Cross-Sector Interactions of Hydrogen Production for the Direct Reduction of Iron in U.S. Steel Manufacturing

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Abstract

U.S. steel production is rooted in a mix of primary and secondary steel produced from blast furnaces and electric arc furnaces, respectively. While primary steel has a higher market value, secondary steel can be produced at a lower cost based on existing technologies. The U.S. steel sector is exploring the use of hydrogen (H_2) to form direct reduced iron (DRI) that can be fed into an electric arc furnace (EAF) for producing primary steel. To inform the siting of H_2-DRI-EAF facilities, we use least-cost optimization for the bulk power and steel sectors to identify candidate locations for H_2-DRI-EAF facilities that power colocated electrolyzers with purchased (grid-connected) or self-generated (off-grid) electricity. The siting of off-grid H_2-DRI-EAF reflects a balance between low-cost hydrogen production and proximity to iron ore and steel demand; the former is achieved through complementary wind and solar generation, which is often paired with geological hydrogen storage. Compared to existing primary steel production, off-grid H_2-DRI-EAF deployment is drawn farther west by high-quality (and complementary) renewable resources and steel demand. Grid-connected H_2-DRI-EAF deployment is concentrated in the midwest, based on proximity to iron ore, regional electricity prices, and spatiotemporal requirements for qualifying for the full value of the 45V hydrogen production tax credit. Bulk power system transmission expansion, carbon dioxide (CO_2) emissions, and wholesale prices are largely insensitive to all siting and design options considered in this study, which reflects the vastness of U.S. bulk power system. Electrolyzer capital cost reductions and competitive retail electricity rates represent the most impactful strategies for improving the cost competitiveness of off-grid and grid-connected H_2-DRI-EAF, respectively.

1. Introduction

In 2024, the United States was the sixth largest producer of steel, after China, India, Japan, Russia, and South Korea. U.S. steel production is demanded by major segments of the U.S. economy such as automotive manufacturing, construction, and agriculture [1]. 12 of the operating U.S. steel manufacturing facilities utilized blast furnace (BF) technologies and were responsible for approximately 30% of U.S. steel production, including nearly all domestic primary steel production. An additional 104 minimills in the United States utilized EAF technologies, which were responsible for the remainder of U.S. steel production, largely based on re-using scrap steel.

An innovative and emerging steel production process involves feeding DRI into an EAF to produce primary steel. In this process, hydrogen can serve as a reductant to transform iron ore into metallic iron, or DRI. Altogether, the corresponding steel production process is known as H_2-DRI-EAF, and it could involve colocating an EAF facility with electrolyzers to generate H_2 for producing DRI.

Planning and siting an H_2-DRI-EAF facility requires weighing the relative merits of powering colocated electrolyzers with either purchased electricity (grid-connected H_2-DRI-EAF) or self-generated electricity (off-grid H_2-DRI-EAF). These options differ in two meaningful and interrelated ways: the costs associated with the electricity used to power electrolyzers, and the certainty (or uncertainty) associated with the CO_2 emissions intensity of each hydrogen molecule produced. These differences are interrelated because the latter influences a new facility's eligibility to receive federal tax credits for the electrolytic hydrogen produced which, in turn, influences the balance of project costs and revenue.

The viability and competitiveness of off-grid industrial facilities is largely dependent on the local availability and costs of developing electricity generation sources; how those costs compare with local grid-based electricity rates; and the costs and availability of hydrogen storage for gigawatt-scale hydrogen production. Large-scale hydrogen storage solutions, such as liquid organic hydrogen carriers, can help ensure a continuous H_2 supply and thus mitigate any potential disruptions to the steel manufacturing process. Geological hydrogen storage is the most cost-effective option, but it is available only in specific locations. The levelized cost of above-ground H_2 storage is also spatially heterogeneous, with recent work indicating more (less) competitive off-grid H_2 production potential in the Midwest (Central California and the Southeast) based on above-ground H_2 storage costs Breunig et al. [2].

Previous studies have explored the design and feasibility of site-specific, plant-level hydrogen production [3, 4, 5, 6, 7, 8, 9, 2], H_2-DRI-EAF facilities [10, 11], and off-grid industrial facilities more generally [12, 13, 14, 15]. These studies focused on producing electrolytic H_2 from co-located variable renewable energy (VRE) resources–such as wind and solar solar photovoltaic (PV)–and they consistently found that the combination of different VRE resources is beneficial for a reliable off-grid hydrogen production system.

Recent studies have begun to clarify key attributes as well as economic and technical considerations for H_2-DRI-EAF facilities that generate steel with dedicated H_2 production units. Within a static view of the bulk power grid, Rosner et al. [14] provides a detailed techno-economic analysis to establish the operational conditions under which H_2-DRI-EAF production can achieve similar costs as conventional natural gas-based DRI processes. This granular, plant-level perspective highlights the break-even H_2 costs needed for hydrogen-based steel-making to be cost competitive; they found that H_2-DRI-EAF could be economic if such a facility could procure H_2 at a cost of \$1.70 per kilogram or less. They further found that, based on a economic analysis performed in 2022, off-grid H_2 production cannot meet that cost target in any location without federal tax incentives. Reznicek et al. [15] found that at some locations in the U.S., electrolytic hydrogen for use in steel production could become more financially attractive than hydrogen production from steam methane reforming with carbon capture and storage (SMR-CCS) by 2035.

The present study focuses on bridging these strands by examining interactions among H_2-DRI-EAF steel facility deployment and bulk power sector operations, infrastructure investment (especially transmission), and prices. We provide a system-level perspective that complements the plant-level techno-economic benchmarks established, and the hydrogen supply and storage insights, from previous papers. We evaluate the tradeoffs of grid-connected and off-grid hydrogen production for H_2-DRI-EAF facilities within the dynamic context of an evolving grid, including the fact that high-quality VRE resources are desirable for both low-cost steel and electricity production–but a given site can only support one or the other.

In this study, we demonstrate the first application of linking the National Renewable Energy Laboratory (NREL)'s large-scale capacity expansion models for the U.S. bulk power and industrial sectors via a single set of constraints and variables as well as a single objective function for cost minimization. In this sense, the models are 'stacked' to form a single model with endogenous consideration of the impacts that industry and fuel production have on the bulk power sector, and vice versa. We explore the least-cost siting and design decisions for H_2-DRI-EAF, which reflect competition among iron ore transportation costs, regional electricity prices, and investment costs for new electricity transmission, VRE generation, and storage. It is important to note that we are not exploring economic deployment potential, and we do not directly compete grid-connected and off-grid design options against one another. Rather, we explore how design decisions influence regional deployment patterns.

This study offers original and innovative contributions to the literature in three ways. First, we evaluate regional differences in (and drivers of) deployment when pursuing grid-connected or off-grid hydrogen production for H_2-DRI-EAF facilities, including the local generation and storage infrastructure required to support fully off-grid hydrogen production. Second, we reveal how the least-cost siting and design decisions for H_2-DRI-EAF facilities could influence electricity transmission expansion, wholesale prices, and CO_2 emissions, as well as the levelized cost of hydrogen production. Finally, this analysis represents competition for high-quality VRE resources for producing electricity or hydrogen and the influence of regional electricity prices on the least-cost deployment of H_2-DRI-EAF facilities.

2. Methods

In this section, we summarize the individual models and the scenario matrix associated with our analysis of the design, siting, and impacts of grid-connected and off-grid H_2-DRI-EAF. Additional details of the methodology are provided in the Appendix.

2.1. FINITO

The Fuels and Industry Integrated Optimization (FINITO) model is a linear program that solves for the cost-minimizing combination of investment and operations for both fuel supply and several industrial sectors, including steel. In particular, FINITO includes an H_2-DRI-EAF investment option that leverages the energy demand and cost assumptions from Reznicek et al. [15]. Detailed documentation of FINITO has been drafted and is available by request.

Figure 1 presents an overview of the FINITO model structure, which includes distinct representations of fossil-fuels, bio-derived fuels, and renewable energy primary and secondary energy carriers. These energy carriers compete in meeting the annual demands from industrial activities and rest-of-economy, final energy demands while accounting for costs associated with transport and storage of commodities, hydrogen, liquid fuels, and captured carbon. FINITO can be solved as either an intertemporally optimized model or a recursive/sequential, myopic model; in this study, it is solved myopically (without any information about future conditions of the U.S. industrial and fuels sectors) in order to maintain consistency with the power sector model with which it is integrated (Regional Energy Deployment System (ReEDS)).

Electrolytic hydrogen production plays a central role in this analysis. Table 1 presents the assumed characteristics of electrolyzers by year, derived from the H2A-Lite tool estimates [16]. Notably, capital costs decline from \$1,750 / kW in 2020 to \$550 / kW between 2020 and 2030 with fixed operation and maintenance (O& M) costs declining by similar magnitudes across the same time period. Electricity intensity is assumed to decline from 56.1 kWh/kg in 2020 to 53.78 kWh/kg in 2035.

