operating margin, build margin	Historical, real-time	Limited free, API	5-minute or 1 hour, by region	5-minute for ISO-provided, 1 day for other regions	Contiguous US, Canada (partial), 8 major ISOs	Balancing authority, some subregions
<b>Groups whose approaches are less applicable to IJA requirements</b>								
EPA AVERT	Statistical dispatch	Short-run marginal	Historical	Free, Excel	Hourly	1–2 years	Contiguous US	14 AVERT regions
EPA eGRID	Nonbaseload	Short-run average	Historical	Free, Excel	Annual	1–2 years	Contiguous US	27 subnational multistate regions
Kevala	Directed graph of power flows	Total, average, and marginal	Historical, real-time	Paid, API	Time horizon agnostic, including real time		Contiguous US	Address
NREL Cambium	Simulation	Long-run and short-run marginal	Forecast	Free, csv, Excel	Month-hour, time of day	Approximately annual	Contiguous US	134 NREL balancing areas*

Notes: \*The balancing area is the finest geographic unit of the Cambium model and is distinct from balancing authorities. See Gagnon et al. (2021).

## 4. Data Standardization: Definitions, Formats, Methods of Transfer, and Potential Benefits

Regardless of the methodologies used to produce emissions rate data, additional questions remain about data standardization, including definitions, formats, and methods of transfer.

Several energy-related data standards have been developed. For instance, the Green Button initiative—which gives utility customers access to their energy usage data—leverages a data standard developed and released in 2011 by the North American Energy Standards Board with support from the National Institute of Standards and Technology, the Department of Energy, and the White House Office of Science and Technology Policy.<sup>52</sup> Another example is the Home Performance eXtensible Markup Language (HPXML), which is a combination of two standards for energy-related data on home attributes and systems, such as building components and energy efficiency features.<sup>53</sup> HPXML was developed and is maintained via a stakeholder-led process established by the nonprofit Building Performance Institute.<sup>54</sup> A final example is the ongoing work of the open-source foundation LF Energy, which through its Carbon Data Specification Consortium is working to produce standards to facilitate the measurement, quantification, and tracking of carbon emissions from energy production and consumption (see below).

Standardization might be appropriate for at least two types of emissions data: (1) data published by utilities or balancing authorities that are not themselves emissions metrics but provide underlying information—for example, about individual generating units and dispatch—that can be useful inputs for creating such estimates; and (2) emissions metrics in their final, published form, such as average and marginal emissions rates. One or more standards for these types of data could build on, be an outgrowth of, or complement the existing standards described above.

There may be instances where a utility or balancing authority can provide only the first type of data, which could then be leveraged by a third party to create the final metrics used by data consumers. In other cases, a utility or balancing authority may be able to publish both types of data. For example, PJM currently provides access to marginal emissions rates as well as other grid-related data sets through its Data Miner 2 tool, which could potentially be adapted to meet future data standards.<sup>55</sup>

---

<sup>52</sup> For more information, see the Department of Energy website (<https://www.energy.gov/data/green-button>) and the North American Energy Standards Board website ([https://www.naesb.org/ESPI\\_Standards.asp](https://www.naesb.org/ESPI_Standards.asp)).

<sup>53</sup> See <https://www.hpxmlonline.com/specifications/>.

<sup>54</sup> See <https://www.hpxmlonline.com/working-group/>.

<sup>55</sup> For more information, see: <https://dataminer2.pjm.com/>.

In both cases, standards for emissions-related data have multiple benefits. One is to increase the transferability and scalability of methodologies and applications from one context to another. For instance, emissions rate estimation methodologies that are designed to ingest data from a particular balancing authority can more easily be ported to other geographies if the data they rely on are in standard form. This is equally true of applications that take emissions metrics and create consumer data products (e.g., smartphone apps for electric vehicle owners). More generally, any technology or platform that leverages data from more than one region or time period would find value in standards.

Another benefit of standardization is the potential to promote transparency and reliability. As more organizations publish data, standards can help set expectations about what is provided, how it is provided, and how it is used. This not only increases data quality—and the quality of the resulting applications built on the data—but may also incentivize more organizations to participate in the broader data ecosystem, since they can take advantage of shared knowledge, best practices, and partnerships that evolve as the standards become more widely adopted. Greater participation and collaboration can also ultimately spur innovation in the energy and decarbonization fields.

Potential components of data standardization include definitions, formats, and methods of transfer. Definitions would specify what each data point means and enumerate any metadata needed to fully describe it. For example, a standard for emissions rate data would describe what concept each emissions metric represents, the underlying methodologies and data sources used to create the values for each metric, and then for every data point, the specific attributes that can be provided alongside it, such as geography, time interval, and units.

Ideally, the data definitions would cover both the concept and the methodology for each metric so that emissions estimates produced for one geography or time can be fully comparable with those produced for another. For example, even with conceptual alignment about what a metric represents, differences in methodologies or differences in the source data that methodologies use can lead to inconsistency. Data publishers should therefore clearly document how estimates are created, and a data standard could help by establishing a common framework within which various approaches are both integrated and differentiated. For instance, such a framework might specify that data sets include one or more fields describing the methodology used to produce estimates, where the potential values for the fields (e.g., economic dispatch model, statistical and machine learning models) are fully enumerated and described by the standard. The benefit of this type of standardization is especially relevant when data sets from different sources will be pooled together and compared.

