

**PETITION TO THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

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| <b>Petition for Rulemaking to List and</b> | ) | <i>Submitted September 15, 2023 to the</i>  |
| <b>Establish National Emission</b>         | ) | <i>Administrator, the Office of Air and</i> |
| <b>Standards for Hydrogen Production</b>   | ) | <i>Radiation, and the Office of Air</i>     |
| <b>Facilities under Clean Air Act</b>      | ) | <i>Quality Planning and Standards, U.S.</i> |
| <b>Sections 111 and 112</b>                | ) | <i>Environmental Protection Agency</i>      |
|  | ) |   |

**I. INTRODUCTION & EXECUTIVE SUMMARY**

Environmental Defense Fund, Sierra Club, Earthjustice, Union of Concerned Scientists, PennFuture, Beyond Toxics, Environmental Health Project, Environmental Integrity Project, Clean Air Council, California Communities Against Toxics, Western Environmental Law Center, Moms Clean Air Force, Imagine Water Works, and The Vessel Project of Louisiana hereby petition the U.S. Environmental Protection Agency (EPA) to list hydrogen production facilities as a stationary source category under Clean Air Act sections 111 and 112 and develop protective national emission standards under both sections to limit climate-destabilizing and health-harming air pollution from new and existing facilities. Fossil-based hydrogen production facilities emit large amounts of harmful greenhouse gases, criteria air pollutants, and hazardous air pollutants. They are often located in communities that already face heavy pollution burdens from industrial facilities, including California’s South Coast and the Gulf Coast portions of Texas and Louisiana. With a significant projected increase in hydrogen production driven, in part, by federal support, the lack of comprehensive emission standards for these facilities is a critical regulatory gap. Accordingly, we respectfully urge EPA to act quickly to develop protective safeguards to limit the harmful climate and air pollution impacts of hydrogen production facilities.

**Hydrogen Production and Infrastructure Buildout Poses Serious Climate, Health, and Environmental Justice Risks**

Hydrogen has the potential to be a promising decarbonization solution, but whether hydrogen delivers any climate benefits depends on how it is produced, transported, stored, and used. Today, nearly all hydrogen in the U.S. is produced from fossil fuels through a high-polluting process, with less than 1% produced using renewable energy.<sup>1</sup> The methods of production greatly

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<sup>1</sup> Saadat & Gersen, *Reclaiming Hydrogen for a Renewable Future: Distinguishing Fossil Fuel Industry Spin from Zero-Emission Solutions*, Earthjustice (2021), <https://earthjustice.org/features/green-hydrogen-renewable-zero-emission>. In the U.S. today, nearly all hydrogen (95%) is produced from fossil fuels through an energy intensive industrial process called steam methane reformation (SMR), and 55-60% of domestic hydrogen demand comes from crude oil refineries, where it is used to lower the sulfur content of diesel. *Id.* at 10.

influence hydrogen’s lifecycle emissions and to what extent using it in place of fossil fuels produces any net climate benefits.

Existing hydrogen production facilities collectively emit tens of millions of tons of greenhouse gases annually. Merchant facilities, meaning those that produce hydrogen to sell, alone emitted over 40 million tons of CO<sub>2</sub>e in the U.S. in 2020.<sup>2</sup> The largest individual merchant facility emitted more than 2 million tons of CO<sub>2</sub>e in a year, comparable to emissions typical of a 300 MW coal-fired power plant.<sup>3</sup> Absent protective safeguards, the next 10 million metric tons of hydrogen production capacity added in the U.S. could add another 40 million metric tons of greenhouse gas emissions annually.<sup>4</sup>

Fossil-based hydrogen production causes significant health-harming pollution too. Some hydrogen production facilities individually emit hundreds of tons of NO<sub>x</sub> that contribute to health-damaging NO<sub>2</sub>, ozone, and particulate pollution, along with VOCs, SO<sub>2</sub> and PM<sub>2.5</sub> that contribute to harmful health effects.<sup>5</sup> Our analysis, described below, shows that future fossil-based hydrogen production facilities could emit hundreds of tons of NO<sub>x</sub>, SO<sub>2</sub>, and particulates each year. Existing facilities also report emissions of hazardous air pollutants (HAPs), underscoring the need to investigate and address these emissions.

On top of the production emissions, there are significant emissions further upstream, as well as the potential for pollution across the supply chain. Fossil-based hydrogen production methods often use methane as a feedstock—methane is a potent greenhouse gas with over 80 times greater near-term warming power than CO<sub>2</sub>, and it commonly leaks at high rates across the oil and gas supply chain.

In addition, leakage of hydrogen itself can be significant and may undermine the potential climate benefits from use of hydrogen because hydrogen is a potent indirect greenhouse gas.<sup>6</sup> Recent studies have found hydrogen’s warming power is over 35 times larger than CO<sub>2</sub> pound for pound over the 20-year period after it is emitted, and about 12 times larger over 100 years—values that are 2-6 times higher than previously thought.<sup>7</sup> When hydrogen is released directly

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<sup>2</sup> See Attachment D (based on EDF analysis of EPA Greenhouse Gas Reporting Program (GHGRP) data, National Emissions Inventory (NEI) data, and California Air Resources Board (CARB) data. This analysis is described fully below.)

<sup>3</sup> *Id.*

<sup>4</sup> *Id.*

<sup>5</sup> *Id.*; Lewis et al., *Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies*, National Energy Technology Laboratory, Report No. DOE/NETL-2022/3241 (2022), <https://www.osti.gov/biblio/1862910> [hereinafter “Lewis 2022”].

<sup>6</sup> Ocko & Hamburg, *Climate consequences of hydrogen leakage*, 22 *Atmos. Chem. & Phys.* 9349 (Feb. 2022), <https://acp.copernicus.org/articles/22/9349/2022/> [hereinafter “Ocko & Hamburg 2022”]; Mejia et al, *Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure*, 45 *Intl. J. of Hydrogen Energy* 8810 (2020), <https://www.sciencedirect.com/science/article/abs/pii/S0360319919347275>.

<sup>7</sup> Ocko & Hamburg 2022, *supra* note 6; see also Warwick et al., *Atmospheric Implications of Increased Hydrogen Use*, Dep’t for Bus., Energy & Indus. Strategy (July 20, 2022) <https://www.gov.uk/government/publications/atmospheric-implications-of-increased-hydrogen-use>.

into the atmosphere, it contributes to climate change by “affecting chemical reactions that increase the amount of greenhouse gases including methane, tropospheric ozone, and stratospheric water vapor.”<sup>8</sup>

Increased demand and use of hydrogen will likely drive greater production at existing facilities and the development of new, similar facilities in overburdened areas, leading to increased air pollution. Greater use and demand for hydrogen could drive other negative environmental impacts, including by contributing to water pollution and scarcity, increasing power sector emissions, and driving demand for unsustainable feedstocks.<sup>9</sup> Fossil-derived forms of hydrogen risk locking in demand for methane gas for decades, driving upstream emissions and other environmental harms associated with oil and gas production, which also disproportionately impact vulnerable communities and worsen climate change.

Hydrogen production, infrastructure buildout, transportation, storage, and end use come with serious environmental justice implications. Hydrogen production facilities are typically co-located with or located alongside petroleum refineries and other chemical manufacturing plants and are often sited in or near communities with high proportions of low-income residents and people of color. According to EPA’s ECHO database, 86% of merchant hydrogen production facilities are in neighborhoods with two or more EJScreen indices at the 80th percentile or above; 76% are in communities with six or more indices at that level; and 41% are in communities with 10 out of the 13 indices at the 80th percentile or above.<sup>10</sup> There are also many plans for future facilities to be built in these same areas.<sup>11</sup> New facilities should not be allowed to move forward if they will contribute to or worsen pollution in heavily overburdened communities.

Increased hydrogen production and demand for hydrogen in new end uses is likely to drive pipeline buildout as well, posing serious safety concerns because hydrogen is flammable. Leaks of hydrogen can pose a fire hazard when mixed with air at certain concentrations and an asphyxiation hazard when it displaces oxygen in the air. Because its molecules are very small, hydrogen is more prone than methane to leaking through joints, cracks, and seals in infrastructure. It can also permeate directly through materials used for natural gas distribution faster than methane, leading to deterioration and embrittlement of pipelines and other infrastructure. This means that existing gas infrastructure is generally not suitable to transport

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<sup>8</sup> Ocko & Hamburg 2022, *supra* note 6.

<sup>9</sup> Combustion of hydrogen for energy in end-use sectors does not emit greenhouse gases, but it can produce significant NOx emissions. Alastair C. Lewis, *Optimising air quality co-benefits in a hydrogen economy: a case for hydrogen specific standards for NOx emissions*, 1 *Env. Sci. Atmospheres* 201 (2021), <https://pubs.rsc.org/en/content/articlelanding/2021/ea/d1ea00037c>.

<sup>10</sup> The 13 EJScreen indexes are: (1) PM<sub>2.5</sub>; (2) Ozone; (3) Diesel Particulate Matter; (4) Air Toxics Cancer Risk; (5) Air Toxics Respiratory Hazard Index; (6) Toxic Releases to Air; (7) Traffic Proximity; (8) Lead Paint; (9) Risk Management Plan Facility Proximity; (10) Hazardous Waste Proximity; (11) Superfund Proximity; (12) Underground Storage Tanks; and (13) Wastewater Discharge.

<sup>11</sup> See U.S. Department of Energy, *Pathways to Commercial Liftoff: Clean Hydrogen*, at 23, Figure 8 (March 2023), <https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf>.

hydrogen. Likewise, hydrogen production facilities utilizing carbon capture technologies would require additional CO<sub>2</sub> pipeline infrastructure that pose serious safety risks and environmental justice implications.

While this petition only concerns air pollution from hydrogen production facilities, we urge EPA to continue to update and enforce other environmental requirements that apply to hydrogen production facilities to reduce the cumulative pollution burden on communities from these plants, beyond the air emissions. Likewise, to address the broad range of concerns outlined above, and to further improve safeguards to protect frontline communities, we encourage EPA to work with other departments and agencies with jurisdiction over these facilities and other portions of the hydrogen supply chain.

In developing hydrogen policies, EPA should elevate the needs of communities facing environmental justice burdens, including communities in the vicinity of petrochemical infrastructure which have historically borne disproportionate pollution burdens and had little voice in decisions affecting their health and well-being. In developing regulations to limit pollution from hydrogen production, we encourage EPA to engage robustly with the communities that have experienced the most harm from refining and petrochemical development and use, as well as from climate change impacts.

For the reasons described in this petition and many other reasons, the Biden-Harris Administration should do everything in its power to incentivize electrolysis powered by new clean electricity supply that is hourly and geographically matched (as described below) rather than methods that rely on fossil fuel feedstocks. At the same time, any new and existing facilities that do pursue fossil-based methods of hydrogen production must reduce their emissions to the greatest extent possible. That is the focus of this petition.

### **Projected Hydrogen Buildout**

Large scale hydrogen infrastructure buildout is projected in the U.S., which underscores the need for EPA to proactively create a clear and protective regulatory structure. At present, about 10 million tons of hydrogen are produced per year in the U.S., mainly for use in petroleum refining (55%) and ammonia and methanol production (35%).<sup>12</sup> This is projected to increase as the federal government and others are supporting increasing use of clean hydrogen produced with low life cycle carbon emissions as a strategy for reducing greenhouse gas emissions from certain difficult-to-electrify sectors to mitigate climate change.

The Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA) included billions of dollars of investments designed to support clean hydrogen. For instance, the IRA offers substantial tax credits to producers of qualified clean hydrogen. The Department of the Treasury is currently developing guidance for how the lifecycle carbon intensity of clean

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<sup>12</sup> DOE, *U.S. National Clean Hydrogen Strategy and Roadmap*, at 14, Figure 6 (June 2023), <https://www.hydrogen.energy.gov/clean-hydrogen-strategy-roadmap.html>.

hydrogen will be determined. The tax credits are tiered by carbon intensity, meaning the lowest carbon-intensity forms of hydrogen production receive the greatest tax credit. The IIJA, in turn, directs the Department of Energy (DOE) to develop a Clean Hydrogen Production Standard and funds a Regional Clean Hydrogen Hub Program and a Clean Hydrogen Research and Development Program.

These federal incentives are projected to increase hydrogen production in the coming years. For example, the *U.S. National Clean Hydrogen Strategy and Roadmap* released in June 2023 envisions scaling up hydrogen production and use to 50 million metric tons per annum (MMTpa) between now and 2050.<sup>13</sup> The Roadmap would seek 10 million metric tons per year of clean hydrogen production by 2030 to supply current end uses, with future growth in production matched by demand from new applications including shipping, steel manufacturing, and aviation fuels.<sup>14</sup> While the goal of these incentives is to drive “clean” hydrogen production, at present, there are no enforceable limitations on pollution from new or existing hydrogen production facilities and no way to ensure production is clean.

Projections show significant new production capacity from fossil-derived hydrogen by 2035. An analysis by EDF of proposed projects and anticipated production suggests that production methods reliant on fossil fuel feedstocks could make up most new capacity additions over the next decade.<sup>15</sup> The analysis shows that over two-thirds of new capacity by 2035 will be fossil-based hydrogen, totaling nearly 10 million tons per year. The projections underscore the need for clear and protective regulatory requirements.<sup>16</sup>

### **Hydrogen Production Methods & Associated Air Pollution**

Hydrogen molecules are produced for industrial purposes by breaking down compounds that contain elemental hydrogen, such as water, methane, or other hydrocarbons and feedstocks. Several pathways can be used to produce hydrogen, including splitting water by electrolysis; biological production from biomass; and thermochemical production from fossil fuels. Renewable-powered electrolysis produces relatively minimal direct emissions, whereas thermochemical production methods reliant on fossil fuels have much greater potential for direct emissions of NO<sub>x</sub>, methane, CO<sub>2</sub>, and other pollutants.

Hydrogen proponents aspire for production through clean pathways with minimal emissions, such as water electrolysis with renewable or other low-carbon electricity. However, most hydrogen used in the U.S. is currently produced through steam methane reforming of natural gas,

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<sup>13</sup> *Id.* at 8.

<sup>14</sup> *See id.*

<sup>15</sup> *See* Attachment B (EDF Analysis of Rystad Energy’s HydrogenCube database).

<sup>16</sup> *See Nat’l Asphalt Pavement Ass’n v. Train*, 539 F.2d 775, 784-85 (D.C. Cir. 1976) (“The Administrator has thus determined that given the number of existing plants, the expected rate of growth in the number of plants, the rate of uncontrolled emissions, and the level of emissions currently tolerated, *potential emissions* from new asphalt concrete plants would contribute ‘significantly’ enough to warrant additional regulation to prevent deterioration of clean air.” (emphasis in original)).

which has significant emissions. Autothermal reforming is another high-polluting process that generates hydrogen from fossil fuel feedstocks and is projected to increase in coming years. These methods emit greenhouse gases both as a byproduct of the hydrogen production itself and through upstream methane releases, resulting in a lifecycle emissions intensity of between 8 and 12 kg of CO<sub>2</sub>e/kg H<sub>2</sub>.<sup>17</sup> Both methods also produce NO<sub>x</sub>, methane, VOCs, and other health-harming and hazardous air pollutants. All fossil-based hydrogen projects must be subject to strict scrutiny and strong climate and health protections, some of which are advocated for by this petition. Any emissions accounting of fossil hydrogen must be updated to reflect the present reality of high system methane leakage and prohibit the use of flawed biomethane assumptions.

Hydrogen can also be produced by splitting water using electricity through a process called electrolysis. But electrolysis requires a substantial energy input, with significant associated upstream emissions if the required electricity is not produced from clean sources. Electrolysis using the current U.S. average grid mix electricity has an estimated carbon intensity of 21 kg of CO<sub>2</sub>e/kg H<sub>2</sub>, while electrolytic hydrogen powered by new clean electricity resources that are hourly matched and regionally delivered can achieve the lowest carbon intensity of 0.45 kg of CO<sub>2</sub>e/kg H<sub>2</sub> or less.<sup>18</sup> According to the International Energy Agency (IEA), water electrolysis accounted for only about 0.1% of global hydrogen production in 2021, although a rapid scale-up is anticipated.<sup>19</sup>

To be considered truly “green” and “clean” and result in zero direct and upstream greenhouse gas and health harming emissions, hydrogen production projects must be electrolytic and those projects must: 1) be powered by new clean energy generation that is not already on the grid (“additionality”); 2) be matched with the clean energy project on an hourly rather than annual basis (“hourly matching”); and 3) be within the same geographic boundary as the clean energy project to prevent region-shifting of emissions (“deliverability”). These criteria are commonly referred to as the “three pillars,” and each is necessary to ensure low lifecycle emissions from electrolytic hydrogen.<sup>20</sup>

## Clean Air Act Legal Overview

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<sup>17</sup> Thomas Koch Blank & Patrick Molly, *Hydrogen Decarbonization Impact for Industry: Near-term challenges and long-term potential*, RMI (2020), [https://rmi.org/wp-content/uploads/2020/01/hydrogen\\_insight\\_brief.pdf](https://rmi.org/wp-content/uploads/2020/01/hydrogen_insight_brief.pdf).

<sup>18</sup> *Id.* Marginal generation increases may lead to even higher carbon intensities as the resources that ramp up to meet greater demand typically consist of fossil generation. The marginal emission rate in a given load region is thus highly relevant for determining the lifecycle emissions associated with hydrogen electrolyzers. In particular, policymakers should consider long-term marginal rates, which, unlike short-term marginal rates, “explicitly take[] into account both the underlying evolution of the electric grid, as well as the potential for an incremental change in electrical demand to influence the structural evolution of the grid (i.e., the building and retiring of capital assets, such as generators and transmission lines).” Pieter Gagnon, Nat’l Renewable Energy Laboratory, *Long-Run Marginal CO<sub>2</sub>e Emission Rates for End-Use Electricity Consumption in the State of Washington*, 4 (June 2021), <https://www.nrel.gov/docs/fy21osti/80057.pdf>.

<sup>19</sup> International Energy Agency, *Global Hydrogen Review 2022*, at 74 (September 2022), <https://www.iea.org/reports/global-hydrogen-review-2022> [hereinafter “IEA 2022”].

<sup>20</sup> Ricks, et al., *Minimizing emissions from grid-based hydrogen production in the United States*, 18 *Env. Res. Letters* 014025 (2023), <https://iopscience.iop.org/article/10.1088/1748-9326/acacb5>.

Congress passed the Clean Air Act (CAA) to “protect and enhance the quality of the Nation’s air resources so as to promote the public health and welfare and the productive capacity of the nation.”<sup>21</sup> As means to achieving that purpose, sections 111 and 112 direct EPA to set national emissions standards for new and existing stationary sources. Under the Administrative Procedure Act, 5 U.S.C. § 553(e), and the Clean Air Act, 42 U.S.C. § 7401 et seq., any interested party has the right to file a petition for rulemaking.