Table 1: Summary of assumed electrolyzer characteristics

	Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr)	Electricity Use (kWh/kg)
2020	1750	87.5	56.10
2025	1300	65	54.55
2030	550	27.5	54.55
2035	550	27.5	53.78

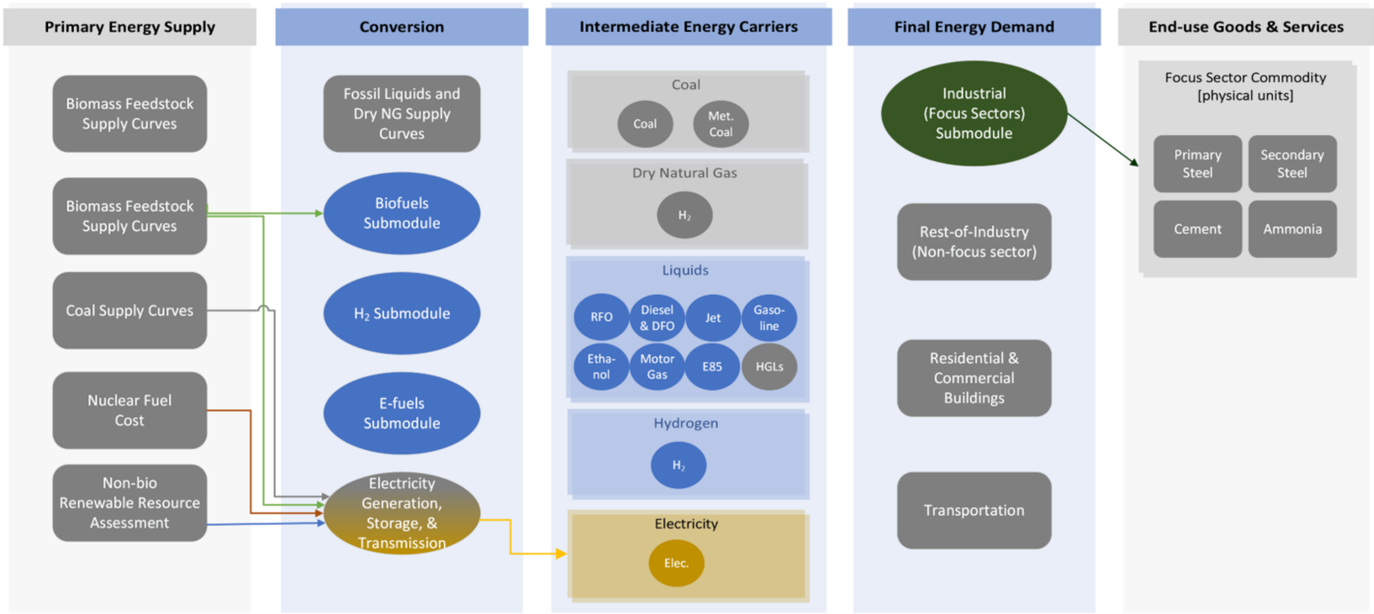

Figure 1: FINITO model structure

For this analysis, we disable inter-regional hydrogen transport, effectively requiring the off-grid hydrogen production to be co-located with the H_2-DRI-EAF facility. Exogenous hydrogen demand and existing hydrogen capacity are both set to zero, given that all hydrogen capacity and production in this analysis is intended for co-located H_2-DRI-EAF facilities. Said differently, hydrogen producers do not participate in a broader hydrogen market, so all production is marginal and devoted to steel production.

The steel module within FINITO includes multiple representations of BF and EAF technologies, with variations based on input fuels and materials. FINITO further distinguishes between primary and secondary steel demand. Primary steel demand is for virgin steel, typically produced in the United States via BF technologies. All steel technologies that produce primary steel can also meet the demand for secondary steel, which is recycled steel and typically produced in the United States via EAF. EAF facilities using predominantly steel scrap are assumed to not meet the quality standards for primary steel. For our scenario analysis, we assume that total steel demand remains constant into the future, but secondary steel's share of total steel production increases over time, capturing approximately 80% of steel demand by 2035 (compared to 70% in 2024 [1]).

For future deployment of steel production capacities, we focus exclusively on H_2-DRI-EAF as the investment option, assuming the characteristics presented in Table 2. Compared to BF technologies, H_2-DRI-EAF technologies involve comparable capital costs, higher O&M costs, lower energy intensity (but higher electricity intensity), and a lower CO_2 emission rate (assuming low or zero emissions H_2 production). Over time, we assume that H_2-DRI-EAF will improve efficiency, leading to reduced energy and material intensity, as well as lower system costs.

Table 2: Summary of assumed H_2-DRI-EAF characteristics

H_2-DRI-EAF		2024	2028	2032
Capital Cost	\$/t	865.1	837.3	809.5
Fixed O&M Cost	\$/t-yr	123.8	119.8	115.8
Variable O&M Cost	\$/t-yr	33.4	32.3	31.2
Electricity Use	MWh/t	0.55	0.66	0.64
Natural Gas Use	MMBtu/t	0.85	0.82	0.79
Hydrogen Use	t/t	0.08	0.08	0.08
Steel Scrap Use	t/t	0.40	0.39	0.38
Iron Ore Use	t/t	1.63	1.57	1.52
Carbon Emission Process Rate	CO2 t/t	0.04	0.04	0.04

For this analysis, electricity demand assumptions associated with H_2-DRI-EAF facilities are consistent with those presented in Reznicek et al. [15]. All electricity demands for the steel facility itself (including the EAF) are purchased from the bulk power system. Steel production and its associated energy consumption are assumed to be constant throughout the year; that is, the electricity demand profile for all steel production facilities is assumed to be flat. The investment options for meeting the H_2 demands associated with H_2-DRI-EAF are covered in the next section.

2.2. ReEDS

The ReEDS model is a linear program that solves for the cost-minimizing combination of investment and operation for the U.S. power sector. ReEDS has been used in an extensive array of previous studies [1], and further information on the ReEDS

[1] https://www.nrel.gov/analysis/reeds/

model can be found in the ReEDS documentation [17].

The ReEDS geographic resolution is presented in Figure 2 and consists of 134 balancing areas. The balancing areas correspond to the resolution at which generation plus net transmission must equal demand; policy and operational reliability constraints are imposed, such as operating reserves and the planning reserve margin; and long-distance transmission capacity and flows are modeled.

Within each balancing area, supply curves capture more granular representations of 50,000 candidate sites for the deployment of PV and wind technologies, including uniquely parameterized capacity factors, capital costs, and grid interconnection (or local transmission) costs. Transmission interconnection capacity consists of a spur line to get from the wind or PV site to an existing transmission substation, combined with network reinforcement to get from the substation to the zone center.

The default temporal representation in ReEDS is on the order of hourly resolution, which applies to electricity demand, VRE generation profiles, transmission flows, and operational decisions. For this study, we simulate 23 representative days, each with six (4 hour) time slices. Similar to FINITO, ReEDS is solved myopically, so it does not have any information about future conditions of the U.S. bulk power system.

ReEDS includes an extensive set of up-to-date federal and state policies, including explicit representations of incentives for both hydrogen production (commonly referred to as 45V[2]) and the technology-neutral investment and production tax credits for electricity generation and storage technologies. Relatedly, ReEDS also solves for the cost-minimizing combination of investment and operation for the production of electrolytic H_2. Electrolyzer operation is assumed to be able to ramp up or down without constraint. Depending on the scenario, electrolyzers must be powered by either purchased electricity (grid-connected) or dedicated electricity generation and storage capacity (off-grid).

The off-grid hydrogen production option identifies the least-cost mix of colocated wind, PV, short-duration electricity storage, and H_2 storage components that is sufficient, on its own, to meet the H_2-DRI-EAF facility's hydrogen demands. Short-duration electricity storage investment options include 4-hr or 8-hr battery storage, based on current lithium-ion technologies. Hydrogen storage investment options include salt cavern, hard-rock, and other geological storage options; salt cavern and hard-rock storage options are only available in select locations, with site-specific injection and storage limits (based on the local geology). Other hydrogen storage investment is allowed (beyond these natural geological storage options), but they come at a higher cost. The off-grid hydrogen production option avoids the need (and associated costs) for transmission interconnection and is therefore unable to sell excess electricity to (or purchase electricity from) the bulk power system (or the grid); in addition, they are unable to recoup any revenue associated with other grid services, including planning and operating reserves.

We assume off-grid H_2 production facilities qualify for both the proposed 45V and electricity and storage tax credits; this policy stacking is enabled by the fact that we require off-grid electrolyzers to be powered by wind, PV, and/or battery storage technologies. That being said, the availability of these tax credits solely informs the relative sizing of components; H_2-DRI-EAF deployment is driven by prescribed market shares. In other words, this study is not designed to identify cost targets for economic H_2-DRI-EAF deployment, but rather to generate insights about siting and design decisions for different levels of deployment.