A data standard may also address formatting, such as which data points are required, which are optional, and their arrangement and form. Building on the previous example, a standard may require that for average emissions rate data, every data point must be accompanied by the geography and time interval for which it was measured or estimated. If the data are provided via a comma-separated-

values (csv) file (see below), the standard might further indicate the order and names of the columns and specify the format for the individual values. Formatting requirements could include, for instance, that times be expressed in Coordinated Universal Time (UTC), which can help prevent confusion when a file contains data for geographies in different time zones. Another formatting requirement might pertain to standardization of units, such as metric tonnes of emissions per megawatt-hour, a common standard. The goal of such detailed specifications is to ensure that data providers and data consumers share a common understanding about the meaning of the data they are sending and receiving.

Data sets can be transferred from one entity to another in several ways. One of the most common is to publish static files, such as comma-separated-values or Excel files, that can be downloaded by data users from an organization's website. This manual approach is generally simpler than other methods, and for limited amounts of data being transferred at relatively low frequency, it is less labor intensive than establishing an automated system.

For higher volumes of data and for data that must be updated frequently, it may be worthwhile to build an automated system for retrieval and processing. An application programming interface essentially allows one piece of software (on the user's side) to interact with another piece of software (on the provider's side). Unlike static files, APIs typically allow the user to specify—via computer code—the exact subset of data to retrieve, and the resulting information can be fed directly into memory in the calling software application for further processing and analysis. This entire process—from retrieval to processing to end data product—can be automated, which can lower costs, improve efficiency, speed data updating, and allow greater scalability and transferability of applications. Data users have both open-source and proprietary options for connecting to APIs, including free-to-use libraries in the programming languages Python and R.

Because data users may want access to the same information via both static files and an API, it is worthwhile for data publishers to consider both implementations. Using a standardized format is helpful: for static files, this includes column headers, ordering, and similar details, and for an API, a schema would indicate the structure and other rules to which the retrieved data should conform.

Efforts are under way to create the types of standards described here. One example is the ongoing work of the LF Energy Carbon Data Specification Consortium,<sup>56</sup> which aims to create standardized data definitions and requirements to facilitate data access and transfer for measuring, quantifying, and tracking carbon emissions from energy production and consumption. The consortium, a community-led effort, comprises a range of stakeholders—utilities, carbon data providers, and corporations with emissions targets. One of its goals is to establish a process for the iterative development of standards over time.

---

<sup>56</sup> For more information, see <https://www.lfenergy.org/projects/carbon-data-specification-cds/>.

The consortium has two working groups: one for customer-level data and the other for power systems data. Together, they aim to establish a specification for the underlying raw data that can be used to calculate energy and emissions metrics. The specification will include a combination of procedures and technical standards pertaining to data access, aggregation, scale, and quality.

Many utilities, balancing authorities, and government agencies already share energy data with the general public, but their data sets are typically not harmonized. For example, EIA provides a free API with a wide variety of energy information on electricity, petroleum, natural gas, and coal.<sup>57</sup> Users can retrieve data in machine-readable JavaScript Object Notation (JSON) format that adheres to an EIA-defined data structure.

Other examples include PJM (which provides an API through the Data Miner 2 platform), the data providers discussed in the previous section (which also have APIs), and the California Energy Commission's Market Informed Demand Automation Server (MIDAS,<sup>58</sup> which provides marginal greenhouse gas emissions information and other electricity data).<sup>59</sup> These data providers and others could consider building in additional flexibility so that their systems—and data—can more easily be adapted to any future standards.

Overall, the more energy- and emissions-related data that utilities, balancing authorities, and government agencies (including EIA) can provide, the larger the benefit of creating robust and harmonized data standards.

---

<sup>57</sup> For more information, see <https://www.eia.gov/opedata/>.

<sup>58</sup> For more information, see the California Energy Commission website at <https://www.energy.ca.gov/publications/2021/market-informed-demand-automation-server-midas-documentation-connecting-and>.

<sup>59</sup> Many utilities also give their customers access to energy usage data through the Green Button initiative. For more information, see <https://www.energy.gov/data/green-button>.

## 5. Barriers to Collecting and Reporting Residual Mix

The concept of residual mix (Section 2) was developed to avoid double-counting of clean energy in accounting for the generation mix and associated emissions intensity of power delivered by local utilities or electricity retailers to their customers.<sup>60</sup> Most consumers' electricity is supplied by the local utility, and for market-based GHG accounting purposes, the emissions intensity of that power should accurately account for the separate sales of any clean power (or associated attributes or both) to other customers who voluntarily purchase green power or to other utilities for compliance with renewable portfolio standards (RPS) or clean energy standards.

