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VIA ELECTRONIC FILING (www.regulations.gov) (REG-117631-23)

The Department of the Treasury
CC:PA:LPD:PR (REG–117631–23), Room 5203,
Internal Revenue Service
P.O. Box 7604, Ben Franklin Station
Washington, DC 20044

RE: Section 45V Credit for Production of Clean Hydrogen, Notice of Proposed Rulemaking, 88 Fed. Reg. 89,220 (Dec. 26, 2023)

Dear Assistant Secretary Batchelder:

The Clean Energy Institute (CEI) at the University of California Irvine (UCI) respectfully submits comments on the proposed regulation relating to the credit for production of clean hydrogen (clean hydrogen production credit) and the energy credit, as established and amended by the Inflation Reduction Act of 2022.

As discussed below, we offer three recommendations for the final U.S. Department of the Treasury (Treasury) final guidance on requirements for establishing eligibility for Section 45V tax credits for the production of very clean hydrogen:

1) Shift Requirements from Pathway Restrictions to Carbon Intensity Validation,
2) Tie the Timing of Changes in the Method and Granularity of Carbon Accounting to Satisfaction of Conditions Precedent, and
3) Hold Carbon Accounting Protocols Fixed for the Life of Each Project.

The Clean Energy Institute

The Clean Energy Institute at UC Irvine elevates and facilitates collaborations and industry connections for UCI's world class engineering and physical science research teams to discover and create needed clean energy technologies and solutions. We are a platform for energy science and engineering, the advancement to real-world application of clean energy technologies, and public education in support of the breakthroughs required to enable a post-fossil fuel energy future. While California has the nation's most aggressive clean energy goals, our existing renewable energy portfolio, policies and plans won't suffice. New research here at UCI will overcome limitations by leveraging both the recent progress made in renewable energy conversion and storage technologies, and the transformation of existing energy infrastructure.

The CEI and its predecessor, the Advanced Power and Energy program, have been active in hydrogen and fuel cell research for more than twenty five years. The organization authored the first roadmap for the build-out of the renewable hydrogen sector under the sponsorship of the California Energy Commission. It has also been very active in helping to craft and implement policy, regulation, and legislation supporting the advancement of renewable hydrogen and related end uses nationally with a focus on California. CEI was a founding partner in the California ARCHES hydrogen hub, and both signatories on this letter have been board members of the California Hydrogen Business Council for more than a decade.

Framing the Issues

The Department of the Treasury and the U.S. EPA are well aware of the debate over various aspects of carbon intensity calculation as it relates to qualification for section 45V tax credits. However, UCI CEI would like to briefly summarize its prior work upon which these recommendations are based and clarify the meaning of key terms for purposes of these comments.

CEI recently published a white paper on issues related to the use of environmental attribute credits (EACs) (UCI EAC WP) (Attachment 1). The paper was informed by academic and institutional research, and the more the 200 comments submitted to the treasury docket on IRA tax credit implementation at the time the paper was published. The paper analyzed the available fact base on seven program design elements related to the use of EACs and how varying degrees of stringency impact attainment of environmental goals and the cost of doing so. The paper presents arguments for and against varying degrees of stringency, the implications of available evidence on each, and provides recommendations on balanced policy options. The analysis included assessment of three especially impactful issues regarding the use renewable power EACs to demonstrate qualification for section 45V tax credits. These are: 1) temporal time frame for assessing GHG emissions (*Time Matching*); 2) permissible physical power delivery pathways (*Deliverability*); 3) vintage restrictions on procured power (*Additionality* or *Incrementality*). Some parties have coined the term, which is adopted in the guidance, *Three Pillars* to refer to the most stringent form of these program design elements.

The debate centers on how and if renewable energy credits (RECs) should be used in assessing pathway carbon intensity (CI) for electrolytic hydrogen production. RECs demonstrate the production and delivery of one MWh of renewable energy. There is no debate that this results in zero direct GHG emissions (also referred to as *attributional* emissions). There is also no debate that the supply of an incremental amount of power to the grid changes the dispatch of grid power if the incremental supply is not match, in real time, with incremental demand within the same dispatch. This change in dispatch can cause incremental emissions (positive or negative). We refer to these as *marginal consequential emissions* (MCE or *consequential* emissions for short).

It is also agreed that incremental permanent load requires the addition of incremental supply which may or may not be renewable (unless there is a mandate that incremental new supply must be renewable). These are also consequential emissions, but we refer to this subset as *induced* emissions as the term is used in the letter from the U.S. Environmental Protection Agency to the U.S. Department of Treasury dated December 20, 2023, providing guidance on provide information related to the definition of lifecycle greenhouse-gas emissions under the Clean Air Act (EPA Letter).

Although there is no debate over the potential for consequential and induced emissions to occur, there is extensive debate and disagreement over the extent to which these will occur under various pathway scenarios, and the extent to which they should be attributed to or assigned to an individual electrolytic hydrogen production facility. One way of avoiding the issue is to mandate the use of a pathway for which consequential and induced emissions are zero. Parties have coined the term "Three Pillars" pathways to describe such a case and the term "Three Pillars" EAC is now a defined term in the GREET 45V model version.

A "Three Pillars" pathway is one in which: 1) uses *Hourly Matching* meaning that renewable power must be delivered to the hydrogen-producing electrolyzer in real time (within the same hour) (under the guidance, annual matching is permitted until 2028); 2) ensures that there are no induced emissions by requiring that the electrolyzer only consume power from newly constructed resources (*Additionality or Incrementality*) 3) meets strict *Deliverability* requirements ensuring that power physically delivered to the electrolyzer through a direct electrical connection to the electrolyzer (referred to as Deliverability).

The 45 V guidance essentially adopts the Three Pillars as a requirement for qualification for credits under the lowest carbon-intensity tier. The draft guidelines employ annual time matching initially and hourly matching from 2028 forward. From the perspective of rulemaking on pathway carbon intensity calculation, there are several major problems with the proposed guidelines:

1) **Lack of Pathway Comprehensive Carbon Intensity Calculation Methodology.** The proposed guidance does not provide a methodology or framework for calculating consequential or induced emissions but proposes instead use case restrictions. The GREET model has heretofore used attributional GHG accounting for procured power – it does not assign pathway emissions to a facility or activity based on consequential or induced emissions and the GREET 45V model does not address this issue. This leaves a pathway that departs from the Three Pillars but has pathway lifecycle emissions

(including consequential and induced emissions) below 0.45 kg-CO2e per kilogram of hydrogen produced with no ability to qualify for credits.

2) **Increase in Renewable Hydrogen Production Cost.** Firm renewable power and/or storage required for hourly matching, restrictive market boundaries, and additionality requirements all increase the cost of renewable hydrogen production. Assertions that they do not cannot be reconciled with the current and mid-term cost of battery energy storage and firm renewable resources.
3) **Barriers and Challenges to Implementing Three Pillars Requirements.** It may be infeasible for many projects to satisfy Three Pillars requirements due to interconnection queues and the illegality of bilateral power purchase agreements (PPAs) in most jurisdictions of the United States (note that none of the modeling results referenced on the Treasury Docket consider real-word restriction and tariffs governing the purchase of power by retail loads and thereby understate the cost of renewable power and access to supply for electrolyzers). As acknowledged by Treasury, the date by which certification and tracking systems for EACs with multiple attributes (at minimum power source, time of production, location of production, and facility vintage) can be fully developed, tested, and implemented is uncertain. The methodological uncertainties in what carbon accounting requirements will be imposed on projects, if not addressed in the guidance and associated regulations, creates a regulatory risk that will be a major barrier to securing financing for 45V projects.

Lack of Carbon Accounting Methodology and Tools

Application of a Three Pillars pathway mandate is not a carbon intensity calculation method. Although it is true that failure to properly account for consequential emissions when renewable power credits are generated at one time and/or location and retired at another time and/or location can lead to inaccurate GHG accounting, hourly matching (as opposed to hourly emissions tracking) is only one way among many to address this and it is the most costly. Hourly matching within a single balancing area without transmission constraints ensures that there will be no consequential emissions from renewable power production and use, but there are more flexible ways to address the issue. For example, consequential emissions can be offset by the retirement of additional EACs. Alternatively, when feasible, 45V qualification could be determined through the use of electric system carbon credits whose creation accounts for consequential carbon emissions at the time and location that they are generated and attributes consequential emissions to the user retiring the credit.

That said, current regimes (the GREET model) do not attribute consequential emissions to pathway carbon intensities and incorporation of consequential emissions in pathway carbon intensity calculations for 45V qualification should be phased in once proper tools and methods for calculating consequential emissions are in place and if implementation does not place unique burdens on electrolyzers not placed on other power consumers. At such time as consequential emissions accounting is phased in to 45V regulations, the requirements should specify how carbon intensity is to be calculated and not specify a single restrictive use case (physically connected real-time production and use of renewable power).

With respect to the electric grid, the term *induced* emissions as used in the EPA Letter and the draft guidance document refers to emissions related to new capacity added in response to an increase in demand on the grid. This is distinct from consequential emissions related to changes in the dispatch of existing resources in response to real-time changes in grid demand.

EPA describes its consideration of the issue of induced emissions caused by indirect land use change resulting from the use of biomass for fuel production and opines that new electrolyzer capacity can reasonably be expected to have an analogous impact on grid emissions. However, they also state the EPA has performed no lifecycle analysis to ascertain the impact of new electrolyzer load on grid emissions. EPA further states that it declined to include such emissions in the pathway carbon intensity calculations for use under the RFS2 rules[1] because of the lack of a sound basis for estimating such emissions. EPA states that assigning the grid average emissions factor to grid power consumed by biofuels production is a proxy for induced emissions but fails to explain how the average emissions of the existing grid has any connection to what resources will be added to meet new demand.

The issue of induced emissions, under varying terminology, was discussed extensively in comments to the Treasury with sophisticated technical analysis being put forward arguing both that new electrolyzer capacity would create significant induced emissions with incrementality (additionality) requirements, <zero lab> and that new electrolyzer capacity would have no or minimal induced emissions <E3>. The empirical evidence is that renewable capacity is added to meet demand without any additionality mandate.[2]

As with land use change, the indirect impact of adding new renewable power demand depends on how the market reacts. The diametrically opposed conclusions on induced emissions noted above derive from differing assumptions on how new resources will be added to meet growing demand. A recent paper seeking to reconcile the findings describes what are referred to as "compete" and "non-compete" assumptions used for determining the electric supply mix with and without electrolyzers.[3] This can also be described as whether electrolyzers are or are not included in an integrated resource planning process, or are considered an overlay (unplanned new load) to the plan. Which assumption is the most accurate reflection of reality is not known at this time, and it will be dependent upon time and location.

In California, a hypothetical new electrolyzer load that contracts for renewable power supply from an existing grid resource would create the need for the addition of a new grid resource to supply the same amount of energy to maintain the same ratio of supply to demand in

[1] 2010 update to the rules governing qualification under the federal Renewable Fuel Standard
[2] See Additionality in Attachment 1 f
[3] https://energy.mit.edu/wp-content/uploads/2023/04/MITEI-WP-2023-02.pdf

aggregate. If the substitute resource is renewable and of the same production capacity is the existing resource, there would be no induced emissions. If the substitute resource were fossil-fueled, then there would be induced emissions. Which case is more likely? In California, were the prior buyer of renewable power an RPS obligated entity, then the replacement resource would be renewable by mandate. Were the prior buyer a voluntary buyer seeking to manage its Scope 2 emissions, logic says that the buyer would contract with another resource and, assuming overall prior demand for renewable energy remained unchanged, then a new resource would be added to serve the net new demand through market forces.

The concept put forward in a number of docket comments that a new load purchasing power from an existing renewable resource increases emissions on the grid by “diverting” renewables from existing load is flawed. The market as a whole determines the aggregate demand for renewable power and the supply side expands to meet demand. A new-capacity requirement on electrolyzers can be justified because the 45V incentive is specifically targeted at adding green hydrogen production capacity (it is not a wind or solar tax credit). Applying a non-market intervention to a process input is not justified. Under such provisions, an electrolyzer owner could not purchase power under a utility green tariff program (which of course would procure more renewables to meet new demand) because the power is only certified as renewable and not “new” renewable power.

Rather than deferring rulemaking on the issue of induced grid emissions until there is adequate information and analysis to support including induced emissions in a pathway carbon intensity calculation (as EPA did in RFS2), the guidance document proposes a power procurement restriction. Stating that mandating a use case for which induced emissions are known is a proxy for addressing induced emissions in pathway CI calculations is technically incorrect.

It is premature for Treasury to establish guidance that attributes any induced emissions to power procured by electrolyzer owners receiving 45V credits until such time as those emissions can be properly calculated using validated tools that apply common assumptions vetted through a robust stakeholder process. The same is true of the inclusion in pathway CI of consequential emissions related to dispatch of existing resources new carbon-intensity calculation tools with much higher temporal and spatial resolution than the current GREET model.

It is unclear what EPA means by “proxy” when they describe the Three Pillars as a proxy for addressing induced emissions. Grid average emissions are a proxy or approximation method for assessing the emissions associated with consumption of grid power when more precise data or analysis is not available. Because GHG and economic activity are highly correlated, GDP could be used as a proxy for estimating national GHG. EPA should clarify how it intends to use the fact (EPA’s finding) that an electrolytic hydrogen produced using directly connected, dedicated, new renewable resource as input has a CI below 0.45 kg-CO2e can be used as a proxy to calculate the carbon intensity of an electrolyzer using a different renewable power procurement strategy.

Increased Renewable Hydrogen Production Cost Under the Three Pillars Mandate

Mandating the use of Three Pillars pathways will increase the cost of renewable hydrogen production. All three pillars increase cost in exchange for unknown incremental GHG emissions reductions, which may be zero.

Time Matching. When power is supplied by intermittent renewable resources, electrolyzers will either need to operate at low capacity factors (25% to 30% for solar power) or incur the cost of physical storage. Operating at a capacity factor of 30% versus 90% triples the capacity portion of hydrogen production cost. Using physical storage would add roughly $7/kg to the hydrogen production cost.[4]

Deliverability. The proposed small market areas will also increase cost. Large energy market areas with regional transmission/transport capability are cost optimal. They allow production to occur at locations of least cost and to deliver energy to demand centers over the transmission network. In the case of California, efforts to regionalize of transmission planning in the WECC have been under way for several years for precisely this reason.[5] The market efficiency of broad market areas has been fully proven in existing energy markets (power, natural gas, and liquid fuels). Energy market mechanisms, such as congestion pricing, and integrated resource planning are the tools that ensure adequate electric system delivery capacity. There is no basis for placing any unique burden on electrolyzers.

It should also be noted that the National Transmission Needs Study (DOE Needs Study) that is the basis for the proposed market boundaries contains no finding that restricting power-purchase transaction to within its modeling zones would avoid or reduce consequential greenhouse gas emissions due to congestion constraints or transmission losses compared to wider market areas. The study does contain, in the sponsor feedback section, a recommendation that the DoE analyze the value of regional transmission planning over broader market areas.

Additionality. Analysis of historical data presented in the UCI EAC white paper shows that renewable capacity additions grow in proportion voluntary demand for renewables in addition to capacity additions mandated by RPS requirements. In essence, market forces ensure additionality. However, it is the market as a whole that drives this with all voluntary buyers being on equal footing. Based on announced projects, most renewable electrolytic hydrogen project plan to add renewable capacity to meet most or all of their demand. However, some may wish to purse other procurement strategies, such as contracting with renewable resources whose sales agreements are expiring, and restricting such transactions creates an unwarranted

[4] Based on electrolyzer installed cost of $1,200/kg and 18% capital cost recover factor for reduced capacity factor case, and for the storage case a cost of $130/MWh for 12-hour storage using the data and formulation from Schmidt, Oliver, Sylvain Melchior, Adam Hawkes, and Iain Staffell. 2019. "Projecting the Future Levelized Cost of Electricity Storage Technologies." *Joule* 3 (1): 81–100. https://doi.org/10.1016/j.joule.2018.12.008.

[5] https://blog.ucsusa.org/vivian-yang/what-does-western-grid-regionalization-mean-for-california/

market distortion. It is important to note that the 45V credits are for hydrogen production, not renewable power production and qualifying power supply should be based only on carbon intensity.

Barriers and Challenges to Implementing Three Pillars Requirements

Methods and protocols. The methods and protocols used for pathway carbon intensity calculations vary with respect to, among other things, background and foreground input assumptions, time horizon used for analysis (e.g., short run or long run marginal analysis), and what consequential and induced emissions should be included in the analysis. Resolution of these issues as related to 45V through a robust stakeholder engagement process should be completed before revisions to GREET are implemented and adopted.

Tools and implementation. System design cannot begin until final regulations are in place based on final methods and protocols, and until the regional tracking systems determine how they will recover costs for system design and implementation. Further information is needed before the earliest practical implementation date of the final regulations can be determined, including the time for robust piloting and validation prior to widescale roll-out of a multi-billion dollar financial instrument that will comprise the tracking system.

Power Market Access. Physical PPAs are not available in many states and transmission and distribution charges far exceed the cost to serve electrolyzers when they operate as dispatchable loads. The timing of implementation of hourly GHG emissions tracking should be conditioned on the ability of electrolytic hydrogen producers to directly purchase renewable power at transmission access rates applicable to wholesale buyers.

Regulatory Certainty. Investors in and debt financers of energy projects require regulatory certainty as a condition of financing. Regulatory risk impacting project returns will lead to a high risk premium or may even make projects unfinanceable. At a recent workshop on international development of hydrogen hubs hosted by Leeds University with more the 50 representatives from the United Kingdom, the European Union, and the United States, regulatory certainty was ranked as the most critical factor among ten potential enablers and barriers identified by the group. In the context of 45V this means that the GHG accounting protocols applicable to a project should stay fixed for the economic life of the project (typically 10 to 20 years) as is standard for GHG offset projects.

Recommended Changes to the 45V Guidance

UCI CEI respectfully offers the following recommendations for the final guidance on demonstration of 45V eligibility.

Shift Requirements from Pathway Restrictions to Carbon Intensity Validation. Define the Three Pillars concept not in terms of mandated pathways but in terms of pathway carbon intensity calculations that properly include consequential emissions related to the time and location of EAC generation and use, and induced emissions. This better aligns with the statute and corrects the exclusion of projects with very low carbon intensity using power procurement strategies other than the one defined in the draft guidance.

Tie the Timing of Changes in the Method and Granularity of Carbon Accounting to Satisfaction of Conditions Precedent. Any date adopted in the final guidance that increases stringency with respect to any aspect of carbon intensity calculation should be a “no sooner than” date with actual implementation date based upon meeting defined feasibility requirements as discussed earlier in this document. These include definitive determination of a methodology for addressing consequential emissions, availability of analytical tools, availability of required EACs including protocols, tracking and verification, and access to directly purchased power at reasonable rates.

Hold Carbon Accounting Protocols Fixed for the Life of Each Project. Treasury should include in the final regulation the provision that the carbon accounting protocols applicable to a project are those in place at the time the project commenced construction.

Sincerely,

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Director, UCI Clean Energy Institute

Dr. Jeffrey Reed
Chief Scientist for Renewable Fuels and Energy Storage
UCI Clean Energy Institute

Attachment 1 of 1

(ENVIRONMENTAL ATTRIBUTE CREDITS -
Analysis of Program Design Features and Impacts)

ENVIRONMENTAL ATTRIBUTE CREDITS

Analysis of Program Design Features and Impacts

Version Date: 09/15/2023

Abstract:

This white paper assesses program design features related to the generation and use of environmental attribute credits, their impact on cost, and on the attainment of environmental goals. The analysis presents perspectives and available evidence on requirements for use of tradable credits, time matching, additionality, geographic boundaries, verification and tracking, preference for nascent technologies, and methods to ensure credit value certainty. There is evidence and rationale to support the range of positions being put forward on these issues. Notwithstanding program differences, there is robust evidence that the use of EACs supports market development and facilitates investment in environmentally preferred resources. Increased stringency in program requirements ensures environmental integrity but can also impede resource expansion if compliance with increased stringency requirements becomes too onerous. The optimal balance depends on the design element being considered, the environmental attribute, and the stage of market development.

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White Paper Purpose

The purpose of this white paper is to inform policy decisions regarding program requirements for the creation and use of environmental attribute certificates or credits (EACs) that represent environmental attributes (EAs) as they relate to the emerging and evolving clean energy (power and fuels) programs in the United States and international markets.[1] Environmental Attributes (EAs) are characteristics of energy sources and other activities that define specific environmental or sustainability aspects of those sources and activities. Specifically, with respect to power and fuel, they have been defined as any and all credits, benefits, emissions reductions, offsets, and allowances associated with generation or production of power or fuel.[2] This assessment examines available data, research, and stakeholder perspectives on the impacts of program features and requirements on EAC program outcomes. The scope focuses on seven key issues under current discussion and debate:

1) The extent to which use of tradable EACs should be permitted as a basis for compliance under mandatory programs or environmental claims under voluntary programs;
2) Requirements for demonstrating additionality of EA's (or indirect EAs)[3] created in generating EACs;
3) Requirements for time matching of EAC generation (booking) and use (claiming);
4) Appropriate infrastructural and geospatial boundaries on EAC generation and EAC use;
5) Requirements for tracking, measurement, and verification (TMV) of environmental attributes;
6) The appropriateness of programmatic preferences in the use of EACs for nascent technologies; and
7) The need for mechanisms to increase EAC value certainty.

Program features will be assessed with respect to effectiveness in stimulating expansion of clean energy capacity and effectiveness in reaching aggregate program goals for environmental improvement (such as a regional goal or mandate for defined quantities of renewable energy consumption or carbon reduction). The levers that maximize program effectiveness will be considered in the context of technology and market maturity, and the extent to which subsidies or preferences are needed to reach environmental objectives.

Context and Motivation

Various programs and protocols have been established for the creation and certification of instruments, typically credits, that represent the production of a specific quantity of clean energy or reduction of a specified quantity of a pollutant. These instruments, described further below, are used to demonstrate compliance with program requirements, such as renewable portfolio standards (RPSs) and tax credit programs, or to demonstrate voluntary use of clean energy or creation of environmental benefits. Credits convey property rights to environmental attributes (EAs), and they are commonly bought and sold. This white paper focuses primarily on renewable energy certificates as there is current debate and deliberation

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[1] For purposes of the discussion, bilateral agreements such as power or fuel purchase agreements in which energy and environmental attributes are conveyed together (bundled) are considered a type of EA transaction.

[2] https://resource-solutions.org/wp-content/uploads/2015/09/ETNNA-Environmental-Attribute-Paper-Final.pdf https://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/86954-06.htm

[3] An indirect environmental attribute is an environmental attribute, such as carbon emissions, that may be derived from a certified attributed such as renewable-source energy.

ongoing in various policy venues regarding the appropriateness of and conditions for the use of such instruments.

For electricity, the most common certified attribute is that the power source is renewable as defined by the program. The associated credits are referred to as Renewable Electricity Certificates (RECs). For renewable natural gas (RNG) and renewable hydrogen (collectively, renewable gas), EAs most often include the qualities which: (i) distinguish renewable gas from geological (fossil) natural gas; (ii) convey the emissions profile of the resource, including the capture or avoidance of greenhouse gas (GHG) emissions; (iii) define the character of the feedstock source of the renewable gas, including whether it meets criteria for being labeled as renewable, sustainable, cellulosic, advanced, biogenic, biomass-based and/or waste-derived; and/or (iv) any attributes which are a necessary prerequisite to the creation of certificates, credits, offsets or allowances. For renewable fuels, various types of credits are used including Renewable Energy Certificates (RECs -- same acronym as for electricity), Renewable Thermal Credits (RTCs), Renewable Thermal Certificates (RTCs), Low Carbon Fuel Standard (LCFS) credits, or Renewable Identification Numbers (RINs). Tax credits related to clean energy are generally referenced by the applicable tax credit code. Each type of credit has specific protocols under which it can be created and certified, and requirements may vary across programs for the same type of energy, such as solar or wind electricity.

As noted above, EACs allow EAs to be separated from the physical power or fuel through which they are created making them a separate, transferable commodity. Transfer of EAs is done under a process known as “book and claim.” EACs can generally be bought and sold through bilateral transactions or via exchanges. The environmental attribute, such as the capture or avoidance of greenhouse gas emissions or the production and use of a unit (e.g., 1 MWh) of renewable electricity, is “booked” at the time and location that the attribute is created, and “claimed” at a later time and different location, usually associated with an action whose emissions profile is improved by application of the claimed attribute.

EACs can facilitate the creation of environmental benefits at the least cost by creating a mechanism by which projects or actions with lower cost to create EAs can generate EAs beyond what they use directly and sell unclaimed EAs to others whose cost to create EAs is higher. In theory, this leads to the least-overall-cost for meeting environmental goals by stimulating the development and operation of least-cost, highest-benefit projects. The ability to monetize EAs is a primary driver of investment in clean energy projects.

Trading programs associated with EAs can help create market liquidity, enable price/cost discovery, and minimize consumer costs through well-functioning competitive markets. They also allow buyers and sellers to create portfolios of different tenor and quantity. These are the same functions as are served by wholesale power exchanges, natural gas and oil commodity markets, and carbon credit exchanges. Unlike conventional commodity markets, EA markets can separate the EA from the underlying commodity (energy). For EACs to serve their function, ensuring the environmental integrity of the certificates and credits is paramount. The creation of verifiable and additional emissions reductions must be certain.

Although the use of RECs in renewable power markets has been ongoing since the late 1990s, and renewable power markets are relatively mature, renewable gas markets are less mature. In theory, EACs would be expected to play a similar role in today’s nascent renewable gas markets as Renewable Energy Certificates (RECs) did for electricity markets more than a decade ago: consumers purchase certificates to claim the environmental benefit of substituting renewable gas for fossil natural gas (thus satisfying compliance obligations or voluntary sustainability goals), which in turn serves as a demand and price signal to the market, encouraging the buildout of renewable gas production facilities.

When clean energy is more costly than fossil energy, and the cost differential exceeds customers' willingness to pay, there is a need for regulatory or statutory mechanisms to promote adoption through mandates or incentives. EACs can be an important tool to facilitate both mandates and incentives.

The strength of restrictions or conditions in clean energy procurement and certificate programs has been termed degree of "stringency" [1].[4] There is a natural tension between the producers of clean power or fuels under such programs who desire simplicity and broad eligibility, and program designers concerned with ensuring that the desired environmental benefits underpinning a given program are achieved. . Greater stringency is generally argued as ensuring higher environmental integrity, while less stringency is argued as more supportive of investment in and deployment of environmentally-preferred resources. Optimal policy balances the two desires with through program requirements that best serve both goals.

Summary of Findings

The policy and program design issues under consideration regarding the provisions and requirements for the use of EACs in voluntary and mandatory programs generally relate to finding a balance between provision of effective incentives to stimulate investment in preferred technologies and pathways and the desire to guarantee that desired environmental benefits are attained. At a macro level, these goals need not be in conflict. However, at the implementation level, stringent program requirements have the potential to stifle project development such that the total investment pipeline creates fewer benefits than would be the case under more permissive or inclusive program requirements. This can be particularly consequential for nascent technologies requiring financial support to enter the market and build efficient scale. Alternatively, program requirements that are not stringent enough can result in reduced achievement of environmental benefits. Some considerations on finding an optimal balance are discussed at the end of this paper. High-level findings on the questions addressed are provided below.

Use of Tradeable EACs

- EACs are used universally to demonstrate certified creation of EAs and convey property rights.
- Trading exchanges create market efficiency and stimulate investment.
- There is nearly universal support for the use of EACs among stakeholders, with differences centered on standards and requirements for EAC generation and use.

Additionality

- Buyer or seller incentives that expand demand for environmentally preferred resources stimulate investment in new supply with or without formal additionality requirements.

Time Matching

- Time-matching modeling results put forward by academic and professional research and analysis groups show contradictory results on the extent to which hourly versus longer, such as annual, time matching requirements impact energy costs, system dispatch, and greenhouse gas emissions.

