Los Angeles Department of Water & Power

BUILDING A STRONGER L.A.



February 23, 2024

Ms. Lily Batchelder
Assistant Secretary for Tax Policy
United States Department of the Treasury
1500 Pennsylvania Avenue NW, Room 3120
Washington, DC 20220

Mr. Douglas W. O'Donnell
Deputy Commissioner for Services and Enforcement
Internal Revenue Service
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*Submitted via Electronic Mail and the Federal eRulemaking Portal at: www.regulations.gov*

Dear Assistant Secretary Batchelder and Deputy Commissioner O'Donnell:

**Subject: REG-117631-23 Section 45V Credit for Production of Clean Hydrogen**

The Los Angeles Department of Water and Power (LADWP) is the largest municipal utility in the United States (US) and is aiming to operate a 100 percent carbon-free energy system by 2035.[1] LADWP continues to make progress towards this goal, with 53 percent of LADWP's retail sales in 2022 served by carbon-free energy resources and its power portfolio will be completely coal-free by July 1, 2025.[2] Hydrogen is a critical component of LADWP's decarbonization strategy,[3] and LADWP is developing and constructing both in-basin and regional hydrogen fueled resources to facilitate its decarbonization efforts.

[1] LADWP provides safe and reliable water and power to 4 million residents in the City of Los Angeles . It is a vertically integrated utility and owns a vast power generation, transmission, and distribution system that spans five Western States. LADWP's net maximum generation capacity is 10,730 MW. In Fiscal Year 2022-23, LADWP supplied 21,600 gigawatt-hours (GWh) to more than 1.6 million electric service customers.
[2] 35.6 percent of power resources in 2022 were from eligible renewable resources (primarily, geothermal, solar and wind).
[3] LA100: The Los Angeles 100 Percent Renewable Energy Study and LA100 Equity Strategies, NREL, March 2021 and November 2023, available at https://www.nrel.gov/analysis/los-angeles-100-percent-renewable-study.html

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LADWP, as the largest participant in the Intermountain Power Project (IPP)[4], is playing a leading role in the transformation of an existing coal-fueled electric generating facility in Millard County, Utah into an 840-megawatt (MW) hydrogen-capable gas turbine combined-cycle power plant (IPP Renewed).

As part of IPP Renewed, Advanced Clean Energy Storage I, LLC, is developing an advanced hydrogen production and storage facility  that will produce and store clean hydrogen for use by IPP Renewed (ACES Facility or ACES I).

Upon commercial operation in 2025, IPP Renewed will be capable of blending up to 30 percent clean hydrogen produced at the ACES Facility blended with natural gas. IPP Renewed is intended to be transformed into a zero-carbon electric generating facility using 100 percent clean hydrogen.

LADWP is submitting this comment letter to request guidance from the United States (US) Department of the Treasury (Treasury) regarding the proposed regulations under Section 45V, Credit for Production of Clean Hydrogen that were published on December 26, 2023 (45V Rule).

These comments have been prepared in coordination with the Brattle Group and Berkeley Research Group (BRG) to ensure alignment with the goal of Section 45V—to support decarbonization through the use of clean hydrogen. Supporting whitepapers from both the Brattle Group and BRG are enclosed hereto as Exhibit A (BRG Whitepaper) and Exhibit B (Brattle Whitepaper).

The ACES Facility is a foundational clean hydrogen project and will be one of the world's largest renewable energy storage facilities, providing a complete end-to-end solution contributing to grid stabilization and reduction of renewable energy curtailments. The ACES Facility can be readily expanded to have over 100 times the storage capacity of ACES I with additional hydrogen conversion capacity.

ACES I is anticipated to be operational near the end of 2024. It will therefore be one of the first large-scale facilities to claim the Section 45V credit.

ACES I is a critical component of LADWP's commitment to decarbonize its electricity supply by 2035. The challenge of decarbonizing LADWP's operations is closely tied to its geography and load density. LADWP's load is in the Los Angeles (LA) Basin which is densely populated and surrounded by mountains with highly limited space for local renewable generation or battery storage. LADWP owns a large amount of transmission connecting LA to power resources from other parts of California and other western states but there are still significant transmission constraints to send power into the basin.

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[4] IPP is owned by the Intermountain Power Agency, a political subdivision of the State of Utah organized in June 1977 pursuant to The Utah Interlocal Co-operation Act and under the Intermountain Power Agency Organization Agreement, dated May 10, 1977.

Therefore, to decarbonize, LADWP needs to build renewables in areas that can be accessed by LADWP's current and future transmission along with a significant build of battery energy storage and hydrogen energy storage. Without the hydrogen energy storage provided by the ACES Facility, there is no feasible mechanism to store excess renewable energy between seasons or years and to remain carbon neutral during extended high demand or low renewable events.

LADWP serves a disproportionate share of residents living in low income and disadvantaged communities. Specifically, more than 2.1 million Angelenos, or 54 percent of residents, reside in disadvantaged communities that suffer from a combination of economic, health, and environmental burdens.[5]

LADWP is committed to transitioning to a clean energy future in an equitable manner. Our goal is for all customers to benefit from carbon-free technologies, programs, and policies so that no one is left behind. To ensure that LADWP's decarbonization efforts do not unduly impact LADWP's ratepayers, LADWP is seeking a full capture of all available tax credits.

These comments are divided into the following sections.

1. An overview of the ACES Facility and its role in decarbonizing LADWP and the western electrical generation system.

2. Comments on how Treasury can align the three qualifying attributes of energy attribute certificates (EACs)—incrementality, deliverability and temporal matching (EAC Criteria)—with the current geographic, market, and technical reality of the western electrical systems to drive decarbonization.

3. Technical comments on the language and interpretation of the rules to address potential ambiguity.

4. Policy proposals in response to specific requests from Treasury, including proposals to use location marginal pricing and location marginal emissions as substitutes for incrementality and temporal matching.

## I. <u>OVERVIEW OF THE ACES FACILITY IN DECARBONIZING THE WESTERN ELECTRICAL GENERATION SYSTEM</u>

IPP currently consists of a two-unit coal-fueled (1,900 gross megawatt nameplate) steam-electric generating plant constructed in 1987. IPP is the largest coal-fueled generation station in Utah (and one of the largest in the Western Electricity Coordinating Council [WECC], generating an average of more than 6.5 million megawatt hours of energy each year. The energy is delivered primarily to 35 municipal electric utilities and rural electric cooperatives principally serving Utah and Southern California.

ACES I is an energy storage and conversion facility that is under construction consisting of (i) a 220 MW bank of electrolyzers capable of splitting water into hydrogen and oxygen and (ii) two salt caverns capable of storing 4.5 million barrels of hydrogen (over 300 gigawatt hours of clean

[5] According to the California Office of Environmental Health Hazard Assessment's CalEnviroScreen tool.

energy) on a long-term, seasonal basis. The ACES Facility will be located adjacent to and across a state highway from, the IPP site.

The electrolyzers, operating at full capacity, are anticipated to generate 3,754 kg of hydrogen an hour. Once operational this year, ACES I will provide more than 100 times the current storage capacity offered by chemical batteries in the United States.

The electric energy required for production of hydrogen at the ACES Facility will be sourced from the electric grid.

The IPP Renewed Project and ACES I are interconnected to the LADWP balancing authority area, with electric energy moved from the IPP switchyard to the LA Basin on the Southern Transmission System (STS) a 2,400 MW HVDC transmission line. However, the area around the facility is located in the PacifiCorp balancing authority area. The STS line is bidirectional (energy can flow from IPP to the LA Basin, or from the LA Basin to IPP). To continue to operate the line effectively, and to continue balancing renewable energy from the intermountain west on an hourly and seasonal basis, LADWP plans to use ACES I in tandem with IPP Renewed to deliver firm energy for its customers in the LA Basin.

## II. REFINEMENTS TO THE EAC CRITERIA

With the 45V Rule, Treasury has determined that a taxpayer may use EACs to document the purchased electricity inputs for purposes of determining the taxpayer's applicable greenhouse gas (GHG) emissions under the most recent Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) model if: (1) "the taxpayer acquires and retires a qualifying EAC … for each unit of electricity that the taxpayer claims from such source"[6] and (2) that the electric generating facility underlying the EAC has certain attributes—incrementality, deliverability and temporal matching. Proposed Reg. § 1.45V-4(d)(1).

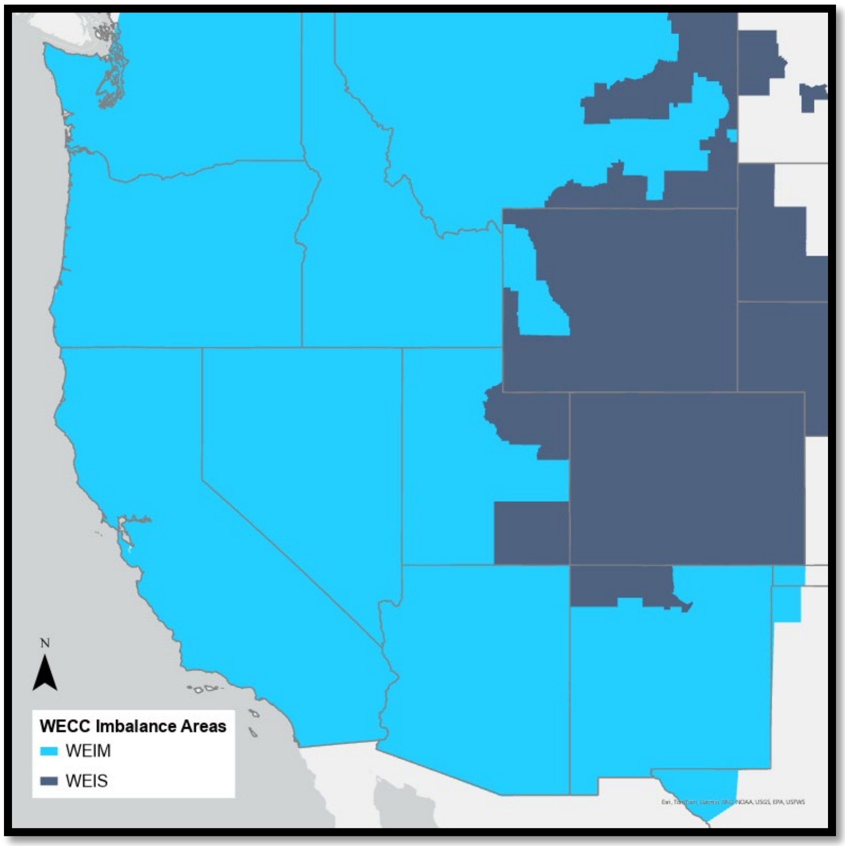
LADWP broadly supports the EAC Criteria and appreciates the exhaustive work and analysis by Treasury and the Department of Energy (DOE) to develop the EAC Criteria. The concept of, the EAC Criteria is an effective means of minimizing induced grid emissions from hydrogen production. The following comments are made in the context of LADWP's deep technical expertise and active procurement of EACs to allow for ACES I to be energized with 100 percent carbon-free energy. With these comments LADWP is proposing additional alignment between the EAC Criteria and the technical realties of WECC to further drive decarbonization.

### (A) WECC should be treated as two deliverability regions based on existing market structure consistent with the rationale for the other deliverability regions.

LADWP urges Treasury to treat WECC as two deliverability regions based on the contours of the Western Energy Imbalance Market (WEIM) and the Western Energy Imbalance Service market (WEIS), which is approximated in the figure below. Such an approach would align WECC based on regional markets in the same way that DOE has created the other deliverability regions. The appropriateness of a two-region deliverability approach to WECC is outlined in the enclosed Exhibit C (WECC Region Proposal) and supported by reference in the Brattle

[6] Section 45V Credit for Production of Clean Hydrogen, 88 Fed. Reg. 89,248 (Dec. 26, 2023).

Whitepaper. A proposed grouping of balancing authority areas consistent with the process outlined in the DOE 45VH2-GREET User Manual is also included in the WECC Region Proposal.[7]




The four deliverability region approach to WECC presents a specific problem for ACES I and LADWP.

Though LADWP's load is concentrated in the LA Basin, LADWP (like other west coast utilities) depends on electric energy from throughout WECC and has an established transmission system that moves electric energy into the LA Basin from each of the four deliverability regions. LADWP's transmission assets give it direct access to each of these regions, making electric energy in these regions "deliverable."

Since ACES I is in LADWP's balancing authority area it would seem that ACES I would be in the California region—even though it is physically in Utah.

[7] U.S. Department of Energy, Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathway using 45VH2, GREET 2023, December 2023, p. 23 (available at https://www.energy.gov/sites/default/files/2023-12/greet-manual_2023-12-20.pdf).

LADWP faces a significant planning challenge for serving customer loads in the LA Basin and is actively planning on procuring renewable resources in a very broad geographic footprint in order to maintain reliability and maximize the use of its transmission assets (and procure inputs to ACES I). It is critical that the deliverability regions reflect the reality of system operation for LADWP and others in the WECC. The transmission constraints into the LA Basin and how these impact system operational requirements are explained in greater detail in the BRG Whitepaper Section 2.

**(B) If four deliverability regions are retained for WECC, additional clarity is needed as to the geography of the regions.**

If Treasury maintains four deliverability regions for WECC, the definition of regions should be modified to indicate regions are a function of the balancing authority area. Treasury should also clarify how pseudo-tied resources interact with the deliverability geography and LADWP requests that pseudo-tied resources be considered per-se deliverable to the balancing authority area they are electrically interconnected to.

The ambiguity around geography is a function of the definitions in the 45V Rule and the integrated maps. Under the 45V Rule, "region" is defined to mean a "region derived from the National Transmission Needs Study that was released by the DOE on October 30, 2023" (DOE Needs Study).[8] Proposed Reg. § 1.45V-4(d)(2)(vi).

It appears that the map on page iii of the DOE Needs Study is the appropriate map to determine derived regions for purposes of Proposed Reg. § 1.45V-4(d)(2)(vi).

In contrast to the text of the actual proposed regulations in the 45V Rule, the preamble provides that "[t]he DOE has mapped the DOE Needs Study regions to actual balancing authorities" in the GREET User Model.[9] The GREET User Model then provides a list of applicable balancing authorities by region and a map which differs from the map contained in the DOE Needs Study.[10] For instance, portions of northern California are contained in the Mountain region in the DOE Needs Study Map, but are in the California or Northwest region in the GREET User Model Map. Both maps are provided below for reference.

This issue is of critical importance for LADWP and ACES I as the ACES Facility is physically interconnected to the LADWP balancing authority area, which would place it in the California region under the GREET User Model approach. However, under Proposed Reg. § 1.45V-4(d)(2)(vi) ACES I would seem to be located in the Mountain region, because this is where the ACES Facility is located. Clarity here is critical so that EACs that are anticipated to be procured for ACES I can be procured from the correct region.

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[8] Section 45V Credit for Production of Clean Hydrogen, 88 Fed. Reg. 89,249 (Dec. 26, 2023).
[9] Section 45V Credit for Production of Clean Hydrogen, 88 Fed. Reg. 89,228 (Dec. 26, 2023).
[10] Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2023, Department of Energy, available at https://www.energy.gov/sites/default/files/2023-12/greet-manual_2023-12-20.pdf (the "**45VH2-Greet Manual**").

**DOE Needs Study Region Map**

**Department of Energy** | October 2023


*Source: National Renewable Energy Laboratory.*

**GREET User Manual Map**

Production Pathways using 45VH2-GREET 2023

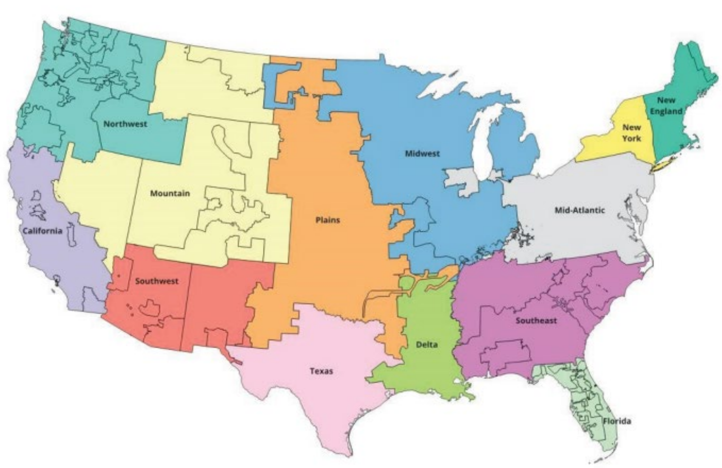


**Figure 2. 45V Regions Based on Needs Study**

**(C) Temporal matching should be implemented region by region based on technical feasibility with sufficient notice to give markets time to synthesize.**

Under Proposed Reg. § 1.45V-4(d)(3)(ii), beginning January 1, 2028, an EAC will not be "eligible" unless it is "temporal matched" in that the EAC must be generated in the same hour that the taxpayer's hydrogen production facility uses electricity to produce the hydrogen.[11]

The concept of temporal matching is reasonable so long as it is technologically feasible and compatible with existing market structures. The ACES Facility is a critical component of LADWP's decarbonization strategy and is intended to operate as a giant grid battery, whereby it would acquire renewable energy to power its electrolyzer when the system is flush with renewables and store such energy—in the form of hydrogen—for later use on a seasonal basis. Under this strategy, LADWP would procure the renewable energy for ACES I through a variety of arrangements, including participation in regional markets. If such markets cannot trade with sufficient granularity and liquidity to meet EAC Criteria then LADWP's ability to utilize ACES I will be significantly limited.

The January 1, 2028, start date for hourly matching is based on the assumption that hourly tracking can be developed within four years. However, that assumption is based on a July 25, 2023, report from the Center for Research Studies (CRS Report), which indicates that the Western Renewable Energy Generation Information System (WREGIS) in particular has significant reservations about a four year hourly matching time horizon. The CRS Report suggests that instead of committing to a four-year horizon, that five years was actually more likely and still required three prerequisites: full state agency buy-in, clear instructions from federal or state agencies, and funding.[12] To date, none of these prerequisites have occurred, and it is unlikely that funding or stakeholder buy-in exists until there is significant expansion of the hydrogen industry in WECC. WREGIS has made no moves to implement hourly matching and it is unlikely that any serious endeavor would begin until the proposed 45V rules are finalized.

To address these issues, LADWP proposes that the start date for temporal matching be determined region by region based on the region's adoption of temporal matching technology and that temporal matching be further delayed by 12-24 months after the implementation of temporal matching by the qualified registry to allow for the market mechanisms to be integrated into temporal matching.

Additional detail on the technical barriers to temporal matching is provided in the BRG and Brattle Whitepapers.

**(D) Incrementality should be delayed or grandfathered for first mover projects.**

Proposed Reg. § 1.45V-4(d)(3)(i)(A) requires that the qualifying EAC come from a facility that has a commercial operation date that is no more than 36 months before the hydrogen production facility for which the EAC is retired was placed in service. For purposes of ACES I, with a projected commercial operation date in Q4 2024 the EAC would have to originate from a

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[11] Section 45V Credit for Production of Clean Hydrogen, 88 Fed. Reg. 89,249 (Dec. 26, 2023).
[12] CRS Report, page 26.

facility that had a commercial operation date after Q4 2021. This three-year look back is restrictive and penalizes entities like LADWP who have been aggressively moving towards decarbonization. It is also inconsistent with project development cycles.

To address this issue while ensuring effective decarbonization Treasury should allow for early mover electrolyzer projects to be excluded from the incrementality criteria if the project achieves commercial operation by August 2025—three years after the passage of Section 45V. Such a rule would be consistent with the other transitory rules, such as the phasing in of the apprenticeship and domestic content requirements that Treasury has adopted.

**(E) Alternatively, incrementality should be delayed until the Department of Energy can publish more granular "grid mixes."**

45VH2-GREET allows for a User Defined Mix, which integrates EACs retired by the taxpayer and the "grid mix" for the particular NERC region that the hydrogen production facility is located in. Under 45VH2-GREET a taxpayer gets a "GHG handicap" based on the background GHG intensity of the taxpayer's NERC region. DOE has indicated that "further version of the model may also include emissions factors corresponding to the regions in the (DOE Needs Study)".[13]

GHG emissions associated with the "grid mix" differ materially from region to region and balancing authority area to balancing authority area. To address this differential, Treasury should delay the incrementality requirement until a grid mix has been developed for each DOE region. Alternatively, Treasury should allow taxpayers to use a "grid mix" for the taxpayer's specific balancing authority area where the electrolyzer is located based on a protocol established by the Department of Energy. The BRG Whitepaper contains additional details on the feasibility and practicality of calculating a discrete grid mix for each balancing authority area or deliverability region.

