MASTER PROJECT
Optimizing Emissions Reduction: Green Hydrogen Subsidies vs. Grid Interconnection in Texas

Authors: Fernando Araya, Marcus Bockhold and Nazarena Marano Suffern

Supervisor: Mar Reguant

Economics of Energy, Climate Change, and Sustainability Program, Class of 2024

Barcelona School of Economics

June-2024

Contents

Abstract

The Inflation Reduction Act (IRA) has allocated significant resources to the development of the green hydrogen industry in the United States (US), given its potential for a low-carbon future. Texas, the leading hydrogen producer in the US, stands to benefit substantially from these subsidies by directing future renewable energy investments towards green hydrogen production. However, developing green hydrogen infrastructure would mean diverting resources away from other urgent decarbonization initiatives like greening the electricity grid and upgrading transmission infrastructure. Our research provides a novel comparison of the decarbonization potential of investments in green hydrogen and transmission infrastructure in Texas.

We simulate the cost and emissions reductions of producing green hydrogen with new wind generation in Texas under the IRA green hydrogen subsidy. Our results show that installing 30 GW of wind capacity for green hydrogen production would reduce annual emissions by 18 million tons (Mt.) of CO_2 at a cost of 300 US$ per ton of CO_2. In an alternative scenario, we simulate adding the same 30 GW of wind capacity directly to the Texas electricity grid, finding that without policy intervention, the grid's capacity to profitably accommodate new renewable investment is capped at 3 GW of wind power, reducing emissions by 5 Mt CO_2 per year. This limitation on new wind capacity stems from the isolation of the Texas grid. Finally, we simulate the decarbonization potential of interconnecting Texas and the Western US grid via increased transmission capacity. We find that building a transmission line with a capacity of 6 GW enables the addition of at least 30 GW of wind capacity in Texas without the need for additional policy intervention. We also find that interconnecting Texas and Western US has the potential to reduce 80 Mt CO_2 per year at an abatement cost between US$ 8-32 per ton of CO_2, making investment in transmission infrastructure a more cost-effective alternative to reduce carbon emissions than subsidizing green hydrogen.

Keywords: *Green hydrogen, Energy transition, Transmission infrastructure, Texas, Inflation Reduction Act (IRA)*

1 Introduction

World leaders and policy makers are under increasing pressure to address the existential threat of climate change. In the landmark Paris Agreement of 2015, governments committed to limiting global warming to no more than 2 degrees Celsius above pre-industrial levels. Achieving this target requires deep and rapid reductions in global greenhouse gas emissions (GHG) by 2030, reaching net zero emissions by 2050 (IPCC, 2023). Accounting for over 70% of global emissions, decarbonization of the energy sector is critical to achieving net-zero emissions (Ritchie and Roser, 2020). Declining costs and expansion of manufacturing have led to rapid deployment of renewable energy technology, with more than $1 billion per day spent on solar deployment alone in 2023 (IEA, 2023a). Despite significant progress, electricity still represents 44% of energy related CO_2 emissions (IEA, 2023b), making the decarbonization of electricity generation a high priority to reduce overall emissions.

The United States (US) is the second largest global emitter, having released 4.5 Gt CO_2 in 2023 (IEA, 2024). US electric power sector emissions amounted to roughly 1.74 Gt CO_2 (EPA, 2024). In 2022, the US government enacted the Inflation Reduction Act (IRA), considered to be the most significant government action on clean energy and climate change in US history. The bill includes a comprehensive package of public subsidies for low-carbon and decarbonization technologies, including incentives to invest in renewable generation, and purchase electric vehicles, among others, signaling the government's prioritization of certain sectors in the nation's decarbonization efforts. The US government expects that the IRA will help the country meet its climate goals, including a net-zero economy by 2050.

Green hydrogen is one of many low-carbon technologies targeted under the IRA. Current hydrogen production is relatively carbon intensive, with emission intensity ranging from 10-14 kg CO_2-eq/kg for hydrogen produced from unabated natural gas, commonly referred to as gray hydrogen, up to 27 kg CO_2-eq/kg for hydrogen produced from coal, known as brown or black hydrogen (Acciona, 2022; IEA, 2023c). Gray hydrogen is the most common type of hydrogen used today, and currently has the lowest cost of production (IEA, 2023c; Acciona, 2022; Iberdrola, 2024). Blue hydrogen is also produced from natural gas[1], and the resulting emissions are abated using carbon capture and storage technologies (CCS) to reduce the overall emission released into the atmosphere (Acciona, 2022). Depending on the capture-rate of the CCS technology used, the emissions intensity of blue hydrogen ranges from 0.8-8 kg CO_2-eq/kg of hydrogen, although technologies achieving the lower bound are not yet in operation (IEA, 2023c). Green hydrogen is produced through a process called electrolysis, and can only be considered green if the electricity used in the production process is generated from renewable sources. Electrolysis for green hydrogen production uses water and renewable electricity as inputs, causing a reaction that splits water molecules into hydrogen and oxygen (Acciona, 2022). No carbon emissions are released in this process, making the emissions intensity of green hydrogen 0 kg CO_2-eq/kg of hydrogen (IEA, 2023c; Iberdrola, 2024). If the electricity used for electrolysis is sourced directly from the grid, then the emissions intensity of the hydrogen produced will depend on the emissions intensity of the particular electricity grid at the time of production (IEA, 2023c).

The IRA subsidy for green hydrogen is set at a maximum of 3 US$/Kg subject to three criteria[2][3]. The first criteria, incrementality, requires hydrogen to be produced from new clean power sources.[4] The second, regionality, requires that the clean electricity used to produce hydrogen must be generated in the same region where hydrogen is produced. The third, time-matching, states that claimed generation must occur within the same time that the electrolyzer claiming the credit is operating.[5]

This subsidy, estimated to cost around US$ 100 billion (Bistline et al., 2023b), is motivated by the expected role that green hydrogen will play in the US low-carbon future. Although hydrogen is currently used predominantly as a feedstock in the chemical or oil refining industry, it offers potential in energy storage, energy transportation, and in the decarbonization of hard-to-abate sectors. Currently, the cost of producing green hydrogen is in the range of 3-12 US$/Kg whereas the cost of producing fossil-based hydrogen ranges between 1-3 US$/Kg (IEA, 2023d). The IRA subsidy aims to make green hydrogen cost-competitive with fossil-based hydrogen by the end of the decade. Reducing the cost of green hydrogen is expected to first lead to the replacement of the current demand for gray hydrogen, and later, to enhance the development of other alternatives such as synthetic liquid fuels (IEA, 2023d).

Within the US, Texas is poised to be a leader in green hydrogen development, with an estimated production potential of 106 Mt per year (Levene et al., 2007). The US Department of Energy has selected Houston, Texas as one of the seven hydrogen hubs nationwide, where 30% of the ongoing or announced hydrogen infrastructure projects are expected to be located. High production potential in Texas stems from the state's capacity to produce low-cost, clean electricity, and an existing market for gray hydrogen, mostly associated with oil refining and ammonia production.

Producing green hydrogen is highly energy intensive, requiring 50.42 MWh to produce one ton of green hydrogen[6]. Thus, it would take 93 TWh per year just to supply the hydrogen demand of oil refineries in Texas, or the addition of approximately 30 GW of wind capacity to the grid. Such investment would be equivalent to an expansion of nearly 84% of existing wind capacity in Texas[7]. New investment in wind generation could otherwise be directly added to the grid to further decarbonize power generation. Our research quantifies the opportunity cost of devoting new renewable generation to hydrogen production in Texas.

This paper provides a novel comparison of public investments in green hydrogen and transmission infrastructure, based on emissions reductions and cost of abatement. We compare the development of the green hydrogen industry in Texas with alternative scenarios where equivalent resources are dedicated to reducing emissions from power generation. Specifically, we simulate a counterfactual

[1]Gray and blue hydrogen are produced from natural gas, through a process called steam reforming, in which natural gas molecules are separated into hydrogen and carbon dioxide.

[2]The tax credit is for "clean" hydrogen and therefore ranges from US$ 0.6-3.0 per Kg of hydrogen depending on the carbon intensity. Given that we are focused on green hydrogen only, we will for the rest of the paper refer to the upper bound (3 US$).

[3]According to the provisional proposed guidance published in December 2022 by the US Department of the Treasury and the Internal Revenue Service (IRS) still subject to further revision. Available here.

[4]New is defined as sourced from operators that began commercial operations within three years of a hydrogen facility.

[5]This will be an hourly matching. However, there is a transition period until 2028 when annual matching is allowed.

[6]Details for these calculations can be found in Table 10

[7]Texas has 35,600 MW of installed capacity according to E-grid 2022.

scenario where additional wind capacity is added to the currently isolated Texas electricity grid, without policy interventions. Additionally, we simulate a scenario where the equivalent wind capacity devoted to green hydrogen is added directly to the grid, with the potential to trade with the Western US through a 6 GW transmission line.