[4] Note that bracketed numbers refer to citations of reports and academic publications in the bibliography at the end of this document; whereas footnotes are used for web links and explanatory notes

- Observed cost and emissions impacts of actual resource deployments will be needed to determine which modeling approach best predicts investor and energy market behavior, and this may depend on the stage of market evolution and the size of the deployment.
- Under all modeling approaches, the consequences of phasing in time matching depend upon the resource mix in the market in question (e.g., lowest hourly carbon intensity to highest hourly carbon intensity) and regulatory realities, such as presence or absence of a binding renewable portfolio standard.
- Fundamentals lead to the conclusion that hourly matching increases cost, and that to achieve deep levels of decarbonization, physical time matching of zero-carbon supply and demand will be necessary.
- The optimal policy on how and when to implement granular (hourly) time matching requirements comes down to balancing stimulation of market formation and investment and collateral benefits, with acceleration of GHG reduction, and this may differ by market.

Geographic Boundaries

- Wider geographic market boundaries better optimize the overall resource supply portfolio if geographic boundaries constrain lower-cost resources[5] from supplying the marginal consumer.
- Transportation constraints (e.g., lack of adequate electric transmission capacity) can lead to dispatch of higher cost, higher emitting resources, however, congestion costs provide a price signal to stimulate investment in new transmission (or pipeline) infrastructure.
- Market boundaries cannot impact GHG emissions under a mandatory market-wide cap.

Tracking, Measurement and Verification

- There are trade-offs between TMV cost and enhanced integrity of EACs, including fraud prevention, which need to be balanced.
- Stakeholder processes balanced this trade-off for existing programs, but there was no published analysis found of TMV costs relative to the consequences of more or less stringent requirements (such as intentional or unintentional double-counting of attributes).
- Technology advances in data collection, storage, and analysis will enable more comprehensive TMV over time but not all regional tracking systems have the same level of ability/infrastructure to track with higher granularity, so regional differences in implementation timing are likely.

Support for Nascent Technologies

- Special support mechanisms for preferred emerging technologies have been common and have included programs incentivizing solar electricity within RPS programs (which were initially dominated by wind due to its cost advantage), electric vehicles, zero-emission vehicle infrastructure, distributed generation technologies, energy efficiency measures, and dairy biomethane production, among other technologies.
- These programs have been effective in supporting market launch and scaling of preferred technologies.
- Some technology-preference incentives have used EAC awards or multipliers to convey financial value such that EAC generation departs from the physical creation of EAs with the objective of enabling downstream benefits.

[5] Including the cost of delivering the power or fuel to the consumer.

- No quantitative analysis of the impact of using EA credits as incentives based on anticipated indirect environmental benefits was found, and qualitative arguments can be made both pro and con.

EAC Value Stabilization

- Suppliers of EACs place certainty in the value of EACs as the top, or a top, priority in program design.
- Program features such as contracts for differences (CFDs) and feed-in tariffs have been used to provide certainty of credit value for investors relying on credit revenues to support project finance.
- Governmental program sponsors may be reluctant to establish such programs due to concerns over financial risk and/or cost to consumers.

Programs in Place

As noted above, environmental attribute certificates or credits represent the creation of a specific and quantified environmental benefit. Certificates and credits are used as instruments to demonstrate compliance with mandates, to support claims of voluntary action, and to represent the monetary value of the underlying environmental attribute. Certificate or credit programs currently in place include those for producing and using renewable electricity, low-carbon fuels, reducing greenhouse gas emissions, and decreasing specific types of pollutants. Mandatory programs include procurement mandates for various types of clean (as defined by the program) resources, and cap and trade programs which allow obligated parties to buy and sell credits under an overall mandatory limit on emissions. Brief summaries of EAC programs currently in place related to clean energy are provided below. Procurement programs are also discussed as they almost universally rely on credits and or certificates to function. Programs and program elements are summarized in greater detail in the Appendix, which also provides links to the source information.

Environmental Certificate and Credit Tracking Systems

Systems are in place throughout the U.S. and in many international markets to verify, issue, and track EACs. The most common are REC tracking and trading systems referred to as RETS. Figure 1 shows a map of the RETS in the North America. There are also carbon credit tracking systems of similar function.

In practice, most RETS function in a similar way: there are rules for what resources are eligible, RECs can only be generated once and claimed once, and RECs often have a vintage over which they are valid. Production of renewable energy must be verified by meter data, documentation of the facility fuel type, and details of the facility interconnection and vintage. REC programs generally employ so-called book-and-claim accounting. The generation of the qualifying environmental attribute is “booked” through the creation of the REC. The attribute is “claimed” when it is retired to convey the attribute at another place and/or time. Program rules determine the limits on when and where RECs can be claimed. Current clean energy programs generally use annual true-up (only RECs generated within the same reporting year can be claimed) and are regional in scale as shown in Figure 1 for renewable electricity. There may also be restrictions on facility vintage.

Certification and Verification Standards and Protocols

While RETS certify that a unit of power, fuel, or heat meets the criteria for being counted as renewable energy (or being produced from renewable energy) set by regional jurisdictions, RETS do not guarantee any other environmental attributes. For example, RETS do not guarantee that purchasing a REC is linked with greenhouse gas or air pollutant emissions reductions, and they do not guarantee that purchasing the

REC encouraged the build of renewable energy facilities that would not have otherwise been built (additionality).

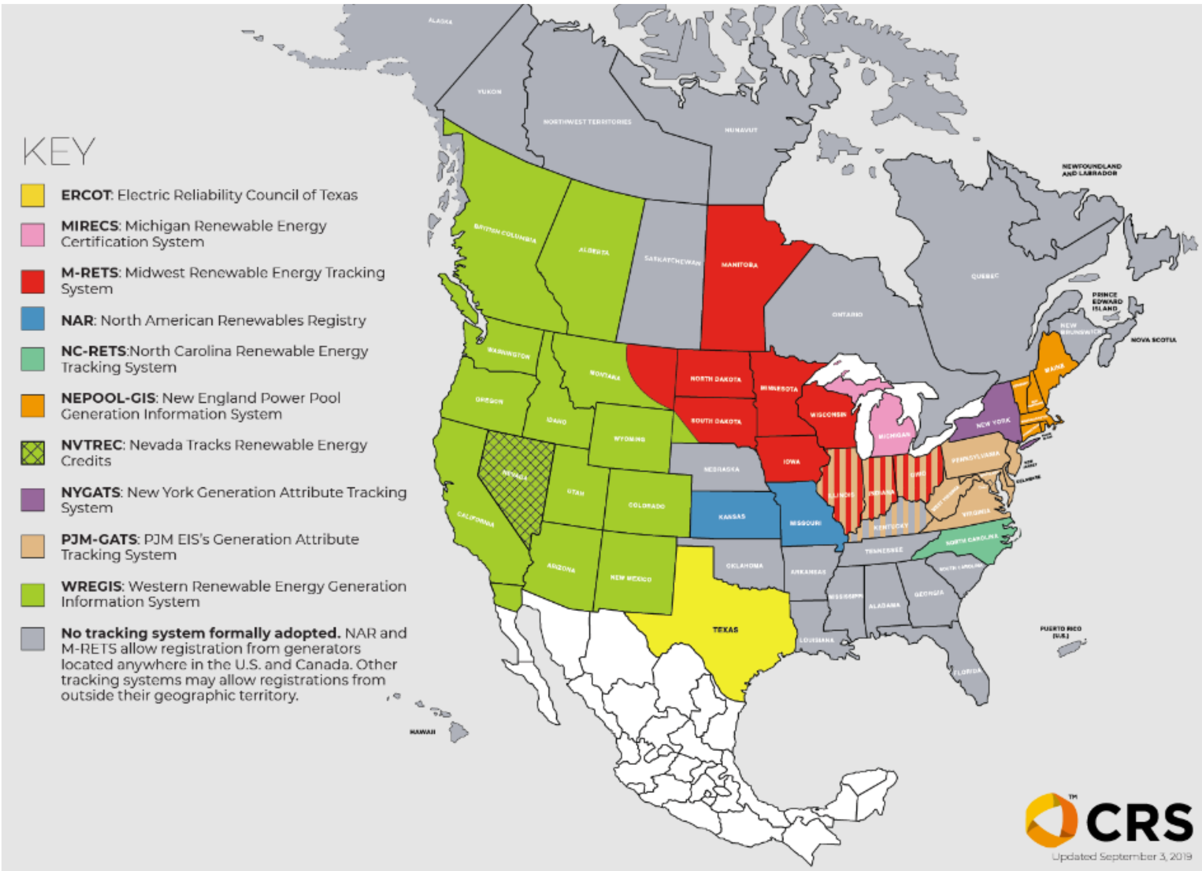

Figure 1. Renewable Energy Certificate Tracking Systems in North America.
https://resource-solutions.org/wp-content/uploads/2018/02/Tracking-System-Map.png

The U.S. EPA recommends that purchasers of RECs seek RECs that are specifically certified or verified by a third-party to correspond to a given environmental benefit.[6] A similar approach is taken in the European Union, where Guarantees of Origin (GOs) can be certified by a third-party. The certification of a REC by a third-party is optional and done at the request of the REC producer. In the U.S., the primary certification for improving confidence in the environmental integrity of a REC is the Green-e certification[7], administered by the Center for Resource Solutions. Green-e certification is also available for different types of products, such as carbon offsets and renewable fuels. To obtain a Green-e certification for renewable electricity represented by a REC, a renewable electricity producer must meet additional criteria above those required to register in a regional RETS, as described in the Appendix along with discussion of other certifying programs.

Renewable Energy Procurement and Incentive Programs

Twenty-eight states currently have renewable and/or clean electricity procurement mandates, and three have established programs with specific targets but not mandates. Figure 2 shows a coded map of

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[6] https://www.epa.gov/green-power-markets/certification-and-verification

[7] https://www.green-e.org/programs/energy

renewable and clean energy programs by state. The map at the host site is interactive with pop-ups providing state-level program specifics. Each state program has specific eligibility requirements, such as qualified resources, technology-specific carve-outs, geographic restrictions, vintage requirements, and presence or absence of an alternative compliance payment option.

Electricity is the most common resource covered under the programs, but three states have established renewable gas procurement standards (and one has set a target), and three have adopted low carbon fuel programs. Some programs also include renewable thermal energy. Only California has a mandatory greenhouse gas cap and associated credit trading program. At the federal level, there is a renewable fuel standard in place, and tax incentives for clean energy have been enacted under the Inflation Reduction Act. Further details on all state and federal clean energy procurement programs and federal tax credits are provided in the Appendix.

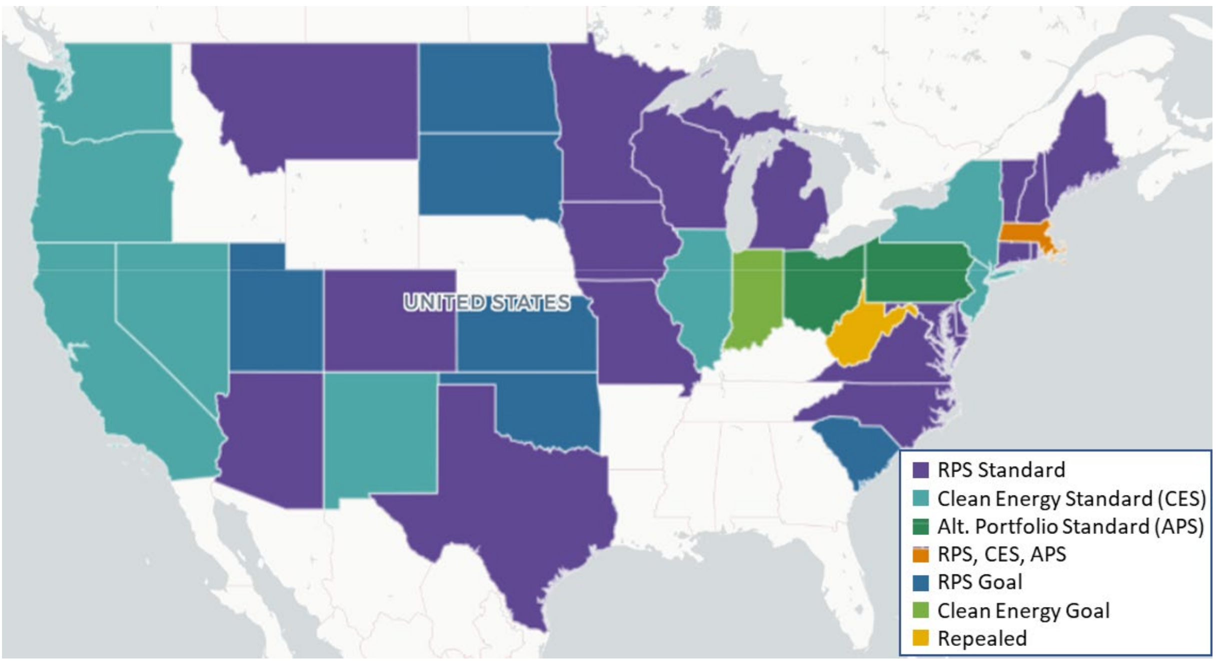


Figure 2. State Renewable and Clean Electricity Procurement Programs. Source: https://www.c2es.org/document/renewable-and-alternate-energy-portfolio-standards/

Trading EACs

One function of EACs is to create a tradeable instrument that allows EAC owners to sell their EACs to buyers that require them for compliance with mandates or that wish to purchase them voluntarily to improve the environmental footprint of their operations. Mature commodity markets, such as the Chicago Mercantile Exchange, trade large volumes of commodities on an open exchange that creates price transparency, liquidity (ability of buyers and sellers to transact at will), and low transaction costs. Conventional energy commodities, such as power, gas, and petroleum trade on similar exchanges.

Such systems for clean energy and GHG credits are nascent. Trading volumes are comparatively low, and the number of buyers and sellers in each market is also relatively low. Some of the RETS, such as PJM, facilitate transactions through bulletin boards for buyers and sellers.[8] There are a few organized exchanges, such as the California Low Carbon Fuel Standard (LCFS) and carbon credit auction processes,

[8] https://www.pjm-eis.com/getting-started/how-do-I-sell-recs

and a number of private platforms. However, brokers facilitate most transactions in the current U.S. EAC markets.

Issues Assessment

The present assessment draws from a range of sources including peer-reviewed articles, reports by research institutions and private organizations, comments to regulatory dockets and stakeholder interviews. We assess seven topics of current interest enumerated in the introduction:

1) The extent to which use of tradable EACs should be permitted as a basis for compliance under mandatory programs or environmental claims under voluntary programs;
2) Requirements for demonstrating additionality of quantified EA's (or indirect EAs)[9] created in generating EACs;
3) Requirements for time matching of EAC generation (booking) and use (claiming);
4) Appropriate geographic boundaries on EAC generation and EAC use;
5) Requirements for tracking, measurement, and verification (TMV) of environmental attributes;
6) The appropriateness of programmatic preferences in use of EACs for nascent technologies; and
7) The need for mechanisms to increase EAC value certainty.

The focus is on renewable and clean fuels, but renewable power is also central to the discussion because of its role as the primary input to electrolytically produced fuels and because of the larger relevant literature on renewable power EACs due to their greater maturity. For each of the issues addressed below, policy alternatives are framed, for most of the issues in terms of arguments for more versus less stringency, followed by presentation of available data and analysis relevant to the issue.

Use of Tradable EACs

The use of certificates and/or credits along with some form of market-based accounting and the ability to trade EACs is universal in current programs in the United States and internationally.[10] However, as the push for greater stringency by some stakeholders has evolved, the question has been raised as to whether EACs and book and claim accounting should be permitted at all. For example, several respondents to the U.S. Treasury Department docket seeking comment on requirements for verifying carbon intensity for Section 45 tax credits oppose any use of book and claim,[11] and the draft Greenhouse Gas Protocol being developed by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD) does not recognize the use of book and claim accounting for biomethane.[12]

Framing the Use of Tradeable EACs Issue

Arguments Against the Use of Tradeable EACs: The argument against the use of EACs for reporting is that only physical tracking of energy from production through use of an environmental attribute, such as

[9] An indirect environmental attribute is an environmental attribute, such as carbon emissions, which may be derived from a certified attributed such as renewable-source energy.

[10] See the Appendix to this white paper for program specific and https://en.energinet.dk/gas/biomethane/biomethane-go-guidelines/ for a European example.

[11] https://www.bakerbotts.com/thought-leadership/publications/2022/december/finding-tool-for-2022-58

[12] https://ghgprotocol.org/survey-need-ghg-protocol-corporate-standards-and-guidance-updates

carbon emissions from power or fuel, can ensure accurate accounting for emissions. In addition, it is argued that the use of tradable EACs that separate environmental attributes from the time and location of generation or use can shift environmental burdens related to but external to EAC accounting (externalities), for example, pollutant emissions from a renewable energy production facility. Benefits, such as job creation, can also be shifted as a result of EAC trading. In addition, as markets mature and trading interregional trading is allowed over long periods of time, certain regions with high mandated EA levels may begin to slow in in-region production of EAs due to physical constraints (e.g., high penetration of solar leading to curtailment, transmission constraints that limit interconnection of new resources, or insufficient deployment of complementary technologies such as storage).

Arguments in Favor of Using Tradable EACs: Those supporting the use of tradable EACs for emissions accounting and compliance argue that verified creation of certificates according to specific protocols, and verified retirement of credits when claimed, is the best way to ensure that environmental goals are met at least cost. They further argue that EACs are the most feasible way to create property rights to EAs that are fungible and tradable. It is argued that the use of EACs expands investment in environmentally preferred resources and lowers the overall cost of mitigating negative environmental impacts. EACs allow consumers to access environmentally preferred resources even when such resources may not be available or feasible at the consumer's location. They additionally argue that externalities should be regulated outside the EAC regime as with any other type of facility or activity.

Available Evidence for Tradable EAC Use

There is minimal empirical evidence to compare outcomes of programs with and without the use of exchangeable EACs, due to their current effectively universal use. For example, both the California RPS and LCFS operate on credits, and book-and-claim accounting is a key element of both programs. The basis of commodity exchanges using fungible market instruments is that they allow producers and consumers to trade on a common platform that provides liquidity and price discovery. This helps minimize the overall cost of the physical supply and consumption that the exchanges facilitate. This helps explain the prevalence of greenhouse gas credit trading programs. Recent work by Xu et al. [2] predicts that the cost of achieving a 98% decarbonized electric system in the western United States would be 23% lower with a trading market for hourly RECs in comparison to a case where only physical delivery or self-generation were permitted (see Figure 3). Since hourly matching was required in both cases, the cost savings reflect the value of locational flexibility.

EACs have been the primary basis for demonstrating compliance with the LCFS programs in California and Oregon. These programs use credits denominated in tons of CO2-equivalent emissions reductions. Similarly, the federal RIN program uses gallons of ethanol-equivalent fuel. In these programs, the environmental attribute is separate from the physical fuel produced. The impact of use of tradable fuel credits is illustrated by biomethane (or renewable natural gas (RNG). As shown in Figure 4, as of mid-2023, there are 300 RNG production facilities across the United States.

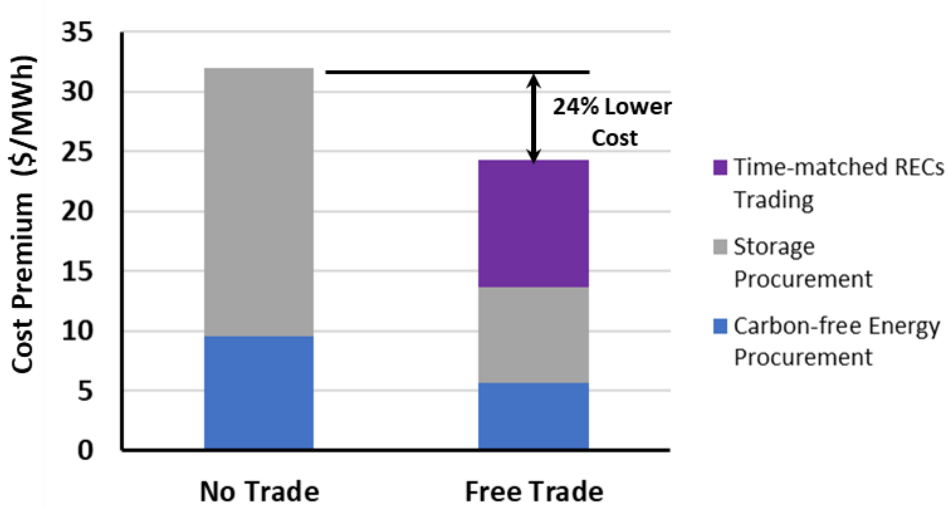


Figure 3. System-wide Cost Reduction Enabled Through Use of Tradeable Hourly RECs. From [2].

Figure 4. Biomethane Facility Count by State (one facility in HI out of frame). Source: Coalition for Renewable Natural Gas.

The facility count has been growing at an average rate of 20% per year over the past decade. Because tradeable credits have been used in all clean fuel programs in North America, direct comparison of a case where tradeable AECs are not allowed is not possible. However, the geographic distribution of production facilities and the location of demand suggests that the locational flexibility enabled by the use of tradeable clean-fuel credits has enabled supply expansion and reduced cost. California is the dominant location of demand for low-carbon fuel while facilities are distributed nationally. If physical delivery of fuel to the end consumer were required, the common-carrier pipeline system could not be used to deliver RNG. Delivery of biomethane using tube trailers would several times more costly than delivery via pipeline. Of the 289 biomethane pathways approved under the California LCFS, only 3 delivery RNG without the use of the common-carrier pipeline.[13]

Dong et al. have proposed an international green hydrogen certificate program which their assessment concludes will enable international market expansion [3]. The approach uses hydrogen credits (HCs) based on carbon intensity to create a mechanism for trading unbundled HCs internationally to support global build-out of low-carbon hydrogen production. Their proposed certificate regime is carbon-based and pathway specific with credit generation based on avoided carbon from the incumbent pathway (similar to current LCFS programs in several states). The analysis assumes the presence of a carbon tax on hydrogen, but the mechanism could also operate in the absence of a tax. The European Union Certificates of Origin (CO) program for clean hydrogen (see Appendix) is intended to serve a similar function.

Although the ability of attribute trading to lower the cost of meeting environmental goals is well-founded in theory and empirical evidence, there is risk of over-counting environmental benefits if the rules for generating, trading, and claiming EACs are not fully aligned with proper EA accounting. In the case of GHG emissions, this means that credits must represent full lifecycle emissions within clear system boundaries and timeframes. A recent analysis concludes that reported corporate GHG emissions reductions related to purchases of RECs could over-estimate actual GHG emissions reductions by more than a factor of two over four years, as shown in Figure 5 [4]. Work by the Princeton Zero Lab [5] similarly predicts that use of RECs for carbon accounting without time-stamping can lead to significant under-estimating of the consequential carbon emissions of electrolytic hydrogen. Although disallowing RECs would cure these issues, both analyses referenced conclude that GHG reporting issues can be cured through program changes without abandoning the use of RECs.

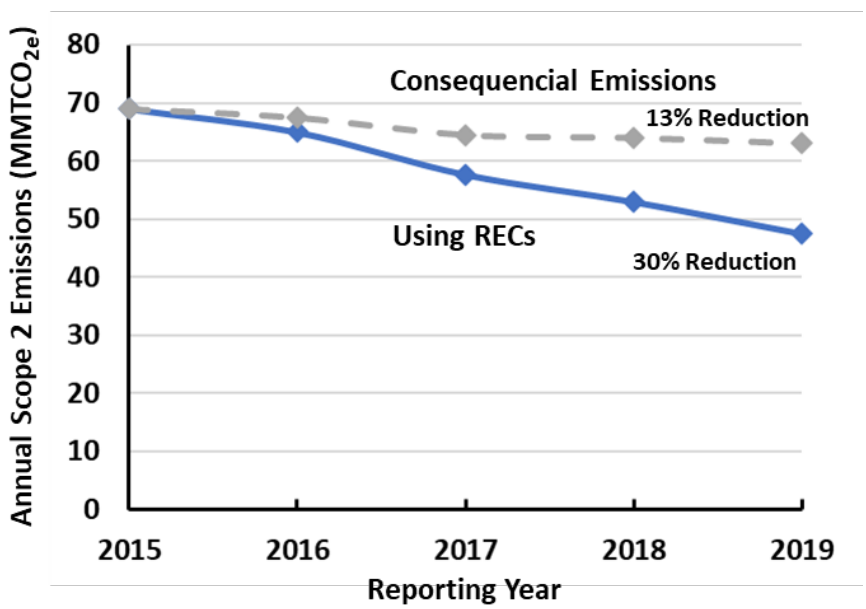


Figure 5. Scope 2 (Purchased Power) Reported Emissions for Sample Corporate Over Four-year Period Using Book-and-Claim versus Attributional (Physical) Accounting. From [4].

[13] https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities

Additionality

Additionality refers to the requirement that environmental attributes created for the purpose of certificate or credit generation must be created from newly constructed facilities or from actions taken that are additional to a reference scenario. The reference case is generally a "business as usual" scenario or an expected state in the absence of a specified action taken to generate the EAC. In the case of GHG credits, additionality generally means that GHG reduction is achieved by the construction of a voluntary project or commitment to a specific action. In the case of renewable energy, the requirement would be that the renewable energy is generated by a project newly constructed for the purpose of creating EAs. Additionality provisions are well established in carbon credit programs but are not currently common in clean energy credit programs, apart from facility vintage provisions in some programs. Investment-based credits, such as investment tax credits, ensure additionality by the nature of the credit.

Currently, additionality requirements have become an issue under debate with respect to renewable power and fuel production. There is extensive discussion of the issue in comments to the U.S. Department of the Treasury docket on requirements for tax credit eligibility under the IRA.[14] Some stakeholders are suggesting that renewable energy production credit generation should be limited to energy produced from newly constructed facilities, and some stakeholders argue that this additionality provision should extend to renewable electricity used to produce electrolytic hydrogen. There is variation in views on how recently a facility must have been constructed to meet the criteria for additionality. As two points of reference, the EU recently established a requirement that renewable power facilities supplying electrolytic renewable gas producers must have been placed in service no more than 36 months prior to the fuel production facility startup,[15] whereas the California renewable portfolio standard allows projects placed in service January 1, 2005, and the California LCFS program has no facility in-service date restrictions.[16]

Framing the Additionality Issue

<u>Arguments for Requiring Additionality:</u> The argument in favor of strict additionality requirements is that only the requirement that renewable energy be produced from new, purpose-built facilities, guarantees that incremental environmental improvement will result from the provision of incentives for the use of renewable energy. The use of existing facilities to generate EACs is argued to potentially divert resources from other uses, resulting in no or diminished environmental benefit. Additionality restrictions also ensure that incentives flow to new facility construction only.

<u>Arguments Against Requiring Additionality:</u> The first argument against additionality requirements is that they are inconsistent with some program designs. Production-based incentives lead to capacity expansion by creating market pull. It is argued that overlaying a requirement that only new facilities are eligible is redundant, and, if incentives for new facilities are intended, they should be part of program design. In addition, it is argued that applying additionality requirements to production inputs (rather than the production facility receiving the inputs) raises cost and thereby reduces overall investment in production capacity.[17] Additionality requirements may also reduce investment by creating real or perceived stranded-asset risk for investors. The fear is that once built, assets may become distressed, if they cannot direct

[14] https://www.regulations.gov/docket/IRS-2022-0029/comments
[15] https://ec.europa.eu/commission/presscorner/detail/en/qanda_23_595
[16] See Appendix for program summaries.
[17] A number of parties commenting on Section 45 V tax credit eligibility for electrolytic hydrogen contend that only hydrogen producers receiving power from newly-constructed renewable facilities should be eligible.

supply to attractive new markets. For example, a wind farm with an expiring long-term power purchase agreement (PPA) or that is serving merchant power markets could become a stranded asset even while there is unserved demand for renewable power to make fuels. Some stakeholders are also concerned about the lack of a clear and consistent definition of additionality.

Available Evidence for Additionality

Renewable Power

No renewable electricity (REC) program in the U.S. applies additionality requirements for the certification of RECs,[18] so a direct comparative assessment of capacity additions with and without additionality requirements for REC certification is not possible. Several recent studies have used statistical analysis and/or modeling to assess the impact of various RPS program design features on renewable capacity expansion [1][6][7][8][9]. The most directly relevant analysis is that of Carely et al. [1] which specifically assesses the correlation of the use of RECs (among other program features related to stringency) with renewable supply and capacity expansion. The strongest drivers of supply expansion are found to be state renewables endowment (wind and solar resources), mandatory and aggressive standards, and the presence of flexible renewable energy credit provisions. As shown by the data presented below, renewable capacity expansion has significantly exceeded that required to meet RPS targets without the imposition of additionality requirements on the creation of RECs.