Treasury should also confirm that 45VH2-GREET allows taxpayers to blend EACs and the relevant balancing authority area's (or deliverability region) "grid mix" to determine the hydrogen production facility's applicable GHG emissions in creating a User Defined Mix.

**(F) Allow expanded hydrogen production facilities to use the incrementality window of the initial facility.**

Treasury should provide a facility expansion rule so that expanded capacity at existing hydrogen production facilities could qualify for the same incrementality look-back as the original facility. The purpose of such rule would be to allow expanded hydrogen production facilities to count Section 45V credits that are counted under the original operation date of the facility without having to differentiate between the original facility and the expanded facility and to allow for integrated planning of the facility's renewable energy pipeline.

The ACES Facility will likely expand in the future to include additional electrolyzers. An expansion rule would allow the new electrolyzers to use the same qualifying energy as the first installed electrolyzers. As such, we request that Treasury allow for such expansion but create

[13] The 45VH2-Greet Model, P. 7.

clear safeguards that the expansion must be directly interconnected with the existing infrastructure of the original facility.

## III. GENERAL COMMENTS ON THE PROPOSED REGULATIONS

### (A) Define the term "placed in service", clarify that the "placed in service" date occurs only after the facility has completed operational testing and allow for a one-year delay window.

The Section 45V credit is available to a qualifying facility during the 10-year period that begins on the date the facility is originally "placed in service."

Treasury should define the term "placed in service" for purposes of the 10-year credit period such that "placed in service" date does not occur until a facility's operational testing is completed. This clarification will allow a facility to claim, and benefit from, the full Section 45V credit once it begins normal operations. This is particularly important for the ACES Facility given that it will be the first large scale commercial effort to pair hydrogen production and storage with a connected generation resource. It is conceivable that the integration of these three processes and technologies will require refinements and associated conditioning and testing.

Treasury should also allow for a facility to delay its placed in-service date for the 10-year credit period by one year to avoid requiring a precise factual determination of the placed in-service date and to provide operational flexibility for the start-up of new hydrogen production facilities. If Treasury maintains the three-year incrementality window, that window should be based on the first production of hydrogen by the facility and not delayed by the optionality for the placed in-service date requested in this section.[14]

Treas. Reg. §§ 1.46-3(d)(1)(ii) and 1.167(a)-11(e)(1)(i) provide the general definition of the term "placed in service." These regulations define the term as the date on which a facility or other property is placed in a condition or state of readiness and availability for a specifically assigned function. This general definition has been applied to other code sections that do not explicitly define the term, and it should be explicitly applied to Section 45V as well.[15]

For purposes of Section 45V, Treasury should further clarify that for a hydrogen production facility, this will generally be when all operational testing is completed.

A fact and circumstances test creates ambiguity as to when the 10-year credit period ends. This problem is further compounded given the extensive testing and conditioning that is required for new hydrogen production technologies in coordination with the complexities of storing a gas. For example, hydrogen will need to be produced and pumped into storage for weeks or months before the storage facilities reach pressures high enough for hydrogen to be withdrawn and combusted; this makes it exceedingly difficult to state exactly when the conversion and storage

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[14] The last utility scale renewable resource that LADWP was able to secure was Red Cloud Wind (331 MW) in New Mexico which was commissioned in December of 2021, placing this resource on the bubble for the three-year incrementality window for ACES I.

[15] See, PLR 144688-12 applying the definition to section 48 and Rev. Proc. 2007-65 applying the definition to Section 45.

facility is "placed in service." In order to avoid these issues, Treasury should allow for hydrogen production facilities to select a placed in-service date that is within a one-year period of the facility's first production of commercial quantities of hydrogen. Such a transition rule will further allow facilities additional lead time to align EAC purchasing and compliance strategies with the evolving Section 45V rule framework.

Accordingly, Treasury should define "placed in service" for the purpose of section 45V using the general definition of "placed in service" found in Treas. Reg. §§ 1.46-3(d)(1)(ii) and 1.167(a)-11(e)(1)(i) to indicate that for purpose of section 45V the "placed in service" date occurs only after a facility completes all operational testing and provide a year election window for a facility.

**(B) Clarify that the anti-abuse rule found in Proposed Reg. § 1.45V-2(b)(1) does not attach to normal grid operations.**

Proposed Reg. § 1.45V-2(b)(1) provides an anti-abuse rule that would make the Section 45V credit unavailable in certain circumstances where, based on the relevant facts and circumstances, the primary purpose of the production and sale or use of the qualified clean hydrogen is to obtain the benefit of the Section 45V credit in a manner that is wasteful. In particular, the anti-abuse rule attaches to situations where the produced qualified clean hydrogen "will be … used to produce hydrogen."[16] Proposed Reg. § 1.45V-2(b)(1).

Treasury should clarify that the operation of grid connected electrolyzer projects with adjacent grid connected hydrogen-based generation projects will not violate the anti-abuse rule when the projects are both operating at the same time for operational or grid reliability reasons. The electrolyzers at the ACES Facility will run at the same time as the IPP Renewed turbines are combusting a fuel blend including both natural gas and hydrogen sourced at ACES to produce electricity.[17] As such, there will be times when hydrogen is being used to produce hydrogen as the electrons from IPP Renewed will flow to the ACES Facility—which, under a strict reading of the anti-abuse rule, could be deemed a violation of the rule.

These situations are anticipated to occur for the following reasons.

A. To satisfy the ramp rates of the ACES Facility and IPP Renewed. Both facilities must respond to changes in the supply and demand dynamics in the context of their ramp rates. As the system moves from a position of surplus when the ACES Facility would be expected to operate to a position of deficit when IPP Renewed would be operating, the ACES Facility will have to continue to operate until it can turn off its electrolyzers.

B. To allow for the ACES Facility and IPP Renewed to provide ancillary services. Both facilities have a useful capacity to provide a variety of ancillary services to the grid. This may require that the facilities operate simultaneously and allow for quick ramping of either when needed to respond to changes in the supply and demand dynamics of the grid.

[16] Section 45V Credit for Production of Clean Hydrogen, 88 Fed. Reg. 89,246 (Dec. 26, 2023).
[17] BRG Whitepaper, p. 7.

C. To meet the load requirements of the STS and depending on renewable resource availability, IPP Renewed is anticipated to run at relatively high capacity factors to replace the energy from IPP that would otherwise have supported the STS.

Treasury should also clarify that the anti-abuse rule does not generally attach to situations between two grid connected facilities that are under separate and non-affiliated ownership.

**(C) Remove the requirement found in Proposed Reg. § 1.45V-4(d)(2)(iii)(C) requiring the EAC to specifically identify the generator commercial operation date (COD) date.**

Treasury should remove the requirement found in Proposed Reg. § 1.45V-4(d)(2)(iii)(C) requiring the inclusion of the "COD of Facility" and simply rely on the qualified verifier to determine the COD date in the context of the verifier determining whether the EAC was a "qualifying EAC" as the "COD of the facility" is not currently tracked with the EAC in the WREGIS database.

## IV. LADWP RESPONSES TO COMMENT AREAS REQUESTED BY TREASURY

The 45V Rule requested comment on the following four particular areas of importance to LADWP, which LADWP has developed responses to in coordination with Brattle and BRG.

*A. "Whether there are additional ways to establish deliverability, such as circumstances indicating that electricity is actually deliverable from an electricity generating facility to a hydrogen production facility, even if the two are not located in the same region"[18] (45V Rule, p. 49)*

LADWP supports the position developed in the BRG Whitepaper, Section 6 that an eligible EAC scheduled from a resource outside the hydrogen facility's deliverability region that has secured firm or non-firm transmission should count as deliverable. Such an approach is consistent with the architecture of the transmission system and is easy to verify.

*B. "Whether a different treatment [from one to one] would be more appropriate to account for transmission and distribution line losses"[19] (45V Rule, p. 28)*

LADWP supports the position developed in the BRG Whitepaper, Section 3 that the appropriate requirement is that EAC procurement matches consumption of electricity by the hydrogen production facility on a one-to-one basis to maintain consistency with state Renewable Portfolio Standard (RPS) mandates and maintain the ability for liquid markets in 45V eligible EACs to develop.

[18] Section 45V Credit for Production of Clean Hydrogen, 88 Fed. Reg. 89,233 (Dec. 26, 2023).
[19] Section 45V Credit for Production of Clean Hydrogen, 88 Fed. Reg. 89,227 (Dec. 26, 2023).

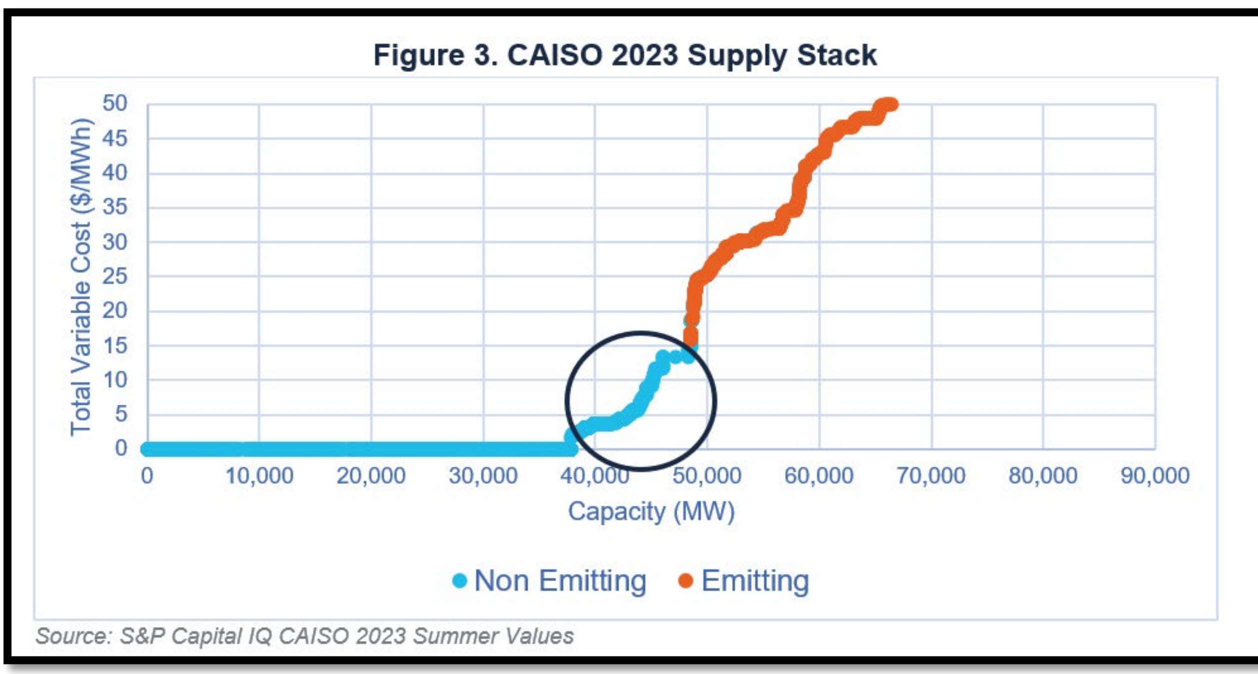
C. *"Whether … other proxy approaches … might replace the five-percent allowance or might be coordinated with the allowance"*[20] *(45V Rule, p. 45-46)*

LADWP supports two additional market-based approaches to ensuring the hydrogen production resources lead to decarbonization, which are developed in more detail in the BRG and Brattle White Papers.

**(A) Use location marginal prices as a proxy for incrementality and temporal matching under certain price conditions.**

This approach can be adopted with current market data in coordination with the Department of Energy and provides an effective, uniform, safeguard in the context of the EAC Criteria.

The locational marginal pricing (LMP) approach is a solid and effective proxy to determine when renewable resources are on the margin which means that additional load on the grid is not resulting in any additional carbon emissions. The following figure shows the 2023 CAISO Summer Supply Stack and the corresponding price condition when "non-emitting" resources were the marginal resource. In this market, in the year, when the LMP marginal price was below $15 per MWh at an LMP there is no corresponding GHG emissions caused by an electrolyzer operating at that time because the marginal ramping costs of the cheapest GHG emitting generation is above the market price. As such, under these conditions the incrementality and temporality attributes of the EAC Criteria are unnecessary to ensure that the hydrogen production resource is not creating additional GHG emissions.




[20] Section 45V Credit for Production of Clean Hydrogen, 88 Fed. Reg. 89,232 (Dec. 26, 2023).

To implement the approach, the Department of Energy would need to determine which LMP is appropriate for the hydrogen production resource and then determine the applicable price point, or "Emitting Resource Threshold" or "ERT". The ERT likely has a seasonal and regional dynamic, but simply reflects the marginal cost of the lowest cost emitting resource in the particular region. Treasury could either publish ERTs or allow taxpayers to demonstrate such market conditions.

**(B) Use the annual aggregate of a project's locational marginal emissions as proxy for temporal matching.**

Location marginal emissions offers a technical alternative to temporal matching which directly aligns incentives with resource and generation placement with decarbonization. The mechanics of the approach are developed further in the Brattle Whitepaper.

*D. An approach whereby "five percent of the hourly generation from minimal-emitting electricity generators ... placed in service before January 1, 2023," would satisfy incrementality*[21] *(45V Rule, p. 45)*

LADWP supports a per se allowance associated with renewable energy facilities with COD dates prior to January 1, 2023. The per se allowance would provide a reasonable approach to utilizing otherwise curtailed electric energy from such facilities and is especially appropriate for entities like LADWP who aggressively developed their renewable energy resource stack prior to 2020.

Respectfully Submitted,

Simon Zewdu
Senior Assistant General Manager - Power System

LCT:ktp
Enclosures

[21] Section 45V Credit for Production of Clean Hydrogen, 88 Fed. Reg. 89,231 (Dec. 26, 2023).

EXHIBIT A

BRG Whitepaper on Technical Issues

# 45V REGULATIONS WHITEPAPER

Comments on the proposed regulations in the context of LADWP’s repowering of the Intermountain Power plant as a hydrogen powered generator.

February 22nd, 2024

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# 1. Background

The Los Angeles Department of Water and Power (LADWP), as the primary participant in the Intermountain Power Agency (IPA) is transforming the Intermountain Power Project (IPP) into a hydrogen-capable combined cycle gas turbine plant (IPP Renewed). Co-located with this project will be ACES I,[1] a hydrogen production and long-term storage facility that will use electrolysis to convert renewable electricity into hydrogen to supply IPP Renewed.

On December 26, the IRS released proposed regulations implementing the 45V Clean Hydrogen Production Tax Credits ("the Regulations"). To receive the maximum tax credit, the lifecycle greenhouse gas emissions from the production of hydrogen must be less than 0.45 kg $CO_2e$ per kg hydrogen. Functionally, the taxpayer must verify the lifecycle greenhouse gas emissions of the hydrogen production using the 45VH2 GREET Model which for production using electrolysis blends an assumed average emissions rate from grid energy with verified zero-emissions inputs that have been matched with a qualified Energy Attribute Certificate (EAC) from a non-emitting generator.[2] The Regulations specify three attributes—incrementality, deliverability, and temporal matching--for an EAC to qualify as a verified zero-emission resource for purposes of determining the hydrogen production facility's applicable lifecycle greenhouse gas emissions.

The Regulations specify the attributes of the EACs generally as follows:

(1) Incrementality – EACs must be produced by generators (or uprates) that have a commercial operation date within 36 months prior to the placed in-service date of the hydrogen production facility. Treasury specifically requests comments on whether there are situations when the incrementality requirements can be waived, such as when renewable curtailments or zero-emitting generation retirements are being avoided due to the operation of the hydrogen production facility.

(2) Temporal Matching – Starting January 1, 2028, EACs must be matched on an hourly basis with the consumption of the hydrogen production facility. Prior to this

[1] It is important to distinguish between ACES I and ACES Delta, which is the parent company of ACES I. The conversion and storage capacity at ACES I is fully committed to Intermountain Power Agency, and its municipal power purchasers, including LADWP, are responsible for procuring and delivering renewable energy to ACES I for conversion into clean hydrogen through a tolling agreement. Importantly, IPA owns the Southern Transmission System, which can deliver energy from the Los Angeles basin to Utah, and IPA also owns a dedicated tie-line that delivers renewable energy from its switchyard to ACES I.

It is expected that ACES Delta will develop additional hydrogen conversion and storage facilities with different customers. While those facilities will likely be located adjacent to ACES I, they will not necessarily have the same electrical connections to the Los Angeles balancing authority area.

[2] Also known in other contexts as a Renewable Energy Certificate (REC) when created by renewable generators.

date, EACs can be matched with consumption on an annual accounting basis.

(3) Deliverability –EACs must be from generators that are within the same region as the hydrogen production facility. There is some ambiguity, especially in the Western Interconnection, about the geography of the regions, but they appear to be a function of which balancing authority area (BAA) the generator and hydrogen production facility are electrically interconnected to. The balancing authority areas are mapped to regions in the Department of Energy's "Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2023". The Regulations request comments on whether there are additional ways to establish deliverability.

The purpose of this whitepaper is to provide analysis of the Regulations from a technical and operational lens in the context of the importance of IPP Renewed and ACES to the decarbonization of LADWP.

While the Regulations are a reasonable framework, there are critical details and points of uncertainty that can be easily clarified by Treasury. The changes that are suggested do not aim to weaken the environmental achievements of the Regulations, instead they should better align the goals of the Inflation Reduction Act, to incentivize the development of hydrogen as a decarbonization option, with the realities of grid operations and market design.

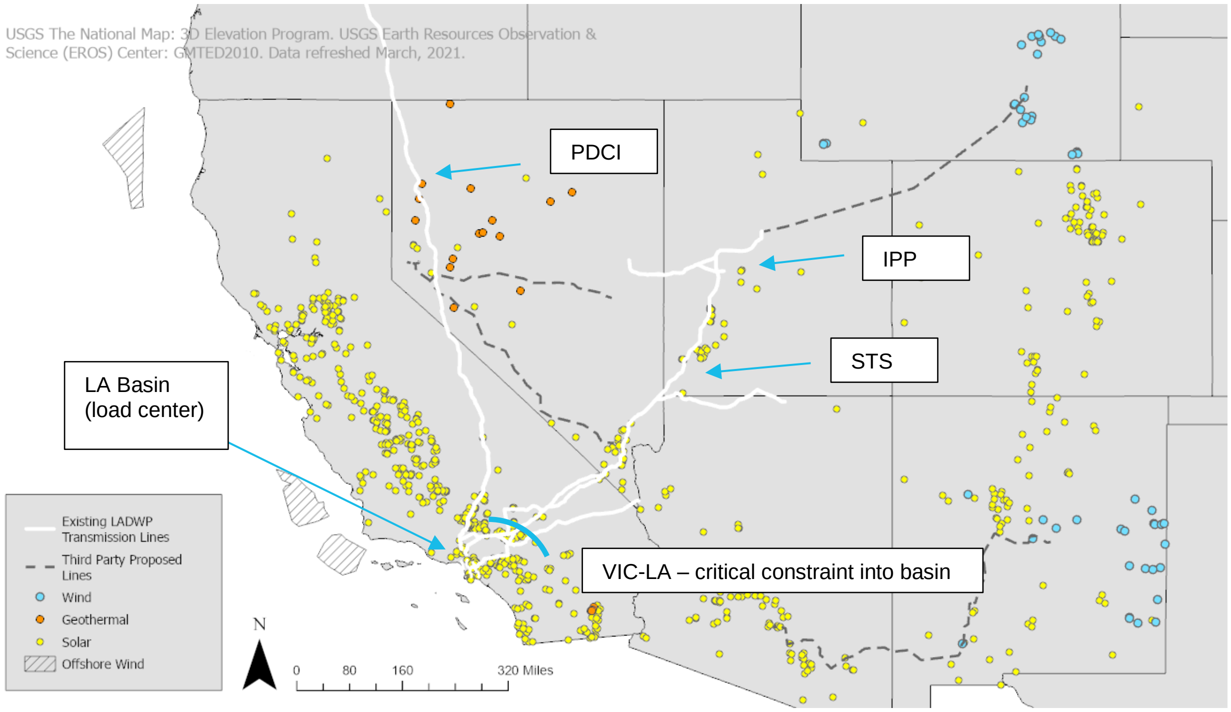
# 2. The LADWP Power System

LADWP is the largest municipal utility in the United States and owns a large generation and transmission system dedicated to supplying electricity to its customers in the City of Los Angeles. The Department has one of the most aggressive decarbonization targets in the world; planning on reaching 100% green energy (fully time-matched) by 2035.