2 Literature review

Decarbonizing the electricity grid and electrifying additional sectors, such as transportation, heating, and cooling, are pivotal to reducing global emissions, with many projecting that anything that can be electrified will be (Oliveira et al., 2021). This increase in electrification is expected to drive up electricity demand and increase the need for further renewable technology deployment.

While renewable energy provides a solution to electricity sector emissions, an increasing share of variable renewable energy (VRE) in the electricity grid brings additional complexities. Primarily, the intermittent nature of renewables means that peak hours of production do not necessarily coincide with peak hours of demand. It is also often the case that locations with the highest renewable generation potential are far from population centers, making transmission a critical piece of the decarbonization puzzle (d'Amore Domenech et al., 2021; DeSantis et al., 2021). For example, in the US, wind and solar resources are concentrated in the geographic center of the country, whereas the population, and therefore demand, is concentrated along the east and west coasts (DeSantis et al., 2021). This variability and mismatch in the location of production and demand necessitates adequate energy storage and transmission infrastructure; a necessity that could be exacerbated by the renewable energy transition. Inadequate infrastructure in this regard can lead not only to energy curtailment but also to a discouragement of new entry and investment in renewables (Gonzales et al., 2022).

Despite the progress made in decarbonizing the electricity sector, there are also several hard-to-abate sectors that remain difficult to electrify, and therefore require an alternative solution to completely decarbonize. In light of the storage and transportation challenges associated with VRE, and these hard-to-abate sectors, many have investigated green hydrogen as a viable solution to fill this gap (Atilhan et al., 2021; Bhaskar et al., 2020; d'Amore Domenech et al., 2021; Galván et al., 2022; Garud et al., 2023; IEA, 2023d; Keith and Leighty, 2002; Komiyama et al., 2015; Oliveira et al., 2021; Rambhujun et al., 2020; Taieb and Shaaban, 2019; Wang et al., 2023). The surge in literature exploring the applications of green hydrogen for decarbonization is focused in three broad categories: direct use (as a chemical feedstock, fuel, or heat source); energy storage; and energy transportation.

In addition to the traditional hydrogen applications, primarily in the chemical industry and in oil-refining, the use of green hydrogen has been proposed to decarbonize additional, hard-to-abate sectors including heavy industry, long-range transport, as well as buildings and power generation Atilhan et al. (2021); Bhaskar et al. (2020); IEA (2023d); Oliveira et al. (2021); Rambhujun et al. (2020); Company (2023). However, current uptake of hydrogen in new applications, such as steel, cement, glass-making, and non-ferrous metals, remains minimal, at less than 0.1% of demand in 2022 (IEA, 2023d).

Regarding heavy industry, Bhaskar et al. (2020) find that green hydrogen applications in the iron and steel sector could reduce global emissions by 2.3 Gt CO_2 per year, but this decarbonization potential is still hypothetical. According to the IEA Net Zero Emissions scenario (NZE), in 2030 8 Mt of hydrogen will be used directly in transport, with 50% used in road transport, and 45% used in maritime shipping, and an additional 8 Mt are used in ammonia and synthetic fuel production for end-use in shipping and aviation (IEA, 2023d)[8]. Although mentioned in the literature as potential applications, the IEA projects that the use of hydrogen in buildings, for heating, and in power generation will be negligible (IEA, 2023d). While there is potential for green hydrogen to reduce emissions across new applications, developing new markets for hydrogen does run the risk of increasing demand for unabated fossil-based hydrogen, which could result in higher total emissions than the direct use of fossil fuels. Therefore, effective policy and regulation will be critical in ensuring that new demand is met by green hydrogen (IEA, 2023d).

In addition to applications for direct use as a fuel or industrial feedstock, hydrogen's properties as

[8] It is important to note that NZE scenario is one potential scenario to reach net zero and should not be interpreted as a forecast.

an energy carrier have led researchers to explore its potential in energy storage systems alongside increasing VRE capacity. However, energy losses in converting electricity to hydrogen, its low volumetric density, in addition to its higher flammability than other fuels, and sensitivity to detonation, make storage a challenge (Rambhujun et al., 2020). Storing hydrogen as ammonia has been proposed as an alternative to conventional storage of pure hydrogen[9], but has not yet been deployed at industrial scale (Rambhujun et al., 2020). Considering relevant energy losses, findings from the literature show that a combination of rechargeable batteries and hydrogen storage is optimal for power systems with large-scale VRE, with battery storage optimal to alleviate hourly fluctuations, and hydrogen to fulfill seasonal storage demand of of up to 15% of total generation (Komiyama et al., 2015; Oliveira et al., 2021).

Several studies have been conducted on the viability, from a cost perspective, of green hydrogen for transportation and export of VRE over various distances. Depending on the distance and whether transportation is over land or sea, transportation by hydrogen, via pipeline, liquified hydrogen, or as ammonia may be preferred to high-voltage direct current (HVDC) transmission, with many agreeing that for distances greater than around 1,000 km hydrogen transportation is more cost effective than transmission (d'Amore Domenech et al., 2021; DeSantis et al., 2021; Keith and Leighty, 2002; Lüth et al., 2023; Taieb and Shaaban, 2019; Wang et al., 2023). Transmission infrastructure has been compared to hydrogen infrastructure at length in the literature, based on relative costs, technological efficiency, and overall profitability for energy transportation. However, to our knowledge, the current literature has not explicitly quantified the relative emissions reduction potential of each technology. Our research seeks to evaluate these alternatives from not only a cost perspective, but based on overall emissions reductions, and relative abatement costs.

Integrating hydrogen production capacity with an increasing share of VRE results in both costs and benefits to the existing energy grid, leading researchers to investigate the optimal balance of both technologies considering overall costs and emissions. Hydrogen production capacity has the potential to provide flexibility to a grid with large shares of VRE, reducing the cost of electricity production, thus allowing for a cheaper electricity system, while providing access to a new industry (Galván et al., 2022). In the case of offshore wind production, Lüth et al. (2023) find that supplying the electricity to the grid has a greater impact on overall emissions from generation than using the same electricity to produce green hydrogen. However, hydrogen production infrastructure does complement offshore power transmission in mitigating intermittency and reducing curtailment (Lüth et al., 2023). Wang et al. (2019) find that at high penetration of renewables in the grid, the use of hydrogen to capture excess renewable generation, avoiding curtailment, has a limited effect on emissions, but can significantly reduce the levelized cost of energy.

Focusing on Texas specifically, several studies have already investigated the economic and decarbonization potential of producing green hydrogen within the state. A 2023 report by McKinsey & Company identified four priority demand areas for low emission hydrogen (ammonia, petrochemicals and refining, ground transportation, and power and utilities) amounting to a total estimated demand of 6.1 Mt of hydrogen produced in Texas by 2030 (Company, 2023). Glenk and Reichelstein (2019) find that hydrogen prices of at least US$3.53/kg are necessary in Texas for green hydrogen production to be economically viable. Given the observed learning curves for electrolysers and wind turbines, they predict that green hydrogen will be economically competitive with industrial-scale gray hydrogen by 2030 (Glenk and Reichelstein, 2019). Bødal et al. (2020) investigate the optimal investment in electricity and hydrogen infrastructure under various low carbon and hydrogen demand scenarios. Their model determines that increasing hydrogen production can enable larger shares of VRE in the grid, up to 94% of total generation. However, in the highest hydrogen demand scenario, emissions increase drastically from the baseline scenario if an adequate CO_2 price is not implemented, as marginal emissions increase with hydrogen demand. Producing green hydrogen from renewables in Texas has the potential to mitigate curtailment, while providing long-term "seasonal" storage with the potential to increase the share of renewables in the Texas grid by 16% (Morton et al., 2023; Wikramanayake et al., 2021).

Regarding electricity transmission, disconnection between regional electricity grids is also a salient issue. Regional disconnection is particularly challenging in the US which has three separate, uncon-

[9] Currently the most common methods to store hydrogen are high pressure vessels (hydrogen tanks) and liquefaction (cryogenic tanks).

nected electricity grids: Texas, the Western Interconnection and Eastern Interconnection (Cantafio and Nowak, 2021). Most studies in Texas explore the transmission constraints in the region by focusing on the intra-regional infrastructure rather than analyzing the potential of connecting Texas to other US regions (Rhodes, 2023; EIA, 2023). King (2012) highlights an important aspect regarding transmission challenges in Texas' integration with other regions, discussing the "chicken and egg" dilemma where wind generators are hesitant to invest without guaranteed transmission capacity, and transmission developers are reluctant to build without assurance of generator use. However, there is a notable gap in the literature with regard to quantifying the effects of increasing transmission capacity between Texas and neighboring grids, as well as the potential emissions reductions and abatement costs of such policies. To our knowledge, no studies in the literature have simulated the decarbonization potential of interconnecting Texas and the Western US.