Section 111 directs EPA to protect the public from pollution sources that significantly contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. EPA is tasked with identifying categories of stationary sources that contribute significantly to air pollution and setting standards of performance to limit those emissions. The standards of performance must be based on “the degree of emission limitation achievable” through use of the “best system of emission reduction” or “BSER.”<sup>22</sup> After setting standards for certain pollutants from new and modified sources, section 111(d) requires EPA to establish guidelines for states to follow in applying performance standards to existing sources.<sup>23</sup> In determining the BSER, EPA must first identify the various “systems of emission reduction” that have been “adequately demonstrated” for a given source category.<sup>24</sup> Of those systems, it must then select the “best,” taking into account the “extent of emission reduction” achieved by the system, “costs,” “nonair quality health and environmental impacts,” “energy requirements,” and “technological innovation.”<sup>25</sup> In setting standards for existing sources under EPA-issued emission guidelines, states must require that sources achieve the degree of emission reduction associated with EPA’s determination of the BSER, but are permitted, in source-specific contexts, to take into account the remaining useful life of the source and other factors defined by EPA.<sup>26</sup>

Section 112 requires EPA to establish emission standards to reduce health and environmental risks from a set of listed hazardous air pollutants and additional pollutants identified as threatening adverse health or environmental effects.<sup>27</sup> EPA is charged with listing all categories and subcategories of major and area sources of these hazardous air pollutants<sup>28</sup> and establishing emissions standards for these categories and subcategories.<sup>29</sup> Stationary sources of hazardous air pollutants that are not major sources are defined as area sources.<sup>30</sup> EPA must then set standards for new and existing major sources to achieve “the maximum degree of reduction in emissions of the hazardous air pollutants” or “MACT,” considering costs and other “non-air quality health and

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<sup>21</sup> 42 U.S.C. § 7401(b)(1).

<sup>22</sup> *Id.* § 7411(a)(1).

<sup>23</sup> *Id.* § 7411(d)(1).

<sup>24</sup> *See, e.g.*, 83 Fed. Reg. at 65,433-34 (expounding upon 42 U.S.C. § 7411(a)(1) and citing relevant cases, including *Costle*, 657 F.2d at 326, 343, 346-7, *Lignite Energy Council v. EPA*, 198 F. 3d 930, 933 (D.C. Cir. 1999), *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), and *Portland Cement Ass’n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975)).

<sup>25</sup> 83 Fed. Reg. at 65,433-34.

<sup>26</sup> 42 U.S.C. § 7411(d)(1).

<sup>27</sup> *Id.* § 7412(b).

<sup>28</sup> *Id.* § 7412(c)(1).

<sup>29</sup> *Id.* § 7412(c)(2).

<sup>30</sup> *Id.* § 7412(a)(2).

environmental impacts and energy requirements.”<sup>31</sup> These MACT standards require that all new sources in a category match the level of emissions achieved by the best controlled similar source, with standards for existing sources meeting the performance of the best performing 12% of existing sources.<sup>32</sup> For area sources of hazardous air pollutants, EPA generally may set the required standards based on MACT or the less-stringent standard of “generally available control technologies or management practices,” or “GACT.”<sup>33</sup>

Where EPA has set MACT standards, section 112(f) requires the agency to review the standards within 8 years to identify any remaining (or “residual”) risk and, if needed, to promulgate additional standards to address this risk and “to provide an ample margin of safety to protect public health.”<sup>34</sup> EPA must review any standard promulgated under section 112(d) at least once every eight years and “revise as necessary (taking into account developments in practices, processes, and control technologies).”<sup>35</sup>

## **Discussion & Recommendations**

As Congress and the Biden-Harris Administration have already recognized through federal research and development funds and tax incentives, the dominant means of hydrogen production must be transitioned as rapidly as possible to efficient water electrolysis using carbon-free electricity. At the same time, recognizing the large number of proposals for new fossil-based production facilities and the heavy burden of emissions from existing facilities, protective standards are needed for facilities using thermochemical technologies, including steam methane reforming (SMR), autothermal reforming (ATR), and gasification.

Hydrogen production facilities using methane and other fossil fuel feedstocks represent a category of stationary sources that cause or contribute significantly to air pollution that endangers public health and welfare, and hence are overdue for category-specific emissions standards.<sup>36</sup> Emissions standards under sections 111 and 112 are needed for new, modified, and existing hydrogen production facilities in light of the emissions from these facilities and the anticipated scale-up in hydrogen production that is being encouraged through federal subsidies.<sup>37</sup>

Existing hydrogen production facilities collectively emit tens of millions of tons of greenhouse gases annually. Merchant facilities alone emitted over 40 million tons of CO<sub>2</sub>e in the U.S. in 2020. The largest individual merchant facility emitted more than 2 million tons of CO<sub>2</sub>e, comparable to emissions typical of a 300 MW coal-fired power plant.<sup>38</sup> Furthermore, direct emissions associated with merchant hydrogen production may be underestimated due to a lack in

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<sup>31</sup> *Id.* § 7412(d)(2).

<sup>32</sup> *Id.* § 7412(d)(3).

<sup>33</sup> *Id.*

<sup>34</sup> *Id.* § 7412(f)(2).

<sup>35</sup> *Id.* § 7412(d)(6).

<sup>36</sup> *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 784-85 (D.C. Cir. 1976).

<sup>37</sup> *Id.*

<sup>38</sup> Attachment D.



reporting requirements for methane emissions from leaks and venting.<sup>39</sup> Planned facilities are projected to produce similar amounts of greenhouse gas emissions. Using historical emission factors and approximate total current production of 10 million metric tons of hydrogen from captive and merchant plants yields an estimate of more than 90 million metric tons CO<sub>2</sub>e emissions annually from current hydrogen production. The few SMR plants that currently use carbon capture and sequestration (CCS) are quoted as achieving 50-60% capture rates. If that capture rate is typical of new production facilities in the future using CCS, without sufficient regulation or incentives to do better, the next 10 million metric tons of hydrogen production added in the U.S. could add another 40 million metric tons of greenhouse gas emissions.

Some existing hydrogen production facilities individually emit hundreds of tons of NO<sub>x</sub>, contributing to health damaging NO<sub>2</sub>, ozone, and particulate pollution, and tens of tons of VOCs, SO<sub>2</sub> and PM<sub>2.5</sub> that contribute to harmful health effects of ozone and particulate matter. Studies suggest that future facilities using SMR with CCS could still emit tens of tons of NO<sub>x</sub> per facility, and future hydrogen production facilities using coal gasification could individually emit hundreds of tons of NO<sub>x</sub>, SO<sub>2</sub>, and particulates. Some existing hydrogen production facilities appear to qualify as major sources of HAPs, while other existing facilities would be classified as area sources based on emissions reported to the National Emissions Inventory (NEI). Inventories indicate that methanol and n-hexane are issues at some existing facilities, and better data may show additional quantities and types of HAPs are emitted from these facilities.

We therefore urge EPA to develop new source performance standards under section 111(b) to reduce greenhouse gas and criteria air pollutant emissions from hydrogen production facilities, as well as emission guidelines under section 111(d) to limit greenhouse gas pollution from existing sources. From an emissions and environmental standpoint, water electrolysis using clean electricity is the best way to produce hydrogen and minimize air pollution. Estimated lifecycle emissions from electrolysis are 0.0 to 0.4 kg CO<sub>2</sub>e/kg H<sub>2</sub> when powered by new clean supply electricity that is hourly matched and regionally delivered (i.e., three-pillars compliant), with negligible direct emissions of greenhouse gases and criteria air pollutants at the electrolysis facility.<sup>40</sup>

Regarding CO<sub>2</sub> pollution, CCS is another commonly cited method for reducing emissions from hydrogen production. If EPA sets a CO<sub>2</sub> standard based on the level of emission reductions achievable through application of CCS, it must match the level of reductions achievable with SMR or ATR using the maximum feasible CO<sub>2</sub> capture rates. For SMR facilities, this would require addressing both the post-combustion and process CO<sub>2</sub> emissions streams, with overall capture rates of 95% or higher. With ATR facilities, natural gas fired burners for process heat are eliminated so combustion-generated CO<sub>2</sub> is reduced, but high rates of process-generated CO<sub>2</sub> capture must be required. If EPA ultimately sets standards for hydrogen production based on

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<sup>39</sup> Official estimates also do not include hydrogen emissions and the associated climate impacts.

<sup>40</sup> Elgowainy et al., *Hydrogen Life-Cycle Analysis in Support of Clean Hydrogen Production*, ANL/ESIA-22/2, Argonne National Laboratory (2022), <https://www.osti.gov/biblio/1892005> [hereinafter “Elgowainy 2022”].

CCS it must consider and address concerns from nearby communities, as well as co-pollutants and cumulative pollution.

EPA should also set standards to reduce NO<sub>x</sub> emissions from new fossil-based hydrogen production facilities, including through use of low- or ultra-low-NO<sub>x</sub> burners with selective catalytic reduction (SCR) for the reformer furnace or low-emissions electricity for process heat. In ATR systems, NO<sub>x</sub> emissions from the reformer furnace are sharply reduced by eliminating the need for combustion air for process heat. Limits on venting as well as leak detection and repair can reduce methane, VOCs, and hydrogen emissions as well.

We likewise urge EPA to develop national emission standards for hazardous air pollution under section 112 to limit toxic air pollution from new and existing hydrogen production facilities.<sup>41</sup> While HAP emissions reported to the NEI differ widely across facilities, some hydrogen production plants report emitting more than 10 tons per year of methanol. Reformer furnaces, process and deaerator vents, catalyst beds and flares are among potential sources of HAPs that should be considered for emissions limits or design or work practice standards, including standards for start-up, shut-down, and maintenance operations, and fence-line monitoring. EPA should further use its authority under section 114 to secure additional supporting detail about hydrogen production processes, emissions, and control opportunities. EPA must likewise ensure these facilities are robustly addressed through the section 112(r) Risk Management Program, along with other federal programs for ensuring safety of chemical production, transport, and distribution.

The publicly available information demonstrates that national-scale emission standards are needed and required for new, modified, and existing hydrogen production facilities under CAA sections 111 and 112. Control requirements that are already being met by hydrogen production facilities in some jurisdictions, standards applied in other industries that can readily be transferred to hydrogen production, the technical literature, and clean hydrogen projects that are already underway demonstrate the availability of feasible and effective systems that would sharply reduce emissions. The process of listing this category and developing standards should move forward without delay.

## **II. LEGAL BACKGROUND**

Congress passed the Clean Air Act (CAA) to “protect and enhance the quality of the Nation’s air resources so as to promote the public health and welfare and the productive capacity of the nation.”<sup>42</sup> As a means toward achieving that purpose, sections 111 and 112 direct EPA to set national emissions standards for new and existing stationary sources.

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<sup>41</sup> Section 112(c)(1) states that EPA “shall from time to time, but no less often than every 8 years, revise, if appropriate, in response to public comment or new information, a list of all categories and subcategories of major sources and area sources.”

<sup>42</sup> 42 U.S.C. § 7401(b)(1).

## A. New Source Performance Standards

In CAA section 111, Congress charged EPA with identifying categories of stationary sources that cause or contribute significantly to dangerous air pollution and setting standards of performance to limit those emissions. Section 111 requires EPA to publish “and from time to time . . . revise” a list of categories of stationary sources that the Administrator finds “causes or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.”<sup>43</sup> Within one year after adding a category to this list, EPA must publish proposed regulations to begin the process of establishing “standards of performance” for new sources within the category.<sup>44</sup> Those standards must “reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.”<sup>45</sup> New sources include “any stationary source, the construction or modification of which” is commenced after the publication of applicable regulations or proposed regulations.<sup>46</sup> In this context, “[m]odification” is defined as “any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.”<sup>47</sup> Within one year of publishing proposed regulations, the agency must finalize those standards.<sup>48</sup>

Once standards have been set for new and modified sources, CAA section 111(d) directs EPA to establish guidelines for states to follow in applying performance standards to existing sources within the category.<sup>49</sup> This provision does not apply to criteria air pollutants that have been listed under CAA section 108<sup>50</sup> (CO, NO<sub>x</sub>, SO<sub>2</sub>, ozone, lead, and particulate matter) or HAPs emitted from sources regulated under section 112.<sup>51</sup>

EPA has promulgated standards of performance for new and modified sources in dozens of industrial and equipment categories, such as residential wood heaters, grain elevators, nitric acid plants, petroleum refineries, and electric utility steam generating units, to name a few.<sup>52</sup> Covered pollutants include criteria pollutants (e.g., NO<sub>x</sub>, particulate matter), criteria pollutant precursors (e.g., VOCs), and greenhouse gases (e.g., methane, CO<sub>2</sub>). EPA is currently revising new source performance standards for the oil and gas industry to strengthen requirements to limit methane

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<sup>43</sup> *Id.* § 7411(b)(1)(A).

<sup>44</sup> *Id.* § 7411(b)(1)(B).

<sup>45</sup> *Id.* § 7411(a)(1).

<sup>46</sup> *Id.* § 7411(a)(2).

<sup>47</sup> *Id.* § 7411(a)(4).

<sup>48</sup> *Id.* § 7411(b)(1)(B).

<sup>49</sup> *Id.* § 7411(d)(1).

<sup>50</sup> *Id.* § 7408(a).

<sup>51</sup> *Id.* § 7412.

<sup>52</sup> U.S. EPA, *New Source Performance Standards*, <https://www.epa.gov/stationary-sources-air-pollution/new-source-performance-standards>.

emissions,<sup>53</sup> and recently proposed new emissions limits and guidelines for greenhouse gas emissions from fossil-fuel fired power plants.<sup>54</sup>

EPA has promulgated guidelines under section 111(d) to address greenhouse gas emissions from existing electric utility generating units and non-methane organic compound emissions from municipal solid waste landfills.<sup>55</sup> EPA's proposed updates to greenhouse gas emissions standards for oil and gas production, transmission and distribution sources and fossil-fuel fired power plants include emission guidelines for existing sources.<sup>56</sup>

In setting performance standards and emission guidelines that reflect the “best system of emission reduction,” EPA must first identify the various “systems of emission reduction” that have been “adequately demonstrated” for a given source category.<sup>57</sup> Of those systems, it must then select the “best,” taking into account the “extent of emission reduction” achieved by the system, “costs,” “nonair quality health and environmental impacts,” “energy requirements,” and “technological innovation.”<sup>58</sup> Lastly, EPA must set the standard at a level that is “achievable”<sup>59</sup> but reflects the “maximum practicable degree” of “control[.]”<sup>60</sup> The CAA provides that EPA “may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.”<sup>61</sup> In setting standards for existing sources under EPA-issued emission guidelines, states must require that sources achieve the degree of emission reduction associated with EPA’s determination of the BSER, but may, in source-specific contexts, take into account the remaining useful life of the source and other factors defined by EPA.<sup>62</sup>

While EPA and states have a number of considerations to take into account, the U.S. Court of Appeals for the D.C. Circuit has made clear that section 111 is a technology-forcing statute.<sup>63</sup> In this regard, when selecting the best system, EPA can require process changes to make production inherently less polluting, in addition to requiring systems to capture or otherwise control pollution before it is emitted to the ambient air.<sup>64</sup> EPA must look broadly at systems and techniques that may be in use in other, comparable industrial sectors; consider future

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<sup>53</sup> 87 Fed. Reg. 74702 (Dec. 6, 2022).

<sup>54</sup> 88 Fed. Reg. 33240 (May 23, 2023).

<sup>55</sup> See 61 Fed. Reg. 9,905 (Mar. 12, 1996); 81 Fed. Reg. 59,276 (Aug. 29, 2016) (municipal solid waste landfills); 80 Fed. Reg. 64662 (Oct. 23, 2015) (electric utility generating units).

<sup>56</sup> 87 Fed. Reg. 74702 (Dec. 6, 2022); 88 Fed. Reg. 33240 (May 23, 2023).

<sup>57</sup> See, e.g., 83 Fed. Reg. at 65,433-34 (expounding upon 42 U.S.C. § 7411(a)(1) and citing relevant cases, including *Costle*, 657 F.2d at 326, 343, 346-7, *Lignite Energy Council v. EPA*, 198 F. 3d 930, 933 (D.C. Cir. 1999), *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), and *Portland Cement Ass’n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975)).

<sup>58</sup> 83 Fed. Reg. at 65,433-34.

<sup>59</sup> *Id.*

<sup>60</sup> 116 Cong. Rec. at 42,385.

<sup>61</sup> 42 U.S.C. § 7411(b)(2).

<sup>62</sup> *Id.* § 7411(d)(1).

<sup>63</sup> *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973),

<sup>64</sup> 42 U.S.C. § 7411(a)(7)(A).

improvements and refinements in emission reduction systems; and consider systems that are not necessarily in “actual, routine use somewhere.”<sup>65</sup>

While EPA has established NSPS for a range of other source categories in the chemical manufacturing industry, including sulfuric acid, nitric acid, phosphate fertilizer plants, natural gas processing plants, and petroleum refineries, it has not established NSPS specific to hydrogen production plants.

## **B. National Emission Standards for Hazardous Air Pollutants**

Section 112 of the Clean Air Act requires EPA to establish emission standards to reduce health and environmental risks from a set of listed hazardous air pollutants and additional pollutants identified as threatening adverse human health effects or adverse environmental effects.<sup>66</sup> EPA is charged with listing all categories and subcategories of major and area sources of these hazardous air pollutants<sup>67</sup> and establishing emission standards for these categories and subcategories.<sup>68</sup> Major sources are defined as “any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.”<sup>69</sup> Stationary sources of hazardous air pollutants that are not major sources are defined as area sources.<sup>70</sup> Under section 112, EPA must set standards for new and existing sources that are major sources of hazardous air pollution to achieve “the maximum degree of reduction in emissions of the hazardous air pollutants” taking into account costs and other “non-air quality health and environmental impacts and energy requirements.”<sup>71</sup> These maximum achievable control technology (MACT) standards require that all new sources in a category match the level of emissions achieved by the best controlled similar source, with standards for existing sources at least meeting the performance of the best performing 12% of existing sources.<sup>72</sup> For area sources of HAPs, the required standards can be set based on generally available control technologies or management practices.<sup>73</sup>

EPA must review any standard—MACT or GACT—promulgated under section 112(d) at least once every eight years and “revise as necessary (taking into account developments in practices, processes, and control technologies).”<sup>74</sup> For MACT standards, section 112(f) requires a risk-based review within 8 years to identify any remaining “residual risk” with the standards in place

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<sup>65</sup> *Portland Cement Ass’n*, 486 F.2d at 391; *see also* H. Rep. No. 91-1146, 91st Cong., 2d Sess. 10 (1970).

<sup>66</sup> 42 U.S.C. § 7412(b).

<sup>67</sup> *Id.* § 7412(c)(1).

<sup>68</sup> *Id.* § 7412(c)(2).

<sup>69</sup> *Id.* § 7412(a)(1).

<sup>70</sup> *Id.* § 7412(a)(2).

<sup>71</sup> *Id.* § 7412(d)(2).

<sup>72</sup> *Id.* § 7412(d)(3).

<sup>73</sup> *Id.* § 7412(d)(3).

<sup>74</sup> *Id.* § 7412(d)(6).

and to promulgate additional standards to address this risk and “to provide an ample margin of safety to protect public health.”<sup>75</sup>

EPA has promulgated national emission standards for hazardous air pollutants (NESHAP) for dozens of industrial, equipment and process categories, ranging from dry cleaners to copper smelters.<sup>76</sup> Although some NESHAP apply to particular equipment and operations that are present at some hydrogen production facilities, as discussed below, EPA has not issued specific and comprehensive NESHAP for hydrogen production facilities.

### C. Information Collection Requests

CAA section 114 authorizes EPA to collect information needed “for the purpose (i) of developing or assisting in the development of any implementation plan under section 7410 or section 7411(d) of this title, any standard of performance under section 7411 of this title, [or] any emission standard under section 7412 of this title,” among other purposes.<sup>77</sup> The statute authorizes the Administrator to require owners and operators of any emissions source and manufacturers of control and process equipment to submit information on emissions tests, equipment parameters, production variables, and “such other information as the Administrator may reasonably require.”<sup>78</sup> Information collection requests can be targeted to specified facilities or cover a source category.

