February 26, 2024

The Honorable Aviva Aron-Dine
Acting Assistant Secretary (Tax Policy)
Department of the Treasury
1500 Pennsylvania Avenue, NW
Washington, DC 20220

William Paul
Principal Deputy Chief Counsel
Internal Revenue Service
1111 Constitution Avenue, NW
Washington, DC 20224

The Honorable Daniel Werfel
Commissioner
Internal Revenue Service
1111 Constitution Avenue, NW
Washington, DC 20224

Submitted via Federal comment portal www.regulations.gov

RE: IRS and REG–117631–23; Section 45V Credit for Production of Clean Hydrogen

Thank you for the opportunity to provide comments. We answered questions to which we have expertise and have an outsize importance.

Founded in 1982 as Rocky Mountain Institute, RMI is an independent, non-partisan, nonprofit that transforms global energy systems through market-driven solutions. RMI engages with global businesses and policymakers on research and strategy to scale low-carbon hydrogen technologies. RMI also hosts the Green Hydrogen Catapult.

Please reach out to John Coequyt (jcoequyt@rmi.org), Alex Piper (apiper@rmi.org), Nathan Iyer (niyer@rmi.org), or Taylor Krause (tkrause@rmi.org) with any questions.

Table of Contents

Introduction

RMI thanks the Treasury Department, Department of Energy, and Environmental Protection Agency, and the many staffers throughout the federal government, who worked to draft this proposed rule. RMI understands that Treasury's task is to provide clarity on complex and diverse lifecycle calculations across a range of technologies that remain robust across geographies and decades. To that end, RMI's comments seek to support Treasury's efforts in achieving three major goals: pragmatic administrability, science-based emissions guardrails in line with the legislation, and flexibility to enable industry liftoff.

The proposed rule provides a strong framework and RMI encourages Treasury to finalize the rule while expanding pathways for eligibility along the legal and logical justifications laid out by the DOE whitepaper and EPA letter. The consideration of indirect emissions impacts associated with this credit is critical for both alignment with the Clean Air Act provisions and is necessary to achieve the stated Congressional intent of 45V in "reducing effective greenhouse gas emissions."

This tax credit will play a critical role in scaling the nascent clean hydrogen industry and incentivize the cleanest possible hydrogen production throughout the supply chain. This proposed rule creates a workable framework, and with the inclusion of additional clarifications for electricity accounting combined with reforms for gas-based pathway emissions accounting, the final rule can achieve both Congressional intent, statutory requirements, and the administration's broader policy goals.

The comment is organized by section: first electrolytic and then gas-based hydrogen production pathways. The comment addresses questions and requests for comment from the Treasury Department and provides comments on unresolved issues and ideas critical to the effective implementation of this tax credit that were not specifically raised by the Treasury. These comments also include some preliminary analysis on the market dynamics of these mechanisms and how to improve that analysis.

RMI comments aim to improve an already thoughtfully designed proposed rule. RMI applauds Treasury's efforts and expects a final rule will incentivize low emissions carbon production and enable flexibilities for first movers in this industry to provide certainty and a greater chance for financing. Key areas of focus within these comments include:

Electrolytic pathways

- Analysis of overall EAC availability under the current rules
- Treatment of "missed" hours during hourly matching
- Accounting for electricity storage
- Demonstrating interregional power flow for deliverability
- Provisional hourly matching registry system before 2028
- Integrating hydrogen EACs with state level policy
- Strategic safe harbors

Gas-based pathways

- Upstream national average methane leakage accuracy
- Path-specific methane leakage certification
- Biomethane and fugitive methane LCA accuracy
    - Landfill gas counterfactual and LCA

Electrolytic pathways

Flexibility, policy certainty, and recommendations

The proposed rule can be framed as creating the rules of the road for a new, liquid EAC market – with attributes being actively generated, traded, and retired. The size and availability of this pool of attributes, from which projects can purchase, hourly match, and retire, is impacted by each component of the proposed rule and further expanded or contracted by flexibilities outlined throughout this comment.

Flexibility within the current NPRM

The proposed guidance includes a number of decisions that make it easier for projects to comply and benefit from the 45V tax credit by creating a large pool of tradeable attributes: incrementality allows a rolling three year window of clean power to qualify as "new", deliverability regions are large and include varied geographies which can help projects source diverse clean energy resources to support higher capacity factors, and hourly matching implementation is delayed until 2028.

Importantly, the guidance must be considered as a whole for market-based mechanisms like EACs – each flexibility point interacts with the others, creating an overall pool of eligible attributes that impacts their price and their impact on the grid. It is possible to expand that pool so broadly, allowing supply to outstrip demand in such a way that the mechanism fails to be descriptive or effective. Capacity expansion modeling is crucial to understand the aggregate impact of the construction posed, and we recommend using the NREL Cambium capacity expansion modeling and expertise from EIA and the national labs to better understand how each choice expands or contracts the given pool.

The existing NPRM includes basic flexibility through "three pillars":

- **New:** Enabling all new incremental clean power to qualify with a three-year grace period, covering all new capacity post-IRA
- **Nearby:** Deliverability regions are large and flexible
- **Matched:** Enabling annual matching through 2028, then requiring hourly matching

Additional flexibilities should be considered by Treasury – for both further industry certainty and ease of administrability. These flexibility points are discussed throughout this comment, and they include the use of qualifying electricity storage, a missed hours system that does not create as much risk for projects for minimal emissions violations, exemptions for smaller grid regions that can demonstrate minimal emissions impacts from incrementality flexibility, retirement avoidance, curtailment qualification, and dual compliance of incremental clean electricity used for 45V qualification and state climate goals. Each one of these points deserves significant consideration on their own. However, it is important to also consider them as a whole and understand how these flexibilities further enhance the embedded flexibilities already included in the proposed rule, and how these interactions support first movers and industry planning to pursue the 45V tax credits.

Challenges Facing the Market

The “three pillars” aim to ensure that the electrolytic (aka green) hydrogen industry scales in a climate-friendly manner. The release of the proposed rules in December 2023 provided industry actors and other stakeholders with clarity of the philosophical definition of clean hydrogen and specificity of how a project must be designed and operated. This section of RMI’s comment analyzes the proposed rule in the context of the seven Regional Clean Hydrogen Hubs (H2Hubs). These hubs are part of a larger national effort to develop a clean hydrogen market that will enable the decarbonization of various sectors of our economy, particularly those that cannot rely on direct electrification. The analysis quantifies the availability of Energy Attribute Certificates (EACs), the relevant documentation system for clean power use, to determine whether there will be enough available 45V-qualifying electricity to meet each hub’s stated electrolytic hydrogen production goal.

With further clarity on the requirements for accessing the 45V tax credit, electrolytic hydrogen developers are now re-evaluating their approach to project designs and investment strategies. They are considering how energy storage and renewable power procurement will shape their production potential, and they are confronting persistent uncertainties related to power grid constraints, product standards, and potential monetization models. Ensuring that project designs enable hydrogen production at or below a buyer’s willingness to pay is a key consideration for first movers securing off-take contracts.

The challenges project developers continue to face should be taken seriously and will need to be overcome for the nascent electrolytic hydrogen market to rapidly, successfully scale up in the US. RMI does not anticipate, however, that the near-term availability of Energy Attribute Certificates (EACs) will be among the primary challenges stalling green hydrogen project buildout. The analysis in the following sections explains why.

Methodology for Total Availability Calculations

This analysis provides a perspective of how much electrolytic hydrogen production could be supported within a hub region through use of credit-qualifying electricity generation that may become available by 2030 and over the course of the tax credit period for a project coming online now. Our methodology demonstrates one pathway among many in evaluating attribute availability from the 45V tax credit.

As these standards are administrable and predictable – capacity expansion modeling can quantify how many attributes are available for each hub. Expected net available electricity generation across hub regions was sourced using data from the National Renewable Energy Laboratory (NREL) Regional Energy Deployment System (ReEDs) capacity expansion model “[Inflation Reduction Act]-[Bipartisan Infrastructure Law] Mid case” scenario, which “represents the power system evolution that would occur if all economically optimal investment and retirement opportunities were executed.” We pulled their estimations of regional electricity capacity growth from 2024-2035 and isolated out the renewable energy projects that meet the incrementality requirements under 45V across wind, solar, nuclear, hydro, and geothermal sources. The use of electricity storage was not considered in this analysis given limited Treasury guidance on if and how the resources will be considered compliant.

To identify net electricity generation available for hydrogen production, we referenced data from the NREL’s Cambium 2022 dataset and subtracted each state’s current electricity consumption needs from generator’s hourly dispatch profile to identify the available amount of electricity generation for hydrogen production. If the additional electricity is generated from renewable sources, it is considered to qualify as an EAC. These results were compiled across the 13 electricity deliverability regions in the US to evaluate regional EAC availability.

We then used the total region-by-region EAC availability to estimate the corresponding total potential of supported electrolytic hydrogen production capacity. To note, this assessment assumes that all available EACS are allocated towards hydrogen production throughout the period assessed.

To calculate hydrogen production potential, we first baselined the electrolyzer capacity if electrolyzers consumed 50% of all available EACs. We then refined the assessment to attempt to maximize total electrolyzer capacity, minimize curtailment of eligible EACs, and result in reasonable capacity factors for electrolyzer utilization. If EAC availability was present in the region to support further hydrogen production, more electrolyzer capacity would be added. The upper bound of allowable electrolyzer utilization was set to 80%; and if utilization exceeded 80%, the model would add marginally more electrolyzer capacity until the target of 80% was converged to. The results provide an approximation of total electrolyzer deployment, the electrolyzer fleet's capacity factor, total hydrogen production, and "curtailed attributes" from eligible generation that lacked sufficient electrolyzer demand during peak production hours, all while assuming that all eligible attributes are assigned to hydrogen production.

Limitations and future directions:

This modeling approach does not account for EAC based market competition and hence any conclusions about attribute availability assume total market access, procurement ease, and static pricing. These are assumptions that do not reflect the real market conditions but allow us to quantify the delivery needs for new renewables and illustrate the case for a higher functioning and liquid traded market. In addition, we have not accounted for transmission and interconnection challenges, which are a significant challenge facing all energy markets--this further illustrates the need for significant and immediate action to address these challenges. Importantly, this analysis does assess hydrogen production costs resulting from production using available EACs; this is a central consideration for a region's near-term hydrogen supply potential. In addition to these considerations, below is a list of other areas of constraint within the analysis and further details of a few critical implementation challenges.

This analysis does not include additional pathways for hydrogen production found through:

- Use of energy storage to time shift EACs (increasing capacity factor)
- Pre-existing demand for EACs and potential for future competition in the target timeframe
- Integration of "curtailed" power from existing resources (increasing EAC availability)
- Interregional or international electricity wheeling (increasing capacity factor balancing across regions)
- Evaluation of mismatches in the pace of electrolyzer deployment with the pace of clean power deployment which could cause dynamic market impacts over the credit period

There are several ways to improve the analysis found through:

- Cost analysis of EACs to understand the market dynamics of increased demand
- Include competitive dynamics with other EAC consumers
- State level policy interactions with EAC availability
- Additional capacity expansion modeling and further sensitivity analysis
- Analysis that includes capacity impacts of increased hydrogen demand (see: EPRI)

Estimating the availability of compliant attributes over the credit period

The analysis produced two perspectives on qualifying three-pillar electricity and corresponding hydrogen production across the various deliverability regions. First, we provide a perspective of near-term hydrogen production potential considering compliant EAC availability between 2024 to 2030. We find that found there are enough qualifying EACs available to meet the stated electrolytic hydrogen production goals across each of the Regional Clean Hydrogen Hubs, as seen in table 1.

Regions like the Plains and Midwest have the potential to support significantly higher levels of hydrogen production than currently proposed by hubs, while other regions like the Northwest have more limited qualifying electricity and may see heightened challenge for competing demand for EACs across hydrogen production and other loads.

Table 1. A comparison of proposed hydrogen production by US hydrogen hubs to the total regional potential hydrogen production.

Hub	Early Hydrogen Production Proposed (kT/yr)	Deliverability Region	Hydrogen Production Leveraging All Qualifying Clean Attributes (kT/yr)
Heartland	110	Plains	3,800
Midwest	50	Midwest	3,440
Gulf	360	Texas	3,020
Pacific Northwest	180	Northwest	180
California	180	California	730
Appalachia	35	Mid-Atlantic*	750
Mid-Atlantic	130	Mid-Atlantic*	750
TOTAL	1,045	TOTAL	11,920

**Note: Hub production proposal volumes are aggregated from early 2023 estimates and are subject to change as applications evolve. Mid-Atlantic region has two proposed hubs, Appalachian hub is mostly blue hydrogen.*

Additionally, we extended the timeframe of the analysis to 2035, representative of the duration of 45V credit-qualification for a project coming online within the year. If all eligible clean attributes were directed toward hydrogen production during this period, this could yield an approximate average of 24 MMT of hydrogen production per year across a total of ~210 GW of electrolyzers operational by 2035, as seen in table 2. Across regions, just below 30% of qualifying EACs remain not utilized to produce these volumes of hydrogen, indicating that additional hydrogen production could be supported through inclusion of electricity storage. These EACs could also be used to support other operations that require hourly renewable electricity supply.

Table 2. A summary of relevant outputs for each deliverability region.

Deliverability Region	Supported Electrolyzer Capacity (GW)	Electrolyzer Electricity Demand (TWh)	Total Hydrogen Produced (MMT)	Electrolyzer Capacity Factor (%)	Unused EACs (TWh)	Total EACs Available (TWh)	Available Unused EACs (%)
Northwest	2	11	0	74	3	15	20
New England	3	20	0	76	13	34	38
New York	5	32	1	78	13	45	29
Delta	7	24	0	42	24	49	49
Southwest	5	31	1	67	30	62	48
Florida	15	59	1	45	58	118	49
Mountain	18	125	2	79	5	131	4
California	12	75	1	73	75	151	50
Mid-Atlantic	12	83	2	80	76	160	48
Texas	32	227	4	80	7	234	3
Plains	34	238	4	80	5	244	2
Southeast	31	131	2	48	131	263	50
Midwest	34	238	4	80	32	270	12
Total	209	1,294	24	73	472	1,776	27

**Note: Regions highlighted in yellow have a lower capacity factor due to a lack of projected resource diversity – when developers are considering new projects to build to meet direct hydrogen loads, identifying resources with a complementary profile or integrating electricity storage would best support hydrogen buildout.*

Two major external influences could drive this market depth up or down:

1. **Competing demand for hourly EACs**: Total US datacenter demand for electricity is projected to grow from 17 GW to up to 35 GW by 2030. Assuming the entire fleet of datacenters require hourly EACs and aim for a similar capacity factor to hydrogen, the overall "market depth" of EACs available to hydrogen producers would decrease by 35 GW. If the datacenters want to procure at a higher capacity factor, the overall capacity factor of electrolyzers could decline in kind (therefore driving down profitability), depending on the region where datacenters are built. As such, adding full demand markets back into the analysis will create demand pressures and drive pricing for EACs higher. This sensitivity around pricing is outside the scope of this initial high-level screening but should be the focus of future work.
2. **Grid response to hydrogen demand:** The Cambium mid-case scenario does not calculate the impact of hydrogen loads on overall clean electricity production, and thus does not consider additional renewable energy development in response to increased electricity demand for hydrogen production. This analysis therefore represents both a major simplification, but also a conservative estimate on the aggregate availability of clean power for electrolysis. New load will

likely be filled, in part or in full, by additional clean capacity beyond the mid-case scenario. The availability of attributes for built electrolyzers will likely immediately exceed the Cambium projections, but the physical barriers (e.g. interconnection, grid upgrades, sufficient net new power capacity, and timeline for new project approval) for individual project development will likely be the bottleneck, rather than a lack of qualifying EACs.

What more is required

Each hub is shown to have enough available attributes to meet their early stated production goals for electrolytic hydrogen production. However, acquiring these attributes in practice for hydrogen projects will require coordination between developers, utilities, and registries over the next five years. Developers have several strategies available to contract for these attributes of varying complexity levels. The value of the credit is significant, suggesting that hydrogen producers could outbid other EAC purchasers and thus be "first in line" for clean capacity as it comes online.

Overall, the fundamentals – the availability of incremental, deliverable, hourly matched clean power – are likely to be available in large volumes. An early bottleneck will be developing the markets and the data infrastructure required to get the associated attributes into the hands of hydrogen developers. This analysis suggests there is significant economic opportunity for players able to bridge this gap rapidly.

Real world barriers to acquiring attributes and growing competition will incentivize additional clean capacity – this is the primary mechanism that enables this accounting mechanism to drive real emissions reductions. This analysis suggests that there is enough qualifying incremental capacity to generate a deep hourly EAC market – what project developers need is the data infrastructure and contracts to predictably acquire these attributes.

The three pillars do not discriminate against new clean capacity, reward balanced regional development, and guard against scenarios where hydrogen production increases **net** emissions throughout the credit period. While this analysis diverts all projected clean power to hydrogen production that could otherwise be used to decarbonize the grid, each attribute considered would be valid for use in 45V in accordance with the rules established by the NPRM.

Hubs and hydrogen projects face other challenges to economic deployment – achieving higher capacity factors, negotiating low-cost rates that value flexibility, and buildout of multi-day hydrogen storage to ensure steady offtake all add costs to project development. EAC price and availability are just one variable of many when optimizing hydrogen projects.

Ultimately, the primary barriers to the green hydrogen economy are not accounting issues associated with the proposed 45V rules, but the traditional physical bottlenecks to clean energy deployment in the real world – siting and permitting, interconnection, regional transmission, and large project management.

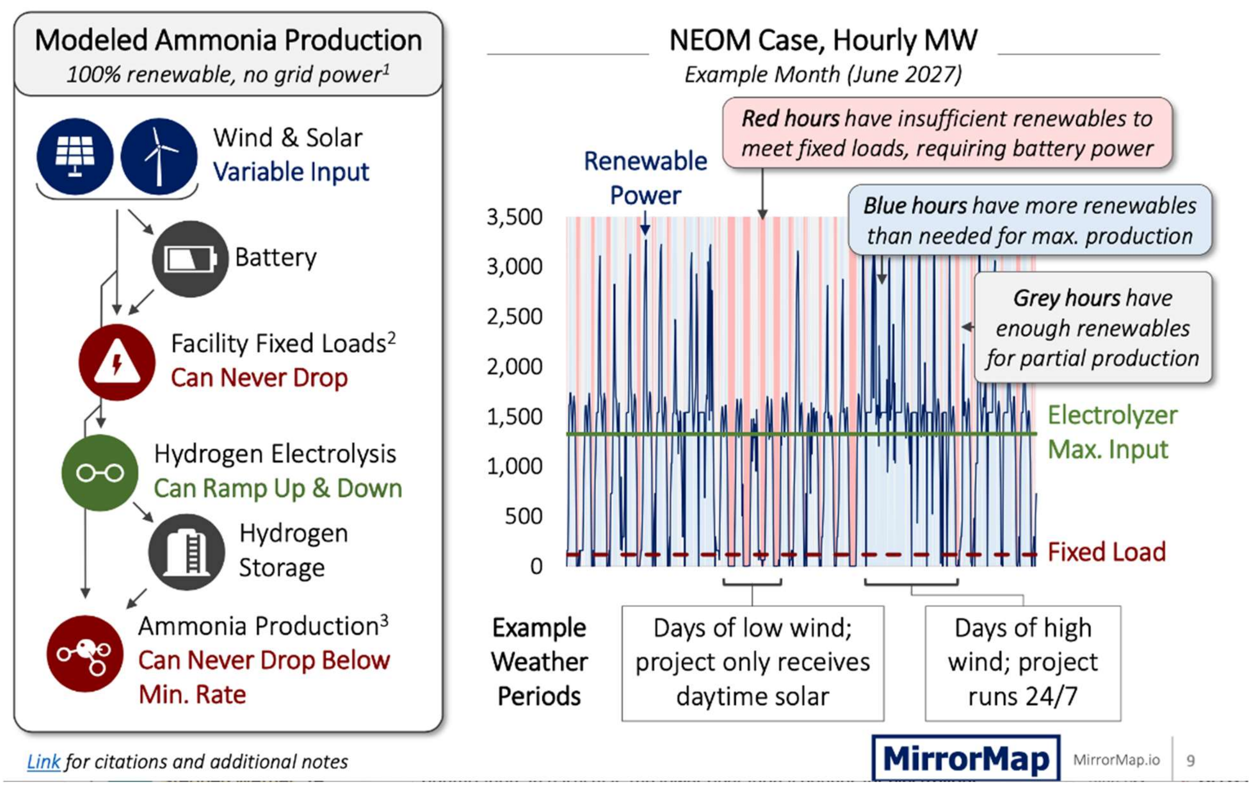
The challenge of missed hours

"Missed hour" – an hour in which retired EACs do not fully account for the electricity used to generate hydrogen. A non-zero emissions intensity should be associated with hydrogen production.

It appears that the proposed rule would require a qualified hydrogen producer seeking qualification for the 45V production tax credit to determine an average emissions rate for all the hydrogen produced throughout the entire year. That emissions rate would then be applied to the total volume of hydrogen produced and a credit value would be determined. This means that for every missed hour—an hour in which there is not a corresponding EAC retired to match generation—would need to be evaluated separately for its emissions impacts, likely often getting the grid average emissions value assigned to that hydrogen production.

This approach creates a very strict scenario in which a small number of missed hours can move a project from one tax credit value to another. The average grid emissions rate is approximately 390g CO_2/kWh in 2022 (0.86 pounds/kWh) according to the EIA. Assuming a production efficiency of 55 kWh/kg of hydrogen, the input electricity across the entire year would have to be around 12.2g CO_2/kWh, allowing a miss rate of 3.1% on average to achieve the top credit over the course of a given year. In other words, if roughly 3% of hours in a year are missed, it could be enough to bump a project from the top credit tier to the second tier – a significant financial consequence for a project seeking investment and cashflow certainty.

The operational profile, seen below, demonstrates some of the challenges projects will face when attempting to achieve this level of accuracy:



Source: MirrorMap

There are a number of hours in a given year where the electrolyzer load drops below the “fixed load”, which is an operational minimum (typically around 20% of the maximum output) below which an electrolyzer cannot drop without causing damage to the stack or larger safety problems. These hours can in some cases add up to greater than 3% of total production hours. An averaging approach to the emissions intensity across a calendar year could put safety and bankability at odds, further exacerbating project finance and operational risk.