The IRA has become a cornerstone of US climate policy, funding many decarbonization initiatives, including the development of green hydrogen. Bistline et al. (2023a) estimates that the IRA, with its mix of tax credits, has the potential to reduce US economy wide emissions between 43-48% by 2035, compared to 2005, with 64% of the total expected reductions coming from the decarbonization of the electricity sector. The authors estimate that the largest effect would come from facilitating the expansion of wind and solar generation, which are expected to grow in a range of 10-99 GW/yr and 58 GW/yr, respectively; more than double what would be expected in the absence of the IRA. This growth in renewables would, in turn, help reduce generation from unabated coal by 38-92% in 2030, compared to 2021 levels. This reduction positively compares with a decrease of 3-60% in the absence of the IRA.

To achieve the expected reductions, the IRA has committed a significant budget to finance economy-wide decarbonization. The Congressional Budget Office (CBO) estimates the total cost of implementing the IRA would be $392 billion over the 10-year budget window (CBO, 2022). However, that number could increase as the IRA subsidies are uncapped. Bistline et al. (2023b) estimate that the total cost of the IRA could be between $780 and $1,070 billion over its duration, significantly higher than official estimates. They estimate that the emissions reduction of the IRA comes at an average abatement cost of $36-87 per ton of CO_2 for the power sector. For context, (Farbes et al., 2021) identify a range of policies from negative abatement costs—where some measures can even generate revenue—to measures exceeding 250 US$ per ton of CO_2. Among the most cost-effective measures are solar PV and wind, both onshore and offshore, with costs ranging from 0 to 60 US$ per ton of CO_2. In contrast, hydrogen electrolysis appears in the relatively higher range of 60-90 US$ per ton of CO_2, similar to other zero-carbon fuels. Thus, the average abatement costs reported by Bistline et al. (2023b) are within the range of cost-effective measures reported in the literature. Additionally, the authors argue that the estimated abatement costs are below the central values of the social cost of CO_2 reported by Rennert et al. (2022) of $120-400 per ton of CO_2 in 2030. However, they do not provide details on the abatement cost for the different subsidies included in the IRA.

Cheng et al. (2023), on the other hand, estimate the abatement cost of subsidizing clean hydrogen produced from natural gas (with and without carbon capture and sequestration), electricity, and biomass in the context of the IRA. They report an abatement cost of clean hydrogen ranging from US$ 65 to 384 per ton of CO_2, depending on the fuel used as its feedstock. The authors estimate that the subsidies offered by the US government are sufficient to make clean hydrogen cost-competitive with gray hydrogen. They also warn about the adverse effects of using existing renewable generation for hydrogen production, as it would force other consumers to switch to electricity generated by fossil fuels. However, that concern has already been addressed by the most recent guidelines of the IRA[10]. Finally, the authors also simulate the impact of IRA on Synthetic Liquid Fuels, estimating that the proposed subsidies are insufficient to make them competitive with petroleum-derived jet fuels.

In summary, reducing the emissions and expanding transmission in the electricity grid are considered high priorities for decarbonization, although it is unlikely that they alone will drive down emissions to net zero. The potential for green hydrogen to fill the gaps left by renewable energy in decarbonizing hard-to-abate sectors, providing seasonal energy storage, and long distance energy transportation has been studied at length, both globally and in the context of Texas. However, to our knowledge, comparative analyses of investments in green hydrogen and alternative decarbonization measures, in the

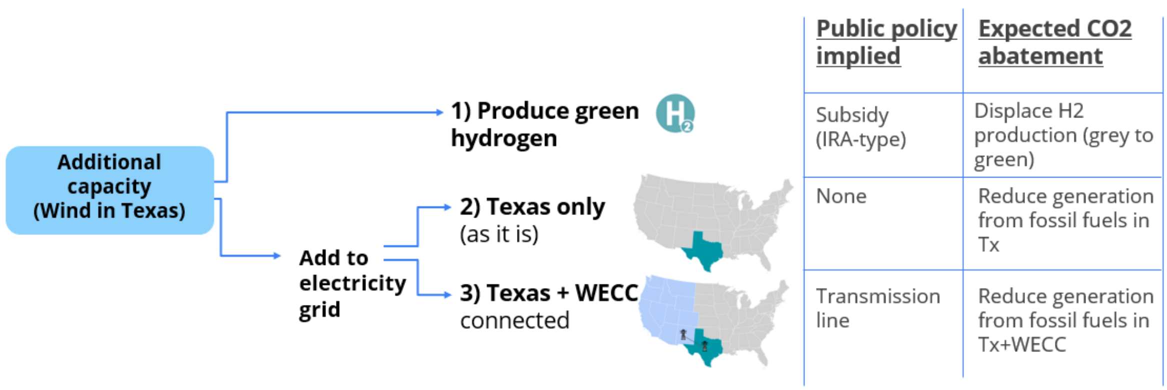
[10]According to the provisional proposed guidance published in December 2022 by the US Department of the Treasury and the Internal Revenue Service (IRS) still subject to further revision. Available here.

context of a least-cost decarbonization strategy, are not present in the literature. Given that Texas is an isolated grid, with abundant renewable energy resources, coupled with government funding allocated to green hydrogen development under the IRA, the most cost effective decarbonization strategy in Texas is yet to be explored. Our research seeks to assess the optimal use of renewable generation in Texas, comparing investments in green hydrogen infrastructure to increased grid interconnection via HVDC transmission infrastructure.

3 Scope and scenarios

In this section, we outline the main assumptions on which we build our simulations to assess the decarbonization potential of green hydrogen production in Texas and the chosen counterfactual scenarios, looking at electricity production in the Electric Reliability Council of Texas (ERCOT) and the Western Electricity Coordinating Council (WECC) in the Western US.[11] Figure 1 summarizes the three scenarios simulated. The simulations' outputs are compared to a business-as-usual baseline where the two systems remain disconnected and hydrogen demand in Texas is supplied by gray hydrogen.

Figure 1: Summary scenarios and assumptions



Source: Own elaboration.

3.1 Produce green hydrogen

Our green hydrogen simulation in Texas is based on the criteria established in the IRA for claiming the entire subsidy. Thus, we assume that green hydrogen is produced with dedicated, new renewable capacity in ERCOT and that green hydrogen production is perfectly matched with the generation of the added installed capacity. The practical implication of this assumption is that the baseline merit order curve is not altered. Thus, the amount of electricity generation that goes into the grid, prices, and emissions remain equal to the baseline. We also assume that the IRA makes green hydrogen cost-competitive with gray hydrogen in Texas, based on Cheng et al. (2023) and our calculation of a levelized cost of hydrogen (LCOH) in the range of US$ 2.8 per kg.[12][13] Therefore, we assume that green hydrogen produced in Texas displaces gray hydrogen currently produced, abating its CO_2 emissions. Finally, we assume that the green hydrogen industry, as a first step, adds 30 GW to the ERCOT grid to supply the existing demand for hydrogen in Texas.

[11] WECC is composed by four subregions: California, Northwest, Southwest and Rockies.

[12] See more details in Appendix A.2

[13] The IRA subsidy increases the likelihood of green hydrogen becoming profitable by reducing uncertainty in the market about its role in decarbonizing the hard-to-abate sectors. Reducing uncertainty can reduce the discount rate for hydrogen projects, facilitating investment and promoting the learning-by-doing virtuous circle of renewables explored in the literature.

3.2 Add renewable Capacity to ERCOT

Our first counterfactual scenario simulates the decarbonization potential of adding up to 30 GW of extra renewable capacity to the ERCOT grid. The most relevant assumption is that ERCOT cannot trade with other electricity systems due to its isolation from other relevant markets. Thus, the new renewable generation is consumed within Texas. Additionally, we assume no transmission constraints within ERCOT. Finally, we assume that this new capacity is added with no policy intervention. Hence, we model the maximum wind capacity that can be added to the grid considering the private sector's profitability (see more details about the definition of profitability in Section 4.2). Once we obtain this maximum capacity, we compute the market outcomes (generation, demand, prices, and emissions) from this scenario.

3.3 Add renewable Capacity to ERCOT+WECC

Our second counterfactual simulates a transmission line connecting ERCOT and WECC, two of the most relevant electricity consumption hubs, accounting for a combined total of 25% of US electricity demand. The simulated transmission line, with a capacity of 6 GW, allows for trade between two systems with distinctive generation profiles. Our central assumption is that the two systems are operated by a social planner that maximizes joint welfare at every hour of the day. Our model also assumes no intra-regional transmission constraints, making the maximum line capacity the only relevant trade constraints between the two regions. This last assumption, which differs from the modeling of internal constraints of Bushnell et al. (2017) and Fowlie et al. (2021), tries to replicate the uniform prices observed within the WECC regions in 2023 (see Section 5 for more details). Finally, we model the market outcomes when adding up to 30 GW extra wind capacity and compute the resulting emissions.