The Lawrence Berkeley National Laboratory (LBNL) 2021 U.S. RPS update [10] finds that non-hydro, utility-scale renewable energy supply expansion from 2000 through 2019 has been more than twice that required to meet mandatory RPS requirements, as shown in Figure 6. The National Renewable Energy Laboratory (NREL) recently analyzed voluntary renewable power markets [11]. As seen in Figure 7, roughly 50% of the transactions are via unbundled RECs (RECs separated from the physical delivery of energy), and another 20% use PPAs, which are usually operationalized using bundled RECs.

The LBNL and NREL reports do not establish a definitive causal relationship between the use of RECs and REC provisions on capacity expansion, but the correlation of voluntary REC and PPA volumes with capacity additions is highly suggestive of a causal effect. Moreover, U. S. renewable generation capacity has doubled over the past 10 years and has grown more than twenty times over the past 20 years [12]. Capacity expansion has occurred due to market demand with no formal requirement for additionality.

The California Energy Commission (CEC) issued solicitations for renewable hydrogen production projects in 2019 and 2021.[19] Redacted copies of the submitted grant applications were requested and received from the CEC. Of the 9 bids submitted for electrolytic renewable hydrogen production, 100% of the bidders proposed to add dedicated renewable capacity to supply power to electrolyzers for hydrogen production in the absence of any requirement to add renewable capacity. In total, new renewable generation was proposed totaling more than three times the proposed electrolyzer capacity. The prevailing strategy was to produce more power than needed by the electrolyzers during times of high solar production, generating unbundled RECs (or equivalent net-metering credits) to apply to grid power received during hours of low or no solar production. Overall, the research and data reviewed demonstrate a strong causal relationship between increased demand for renewable power (facilitated by the use of RECs) and renewable capacity expansion.

[18] Although some programs have requirements on the earliest in-service date of eligible resources.
[19] Funding opportunities GFO-17-602 and GFO-20-609.

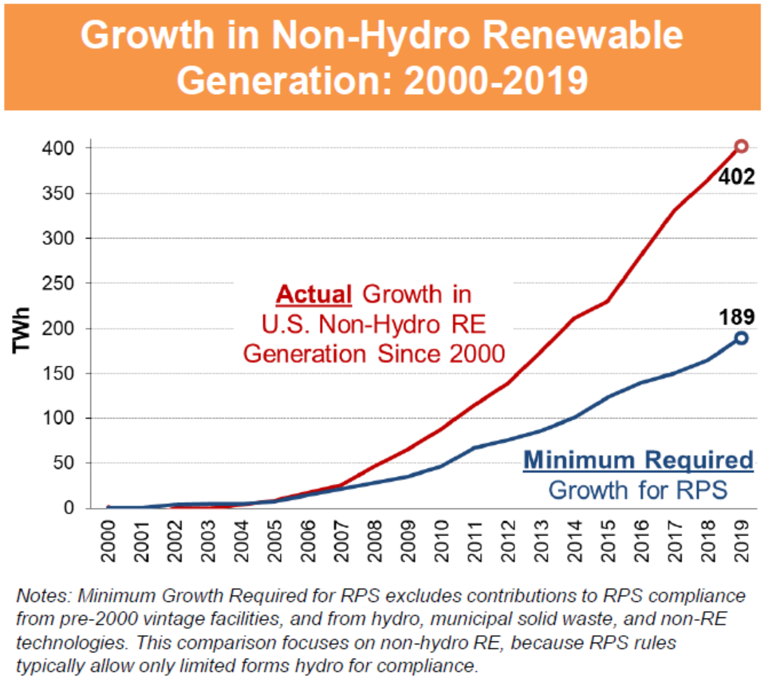


Figure 6. Total Renewable Energy Production versus Minimum Required for RPS Compliance. Source: Lawrence Berkely National Laboratory.[10]

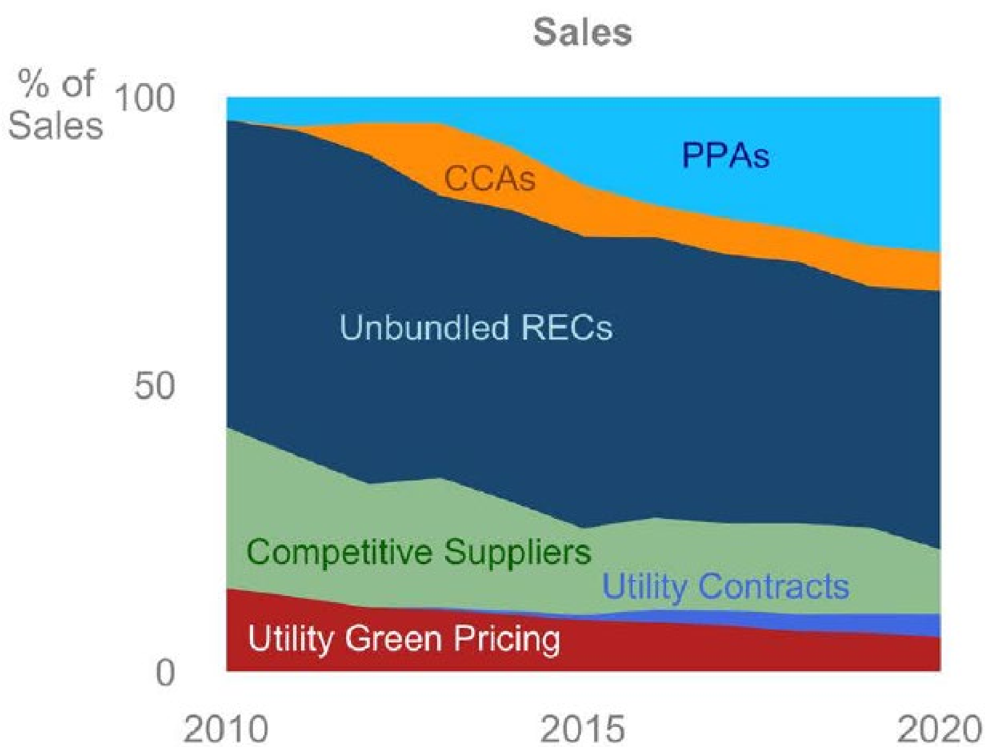


Figure 7. Distribution of U.S. Voluntary Renewable Power Purchases. Source: Heeter et al. [11].

Renewable and Low-carbon Fuels

No low-carbon or renewable fuel program currently active in the United States requires that credits be produced only from new facilities built for the purpose of generating credits under the program. However, there is strong evidence that demand for clean resources either driven by procurement mandates or voluntary action leads to resource additions without formal additionality requirements.

Analysis published in the Utah Law Review [13] finds that the introduction of the U.S. renewable fuel standard program in 2007 was followed by rapid expansion in ethanol production capacity (see Figure 8). Figure 9 shows the evolution of low-carbon fuel volumes used to meet the California Low Carbon Fuel Standard (LCFS) program standards.[20] While existing facilities serve a significant amount of ethanol demand, and most electricity comes from existing facilities, capacity growth for biomethane, biodiesel, and renewable diesel has been dramatic without any formal requirement for additionality. Two large renewable hydrogen facilities, one announced and under development and one recently commissioned, were developed for the specific purpose of serving the California LCFS market.[21] Numerous new dairy methane capture projects have been built or are under construction to serve the LCFS market.[22] Some pre-existing facilities, such as ethanol plants, power generation facilities, landfill methane capture facilities and livestock methane projects originally developed for the power market, have supplied fuel to the LCFS market. Although the associated fuel quantities could be argued to be non-additional, these resources have helped provide cost-effective fuel supply to the early low carbon fuel market and have reduced the time required to build fuel volume.

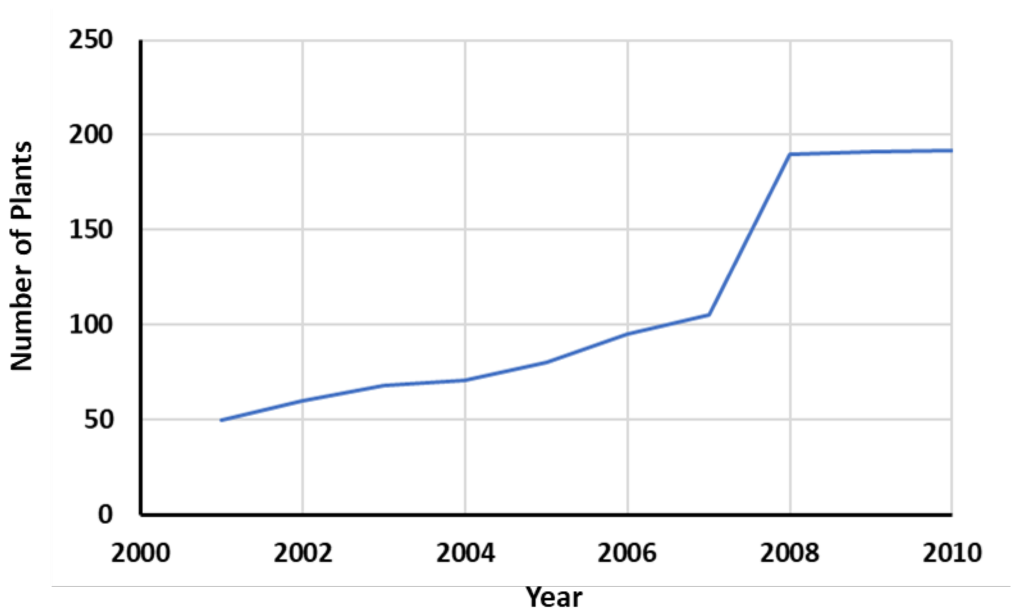


Figure 8 Ethanol Plant Count Trend. Note that the U.S. federal renewable fuel standard was implemented in 2007. Source: Re-plot of data from Kesan et al.[13].

[20] https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard
[21] https://www.ir.plugpower.com/press-releases/news-details/2021/Plug-Power-to-Build-Largest-Green-Hydrogen-Production-Facility-on-the-West-Coast-2021-9-20/default.aspx
https://usa.airliquide.com/sites/al_us/files/2022-07/nlv_facility_one-pager-bracewell_final_5_24_22.pdf
[22] https://www.cdfa.ca.gov/oefi/DDRDP/docs/DDRDP_Project_Level_Data.pdf

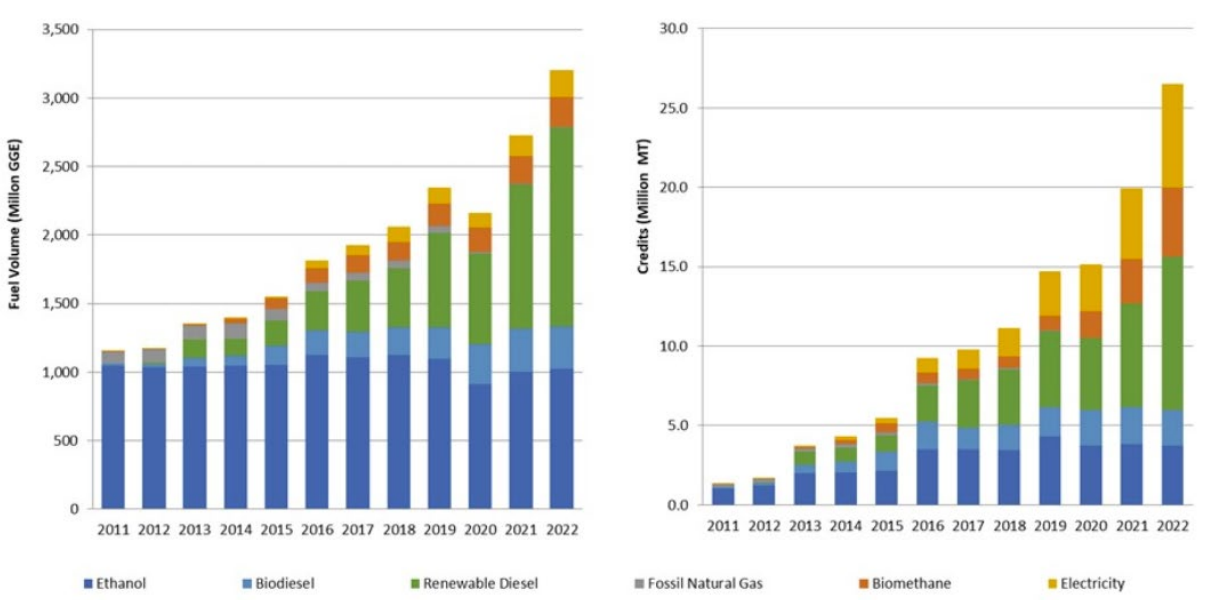


Figure 9. Fuel and Credit Volumes Under the California LCFS. https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard

Time Matching

Another emerging issue that has been flagged by the U.S. EPA Green Power Markets program is whether requirements should be put in place for RECs to be timestamped on an hourly basis.[23] This approach would restrict REC claiming to RECs timestamped in the same hour. The foundation of the issue is that, without physical storage, power must be delivered to load in real time. If a REC is unbundled from the power by which it was generated, then that power is delivered in real time to a load without the renewable attribute. When the REC is later used to qualify purchased power as renewable, the delivered power can be of any type. While this unbundled REC transaction is balanced (actually delivered the EA required) it can result in incremental carbon emissions under some circumstances by changing the non-renewable supply mix and can also lead to inaccurate carbon reporting by voluntary unbundled REC purchasers purporting to use RECs to report Scope 2 carbon emissions from purchased power [4][14].

In any case where the marginal carbon intensity of the grid into which renewable power is physically delivered is lower than the marginal emissions on the grid at the time and location that the renewable power attribute is claimed, incremental emission of greenhouse gas will occur from the transaction (in comparison to direct delivery of renewable power to the claiming load). It should be pointed out that the inverse is also true and displacement transactions can lead to incremental carbon reductions in some circumstances. For the case when a grid has the same marginal emissions when a credit is booked and when it is claimed, unbundled REC transactions will have zero incremental GHG emissions related to changes in grid dispatch from the REC transaction.

As regional grids evolve to reach high renewable fractions, there are fewer hours in which temporal "swapping" of carbon emissions can occur, and time matching becomes a physical necessity to meet carbon constraints. This can be accomplished through real-time supply of generated renewable power to load (e.g., by transmission and distribution investments that make it possible), or through physical storage of electricity for delivery when demanded. The policy question is at what point in time should time

[23] https://www.epa.gov/green-power-markets/emerging-issues

matching requirements be imposed on the use of RECs and to which purchasers (loads) they should be applied.

Framing the Time Matching Issue

Arguments in Favor of Hourly Time Matching: The argument in favor of hourly time matching is that without hourly time matching, unbundled REC transactions can lead to incremental GHG emissions due to changes in the grid dispatch resulting from the unbundled REC transaction. Proponents argue that hourly time matching will have minimal impact on the cost of renewable power, and that tracking systems can be put in place rapidly using interim approaches, such as regional, hourly grid marginal carbon intensity tables, if necessary, as real-time systems are implemented.

Arguments Against Hourly Time Matching: Arguments against hourly matching primarily relate to timing and phase-in. Opponents of immediate implementation of hourly time matching argue that such requirements will increase the cost of renewable power, will not materially impact overall GHG reductions, and cannot be supported with existing tracking and trading systems. Opponents generally acknowledge the need for granular time matching to be implemented over time. They also assert the need to support nascent technologies and the potential market chilling effect of abrupt changes in established protocols and policies.

Available Evidence on Need for Time Matching

Emissions Impact

A key policy question on time matching is the extent to which lower stringency in time matching, such as weekly up to annual matching requirements, lead to increased GHG emissions and, if so, how much. A key and closely related question is the cost impact of differing matching requirements. That will be discussed in the next section. The companion assumptions regarding additionality and deliverability have a significant impact on modeling results for both emissions and cost.

There is no dispute that there can be incremental consequential emissions (increase or decrease) from the use of RECs that are not time stamped. This occurs when the marginal emissions on the grid to which the renewable power is delivered at the time the RECs are generated (booked) differs from the marginal emissions on the grid at the time that the RECs are used (claimed). However, the method by which consequential emissions are calculated is a matter of significant disagreement, and the prevailing differences in approach lead to opposite conclusions on whether matching over longer time horizons, such as annual matching, leads to substantially higher GHG emissions than hourly matching. There is consensus and a vast body of experience in electric-sector integrated resource planning (IRP), among other domains of economic analysis, that a marginal approach is the correct method of analysis. This means that changes in supply and demand on the electric system are assessed based on the incremental impact on emissions and cost.

While there is consensus on the appropriateness of the use of marginal analyses, published analyses of time matching differ on two key dimensions in assessing marginal impacts:

- How the resource portfolio is modeled with respect to future resource additions and retirements
- The time horizon over which the marginal analysis occurs

A recent study by Cybulsky et al. from the Massachusetts Institute of Technology Energy Initiative [15] assesses two approaches to modeling the resource portfolio in the context of adding electrolytic hydrogen production in a market area. They compare an analysis by Ricks and colleagues at the Princeton Zero Lab

[16] with a study by Zeyen et al. [17]. Both assume that contract renewable electricity supply is procured in an amount equal to the electricity consumed to produce renewable hydrogen, and they compare consequential emissions (and costs) of annual versus hourly time matching procurement approaches. Ricks et al. analyzed the power supply in the Western Electric Coordinating Council (WECC) in planning-year 2030 with the hypothetical addition of 1 GW and 5 GW of electrolyzer capacity and the supply system optimized to accommodate that new load. Zeyen et al. modeled additions of a fixed demand for 840 million kilograms (roughly 5 GW of electrolyzer capacity at 100% capacity factor) in the German and Dutch markets in 2025 and 2030.

A key difference between the two methodologies is that Ricks et al. assume that the added electrolyzer demand is included in the optimal resource portfolio design. Electrolyzers with a specified load profile are added to system load, and the resource portfolio and dispatch are optimized under a constraint of zero-carbon operation of the electrolyzers under an annual or hourly time-matching requirement. The electrolyzer owners adopt a cost optimal mix of directly contracted or self-generated ("dedicated") wind and solar, and renewable power purchased from or sold to the grid.

Zeyen et al. assume that electrolyzers and their contracted or owned renewable resources are added to a grid that is optimized to serve load not including the electrolyzers, in essence, a pre-existing grid. This approach was also used in a similar analysis by Energy and Environmental Economics (E3) and the American Council on Renewable Energy (ACORE) led by Olson [18]. The Ricks et al. approach reduces the added capacity of non-dedicated wind and solar under both time-matching approaches, and, under the hourly-matching scenario reduces natural gas capacity and dispatch.

Another key difference among approaches is how marginal emissions are assessed. Olson et al. use a short-run marginal emissions (SRME) approach in which electrolyzer consequential emissions are based on the grid marginal intensity in each hour. This means that, in a given hour, if a combined cycle power plant is the marginal resource in the economic dispatch, the emissions rate of a combined cycle power plant is attributed to changes in demand or supply in addition to any direct emissions. Figure 10 shows heat maps from the Olson et al. analysis for several U.S. power markets. Many hourly swaps can occur with no incremental impact on GHG emissions. However, some swaps have hourly grid carbon-intensity differences of up to 400 kg-CO_2/MWh resulting in marginal consequential emissions from electrolytic hydrogen production on the order of 20 kg-CO_2 per kilogram of hydrogen.

Ricks et al. use an alternative approach to calculating SRME rates (SRMER). They optimize the resource portfolio including electrolyzers, allowing the electrolyzer load addition to change the installed resource mix as well as how resources are dispatched. They then model the optimal dispatch of electrolyzers to achieve least-cost hydrogen production under the applicable time matching constraint. The consequential GHG emissions impact is defined as the system-wide emissions with the electrolyzer minus that without divided by the difference grid energy to serve the marginal load.

An alternative approach to short-run marginal analysis is to use long-run marginal analysis such as that employed in the NREL Cambium tool.[24] Figure 11 shows heat maps of the levelized 2028 – 2048 power grid long-run marginal emissions rates (LRMER) for six states spanning the U.S. and featuring differing resource mixes. The hourly spreads in carbon emissions are substantially higher in most market areas

[24] https://www.nrel.gov/analysis/cambium.html

using grid average carbon intensities than using marginal intensities. NREL argues that this method is a better planning approach than the SRME for long-horizon changes in supply and load.

ERCOT

Hour of the Day

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.3	0.3	0.3	0.3	0.4	0.5	0.3	0.3	0.4	0.3	0.3	0.3	0.2	0.2	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.4	0.4
Feb	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.3	0.2	0.2	0.2	0.2	0.4	0.5	0.5	0.6	0.6	0.5	0.4	0.4	0.3
Mar	0.4	0.4	0.4	0.5	0.5	0.4	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.2	0.3	0.5	0.5	0.4	0.5	0.5	0.5	0.5	0.4
Apr	0.3	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0	0.1	0.1	0.2	0.5	0.5	0.5	0.4	0.4	0.4	0.3	0.3
May	0.4	0.5	0.3	0.3	0.3	0.3	0.2	0.3	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.5	0.5	0.5	0.4	0.4
Jun	0.4	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.2	0.3	0.4	0.5	0.5	0.5	0.4	0.5	0.8	0.8	0.5	0.4	0.4	0.5	0.4
Jul	0.5	0.5	0.5	0.6	0.5	0.4	0.4	0.3	0.4	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.6	0.9	0.9	0.5	0.5	0.5	0.4	0.4
Aug	0.4	0.4	0.5	0.4	0.4	0.5	0.4	0.4	0.4	0.6	0.6	0.5	0.5	0.4	0.4	0.4	0.7	0.8	0.8	0.5	0.5	0.4	0.4	0.4
Sep	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.3	0.3	0.4	0.5	0.5	0.5	0.5	0.4	0.8	0.8	0.7	0.5	0.5	0.5	0.4	0.4
Oct	0.3	0.3	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.3	0.3	0.4	0.6	0.7	0.6	0.5	0.5	0.5	0.5	0.4	0.4
Nov	0.3	0.3	0.3	0.4	0.4	0.5	0.3	0.3	0.3	0.2	0.3	0.2	0.2	0.2	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4
Dec	0.4	0.4	0.4	0.4	0.4	0.5	0.3	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.4	0.5	0.4	0.5	0.5	0.4	0.4	0.4	0.3	0.3

MISO North

Hour of the Day

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.6	0.5	0.5	0.5	0.6	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6
Feb	0.4	0.4	0.3	0.5	0.4	0.4	0.4	0.3	0.6	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.4	0.4	0.5	0.3	0.3
Mar	0.4	0.4	0.4	0.5	0.5	0.5	0.4	0.5	0.5	0.4	0.6	0.5	0.5	0.4	0.5	0.5	0.4	0.6	0.4	0.6	0.6	0.5	0.4	0.4
Apr	0.3	0.3	0.3	0.3	0.3	0.5	0.4	0.5	0.6	0.5	0.5	0.5	0.4	0.4	0.3	0.3	0.3	0.4	0.3	0.4	0.3	0.5	0.4	0.3
May	0.3	0.4	0.3	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.4	0.4	0.5	0.4	0.4	0.3
Jun	0.5	0.3	0.4	0.3	0.4	0.4	0.5	0.4	0.5	0.6	0.5	0.6	0.6	0.6	0.5	0.6	0.6	0.5	0.5	0.6	0.6	0.6	0.5	0.4
Jul	0.5	0.5	0.3	0.3	0.4	0.6	0.5	0.5	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.5	0.5	0.4	0.5	0.6	0.7	0.6	0.6	0.6
Aug	0.5	0.4	0.4	0.3	0.4	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.6	0.5	0.6	0.6	0.5	0.6	0.6	0.6
Sep	0.4	0.4	0.3	0.4	0.4	0.5	0.4	0.4	0.5	0.6	0.6	0.7	0.6	0.6	0.6	0.5	0.5	0.4	0.4	0.6	0.6	0.4	0.3	0.4
Oct	0.4	0.4	0.3	0.3	0.3	0.4	0.3	0.4	0.6	0.4	0.4	0.4	0.4	0.5	0.5	0.4	0.5	0.3	0.4	0.3	0.5	0.4	0.4	0.5
Nov	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.3	0.4	0.4	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.4	0.3	0.3	0.3	0.3
Dec	0.5	0.3	0.4	0.5	0.4	0.5	0.5	0.3	0.5	0.5	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.7	0.6	0.6	0.5	0.5

PJM

Hour of the Day

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.7	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.7	0.6	0.6	0.6	0.5	0.5	0.5
Feb	0.6	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Mar	0.5	0.5	0.4	0.4	0.5	0.5	0.6	0.5	0.7	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.5	0.6	0.5	0.5	0.6	0.5	0.4
Apr	0.5	0.5	0.4	0.4	0.4	0.5	0.6	0.6	0.6	0.5	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.5	0.6	0.6	0.4	0.4
May	0.5	0.4	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.7	0.5	0.5	0.5
Jun	0.6	0.5	0.5	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.4	0.5	0.6	0.7	0.6	0.6
Jul	0.6	0.5	0.6	0.5	0.5	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.6	0.6	0.6	0.6	0.7	0.6
Aug	0.5	0.6	0.5	0.4	0.5	0.6	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.6	0.4	0.5	0.6	0.6	0.6	0.7	0.7
Sep	0.5	0.5	0.4	0.4	0.5	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.7	0.6	0.6	0.6
Oct	0.4	0.5	0.4	0.4	0.4	0.5	0.6	0.6	0.5	0.6	0.5	0.5	0.6	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.5	0.4	0.5
Nov	0.5	0.5	0.5	0.4	0.5	0.5	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.5	0.6	0.5	0.5	0.6	0.6	0.6	0.7	0.5	0.5	0.5
Dec	0.6	0.5	0.5	0.5	0.6	0.5	0.6	0.7	0.6	0.5	0.6	0.6	0.7	0.6	0.6	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.5	0.6

SPP

Hour of the Day

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.6	0.5	0.5	0.5	0.5	0.6	0.5	0.4	0.5	0.5	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.6	0.6
Feb	0.6	0.5	0.4	0.5	0.5	0.5	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.6	0.6	0.6	0.5
Mar	0.5	0.5	0.4	0.4	0.5	0.5	0.5	0.4	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Apr	0.4	0.4	0.4	0.5	0.5	0.5	0.4	0.5	0.4	0.4	0.5	0.5	0.4	0.5	0.5	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
May	0.5	0.5	0.4	0.4	0.4	0.5	0.6	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.7	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.6
Jun	0.6	0.5	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.5	0.6	0.6	0.6	0.5	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.5
Jul	0.6	0.5	0.4	0.4	0.5	0.6	0.5	0.5	0.6	0.7	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.7	0.6
Aug	0.6	0.5	0.4	0.3	0.4	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.5	0.5	0.4	0.6	0.6	0.6	0.7	0.6
Sep	0.6	0.5	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.5	0.6	0.6	0.5	0.5	0.6	0.5	0.5	0.4	0.6	0.6	0.6	0.6	0.5	0.5
Oct	0.5	0.4	0.4	0.3	0.4	0.5	0.5	0.5	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Nov	0.4	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.3	0.5	0.5	0.5	0.5	0.4
Dec	0.5	0.6	0.5	0.5	0.6	0.5	0.5	0.5	0.4	0.5	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.5	0.5	0.6	0.7	0.7	0.5

Figure 10. Heat Maps of Grid Carbon Intensity in Several U.S. Power Markets (metric tons CO_2 per MWh). . Source: Olson et al. [18].