There are likely to be events in which the clean electricity generator supplying EACs for a hydrogen producer is unable to produce qualifying clean electricity, either due to a natural disaster, a period of time in which little or no energy can be generated with wind and solar power, an unplanned outage, or even a forecasting error. Due to operational commitments with an off taker to provide consistent streams of hydrogen or an inability to plan for an emergency scenario, it is possible that a hydrogen producer will suddenly be faced with a scenario where hydrogen produced does not qualify for the tier of credit expected.

It is not impossible to design a project with this level of accuracy. By integrating hydrogen storage, ramping the electrolyzer to match contracted EAC availability with real-time monitoring, over procuring clean power, and using battery facilities to manage "operational minimums", it is technically possible to achieve the top credit. However, additional flexibility in credit calculations can reduce overall risk and project cost, supporting the goals of industry liftoff and low-emissions hydrogen production.

Missed hours

Fundamentally, the difference between hourly and annual matching is the ability for projects to account for emissions over a given year. For annual matching, any hourly misses can be accounted for by extra clean power production at another time. A simple example is an electrolyzer pulling electricity from a solar facility during the day and gas plants at night. The night-time gas is accounted for by excess solar electricity production that cannot be consumed by electrolyzers. For hourly matching however, the night-time gas consumption is classified as a miss and the induced emissions of pulling electricity from that plant are considered. Excess daytime solar is not permitted to account for these misses, creating a one-way ratchet.

This one-way ratchet makes the averaging of hours a challenging standard because it flattens the overall emissions intensity to one value without distinguishing between hours of clean and dirty production. By requiring more granular data via an hourly matching standard, Treasury will have the information required to make distinctions between the emissions intensity of hydrogen production for each hour, and thus can provide more flexibility when calculating the credit.

Calculating credit values when hourly matching is required

The proposed rule currently appears to outline a process in which a facility must report the emissions of its hydrogen production across *every* hour in the year, then those emissions values are aggregated and averaged out for one emissions value. That value is then what is used to determine the credit tier for the entire project and *all* of the hydrogen produced at that facility in a given year.

As described above, this creates significant risks for projects. One potential solution and added point of certainty for projects to reduce risk of the aggregated emissions value, is to calculate each hour separately when calculating the credit value, with some guardrails to ensure that the credit is not being gamed. This operational minimum threshold would help to ensure certainty for projects that missed hours due to renewable variability will not sink their project economics, and it will also prevent an issue in which a hydrogen facility has to decide between shutting down operations, risking safety hazards, and missing a 45V threshold critical for the project financing.

On the other hand, a rule that allows projects to “cherry pick” or evaluate each hour of hydrogen production independently for credit qualification can incentivize emissions intensive gaming decisions within a facility and across electrolyzer stacks.

RMI recommends a two-step test when calculating the credit under an hourly matched rule:

1. Annual Averaging to Determine if a Facility Produces Qualified Clean Hydrogen

First, the threshold for “qualified clean hydrogen” in the Inflation Reduction Act is 4 kg CO_2e/kg H_2. Over the course of a given year, Treasury could establish that a facility that produces hydrogen with an emissions intensity greater than 4 kg CO_2e/kg H_2 is not eligible for tax credits because the overall pool of hydrogen produced over that year is not considered “qualified clean hydrogen.” This process is similar to how Treasury currently proposes evaluating emissions and has the advantage of avoiding the worst gaming consequences of a purely hour by hour evaluation of emissions intensity and credit attribution.

2. Hour by hour calculations to determine precise credit value

Once a facility is deemed “qualifying” over a given year—by achieving an under 4 kg CO_2e/kg H_2 standard aggregated across their production that year—each **hour** of production would then be calculated separately to determine the credit value for the hydrogen production within that hour.

A facility that has enough zero carbon EACs to cover total electricity consumption would have an emissions value of 0 for that hour, while a facility that has partial coverage would multiply the remaining power by the grid average emissions rate in GREET. This calculation is similar to the way the EU is planning on handling hourly EACs.

To do this calculation, Treasury could make the following calculation for each hour:

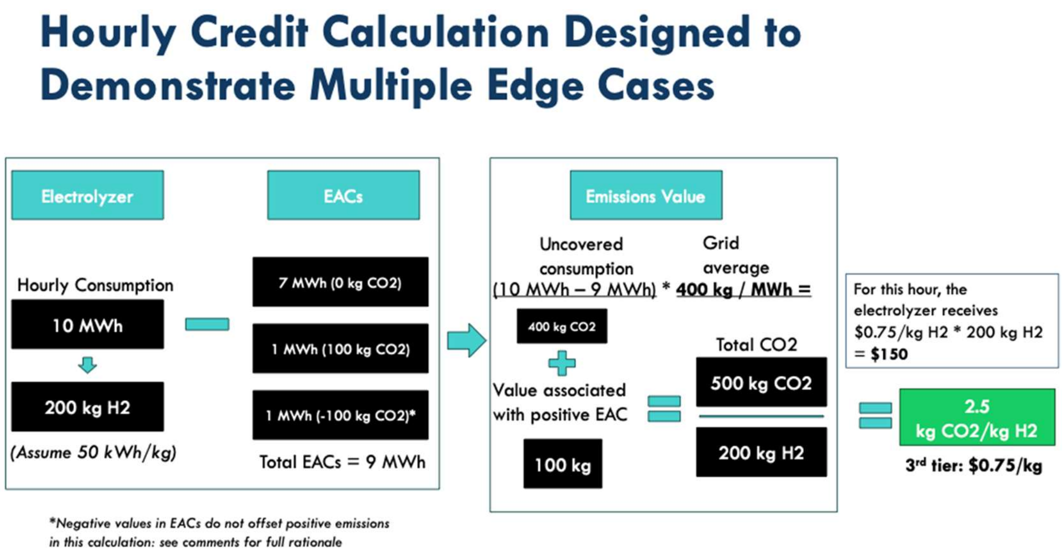
> Emissions Rate = (Total Electricity Consumption MWh – Volume of Hourly EACs MWh) * Grid Average Emissions Rate (GREET) + emissions associated with positive EACs (if applicable)

The calculation could be sequenced as follows:

- The hydrogen producer submits the hourly energy consumption of the electrolyzer, along with receipt of the retirement of the associated hourly time stamped zero carbon EACs
  - Note: both zero carbon and “negative” EACs are both weighted equally to avoid gaming: see the later discussion on the risks of EACs with a negative associated emissions value
- Any volume of consumed power that is not matched with EACs is multiplied by the grid average emissions rate, defined in GREET
- Finally, any EACs that have emissions associated with them (e.g. from a CCS facility) add the associated emissions to the total

For each hour, this calculation is repeated, and the associated credit value is assigned to the hydrogen production for that hour. All the hydrogen production and its associated credit values are summed to calculate the total credit value for that year.

Example of an hourly calculation for a project that matches 9 out of 10 MWh with EACs of varying carbon intensities and the final MWh from the grid:



This strategy can be legally justified because it is not unduly crediting hydrogen production during the hours with higher emissions – it evaluates each hour of hydrogen production based on its emissions intensity. Further, it establishes a guardrail against a facility seeking to game the system under a purely hour by hour approach by requiring the facility to qualify as a clean hydrogen production facility by meeting the 4 kg CO_2/kg H_2 standard across an entire year.

The hour-by-hour calculations remove some of the financial and safety risks associated with averaging all hours over a given year. This calculation also allows Treasury to distinguish between production across the separate tiers.

RMI's financial modeling finds that hours in which electrolyzers have difficulty accessing EACs are correlated with periods of higher power prices – if those hours provide lower or zero credits to the hydrogen production, each kilogram would be produced at a loss during those hours and thus the credit would maintain alignment between economics and low emissions. This economic guardrail supports other anti-abuse provisions.

RMI does not recommend a "kilogram by kilogram" calculation, which allows for all zero carbon EACs to translate to a full $3/kg regardless of whether dirty power is being consumed at the same time. This is because the EACs can be assigned to individual kilograms of hydrogen produced, not to all the hydrogen produced within a certain window of time. This reduces the economic incentive for electrolyzer to ramp and is not consistent with other approaches. Furthermore, RMI does not recommend the use of blending EACs that achieve negative carbon intensity scores with EACs that have a positive carbon intensity score when calculating hourly emissions for reasons addressed in a later section.

Alternative approach: Cap on missed hours

Another potential threshold for flexibility would be allowing a subset of hours to not be counted against a facility's overall yearly emissions rate, while also not crediting hydrogen production during those hours. A cap of 5-10% could allow projects to navigate operational issues cleanly, while not providing too much flexibility to the point of a significant emissions impact. RMI recommends that the DOE analyzes how different missed hour caps impact project viability and emissions impacts.

Facility definition

One important anti-abuse requirement will be an effective definition of "facility" in which all electrolyzer stacks within a balance of plant should be included together as one facility. This will help prevent certain opportunities for gaming when a facility chooses to "sacrifice" one electrolyzer stack by saddling it with hydrogen produced without EACs should there be insufficient total EACs to ensure all hydrogen produced is qualified under 45V. If a facility can sacrifice one electrolyzer, it is possible that it could produce significant amounts of dirty hydrogen and still receive a very high 45V threshold for the remaining hydrogen produced and matched with EACs.

This will be important if considering additional flexibility for missed hours as suggested above. The hybrid approach of an aggregated carbon intensity score across a year combined with an hourly evaluation of hydrogen production for credit compliance does help mitigate some of the worst versions of this abuse, but it is still valuable to adopt the belt and suspenders approach. The guardrails around a facility and preventing the sacrifice of electrolyzer stacks as their own facilities will be critical no matter how missed hours are accounted.

Safe harbors and policy certainty

Strategic safe harbors are helpful to provide producers with certainty over a 10-year credit period on a dynamic grid and a dynamic LCA calculator. RMI proposes a safe harbor designation for certain portions of the final rulemaking, including:

- RMI supports a safe harbor stating that electrolyzer projects that commence construction (defined similarly to the renewable energy tax credits) can have 4 years to place their electrolyzer in service before the credit clock begins (assuming no grandfathering of interim rules). The ultimate standards (e.g. hourly matching, deliverability, incrementality rules), but **not the interim standards (annual matching),** also could be considered part of the safe harbor to provide additional certainty.
    - RMI does not recommend grandfathering interim standards as it would create perverse incentives where projects with standards that allow for emissions intensive hydrogen production are more competitive than projects that reduce effective GHG emissions. This approach would see 45V credits going to projects that increase effective carbon emissions out to the mid-2040s.
- If a hydrogen facility that has construction work in progress creates a 10-year contract with a qualifying clean power facility that is considered deliverable at the time of the contract being signed, it should be able to pull qualifying EACs from that facility over the credit period, even if the deliverability zone changes.

- GREET model safe harbor should be considered. If the GREET model changes dramatically, it could undermine investor confidence given uncertainty around how the changes impact projects. The hydrogen production assets brought online are capex heavy and require sufficient certainty for regulatory compliance to be financed. If projects bounce in and out of "deliverability" compliance without up-front certainty, then it becomes unlikely that developers will be able to depend on those attributes when pulling together project finance.

Example demonstrating how a producer could design a 45V compliant project

An optimal hydrogen project under the rules outlined likely has the following elements:

- Ramping electrolyzer
- Hydrogen storage
- Power contracts
- Contracts for hourly EAC loads (at times bundled)
- Dedicated clean power facilities

The sizing of the electrolyzer, storage, and the resource diversity and scale of the contracts will differ based on region. In some areas of the country (e.g., Texas) where permitting is permissive, projects will have dedicated clean power facilities. In other regions, the hydrogen facility will likely contract just the hourly attributes from a variety of qualifying clean power sources that check the vintage and regionality box. While there are several different strategies for hydrogen producers to secure these contracts, it's worth noting that the value of 45V combined with current shallow demand for hourly EACs indicates that hydrogen producers could be among the most competitive procurers of hourly attributes.

The current guidance allows unbundling and trading of hourly EACs if the vintage and regionality requirements are met. This enables market liquidity and will likely reduce the cost of EACs because hydrogen producers do not have to bear the total project risk of clean power facilities beyond credit expiration and enables a higher capacity factor than expected if bilateral contracts were required. We expect platforms that help manage hourly EAC contract portfolios will emerge to broker these agreements and connect them with the appropriate registry infrastructure.

Achieving hourly matching capacity factors

Running an electrolyzer facility 24/7 is unlikely to be competitive, even when electrolyzer costs are expensive. The IEA finds on page 48 of this analysis that the cost of hourly matching at a very high-capacity factor is far more expensive than at the 60-80% range (this largely depends on the region). This dynamic makes intuitive sense: clean firm generators like nuclear and geothermal are currently more expensive to build, and electricity storage adds progressively more costs as the need for firming increases.

However, electrolysis can be flexible, and hydrogen can be stored at an order of magnitude less than the costs of standalone electricity storage; even above ground steel tanks at $500/kg translate to around $10/kWh storage, while current batteries cost above $200/kWh. This implies that ramping will be an important part of any hydrogen project strategy.

Once sufficient contracts are signed, the hydrogen producer will be able to run a stochastic analysis that identifies the probable capacity factor based on the fleet's production over a 10-year period. This provides information on how to size the hydrogen storage, and what provisions to include in offtake agreements. This phase of the project will be heavily impacted by the Treasury's decision on how to handle missed hours. If ~3% of hours translate to losing the top credit for an entire year (assuming national grid average), the need for operational accuracy becomes existential, increasing the need for a variety of insurance and hedging mechanisms to avoid that outcome, which adds costs. More flexibility on the missed hours front would still drive a strong financial incentive to minimize high emissions and dramatically reduce the project risk.

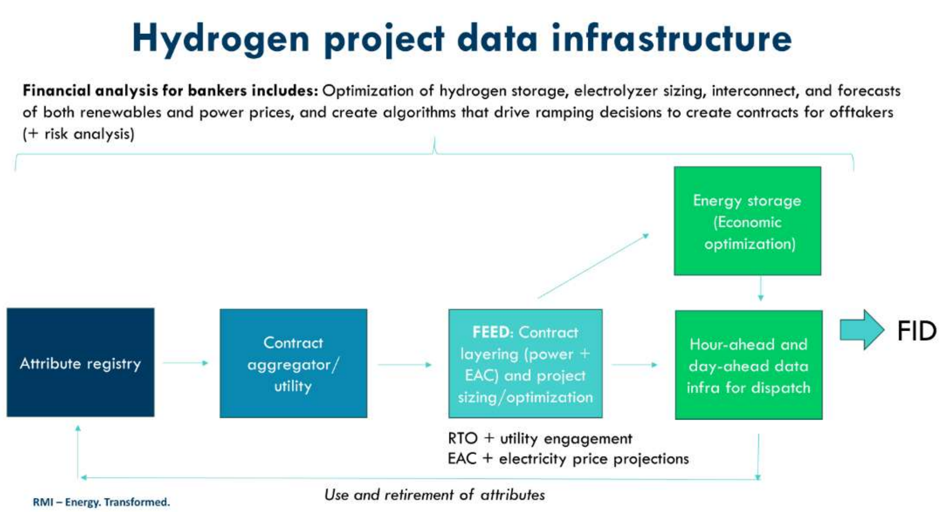
Once the hydrogen facility is built, two major dynamics emerge:

First, the project will need real time data from the associated clean power facilities. 5-minute, 15-minute, hour-ahead, day ahead, and week-ahead data all can provide important information for electrolyzer operators to align their demand with supply. In periods where available hourly EACs are fewer than the electrolyzer's operational minimum, producers have the choice to use grid emissions and increase the likelihood of losing the credit or using energy storage. Flexibility for these missed hours would be helpful during these periods of low EAC supply. Given the hydrogen producer could have real-time assessment of both production and consumption data, providing the necessary information to registries for validation can happen quickly.

In many project configurations, the hydrogen will then get stored in a salt cavern, steel tank, or pipeline. This buffer should allow for a steady stream of hydrogen for an offtaker, but there still will be periods when the storage facility is full (forcing the hydrogen facility to stop producing) or empty (forcing the offtaker to ramp down production). For a well-balanced system with a multi-day buffer, offtake ramping will likely only occur a couple times a year. However, the flexibility for missed hours would enable hydrogen producers to meet that demand during periods of EAC drought while foregoing the credit for those periods, making it easier for producers to guarantee steady offtake if willing to accept a marginal loss during those hours. This is also a safety issue – allowing producers to maintain a level of activity within the electrolyzer to ensure plant safety without penalizing the production that may not qualify as low-emissions for those hours will help prevent a difficult, and costly, decision for producers.

To operationalize and validate the production, the EAC registries either verify the volumetric attribute retirement or the hourly attribute retirements, bundle this data monthly, and submit the overall package to Treasury for final confirmation. Treasury could then verify the matching data from the registry and calculate the credit based on a transparent formula when evaluating missed hours – once confirmed, the producer receives the tax credits.

Before FID, the hydrogen project data infrastructure could look like the diagram below, ensuring that each piece of the compliance puzzle is ready before breaking ground.



Circular production and consumption of hydrogen:

The proposed anti-abuse measures preventing qualified clean hydrogen receiving the 45V tax credit from being used to produce electricity which can then be used to produce more hydrogen with the intention of further collecting the tax credit is critical. Additionally, hydrogen produced to knowingly waste, vent, or otherwise discard, purely to benefit from the 45V tax credit should be disallowed.

However, RMI does note that using clean hydrogen to produce electricity in peak periods can be a productive use. The easiest way to identify circular production is if hydrogen is being used to produce electricity at the same time as the electrolyzer is producing hydrogen. One way to account for this edge case is to not allow the use of qualifying hydrogen for the purpose of electricity generation at the same time the associated electrolyzer is running above the operating minimum. Depending on the electrolyzer technology, this can range from 10-20% of the hydrogen production facility's total power consumption. In many cases, there are system critical loads that cannot be shut off trivially.

Contracting directly with fossil generators

The NPRM currently allows hydrogen producers to purchase grid power and buy EACs to demonstrate that the power purchased is in fact clean. However, RMI strongly recommends disallowing hydrogen producers from contracting and buying power directly from a fossil fuel facility while buying EACs to neutralize the emissions. This would violate the language and the spirit of the law and would directly result in the credit directly subsidizing high emissions facilities.

Instead, requiring hydrogen procurers to purchase from the grid (e.g., via wholesale markets) or enabling power purchases from non-incremental zero carbon power (e.g., hydro or nuclear) would create reasonable guardrails to avoid gaming the EAC market while consuming power with high associated emissions.

Disallowing the use of carbon offsets

RMI applauds the Treasury for not allowing offsets decoupled from the physical production of hydrogen and emphasizes the importance of extending this logic to electrochemical pathways. The use of offsets creates the risk of massive regulatory arbitrage.

Not all emissions are equal in the hydrogen PTC

The structure of the hydrogen PTC is non-linear. The top credit provides \$2/kg H2 more than the second highest credit, for a marginal emissions reduction of 1.05 kg CO2e/kg H2. The second credit provides \$0.25 for a marginal emissions reduction of 1 kg CO2e/kg H2 – a factor of 8 difference. Treasury needs to be able to readily distinguish between these cases, or risks rendering the credit meaningless.

The non-linear credit structure serves an essential policy purpose – the substantial innovation benefits of ultra-low carbon hydrogen production. The difference between tiers in many cases represents a step change in technology, and a step change in cost. The implementation of the credit must consider this essential dynamic and avoid conflating emissions reductions.

Take for example the marginal credit for moving from the second highest tier (1.5kg CO2/kg H2) to the highest tier (0.45 kg CO2/kg H2). For abating ~1 kg CO2, the credit increases by \$2/kg, an effective subsidy of $2000/metric ton of CO2 abated. This value is several orders of magnitude higher than any carbon market or offset system in place to date. As a result, any offset availability will be far cheaper to receive the credit, rather than the hard work of optimizing hydrogen production. The incentive will be to divert investment away from hydrogen systems and infrastructure, and instead to unrelated emissions reductions based on the false idea that all emissions reductions are valued equally in this policy – they are obviously not. Treasury should take great care to avoid this form of regulatory arbitrage.

As a result, the deliverability and time matching requirements are essential to ensure the EACs have a physical association with the feedstocks entering an electrolyzer. The use of book and claim systems are necessary for scenarios where clean and dirty feedstocks are mixed (e.g., the grid, pipeline networks), but physical and temporal alignment is critical to ensure investments are flowing to the enabling infrastructure of clean hydrogen production, rather than subsidizing high carbon hydrogen production along with unrelated offsets.

Immiscibility of negative emissions feedstocks

The risk of regulatory arbitrage undermining the credit creates the need to establish a special case for handling "negative emissions" EACs (e.g., offsets) separately from zero or positive emissions EACs.

Not all emissions reductions are equivalent for the purpose of this tax credit. The credit is non-linear, providing significantly higher incentive for the top tier compared to the lower value credit tiers. Additionally, negative emissions scores are a unique circumstance within carbon accounting – it can be useful for incentivizing certain actions (adding carbon capture to a biomass generating facility, or capturing methane at a landfill), but has potentially harmful impacts when being used for qualification under a credit like 45V.

RMI in general opposes the use of negative EACs for this credit. The negative value associated with these EACs typically is based on one of two scenarios: biogenic carbon permanently sequestered, or capturing methane pollution, reducing emissions compared to an alternative universe where methane was not captured. While the feedstock generates zero carbon when used and thus deserves a zero carbon EAC, but the "offsets" associated with the feedstock must be evaluated separately to maintain policy coherence.

Methane leaks and carbon sequestration are best tackled by other policy mechanisms in the Inflation Reduction Act and the government – using a hydrogen subsidy for tangentially related emissions reductions activities opens a lot of doors for gaming, fraud, and unintended consequences. As a result, RMI suggests that all EACs used at any point of the production chain be valued at zero emissions (at minimum) to reflect the fact that offsets are incompatible with the logic of the clean hydrogen tax credit—allowing one unit of clean hydrogen production to fully offset the emissions of another unit of dirty hydrogen production is incompatible with the intent of the law. Additionally, the use of venting as a counterfactual case has been globally recognized as inappropriate and should not be a method used to calculate negative carbon intensity scores.

However, if the GREET does maintain that some feedstocks have a "negative emissions" value, we recommend calculating negative and positive EACs separately to avoid improperly subsidizing carbon-intensive hydrogen production.