4 Model

4.1 Produce green hydrogen

We model green hydrogen production and its decarbonization potential following the assumptions stated in the previous section. First, we estimate the annual production of hydrogen associated with installing 30 GW of wind capacity in Texas, following equation (1).

$$Q_H = \sum_{t=0}^{T} (GW_{wind} * CF_t) * TransRate \tag{1}$$

Where:

- Q_H is the quantity of hydrogen produced in one year in Mt
- GW_{wind} is the installed capacity of wind generation dedicated to hydrogen.
- CF_t is the wind capacity factor at time t.
- $TransRate$ is the transformation rate of electricity to hydrogen[14]

Then, we estimate emissions abatement of replacing gray for green hydrogen following equation (2):

$$\Delta CO_2 = Q_H * ER_{GH} \tag{2}$$

Where:

[14] Measured as 1 over the amount of KWh of electricity needed to produce 1kg of hydrogen = 50KWh. Details about this calculation can be found in Table 10

- ΔCO_2 = emissions reduction (Mt CO_2)
- ER_{GH} = emission rate of gray hydrogen (10 kg CO_2/kg)

With results from equation (1) we estimate the cost of subsidizing hydrogen production in Texas with the IRA:

$$CostH_2Policy = Q_H * Sub_{IRA} \tag{3}$$

Where:

- $CostH_2Policy$ = cost of subsidizing green hydrogen production (US$ million)
- Sub_{IRA} = US subsidy for green hydrogen production under the IRA (US$ 3/kg)

Finally, equations (2) and (3) allow us to estimate the abatement cost of the policy:

$$AbatementCostH_2 = \frac{CostH_2Policy}{\Delta CO_2} \tag{4}$$

4.2 Add Renewable Capacity to ERCOT

We construct a partial equilibrium model that simulates the ERCOT system. We model our solutions as maximizing aggregated surplus considering electricity demand and generation cost of different sources available throughout the day. The social planner simultaneously chooses the wind capacity that maximizes social welfare subject to the profitability of the investment.

Formally, the social planner maximizes equation (5):

$$max_{Q_t, GW_{wind}} \sum_{t}^{T} [GS(Q_t) - C(Q_t)] \tag{5}$$

Where:

GW_{wind} is the wind capacity added to the grid,

$GS(Q_t)$ is the social surplus at time t, defined by equation (6):

$$GS(Q_t) = \int_{p_t}^{\infty} D(p_t) dp_t \tag{6}$$

$D(p_t)$ is the demand at time t, which takes the following linear expression:

$$D(p_t) = \alpha - \beta p_t \tag{7}$$

$C(Q_t)$ is the cost function, which is itself a function of the quantity produced by each unit and its marginal cost, as expressed in equation (8):

$$C(Q_t) = \sum_{i}^{N} c(q_{i,t}) = \sum_{i}^{N} c_i * q_{i,t} \tag{8}$$

Our model specification simplifies reality, as it does not model separately the different nodes that compose the ERCOT grid and thus does not consider intra-grid transmission constraints.

The resulting emissions from the maximization problem are given by the following equation:

$$E_t = \sum_{i}^{N} q_{i,t} * er_i \tag{9}$$

Where er_i is the emissions rate per plant.

These emissions and their social cost do not enter the maximization problem as Texas does not currently tax carbon emissions from power generation. Using the estimated emissions, we can calculate variations to the baseline scenario.

The social planner maximization problem includes the following constraints:

1. Following Fowlie et al. (2021), we restrict capacity from fossil fuel plants at 95%:

$$\sum_{i}^{N} q_{i,t} \leq 0.95 * Capacity \tag{10}$$

2. We impose a profitability constraint to the maximization of new wind, GW_{wind}, added to the grid, as follows:

$$\sum_{i=1}^{t} \pi_t = (p_t - LCOE_{wind}) * CF_t \geq 0 \tag{11}$$

Where π_t are the profits obtained by new wind producers at time t, p_t is the equilibrium price at time t, $LCOE_{wind}$ is the levelized cost of wind generation [15], and CF_t is the wind capacity factor at time t.

3. We impose the market-clearing condition at every hour of the day:

$$D_t = \sum_{i}^{N} q_{i,t} + Qhydronuc_t + Qsolar_t + Qwind_t + Qnewwind_t \tag{12}$$

Where $\sum_i^N q_{i,t}$ is the total fossil fuel generation at time t. $Qhydronuc_t$, $Qsolar_t$, and $Qwind_t$ are hydro-nuclear, solar, and wind electricity generated with current Texas installed capacity at time t.[16] $Qnewwind_t$ is the new wind generation associated with the investment that maximizes social surplus.

Finally, since emissions reductions are obtained without policy intervention (i.e. cost of the policy is zero), the abatement cost of this scenario is negligible.

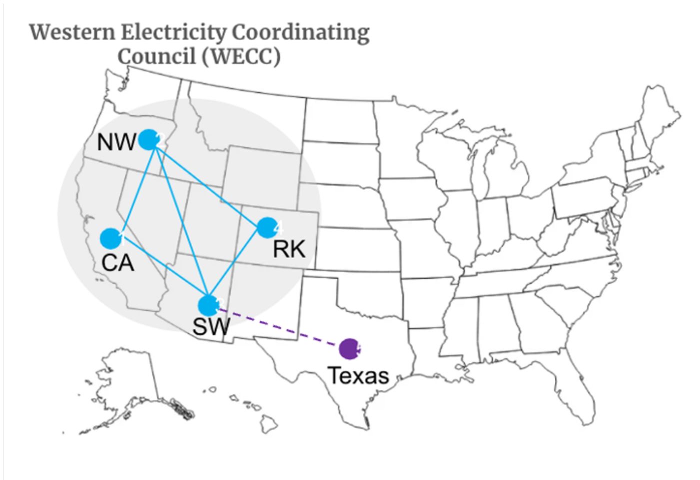
4.3 Add renewable Capacity to ERCOT+WECC

We construct an extension of the partial equilibrium model for the second scenario, where we simulate the ERCOT and WECC systems. We model our solutions as maximizing the aggregated surplus of both systems considering regional electricity demand and generation units and the transmission constraints of the line connecting both systems. Figure 2 graphically represents the simulated scenario. The social planner simultaneously chooses the wind capacity that maximizes aggregated social welfare subject to the profitability of the investment.

[15] We estimate a LCOE of wind in Texas of US$ 35/MWh. For details, refer to Appendix A.1

[16] An implicit restriction of our model is that producers for hydro, nuclear, solar, and wind generation do not engage in strategic behavior, injecting all their available generation in the market at every point in time.

Figure 2: Representation of the simulated interconnection between ERCOT and WECC



Source: Own elaboration.

Formally, we assume that the social planner maximizes aggregated social surplus in all four regions of WECC (California, Northwest, Southwest, and Rockies) and ERCOT, denoted by subscript r. When doing so, the social planner also considers the emission cost in California accounted for by its current carbon tax of US$ 33 per ton of CO_2, as shown in the following equations:

$$max_{Q_{r,t},GW_{wind}} \sum_{t}^{T} \sum_{r}^{R} [GS(Q_{r,t}) - C(Q_{r,t}) - EC(Q_{r,t})] \tag{13}$$

Where $EC(Q_{r,t})$ are the emissions costs, which is itself a function of the carbon tax and the emission rate of each producing plant (er_i), given by equation (14).

$$EC(Q_{r,t}) = tax * \sum_{i}^{N} q_{i,t} * er_i \tag{14}$$

As detailed in equation (15), the market clearing restriction in the integrated scenario includes trade flows with their corresponding constraints.

$$D_t + yflow_{rt} = \sum_{i}^{N} q_{i,t} + Qhydronuc_t + Qsolar_t + Qwind_t + Qnewwind_t \tag{15}$$

Where $yflow_{rt}$ are the net imports from one region to another. The trade flows are subject to the following constraints:

$$\text{-}lines_l \leq \sum_{\notin CA} fct_l * yflow_{rt} \leq lines_l \tag{16}$$

Here, fct_l is the distribution of the electricity flows originating in a region among the transmission lines, and $lines_l$ is the maximum capacity that can flow through a transmission line. Regarding the former, we assume that the matrix of transmission flows can be modeled as presented in Table 1, which takes California as the base node (region 1). We maintain the transmission flows between the WECC and assume that the interconnection between the two systems only affects flows between the Southwest and Texas.

Table 1: Matrix of Transmission Factors
(Flows expressed in reference to 1=California)

Region	1-2	1-3	4-2	4-3	2-3	3-5
2	0.623	0.378	-0.144	0.144	0.234	0
3	0.378	0.623	0.144	-0.144	-0.234	0
4	0.5	0.5	0.5	0.5	0	0
5	0.378	0.623	0.144	-0.144	0	1

Source: Own elaboration based on Reguant et al. (2021).

As for the maximum capacity vectors, we assume that intra-WECC transmission lines have unlimited capacity. This is an adaptation to the original model to reflect price homogeneity across WECC regions in 2023 [17], suggesting that the constraints are less binding than with the original data of 2019. Thus, the only relevant constraint for trading is the 6 GW transmission line that we model connecting Texas with WECC. The remaining constraints are adaptations to the constraints modeled for our second scenario for multiple regions.

The transmission line is modeled using the least cost path methodology connecting two relevant consumption hubs in ERCOT and WECC. We constrain the line to go through existing electricity networks in the US to increase its feasibility, discarding areas that could not support a line due to technical constraints or to social opposition. Its cost, in turn, is calculated based on cost-per-mile-per-GW found in the literature (See appendix A.5 for details).