Meeting this target is complicated by the geography of the City of Los Angeles. Figure 1 shows the geography of the system and highlights some of the challenges. The Department's load is concentrated in the LA Basin in Southern California. This region is densely populated and surrounded by mountains or coastline. There is very little potential for renewable generation to be developed in the basin. In response to this, LADWP has built or procured rights to a large amount of transmission to link the load in the basin to generation outside the basin. While historically this transmission allowed external fossil-fuel, hydro, or nuclear resources to serve LADWP, the transmission is being repurposed to bring 100% green energy into the LA Basin in support of the city's decarbonization target.

To maintain system reliability and meet future load growth, it is necessary for LADWP to maximize the value of this transmission network to procure geographically dispersed and technologically diverse renewable generation that can be balanced with batteries and hydrogen generation. The critical operational challenge is how to do this given transmission constraints between generation and load such as the Vic-LA Transmission Interface (shown on the map in Figure 1).

**Figure 1. Renewable Basins and LADWP Transmission System**




LADWP's operational challenges provide a useful lens for evaluating potential amendments to the Regulations. The successful early decarbonization of a system as challenging as LADWP's will stand as evidence that it can be done broadly in the United States and globally. IPP Renewed and ACES I are important pieces of LADWP's strategy to a successful transition to 100% decarbonization. It is consistent with the broader goals of the Inflation Reduction Act to ensure that these projects are not disadvantaged by the final regulations as long as system emissions do not increase from hydrogen production. For this to be possible, it is critical that LADWP's strategy of firm procurement of geographically dispersed resources that span nearly the entirety of the Western Interconnection qualify as eligible EACs.

## 2.1. The Importance of Hydrogen Generation to LADWP Decarbonization

LADWP is committed to providing fully time-matched clean electricity to its full load by 2035 all while the city accelerates the electrification of transportation and buildings. To do this, LADWP must be able to store excess renewable energy over long periods, including weeks or even seasons, so that it can be used when needed. IPP Renewed and ACES I are very early movers in the hydrogen production, storage, and generation industry and present what appears to be the most readily deployable and scalable solution for long-term storage.

The 45V tax credits are an important driver of the economics of this project to LADWP's ratepayers – particularly given risks in developing and deploying new technologies. The success of the project to cost-effectively decarbonize LADWP is important for demonstrating to the rest of the world that it is possible to decarbonize now rather than decades down the road. Furthermore, LADWP serves a disproportionate share of residents living in low income and disadvantaged communities that suffer from a combination of economic, health, and environmental burdens, amounting to more than 2.1 million Angelenos, or 54% of residents.[3] It is critical that the Regulations these do not further economically disadvantage these communities.

The strategy for decarbonizing generation while maintaining electric system reliability depends on LADWP procuring a significant overbuild of renewables in areas that can be accessed by LADWP's transmission.[4] The renewable generation (alongside hydroelectric and nuclear power) will be supported by a significant build of battery energy storage and hydrogen storage and generation. The battery energy storage is well-suited for hour-to-hour and day-to-day variations. However, without hydrogen generation and storage, there is no feasible mechanism to store excess renewable energy over sufficiently long timeframes to remain carbon-neutral during events of extended high demand and/or low renewable generation. Instead, LADWP would be forced to operate or purchase power from fossil-fuel fired generation. This would both harm LADWP ratepayers and increase system emissions.

LADWP's longer-term plans include expanding the use of hydrogen at IPP Renewed and converting current in-basin gas generation to hydrogen-capable generation. While IPP Renewed will use hydrogen produced on-site, the latter plans are dependent on the future existence of a cost-effective independent market source of hydrogen; the development of which will be supported by the 45V tax credits.

## 2.2. How IPP Renewed and ACES I will Operate

Operating IPP Renewed will be a unique challenge as while it will be part of LADWP's BAA and most of its energy will serve LADWP's customers inside of the LA Basin in Southern California, it will be geographically located in Utah (Figure 2). The only direct transmission connection between the plant and the rest of LADWP's bulk transmission system is a 500 kV HVDC line with a 2,400 MW power rating called the Southern Transmission System (STS).[5]

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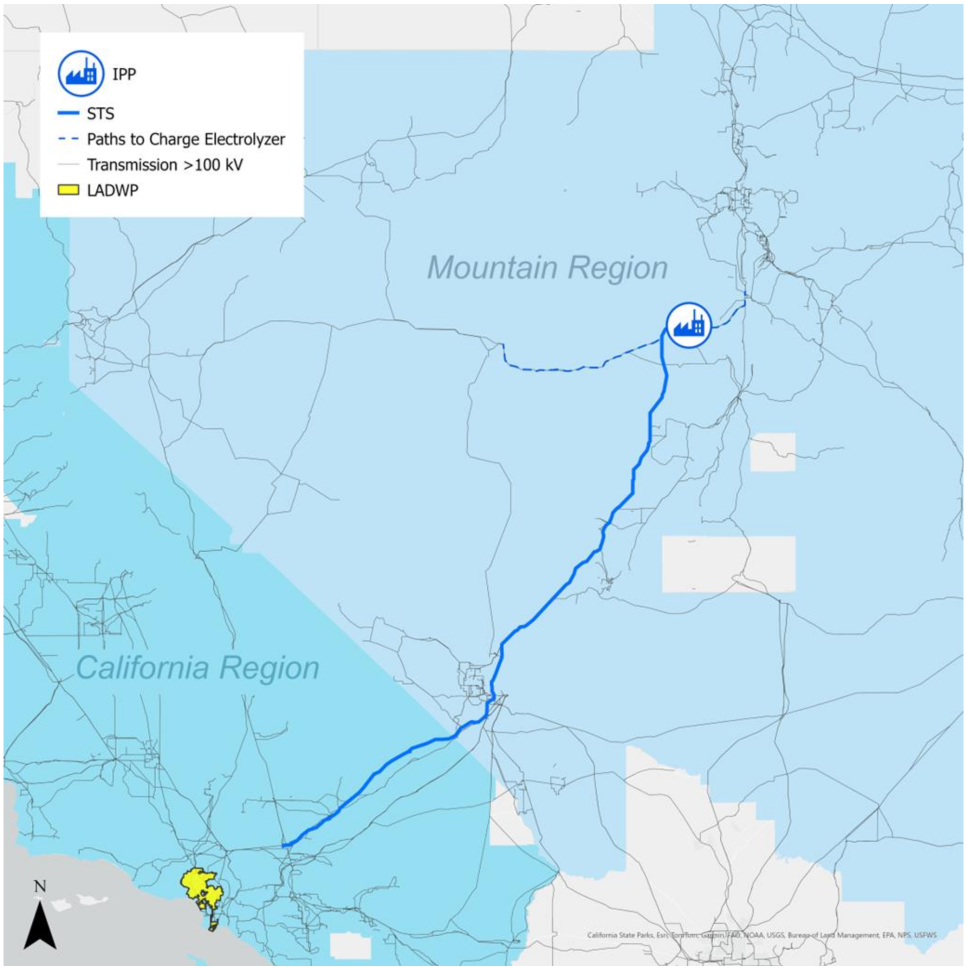
[3] According to the California Office of Environmental Health Hazard Assessment's CalEnviroScreen tool.
[4] Given the relative cost of new transmission vs. new renewables and the need to maintain very high levels of reliability, it is often economically optimal to overbuild renewable generation to maximize the use of the transmission system and ensure sufficient energy to satisfy load when intermittency results in lower-than-expected generation.
[5] IPA is evaluating plans to upgrade the STS to 3,000 MW to allow increased clean generation to be transmitted to Southern California.

**Figure 2. IPP Transmission Connections**




IPP Renewed will be a transformation of the existing Intermountain coal plant into a hydrogen-capable combined cycle gas turbine (CCGT) plant with an ability to initially use 30% hydrogen fuel and transition to 100% hydrogen fuel as technology advances and becomes commercially available. The hydrogen fuel will be created by ACES electrolyzer and stored on-site in salt caverns. Combined IPP renewed and ACES electrolyzer will allow LADWP to cost-effectively store excess energy from its portfolio of renewable power generators and continue to utilize the STS to efficiently provide power to customers in the LA Basin.

Another consideration of the operation of IPP Renewed (and therefore the operation of ACES electrolyzer) is that it is replacing the baseload generation of the current Intermountain coal plant which provides significant reliability benefits to LADWP. To maintain the baseload reliability benefit from IPP renewed, there will be a significant number of times when it will be necessary to run both IPP Renewed and ACES electrolyzer. From an operational perspective it may be necessary to run both IPP Renewed and the electrolyzer at ACES:

(1) To satisfy the ramp rates of the ACES Facility and IPP Renewed. Both facilities must respond to changes in the supply and demand dynamics in the context of their ramp rates. As the system moves from a position of surplus when the ACES Facility would be expected to operate to a position of deficit when IPP Renewed would be operating, the ACES Facility will have to continue to operate until it can turn off its electrolyzers.

(2) To allow for the ACES Facility and IPP Renewed to provide ancillary services. Both facilities have a useful capacity to provide a variety of ancillary services to the grid. This may require that the facilities operate simultaneously and allow for quick ramping of either when needed to respond to changes in the supply and demand dynamics of the grid.

(3) To meet the load requirements of the STS and depending on renewable resource availability, IPP Renewed is anticipated to run at relatively high capacity factors to replace the energy from IPP that would otherwise have supported the STS.

As the decision to run both IPP Renewed and ACES will be driven by power system operational need (as opposed to actual arbitrage of the regulations), it is important that the final regulations ensure that these modes of operation are allowable and do not violate the anti-abuse rule.

# 3. Comments on EAC Procurement

The Regulations require that each MWh of electricity credited as non-emitting in 45VH2-GREET should be matched with the retirement[6] of an EAC. The fundamental purpose of EACs is to provide a framework for differentiating and valuing electricity generated from non-emitting resources with electricity generated from emitting resources. Currently, wholesale electricity markets (such as ISO/RTO or energy imbalance markets) do not consider the underlying attributes associated with EACs. Instead, regions have “qualified registries” that are largely focused on renewable energy credits (RECs), a subset of EACs tied to renewable generation rather than broadly zero greenhouse gas (GHG) emissions generation.[7] It is likely that these qualified registries could be expanded to consider all classes of EACs but unlikely that the wholesale market operators will quickly implement consideration of EAC attributes in dispatch decisions.

A result of EAC trading and settlement being outside of wholesale electricity markets is that the timing and liquidity of EAC procurement is different from that of wholesale electricity procurement. Purchasing wholesale electricity is generally done either forward (long-term contracts) or spot (day-ahead and hourly procurement) – the spot markets in particular are centrally organized, liquid, and trade hourly or sub-hourly. If the

[6] Retirement of an EAC refers to using the EAC to match non-emitting electricity to consumed electricity.
[7] There are regions that track zero emissions credits (ZECs) or hydro RECs as well.

current REC trading regime and software is extended to EACs, EACs would be purchased in much less liquid markets (as they are only relevant to 45V tax credits) at larger time aggregations (monthly or annually), and it will likely be difficult or expensive to back-procure or “true-up" EACs to meet specific hourly temporal-matching or narrow deliverability needs given the lack of liquidity in the market.

The architecture of the Regulations offers three attributes (incrementality, deliverability, and temporal-matching) for when EAC retirement would be sufficient to demonstrate that the electricity input to an electrolyzer is zero emissions. In reviewing the Regulations, two issues that must be considered are:

(1) Practicality – the requirements to temporal-match use of electricity to hourly EACs is currently beyond the administrative capabilities of major tracking systems such as PJM-GATS or WREGIS.[8] While these systems do account for geography and year of generation, they do not yet track the specific time of generation on an hourly basis. It is not reasonable to require temporal-matching of EACs if the mechanisms to procure and verify the temporal-matching do not yet exist.

(2) Emissions Impact – the stated purpose of the 45V guidelines around EAC eligibility is to ensure that GHG emissions do not rise because of the tax credits. Alternative structures or rules that meet these same targets should also be eligible for verification.

The Regulations request comments on whether EACs need to match load at the hydrogen production facility on a one-to-one basis or whether additional EACs should be required to account for losses. Our view is that it makes sense to maintain a one-to-one ratio for EAC procurement for two reasons:

(1) This is consistent with the broadly accepted structure of state RPS mandates across the U.S. such as California’s that requires REC procurement to match a percentage of retail load on a one-to-one basis.

(2) It is not practical to match EACs to actual losses on an administrative basis. They would likely stop being broadly tradeable if specific grid location were part of EACs rather than region of production (and eventually temporality). It is not reasonable or fair to make broad assumptions on transmission losses as this can vary greatly by location.

The broad structure of the Regulations makes sense for avoiding additional carbon emissions from electricity serving hydrogen production facilities, but it is critical that the

[8] EACs are tracked by qualified registries. WREGIS is in the West. PJM-GATS is in PJM. Other regions have their own tracking services.

regulations for eligible EACs avoid overly stringent requirements as long as it can be shown with reasonable certainty that the hydrogen production is not increasing emissions.

# 4. Comments on Incrementality

The Regulations request comments on circumstances[9] for which incrementality can be satisfied by power purchased from the grid or by existing zero emissions generation projects that may predate the COD of the hydrogen production facility by more than three years. The following provides an explanation and methodology for calculating regional Emitting Resource Threshold (ERT) prices below which purchased power can be assumed to be non-GHG emitting.

## 4.1. The ERT can be Greater than $0/MWh in Certain Regions or Time Periods

In the Regulations, the IRS acknowledges that during times of zero or negative wholesale electricity prices purchasing EACs from existing minimal-emission electricity generators, whether from the electricity generators that would otherwise curtail their output or not, would have limited risk of induced grid emissions.[10]

This statement is certainly true within wholesale markets because emitting resources require fuel to operate, which in turn means that they have a variable cost associated with burning that fuel. Barring any special operational circumstances, these emitting resources will offer into the wholesale market at or near their variable operating cost which is driven primarily by their fuel costs. As fuel costs are above zero, all emitting resources will offer in at a price greater than zero that is highly correlated with their fuel cost and efficiency rate.

Given the clear availability of data and reporting available in wholesale power markets to determine the periods during which marginal grid emissions are at or near zero, the question becomes ‘what is the appropriate metric to use.’ While some argue that less than or equal to zero is the proper threshold, there are a few key reasons why it would be more accurate to use a higher price:

(1) Hydro energy and geothermal have a small but notable variable O&M[11] associated with operation.

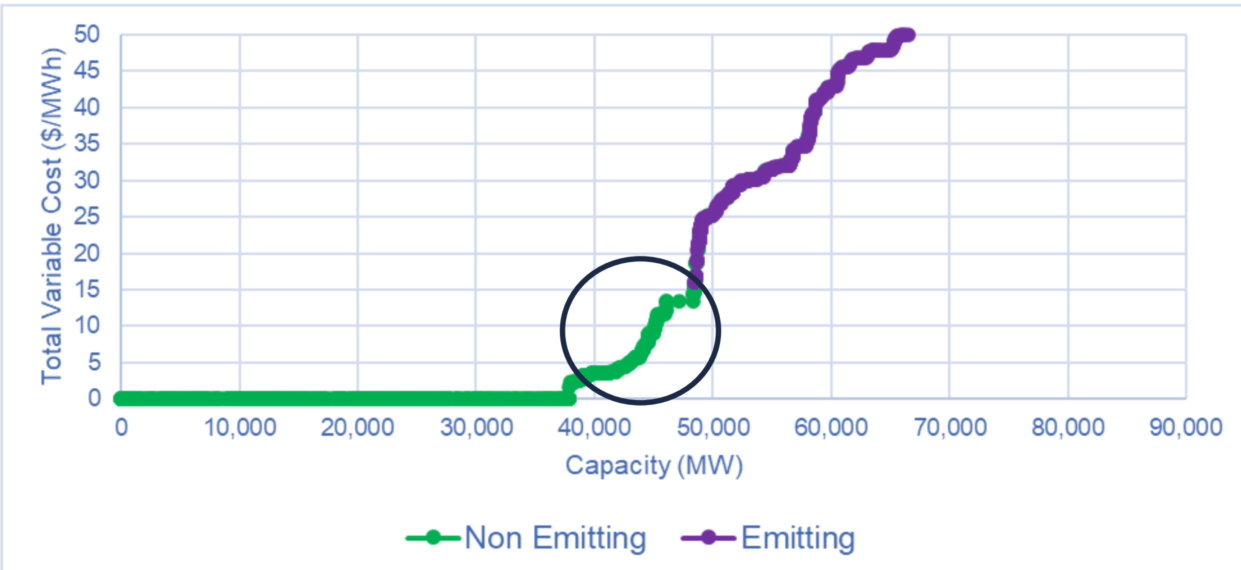
(2) Battery storage, hybrid, and hydro with ponding resources may offer in at a fairly low but positive price if they were able to charge at an even lower or negative price via renewables but face variable operating costs or opportunity costs

[9] other than generation from projects constructed within 3 years of the COD of the hydrogen production facility.
[10] IRS 45V Guidelines Page 89231
[11] The EIA estimates this to be $1.57 for hydro and $1.31 for geothermal in the 2023 AEO. Though actual values are often reported as higher https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

(3) Transmission hurdle rates between balancing areas will result in increased locational prices even if the imported energy is emissions free.

One clear indicator to show that non-emitting resources are still on the margin at prices above zero is by looking at a supply stack. A supply stack orders grid interconnected plants by their total variable cost[12] versus their summer capacity. A supply stack for CAISO for the summer of 2023 is shown in Figure 3.

**Figure 3. CAISO 2023 Supply Stack**

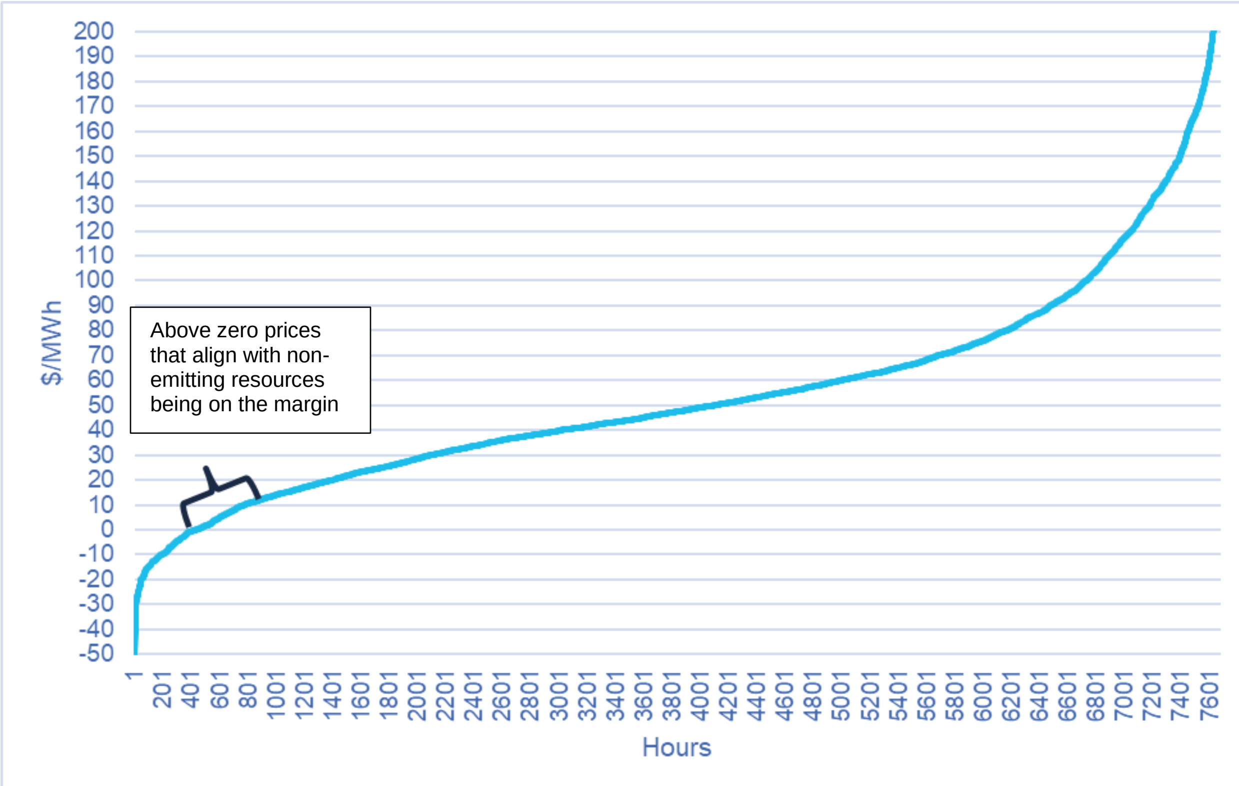



*Source: S&P Capital IQ CAISO 2023 Summer Values*

The values in the circle demonstrate numerous generating facilities that have zero generating emissions but have total variable costs at prices higher than $0. This, in turn, corresponds with a small number of hours during which LMPs will be above zero despite non-emitting resources being on the margin. It is worth noting that as hybrid renewable and storage project become more common, it is likely that the number of hours with zero emissions but LMPs greater than zero will increase – making the proper calculation of the ERT more important.