Take for example a feedstock that enables hydrogen production at –10 kg CO2/kg H2 and produces 1 kilogram of hydrogen. Given the emissions intensity is less than 0.45 kg CO2/kg H2, that production should qualify for the top credit and receive $3/kg. Later, 10 kilograms of hydrogen are produced with an emissions intensity of 1.5 kg CO2/kg H2, receiving the second highest credit. However, by mixing the emissions values to achieve an "average" emissions rate that qualified all of the hydrogen into the top tier, the producer could receive an additional $20/kg. Thus, the original kilogram of hydrogen is effectively subsidized at a rate of $23kg CO2/kg H2, which is far above what the law allows. **Put another way, in this scenario the "offset" is worth $20,000/ton CO2e abated.** RMI argues that this kind of gaming can and should be prevented.

This anti-abuse measure would also apply to the electricity sector. Imagine two cases:

Case 1: A CCGT facility buys negative biomethane EACs that applies to 25% of the overall volume which then allows the unabated gas facility to produce zero-carbon electricity EACs for all its production, effectively considering that facility to be a zero-carbon generator for the purposes of 45V.

Case 2: A CCGT facility with 50% CCS purchases a zero carbon EAC from a biogenic feedstock. The biogenic feedstock combined with the sequestration of that feedstock enables the facility to generate a negative EAC. That negative EAC enables unrelated coal or gas generation to be used for hydrogen while providing the top credit.

Both cases could be avoided if the guidance does not allow the use of negative EACs, which is RMI's primary recommendation, due to the indirect emissions associated with the offset and the non-linearity of credit values.

But, in the cases where it does, isolating the energy content associated with the negative EAC feedstocks is essential to avoid multiplying the credit for these inputs. This potential abuse would be further mitigated by a process that evaluates missed hours (discussed in the missed hours section) on an hour-by-hour basis (as long as other outlined requirements are met). The annual aggregation proposed in the proposed rule creates the risk that a negative or low-emissions EAC can help offset carbon-intensive hydrogen processes and subsidize these carbon-intensive hydrogen production pathways in contradiction with the law.

Additional areas in which Treasury is actively seeking comment

Coproducts

The treatment of co-products as described is consistent with ISO-14044 sections 4.2.3.3.3 (use energy and environmental significance beyond mass contribution alone) and 4.3.4.2 (Allocation Procedure) and sufficient for electrolytic hydrogen production.

Waste hydrogen co-produced from chemical processes is an emerging electrolytic pathway and should be included as a route for low-carbon hydrogen production following Together For Sustainability's "The Product Carbon Footprint Guideline for the Chemical Industry". This open-source guidance specifies the widest current global chemical industry agreements on carbon allocation rules for chemical processes including hydrogen production. Hydrogen allocation rules follow the Plastics Europe Product Category Rule (HVC Mass Allocation) for steam cracking, Eurochlor Product Category Rule (stoichiometry for salt in, mass for energy in) for the chlor-alkali process, and heating value allocation for all other chemical processes. Both steam cracking and the chlor-alkali processes are already modeled in the full version of GREET.

Provisional emissions rate

The most notable missing emissions rate pathway within the GREET model is solid oxide electrolysis, a near-commercial technology that is not included in GREET except when paired with nuclear. This approach of only pairing the pathway with nuclear misses valuable efficiency gains solid oxide can achieve when powered by waste heat from industrial processes such as ammonia or steel production. While the electricity input calculations are covered by the guidance, solid oxide electrolysis also utilizes heat to operate efficiently. Determining the LCA of heat, especially if considered "waste heat", adds additional considerations.

In general, RMI recommends using a standard heat rate across fuels. For waste heat from a zero-carbon source (e.g., geothermal or nuclear), that heat could be considered zero carbon. Treasury could use the mass-balance ISO standard mentioned above for heat associated with fossil combustion (using energy as a proxy to allocate emissions).

Transmission and distribution losses

RMI proposes that grid connected hydrogen production projects should be required to attribute the GREET average deliverability loss rate (4.9%) unless a project can otherwise demonstrate lower rates of transmission and distribution losses. This would require a qualifying hydrogen production facility to procure EACs in excess amount to cover this assumed transmission loss rate. This method would capture losses while avoiding the need for advanced power flow modeling and shift-factor calculations that require more modeling effort than necessary to approximate the impact of grid losses.

However, for directly connected or behind-the-meter generation, Treasury can enable the use of measured data instead of the national average. This provisional rate can be calculated by measuring the input electricity from the directly connected clean power facility. If the electricity is mixed with grid electricity, the producer could use the meter data from grid imports to calculate the energy from the behind-the-meter facilities.

Adjusting the grid deliverability zones further will help reduce transmission and distribution losses but is not recommended due to the regulatory uncertainty introduced that arises when the deliverability zones change over time. As a result, RMI recommends providing a deliverability safe harbor for projects that fixes the deliverability zone once a project commences construction and allows those projects to maintain that same deliverability zone through the credit period to avoid disrupting contracts and open the door for DOE to update the deliverability zones without undermining existing projects.

Incrementality flexibility

5% blanket allowance

A blanket 5% allowance for existing zero-carbon power to qualify as incremental under the 45V guidance would undermine the legal justification and logic laid out by the Environmental Protection

Agency and Department of Treasury. Requiring the generation, acquisition, and retirement of EACs with incrementality, deliverability, and temporal matching acknowledges the indirect emissions impact of using existing zero-carbon power to generate clean hydrogen. A 5% allowance for existing zero-carbon power to qualify as incremental is not an accurate strategy for capturing curtailment and supporting at-risk plants—the stated reasoning for this 5% proxy. There are more accurate ways to qualify these unique generators while avoiding significant emissions impacts in line with the law.

Given that approximately [40% of the current clean generation comes from clean sources](), a broad exemption would enable around 2% of total US generation (enough to power an average state) to create qualifying EACs with no certainty that that generation was on the margin during the time of production. While it could create liquidity in the future hourly market by adding additional attributes to the market, the emissions logic is not defendable. As a result, RMI suggests alternative avenues to provide operational flexibility while aligning with the legal requirement to only credit hydrogen with a low lifecycle emissions profile.

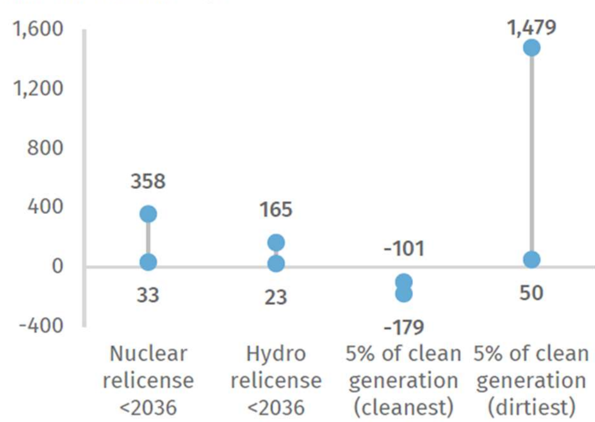
As [Rhodium Group has modeled](), a blanket 5% exemption would have unknown emissions impacts and could undermine much of the excellent work outlined in the proposed rule. They explain that this 5% exemption could have emissions reduction impacts if applied on a marginal emissions rate basis—in essence, allowing existing clean power to qualify as incremental as long as the generator on the margin during those times is clean and therefore the diversion of that existing power to hydrogen production has minimal emissions impacts.

However, a similar positive emissions story could be told by implementing a strong, credible flexibility for curtailed power – this 5% exemption is considered reasonable in theory and counterproductive in practice. This is further demonstrated by the highly consequential scenario in which this 5% exemption is applied to generation during times of high marginal emissions rates (which is frequent on grids throughout the nation). Rhodium finds that should this blanket exemption be applied to all generators it could result in roughly 1.5 billion metric tons of increased emissions (see Figure 4 below).

FIGURE 4

Range of cumulative emissions impacts in 2024-2035 under existing generation qualification options

Million metric tons CO_2-e



Source: Rhodium Group. Note: The nuclear and hydro relicense emission scenarios are relative to a future where these facilities relicense on the same schedule and then continue to serve load on the grid.

Other research and analysis has been done to understand potential impacts of a blanket incrementality allowance, including work from Princeton and Energy Innovation.

RMI recommends abandoning the proposal to allow 5% of existing clean electricity to qualify as incremental, even with guardrails, because of the high potential risk. However, in the case that Treasury decides to pursue this approach, it should implement guardrails to prevent the worst outcomes of hydrogen production resulting in significant emissions increases:

- Any blanket exemption should not apply to all facilities in all locations. Given the potential consumer price impacts of diverting existing clean power to hydrogen production, only facilities and regions that can prove there will not be a retail electricity price increase because of diverting existing zero-carbon power to hydrogen production should qualify.
- The blanket flexibility should be applied at a facility-by-facility level, requiring modeling to demonstrate that the qualifying EACs generated from this facility are being produced and retired for 45V compliance at a time that induces the lowest overall emissions based on the likely grid dispatch algorithm in that region. Providing blanket flexibility at the fleet level across a deliverability region will create incentives for fleet operators that do not align with the statutory requirement to produce low carbon hydrogen. There will be greater risk of significant induced emissions should any blanket percentage be applied across a fleet by allowing entire plants to have their power diverted from grid decarbonization into clean hydrogen production.

The requirements necessary to making the 5% exemption proposal work under the legally required emissions tiers for the 45V credit, and avoiding harmful negative externalities such as retail electricity price increases, are likely to be difficult for Treasury to administer and projects to track and comply with. This is not to suggest that guardrails should be eschewed, rather that an administrable solution that achieves the stated outcome goals of this proposal are possible and preferred.

Understanding Treasury is interested in providing some certainty and pathways for existing clean electricity generation under specific circumstances (facing curtailment, retirement, relicensing, existing in states or grids with policy or low emissions), RMI recommends that specific pathways are developed to address these instances. A blanket exemption may capture some of these instances, but it is more likely to allow a significant amount of clean existing power to qualify with emissions consequences beyond the limits allowed by statute and therefore should not be the solution pursued.

Curtailment

Curtailed renewable power is, by definition, wasted, and thus the use of "otherwise curtailed" power is not observable—it exists only in counterfactual. However, it may be possible to develop proxies for when clean energy is the marginal generator and thus the production of hydrogen has no impact on overall grid emissions. Without precisely identifying the location of the curtailment event at the clean energy generator, the infrastructure between the generator and the H2 production facility, and modelling the grid conditions at a specific timestamp, it cannot be guaranteed that a H2 production facility is taking advantage of a curtailment event. While the above approach is not administrable or cost effective, there are proxy approaches to consider that can evaluate the level of certainty in which H2 production facilities are not impacting overall grid emissions. These approaches vary in level of rigor and data quality required, which varies across the US. This allowance should have rules for compliance that align with real-time, location specific congestion events.

RMI has previously recommended a locational marginal price (LMP) threshold of $10/MWh, below which clean power can be assumed to be in a curtailment event for that balancing authority. At that point, all existing clean generators in that balancing authority can be considered incremental because clean power is on the margin, resulting in a low or negative LMP. The EU Delegated Act also includes an LMP threshold when considering power curtailments.

This would be a special rule, allowing those balancing authorities and facilities that are sophisticated enough to demonstrate such events and LMP dynamics to further participate and benefit from this tax credit. Due to the risks of indirect emissions impacts when existing clean generators are diverted for hydrogen production, a blanket flexibility as proposed should not be the general rule for 45V. Instead, special rules, which are both more likely to reflect real-world emissions impacts and conditions and are slightly more complex for operators, should be utilized. While not all electricity markets use or publicize LMPs, this data is often available and should be required to be provided to Treasury for auditing purposes to ensure accuracy.

Unlike emissions data, which can be approximated accurately on an hourly basis, LMPs are often published in 5-minute increments, as congestion events within grids can be acute and rapid. Aligning these time periods is necessary to accurately account for emissions at an hourly level. The Treasury has several options to manage this mismatch:

1. Use the hourly average LMP: the pros are this is administrable; the cons are that it lacks the granularity to demonstrate that only a portion of that hour had curtailed power
2. Use the minimum LMP: this is much more permissive but can enable sharp spikes to enable a full hour of production without EACs.
3. Use the median LMP: this ensures that at least half of the hour is under the threshold, but again doesn't have full coverage.
4. Require the full hour to remain under the LMP threshold: this maximizes emissions benefits but does not enable many curtailment events to be used.
5. Fractionalized approach: enable hydrogen producers to not cover the MWh used during the curtailment event. For example, if 50% of the hydrogen within a given hour was produced during a period where nodal prices are below $10/kWh, then the electrolyzer just needs to pull EACs worth 50% of the total consumption across the entire hour.

The fractionalized approach may be the most accurate, enabling sub-hourly data to prove alignment while covering the rest with attributes or grid average power. However, it's worth noting that curtailment is both rare (but growing) and concentrated in hours where the availability of attributes is high.

The most accurate curtailment metrics are related to actual volumes of curtailed VRE and are published by grid operators. To inform complex corporate actions, in-depth analysis of volumetric curtailment data can provide more precise evaluation of an action's system impacts.

The below table includes an overview of operational curtailment data resources by grid region.

Region	Data Type	Geography	Granularity	Publication Frequency	Curtailment Data Link
SPP	Curtailed wind/solar (MWh)	System-level	5 min	Daily, annual rollup	VER Curtailments
CAISO	Curtailed wind/solar (MWh)	System-level	5 min	Daily, annual rollup	CAISO Curtailment Data
NYISO	Curtailed wind/solar (MWh)	System-level	Hourly	Annual	NYISO Curtailment Data
PJM	Marginal Fuel (%)	Nodal	Hourly	Monthly	Marginal Fuel (%)
MISO	Marginal Fuel (%)	System-level	5 min	Annual	Marginal Fuel (%)
ISONE	Marginal Fuel (%)	System-level	Hourly	Daily	Marginal Fuel (%)
ISONE	*Curtailed wind/solar (MWh)*	*Zonal*	*Monthly*	Annual	Undelivered Energy
ERCOT	Capability vs actual output (MWh)	Zonal	Hourly	Daily	HSL - Actual = Curtailment
IESO	Capability vs actual output (MWh)	Zonal	Hourly	Daily	Forecast - Output = Curtailment

The most accurate curtailment data, though widely available, lacks consistency. Specific challenges to analyzing grid operator VRE curtailment data include:

- **Data type** – Volumetric operational curtailment data is the most robust source of truth for curtailment mitigation evaluation yet is published in only a handful of grid regions. Still, useful curtailment proxies like marginal resource percentage and capability vs output are often available. Supplementing curtailment impact analysis with proxy indicators of curtailment can still yield actionable insights.
- **Spatial granularity** – Most markets publish curtailment data at a regional level. If higher fidelity insights are needed, curtailment proxy data like zonal or nodal congestion costs can support system-level action.
- **Temporal granularity** – Some markets publish 5-minute curtailment data, and others publish only hourly. Depending on the solution type, intra-hourly curtailment dynamics can be a crucial nuance to include in an analysis. Incorporating highly granular temporal market data like 5/15-minute congestion pricing can enhance the analysis of nuanced operational actions.
- **Accessibility** – Curtailment and related proxy metrics can be difficult to locate on a system operator's website, but the above curtailment data table can serve as a navigation resource.
- **Publication frequency** – Some grid operators publish curtailment data in daily reports which require manual consolidation. Others only publish curtailment data on an annual basis, limiting up-to-date curtailment insights. If curtailment data aggregation becomes too onerous, corporates should look to proxy data with simplified reporting.
- **Limited forecasted data** – While historical curtailment data can inform near-term operational decisions and evaluate past actions, when implementing solutions over long time horizons, corporates should consider future market changes like transmission buildout or VRE capacity additions which may influence future curtailment dynamics. Granular forecasted curtailment data is most readily available today through subscription-based third-party data providers, but publicly available datasets like NREL's Cambium can provide qualitative perspectives of future market changes.

This kind of special rule must also include a more accurate deliverability region. This is because curtailment suggests clean electricity on the margin that is not being delivered. Despite the attempts through the DOE Congestion Regions to ensure clean electricity can reach hydrogen production facilities without congestion, the curtailment exception needs to provide proof that both the electrolyzer and the associated load are on the same side of the congestion event. As a result, RMI suggests testing the LMP price at the node closest to the electrolyzer, if available, rather than enabling hydrogen production during any congestion event over the entire deliverability region.

It will be especially important under a special rule allowing curtailed facilities to qualify as “incremental” to ensure that congestion is avoided. This will require a tighter deliverability zone to make sure the dispatch effects are not inducing significant emissions on the margin with fossil generators coming online to meet increased electricity demand as a result.

Protecting against gaming

In many cases, curtailment occurs due to insufficient grid capacity and is thus a result of congestion rather than regional or global overproduction. As a result, it does create a local incentive to oppose additional grid capacity because it would remove curtailed hours and could even create an incentive to reduce grid connectivity. Market monitors, ISO/RTOs, and PUC’s will be the first line of defense, but some anti-abuse provisions that examine the strategic reduction of grid connectivity to decrease local LMPs could deter similar strategies.

Avoided retirement and relicensing

Avoided retirement could be a pathway for incrementality compliance. Note that this is distinct from the proposed rule to apply the 80/20 rule to retrofitting clean power. When considering qualifying existing power facing retirement, the burden of proof of economic distress should be on the project seeking qualification, and it should be necessary for that plant to demonstrate that its relationship with a hydrogen producer is a primary driver for continued operation and retirement avoidance.

This pathway should be treated with utmost caution. It depends on a counterfactual that is not observable (namely: a facility will retire but for hydrogen demand). Without thoughtful guardrails and relative certainty that this compliance pathway is being adopted only by projects at risk of retirement, the indirect emissions impact will be significant.

Nuclear plants up for relicensing are one class of projects that may seek this pathway. Relicensing cannot be the sole activity taken by a facility to qualify as incremental, it must be combined with some suite of requirements such as proof of economic distress, commitment to operate, and existence in a location and market that provides less certainty than another—for instance, only plants operating in wholesale markets (facing more economic uncertainty) without access to state policy support or otherwise committed to providing low carbon power for mandatory programs could be allowed to pursue the relicensing compliance pathway.

If relicensing plants are likely to continue operations without additional revenue from hydrogen contracts benefiting from 45V, then qualifying that relicensed plant as incremental is the same as enabling existing clean electricity to be incremental. A pathway that simply allows nuclear plants relicensing during the tax credit window to qualify as incremental is dangerous and misaligned with the proposed rule.

One potential pathway Treasury could consider for treatment of existing nuclear plants at risk of closure establishes a universe of potentially qualifying nuclear plants and then requires those plants to meet standards to be considered incremental under 45V. Only plants located in wholesale markets or in a cost of service utility region in which the plant is deemed economically inviable *and* have filed for relicensing within the window of the tax credit would be considered for the narrowing metrics. From that universe of nuclear plants, the facilities would need to meet a financial test to demonstrate economic need by qualifying for the 45U or Civilian Nuclear Credit Program in a subset of previous years such that consistent financial stress is demonstrated. Two out of the previous three years seems to be a reasonable test, but Treasury may want to explore other standards. Finally, if the plant qualifies as incremental by meeting those thresholds, the electrolyzer plant should be co-located with the nuclear plant or sign a PPA with the nuclear plant for the lifetime of the credit (10 years) to demonstrate a direct relationship between hydrogen production and 45V subsidy with ongoing operations for the nuclear plant.

Modeled qualification

The core risk of this pathway is the creation of offsets (see our discussion on offsets below). By modeling emissions reductions that are separated from the hydrogen producer over time or space, the Treasury risks crediting emissions reductions unrelated to hydrogen production.

As a result, the modeled emissions should focus on modeling that demonstrates low emissions impact on the direct electricity node nearest to the electrolyzer or the direct pipeline network.

The place where modeled emissions can be useful is when evaluating when clean power is on the margin. While an LMP threshold is useful for grids with zero marginal priced electricity, it may not be appropriate for other resources (e.g., nuclear/ hydro), nor is it fully able to capture all cases where clean power is on the margin due to the local power flow dynamics.

There may be select cases where hourly marginal emissions data that identifies periods when clean power is the marginal resources, in which case the use of a model could be appropriate. DOE will likely need to identity a shift factor threshold when establishing what it means for clean power to be the marginal resource in relation to an electrolyzer. The added complexity may not be worth the squeeze, given the curtailment rules and the use of EACs – after all, when clean energy is on the margin, that typically signals that a large amount of clean power is available.

Fossil powered electricity upgrades

Adding CCS to an existing generator does not change the overall supply of electricity on the grid and should therefore not be considered incremental. If an existing fossil generator with CCS were to be considered incremental (and then be used to qualify for 45V), the new hydrogen load would increase total electricity demand on a system with static electricity supply and that dynamic would induce emissions increases. Allowing these facilities to qualify will not address the capacity effect as intended by the incrementality requirement. Installing CCS while enabling new unabated fossil plants is neither emissions friendly nor a preferred outcome of this policy.

When new clean power is added, it is considered incremental, and its capacity serves the new hydrogen load. However, a generator that just decreases their onsite emissions does not add capacity to the grid (and in fact decreases capacity via parasitic loads). As a matter of policy, CCS for existing facilities is largely covered by 45Q and further subsidy via hydrogen EACs does not address the need for new electricity load to serve the additional demand. While CCS buildout reduces the grid average emissions, isolating that improvement to allow additional public revenue towards the CCS facilities for 45V compliance purposes is not recommended.

If the Treasury does move forward with providing EACs to a generator that adds CCS, RMI recommends the following guardrails:

1. **Calculate the plant as a whole**: a gas plant with 80% CCS would create EACs that represent the aggregate emissions intensity of the output (e.g. 80g CO_2/kWh) rather than cherry-picking 80% zero carbon attributes and concentrating the rest of the emissions into the remaining 20% of the power. Cherry-picking emissions would not align with the physics of the generator and create a negative precedent where any marginal increase in emissions could be translated into an offset for 45V compliance. As a result, the EAC should not have a value of zero, but instead the lifecycle emissions intensity of the overall plant.
2. **Include upstream emissions:** if the powerplant fuel has associated leakage emissions, consistency would require that those emissions would be included in a well-to-gate standard. For example, a gas powerplant should include the leakage of input methane. Further comments on upstream methane leakage tracking and calculations are provided later in this comment.
3. **Require continuous monitoring**: once hourly matching is required, hourly outputs of total CO_2 capture and releases are necessary to calculate the hourly EAC value to ensure alignment with the credit.