## III. FACTUAL BACKGROUND

### A. Climate Change

The urgency and severity of the climate crisis is becoming clearer by the day. The Biden-Harris Administration has established ambitious goals to reduce greenhouse gas pollution from 2005 levels by 50-52% in 2030 under the Paris Agreement, create a carbon pollution-free power sector by 2035, and reach net-zero emissions no later than 2050.<sup>79</sup> EPA has likewise recognized and repeatedly reaffirmed the damaging consequences of greenhouse gas emissions, including through a suite of recent actions under the CAA.<sup>80</sup>

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<sup>75</sup> *Id.* § 7412(f)(2).

<sup>76</sup> EPA, *National Emission Standards for Hazardous Air Pollutants (NESHAP)*, <https://www.epa.gov/stationary-sources-air-pollution/national-emission-standards-hazardous-air-pollutants-neshap-8>.

<sup>77</sup> 42 U.S.C. § 7414(a).

<sup>78</sup> *Id.* § 7414(a)(1).

<sup>79</sup> The White House, *Fact Sheet: President Biden Sets Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Jobs and Securing U.S. Leadership on Clean Energy Technologies*, (April 22, 2021), <https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/>.

<sup>80</sup> *See, e.g.*, Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 86 Fed. Reg. 63110, 63124-27 (proposed Nov. 15, 2021).

While the use of hydrogen may aid in the decarbonization of certain end use sectors where the development of electrification and other solutions is proceeding more slowly, it is essential to ensure that hydrogen is produced, transported, stored, and used with minimal greenhouse gas emissions, including those at and upstream of the production facility. Without low lifecycle greenhouse gas emissions, hydrogen could damage the climate more than the fossil fuels it would replace. Using fossil-based production methods, hydrogen production facilities in the U.S. directly emit large quantities of CO<sub>2</sub>, alongside significant methane emissions from upstream natural gas production, processing, transmission, storage, and distribution. Additionally, emissions of hydrogen itself have deleterious climate effects. In the atmosphere, hydrogen reacts with the hydroxyl radical, which is important for the destruction of methane and other air pollutants. Reducing hydroxyl radical concentrations increases the lifetimes and atmospheric concentrations of methane and ozone in the troposphere and water vapor in the stratosphere, exacerbating their climate impacts.<sup>81</sup>

As the Intergovernmental Panel on Climate Change (IPCC) stated in its most recent report (AR6), “[h]uman influence has warmed the climate at a rate that is unprecedented in at least the last 2000 years.”<sup>82</sup> Climate impacts are now having devastating impacts across the U.S. and the globe, as experienced this summer—which was the hottest on record<sup>83</sup>—with extreme heat waves in many parts of the U.S. and unprecedented wildfires in Maui, Greece, and Canada. According to scientists from the World Weather Attribution collaborative network, heatwaves in July 2023 that broke records in parts of the U.S., Mexico, China, and southern Europe were made much more likely due to climate change.<sup>84</sup> As the U.S. Global Change Research Program (USGCRP) concluded in 2018, “evidence of human-caused climate change is overwhelming and continues to strengthen,” “the impacts of climate change are intensifying across the country,” and “climate-related threats to Americans’ physical, social, and economic well-being are rising.”<sup>85</sup>

The well-documented impacts of climate change that are already being felt and will accelerate in years to come include increases in hurricane frequency and intensity;<sup>86</sup> sea level rise and

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<sup>81</sup> Ocko & Hamburg 2022, *supra* note 6.

<sup>82</sup> Masson-Delmotte et al., Intergovernmental Panel on Climate Change, Summary for Policymakers in *Climate Change 2022: Impacts, Adaptation, and Vulnerability: Contribution of Working Group II to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*, p. 6, <https://www.ipcc.ch/report/ar6/wg2/>.

<sup>83</sup> World Meteorological Organization, *Earth had hottest three-month period on record, with unprecedented sea surface temperatures and much extreme weather* (Sept. 6, 2023), <https://public.wmo.int/en/media/press-release/earth-had-hottest-three-month-period-record-unprecedented-sea-surface>.

<sup>84</sup> Zachariah et al., *Extreme heat in North America, Europe and China in July 2023 made much more likely by climate change* (2023), <https://www.worldweatherattribution.org>.

<sup>85</sup> Jay et al., *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment*, Volume II (Reidmiller et al. eds.), Ch. 1 at 36, (2018), <https://nca2018.globalchange.gov/chapter/1/> [hereinafter “USGCRP 2018”].

<sup>86</sup> Kossina et al., *Global increase in major tropical cyclone exceedance probability over the past four decades*, 117:22 *Proceedings of the National Academy of Sciences*, 11975-11980 (2020), <https://www.pnas.org/content/117/22/11975>.

increased frequency and severity of coastal flooding;<sup>87</sup> extreme precipitation and associated inland flooding;<sup>88</sup> and exacerbation of droughts and wildfires.<sup>89</sup> Higher warming also increases the probability and frequency of compound events, such as concurrent heatwaves and droughts, in many regions.<sup>90</sup> In AR6, the IPCC also makes clear that, since the 1950s, anthropogenic emissions have *likely* “increased the chance of compound extreme events,” including “increases in the frequency of concurrent heatwaves and droughts on the global scale (*high confidence*), fire weather in some regions of all inhabited continents (*medium confidence*), and compound flooding in some locations (*medium confidence*).”<sup>91</sup>

Climate- and weather-related disasters are already harming the U.S. economy. Since 1980, there have been 308 weather and climate disasters that cost the country at least \$1 billion each, for a total cost of more than \$2 trillion.<sup>92</sup> Data indicates that the economic damage from extreme weather events has been increasing in recent years.<sup>93</sup> In the last 5 years, there have been 81 such events, resulting in nearly 4,000 deaths and over \$640 billion in damages.<sup>94</sup> According to a 2017 technical assessment by EPA’s Climate Change Impacts and Risk Analysis project, climate change will cost the U.S. economy hundreds of billions of dollars each year under conservative estimates.<sup>95</sup> Projected damages are significantly larger under a high-emissions scenario.

Anthropogenic climate change is also having a drastic impact on public health, and will pose even more severe threats without action to greatly limit greenhouse gas emissions and rapidly phase out fossil fuels.<sup>96</sup> Heat is the most direct health threat from climate change,<sup>97</sup> particularly for older adults and young children, outdoor workers, low-income communities, communities of color, and people with chronic illnesses (*very high confidence*).<sup>98</sup> Climate-related disasters like inland flooding, wildfires, and hurricanes pose a myriad of health threats including injuries, skin infections, mental health conditions, and deaths (*high confidence*).<sup>99</sup> EPA has previously

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<sup>87</sup> USGCRP, *Climate Science Special Report: Fourth National Climate Assessment*, Vol. I (Wuebbles, D.J. et al. eds.) at 25-26, 27, 333, 343 (2017), [https://science2017.globalchange.gov/downloads/CSSR2017\\_FullReport.pdf](https://science2017.globalchange.gov/downloads/CSSR2017_FullReport.pdf) [hereinafter “USGCRP 2017”]; IPCC AR6, *Summary for Policymakers*, at 25, C2.6, [https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC\\_AR6\\_WGI\\_SPM.pdf](https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_SPM.pdf) [hereinafter “IPCC AR6 SPM”].

<sup>88</sup> USGCRP 2017, *supra* note 87, at 218.

<sup>89</sup> *Id.* at 231.

<sup>90</sup> IPCC AR6 SPM, *supra* note 87, at 25, C2.7

<sup>91</sup> *Id.* at 9, A.3.5.

<sup>92</sup> NOAA National Centers for Environmental Information (NCEI), *U.S. Billion-Dollar Weather and Climate Disasters*, <https://www.ncdc.noaa.gov/billions/>.

<sup>93</sup> NOAA, *2020 Annual National Climate Report, Billion-Dollar Weather and Climate Disasters* (2022), <https://www.ncdc.noaa.gov/sotc/national/202013>.

<sup>94</sup> NOAA National Centers for Environmental Information (NCEI), *U.S. Billion-Dollar Weather and Climate Disasters* (2021), <https://www.ncdc.noaa.gov/billions/>.

<sup>95</sup> US EPA, *Multi-Model Framework for Quantitative Sectoral Impacts Analysis: A Technical Report for the Fourth National Climate Assessment*, 209-10 (2017), [https://cfpub.epa.gov/si/si\\_public\\_record\\_Report.cfm?dirEntryId=335095](https://cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=335095).

<sup>96</sup> USGCRP, *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment*, 26 (2016), <https://health2016.globalchange.gov/> [hereinafter “USGCRP 2016”].

<sup>97</sup> *Id.* at 30.

<sup>98</sup> *Id.* at 44.

<sup>99</sup> *Id.* at 100.



recognized that “climate change is expected to increase ozone pollution over broad areas of the U.S., especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality.”<sup>100</sup> Climate change is also likely to increase fine particle pollution and ozone pollution from wildfires (*high confidence*), and make pollen and mold allergy seasons longer and more severe (*high confidence*).<sup>101</sup> The USGCRP has determined with *high confidence* that climate change will alter the geographical extent and seasonal timing of tick- and mosquito-borne diseases like Lyme disease and West Nile Virus.<sup>102</sup>

Climate change raises and exacerbates critical issues of environmental and social justice. EPA’s September 2021, report *Climate Change and Social Vulnerability in The United States: A Focus on Six Impacts*, finds that, within the United States, communities of color and low-income communities are at increased risk of climate-driven harms compared to other populations.<sup>103</sup> Communities of color face heightened exposure and vulnerability to extreme temperatures and coastal flooding, among other disproportionate impacts.<sup>104</sup> EPA has also found “climate change, in addition to chronic stresses such as extreme poverty, is negatively affecting Indigenous peoples’ health in the U.S. through impacts such as reduced access to traditional foods, decreased water quality, and increasing exposure to health and safety hazards.”<sup>105</sup>

Climate change is also having catastrophic impacts on the health of oceans and biodiversity. This summer, ocean temperatures in Florida exceeded 100 degrees Fahrenheit, posing major risks to coral and other marine life.<sup>106</sup> The IPCC projects that coral reefs will “decline by a further 70–90% at 1.5°C (*high confidence*) with larger losses (>99%) at 2°C (*very high confidence*)” and that “[t]he risk of irreversible loss of many marine and coastal ecosystems increases with global warming, especially at 2°C or more (*high confidence*).”<sup>107</sup> And according to NOAA, “[o]ver half a billion people depend on reefs for food, income, and protection.”<sup>108</sup> In addition, according to the IPCC, it is *virtually certain* that temperatures in the top layer of global oceans have increased since the 1970s, with human influence *extremely likely* to be the main driver.<sup>109</sup> Beyond increasing ocean temperatures, CO<sub>2</sub> emissions have made the surface of global oceans about 30

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<sup>100</sup> Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64661, 64682 (2015).

<sup>101</sup> USGCRP 2016, *supra* note 96, at 70.

<sup>102</sup> *Id.* at 130.

<sup>103</sup> U.S. Env’tl Protection Agency, *Climate Change and Social Vulnerability in the United States* (2021), [https://www.epa.gov/system/files/documents/2021-09/climate-vulnerability\\_september-2021\\_508.pdf](https://www.epa.gov/system/files/documents/2021-09/climate-vulnerability_september-2021_508.pdf) [hereinafter “EPA Climate & Social Vulnerability Report”].

<sup>104</sup> *Id.* at 50.

<sup>105</sup> 80 Fed. Reg. 64683.

<sup>106</sup> NOAA, *The ongoing marine heat waves in U.S. waters, explained* (July 14, 2023), <https://www.noaa.gov/news/ongoing-marine-heat-waves-in-us-waters-explained>.

<sup>107</sup> IPCC, *Global Warming of 1.5°C, Summary for Policymakers*, 8 (2018), [https://www.ipcc.ch/site/assets/uploads/sites/2/2022/06/SPM\\_version\\_report\\_LR.pdf](https://www.ipcc.ch/site/assets/uploads/sites/2/2022/06/SPM_version_report_LR.pdf).

<sup>108</sup> National Oceanic and Atmospheric Administration, *Coral reef ecosystems*, <https://www.noaa.gov/education/resource-collections/marine-life/coral-reef-ecosystems>.

<sup>109</sup> IPCC AR6 SPM, *supra* note 87, at 5, A.1.6

percent more acidic over the last 150 years.<sup>110</sup> Under continued high emissions of CO<sub>2</sub>, surface acidity is expected with *high confidence* to increase by another 100-150% by the end of the century.<sup>111</sup> Human-caused CO<sub>2</sub> emissions are *virtually certain* to be the main driver of acidification in the open ocean.<sup>112</sup>

Because species often respond to new environmental pressures by shifting their range, climate change is already “impelling a universal redistribution of life on Earth.”<sup>113</sup> A recent review of 976 plant and animal species around the world found that 47% have experienced climate-related local extinctions, with the highest extinction rates occurring in tropical species, animals, and freshwater habitats.<sup>114</sup> The redistribution of species has been linked to reduced terrestrial productivity, alterations in ecological networks in marine habitats, and the development of toxic algal blooms.<sup>115</sup>

If climate change continues to accelerate, many species will be unable to move quickly enough—or at all—due to geographical barriers such as oceans or mountains, characteristics of their life history, a lack of suitable new habitat, or the rapid pace of local changes in climate.<sup>116</sup> For example, the American pika, a small, high-alpine dwelling relative of the rabbit, is adapted to cold weather ecosystems and cannot survive temperatures above 78 degrees Fahrenheit for more than six hours.<sup>117</sup> In the face of warming temperatures, pikas may move upward, but they are ultimately trapped on mountaintops and their widespread deaths in certain regions have been attributed to climate change.<sup>118</sup>

In summary, recent scientific studies confirm that climate change harms are escalating, and that the U.S. must take immediate action to rapidly reduce greenhouse gas pollution and phase out fossil fuels to avoid catastrophic harms. According to the Fourth National Climate Assessment, “[t]he impacts of global climate change are already being felt in the United States and are projected to intensify in the future—but the severity of future impacts will depend largely on

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<sup>110</sup> USGCRP 2017, *supra* note 87, at 372.

<sup>111</sup> *Id.*

<sup>112</sup> IPCC AR6 SPM, *supra* note 87, at 5, A.1.6

<sup>113</sup> Pecl et al., *Biodiversity Redistribution Under Climate Change: Impacts on Ecosystems and Human Well-Being*, 355 *Science* eaai9214 (2017), <https://www.science.org/doi/10.1126/science.aai9214> [hereinafter “Pecl 2017”].

<sup>114</sup> Wiens, *Climate-Related Local Extinctions are Already Widespread Among Plant and Animal Species*, 14 *PLOS Biology* e2001104 (2016), <http://journals.plos.org/plosbiology/article?id=10.1371/journal.pbio.2001104> [hereinafter “Wiens 2016”].

<sup>115</sup> Pecl 2017, *supra* note 113.

<sup>116</sup> Wiens 2016, *supra* note 114; Vázquez et al., *Ecological and Evolutionary Impacts of Changing Climatic Variability*, 92 *Biol. Rev.* 22 (2017; first published Aug 2015), <http://onlinelibrary.wiley.com/doi/10.1111/brv.12216/abstract>.

<sup>117</sup> The National Wildlife Federation, *American Pika*, [https://www.nwf.org/Educational-Resources/Wildlife-Guide/Mammals/American-](https://www.nwf.org/Educational-Resources/Wildlife-Guide/Mammals/American-Pika#:~:text=Without%20protection%20and%20help%2C%20American,that%20are%20cool%20and%20moist.)

[Pika#:~:text=Without%20protection%20and%20help%2C%20American,that%20are%20cool%20and%20moist.](https://www.nwf.org/Educational-Resources/Wildlife-Guide/Mammals/American-Pika#:~:text=Without%20protection%20and%20help%2C%20American,that%20are%20cool%20and%20moist.)

<sup>118</sup> Beever et al., *Pika (*Ochotona princeps*) losses from two isolated regions reflect temperature and water balance, but reflect habitat area in a mainland region*, 97 *J. of Mammalogy* 1495-1511 (2016), <https://academic.oup.com/jmammal/article/97/6/1495/2628942>.

actions taken to reduce greenhouse gas emissions and to adapt to the changes that will occur.”<sup>119</sup> The IPCC has concluded that “reaching net zero anthropogenic CO<sub>2</sub> emissions is a requirement to stabilize human-induced global temperature increase at any level.”<sup>120</sup> The takeaway from these most recent reports is clear: human-caused climate change is already and will continue causing vast and escalating harms—which disproportionately impact communities of color and low-income communities—absent urgent action to reduce greenhouse gas emissions.

## **B. Regional and Local Air Quality**

In addition to greenhouse gases, hydrogen production facilities that use fossil fuels as feedstocks are responsible for emissions of NO<sub>x</sub>, VOCs, SO<sub>2</sub>, primary particulate matter, and HAPs that contribute to local and regional air pollution, harming people’s health and welfare. Existing hydrogen production facilities are clustered in locations with historically poor air quality and disproportionately burdened communities, including in California’s South Coast and the Gulf Coast portions of Texas and Louisiana.

Precursors to formation of ground-level ozone include NO<sub>x</sub> and VOCs. A longstanding body of scientific research, including numerous EPA assessments, demonstrates that exposure to ground-level ozone seriously harms human health. In its 2020 Integrated Science Assessment (ISA) for Ozone, EPA concluded that the scientific evidence supports finding a causal or “likely to be causal” relationship between short-term exposure to ozone and respiratory effects (causal) and metabolic effects (likely to be causal).<sup>121</sup> The ISA also found that long-term exposure to ozone was likely to be causally linked to respiratory effects. The review catalogs numerous studies that point to “suggestive” associations between ozone exposure and cardiovascular, central nervous system, reproductive effects, and total mortality.

As EPA recognizes, ozone pollution is particularly harmful for vulnerable populations, such as people with respiratory diseases or asthma, older adults, and people who are active outdoors, especially outdoor workers.<sup>122</sup> Children with asthma face heightened risks from ozone exposure. Many studies have demonstrated that children with asthma experience decrements in lung function and increases in respiratory symptoms when exposed to ozone pollution.<sup>123</sup> In addition to harms to human health, the ISA found causal relationships between ozone and a number of economically and ecologically significant effects on vegetation, including reduced vegetation growth, reduced crop yields, and reduced ecosystem productivity.<sup>124</sup> As of June 2023, more than 45 areas in the U.S. were designated nonattainment for the national ambient air quality standard

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<sup>119</sup> USGCRP 2018, *supra* note 85, at 34.

<sup>120</sup> IPCC AR6 SPM, *supra* note 87, at 28, D.1.1.

<sup>121</sup> U.S. EPA, *Integrated Science Assessment (ISA) for Ozone and Related Photochemical Oxidants* (Final Report, Apr 2020), EPA/600/R-20/012, <https://cfpub.epa.gov/ncea/isa/recordisplay.cfm?deid=348522> [hereinafter “ISA 2020”].

<sup>122</sup> *Id.* at 1-8.

<sup>123</sup> *Id.* at 3-45, 3-48; Mortimer et al., *The Effect of Air Pollution on Inner-City Children with Asthma*, 19 Eur. Respiratory J. 699 (2002), <https://pubmed.ncbi.nlm.nih.gov/11999000/>.