In the grid-connected hydrogen production option, electricity demand for electrolysis is combined with all other electricity demands in ReEDS. Therefore, this option represents a system-level optimization of generation, storage, and transmission capacities for all loads. The H_2-DRI-EAF facility is required to purchase the electricity needed to power its colocated electrolyzers–inclusive of the other electricity services required to maintain a reliable grid–using an industry-specific retail electricity price. Beyond a simulated wholesale electricity price, we assume a retail price adder of $28 / MWh[3], which is the average difference between the price faced by industrial consumers and the wholesale energy price from the 2023 Annual Energy Outlook EIA [18]. The resulting retail price is assumed for electricity purchased by the H_2-DRI-EAF facilities, including both facility and grid-connected electrolyzer demands.

Grid-connected electrolytic H_2 production facilities are eligible for the full 45V incentive but must qualify their generation through the purchase of energy attribute credit (EAC)s. The EAC system requires the electrolyzer unit to purchase electricity credits from new (incremental or additional) electricity generation technologies with emissions rates that would retain their eligibility for the full 45V incentive. The modeled EAC requirement allows for intra-regional trade within the legislated boundaries and is satisfied annually until 2028 after which it requires hourly matching; in this sense, the 'three pillars' of electricity accreditation are enforced. The Appendix details the indices, parameters, variables, and constraints associated with the EAC scheme.

2.3. Scenario Framework

To generate insights regarding siting and design decisions for H_2-DRI-EAF facilities, we co-optimize NREL's large-scale capacity expansion models for the U.S. bulk power (ReEDS) and steel (FINITO) sectors. We use the resulting linked ReEDS-FINITO optimization to explore a counterfactual framework with two relevant variations:

1. **Increasing market shares for H_2-DRI-EAF steel production**: We explore scenarios in which H_2-DRI-EAF facilities are required to produce 0%, 10%, 20%, or 30% of U.S. steel production in 2035, following a linear growth

[2]This analysis was performed prior to the release of the final 45V guidance from the U.S. Department of Treasury. The 45V representation in this analysis may differ from the final guidance.

[3]All currencies in this paper are expressed in 2022 USD.

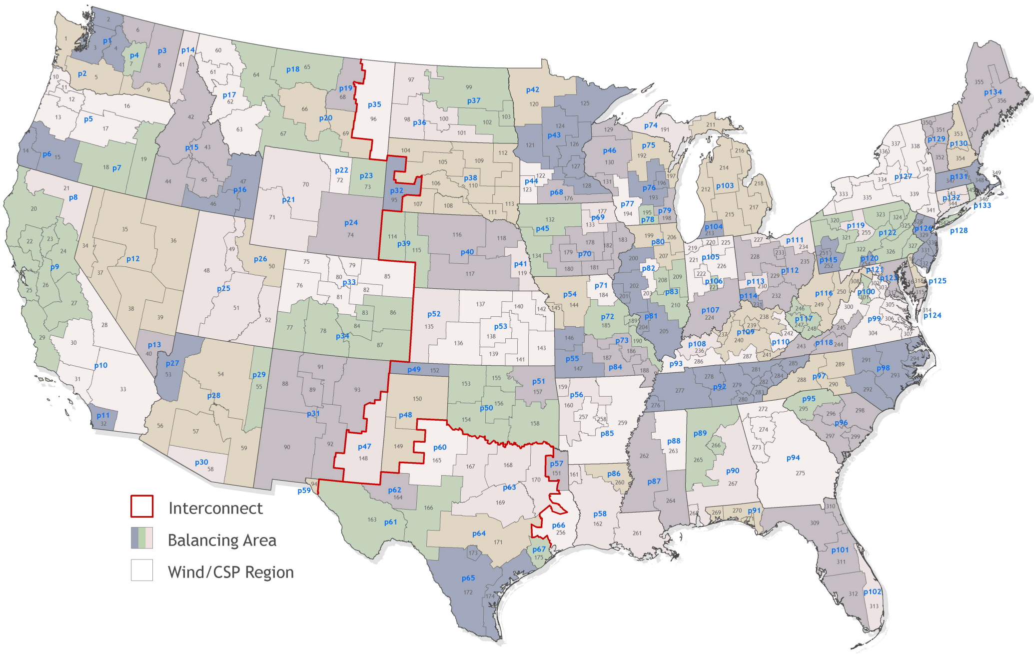

Figure 2: Default geographical resolution in ReEDS

trajectory between 2025 and 2035. The linked ReEDS-FINITO optimization determines the location, sizing, and configuration of new H_2-DRI-EAF facilities, as well as whether they are deployed to meet primary and/or secondary steel demands.

2. **Hydrogen production pathways:** We explore a set of scenarios that meet H_2-DRI-EAF hydrogen demands through fully off-grid hydrogen production pathways, and a separate set of scenarios that involve electrolysis powered by electricity purchased from the bulk power system (or grid). Competition between off-grid and grid-connected hydrogen production pathways is reserved for future work.

For each scenario, we assume reference market conditions outside of the steel sector. We rely on previously published work for assumptions related to electricity demand [19], technology cost and performance [20], and fuel prices [18], as summarized in Table 3. It is important to note the relevant magnitudes of electricity demand associated with hydrogen production for H_2-DRI-EAF facilities [15] versus that for all other end-uses.

Table 3: Sources and Additional Information for Key Model Assumptions

	Source	Additional Details
Electricity demand (excluding H2-DRI-EAF)	NREL Standard Scenarios 2023	4,000 TWh in 2023; 5,000 TWh in 2035
Electricity demand (H2-DRI-EAF facility, excluding electrolysis)	Reznicek et al. (forthcoming)	0 TWh in 2023; 4-11 TWh in 2035
Electricity demand (H2-DRI-EAF electrolysis)	Reznicek et al. (forthcoming)	0 TWh in 2023; 35-105 TWh in 2035
Technology cost and performance	Annual Technology Baseline 2023	"Moderate" trajectory
Fuel prices	2023 Annual Energy Outlook	"Reference" scenario

3. Results

Figure 3 presents the simulated mix of technologies utilized in U.S. production of primary (top) and secondary (bottom) steel in 2035 across the range of H_2-DRI-EAF market shares explored. When considering only the type of steel that H_2-DRI-EAF is deployed to produce, the patterns for H_2-DRI-EAF are identical when the colocated electrolyzers are powered by purchased (grid-connected) or self-generated (off-grid) electricity.

In the absence of a market share requirement, we do not observe any H_2-DRI-EAF deployment. Said differently, we find that H_2-DRI-EAF is not competitive with existing steel manufacturing facilities, based on our cost and demand assumptions.

Under a 10% market share requirement, H_2-DRI-EAF (blue bars) is deployed to meet primary steel demands. Under the 20% market share requirement, H_2-DRI-EAF captures nearly all of the primary steel production; the remaining BF production reflects the fact that we assume a linear transition to primary steel representing 20% of total steel demand in 2050. The

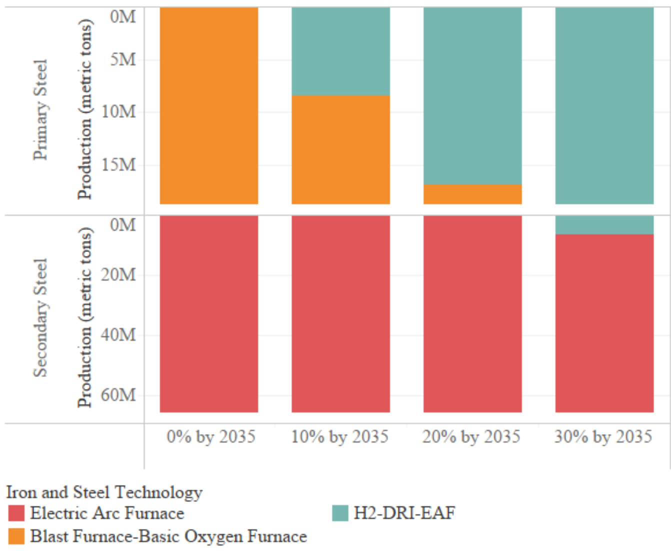

Figure 3: Primary (top row) and secondary (bottom row) steel production in 2035 by technology (color), configuration, and scenario (horizontal axis)

30% market share requirement is greater than the total assumed primary steel demand in 2035; in this case, H_2-DRI-EAF becomes the only source of primary steel production, and it also (necessarily) captures a minority share of secondary steel production.

Figure 4 shows a regional breakdown of the BF (orange), EAF (red), and H_2-DRI-EAF (blue) capacities in 2035 for the full range of market share assumptions. Siting decisions for grid-connected H_2-DRI-EAF facilities are driven by a combination of regional electricity prices; proximity to iron ore production and steel demand; and spatiotemporal EAC requirements for qualifying for the full value of the 45V incentive.