	Levelized Hourly LRMER -- Base Scenario						Levelized Hourly LRMER -- Low Carbon Scenario					
Hour of the day	CA	FL	IL	NY	TX	WA	CA	FL	IL	NY	TX	WA
0	41.9	459.8	276.7	39.5	103.8	12.4	46.7	261.3	185.0	42.1	78.7	12.2
1	45.2	482.8	277.3	38.9	104.6	12.6	49.7	289.1	184.4	40.7	78.0	12.4
2	47.4	492.4	278.0	38.2	105.1	12.7	51.6	301.6	186.0	40.5	79.6	12.6
3	47.2	486.6	278.5	38.0	104.9	12.5	51.5	296.6	187.1	40.1	80.1	12.3
4	45.2	466.4	269.4	37.4	103.8	11.8	50.0	272.1	175.9	38.7	79.4	11.8
5	37.1	422.4	235.1	32.1	99.1	10.7	41.0	228.2	149.9	32.6	73.8	10.9
6	24.2	304.4	201.1	25.5	84.4	7.8	26.8	146.5	126.7	26.0	60.7	8.7
7	10.2	192.7	163.8	19.9	70.8	4.7	12.1	81.0	99.7	20.3	49.6	6.1
8	6.4	152.2	149.6	16.5	65.1	3.9	8.0	58.6	90.7	16.4	43.6	5.0
9	6.1	148.9	146.8	15.6	64.5	3.8	7.6	56.0	89.2	15.7	44.5	4.7
10	6.2	147.7	146.0	15.7	66.6	3.7	7.5	55.0	88.0	15.7	48.7	4.7
11	6.5	145.7	145.7	16.0	69.7	3.8	7.8	54.8	87.5	15.8	50.5	4.8
12	6.5	148.6	145.5	16.1	71.7	3.7	7.8	55.9	86.8	16.0	51.7	4.7
13	6.6	152.1	147.0	16.2	71.3	3.8	8.1	57.5	87.4	16.3	51.8	4.8
14	7.3	158.3	157.8	17.0	71.7	4.1	8.5	59.7	94.1	17.2	50.4	4.7
15	13.7	170.3	199.0	20.1	75.5	5.3	15.9	64.4	120.1	20.7	51.1	5.8
16	25.9	226.4	255.8	26.2	96.2	8.6	28.8	89.7	156.5	27.2	66.5	8.7
17	32.6	319.9	301.5	33.5	142.0	10.1	35.8	136.6	184.3	33.9	108.0	10.0
18	37.9	395.8	315.2	42.3	158.6	10.7	42.0	169.1	191.5	42.4	124.7	10.7
19	33.4	385.3	298.8	41.8	135.8	10.4	37.3	166.5	183.6	42.1	100.8	10.5
20	32.5	365.2	290.1	38.4	116.5	10.6	36.3	164.0	177.3	39.7	82.8	10.6
21	34.0	363.9	288.6	37.9	105.3	11.0	38.3	163.9	177.4	39.5	76.9	10.8
22	35.4	386.8	284.7	38.6	102.0	11.7	40.4	181.5	182.6	40.2	75.9	11.5
23	38.5	421.7	278.8	39.9	108.9	12.1	43.8	217.5	186.5	42.2	80.5	11.8
Min to Max	41.3	346.7	169.7	26.7	94.1	9.0	44.1	246.7	104.8	26.7	81.0	7.9
Average to Max	22.4	204.7	76.5	2.8	54.8	0.3	23.6	165.8	48.9	12.8	54.3	4.0

Figure 11. Cambium Model Carbon Intensities (kg-CO2e per MWh) Levelized from 2028 to 2048 in 6 States Spanning the U.S. Under the Base or Mid-Case (Continuing Current Policies) Scenario and Low-carbon (95% Decarb by 2050) Scenario.

Cybulsky et al. refer to the methodology employed by Ricks et al. as the "Compete" framework and to that of Zeyen and Olson et al. as the "Non-compete" framework. Another way to describe these would be that the Compete framework includes electrolyzers and their dedicated renewable resources within an optimized, integrated resource plan, and the Non-compete framework treats them as exogenous to the planned resource portfolio. As a consequence of the differing modeling approaches, the "Compete" framework predicts a much higher consequential emissions increase between hourly and annual matching than does the "Compete" framework. Which approach better predicts future measured emissions depends on many factors related to the regulatory frameworks under which electric-system supply and demand resources are added to or removed from the resource portfolio, who owns them, and the rules under which resource owners can buy and sell power and grid services such as load dispatch.

Cost Impact

Findings from quantitative analysis of the likely impact of hourly time matching on hydrogen production cost are mixed due to differences in modeling methodology as discussed above. In addition, results vary by region, the time point of the analysis, differing assumptions on technology cost, and the presence or absence of mandates or incentives. The results also depend strongly on if and how additionality requirements (requirement that power be sourced from new facilities only) are applied. If buyers are able to procure firm, zero-carbon resources, such as hydro or nuclear power, the cost impact of hourly matching may be minimal. However, both regulation and existing rights to these resources limit the ability to procure these resources, and the present discussion assumes that power is procured from wind and solar resources, and that battery storage is an option for time shifting.

As a fundamental matter, achieving a high load factor for any consumer of 100% variable renewable energy requires storage, and storage increases cost. Analysis by the Rocky Mountain Institute [19] of representative data center and building loads projects that applying a 90% time matching requirement in the PJM balancing authority would add $60/MWh to the price of renewable power, about a 90% increase in price relative to a scenario without a time-matching requirement as seen in Figure 12. Figure 13 shows the projected cost-optimal resource additions on the California grid in a scenario reaching full decarbonization by 2045. Physical storage grows dramatically as the renewable fraction grows beyond 60%, and average constant-dollar generation rates increase by about 15% over the modeled time horizon.[25]

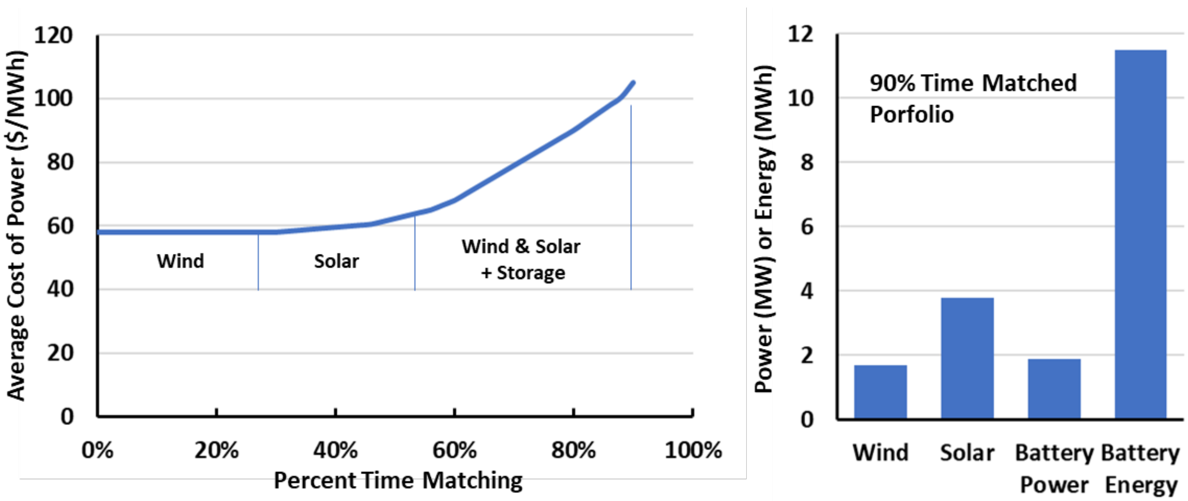
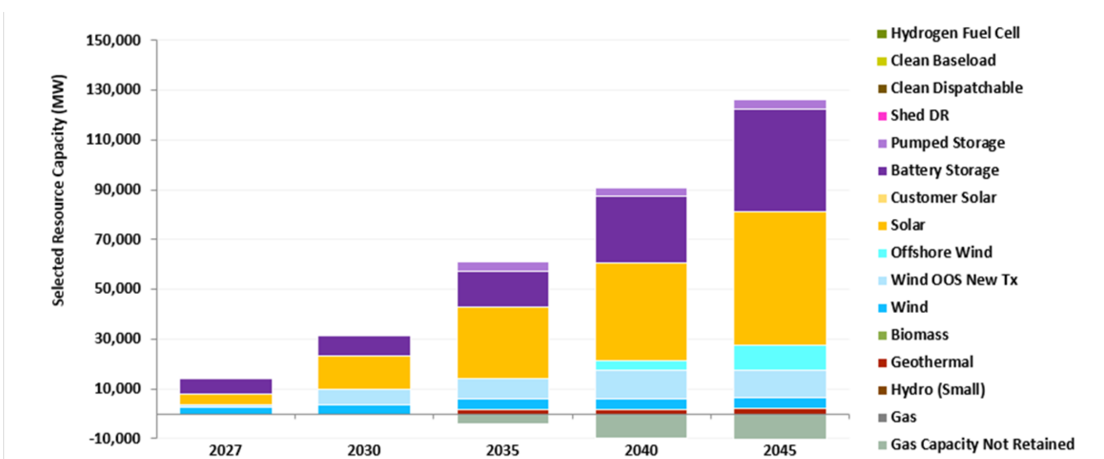


Figure 12. Cost Impact of Time Matching Renewable Power at 90% Match in PJM Balancing Authority. Source: Figure created using data from RMI analysis [19].



RPS Percent of Retail Sales	52%	60%	68%	77%	86%
Average Generation Rate ct/kWh	7.5	7.6	8.0	8.3	8.8

Figure 13. Optimal Resource Additions and Generation Rates Under California Renewable Portfolio Standard. Source: California Energy Commission SB 100 Report and Modeling Scenarios available at https://www.energy.ca.gov/sb100/sb-100-events-and-documents .

25 https://www.energy.ca.gov/sb100/sb-100-events-and-documents

The studies by Ricks et al. [16], Zeyen et al. [17], Olson et al. [18] described above focus on qualification for the U.S. federal tax credit authorized under the Bipartisan Infrastructure Law, but the conclusions can be applied to other types of load. As with emissions impacts, the approaches yield opposite conclusions on the cost of achieving a near-zero carbon intensity under hourly versus annual matching requirements.

Ricks et al. find that, in most zones modeled, the production cost uplift for electrolytic hydrogen under hourly versus annual matching is minimal (0% to ~5%). The group concludes that hourly matching can be implemented with minimal cost impact. However, the increment reaches $1/kg in the Northern California market. At the level of $1/kg, the impact would be significant given an unsubsidized target cost of $1/kg by 2030 under the U.S. DOE program Hydrogen Shot. A cost point of $2/kg (net of a $3/kg subsidy) is more in line with industry expectations. At this cost point, $1/kg increases the net cost of hydrogen by 50%. The research group advocates strongly for near-term implementation of hourly matching.

Analysis of four regional grids by Olson et al. projects that imposing an hourly versus annual time matching requirement in 2025 and 2030 increases hydrogen production cost by 14% to 108%, with 50% of the cases showing cost increments between 25% and 54% [18]. The group concludes that annual matching reduces cost and can be achieved with minimal emissions impact.

Whether the “within the IRP” versus “outside the IRP” approach, or SRMR versus LRMR modeling approach is more accurate cannot be determined with certainty. Empirical data on costs and measured emissions are necessary to calibrate these models and determine which approach or combination best reflects reality. A necessary next step in the analysis area is to consider the resource planning, ownership models, and market rules, such as ability to procure power on real-time wholesale markets, which will actually apply in the regions analyzed during the launch phase of the renewable electrolytic hydrogen market. In addition, when considering renewable hydrogen, the GHG benefits of the use of hydrogen as a fuel should be reflect in lifecycle GHG analysis and, while outside the system boundary for the U.S, federal tax credit carbon intensity calculation, are highly relevant to determining appropriate policy.

Notwithstanding arguments on appropriate modeling methods, under current economics and market structures, it can be stated with certainty that hourly matching requirements will raise hydrogen production cost significantly. Delivery of energy from variable renewable resources to load requires investment in physical storage, such as batteries, or maintaining a load factor to match the physical production profile of the contracted or owned renewable portfolio. Either approach increases the cost of produced hydrogen. As an illustration, at a capital cost recovery factor of 15% and an electrolyzer installed cost of $1000/kw (current cost is roughly $1,200/kw) a reduction in capacity factor from 90% to 45% increases average hydrogen production cost by just over $1.00/kg. If capacity factor is maintained at 90%, but the levelized cost of stored renewable electricity is 150/MWh, the average production cost is increased by roughly $3/kg assuming the direct renewable supply costs $30/MWh.[26]

[26] A current-generation electrolyzer requires roughly 55 kWh of input power per kilogram of hydrogen produced, so a 1 kW electrolyzer would produce 160 kg of hydrogen per year at 100% capacity factor (8760 kWh / 55 kWh/kg). At a fixed annual capital cost charge of $150/KW, the difference in capital charge per kilogram as $150/(45%*160 kg) minus $150/(90%*160 kg) = $1.04/kg. In this example, there is no change in the energy cost per kilogram. For the storage case, the cost increase for hydrogen produced from stored electricity is the price difference between direct and storage energy multiplied by the production efficiency: $0.12/kWh*55 kwh/kg = $6.60/kg). The increase in average cost of produced hydrogen is $3.30/kg assuming a 50/50 mix of direct and stored electricity powering the electrolyzer.

Feasibility

Several proposals have been put forward for implementing hourly time-stamped RECs [20], [21],[22]. In general, these proposals feature a gradual phase-in and recognize that the systems and data required for tracking, measurement and verification of times-stamped RECs will take time to implement. Establishing the software platforms and protocols could potentially be accomplished over a few years according to the Center for Resource Solutions [23]. The main argument for a longer phase-in is less about technical feasibility of establishing verification and tracking systems, and more about concern that the cost of meeting hourly matching requirements will inhibit the investment that EA credit incentives are intended to create. In addition, as discussed in the next section, existing regulations do not permit generation of RECs in all parts of the U.S. (see Figure 15 below), establishing regulatory frameworks to enable hourly matching will require time even where RECs are used.

The deliberations on this topic in the European Union have led to implementation of hourly matching beginning in 2030, with member states having the option to implement more stringent requirements beginning in 2027. The phase in is intended to allow project developers time to adapt to the new requirements and to expand power sourcing options for electrolytic hydrogen during the launch phase of the green hydrogen market in Europe.[27]

Geographic Boundaries

Power and fuels markets deliver energy over networks. In such systems, the energy placed on the delivery system is not physically the same electrons or molecules that are delivered to the user. All current renewable energy procurement and credit programs require energy to be delivered to an interconnection or receipt point that is part of the same energy network as that from which the buyer is receiving energy. Some impose tighter limitations on the location of eligible resources with the goal of reducing the risk of increased emissions in locations not subject to program requirements (sometimes called resource shuffling), and/or to concentrate economic development in the area bearing the incremental cost of renewables.

There is currently discussion and debate with respect to both clean fuels and clean electricity on the appropriateness of geographic restrictions on generation and use of EACs. In the most stringent scenario, clean energy production and use would be required to be co-located or physically connected, and physical delivery would be required. Less stringent provisions may place requirements on deliverability (such as source and load on the same network) without requiring physical delivery. The most permissive proposals would allow EACs to be used to book and claim attributes at a large regional or continental scale.

Framing the Issue

Arguments in Favor of Tighter Geographic Restrictions: There are several arguments in favor of more stringent geographic requirements. These relate to local impacts, such as export of jobs and negative local environmental impacts, and constraints on delivery systems that lead to resource substitution with negative environmental consequences. This would occur, for example, if an electric transmission constraint prevented physical flow of renewable power to a buyer leading to the need to dispatch fossil power.

Arguments for Wider Geographic Boundaries: Proponents of broader geographic market boundaries assert that such provisions reduce the overall cost of meeting environmental targets or mandates and

[27] https://ec.europa.eu/commission/presscorner/detail/en/ip_23_594

provide market signals to incent investment in fuel and power delivery infrastructure to alleviate constraints. The idea is that larger geographic market areas reduce overall cost by allowing clean energy production to occur where it is most cost-effective, and that program design can minimize negative impacts of locational resource substitution. The argument is essentially that of comparative advantage recognizing that high-quality renewable resource areas may not be co-located with demand.[28]

Available Evidence

Integrated resource planning (IRP) modeling tools are commonly used to model optimal capacity additions and least-cost dispatch of electric systems at various geographic scales. When least-cost supply resources are remote from load, larger market areas lead to lower costs provided that the resource cost differential exceeds the cost of transporting the energy. California has been on the leading edge of assessing the impact of geographic market boundaries on attainment of its renewable and clean power mandates. The topic of "regionalization" has been actively discussed as an approach to reducing the need for batteries and other electrical energy storage technologies. Figure 14 shows the results for optimal resource additions in California with and without the ability to expand regional import transmission capacity. Restricting regional imports increases the cost of generation plus storage by over $2 billion per year (or 8%) in 2045. The cost uplift is driven by additional storage costs and increased overbuild of solar resources inside California.

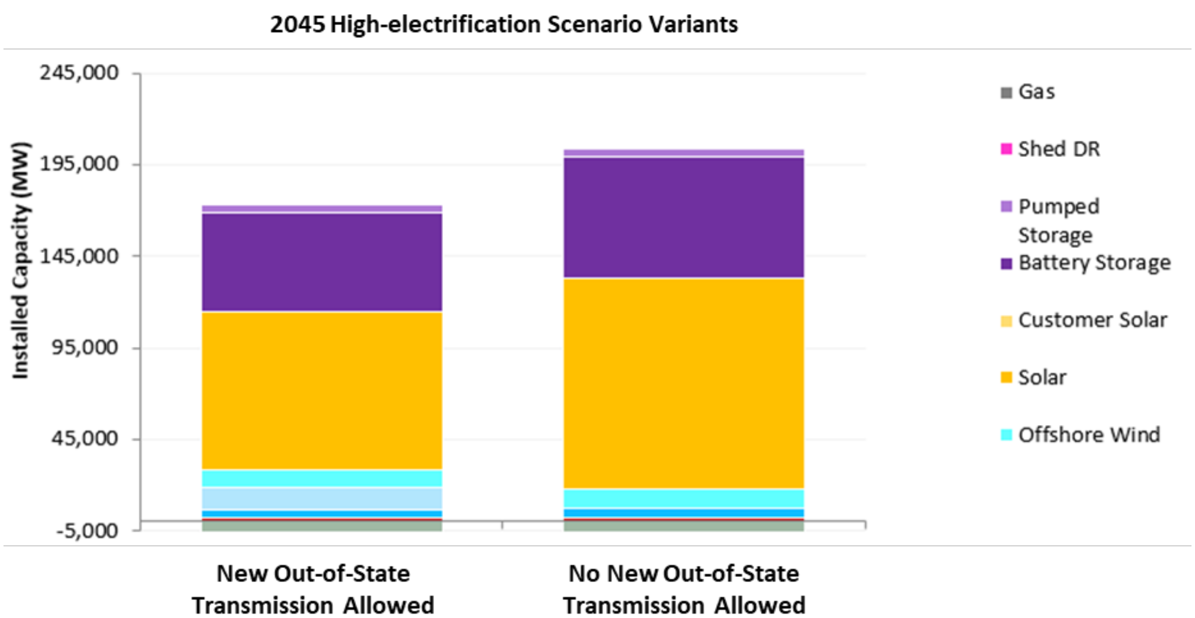


Figure 14. Comparison of California Resource Additions with and without Expanded Regional Power Import Allowed. Source: California Energy Commission SB 100 RESOLVE Modelling Cases. Available at: https://www.energy.ca.gov/sb100/sb-100-events-and-documents .

As noted earlier, in the absence of a market-wide carbon cap or RPS mandate, REC transactions can lead to significant incremental GHG emissions. This occurs when the generating source that is backed out of the dispatch when the REC is created has a lower carbon intensity than the resource providing power when the REC is claimed. This is sometimes referred to as resource shuffling. Transmission constraints can

[28] Adam Smith wrote in "The Wealth of Nations" (1776), "If a foreign country can supply us with a commodity cheaper than we ourselves can make it, better buy it of them with some part of the produce of our own industry, employed in a way in which we have some advantage" (Book IV, Section ii, 12).

exacerbate this negative environmental impact and should be considered in establishing market boundaries.

Access to the Grid and Power Markets

In the context of geographic boundaries for EAC programs, consideration should be given to the fact that tracking, verification, and trading systems do not cover all areas of the U.S. Ten states in the U.S. are not covered by REC tracking systems (see Figure 1 above), and, as seen in Figure 15, bilateral PPAs are only available in some locations. Universal market coverage for RECs and PPAs would reduce the overall cost of attaining environmental goals as lack of universal coverage restricts both supply and demand.

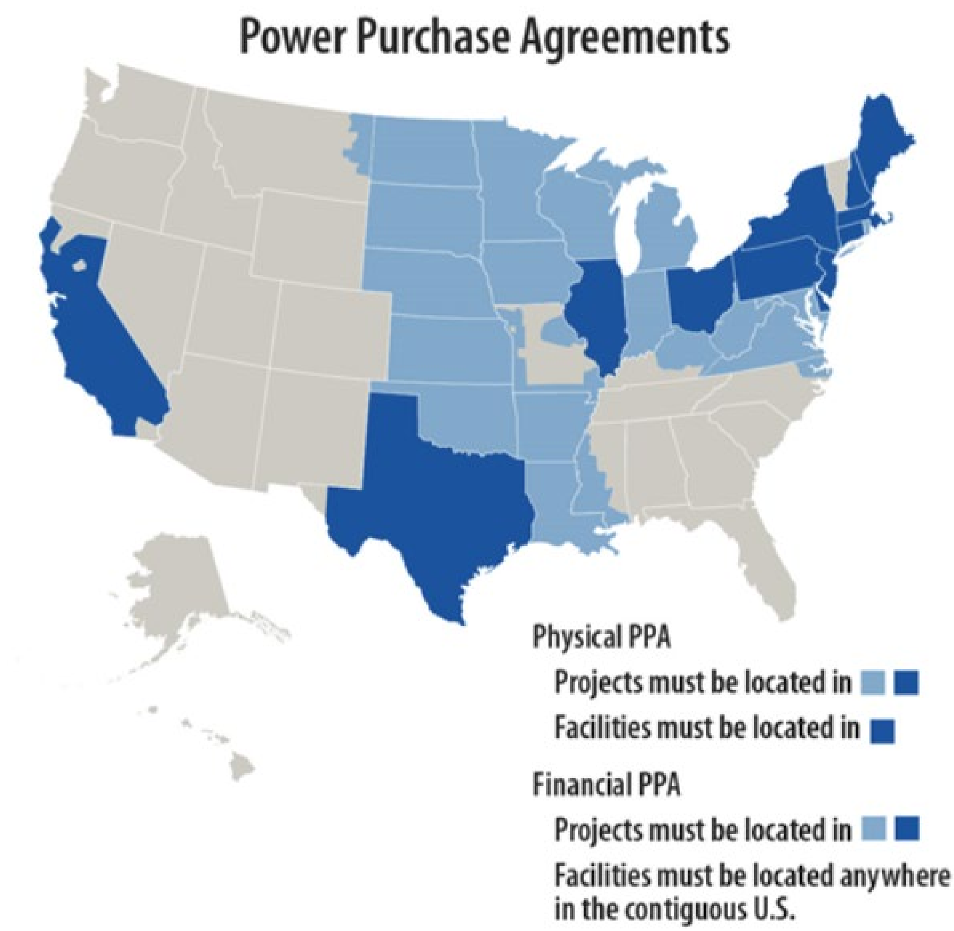


Figure 15. Locational Availability of Bi-lateral Power Purchase Agreements in the U.S. From: https://www.epa.gov/green-power-markets/us-electricity-grid-markets

For biomass resources, the least-cost energy production areas may be distant from demand centers. This is similar to what is seen with the current natural gas and oil markets. The U.S. Department of Energy Billion Tons Report [24] assessed the availability of biomass at various recovery cost points across the U.S. Like wind and solar, biomass density varies significantly across regions, as seen in Figure 16. To the extent that the demand for biomass-derived renewable gas and the resource potential are not co-located, and provided that the cost differential between local and remotely-sourced renewable gas exceeds the cost of transporting the fuel, then allowing region-wide or inter-regional supply arrangements lowers cost. In addition, allowing region-wide or inter-regional sourcing provides a financial incentive to build transmission infrastructure. For gaseous and liquid biofuels, local benefits, such as jobs, and burdens, such as non-GHG pollution, are relevant policy considerations in establishing market boundaries, but resource shuffling is not a significant issue, due to the prevalence of low-cost transport and storage for gaseous and liquid fuels.

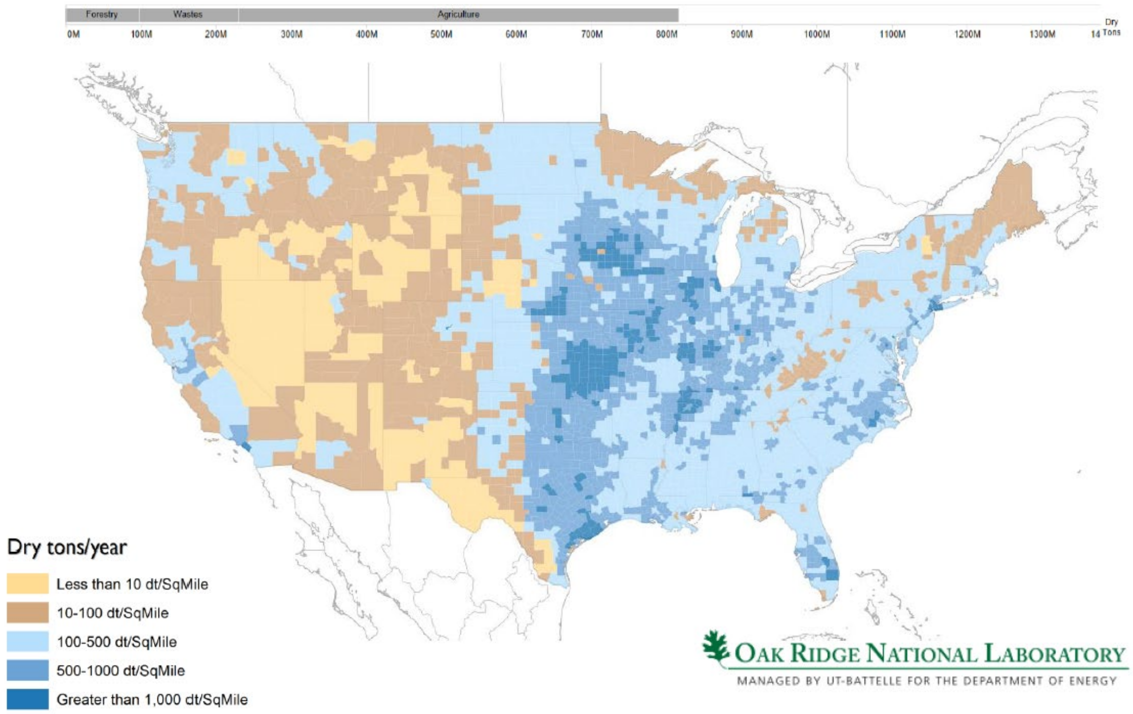


Figure 16. Biomass Resource Density in Dry Tons (dt) per Acre at $60/ton Recovery Cost. [24]

Wholesale power and gas markets provide empirical evidence that energy markets operating at regional or national scale are cost optimal. Current natural gas markets operate on contract paths (contracts for delivery capacity between buyer and seller) that may be across thousands of miles and do not require physical delivery of molecules from buyer to seller. This is the approach that has been taken to date for biomethane supply contracts.

Tracking, Measurement, and Verification

Tracking, monitoring and verification protocols and systems serve the function of tracking quantities of qualifying energy production for purposes of credit generation and monitoring system performance, inputs, and outputs to verify compliance with applicable standards and protocols. Typically, validation is rigorous and detailed at project commissioning with ongoing monitoring, verification and reporting requirements of frequency and degree of detail dependent upon the specific program. Ultimately the purpose is to ensure that the environmental attribute instrument conveyed under the applicable program meets all program protocols and requirements. Credit invalidation and, in some cases, penalties are imposed, if TMV requirements are not met.

EACs are used not only as instruments to certify environmental attributes, but as instruments to support market transactions among parties. As instruments of value for compliance purposes and instruments carrying market value, EACs carry risk of fraud and inaccurate representation of environmental performance. It is critical from both policy and market perspectives that all parties have faith in the integrity of EACs. The question is the appropriate degree of stringency in tracking, measurement, and verification protocols. At the highest level of stringency, key inputs, outputs, and process states are measured in real time and reported frequently or remotely monitored. On the less stringent end of the spectrum, project, process, or program elements are verified at initiation of the activity with only high-level measurement of key quantities, such as purchased inputs and metered fuel or power outputs, measured and/or verified on a frequent basis unless there is a major change to the process or equipment.