Finally, the emissions resulting from this model are compared to baseline emissions, and emissions reductions are then contrasted with the annualized cost of building the transmission line to estimate the abatement cost.

5 Data

We base our green hydrogen production simulation on parameters for inputs, efficiencies, emissions, and infrastructure investment costs taken from various sources reported in Section A.4.1. We estimate the current demand for gray hydrogen in Texas to be 3.2 Mt per year, based on total US production, state-level oil refining, and ammonia production. Table 2 summarizes the assumptions made for estimating gray hydrogen demand in Texas.

Table 2: Annual hydrogen demand in Texas (Million tons/year)

Item	Value	Source
Total annual US hydrogen production	10	US Department of Energy
Share US hydrogen for refining	68%	US Department of Energy
Share US hydrogen for ammonia	32%	US Department of Energy
US hydrogen for refining	6.8	-
US hydrogen for ammonia	3.2	-
Oil production in Texas	43%	US Department of Energy
Texas hydrogen production for refining	2.9	-
Percentage of H2 produced as a byproduct	37%	IEA 2023
Texas hydrogen dedicated production for refining	1.8	-
Texas ammonia production	8%	Statista
Texas hydrogen production for ammonia	0.3	-
Texas' total annual production of hydrogen	3.2	-

Source: Own elaboration based on data from various sources.

For our electricity modeling of ERCOT and WECC, we use hourly electricity generation, demand, and price data from 2023 and plant-level emissions, capacity, and cost data from 2022. The data

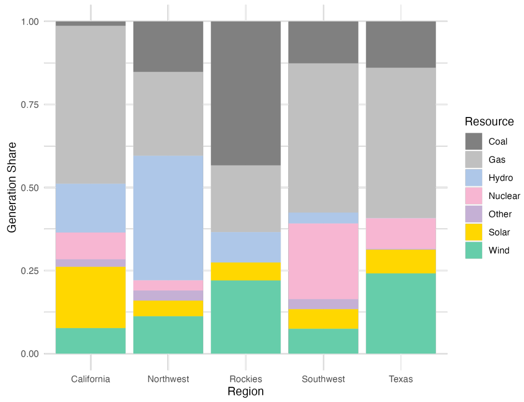
[17] Prices in the four regions have a 99% correlation between each other.

was collected from different sources and then aggregated by region following the work of Fowlie et al. (2021). For the purposes of this analysis, we focus on a select subset of balancing authorities within ERCOT and the WECC subregions (California, Northwest, Southwest, and the Rockies). Details on the data sources and how they were collected and processed can be found in Appendix A.4.2.

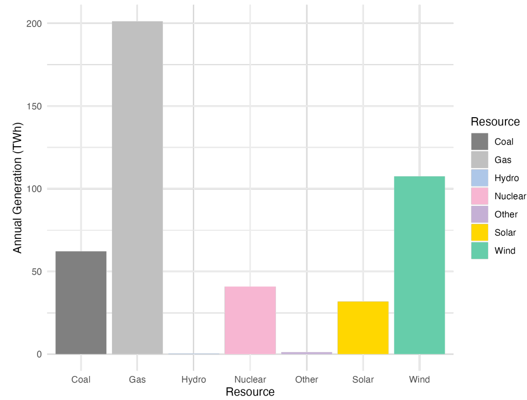
Generation

Each of the five regions under analysis has a unique electricity generation resource mix (Figure 3) and hourly renewable generation profile by technology (Figure 4). Figure 3 shows that ERCOT has the highest generation of the five regions, with a total annual generation of 445 TWh in 2023. The largest system in WECC is Northwest (275 TWh), followed by California (220 TWh), Southwest (139 TWh) and Rockies (83 TWh). Natural gas is the primary electricity generation source, accounting for the highest share of total electricity generation in California, the Southwest, and Texas. In contrast, hydro and coal are the most prominent generation sources in the Northwest and Rockies, respectively. Wind is the largest renewable energy source in all regions except California, where solar generation is most prominent. Figure 4 presents the different hourly generation profiles for solar and wind, respectively, for all regions in our analysis, illustrating the regional variation in maximum generation from each technology. Differences in the hourly generation of variable renewables in the regions under analysis stem from variations in installed capacity, technical potential (or average capacity factor), and the slight variation in time zones across regions. Figure 4 shows that total solar generation across all regions is driven by generation in California and Texas, explaining 74% of total solar generation within the five regions, whereas Texas drives total wind generation with 58% of total wind power produced. Finally, Figure 4 demonstrates that wind and solar have opposite and complementary hourly generation profiles, providing evidence that an optimal combination of both technologies could smooth the intermittency of renewable generation, thus highlighting the potential benefits from trade between wind and solar-producing regions.

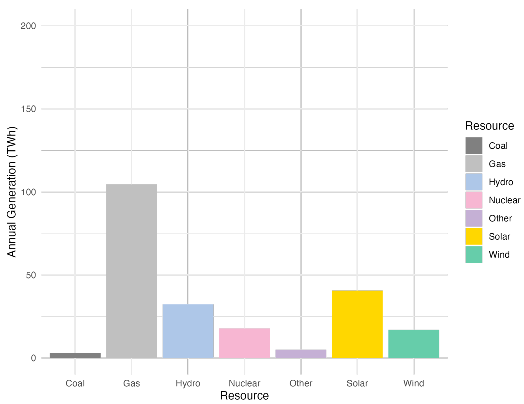
Figure 3: 2023 Regional Electricity Generation (GWh)



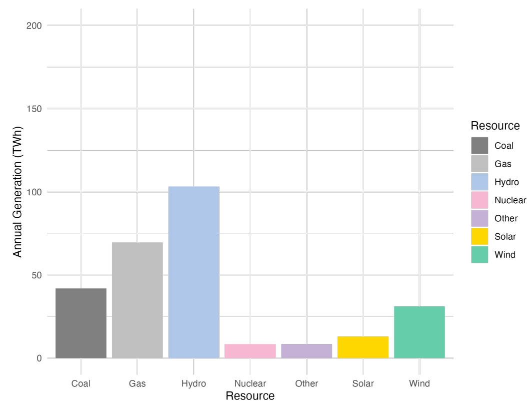
(a) Generation Mix By Region (%)



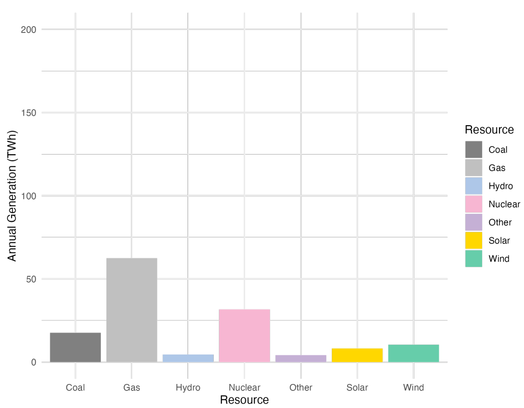
(b) Texas



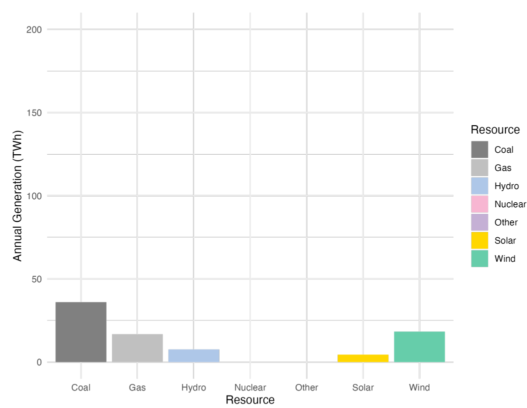
(c) California



(d) Northwest



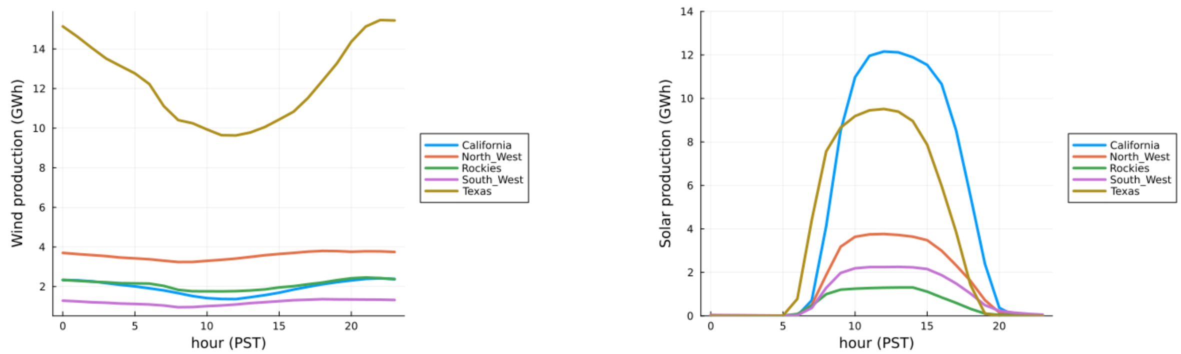
(e) Southwest



(f) Rockies

Source: Own elaboration based on data from the EIA.