Balancing all of these drivers, a large number of relatively small grid-connected H_2-DRI-EAF facilities appear throughout the interior of the contiguous United States. Many of the new grid-connected H_2-DRI-EAF facilities are sited in the midwest, which is consistent with the locations of current primary steel production from existing BF facilities. However, grid-connected H_2-DRI-EAF deployment extends further west and south to capture high-quality renewable resources that are leveraged to qualify for the full 45V incentive value. Grid-connected H_2-DRI-EAF facilities power the colocated electrolyzers with purchased electricity, thus relying on the grid to facilitate a consistent supply of H_2 production and negating the need for significant on-site H_2 storage.

Off-grid H_2-DRI-EAF deployment spans similar regions (Figure 4), but it is concentrated in just three locations which are driven by proximity to geological hydrogen storage, high-quality renewable resources, and iron ore production. Off-grid H_2-DRI-EAF in Colorado is selected for the high-quality wind and solar resources, which provide a relatively consistent supply of electricity to the colocated, off-grid electrolyzers. Off-grid H_2-DRI-EAF in Michigan and North Carolina are driven by proximity to iron ore and high-quality solar resource (respectively), as well as geological hydrogen storage, which is selected over the short-duration battery storage option. Salt cavern storage is the lowest-cost investment option, and it is typically preferred (in locations where it is available); however, similar amounts of hardrock hydrogen storage are developed by 2035.

Altogether, the deployment patterns for off-grid H_2-DRI-EAF illustrates new and additional drivers (access to high-quality renewable resources and geological hydrogen storage) beyond those that informed siting of existing primary steel production facilities (proximity to iron ore). In other words, the spatial pattern of off-grid H_2-DRI-EAF deployment highlights the value of a low-cost, consistent supply of hydrogen.

4. Discussion

This section synthesizes the driving factors and impacts of siting off-grid or grid-connected H_2-DRI-EAF. As a reminder, this article is not designed to compete these hydrogen production pathways against one another; instead, this section seeks to highlight the relative merits of off-grid and grid-connected hydrogen production pathways for colocated H_2-DRI-EAF steel production.

The left panel of Figure 5 presents the self-generation mix of wind (blue) and solar (yellow) for each of the regions in which off-grid H_2-DRI-EAF deployment is observed. In Michigan (p74) and Colorado (p33), wind provides the majority of electricity generation to the colocated electrolyzer, whereas wind and solar make relatively equal contributions in North Carolina (p97). Short-duration battery storage is not shown because it is not selected to support off-grid H_2-DRI-EAF facilities; therefore, the height of the stacked bars in the left panel of Figure 5 corresponds to the total electricity demand for electrolysis in support of H_2-DRI-EAF steel production in each region.

The right panel of Figure 5 presents the corresponding, regional levelized cost of hydrogen (LCOH), including infrastructure and operations for the colocated off-grid generation (green and yellow), electrolyzer (orange, teal, and purple), and geological hydrogen storage (brown and gray). For all regions, the cost components add up to an LCOH that is greater than \$3 per kilogram, before subtracting the value of the 45V incentive (blue, which is approximately \$1.2 per kilogram). Therefore, none of the observed off-grid H_2-DRI-EAF configurations satisfy the previously-identified cost-effectiveness threshold of \$1.70 per kilogram (Rosner et al. [14]).

For the off-grid H_2-DRI-EAF deployment in Michigan and North Carolina, colocated wind and solar generation assets are complemented by geological hydrogen storage; this additional investment is designed to ensure a consistent supply of affordable H_2 in these locations, based on the cumulative, hourly electricity generation from the colocated wind and solar resources.

The self-generation (left panel) is highest in Colorado; this partially reflects the larger volume of simulated steel production in this region, but it is primarily due to the lack of hydrogen storage. Instead, off-grid H_2-DRI-EAF steel manufacturing in Colorado leverages the low cost, and high complementarity,

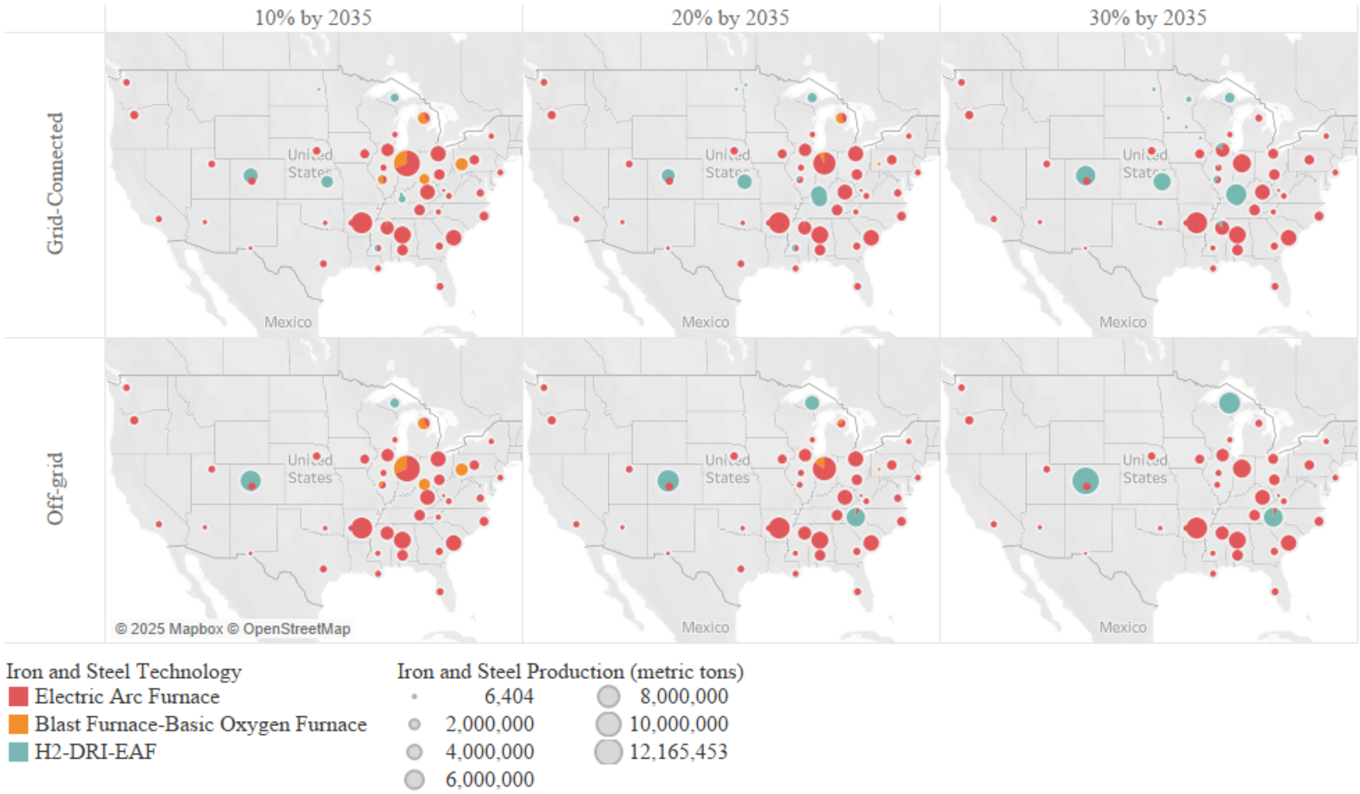

Figure 4: Regional steel production in 2035 by technology (color), prescribed market share for the steel sector (column), and hydrogen production pathway (rows)

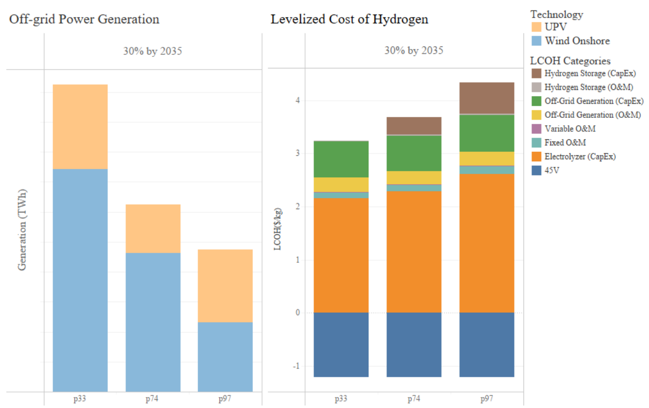

Figure 5: The mix (color) of technologies for self-generation to support off-grid electrolyzers and Levelized Cost of Hydrogen in 2035

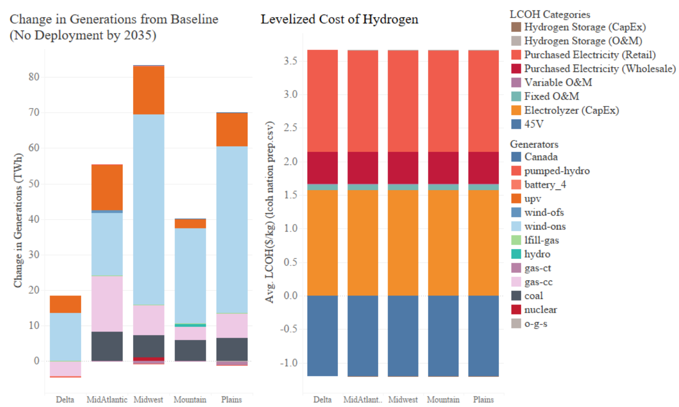

Figure 6: The mix (color) of technologies for self-generation to support off-grid electrolyzers and Levelized Cost of Hydrogen in 2035

of wind and solar resources in the state. In other words, the timing of wind and solar generation in Colorado is largely staggered in time, and oversizing both wind and solar (relative to the electrolyzer) results in a relatively consistent supply of electricity to the colocated electrolyzer. The contribution of off-grid generation to the LCOH in Colorado remains similar to that in Michigan and North Carolina because of the vast wind and solar resources in Colorado with comparable (and competitive) cost and performance characteristics.