[12] Total variable cost is the summation of variable O&M, fuel costs, emissions costs, and start costs

**Figure 4. SP15 Real-Time Hourly Avg Price – 2023**




*Source: oasis.caiso.com*

It is possible to appropriately capture these values while also avoiding any unintended hours where emitting resources are marginal. This would be done by requiring that any load from a hydrogen production facility that wishes to claim purchased power below the calculated ERT be purchased directly from the relevant wholesale market so that the price impacts of the additional load are endogenous to the purchase price.

## 4.2. Suggested Approach to Calculate Regional or Seasonal ERTs for when Incrementality can be Waived

The most logical method to determine the hours with zero marginal emissions rates would be to eliminate all hours during which emitting resources would be cleared in the market.[13] This can be done by determining the total variable cost of the lowest-priced emitting resource in the deliverability area, which would correspond to that resources offer in the market and setting the threshold price below this value. Since calculating the total variable cost for each unit can be complicated, a simpler and more conservative approach would be to simply consider the lowest annual fuel cost for any resource within the deliverability area.

Two possible formulas would be as follows for each deliverability area for the prior time-period, for example, the prior year or month:

[13] Except due to specific operational constraints which ensure they are not marginal in an hour

(1) From EIA Form 923, determine the fuel costs ($) and generation (MWh) for each plant

(2) Divide the reported fuel cost by the reported generation to get a $/MWh value

(3) Pull the value with the lowest $/MWh

(4) Divide this number by 2 (to have an abundantly conservative estimate of the most efficient operating point versus the average fuel cost per MWh)

Or

(1) Using the prior year continuous emissions monitoring systems (CEMS) data from the EPA, determine the generation (MWh) and heat consumption (MMBtu) of each plant.

(2) Using these two values, determine the average heat rate (efficiency) of each plant.

(3) From market data from the New York Mercantile Exchange (NYMEX), Intercontinental Exchange (ICE), or other public market sources, determine the lowest available delivered natural gas and coal price in the region

(4) Multiply the lowest heat rate by the lowest daily or monthly fuel price available in the time period (i.e.: 1 year) to calculate the least expensive emitting plant fuel cost on a $/MWh basis.

(5) Divide this number by 2 (to have an abundantly conservative estimate of the most efficient operating point versus the average fuel cost per MWh)

Both approaches yield similar results. By using the second approach, the price during which it could be assumed hydrogen was charging from non-emitting resources in California in 2022 would be approximately $12/MWh. This increases the number of hours from 2.5% to 3.8% versus a zero-price threshold. An additional benefit of this approach is that it considers the variance in energy prices due to changes in commodity prices and efficiency gains from new thermal resources, therefore it will adapt to market conditions and market offers. For example, if completing the same exercise for the same region in 2023, the price would be approximately $5/MWh. This corresponds with an increase from 3.3% to 5.3% of hours when compared to the zero-price threshold.

While this approach or another using the same principles would likely have a minimal impact in some regions it will have a modest but important impact in others. This approach would provide a more accurate and flexible representation of the number of hours with zero or near zero marginal emissions rates, sending the proper signal to hydrogen production facilities which ultimately aids in curtailment reduction and renewable integration.

Other approaches to calculate the ERT are certainly possible, and the concept can be extended to consider seasonal differences as well as regional differences.

# 5. Comments on Temporal Matching

The Regulations require temporal-matching by January 1, 2028, but as acknowledged in the Regulations, this may not be feasible at that time if the software systems that currently underpin the REC market are not sufficiently upgraded, or if there is not sufficient liquidity in the EAC market.

While temporal-matching is eventually an important component of ensuring that emissions do not rise because of hydrogen production, it is important to ensure that market structures are in place to make temporal-matching feasible. This section expands on those risks and offers an approach for modifying the deadlines to provide sufficient time for temporal-matching to be feasible. This section continues with a discussion of two cases when the temporal-matching requirement should be waived.

## 5.1. Providing Sufficient Time for Temporal-Matching to be Feasible

One of the significant challenges to expanding EAC registries to time-track is that even with 45V credits in place, the demand for EACs subject to temporal-matching will likely be small compared to the overall REC market. Given the significant costs and effort to upgrade the qualified registries, it may not be a high priority for qualified registries to implement temporal-matching quickly given their other obligations.

The challenge is that owners of 45V-eligible projects do not individually have control over the pace with which qualified registries implement temporal-matching in their software or over the liquidity of the market for temporal-matched EACs. There is a very real risk that software vendors will not implement temporal-matching by the January 1, 2028 deadline, and that on this date 45V-eligible projects will have to substantially curtail operations even if they have procured sufficient resources on a less granular basis, which in turn could lead to a reduction in the availability of low-carbon hydrogen to support broader decarbonization goals. Similarly, this uncertainty could deter investment in hydrogen production facilities which further challenges decarbonization goals.

One proposal to reduce the risk of delayed implementation of temporally-matched EAC registries is that rather than the current requirement date of January 1, 2028, the requirement for temporal-matching be set to the latter of January 1, 2028, or a date 12-24 months after the implementation of temporal-matching in a qualified registry of EACs in the relevant deliverability area. This will ensure that resources intending to procure temporal-matching EACs to support their 45V-eligible facility are not left in a position where they cannot practically procure EACs for reasons beyond their control.

A requirement occurring 12-24 months after software implementation is likely necessary to ensure that qualified registry software have debugged their system, and that sufficient liquidity has materialized on the qualified registry to support a best-efforts procurement strategy. The implication of this rule is that the implementation date of the temporal-matching requirement can vary between regions.

To prevent abuse, a date sometime after January 1, 2028 when temporal-matching is mandatory regardless of software availability would ensure that an incentive is not created to intentionally delay the introduction of temporal-matching on a qualified registry.

### 5.2. A Temporal-matched EAC is Not Needed if the Electricity was Purchased Below the ERT

As discussed in section 4.1, when power is purchased in an organized wholesale market below the variable cost of the cheapest thermal generating station, a minimal-emitting resource will be on the margin in that hour and the marginal generation used to power the facility in that hour will be from a zero-emissions resource.[14] And while it remains necessary that this purchased power should be accompanied by retiring an unbundled EAC in the appropriate deliverability area to ensure additionality and avoid double counting, the EAC should not be required to be hourly temporal-matched.

The retirement of an unbundled EAC is necessary because when curtailment was avoided, a new EAC was created for the owner of the generation of the non-curtailed resource. That owner could have retired the new EAC to meet a state RPS requirement or another renewable mandate and so it would be possible for the EAC to be double counted.

However, since temporal-matching RECs are not currently required under any applicable state RPS policies in the United States, the EAC created in this circumstance by avoided curtailment would not be hourly time-stamped, and so retiring a general deliverable EAC to the facility at the same temporal granularity as the relevant state RPS policy should be sufficient to ensure additionality from existing resources.

Under existing market dynamics, requiring retirement of a temporal-matched EAC would produce an unnecessary procurement burden of an illiquid or otherwise unavailable product without impacting additionality in hours with prices below the defined threshold.

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[14] Note that this does not require that no fossil generators be online in a deliverability area. There are circumstances where fossil generators will still be online due to transmission constraints elsewhere in a deliverability area, ancillary services requirements, or fundamental limits on generator operations (such as minimum uptimes for fossil-fired assets) where fossil generators will still be generating, but because they are not setting the price and are rather generating due to these constraints they will not increase generation due to the hydrogen production facility load.

If any changes are made in the future to state RPS policies which create more granular temporal-matching requirements then a requirement to retire correspondingly granular EAC when purchasing power at below the ERT could be added to cover this circumstance. In this scenario the existence of a more granular RPS would necessarily ensure sufficient software availability and a more liquid market for more granular EACs.

# 6. Comments on Deliverability

The GREET manual[15] states “As per the 45V NPRM, the location of a generation source and the location of a hydrogen production facility is based on the U.S. Balancing Authority to which it is electrically interconnected (not its geographic location), with each balancing authority linked to a single region.” The BRG Memo on 45V Deliverability Regions attached to this submission discusses issues with the specific deliverability regions in the Regulations and demonstrates that the proper regions for the WECC are the Western Energy Imbalance Market (WEIM) and the Western Energy Imbalance Service (WEIS).

The proposed regulations also request comments on “whether there are additional ways to establish deliverability, such as circumstances indicating that electricity is actually deliverable from an electricity generating facility to a hydrogen production facility, even if the two are not located in the same region”. The following is in response to this request from Treasury.

## 6.1. Transmission rights to the 45V deliverability region should be eligible for demonstrating deliverability for EACs

The Regulations state that resources that are electrically connected to a BAA are considered part of that BAA for deliverability. This suggests that resources that are pseudo-tied[16] to a balancing area will be eligible under the deliverability requirements, however, resources with transmission rights between the resource and the deliverability region may be excluded. This exclusion would be inappropriate because it is common practice for utilities or other load serving entities to sign Power Purchase Agreements (PPAs) or directly own generation resources that are interconnected to other transmission systems outside their own service territory or balancing area. Such resources may not be pseudo-tied to the balancing area of their owner because of shared ownership of a larger generating resource, requirements of operating the transmission system, or other technical reasons.

For a utility or load to demonstrate deliverability, it is sufficient to secure transmission rights between the resource and the load or balancing area over which the resource’s generation can then be scheduled. This is particularly common practice in WECC with its large, shared generating resources, large transmission corridors, and the federal hydroelectric system. If this is not accounted for within the deliverability requirement, it will prevent owners and off-takers of generating resources who have secured firm

[15] Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2023
[16] A pseudo-tied resources virtually connected to a balancing area for the purposes of dispatching the system.

transmission (often on very long time-frames) from utilizing these resources and limit the ability to use the bulk transmission system of the West to site large renewable projects where they are best suited.

Using firm transmission rights is common practice to demonstrate deliverability. PJM's capacity market, the Reliability Pricing Model (RPM), provides an example by requiring firm transmission rights for resources external to the PJM footprint to participate: "The Capacity Market Seller has demonstrated that it has, for transmission outside PJM, obtained long-term firm point-to-point transmission service (evaluated for deliverability from the unit-specific physical location of the resource to PJM)."[17] RPM is a resource adequacy program, where failure to deliver energy when called can result in grid failure. The lenience in this high-stakes market compared to the Regulations highlight the reasonability of qualifying out of region resources that have secured firm transmission rights as deliverable.

It is important to note that one of the primary purposes of the WEIM is to pool transmission resources and reduce the importance of firm transmission rights in determining how generation meets load across the market footprint. Allowing resources with firm transmission to count as deliverable is not a substitute for properly defining the Western deliverability regions as the WEIM and WEIS (similar to how PJM pools transmission and generation). However, given the reality of how deliverability is defined across the U.S. and the importance of transmission rights to allow large, cost-effective renewable projects in regions with high quality resources, it is appropriate for the 45V guidelines to be consistent and allow EACs from resources connected to the deliverability region with firm transmission to count towards verification.

A specific rule could be that any generation associated with eligible EACs scheduled from a resource outside of the hydrogen facility's deliverability region that has secured firm or non-firm transmission to the deliverability region will count as deliverable.

# 7. Potential Calculation of Grid Carbon Intensity at a BAA Level

The 45VH2-GREET model allows for a user-defined mix, where taxpayers can combine EACs they retire with the "grid mix" for the NERC region that they're located in. The current iteration of the GREET model also only calculates the grid mix at the scale of a NERC region. This is likely to cause some unintended consequences. In particular, even with the proposed updates to the regional definitions, there are BAAs which will have carbon intensities substantially below their regional averages. This is especially relevant for those with carbon pricing regulations, which applies not only to the generation within their BAA, but also to the imports into that BAA. Regions like these that reside in a broader NERC region with a higher carbon emissions rate will be penalized.

[17] PJM Manual 18, https://www.pjm.com/-/media/documents/manuals/m18.ashx, November 2023

Because the GREET model is meant to capture the carbon intensity of grid-supplied power for an electrolyzer, the region or BAA used for GREET modeling purposes need not be the same as the deliverability area for 45V purposes. There will be cases, like with California BAAs, where a carbon tax applying to generation and imports into a BAA means that increased load in an area will be met with a lower emitting generation mix and where electricity from non-emitting resources can be economically imported while electricity from emitting resources cannot.

This limits opportunities to cost-effectively serve hydrogen production facility load with minimal increases in greenhouse gas emissions and removes some incentives to site electrolyzers in lower carbon intensity areas within the broader NERC region.

One solution to the problem would be to calculate grid carbon intensity on a BAA level, and to provide the option to taxpayers to calculate grid carbon intensity at either an hourly or annual granularity. At an annual granularity this can be done prospectively, using historical average emissions rates, or retrospectively using emissions rates as they occurred. At an hourly granularity this can be done retrospectively. At either level of granularity, grid carbon intensity for load in a BAA can be calculated using the following formula:

$$Grid\ Carbon\ Intensity = \frac{CO_2 from\ Generation\ in\ BAA + CO_2\ from\ Specified\ Imports\ into\ BAA + CO_2\ attributable\ to\ Unspecified\ Imports\ into\ BAA}{Consumption\ of\ Electricity\ In\ BAA + Exports\ of\ Electricity\ from\ BAA}$$

Specified imports in this context refers to imports from named facilities, specifically those contractually committed to deliver power into the BAA with full transmission rights to do so. Unspecified imports, in contrast, refers to electricity imported from neighboring BAAs for which no specific source can be determined. While existing reporting requirements cover calculation of $CO_2$ emissions within a BAA, emissions from specified imports into a BAA, consumption of electricity in a BAA, and exports of electricity from a BAA,[18] a separate process would be needed to calculate the $CO_2$ attributable to unspecified imports.

One potential approach, currently applicable to balancing authorities with native load in California, would be to utilize the current California Air Resources Board (CARB) regulatory process to calculate greenhouse gas emissions for reporting and compliance purposes. In this process, the carbon intensity of unspecified imports is calculated automatically in the EIM algorithm and used for both reporting and state compliance purposes. This calculation of carbon emissions could similarly be used to calculate 45V carbon intensity, at either an hourly or annual granularity.

A separate approach, which could be utilized throughout the Lower 48 states, would be to create a similar process to the current estimation process for carbon emissions in the

[18] Including EPA Continuous Emissions Monitoring System (CEMS) data, which mandates hourly reporting of $CO_2$ emissions and generation from emitting generating units greater than 25 MW, and the EIA Form 930, which tracks hourly demand in and interchange between BAAs.

EIA Hourly Electric Grid Monitor, which seeks to calculate hourly carbon intensity on a BAA level.[19] The EIA 930 tracks hourly demand and interchange by BAA, as well as hourly generation by fuel type, and uses these values to estimate $CO_2$ emissions and carbon intensity by BAA, including an estimate of carbon intensity of imports and exports. While some modifications to this process (such as separately accounting for specified and unspecified imports) would be necessary, the basic data sources and calculation framework utilized in this process could be extended to the calculation of grid carbon intensity at a BAA level for 45V purposes. This data can be calculated hourly using existing EIA 930 reporting requirements, and trued-up to an annual level using a combination of data sources including EPA CEMS and EIA 923.

As discussed above, either of these approaches can be calculated prospectively at an annual level, ahead of a tax year, by using historical average annual emissions rates, or retrospectively at an hourly or annual level, after a tax year by using realized emissions rates for the BAA in question. While the GREET model is currently only tailored to using annual data, it is important to provide at least the option to use hourly grid carbon intensities for a BAA to ensure that hydrogen production facilities have the ability to use grid-sourced power when renewables are on the margin and few if any thermal facilities are online in a BAA.

# 8. About BRG

Berkeley Research Group, LLC (BRG) is a global consulting firm that helps leading organizations advance in several key areas including disputes and investigations, energy, corporate finance, and performance improvement and advisory. Headquartered in California with offices around the world, we are an integrated group of experts, industry leaders, academics, data scientists, and professionals working across borders and disciplines.

Our Power and Utilities teams works on challenging technical and economic aspects of decarbonization across the United States. We focus on the intersection of reliable system operations and power markets to help clients develop strategies and methodologies to successfully decarbonize. We have worked directly with LADWP for the past decade leveraging our deep understanding of western power markets to support them pursue their 100% green energy policy by developing detailed operational requirements and detailed analysis of system interactions between LADWP and the broader bulk transmission system.

The following are bios for the team:

**Matthew Tanner, Ph.D.,** is a Managing Director in the Energy and Climate practice with fifteen years of experience advising clients across the power-sector value chain on strategy, risk, and planning. He leads the Power and Renewables team and his expertise includes power finance advising, renewable integration, power market hedging, utility resource planning, and risk evaluation. He has advised some of the

[19] https://www.eia.gov/electricity/gridmonitor/about

world's largest IPPs, investors, utilities, and corporate power consumers on market opportunities, risks of changing market structures, and investment strategies.

Dr. Tanner provides highly analytical and creative approaches for his clients to adapt their business models as decarbonization regulations drive power market changes. He has deep expertise in power economics and valuation through modelling of power markets, optimizing generator portfolios, and assessing the impact of emerging technology on the power sector. He is an expert in helping clients understand the fundamental underlying market drivers and regulatory and technological changes in the power sector that impact revenue, operations, and investment opportunities. He also helps utilities and system operators understand future requirements to operate the power system reliably while reducing emissions and minimizing cost.

Dr. Tanner has served as an expert witness in both Federal and state courts and testified before state utility commissions on on-going changes in power markets and the power system. His testimony in court has included evaluation of generation financing, damages from lost opportunities, evaluation of the market hedging programs, market rules, and evaluation of the implications of power and fuel procurement contracts. Before state utility commissions, he has testified on future system requirements to maintain reliability in high renewable systems.

**Vir Chahal** is a Managing Director in the Energy and Climate Practice. He leads the Power and Renewables team and has over 16 years of experience leading diverse teams and implementing bespoke solutions focusing on power industry consulting services and power economics. He has led engagements across the power sector as an expert in integrated resource planning, power asset transactions and valuation, decarbonization pathways, strategic entry for various stakeholders, and as an expert witness. His expertise also includes power market forecasting and production cost modeling, energy storage and hybrid system dispatch, resource adequacy planning, and portfolio optimization.

Mr. Chahal has performed numerous utility planning and renewable integration studies for some of the largest utilities in North America highlighting the impact of increased renewable penetration on operations, ancillary service requirements, reliability, carbon reduction, and system costs. He has also assisted large corporations in strategic initiatives in the power sector and evaluated hedging strategies for generation and demand owners. Furthermore, he has extensive experience in stakeholder engagement and has presented in front of system operators such as the NYISO and IESO, on behalf of utilities in front of public service commissions, and in front of governments officials in Texas and California.

Mr. Chahal has also served as an expert witness and submitted testimony related to disputes in ERCOT, NYISO, PJM and Southeastern power markets.