Figure 4: Average Hourly Electricity Generation by Region (GWh)



(a) Wind

(b) Solar

Source: Own elaboration based on data from the EIA.

Demand

In 2023, the four WECC regions consumed a total of 732 TWh, whereas Texas consumed 444.1 TWh, which is 61% of total WECC consumption. Table 3 presents the demand separated by region. Texas consumed more electricity than the other regions considered in our analysis, with an average hourly consumption of 50.7 GWh, followed by Northwest and California, consuming 32.1 and 29.6 GWh, respectively.

Table 3: Summary of Demand of Electricity per region, 2023

Region	Total Demand (TWh)	Average Hourly Demand (GWh)
California	259.5	29.6
North West	281.3	32.1
South West	117.2	13.4
Rockies	73.9	8.4
Texas	444.1	50.7

Source: Own elaboration based on data from the EIA.

Prices

Regional price data used in our analysis is summarized in Table 4. Prices in the WECC subregions are similarly distributed, with a mean price of around \$60/MWh and values ranging between approximately -\$19/MWh and \$1,200/MWh. Texas, on the other hand, has slightly lower prices on average, at around \$56/MWh; however, with much higher price volatility, ranging from approximately \$0 to over \$4,000/MWh. Figure 5 further describes the distribution of regional prices, illustrating similar distributions centered around the mean price for each of the WECC subregions, whereas prices in Texas appear to be highly concentrated around the median value, \$22/MWh, but with more extreme values [18].

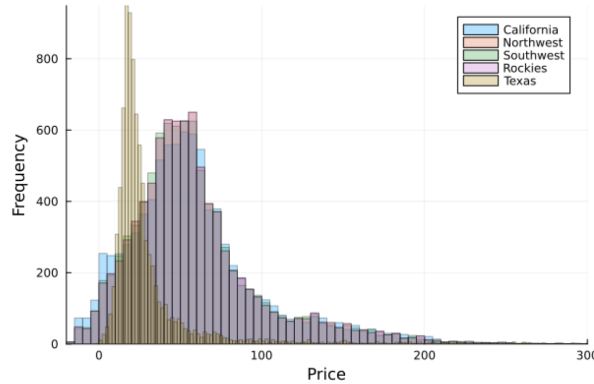
Table 4: Summary Statistics of Prices per Region, 2023 ($/MWh)

Region	Mean	Median	Min	Max
California	60.49	52.63	-18.96	1238.50
Northwest	59.73	51.76	-18.48	1157.29
Southwest	59.52	51.68	-18.47	1203.11
Rockies	59.73	51.76	-18.48	1157.29
Texas	55.75	21.82	-0.96	4199.16

Source: Own elaboration based on data from CAISO and ERCOT.

[18] Maximum values are outside the range plotted in Figure 5

Figure 5: Distribution of Prices by Region, 2023

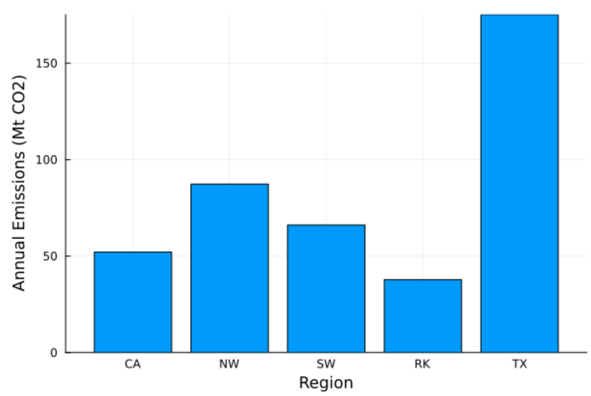


Source: Own elaboration based on data from CAISO and ERCOT.

Emissions

Annual emissions from electricity production in 2022 from each region are presented in Figure 6. Texas has the highest annual emissions at roughly 175 Mt CO_2, consistent with its higher energy demand relative to the other regions analyzed, as well as the region's reliance on natural gas as its primary generation source. The Northwest and Southwest are the second and third largest emitters, partially explained by the relatively high share of coal in their respective generation mixes. Total annual emissions from all five regions are approximately 418 Mt CO_2, which represents nearly 24% of total US electricity sector emissions.

Figure 6: Annual Electricity Sector Emissions by Region, 2022 (Mt CO_2)



Source: Own elaboration based on information from eGrid 2022.

Marginal costs

Data on the marginal costs of operating a plant are not publicly available. However, they can be estimated based on the heat rate (HR) of the plant and the cost of fuel. Following Fowlie et al. (2021), we estimate the plant-level marginal cost for all five regions[19] assuming the following linear relationship:

$$MC = heat\_rate * 1000 * cost\_fuel + FC$$

To do this, we proceed as follows:

1. We take the heat rate of each plant from the EGrid 2022.
2. We take the average fuel prices for each region in 2023 from the EIA's website.

[19]See appendix A.4.2 for more information on how we filter plant-level data from Egrid

3. We assume that the fixed costs of operating a plant remains unvaried from the ones used in Fowlie et al. (2021).

Table 5 summarizes the assumptions made to estimate the marginal cost of each plant:

Table 5: Calculating marginal costs

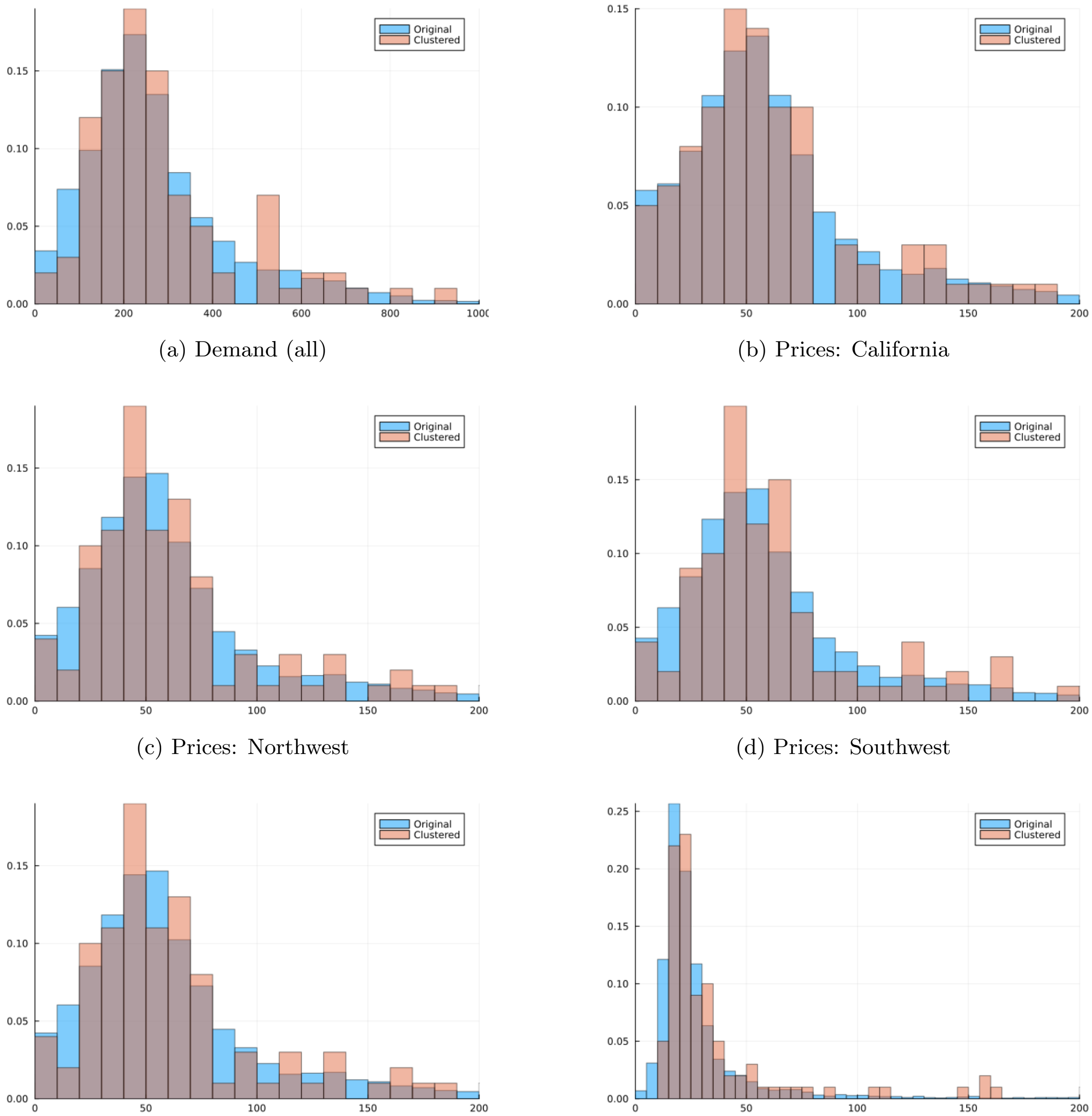
Fuel type	**Marginal cost ($/MWh)**
Gas in Texas	HR*1000*2.3+5.0
Gas in WECC regions	HR*1000*7.5+3.0
Coal	HR*1000*2.3+5.0
Oil	HR*1000*23.5+3.0

Source: Own elaboration based on Fowlie et al. (2021).