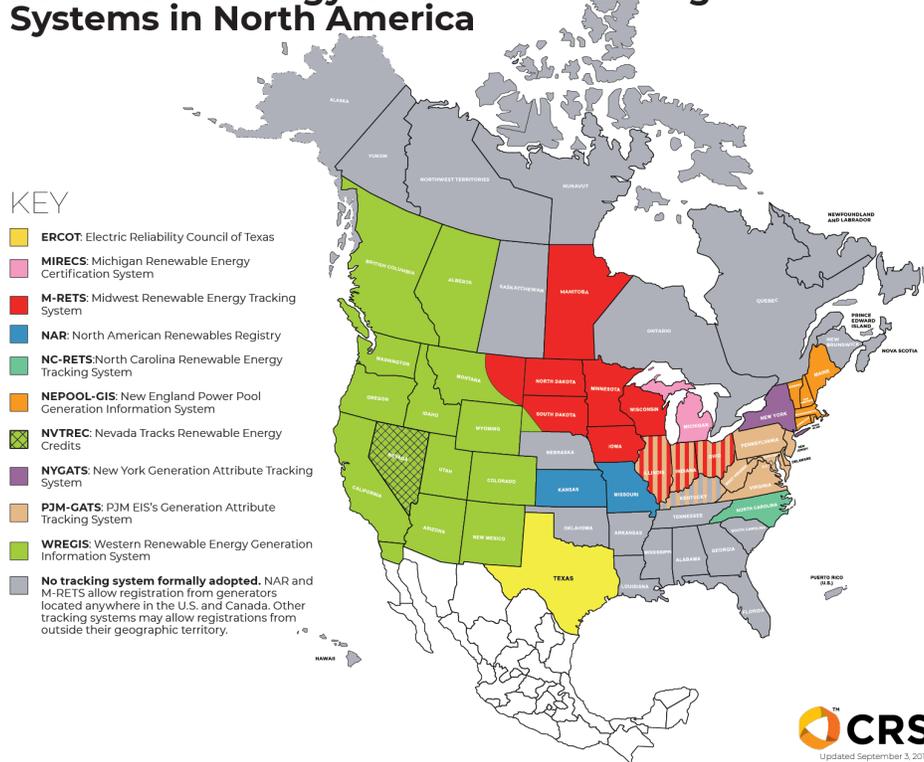
Creating a measure of residual mix requires tracking the creation of renewable energy credits within a region and their ultimate use. Users of RECs fall largely into two categories: (1) consumers who voluntarily choose to purchase renewable power and associated RECs; and (2) utilities that purchase RECs (or generate them through utility-owned renewable generators) to surrender them for compliance with regulatory requirements. For calculating residual mix, both power associated with voluntary RECs and with RECs sold for RPS compliance in other regions should be excluded from renewables generation available for regular sales to local consumers.

REC creation and transactions are tracked by the regional REC registries. A map from the Center for Resource Solutions (Figure 1) shows the organizations serving in this role in each state or region. Registries have information on the RECs created in their region and how they are used—whether for compliance or for private renewable energy transactions. Several REC registries, including PJM-GATS, NYGATs, and NEPOOL-GIS, also report data on regional grid mix and associated emissions factors on either a quarterly or an annual basis (CRS 2021b); more granular data, such as hourly, would require RECs to be time stamped hourly.

---

<sup>60</sup> The renewable energy included in the electricity delivered by utilities to customers who purchase a basic electricity product is called standard delivery renewable energy (CRS 2021a).

**Figure 1. Renewable Energy Certificate Registries  
Renewable Energy Certificate Tracking  
Systems in North America**



Source: <https://resource-solutions.org/wp-content/uploads/2018/02/Tracking-System-Map.pdf>.

Information on a form of residual mix known as utility residual mix or standard delivery mix is also available from the Edison Electric Institute (EEI) for utilities that provide the information voluntarily by June of each year for the prior two years (the most recent version covers only 2020).<sup>61</sup> EEI's data are used by customers to develop Scope 2 carbon emissions estimates.<sup>62</sup> Residual mix data from EEI appear to be limited to utility programs to deliver green power as well as some community solar programs that retire RECs; contractual transactions for green power that do not involve the utility are not captured (CRS 2021b).

EIA faces several challenges in reporting residual mix emissions rates. First, EIA has not historically collected data from the REC registries. Moreover, even if there were a direct line from EIA to a REC registry, renewable energy credits are generally

<sup>61</sup> For information on EEI data on annual CO<sub>2</sub> emissions rates, including for the residual mix, see <https://www.eei.org/issues-and-policy/national-corporate-customers/co2emissions-access>.

<sup>62</sup> EEI's utility residual mix calculation nets out of the denominator of the emissions rate clean energy and RECs that are sold to third parties outside their system or that are retired for customers who buy power under a green tariff or in some cases for community solar programs that generated RECs.

denominated by year (in some cases by month), so accounting of residual mix by more detailed time steps such as hourly is not yet possible in most locations.<sup>63</sup>

However, EIA does regularly collect data from load-serving entities and electricity distribution companies, which themselves often use REC tracking systems for compliance and voluntary transactions. This connection suggests a logical first step: to collect information on the utility's standard delivery mix, which omits electricity sold in voluntary green power programs (for which the utility has data from utility average emissions rates, as evidenced in emissions rate data collection by EEI and other utilities, as described in CRS 2021b). This type of data collection could provide annual (and in some cases perhaps more frequent) information that excludes some voluntary green power sales from the emissions rates for standard electricity delivery. It could also be a first step toward more comprehensive accounting of the broader range of voluntary clean power purchases through third-party providers and direct contracts between customers and clean energy developers. A proper calculation of the residual mix, however, would require comprehensive measures of claimed clean generation, including not just those procured through utility programs but also privately retired RECs. To obtain such a comprehensive accounting, EIA would need to collect data from REC registries, likely on a voluntary basis.