**Matt Drews**, an Associate Director in BRG's Energy and Climate practice, is a strategy and finance professional with broad experience helping clients understand and respond to rapidly changing energy markets and regulations. Mr. Drews' areas of expertise include wholesale power markets, power generation portfolio strategy, generator dispatch modeling, due diligence transaction support, renewable fuels policy and analysis, net zero studies, energy transition strategy, corporate finance, mergers and acquisitions, and energy storage modeling. As an energy, finance, and modeling expert, he has worked on investment advisory, planning, finance, and strategy projects for numerous major US, Canadian, and international clients and employers on a wide range of energy assets.

EXHIBIT B

Brattle 45V White Paper

# Section 45V Clean Hydrogen Production Tax Credits

## COMMENTS ON PROPOSED TREASURY GUIDELINES

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FEBRUARY 26, 2024

Brattle

LA DWP Los Angeles Department of Water & Power

NOTICE

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# I. Background and Summary

On December 26, 2023, the U.S. Department of Treasury (Treasury) released the proposed rules related to the tax credit for production of clean hydrogen under Section 45V of the Internal Revenue Code (Section 45V rules).[1] The Section 45V rules establish three criteria (Energy Attribute Credit Criteria or EAC Criteria) applicable to electricity from a particular source for purposes of calculating the lifecycle greenhouse gas (GHG) emissions under the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model.

These comments have been prepared on behalf and at the request of the Los Angeles Department of Water and Power (LADWP), in support of their efforts to achieve decarbonization by 2035, which will rely upon hydrogen as a resource.

The amount of lifecycle GHG emissions determine the amount of tax credit available, if any, for the production of hydrogen under Section 45V. The three EAC Criteria are:

- **Incrementality**: Electricity must be sourced from renewable resources that began commercial operation within three years of the hydrogen facility being placed into service.[2] Uprates to the renewable energy generators can count as a new source of clean energy.[3] The Section 45V rule requests comments about counting incremental energy from existing resources (*i.e.*, nuclear and hydropower power facilities), avoided retirements, and avoided curtailed energy from existing renewable resources.[4] Treasury has asked commenters to provide input on the appropriateness of a 5% cut-off for

[1] Federal Register, "Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property," December 26, 2023, https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen

[2] Prop. Reg. 1.45V-4(d)(3)(i)(A)

[3] Prop. Reg. 1.45V-4(d)(3)(i)(B)

[4] 88 FR 89230-89233

curtailment and other approaches to situations when the incrementality criteria can be waived.[5,6]

- **Deliverability**: Electricity must be sourced from generators in the same region as the hydrogen producer.[7] The applicable regions are as defined in the U.S. Department of Energy's (DOE's) 2023 National Transmission Needs Study.[8] Specifically, the preamble of the proposed regulations states that DOE mapped the regions in the study to the Balancing Authorities Areas (BAAs) in the 45VH2-GREET model user manual (GREET User Manual).[9] The GREET User Manual provides a list of applicable balancing authorities by region, which differs from the map in the DOE National Transmissions Needs Study.

- **Temporal Matching**: Electricity used to produce hydrogen must be matched on an annual basis until December 31, 2027.[10] Thereafter, the energy consumed by the hydrogen producer must be matched on an hourly basis with production.[11] The annual matching period is considered a transition period to allow the electric power industry to develop time-specific EACs sufficient to track the three criteria of 45V on an hourly basis.

In this white paper, we provide comments on each of the EAC Criteria proposed by the Treasury and in some instances propose alternative approaches for each criteria where we believe they will be helpful in achieving the goal of reducing GHG emissions from hydrogen production. In general, our proposed alternatives are meant to help align the Section 45V Rule with real-world operation of the power system, with specific focus on power system operations in the Western Electricity Coordinating Council (WECC). We summarize our comments and recommendations as follows:

- **Incrementality:** The proposed 5% limit on claiming avoided curtailed renewable energy will not fully capture locational differences in system curtailments. We propose a

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5 *Ibid*.

6 We interpret the suggested approach to curtailment to provide all renewable facilities that ability to allocate 5% of the facility's production as meeting the incrementality criteria.

7 Prop. Reg. 1.45V-4(d)(3)(iii)

8 Prop. Reg. 1.45V-4(2)(d)(vi). See also U.S. Department of Energy, "National Transmission Needs Study," October 30, 2023, https://www.energy.gov/gdo/national-transmission-needs-study

9 Prop. Reg. 1.45V-4(b)

10 Prop. Reg. 1.45V-4(d)(3)(ii)(A) and 1.45V-4(d)(3)(ii)(B)

11 *Ibid*.

methodology that relies on the Locational Marginal Price (LMP) at the location of the hydrogen production load to identify hours when there is excess renewable energy on the system (a Per Se Curtailment Rule). In hours when the LMP is less than or equal to zero, the electrolyzer would be allowed to claim consumption in that hour as incremental renewable energy, even if produced by existing resources, as long as a Renewable Energy Credit (REC) is procured and retired.

- **Deliverability:** Our comments will explain existing power sourcing arrangements in the WECC, and how they do not conform to Section 45V rule on deliverability. The Section 45V rule will likely render current plans to develop new renewable resources unable to serve hydrogen production load for some utilities in the WECC. We propose an alternative mechanism that will ensure renewable generation is deliverable to hydrogen production load and utilizes functionally appropriate and well-established regions that align with regional wholesale markets in the WECC. This would include the Western Energy Imbalance Market (WEIM) and the Western Energy Imbalance Service (WEIS). This is similar to the treatment allowed in most of the Eastern Interconnection under Treasury's proposed deliverability regions. We further propose that incremental renewable resources not located in the same regional wholesale market as the electrolyzer can meet the deliverability requirement by securing firm transmission rights from the renewable source location to a delivery point within a BAA in the same regional wholesale market as the electrolyzer. The deliverability region requirement could be supplemented by an hourly emissions impact test (discussed in further detail below) to ensure that electrolyzer owners are incentivized to locate renewable resources where they will have a commensurate emissions impact relative to the emissions caused by the hydrogen production load.

- **Temporal Matching:** We comment on the potential cost of the proposed hourly matching requirement and propose an alternative approach based on annual matching. When coupled with the proposed deliverability requirements and the hourly emissions impact test, this ensures that hydrogen production load reduces overall system emissions, without imposing the same costs as hourly matching.

In the remainder of this whitepaper, we discuss our comments and recommendations in detail. In Section II, we discuss the incrementality criteria. Then, in Section III, we discuss the deliverability criteria. Next, in Section IV we discuss temporal matching. Finally, we provide a brief summary of our conclusions.

# II. Incrementality

Renewable generation that would have otherwise been curtailed meets the “incrementality” criteria of eligibility as this energy is incremental to electricity that would be consumed by existing demand. Treasury recognizes this and, in their proposed clean hydrogen tax rule, requests comments on allowing electrolyzers to claim avoided curtailment of renewable energy from existing renewable resources (those placed into service more than three years prior to the in-service date of the electrolyzer) as additional or incremental.[12] Treasury has suggested that such energy (claimed as incremental from avoided curtailment of existing renewables) be limited to 5% of generation from existing renewable resources, based on a nation-wide analysis of negative wholesale prices in recent years and forecasted long-run marginal emissions rates.[13]

A singular, nation-wide, static metric, does not capture the significant locational and temporal differences in curtailment patterns across the country and disregards how these are expected to change over time, given higher renewable penetration. We propose that Treasury use transparent market signals that are inherently poised to reflect locational and hourly variations in grid operation and curtailment patterns.

## A. Non-Positive LMP Screen to Identify Avoided Curtailed Energy

It would be consistent with current and expected future grid operations for Treasury to allow electrolyzers to claim different amounts of avoided curtailed renewable energy as incremental clean energy based on their location. For example, the southwestern U.S., including southern California, Arizona, Nevada, and Utah, has abundant solar resources and experiences significant solar curtailments during daylight hours. This is especially true during spring months when electrical demand is low and hydro resources produce excess power due to snowmelt and

[12] Treasury seeks these comments in connection with Proposed Regulation 1.45V-4(d)(3)(i)(A) on the following items: (1) whether a higher limit, such as 10%, would be appropriate; (2) how a 5% allowance should be tracked, allocated, and administered and how feasible it is for EAC tracking systems to incorporate data on such an allowance; (3) whether the 5% should apply to all existing minimal-emitting electricity generators in all locations or a subset; (4) whether such allowance should be assessed at the individual plant level or across an operator’s fleet within the same deliverability region; and (5) any other administrability considerations. See 88 FR 89232.

[13] 88 FR 89231-89232.

associated water runoff.[14] This pattern is expected to expand in coming years as more renewable resources come onto the system, and will likely affect a larger geographic area during more months of the year, and more hours of the day (see Figure 3 below). Even within Treasury's proposed deliverability regions, renewable curtailments will vary significantly in the same region and at different times. It would align with the reality of the power system for Treasury to account for the temporal nature of curtailments. In certain seasons and at certain times of day, an electrolyzer located in the southwestern U.S. may be able to utilize avoided curtailed renewable energy for 100% of its consumption.

We propose an approach that is location-specific and time-matched (hourly or sub-hourly), based on transparent market signals, and demonstrates that curtailed renewable energy was available for consumption by an electrolyzer. In particular, we propose using the LMP at the location of the electrolyzer to determine if curtailed renewable energy is available in that time interval for consumption by the electrolyzer. Specifically, any time the LMP is equal to or less than $0/MWh, curtailed energy is available for consumption in that time interval and that location (a **Per Se Curtailment Condition**).

LMPs are transparent and publicly available market signals that provide information on the cost of the marginal generation resource at a specified location on the gird. Meaning, that the LMP indicates the cost of the generation resource available at that location and time to serve an incremental amount of load. LMPs are determined through a market-clearing engine implemented by the local market administrator and are based on offers to sell energy made by generation facilities in the market. All the Regional Transmission Organization (RTO)- and Independent System Operator (ISO)-administered markets in the country, including energy imbalance markets, such as the WEIM and WEIS, publish LMPs, [15] making LMPs available for almost all locations on the grid in the continental U.S.[16]

We propose that all consumption by an electrolyzer in any time period during a Per Se Curtailment Condition be attributed to incremental non-emitting energy, therefore the retired

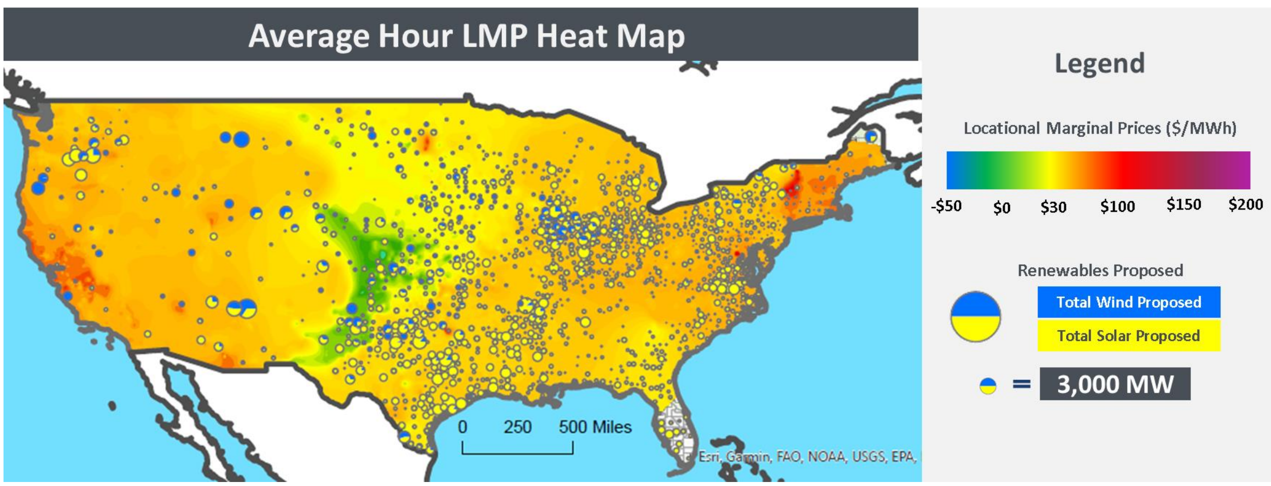
[14] U.S. Energy Information Administration (EIA), "Solar and wind power curtailments are rising in California," accessed February 8, 2024.

[15] The California ISO (CAISO), the Electric Reliability Council of Texas (ERCOT), the New York ISO (NYISO), the Midcontinent ISO (MISO), New England ISO (ISO-NE), the PJM Interconnection (PJM), the Southwest Power Pool (SPP), the Western Energy Imbalance Market (WEIM), and the Western Energy Imbalance Service (WEIS).

[16] In regions where LMPs are not available, there are proxies that Treasury can use to implement a similar rule. For example, BAAs report system lambdas to FERC, which indicate the cost of the marginal generation resource in their BAA. However, system lambdas do not provide the same locational information as LMPs.

REC in that time period is excused from the incrementality requirement. The electrolyzer should not be required to procure and retire RECs from new renewable resources[17] for consumption in any period where the LMP is less than or equal to $0/MWh. In effect, the proposed incrementality criteria in the Section 45V rules would be waived for all energy consumed by the electrolyzer when the LMP is less than or equal to $0/MWh. For example, picture an electrolyzer that consumes 100 GWh of electricity in hours when its load node LMP was less than or equal to $0/MWh, out of a total consumption of 1,000 GWh of electricity in that year. That electrolyzer would have to procure and retire 1,000 GWh worth of total RECs in that year, but only 900 GWh would have to be from resources that meet the incrementality requirement. The remaining 100 GWh worth of RECs could be from *any* resource meeting the deliverability, and the temporal matching requirement, including existing renewables, as this energy would correspond to avoided curtailments.

**FIGURE 1: ANNUAL AVERAGE LMP HEAT MAP**




Source: The Brattle Group, data sourced from Hitachi Energy, Velocity Suite; Price Node coordinates come from S&P Global; Renewables proposed data comes from analysis of ISO interconnection queues and Lawrence Berkeley National Laboratory. Southeast and Florida represent the prices at power hubs.

LMPs are equal to the marginal cost of energy available at their location, based on the bids of sellers of power in the market.[18] In time periods when the LMP is less than or equal to $0/MWh, consumption of electricity is being compensated at that location, indicating that there is an excess of supply on the grid at that location.[19] Conditions of excess supply is what

[17] That is, renewable resources with in-service dates within three years of the in-service date of the electrolyzer.

[18] CAISO Tariff, Appendix C Locational Marginal Price. See https://www.caiso.com/Documents/AppendixC-LocationalMarginalPrice-asof-Feb1-2023.pdf.

[19] Seel et. al. ,Plentiful electricity turns wholesale prices negative, Advances in Applied Energy,2021; M Bajwa, J Cavicchi, Growing evidence of increased frequency of negative electricity prices in U.S. wholesale electricity markets, IAEE Energy Forum, 2017

leads to the curtailment of renewable energy. Stated differently, an LMP less than or equal to $0/MWh indicates that the cost of the generation resource available to serve an incremental increase in load at that location is $0/MWh or less and that incremental load would be paid to take energy off the grid at that time and location. These conditions indicate that the grid is inundated with excess renewable energy at this location and time and support the idea that incremental consumption, such as an electrolyzer, on the system at that location and time is being served by energy that would otherwise be curtailed.

It appears Treasury agrees with the assessment that negative wholesale prices indicate that incremental load would not increase emissions. Treasury states "curtailment is most likely to occur in the face of negative wholesale electricity prices if the marginal grid emissions rate is minimal or zero… [t]hese are times during which increased load is unlikely to increase significantly induced grid emissions."[20] However, Treasury does not propose a requirement based on this finding. The simplest approach would be to utilize the information provided by wholesale market prices, as pointed out by Treasury, and allow electrolyzers to claim the production of any renewable resources as incremental in hours when LMPs at the electrolyzer's location are less than or equal to zero.

## B. Analysis of Non-Positive Prices in the WECC

LMPs are reported for different time intervals, for five-minute intervals up to hourly intervals, for all locations in the wholesale markets across the U.S. Therefore, they are able to capture both the temporal and the locational variability in curtailments (i.e., when LMPs are less than or equal to zero) in most regions of the U.S. In Figure 2 below, we analyzed the pattern of negative LMPs at the Intermountain Power Plant (IPP) node in 2023, on a monthly and hourly basis. The results demonstrate that curtailments are considerably higher during daylight hours and concentrated during the spring months, given the high levels of hydro generation and relatively low load during this period in the WECC.

[20] 88 FR 89232

### FIGURE 2: FREQUENCY OF NEGATIVE LMPS AT INTERMOUNTAIN BY HOUR OF DAY AND MONTH

| Year | Month | % of Hours with LMP <= 0 | | | | | | | | | | | | | | | | | | | | | | | | # of Hours Curtailed | % of Hours |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | | |
| 2023 | Jan | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0 | 0% |
| | Feb | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 4% | 4% | 7% | 7% | 7% | 7% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 10 | 1% |
| | Mar | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 3% | 10% | 13% | 19% | 32% | 23% | 19% | 23% | 6% | 0% | 0% | 0% | 0% | 0% | 0% | 46 | 6% |
| | Apr | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 3% | 13% | 20% | 23% | 33% | 33% | 30% | 30% | 27% | 7% | 0% | 0% | 0% | 0% | 0% | 0% | 66 | 9% |
| | May | 0% | 0% | 0% | 0% | 0% | 0% | 3% | 26% | 39% | 48% | 55% | 48% | 48% | 42% | 48% | 48% | 45% | 23% | 0% | 0% | 0% | 0% | 0% | 0% | 147 | 20% |
| | Jun | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 7% | 23% | 20% | 23% | 17% | 23% | 23% | 20% | 10% | 7% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 53 | 7% |
| | Jul | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0 | 0% |
| | Aug | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0 | 0% |
| | Sep | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 3% | 7% | 7% | 3% | 3% | 7% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 10 | 1% |
| | Oct | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 6% | 6% | 10% | 10% | 6% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 12 | 2% |
| | Nov | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 3% | 3% | 3% | 7% | 7% | 10% | 7% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 12 | 2% |
| | Dec | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0 | 0% |
| Annual Average | | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 3% | 6% | 8% | 11% | 10% | 13% | 13% | 12% | 10% | 8% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 356 | 4.1% |

Sources and Notes: California ISO OASIS database: Real-Time 5 Minute LMPs averaged to the hourly level for the INTGS_3_UAMGNODE price node.

Figure 2 indicates that in 2023, during daylight hours and especially in spring months, electricity is often available at a non-positive price. In May of last year, approximately 20% of all hours had average 5-minute LMPs that were less than or equal to $0/MWh, and between 40% and 50% of these hours occurred between 8 am and 5 pm.

An analysis by Lawrence Berkeley National Laboratory (LBNL),[21] cited by Treasury in their guidance,[22] analyzed the frequency of negative pricing across over 50,000 nodes in the U.S. from 2012 to 2022. The analysis found that the frequency of negative prices has increased across the country due to the growth of renewable energy and the frequency varies widely as well (see Figure 3 below). The Southwest Power Pool (SPP) experiences higher frequency of negative prices in over 20% of hours, as compared to the Northeast and Mid-Atlantic regions that experience relatively low levels of negative prices. This analysis highlights the importance of taking into account the changing nature of the grid with the penetration of a higher amount of renewables.

Figure 3 shows data from the LBNL on the frequency of negative LMPs across the country in 2015 and 2022, illustrating the increasing trend in negative prices due to the growth of renewable energy. In 2015, few locations in the country saw negative LMPs greater than 10% of the time. Just seven years later, in 2022, a large region of the country from western Texas to North Dakota saw negative prices 20% of the time or more, and several locations in southern California saw negative prices approximately 10% of the time. As more renewable resources come online in future years, we expect this trend to continue and for negative prices to occur more frequently over a larger geographic region.