Clean grids

Exemptions for regions with “clean grids” or grids that can demonstrate minimal dispatch emissions impacts of added hydrogen load met by existing clean power, such as from dispatchable renewable power such as hydropower or electricity storage following rules outlined in this comment, are being sought by states and areas with leading climate policies in place.

Most of the exemptions are covered by the use of EACs, the curtailment pathway, and additional clarity around how the use of EACs works with state-level policies. However, there is one case that has not been explored: very low overall grid emissions.

GREET currently uses eGRIDs regions when evaluating regional emissions, and it’s possible that in the later stages of this credit, certain regions will have very low emissions, and in some cases low enough to qualify for the top credit. As a result, it would be logical for electricity consumption uncovered by EACs to use the grid average emissions. As the Cambium dataset demonstrates, this emissions value varies hour-by-hour. As a result, we recommend that using eGrid average hourly emissions should be available when calculating uncovered grid emissions. This may not be available in real-time but enables electrolyzers in cleaner grids to take advantage of existing low carbon assets when calculating credit values.

States with binding emissions caps

Some states have policies in place that attempt to put a cap on emissions from their power sector. These states and regions may seek to claim that new load in the form of hydrogen projects in the utility service should not have to meet the incrementality requirement because the electricity with which the electrolyzer will draw power is part of a system under the cap.

Unfortunately, there is research to suggest that a binding state emissions cap does not have sufficient emissions reduction measures based on imports and exports of electricity and the induced (indirect) emissions impacts of the policies and additions of load without new power to match. Additionally, an emissions cap has been shown to increase power imports from neighboring states, which can lead to significant emissions impacts without a proper carbon border adjustment in place – something that does not effectively occur under state policies at this point.

When a state with an emissions cap adds new load in the form of a hydrogen project, they redirect existing electricity towards that load. The consequence is a reduction in clean electricity exports to other states and in neighboring states without similar emissions policy, there is likely to be a fossil-based generator on the margin in hours of low renewable resource that ramps up to meet the demand needs in that utility region.

For these reasons, a state with a binding emissions cap should not receive a blanket exemption from the proposed rules for 45V compliance. However, Treasury could propose a pathway for exemption if the state partners with the Department of Energy to model how power sector emissions will be impacted by adding hydrogen projects in their utility territory. If the import and export impacts can be modeled to demonstrate minimal emissions impacts and policies in place support low-emissions hydrogen production accounting for both direct and indirect emissions impacts, the Treasury could approve case-by-case hydrogen projects to qualify for 45V without meeting the incrementality standard.

A state emissions cap would also need to remain binding—preventing the availability of environmental attributes to not exceed the quantity required to meet the policy, allowing for additional local emissions to occur—for the entire credit period for any exemption allowed by Treasury to maintain its credibility. Period evaluation of the emissions impact and validity of an exemption for a state based on their emissions policy is encouraged.

Hourly phase-in timeline

Phasing in hourly matching by 2028 rather than requiring hourly matching out of the gate provides key flexibility for producers. RMI analysis suggests project flexibility in early years will enable market development and industry scaleup, but that an hourly matching requirement is necessary to meet the emissions thresholds required in statute for the 45V tax credit. The structure of the credit does not provide undue flexibility for first movers – all projects will need to be “hourly ready” to get financing, and therefore the Treasury is not unduly incentivizing lower accuracy accounting.

Fundamentally, the rationale behind the 2028 phase-in is about **administrability** for the Treasury, but ultimately the text of the law is silent on phase-ins for the purpose of industry liftoffs. However, the

2028 hourly phase-in is aligned with both registry needs and provides needed flexibility to use electricity as a feedstock for hydrogen production.

An important note is that **registries develop for regulatory compliance**, and not the other way around. In other words, they exist and are shaped by regulatory requirements, and therefore are adaptable to policy needs. The current snapshot of registries was designed for specific state policies, and there is room for competition to provide the assurance Treasury requires among verifiers. As long as the requirements are clear, the history of registries demonstrates clearly that necessity drives innovation.

Impacts of phase-in on market development

Should other hydrogen production pathways continue to dominate the market (due to uncertainty around electrolytic hydrogen pathways), the overall emissions impacts would be significant. However, the emissions impact may be even greater if ineffective rules enable grid-connected electrolysis hydrogen pathways to pull from coal or gas resources (annual matching throughout the lifetime of the credit and/or grandfathering of annual matching for projects that begin before a certain date). A transition period for hourly matching makes sense, and RMI analysis suggests the 2028 timeline can be aligned with industry liftoff.

Europe is currently building its clean hydrogen economy and could serve as a large offtake market for U.S. hydrogen producers. The 2028 hourly phase-in timeline aligns with the most progressive European states who may decide to transition to hourly matching by mid-2027. The rest of Europe will transition to hourly matching in 2030 with no grandfathering, and standard alignment helps ensure clean hydrogen and hydrogen-derived products such as ammonia, steel, and fertilizer can be traded with allies in Europe without confused, disjointed, or weak claims of low-carbon status.

A transition to hourly matching rules creates better long-term project outcomes without stifling early-stage industry growth. A transition to hourly matching in 2028 will ensure that hydrogen production maintains long-term emissions reduction ambitions, disincentivizes projects that will not be competitive in the long run and provides necessary conditions for the United States to establish itself as a leading presence in the global hydrogen market.

Early projects will benefit from annual matching across two main dimensions:

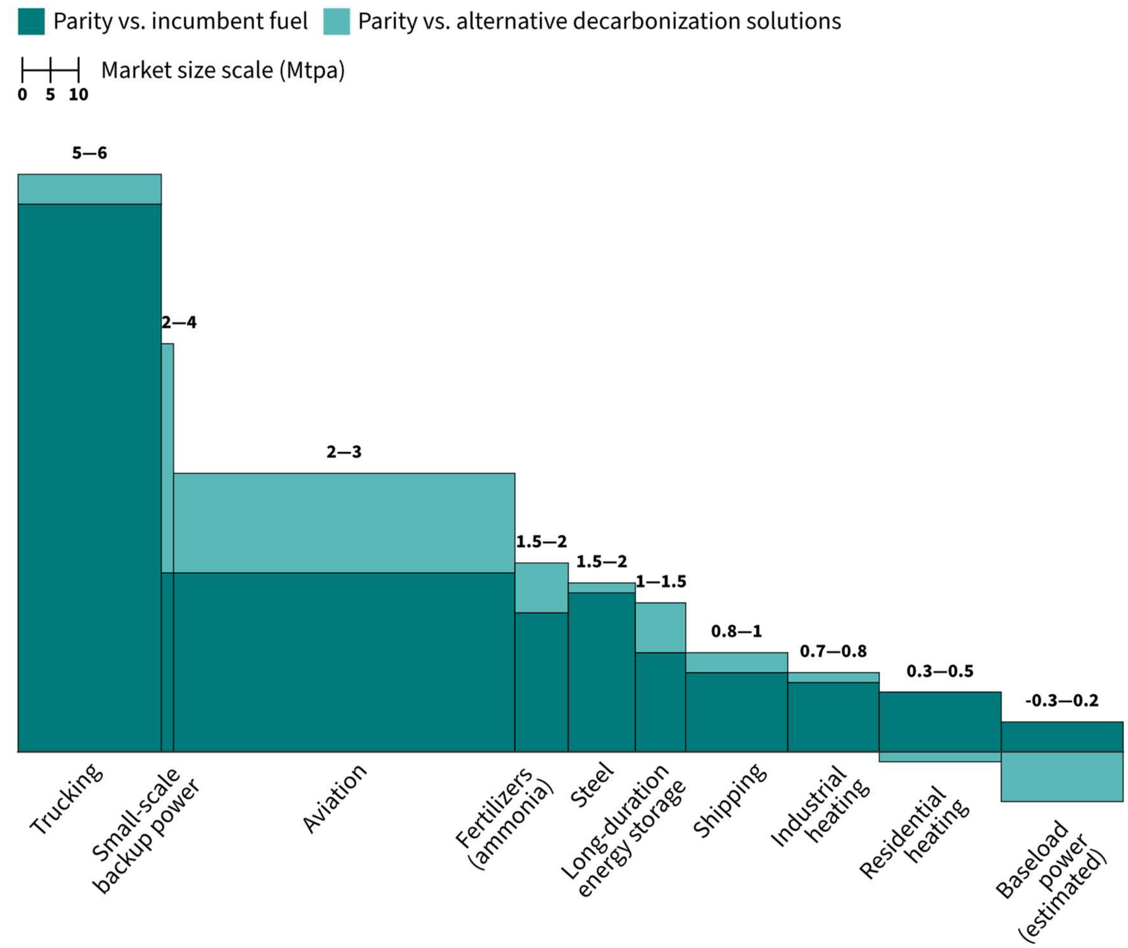
- Higher electrolyzer utilization rates can be realized due to the increased flexibility in when electrolyzers can draw power from the grid, which helps to supplement revenue during a financial period when paying down large capital expenditures is critical and increase resiliency of supply to meet offtake specifications.
- The timeline in which the added infrastructure requirements for an hourly matching requirement is delayed. This can lower the required initial capital outlay for projects, provide flexibility through longer project construction periods, and ease the risk of new renewable load failing to connect to the grid given the current project backlog and transmission constraints.

These benefits from initially relaxed temporal matching requirements provide first movers with a broader set of immediately cost-competitive projects across a greater breadth of serviceable offtake markets and feasible production locations, given the lower production costs associated with near-term flexibility.

With a lower delivered price, hydrogen can access more end-use markets (see Exhibit 4), which helps de-risk investments for first-mover producers as there are a greater set of possible off-takers as well as helps align with ambitions of offtake diversity in the US hydrogen strategy. If delivered prices are above \$2/kg, clean hydrogen may only be able to access the trucking sector as it has the highest allowable price threshold (up to \$5/kg, see exhibit below). If delivered prices reach \$1–\$1.50/kg, hydrogen can start to penetrate steel production, maritime shipping, or industrial heating end uses.

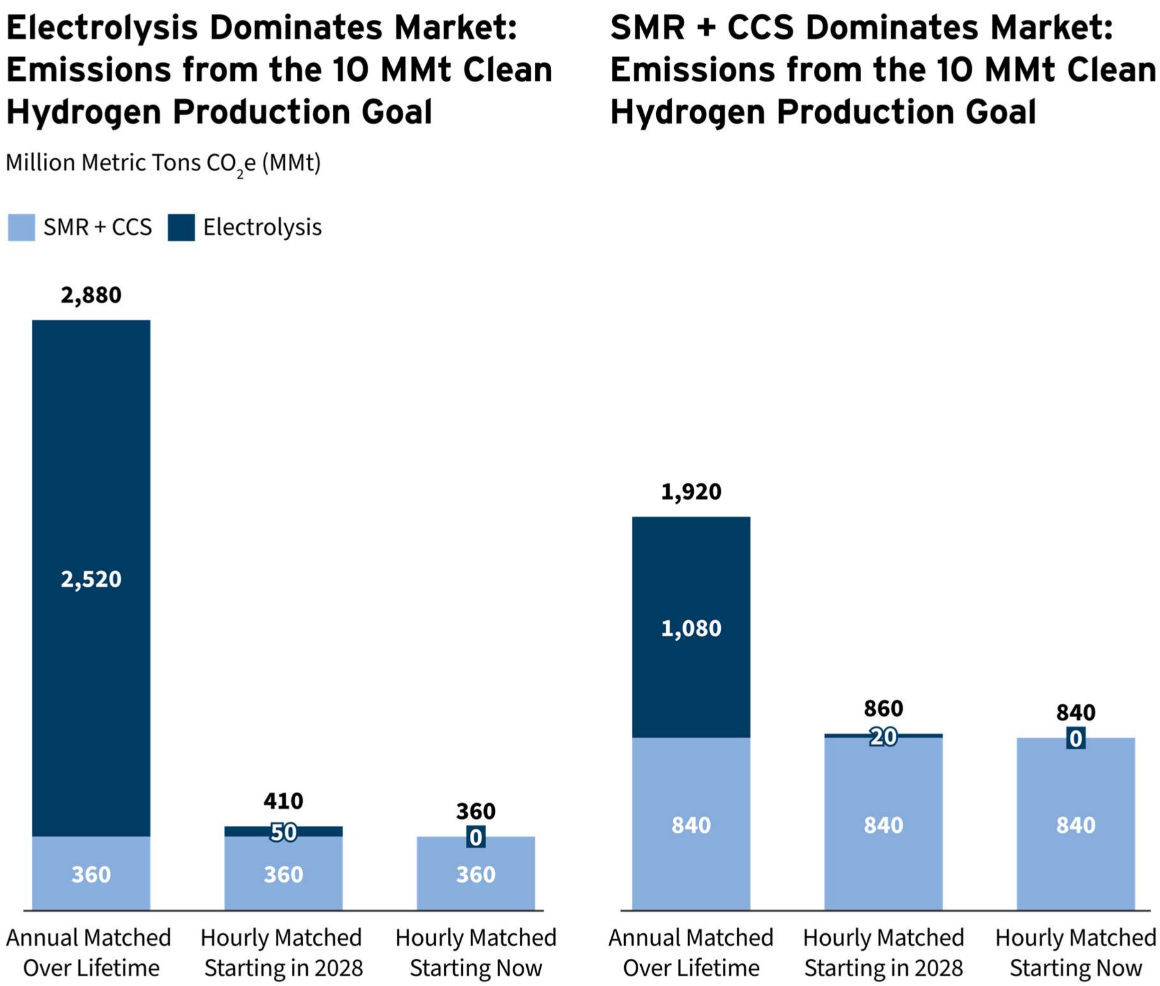
US Competitive Prices and Market Size for Hydrogen Across Possible End-Uses

$/kg vs. metric ton per annum (Mtpa) sectoral market



A long-run mandate of hourly matched hydrogen production is necessary to ensure the emissions of grid-connected hydrogen production are minimized. The exhibit below illustrates the significantly higher emissions if annual matching is allowed over the long run compared to hourly matching requirements.

Emissions impacts of policy decisions when electrolysis or blue hydrogen production dominates



The transition to hourly matching in 2028 is feasible for a few reasons:

- An hourly transition in 2028 is in line with EU regulations for ambitious Member States, which will ensure that the United States can compete on a global scale for exports into demand centers like Europe with strict carbon limits.
- Hourly matching market infrastructure will have time to develop, and rules will be clarified in a safe environment for early projects, giving them operational flexibility in early years while not locking in inflexible project configurations. While some United States tracking systems are starting to implement hourly energy attribute certificates (EACs) and hourly tracking accounting

measures, such as M-RETS and PJM's Generation Attribute Tracking System, widespread hourly matching schemes are relatively nascent. By 2028, the wider availability of temporal renewable energy credits and higher maturity of accounting systems will enable widespread implementation of tradeable hourly tracked EACs.

- By 2028, cost premiums of hourly matching are projected to fall as electrolysis technologies become cheaper and least-cost operation will start to converge with regulations. This is due to the correlation between lowest-cost grid electricity with the times in which clean electricity is generated. Once electrolyzer capital costs fall down their learning curves with greater deployment or individual projects pay off their initial capital outlay, hydrogen producers will pivot from prioritizing increased electrolyzer utilization to pay off capital expenditures to optimizing for lower electricity costs.
- The hourly requirement development process is aligned with a broad range of government efforts related to differentiating low carbon industrial products.
- A mandate of hourly match within the decade will help accelerate the markets and technology needed to achieve the administration's goal that 50% of the clean electricity procured by the federal government will be hourly matched by 2030.

Registry readiness

EAC registries will be the critical entity making an hourly system functional, credible, and transparent. Based on discussions with leading EAC providers, RMI is confident that existing registries can achieve the technical capacity to issue, verify, retire, and prevent double counting of hourly EACs. Some already have this capability and will simply require more resources to scale this functionality up to a system that can cover all geographies. Policy certainty is critically important to ensure the technological infrastructure development is aligned with the incentives in the policy.

The proposed phase-in timeline and the credit value will create a powerful market signal to ensure the rapid development of trusted, accurate hourly EAC systems necessary to make the hourly matching requirement work.

Provisional compliance

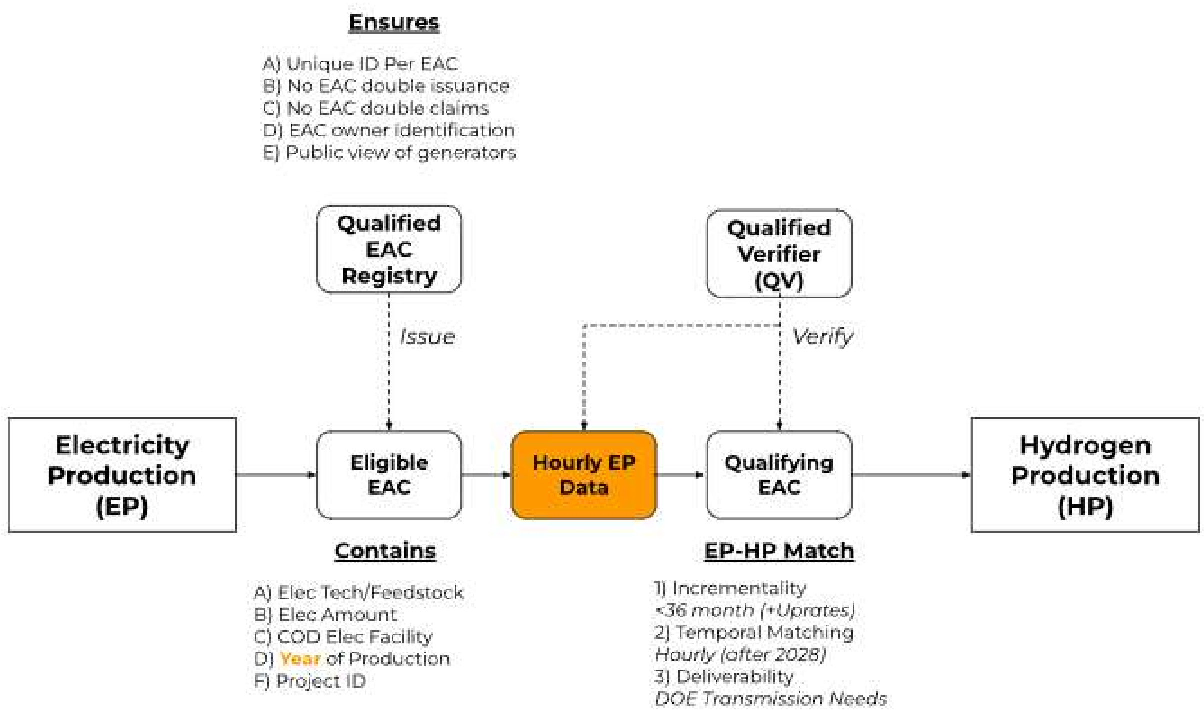
The nature of a 2028 transition period means that all projects will need to be "hourly-ready" to be financed – as a result, the rules around hourly matching will need to be clarified up front in order to provide enough certainty for projects to move forward. Treasury cannot delay publication of clear hourly rules, or it risks delaying all projects awaiting this clarification.

RMI argues that a bridge system of hourly matching and verification is possible now, well before hourly registries are fully operational.

Existing registries operate on a volumetric basis, and ensure no double counting occurs, and most do not have the capabilities to integrate hourly data yet. However, it should be easy to audit a bilateral contract between a clean electricity producer and a hydrogen producer to see how the hourly profiles line up.

The hydrogen producer and the qualifying clean electricity producer could integrate hourly meter data and meet the standards for hourly matching today with bilateral contracts. A hydrogen producer with a formal contract with a qualifying clean electricity generator could thus use existing qualifying EAC registries with annual or volumetric attributes to ensure that the overall MWh volumes are not being double counted, while facility specific data is confirmed separately as part of the contract. If a generator only provides hourly attributes to one load and no trading occurs, the chances of double counting of hourly attributes would be minimal. There is a possible case where a generator could sell the same hourly EAC to a voluntary customer (e.g. a datacenter) without disclosing this sale to Treasury, but any double dipping for compliance purposes would be easy to identify.

The totality of data required to confirm all likely bilateral contracts could likely fit on an individual Excel sheet, if aggregated hourly and verified meter data is provided in a secure form to the Treasury. The EnergyTag protocol, visualized below, demonstrates the need for a "qualified verifier" to review this data, which could be a within Treasury capability or outsourced to a third party.



Source: EnergyTag

The Treasury could simply audit the hourly electrolyzer producer data via a qualifying verifier to ensure no double counting will occur.

However, once **multiple** hourly matched EAC consumers purchase from an **individual** clean generating facility, the chances of double counting become non-zero and the need for a registry to integrate hourly data becomes more important. In addition, trading EACs between hydrogen producers or through electricity storage facilities increases the chance of double counting.

Tracking these transactions is a critical capability to enable hourly EAC trading and build liquidity in the overall attribute market. Based on conversations with developers and financiers, we expect that early on, widespread hourly EAC trading will not be common at first. However, contract aggregators like Level10 Energy are developing services to help electricity consumers aggregate contracts and trade attributes. Middle market institutions designed to improve liquidity will naturally emerge based on the fundamentals of this market, and the fundamental need is for registries to prevent double counting as the market becomes more complex.

This is the core task of registries by 2028 – enabling a highly liquid and tradeable market. The bridge accounting system above can be implemented across the nation in the interim for bilateral contracts. This should provide an option for first-mover projects hoping to achieve FID in the next year who need to ensure they can demonstrate hourly matching to secure financing.

The role and function of hourly registries

By 2028, RMI expects the full integration of hourly attributes into existing registries (or the expansion of hourly-capable registries into lagging areas). If this is not the case, the provisional system will continue to work for all forms of bilateral contracts.

The hourly registry integrates the meter data into the platform and enables trading. The EnergyTag protocol, demonstrated below, is one example of a fully developed registry protocol. The entire standard, found here, illustrates how the registry would work, along with key discussions about fraud prevention and audit protocols. While this is just one example, it demonstrates some of the key features, including double counting and double issuance protection. While this functionality could be offloaded to third parties and provide Treasury with a simple verification of hourly matching, Treasury could also bring some of these capabilities in-house as a backstop.