<sup>124</sup> ISA 2020, *supra* note 121, Table ES-2, p. ES-13.

for ozone that was set in 2015, meaning people in those areas regularly breathe dangerous levels of health-harming pollution.<sup>125</sup>

Hydrogen production facilities also emit pollution that forms particulate matter, another dangerous pollutant that causes serious negative health effects. Emissions of primary particulate matter, along with NO<sub>x</sub>, SO<sub>2</sub>, and VOCs that react to form secondary particulate matter, contribute to serious health effects of PM<sub>2.5</sub> along with visibility degradation and other welfare effects. As of June 2023, 11 areas in the U.S. remained designated nonattainment under the 24-hour PM<sub>2.5</sub> NAAQS set in 2006 and 5 areas are designated nonattainment under the annual PM<sub>2.5</sub> standard set in 2012.<sup>126</sup> In January 2023, EPA proposed to lower the annual health-based PM<sub>2.5</sub> standard from 12 µg m<sup>-3</sup> to a level in the range from 9 to 10 µg m<sup>-3</sup>, recognizing the severe health burden of this pollutant, including premature mortality risks in areas that meet the current standards.<sup>127</sup> The 2022 Supplement to the Integrated Science Assessment for Particulate Matter concluded that a very large body of scientific evidence supports finding causal relationships between both short- and long-term exposure to PM<sub>2.5</sub> and mortality and cardiovascular effects, and “likely to be causal” associations of short- and long-term exposures with respiratory effects, and long-term exposure with nervous system effects and cancer.<sup>128</sup> A report by Industrial Economics assessing the most recent PM NAAQS review found that just lowering the annual PM<sub>2.5</sub> standard from 12 µg m<sup>-3</sup> to 9 µg m<sup>-3</sup> would prevent up to 9,300 premature deaths per year from long-term PM<sub>2.5</sub> exposure.<sup>129</sup> Peer-reviewed studies estimate that there are hundreds of thousands of premature deaths in the U.S. from PM<sub>2.5</sub> exposure each year.<sup>130</sup>

### C. Environmental Justice

Along with petroleum refineries and other chemical manufacturing plants, hydrogen production facilities are often located in or near communities with high proportions of low-income residents and people of color. As detailed below, we identified 54 existing merchant hydrogen plants based on facilities reporting to the Greenhouse Gas Reporting Program (GHGRP) under Subpart

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<sup>125</sup> U.S. Environmental Protection Agency, *Green Book PM-2.5 (2006) Area Information*, <https://www.epa.gov/green-book/green-book-pm-25-2006-area-information>; U.S. Environmental Protection Agency, *Green Book PM-2.5 (2012) Area Information*, <https://www.epa.gov/green-book/green-book-pm-25-2012-area-information>.

<sup>126</sup> *Id.*

<sup>127</sup> 88 Fed. Reg. 5558 (Jan. 27, 2023).

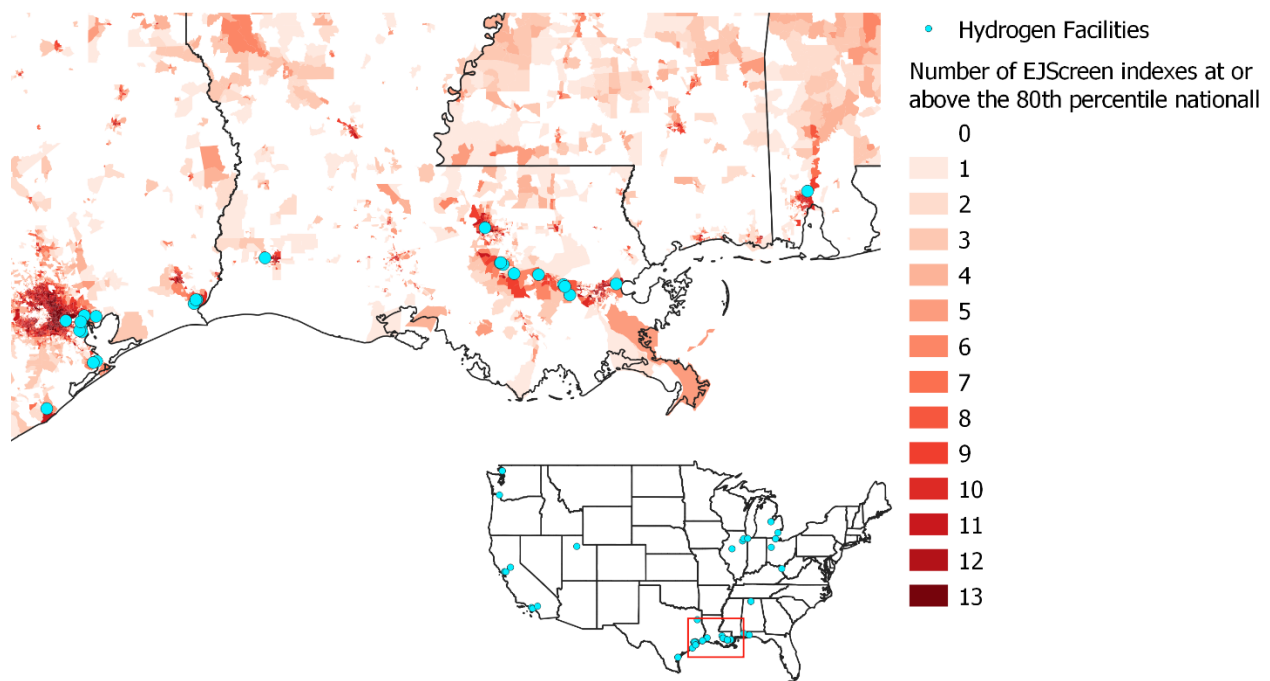
<sup>128</sup> U.S. Environmental Protection Agency, *Supplement to the 2019 Integrated Science Assessment for Particulate Matter*, EPA/600/R-22/028, Table 2-1, p. 2-3 (May 2022).

<sup>129</sup> Comment submitted by Appalachian Mountain Club et al. (Part 1 of 3), IEc updated report PM NAAQS Analysis March 2023, 5-9, <https://www.regulations.gov/comment/EPA-HQ-OAR-2015-0072-2422>.

<sup>130</sup> Spiller et al., *Mortality Risk from PM2.5: A Comparison of Modeling Approaches to Identify Disparities across Racial/Ethnic Groups in Policy Outcomes*, 129 *Env. Health Perspectives* 127004 (2021), <https://ehp.niehs.nih.gov/doi/10.1289/EHP9001> (“Our estimate of approximately 100,000 premature deaths from PM2.5 exposure for populations over the age of 65 is in line with previous estimates. Tessum et al. (2019) estimated 131,000 deaths in 2015 using a different integrated assessment model and the Krewski et al. CRF (2009). Although this estimate included all persons over the age of 25, older individuals incur the majority of premature mortality risk. Further, Burnett et al. (2018) report a range of premature deaths from PM2.5 in the U.S. of between 121,000 and 213,000, inclusive of all age groups.”).

P. “Community” information on EPA environmental justice indices<sup>131</sup> and neighborhood demographic profile data were available for 51 of them through EPA’s Enforcement and Compliance History Online (ECHO) website. (The compiled data are presented fully in Attachment A.) Of those 51 facilities, 44 are located in neighborhoods with 2 or more of the 13 EJ screen indices<sup>132</sup> at the 80<sup>th</sup> percentile or above; 39 with 6 or more indices at that level; and 21 with 10 or more of the indices at the 80<sup>th</sup> percentile or above. Of the 51 facilities, 23 are located in neighborhoods where 50% or more of the residents living within a mile of the facility were people of color,<sup>133</sup> and 18 of the 51 facilities are in neighborhoods where 50% or more of the residents live in low-income households.<sup>134</sup> Existing hydrogen production facilities are thus highly concentrated in environmental justice communities.

**Figure 1: Gulf Region Hydrogen Production Facilities Overlaid with EJ Screen Indices<sup>135</sup>**



<sup>131</sup> U.S. Environmental Protection Agency, *EJ Screen: Environmental Justice Screening and Mapping Tool*, <https://www.epa.gov/ejscreen>.

<sup>132</sup> The 13 EJScreen indexes are: (1) PM<sub>2.5</sub>; (2) Ozone; (3) Diesel Particulate Matter; (4) Air Toxics Cancer Risk; (5) Air Toxics Respiratory Hazard Index; (6) Toxic Releases to Air; (7) Traffic Proximity; (8) Lead Paint; (9) Risk Management Plan Facility Proximity; (10) Hazardous Waste Proximity; (11) Superfund Proximity; (12) Underground Storage Tanks; and (13) Wastewater Discharge. EPA has considered an area with any of the 13 EJ Indexes at or above the 80<sup>th</sup> percentile nationally as a potential candidate for further review as an “EJ Community.”

<sup>133</sup> Percent of individuals who list their racial status as a race other than white alone and/or list their ethnicity as Hispanic or Latino.

<sup>134</sup> Defined as living in households where the income is less than or equal to twice the federal “poverty level.”

<sup>135</sup> Facilities shown are a regional subset of those presented in Attachment A, and the color gradients represent the number of EJ screen indices exceeding the 80<sup>th</sup> percentile (white means no indices exceed the 80<sup>th</sup> percentile, while the darkest red indicates that all 13 indices exceed the 80<sup>th</sup> percentile).

Disproportionate air pollution exposure burdens among African-Americans have been implicated in racial disparities in health outcomes such as asthma<sup>136</sup> and cancer risk.<sup>137</sup> Approximately 13.4% of African American children have asthma (over 1.3 million children), compared to 7.3% for white children.<sup>138</sup> Hispanics are 51% more likely to live in counties with unhealthy levels of ozone than are non-Hispanic whites.<sup>139</sup> Approximately 8.5% of Hispanic children have asthma, including 23.5% of Puerto Rican children.<sup>140</sup>

In 2021, the White House launched the Justice40 Initiative, which pledges that at least 40% of overall benefits from Federal investments in climate and clean energy be delivered to disadvantaged communities.<sup>141</sup> Many significant hydrogen programs moving forward, including DOE’s Regional Clean Hydrogen Hubs Program, and the Clean Hydrogen Manufacturing and Recycling Research, Development and Demonstration Program, are included in the Justice40 Initiative.<sup>142</sup> Setting protective emissions standards for hydrogen production facilities can help further these initiatives. Doing so is also consistent with and would help further EPA’s own environmental justice efforts.<sup>143</sup>

#### **D. Hydrogen Production Industry Potential**

At present, about 10 million metric tons of hydrogen are produced per year in the U.S., mainly for use in petroleum refining (55%) and ammonia and methanol production (35%).<sup>144</sup> Ninety-five percent of current production uses steam methane reforming without carbon capture and sequestration (CCS), less than 5% uses reforming with CCS, less than 1% uses electrolysis with electricity from the grid and less than 1% uses electrolysis with renewable or nuclear power.<sup>145</sup>

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<sup>136</sup> Hill et al., *Racial disparities in pediatric asthma: a review of the literature*, 11 *Curr Allergy Asthma Rep.* 85–90 (2011), <https://pubmed.ncbi.nlm.nih.gov/21107764/>; Nachman & Parker, *Exposures to fine particulate air pollution and respiratory outcomes in adults using two national datasets: a cross-sectional study*, 11 *Env. Health* 1 (2012), <https://pubmed.ncbi.nlm.nih.gov/22490087/>.

<sup>137</sup> Apelberg et al., *Socioeconomic and racial disparities in cancer risk from air toxics in Maryland*, 113 *Env. Health Perspectives* 693–699 (2005), <https://www.ncbi.nlm.nih.gov/pmc/articles/PMC1257593/>.

<sup>138</sup> CATF, *Fumes Across the Fence-Line, The Health Impacts of Oil & Gas Facilities on African American Communities*, 8 (2017), [https://cdn.catf.us/wp-content/uploads/2017/11/21094509/CATF\\_Pub\\_FumesAcrossTheFenceLine.pdf?\\_gl=1\\*g49jxx\\*\\_gcl\\_au\\*MTk0MTI0NDc0OS4xNjkxMDAwMTcw](https://cdn.catf.us/wp-content/uploads/2017/11/21094509/CATF_Pub_FumesAcrossTheFenceLine.pdf?_gl=1*g49jxx*_gcl_au*MTk0MTI0NDc0OS4xNjkxMDAwMTcw).

<sup>139</sup> CATF, *Latino Communities at Risk: The Impact of Air Pollution from the Oil and Gas Industry*, 4 (2016), [https://cdn.catf.us/wp-content/uploads/2016/09/21094458/CATF\\_Pub\\_LatinoCommunitiesAtRisk.pdf?\\_gl=1\\*11mgsuy\\*\\_gcl\\_au\\*MTk0MTI0NDc0OS4xNjkxMDAwMTcw](https://cdn.catf.us/wp-content/uploads/2016/09/21094458/CATF_Pub_LatinoCommunitiesAtRisk.pdf?_gl=1*11mgsuy*_gcl_au*MTk0MTI0NDc0OS4xNjkxMDAwMTcw).

<sup>140</sup> *Id.* at 5.

<sup>141</sup> The Whitehouse, *Justice40: A Whole-of-Government-Initiative*, <https://www.whitehouse.gov/environmentaljustice/justice40/>.

<sup>142</sup> DOE, *U.S. National Clean Hydrogen Strategy and Roadmap*, at 6 (June 2023), <https://www.hydrogen.energy.gov/clean-hydrogen-strategy-roadmap.html> [hereinafter “Clean Hydrogen Strategy”].

<sup>143</sup> See, e.g., EPA, *E.O. 13985 Equity Action Plan* (April 2022), [https://www.epa.gov/system/files/documents/2022-04/epa\\_equityactionplan\\_april2022\\_508.pdf](https://www.epa.gov/system/files/documents/2022-04/epa_equityactionplan_april2022_508.pdf) (citing as a top priority action “[i]dentify[ing] and promot[ing] uses of cumulative impacts analysis for multiple decision contexts, such as permitting, compliance monitoring and enforcement, cleanups, and rulemaking.”).

<sup>144</sup> Clean Hydrogen Strategy, *supra* note 142, at 14, figure 6.

<sup>145</sup> *Id.* at 38, figure 18.

The federal government has viewed increasing use of clean hydrogen produced with low lifecycle carbon emissions as an important strategy for reducing greenhouse gas emissions from certain difficult-to-electrify sectors to mitigate climate change. For instance, the Department of Energy's *U.S. National Clean Hydrogen Strategy and Roadmap* released in June 2023 envisions scaling up hydrogen production and use to 50 million metric tons per annum (MMTpa) between now and 2050.<sup>146</sup> The Roadmap would seek 10 MMTpa of clean hydrogen production by 2030 to supply current end uses, with future growth in production matched by demand from new applications including shipping, steel manufacturing, and aviation fuels.<sup>147</sup>

In 2021 and 2022, Congress put in place major incentive programs for hydrogen demand and for clean hydrogen production. Among these programs, the Infrastructure Investment and Jobs Act (IIJA, Public Law No. 117-58), which was signed into law on November 15, 2021, includes \$1 billion to support research, development, demonstration and commercialization projects to improve electrolysis technologies, as well as \$8 billion for regional Clean Hydrogen Hubs encompassing production, storage, transport and end uses.<sup>148</sup> In addition, the Inflation Reduction Act (IRA, Public Law No. 117-169), which was signed into law August 16, 2022, provides for hydrogen production tax credits of up to \$3/kg of hydrogen produced.<sup>149</sup> The value of the production tax credit increases as the carbon intensity of hydrogen production declines, with credits of \$3/kg applying to hydrogen produced with well-to-gate emissions of 0.45 kg CO<sub>2e</sub>/kg H<sub>2</sub> or less; \$1/kg for hydrogen with emissions of 0.45–1 kg CO<sub>2e</sub>/kg H<sub>2</sub>; \$0.75/kg with 1.5–2.5 kg CO<sub>2e</sub>/kg H<sub>2</sub>; and \$0.6/kg with 2.5–4 kg CO<sub>2e</sub>/kg H<sub>2</sub>. Specification of credits based on well-to-gate CO<sub>2e</sub> intensity is critical, as hydrogen derived from fossil fuels can have significant upstream emissions associated with fuel production, processing, and transmission.<sup>150</sup> Likewise, hydrogen produced through electrolysis is highly energy intensive, and electrolysis using average grid mix electricity causes estimated emissions of 21 kg CO<sub>2e</sub>/kg H<sub>2</sub>. Furthermore, the IRA includes incentives to promote the use of hydrogen, including opportunities for auto manufacturers to claim credits for fuel cell vehicles and incentives for ports to use fuel cells to reduce emissions.

Spurred in part by these legislative efforts, EPA recently proposed CO<sub>2</sub> standards for power plants under section 111 that would designate co-firing low greenhouse gas emissions hydrogen with natural gas as a best system of emissions reduction (BSER) option for certain stationary combustion turbines.<sup>151</sup> The proposed regulation contemplates requiring that the co-fired hydrogen would have to be produced with well-to-gate greenhouse gas emissions of 0.45 kg CO<sub>2e</sub>/kg H<sub>2</sub> or less.<sup>152</sup> This action underscores the importance of limiting emissions during

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<sup>146</sup> *Id.* at 8.

<sup>147</sup> *See id.*

<sup>148</sup> *Id.* at 7.

<sup>149</sup> 26 U.S.C. § 45V.

<sup>150</sup> Bauer et al., *On the Climate Impacts of Blue Hydrogen Production, Sustainable Energy & Fuels*, 6, 66-75 (2022), <https://pubs.rsc.org/en/content/articlelanding/2022/se/d1se01508g> [hereinafter "Bauer 2022"].

<sup>151</sup> 88 Fed. Reg. 33240.

<sup>152</sup> *Id.* at 33240, 33364.

hydrogen production for achieving real-world emission reductions across the life cycle and end uses.

While these programs and proposals target “clean” hydrogen, the proposed criteria only consider certain greenhouse gas emissions and thus do not specify emissions limits for other air pollutants from hydrogen production or across the value chain. Further, none place any enforceable emission limits on hydrogen production facilities. Performance standards that comprehensively address greenhouse gas, criteria pollutants, and HAPs from these facilities are therefore necessary to protect local communities and the environment. Current emissions from hydrogen production underscore the urgent need for greenhouse gas emissions reduction efforts, and the need to protect the communities where these facilities are located.

According to the U.S. Department of Energy’s (DOE) *Pathways to Commercial Liftoff* report, before March 2023 more than 100 clean hydrogen production projects totaling ~12 MMTpa of production capacity had been announced, with projects totaling ~1.5 MMTpa capacity having reached a final investment decision.<sup>153</sup> EDF analyzed information on proposed U.S. hydrogen production projects from Rystad Energy’s proprietary HydrogenCube database to identify proposed projects and anticipated production capacity by technology type. Capacity was totaled for all current U.S. project proposals in the database, including those at the conceptual, application, final investment decision and under construction stages, and including projects of commercial, demonstration, pilot, or unknown scale. (This analysis is presented fully in Attachment B).

The proposals suggest that thermochemical production methods with fossil fuel feedstocks could make up the majority of new capacity additions over the next decade, adding to the existing fleet of SMR plants. Furthermore, and critically, as shown in DOE’s *Liftoff* report, new thermochemical plants are disproportionately proposed for the Gulf Coast areas of Texas and Louisiana,<sup>154</sup> areas that are heavily overburdened already due to an existing concentration of refineries, chemical production, and other heavy industry. Although many of the ATR, SMR, and biomass gasification proposals include plans for CCS to qualify for tax credits, emissions standards are still needed to secure enforceable greenhouse gas emission reductions and to address criteria and hazardous air pollutants.

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<sup>153</sup> U.S. Department of Energy, *Pathways to Commercial Liftoff: Clean Hydrogen* (March 2023), <https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf> [hereinafter “Liftoff”].

<sup>154</sup> *Id.* at 23, Figure 8.