---

<sup>63</sup> M-RETS CEO Ben Gerber has facilitated hourly tracking of RECs for Google, which finalized an hourly REC retirement in January 2021 (Gerber 2021).

## 6. Potential Pathways for EIA

This section lays out potential pathways for EIA to fulfill the data requirements in the IJA for both average emissions rates and marginal emissions rates.

### Average Emissions Rates

EIA is already well positioned to produce estimates of average emissions rates. As of March 2022, EIA began **releasing** hourly estimated average emissions rates for the contiguous United States. The **methodology** underlying these estimates uses annual average nationwide emissions factors for coal, gas, and “other” (mostly oil) generation in lbs. CO<sub>2</sub>/kWh generated, which are then multiplied by the total real-time generation (in MWh) of each fuel type as reported on form EIA-930. For example, for 2022, EIA uses an emissions factor of 2.23 lbs. CO<sub>2</sub>/kWh for all coal generation<sup>64</sup>; if 100 million kWh of coal generation is reported for a particular hour, EIA calculates emissions as 2.23 lbs./kWh \* 100 million kWh = 223 million lbs. CO<sub>2</sub>, or about 100,000 tons, of CO<sub>2</sub>. Analogous calculations are performed for generation from gas and “other” emitting generation sources to yield total emissions from US generation, which can be divided by total generation to yield a production-based average.

Obtaining a consumption-based average also entails accounting for emissions associated with imported (and exported) electricity, which involves assigning an emissions intensity value to imported (or exported) electricity. At the national level, net imports primarily reflect imports from Canada (and a relatively small amount of exports to Mexico). EIA’s current approach treats net imports as if they have the same emissions intensity (in lbs./kWh) as the US average. This treatment of imports is a reasonable simplification that is unlikely to have much effect on emissions rate estimates at the national level, since net imports typically amount to less than 0.5% of US annual load (and are rarely more than 2% of load in any given hour).

That approach could be extended to calculate analogous average emissions rate estimates at the balancing authority level. For production-based average estimates, this is straightforward, and the approach can be the same as at the national level, with one caveat: we recommend that where possible, any emissions factors used should reflect values specific to each balancing authority.

A consumption-based average is more difficult because the simplifying assumption about imports will be more problematic at the balancing authority level (in particular for small balancing authorities), since imports and exports are often much larger across balancing authorities than across countries. A proper consumption-based

---

<sup>64</sup> EIA reports fuel-specific emissions rates, such as this one, in imperial units of 2.23 lbs. CO<sub>2</sub>/kWh, then converts to the more commonly used metric unit of tonnes of CO<sub>2</sub> when reporting total emissions, before converting back to imperial units for the grid emissions rate. The different units could create confusion—for example, between short tons and metric tonnes. Metric units, typically tonnes for CO<sub>2</sub>, are standard.

average would entail a careful accounting of imports from other balancing authorities, including accounting for the emissions associated with its trade partners' imports, their trade partners' imports, and so on.<sup>65</sup>

Further improvements to estimating averages entail more refinement of the assumed emissions factors, such as the 2.23 lbs./kWh value that is applied to all coal generation. That value is the US average for 2020, but it masks the heterogeneity in the emissions factor (lbs./kWh) due to variation in the efficiency (heat rate) of generators and the rank and source of coal. This value is also treated as constant across (at least) a year, but in reality, emissions factors at a given plant can vary within a year.

That suggests the following opportunities for improvement, to the extent possible given the data that can be collected under form EIA-930:

- using emissions factors that vary by balancing authority;
- using emissions factors that reflect the subtype of fuel (such as rank of coal); and
- using emissions factors that vary over time, such as seasonally or monthly, or by hour of day (or on-peak versus off-peak, as in ISO-NE's methodology) and updating the values annually to reflect recent changes in the structure of the grid.

The greatest degree of granularity would be to use unit-specific emissions factors. These can already be calculated easily using publicly available data from EPA CAMD. The obstacle for EIA would be obtaining real-time plant-specific or unit-specific generation to which those emissions factors would be applied. Balancing authorities could report these data, but in competitive markets, there may be restrictions on identifying the unit-specific generation in real time to help prevent market manipulation, at least until some time after the associated market transaction.

## Marginal Emissions Rates

As EIA contemplates its options for developing and publishing estimates of operational marginal emissions, its preferred approach is likely to draw on the agency's strengths, which tilt more toward collecting, verifying, and reporting data from energy industry participants and less toward generating its own estimates. However, given recent progress in developing methodologies for producing marginal emissions rate estimates and the number of organizations that are already estimating and publishing marginal emissions data, EIA does have several options.

---

<sup>65</sup> Such approaches may require an assumption regarding "mixing" within a balancing authority, such as the "perfect mixing" assumption. For more information on flow-tracing methods, see Bialek (1996), Bialek and Kattuman (2004), and Tranberg et al. (2019).