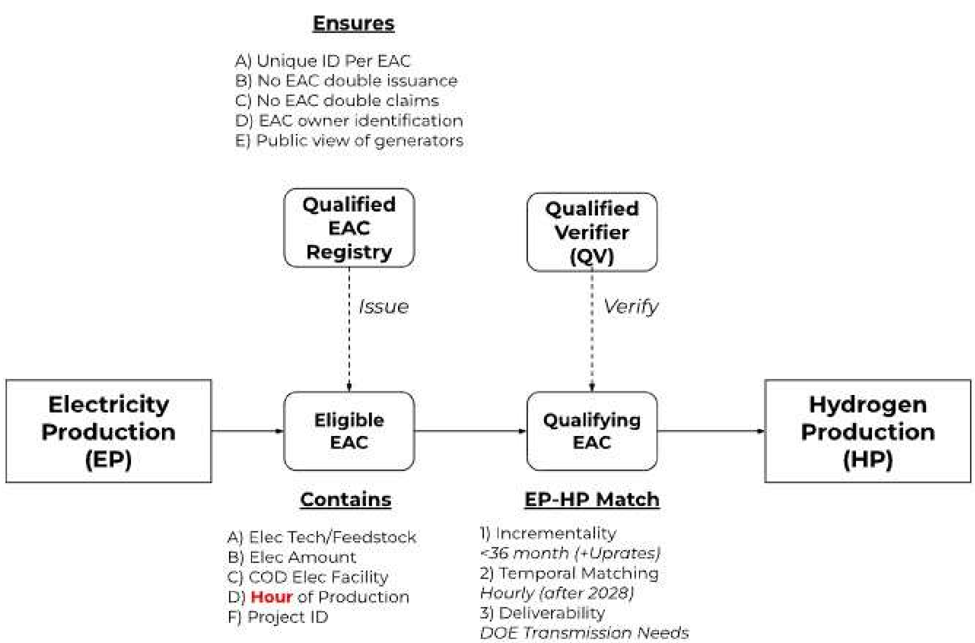


Figure 1 - Hourly Matching with Hourly EACs as detailed in 45v Guidance

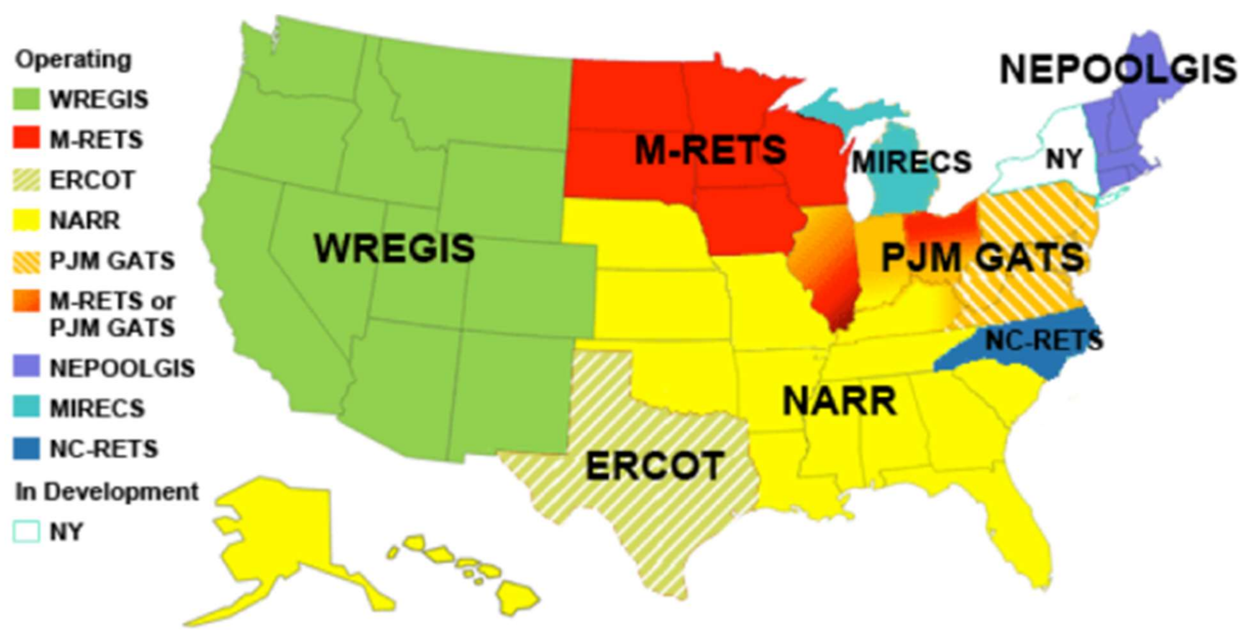
There will be a transition point where producers are using both the bridge system (e.g. use existing registries + meter data) and the fully integrated registry (e.g. registry mints and retires hourly EACs and guards against double counting). Since integrated registries have more capabilities and assurances against hourly EAC double counting, they are the best “point of truth” as the EAC market increases in complexity. Ultimately, it will be the responsibility of registries to sort out this transition, but the output to Treasury will likely look the same regardless of how the verification happens. A sanity check would at minimum include a database that includes each plant’s ID number (see: EIA . RMI also recommends a monthly stock-take where registries share processed data to Treasury.

Alignment with 45Y

Treasury will collect national electricity data for the clean electricity tax credits under Section 45Y. Due to the incrementality provision in the 45V guidance, nearly all electricity generation that qualifies for 45V will also be tracked and credited under 45Y except for electricity falling under proposed financial distress or curtailment pathways. As a result, Treasury could develop in-house tracking capabilities by requiring hourly generating information when projects claim 45Y with a unique project ID. This background data collection could support the auditing capabilities of the IRS as the agency builds enforcement capabilities and improves the efficiency and speed of the agency’s processing capabilities.

Registry interoperability

The registries that currently exist have fragmented and semi-overlapping informal territories with some interoperability that may cross deliverability regions. As a result, we could expect some hydrogen producers to operate across multiple registries when establishing contracts to bolster their capacity factor. This opens the door to potentially fraudulent behavior if producers double count hourly attributes across registries.



Source: eGrid

Strong data-sharing requirements and the development of a national interoperable API and standardized reporting requirements will be essential to avoid the following outcomes:

- **Registry cherry-picking**: if certain registries have weaker standards or verification methods, producers may have a race to the bottom.
- **Data loss**: the informal registry territories cross over the deliverability zones – it's possible that registries that are not integrated are unable to catch double counting.

EAC fractionalization

RMI supports EAC fractionalization rounded to the nearest kWh (0.001 MWh) to ensure that enough accuracy is available to evaluate the total credit. The Inflation Reduction Act provides taxpayer dollars based on a kg threshold. An individual kWh of grid emissions is sufficient in some regions to bump an electrolyzer from the first to the second credit threshold. Therefore, the granularity required to accurately evaluate emissions intensity to the kilogram is at the kWh level.

Grandfathering impacts

When considering whether to allow projects that either commence construction or are placed in service before a certain date to operate their projects under interim rules (annual matching), it is important to understand the volume of hydrogen and potential emissions impacts related to that decision.

Princeton University analysis shows the projects volumes of hydrogen that would be covered under different decisions on grandfathering, the emissions impacts, and the costs associated. Emissions impacts pertinent to the current NPRM are under the "2028" date of phase-out column.

The results show significant emissions impacts of allowing grandfathering, especially with a commence construction standard, and illustrates how pushing back the date of a grandfathering date increases the emissions impacts and the taxpayer subsidies spent on that high-emissions hydrogen production.

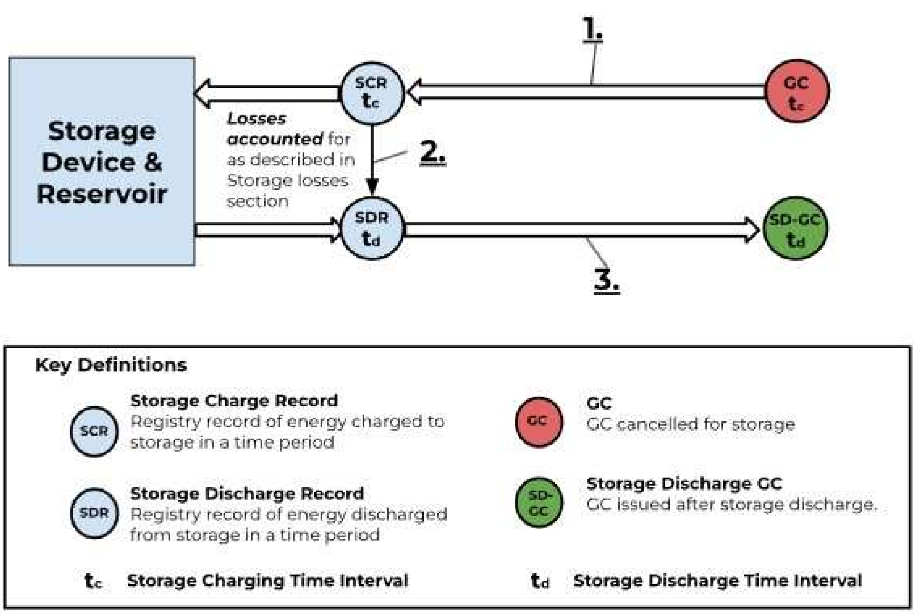
	Total MMT H2 covered by annual matching								
Date of phase-out	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Phase-out (no grandfathering)	0	0	0	0	1	2	4	8	15
Placed in service (grandfathering)	0	0	1	3	6	11	21	39	69
Commence construction (grandfathering)	6	11	21	39	69	103	141	182	227
	Total MMT CO2e induced by phase-in								
Date of phase-out	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Phase-out (no grandfathering)	0	0	1	4	10	21	42	81	150
Placed in service (grandfathering)	0	0	10	28	59	115	213	387	694
Commence construction (grandfathering)	59	115	213	387	694	1033	1405	1815	2266
	Total $B Spent on Annual Matched H2 Subsidies								
Date of phase-out	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Phase-out (no grandfathering)	0	0	0	1	3	6	13	24	45
Placed in service (grandfathering)	0	0	3	8	18	34	64	116	208
Commence construction (grandfathering)	18	34	64	116	208	310	422	545	680

Note: The blue bolded cells represent the EU rules for a phase-in to hourly matching for all projects in 2030 and the red bolded cells represent ACP's proposed exemption for projects that commence construction before the end of 2028.

Grid connected battery storage

Enabling storage facilities to participate creates flexibility for the nascent industry and creates further certainties that can help secure financing. Storage facilities could charge and consume a qualifying EAC (retiring that attribute), then discharge that electricity at another time, reissuing a new EAC, which can then be sold to a hydrogen facility. Grid connected battery storage operators, either standalone or behind the meter with renewables or hydrogen production, should be permitted to shift EACs from a time of abundant renewable generation to hours with need to meet 45V compliance provided the following is met:

- At time of charge, there is record of 1MWh of charging occurring and purchase of an EAC that meets all proposed requirements (incrementality, deliverability, hourly matching)
- At time of discharge, there is record of 1MWh of discharge occurring and an EAC is sold that meets all proposed requirements. This transaction also requires the retirement of a commensurate amount of EACs purchased upon charge (ex. If 50% losses, 2 EACs from charging will need to be retired alongside generation of an EAC that is tagged with the hour of discharge.)
    - Removing EACs associated with roundtrip efficiency losses – there are two choices, a battery average or a real-time calculation. While RMI suggests a battery average efficiency loss for ease of accounting, it's worth noting that real-time calculations are technically feasible.
- A battery may not hold a volume of EACs greater than its current state of charge
- The grid connected battery can and should participate in unrelated events that benefit the grid (e.g. peak load shaving, congestion events, grid firming, etc.)
- Require state of charge transparency: storage operators provide data on percentage charge



Storage Schematic for GC Schemes

Source: EnergyTag

The goal of using electricity storage is to move clean electricity across time and therefore arbitrage carbon emissions by using that clean electricity at a time when higher carbon resources are on the margin.

Because the deliverability regions are larger than individual nodes, it is possible that EACs "charging" a standalone battery will result in dispatch effects that are less predictable than if the battery was directly connected to the electrolyzer. These dispatch effects could mitigate carbon emissions by storing oversupplies of clean electricity and redistributing that electricity during times of high demand and low clean electricity supply. However, the incentives could also allow storage to charge using grid power and claiming EACs outside of their local grid, then using that electricity to discharge later without clear signals that carbon emissions are being arbitraged or that clean electricity is achieving a time shift.

However, allowing incremental storage to participate could have a positive capacity effect (encouraging new zero carbon power buildout). More electricity storage on the grid encourages the buildout of cheap low-carbon power because it is more likely that this power will be able to operate at higher capacity factors with storage facilities who will purchase that power. Curtailment and oversupply can be detrimental to project economics for new renewables; a 45V rule that encourages participation from electricity storage facilities could support their buildout and support the business case for renewable development.

Other groups have done significant work on how storage could effectively track EACs through the charge, storage, and discharge processes. RMI proposed the guardrails above because they follow the pattern of logic and legal justification laid out in the proposed rule. They additionally provide flexibility and certainty for industry while also incentivizing the buildout of energy storage technologies which continue to play an important role in broader decarbonization.

Emissions dynamics of energy storage:

If the administrability concerns were of no issue, calculating the marginal emissions impacts of storage participation in this system would be the most accurate way to qualify their participation. As discussed in RMI's comments from December 2022, marginal emissions accounting is technically challenging but rapidly improving. See RMI's recommendations on "modeled emissions reductions." Importantly, the use of energy storage dispatch as an offset is not recommended, and thus deliverability and temporal matching remains essential.

Given the large deliverability regions and the complex emissions impacts of injecting power into a local node on the marginal generator, it will not always be possible to predict the dispatch effects of storage participation. However, following the logic of the three pillars, energy storage also plays an important capacity effect on the grid. By enabling participation and encouraging the new building of storage that charges and discharges from incremental, deliverable, and hourly matched clean power on the grid, the long-run marginal emissions impacts are minimized. Therefore, the emissions benefits of storage largely come from the capacity effects of new induced clean power, rather than dispatch effects, which require marginal emissions calculations.

Incrementality for storage

To achieve the theoretical long run marginal emissions gains of storage, RMI notes that the three pillars should likely also apply to standalone storage assets: All new storage should qualify with a three-year grace period (covering all new capacity post-IRA), placement within the same deliverability region, and hourly data tracking.

However, waiving the incrementality requirement for standalone storage could be a way to improve the overall flexibility of the hourly EAC system and could be acceptable.

Deliverability

Deliverability regions attempt to provide a proxy for avoiding congestion of clean electricity between generator and consumer. The DOE Congestion Zones highlighted as geographical boundaries for the purpose of proving deliverability under this rule supports a balanced regional buildout of clean power and supports the reduction of effective greenhouse gas emissions. Larger regions such as full ISO or RTO regions include significant congestion and would be too large, while smaller regions like balancing authorities could be too restrictive to develop the hydrogen market. The deliverability zones offers significant flexibility and is likely too expansive to prevent all cases grid congestion and therefore cannot be considered to be truly deliverable throughout each region at all times. However, RMI supports the decision to initially use the DOE Congestion Zones as “deliverability regions” for administrability purposes.

Any geographic boundary is an imperfect proxy of grid topology, and as a result, there are tradeoffs. It is important to note that tighter deliverability zones would more accurately represent geographic regions that contain deliverable electricity from one point to another. However, true deliverability may never be perfectly approximated through a regionality requirement, and balancing the competing demands of demonstrating deliverability alongside setting rules that allow industry to participate and take advantage of the credit need to be considered – the DOE Congestion Zones do that.

The grid is dynamic, and if Treasury would like the optionality to change these regions over time, it will be important to provide a deliverability safe harbor. There are two major options:

1. Lock in deliverability regions: the deliverability map is fixed for a given electrolyzer once it commences construction
2. Lock in contracted power: if a given electrolyzer establishes a 10-year contract with a clean power facility after developers commence construction, that clean facility will qualify as deliverable over the contract period

Allowing projects to “lock-in” the deliverability region that exists when the project commences construction creates needed certainty for developers while enabling the deliverability regions to remain dynamic over the credit period without harming previous projects. However, adjusting the deliverability zones over time could introduce additional (but very manageable) complexity when auditing EAC availability.

Recommended special rule:

There will be instances in which a clean electricity generator and a hydrogen production project will claim to be deliverable and will seek special qualification, despite being in two different DOE Congestion Zones. This is especially apparent in Congestion Zones that do not follow conventional geographic borders (mid-Atlantic extending into Midwest, overlap between Plains and Delta.) This will likely only occur near the borders of these regions, and RMI recommends a pathway for operators to demonstrate physical flows of power between the deliverability zones.

Singularity wrote a report about deliverability and importance of ensuring power flows can achieve a deliverability standard:

> "Flow-based deliverability metrics trace the flow of power through the transmission and distribution network" while "fungible deliverability metrics are less-precise generalizations that evaluate the ability of the consumer's load to be balanced by generation in another part of the grid."

The deliverability zones proposed in the rule meet the standard of fungible deliverability metrics, which is an improvement to national accounting. The primary function of the fungible zone creates an observable, predictable, and administrable classification that project developers can easily prove and Treasury can easily confirm without introducing the complexities of power flow modeling for the bulk of qualifying generation.

Flow-based deliverability criteria is defined:

> "To determine flow-based deliverability, power flow tracing is used to trace generation from each generator on a power grid to each load on that grid. We call this bilateral delivery, since it describes the flow-based delivery between a specific generator-load pair on the grid at a specific time. Bilateral delivery can be quantified from either the consumer's upstream perspective, or the generator's downstream perspective. Upstream delivery describes what percentage of the total load delivered to each node originates from the generator, and can be used to answer "Where is the electricity I consume coming from?" Alternatively, downstream delivery describes what percentage of the total power generated by the generator is consumed at each node, and can be used to answer the question "Where is the electricity I generate going?""

The Department of Energy could consider performing power flow tracing for projects connected on interregional transmission nodes to help determine whether there are further connectivity opportunities outside of the assigned geographic deliverability regions. Eligibility should be considered based on the following criteria:

- If the project lies alongside the border to congestion zones that do not follow natural geographic boundaries.
- If the project has sufficient connectivity (inter-region transmission) to the alternative congestion zone so as not to exacerbate congestion.

Projects could also be allowed to demonstrate deliverability using an approved power flow tracing standard as defined by DOE. This would put the burden of proof on a project if it does not fall within the exception described above. Another benefit of these alternative deliverability pathways is it may encourage grid operators to begin offering this kind of analysis in their forward modeling to support certainty for projects and Treasury's approval process.

Safe harbor

RMI recommends that once a project commences construction, the deliverability regions defined at that moment should stay fixed for that generator. While deliverability regions can and should change over time as flow-based deliverability is further assessed which can enable a growing pool of qualifying generators, projects should be able to ensure certainty of their deliverability zones throughout the 10-year 45V window in which they are qualified. Stable contractual relationships over the credit period will be essential to secure financing.

Further resources
Singularity published a white paper that also outlines considerations for evaluating how proposed deliverability regions in this rule can achieve a deliverable standard. This kind of framework can be used to continually evaluate deliverability regions and their effectiveness within this policy. In Pease (2023), the authors present a range of additional bilateral delivery relationships that could be considered to evaluate the existing deliverability region and for potentially crafting special rules to demonstrate it. The 2022 LNBL study titled Empirical Estimates of Transmission Value using Locational Marginal Prices also offers a set of methodologies to calculate congestion over a given year – the use of nodal real time prices as a proxy for congestion is a useful tool for calculating deliverability.

Anti abuse

Double counting and interactions with local policies

The principle of avoiding double counting clean electricity attributes is critical to ensure accuracy and fairness in tracking energy usage and emissions reductions. This concept is particularly straightforward when allocating attributes to multiple voluntary electricity consumers but presents challenges when applied to broader compliance schemes like Clean Energy Standards (CES) or carbon caps. There's an inherent tension between maintaining stringent accounting standards and accommodating the flexible application needed by various policy frameworks.

RMI's first recommendation is for Treasury to clarify that each EAC shall be counted only once for verifying retail electricity use claims for the purpose of 45V or any other program. An EAC used for any other retail use or claim in this or any other program shall not be eligible – this is an explicit prohibition against "double counting."

This does not disallow the same entity to make one retail claim on the qualifying EAC and demonstrate compliance with multiple programs at the state or federal level. However, Treasury can determine whether the singular retail claim for an EAC used to demonstrate compliance with other programs can also be used in 45V compliance.

States will have latitude to reshape their programs and policies to adjust to the rules outlined for 45V, and there is precedent for renewable portfolio standards (RPS) and CES programs to address how voluntary loads (in this case hydrogen production) interact with state policy.

RMI outlines a few paths for Treasury to consider: partial cross-validation, removing load, and regulatory surplus. See the table below for a simplified analysis on impacts because of this decision.

A simplified example:

A utility with 100 MWh of retail sales in a state with a 50% CES currently sells 40 MWh of clean generation and therefore needs to sell an additional 10 MWh to comply with the CES. An electrolyzer is built in the utility territory that consumes 10 MWh of electricity annually.

Utility retail sales are now 110 MWh. At this point, 55 MWh of total retail sales, and an additional 15 MWh above current sales, are needed to comply with the CES. The electrolyzer would need to claim 10 MWh of clean generation for its use to get the full 45V credit.

Below are three different ways to handle this simplified example.

1. **Partial cross-validation**

Definition: The hydrogen project can count its EACs (and therefore clean electricity sales) towards its share of the CES up to the required standard.

In action: With the 50% CES, the hydrogen project would apply the first 5 MWh of electricity generation towards 45V compliance and CES compliance. An additional 5 MWh of electricity generation would not count towards CES compliance. This means another 10 MWh of clean electricity generation would be needed to meet the CES (the 5 MWh from the project plus the new 10 MWh meets the 15 MWh needed in total).

The total new, clean generation would be 60 MWh (voluntary plus compliance) and 110 MWh is total retail sales. This results in an effective 54% CES standard.

Challenge: Currently, RECs get aggregated across retail electricity customers in a geography with an RPS or CES. They are not typically assigned on a REC or facility-specific basis to individual customers.