**Table 1. Technology breakdown of announced hydrogen production projects slated to come online between 2020 and 2035<sup>155</sup>**

| New Capacity by 2035                |               |                        |               |              |       |      |       |
|-------------------------------------|---------------|------------------------|---------------|--------------|-------|------|-------|
|                                     | ATR w/<br>CCS | Gasification<br>w/ CCS | SMR w/<br>CCS | Electrolysis | Waste | SMR  | Total |
| Capacity (thousand tonnes per year) | 4220          | 319                    | 4029          | 4477         | 268   | 1280 | 14592 |
| Percentage                          | 29%           | 2%                     | 28%           | 31%          | 2%    | 9%   | 100%  |

### E. Hydrogen Production Methods

Hydrogen (H<sub>2</sub>) is produced for industrial purposes by breaking down compounds that contain it, such as water, methane, or other hydrocarbons. Several pathways can be used to produce hydrogen, including splitting water by electrolysis; biological production from biomass; and thermochemical production from fossil fuels or biomass. Electrolysis using new, hourly-matched, and regional clean electricity and biological processes produce relatively minimal direct emissions, whereas thermochemical production methods have greater potential for direct emissions of NO<sub>x</sub>, methane, CO<sub>2</sub>, and other pollutants and greenhouse gases.

The U.S. government aspires to promote hydrogen production through clean pathways with minimal emissions, such as water electrolysis with renewable or other low-carbon electricity. However, most hydrogen used in the U.S. is currently produced through steam methane reforming of natural gas, which has significant emissions. Other thermochemical methods, including autothermal reforming of natural gas and coal or combined coal and biomass gasification can also have high emissions. As shown in Table 1 above, more than two-thirds of projected hydrogen production capacity through 2035 is expected to come from these high-polluting, fossil fuel-based methods.

#### Steam Methane Reforming (SMR)

SMR proceeds in several steps, starting with gas cleaning to remove sulfur and other impurities that would poison the catalysts in the reformer. In the pre-reformer stage, natural gas is heated to about 500 °C and mixed with steam to react over a catalyst, converting CH<sub>4</sub> and higher hydrocarbons in the natural gas mixture to CO and H<sub>2</sub>.<sup>156</sup> The reformer itself uses a steam and methane mixture at high temperature (~900 °C) and pressure (~2.8 MPa) in the presence of a nickel catalyst to convert methane (CH<sub>4</sub>) and water to CO and H<sub>2</sub>, a mixture known as syngas<sup>157</sup>:

<sup>155</sup> Attachment B (presenting data extracted by EDF in July 2023 from Rystad Hydrogen Cube Browser version 2.6.14).

<sup>156</sup> Lewis 2022, *supra* note 5.

<sup>157</sup> *Id.*

*Steam-methane reforming reaction*  $CH_4 + H_2O \rightarrow CO + 3H_2, \Delta H_r^\circ = 206 \text{ kJ/mol}$

In the reformer, the steam and natural gas mixture flows through steel-alloy tubes containing the catalyst that are heated by natural gas burners, with NO<sub>x</sub> and CO<sub>2</sub> produced in the combustion process. Low-NO<sub>x</sub> burners, flue gas recirculation and selective catalytic reduction can be used to reduce NO<sub>x</sub> emissions.<sup>158</sup> Heat can be recovered from the reformer flue gas in a convective heat exchanger and used for natural gas and steam preheating to improve process efficiency.

In the next stage, the carbon monoxide is reacted with steam over a catalyst to produce CO<sub>2</sub> and more hydrogen:<sup>159</sup>

*Water-gas shift reaction*  $CO + H_2O \rightarrow CO_2 + H_2, \Delta H_r^\circ = -41 \text{ kJ/mol}$

The mixture of CO<sub>2</sub> and H<sub>2</sub> from the water-gas shift reaction is cooled, and then in most SMR facilities, the CO<sub>2</sub> and other impurities are separated from the hydrogen through a process called pressure-swing adsorption (PSA). Tail gas from the adsorption process that is H<sub>2</sub>-rich but doesn't meet purity specifications is largely routed back to the reformer. In the final production step, purified H<sub>2</sub> is compressed for storage or transport. Some older SMR facilities use an amine solvent to separate CO<sub>2</sub> from the H<sub>2</sub> in place of the PSA process.<sup>160</sup>

Depending on the plant design and operating conditions, ammonia, as well as methanol and other VOCs, can be produced as byproducts of the reforming reactions and absorbed in steam condensate. These contaminants are stripped from the condensate and can be recycled to the reformer, but some fraction may also be released to the atmosphere through deaerator vents.<sup>161</sup> Gas venting during startup, shutdown, and maintenance activities, and leaks from valves, flanges, and connectors are also potential sources of volatile and/or toxic organic compounds, methane, and hydrogen emissions. Hydrogen production facilities that use evaporative cooling towers may also have significant drift emissions of particulate matter, depending on cooling tower design and source water characteristics.<sup>162</sup>

About 60% of the CO<sub>2</sub> produced in SMR comes from the steam-methane reforming and water-gas shift reaction in a high partial pressure process (synthesis gas) stream that can be relatively readily captured.<sup>163</sup> The rest of the CO<sub>2</sub> is present at lower partial pressure from the combustion

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<sup>158</sup> *Id.*; Hensley Energy Consulting, Report on CO<sub>2</sub> Abatement Opportunities at Existing Industrial Hydrogen and Ammonia Production Plants (January 2023) (submitted as Attachment C) [hereinafter "Hensley 2023"].

<sup>159</sup> Lewis 2022, *supra* note 5.

<sup>160</sup> Hensley 2023, *supra* note 158.

<sup>161</sup> See, e.g., Environmental Resources Management, Air Liquide, Rodeo, California, Hydrogen Plant Project Application for Authority to Construct and Major Facility Review Permit (October 2005), <https://www.contracosta.ca.gov/DocumentCenter/View/28467/Fox-Report-Exh-40-Air-Liquide-Hydrogen-Project-Application-and-Permit>.

<sup>162</sup> U.S. EPA, *Compilation of Air Pollutant Emissions Factors, AP-42*, Fifth Edition, Chapter 13.4 (January 1995), <https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors>.

<sup>163</sup> Lewis 2022, *supra* note 5.

of natural gas or tail gas with air in the furnace burners, and as such is somewhat more costly to capture. The CO<sub>2</sub> coming out of the shift reaction can be separated from the H<sub>2</sub> in the synthesis gas stream using a packed absorption tower with a selective solvent, using either chemical or physical absorption.<sup>164</sup> After removing the CO<sub>2</sub> from the synthesis gas stream, the solvent would be regenerated in a steam reboiler to remove the CO<sub>2</sub> by fractionation. The captured CO<sub>2</sub> would then be sent to a compressor for pipeline transport or storage. In an SMR system without CO<sub>2</sub> capture, the CO<sub>2</sub> present in the tail gas helps limit NO<sub>x</sub> emissions from the reformer by reducing the flame temperature in the furnace. If CO<sub>2</sub> is removed prior to routing the tail gas back to the reformer furnace, the potential for increased NO<sub>x</sub> emissions must be addressed, using NO<sub>x</sub> control methods such as flue gas recirculation or selective catalytic reduction.<sup>165</sup>

To increase CO<sub>2</sub> recovery beyond the portion coming from the process stream, the combustion flue gas also needs to be addressed. A system designed for post-combustion CO<sub>2</sub> capture requires a chemical solvent and a more involved stripping/regeneration process, due to the low concentration of CO<sub>2</sub> in the flue gas.<sup>166</sup> If tail gas from the shift reaction has been routed to the reformer, post-combustion removal systems will address both process and combustion-generated CO<sub>2</sub>. Overall CO<sub>2</sub> capture rates of 90% are commonly assumed in environmental assessment studies of SMR with CCS.<sup>167</sup> Proposed new projects with carbon capture reviewed by Lewis et al. (2022) target 94.2 to 98.7% capture rates,<sup>168</sup> and the IEA finds that with post-combustion capture technology, over 90% capture can be achieved in an integrated SMR system with a relatively low energy penalty.<sup>169</sup> However, the small number of SMR facilities that currently employ carbon capture typically achieve only 50–60% plant-wide capture rates, indicating that regulatory standards would be required for wide scale achievement of higher capture rates.<sup>170</sup> It is also worth noting that with CCS applied to hydrogen production, the steam required for solvent regeneration and electricity needed for CO<sub>2</sub> compression can typically be recovered from the hydrogen production process, minimizing additional energy requirements, (although with reduced opportunities for steam or electricity exports).<sup>171</sup>

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<sup>164</sup> IEAGHG, *Low-Carbon Hydrogen from Natural Gas: Global Roadmap*, Report # 2022-07 (2022), [www.ieaghg.org](http://www.ieaghg.org).

<sup>165</sup> Hensley 2023, *supra* note 158.

<sup>166</sup> Lewis 2022, *supra* note 5.

<sup>167</sup> Riemer & Duscha, *Carbon Capture in Hydrogen Production – Review of Modelling Assumptions*, *Fraunhofer Institute for Systems and Innovation Research*, Energy Proceedings, ISSN 2004-2965 (2022), <https://publica-rest.fraunhofer.de/server/api/core/bitstreams/77ec29e5-4af8-4812-9793-8501f92a6f8d/content> [hereinafter “Riemer & Duscha”].

<sup>168</sup> Lewis 2022, *supra* note 5.

<sup>169</sup> International Energy Agency (IEA), *Global Hydrogen Review 2022* (Sept. 2022), <https://www.iea.org/reports/global-hydrogen-review-2022>.

<sup>170</sup> Riemer & Duscha, *supra* note 167; Lewis 2022, *supra* note 5. A DOE-supported CCS project at the Vallerio Port Arthur Refinery is reported to have captured more than 90% of CO<sub>2</sub> from the product streams of two SMR units that were retrofit with vapor swing adsorption in 2013. Overall capture rates for the facility were not reported in the DOE notice. DOE, *DOE-Supported CO<sub>2</sub>-Capture Project Hits Major Milestone: 4 Million Metric Tons* (Oct. 2017), <https://www.energy.gov/fecm/articles/doe-supported-co2-capture-project-hits-major-milestone-4-million-metric-tons>.

<sup>171</sup> Bauer 2022, *supra* note 150.

Post-combustion CO<sub>2</sub> capture is typically accomplished with amine-based scrubbing, most commonly using monoethanolamine (MEA). This process entails potential loss of the amine solvent and its degradation products to the environment, either through flue gas emissions or wastewater streams.<sup>172</sup> Studies of amine-based post-combustion capture systems have also shown potential for emissions or environmental formation of nitrosamines, among other oxidation products.<sup>173</sup> The potential for amine slip and related emissions needs to be strictly limited and managed during both routine operations and start-up, shut-down, and other intermittent conditions through system design, solvent purity controls, and emissions and discharge monitoring requirements.<sup>174</sup>

Hensley Energy Consulting developed preliminary capital and operating cost estimates for retrofitting hydrogen production facilities with carbon capture based on published studies and internal confidential data, assuming a Gulf Coast location. Future, “nth of a kind” costs for carbon capture ranged from \$35 per short ton of captured CO<sub>2</sub> for systems placed upstream of the PSA unit with 50% overall capture effectiveness to \$55 per short ton of captured CO<sub>2</sub> for post-combustion or combined systems with 90% to 96% overall capture effectiveness.<sup>175</sup>

As an alternative to CO<sub>2</sub> capture, use of electricity instead of natural gas for process heat in the reformer has been demonstrated at lab scale as a method to eliminate the burner NO<sub>x</sub> and post-combustion CO<sub>2</sub> emissions and reduce the size of the reformer.<sup>176</sup> Electrification of the reforming process, if based on low-emissions electricity, could sharply reduce NO<sub>x</sub> emissions and reduce direct CO<sub>2</sub> emissions by about one-third.<sup>177</sup> The extent to which electrification would reduce emissions would vary depending on the marginal emission rate of the grid supplying the electricity. As discussed in the next section, plants can also be designed to use autothermal reforming as an alternative to SMR to avoid using fuel combustion for process heat and thus reduce CO<sub>2</sub> emissions intensity.

### **Autothermal Reforming (ATR)**

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<sup>172</sup> Reynolds et al., *Towards Commercial Scale Postcombustion Capture of CO<sub>2</sub> with Monoethanolamine Solvent: Key Considerations for Solvent Management and Environmental Impacts*, 46 *Env. Sci. & Tech.* 3643-3654 (2012) <https://pubs.acs.org/doi/10.1021/es204051s> [hereinafter “Reynolds 2012”]; Veltman et al., *Human and Environmental Impact Assessment of Postcombustion CO<sub>2</sub> Capture Focusing on Emissions from Amine-Based Scrubbing Solvents to Air*, 44 *Env. Sci. & Tech.* 1496-1502 (2010), <https://pubs.acs.org/doi/10.1021/es902116r>.

<sup>173</sup> Nielsen et al., *Atmospheric Chemistry and Environmental Impact of the Use of Amines in Carbon Capture and Storage (CCS)*, 41 *Chem. Soc. Rev.* 6684-6704 (2012), <https://pubs.rsc.org/en/content/articlelanding/2012/cs/c2cs35059a>.

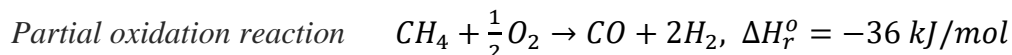
<sup>174</sup> Reynolds 2012, *supra* note 172.

<sup>175</sup> Hensley 2023, *supra* note 158, Table 8. The “central” (at a 3% discount rate) value of the Interagency Working Group’s social cost of carbon is \$55 in 2024 and only increases thereafter, demonstrating these controls are cost-effective solely based on CO<sub>2</sub> reductions. EPA’s own social cost of carbon numbers are far higher: between \$128 and \$356 for 2024 and increasing thereafter.

<sup>176</sup> Wismann et al., *Electrified methane reforming: a compact approach to greener industrial hydrogen production*, 365 *Science* 756-759 (2019), <https://www.science.org/doi/10.1126/science.aaw8775>.

<sup>177</sup> IEA 2022, *supra* note 19.

ATR is an alternative process for converting natural gas to hydrogen, without the use of supplemental natural gas for process heat. ATR is anticipated to become more common in the future due to better economies of scale compared to SMR.<sup>178</sup> In an ATR system, partially reformed natural gas from the pre-reformer is mixed with oxygen in a partial oxidation step, where methane and oxygen react to produce CO, H<sub>2</sub>, and heat:<sup>179</sup>



The heat from this reaction drives the steam-methane reforming reaction in a fixed bed catalytic section.<sup>180</sup> The syngas from the reformer is then processed through the shift reactor and pressure swing adsorber in a manner similar to that used for SMR.

With ATR, NO<sub>x</sub>, and CO<sub>2</sub> emissions per unit of H<sub>2</sub> production are reduced due to the elimination of natural gas burners for process heat. CO<sub>2</sub> capture is facilitated because only the post-shift capture system is required. However, the tradeoff in cost and complexity with ATR is that it requires an energy-intensive cryogenic air separation unit to produce the oxygen needed in the partial oxidation step. Emissions of CO<sub>2</sub>, NO<sub>x</sub> and other pollutants associated with electricity production for the air separation step need to be addressed in considering net emissions from ATR. According to the IEA, new facilities planning to use ATR with CO<sub>2</sub> capture include the Stanlow Refinery and Saltend projects in the United Kingdom, the Barents Blue Ammonia project in Norway, and the Dakota H<sub>2</sub> Hub in the U.S.<sup>181</sup>

### **Coal and/or Biomass Gasification**

Coal gasification accounts for almost 20% of hydrogen production worldwide, with most of that occurring in China.<sup>182</sup> This technology has also been proposed for use with biomass or petroleum coke, or a combination of these three feedstocks. The process of hydrogen production from coal gasification proceeds by reacting coal with an oxidizer (typically oxygen) and steam in a gasifier to produce syngas comprised of CO and H<sub>2</sub>, followed by the water-gas-shift reaction to convert CO and water to CO<sub>2</sub> and H<sub>2</sub>.<sup>183</sup> Oxygen-blown, entrained-flow gasifiers are commonly used, requiring an air separation unit to provide the oxygen as part of the process, as well as an acid gas removal step to capture H<sub>2</sub>S and other contaminants. Coal gasification entails significant emissions of particulate matter, from coal handling and preparation steps as well as the gasifier unit. Part of the coal ash is removed from the gasifier in dry ash form and part as slag, with the balance depending on gasifier design.<sup>184</sup> Mercury removal with activated carbon may also be

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<sup>178</sup> Bauer 2022, *supra* note 150.

<sup>179</sup> Lewis 2022, *supra* note 5.

<sup>180</sup> *Id.*

<sup>181</sup> IEA 2022, *supra* note 19.

<sup>182</sup> *Id.*

<sup>183</sup> Lewis 2022, *supra* note 5.

<sup>184</sup> *Id.* at 25.

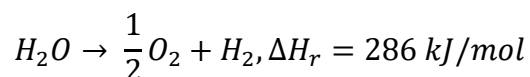
required;<sup>185</sup> vanadium and nickel recovery may be necessary with petroleum coke.<sup>186</sup> As with ATR, separation of CO<sub>2</sub> is facilitated by the relatively high concentration of CO<sub>2</sub> exiting the water-gas-shift reactor, allowing use of physical solvents such as Selexol that are less costly to regenerate than chemical absorbents. Hydrogen can also be produced through gasification of biomass or a combination of coal and biomass. According to IEA, the first commercial biomass gasification plant to produce H<sub>2</sub> with CO<sub>2</sub> capture may start operation in California in 2025.<sup>187</sup>

### Catalytic (Naphtha) Reforming

At petroleum refineries, an alternative means of producing hydrogen is through reforming naphtha, a heavier portion of crude oil that needs to be reformed into lighter components that are blending stocks for gasoline. The hydrogen by-product is used in other refining processes.

### Water Electrolysis

Water provides a large resource for hydrogen, but water splitting requires a substantial energy input, with significant associated upstream emissions if the required electricity is not produced from clean sources. According to IEA (2022), water electrolysis accounted for only ~0.1% of global hydrogen production in 2021, although a rapid scale-up is anticipated. In electrolysis, an electric current is passed through water in an electrolytic cell to split the hydrogen from the oxygen. The overall reaction is:



The energy required for this endothermic reaction is very high, so while electrolysis plants have negligible process emissions, the source of the supplied electricity and the amount of electricity required per unit of hydrogen production are critical in determining lifecycle emissions. DOE (2023) estimates that hydrogen produced from grid electricity could have emissions intensities of 20 to 40 kg CO<sub>2</sub>e/kg H<sub>2</sub>, while electrolytic hydrogen produced with clean electricity that is additional and hourly and geographically matched to demand would have intensities below 0.45 kg CO<sub>2</sub>e/kg H<sub>2</sub>.<sup>188</sup> According to IEA (2022), globally about 70% of current electrolysis facilities use alkaline electrolyte systems, which operate at relatively low temperature and use a liquid alkaline solution of sodium or potassium hydroxide.<sup>189</sup> Low-temperature polymer electrolyte (also known as “proton exchange”) membrane (PEM) technology comprises most of the balance. High temperature solid oxide electrolysis cell (SOEC) systems with ceramic electrolytes are considered an emerging technology. SOEC systems can reduce electricity requirements by

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<sup>185</sup> *Id.* at 140.

<sup>186</sup> Murthy et al., *Petroleum Coke Gasification: A Review*, 92 *Canadian J. of Chem. Engineering*, 441–468 (2012), <https://onlinelibrary.wiley.com/doi/abs/10.1002/cjce.21908>; Schlesinger et al., *Global Biochemical Cycle of Vanadium*, *PNAS*, E11092-E11100 (2017), [www.pnas.org/cgi/doi/10.1073/pnas.1715500114](http://www.pnas.org/cgi/doi/10.1073/pnas.1715500114).

<sup>187</sup> IEA 2022, *supra* note 19.