We review the options here and discuss the benefits of an independent quantitative evaluation that would compare the approaches and resulting estimates.

One option for EIA is to develop its own estimates of marginal emissions rates, making use of data already collected by EIA and other government agencies. We view this as unrealistic in the near term, however: as evidenced by the time and effort spent by the various third-party data providers in developing estimates over many years, the amount of effort required far exceeds EIA's capacity, absent additional resources. Moreover, unlike most of the information EIA now collects, the data could not be easily verified through records or meter readings. This approach would likely take substantially more time than the options discussed below.

### **EIA Collects Marginal Emissions Rate Data from Balancing Authorities**

A more natural approach that coincides squarely with EIA's remit is to collect marginal emissions rate data from all balancing authorities and make those data publicly available in a timely fashion. EIA currently uses form EIA-930 to collect information on generation by fuel type in each hour for each balancing authority. The request for marginal emissions rates could be added to that form, although such a survey modification would likely require OMB review and approval and thus take time. The balancing authorities could respond to the new data request in several ways. We discuss these approaches in order of preference, contingent on implementability, which may vary by balancing authority. That is, we do not mean to foreclose the use of less preferred options if the preferred ones are less feasible for a balancing authority to implement, given institutional, regulatory, or resource constraints.

For balancing authorities that are also ISOs that operate wholesale electricity markets, estimating marginal emissions rates could be a straightforward exercise, as demonstrated by PJM and ISO-NE. PJM already collects and reports this information at the five-minute level by load-serving pricing node and would merely need to aggregate these data to hourly—for example, by taking a simple or load-weighted average across the twelve five-minute estimates in each hour (Section 2).<sup>66</sup> ISO-NE also appears to be calculating marginal emissions rates at the nodal level now (or could do so in a straightforward manner as part of its existing approach), although it currently reports only balancing authority-wide aggregates.

Other ISOs could produce marginal emissions rates using a similar methodology, or they could use their own preferred methods. For example, CAISO could embrace the existing estimates of marginal emissions rates already produced on a five-minute basis by WattTime for the state's Self-Generation Incentive Program, operated by

---

<sup>66</sup> Note that the resulting marginal emissions rate, while true on average, would not apply to any of the five-minute intervals except perhaps by coincidence.

the three large California investor-owned utilities.<sup>67</sup> That program provides information on marginal emissions rates for three CAISO subregions, known as default load aggregation points, and for eight other balancing authorities that operate in California.

For other ISOs (Figure 2), developing marginal emissions rates would likely require additional work but could build on information that they track and report publicly. For example, ISOs could publish supply stacks or offer the curve data necessary to generate them (as ERCOT does). Of course, many ISOs do not publish supply stacks, perhaps because it could reveal sensitive information; one work-around would be to aggregate supply stacks by fuel type so as to not reveal the identity of marginal generators. Information on marginal fuel types could then be combined with emissions factors for each fuel type to estimate marginal emissions rates.<sup>68</sup> MISO already reports information on the fuel used by the marginal unit in each of its three subregions for each five-minute interval of the prior day.<sup>69</sup> Marginal emissions rates for these subregions of MISO could be estimated by associating an ISO average CO<sub>2</sub> emissions rate for each generator (or generator type) using data provided by EIA or EPA. This calculation could be done by MISO, EIA, or even independent third parties. To capture variations in emissions rates by fuel type based on generator utilization rates and other factors, more focused emissions rate estimates could be based on seasonal fuel consumption data collected by EIA in its EIA-923 survey, which is conducted monthly for a sample of respondents.

Balancing authorities that are not ISOs might require additional assistance in complying with EIA's request for hourly marginal emissions rate data. EIA collects data for form EIA-930 from 63 balancing authorities, whose locations are shown in Figure 3.<sup>70</sup> Only seven of those are ISOs that operate wholesale electricity markets in real time, day ahead, or both. For the remaining 56 balancing authorities, the concept of a pricing node is not relevant, although the region could still be divided into subregions if intraregion transmission constraints limit power flows.

Many system operators use an economic dispatch approach to determine which generators can meet a marginal change in load at lowest cost. That approach

---

<sup>67</sup> For information about SGIP, see <https://www.selfgenca.com/>.

<sup>68</sup> Information on the full supply stack, rather than just the identity of the marginal generator, can also inform how much emissions rates might change in response to large versus small changes in load (see the discussion and evaluation subsection in Section 3). Although a supply stack is necessary to compute marginal emissions rates, it is not strictly sufficient; a complete analysis would also require information on transmissions constraints.

<sup>69</sup> For more information on how MISO reports on the fuel type of the marginal generator, see [https://misodocs.blob.core.windows.net/marketreports/Real-Time%20Fuel%20on%20the%20Margin\\_Real-Time%20Fuel%20on%20the%20Margin%20Report%20Readers%20Guide.pdf](https://misodocs.blob.core.windows.net/marketreports/Real-Time%20Fuel%20on%20the%20Margin_Real-Time%20Fuel%20on%20the%20Margin%20Report%20Readers%20Guide.pdf).