Clustering

To run our model, we use clustered data using the k-means clustering algorithm to group hourly demand, generation, and price data for 2023 into 100 weighted representative hours, following Fowlie et al. (2021). A 500-hour cluster was also tested; however, we did not find evidence that a larger number of observations improves the replication of the original data. The plots presented in Figure 7 suggest that our clustered data sufficiently represents the original distribution of the data.

Figure 7: Original and clustered data distribution



(a) Demand (all)

(b) Prices: California

(c) Prices: Northwest

(d) Prices: Southwest

(e) Prices: Rockies

(f) Prices: Texas

Source: Own elaboration based on data from the EIA, CAISO and ERCOT.

6 Results

We estimate the annual production of green hydrogen to be 1.8 Mt when the additional 30 GW of wind generation is dedicated to hydrogen production, almost equivalent to the hydrogen demand by the oil-refining sector in Texas. Thus, if we assume a substitution of gray for green hydrogen by the oil-refining sector, the emissions reduction amounts to 18 Mt CO_2 per year[20], representing a 5% decrease from the baseline[21]. The fiscal cost of subsidizing green hydrogen production via the IRA subsidy amounts

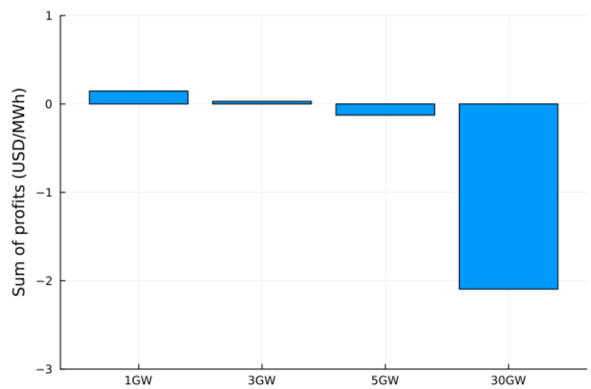
[20] Our analysis does not consider a potential increase in Scope-3 emissions from possible production increases from the oil-refining industry if the green hydrogen subsidy results in lower production costs or extra profits.

[21] Baseline emissions are 381 Mt CO_2 (32 from hydrogen sector, 192 from electricity in WECC, and 157 from electricity in Texas)

to US$ 5,000 million per year, with a net present value of the policy of US$ 41,670 million during the estimated duration of the IRA subsidy. It is important to note that since the hydrogen industry entirely consumes the extra electricity generated, the merit order curve of the Texas electricity grid is not altered; thus, the prices and emissions of the ERCOT system remain unaffected. Finally, the cost of abatement of the IRA subsidy is US$ 300 per ton of CO_2, which lies in the high range of abatement costs reported in the literature.

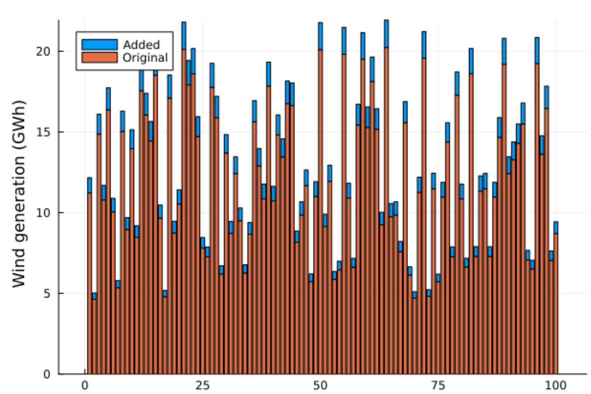
Figure 8, in turn, shows that, in the absence of subsidies, the ERCOT grid can profitably incorporate up to 3 GW of extra wind power.[22] Adding 3 GW of wind, which represents a yearly increase of 9,075 GWh of wind generation in the ERCOT grid, reduces CO_2 emissions by 5 Mt annually. This reduction is obtained by displacing the more expensive generation units in the merit order curve when the wind is more abundant, which leads to a reduction of fossil fuel generation of 8,350 GWh per year. Furthermore, given that this scenario does not include subsidies, the cost of the policy is zero, and thus, the cost of abatement is negligible. Finally, introducing this extra renewable capacity reduces Texas's average electricity price by 1%.

Figure 8: Profitability of new wind in different scenarios of added capacity



Source: Own elaboration

Figure 9: Extra wind generation with the 3 GW of wind capacity



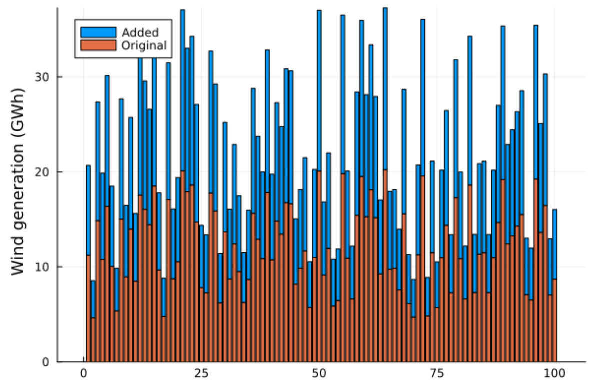
Source: Own elaboration

Alternatively, when a new transmission line of 6 GW connecting WECC and ERCOT is added to the model, the 30 GW of wind modeled for the green hydrogen scenario can be added to the integrated grid without subsidies. Adding 30 GW of wind power to this unified grid reduces 80 Mt CO_2 annually, equivalent to 6% of US electricity emissions or 0.2% of total global CO_2 emissions. This emissions

[22]Profitability is measured by calculating the price minus the LCOE times the capacity factor per hour, as explained in Section 4.2.

reduction is explained by both the addition of the extra renewable power, as shown in Figure 10, and the interconnection of the two electricity systems.

Figure 10: Extra wind generation with the 30 GW of wind capacity



Source: Own elaboration

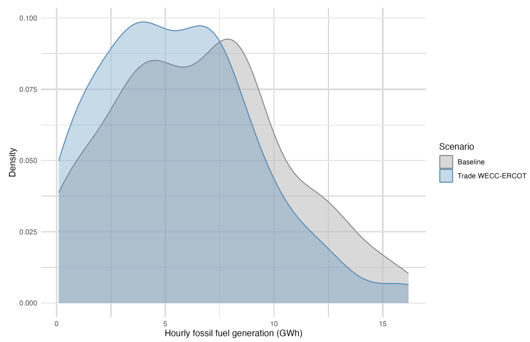
The integration of the two grids allows for the optimization of existing generation units, which leads to the substitution of the more expensive carbon-intensive plants (mainly coal plants in the Rockies system) by the cheaper-less polluting natural gas plants of Texas. Figure 11 shows how the distribution of hourly fossil fuel generation shifts to the left when the two markets are integrated through the transmission line.

We conservatively estimate a total cost of US\$ 10,000 million - and an annualized investment cost of US\$ 650 million - for building the transmission line connecting Phoenix (Southwest - WECC) and Austin (ERCOT).[23]. Thus, we estimate the cost of abatement of interconnecting WECC and Texas in US\$ 8 per ton of CO_2, which lies in the lower range of abatement costs estimated in the literature. One important note is that the integrated operation of the two grids leads to an increase, on average, of 23% in electricity prices of ERCOT and a reduction of 3% in electricity prices of WECC. Moreover, the fact that carbon emissions are currently only taxed in California might lead to carbon leakage, especially in Texas, where fossil fuel generation costs are the cheapest. Although relevant, both of these issues are outside the scope of our analysis.

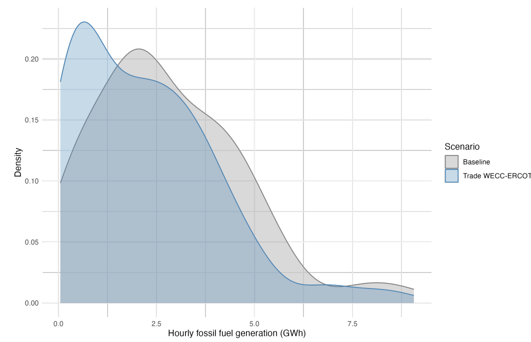
Table 6 summarizes the results of our different simulations. The main result is that the most significant emission reduction is achieved with the use of 30 GW of extra wind to supply the electricity generation of the integrated grids of Texas and WECC, which leads to a reduction of 80 Mt CO_2 per year, 4.5 times the emissions reduction achieved when an equivalent wind capacity is used to supply the green hydrogen sector, and 16 times the emissions reduction when 3 GW of wind are added to the isolated grid of ERCOT. The total cost of building a transmission line is estimated at US\$ 10,000 million, representing around 25% of the cost of subsidizing green hydrogen production over the expected duration of the IRA. Finally, adding 3 GW of electricity to the Texas grid at US\$ 0 per ton of CO_2 results in the lowest abatement cost. In contrast, we estimate the cost of abatement of interconnecting the two grids at US\$ 8 per ton of CO_2, 97% less expensive than reducing emissions by subsidizing green hydrogen production at an abatement cost of US\$ 300 per ton.