Figure 6 presents related information for grid-connected H_2-DRI-EAF under the 30% market share assumption. Results are presented for each of the five EAC regions in which grid-connected H_2-DRI-EAF is deployed. The right panel of Figure 6 presents the LCOH stack for grid-connected H_2-DRI-EAF, which indicates no regional variation. The electrolyzer capital expenditure (CapEx) and assumed retail electricity price adder ($28 per MWh) each contribute more than $1.5 per kg to the total LCOH. The retail price adder's contribution to the LCOH (light red) is more than 3x that of the wholesale electricity price (dark red), the latter of which is a direct output from ReEDS.

Given the inherent uncertainty around industrial retail (versus wholesale) electricity prices, this is an area that requires further investigation in a future study.

Compared to the off-grid LCOH stack, the smaller contribution of the electrolyzer CapEx reflects the smaller electrolyzer capacities in the grid-connected pathway. In other words, grid-connected H_2-DRI-EAF leverages smaller electrolyzer capacities and higher utilization rates, due to the consistent availability of electricity purchased from the grid. As with the off-grid hydrogen production pathways, none of the grid-connected H_2-DRI-EAF configurations satisfy the previously-identified cost-effectiveness threshold of \$1.70 per kilogram (Rosner et al. [14]), even after accounting for the full value of the 45V incentive.

The left panel of Figure 6 presents corresponding changes to the regional electricity generation mix, relative to a scenario with no grid-connected H_2-DRI-EAF. These changes reflect the increased electricity demand from both grid-connected electrolysis and the colocated EAF facility, as well as hourly EAC matching requirements, which dictate that all electricity generation in support of grid-connected electrolytic hydrogen production must be zero-emitting to qualify for the full 45V incentive. The addition of grid-connected H_2-DRI-EAF typically drives increased investments in wind (primarily) and solar (secondarily) generation. However, the dynamic interactions among electricity generation resources and demand profiles influences the economics of fuel-based generation. In most regions, the least-cost solution involves increased utilization of existing coal and gas-fired power plants; regionally specific changes include modest increases in nuclear (Midwest) and hydropower (Mountain) output. This incremental utilization of existing assets is driven by a flattening of the net-load profile shape and, in turn, the ability of these more baseload-type resources to operate at a higher output level (or capacity factor).

As a result, combustion-related CO_2 emissions for the power sector increase by approximately 10 million metric tons (or 3%) when grid-connected H_2-DRI-EAF provides 30% of U.S. steel production (Figure 7). The same increase in power sector emissions holds when comparing against a scenario using existing steel facilities (only) or with 30% steel production from off-grid H_2-DRI-EAF. That being said, the increase in power sector CO_2 emissions is smaller than the decrease in steel sector CO_2 emissions (not shown). In other words, the combined power-and-steel sector CO_2 emissions are lower when H_2-DRI-EAF facilities capture 30% market share for steel production, for both grid-connected and off-grid scenarios.

The right panel of Figure 7 illustrates that inter-regional transmission capacity is largely insensitive to the deployment of H_2-DRI-EAF facilities, varying by less than 1% in 2035 across all scenarios explored. When comparing the grid-connected and off-grid versions of a given market share assumption, inter-regional transmission capacity in 2035 varies by less than 0.6%; this suggests that the incremental transmission expansion associated with powering H_2-DRI-EAF electrolyzers is less than 1%, even when such facilities are providing 30% of U.S. steel production.

Relatedly, we estimate a wholesale price for electricity by using the marginal value of the ReEDS supply-demand constraint. Simulated 2035 electricity prices suggest that growing deployment of H_2-DRI-EAF has modest impacts on national-average wholesale electricity prices. We find that introducing enough H_2-DRI-EAF capacity to satisfy nearly all primary steel demands in 2035 (20% market share) could drive a 0.7% increase in wholesale electricity prices, relative to a scenario where the steel sector remains unchanged through 2035. If H_2-DRI-EAF were to capture 30% of U.S. steel production, the corresponding impact on wholesale electricity prices in 2035 could be on the order of 1%. These results hold for both grid-connected and off-grid configurations: for a given market share assumption, the simulated wholesale electricity prices associated with grid-connected and off-grid H_2-DRI-EAF vary by less than 0.3%. In other words, the incremental investment and changes in operations associated with powering H_2-DRI-EAF electrolyzers from purchased grid electricity is modest, beyond the investment associated with the new steel manufacturing facility itself.

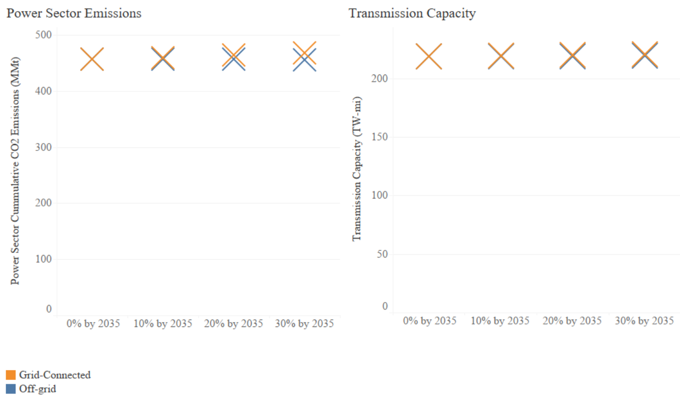

Figure 7: Power sector emissions (left) and transmission capacity (right) for all combinations of steel market share requirements and hydrogen production pathways explored

Altogether, the similar simulated wholesale electricity prices, new transmission infrastructure, and power sector emissions for grid-connected and off-grid hydrogen production in support of H_2-DRI-EAF steel manufacturing reflects the vastness of the U.S. bulk power system. Even when H_2-DRI-EAF is responsible for 30% of U.S. steel production, the amount of electricity purchased by such facilities (for facility and electrolysis loads) accounts for less than 3% of U.S. electricity demand. Our simulated transmission expansion and wholesale electricity price metrics are also inter-related, since transmission expansion within the ReEDS optimization influences simulated wholesale electricity prices.

5. Conclusions and Next Steps

This work is the first to use the ReEDS-FINITO model to co-optimize the evolution of the U.S. bulk power and steel sectors. We explored a range of market shares for H_2-DRI-EAF steel production, layered with growing demand for secondary steel (and a corresponding reduction in primary steel demand).

These drivers forced an evolution of the U.S. steel sector, in which the siting of new H_2-DRI-EAF steel manufacturing facilities was informed by available configurations, regional electricity prices, and proximity to iron ore production, steel demand, and geological hydrogen storage locations. The overarching purpose of this analysis is to explore the siting and design considerations for H_2-DRI-EAF, accounting for dynamic interactions of decisions made within the U.S. steel and bulk power sectors.

We observed a concentrated deployment of off-grid H_2-DRI-EAF in three regions, which span a wider geographical range than existing primary steel production. The expanded deployment of off-grid H_2-DRI-EAF reflects the balance between historical (proximity to iron ore) and potential new (a consistent and relatively low-cost supply of H_2 production) drivers of siting for primary steel production. The availability of geological hydrogen storage also influences the siting of off-grid H_2-DRI-EAF–it is typically part of the least-cost portfolio, and it is selected over the short-duration battery storage option.

Grid-connected H_2-DRI-EAF facilities (that rely on purchased electricity to power colocated electrolyzers) have more flexibility in their siting decisions. Such facilities appear throughout the midwestern United States, in a spatial pattern that is similar to existing BF facilities. Siting decisions for grid-connected H_2-DRI-EAF are informed by a combination of regional electricity prices, proximity to iron ore production, and spatiotemporal requirements for accessing the full value of the 45V hydrogen production tax credit. In particular, grid-connected H_2-DRI-EAF facilities can achieve a similar incentive value for hydrogen production through the purchase of EACs that demonstrate investment in nearby, incremental sources of eligible electricity in all hours of hydrogen production.

Bulk electric sector transmission, CO_2 emissions, and wholesale electricity prices are similar for grid-connected and off-grid hydrogen production across all H_2-DRI-EAF market shares explored. The relative insensitivity of these bulk power system and economic metrics reflects the fact that the steel sector is a small portion of overall demand on the vast U.S. bulk power system. However, local impacts need to be evaluated further.