<sup>70</sup> For the list of balancing authorities from which EIA collects data, see <https://www.eia.gov/electricity/gridmonitor/openAcroDialog/BA>.

typically identifies a marginal generator for each balancing authority at each point in time.<sup>71</sup> However, in the absence of a market-based pricing mechanism, the information on that marginal unit is not typically needed for any particular purpose, and therefore it may not be collected and stored. In these cases, EIA may need to provide technical assistance to the balancing authority to help facilitate ongoing collection of the data. EIA could use the emissions rate and generation mix data reporting requirements of the IJJA to create demand among balancing authorities for data on a consistently well-defined measure of marginal emissions rates that third-party providers could help provide. EIA typically issues detailed instructions for reporting particular data, and this could be a place to provide guidance to the balancing authorities on approaches that would yield acceptable values for marginal emissions rates, including those options described in this report.

Where balancing authorities are not typically collecting information that identifies a marginal generator in close to real time, EIA could request data that others need to calculate this information; such data could include the fuel type of the marginal generator in each hour. Although identifying the specific marginal generator may be precluded by competitive concerns or confidentiality requirements, information about fuel type may fall outside those restrictions and could feed into emissions calculations.

### **EIA Supplements Balancing Authority Data with Third-Party Sources**

It is unlikely that all balancing authorities will be able to produce marginal emissions rate estimates right away; therefore, EIA will need additional data sources. Although some existing methods (such as the statistical methods discussed in this report) can produce geographically comprehensive estimates of marginal emissions rates for all balancing authorities in the contiguous 48 states, quantitative comparisons of their estimates are insufficient. Thus, we recommend that an independent organization work with the third-party providers of emissions rate data and compile a comprehensive set of marginal emissions rate estimates, then quantify their similarities and differences and assess their relative reliability. A careful, publicly available comparison and assessment of methodologies and data across different providers, conducted by an independent entity, could assuage some concerns and be useful not only to EIA but also to researchers, analysts, and data users more broadly. This compilation and quantitative comparison of data would help analysts understand the differences between alternative estimates. It would also enable data

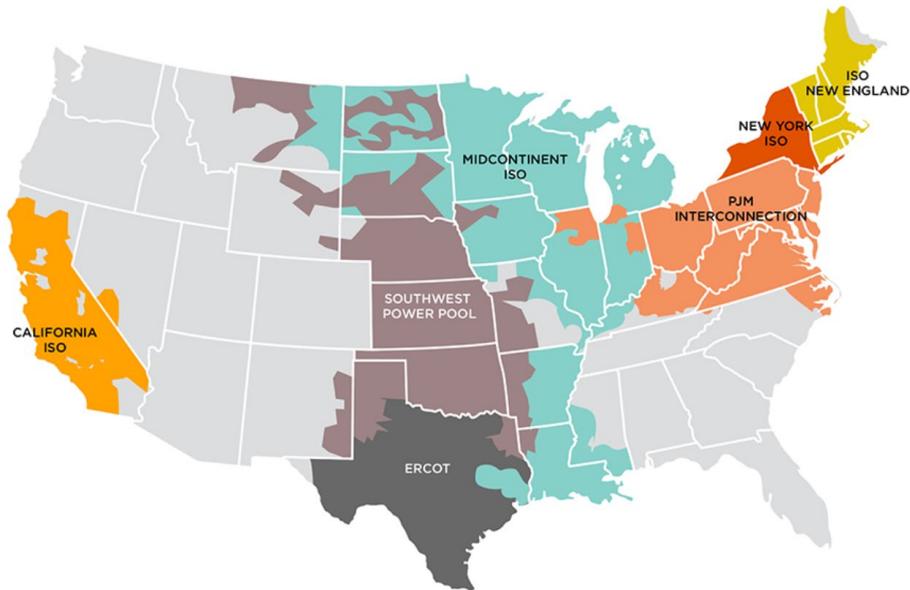
---

<sup>71</sup> The marginal generator's marginal cost for a balancing authority as a whole is sometimes called the "system lambda" and is sporadically reported to the Federal Energy Regulatory Commission (FERC) on FERC form 714: <https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/overview>. Many balancing authorities do not report these data. For those that do, the reporting allows for many different definitions, including the dual variable on the system balance constraint and the marginal cost of the most expensive unit, so inconsistency in data definitions across those that do report is an issue. In general, the data quality is not sufficient for EIA's purposes, and reporting is on an annual basis, with reports due to FERC six months after the end of the reporting year.

providers and other analysts to improve, compare, validate, stress-test, and harmonize their methods and data products.