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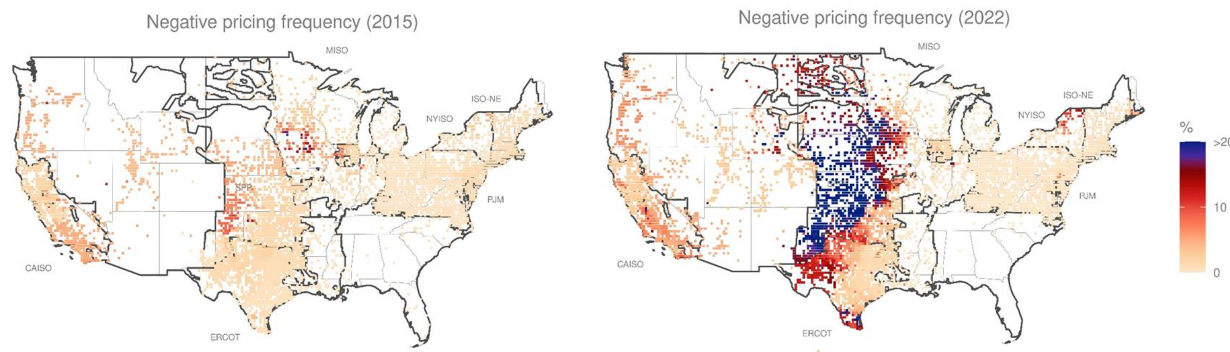
[21] Berkeley Lab, Electricity Markets & Policy, The Renewables and Wholesale Electricity Prices (ReWEP) Tool.

[22] 88 FR 89232

**FIGURE 3: FREQUENCY OF NEGATIVE LMPS IN 2015 AND 2022 ACROSS RTOS**




Source: Berkeley Lab, Electricity Markets & Policy, The Renewables and Wholesale Electricity Prices (ReWEP) Tool

A Per Se Curtailment Rule is uniquely aligned with electrolysis based hydrogen production, which has the operational capability to take advantage of negative price conditions, by purchasing electric energy under such conditions to run the electrolyzer and making hydrogen available for consumption, including electrical generation, during periods of high pricing.

The Advanced Clean Energy Storage (ACES) Facility, which is scheduled for commercial operation in 2024, is a prime example of the feasibility of such arbitrage. A Per Se Curtailment Rule based on LMP pricing at IPP would directly align the operational incentives of the ACES Facility with the intent and purpose of Section 45V.

# III. Deliverability

The requirements to demonstrate the deliverability of renewable energy to hydrogen production load need to align with the real-world operation of the power system, including wholesale power markets that pool transmission assets and rights to deliver economic energy across the market footprint. Deliverability requirements should also provide the correct incentives to locate new renewable resources on the grid in locations where they will have an impact on reducing carbon emissions. We find that the Section 45V Rule fails on both objectives. To address this, Treasury should realign the regions in the WECC and clarify the role of firm transmission rights in establishing deliverability. We discuss an approach that would provide correct incentives for locating new renewable resources in Section III on Temporal Matching.

## A. Aligning Deliverability with Grid Operation

The deliverability regions proposed by Treasury do not align with how the power system operates, how resources are procured and delivered, or with the operation of wholesale power markets. This is particularly true in the WECC region.

The deliverability regions identified by Treasury were adopted from the National Transmission Needs Study conducted by DOE.[23,24] There are several issues Treasury should clarify or amend with respect to the DOE Transmission Study regions as applied to Section 45V:

- Treasury should confirm that the proposed deliverability regions in the Section 45V rules align with BAA regions, including pseudo-tied generation resources that are physically interconnected in one BAA but are deemed to be produced in a different BAA, which provides Balancing Authority (BA) services and exercises BA jurisdiction over the resource. As discussed later, it would be appropriate for Treasury to consider delivery regions that align with wholesale market boundaries, but at a minimum, delivery regions should not split BAAs between multiple regions.
- The DOE Transmission Study regions do not align with how resource procurement and delivery occur in the WECC. The majority of utilities and customers in the WECC are not members of large, multi-state RTOs as is the case in the eastern U.S. In an RTO region, all transmission owners (TOs) participate in a joint transmission tariff. Therefore, a generation resource interconnected to any TO in the RTO only needs to secure transmission service once, under the RTO's tariff, to deliver to load interconnected anywhere in the same RTO. In the WECC, it is common practice for utilities to sign Power Purchase Agreements (PPAs) or directly own generation resources that are interconnected to other utilities' transmission systems and in other BAAs. Utilities will secure long-term firm transmission rights on a neighboring utility's transmission system to ensure that remotely located generation resources are deliverable to their load. For example,
  - The Los Angeles Department of Water and Power (LADWP) contracts and owns generation resources that are interconnected across multiple BAAs in California, Utah, and Arizona.[25]
  - The Tri-State Generation & Transmission Cooperative (Tri-State) owns generation resources physically interconnected to the Public Service Company of Colorado (PSCO)

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23 Prop. Reg. 1.45V-4(d)(2)(vi)

24 U.S. Department of Energy, "National Transmission Needs Study," October 30, 2023,

25 Los Angeles Department of Water & Power, "Power System," 2023.

BAA, the Western Power Area Administration (WAPA) Colorado-Missouri (WACM) BAA, and the Public Service Company of New Mexico (PNM) BAA. Tri-State uses these resources, spread over three BAAs in the WECC, to serve their load across multiple DOE Transmission Study regions (the proposed Mountain, Southwest, and Plains 45V regions).[26]

- WAPA Upper Great Plains West (WAUW BAA) has hydro resources in Montana[27] (the proposed Mountain 45V region) that it uses to serve load[28] in the SPP BAA (the proposed Plains 45V region).[29]
- WAPA Colorado River Storage Project (CRSP) is in the WACM BAA, which is in the Mountain DOE region, but has federal statutory customers in the PNM and El Paso Electric (EPE) BAAs, which are in the Southwest DOE region.[30]
- Palo Verde nuclear power plant is located in the Southwest region but Southern California Edison Co. (SCE), LADWP, and several California Municipalities have an ownership stake in the facility.[31]
- The Hoover Dam, owned by the U.S. Bureau of Reclamation, is located in the WAPA Lower Colorado BAA (WALC), meaning that it is located in the proposed Southwest 45V region. However, there are long-term supply agreements in place to sell power from the Hoover Dam to public utilities, cooperatives, municipalities, irrigation districts, and tribes in Arizona, California, and Nevada. These utilities span two of the proposed 45V regions (California and Southwest).[32]
- Several utilities in the Pacific Northwest own or contract for generation resources that are physically interconnected on the Bonneville Power Administration (BPA) or the NorthWestern Energy (NWMT) BAAs, and secure firm rights on the BPA and NWMT transmission systems to deliver that power to their BAAs.
  - For example, the Colstrip power plant, located in the Northwestern Energy (NWMT) BAA (placing it in the proposed Mountain 45V region) was historically co-owned by

[26] Tri-State has 55 MW of solar contracted and 200 MW currently under construction in New Mexico. Tri-State Generation and Transmission Association, Inc., "Annual Progress Report 2020 Electric Resource Plan," Dec. 1, 2021; Unit Power Purchase Contracts Dataset from HitachEnergy.

[27] WAPA, "About UGP," 2024.

[28] WAPA, "UGP Customers," 2024.

[29] WAPA, "SPP Membership," 2024.

[30] WAPA, "CRSP Customers," 2023.

[31] EIA, "Nuclear Reactor Ownership," September 2023.

[32] WAPA, "Power Projects," Oct. 27, 2023.

Portland General Electric (PGE), Puget Sound Energy (PSE), Avista, PacifiCorp, and Northwestern Energy. These owners had long-term transmission rights to deliver power from the plant to their respective BAAs, some of which are located in the proposed Northwest 45V region (PGE, PSE, Avista). Two of the Colstrip units have retired in recent years, and several of the owners have sold their shares as they move to exit thermal generation and decarbonize their resource mix. However, some of the previous owners of Colstrip have retained their transmission rights to Montana and are using those rights to develop clean energy resources near the Colstrip.[33] These new clean energy resources will be in the NWMT BAA, and therefore the proposed Mountain 45V region, which would exclude them from being deliverable for an electrolyzer developed by one of the Northwest entities with transmission rights to Colstrip.

  - PGE plans to procure 311 MW of the Clearwater Wind Project in Eastern Montana. PGE will own 208 MW of the plant and plans to procure 103 MW through PPAs. The final phase of construction will be complete in June 2024.[34]
  - PSE also signed a 20-year PPA for 350 MW of the Clearwater Wind Project, and plans to develop Beaver Creek wind farm in Stillwater County, MT, a 248 MW plant planned to come online in 2025.[35]

- PacifiCorp is developing the Gateway West transmission projects to transport wind energy in Wyoming, which lies in the PacifiCorp East BAA and the proposed Mountain 45V region, to the PacifiCorp West BAA that is in the proposed Northwest 45V region. Under the current proposal for deliverability, a potential electrolyzer in PacifiCorp West will be unable to take advantage of this wind energy from this new transmission project[36]

Figure 4 illustrates some of these examples.

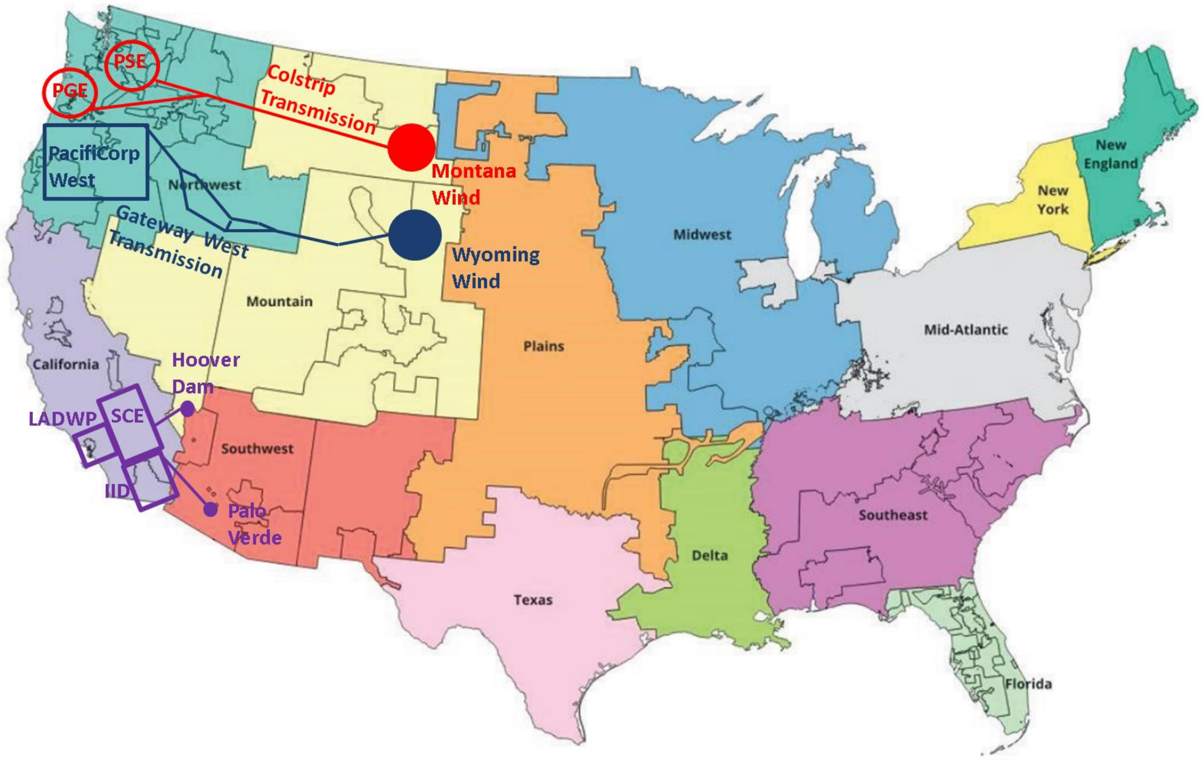
[33] Portland General Electric, "Clean Energy Plan and Integrated Resource Plan 2023," June30th, 2023; PSE, "PSE in Montana: Power Purchase Agreements,"2022.

[34] Ibid.; Capital IQ Clearwater Wind Power Plant Profile.

[35] PSE, "Puget Sound Energy announces clean energy wind project," 2023.

[36] PacifiCorp, Energy Gateway, accessed February 9, 2024

**FIGURE 4: EXAMPLES OF RESOURCE PROCUREMENTS CROSSING 45V REGION BOUNDARIES**




Source: Original 45V Regions map sourced from U.S. Department of Energy, Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2023, December 2023; annotated to include approximate locations of resources and transmission projects

In all these examples, the proposed DOE Transmission Study regions would split apart the utilities from their owned or contracted generation resources (See Figure 4). Therefore, regardless of the final deliverability regions determined by Treasury, it would be consistent with power system operations to allow resources to be claimed as deliverable across regional boundaries. Treasury has requested comments on how to verify that power outside of one region is actually deliverable to an electrolyzer in another region.[37] This can be accomplished by requiring the claiming entity to demonstrate that they have secured firm transmission rights to deliver the remote generation to their BAA, and to provide an electronic record of the transmission scheduled on an hourly basis to deliver the power into their region (commonly referred to as a NERC Tag or E-Tag).

The examples demonstrate how the use of long-term firm transmission rights to deliver power from remotely located resources has been common practice in the WECC for decades, and will continue to be an important driver of decarbonisation efforts as the region seeks to integrate a

[37] 88 FR 89233

geographically and technologically diverse supply of clean energy. In fact, the sale of long-term firm transmission rights has recently enabled the development of regional transmission infrastructure in the WECC to deliver clean energy to load, in the absence of an RTO-style regional transmission planning process.[38] In addition, delivery of power using firm transmission rights is easily verified, using an E-Tag. Therefore, excluding incremental renewable resources from being counted as deliverable across 45V regions, if backed up by firm transmission rights and an E-Tag, would bias electrolyzers located in the WECC and potentially undo existing resource plans aimed at decarbonizing the power system in the region.

A further bias against electrolyzers in the WECC, compared to the eastern U.S., is created by the proposed 45V regions due to the misalignment of western regions with existing regional wholesale markets. The DOE Transmission Study regions in the eastern U.S. align closely with wholesale markets. ERCOT, NYISO, ISO-NE, PJM, and SPP closely align with individual regions in the DOE Transmission Study, while MISO is split into MISO-North (approximately the Midwest region) and MISO-South (the Delta region). The DOE did not apply similar treatment of wholesale power markets in the WECC. The CAISO market loosely aligns with the California region, with the inclusion of the LADWP BAA, the BANC BAA, and other smaller BAAs located in California. However, the Western EIM (WEIM) and Western EIS (WEIS) are not reflected in the DOE Transmission Study regions. Ignoring the WEIM and WEIS in developing the deliverability regions is inconsistent with how these markets improve the deliverability of power across their footprints.

The members of the WEIM and WEIS pool their transmission assets and contracted transmission rights to allow the market to deliver power across the footprint without having to procure or pay for separate transmission service. Furthermore, the WEIM and the WEIS, administered by CAISO and SPP respectively, conduct a Security Constrained Economic Dispatch (SCED) to determine the lowest cost dispatch of resources in the market to serve load, subject to deliverability constraints on the transmission grid.

In this way, the WEIM and WEIS solve for deliverability of power collectively across their entire footprints in a single, centralized market-clearing process. Establishing deliverability regions in the WECC that align (or closely align) with the WEIM and WEIS footprints would be consistent with Treasury’s treatment of wholesale markets in the eastern U.S.

[38] Merchant transmission projects that rely on the sale of long-term firm transmission rights and are currently under advanced development in the WECC, include SunZia, SWIP-North, TransWest Express, Cross-Tie, and Southline.

In the next section, we discuss the need to align incentives for locating new renewable resources on the grid at locations where they will have a commensurate impact on reducing carbon emissions as hydrogen production load. We explain why the three criteria work in concert to achieve Treasury's overall objective of ensuring that hydrogen production load does not increase emissions in the power sector, and why it is not sufficient to only require that new generation resources be located in the same geographic regions as the hydrogen production load.

# IV. Temporal Matching

Recent studies evaluating temporal matching requirements indicate hourly matching achieves the largest emissions reduction compared to other temporal matching options (e.g., annual matching) over the long-term and attracts investment in the necessary resources to achieve long-term deep decarbonisation.[39] However, the same studies also indicate that the cost of hourly matching is considerably higher than other temporal matching options.[40] In addition, the data and instruments needed to implement hourly matching are not immediately available and will likely not be available to implement hourly matching by 2028 as Treasury proposes.

We propose an alternative approach that combines some elements of both annual and hourly matching. Our proposed approach would achieve emissions reductions at a lower cost than pure hourly matching and can be implemented with less effort than hourly matching, which would require the development of time-matched EACs. In the future, as the grid becomes increasingly decarbonized and the tracking of hourly energy attributes matures, hourly matching may be necessary to achieve full decarbonization.

## A. Background on Hourly Matching

One of the primary goals of the Section 45V Rule is to incentivize the production of clean hydrogen without diverting renewable energy from other uses. If energy were diverted, fossil generation would likely have to increase to meet demand, resulting in an overall increase in

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39 Ricks et al., "Minimizing emissions from grid-based hydrogen production in the United States," Environmental Research Letters. Jan 6, 2023; Zeyen et al., "Hourly versus annually matched renewable supply for electrolytic hydrogen," Zenodo, Dec. 19, 2022.

40 Zeyen et al., "Hourly versus annually matched renewable supply for electrolytic hydrogen," Zenodo, Dec. 19, 2022; BCG, "Green Hydrogen: An assessment of near-term power matching requirements," Apr, 2023.

emissions. Hourly matching (in concert with the other criteria) avoids this by requiring hydrogen producers to consume carbon-free electricity that is produced in the same hour that it is consumed.

Proponents of hourly matching argue that emissions are (usually[41]) lower with this strategy than with annual matching, largely due to higher volumes of renewable build.[42] Though it is not possible to fully disentangle the factors producing superior GHG performance of hourly matching, a common element driving this result seems to be the propensity of hourly matching to require the hydrogen electrolyzers to procure *more total renewable* supply than the electricity they consume (i.e., to overbuild renewables relative to their total demand). If the excess renewable supply can be sold into the power grid, it can displace fossil supply; in scenarios where excess renewable purchase and sales are large enough, it can more than offset the renewable-competition effect and induce net negative emissions in the long run.

Conversely, studies have found that this overbuilding leads to considerably higher costs under an hourly matching than under other clean energy procurement approaches, especially when applied individually on a specific customer-resource basis, rather than in aggregate. Relatedly, studies also find that it is more expensive (with \$0.4–\$1/kg being the “consensus range” of incremental costs across studies) to produce hydrogen with hourly matching than with annual matching, as shown in Figure 5. The drivers of the higher cost of production from hourly matching are associated with the mismatch between variable and patterned renewable profiles versus the flat production profile that would be preferred by electrolyzer developers to maximize their capacity factors (and reduce levelized electrolyzer cost). To match the renewable output with electrolyzer demand, studies model alternative options all of which impose some cost, including: (a) curtailing or selling excess renewables, (b) deploying batteries

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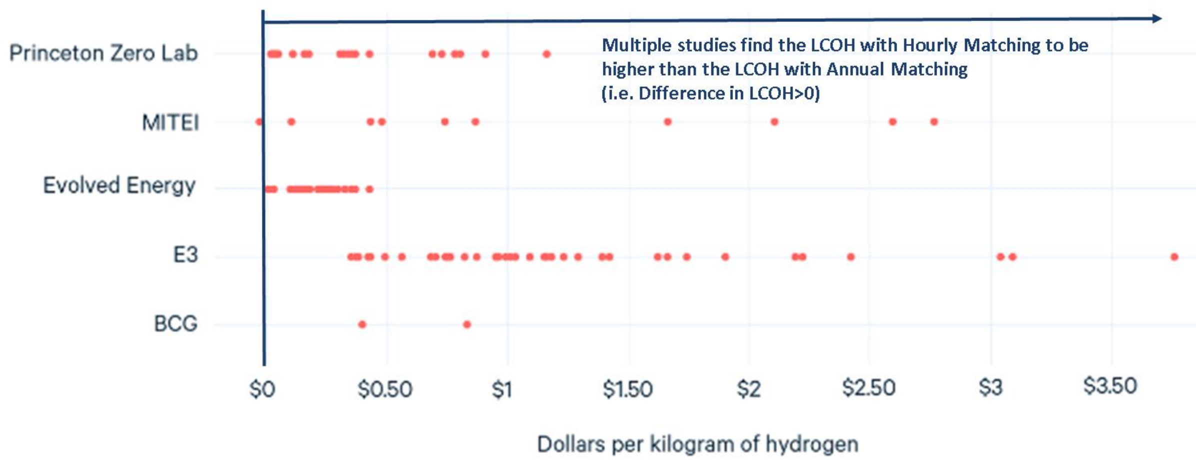
[41] Under certain specific conditions, hourly matching can produce more emissions than an annual matching approach. As an example of when this could occur, consider a scenario where wind is the renewable resource producing excess supply in the middle of the night relative to hydrogen production load. If the excess wind can be sold overnight in an annual matching strategy, it may displace emitting generation leaving the electrolyzer to charge from grid power during the daytime hours when there is excess solar that might otherwise get curtailed. In this circumstance, an hourly matching constraint would incentivize the electrolyzer owner to store the excess wind in a battery and discharged during the day when the system has excess solar generation (this is the opposite of how a battery would operate if seeking to reduce system-wide emissions). The likelihood hourly matching will misalign with overall GHG abatement will diminish as the system becomes increasingly decarbonized.