Finally, the LCOH that can be achieved with our cost and performance assumptions remain above the level previously found to indicate cost-competitiveness, for both the grid-connected and off-grid hydrogen production pathways. Electrolyzer CapEx reductions and/or lower industrial retail electricity rates could help close the observed gap.

For next steps, several advancements to the analysis have been identified. First, we would like to explore variations on the assumed magnitude and flexibility of electricity demand at H_2-DRI-EAF facilities. In the present analysis, the load profiles for steel producers are assumed to be flat and inflexible. Further data are needed to relax this assumption, which would enable exploration of the impact of intra-day, inter-day, and inter-seasonal load flexibility on the further electrification of steel production.

Second, we recommend exploring scenarios that relax the requirement for colocating the two dominant processing steps: H_2-DRI and EAF. Separating, and optimally siting, each of these process steps could lead to a lower total cost, depending on the tradeoffs between economies of scale and increased transport costs. For example, H_2 direct reduction can be concentrated where it can be done at lowest cost, allowing for centralized production of hot bricked iron that can be distributed to many EAF facilities. However, the hot bricked iron will be heavier and may require transport over larger distances, compared to the spatial patterns presented in the current study. Future work could evaluate changes to the deployment patterns and sector-wide system costs when the two dominant processing steps of this study are colocated versus sited separately.

Finally, while the linked ReEDS-FINITO optimization identifies the least-cost H_2-DRI-EAF configurations and locations, grid-connected and off-grid investment options are treated independently in this analysis. A deeper understanding of future deployment potential requires an exploration of the competition for grid-connected and off-grid applications across a range of assumptions related to retail adders and load flexibility. In addition, evaluating the potential for economic deployment should involve the consideration of previously identified cost targets (e.g., for hydrogen procurement), an evaluation of the minimum sales price for steel that is competitive, and an explicit representation of the 45V tax credit program.

6. Acknowledgments

The authors acknowledge J. King, D. Rowlands, M. Koleva, H. Breunig, S. Hammond, C. Avraam, D. Steinberg, I. Chernyakhovskiy, K. Anderson, J. Cochran and the members of GreenHEART and FINITO teams for helpful discussions and careful review of previous versions of this manuscript. This work was authored by the National Renewable Energy Laboratory for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Hydrogen and Fuel Cell Technologies Office. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes. Moreover, this research was performed using computational resources sponsored by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy and located at the National Renewable Energy Laboratory.

Appendix A. Methodology Details

To perform the work presented here, we leverage the linked version of the ReEDS and FINITO models, referred to as ReEDS-FINITO. The following subsections provide a description of the two models, a more detailed coverage of the representation of steel in FINITO, an overview of the linkage methodology, and a description of the scenario design.

Appendix A.1. ReEDS

ReEDS is a linear program that solves for the cost-minimizing combination of investment and operation for the US power sector. The default setup in the model maintains a myopic perspective in that it does not have any information about future conditions of the US power sector; the myopic framework is structured such that investments are considered in their overnight capital cost and operations are weighted for 20-years while the conditions of the presently-modeled year are assumed to persist. Said differently, the model weighs operations to persist for 20 years while making contemporaneous investment decisions for that year.

The default geographical resolution of ReEDS, presented in Figure 2, consists of 134 balancing areas for capacity parameterization. The balancing areas are where (a) generation plus net transmission must equal demand and (b) policy and operational reliability constraints are imposed, such as operating reserves and the planning reserve margin. Within each balancing area, supply curves capture more granular representations of 50,000 candidate sites for the deployment of PV and wind technologies, including uniquely parameterized capacity factors and capital costs.

Transmission flows and long-distance transmission capacity are similarly modeled at the spatial resolution presented in Figure 2, but site-specific grid interconnection (or local transmission) costs are applied within the previously mentioned supply curves. For each of the 50,000 candidate investment sites for VRE deployment, we approximate an interconnection cost to move power from the site to the zone "center", which is usually located in the largest urban area within the zone. That interconnection capacity consists of a spur line to get from the wind or PV site to an existing transmission substation, combined with network reinforcement to get from there to the zone center. We model network reinforcement as reconductoring of an existing transmission line, following the shortest path through the existing network to the zone center. Altogether, local and long-distance transmission costs combine regional base costs, terrain and land-type cost multipliers, high-resolution land-type data, and least-cost-path routing.

The default temporal resolution for the ReEDS model is hourly, which applies to electricity demand, VRE generation profiles, transmission flows, and operational decisions. For this study, we simulate 13 representative days, each with six (4hr) time slices. Representative periods are identified by hierarchical clustering, with regional load, solar, and wind profiles used as features with a weighting of 1:0.5:0.5 (respectively). We capture resource adequacy through a capacity credit calculation, based on the full 8760 time-series and seven historical weather years.

ReEDS also includes an extensive set of up-to-date federal and state policies including, non-exhaustively, the incentives available through the Inflation Reduction Act (IRA), state renewable portfolio standards (RPS) and clean energy standards (CES), the Regional Greenhouse Gas Initiative (RGGI), and California's emissions cap. Further information on the ReEDS model can be found in the ReEDS documentation [**?**] and on the ReEDS website[4].

The version of ReEDS used in this analysis also has two distinct options for meeting demands for electrolytic hydrogen: grid-connected and off-grid[5] electricity generation and storage capacity. The grid-connected capacity could be used to inject electricity into the bulk power transmission network or to power colocated electrolyzers for the production of hydrogen. The off-grid electricity option allows for wind, solar, and/or integrated storage to be deployed for the sole purpose of powering colocated electrolyzers to meet local (facility-level) hydrogen demand. The renewable resource at a given location can only be developed for either grid-connected or off-grid electricity generation; therefore, this analysis captures competition for high-quality VRE resources for the production of electricity or hydrogen. The modeled combinations of grid- and hydrogen network-connected generators and hydrogen producers, respectively, as well as their use in steel production is explained further in Section Appendix A.5.

Appendix A.2. Tax Credit Qualification

An impactful consideration for this work is the availability and representation of hydrogen production incentives, commonly referred to as 45V. In the context of 45V, hydrogen production refers to an electrolyzer emissions rate below the 0.45 tonnes CO_2-equivalent per kilogram of hydrogen produced. In practice, eligible generation technology options that are commercially available today include zero-emissions electricity generation technologies and natural gas-fired combined cycle units with carbon capture and storage (CCS).

Given the 45V incentive is only available for 10 years of electrolyzer operation, the 20-year operational weighting of ReEDS, and the myopic nature of ReEDS, the incentive is weighted by the ratio of the 10- to 20-year capital recovery factors. The default policy framework in this study includes hydrogen incentives for all off-grid production facilities as they are assumed to be powered solely by technologies that would retain their qualifying status for the full 45V incentive. Grid-connected electrolytic hydrogen facilities are eligible for the full 45V incentive but must qualify their generation through the purchase of EACs. The EAC system requires the electrolyzer unit to purchase electricity credits from new (incremental) electricity generation technologies with emissions rates that would

[4] `https://www.nrel.gov/analysis/reeds/`

[5] Off-grid generation does not qualify for RPS credits as states' RPS policies are generally based on post-distribution, grid-connected sales of electricity.

retain their eligibility for the full 45V incentives. The EAC requirement is satisfied annually until 2028, and it requires time slice matching in 2028 and beyond.

The following indices, parameters, and variables as well as the constraints further below, explain the EAC scheme in more detail.

Sets:
$\mathcal{I}$: Electricity generation triplets, combinations of technology, vintage, and region
$\mathcal{I}^{45V}$: Subset of electricity generation triplets, combinations of technology, vintage[6], and region such that electrolysis units are within the bounds of the \$3/kg 45V incentive (nuclear, VRE, gas-cc-ccs, other zero-carbon techs and within the same NTNS region)
$\mathcal{J}$: Hydrogen producer triplets, combinations of technology, vintage, and region
$\mathcal{H}$: Time slice (hour) covering periods from 2020 to 2050
$\mathcal{H}^B$: Subset of time slices covering periods before 2028 (hours)
$\mathcal{H}^A$: Subset of time slices covering periods after 2028 (hours)

Parameters:
c_i^{ele}: Carbon intensity of electricity generation technology i (tonnes CO_2 / MWh)
$c_j^{H_2}$: Direct carbon intensity of hydrogen production technology j (tonnes CO_2 / tonne H_2)
$\bar{L}_h$: Reference electricity load at hour h (MWh)
e_j: Electricity intensity of hydrogen production technology j (MWh / tonne)

Variables:
$G_{i,h}$: Electricity generation of technology i at hour h (MWh)
$Q_{j,h}$: Hydrogen production of technology j at hour h (tonnes)
$\mu_{i,h}$: Energy attribute credit to certify compliance for 45V emissions accounting of electricity generation technology i at hour h (MWh)
L_h: Endogenous electricity load at hour h (MWh)

Constraints
Electricity load in the model is the reference load plus demand from electrolyzers:

$$L_h = \bar{L}_h + \sum_{j\in\mathcal{J}} e_j Q_{j,h} \quad \forall h \in \mathcal{H} \tag{A.1}$$