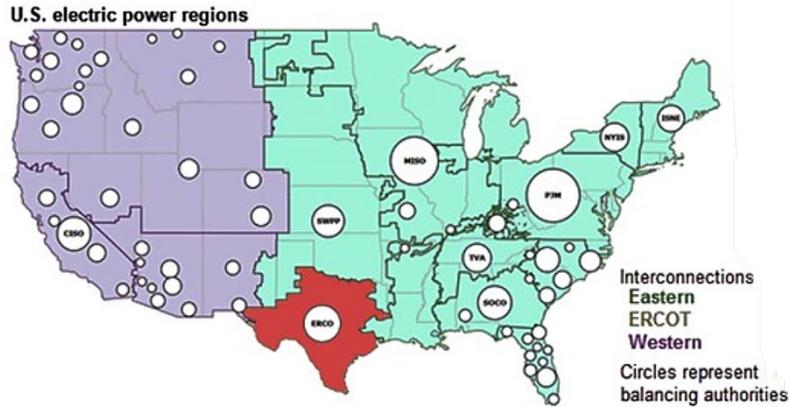
Such a public quantitative comparison would inform EIA's task of determining marginal emissions rates in regions where balancing authorities cannot yet produce the necessary data. With a public data comparison in place, EIA could then consider publishing data provided by third-party organizations, such as those discussed in this report, with clear and appropriate data definitions, descriptions, and caveats. To the extent that EIA feels it cannot properly evaluate a methodology because of confidentiality or intellectual property concerns, EIA could arrange for a conditional engagement to confidentially review data providers' methodologies and assess their approaches before finalizing the partnership.

**Figure 2. Regional Transmission Organizations and Independent System Operators**



Source: **Sustainable FERC.**

**Figure 3. Locations of Electricity Balancing Authorities**



Source: Groutis (2021)

If multiple approaches to estimating a particular emissions rate metric are available and deemed reliable, EIA should consider presenting more than one set of estimates for data users and researchers, at EIA and elsewhere, to compare. EIA should proceed with caution on such a partnership, since its endorsement of a single approach may give undue legitimacy to estimates with degrees of uncertainty beyond what is typical of EIA data. When presenting multiple estimates for the same metric, EIA should include clear definitions of the data, list caveats, and note the type of methodology underlying each estimate (e.g., economic dispatch, statistical). These recommendations would apply regardless of the entity—EIA or a third party—presenting the standardized estimates.

## **Anticipate Data Standards**

If data standards are developed, EIA should consider making the emissions rate estimates and other data conform to the standards, to the extent applicable. Such standardization might cover data format requirements, access by users, and guidelines on accompanying information, including emissions metric definitions, methods of metric construction, and underlying data sources. Data standards could also facilitate EIA’s ability to present several sets of estimates, especially if some estimates are retrieved from other entities that have already implemented the standards.

## 7. Appendix A: Other Approaches to Emissions Rates

### EPA AVERT

EPA's AVOIDed Emissions and geneRation Tool (AVERT) is used for preliminary policy analysis of energy and air quality policies at state or regional levels. AVERT uses a statistical dispatch modeling approach and historical data on generation and emissions to produce estimates of short-run marginal emissions from energy efficiency improvements, deployment of renewable energy, and other changes that would affect electricity demand. These estimates are produced approximately annually on a backward-looking basis.

With data and projections from EPA CAMD, the National Emissions Inventory, and EIA's AEO, it considers fossil fuel plants with capacity over 25 MW within 14 constructed US regions. AVERT does not account for imports and exports, though balancing authorities are assigned to regions to minimize interchange.

### EPA eGRID

The EPA Emissions & Generation Resource Integrated Database (eGRID) presents generation and emissions rate data from US electric power operations, with an online dashboard for visualization.<sup>72</sup> As part of the database, eGRID publishes annual production-based average emissions rates and “nonbaseload” emissions rates at various degrees of regional aggregation, including at the balancing authority level. The nonbaseload emissions rate, meant to approximate a measure of marginal emissions rates, is calculated as a weighted average of emissions rates across plants that have relatively low capacity factors, suggesting that they ramp up and down to meet fluctuations in demand.<sup>73</sup> These calculated emissions rates are based on data from form EIA-930, form EIA-860, and EPA's CAMD.

### Kevala

Kevala's approach to estimating the emissions associated with electric power generation is unique among those discussed in this report. Although able to calculate marginal and average emissions rates, Kevala prefers a different metric, that they call “total carbon accounting.” Total carbon accounting (TCA) models power flows to map power consumption at all locations to the associated generation, and in doing so it quantifies the carbon intensity of all energy consumption.<sup>74</sup> TCA combines technoeconomic analysis with engineering analysis, focusing on physical power flow tracing to assign carbon emissions associated with energy consumption

---

<sup>72</sup> <https://www.epa.gov/egrid/data-explorer>

<sup>73</sup> See page 28 of [https://www.epa.gov/system/files/documents/2022-01/egrid2020\\_technical\\_guide.pdf](https://www.epa.gov/system/files/documents/2022-01/egrid2020_technical_guide.pdf).

<sup>74</sup> <https://kevala.com/wp-content/uploads/2021/11/Total-Carbon-Accounting.pdf>

to specific generators. The process involves applying machine learning to data on generation, transmission infrastructure, weather, and socioeconomic and other data to model power flows all the way to the substation level to inform historical, real-time, and day-ahead estimates of TCA.