<sup>188</sup> Liftoff, *supra* note 153, at 10, Figure 2.

<sup>189</sup> IEA 2022, *supra* note 19.

supplying part of the required energy as heat.

## **F. Emissions from Hydrogen Production**

As introduced above, current hydrogen production in the U.S. directly produces emissions of CO<sub>2</sub>, NO<sub>x</sub>, VOC, PM, and HAPs at the production facility, with additional emissions upstream from natural gas production, processing, transmission, storage, and distribution. Published literature and public databases enable partial quantification of the emissions associated with current hydrogen production, although the picture is incomplete due to different reporting streams for greenhouse gas emissions from captive (non-merchant) production at refineries<sup>190</sup> and challenges in allocating emissions at plants that produce multiple industrial chemicals or that export steam or electricity. Reporting of direct emissions from hydrogen production facilities also omits the contributions of upstream emissions from the production, processing, transmission, storage, and distribution of natural gas and other fossil fuel feedstocks. There is also uncertainty in the accuracy and representativeness of emissions reported through existing programs, especially with respect to HAPs. The review of literature and data provided below is therefore offered as a starting point for estimating the magnitude of emissions from the hydrogen production sector, with the caveat that it focuses on direct emissions at merchant facilities.

### **Published Emissions and Emission Factor Estimates for Existing Steam Methane Reforming Plants**

Sun et al. (2019) summarized emissions of criteria pollutants and greenhouse gases from SMR hydrogen production facilities in the U.S. circa 2014.<sup>191</sup> They focused on merchant hydrogen production plants for which emissions were reported in EPA's 2014 National Emissions Inventory (NEI) and its Greenhouse Gas Reporting Program (GHGRP). Approximately 30 facilities were identified for which emissions were included in both data sets. The facilities cover a wide range of sizes, and consequently a wide range of emissions. Excluding facilities that co-produce other chemicals, Sun et al. show 2014 NEI-reported emissions for hydrogen production facilities ranging from 0.5 to 42 metric tons of VOCs per year (metric tpy); 1.3 to 477 metric tpy NO<sub>x</sub>; 0.1 to 51 metric tpy SO<sub>2</sub>; and 0.6 to 88 metric tpy PM<sub>2.5</sub>. Greenhouse gas emissions they report from 2014 GHGRP data range from 24,900 to 2.6 million metric tpy of CO<sub>2</sub>.<sup>192</sup> Sun et al. did not report emissions of HAPs.

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<sup>190</sup> The GHGRP Subpart Y Petroleum Refineries source category includes non-merchant hydrogen plants (those owned or under the direct control of the refinery owner and operator. 40 C.F.R. § 98.250. *See also* EDF Comments on Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule at 12-14 (Oct. 6, 2022), <https://blogs.edf.org/energyexchange/wp-content/blogs.dir/38/files/2022/10/EDF-GHGRP-Comments-10.6.2022-Final.pdf>.

<sup>191</sup> Sun et al., *Criteria air pollutants and greenhouse gas emissions from hydrogen production in U.S. steam methane reforming facilities*, 53 *Env. Sci. Tech.* 7103-7113 (2019), <https://pubs.acs.org/doi/10.1021/acs.est.8b06197> [hereinafter "Sun 2019"].

<sup>192</sup> *Id.* at Table S2.

Estimates of emissions normalized to production volume are of interest for environmental impact assessments and prediction of future emissions potential. Because annual hydrogen production volumes are often treated as confidential business information, Sun et al. estimated emissions per unit H<sub>2</sub> production using four different databases and approaches: 1) direct reporting to EPA’s Chemical Reporting Database for the 2011 production year matched with 2011 NEI and GHGRP emissions; 2) estimating production based on plant capacity with an 80% utilization rate; 3) estimating H<sub>2</sub> production from reported CO<sub>2</sub> emissions using a ratio of 9.0 kg CO<sub>2</sub>/kg H<sub>2</sub>; and 4) for a few facilities, using directly reported H<sub>2</sub> production and emissions for 2016.<sup>193</sup> Median estimates of emission rates per MJ H<sub>2</sub> produced are shown in Table 2, but the authors note that emissions rates vary widely by facility. For CO<sub>2</sub>, the estimates developed by Sun et al. are in accord with the range of 62.5–83.3 g CO<sub>2</sub>/MJ H<sub>2</sub> the authors found in their review of the literature.<sup>194</sup> Approximately 30% of the CO<sub>2</sub> emissions are assumed to come from combustion for process heat, with most of the balance from the shift reaction in the CH<sub>4</sub> reforming process.<sup>195</sup>

**Table 2. Estimated national median and California median emissions rates for SMR facilities from Sun et al. (2019) Tables S6 and S7.**<sup>196</sup>

(Emissions for criteria pollutants and greenhouse gases normalized by hydrogen production in MJ (assuming a lower heating value of 120 MJ/kg). Criteria pollutant emissions factors are derived from NEI data; those for CO<sub>2</sub>e from GHGRP data.)

| Pollutant         | Emissions Rate (mg/MJ H <sub>2</sub> )<br>(# of facilities) |              |                 |                  |                   |                 | Emissions Rate (g CO <sub>2</sub> e /MJ H <sub>2</sub> ) (# of facilities) |
|-------------------|---|--------------|-----------------|------------------|-------------------|-----------------|--|
|                   | VOC   | CO           | NO <sub>x</sub> | PM <sub>10</sub> | PM <sub>2.5</sub> | SO <sub>2</sub> | CO <sub>2</sub> e  |
| National Median   | 1.70<br>(32)  | 2.18<br>(32) | 6.26<br>(32)    | 2.08<br>(32)     | 1.97<br>(32)      | 0.11<br>(31)    | 77.78<br>(36)  |
| California Median | 0.75<br>(7)   | 1.45<br>(7)  | 1.95<br>(7)     | 1.12<br>(7)      | 1.17<br>(7)       | 0.16<br>(7)     | 76.07<br>(6)   |
| Literature Review |   |              |                 |                  |                   |                 | 62.5 – 83.3  |

While Sun et al. derived the emissions factors in Table 2 from a subset of facilities used to produce hydrogen, the emissions factors can be used to roughly estimate total direct emissions for hydrogen production more broadly, assuming SMR without carbon capture dominates production. Using the values from Table 2 with an approximate 10 million metric tons or 1.2 x 10<sup>12</sup> MJ of current H<sub>2</sub> production in the U.S. from captive as well as merchant plants, we

<sup>193</sup> See *id.*

<sup>194</sup> *Id.*

<sup>195</sup> *Id.*

<sup>196</sup> Emissions of methane and nitrous oxide were converted from reported CO<sub>2</sub>-e emissions using factors for Global Warming Potential (GWP) based on a 100-year time horizon as reported in the IPCC AR4 assessment report (i.e., a GWP of 25 for methane and 298 for nitrous oxide), consistent with EPA FLIGHT.



estimate total annual emissions of 2,000 metric tons (approximately 2,200 short tons) of VOCs, 7,500 metric tons (approximately 8,300 short tons) of NO<sub>x</sub>, 2,400 metric tons (approximately 2,600 short tons) of primary PM<sub>2.5</sub> and 93 million metric tons of CO<sub>2</sub>e.

### **Recent Emissions from Existing Hydrogen Production Facilities**

To update the emissions information reported by Sun et al., we compiled 2020 emissions data for merchant hydrogen production plants in the U.S. The list of merchant SMR facilities in Sun et al. Table S2 was used as a starting point to help identify and cross-check facilities. We downloaded 2020 data for greenhouse gas emissions from EPA's Facility-Level Information on Greenhouse Gases Tool (FLIGHT) for hydrogen production facilities reporting to the GHGRP, including CO<sub>2</sub>, methane, and N<sub>2</sub>O emissions, as well as total CO<sub>2</sub>e emissions.<sup>197</sup> Data for hydrogen production (Subpart P of the GHGRP) and stationary combustion (Subpart C) were included for facilities in Sun et al. Table S2 and any newer facilities that reported only under GHGRP Subparts P and C.<sup>198</sup> We then downloaded 2020 facility-level criteria and hazardous air pollutant emissions data from EPA's National Emissions Inventory (NEI) for these same merchant facilities, confirming that they were identified with NAICS Code 325120 (Industrial Gas Manufacturing) or another relevant NAICS Code.<sup>199</sup> We checked 2014 EPA NEI and GHGRP data reported in Sun et al. Table S2 to confirm facility-identifying data for these plants (e.g., name, address, ID, etc.).<sup>200</sup> For the California hydrogen plants we also downloaded 2020 criteria and hazardous air pollutant data from CARB's Pollution Mapping Tool.<sup>201</sup>

Table 3 provides a statistical summary of the emissions information, including the number of facilities for which emissions information was included for each pollutant, the range of emissions, and the median level of emissions. (Note that the entries for criteria and hazardous air pollutants are in U.S. short tons and those for CO<sub>2</sub> are metric tons, in keeping with the original data.) The full set of compiled information, including data from both the EPA and CARB databases, are presented in Attachment D. The ranges found in the compiled NEI, GHGRP and CARB data for 2020 and shown in Table 3 are generally consistent with those reported by Sun et

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<sup>197</sup> *Id.*

<sup>198</sup> 40 C.F.R. Part 98, Subpart P – Hydrogen Production applies to hydrogen producers that emit more than 25,000 tons per year of GHG emissions and “produce hydrogen gas sold as product to other entities.” The source category “includes merchant hydrogen production facilities located within another facility if they are not owned by, or under the direct control of, the other facility's owner and operator.” 40 C.F.R. § 98.160. Subpart P requires reporting CO<sub>2</sub> from each hydrogen production process unit under subpart P, and reporting under Subpart C the CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each stationary combustion unit other than hydrogen production process units. *Id.* § 98.162. Note that reporting is apparently not required for methane emissions other than those from stationary combustion units, so fugitive or vented methane may not be included. We omitted facilities that also reported under other GHGRP subparts, such as Subpart Y for petroleum refineries.

<sup>199</sup> EPA NEI facility-level data were found in the: (1) Facility-level By Pollutant dataset; and (2) Facility Mapping query.

<sup>200</sup> We were able to confirm 2014 EPA NEI and GHGRP data for all but two facilities in Sun 2019, *supra* note 191, Table S2.

<sup>201</sup> CARB Pollution Mapping Tool (v2.6), <https://www.arb.ca.gov/carbapps/pollution-map/> (Facility Search = “hydrogen plant”).

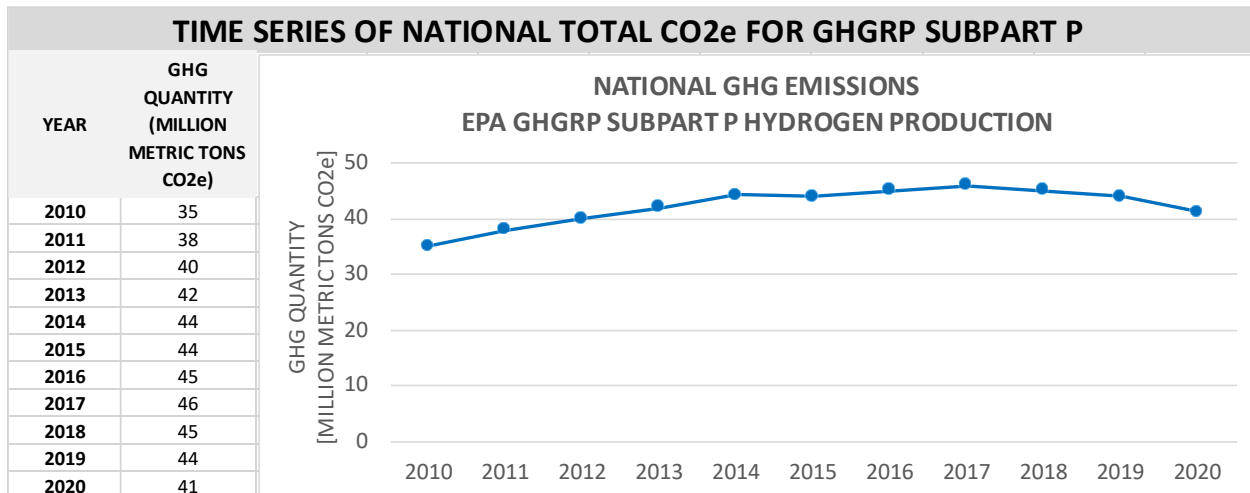
al. for the year 2014.<sup>202</sup> Figure 2 provides a time series plot of greenhouse gas emissions from merchant hydrogen production facilities that reported under GHGRP Subpart P from 2010 to 2020. Data shown in Figure 2 are a fraction of total greenhouse gas emissions from hydrogen production, since they are limited to direct emissions at merchant facilities.<sup>203</sup> As shown in Figure 2, Subpart P-reported greenhouse gas emissions have averaged about 40 million metric tons CO<sub>2</sub>e each year over the decade from 2010 to 2020.

**Table 3**

|        | VOC<br>[SHORT<br>TONS] | NO <sub>x</sub><br>[SHORT<br>TONS] | SO <sub>2</sub><br>[SHORT<br>TONS] | PM <sub>2.5</sub><br>[SHORT<br>TONS] | Hexane<br>[LBS] | Methanol<br>[LBS] | CO <sub>2</sub><br>[METRIC<br>TONS] |
|--------|------------------------|------------------------------------|------------------------------------|--------------------------------------|-----------------|-------------------|-------------------------------------|
| Count  | 29                     | 29                                 | 29                                 | 29                                   | 19              | 22                | 43                                  |
| Min    | 0.4*                   | 0.3*                               | 0.0003*                            | 0.01*                                | 0.8             | 0.001             | 28,855                              |
| Max    | 31                     | 328                                | 51                                 | 87                                   | 8,498           | 20,379            | 2,422,230                           |
| Median | 13                     | 30                                 | 0.3                                | 10                                   | 771             | 1,979             | 377,657                             |

\*These are the minimum values reported in the NEI database among 29 hydrogen production facilities. However, emissions from this same facility reported in the CARB database are 6, 19 0.6, and 2 tons per year for VOC, NO<sub>x</sub>, SO<sub>2</sub> and PM<sub>2.5</sub>, respectively. We did not have information to reconcile the discrepancy, so are reporting the values in the table as found in the NEI.

**Figure 2. Greenhouse gas emissions for merchant hydrogen production facilities as reported under GHGRP Subpart P.<sup>204</sup>**



<sup>202</sup> The comparison accounts for the difference in U.S. versus metric units for the criteria pollutant tabulations.

<sup>203</sup> The GHGRP Subpart Y Petroleum Refineries source category includes non-merchant hydrogen plants (those owned or under the direct control of the refinery owner and operator. 40 C.F.R. § 98.250.

<sup>204</sup> Emissions of methane and nitrous oxide were converted from reported CO<sub>2</sub>-e emissions using factors for Global Warming Potential (GWP) based on a 100-year time horizon as reported in the IPCC AR4 assessment report (i.e., a GWP of 25 for methane and 298 for nitrous oxide), consistent with EPA FLIGHT.

Emissions of HAPs reported for hydrogen production facilities in the NEI are highly variable, with some facilities not reporting HAPs at all. The emissions reported in the greatest quantities are n-hexane and methanol, with median emissions of 771 and 1,979 pounds per year, respectively. Excluding facilities that we identified as co-producing other chemicals, the maximum methanol emissions of 20,379 pounds per year would classify that facility as a major source of HAPs. Because nickel and chromium are used as catalysts in the steam reforming process, we also examined NEI-reported emissions for nickel and hexavalent chromium. Nickel emissions were reported by 10 facilities not identified as co-producing other chemicals, with maximum emissions of seven pounds per year. Hexavalent chromium emissions were reported by nine non-co-producing facilities with a maximum report of 0.6 pounds per year. As indicated in the attachment, some facilities identified as co-producing hydrogen with other chemicals had higher emissions of nickel and hexavalent chromium, but we did not determine if those emissions are associated with hydrogen production or other products. An air toxics health risk assessment completed for the Air Liquide El Segundo Hydrogen plant found maximum “offsite” cancer risks of 7.1 per million for a 30-year exposure, with diesel particulate matter from internal combustion engines and hexavalent chromium from the reformer heater identified as the primary cancer risk drivers.<sup>205</sup> The health risk assessment report listed hexavalent chromium emissions of 0.23 pounds per year for this facility in 2016.<sup>206</sup>

### **Modeled Emissions Estimates for Alternative Technologies at New Facilities**

Lewis et al. (2022)<sup>207</sup> developed performance and cost estimates for greenfield hydrogen production using current commercial technologies: SMR and ATR with natural gas, and coal or coal/biomass gasification, with and without CCS. (Lewis et al. were specifically focused on fossil fuel-based technologies, so their study did not include water electrolysis, which would have minimal emissions at the production facility.) Plant performance was simulated using Aspen Plus process modeling software, with energy and material balances used to size equipment for cost estimation. As one of the plant performance metrics, Lewis et al. present the effective thermal efficiency (ETE) of the production process, defined as:

$$ETE = \frac{TP + P_{net}}{TI}$$

where TP is the thermal energy content per unit time of the hydrogen product based on the higher heating value, TI is the thermal energy input to the system per unit time, and Pnet is the gross electrical power produced minus the electrical power used by the system.<sup>208</sup> For most hydrogen production facilities, Pnet will be negative as power is not generated. Production facility emissions of NO<sub>x</sub>, SO<sub>2</sub>, PM, and CO<sub>2</sub> were estimated for each case. In addition, well-to-

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<sup>205</sup> Davenport Engineering, Inc., *Health Risk Assessment RY 2016*, prepared for Air Liquide El Segundo Hydrogen Plant, July 30, 2020.

<sup>206</sup> *Id.*

<sup>207</sup> Lewis 2022, *supra* note 5.

<sup>208</sup> *Id.* at 57.

gate greenhouse gas emissions were estimated, including methane and CO<sub>2</sub> emissions from natural gas, coal, biomass, and electricity production as applicable. The lifecycle estimates do not include emissions associated with plant construction or energy and materials delivery infrastructure. A GWP of 36 was used for methane in the CO<sub>2</sub>e calculation. Table 4 summarizes key plant configuration assumptions, levelized cost of hydrogen, and emissions results for five of the six cases, with the comparatively costly coal/biomass gasification excluded for brevity. The analysis shows that direct CO<sub>2</sub> emissions can be reduced significantly by requiring CCS with SMR, ATR, and gasification technologies, with modest cost increases of 50–55%, and 20% for natural gas reforming and coal gasification, respectively.