Validation of a given facility requires that all EACs are retired on the facility's behalf, and that record of retirement is provided for compliance purposes. Retirements in RPS or CES programs can be done without specific facility level retirements - entities can retire a bulk volume of EACs on behalf of the customer base. To allow partial cross-validation (in which a compliant 45V project purchases and reports its share of EACs retired for the state policy), the entire REC pool would need to be disaggregated and reassigned to facilities. In this case, the hydrogen facilities attempting to qualify for 45V would need to have the attribute retired by the utility for purposes of meeting the state policy that is incremental, hourly, and deliverable be assigned to their facility. One consequence of this process, besides an administrative burden, is that this creates a situation in which ratepayers paying into this program are being assigned specific attributes, rather than sharing in the contribution to all new, clean generation. This could pose some equity concerns as it would incentivize utilities to assign new supply attributes to the hydrogen facilities so they can claim the 45V credit and would leave other entities to be claiming older, clean generation. Many RPS and CES targets have a vintage requirement that is greater than the 36 months required by the proposed 45V rule.

2. **Regulatory surplus (EACs are surplus to RPS/CES)**

Definition: Hydrogen production must procure incremental clean electricity to comply with 45V rules, but the project cannot count those EACs towards its share of the state policy.

In action: The 10 MWh of clean generation added for the hydrogen production to get full 45V credit would not be included in the generation used to comply with the 50% CES. The utility territory would still need another 15 MWh of clean generation.

In total, there would be 65 MWh of clean generation (voluntary plus compliance) and 110 MWh of total retail sales. This is an effective 59% CES.

Challenge: 15 MWh of clean power are retired on behalf of the hydrogen project's 10 MWh load (the 10 MWh procured by the project and the utility territory retiring EACs on behalf of the project at a 50% rate) – resulting in 5 MWh of over-procurement.

The two policies stack on one another for a larger driver of clean generation deployment. Fossil-based sales could be reduced by the state policy.

3. **Removing hydrogen load from CES**

Definition: A state removes the load of the hydrogen project from the total retail load subject to the CES.

In other words, the state CES isolates and removes 45V compliant hydrogen and the related attributes before conducting the CES calculation. This already occurs under state policies for other types of voluntary loads.

In action: The utility territory removes the 10 MWh of hydrogen project load from its total retail sales subject to the CES, the new load subject to the policy is 100 MWh. In this case, the CES requirement is 50 MWh of clean generation and 10 MWh of new generation would need to be added to the utility territory to meet compliance.

In total, 60 MWh of clean generation would be in place (voluntary plus compliance) and the total load would be 110 MWh. This is an effective 54% CES.

Challenge (and benefit): This solution reduces the additive impact of the CES and new generation driven by the hydrogen projects seeking 45V compliance because every 1 MWh of voluntary demand results in less than 1 new MWh of total clean generation as the CES percentage applies to 1 MWh fewer load. However, this approach avoids over-procurement seen in the regulatory supplies approach and the disaggregation of CES/RPS EACs seen in the partial cross-validation approach.

Summary:

Partial cross-validation and removal of the hydrogen load from state policy (options 1 and 3) are two forms of dual compliance. Regulatory surplus (option 2) allows no dual compliance between programs.

Until the grid is 100% clean, partial cross validation (option 1) and removing hydrogen load from the state policy (option 3) would result in less clean generation being deployed compared to no dual compliance at all (option 2). However, allowing dual compliance can help avoid over-procurement and leverage a stacking benefit while ensuring both 45V and the state policy achieve their goals. The removal of hydrogen load from total utility territory load (option 3) also avoids the challenge of disaggregating attributes generated and retired under the RPS/CES policy. Following existing precedent, removing load may be the simplest approach because it achieves similar benefits to the partial cross-validation approach without requiring the disaggregation of attributes within current RPS and CES programs. Partial cross-validation would allow for a greater pool of certificates to qualify for 45V compliance, reducing cost burdens on hydrogen development, while increasing regulatory burdens for CES/RPS programs. This increase in burden would derive mostly from disaggregating the attribute pool and attributing certificates to specific customers, which might lead to a desire for greater consumer choice where attribute type is important (e.g. voluntary corporate disclosure).

Treasury must decide whether dual compliance is allowed (which opens the door to all three options for states) or whether dual compliance is not allowed (which opens the door only to option number 2).

Option	Fossil-based Sales (MWh)	Clean Sales (MWh)	Total Clean Generation (%)
1. Partial Cross-Validation	50	60	54.5
2. Regulatory surplus	45	65	59.0
3. Removing Hydrogen Load from CES/RPS	50	60	54.5
4. No hydrogen production	50	50	50.0

Contracting directly with fossil generators

The NPRM currently allows hydrogen producers to purchase grid power and buy EACs to demonstrate that the power purchased is in fact clean. However, RMI strongly recommends disallowing hydrogen producers from contracting and buying power directly from a fossil fuel facility while buying EACs to neutralize the emissions. This would violate the language and the spirit of the law and would directly result in the clean hydrogen industry directly subsidizing high emissions facilities.

Gas-based Pathways

Areas in which Treasury is actively seeking comment

Biomethane Questions

(1) What data sources and peer reviewed studies provide information on RNG production systems (including biogas production and reforming systems), markets, monitoring, reporting, and verification processes, and GHG emissions associated with these production systems and markets?

There are a number of peer reviewed studies that can help Treasury understand the impacts of qualifying biomethane pathways for hydrogen production, the concerns outlined on business as usual assumptions, and leakage challenges. A few are mentioned below, and Earthjustice's comments include a broader list with more detailed findings outlined:

- Full Biomethane Supply Chain Emissions – Semra Bakkaloglu et al., Methane Emissions Along Biomethane and Biogas Supply Chains are Underestimated (June 2022) – This study shows higher leakage rates within the biomethane supply chain compared to oil and natural-gas supply chain. https://doi.org/10.1016/j.oneear.2022.05.012.
- Emissions from Biogas Plants – Charlotte Scheutz et al., Total Methane Emission Rates and Losses from 23 Biogas Plants (2019) – This study measures plant-integrated methane emissions rates from commercial biogas plants in Denmark. https://doi.org/10.1016/j.wasman.2019.07.029.

- Emissions from Counterfactuals and Leak Rates for Biogas – Emily Grubert, At Scale, Renewable Natural Gas Systems Could be Climate Intensive: The Influence of Methane Feedstock and Leakage Rates (2020) – This analysis evaluates counterfactuals for methane produced at biomethane production sites. It outlines the emissions impacts resulting under different baselines and leakage rates. https://doi.org/10.1088/1748-9326/ab9335.

(2) What conditions for the use of biogas and RNG would ensure that emissions accounting for purposes of the section 45V credit reflects and reduces the risk of indirect emissions effects from hydrogen production using biogas and RNG? How can taxpayers verify that they have met these requirements?

1. Biomethane, when used as a feedstock for hydrogen production and blended with fossil gas, should be evaluated as a separate facility and therefore no carbon intensity scores should be blended with hydrogen production, which uses fossil gas or other types of biomethane. The logic for this separation of carbon intensity is based on the definition of facility which states: "A 'single production line' would include all components of property that function interdependently to produce qualified clean hydrogen." Since biomethane of all types and fossil methane are sourced from different production lines, all which function as interdependent components, each feedstock can be considered different facilities. This means as gas is blended to produce hydrogen, the source of that gas should be evaluated on independent bases when considering a carbon intensity score and a credit threshold for the volume of hydrogen produced using that gas.

2. Biomethane should not receive a negative carbon intensity score by claiming a business-as-usual case of venting methane. At the most generous, this methane should be considered to be captured and flared, which would make the use of this methane for hydrogen production—with the waste stream of carbon dioxide—receive at best a carbon intensity score of zero.
    a. Agricultural digester systems, which typically generate the greatest negative carbon intensity score, do so under other state policies such as low carbon fuel standards to discourage the export of the industry and carbon leakage as a result of the policy. However, this negative intensity generates credits which then offset far more carbon-intensive activities. If 45V rules allow a similar offsetting accounting approach in which negative CI EACs are generated and can blend with non-negative CI EACs, the system could inadvertently allow heavily emitting processes to comply with the tax credit rules by offsetting with negative CI EACs from digesters.

3. Allowing previously flared or vented biogas to be considered as "incremental" as a first productive use also brings significant emissions risks by encouraging the expansion of facilities waste methane streams over prior years to qualify that methane waste for hydrogen production in the future. For landfill gas, considering an "above average" approach for incrementality when considering a facility that has no established energy project could be one way of encouraging investment in greater capture rates.

4. Deliverability standards should be established for book and claim of biomethane certificates – Treasury should consider a phase-in of this flexibility if the data and transparency standards are not ready for immediate enactment.

5. For biomethane from landfills, the lifecycle analysis in 45VH2-GREET should account for any uncaptured methane at the landfill. This would more accurately reflect the climate impacts of landfilling organic waste and give projects a clear incentive to improve gas collection efficiency and reduce fugitive emissions. This approach would instill confidence that low-emissions hydrogen production is not coming from a source that is releasing planet-heating methane and toxic co-pollutants to the atmosphere that could feasibly be captured. In addition, there should be clear guidelines around feedstock eligibility to minimize indirect emissions risks. First, the feedstock should be constrained to waste-in-place at the time of IRA passage (2022) to prevent the routing of future waste to landfills instead of lower-emitting disposal methods, like composting. Second, the feedstock should be constrained to landfills that are verified to be low-methane-leakage, by measuring and reporting their site-wide collection efficiency and maintaining best management practices that minimize fugitive emissions.

(3) How broadly available and reliable are existing electronic tracking systems for RNG certificates in book and claim systems? What developments may be required, if any, before such systems are appropriate for use with RNG certificates used to claim the section 45V credit?

While some book and claim systems already exist (such as the M-RETS system) to track biomethane certificates, this remains an emerging area where further development could help ensure accuracy and reliability.

Tracking systems should be able to allocate emissions based on different levels of gas blending from different feedstocks (as discussed above), enable the differentiation of carbon capture rates to those different feedstock production pathways, and determine credit values based on these evaluations.

(4) How should RNG or fugitive methane resulting from the first productive use of methane be defined, documented, and verified? What industry best practices or alternative methods would enable such verification to be reflected in an RNG or methane certificate or other documentation? What additional information should be included in RNG certificates to help certify compliance?

Fugitive methane should not be considered incremental if it comes from the fossil fuel system, as this is already accounted for under the current GREET model.

For landfills, any site with an operational beneficial use project (487 MSW landfills as of July 2023, according to LMOP) would not be eligible for the 45V credit, as they already have infrastructure in place to capture and productively use that methane, often with multi-year offtake contracts. The remaining potentially eligible landfills would include those with gas collection systems but no beneficial use project (e.g., routing collected gas to flares) and smaller landfills that are not regulatorily required to install gas collection systems.

(5) What are the emissions associated with different methods of transporting RNG or fugitive methane to hydrogen producers (for example, vehicular transport, pipeline)?

Once biomethane enters the pipeline system, it faces similar leakage rates and challenge as fossil methane and should be accounted for in the production LCA. As noted above, peer reviewed research suggests leakage from the biomethane supply chain may actually be worse than the fossil gas supply chain.

Should biomethane be transported outside of the pipeline, all effort to track, report, and evaluate leakage must be made for an accurate LCA. The waste biomass byproducts generated from biomethane production will require transportation, storage, and disposal actions – the LCA of these steps must be accounted.

(6) How can the section 45V regulations reflect and mitigate indirect emissions effects from the diversion of biogas or RNG or fugitive methane from potential future productive uses? What other new uses of biogas or RNG or fugitive methane could be affected in the future if more gas from new capture and productive use of methane from these sources is used in the hydrogen production process?

Reducing organic waste disposal in landfills – through waste prevention and organics recycling – is the most effective way to avoid the generation and release of methane to the atmosphere. For organic waste already in landfills, it is critical to maximize methane capture and minimize fugitive emissions. Captured gas should then be prioritized for use in hard-to-abate sectors without an electric alternative, such as methanol production for shipping applications. Diverting landfill gas from these applications to hydrogen production – which *can* be produced with clean electricity – is not a climate-beneficial outcome. Importantly, if landfill gas were not used for hydrogen production, it would likely be put to another productive use, given numerous federal and state incentives and strong demand for low-carbon fuels. For 45V to achieve any incremental methane reductions, there must be strong standards in place for landfill gas collection efficiency and guardrails to avoid the continued landfilling of organic waste.

(7) How can the potential for the generation of additional emissions from the production of additional waste, waste diversion from lower-emitting disposal methods, and changes in waste management practices be limited through emissions accounting or rules for biogas and RNG use established for purposes of the section 45V credit?

Ways to mitigate potential generation of additional emissions because of 45V incentives include restricting waste methane and biogas inclusion in 45V to sources generating prior to the passage of the IRA, ensuring biomethane receives no lower than a zero-carbon intensity score (no negative carbon intensity scoring), and requiring deliverability regions to ensure a tighter book-and-claim system for biomethane certification. Appropriate counterfactuals should be used to determine emissions impacts and provide a more accurate carbon intensity.

(8) To limit the additional production of waste, should the final regulations limit eligibility to methane sources that existed as of a certain date or waste or waste streams that were produced before a certain date, such as the date that the IRA was enacted? If so, how can that be documented or verified? How should any changes in volumes of waste and waste capacity at existing methane sources be documented and treated for purposes of the section 45V credit? How should additional capture of existing waste or waste streams be documented and treated?

Treasury should limit eligibility to feedstocks arising before the date of implementation of the IRA to defend against an incentive to increase waste streams. Only the methane generation potential of waste-already-in-place at the time of IRA passage should be eligible for the credit. To calculate this for landfills, Treasury could use the waste-in-place value reported to the GHGRP or LMOP in 2022 to estimate the methane generation potential of the degradable organic carbon in that buried waste. Only this quantity of gas, with a standard collection efficiency assumption applied, should be eligible as a feedstock under

45V. This approach is important to avoid diversion from lower-emitting disposal methods, like composting.

Fugitive methane from the oil and gas sector should not be compliant for 45V hydrogen production. This may result in incentivizing oil and gas operators to allow leaks to begin or continue unabated to benefit from the use of leaked methane. This policy would also run counter to the policies and economics attempting to drive oil and gas producers to fix and avoid methane leaks – a better use of public funds for the goals of mitigating methane leakage emissions from the oil and gas supply chain.

(9) Are geographic or temporal deliverability requirements needed to reflect and reduce the risk of indirect emissions effects from biogas and RNG or fugitive methane use in the hydrogen production process? If so, what should these requirements be and are electronic tracking systems able to capture these details?

Like the electrolytic hydrogen production proposed rules, deliverability requirements should be included for biogas and biomethane certification when claiming certificates for use.

Any biomethane claimed for hydrogen production for 45V compliance should be physically deliverable to the hydrogen production plant to ensure a robust book and claim system with climate integrity. While much of the North American gas system is considered connected, there are key considerations to consider when designing rules for qualifying gas pathways for 45V emissions targets:

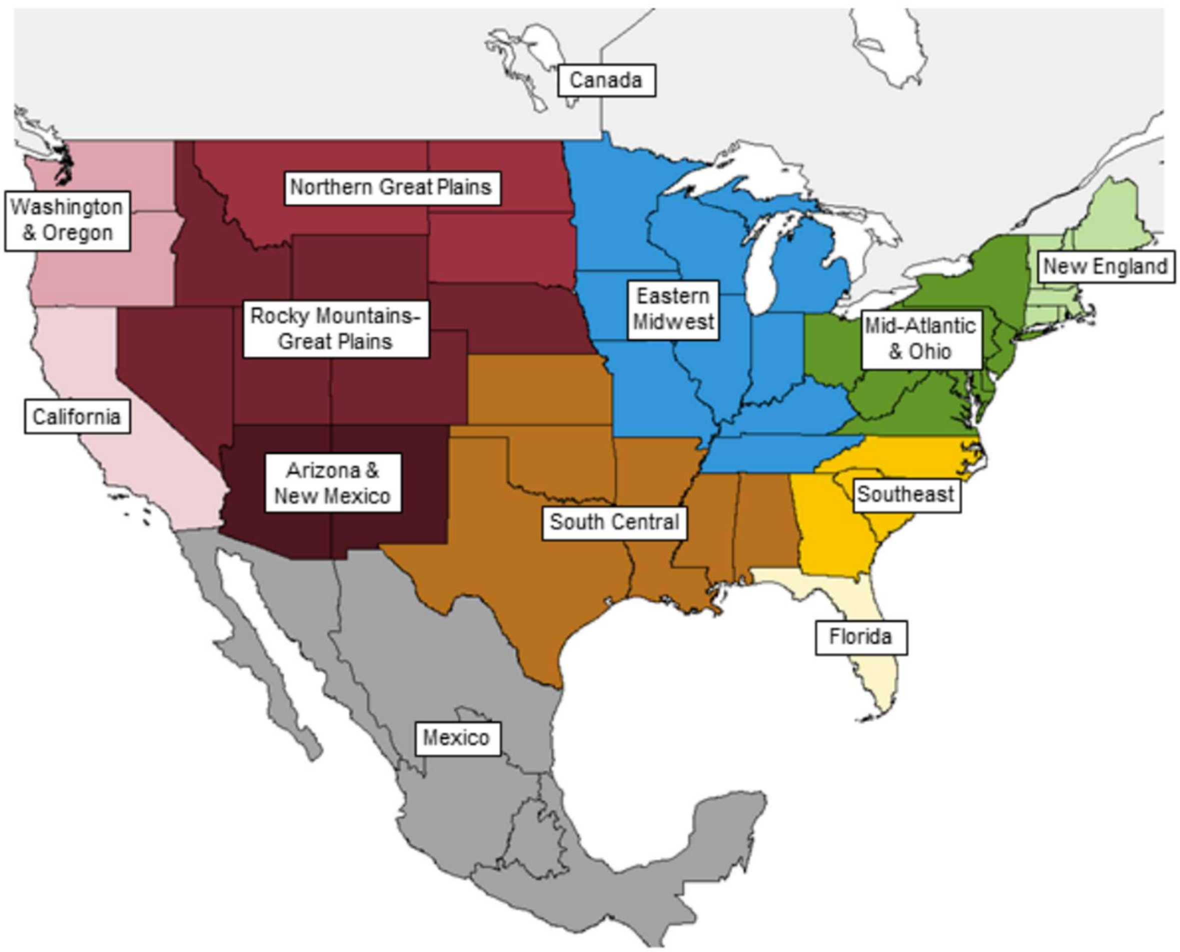
- **Local air quality and environmental justice concerns** when trading gas attributes across significant distances.
    - For instance, if a dairy digester in the Midwest can transfer its emissions attributes to a blue hydrogen facility in California, it is the communities in California that will be adversely impacted by the combustion and fossil-gas hydrogen production taking place. And the reverse is also true – communities in the Midwest must suffer the air pollution and health hazards of largescale dairy digesters maintaining economic viability due to sales of environmental attributes without the local economic or decarbonization benefits of producing and using hydrogen nearby.
- **Gas system deliverability is dynamic**: this credit has a roughly 20-year timeline and regulations should plan for a time when gas infrastructure may be coming offline and less interconnected than it is today. Finally, when considering deliverable gas over long distances, there is bound to be greater leakage along the transmission and distribution networks. Should Treasury adopt a granular leakage certification method for biogas transportation, the deliverability issue becomes less critical from an emissions accounting perspective. But if that is not considered, a requirement of deliverability will help mitigate leakage that occurs as gas is “delivered” over longer distances.

Biomethane produced and supplied to a gas distribution system then claimed and “used” a significant distance away is unlikely to contribute to the gas mix when steam methane reformation occurs. The carbon intensity factor and emissions assigned to biomethane produced separately from the fossil gas hydrogen project should not be transferred because those attributes are not physically interconnected.

Contrary to new power being important for grid-connected hydrogen production pathways to further approximate additionality, it would be an adverse outcome to use the financial incentive of 45V to encourage additional biogenic methane production. While some biomethane generators, such as methane digesters, may be established regardless of 45V, this incentive should not be used for large farms and methane producers to further expand their operations for the purpose of profiting off the tax credit. A recently introduced bill in Minnesota, SF 2584, prevents the generation of low carbon fuel credits from biomethane produced at new or expanded agricultural livestock production facilities. This helps ensure that additionality derived from 45V incentives is not undermining climate targets and attempts to decarbonize the agricultural sector.

One such option for deliverability zones for gas book-and-claim could be EIA's gas market regions from NEMS. They're designed to represent regions with different gas prices:

Figure 2.5. Natural gas (NG) regions used to report regional flows and capacity



Data source: U.S. Energy Information Administration

Source: EIA

Treasury should also consider phasing in the allowance of book and claim biomethane certificate trading and retirement within a deliverability zone. Like hourly EAC registry infrastructure, Treasury could determine that the data infrastructure, verification, and transparency processes need time to develop and scale up before being credible enough to allow this as a pathway for 45V compliance. Until that point, directly connected and contracted biomethane could be the only pathway allowed to claim this carbon intensity for the hydrogen production.

(10) How should variation in methane leakage across the existing natural gas pipeline system be taken into account in estimating the emissions from the transportation of RNG or fugitive methane or establishing rules for RNG or fugitive methane use? How should methane leakage rates be estimated based on factors such as the location where RNG or fugitive methane is injected and withdrawn, the distance between the locations where RNG or fugitive methane is injected and withdrawn, season of year, age of pipelines, or other factors? Are data or analysis available to support this?

The NEMS model can be used for deliverability standards, however it is unlikely to apply as effectively to limiting leakage. The NEMS model does not apply to leakage potential as different regions have dramatically different ages, flow capacities (and thus compression needs) which have a much greater influence than distance traveled.

Note that fugitive methane is a highly risky energy source and compliance pathway (more on this below).

While there are studies that portray how travel distance, pipeline condition/age/material, and pipeline type (gathering vs. transmission vs. distribution) do impact emission rates of gas transportation through pipelines, there is not yet a concrete pathway to estimate pipeline emissions variation over time.

While EPA recently updated emissions factors for different types of pipelines in its latest GHGRP Subpart W proposal, and RMI recommends interagency coordination to ensure the most up-to-date federal values are used in estimating emissions, such emission factors cannot estimate emissions fluctuations as they are not based on real-world data.

Incorporating empirically measured data would be the most accurate way to characterize emissions variations between pipelines. For example, the EPA's new Super Emitter Program aims to incorporate measured large emission events (100+ kg methane/hour) from the oil and gas sector into GHGRP Subpart W inventories, but inventories are largely still desktop-calculation based.

(11) What counterfactual assumptions and data should be used to assess the lifecycle GHG emissions of hydrogen production pathways that rely on RNG? Is venting an appropriate counterfactual assumption for some pathways? If not, what other factors should be considered?