Electricity generation must meet[7] load:

$$\sum_{i\in\mathcal{I}} G_{i,h} = L_h \quad \forall h \in \mathcal{H} \tag{A.2}$$

Credits (EACs) are created from valid generation sources:

$$G_{i,h} \geq \mu_{i,h} \quad \forall i \in \mathcal{I}^{45V}, \forall h \in \mathcal{H} \tag{A.3}$$

[6]Note the EAC and TEAC requirements imply all generation capacity must be as new or newer than the electrolyzer capacity

[7]Net electricity transmission and storage are omitted here for brevity

Electrolyzer consumption of credits cannot exceed credit availability at the annual level until 2028 to qualify for the full 45V incentive:

$$\sum_{i\in\mathcal{I}^{45V}} \sum_{h\in\mathcal{H}^B} \mu_{i,h} \geq \sum_{j\in\mathcal{J}} \sum_{h\in\mathcal{H}^B} e_j Q_{j,h} \tag{A.4}$$

and at the hourly[8] level after 2028:

$$\sum_{i\in\mathcal{I}^{45V}} \mu_{i,h} \geq \sum_{j\in\mathcal{J}} e_j Q_{j,h} \quad \forall h \in \mathcal{H}^A \tag{A.5}$$

The IRA also re-introduced and expanded the Qualifying Advanced Energy Project Credit Program under Section 48C(e) of the internal revenue code. The so-called 48C incentive offers an investment tax credit "to expand U.S. manufacturing capacity and quality jobs for clean energy technologies (including production and recycling), to reduce greenhouse gas emissions in the U.S. industrial sector, and to secure domestic supply chains for critical materials (including specified critical minerals) that serve as inputs for clean energy technology production." New low-carbon steel manufacturing facilities–and any existing steel manufacturing facility pursuing retrofits to reduce their greenhouse gas emissions footprint by at least 20 percent–are eligible for up to a 30 percent investment tax credit; however, the project must be completed and operating within four years of an allocation round. Given the short time frame and the lack of existing announcements, we do not represent the 48C incentive for low-carbon steel manufacturing facilities.

Appendix A.3. FINITO

FINITO is a linear program that solves for the cost-minimizing combination of investment and operations for both fuel supply and several industrial sectors including steel, cement, ammonia, and hydrogen. Ongoing work is being done to also include food processing, aluminum, and glass sectors. The model solves at the same geographical resolution of ReEDS at an annual level.

Figure 1 presents an overview of the FINITO model structure. From left to right, primary energy is provided through fossil fuel supply and biomass feedstock curves. The fossil-derived products compete with those produced from corn, corn stover, oil crops, woody biomass, and fats oils and greases (FOG) as inputs. The pooled fossil- and bio-derived fuels are used either in the power sector, the fuels production module, or industrial manufacturing facilities, or to meet exogenously-specified, rest of economy demands. The fuels production module also includes an e-fuels representation which converts stored CO_2 to liquid fuels. The commodity transport and storage sub-module allows for inter-regional trade and storage of commodities, hydrogen, liquid fuels, and captured carbon.

FINITO represents three variations of blast furnace-basic oxygen furnace (BF-BOF) based on on-site coke and pig iron production. Integrated BF-BOF facilities have an on-site coke

[8]Compared to the annual equation, the constraint is enforced $\forall h$, no longer summing over h

oven and use metallurgical coal as feedstock [21] while merchant BF-BOF facilities do not have a coke oven onsite, and purchase coke from off-site merchants. Merchant BOF facilities do not have a BF onsite and require pig iron as an input to produce steel.

FINITO represents five variations of EAF technologies based on fuel input and iron quality. The standard EAF technology mainly uses steel scrap while the integrated DRI-EAF technology uses a combination of DRI and steel scrap [21]. DRI can be produced from natural gas or hydrogen, depending on the technology of the facility. Natural gas sourced DRI-EAF can incorporate CCS. Finally, the FIT-EAF processes iron ore concentrate directly into an electric arc furnace using hydrogen as a feedstock [22].

The FINITO dataset covers existing single BF-BOF and merchant BOF facilities and 8 merchant BF-BOF facilities as well as 81 EAF facilities. Table A.4 highlights average characteristic values of these facilities. Comparison of BF-BOF technologies shows that costs, energy intensity, and carbon emission rates vary depending on on-site pig iron and coke production. Since merchant BOF facilities do not produce pig iron on-site, they have the lowest capital cost, and energy intensity, but the highest iron material cost. In contrast, both BF-BOF and merchant BF-BOF facilities have the same iron material intensity, though BF-BOF facilities have higher energy intensity rates from combustion due to additional coke production. Finally, EAF facilities are more advantageous in terms of cost compared to BF-BOF facilities. Additionally, EAF operations are less energy-intensive compared to BF-BOF facilities with BFs.However, they can only produce secondary quality steel.

For future deployment of steel production capacities, the FINITO dataset includes 11 technologies, featuring both BF-BOF and EAF versions with CCS integration. In this study, we focus exclusively on H_2-DRI-EAF as the investment option for future deployment. Table 2 summarizes the characteristics of H_2-DRI-EAF. We assume that H_2-DRI-EAF will improve efficiency, leading to reduced energy and material intensity, as well as lower system costs. To reflect this, we reduce energy intensity and system costs by 3% every four years.A comparison of H_2-DRI-EAF characteristic values over all years with other existing technologies shows that, while its capital costs are comparable to BF-BOF facilities with BFs, its operational costs are higher than those of other facilities. Furthermore, the energy intensity of H_2-DRI-EAF is lower than BF-BOF facilities with BFs, but higher than that of EAF and BF-BOF facilities without BFs.

Appendix A.4. Steel Sector Assumptions

There are two types of steel demand represented in FINITO: primary and secondary. Primary steel demand is for virgin steel, typically produced in the United States via BF technologies and iron ore. Secondary steel demand is produced from recycled steel, typically using EAF technologies in the United States. All steel technologies that produce primary steel can also meet the demand for secondary steel. However, EAF technologies using only steel scrap are assumed to not meet the quality standards for primary steel.

In 2021, demand for primary and secondary steel were approximately 25 and 60 million metric tons (respectively) [23]. For our scenario analysis, total steel demand is assumed to remain constant, as the historical steel demand trend has been stable [23]. Additionally, we assume that secondary steel's share of total steel production will increase over time, capturing approximately 80% of steel demand by 2035 (Figure A.8). Finally, we assume that the regional distribution of steel demand across the United States remains unchanged through 2035 (Figure A.9).

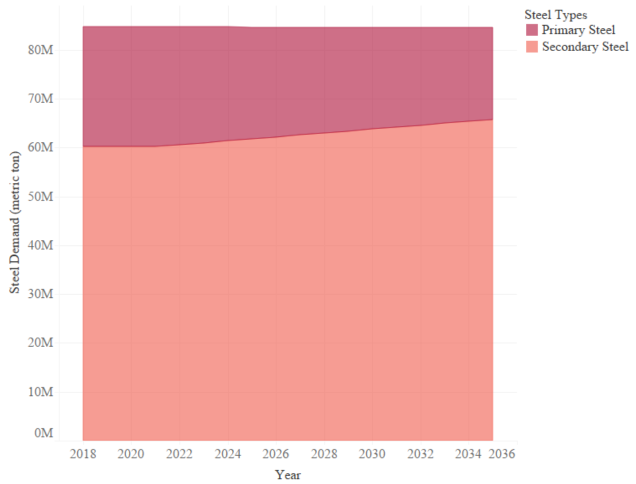

Figure A.8: Assumed evolution of primary and secondary steel demand over time

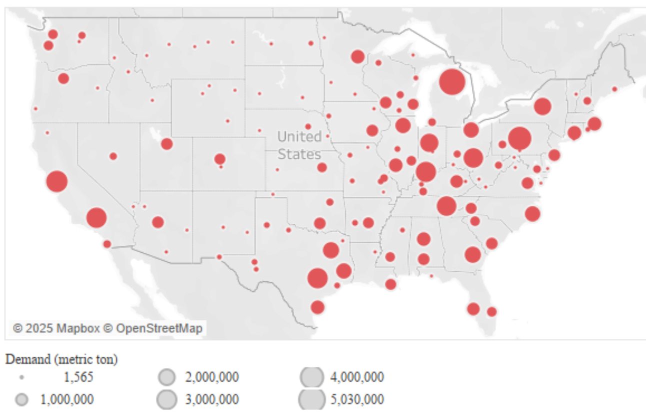

Figure A.9: Assumed demand for steel in 2035

Appendix A.5. ReEDS-FINITO Linkage

The ReEDS-FINITO linkage is performed through co-optimization of both models. Said differently, the two models are combined into a single set of constraints and variables as well as a single objective function for cost minimization. In this sense, the models are 'stacked' to form a single model with endogenous consideration of the impacts that industry and fuel production have on the power sector and vice versa.