Framing the Issue

Arguments in Favor of Stringent TMV: The primary arguments in favor of stringent TMV requirements are that they ensure environmental integrity, increase credit market confidence, reduce potential fraud, and, with increasingly low costs for automated measurement, data acquisition and analysis costs and human effort are not burdensome. It is also argued that higher stringency than current practice is needed to implement time matching and deliverability requirements.

Arguments in Favor of Less Stringent TMV: The primary arguments in favor of lower stringency requirements are cost, feasibility, financial risk, and lack of need. Proponents of lower stringency requirements are concerned about the cost of complying with what they view as stringency requirements beyond what they see as necessary to meet program goals and ensure program integrity. Such costs include monitoring and recording equipment, as well as the labor required to gather, synthesize and report required data. Some argue that some proposed requirements would require slow-down or shutdown of otherwise continuous operations to conduct measurement and verification and are infeasible from a practical perspective. The concern over financial risk stems from the potential for EACs to fail certification or face invalidation due to failure to meet TMV requirements that they view as overly onerous. They argue that more light-handed approaches are adequate and that the risk of gaming and fraud are low.

Available Evidence

No rigorous analysis balancing the cost of more stringent TMV requirements against the cost of inaccurate environmental attribute tracking was found through the research conducted for this white paper. Anecdotally, the prevalence of credit disallowance in California carbon credit markets is low[29] and invalidation insurance for carbon credits in voluntary markets is relatively inexpensive. These are indicators that TMV protocols are functioning adequately and that new requirements should be focused on technical program changes such as more granular time matching. Some commenters to the U.S. Treasury Department docket on implementation of tax credits authorized under Inflation Reduction Act, such as Constellation Energy,[30] have provided specific arguments on why some proposals for more stringent monitoring and verification requirements add cost and pose operational challenges but no analysis was identified that quantifies the cost of alternative approaches to tracking, measurement, and verification. The bottom line is that more rigorous analysis of this topic area is needed to support fact-based policy decisions on the balance between ensuring the environmental integrity of attribute credits and the costs and operational impacts of tracking, measurement, and verification.

Technology Differentiation and Early-Market Preferences

A policy question arises as to what, if any, special provisions, or support are appropriate when nascent clean energy technologies that are in need of scale to reduce cost are introduced into the market. As a

[29] https://ww2.arb.ca.gov/resources/documents/lcfs-enforcement
https://ww2.arb.ca.gov/our-work/programs/compliance-offset-program/offset-credit-invalidation
[30] https://www.regulations.gov/docket/IRS-2022-0029/comments

general principle, it can be argued that policies should be technology neutral, and market forces should determine winners. This argument is sound but, but technology-neutrality can be viewed over the technology lifecycle. From that perspective, technology-neutral treatment could include similar preferences during the launch and scaling phases for emerging technologies deemed to have the potential to compete on a level playing field in the timeframe needed to reach policy goals. Renewable gaseous fuels are such a nascent resource. The two primary processes for producing renewable methane and hydrogen at scale are thermochemical conversion of biomass and electrolysis of water. Both pathways are significantly more expensive than fossil pathways using carbon capture, and, as can be seen in Figure 17, both project to have the potential to be cost-competitive within five to ten years if deployed at scale. Debate is currently active on the degree of stringency that should be applied for credit generation (tax credits under IRS Section 45V, renewable gas qualification under WRI greenhouse gas reporting protocol, and eligibility in low carbon fuel standard programs) from renewable methane and hydrogen. The key issues are requirements for deliverability, additionality, and in the case of electrofuels, time matching of input RECs for input electricity.

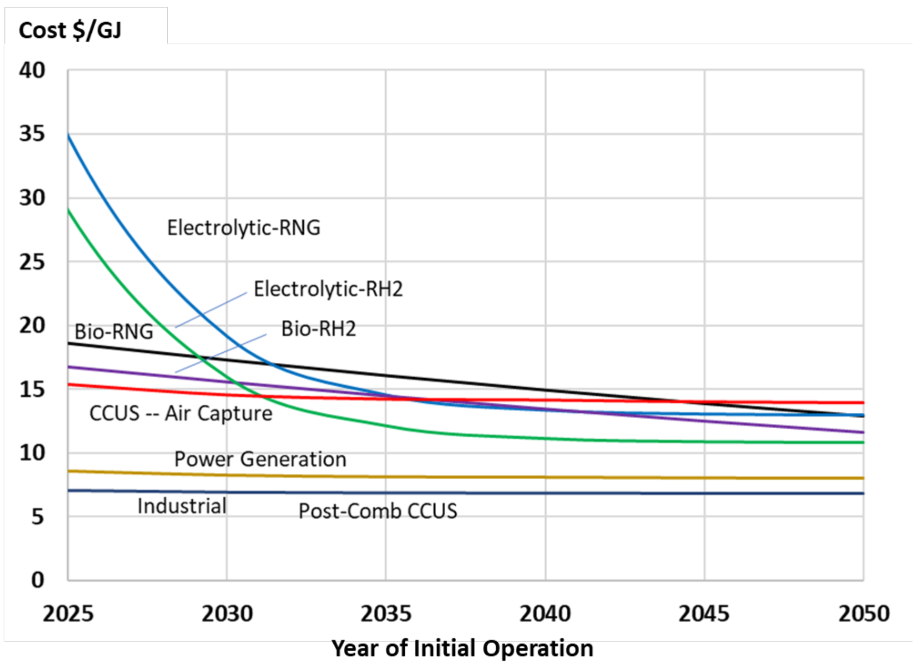


Figure 17. Projected Cost Projection for Renewable Hydrogen and Methane (2020 Constant Dollars). CCUS is carbon capture utilization and storage. RNG is renewable natural gas. [25]

Framing the Issue

Arguments in Favor of Preferences

The argument in favor or preferences for nascent technologies is that special measures to support entry and scaling of new technologies create downstream benefits to justify the preferences. Compliance flexibility and a variety of subsidies have aided wind and solar technologies in reaching a point, absent storage requirements, of cost parity with conventional resources. It is argued that such preferences are consistent with technology neutral policy if applied evenly to new technologies as they enter the market and if preferences have a finite life.

Arguments Against Preferences

The argument against technology-specific preferences is that they interfere with market forces that should properly determine which technologies enter and succeed in the market. Under this view, all clean-technology preferences should be technology neutral. A related argument is that preferences should be transparent and not provided in ways that skew tracking and reporting of environmental benefits, such as GHG reductions.

Available Evidence

Many clean energy programs provide, or have provided in the past, preferences for emerging technologies with the expectation that their cost and performance would improve over time to the degree that preferences would not be needed. Solar photovoltaic technology is the most prevalent example. As of 2021, 19 states have implemented technology preferences (such as credit multipliers) or carve-outs (technology-specific minimums) within RPS programs [10]. The motivation for solar preferences has been that, while wind power costs were significantly lower than solar PV costs until the late 2010s, solar costs were dropping rapidly as deployment volume increased. Separately traded RECs, referred to as solar RECs (SRECs), have been implemented in many cases to facilitate these preferences. Low-carbon fuel standards are another example. Such programs partition the carbon emissions from the transportation sector from other sectors. The objective is to incent investment in zero-emission drive technologies and fuels with the expectation of ultimately achieving cost parity with incumbent technologies. Figure 18 shows the required growth in solar capacity through solar carve-out under state RPS programs. Solar capacity in New Jersey has grown from under 300 MW when the solar carve-out was implemented to 4,000 MW by mid-2022 through a variety of pro-solar policies.[31]

It is worth noting that preferences that use EACs as the vehicle for conveying incentives to preferred resources often depart from pure attribute accounting. For example, REC multipliers for solar resources (implemented in several states) create a situation in which the RECs generated exceed the megawatt-hours of renewable energy delivered. The refueling capacity credits generated under the California LCFS program represent potential future reductions in greenhouse gas enabled by the up-front provision of infrastructure.[32] Those credits are a means of providing an incentive but do not represent a metric ton of achieved carbon reduction as other LCFS credits in this program do. A valid argument can be made that incentives should be direct and transparent, and attribute credit generation should not depart from verifiable attribute creation. However, the use of existing instruments to provide resource specific incentives is common when working within established statutory or regulatory frameworks.

[31] https://www.nj.gov/bpu/newsroom/2022/approved/20220715.html
[32] https://ww2.arb.ca.gov/resources/documents/lcfs-zev-infrastructure-crediting

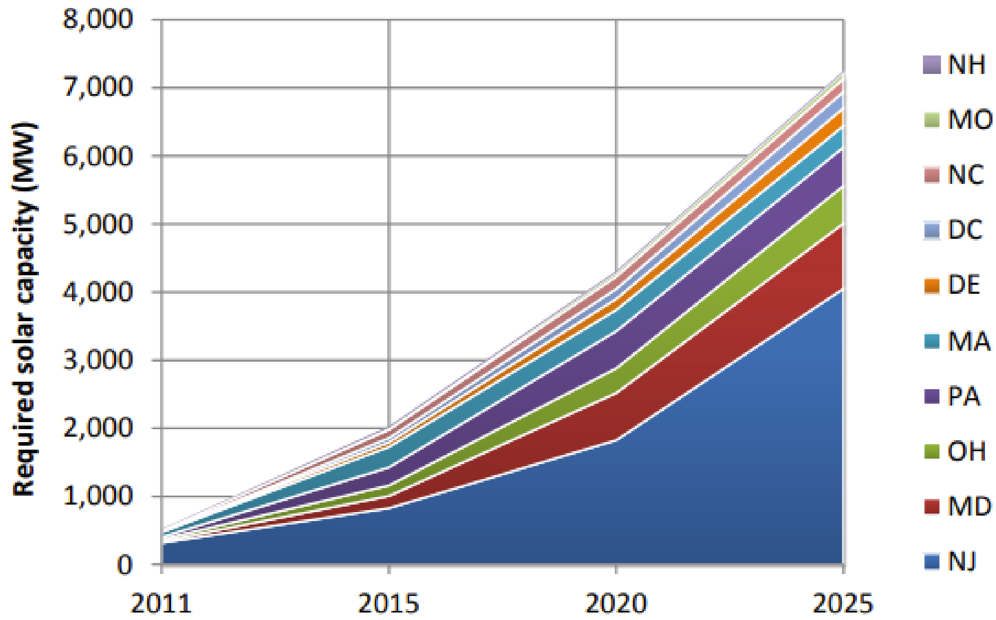


Figure 18. Solar-Specific RPS Requirements in the U.S. Source: NREL [26].

EAC Value Certainty

The conveyance of predicable financial value is critical to attracting investment to clean energy technologies. In the interviews for this white paper, stable supportive policies emerged as the most critical factor in attracting investment. For EACs this means low risk of invalidation, certainty of program continuation, and stable prices for traded attributes. In this section, we discuss price certainty. Grants and tax credits convey a pre-defined financial value. However, EACs such as RECs, LCFS credits, carbon credits, and thermal energy certificates exhibit price volatility as supply and demand fluctuate. This volatility creates investor risk which can stifle investment. Developers of clean energy projects identify uncertainty in credit prices as a significant barrier to investment. Once clean energy and carbon markets are fully mature and traded on traditional exchanges, hedging instruments can be expected to be readily available in the form of futures. The question is whether, in the early phase of these markets, the program sponsors (state or federal agencies) should step in to provide a price-stabilizing function.

Framing the Issue

<u>Arguments in Favor of Regulator Action:</u> The argument in favor of program sponsors establishing mechanisms to stabilize EAC prices is to ensure that program objectives are achieved. EAC programs are put in place to create environmental benefit through funding of environmentally beneficial projects and activities. To the extent that EAC price volatility is hindering investment, establishment of price stabilizing mechanisms may be justified. It is also argued that, in the early stages of market development for tradeable EACs, market guardrails are appropriate as trading volumes and market participation build.

<u>Arguments Against Regulator Action:</u> The argument against program sponsors establishing mechanisms to stabilize EAC prices is that such programs place risk on the sponsors and may distort market forces. Program designs that feature credit trading seek to rely on market forces to optimize investment and are argued to function most efficiently without interference. In addition, providing price guarantees involves risk that is not appropriate for program sponsors to assume.

Available Evidence

Typical of other commodities, EAC price volatility can be significant. Figure 19 through Figure 22 show the price history for a range of EACs. As can be seen in these figures, price volatility is significant across both long (several years) and short (quarterly) time horizons. Statistical analysis and modeling of SRECs in New Jersey finds that price volatility reduces investment [27]. Similar analysis of uncertainty in wind production tax credit continuation show of solar incentives find that uncertainty of continuation of incentives also reduces investment [28][29].

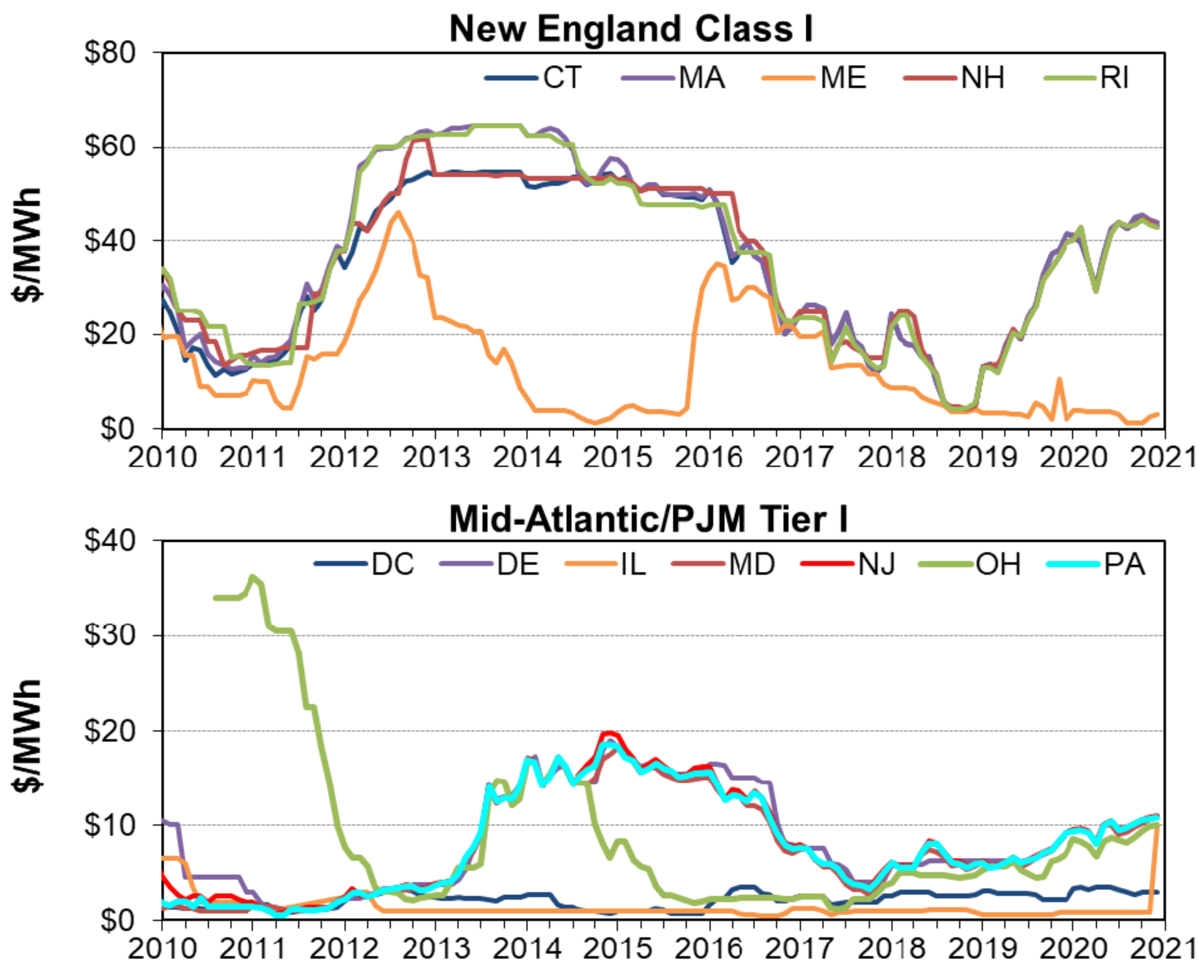


Figure 19 – Historical REC Pricing for meeting primary RPS goals in New England and Mid-Atlantic states, 2010 – 2021. Source: Lawrence Berkeley National Lab, using data from Marex Spectron [10].

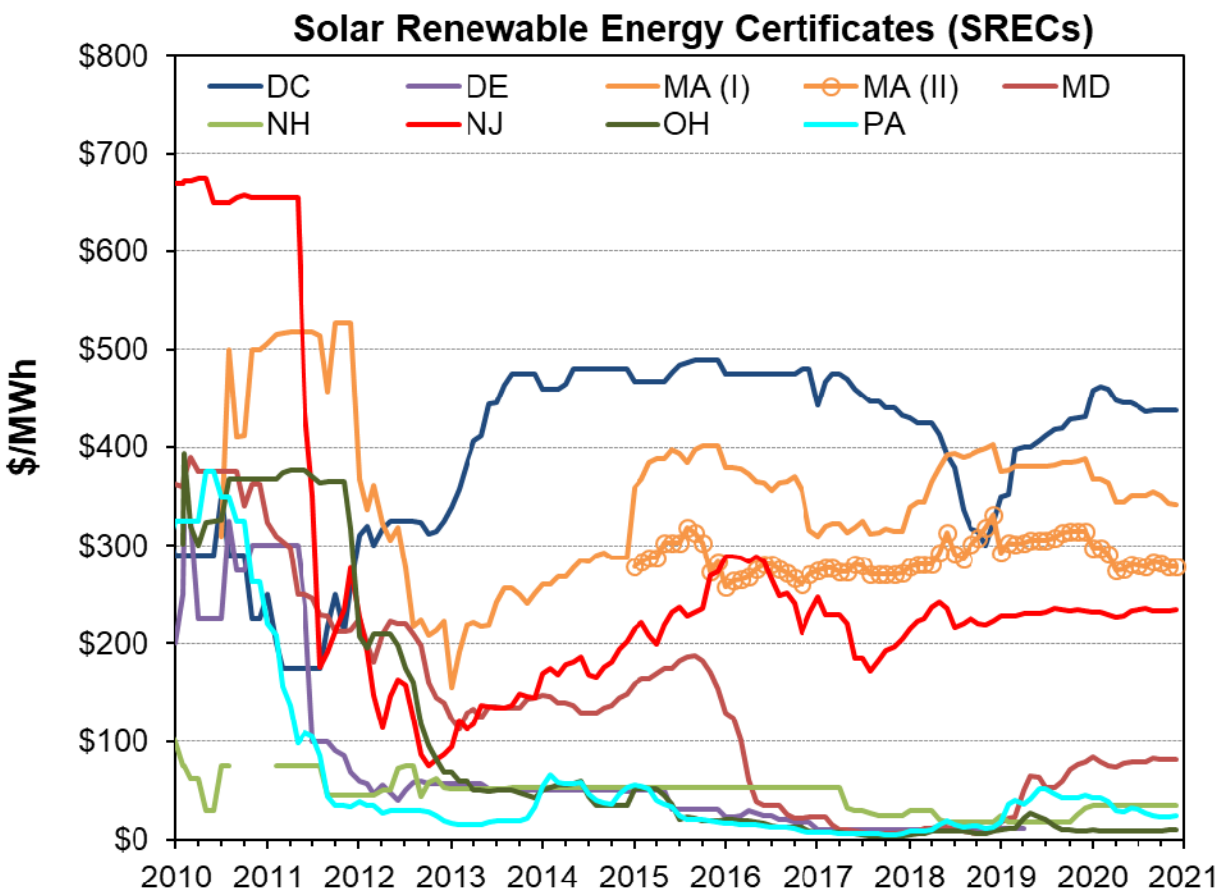


Figure 20 – Historical SREC Pricing for meeting primary RPS goals in New England states, 2010 – 2021. Source: Lawrence Berkeley National Lab, using data from Marex Spectron [10]*.*

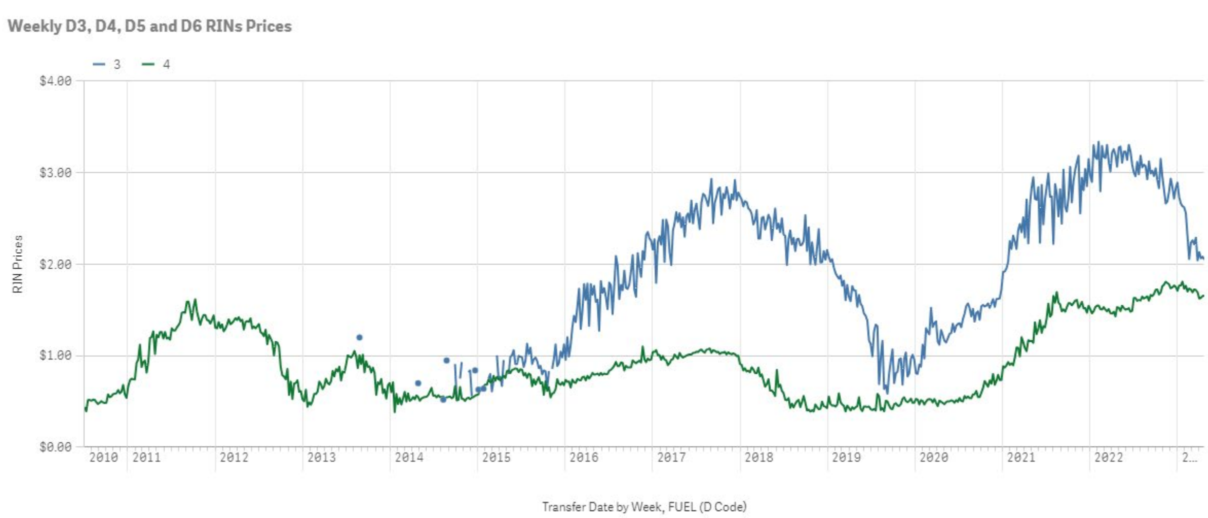


Figure 21 – Historical trends in RIN prices from 2010-2023 for D3 (cellulosic) and D4 (advanced biomass-based diesel) biofuels. Source: U.S. EPA RIN Trades and Price Information https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information

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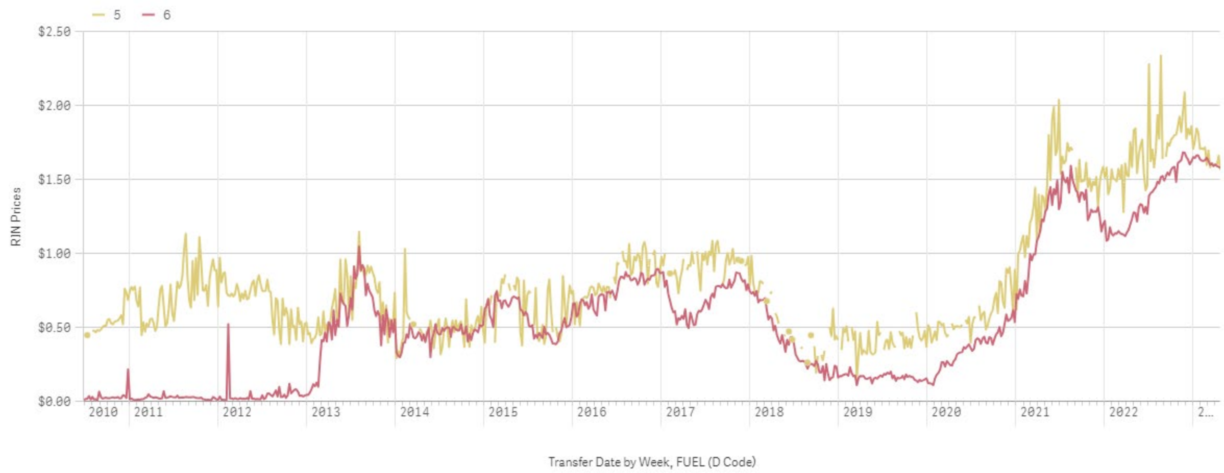

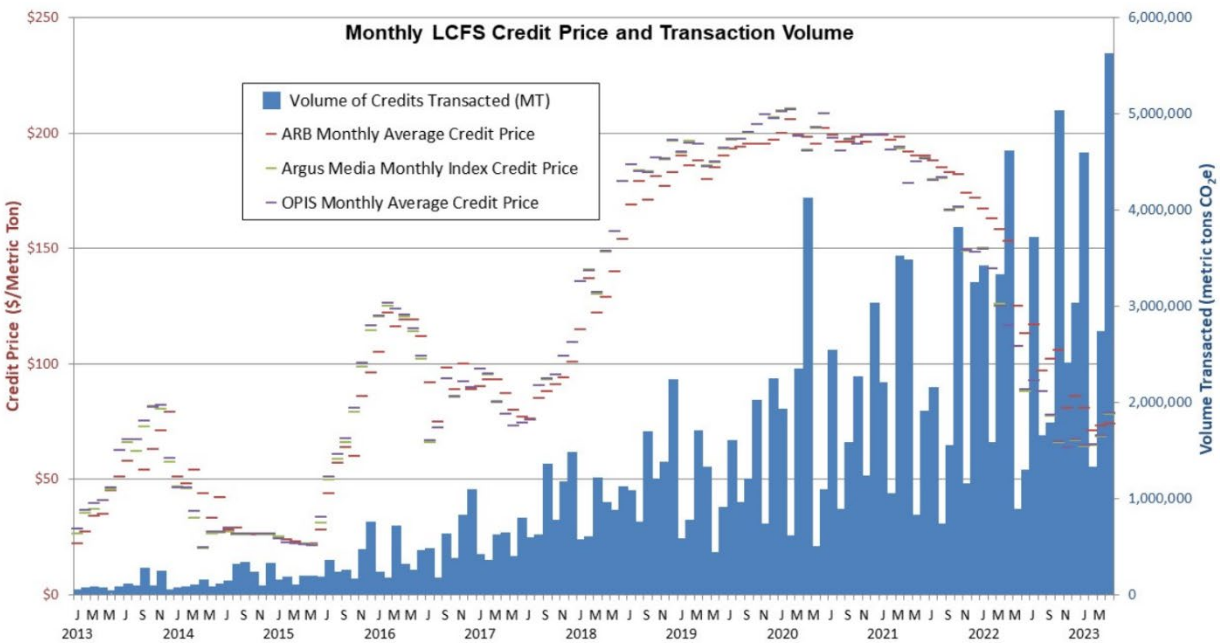

Figure 22 – Historical trends in monthly LCFS credit prices and volume of LCFS transactions. Source: California Air Resources Board, using price data from Argus and OPIS, updated 5/15/2023. *https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard, updated 5/15/2023*

A variety of mechanisms have been used to create price stability and compliance flexibility (in mandatory markets) for EACs. These include feed-in tariffs, contracts for differences (CFD), reserve auction mechanisms, and banking and borrowing provisions.

The contracts for differences program in the U.K. renewable power market has proven successful in providing EAC value certainty for investors. A contract for differences is a contract between two parties, typically a renewable energy producer and a financial counter-party, under which an uncertain credit revenue stream is exchanged for a certain (often constant) revenue stream. In the U.K., the level of the certain revenue stream is negotiated between the two parties or through a reverse auction. Wellisch and Rahmatallah show the effectiveness of the approach in stimulating investment in offshore wind under an emerging-technology carve-out and suggest some improvements to reduce artificially low clearing prices [30]. Savelli et al. describe an approach to internalizing transmission congestion costs in the CFD framework to create funding to expand transmission capacity to reduce curtailment [31].

Stakeholder Perspectives

Stakeholder perspectives and priorities on the role and requirements for EACs were compiled from several sources. Ten stakeholder interviews were conducted as part of the current study, the roughly 200 comments to the docket in response to the IRS request for comments on requirements for generating Section 45 tax credits enacted under the Inflation Reduction Act were reviewed,[33] and reported findings from 42 stakeholder interviews conducted as part of the Carley et al. study to aid in interpreting their statistical correlations were incorporated [1].

Developer, Investor and Technology Provider Perspectives

The perspective of supply-side stakeholders with few exceptions is that policies should be designed to maximize deployment of preferred technologies. With respect to environmental attribute credits, this means favoring maximization of credit value, flexible program features for the generation of EACs, and certainty in the stability of program features. The ability to finance projects is the key to capacity expansion. Finance is provided based on the pro forma free cash flow of projects which flows from predicable revenue streams.