**Table 4. Comparison of efficiency, cost, and emissions performance for alternative fossil-fuel based hydrogen production technologies, from Lewis et al. (2022).<sup>209</sup>**

| Technology  | SMR  | SMR w/<br>CCS     | ATR w/ CCS | Coal<br>Gasification | Coal Gasifi-<br>cation w/ CCS |
|---|------|-------------------|------------|----------------------|-------------------------------|
| Fuel  | NG   | NG                | NG         | Illinois # 6 coal    | Illinois # 6 coal             |
| Capacity (tonnes H <sub>2</sub> /day)   | 483  | 483               | 660        | 660                  | 660                           |
| Capacity Factor   | 90   | 90                | 90         | 80                   | 80                            |
| Carbon Capture System   | NA   | MDEA +<br>Cansolv | MDEA       | NA                   | Selexol                       |
| Carbon Capture Rate (%)   | 0    | 96.2              | 94.5       | 0                    | 92.5                          |
| NO <sub>x</sub> Control System  | LNB  | LNB               | LNB        | LNB                  | LNB                           |
| Effective Thermal<br>Efficiency (%)   | 75.4 | 68.4              | 67.9       | 65.0                 | 64.1                          |
| LCOH (\$/kg H <sub>2</sub> )  | 1.06 | 1.64              | 1.59       | 2.58                 | 3.09                          |
| SO <sub>2</sub> emissions (tonne/yr)  | 1.4  | 0                 | 0          | 462                  | 0                             |
| NO <sub>x</sub> emissions (tonne/yr)  | 35   | 31                | 8          | 291                  | 121                           |
| PM emissions (tonne/yr)   | 5    | 0                 | 0          | 123                  | 123                           |
| Hg emissions (tonne/yr)   | 0    | 0                 | 0          | 0.010                | 0.010                         |
| Direct CO <sub>2</sub> emissions<br>(million tonne/yr)                                    | 1.5  | 0.06              | 0.11       | 3.5                  | 0.26                          |
| Direct CO <sub>2</sub> emissions rate<br>(kg CO <sub>2</sub> /kg H <sub>2</sub> )         | 9.3  | 0.4               | 0.5        | 17.9                 | 1.3                           |
| Life Cycle CO <sub>2</sub> e emissions<br>(million tonne/yr)                              | 2.1  | 0.86              | 1.40       | 3.8                  | 0.76                          |
| Life Cycle CO <sub>2</sub> e emissions<br>rate (kg CO <sub>2</sub> -e/kg H <sub>2</sub> ) | 12   | 4.6               | 5.6        | 20                   | 4.1                           |

In addition, Elgowainy, et al. (2022) developed updated estimates of greenhouse gas emissions from hydrogen production for use in the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) 2022 transportation lifecycle analysis model.<sup>210</sup> Their estimates for greenhouse gas emissions from hydrogen production via SMR with and without CCS and for coal gasification with CCS were derived with some adjustments from the mass and energy balance modeling study by Lewis et al.<sup>211</sup> For SMR, Elgowainy et al. allocate part of the emissions to exported steam.

<sup>209</sup> *Id.*

<sup>210</sup> Elgowainy 2022, *supra* note 40.

<sup>211</sup> Lewis 2022, *supra* note 5.

In contrast, the results from Lewis et al. shown in Table 4 and the results from Sun et al. in Table 2 show full emissions attributed to hydrogen production. With the allocation between hydrogen and exported steam, Elgowainy et al. estimate on-site greenhouse gas emissions of 7.6 kg CO<sub>2</sub>e/kg H<sub>2</sub> for SMR without CCS, or 0.4 kg CO<sub>2</sub>e/kg H<sub>2</sub> with CCS (applied to both flue gas and process emissions with an overall capture rate of 96%).<sup>212</sup> In the context of a well-to-gate lifecycle analysis for hydrogen production, Elgowainy et al. (2022) estimate total greenhouse gas emissions, including upstream emissions, of 9.4 to 10.2 kg CO<sub>2</sub>e/kg H<sub>2</sub> for SMR without CCS, or 3.4 to 4.5 kg CO<sub>2</sub>e/kg H<sub>2</sub> with CCS, with the ranges depending on the assumed methane leakage rate upstream.<sup>213</sup> Upstream emissions from natural gas production, processing, transmission, storage, and distribution are clearly critical in accounting for the full impact of hydrogen production.<sup>214</sup>

For coal gasification with CCS, Elgowainy et al. estimated well-to-gate emissions of 2.9 kg CO<sub>2</sub>e/kg H<sub>2</sub>, about half of which occurs on-site at the production facility.<sup>215</sup> For coal gasification, noted differences from Lewis et al.'s analysis include the assumption of a different grid mix for electricity and Elgowainy et al.'s exclusion of emissions from hydrogen product compression.

Elgowainy et al. also present estimates of well-to-gate CO<sub>2</sub> emissions from water electrolysis, excluding emissions associated with manufacturing the electrolyzer. They present estimates for PEM technology powered by low-carbon electricity from nuclear power plants or renewables and from SOEC technology using steam and electricity produced with nuclear power. Well-to-gate life cycle emissions range from 0.0 to 0.4 kg CO<sub>2</sub>e/kg H<sub>2</sub>, with negligible emissions at the electrolysis plant.

Bauer et al. (2022)<sup>216</sup> used a coupled process simulation-lifecycle analysis model to explore the effect of key parameters on well-to-gate CO<sub>2</sub> emissions from natural gas-based hydrogen production. They considered SMR without CCS, SMR with CCS at a 55% CO<sub>2</sub> capture rate (CCS-low) and ATR with CCS at a 90% capture rate (CCS-high), with upstream natural gas (methane) leakage rates ranging from 0.2% to 8%. As shown in Figure 3, with the higher leakage rate, upstream emissions dominate well-to-gate greenhouse gas intensity. Even with the highest CO<sub>2</sub> capture rate and using a 100-year GWP value for methane, with natural gas supply chain leakage of 8%, well-to-gate emissions are estimated at about 9 kg CO<sub>2</sub>e/kg H<sub>2</sub>. In contrast, well-

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<sup>212</sup> Using a LHV of 120 MJ/kg H<sub>2</sub>, these values correspond to 63.33 g CO<sub>2</sub>e/MJ H<sub>2</sub> and 3.33 g CO<sub>2</sub>e/MJ, with and without CCS.

<sup>213</sup> Elgowainy 2022, *supra* note 40, Table 4. CO<sub>2</sub>-equivalent methane emissions are estimated using AR6 GWP estimates for fossil methane.

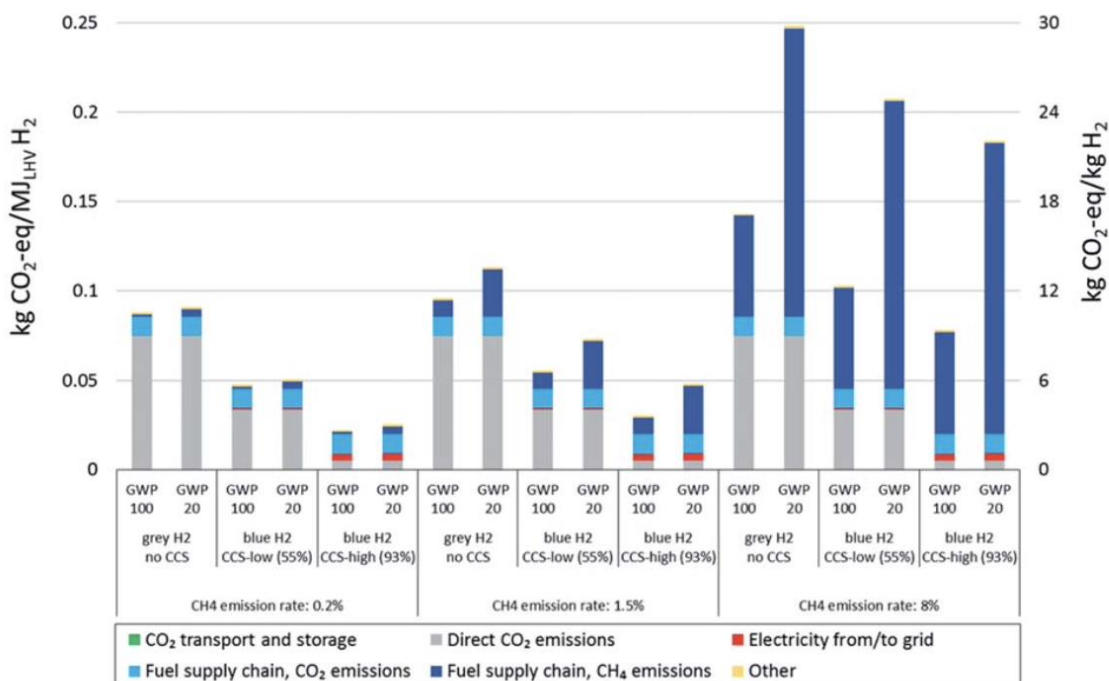
<sup>214</sup> The methane leak rate assumptions in GREET range from 1-2%, which is significantly lower than that reported in observational studies across oil and gas basins, which can be higher than 9%. Chen et al., *Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey*, 56 *Env. Sci. Tech.* 4317 (2022), <https://pubs.acs.org/doi/10.1021/acs.est.1c06458>. A comprehensive national study in 2018 found a nationwide average methane leak rate of 2.3%. Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 361 *Science* 186 (2018), <https://science.sciencemag.org/content/361/6398/186>.

<sup>215</sup> Elgowainy 2022, *supra* note 40, Figure 2.

<sup>216</sup> Bauer 2022, *supra* note 150.

to-gate emissions intensities of 3–4 kg CO<sub>2</sub>e/kg H<sub>2</sub> are achieved with natural gas supply chain leakage of 0.2–1.5%.

**Figure 3. Effect of technology, natural gas supply chain leakage rate, and time horizon of methane GWP on CO<sub>2</sub>e emissions intensities of hydrogen production, reproduced from Bauer et al. (2022).<sup>217</sup>**



### State and Local Emissions Control Requirements for Hydrogen Production Facilities

At present, there are no national emissions standards that apply specifically to merchant hydrogen production facilities.<sup>218</sup> Depending on circumstances, including the other products generated by the same facility or at the same location, equipment and operations at some hydrogen production facilities may be subject to certain NSPS or NESHAPs for other categories of sources, such as petroleum refining<sup>219</sup> or organic chemical manufacturing or service.<sup>220</sup> Some process heaters at hydrogen production facilities should be subject to the requirements of 40 C.F.R. Part 63, Subpart DDDDD, which addresses a subset of HAPs through work practice standards and emissions limitations for specified fuel/combustion technology combinations but does not limit NO<sub>x</sub> or greenhouse gas emissions.<sup>221</sup> These existing regulations are thus limited in

<sup>217</sup> *Id.*

<sup>218</sup> While the GHGRP imposes reporting requirements, it does not require any actions to reduce or limit emissions.

<sup>219</sup> See, e.g., 40 C.F.R. Part 60 Subpart GGG; 40 C.F.R. Part 60 Subpart GGGa; 40 C.F.R. Part 60 Subpart J; 40 C.F.R. Part 60 Subpart Ja; and 40 C.F.R. Part 63 Subpart CC.

<sup>220</sup> See, e.g., 40 C.F.R. Part 63 Subpart G; 40 C.F.R. Part 63 Subpart H.

<sup>221</sup> 40 C.F.R. Part 63 Subpart DDDDD.

their applicability and do not comprehensively cover criteria pollutants, HAPs, or greenhouse gases of concern from hydrogen production facilities. Furthermore, outside of severe and extreme ozone nonattainment areas, most hydrogen production facilities would not be classified as major sources for criteria air pollutants, so federal new source review requirements would also be lacking. The absence of federal regulations that apply across the country to hydrogen production using thermochemical processes is a critical regulatory gap.

In a limited search, petitioners identified regulations that are specifically applicable to hydrogen production facilities from two jurisdictions: California's South Coast Air Quality Management District (SCAQMD) and its Bay Area Air Quality Management District (BAAQMD). These are described below. Information presented from this limited review should not be construed to constrain EPA's consideration of other relevant standards, control methods, or work practice requirements.

### **SCAQMD Rule 1109.1**

In November 2021, the SCAQMD adopted Rule 1109.1 setting new NO<sub>x</sub> and CO emissions limits for combustion equipment at petroleum refineries and facilities with related operations, including hydrogen production plants.<sup>222</sup> The rule applies to 16 existing facilities including 3 merchant hydrogen plants,<sup>223</sup> and is intended to help transition refineries and related facilities from the market-based Regional Clean Air Incentives Market (RECLAIM) to a command and control system based on Best Available Retrofit Control Technology (BARCT).<sup>224</sup> For steam methane reformers, Rule 1109.1 sets emissions limits of 5 parts per million by volume (ppmv) NO<sub>x</sub> and 400 ppmv CO, adjusted for 15% oxygen, on a rolling 24-hour basis.<sup>225</sup> The staff report accompanying the rule indicates the NO<sub>x</sub> limits can be met with selective catalytic reduction (SCR) or a combination of low or ultra-low NO<sub>x</sub> burners and SCR.<sup>226</sup> Rule 1109.1 includes alternative compliance plants, including higher temporary transitional limits and conditional limits for facilities for which required retrofits are not cost-effective. An accompanying change to rule 429.1 provides for exemptions from the NO<sub>x</sub> and CO limits during start up and shutdown operations of limited duration and frequency.<sup>227</sup>

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<sup>222</sup> SCAQMD Rule 1109.1 Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations, South Coast Air Quality Management District, adopted November 5, 2021, <https://www.aqmd.gov/docs/default-source/rule-book/reg-xi/r1109-1.pdf?sfvrsn=8>.

<sup>223</sup> SCAQMD, Rule 1109.1 - NO<sub>x</sub> Emissions From Petroleum Refineries (Home Page), <https://www.aqmd.gov/home/rules-compliance/compliance/1109-1>.

<sup>224</sup> SCAQMD, Final Staff Report, Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Refineries and Related Operations and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries, November 2021.

<sup>225</sup> SCAQMD Rule 1109.1

<sup>226</sup> SCAQMD, Final Staff Report Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Refineries and Related Operations and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries, November 2021, p. 2-45.

<sup>227</sup> SCAQMD Rule 429.1 Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, adopted November 5, 2021, [https://www.aqmd.gov/docs/default-source/rule-book/recent-rules/r429-1-110521.pdf?sfvrsn=10#:~:text=\(A\)%20An%20owner%20or%20operator.combustion%20control%20equipment%20C%20if%20applicable](https://www.aqmd.gov/docs/default-source/rule-book/recent-rules/r429-1-110521.pdf?sfvrsn=10#:~:text=(A)%20An%20owner%20or%20operator.combustion%20control%20equipment%20C%20if%20applicable).

## **SCAQMD Rule 1118**

SCAQMD Rule 1118 requires monitoring and record keeping of flaring operations and has the intent of controlling and minimizing flaring and flare-related emissions.<sup>228</sup> The rule applies to hydrogen production plants that supply petroleum refining operations as well as petroleum refineries themselves and sulfur recovery operations. The rule requires facilities to develop and comply with an approved flare monitoring and recording plan, to conduct specific cause analysis, and to undertake corrective action for flare events exceeding specified thresholds for VOC emissions, SO<sub>2</sub> emissions, total vent gas quantity or visibility limits.

## **SCAQMD Rule 1189**

SCAQMD Rule 1189, which was adopted in January 2000, limits VOC emissions from hydrogen plant process vents. For plants permitted after that date, the rule limits total VOC emissions from all process vents of the plant combined to 0.5 pounds per million standard cubic feet of hydrogen produced. The rule requires annual testing to certify compliance.<sup>229</sup>

## **BAAQMD Rule 13-5**

In May 2022, the BAAQMD adopted Regulation 13: Climate Pollutants Rule 5: Industrial Hydrogen Plants (Rule 13-5) to limit emissions of methane and other organic compounds from hydrogen production plants and hydrogen carrying systems.<sup>230</sup> The rule applies to 8 facilities in the district, including merchant and refinery-captive hydrogen production facilities. The rule sets a total organic compound (TOC) emissions standard for each industrial vent at 15 lb total organic compounds per day and 300 ppmv.<sup>231</sup> Monitoring of TOC emissions and associated operating parameters is required for each vent. The rule sets limited exemptions for deaerator and CO<sub>2</sub> scrubbing vents. According to the accompanying staff report, hydrogen production facilities that only vent gas after processing through a pressure swing adsorption (PSA) system should have minimal venting of methane and organic compound emissions. The staff report found that for most facilities in the Bay Area, hydrogen gases with associated impurities are only vented “when necessary for safety-related reasons,” but that two of the eight facilities in the district “regularly vent hydrogen gas from various atmospheric vents during normal operations.”<sup>232</sup> Prior to

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<sup>228</sup> SCAQMD Rule 1118. Control of Emissions from Refinery Flares, South Coast Air Quality Management District, adopted February 13, 1998, most recently amended January 6, 2023), <http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1118.pdf?sfvrsn=4>.

<sup>229</sup> SCAQMD Rule 1189, Emissions from Hydrogen Plant Process Vents, adopted January 21, 2000, <http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1189.pdf>.

<sup>230</sup> BAAQMD Rule 13-5, Regulation 13 Climate Pollutants Rule 5 Industrial Hydrogen Plants, May 4, 2022, [https://www.baaqmd.gov/~media/dotgov/files/rules/reg-13-rule-5-petroleum-refinery-hydrogen-systems/rule-version/documents/20220504\\_rg1305-pdf.pdf?la=en](https://www.baaqmd.gov/~media/dotgov/files/rules/reg-13-rule-5-petroleum-refinery-hydrogen-systems/rule-version/documents/20220504_rg1305-pdf.pdf?la=en).

<sup>231</sup> BAAQMD Rule 13-5.

<sup>232</sup> BAAQMD Final Staff Report, Proposed New Regulation 13 Climate Pollutants Rule 5: Industrial Hydrogen Plants, and Proposed Amendments to Rule 8, Organic Compounds, Rule 2: Miscellaneous Operations, April 2022, p. 16, [https://www.baaqmd.gov/~media/dotgov/files/rules/reg-13-rule-5-petroleum-refinery-hydrogen-systems/rule-version/documents/20220504\\_fsr\\_1305\\_0802-pdf.pdf?la=en](https://www.baaqmd.gov/~media/dotgov/files/rules/reg-13-rule-5-petroleum-refinery-hydrogen-systems/rule-version/documents/20220504_fsr_1305_0802-pdf.pdf?la=en).



adoption of Rule 13-5, TOC emissions from hydrogen production process vents were only partially addressed under BAAQMD Rule 8-2, which limited precursor organic compounds (not methane) from miscellaneous operations.<sup>233</sup> The staff report found that facilities could comply with the standards in Rule 13-5 by using PSA to purify hydrogen prior to any venting, or by using flares, thermal oxidizers, or closed loop systems.<sup>234</sup>

SCAQMD, BAAQMD and other jurisdictions also have other generally applicable rules that have been applied to hydrogen production facilities. Examples include BAAQMD Rule 8-18 Organic Compounds Rule 18, Equipment Leaks;<sup>235</sup> BAAQMD Rule 8-28 Organic Compounds Rule 28, Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants;<sup>236</sup> and SCAQMD Rule 1173 Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Refineries and Chemical Plants.<sup>237</sup>

#### IV. DISCUSSION & RECOMMENDATIONS

##### **A. EPA Should List Facilities that Produce Hydrogen from Fossil Fuel Feedstocks as Significant Sources of Pollution Under CAA Sections 111 and 112**

As Congress and the Biden-Harris Administration have already recognized through federal research and development funds and tax incentives, the dominant means of hydrogen production must be transitioned as rapidly as possible to efficient water electrolysis using carbon-free electricity. At the same time, recognizing the large number of proposals for new thermochemical production using hydrocarbon feedstocks and the heavy burden of emissions from existing facilities, protective standards are needed for facilities using thermochemical technologies.

Hydrogen production facilities using methane and other hydrocarbon feedstocks represent a category of stationary sources that cause or contribute significantly to air pollution that endangers public health and welfare. Existing hydrogen production facilities already represent significant sources of air pollution and hence warrant applicable emissions standards under section 111(d) and 112. The anticipated scale-up in hydrogen production further heightens the imperative for protective standards under sections 111(b) and 112 for new and modified hydrogen production facilities.

As shown in Tables 2 and 3 above, some existing hydrogen production facilities emit hundreds of tons of NO<sub>x</sub> emissions contributing to health damaging NO<sub>2</sub>, ozone, and PM pollution, and

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<sup>233</sup> *Id.* at 19.

<sup>234</sup> *Id.* at 21.

<sup>235</sup> EPA-Approved Bay Area Air Quality Management District (BAAQMD) Regulations in the California SIP, <https://www.epa.gov/air-quality-implementation-plans/epa-approved-bay-area-air-quality-management-district-baaqmd#doc>.