Table A.4: Average characteristic values of existing steel facilities

		BF-BOF	Merchant BOF	Merchant BF-BOF	EAF
Number of Existing Facilities		1	1	8	81
Capital Cost	$/t	847.05	170.36	847.05	141.76
Fixed O&Ma	$/t-yr	76.79	76.79	76.79	46.80
Electricity Use	MWh/t	0.19	0.05	0.16	0.48
Coal Use	MMBtu/t	0.83		0.91	
Metallurgical Coal Use	MMBtu/t	17.20			
Coke Use	MMBtu/t			15.88	
Natural Gas Use	MMBtu/t	4.41	1.46	2.49	0.51
Propane Use	MMBtu/t				0.01
Residual Fuel Oil Use	MMBtu/t			0.09	
Distillate Fuel Oil Use	MMBtu/t			0.00	0.01
Steel Scrap Use	t/t	0.25	0.25	0.25	0.80
Iron Ore Use	t/t	1.10		1.10	
Pig Iron Use	t/t		0.85		
Carbon Emission Process Rate	CO2 t/t	0.81	0.81	0.81	0.08
Carbon Emission Combustion Rate	CO2 t/t	0.31	0.08	0.22	0.03

The connection of FINITO with the electricity sector requires disaggregating the industrial sectors' annual demands to the timeslice resolution in ReEDS. For electrolysis, the dominant source of new load, operation is flexible in that production can ramp up or down without constraint; the electricity intensity for electrolytic hydrogen production are featured in 1. However, in the present formulation, steel production and its associated energy consumption is assumed to be constant across all timeslices; that is, the electricity demand profile for all industrial manufacturing facilities is assumed to be flat. Despite the lack of available load shapes at facility or sector level, this is the first step towards capturing exogenous effect of green facilities deployment on both the power and steel sectors, simultaneously. Ongoing work is focused on the value of sub-annual production flexibility in industrial electrification.

The price paid for electricity by industrial facilities is a key feature of the ReEDS-FINITO linkage. The shadow value off the supply-demand constraint serves this purpose and can best be interpreted as the wholesale price for electricity as it does not include any retail components - it is only the cost of delivering bulk power to the busbar. Thus, we incorporate a grid-connected retail price adder at $28 / MWh[9], computed as the average difference between the price faced by industrial consumers and the wholesale energy price from the 2023 Annual Energy Outlook EIA [18].

The linked version of the model shares two sub-modules which entail the characteristics, constraints, and costs of CCS and hydrogen production. The linked model defaults to the sub-annual representations of CCS and hydrogen included in the ReEDS model and co-optimizes the operations and investment for the shared resources. Again, steel production activity is assumed to be flat across all timeslices, and this analysis assumes no flexibility related to the associated hydrogen demand of steel facilities or carbon capture activity.

Appendix B. Discussion Details - Sensitivity Assessment of the Levelized Cost of Hydrogen

The levelized cost of hydrogen (LCOH) is influenced by a range of factors, including technological performance and financial assumptions. In this study, the reference assumptions for electrolyzer CapEx and fixed O&M costs are set at $\$550/kW$ and $27.5 per kW-year, respectively. Additionally, the power retailer markup is assumed to be $\$28/MWh$ for the year 2035. In this section, the impact of variations in electrolyzer performance and power retailer markups on the LCOH is evaluated using nine sensitivity cases, as outlined in Table B.5. Cases names represents the combination of electrolizer CapEx, fixed O&M, and power retailer adder, respectively. In five of these cases, electrolyzer CapEx values range from $\$451.83/kW$ to $\$2000/kW$, while the fixed O&M costs are set at $12.8, $22.6, or $27.5 per kW-year, all under a constant reference power retailer markup. The remaining four cases introduce 10% and 20% deviations from the baseline retailer adder, while keeping the electrolyzer CapEx and O&M at their reference values. These scenarios enable a comprehensive sensitivity analysis of how both technological parameters and electricity pricing structures affect the LCOH.

Figure B.10 illustrates the LCOH values under 30% deployment of H_2-DRI-EAF for nine sensitivity cases, along with a reference case, across all deployment and market configuration scenarios. The three key cost components —electrolyzer CapEx (orange bars), fixed O&M (teal bars), and power retailer markup (dark red bars) — are visualized to highlight their contributions and variations across the different cases, while all other LCOH components remain consistent with the reference case. The results show that, for grid-connected systems, the power retailer markup has a more significant impact on LCOH

[9] All currencies in this paper are expressed in 2022 USD

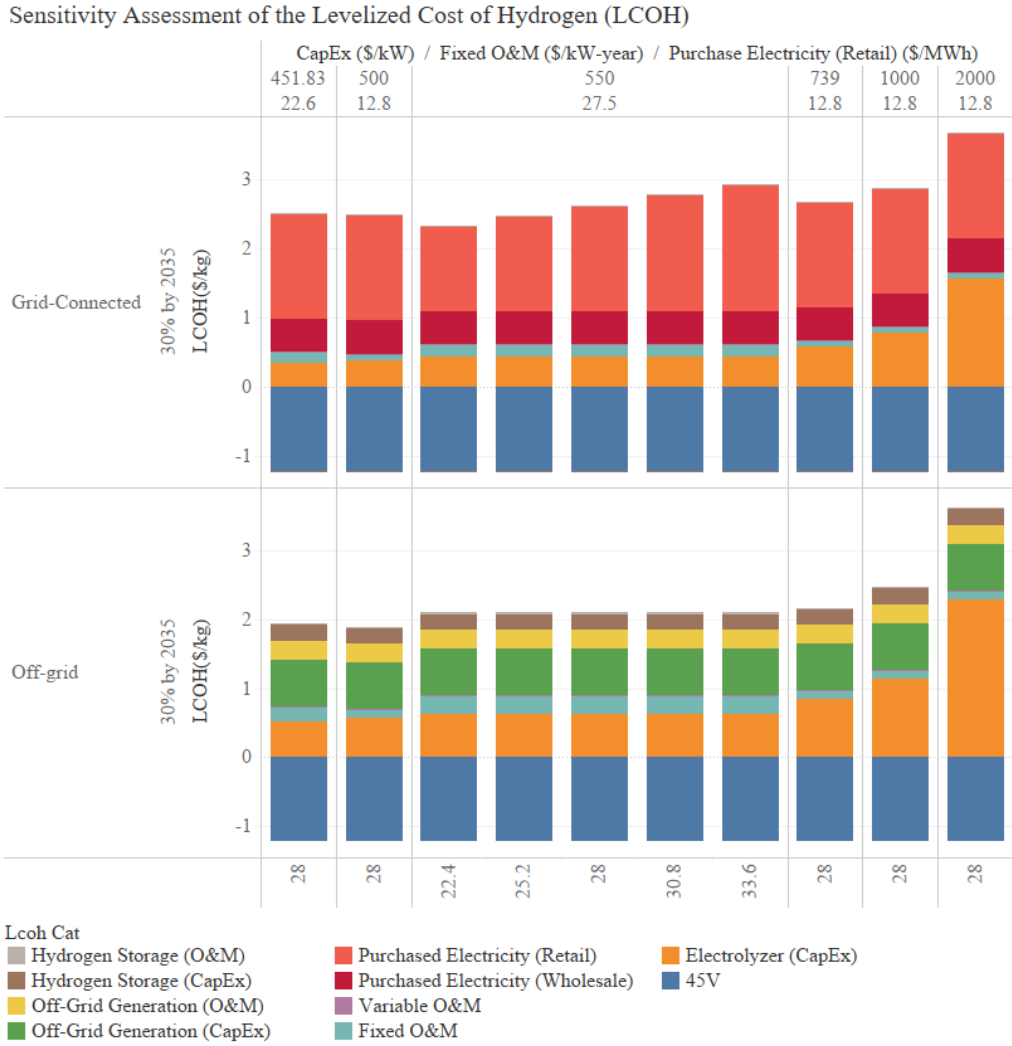

Figure B.10: Sensitivity Assessment of the Levelized Cost of Hydrogen

Table B.5: Summary of cases used in sensitivity assessment of the LCOH

Case Name	CapEx ($/kW)	Fixed O&M ($/kW-yr)	Retailer Markup ($/MWh)
2000-12.8-28.0	2000	12.8	28.0
1000-12.8-28.0	1000	12.8	28.0
739-12.8-28.0	739	12.8	28.0
500-12.8-28.0	500	12.8	28.0
452-22.6-28.0	452	22.6	28.0
550-27.5-22.4	550	27.5	22.4
550-27.5-33.6	550	27.5	33.6
550-27.5-25.2	550	27.5	25.2
550-27.5-30.8	550	27.5	30.8

than electrolyzer-related parameters. Although the marginal effects of electrolyzer CapEx and fixed O&M are less pronounced in grid-connected systems, these factors have a greater influence on LCOH in off-grid configurations. Moreover, the relative impact of these three cost components on LCOH remains consistent across varying levels of H2-DRI-EAF deployment.

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