### **NREL Cambium**

The NREL Cambium project publishes data on simulated long-run, future hourly emissions, wholesale power cost, and grid operation data.<sup>75</sup> Cambium uses simulation modeling of electricity system investments and hourly operations in future years (e.g., Cambium 2021 projects over 2022–2050 in two-year time steps). Cambium uses NREL’s Regional Energy Deployment System (ReEDS) least-cost grid investment model, complemented by the PLEXOS system operation simulation model, to estimate both short- and long-run marginal emissions rates. Whereas other organizations discussed in this report focus on short-run marginal emission rates, Cambium emphasizes the role of long-run marginal emission rates for use in long-term planning decisions, such as investments that lead to persistent changes in electricity demand over several years. Long-term changes to energy infrastructure can be expected to shift market equilibria, changing the kinds of generating capacity and how much is built.

---

<sup>75</sup> <https://www.nrel.gov/analysis/cambium.html>

## 8. References

- Bialek, Janusz. 1996. "Tracing the Flow of Electricity." *IEE Proceedings-Generation, Transmission and Distribution* 143 (4): 313–20.
- Bialek, Janusz W., and Paul A. Kattuman. 2004. "Proportional Sharing Assumption in Tracing Methodology." *IEE Proceedings-Generation, Transmission and Distribution* 151 (4): 526–32.
- CRS. 2021a. "Accounting for Standard Delivery Renewable Energy." Center for Resource Solutions (CRS). <https://resource-solutions.org/document/03152101/>.
- . 2021b. "Data Sources: Accounting for Standard Delivery Renewable Energy." CRS. March 2021. <https://resource-solutions.org/document/03152101/>.
- Daniels, Lynn, Britta Gross, Christy Lewis, and Laurie Stone. 2022. "More EVs, Fewer Emissions: How to Maximize Emissions Reductions by Smart Charging Electric Vehicles." RMI. <https://rmi.org/insight/more-evs-fewer-emissions>.
- Gagnon, Pieter, and Wesley Cole. 2022. "Planning for the Evolution of the Electric Grid with a Long-Run Marginal Emission Rate." *iScience* 25 (3): 103915.
- Gagnon, Pieter, Will Frazier, Cole Wesley, and Elaine Hale. 2021. "Cambium Documentation: Version 2021." Technical Report. National Renewable Energy Laboratory. <https://www.nrel.gov/docs/fy22osti/81611.pdf>.
- Gerber, Ben. 2021. "A Path to Supporting Data Driven Renewable Energy Markets." M-RETS. <https://www.mrets.org/wp-content/uploads/2021/02/A-Path-to-Supporting-Data-Driven-Renewable-Energy-Markets-March-2021.pdf>.
- Groutsis, Nancy. 2021. "U.S. Energy Grid 101." *Daily Kos*, February 21, 2021. <https://m.dailykos.com/stories/2021/2/21/2017336/-U-S-Energy-Grid-101>.
- Infrastructure Investment and Jobs Act. 2021. <https://www.congress.gov/bill/117th-congress/house-bill/3684/text>.
- Miller, Gregory. 2022. "Applying the Consequential Emissions-Optimized Energy Procurement and Management."
- Miller, Gregory J., Kevin Novan, and Alan Jenn. 2022. "Hourly Accounting of Carbon Emissions from Electricity Consumption." *Environmental Research Letters* 17 (4): 044073.
- Rudkevich, Aleksandr, Pablo A. Ruiz, and Rebecca C. Carroll. 2011. "Locational Carbon Footprint and Renewable Portfolio Policies: A Theory and Its Implications for the Eastern Interconnection of the US." In *2011 44th Hawaii International Conference on System Sciences* (pp. 1-12). IEEE.
- Schlömer, S., T. Bruckner, L. Fulton, E. Hertwich, A. McKinnon, D. Perczyk, J. Roy, et al. 2014. "Annex III: Technology-Specific Cost and Performance Parameters." *Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. IPCC. [https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc\\_wg3\\_ar5\\_annex-iii.pdf#page=7](https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_annex-iii.pdf#page=7).
- Securities and Exchange Commission. 2022. *The Enhancement and Standardization of Climate-Related Disclosures for Investors*. RIN 3235-AM87. <https://www.sec.gov/rules/proposed/2022/33-11042.pdf>.

- Sotos, Mary. 2015. "GHG Protocol Scope 2 Guidance." World Resources Institute. [https://ghgprotocol.org/sites/default/files/standards/Scope%20%20Guidance\\_Final\\_Sept26.pdf](https://ghgprotocol.org/sites/default/files/standards/Scope%20%20Guidance_Final_Sept26.pdf).
- Spees, Kathleen, Judy Chang, David Luke Oates, and Tony Lee. 2017. "A Dynamic Clean Energy Market in New England." November. [https://www.brattle.com/wp-content/uploads/2021/06/11819\\_a\\_dynamic\\_clean\\_energy\\_market\\_in\\_new\\_england-1.pdf](https://www.brattle.com/wp-content/uploads/2021/06/11819_a_dynamic_clean_energy_market_in_new_england-1.pdf).
- Tranberg, Bo, Olivier Corradi, Bruno Lajoie, Thomas Gibon, Iain Staffell, and Gorm Bruun Andresen. 2019. "Real-Time Carbon Accounting Method for the European Electricity Markets." *Energy Strategy Reviews* 26: 100367.
- US Environmental Protection Agency. 2022. "Emissions & Generation Resource Integrated Database (EGRID)." Office of Atmospheric Programs, Clean Air Markets Division. <https://www.epa.gov/egrid>.