Venting is not an appropriate counterfactual assumption for biomethane– it is an irresponsible practice which provides the greatest value to gas producers who are investing the least in the environmental quality and emissions reduction technologies at their facilities. The use of "vented" natural gas in addition is not observable – all gas that is captured is not vented by definition. As a result, there is no administrable system that credibly enables producers to distinguish the gas that "would be vented if not for the existence of 45V credits". For instances like wastewater treatment in which venting is the norm, that gas, if captured, should not receive a negative carbon intensity score. See the discussion in comments above regarding the treatment of negative carbon intensity scores and the reasons they are inappropriate for consideration within an emissions-based tax incentive like 45V.

In the GREET lifecycle analysis, Treasury should account for the fugitive methane emissions from uncollected landfill gas associated with biomethane-H2 production by using a counterfactual that aligns with EPA's Waste Management Hierarchy and Wasted Food Scale. In the current GREET model, flaring is the counterfactual scenario for landfills. This approach fails to account for the methane emissions from uncollected landfill gas. To remedy this, Treasury should consider more sustainable waste management approaches for organic waste as the counterfactual or reference case, such as waste prevention, composting or anaerobic digestion. This approach would include methane leakage at the landfill in the LCA, creating an incentive for operators to improve their methane collection rate and demonstrate lower leakage than the default. EPA's WARM model estimates that the average LFG collection efficiency at U.S. landfills is about 65%, while aerial surveys suggest it may be lower.

(12) What criteria should be used in assessing biogas and RNG-based PERs? What practices should be put in place to reduce the risk of unintended consequences (for example, gaming)? Should conservative default parameters and counterfactuals be used unless proven otherwise by a third party?

Care should be taken to ensure gaming of a facility definition, blending of multiple feedstocks, and carbon capture accounting are not occurring when a project applies for a PER.

Given that landfills can generate super-emitting plumes and studies suggest collection efficiency can be overestimated, conservative default parameters and counterfactuals that reflect this high potential leakage at landfills are appropriate.

Biomethane LCA and treatment

Biomethane qualification under this credit is largely addressed above. To reiterate, flawed counterfactual assumptions for biomethane generated in digesters establishes an inaccurate carbon intensity. The treatment of biomethane should be changed, but either way the carbon intensity of this pathway should not be blended with the carbon intensity of another feedstock pathway to establish a blended emissions level, qualifying what would otherwise be a high emitting process as low emissions and heavily subsidized with the 45V credit.

National average methane leakage rate

The upstream methane leak rate assumed in the GREET model should be re-examined. As a national average, the 0.9% value will result in an underestimate of the true methane emissions intensity of the U.S. upstream oil and gas sector. Importantly, the 0.9% rate includes distribution which may not be a part of hydrogen production pathways, so the real value used in the GREET model would be 0.85%, an even greater underestimate. To remedy this, Treasury and DOE should replace this input with a more accurate value reflecting the latest scientific research and update these leakage rates annually.

Recent studies like those by Sherwin et al. (2023) that incorporate data from measurement campaigns and modeling suggest a national average methane leak rate of about 2.2% using allocation. Similarly, Alvarez et al. (2018) found a national leak rate of 2.3% using a bottom-up model tuned with measurements. The 2.3% rate is unallocated, and is adjusted to 1.9% using a method to allocate the rate to the natural gas product. In addition to these studies, other data sources offer options for a more realistic upstream methane leak rate value. MiQ and Highwood Emissions Management have published the first open-access, measurement-informed methane leak rate index for the U.S. oil and gas industry, the MiQ-Highwood Index. The MiQ-Highwood Index provides methane leak rates for oil and gas production based on leading academic research, Sherwin et al, and finds a national average leakage rate of 2.2% for the full natural gas supply chain, using allocation. This index and the underlying data serve as an example of information that can be leveraged to update the assumed methane leak rate value in GREET to reflect the most current understanding. A more accurate level of national average leakage rates is critical to ensuring the LCA for gas-based hydrogen production reflects the real emissions impacts.

The proposed plan to update the upstream methane leak rates over time is a step in the right direction. It is our recommendation that the 45VH2-GREET model be reviewed and updated regularly per interagency coordination and related efforts, as well as the most current scientific understanding available.

The Methane Emissions Reduction Program (MERP) in the Inflation Reduction Act (IRA) demonstrates a broader Congressional commitment to increase data transparency, with significant funding to do so. The IRA allocates $1.55 billion to EPA for methane monitoring and mitigation, and EPA's final New Source Performance Standards and Emission Guidelines for Oil and Natural Gas Operations require leak monitoring at well sites, allow advanced detection methods, and establish the Super Emitter Program (SEP) via remote sensing.

Path-specific leakage rate

To improve the accuracy of upstream methane emissions estimates, RMI urges Treasury to go beyond simply updating the national average methane leak rate by increasing the granularity of this value and allowing the use of path-specific methane leak rates. We encourage Treasury to explore options for determining path-specific leak rates using verified, measurement-based standards that are technically robust, open-source and independent to evaluate the methane intensity of gas assets. RMI recommends that direct measurement (including informed modeling, metering, enhanced emissions factors) used to determine path-specific methane leak rates at a facility level follow established methodologies with third party verification.

The transparency, independence and completeness of any measurement-informed emissions reporting standard used is critically important. Allowing use of emissions intensity information from certification, in lieu of standard pre-defined metrics, would require significant oversight to ensure that tax incentives are deployed in alignment with proposed hydrogen production goals and do not incentivize an increase in total national gas production as a result.

To enable the use of path-specific leak rates as foreground inputs into GREET, Treasury should work with DOE and EPA to officially accredit or recognize measurement-informed emissions reporting standards, verification programs, and certificate registries that meet the following criteria:

- Measurement-informed emissions reporting standards that:

    - Recognize top-down and bottom-up measurement-informed evaluation of emissions, reconciling source-level and facility- or asset-level data in the accounting of total emissions
    - Represent a complete assessment of all emissions sources, all technologies, and all gas flow from an entire asset or facility
- Verification programs that:
    - Are independent, unconflicted to the data (no financial interest), and technically accredited
- Certificate registries that:
    - Provide sufficient information to issue, track, and ultimately retire certificates and their corresponding environmental attributes and prevent double counting

Efforts to gather data and programs that track methane leakage at a broader scale, such as the Colorado Methane Intensity Verification Rule methodology, will help inform a more frequent and accurate update of leakage rates. Treasury could also consider a phased-in requirement that all projects use a path-specific leakage rate to qualify for 45V after a date. Similar to the delay on hourly matching so infrastructure, data, and project finance can prepare for the transition, a more emissions accurate process of path-specific leakage rate requirements could be phased in starting in 2028 (or a more appropriate time after evaluating the landscape).

Upstream methane leakage

Accurate well-to gate emissions accounting for gas-based hydrogen production pathways, using the most up to date research on methane leakage throughout the oil and gas supply chain and without the use of artificially negative carbon intensity scores for faulty assumptions on the business as usual cases for flared and vented methane, will be critical to the credible distribution of the 45V clean tax credit for hydrogen produced with fossil or bio-based methane.

There are a few key issues Treasury should address and clarify in the final rule. The upstream leakage assumption in the DOE GREET model needs to be a more accurate reflection of the true average leakage occurring throughout the system. Biomethane and “fugitive methane” sourced from abandoned wells, coal mines, or elsewhere should not receive a negative carbon intensity score in which the combustion of the methane to produce hydrogen with significant carbon emissions is considered “carbon negative” because it is compared to a baseline of vented methane, which has been globally recognized as not being a recommended business as usual case. Fugitive methane emissions from oil and gas activities should not be included in the ultimate definition of fugitive methane, accordingly, as doing so would conflict with federal and international emissions mitigation initiatives. See the discussion on Fugitive Methane below. Finally, no matter what the final rule and GREET model includes for a carbon intensity given to the cleanest gas-based pathways, gas should never be able to qualify more carbon intensive hydrogen production pathways for 45V by offsetting the emissions of the higher carbon-intensity pathway.

A facility-based emissions accounting approach should be adopted and require robust measurement-based emissions quantification, verification from a third party, and disallow cherry-picking of sources to represent a facility. The emissions reduction technologies used and applied at a particular facility can be credited, but this cannot be used to mitigate the emissions impact at another facility.

Finally, Treasury has asked that proposed rules addressing the gas-based pathways logically align with the legal and physical justifications for the electrolytic rules outlined in the proposed rule. It is important that all final rules related to gas-based production pathways consider whether incrementality for gas-based production results in similar emission reduction impacts as the incrementality requirement for electrolytic pathways, address potential gaming of facilities to blend their intern carbon intensity scores to maximize credit uptake, and ensure that there are guardrails of deliverability for any allowance of book-and-claim systems under the final rule.

Anti Abuse and First Productive Use

The proposed rule that limits the intentional production of additional biogas for the purposes of claiming 45V credit by requiring that the gas used to claim the credit is originating from the "first productive use" of the relevant methane. This is a necessary limit on any existing facility already producing biogas that may be incentivized to increase production by generating more waste than would otherwise happen without the 45V incentive in place.

However, further guardrails will be needed and should be considered to further lessen the risk that increased waste streams will occur with a primary motivation to capture the 45V incentive. Importantly, the first productive use requirement cannot be seen as a clear parallel to incrementality in the case of electrolytic hydrogen production. Incrementality incentivizes the addition of low-carbon electricity production facilities onto the grid. While this increased supply can exacerbate and face challenges of interconnection delays, curtailment, permitting restrictions, land-use debates, and ethical material sourcing, incentives supporting the addition of low-carbon generation onto the grid is generally a no-regrets policy decision because it supports broader grid decarbonization, air quality improvements, grid flexibility, and economic development. This is not the case when requiring the first productive use of biogas for 45V compliance. A critical difference between biogas hydrogen production and electrolysis hydrogen production is that the former requires a stream of waste as feedstock and the latter requires a feedstock of low carbon electricity. Requiring a first productive use for biogas will incentivize an increase in this waste stream to be used as a feedstock—this results in almost no positive externalities and is often an air quality, environmental justice, and sustainability disaster.

Treasury proposes that any gas vented or flared currently under business-as-usual cases could be considered "first productive use" under these rules if the facility can prove that this gas had been being vented and/or flared previously. If this preexisting gas production facility is allowed to prove that this wasted gas is a business as usual case via submission of this information to an annual program—such as the Greenhouse Gas Reporting Program—it will pose significant conflicts of interest and encourage facilities to waste (via venting or flaring) more gas each year than would typically occur due to the generous potential incentives from 45V.

Fugitive methane

Allowing fugitive methane to qualify as a first productive use is a highly risky compliance pathway which could result in far greater emissions than a business-as-usual case. This proposal would reward the largest emitters of methane – and unlike biogenic methane capture, this fugitive methane is not biogenic and not avoided, it is fossil fuel resulting from an extraction process. This should have different rules and be treated similar to unabated fossil gas under the GREET model.

At the very least, the base case for this fugitive methane should be capture and flaring – not venting.

A project should also not be allowed to use this methane to power an electrolyzer to get a better CI score than can be achieved through the electrolytic pathways in the proposed rule.

Areas in which RMI would like to provide comment

Landfill Methane

About 70 percent of current U.S. biomethane supply comes from municipal solid waste (MSW) landfills. However, MSW landfills only capture a portion of the methane they generate, and landfill emissions are the third largest source of anthropogenic methane in the United States. Incentivizing hydrogen production at these sites does little to curb these emissions, and if not designed carefully, could risk exacerbating their climate impacts.

Landfill methane emissions are avoidable: reducing disposal of organic waste in landfills – through waste prevention and organics recycling programs – avoids future methane generation. In addition, implementing best management practices for landfill monitoring, design, and operations can significantly reduce fugitive emissions from previously landfilled organic waste.

As proposed, the 45V credit provides a financial incentive to *continue* landfilling organic waste that would put more sustainable waste management pathways, such as waste prevention and composting, at a disadvantage. Furthermore, the program provides no guardrails to minimize methane leakage at the landfill, which could perpetuate the release of highly potent, planet-warming emissions. Below, we describe the climate impacts of landfilling organic waste, the limitations of current lifecycle modeling for landfill gas pathways, and provide recommendations for how Treasury and the IRS can structure the 45V tax credit to limit landfill methane pollution and other indirect emissions effects.

Specifically, we recommend 1) high standards for incrementality, 2) a lifecycle analysis that aligns with EPA's waste management hierarchy, and 3) feedstock eligibility requirements that counter perverse incentives to continue landfilling organic waste and minimize methane leakage at the landfill. In addition, we note that EPA is statutorily required to revisit its Section 111 New Source Performance Standards and Emission Guidelines for MSW landfills in August 2024, and should seize this opportunity to develop an ambitious framework that reflects the latest best practices in methane monitoring and control, while advancing organics diversion.

Landfills are a significant source of planet-warming methane emissions. Accelerated methane abatement is crucial to limit temperature rise over the near term and avoid the worst impacts of climate change. In 2021, U.S. MSW landfills emitted an estimated 3.7 million metric tons of methane, according to EPA's inventory, or about 295 million metric tons of carbon dioxide equivalent on a 20-year time horizon. That's equivalent to the annual greenhouse gas pollution from 66 million gas-powered passenger vehicles or 79 coal-fired power plants. In 37 states, a landfill was the single largest industrial methane emitter reported to EPA's Greenhouse Gas Reporting Program (GHGRP) in 2021.

Landfills generate methane as the organic fraction of buried waste (e.g., food waste, yard waste, cardboard) decomposes in anaerobic conditions. Food waste is the largest MSW component landfilled, responsible for an estimated 58% of fugitive methane emissions from U.S. MSW landfills. Data reported voluntarily to EPA's Landfill Methane Outreach Program (LMOP) shows that the majority of landfills with more than 1 million tons of waste-in-place (that are currently accepting waste or were closed within the last five years) have a gas collection system in place to capture a portion of their methane emissions. As of July 2023, 487 landfills had operational energy projects, utilizing the captured methane to generate electricity or upgrading it to biomethane (or "RNG") for pipeline injection or transportation fuel. Otherwise, collected methane is typically routed to a flare for destruction.

Importantly, collection and control systems do not capture all generated methane, as they are not installed in all areas of the landfill, experience downtime, and can malfunction. Large amounts of methane escape from landfills into the atmosphere, diffusely through the landfill surface and in more concentrated hot spots, often due to cracks or gaps in the landfill cover, leaking gas wells, or the exposed working face. Landfill gas collection efficiency can vary widely by site, driven in part by design and operational factors. While landfill emissions models often assume a default collection efficiency of 75% (EPA's WARM model estimates that the average LFG collection efficiency at U.S. landfills is 64.8%), studies show instances where collection efficiency can be much lower. As we discuss further below, implementing best practices around landfill monitoring, design, and operations can meaningfully improve methane capture and reduce fugitive emissions at these sites.

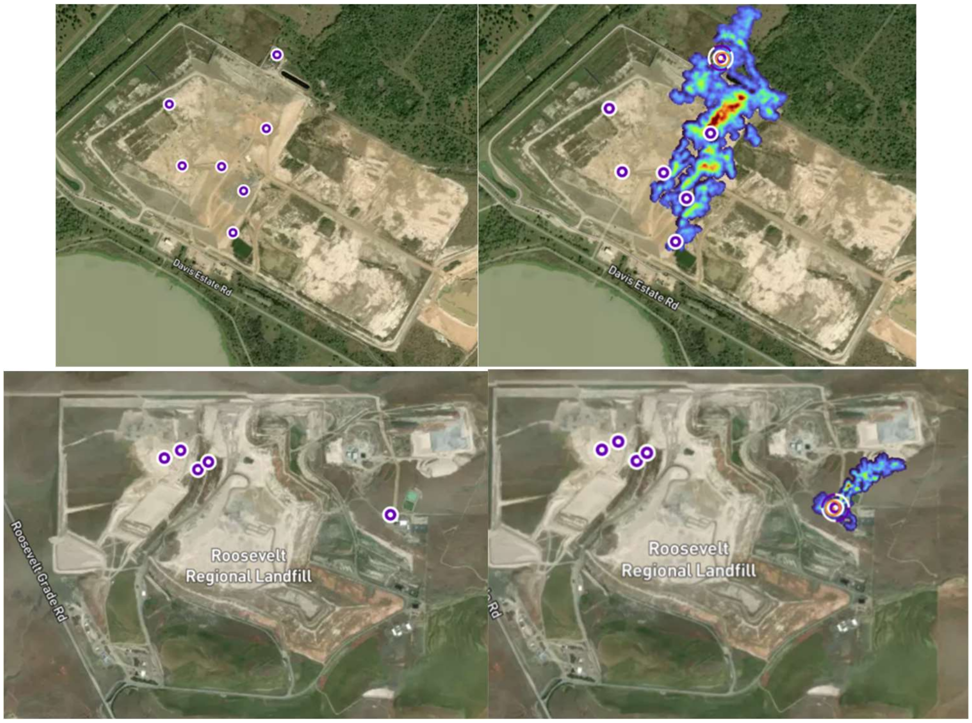
Recent airborne methane surveys suggest that landfill emissions may be higher and more persistent than previously expected. Since 2016, airborne surveys conducted by Carbon Mapper and partners have detected high-emitting methane plumes at more than 200 U.S. landfills across 29 states. In California, Carbon Mapper's flyovers found that a subset of landfills were the state's largest methane emitters (41 percent), with higher observed emission rates than the oil & gas or agriculture sectors. Detectable methane plumes at California landfills often reached 1,000 kg/hour, ten times what EPA considers to be a super-emitter in the oil & gas sector.

Furthermore, a recent study under review in Atmospheric Chemistry and Physics uses observations from the TROPOMI satellite instrument to quantify methane emissions from 70 landfills reporting to EPA's GHGRP across the contiguous United States. The authors find a median 77% increase in observed emissions (13 Gg/a), compared to reported emissions (7.2 Gg/a). At the 38 facilities that recover gas, the authors find a mean recovery efficiency of 0.50 (0.33 – 0.54) that is much smaller than the GHGRP mean of 0.61 and the default assumption of 0.75. The authors attribute the discrepancy to two main factors: 1) over-estimated recovery efficiencies at facilities with gas collection systems and 2) under-accounting of site-specific operational changes across facilities.

Landfill emissions threaten nearby communities. Beyond the planet-heating methane, landfills release harmful co-pollutants that adversely impact the health and wellbeing of nearby communities. Landfill gas contains hazardous air pollutants (e.g., vinyl chloride, 1,1,1- trichloroethane, 2-butanone, organic mercury compounds), precursors to ozone and particulate matter (PM) (e.g., VOCs), and odor nuisance compounds (e.g., H2S). These compounds have been found to contribute to urban smog and impact human health and the environment. In addition, the leachate from landfills can contaminate nearby soil and groundwater. One study found that the typical emissions of ozone precursors from a single hypothetical landfill may result in persistent daytime additions to ozone of over one part per billion (ppb) by volume tens of kilometers downwind, and large leaks of landfill gas can enhance ozone pollution by over a tenth of a ppb. In Southeast Michigan, the combined influence of several landfills upwind of key monitoring sites may contribute significantly to observed exceedances of the U.S. ozone standard. Studies have also shown that landfills can decrease neighboring residential property values.

Landfills are often sited near vulnerable communities. Analysis using the EPA's Environmental Justice Screening and Mapping Tool (EJScreen) shows that 54 percent of MSW landfills reporting to the GHGRP have communities located within one mile that exceed the national average for either percent low-income or percent people of color. Across the country, journalists have documented the adverse impacts of landfills on nearby communities. Recent stories highlight the prevalence of cancer and kidney failure in the Snow Hill community near North Carolina's Sampson County landfill, lung cancer clusters near New York's Seneca Meadows landfill, and odor violations from California's Chiquita landfill that left some residents vomiting and with severe migraines. A winner of U.S. EPA's 2023 EJ Video Challenge for Students, *Pollution to Prosperity: Tackling Landfill Impacts for a Thriving Future*, highlights the air quality, water, and health impacts of Virginia's first mega-landfill on the surrounding community in Charles City County, which has left some families boiling their tap water to avoid contaminants. The film also proposes solutions, including air monitoring, community health surveys, water quality testing, and waste diversion.

Energy projects alone are not a solution, as landfills with biomethane projects can adversely impact the climate and communities. EPA acknowledges in its RNG Operations Guide that "fugitive emissions of methane, depending upon their magnitude, can negate the climate and environmental benefits of RNG projects." While a well-run anaerobic digester is estimated to collect 95 to 98 percent of the methane generated, the default collection efficiency for landfills is about 75 percent and can vary widely based on design and operational practices. MSW landfills with operational RNG projects still release substantial amounts of methane to the atmosphere. Carbon Mapper has detected super-emitting methane plumes at 37 out of 46 surveyed MSW landfills with biomethane projects (80% of surveyed landfills with biomethane projects had detectable plumes). For example, at the Fort Bend Regional Landfill in Needville, Texas and the Roosevelt Regional Landfill in Roosevelt, WA (see plume images below), Carbon Mapper observed plumes emanating from the biomethane upgrading facilities and across the landfill surface. In addition, EPA inspection reports of landfills with biomethane projects show dozens of exceedances of the 500 ppm regulatory methane threshold per site (see summary of inspection reports submitted to this docket by Industrious Labs). This underscores the fact that just because a site has an energy project does not mean it is effectively capturing methane or minimizing fugitive emissions at the landfill. Furthermore, energy project infrastructure can create incentives to continue landfilling organic waste rather than preventing it or recycling it into compost.



Biomethane landfill projects can also negatively impact surrounding communities. For example, the Keystone Landfill in Lackawanna County, PA is home to the highest capacity operational biomethane facility in the world. After an increasing number of odor complaints from nearby residents, the Pennsylvania Department of Environmental Protection (PA DEP) issued a Notice of Violation (NOV) to Keystone Landfill for failing to maintain a uniform intermediate cover that prevents odors. The NOV referenced "extensive areas of intermediate cover with excessive methane emissions" and strong landfill gas odors emanating from the landfill. The NOV response outlines potential mitigation efforts that would better control methane and odors, including: accelerated installation of new gas wells, accelerated installation of permanent cover, and utilization of monthly aerial drone methane detection.