[42] Ricks et al., "Minimizing Grid-Based Hydrogen Production in the United States,” Jan. 6th, 2023; E3 and ACORE, “Analysis of Hourly & Annual GHG Emissions,” Apr. 2023.

to absorb and reshape renewable supply, and/or (c) building excess renewables relative to an annual energy matching volume.[43]

**FIGURE 5: LEVELIZED COST OF HYDROGEN (LCOH) IN HOURLY MATCHING MINUS LEVELIZED COST OF HYDROGEN IN ANNUAL MATCHING ACROSS SCENARIOS**




Source: Adapted from Resources for the Future

Given that the ultimate objective is to ensure that hydrogen production reduces more emissions than it causes, we propose an alternative approach that combines elements of annual and hourly matching and is less expensive, yet effective, at meeting the same goals for the near term rather than the overly restrictive requirement of hourly matching.

## B. Annual Matching with Hourly Impact Test

We propose an alternative that combines elements of an annual and hourly matching requirement for grid connected hydrogen production facilities. We proposed that electrolyzers be subject to an annual matching requirement, coupled with an hourly emissions impact test using the Locational Marginal Emissions (LME) at the electrolyzer location and the renewable resource location (LME Netting). The annual matching requirement would force each electrolyzer to procure and retire RECs equal to its annual consumption.

[43] Ricks et al., "Minimizing emissions from grid-based hydrogen production in the United States," Environmental Research Letters. Jan 6, 2023; Energy Innovation Policy & Technology LLC. 'Smart Design Of 45V Hydrogen Production Tax Credit Will Reduce Emissions And Grow The Industry," Apr. 2023; Wood Mackenzie, "Green hydrogen: what the Inflation Reduction Act means for production economics and carbon intensity," Mar. 2023.

The objective of the hourly emissions impact test is to provide the correct incentives to locate new renewable generation resources on the grid at locations where they will have a commensurate impact on reducing carbon emissions as hydrogen production load.

Renewable resources have the incentive to locate where there is the best wind or solar on the grid, which creates pockets of wind or solar production in certain regions. Incremental wind or solar added to an existing pocket of the same resources on the grid creates operational problems for the system, but also has a diminished emissions reduction impact. Development of the same type of renewable resources at the same location creates several problems:

- Increased congestion on the system, which will have financial implications for customers and require grid operators to dispatch higher-cost resources that are likely carbon emitting to alleviate congestion and serve load.
- Higher interconnection costs for future renewable resources that will likely require expensive transmission upgrades.
- Greater curtailment of renewable energy due to limited transmission capacity to deliver excess renewable generation to load that reduces the long-term value of renewables located in the area.

LME Netting would measure the relative emissions impact of hydrogen production load compared to the emissions abatement impact of the renewable generation claimed by that electrolyzer. LME Netting, paired with an annual matching requirement, would be an alternative to the proposed hourly matching criteria. The screen would compare the LME at the hydrogen production load location and at the renewable resources to determine the annual GHG impact of hydrogen production net the GHG emissions abatement impact of the renewable resource. At the end of the year, if the emissions impact of the electrolyzer are found to be greater than the emissions abatement of the generators, the electrolyzer will be required to procure and retire an additional amount of RECs to make up for the differential that would have to meet the deliverability, incrementality criteria, and be matched on an annual basis with the hydrogen production load.

LME Netting aligns incentives to locate resources in areas where they will have the greatest emissions impact, and to locate hydrogen production resources in areas where there is abundant opportunity to develop new renewable resources. The proposed screen would provide a clear signal on the actual emissions impact of electrolyzer consumption relative to the emissions abatement created by new renewable resources. The LME test is likely to be less costly than the proposed hourly matching requirement, as it increases flexibility on REC purchases, lowering the cost of integrating hydrogen production onto the grid. This will help decarbonize other sectors of the economy that can use clean hydrogen as a substitute for fossil fuels, while ensuring that hydrogen production has a positive impact on emissions reduction in the power sector.

Treasury's proposed EAC Criteria approach of deliverability based on the DOE regions, hourly matching, and incrementality based on the in-service date of resources, can be enhanced with LME Netting to provide the correct incentives to locate new renewables on the grid at locations where they will have the largest emissions reduction impact. There is an implicit assumption in Treasury's proposal that hourly matching will solve this problem by forcing electrolyzers to over procure renewables. This is incorrect. While the hourly matching requirement will force electrolyzers to over procure, there is nothing preventing an electrolyzer from locating their resources in the most renewable-rich areas of the grid that are already over saturated with renewable generation, while getting full credit for 100% of the production of those resources. This will exacerbate the problem of crowding renewables onto the grid in the same locations, increasing interconnection costs for other new renewable resources (potentially crowding them out and preventing them from being built), increasing congestion on the grid, and increasing system curtailments without ensuring that the power consumption from the associated electrolyzer does not have a relatively high emissions impact in another location on the grid.

LMEs provide location and time specific emissions rates for electricity consumption on the grid. To date, only PJM has released locational emissions data for their market.[44] To apply this test nationwide would require other market operators to produce the same data. However, given that this data is already calculated by third-party providers, it should be easily provided by the market operators and is likely less burdensome to implement then the temporal matching regime proposed by Treasury. LMEs would allow electrolyzers to compare the hourly emissions impact of their consumption against the hourly emissions reduction from renewable generation. The LME measures the amount of carbon emissions displaced by injecting a unit of clean energy at the grid in every hour, at every node. This data are both locationally and temporally granular. The LME differential between the supply and demand locations is thus representative of the difference between the LME *avoided* by the supply and LME *caused* by the demand. If the electrolyzer's LMEs were lower than the LMEs of the renewables, the facility would receive a credit equal to the difference multiplied by its consumption in that hour.

[44] Proprietary LME data is available through vendors such as ReSurety for most of the RTO/ISO markets in the U.S. See "ReSurety and WattTime to Make Marginal Emissions Data Widely Available to Support More Impactful Climate Action". REsurety.com, January 10, 2023. https://www.pjm.com/markets-and-operations/m/emissions

Alternatively, if the electrolyzer's LMEs were higher than the LMEs of the renewables, the facility would have a deficit for that hour. At the end of the year, the hourly credits and deficits are totalled, and if the facility has an aggregate deficit it would be required to buy additional RECs equal to that deficit.

LME Netting creates the right incentives for siting renewables in zones without congestion but also ensures that the hydrogen production load has a negative impact on overall system emissions.

# V. Conclusion

The Section 45V Rule establishes a framework to determine the amount of tax credit available, if any, for the production of clean hydrogen. The proposed framework centers on three criteria—Incrementality, Deliverability, and Temporal Matching—designed to ensure that the tax credits are available only to hydrogen production with little or no greenhouse gas emissions and do not divert renewable energy from other uses. While we support the Treasury's objectives, we have identified several opportunities to improve the proposed rules to better align with real-world operation of the power system, particularly in the WECC. Specifically, we propose the following:

- **Incrementality:** We agree that avoided curtailments should count towards the incrementality requirement and propose that an electrolyzer be allowed to claim its energy consumption as avoided curtailment in all hours when the LMP at the location of the electrolyzer is less than or equal to zero, as long as a REC is procured and retired. The energy consumed during these hours would count towards the incrementality requirement, even if the power is sourced from existing resources, as it corresponds to excess energy.

- **Deliverability:** We propose an alternative geography for WECC that will ensure renewable generation is deliverable to hydrogen production load and utilizes functionally appropriate and well-established regions that align with regional wholesale markets in the WECC. This alternative geography is similar to the treatment allowed in most of the Eastern Interconnection under Treasury's proposed deliverability regions. We also propose that incremental renewable resources not located in the same regional wholesale market as the electrolyzer can meet the deliverability requirements by securing firm transmission rights and providing an E-Tag from the renewable resource to a delivery point in a BAA in the same regional market as the electrolyzer.

- **Temporal Matching:** Given the potential cost of the proposed hourly matching requirement, we propose that this condition be replaced with an annual matching requirement with LME Netting with an hourly emissions impact test to ensure that electrolyzer owners are incentivized to locate renewable resources where they will have a commensurate emissions impact relative to the emissions caused by the hydrogen production load. LME Netting would sum the annual difference between the hourly LME of the load and supply nodes and require the electrolyzer to procure RECs in an amount equivalent to the “excess” emissions at the load node.

These alternative approaches are consistent with the Section 45V Rule. However, these proposed alternatives better reflect the real-world operating conditions of the wholesale electric markets, particularly in the WECC.

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## ABOUT BRATTLE

The Brattle Group is an economic consulting firm with 500 professionals across North America, Europe, and Asia-Pacific. Brattle has assisted market operators, utilities, regulators, and market participants in the US, Canada, and worldwide with insightful, rigorous analyses that help navigate a changing energy landscape. Our work informs wholesale market designs, planning processes, and investment decisions to meet reliability and environmental objectives cost-effectively.

We have contributed to the design of capacity markets and/or energy and ancillary services (E&AS) markets such as PJM, MISO, ERCOT, CAISO, NYISO, ISO-NE, and SPP in the US, and the AESO and IESO in Canada. Brattle has also evaluated regional transmission organization (RTO) formation/expansion benefits in the U.S. West and Southeast; developed a framework and tools for transmission benefit-cost analysis and applied them to many of the large transmission projects in the U.S.; and advised state agencies on their procurements and transmission plans for meeting clean energy objectives.

Brattle has deep expertise in the hydrogen industry, assisting clients in North America and Europe evaluate the economics of hydrogen production, transportation, and end-use applications. In addition, we have assisted clients evaluate proposed hydrogen infrastructure regulations and clean production tax credits.

For more information, please visit brattle.com.

EXHIBIT C

BRG Memo on 45V Deliverability Regions

# 45V DELIVERABILITY REGIONS

Comments on the proposed deliverability regions and an alternative proposal to improve regional alignment with WECC operating procedures

February 22nd, 2024

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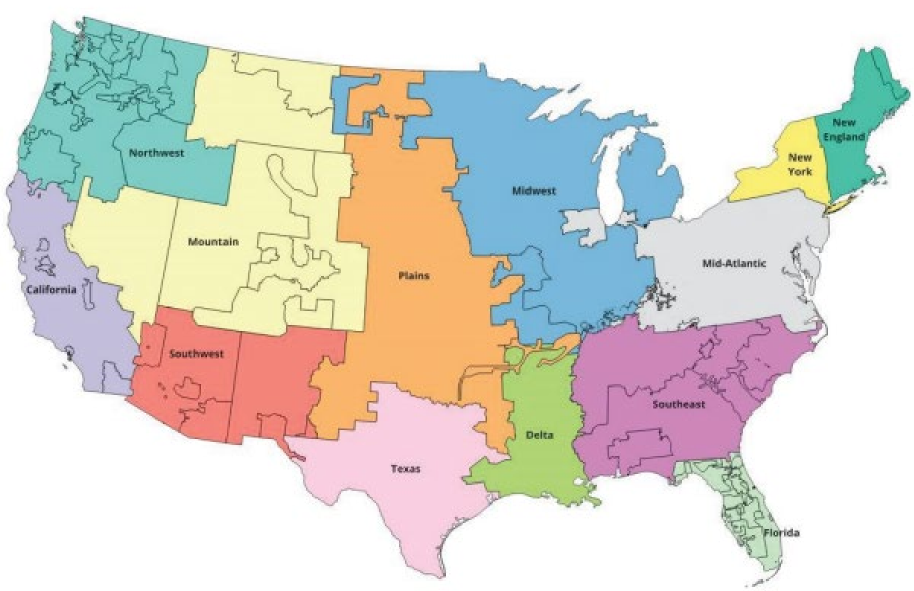
*The views and opinions expressed in this article are those of the author(s) and do not necessarily reflect the opinions, position, or policy of Berkeley Research Group, LLC or its other employees and affiliates.*

# 1. Background

The IRS 45V proposed regulations (the "Regulations") establish deliverability regions that require the electricity from a qualifying Energy Attribute Certification (EAC) be produced in the same deliverability region as the hydrogen production facility.

Designing requirements that ensure the physical deliverability of clean electricity to hydrogen production facilities is necessary to confirm that the production of hydrogen does not increase system emissions through regional arbitrage (Emissions in Region X increase more than the decrease in Region Y). The currently proposed Regulations have split the continental United States into thirteen regions, which are approximated by the Department of Energy in Figure 1 in the DOE 45VH2-GREET User Manual.[1] Though not contained directly in the Regulations, the regions appear to be intended to map to balancing authority areas (BAAs) (the "45V Regions").[2] Table 2 in the Appendix gives the mapping of BAAs to 45V Regions both from the DOE 45VH2-GREET User Manual and the proposed region mapping in this whitepaper.

**Figure 1. 45V Regions Based on DOE Needs Study from DOE**




While most of these regions are based upon ISO/RTO footprints, others are not. Additionally, some regions, particularly those in the Southeast and the four western

[1] U.S. Department of Energy, Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathway using 45VH2, GREET 2023, December 2023, p. 23 (available at https://www.energy.gov/sites/default/files/2023-12/greet-manual_2023-12-20.pdf).

[2] The Preamble to the Regulations provides "The DOE has mapped the DOE Needs Study regions to actual balancing authorities" (P. 13). The DOE's mapping appears to be contained in the GREET User Manual. However, the "region" map in the Greet User Manual differs from the DOE Regional Transmission Study Map, which is the region map that is specifically referenced in the Regulations. ("Region" is defined to mean a region derived from the National Transmission Needs Study that was released by the DOE on October 30, 2023) (the "2023 Study") 1.45V-4(2)(d)(vi).

regions (California, Mountain, Northwest, and Southwest) presumably group several different balancing authority areas.[3]

The intent of the 45V Regions is to ensure a reasonable assurance of deliverability – that the electricity from an EAC-producing resource can be physically delivered to the EAC-retiring hydrogen production facility (to avoid an emitting generator being ramped up to meet the hydrogen production facility demand). However, the regions as proposed, particularly in WECC, fail to meet this standard. The four western regions do not reflect the reality of the west's market dispatch and as drawn effectively sever generation from load in an arbitrary manner.

The western 45V Regions, as currently defined, aggregate balancing authority areas by broad consideration of state lines (for example Mountain is largely coterminous with Nevada, Utah, Colorado, Wyoming, and Montana). This is not in line with actual scheduling or dispatch in the WECC power system. Many load centers on the Pacific Coast are served by a series of transmission lines that deliver energy from the interior to the coast or from north to south. These lines were originally constructed to make baseload generating resources such as coal (Intermountain Power Plant, Navajo, or Colstrip), federal hydro, and nuclear (Palo Verde) available to serve load centers. Much of the coal has been or is being retired as the power system decarbonizes and these transmission lines are now moving renewable energy from the less land-constrained interior WECC to the more land-constrained, higher load coastal areas. System dispatch and market structures in WECC are designed to facilitate this and to allow for arbitrage between western utilities of available renewable generation.

By comparison, the 45V Regions for the other two North American electricity interconnects (Eastern Interconnect and ERCOT) largely match market structure and joint dispatch of generation and transmission and are therefore appropriate to meet the deliverability goals, providing reasonable assurance that emissions will not increase due to hydrogen production demand.

# 2. Western Interconnect Power Alignment Mismatch

The 45V Regions do not properly incorporate power system organization in WECC.

The Regulations state that the proposed 45V Regions "provide[s] reasonable assurances of deliverability of electricity because the regions, as defined earlier, were developed by the DOE in consideration of transmission constraints and congestion and, in many cases, match power-systems operation." While we agree that the deliverability rules should consider both transmission constraints/congestion and the reality of power-

[3] DOE 45VH2-GREET User Manual, p. 22. "The DOE has mapped U.S. [balancing authority areas] to the regions defined in the [DOE Needs Study]." It is not clear from the DOE Needs Study that any balancing authority area mapping was completed as there is no index in the DOE Needs Study indicating which regions correspond to which balancing authority areas.

system operation, we do not agree that the 45V Regions as defined by the DOE uniformly succeed in doing so.

Fundamentally, the 45V Regions cut across major transmission corridors in WECC with the impact of severing critical renewable development basins off from load. These transmission corridors were developed to provide deliverability of resources to load and to increase grid stability through regional arbitrage and are being further developed and enhanced to specifically bring increased renewable energy to load. It is unreasonable to define deliverability regions that do not consider important, large transmission corridors. At worst, given the realities of how decarbonization is being planned in the West, this dynamic may disincentivize efficient siting of new renewable energy and/or new transmission lines needed to decarbonize the broader power system and prevent hydrogen hubs from developing on the west coast.

Figure 2 graphically shows three major transmission corridors that cross the 45V Region boundaries. In each of these cases, the large load centers are on the coast and the transmission was constructed to access generation inland. Historically, the inland generation has often been coal (Colstrip) or nuclear (Palo Verde) but current plans at coastal utilities with large loads in the California and Northwest Regions, including Puget Sound Energy, Portland General Electric, PacifiCorp, Los Angeles Department of Water and Power, and Southern California Edison appropriately include procurement of renewable power outside their 45V Region leveraging the bulk transmission system and these major corridors.

**Figure 2. Transmission Corridors that Cut Across 45V Regions**


Further detail on select transmission paths, resource basins, and large non-emitting resources that cut across the proposed 45V Regions are provided in Table 1.

**Table 1. Select Examples of WECC Operations Misaligned with 45V Regions**

**Hoover Dam (Southwest to California)**

- Owned by the U.S. Bureau of Reclamation, The Hoover Dam is located in the Western Area Power Administration (WAPA) Lower Colorado BAA (WALC), meaning that it is electrically connected to the Southwest 45V Region. However, Hoover has long-term supply agreements with entities in the California 45V Region. Transmission was constructed to access power from the Hoover Dam, leading to plans to continue to expand renewables in the area and leverage existing transmission capabilities.

**Colstrip (Mountain to Northwest)**

- Colstrip is located in Montana and is part of the Northwestern Energy (NWMT) BAA, placing it in the Mountain 45V Region. Historically the power plant was co-owned by Portland General Electric (PGE), Puget Sound Energy (PSE), Avista, PacifiCorp, and Northwestern Energy, among others. These owners had long-term transmission rights to deliver power from the plant to their respective BAAs, most of which are located in the Northwest 45V Region (including PGE, PSE, Avista). Two of the Colstrip units have retired in recent years, and several of the owners have sold or plan to sell their shares as they move to exit thermal generation and decarbonize their resource mix. However, some of the previous owners of Colstrip have retained their transmission rights to Montana and are using those rights to develop clean energy resources. These new clean energy resources will be in the NWMT BAA, and therefore the Mountain 45V region, which would exclude them from being counted as deliverable for an electrolyzer developed by one of the Northwest entities with transmission rights to Colstrip. This could also impact any hydrogen hub in the Pacific Northwest.

**Palo Verde (Southwest to California)**

- The Palo Verde trading hub is physically located in Arizona, and the Palo Verde (PV) nuclear plant is in the Arizona Public Service (APS) BAA placing it in the Southwest 45V Region. Several owners of PV Nuclear, who have firm transmission rights to their load, are in the California 45V Region. Similarly, there are several generators connected to the PV trading hub, including many renewable resources, that are owned by or contracted to entities in the Claifornia 45V Region.

**WAPA Colorado River (Mountain to Southwest)**

- WAPA's Colorado River Storage Projects (CRSP) division is in the Western Area Colorado Missouri (WACM) BAA, making it part of the Mountain 45V Region. However, its federal statutory customers and the corresponding long-term transmission rights it controls are spread across the Mountain and Southwest 45V Regions.