For clean energy projects, particularly for nascent technologies, EACs may be a primary source of project revenue. Both credit value and credit value certainty are important. Tax credits and direct incentives provide both. Credit exchanges, such as those under cap-and-trade programs, are arguably the most market-efficient mechanisms, but investors will apply a risk premium when depending on returns from these instruments, correlating to the uncertainty in or volatility of prices. To reduce uncertainty, several jurisdictions have explored the use of contracts for differences and other approaches to creating credit-price floors, usually in exchange for capped returns on credit sales. Supply-side stakeholders are strong proponents of such programs. They also advocate strongly against abrupt changes in program features and incentive program “cliffs” and instead favor phased-in or phased-out provisions.

It should also be noted that entities on the clean-energy supply side may advocate strongly for policies that favor their technology class at the expense of competing clean-energy technologies. Due to this competitive dynamic, supply-side stakeholders may take differing positions.

Regulator Perspectives

Regulators are focused on meeting their statutory mandates. This generally translates into achieving regulatory and statutory environmental mandates at least cost. Regulators are charged with balancing stakeholder interests and follow well defined procedures for receiving stakeholder feedback and adjudicating issues impartially in line with policy goals and the public interest. Energy regulators seek to balance stringency with technical feasibility and deployment timelines that enable policy goals to be met. Regional variations on perspective are driven by differences in renewable resource availability and individual state policy frameworks and priorities.

[33] https://www.regulations.gov/docket/IRS-2022-0029/comments

Buyer Perspectives

Relative to EACs, there are two primary buyer groups: compliance buyers and voluntary buyers. The primary compliance buyers are electric utilities under mandatory RPS regimes (and a small number of gas utilities under renewable gas procurement mandates), and corporations subject to greenhouse gas cap provisions. The primary voluntary buyers are corporations seeking to reduce their environmental footprints outside of mandated programs and individual consumers participating in voluntary programs, such as green tariffs. Both mandatory (compliance) and voluntary buyers advocate policies that allow them to achieve procurement goals at least cost and little or no risk of credit invalidation.

Third-party Advocates

Third parties are non-regulator entities that are not parties to EAC transactions (buyers or producer/sellers) that assert a stake in the rules for the generation and use of EACs. Regulators are a special class of this group and are treated separately due to their authority. Environmental non-governmental organizations (ENGOs) with varying missions related to improving the environment are a primary stakeholder group in this category. Organized Labor is the other major group in this category. The majority of stakeholders in the ENGO group are strong advocates for stringency in all forms. Labor groups focus on job creation and job quality within their represented trades and geography.

Table 1 below summarizes the typical perspectives of the various stakeholder groups. The majority of stakeholder input relates to the use of EACs representing renewable power or renewable fuel, and much of the input relates to implementation of the tax credits enacted under the Inflation Reduction Act.

Balanced Policy Options

The policy and program design issues under consideration regarding the provisions and requirements for the use EACs in voluntary and mandatory programs generally relate to finding a balance between provision of effective incentives to stimulate investment in preferred technologies and pathways, and the desire to guarantee that desired environmental benefits are attained. At a macro level, these goals need not be in conflict. However, at the implementation level, stringent program requirements have the potential to stifle project development such that the total investment pipeline creates fewer benefits than would be the case under more permissive or inclusive program requirements. Alternatively, program requirements that are not stringent enough can result in reduced environmental benefits being realized. Some considerations on finding an optimal balance are discussed below.

Targeted Support for Nascent Markets and Technologies

In cases where a program goal is to advance a particular resource class predicated on expectation and evidence that it will yield cost-effective environmental benefits once fully established, more permissive program requirements and preferences may be justified. This has been the case, for example, with solar carve-outs in RPS programs, the Hydrogen Refueling Infrastructure credit program in the California LCFS, special subsidized rates for electric vehicles, and net metering programs for renewable resources. Arguments can be made regarding the relative merits of using direct grant incentives, production-based incentives, tax credits, or other vehicles. However, once an incentive approach has been defined, program design should consider the stage of the market for the relevant resource class(es).

Table 1. Typical Stakeholder Positions on EAC Policy Issues.

	Clean Energy Supply Side	**Regulator**	**Buyer**	**3rd Party Advocate**
Additionality	• Most assert that additionality is ensured by the incentives themselves • Strong concern from green hydrogen producers on overlay of additionality requirement on an input (renewable electricity) • Some are neutral, but are concerned about lack of clear definition of additionality • Some believe support for existing renewable resources is also needed to avoid stranded assets • Build and interconnection timelines are a major concern • Positions driven by expected business impact on supplier / developer	• Energy regulators may view as an impediment to cost-effective achievement of mandates • Concerned about lack of clear definition of additionality	• Both mandatory and voluntary buyers favor compliance flexibility • Voluntary buyers concerned about environmental integrity, so may support provisions ensuring that voluntary demand leads to incremental supply	• ENGOs support imposition of additionality tests for all EACs • Labor generally supports new-build requirements due to associated increase in construction activity
Time Matching	• Most power producers and electrolytic hydrogen producers favor phase-in, typically in the 2030 timeframe due to cost and feasibility concerns • A few favor earlier implementation noting that the trend toward hourly matching is already under way • Storage providers favor rapid implementation	• Support to the extent required to meet mandates -- guided by resource planning models • Concerned about technology readiness of hourly time matching products, with some indicating monthly time matching is presently more technically feasible	• May support in principle but concerned about cost and supply availability • Some large voluntary buyers are entering into time-matched agreements already	• Strongest advocacy for time matching is from ENGOs although positions vary • Strong concern among many over shortfall in attaining GHG reduction goals without hourly time matching
Geographic Restrictions	• Generally, favor broad market boundaries to avoid development impediments and constraints • Support actions to address transmission and interconnection constraints to facilitate larger market areas	• Positions are mixed based on statutory provisions and balance between rate containment and utility labor interests • Some consider geographic restrictions among the simpler to implement	• Both mandatory and voluntary buyers favor compliance flexibility • Voluntary buyers concerned about environmental integrity so may support provisions requiring deliverability	• ENGO positions similar to time matching • Labor positions align with job maximization in the trades and geographic area represented
Tracking, Measurement, and Verification	• Rigorous at project start and minimum ongoing TMV to demonstrate compliance	• Sufficient to ensure statutory requirements	• Sufficient to provide de minimis risk of invalidation	• Rigorous throughout project life and evolution toward real-time automated

Note: Legislators are also key stakeholders but do not have systematic alignment of positions on EACs.

Consistency with Program Purpose

Incentive programs are designed for a variety of purposes. For environmental programs, the purpose is generally to achieve particular environmental goals, but the mechanism varies across programs. A remediation program may focus on immediate and specific action to correct environmental damage, while a program seeking to promote deployment of a preferred technology would focus on maximizing deployment over a particular time horizon predicated on a longer-term view of environmental benefits to accrue from deployment of the technology.

There is current debate over the requirements to be met to qualify for tax credits enacted under the IRA. The stated purpose of the program is to stimulate private investment in clean energy technologies with carbon intensity as a key criterion for qualification for tax credits. For example, the statute provides for tax credit eligibility for clean hydrogen with a carbon intensity below 4 kilograms $CO2_e$ per kilogram of hydrogen and provides additional credits in tiers for CI below the threshold. Much of the controversy is over the use of RECs for calculating Scope 2 emissions (procured power). Similarly, there is debate over how to assess carbon intensity of clean fuels derived from biomass, particularly with respect to indirect land use impacts. While accurate GHG accounting is critical to achieving climate goals, the method of carbon-intensity calculation used in determining tax credit qualification should match that envisioned when the amount and value of tax credits was determined. Delinking credit value and carbon-intensity calculations may lead to failure in stimulating investment in clean energy resource supply. Given that the tax credit amounts are specified in statute and cannot easily be adjusted to reflect changes in carbon-accounting methodology, compromise on implementation of new stringency requirements seems in order.

Importance to Investors of Program Certainty

Clean energy investors identify certainty in program features as a top priority. The underlying desire is to have certainty in EAC revenue to support project finance. Direct stabilization of credit value through feed-in tariffs and contracts for differences have proven effective. A measured pace in program change is also important to investors. The analysis of Carley et al. [1] and others show that programs evolve over time to accommodate technology and market evolution and to enhance program effectiveness. RPS standards have ratcheted up progressively in many jurisdictions, and direct and indirect subsidies, such as solar tax credits and net metering credits, have been ramped down as technology costs near parity with incumbent resources. However, abrupt imposition of new requirements could strand assets and chill investment.

Balanced Allocation of Costs and Benefits

The incremental cost of environmentally beneficial programs does not necessarily accrue to the beneficiaries. Program costs may be borne by utility ratepayers, state taxpayers, federal taxpayers, or voluntary buyers. In addition to potential geographic disparity between costs and benefits, some formulations are regressive and some progressive. Increasingly, program designs are also considering environmental and economic stress through disadvantaged community (DAC) preferences. Program design should seek to quantify distributions of costs and benefits as a key program design consideration. For example, states with strong RPS mandates can reduce their compliance costs by allowing out-of-state resources to participate in the program. This reduces economic development in the RPS state relative to the case where only in-state resources are permitted. The costs and benefits, and their distribution to stakeholders can be assessed quantitatively, for example, through electric system resource models and econometric models of employment and economic output. Using such models may facilitate achieving consensus among stakeholders on program design.

Context of National Policy Evolution

Many of the issues under discussion and debate regarding EAC policy and program design emanate from the patchwork of state and federal programs that govern their use. Different states and regions have differing resource endowments. For this reason, well-functioning, national clean energy markets, like conventional energy markets, would allocate production to the most cost-effective locations and supply based on the national demand distribution and resource transportation cost. The dynamic of wealth transfer based on asymmetric environmental mandates would not be an issue. In addition, under a national GHG program (cap and trade, carbon tax, or other), issues related to voluntary actions and reporting thereof would not be eliminated, but the potential impact would be dramatically reduced as the national glidepath would be mandated in statute. The potential effectiveness of such national policy has been demonstrated through the significant air-quality improvements resulting from the national Clean Air Act.

A recent example of a unified regional policy is the Delegated Acts on Renewable Hydrogen passed by the European Union.[34] This legislation specifies criteria for the definition of renewable hydrogen production, specifically: 1) lifecycle GHG emissions of at least 70% below that of fossil natural gas, 2) monthly temporal matching until 2030, then hourly temporal matching from 2030 onwards, and 3) meeting additionality criteria starting in 2028. Additionality here is defined as using renewable electricity from electricity-producing facilities installed within 36 months prior to the fuel production facility startup. These acts provide regulatory certainty for different stakeholders and investors in the renewable fuel production space with which they can plan investment actions with reduced risks.

The EU policy uses phase-in timelines for requiring hourly time-matching and additionality compliance of 7 years and 5 years, respectively. These timelines may be viewed as somewhat long; however, it is important to note that the EU has other, complimentary policies in place that function as safeguards against potential unintended consequences of a long phase-in time. These include but are not limited to an EU-wide cap-and-trade system[35] for ensuring emission decline, as well as national renewable electricity targets in EU member states.

In the U.S., however, there is a lack of national safeguards against potential issues of a longer phase-in time, primarily because only certain states have cap-and-trade systems with mandated emissions declines and/or aggressive renewable electricity targets. In states that do have complimentary policies, stringency for renewable fuel programs is important but not as critical, while in other states more stringency may be more critical for ensuring realization of environmental benefits.

[34] https://ec.europa.eu/commission/presscorner/detail/en/qanda_23_595

[35] https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets_en

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APPENDIX

Current Environmental Certificate and Credit Tracking

Environmental attribute certificates or credits represent the creation of a specific and quantified environmental benefit. Programs currently in place include those for producing and using renewable power and low-carbon fuels, for reducing greenhouse gas emissions, and for reducing specific types of pollutants. The programs under which certificates or credits are traded can be voluntary or mandatory. Mandatory programs include procurement mandates for various types of clean (as defined by the program) resources, and cap and trade programs which allow obligated parties to buy and sell credits under an overall mandatory limit on emissions. Certificates and credits are used as instruments to demonstrate compliance with mandates, support claims of voluntary action, and financially represent the value of the underlying environmental attribute. Programs are active throughout the U.S. and in many international markets. Figure 23 shows a map of the REC tracking and trading systems in the North America. Each tracking system applies its own requirements and standards for creating certificates.

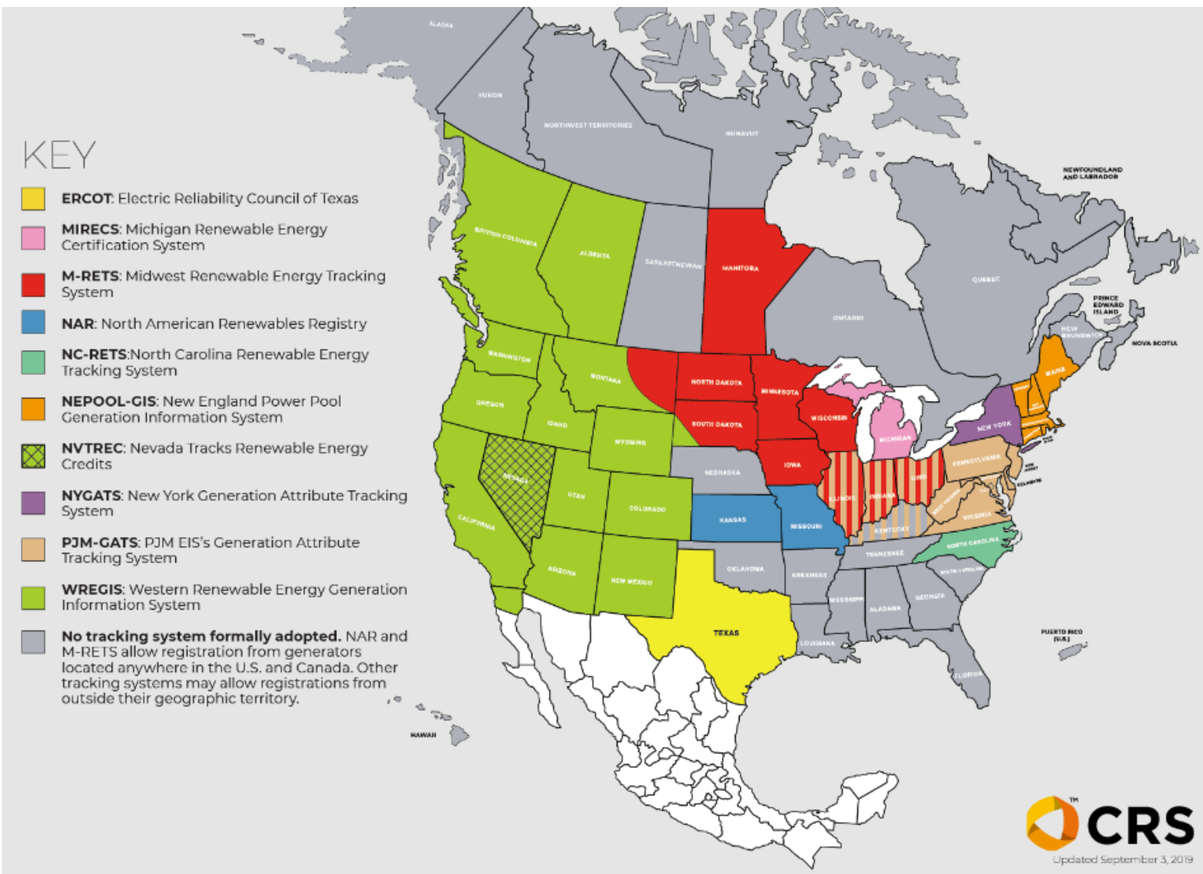

Figure 23. Renewable Energy Certificate Tracking Systems in North America.

https://resource-solutions.org/wp-content/uploads/2018/02/Tracking-System-Map.png

Tracking System Name	Facilitating Authority	Traded Attributes	Geographical Constraints	Other Notes
ERCOT Renewable Energy Credit Program[36]	Electric Reliability Council of Texas (ERCOT)	1 MWh of renewable electricity	Connected to the ERCOT Grid	• If a facility uses fossil fuel, it must not exceed 25% of the primary energy input. • Excludes energy from waste products of inorganic sources
Michigan Renewable Energy Certification System (MIRECS)[37]	Michigan Public Service Commission (MPSC)	1 MWh of renewable electricity	Connected to the State of Michigan	• MIRECS also facilitates trading of other types of energy credits • Hydropower facilities excluded unless it was constructed before MIRECS was established.
Midwest Renewable Energy Tracking System (M-RETS)[38]	Midcontinent Independent System Operator (MISO)	1 MWh of renewable electricity 1 Dth of renewable thermal energy	Jurisdiction over North Dakota, South Dakota, Iowa, Minnesota, Wisconsin, Manitoba CA, and part of Montana	• Allows registration of generators outside their key territory • Renewable Thermal Certificates (RTCs) are a novel product, includes hydrogen, heat pumps, RNG, and heat recovery • Eligibility is set by state lawmakers, not internally • Tracks timestamp of REC production since 2019, informative for REC buyers
North American Renewables Registry (NAR)[39]	APX, Inc	1 MWh of renewable electricity	Can be used by any entity in North America, currently used by Kansas and Missouri	• Third-party platform that any North American jurisdiction can use • Attempts to standardize information requirements • Integrated with the Green-e REC certification system.
North Carolina Renewable Energy Tracking System (NC-RETS)[40]	APX, Inc	1 MWh of renewable electricity	Connected to a North Carolina Utility	• Platform administered by same entity as NAR • Registry only, does not facilitate markets. • Note: NC-RETS informational site has not been updated in a few years, information may not be current.
New England Power Pool Generation Information	APX, Inc	1 MWh of renewable electricity	Vermont, New Hampshire, Massachusetts,	• Platform administered by same entity as NAR • Tracks all generation, not only renewable, but is

36 https://sa.ercot.com/rec/home
37 https://mirecs.org/
38 https://www.mrets.org/
39 https://apx.com/about-nar/
40 https://ncrets.org/

Tracking System Name	Facilitating Authority	Traded Attributes	Geographical Constraints	Other Notes
System (NEPOOL-GIS)[41]			Connecticut, Rhode Island, Maine	responsible for overseeing REC trading. • Provides emissions labeling for generators in its territory
Nevada Tracks Renewable Energy Credits (NVTREC)[42]	State of Nevada	1 kWh of renewable electricity	Nevada	• Minimum capacity of 150 kW nameplate • Higher weighting given to solar PV and distributed generation over other renewable energy types
New York Generation Attribute Tracking System (NY-GATS)[43]	State of New York	1 MWh of renewable electricity	Within NYISO or contractually connected to NYISO	• New hydropower not eligible • Fuel cells are eligible if verified to use a non-fossil fuel resource
PJM EIS Generation Attribute Tracking System (PJM-GATS)[44]	PJM Interconnection	1 MWh of renewable electricity	Within or connected to the PJM Interconnect	• Tracks timestamp of REC production as of Feb. 2023, informative for REC buyers
Western Renewable Energy Generation Information System (WREGIS)[45]	Western Electricity Coordinating Council	1 MWh of renewable electricity	Within the WECC territory	• REC eligibility determined by state governments • Registry only does not facilitate REC trading

Power and fuels credit programs have been established to promote the construction of energy provision facilities and supply chains with specific attributes. In these programs, facilities that meet specific attributes are eligible to generate a certificate representing energy produced from that facility that can be bought directly by another entity or sold on in a certificate market. To date, these programs are ubiquitous for renewable electricity production in the form of Renewable Energy Certificates (RECs), aimed at incentivizing developers to construct new renewable electricity production facilities. Programs are also in place for renewable fuels and thermal energy, although these are newer and less widespread than the REC programs.

Greenhouse gas offset programs are also widespread, but they differ from renewable or clean energy programs as they represent the reduction of a specific pollutant and not production of a quantity of energy through a qualified pathway. This distinction is important in the discussion of the use of renewable energy credits for voluntary and compliance GHG reporting purposes.

41 https://nepoolgis.com/
42 https://www.nvtrec.com/
43 https://www.nyserda.ny.gov/All-Programs/NYGATS
44 https://www.pjm-eis.com/
45 https://www.wecc.org/WREGIS/Pages/Default.aspx

Markets for RECs and the rules for eligibility, trading, and accounting, are established on a regional basis. Renewable Energy Tracking Systems (RETS)[46] refer to registries and accounting systems established by regional authorities to set rules for the generation and claiming of RECs, such as eligibility for producing RECs, accounting of REC generation, and claiming to prevent double counting, ensuring that electricity represented by a REC is not separately counted as contributing to other registries, and the documentation needed to verify REC generation and claiming. In the European Union, a similar instrument is termed the Guarantee of Origin (GO)[47], which functions essentially like a REC but with a wider scope for what types of resources and energy carriers are eligible and facilitated on a national scale instead of a regional scale.

In practice, most RETS function in a similar way: there are rules for what resources are eligible, RECs can only be generated once and claimed once, and RECs often have a vintage over which they are valid. Production of renewable energy must be verified by meter data, documentation of the facility fuel type, and details of the facility interconnection and vintage. REC programs generally employ so-called book-and-claim accounting. The generation of the qualifying environmental attribute is "booked" through the creation of the REC. The attribute is "claimed" when it is retired to convey the attribute at another place and/or time. Program rules determine the limits on when and where RECs can be claimed. Current programs use annual true up (only RECs generated within the same reporting year can be claimed) and are regional in scale. There may also be restrictions on facility vintage.

While different regional RETS vary in the extent of their jurisdictions and rules, all RETS perform a similar function of tracking the generation and claiming of RECs and ensuring accurate accounting of these transactions. Some RETS also facilitate markets, while others act solely as registries. Currently, M-RETS is the only system that is set up for non-electricity renewable energy products.

An important note about the function of RETS is that these systems only guarantee that a unit of electricity produced and injected onto the regional electricity grid meets the regional requirements for being counted as renewable energy. These requirements can vary from region to region. Importantly, however, RETS do not make any guarantees about explicit environmental benefits, such as greenhouse gas emissions reduction or other types of environmental impact reduction, associated with buying a REC.

Therefore, when entities buy RECs from their regional markets and subsequently advertise environmental benefits, the linkages between claiming RECs and purported environmental benefits are posed by the claiming entities (using either internal or third-party analysis), not by the RETS themselves.

Outside of electricity systems, there are other tracking and credit systems that track the production of fuels that meet different criteria, such as the U.S. Environmental Protection Agency Moderated Transaction System (EMTS) for tracking the renewable content of transportation fuels and the California Low Carbon Fuel Standard (CA LCFS) based on carbon intensity.

The EMTS[48] is a tracking system for transportation fuels to monitor compliance with the U.S. Renewable Fuel Standard using Renewable Identification Numbers (RINs). RINs are numbers assigned to each physical gallon of renewable fuel produced or imported to the U.S. RINs designate the source and time of production of a gallon of renewable fuel, as well as the type of renewable fuel. In practice, the RINs act as

46 https://www.epa.gov/green-power-markets/renewable-energy-tracking-systems#certificate https://resource-solutions.org/wp-content/uploads/2018/02/Tracking-System-Map.pdf

47 https://www.aib-net.org/certification/certificates-supported/renewable-energy-guarantees-origin

48 https://www.epa.gov/fuels-registration-reporting-and-compliance-help/how-use-emts-report-transactions-fuel-programs

credits. Producers of fuels with high renewable content generate RINs that can be sold to producers of fuels that do not have enough renewable content to comply with the Renewable Fuel Standard.

The CA LCFS[49] is one of the only programs that focuses specifically on tracking the carbon intensity of fuels and is aimed at reducing the use of petroleum in the transportation sector. This differs from other ubiquitous programs that focus on renewable energy content, rather than explicitly on emissions. Specifically, the CA LCFS provides monetary credits to producers of transportation fuels that fall below an annually defined benchmark for carbon intensity. Producers of transportation fuels whose products are above the carbon intensity benchmark must then purchase credits from the former to comply with state regulations. The benchmark carbon intensity decreases over time, incentivizing the production of lower carbon intensity fuels and disincentivizing conventional fuels. Carbon intensity is calculated using life cycle assessment tools, such as CA-GREET, a California-specific version of the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model developed by Argonne National Laboratory. Official reporting for participation in the CA LCFS program is facilitated in the LCFS Reporting Tool and Credit & Bank & Transfer System (LRT-CBTS), which tracks the generation and sale of LCFS credits.

Certification and Verification Standards and Protocols

While RETS certify that a unit of a produced energy carrier meets the criteria for being counted as renewable energy (or being produced from renewable energy) set by regional jurisdictions, as mentioned, RETS do not guarantee any other environmental attributes. For example, RETS do not guarantee that purchasing a REC is linked with greenhouse gas or air pollutant emissions reductions, and they do not guarantee that purchasing the REC encouraged the build of renewable energy facilities that would not have otherwise been built (additionality).

The U.S. EPA recommends that purchasers of RECs seek RECs that are specifically certified or verified by a third-party to correspond to a given environmental benefit. A similar approach is taken in the European Union, where Guarantees of Origin (GOs) can be certified by a third-party. The certification of a REC by a third-party is optional and must be made at the request of the REC producer. In the U.S., the primary certification for improving confidence in the environmental integrity of a REC is the Green-e certification[50], administered by the Center for Resource Solutions. Green-e certification is also available for different types of products, such as carbon offsets and renewable fuels.

To obtain a Green-e certification for renewable electricity represented by a REC, a renewable electricity producer must meet additional criteria above those required to register in a regional RETS. Key additional criteria include:

- Vintage of the energy producing facility: the facility that produces the energy represented by a REC must not be more than 15 years old. This is aimed at incentivizing new builds of renewable electricity facilities in order to stay eligible for certification and therefore incentivizes additionality, albeit at a relatively slow pace.
- Environmental criteria:
    - Biomass/biogas fuels: Fuels produced from certain types of biomass or environmentally destructive methods are not allowed, and others must demonstrate that their fuels do not contain certain toxic compounds including but not limited to plastics and arsenic.
    - Hydropower: Only existing hydropower is eligible unless a new build meets certification from the Low Impact Hydropower Institute or EcoLogo (Canada), or if the electricity is produced from turbines in human-made conveyance.

49 https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard
50 https://www.green-e.org/programs/energy

- Use for Renewable Portfolio Standard Compliance: Renewable energy represented by a REC must not be simultaneously counted as contributing to mandated state goals (i.e., RPS). This ensures that a certified REC does contribute somewhat to additionality, since it would have been built in the absence of a regional mandate. This point is important since many RECs that are tracked in RETS are used by utilities to count as their compliance with state-mandated renewable portfolio standards.

A REC that is Green-e certified is more likely to be tied with lower environmental impacts, and purchasing such a REC is better associated with additional renewable energy production. However, the Green-e certification still does not guarantee any claims about explicit reduction in emissions or other environmental impact criteria. Additionally, Green-e certification does not address the need for produced renewable energy to align temporally with electricity demand in order to contribute to offsetting other (typically fossil-fuel-based) generation.

Green-e certification also exists for renewable fuels,[51] but currently only applies to biomethane. This certification requires that the carbon intensity of a certified fuel must be at least 10% lower than a reference fossil fuel at the point of injection into the gas pipelines, including transportation. Additionally, Green-e certified biomethane cannot be counted as simultaneously meeting a mandated goal, contributing to additionality.

In the European Union, an analogue to the Green-e certification is the EKOenergy label.[52] EKOenergy certification can also be used for U.S. RECs, as well as GOs in the EU. To obtain an EKOenergy certification for renewable electricity, producers must prove that their facility meets certain environmental impact criteria. The criteria are resource-specific, for example, solar, wind, geothermal, and biomass/biogas facilities have different criteria that they need to meet. However, it should be noted that many of these criteria are qualitative and that there is not a standardized tool or method that is used to demonstrate compliance, rather, entities seeking certification must adequately make their case that they comply with the criteria sufficiently. EKOenergy addresses additionality differently than Green-e, by taking some of the fees for certification and putting them into a fund that finances new renewable energy projects.
EKOenergy also has a certification for renewable gas[53] that differs from Green-e in that it also includes hydrogen. For biomethane, restrictions are placed on the type of feedstocks considered and their production methods. For hydrogen, certification is only allowed for hydrogen produced via electrolysis using electricity inputs that are also EKOenergy certified.