<sup>236</sup> *Id.*

<sup>237</sup> SCAQMD Rule 1173, Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Refineries and Chemical Plants, adopted July 7, 1989, most recently amended February 6, 2009, <http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1173.pdf?sfvrsn=4>.

tens of tons of VOCs, SO<sub>2</sub>, and primary PM<sub>2.5</sub> that contribute to harmful health effects of ozone and/or PM. Using historical emissions factors per unit of hydrogen production with estimated current production of 10 million metric tons yields estimated current totals of approximately 2,200 short tons of VOC, 8,300 short tons of NO<sub>x</sub>, and 2,600 short tons of PM<sub>2.5</sub>. These quantities of criteria pollutant emissions are greater than the emissions reductions anticipated from other sources for which NSPS have been issued, such as the 2,100 tons per year of NO<sub>x</sub> reductions expected from the NSPS for nitric acid plants adopted in 2012.<sup>238</sup>

EPA is also charged with listing all categories and subcategories of major and area sources of hazardous air pollutants and establishing emissions standards for these categories and subcategories.<sup>239</sup> EPA also has a recurring duty, at least once every eight years, to revise the list of source categories, “if appropriate, in response to public comment or new information.”<sup>240</sup> Hydrogen production facility emissions reported in the NEI indicate that these facilities are sources of multiple HAPs, with methanol and n-hexane emitted in the largest quantities. Some existing hydrogen production facilities appear to qualify as major sources of HAPs, while other existing facilities would be classified as area sources of HAPs based on NEI-reported emissions.

Process simulation studies suggest that future “blue” hydrogen facilities, such as those using SMR with CCS, could still emit tens of tons of NO<sub>x</sub> per facility, while future hydrogen production facilities using coal gasification could individually emit hundreds of tons of NO<sub>x</sub>, SO<sub>2</sub>, and PM. As indicated in Table 1, Rystad Energy’s Hydrogen Cube database of proposed projects indicates that SMR and SMR with CCS projects proposed for completion by 2035 could add another 5.3 million tons per year of hydrogen production. Without regulations to require improved emissions performance, this 50% increase in production could be matched by a 50% increase in emissions of some criteria pollutants. Information on potential HAPs from blue hydrogen facilities appears to be lacking, representing an area where further information collection should be conducted.

The significance of current and anticipated emissions from hydrogen production facilities is heightened by their concentration in environmental justice communities. According to EPA’s ECHO database, 86% of merchant hydrogen production facilities are located in neighborhoods with 2 or more EJScreen indices at the 80<sup>th</sup> percentile or above; 76% are in communities with 6 or more indices at that level; and 41% are in communities with 10 out of the 13 indices at the 80<sup>th</sup> percentile or above. This indicates a remarkable concentration of hydrogen production facilities in environmentally overburdened and/or disadvantaged communities. The DOE’s *Liftoff* report on hydrogen suggests that many proposals for new facilities are concentrated in these same areas.<sup>241</sup>

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<sup>238</sup> 77 Fed. Reg. 48433, 48442 (Aug. 14, 2012).

<sup>239</sup> 42 U.S.C. § 7412(c)(1), (2).

<sup>240</sup> *Id.* § 7412(c)(1).

<sup>241</sup> Liftoff, *supra* note 153, Figure 8

Furthermore, existing hydrogen production facilities collectively emit tens of millions of tons of greenhouse gas emissions on a CO<sub>2</sub>-equivalent basis. As shown above in Figure 2, merchant facilities alone emitted over 40 million tons CO<sub>2</sub>e in the U.S. in 2020. The highest-emitting individual merchant facility that year reported emissions of more than 2 million tons of CO<sub>2</sub>e, comparable to emissions typical of a 300 MW coal-fired power plant.<sup>242</sup> As described above, using historical emissions factors and assuming approximate total current production of 10 million metric tons of hydrogen from captive and merchant plants, we estimate more than 90 million metric tons CO<sub>2</sub>e emissions from current hydrogen production. The few SMR plants that currently use CCS are quoted as achieving 50 to 60% capture rates. If that capture rate is typical of new production facilities in the future, without sufficient regulation or incentives to do better, the next 10 million metric tons of hydrogen production capacity added in the U.S. could add another 40 million metric tons of greenhouse gas emissions annually even if all such facilities are equipped with CCS.

Direct greenhouse gas emissions associated with merchant hydrogen production may be underestimated due to neglect in GHGRP protocols of methane emissions from leaks and venting. Of course, direct emissions are only part of the story, as they exclude upstream methane emissions from production, processing, transmission, storage, and distribution of fossil fuel feedstocks. Elgowainy et al. estimated that upstream emissions increase the greenhouse gas emissions footprint of new hydrogen production from SMR by one-third, based on estimated national average upstream methane leak rates.<sup>243</sup> Bauer et al. found that upstream methane emissions would nearly double the well-to-gate greenhouse gas footprint for new hydrogen production from SMR if natural gas were produced and delivered with an 8% leak rate, assuming a 100-year global warming potential (GWP) for methane.<sup>244</sup> The well-to-gate greenhouse gas footprint is tripled for this scenario if a 20-year GWP is assumed.<sup>245</sup> Climate disruption impacts of hydrogen production are also understated because leakage of hydrogen itself is generally unquantified and effects of this indirect warming agent are not considered in emissions reporting.

Section 111 requires EPA to publish “and from time to time . . . revise” a list of categories of stationary sources that the Administrator finds “cause[] or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.”<sup>246</sup> The emissions reported for existing merchant hydrogen production facilities already demonstrate that this stationary source category should be listed. In addition, given the number and scale of projects announced for development in the coming decade, the source category can be expected to contribute even more significantly in the future.

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<sup>242</sup> As examples, in 2020 the 280 MW Rawhide power plant reported 1.81 million metric tons CO<sub>2</sub> emissions and the 275 MW Hayden power plant reported 2.25 million metric tons CO<sub>2</sub> emissions, according to the Greenhouse Gas Reporting Program Facility Level Information on GreenHouse gases Tool.

<sup>243</sup> Elgowainy 2022, *supra* note 40.

<sup>244</sup> Bauer 2022, *supra* note 150.

<sup>245</sup> *Id.*

<sup>246</sup> 42 U.S.C. § 7411(b)(1)(A).

## B. Standards of Performance for New and Modified Hydrogen Production Facilities

In setting new source performance standards under section 111(b), EPA must look broadly at systems and techniques that may be in use in other, comparable industrial sectors; consider future improvements and refinements in emission reduction systems; and consider systems that are not necessarily in “actual, routine use somewhere” but that will nevertheless be “available for installation at new plants.”<sup>247</sup> From an emissions and environmental standpoint, it is clear that three pillars-compliant water electrolysis using carbon-free electricity is the best way to reduce emissions and would be considered the best system of emissions reduction for hydrogen production. As noted above, Elgowainy et al. estimate lifecycle greenhouse gas emissions of 0.0 to 0.4 kg CO<sub>2</sub>e/kg H<sub>2</sub> for electrolysis with nuclear or renewable electricity, with negligible direct emissions at the electrolysis facility. Globally, the IEA forecasts a rapid scale-up in “green” hydrogen production using electrolysis, bolstered by favorable policy environments in Europe, China, and Australia, as well as the U.S.<sup>248</sup> In the U.S., DOE has awarded a \$504.4 million loan guarantee for the Advanced Clean Energy Storage hydrogen project in Utah, which includes a 220 MW electrolyzer bank using intermittent renewable electricity.<sup>249</sup> EPA’s proposed carbon pollution standards, which designates low-GHG hydrogen co-firing as the BSER for certain electricity generating units lists a number of other electrolysis projects that are moving forward in the U.S.<sup>250</sup> Rystad Energy’s Hydrogen Cube database indicates that over 30% of capacity from new proposals that could come on-line by 2035 are for water electrolysis. These projects and proposals are evidence that water electrolysis should be considered an adequately demonstrated process for hydrogen production.

If, however, EPA were to conclude that hydrogen production from natural gas and other hydrocarbons with CCS should be considered as a possible best system of emission reduction under section 111(b), the agency must set protective standards that minimize emissions of criteria and hazardous air pollutants, as well as greenhouse gas emissions. Specifically, EPA must set protective emissions standards for new and modified facilities that match the level of reductions achievable with SMR or ATR and maximum feasible CO<sub>2</sub> capture rates with permanent sequestration. As discussed above, for SMR facilities, the best system of emission reduction would address both the post-combustion and process CO<sub>2</sub> emissions streams, with overall capture rates of 95% or higher. With ATR facilities, natural gas fired burners for process heat are eliminated so combustion-generated CO<sub>2</sub> is reduced, but high rates of process-generated CO<sub>2</sub> capture must be required. As part of the performance standards for systems involving amine scrubbing, EPA must ensure that amine slip and related emissions are strictly limited with

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<sup>247</sup> *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973); see also H. Rep. No. 91-1146, 91st Cong., 2d Sess. 10 (1970).

<sup>248</sup> IEA 2022, *supra* note 19, at 74.

<sup>249</sup> U.S. Department of Energy, Loan Programs Office, *Hydrogen: Advanced Clean Energy Storage, Delta, UT* <https://www.energy.gov/lpo/advanced-clean-energy-storage>.

<sup>250</sup> 88 Fed. Reg. 33240, 33255, 33312 (May 23, 2023). U.S. Environmental Protection Agency, *Office of Air and Radiation, Hydrogen in Combustion Turbine Electricity Generating Units*, Technical Support Document, May 23, 2023.

protective emissions and discharge limits and monitoring. In case thermochemical hydrogen production with CCS is included as a method to meet NSPS, EPA must also consider and exercise its authorities to ensure CO<sub>2</sub> transport and sequestration processes are safe and sequestration is permanent.

If CCS is chosen as the BSER, EPA should set emission rate standards based on the best possible performance of these CCS-based systems while allowing for alternate technologies, including inherently nonpolluting technologies, to be used in achieving them. As long as fossil fuels are used as feedstocks for hydrogen production, lifecycle greenhouse gas emissions will still be problematic. Protective requirements to limit emissions at the production facility are critical, in addition to rigorous methane requirements and enforcement of methane emissions standards for the oil and natural gas sector. To this end, EPA must strengthen and then vigorously pursue implementation and enforcement of the methane emissions standards stemming from its oil and natural gas sector climate review.<sup>251</sup> As demonstrated by Bauer et al., expected greenhouse gas reductions from CCS can be easily erased if leak rates in the natural gas supply chain are excessive. Their study suggests both high CO<sub>2</sub> removal rates and methane supply chain leakage rates below 1% (considering methane's 100-year methane GWP) or 0.3% (20-year GWP) are needed for "blue" hydrogen to be competitive with green hydrogen in terms of its lifecycle emissions footprint.<sup>252</sup>

CO<sub>2</sub> and upstream methane are not the only emissions of concern with thermochemically produced hydrogen. For these facilities, NO<sub>x</sub>, VOC, PM, directly emitted methane, HAPs, and hydrogen emissions also need to be addressed. Control requirements that are already being met by hydrogen production facilities in some jurisdictions, standards applied in other industries that can readily be transferred to hydrogen production and the technical literature already demonstrate the availability of achievable systems of emission reduction for new and modified hydrogen production facilities that would sharply reduce emissions rates compared to current levels.

Options to cut NO<sub>x</sub> emissions from thermochemical hydrogen include ATR with CCS, SMR with CCS using low or ultralow NO<sub>x</sub> burners with SCR for the reformer furnace, or SMR with CCS using low-emissions electricity for process heat. In ATR systems, NO<sub>x</sub> emissions from the reformer furnace are sharply reduced by eliminating the need for natural gas combustion in air for process heat. In their process simulation study, Lewis et al. found NO<sub>x</sub> emissions were reduced by 80% per unit of hydrogen production with ATR with CCS in comparison to SMR with CCS. SCAQMD Rule 1109.1 demonstrates that SCR can be used to limit NO<sub>x</sub> emissions to 5 ppmv or lower, even at existing facilities. In fact, SCR technology is already used at SMR facilities, but should be more widely and effectively applied. If SCR is used, limits on ammonia

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<sup>251</sup> 87 Fed. Reg. 74702 (Dec. 6, 2022).

<sup>252</sup> Recent methane leak rate estimates far exceed 1% and vary regionally. A comprehensive national study in 2018 found a nationwide average methane leak rate of 2.3%. Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 361 Science 186 (2018), <https://science.sciencemag.org/content/361/6398/186>.

emissions and continuous emissions monitoring are also needed as adjuncts to NO<sub>x</sub> emissions limits for reformer furnaces.

BAAQMD Rule 13-5 demonstrates the need for and feasibility of addressing VOC and methane emissions from SMR and ATR process vents, by placing stringent limits on concentrations and maximum daily amounts of total organic compounds (including methane) that can be vented to the atmosphere as impurities in hydrogen gas streams. For new and modified facilities under section 111(b), EPA should go beyond this rule and consider requiring closed loop systems to minimize venting of hydrogen gas streams. Doing so would not only help address methane emissions but would also help address concerns about the indirect climate impacts of hydrogen emissions.<sup>253</sup> In addition to limits on venting, EPA should reference protective local, state and federal requirements and proposed requirements<sup>254</sup> for leak prevention, detection and repair in the natural gas and other chemical industries to determine what requirements should be transferred to hydrogen production facilities using natural gas or other hydrocarbons as a feedstock. EPA should also investigate the potential for new monitoring and leak detection methods to systematically find hydrogen leaks at levels relevant to curtailing hydrogen emissions. For thermochemical hydrogen production facilities, standards and work practice requirements are also needed to minimize use of flares to the extent feasible while maintaining safe operations, and to address drift emissions of PM<sub>2.5</sub> if cooling towers are used.

### **C. Emission Guidelines for Existing Hydrogen Production Facilities**

As discussed above, existing hydrogen production facilities are a significant source of greenhouse gas emissions. EPA must accompany any NSPS for greenhouse gas emissions from new and modified hydrogen production facilities with emissions guidelines covering those same pollutants for states to follow in applying performance standards to existing facilities.<sup>255</sup> EPA's guidelines may reflect the degree of emission limitation achievable through retrofits at existing SMR hydrogen production facilities with CCS achieving a high plant-wide capture rate. As with the NSPS, the emission guidelines should also minimize on-site methane emissions. As applicable, this could entail replacing process gas amine separation units with pressure swing adsorption, limiting total organic compound concentrations in vented gas streams, as well as requirements for leak prevention, detection, and repair, among other measures.

### **D. Emission Standards for Hazardous Air Pollutants**

Section 112 of the Clean Air Act requires EPA to establish emissions standards that require the maximum degree of emission reduction achievable (i.e., MACT) and that reduce health and environmental risks from HAPs.<sup>256</sup> Furthermore, in setting standards under section 112, EPA must set limits on all currently uncontrolled hazardous air pollution from hydrogen production

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<sup>253</sup> Ocko & Hamburg, *supra* note 6.

<sup>254</sup> 87 Fed. Reg. 74702 (Dec. 6, 2022).

<sup>255</sup> 42 U.S.C. § 7411(d)(1).

<sup>256</sup> *Id.* § 7412(d)(2)-(3), (f)(2).

facilities.<sup>257</sup> Hydrogen production using thermochemical methods is a source category for which emission standards for HAPs should be required. While HAP emissions reported to NEI differ widely across facilities, some hydrogen production plants report emitting more than 10 tons per year of methanol. The Health Risk Assessment conducted for the El Segundo hydrogen production facility identified hexavalent chromium from the reformer as a significant risk driver, along with diesel particulate emissions. Similar health risk assessments are needed for other facilities. Reformer furnaces, process and deaerator vents, catalyst beds, and flares are among potential sources of HAP emissions that should be considered for emissions limits or design or work practice standards, including standards for start-up, shut-down, and maintenance operations, as well as requirements for fence-line monitoring.

### **E. Section 114 Information Collection Requests**

This limited review of publicly available information demonstrates that national-scale emissions standards are needed and required for new, modified, and existing hydrogen production facilities under CAA sections 111 and 112. Control requirements that are already being met by hydrogen production facilities in some jurisdictions, standards applied in other industries that can readily be transferred to hydrogen production, the technical literature, and clean hydrogen projects that are already underway demonstrate the availability of feasible and effective systems that would sharply reduce emissions. The process of listing this category and developing standards should move forward without delay. At the same time, EPA should use its authority under section 114 to secure additional supporting detail about hydrogen production processes, emissions, and control opportunities. Because this source category has not been subject to federal emission standards, there is limited compiled information on variations in hydrogen plant design, equipment parameters, and operating practices, as well as emissions. Information on emissions of hazardous air pollutants, methane, and hydrogen is especially limited. EPA should direct an information collection request to owners and operators of hydrogen production facilities to fill these gaps. EPA should look to its recent information collection request pursuant to its revision of the Hazardous Organic NESHAP (HON) and Group I Polymers and Resins NESHAP standards and the Synthetic Organic Chemical Manufacturing Industry (SOCMI) NSPS, in which the agency required operators to conduct fence-line monitoring at their facilities and other forms of direct measurement of emissions.<sup>258</sup>

The agency should also collect information from equipment manufacturers to secure additional information on emissions, cost, performance, and design and operational constraints with new hydrogen production and emissions control methods. EPA should use its section 114 authority and other available information to assess the need to bolster health and safety protections for

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<sup>257</sup> See *La. Env't Action Network v. EPA*, 955 F.3d 1088, 1097, 1099 (D.C. Cir. 2020) (“There is no dispute that the Act requires EPA to have in place emission standards to control *all* the listed pollutants that a source category emits, and requires the Agency to revise existing standards that are underinclusive to add section 112(d)(2)-(3) controls for listed but unaddressed pollutants.”)

<sup>258</sup> See EPA, Chemical Sector Clean Air Act Section 114 Information Collection Request (Jan. 19, 2022), <https://www.epa.gov/stationary-sources-air-pollution/chemical-sector-clean-air-act-section-114-information-collection>.

hydrogen production facilities, covering all current and prospective feedstocks and production techniques.

EPA must ensure these facilities are robustly addressed through the Clean Air Act's section 112(r) Risk Management Program, along with other federal programs for ensuring safety of chemical production, transport, and distribution. The safety of hydrogen production is of the utmost urgency and importance, and is heightened by the planned growth in production, by increasing risks from extreme weather events that can trigger industrial disasters, and by the location of many facilities in vulnerable communities.<sup>259</sup>

Respectfully Submitted,

Environmental Defense Fund  
Sierra Club  
Earthjustice  
Union of Concerned Scientists  
PennFuture  
Beyond Toxics  
Environmental Health Project  
Environmental Integrity Project  
Clean Air Council  
California Communities Against Toxics  
Western Environmental Law Center  
Moms Clean Air Force  
Imagine Water Works  
The Vessel Project of Louisiana

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<sup>259</sup> Anenberg & Kalman, *Extreme weather, chemical facilities, and vulnerable communities in the U.S. Gulf Coast: a disastrous combination*, 3 *GeoHealth* 122-126 (2019), <https://doi.org/10.1029/2019GH000197>.



**Petition Submitted Via Email to:**

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**cc:**

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Tomás E. Carbonell, *Deputy Assistant Administrator for Stationary Sources*  
Peter Tsirigotis, *Director, Office of Air Quality Planning and Standards*

**Enclosed:** List of attachments submitted via email

Attachment A – Hydrogen Production Facility Community Impacts Data  
Attachment B – EDF Analysis of HydrogenCube Data  
Attachment C – Hensley Energy Consulting – Hydrogen and Ammonia Final Report  
Attachment D – H2 Facility Emissions NEI GHGRP CARB