There are viable solutions to reduce landfill methane emissions today. Reducing organic waste disposal in landfills prevents future methane generation and captures the value of organic materials. Strategies include: reducing and redistributing surplus organics and recycling the remaining organic waste into beneficial end products. Minimizing waste on farms, improving food inventory management, and donating excess edible food to shelters or converting it to animal feed all put organics to good use and keep them out of the waste stream. The remaining organic waste can then be separated and processed at a composting facility or anaerobic digester into compost, digestate, and biogas.

EPA's waste management hierarchy ranks various management strategies from most to least environmentally preferred, placing emphasis on reducing, reusing, recycling and composting as key strategies to reduce greenhouse gas emissions.

In addition, in October 2023, EPA released the [Wasted Food Scale](), which prioritizes actions that have the greatest benefits to the environment and to a circular economy. The least preferred pathways – which includes landfilling and incineration – have the largest environmental impacts and limited potential for circularity.

EPA developed the Wasted Food Scale based on the findings of its 2023 report *[From Field to Bin: The Environmental Impacts of U.S. Food Waste Management Pathways]()*. In the report, EPA compares the lifecycle greenhouse gas emissions, or global warming potential (GWP), of different food waste management pathways (in kg CO_2e per metric ton of food waste). EPA found that source reduction had order-of-magnitude greater GWP benefits than any other pathway, by reducing the amount of additional food that must be produced. Landfills tend to have the highest GWP values, while food donation, upcycling, animal feed, AD, and composting can achieve substantial relative emissions reductions with beneficial or near neutral GWP.

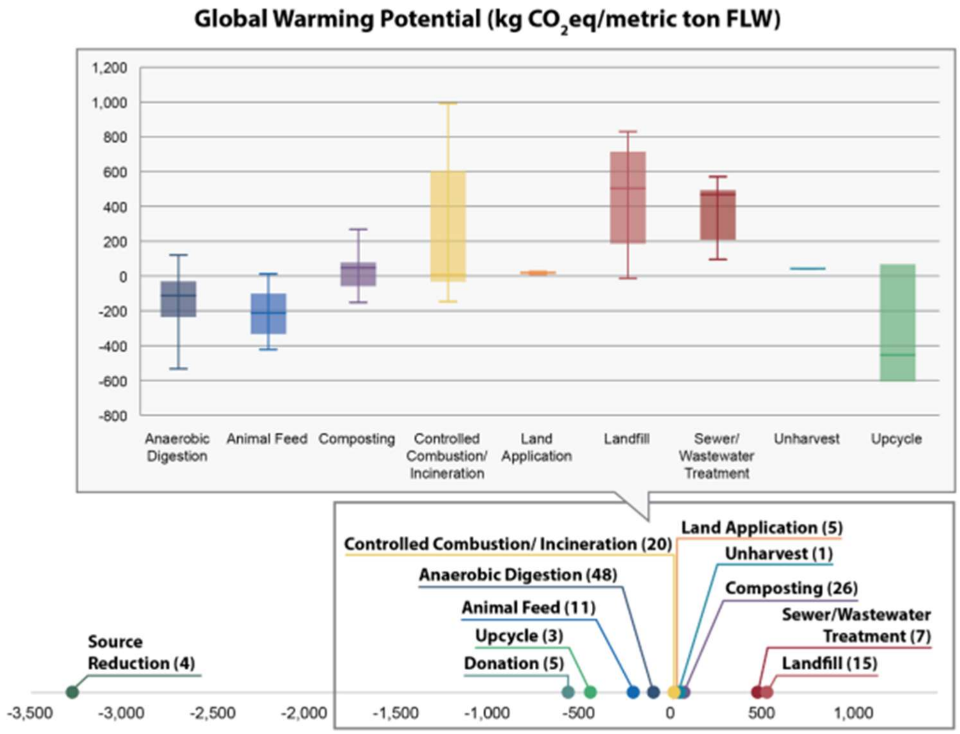


FIGURE 3-3. COMPARISON OF GLOBAL WARMING POTENTIAL OF WASTED FOOD PATHWAYS ACROSS LCA STUDIES

AD data assumes land application of digestate or biosolids. Sewer/WWT studies varied in assumptions about biosolids' destination. Carbon sequestration not consistently assumed for some pathways. See Table 3-4 for details. Donation excluded from boxplot because the range extends an order of magnitude below the next lowest value in the boxplot. See Appendix Table D-1 for data and sources.

Furthermore, reducing organic waste disposal in landfills brings numerous community benefits: for local food systems, ecosystems, climate resilience, and job creation. Expanding surplus food donation can help to address local food insecurity, while composting can improve soil health and support local food production. Compost application has several additional benefits for local ecosystems and can boost local climate resilience; it sequesters carbon, prevents soil erosion, aids in reforestation and wetlands restoration, and assists in stormwater management and water conservation by better controlling and retaining runoff through soils. Finally, organics recycling can create jobs and workforce development opportunities in the circular economy at a higher rate per ton than landfills or incinerators. For example, one study found that for every $10 million invested, composting sites can support 21.4 full-time jobs, while landfilling supports 8.4 and incineration supports 1.6.

There are also readily available, well-understood strategies to reduce methane emissions from the organic waste already decomposing in landfills. Expanding landfill gas collection system coverage and boosting the collection efficiency of existing systems through best management practices can substantially reduce fugitive methane emissions at U.S. landfills. Strategies include: improving landfill gas collection system coverage and performance to increase methane capture, expanding methane monitoring to quickly find and fix leaks, and implementing landfill cover practices that better mitigate surface emissions. A recent paper, *The impact of landfill management approaches on methane emissions*, calculated the emission reduction potential of different management choices relative to business-as-usual (BAU) scenarios at North American (NA) landfills. For a typical NA landfill implementing few best practices, early gas collection and reducing the landfill cell size can reduce methane emissions by 27% vs. BAU. For a typical landfill implementing some best management practices, early and extended gas recovery can reduce methane emissions by 38% vs. BAU. For a typical landfill implementing nearly all best management practices, early sealing of the landfill could reduce methane emissions by 44% vs. BAU. According to the paper, these approaches entail "basic, standardized, technology that can be deployed swiftly and at moderate cost" to reduce methane emissions today. State rules underscore the methane reduction potential of these best practices. For example, Maryland's landfill rule (COMAR 26.11.42), finalized in June 2023, is projected to deliver an estimated 25-50% reduction in landfill gas emissions from covered landfills when fully implemented, according to estimates from the Maryland Department of Environment (MDE).

In August 2024, EPA is statutorily required to reassess its New Source Performance Standards (NSPS) and Emission Guidelines (EG) for MSW Landfills under Section 111 of the Clean Air Act – and the agency should move swiftly to advance a standard that incorporates the latest best practices in methane monitoring and control, while promoting waste prevention and organics recycling strategies. In addition to cutting planet-heating methane, reducing landfill emissions creates local benefits. Improving landfill methane capture also better controls for emissions of hazardous air pollutants, smog-forming compounds, and odors, while reducing explosion hazards. This all helps to improve air quality, safety, public health, and quality of life for the communities near landfills. Expanding landfill methane monitoring and implementing best management practices can also create local jobs in methane mitigation.

Concerns about the landfill gas pathways in 45V: A 45V framework that incentivizes hydrogen production from landfill biomethane can create climate risks. For one, subsidizing landfill energy production puts the more sustainable waste management alternatives with lower lifecycle emissions (e.g., waste prevention, reuse, recycling, and composting) at a relative disadvantage. It creates an economic incentive to continue landfilling methane-generating organic waste rather than moving up the waste hierarchy to prevent and reduce methane pollution.

Incentivizing landfill energy production is also dangerous without robust standards in place to efficiently capture methane emissions and co-pollutants from the landfill. As discussed above, landfill gas collection efficiency can vary widely, including at landfills with energy projects. At biomethane-producing landfills, operators may optimize wellfield tuning for landfill gas quality rather than the quantity, which in some cases can lead to more fugitive emissions than at a landfill with an electricity project or a flare. Landfills may engage in other potentially harmful management practices, such as leachate recirculation, that accelerate methane production in the present. This can also expose nearby communities to additional hazardous air pollutants and odors.

Importantly, the GREET model does not include fugitive emissions that occur at the landfill in its life-cycle analysis, as they are determined to occur regardless of whether landfill gas is used for an energy project or collected and flared. This is a major limitation, as EPA notes that fugitive emissions of methane, depending upon their magnitude, can negate the climate and environmental benefits of biomethane projects. A landfill operator implementing best management practices can meaningfully improve collection efficiency - and reduce fugitive emissions of methane and co-pollutants - but under the proposed 45V framework, there is no incentive to do so, since these fugitive emissions are considered outside the system boundary of the lifecycle analysis.

Landfill methane recommendations to Treasury and IRS

In addition to the recommendations above on offsetting and deliverability, we make the following recommendations specific to the landfill gas pathway:

1. **Incrementality: we support Treasury's proposal that the RNG used during the hydrogen production process must originate from the first productive use of the relevant methane.** This would help to limit emissions associated with the diversion of biogas from other pre-existing productive uses. For landfills, we recommend that any site with an operational beneficial use project (i.e., 487 MSW landfills as of July 2023, according to LMOP) should not be eligible for the 45V credit, as they already have infrastructure in place to capture and productively use that methane, often with multi-year offtake contracts. The remaining potentially eligible landfills would include those with gas collection systems but no beneficial use project (e.g., routing collected gas to a flare) and smaller landfills that are not regulatorily required to install gas collection systems. For landfills with gas collection systems and flares, Treasury should consider limiting the eligible feedstock to the *incremental* amount of methane captured once the biomethane project is in place. For example, if a landfill with a gas collection system and flare is capturing about 65% of its generated methane, and the biomethane project is able to achieve an 80% capture rate, the incremental 15% of methane captured could then be eligible as a feedstock. For landfills without gas collection systems, it is important to note that the U.S. EPA is in the process of reviewing and potentially updating the Clean Air Act Section 111 standards for MSW landfills in 2024, which could include lowering the threshold for gas collection system installation, meaning smaller landfills may be regulatorily required to collect their gas anyways, which would diminish the "incremental" benefits.
2. **Treasury should work with DOE to update the landfill gas pathways in 45VH2-GREET to account for the emissions resulting from uncollected methane at the landfill, by aligning the reference case with EPA's waste management hierarchy.** In the 45VH2-GREET 2023, flaring is the counterfactual scenario for landfills. As discussed above, this approach fails to account for the methane emissions from uncollected landfill gas, as they are assumed to occur regardless of whether the collected gas is flared or used for hydrogen production. This approach is misleading because these emissions are avoidable: organics diversion can prevent further landfill methane generation, and improved landfill management practices can maximize landfill gas capture and minimize leakage from previously landfilled waste. Including the emissions from uncollected gas in the GREET landfill-to-hydrogen pathways would more accurately reflect the warming impacts of landfilling organic waste and motivate operators to adopt best practices that limit leakage. To remedy this, Treasury should consider using more sustainable waste management approaches for organic waste as the counterfactual or reference case, such as waste prevention, composting, or anaerobic digestion, as outlined in EPA's Waste Management Hierarchy and Wasted Food Scale. This approach would include methane leakage at the landfill in the lifecycle analysis, creating an incentive for operators to improve their methane collection rate and demonstrate lower leakage than the default. EPA's WARM model estimates that the average LFG collection efficiency at U.S. landfills is 65%. A portion of uncollected gas may be oxidized into less-potent (biogenic) carbon dioxide, depending on cover materials, but most of it is

released to the atmosphere as fugitive methane emissions. These fugitive emissions should be part of the lifecycle analysis. Facilities that are implementing best management practices to improve their methane capture rate could demonstrate they have higher collection efficiency, and a lower leakage rate than the default, through methane monitoring surveys and gas collection system data.

3. **Treasury should include feedstock eligibility restrictions to defend against perverse outcomes and actualize pollution benefits.** This should include limitations around the age of the waste stream and methane leakage at the landfill.
    a. **Treasury should limit eligibility to feedstocks arising before the date of implementation of the IRA to defend against an incentive to increase waste streams.** Only the methane generation potential of waste-already-in-place in landfills at the time of IRA passage should be eligible for the credit. Otherwise, 45V risks encouraging the continued landfilling of organic waste for biomethane generation, rather than moving up the waste hierarchy to organics recycling or waste prevention, which are the most effective strategies to curb methane emissions. To calculate this, Treasury can use the waste-in-place value reported to EPA's GHGRP or LMOP in 2022 to estimate the methane generation potential of the degradable organic carbon in that buried waste. Only this quantity of gas, with a standard collection efficiency assumption applied, should be eligible as a feedstock under 45V. This approach is important to prevent diversion from lower-emitting disposal methods to landfills – and to avoid undermining climate targets and other efforts to decarbonize the waste sector.
    b. **Treasury and EPA should set standards to ensure eligible projects are capturing generated methane and co-pollutants to the maximum extent practicable.** Treasury should consider setting a minimum gas collection efficiency requirement for LFG-H2 pathways, which qualifying projects would need to maintain and verify through gas collection system data and high-frequency or continuous monitoring surveys. Ideally, the site-specific landfill leakage rate would then be reflected in the carbon intensity score in GREET. Otherwise, it could be part of a work practice standard required of eligible facilities to prove "clean" hydrogen is not coming from a source that is releasing methane that could feasibly be captured. There are several approaches to quantify site-wide landfill methane emissions, including by aircraft (mass balance), drone (flux curtain), vehicle (OTM-33; tracer correlation), and with fixed sensors. These site-wide quantification approaches, conducted at least quarterly by an approved party, could then be compared to gas collection system data (captured continuously with a flow meter) to calculate site-wide collection efficiency. While average collection efficiency is around 65%, collection efficiency observed in the field can vary widely, from the low 20% range to the high 90% range. Treasury and EPA should take steps to ensure eligible facilities are at the upper end of this range. In addition, Treasury and EPA should require qualifying landfills to follow best management practices around gas collection, cover, and leak detection and repair (LDAR) to maximize methane recovery and minimize fugitive emissions. EPA should incorporate these best management practices into a Section 111 update, but in the interim, these practices should be required of all 45V-eligible landfill sites. In November 2023, the state of Michigan took a similar step in its clean energy standard by requiring the operator of a qualifying landfill gas recovery and

electricity generation facility to employ [“best practices for methane gas collection and control and emissions monitoring."] These recommended best practices (described further in the appendix) often come at modest cost, especially compared to the potential value of the 45V credit. While the party overseeing landfill operations may differ from the party developing the biomethane project, the two can work together to ensure best practices and high collection efficiency are maintained. Strong standards for methane capture would also better control the pungent, toxic, and smog-forming gases that harm the health and wellbeing of nearby communities. Treasury and EPA should also develop a mechanism to revoke a facility’s eligibility in instances of persistent harm to neighboring communities.

GREET assessment

RMI is pleased to know DOE is considering adding more co-products to the future version of 45VH2-GREET. RMI suggests adjusting the calculation and allocation of emissions accordingly for different co-products and including chemical co-production pathways.

1) If the conversion of hydrogen non- CO_2 co-products to valuable materials can be certified, we recommend that these co-products continue to be included in the allocation process. For example, the syngas generated by SMR or autothermal reforming processes may contain carbon monoxide and waste methane that could be collected to produce methanol and other high value chemicals (HVCs). If these hydrogen co-products are certified for use as chemical feedstock, for example with ISCC+ or SCS standards, there is an opportunity to ignore those additional combustion emissions that should have been generated by the waste components in the syngas as impurities, which will incentivize the hydrogen producers to make full use of co-products.

2) We also recommend including byproduct hydrogen produced during other chemical production processes, especially steam cracking, in the future GREET Model version’s expanded scope. This pathway should allow similar hydrogen non-CO_2 co-product exemptions as outlined in the recommendation above. This can remove barriers for upgrading low-intensity hydrogen and methane to more valuable chemicals if chemical processes choose to electrify.

Clean hydrogen finance roundtable

On February 7, 2024, RMI convened and facilitated a roundtable with representatives from financial institutions, developer companies, and insurance to better understand the perspective on the proposed 45V rule and incorporate feedback into comments. The roundtable was conducted under Chatham House Rules and below are the learnings our team found relative to be included in this comment.

A few takeaways for consideration from this conversation:

- A main point of concern developers and investors expressed was that the lack of grandfathering of less stringent rules would make projects difficult to become bankable. RMI recommends the

Treasury help these concerns by providing additional flexibilities within the current framework without allowing grandfathering under this policy.

- Achieving hourly matching under the 45V tax credit puts the stress of achieving this benchmark on one industry – consider the burden when designing demand side support policies and implementing other programs.
    - The clean hydrogen market is novel and it needs a push – it may require further support and guidance to get the first movers and first offtakers on board with project announcements given the unknowns.
- Policy certainty cures many of these concerns – right now, the proposed rule leaves a window of opportunity open for those seeking less stringent rules. Once the rule is finalized, the market will adjust and projects/investors will innovate.
    - One important data point is the first-ever Innovation Fund auction for renewable hydrogen support in Europe drew 132 bids. This indicates a significant number of clean hydrogen projects were able to achieve bankability, secure offtake, and optimize to meet rules similar to the proposed 45V rule by the US Treasury Department.
- Between insurance and pricing, there are many ways to hedge and protect against inherent project risk. Risk is not new to this industry, but it is coming in a different form for new, green, 45V-aligned hydrogen projects.
- The question of what to do with missed hours (discussed above) is critically important.

As described throughout this comment, RMI believes there are flexibilities already built into the proposed rule that can support risk mitigation and investment in these novel projects. Additionally, there are opportunities for tweaks in a final rule that would provide even greater certainty for projects and support deployment without sacrificing the bedrock logic and requirement to ensure 45V promotes low-emissions hydrogen production.

Appendix

Best Management Practices to Limit Fugitive Methane Emissions at Landfills

Below, we summarize best management practices that should be incorporated into an updated section 111 standard and required at eligible landfills capturing their gas for hydrogen production.

- **Earlier installation and expansion of wells to maximize gas collection system coverage**: According to EPA, 61% of methane generated by landfilled food waste is not captured by landfill gas collection systems and is released to the atmosphere as fugitive emissions. Because food waste decays relatively quickly, its emissions often occur before landfill gas collection systems are required to be installed or expanded. However, it is technically feasible to install and expand the gas collection system within one year after waste is placed, rather than the more extended time frames currently allowed (up to 5 years). Eastern Research Group (ERG)'s analysis for EPA's 2019 technology review process for the Sec 112 Clean Air Act standards, found that earlier expansion of gas control systems (after 2 years) could reduce methane emissions by 300,000 tons per year at a cost-effectiveness of about $130 per metric ton of methane reduced (or just ~$2/ton CO_2e using the 20-year global warming potential). This is well below the cost-effectiveness threshold that EPA found to be reasonable for the oil and gas industry. Using horizontal collectors during the disposal of waste can help capture gas as the lifts are being constructed, and installing the gas collection system as new waste is buried is already required under some state laws. Optimizing wellhead spacing can also help ensure comprehensive coverage and reduce fugitive emissions.

- **More robust wellhead tuning and maintenance to boost gas collection system performance:** More frequent wellfield monitoring and adjustments to system vacuum can help increase landfill gas recovery and limit system downtime. For example, automated tuning systems adjust the vacuum continuously, as temperature, pressure, and weather conditions fluctuate, and can improve methane recovery and reduce fugitive emissions by 10-20% compared to baseline. These systems can also provide operators with real-time information on potential issues related to the gas collection system, such as flooded wellheads or cover integrity issues, to inform timely repairs. Incorporating the gas collection system into the leachate system, or using gabion cubes along the bottom landfill liner, can also help enhance drainage, prevent flooding, and limit downtime.

- **Enhanced landfill cover practices to better control surface methane**: Increasing the thickness and compaction of daily and intermediate cover can allow for greater vacuum and lower surface methane emissions. Studies have shown that landfill methane emissions decrease when moving from areas of daily to intermediate to final cover; reducing lag times between these cover stages and minimizing the exposed surface area of the daily uncovered working face can help reduce fugitive emissions. Applying a vegetative biocover as intermediate cover helps to enhance the microbial oxidation of methane escaping to the surface. A well-made biocover employing a large volume of aged compost can oxidize up to 35 or 40 percent of the methane in the gas passing through it.

- **More comprehensive monitoring surveys to reduce fugitive methane**: The White House monitoring strategy acknowledges that walking surface emission monitoring (SEM) surveys "are not able to detect all anomalous emissions at a landfill that occur over a large footprint, some extending for hundreds of acres." Maryland Department of Environment estimates that the more robust surface emission monitoring requirements in their recent rulemaking – which includes a tighter walking pattern – could reduce fugitive emissions by 10-40%. Advanced methane detection technologies, such as drones, provide additional benefits relative to walking SEM approaches, including expanded coverage of the landfill surface area (including the active face, construction areas, and steep slopes), faster survey times, improved worker safety, and more objectivity and replicability. Using drones for SEM, which EPA approved in December 2022 as an alternative method, is cost-competitive with traditional manual surface emissions monitoring. In addition to drone methods, continuous monitoring systems can be positioned throughout the landfill or around critical components to provide operators with real-time data to respond quickly to instances of elevated methane concentration and inform operational improvements. Environment and Climate Change Canada (ECCC)'s proposed regulatory framework for reducing Canada's landfill methane emissions incorporates both drone and continuous monitoring approaches, while providing flexibility for alternative monitoring methods with demonstrated performance equivalency.

- **Leveraging remote sensing to fix large leaks fast**: Remote sensing technologies, like aircraft and satellites, can alert operators to large methane releases to inform fast investigation and effective remediation on the ground. For example, environmental agencies in California and

Pennsylvania worked with third-party aerial monitoring providers to survey for methane leaks and alerted landfill operators of large detected plumes. Operators took voluntary action to locate and mitigate the leaks. Overflights conducted by the Pennsylvania Department of Environmental Protection, in partnership with Carbon Mapper, achieved a 37% reduction in observed methane emissions from landfills. EPA finalized a super emitter program in the oil and gas sector Sec 111 rules and could expand this to MSW landfills.

- **High-efficiency flares to avoid methane slip during combustion**: Enclosed flares with high destruction efficiency (>99%) help avoid methane leakage during combustion. ERG's report for EPA's 2019 NESHAP technology review, found that enclosed flares with a destruction efficiency of 99.5% could reduce methane emissions by 99,000 tons per year at a cost-effectiveness of about $160-$330 per ton of methane (or ~$2-$4 per ton CO_2e, GWP20).