**Pacific DC Intertie (Northwest to California)**

- The Pacific Direct Current Intertie (PDCI) is a large HVDC line connecting BPA in the Northwest 45V Region to the California 45V Region. The proposed regional split would limit the ability to use the PDCI to share renewable energy between the two regions.

**Pacificorp East to Pacificorp West (Mountain to Northwest)**

- Through the ongoing Energy Gateway Transmission Expansion Plan, PacifiCorp is developing new transmission to improve connectivity in and between PacifiCorp East and West as well as create pathways to deliver renewable energy to load centers. The Gateway West and the Boardman-to-Hemingway Line will connect PacifiCorp West to PacifiCorp East by connecting Pacificorp Wind in Wyoming to load centers in Washington through 1,189 miles of 500 kV, single circuit transmission. The increased range of deliverability available to PacifiCorp through these projects would be stymied by the proposed Mountain and Northwest 45V Region definitions.

Given the importance of these large transmission corridors to procurement, siting, and deliverability of power between inland generation and coastal load, it is necessary that the final 45V Regions reflect the reality of what makes a resource deliverable in WECC and do not unreasonably cut off renewable energy basins from the hydrogen production facilities.

# 3. Appropriate Region Aggregation Criteria

Matching the 45V deliverability regions with regional wholesale markets that jointly operate transmission and generating resources defines more appropriate regions.

An area of concern for the deliverability region definitions is that they are inconsistent across the U.S, and thereby disadvantage certain regions. Texas (ERCOT), Plains (SPP), Mid-Atlantic (PJM), New York (NYISO), and New England (ISONE) are all aggregated so that the region appropriately matches a jointly dispatched generation and transmission market that reflects how the system is actually operated.

The Western Energy Imbalance Market (WEIM), and MISO are the only two regional wholesale markets that jointly operate transmission and generation that are not aggregated in the 45V regions. The Western Energy Imbalance Service (WEIS), operated by SPP, is the other regional market in WECC not explicitly considered in the regional definitions but its entire footprint is located in the proposed Mountain region. In the Southeast, several large BAAs in the SERC region are being treated as one region despite having multiple balancing areas without jointly operated transmission.

Joint operation of transmission and generating assets is the most important part of deliverability.[4] This joint operation, such as in the Eastern RTO/ISO markets and in the WEIM is designed to optimally dispatch generation to minimize customer costs. In practice this means maximizing generation from zero marginal cost renewable generation across the market footprint. This functionally maximizes the displacement of emitting generation by deliverable non-emitting resources which aligns with the intent of the deliverability requirement in the Regulations.

Furthermore, a large producer of hydrogen such as an electrolyzer should participate directly in wholesale markets – making bids for purchasing electricity and providing system operators with the option to turn the project down when prices are high or power is short. In times of low prices, the load associated with hydrogen production is effectively converting unneeded power into fuel which can displace emissions in industrial or transportation systems or provide dispatchable power generation. In times of high prices, hydrogen may be used to provide power to the broader system.

Given this, regional wholesale markets are the proper aggregation and ignoring the structure and operation of the WEIM and WEIS biases against hydrogen production facilities located in these regions in several key ways:

(1) It ignores the flexibility that these markets bring to new resource procurement in WECC, resulting in 45V tax credits creating a conflicting incentive with existing regional integration efforts.

(2) It unfairly ignores that these markets operate with respect to transmission usage and resource dispatch in similar manner as the regional wholesale markets in the eastern U.S that are defined as their own regions.

[4] The Regulations note that internal regional transmission congestion could limit deliverability for specific projects but that there is no administratively feasible manner to include this in a verification test.

(3) It ignores the critical integration of hydrogen production facilities with the broader market in terms of bidding into the market and dispatch of resources to serve those bids when market prices are sufficiently low.

# 4. Proposed WECC Regions

The proper regional aggregation in the WECC is to split between the Western Energy Imbalance Market (WEIM) and the Western Energy Imbalance Service (WEIS).

We acknowledge that transmission constraints and the realities of system dispatch mean that it is appropriate to split the WECC into several subregions for the purposes of validating deliverability. However, for all the reasons explained in this report, the current regions in the Regulations are arbitrary and do not properly represent how the transmission system and market structures should build up into appropriate regions.

For example, within the WEIM footprint, all participating balancing authority areas allow a centralized market operator to use the generation across the entire footprint to balance real-time supply and demand, leading to more economic and reliable dispatch. The DOE National Transmission Study acknowledges that the WEIM helps coordination with generators and transmission operators for WEIM participants[5], which while accurate, undersells the full dispatch that is performed as part of the WEIM process.

The members of the WEIM and WEIS pool their transmission assets and contracted transmission rights. This allows the market to deliver power across the footprint without having to procure or pay for separate transmission service. The designated market operator does this by using security constrained economic dispatch (SCED) to leverage the most economic generation available, subject to the operating constraints of the generating units and transmission assets[6], just as would be done within an RTO/ISO real-time market. In this way, the WEIM and WEIS solve for deliverability of power collectively across their entire footprints through a centralized market-clearing process, consistent with how wholesale markets in the eastern U.S. solve for deliverability. Therefore, it would be appropriate for Treasury to establish the deliverability regions in the WECC consistent with the WEIM and WEIS footprints, as shown in Figure 3.[7]

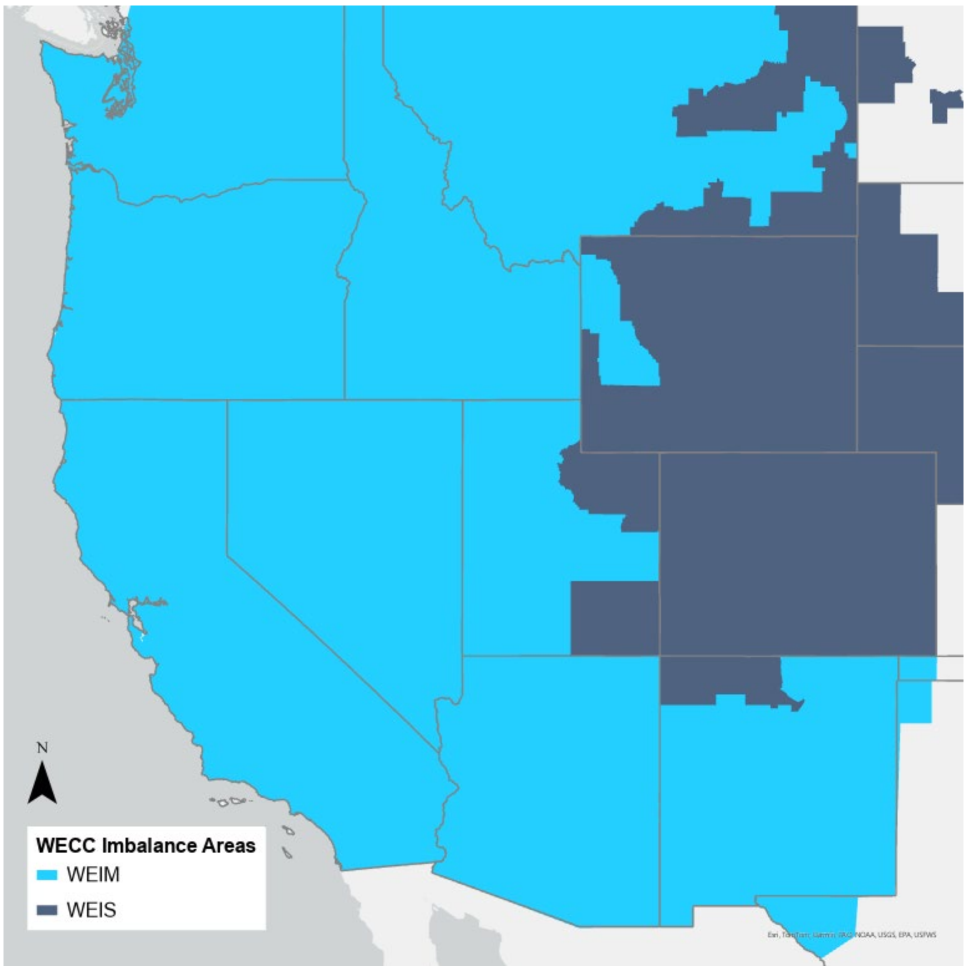
The WEIM was explicitly designed to increase the use of the transmission system to integrate renewable energy across its entire footprint. In the California ISO's (CAISO's) 2022 Annual Report on Market Issues and Performance, they reported: "The WEIM was designed to provide benefits from increased regional integration by enhancing the efficiency of dispatch instruction, reducing renewable curtailment, and reducing total requirements for flexible reserves. The CAISO real-time market software solves a cost minimization problem for dispatch instructions to generation considering all of the

[5] https://www.energy.gov/sites/default/files/2023-10/National_Transmission_Needs_Study_2023.pdf p.46
[6] https://www.wapa.gov/wp-content/uploads/2023/04/WEIS_FAQ.pdf
[7] Certain non-participating balancing areas such as the Imperial Irrigation District (IID) are mapped to the WEIM for administrative simplicity because they are deeply tied to surrounding BAAs in the EIM and their resources are able to participate in the market. These non-participating BAAs are limited to IID, small Public Utility Districts in the Northwest, and a few small (often no load and one generator) BAAs in the Northwest and Southwest.

resources available to the market including both the WEIM and CAISO areas. This can allow the market to increase efficiency by optimizing energy transfers economically in real-time between WEIM areas, balancing supply and demand across the footprint with lower-cost generation. Energy transfers between balancing areas helps to reduce curtailment of low cost renewables during times of excess generation."

Like the regions proposed by Treasury, the WEIM and WEIS footprints map to BAAs. In Table 2, we have provided a proposed mapping of BAAs to WEIM and WEIS regions.

**Figure 3. WEIM and WEIS Footprint**




Source: BRG, illustrative of expanded WEIM and WEIS service territories

In addition to utilizing a consistent approach that aligns with the actual dispatch of transmission and resources, aligning to the WEIM and WEIS would support existing decarbonization policy and avoid unintended consequences with misaligned incentives for various credits or governmental policies as the WEIM:

(1) Considers carbon leakage explicitly and has dispatch rules to limit how much the regional market redispatches to increase emissions when determining

market trades with states that have a carbon price such as California and Washington. The proposed EDAM (WEIM day ahead market) and Markets+ (WEIS day ahead market) regional wholesale markets would further integrate deliverability and integration of power operations across WECC and should be considered by Treasury in establishing the WECC's 45V regions.

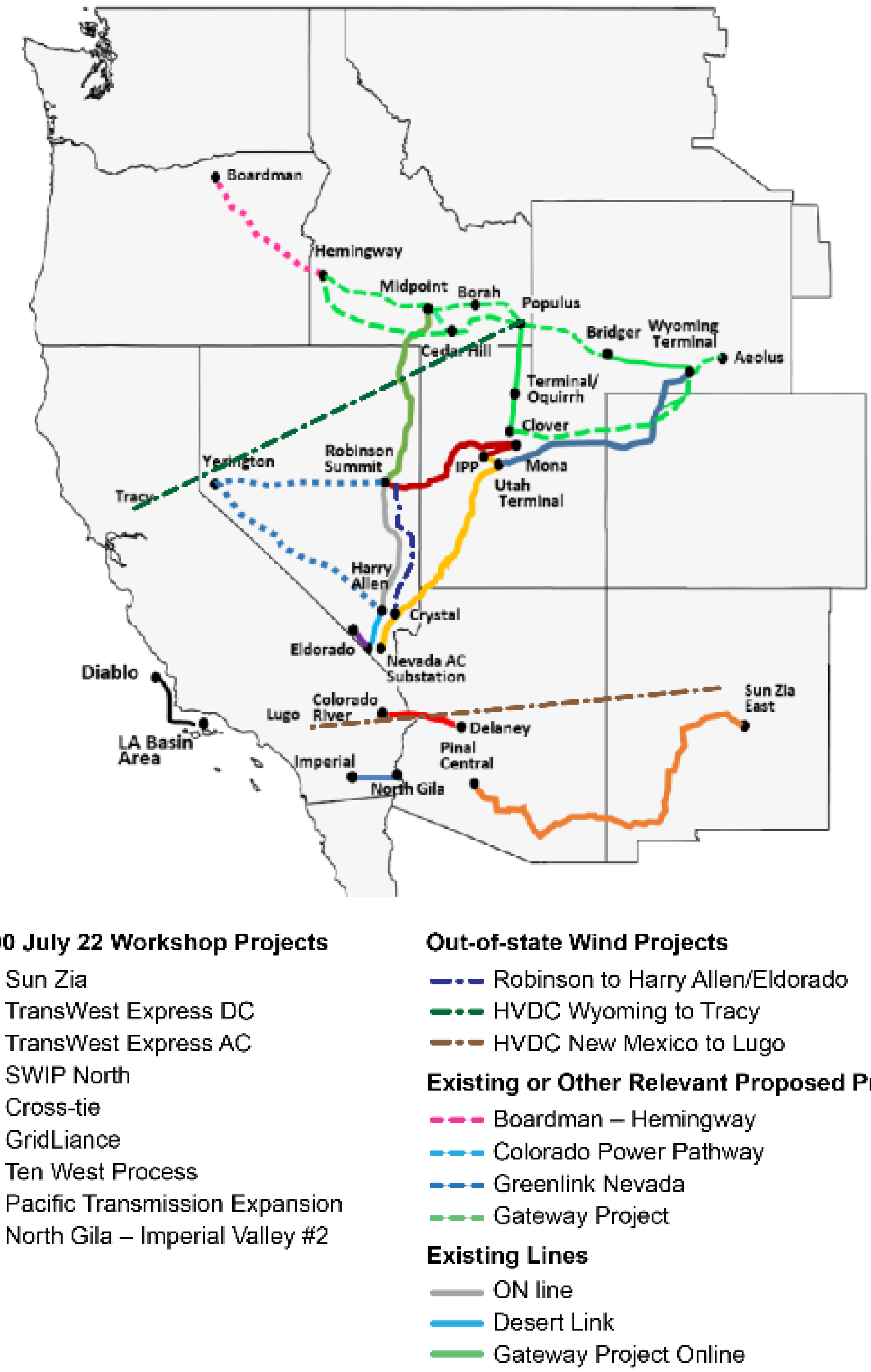
(2) Was specifically devised to better integrate renewable energy and better utilize the transmission system across the footprint. Splitting regions for 45V negates some of these incentives to fully participate in the WEIM for system operation when conflicting incentives need to be followed to qualify for tax credits.

(3) Will be relied upon by California and Washington for the verification of their decarbonization policies.

Another issue if the deliverability regions are not aligned with the WEIM and WEIS market structures is that planned transmission builds necessary to build out new renewable energy basins will be disincentivized by the rules. The following map shows some of the transmission corridors identified by California as necessary for being able to meet 100% carbon free electricity. These are large transmission corridors that will link to large renewable projects. Many of these projects will be jointly owned and they cut across the currently defined 45V Regions. Integrating the renewable power linked to these transmission projects and successfully decarbonizing the region will require market structures like the WEIM to properly optimize the use of all assets. Anything that reduces the value of these corridors, such as not allowing all the renewable energy to qualify for hydrogen tax credits, has the potential for disincentivizing investment necessary for regional decarbonization. The most consistent approach that aligns with both system operations and decarbonization goals of the treasury would be to create western deliverability areas around the WEIM and WEIS.

In adopting the final 45V Regions, Treasury should be mindful that market structures can shift over time and provide certainty that once a generator is determined to be deliverable to a specific electrolyzer that it remains so even if an adjustment to DOE Regions is necessary to reflect updated market structures.

## Figure 4. Existing and Proposed Transmission Projects



# 5. Appendix

**Table 2. Mapping Balancing Authorities to 45V Regions**

| Balancing Authority | 45V Region Based on DOE Needs Study | 45V Region Based on Actual Market Structure |
|---|---|---|
| Balancing Authority of Northern California | California | WEIM |
| Balancing Authority of Northern California | California | WEIM |
| California Independent System Operator (Balancing Authority) | California | WEIM |
| Imperial Irrigation District | California | WEIM |
| Los Angeles Dept of Water & Power | California | WEIM |
| Turlock Irrigation District | California | WEIM |
| Midcontinent ISO (Balancing Authority): South | Delta | Delta |
| Duke Energy Florida Inc | Florida | Florida |
| Florida Municipal Power Pool | Florida | Florida |
| Florida Power & Light | Florida | Florida |
| Gainesville Regional Utilities | Florida | Florida |
| Homestead (City of) | Florida | Florida |
| JEA | Florida | Florida |
| New Smyrna Beach Utilities Commission | Florida | Florida |
| Reedy Creek Improvement District | Florida | Florida |
| Seminole Electric Coop Inc | Florida | Florida |
| Tallahassee FL (City of) | Florida | Florida |
| Tampa Electric Co | Florida | Florida |
| East Kentucky Power Coop Inc | Mid-Atlantic | Mid-Atlantic |
| LG&E & KU Services Co | Mid-Atlantic | Mid-Atlantic |
| Ohio Valley Electric Corp | Mid-Atlantic | Mid-Atlantic |
| PJM Interconnection | Mid-Atlantic | Mid-Atlantic |
| Associated Electric Coop Inc | Midwest | Midwest |
| Electric Energy Inc | Midwest | Midwest |
| Gridliance Heartland | Midwest | Midwest |
| Midcontinent ISO (Balancing Authority): North | Midwest | Midwest |
| NaturEner Power Watch LLC (GWA) | Mountain | WEIM |
| NaturEner Wind Watch LLC | Mountain | WEIM |
| Nevada Power Co | Mountain | WEIM |
| Northwestern Energy | Mountain | WEIM |
| PacifiCorp East | Mountain | WEIM |
| Public Service Co of Colorado | Mountain | WEIS |
| WAPA Rocky Mountain Region | Mountain | WEIS |
| WAPA Upper Great Plains West | Mountain | WEIS |
| New England ISO (Balancing Authority) | New England | New England |
| Northern Maine | New England | New England |
| New York ISO (Balancing Authority) | New York | New York |
| Avangrid Renewables LCC | Northwest | WEIM |
| Avista Corp | Northwest | WEIM |

| | | |
|---|---|---|
| **Bonneville Power Administration** | Northwest | WEIM |
| **Gridforce Energy Management LLC** | Northwest | WEIM |
| **Idaho Power Co** | Northwest | WEIM |
| **PacifiCorp West** | Northwest | WEIM |
| **Portland General Electric** | Northwest | WEIM |
| **PUD No 1 of Chelan County** | Northwest | WEIM |
| **PUD No 1 of Douglas County** | Northwest | WEIM |
| **PUD No 2 of Grant County** | Northwest | WEIM |
| **Puget Sound Energy Inc** | Northwest | WEIM |
| **Seattle City Light** | Northwest | WEIM |
| **Tacoma Power** | Northwest | WEIM |
| **Southwest Power Pool (Balancing Authority)** | Plains | Plains |
| **Southwestern Power Administration** | Plains | Plains |
| **Alcoa Power Generating Inc Yadkin Division** | Southeast | Southeast |
| **Duke Energy Carolinas LLC** | Southeast | Southeast |
| **Duke Energy Progress East** | Southeast | Southeast |
| **Duke Energy Progress West** | Southeast | Southeast |
| **PowerSouth Energy Coop** | Southeast | Southeast |
| **South Carolina Electric & Gas Co** | Southeast | Southeast |
| **South Carolina Public Service Authority** | Southeast | Southeast |
| **Southeastern Power Administration (Southern)** | Southeast | Southeast |
| **Southern Co Services Inc** | Southeast | Southeast |
| **Tennessee Valley Authority** | Southeast | Southeast |
| **Arizona Public Service Co** | Southwest | WEIM |
| **Arlington Valley LLC** | Southwest | WEIM |
| **El Paso Electric** | Southwest | WEIM |
| **Gila River Power LLC** | Southwest | WEIM |
| **Griffith Energy LLC** | Southwest | WEIM |
| **New Harquahala Generating Co LLC** | Southwest | WEIM |
| **Public Service Co of New Mexico** | Southwest | WEIM |
| **Salt River Project** | Southwest | WEIM |
| **Tucson Electric Power Co** | Southwest | WEIM |
| **WAPA Desert Southwest Region** | Southwest | WEIM |
| **ERCOT ISO (Balancing Authority)** | Texas | Texas |