While neither the current Green-e and EKOenergy certifications address the issue of temporal matching between renewable energy production and electric load in RECs, there is discussion and motivation to move towards such a framework. First, hourly timestamp information for RECs is not widely available in all RETS. However, the Center for Resource Solutions – which facilitates the Green-e certification – has put together a framework[54] for data needs and metrics to determine the temporal characteristics of a REC and link these to different environmental benefits, including reductions in Scope 2 greenhouse gas emissions. Questions currently remain, however, regarding differentiating between impacts attributed to raw renewable generation data, estimating avoided emissions at each timestep, and whether hourly procurement can be assigned the same impacts. Currently, only M-RETS and PJM-GATS track hourly production data associated with RECs tracked in their systems.

51 https://www.green-e.org/programs/renewable-fuels
52 https://www.ekoenergy.org/ecolabel/
53 https://www.ekoenergy.org/ecolabel/criteria/ekoenergy-gas/
54 https://resource-solutions.org/document/121420/

A protocol for better enabling the tracking of hourly generation timestamps associated with RECs is the Energy Tag standard, proposed by the EnergyTag Initiative.[55] This standard proposes the use of Granular Certificates (GCs) that provide data on the generation time associated with energy represented by a REC, enabling buyers of RECs to potentially enable their purchases with the temporal profile of their own entity's electric load profile and better characterize emissions reductions associated with that purchase. The EnergyTag standard also includes protocols for standardized hourly carbon emissions tracking from regional electricity systems to assist REC buyers in calculating avoided emissions associated with buying a REC. Additionally, the EnergyTag Initiative also includes guidelines for auditing a REC registry for compliance with the standard.[56]

Finally, guidance for translating procurement of instruments, such as RECs by corporations, to changes in corporate Scope 2 greenhouse gas emissions is available from the World Resources Institute GHG Protocol Scope 2 guidance,[57] as an update to the previous Corporate Standard. Note, however, that this standard represents voluntary guidelines and does not carry an official certification for compliance, and therefore implementation may vary between different REC-buying entities. This standard provides guidance on reporting requirements, emissions factors, and types of instruments that are eligible for counting towards GHG emissions reductions, and electricity consumption data for corporations in order to more accurately characterize GHG emissions reductions associated with RECs or other instruments.

Renewable Energy Procurement and Incentive Programs

Thirty-three states have been identified as having adopted renewable (or clean, with varying qualifications) power procurement mandates or voluntary targets that include or have included at least some types of renewable gas. Four states have renewable gas procurement programs, and three states have low carbon transportation fuel procurement programs. There are also several federal programs that mandate or support procurement of renewable gas for use in various sectors. Most of these programs use a regulatory credit mechanism to account for renewable content. Below is a summary of these various programs.

State Renewable Electricity Procurement Programs

Most states in the U.S. have adopted procurement programs for renewable electricity, since Iowa passed the first law in the nation in 1983 requiring electricity providers to procure power from renewable resources.[58] The majority of such states require a certain percentage or fixed amount of renewable electricity to be procured, although some, such as Kansas[59] and South Dakota[60], have voluntary programs.

Several states include an alternative compliance payment or penalty provision in their renewable electricity procurement programs, which requires electricity providers to pay a fee in lieu of retiring RECs, if they are unable to meet renewable procurement targets in a given compliance period. Some states, such as Pennsylvania,[61] have fixed per megawatt-hour prices for such payments that were set in statute, while several others adjust ACP pricing over time to reflect market changes.

States vary widely in the amount of renewable electricity required or encouraged in their programs, from small portions of the total power portfolio to up to 100%. To date, thirteen states have enacted laws

[55] https://energytag.org/wp-content/uploads/2022/03/20220331-EnergyTag-GC-Scheme-Standard-v1-FINAL.pdf
[56] https://energytag.org/wp-content/uploads/2022/09/Audit-process.pdf
[57] https://ghgprotocol.org/sites/default/files/2023-03/Scope%202%20Guidance.pdf
[58] https://www.legis.iowa.gov/docs/publications/iactc/70.1/CH0182.pdf
[59] https://kcc.ks.gov/electric/renewable-energy-standard
[60] https://sdlegislature.gov/Session/Bill/4678
[61] PA Act 35 (HB 1203, 2007), Section 3.(f); https://www.pjm-eis.com/program-information/pennsylvania

requiring 100% renewable or carbon free electricity procurement by mid-century, with some states, such as Hawaii[62], Maine[63], and Rhode Island[64], specifically mandating 100% renewable resource requirements. All Arizona major utilities also voluntarily committed to achieving 100% carbon free electricity from renewables, hydropower, and nuclear energy by 2050,[65] which given that the state only generates approximately 30% of power from nuclear resources and 5% from hydropower,[66] means this goal vastly exceeds the state's Renewable Energy Standard and Tariff (REST), which only requires 15% renewable power procurement by 2025.[67]

Nearly all state renewable electricity procurement programs use RECs (or a similar credit system using a different name) as the regulated currency and compliance tracking mechanism. Most allow both bundled and unbundled RECs, with the exception of a few states, such as Arizona,[68] that allow bundled RECs only.

New capacity is required by several programs, but additionality is not a test used for RECs and is not included as a requirement in any program that uses this type of credit.[69] The state of California, however, does require methodology to calculate the GHG emissions intensities associated with retail electricity portfolios reported under a power source disclosure program.[70] Specified procurement claims from eligible renewable facilities must include the associated RECs. While unbundled RECs may be used to count as a percentage of the power portfolio, they cannot be used to calculate the GHG intensity of the portfolio because unbundled RECs are by nature not attached to renewable electricity procurement.

Several states, such as Arizona,[71] California,[72] Indiana,[73] Maryland,[74] Maine,[75] New Hampshire,[76] New York,[77] Pennsylvania,[78] Utah[79] and Vermont,[80] place some geographic restrictions on compliance, typically requiring that some or all renewable electricity be generated within or delivered to the state or region.

Requiring time matching is atypical in state renewable power procurement programs, an exception being the state of Washington, which requires that facilities deliver renewable electricity into the state on a

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[62] https://www.capitol.hawaii.gov/session/archives/measure_indiv_Archives.aspx?billtype=SB&billnumber=3057&year=2022

[63] https://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0457&item=3&snum=129

[64] https://legiscan.com/RI/text/S2274/2022

[65] https://www.azcc.gov/news/2022/01/27/arizona-electric-utilities-voluntarily-commit-to-100-clean-energy#gsc.tab=0

[66] https://www.eia.gov/state/?sid=AZ#tabs-4

[67] https://www.azcc.gov/utilities/electric/renewable-energy-standard-and-tariff#gsc.tab=0

[68] TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS; SECURITIES REGULATION CHAPTER 2. CORPORATION COMMISSION-FIXED UTILITIES ARTICLE 18. RENEWABLE ENERGY STANDARD AND TARIFF, R14-2-1804. Annual Renewable Energy Requirement, Appendix A

[69] According to the U.S. EPA, Additionality is a test(s) used only for project offsets that result in direct emissions accounting and not for RECs or green power purchases; U.S. EPA, p. 11-3, Guide to Purchasing Green Power Glossary,

[70] https://www.energy.ca.gov/programs-and-topics/programs/power-source-disclosure/psd-frequently-asked-questions

[71] TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS; SECURITIES REGULATION CHAPTER 2. CORPORATION COMMISSION-FIXED UTILITIES ARTICLE 18. RENEWABLE ENERGY STANDARD AND TARIFF, R14-2-1803. Renewable Energy Credits (See Appendix A)

[72] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-compliance-rules-and-process/60-percent-rps-procurement-rules

[73] https://legiscan.com/IN/bill/SB0251/2011

[74] https://mgaleg.maryland.gov/2019RS/bills/sb/sb0516E.pdf

[75] https://www.mainelegislature.org/legis/statutes/35-A/title35-Asec3210.html

[76] https://www.energy.nh.gov/renewable-energy/renewable-portfolio-standard

[77] https://legislation.nysenate.gov/pdf/bills/2019/S6599

[78] https://pennaeps.com/about/

[79] https://le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

[80] https://legislature.vermont.gov/Documents/2016/Docs/ACTS/ACT056/ACT056%20As%20Enacted.pdf

real-time basis in order to comply with the program.[81] Some large corporations, like Google, have also committed to procuring 24/7 clean energy, and while not states, such companies have a large energy footprint and buying power to drive investment into developing technological solutions to meet this challenge.[82] [83] The federal government, as previously mentioned, has also signaled interest in time matching renewable electricity procurement, as has local electricity provider Peninsula Clean Energy, a San Mateo, CA based Community Choice Aggregator, which in 2017 set a goal of delivering 100% renewable energy to match customer demand on an hour-by-hour basis by 2025 and has developed a modeling system aimed at helping to achieve this.[84] The EPA reports that 24/7 hourly matching of renewable electricity is an important development to pursue, but also presents many challenges that must be overcome.[85]

Some programs include carve-outs for sizes and locations of renewable electricity facilities, such as distributed generation, or particular renewable technologies like solar. In 2016, California also created two special programs for bio-energy: 1) The BioRAM reverse auction mechanism was established to enable California electrical corporations to meet a requirement to collectively procure over five years 125 MW of cumulative generating capacity from existing biomass projects, primarily from those using forest waste as feedstock.[86] 2) California also implemented the BioMAT feed-in tariff program, which seeks to drive deployment of 250 MW of small biogas and biomass electricity projects.[87]

Please see Table 1 for more details on state renewable power procurement programs.

Renewable Gas and Low-carbon Fuels Procurement Programs

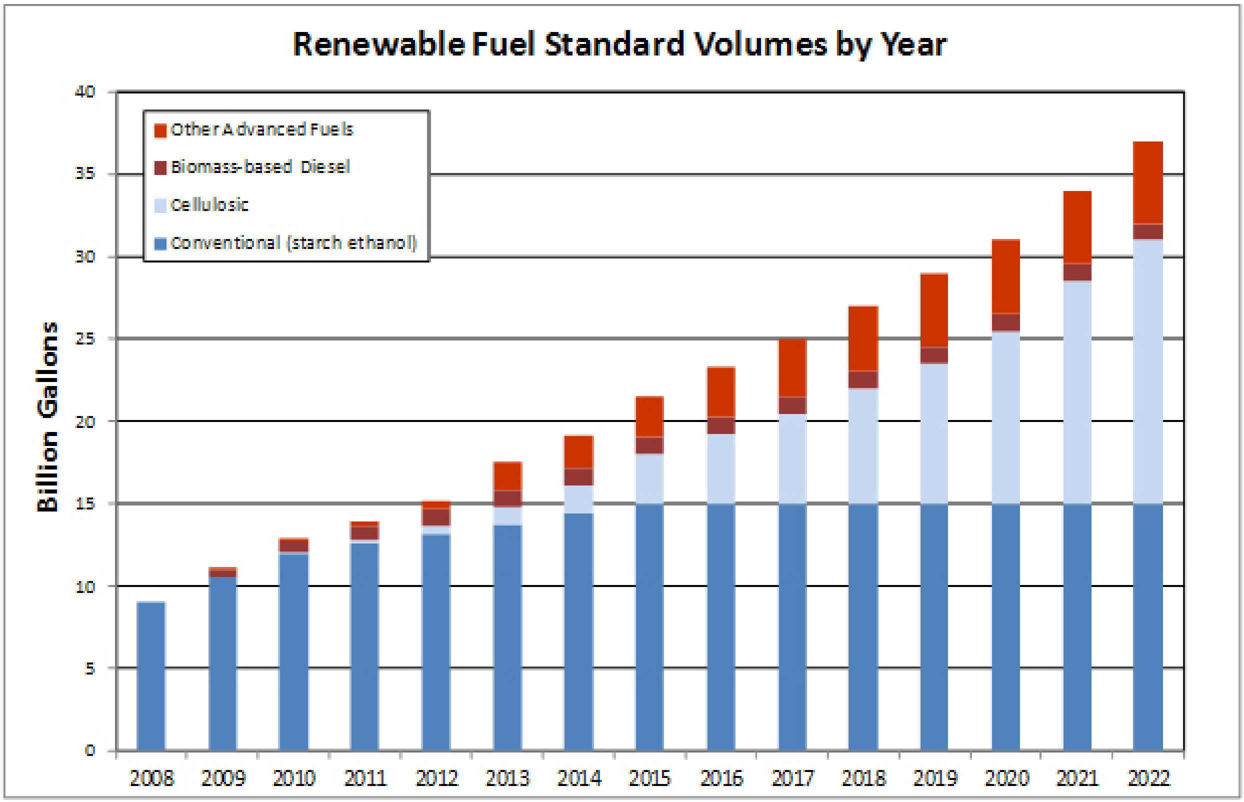
Several federal and state policies require or seek to encourage the procurement of at least some types of renewable gas. Programs to implement these policies fall predominantly into three categories: 1) Federal incentive programs that seek to expand markets for the production of clean hydrogen or biogas for use in range of applications; 2) State renewable gas procurement programs with targets for increasing renewable content in gas delivery systems; 3) State renewable or low carbon fuel programs with targets for increasing renewable and low carbon content of transportation fuel.

Federal Programs

Among the first federal renewable energy procurement programs to be adopted was the Renewable Fuel Standard, first enacted in 2005 with later revisions, which requires the transportation, heating, and aviation sectors to reduce or replace conventional fuel with set minimum amounts of various types of renewable fuels derived from renewable biomass or a biointermediate produced from renewable biomass. Annual targets started in 2009, when a total of 11 billion gallons of qualifying renewable fuel was required, and increased through 2022, when the target reached 36 billion gallons. The target increases to 37 billion gallons in 2025. Several biogas pathways and landfill gas that meet a standard requirement of 60% GHG reduction compared to baseline petroleum are eligible for compliance.[88] Since 2014, renewable compressed natural gas and renewable liquefied natural gas, both considered advanced

[81] SB 5116, Sec. 28(12)(a)(ii)
[82] https://sustainability.google/progress/energy/
[83] https://aescorp2020cr.q4web.com/press-releases/news-details/2021/AES-Announces-First-of-Its-Kind-Agreement-to-Supply-247-Carbon-Free-Energy-for-Google-Data-Centers-in-Virginia/default.aspx
[84] https://www.peninsulacleanenergy.com/our-path-to-24-7-renewable-power-by-2025/
[85] https://www.epa.gov/green-power-markets/247-hourly-matching-electricity
[86] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-procurement-programs/rps-bioram
[87] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-procurement-programs/rps-sb-1122-biomat
[88] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results

biofuel pathways under program rules, have constituted the majority of the EPA cellulosic biofuel volume requirements.[89]



Source: EPA[90]

EPA is considering proposals to allow eligibility for new fuel pathways that use RNG produced from biogas from anaerobic digesters or landfills as a feedstock to produce hydrogen fuel for use in fuel cell electric vehicles (FCEVs).[91]

As previously noted in this document, RINs are the regulatory credit that make up the currency for the Renewable Fuels Standard program. These may be either assigned (i.e., purchased with the fuel) or separated (i.e., purchased on their own). The EPA sets the minimum and maximum price for RINs, helping to maintain price stability.[92]

Other federal laws have recently been enacted that provide tax incentives and grant funding to encourage increased production and procurement of clean (i.e., low or zero carbon) hydrogen and qualified biogas for various end uses, in order to lower greenhouse gas emissions, support American economic and workforce development, and advance energy and social justice. These are:

- *The 2021 Inflation, Infrastructure and Jobs Act (HR 3684)*, which set aside $8 billion for the deployment of at least four regional clean hydrogen hubs to be deployed over a ten-year period.

[89] *U.S. Environmental Protection Agency, Public Data for the Renewable Fuel Standard Data*, July 7, 2022, as reported by the Congressional Research Service on p. 2 of *The Renewable Fuel Standard (RFS): An Overview*, August 10, 2022
[90] https://afdc.energy.gov/laws/RFS
[91] https://www.federalregister.gov/documents/2022/12/30/2022-26499/renewable-fuel-standard-rfs-program-standards-for-2023-2025-and-other-changes
[92] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information

[93] The law asserts that clean hydrogen can be made using any renewable resource as a feedstock, including biomass, as well as with nuclear power or carbon capture and storage. The law also specifically aims to reduce the price of electrolytic hydrogen to $2/kg by 2026, which is in line with the Department of Energy Hydrogen Shot program that seeks to lower the cost of electrolytic hydrogen to $1/kg by 2031.[94]

- *The 2022 Inflation Reduction Act (HR 5376)*, which additionally provides a production tax credit for clean hydrogen that increases as lifecycle carbon intensity of the hydrogen production declines from 4 kg/CO2e per kg to zero kg/CO2e per kg. The law also includes an investment tax credit for clean hydrogen production facilities that do not opt for the production tax credit, as well as for qualifying biogas facilities.[95] Projects must start construction by December 31, 2024 to be eligible for the investment tax credit and before January 31, 2033 to be eligible for the production tax credit.

Design of credits for clean hydrogen and clean fuel production is currently under review by the Department of the Treasury and the Internal Revenue Service, and a public proceeding was opened in December 2022 to address among other issues, additionality, geographic boundary ("deliverability"), and time matching requirements.[96] The section in this document on Stakeholder Perspectives contains discussion of the various opinions shared on the docket on these issues.

Federal agencies also have renewable energy procurement targets with which they are required to comply. For example, Executive Order 14057 (2021) requires all US federal agencies to procure 100 percent carbon pollution-free electricity on a net annual basis by 2030. 50 percent of this total is subject to time matching and deliverability requirements, signaling a federal government interest in applying greater stringency in these areas. Specifically, this amount of carbon pollution-free electricity must be procured to match actual electricity consumption on an hourly basis and produced within the same regional grid where the energy is consumed. Federal agencies carry benefits, such as regulatory flexibility and geographic diversity, which make them good test beds to work out issues in preparation for full market readiness of emerging technologies.

Please refer to Table 2 for more details on federal renewable energy procurement laws.

State Renewable Gas Procurement Programs

Several states have passed laws in recent years requiring renewable gas procurement programs to be established that aim to increase the volume of renewable gas in the gas delivery system, in order to provide benefits such as reducing greenhouse gas emissions or lowering air pollution. Most of these programs include both biomethane and renewable hydrogen as eligible resources. California's program to date only includes biomethane, although state regulators are considering pathways for including renewable hydrogen.

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[93] See Subtitle B – Hydrogen Research and Development https://www.congress.gov/bill/117th-congress/house-bill/3684/text. Clean hydrogen is defined in this bill as hydrogen produced using renewable energy, including biomass, nuclear power, or natural gas with carbon capture and storage and that has a carbon intensity of ≤ 2 kg/CO2e per kg of hydrogen. Documents such as the *U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance,* September 22, 2022, suggest that the definition will be harmonized with that used in the Inflation Reduction Act.

[94] https://www.energy.gov/eere/fuelcells/hydrogen-shot

[95] See IRA Sections 45V and 48.

[96] https://www.irs.gov/pub/irs-drop/n-22-58.pdf

Some states, including California, Nevada, and Oregon, have mandated targets, while Minnesota has required establishing renewable gas procurement policies and regulations that support state greenhouse gas reduction targets that may or may not be tied to specific required procurement amounts.[97] New Hampshire's renewable gas program encourages voluntary procurement, as long as renewable gas does not exceed 5% of total gas volume delivered, and contracts are no longer than 15 years. RTCs managed by M-RETS are used in Oregon and California to represent environmental attributes of renewable gas purchased by gas utilities for compliance.

Please refer to Table 3 for more information on state renewable gas procurement programs.

State Low Carbon Transportation Fuels Procurement Programs That Include Renewable Gas

Three states in the western US – California, Oregon, and Washington – have adopted clean fuels procurement policies that include renewable gas. All three programs have mandatory carbon intensity reduction targets that tighten over approximately the next decade and use a book and claim system to track compliance.

Oregon has adopted requirements that RECs retired to claim carbon intensity in their clean fuel programs must meet Green-e certification standards, which contain stringent additionality requirements.[98]

Washington is phasing in additionality requirements for RECs used to claim carbon intensity, requiring starting in 2025 that RECs be generated from electric generators placed into service after 2023.[99] Washington also has stringent real-time matching requirements for RECs.

The California Air Resources Board (CARB) has issued guidance for additionality and deliverability for fuels produced with low carbon electricity.[100] Specifically, low carbon intensity electricity used as a transportation fuel to make hydrogen must be in addition to California RPS requirements (or local renewable requirements for electrolytic hydrogen produced out of state) and must meet CARB RECs retirement and reporting requirements to demonstrate additionality. Low carbon electricity used must also be supplied to the grid by a resource located within a California Balancing Authority (or local balancing authority for electrolytic hydrogen produced out of state). Alternatively, to show electricity generated from an out-of-state resource was supplied to the California grid, the low-CI electricity must meet the deliverability requirements of California Category 1 (bundled, within California Balancing Authority) RECs in the state RPS statute.[101]

Please refer to Table 4 for more information on state low carbon fuel procurement programs that include renewable gas.

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[98] Oregon Clean Fuel Standard **340-253-0470** (5)(a)

[99] p. 180, Washington Department of Ecololgy, *Concise Explanatory Statement Chapter 173-424 WAC, Clean Fuels Program Rule & Chapter 173-455 WAC, Air Quality Fee Rule*, November 2022

[100] https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/guidance/lcfsguidance_19-01.pdf

[101] See definition of California Category 1 RECs here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-compliance-rules-and-process/60-percent-rps-procurement-rules

Table 1-State Renewable Power Procurement Policies

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism [102]	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
AZ	Renew-able Energy Standard and Tariff (REST)	2006 Final Rules AAC R14-2-1801 et seq.	***2006** - 1.25% retail electricity sales must be generated from renewable resources ***2007** - 1.5% renewable with 5% from distributed resources, with annually increasing targets for both until: ***2012** - 3.5% renewable with 30% from distributed resources, with annual increasing target for renewables until: ***2025** - 15% with 30% from distributed resources *Note that from 2019-2021, all Arizona major utilities also committed to voluntarily achieve 100% carbon free electricity from renewables, hydropower, and nuclear energy by 2050.*	• Biogas derived from various pathway • Fuel cells using fuels derived from renew-able sources	• Bundled RECS delivered to state and acquired after 1997 (exceptions for incremental hydropower) • Note pre-2005 installations were eligible for multipliers for solar and in-state manufacturing	Eligible facilities must commence operation on or after January 1, 2005 (CA Pub Util Code Section 25741), with restrictions on hydropower that same online after 2005 and some municipal solid waste that came online after September 1996 (CA Pub Util Code § 399.12) •RECs must be bundled. •No more than 20% of an affected utility's Annual Renewable Energy Requirement may be met with RECs. •Eligible Renewable Energy Resources shall not include facilities installed before January 1, 1997.	Energy produced by eligible renewable energy systems must be deliverable to the state.	N/A	Penalties may be assessed for failure to comply (Sec. R14-2-815 of Renewable Energy Standard and Tariff)

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[102] Note that for simplicity, the term REC in this table is used for any type of credit representing one megawatt-hour (MWh) of electricity generated and delivered to the electricity grid from a program eligible energy resource. Some states include other alternative or clean resources that are not necessarily renewable or call their credit system by another name (e.g., clean energy credit or alternative energy credit).

Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	• Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
CA	Renew-able Portfolio Standards	SB 1078 (2002), SB 1122 (2012), AB 327 (2013), SB 350 (2015), SB 859 (2016), SB 100 (2018), SB 901 (2018), SB 1020 (2022)	***2013** - 20% of retail electricity sales generated from renewable resources ***2016** - 25% of retail sales ***2020** - 33% of retail sales ***2024** - 44% of retail sales ***2027** - 52% of retail sales ***2030** - 60% retail electricity sales ***2035** - 90% retail electricity sales from renewable and zero carbon resources ***2040** - 95% retail electricity sales from renewable and zero carbon resources ***2045** - 100% retail electricity sales from renewable or zero carbon sources *Note that CA climate policy also requires carbon neutrality economy wide by 2045, which will apply to all energy uses, not only retail electricity sales* ***Bioenergy specific targets* Starting in 2016:** Electrical corporations shall collectively procure, through financial commitments of five years, their proportionate share of 125 MW from existing bioenergy projects, primarily from byproducts of sustainable forestry in high hazard zones.	• Biogas, digester gas • Landfill gas • Bioenergy using byproducts of sustainable forest mgt	• RECs tracked by WREGIS, with lifetime of 3 years • Since 2011, CPUC has allowed tradeable, unbundled RECs (TRECS) to be used for compliance. • *For bioenergy only:* ·Bio-RAM - Reverse Auction Mechanism for large utilities to procure bioenergy from High Hazard Zones to mitigate wildfire (2016, 2018) ·Bio-MAT - Feed-In tariff for bioenergy: Starting in 2016, up to 250 MW bioenergy offered monthly or bi-monthly from Bio-MAT feed-in tariff program.	Unbundled RECs (Category 3) capped at: • 2010-2013: 25% of RPS requirement • 2014-2016: 15% • 2016 and after: ≤10% (PUC §399.16(c)(3))	• Since 2010, must be ≥75% from facilities with first point of interconnection within a California Balancing Authority (CBA) • ≤~15% of RECs allowed to be generated from out of state	For Category 1 RECs only: Electricity delivered to first point of connection within a CBA to meet requirement must be so done on an hourly or sub-hourly basis	N/A

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Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	• Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
CO	Renew-able Energy Standards	SB 252, SB 263	***2020** - 30% (IOUs), 20% for coops serving ≥100k meters, 10% for coops serving 40k-100k meters ***2050** - 100% of electricity from clean resources by 2050 for utilities serving 500k or more customers;10% or 20% for municipalities/electric coops depending on size; includes 3% distributed generation requirements for IOUs, 1% for larger rural coops, .75% for smaller rural coops. **Plus Interim targets*	• Synthetic gas produced by pyrolysis of waste • Landfill gas • Waste-water treatment • Anaerobic digestion • Fuel Cells using Renewable Fuels	RECs traded and tracked on the WREGIS system Compliance multipliers of 1.50 for electricity generated at a "community-based project" (others for projects installed prior to 2014-16)	N/A	N/A	N/A	N/A
CT	Renew-able Portfolio Standards	Public Act No. 18-50 (2018)	***2030** - 40% electricity sales from Class I renewable energy resources + 4% Class II + 4% Class III, with interim targets	Class I: • Fuel cells • Landfill methane • Biogas Class III: • CHP	Bundled and unbundled RECs, traded and tracked on NEPOOL GIS	N/A	N/A	N/A	3-month grace period (aka 5th Quarter) after which ACP of Class I and II: $55/ MWh, Class III: $31/MWh (DSIRE)
DE	Renew-able Portfolio Standards	SB 33 (2021)	***2035** - 40% electricity sales derived from renewable resources, including 10% carve out for solar Also includes aggregated generation of < 100 kW, or compliance via customer sited generation	• Fuel cell • Landfill gas • Biogas produced by anaerobic digestion	RECs tracked by PJM GATS - REC multipliers for solar and wind, including for local manufacturing and workforce	N/A	N/A	N/A	ACP: $25/MWh SACP: $150/MWh (DSIRE)

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Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
HI[103]	Renew-able Portfolio Standards	Act 272 (2001), SB 2474 (2004), HB 1464 (2009), HB 623 (2015), HB 2089 (2022), SB 3057 (2022)	***2010** - 10% of net electricity sales derived from renewable resources ***2015** - 15% ***2020** - 30% ***2030** - 40% ***2040** - 70% ***2045** - 100%	• Biogas (including landfill and sewage-based digester gas) • H2 produced from renewable energy source	No credit trading system. Compliance tracked by Hawaii Natural Energy Institute peer reviewed study every 5 years.	N/A	N/A	N/A	Utilities that fail to comply are subject to penalties.
IL	Renew-able Portfolio Standards	SB 2814 (2016), SB 2408 (2021)	***2025-26** - 25% of electricity utility sales derived from renewables by 2025-2026, with targets within the total for distributed generation, wind, solar, and 60% of total required by alternative electricity generators ***2030** - 40% renewable electricity procurement ***2040** - attempt to reach 50% renewable electricity procurement ***2050** - 100% of electricity utility sales derived from clean energy sources, which includes renewables, nuclear, and other zero carbon sources, such as hydrogen	• Biogas produced via anaerobic digestion • Hydrogen • Landfill gas	RECs, carbon emission credit, zero emission credit, or carbon mitigation credit Traded and tracked via M-RETS, PJM-GATS	N/A	Resources must be procured from facilities located in IL or states that adjoin Illinois. If resources are not available in IL or in states that adjoin Illinois, then they may be procured elsewhere.	N/A	Previously allowed. (Statute; Archive)

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103 Note that Hawaii also has a Renewable Hydrogen Program that required the state, from 2007-2010, to develop a plan to transition the island of Hawaii to a hydrogen-fueled economy and to extend the application of the plan throughout the State, e.g. by developing policies to advance hydrogen fueled vehicles and hydrogen infrastructure, including production, storage, and dispensing facilities.

Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
IN	Voluntary Clean Energy Portfolio Standard	IC-8-1-37, SB 251 (2011)	**2013-2018** - Average of 4% of total annual retail electricity to be supplied by clean energy, ≤30% of which can be met with "clean coal" technology, CHP, nuclear energy, natural gas that displaces electricity from coal, or net-metered distributed generation **2019** - Average of 7% **2025** ≥ 10%	• H2 • Bioenergy • Fuel cells (not specified that renewable gas is required) • CHP (any fuel)	Clean Energy Credits	N/A	50% of energy toward target must be produced in state	N/A	N/A
IA	Alternative Energy Law (AEL)	SF 380 (1983)	***105 MW** of total annual electricity sales from the state's two electric utilities combined must come from renewable resources	•Landfill Gas •Biogas via anaerobic digestion	None *(can only be used for renewable electricity production outside of AEL compliance)*	N/A	N/A	N/A	N/A
KS	Renewable Energy Standard	K.S.A. 66-1256 (2016), 66-1257 (2016), and 66-1259 (2015)	**2020** - 20% of utility peak electricity demand met with renewable resources	•Methane from landfills or wastewater treatment •Fuel cells using renewable H2	RECs based on capacity and tracked and traded by NAR Multiplier for renewable power facilities installed after 2000	N/A	N/A	N/A	N/A
ME	Renewable Portfolio Standards	S.P. 457 - L.D. 1494 (2019)	***2030** - 80% retail electricity sales from renewable resources, with interim targets ***2050** - 100% retail electricity sales from renewable resources, with interim targets *Note separate targets for heating/cooling.*	• Biogas via anaerobic digestion • Fuel cells (does not specify what type of gas)	GIS Certificates (similar to RECs) traded and tracked by NEPOOL-GIS[104] Multipliers for community-based energy projects	2008: 1% sales must be new capacity 2017 and after: 10% sales must be new capacity	Starting 2030: 30% of retail renewable electricity sales have to be delivered within the region	Specific goals for offshore wind	N/A

[104] Also traded are Thermal Renewable Energy Certificates for heating and cooling applications

Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
MD	Renew-able Energy Portfolio Standard	SB 516 (2019)	***2030** - 50% of retail electricity must procured from renewable resources	• Biogas/biomethane via anaerobic digestion • Fuel cell using renewable sources • Landfill gas	RECs traded and tracked by PJM-GATS	N/A	RECs must be derived from renewable electricity generated in in PJM (or designated offshore areas). PJM adjacent generation was eligible until 2011.		• Tier 1 - $40/MWh through 2016, then $37.50/MWh in 2017 and 2018, $30.00 in 2019 through 2023, declining to $22.35 in 2030 • Tier 2 - $15/MWh • Solar - $400/MWh in 2009 through 2014, $350 in 2015 and 2016, $195 in 2017, $175 in 2018, $100 in 2019 and 2020, $80 in 2021, $60 in 2022 through 2024, declining to $22.50 in 2030 and thereafter (PJM-EIS)
MA	Renew-able Portfolio Standard	H.4857 (2017-18)	***2030** - 40% of electricity sales, with and an additional 1% of sales each year thereafter, with no stated expiration date, plus requirements that a portion serve seasonal peak demand	• Fuel cells utilizing renewable fuels • Landfill gas • Biogas	RECs and Clean Peak Energy Certificates traded and tracked by NEPOOL-GIS w/ carve out for solar until 400 MW (~1% of total electricity) installed	N/A	N/A	N/A	Varies by year 2023 ACP: Class I: $40/MWh Class I Solar Carve Out: $330/MWh Class I Solar Carve Out II: $271/MWh Class II: $33.06/MWh (State of MA)

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Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
MI	Renew-able Energy Standard	Public Act 295 (2008), SB 438 (2016)	***2012:** Existing renewable energy baseline (Oct 2007-October 2008) plus 20% of the gap between baseline and 10% ***2013:** Existing renewable energy baseline plus 33% of the gap between baseline and 10% ***2014:** Existing renewable energy baseline plus 50% of the gap between baseline and 10% **2015-*2019** - 10% of retail electricity portfolio supplied by renewables ***2019-20** - 12.5% of retail electricity portfolio supplied by renewables ***2021** 15% of retail electricity portfolio supplied by renewables	• Landfill gas produced by municipal solid waste • Biogas via anaerobic digestion	RECs tracked and traded on MIRECS Multipliers for solar in service before 2017, non-wind peak suppliers, storage (more for peak), equipment produced in-state, in-state labor	N/A	N/A	N/A	N/A
MN	Carbon Free Standard	SF 4 (2023)	***2030** - 80% carbon free generation or procurement for public utilities; 60% for other electric utilities ***2035** - 90% for all electric utilities ***2040** - 100% for all electric utilities	• Landfill gas • Anaerobic digestion • Waste-water treatment • Renewable hydrogen	RECs which are tradeable between states, tracked by M-RETS	N/A	N/A	N/A	N/A
MO	Renew-able Energy Standard	Missouri Clean Energy Act (Proposition C)(2008)	***Starting in 2021** - 15% generation or purchase by electricity utilities must be from renewable energy resources, including 2% from solar	• Biogas • Pyrolysis/ thermal depolymer-ization • Fuel cells using renewable H2	RECs traded and tracked with the North American Renewables Registry	N/A	N/A	N/A	N/A

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Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
NH	Electricity Renew-able Portfolio Standard	RSA 362-F	***2025** - 25.2% purchase of or acquirement of RECs representing generation from renewable resources, with interim targets	H2 derived from biomass fuels, water, or methane gas if the methane gas energy output is in the form of useful thermal energy, provided unit began operation after January 1, 2013, and increases renewable energy output.	RECs traded and tracked by NEPOOL-GIS (in addition to PUC calculation of in-state net-metered resources that are not required to use RECs)	N/A	Generators must be in New England control area, or adjacent, if the power produced is delivered into the New England control area for consumption by New England customers.	N/A	Varies by year 2022 ACP: Class I non-thermal: $59.12/MWh Class I thermal: $26.86/MWh Class II: $59.12/MWh Class III: $36.36/MWh Class IV: $36.59/MWh (NH PUC)
NJ	Renew-able Portfolio Standard	AB 3723 (2018), AB 3455 (2015) SB 1925 (2012)	***2025** - 30% of electricity sold from Class I renewable resources ***2050** - 50% of electricity sold from Class I renewable resources	• Landfill gas • Anaerobic digestion • fuel cells using renewable fuels (All Class I)	RECs tracked and traded by PJM-GATS	Projects must be online 2003 or later to qualify	N/A	N/A	• ACP and Solar ACP vary • 2023 ACP $50 • Solar ACP set at rates ranging from $638/MWh in 2010 to $128/MWh in 2033; 2023 solar ACP is $228
NM	Renew-able Portfolio Standard	SB 43 (2004), SB 489 (2019)	***2030** - 50% total retail sales from renewable resources ***2050** - 100% total retail sales from carbon-free resources	• Fuel cells that use non-fossil energy • Anaerobic digestion • Landfill gas	RECs tracked and traded by WREGIS	N/A	N/A	N/A	N/A

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Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
NY	Clean Energy Standard	Climate Leadership and Community Protection Act, SB 6599 (2019)	***2030** - 70% renewable electricity procurement ***2040** - 100% carbon-free electricity procurement	Fuel cells that use non-fossil energy resource	RECs tracked by NYGATS and purchased from NYSERDA or another source.	A minimum percentage of eligible renewable generation must be newly added starting in 2016 to reach the following percentages of the total portfolio: 2017 0.6% 2018 1.1% 2019 2.0% 2020 2.84% 2021 2.04% 2022 5.61% 2023 8.20%	RECs associated with production from otherwise Tier 1 eligible RES resource (projects that came online in or after 2015) can satisfy Tier 1 RES obligations, if the resource is (i) physically located within jurisdiction of the NYISO or a control area adjacent to NYISO and (ii) the associated energy is consumed in NY per RES delivery requirement	N/A	ACP varies by year 2023 ACP: $31.89/MWh (NYSERDA)
NC	Renew-able Energy and Energy Efficiency Portfolio Standard (REPS)	SB 3 (2007)	***Starting in 2021** - 12.5% generation or purchase by electricity utilities must be from renewable energy resources. Out-of-state new renewable energy facilities shall not be used to meet more 25% of the RPS requirements, with an exemption for public utilities with <150,000 North Carolina retail jurisdictional customers as of 12/31/2006.	• Landfill gas • Renewable hydrogen	RECs traded by NC-RETS. Triple credit for RECs generated by the first 20 MW of a biomass facility located at a "cleanfields renewable energy demonstration park."	N/A	N/A	N/A	N/A

Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
OH	Renew-able Energy Portfolio Standard	SB 221 (2008), SB 310 (2014), HB 6 (2019)	***2026** - ≥ 8.5% of electricity sales from generation derived from renewable resources, with interim targets and compliance requirement ending in 2026	• Biologically derived methane gas • Fuel cells	RECs with a lifetime of 5 years, traded and tracked by M-RETS, PJM-GATS. RECs may continue to be purchased and traded after the RPS ends in 2026. Solar carve out ended in 2019 (OH PUC)	N/A	N/A	Eligibility requires generation to be within or delivered to the state.	Non-solar ACP varies by year 2022 non-solar ACP: $56.99/MWh (OH PUC)
OR	Renew-able Portfolio Standard and GHG Free Electricity Law	SB 1547 (2016), HB 2021 (2021), ORS 469A.145	**<u>2021 GHG Free Electricity Law</u>** ***2030** - 80% of retail electricity sales must be below baseline (2010-2012) GHG emissions level. ***2035** - 90 % below baseline emissions level. ***2040,** and for every subsequent year - 100% baseline emissions level **<u>2016 RPS Law</u>** ***2025** - 25% of large utility electricity demand met with renewables, Small utilities: 10% by 2025, Smallest utilities: 5% by 2025 ***2040** - 50% of large utility electricity demand met with renewables	Landfill and other types of biogas	·RECs tracked and traded by WREGIS ·	Until 2021, unbundled RECs could only meet 20% of large utility compliance obligation and 50% of large consumer-owned utility obligation, and starting in 2021, both can only use up to 20% unbundled RECs to meet compliance obligations. RECS related to net metering facilities and certain public utilities exempt from this limit.	N/A	N/A	ACP set by state PUC, per ORS 469A.180 and ORS 469A.200

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Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
PA	Alterna-tive Energy Portfolio Standard	Pennsylvania Act 213 (2004), Act 35 (2007), Act 129 (2008), Act 40 (2017), Act 114 (2020)	***2021** - 18% RPS from eligible alternative resources, including 10% from Tier I (new/ existing solar PV, solar-thermal energy, wind, low-impact hydro, geothermal, biomass, wood pulping and mfg. byproducts from energy facilities within state, biologically-derived methane , coal-mine methane, and fuel cells), 8% from Tier II (new and existing alternative fossil fuel resources, distributed generation, demand-side management, out of state facilities that produce electricity from wood pulping and manufacturing byproducts, large hydro, municipal solid waste). Carve outs for PV, to provide .5% of the electricity by 2021.	• Fuel cells • Biologically-derived methane gas	RECs managed by PJM-GATS	N/A	Electricity derived from wood pulping; manufacturing byproducts must be from in state to qualify as Tier I. As of 2017, solar PV must be connected to a PA EDC's transmission system within PA EDC's territory As of 2020, Tier II sources must be located within the state or local service territories	N/A	• Non-solar ACP of $45/MWh • Solar ACP varies – 200% of the average market value for solar RECs sold in the RTO (PA Code § 75.65, PJM-EIS)
RI	Renew-able Portfolio Standard (RI RES)	R.I. Gen. Laws Section 39-26-1-10 (2004), H7413A (2016) SB 2274 (2022)	***2033** - 100% retail electricity from renewable by 2033, with interim targets ranging from 4% to 9.5% increases per year	• Landfill gas • Fuel cells using renewable fuels • Anaerobic digestion	RECs managed by NEPOOL-GIS	N/A	N/A	RECS limited to 2 yr lifetime capped at 30% of current year's obligation	ACP varies 2023 ACP: $80.59 (RI RES)
SD	R.E. Conservation Portfolio Standard	HB 1123 (2008)	**2015** - 10% of retail electricity sales from eligible renewable or conserved energy resources	• Renewable hydrogen • Anaerobic digestion • Landfill gas • CHP	RECs tracked by state PUC	N/A	N/A	N/A	N/A

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Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
TX	Renew-able Portfolio Standard	SB 7 (1999)	***2015** - 5,880 MW (including voluntary target of 500 MW non-wind), with interim targets ***2025** - 10,000 MW, with interim targets *(2025 target achieved in 2009)*	Landfill gas	RECs administered by ERCOT (ended in 2019)	Renewable generation had to be installed after 1999; Opt out for lg. utility customers served by transmission voltage	N/A	N/A	Penalty of $50/MWh of deficiency for non-compliance (TX PUC Code §25.173)
UT	Renew-able Porfolio Standard (Goal)	SB 202 (2008)	***2025** - 20% of retail sales adjusted to total kWh minus kWh from nuclear, DSM, and fossil fuel with carbon sequestration	• Landfill gas • Biogas	• RECs tracked and traded by WREGIS • Multiplier for solar	N/A	Renewable facilities must be within the WECC boundary	N/A	N/A
VT	Renew-able Energy Standard	Act 56 (2015)	***2017** - Distribution utilities (DUs) must cover 55% of sales with eligible renewables, including 1% from new, local distributed generation, with a 3/5% increase thereafter until 2032. Also 2% equivalent of retail sales covered by "energy transformation" projects that do not generate electricity but reduce use of fossil fuels (e.g., EV charging, storage, home weatherization, etc.); smaller utilities have until 2019. ***2032** - DUs must cover 75% annual sales with eligible renewables, including 10% distributed generation. Additional 12% of energy met with energy transformation projects (10% for smaller utilities).	Methane gas and other flammable gases produced by the decay of sewage treatment plant wastes or landfill wastes and anaerobic digestion of agricultural products, byproducts, or wastes, or of food waste	RECs tracked and traded by NE-GIS	Distributed generation required to be new in compliance year and connected to a Vermont distribution or sub-transmission line	Qualifying facilities must be either in the distributed utility territory, or from plants whose energy is capable of delivery in New England	N/A	ACP varies; 2022 ACP: $66.94/MWh (ISO NE)

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Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
VA	Renew-able Portfolio Standard	56-585.2 H (2011) - repealed; HB 1526 (2020)	*2011-2020 voluntary RPS (repealed and replaced by mandated targets below)* ***2021** - 6% electricity generation from renewable resources for Phase I Utilities (IOU that, as of July 1, 1999, is not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002), 14% for Phase II Utilities (IOU not bound by such settlement), with interim targets until: ***2045** - 80% for Phase I Utilities, 100% for Phase II Utilities ***2050** - 100% for Phase I Utilities	Landfill gas Waste to energy *(law specifies no natural gas)*	RECs tracked and traded by PJM-EIS		• 2021 to 2024: Dominion and Appalachian Power may use RECs from any renewable energy facility located in VA or the PJM region. • 2025 and thereafter: ≥75% of RECs used by Dominion must be from RPS resources located in VA		2021 ACP: Renewables: $45/MWh Distributed Generation (<1 MW) - $75/MWh Increasing by 1% annually after 2021. (PJM-EIS)
WA	Renew-able Portfolio Standard and Conservati on	I-937 (Energy Independenc e Act), SB 5116 (2019)	***2020** - 15% of electricity retail sales of utilities serving >25k customers from renewable resources and cost-effective conservation (achieved) ***2045:** 100% of retail sales must come from clean electricity, with interim targets including retirement of all coal generation by 2025, carbon neutrality by 2030 some offsets allowed.	Renewable natural gas, renewable hydrogen	RECs traded by WREGIS	Facility must commence operation after March 31, 1999	Electricity must be delivered into Washington State to be eligible	Electricity from must be delivered into Washington State on a real-time basis. RECS bankable for 1 year for future compliance and may be used for prior year's compliance	Penalty of $50 per MWh shortfall (DSIRE)

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Table 1-State Renewable Electricity Procurement Policies (continued from previous page)

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement	Temporal Requirement for Delivery	ACP/Penalty
WV	Alterna-tive Energy Portfolio Standard	HB 3 (2009), HB 2001 (2015) - repealed HB 3	***2015-2019** - 10% of electricity sales from alternative (various unconventional fossil fuel pathways, pumped hydro, recycled energy) and renewable resources ***2025** - 25% of electricity sales from alternative and renewable sources **Targets can be adjusted or eliminated if the Commission finds alternative or renewable energy resources are not available to meet compliance requirements*	Biologically derived fuel including methane gas, ethanol not produced from corn, or biodiesel fuel; Fuel cells (not specified that must use renewable fuel)	RECs with multipliers for renewable energy generated in state or service territory, with an adder if located on a surface mine; Additional credits may be purchased to reach compliance targets ; Credits obtained via GHG reduction or offsets verified by Secretary of the Dept of Environmental Protection, as well as by certain demand-side management or efficiency projects	N/A	Alternative energy resource facility located within geographical boundaries of this state or within the service territory of a regional transmission organization, as that term is defined in 18 C.F.R. §35.34, that manages the transmission system in any part of this state	N/A	N/A
WI	Renew-able Portfolio Standard	Act 141(2005); s.196.378	***2010-2014** – increase renewable electricity retail sales 2% above baseline ***2015 and after** - 10% of retail electricity sales from renewable resources	Fuel cell technology (not specified that must use renewable fuel)	·RECs tracked and traded by M-RETS	2006-2009: Maintain baseline 2010-2014: increase renewable percentages to 2% above baseline. 2015 and after: Renewable percentages of 6% above baseline	Renewable electricity generated must be delivered to Wisconsin customers.	N/A	N/A

Table 2- Federal Renewable Gas Procurement Programs

Policy/Program	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	Deliverability Requirements	Time Matching Requirements
Federal Renewable Fuel Standard	***Out to 2022**: 36B gal. renewable fuel derived from renewable biomass or from a biointermediate produced from renewable biomass and that, unless exempt, reduces lifecycle GHG 20%-60% below the petroleum baseline, to replace or reduce petroleum fuels, heating oil or jet fuel. **2023-2025:** EPA has proposed additional targets to increase total renewable fuel volumes by 2.05B gal. to 22.68B gal	• Renewable CNG • Renewable LNG • Renewable Electricity produced from biogas from landfills • Anaerobic digesters • Biogas from cellulosic components of biomass processed in other waste digesters (EPA). • These renewable gas pathways must meet a 60% GHG reduction below baseline petroleum fuel	Renewable Identification Numbers (RINs) with penalties assessed by EPA for compliance violations	N/A	N/A
Clean Hydrogen Production Tax Credit	Aligned with federal goals laid out in the Infrastructure Investment and Jobs Act to reduce the cost of electrolytic H2 to \$2/kg by 2026, and the US DOE Hydrogen Shot goal to reduce the cost of clean H2 to \$1/kg by 2031.	Qualified Clean H2 (i.e., H2 produced through a process that • results in lifecycle GHG emissions rate of ≤ 4 kg CO2e/kg H2 • is produced in US • is in ordinary course of business or trade for the taxpayer, and production, sale, or use of which is verified by an unrelated party • is produced in facilities that start construction before 1/31/2033	Production tax credit (PTC) with rules pending	N/A	N/A
Federal Energy Credit	Aligned with federal electrolytic/clean H2 cost reduction goals cited above	• Biogas property system that converts biomass to gas containing at least 52% methane for sale or productive use and not for combustion • Clean H2 facilities that do not use PTC • Projects that start construction after 12/31/2024 are ineligible.	Investment tax credit (ITC) with rules pending	N/A	N/A
Regional Clean Hydrogen Hubs	• *\$8 billion to fund at least 4 regional clean H2 hubs • *Reduce cost of clean H2 to ≤\$2/kg over course of ~10 yr program	Clean hydrogen produced using renewable energy, nuclear power, or natural gas with carbon capture and storage with a carbon intensity of ≤ 2 kg/Co2e per kg/H2.	Grant program with awards pending	N/A	N/A
Federal Agency 100% Carbon-Pollution Free Electricity Procurement	• **2030** - 100% carbon pollution-free electricity on a net annual basis including 50 percent 24/7 carbon pollution-free electricity			24/7 carbon-pollution free electricity must be produced within same regional grid where energy is consumed.	24/7 carbon pollution-free electricity must be procured to match actual power consumed

Table 3 – State Renewable Gas Procurement Programs

State	Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement
CA	Biomethane Procure-ment Program	SB 1383 (Lara, 2016), SB 1440 (Hueso, 2018)	***2025** - sufficient biomethane to divert 8M tons of organic waste from landfills ***2030** - 75.5 MMBtu (72.8 Bcf) biomethane annually (~12.3 % of total annual 2020 statewide gas IOU core customer consumption). *Targets intended to further state targets to divert organic waste in landfills, reduce short lived climate pollutants (reduction in methane by 40%, hydrofluorocarbon gases by 40%, and anthropogenic black carbon by 50% below 2013 levels by 2030).*	• Biomethane from source other than dairy operations, as long as it meets program cost effectiveness criteria • May be substituted by well gas, if this is a cost effective means of reducing short lived climate pollutants	• Joint Utility Biomethane Procurement Plan • EAs from contracted renewable fuel source of which procuring gas utility must maintain exclusive ownership to avoid double counting • Verifiable renewable thermal certificates traded and tracked via M-RETS	Bundled renewable thermal certificates only	Renewable gas must be delivered to and environmentally benefit CA
MN	Natural Gas Innovation Program	HF 6 (2021)	***2025:** Establish policies and regulations to support innovative gas resources helping to meet or exceed state GHG emission goals of 30% below 2005 levels ***2050:** Do same to reduce GHG 80% below 2005 levels	• Biogas • Renewable natural gas • Power-to-hydrogen • Power-to-ammonia • District energy	Framework to calculate lifecycle GHG intensities of each innovative resource plus potentially other policies to be determined by state PUC.	N/A	N/A
NH	Procure-ment of Renewable Natural Gas	SB 424 (2022)	Maximum 5% of gas utility total volume delivered, maximum 15-year contracts	• Biogas upgraded to meet gas pipeline quality standards • Fuel produced by biomass gasification processes • H2 derived from clean energy • Methane derived from biogas, H2 and/or carbon oxides derived from renewables or waste CO2.	Utilities may submit RFPs, plus pursue cost recovery mechanism at state PUC.	N/A	N/A

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Table 3 – State Renewable Gas Procurement Programs (continued from previous page)

State	Policy/ Program	Primary Authorizing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types	Regulatory Credit Mechanism	New Capacity Requirement	Geographic Requirement
NV	Renewable Natural Gas (RNG) Use and Cost Recovery Authorization	SB 154 (2019)	***January 1, 2025 -** ≥1% retail sales ***January 1, 2030** - ≥2% retail sales ****January 1, 2035** - ≥3% retail sales	Procurement of or investment in infrastructure for processed biogas, P2G / electrolysis, so long as the renewable gas contains certain EAs and the meets quality standards applicable to the natural gas pipeline into which the gas will be injected.	Rules may be made by state PUC to allow public utilities or their customers to purchase renewable gas to use or sell, whether or not the gas has EAs, or to participate in a state or federal renewable energy program/ project, if doing so consists of the purchase or sale by the public utility of gas or EA; and reduces the cost of gas produced from a renewable gas facility to the customers of the public utility.	N/A	N/A
OR	Renewable Natural Gas Program	SB 98 (2019)	**2020-24** - 5% **2045-50** - 30%	• Biogas upgraded to meet gas pipeline quality standards • Fuel produced by biomass gasification processes • H2 derived from clean energy • Methane derived from biogas, H2 and/or carbon oxides derived from renewables or waste CO2.	"Renewable Thermal Certificate" (RTC), which represent environmental attributes based on CI, which are issued, tracked, traded, and retired through the M-RETS electronic system	N/A	N/A

Table 4 – State Low Carbon Fuel Procurement Programs that Include Renewable Gas

State	Policy/ Program	Primary Authoriz-ing Law(s)	Target(s) *Mandated	Eligible Renewable Gas Types I	Regulatory Credit Mechanism	Additionality Requirements	Geographic Requirements	Temporal Requirements	Penalty/ ACP
CA [105]	Low Carbon Fuel Standard (LCFS)	AB 32 (2006) Scoping Plan	***2018** – H2 dispensed at stations receiving H2 Refueling Incentive (HRI) capacity credits must be produced using 40% RPS eligible renewables ***2030** – CI of dispensed transport fuels in CA must be 20% below 2010 baseline, based on an annual declining target.	• RNG • H2	Book and claim (Credits based on CI that are bought and sold to comply with the Clean Fuels Standard)	Per LCFS Guidance 19-01, low-CI electricity used as transportation fuel to make H2 must be in addition to CA RPS requirements (or local renewable requirements for electrolytic hydrogen produced outside of CA)	Per LCFS Guidance 19-01, low-CI electricity used must be supplied to grid by a resource located within a CA Balancing Authority (or local balancing authority for electrolytic hydrogen produced out of state). Alternatively, to show electricity generated from an out-of-state resource was supplied to the CA grid, the low-CI electricity must meet the deliverability requirements of California PUC code section 399.16, subdivision (b)(1) which details the deliverability requirements for Portfolio Content Category 1 RECs.	Book-and-claim accounting for low-CI electricity and for biomethane may span only three quarters. i.e. If a quantity of low-CI electricity (and all associated EAs, including a beneficial CI) is supplied to the grid in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to grid electricity used as a transportation fuel or for electrolytic hydrogen production no later than the end of the third calendar quarter.	Penalty commensurate with deficit fined for compliance failure
OR	Clean Fuels Standard	SB 324 (2015)	***2025** - 10% reduction in average CI from 2015 levels ***2030** - 20% reduction ***2035** - 37% reduction	RNG (Renewable H2 under consideration)	Book and Claim	Requires that RECs ret	RECs must be generated from facilities located in the WECC[107]	N/A	Penalty assessed in proportion to environmental benefit lost by compliance failure (OR SOS/DEQ)

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[105] Note that per SB 1505, California also requires 33.3% of hydrogen fuel dispensed for transportation to come from renewable resources, which largely been assured by the eligibility criteria and the grant agreements developed through the Energy Commission's grant solicitation process (p. xvii, *2019 Annual Evaluation of Fuel Cell Electric Vehicle Deployment & Hydrogen Fuel Station Network Development*, CARB). This target has been surpassed, as most recently reported in the CARB 2022 Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Cell Station Network Development.

[106] Oregon Clean Fuel Standard 340-253-0470 (5)(a)

[107] Oregon Clean Fuel Standard 340-253-0470 (5)(c)

Table 4 – State Low Carbon Fuel Procurement Programs that Include Renewable Gas (continued from previous page)

WA	Clean Fuels Standard	HB 1091 (2021)	***2034** - 20% reduction below 2017 levels in avg. CI	• Bio-CNG • Bio-LNG • Bio-L-CNG • Alt. jet fuel • Renew-able propane • Renew-able LPG.	Book and Claim	Additionality requirements for RECs used to claim carbon intensity, requiring starting in 2025 that RECS be generated from electric generators placed into service after 2023.[108]	RECs must be generated from facilities located in the western electricity coordinating council[109]	State requires real-time matching for RPS, unclear how this will impact clean fuels standard rules	N/A

[108] p. 180, Washington Department of Ecololgy, *Concise Explanatory Statement Chapter 173-424 WAC, Clean Fuels Program Rule & Chapter 173-455 WAC, Air Quality Fee Rule*, November 2022
[109] WAC 173-424-630 (5)(c)