[23]Details on the simulation of the transmission line are provided in Appendix A.5)

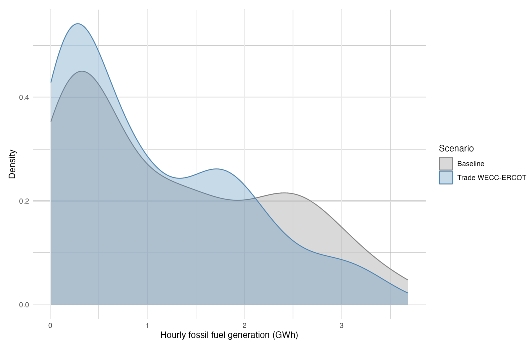
Figure 11: Distribution of hourly fossil fuel generation by scenario



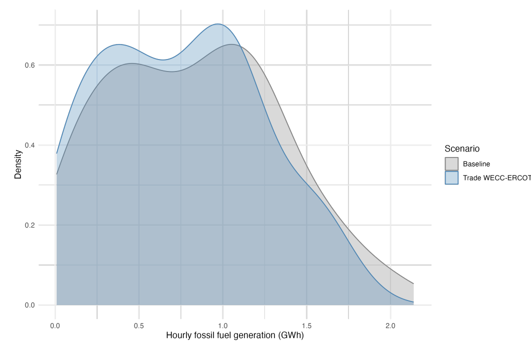
(a) All regions



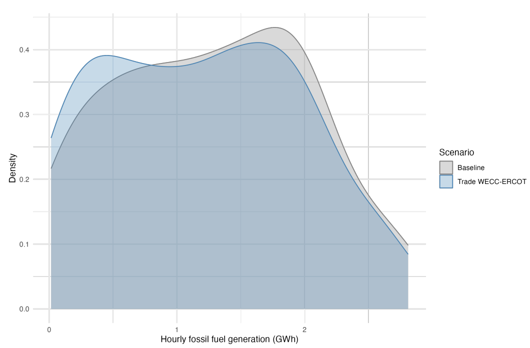
(b) Texas



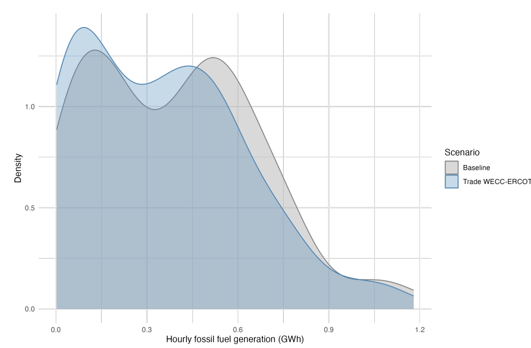
(c) California



(d) Northwest



(e) Southwest



(f) Rockies

Source: Own elaboration.

Table 6: Summary of results per scenario

Variables	Scenarios			
	Baseline	Produce green H2 w/ subsidy	Add into grid (ERCOT)	Add into grid (ERCOT+WECC)
Capacity Added (GW)	0	30	3	30
Annual Emissions (Mt CO_2)	381	363	376	301
	(n.a.)	(-18)	(-5)	(-80)
Cost of Policy (million US$)	-	41,760	0	10,071
Annual Cost (million US$)	-	5,400	0	655
Abatement cost (million US$)	-	300	0	8

Source: Own elaboration.

7 Sensitivity analysis

To test the robustness of the relative abatement costs of the interconnection of the WECC and ERCOT grids and the green hydrogen subsidy scenarios, we perform a sensitivity analysis of the estimated cost of the transmission line and the energy added to the grid. Regarding the former, we assume that the cost of building the transmission line increases up to 100%, which might be explained by higher building costs and the need to make additional investments to optimize the regional grids to take full advantage of the interconnection, or by a higher cost of financing. The first row of Table 7 shows that, depending on the assumed cost of the line, the abatement cost ranges between US$ 8 and US$ 16 per ton of CO_2. The high end of the abatement cost range assumes a duplication of the total cost of the line or an increase in the discount rate from 5% to 13%. Regarding the latter, we simulate scenarios where only a fraction of the 30 GW of wind power is added to the grid after building the transmission line. The first column of the table shows that the abatement cost per ton of CO_2 ranges between 8-16 US$ per ton of CO_2, with the highest number representing the scenario where the line is built, and no additional capacity is added to the grid. For additional robustness, we combine both sensitivity scenarios (i.e., a more expensive line and less capacity added to the grid) and find that when the cost of the line doubles, and no wind is added to the grid, the abatement cost increases from US$ 8 to US$ 32 per ton of CO_2. Notwithstanding, this number is still one-tenth of the abatement cost of subsidizing the green hydrogen industry, which strengthens the cost-effectiveness of building a transmission line compared to subsidizing green hydrogen.

Table 7: Sensitivity analysis of abatement costs

Extra Capacity Added	Incremental Cost			
	0%	10%	50%	100%
30 GW	8	9	11	16
27 GW	9	10	12	18
15 GW	12	13	16	24
0 GW	16	17	22	32

Source: Own elaboration.

8 Limitations and areas for further research

In this section, we acknowledge the limitations of the model used in this analysis and present several avenues for further research.

Within the scenarios analyzed, the results suggest that the most effective way to reduce emissions in the US, both in terms of cost and total abatement, is to prioritize greening the electricity grid by building a transmission line connecting Texas and the WECC, two of the country's largest consumption hubs, and increasing renewable capacity in the newly interconnected grid. However, there are some limitations to our study that impact the interpretation of these results. Regarding our hydrogen production scenario, first, our model does not account for the possibility that the IRA subsidy for green hydrogen will drive down the cost of the technology, which could, in turn, facilitate the development of hydrogen projects in other parts of the world. Reductions in technology costs may be relevant to our analysis, given the precedent set by past subsidies in the energy sector, particularly the drastic reductions in costs for wind and solar generation over the last two decades, spurred by feed-in-tariffs and other government incentives. Additionally, this analysis focuses solely on the implications of a subsidy to green hydrogen, and does not consider potential interactions with other subsidies and financial incentives included in the IRA.

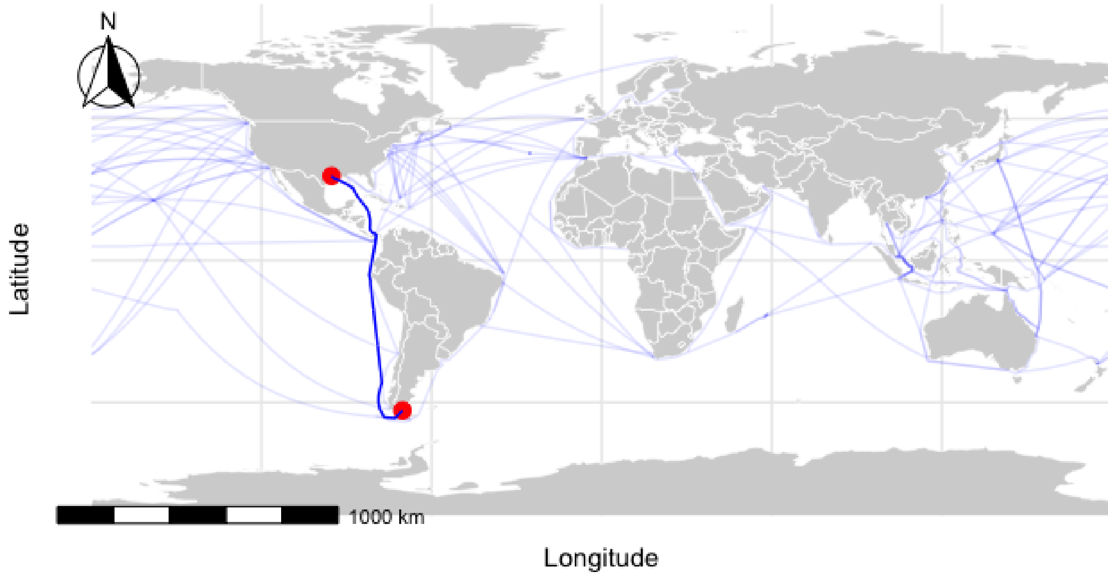
Second, our analysis does not take into account the geopolitical dimension of investing in a strategic industry that has the potential to help achieve carbon neutrality while improving energy independence for countries that rely on imports of fossil fuels. Third, our hydrogen scenario does not allow for investors to optimize their decision on whether to produce hydrogen (and receive the IRA subsidy) or sell their renewable power directly to the electricity grid when market prices are high. The ability for electricity producers to choose in real time whether to produce hydrogen or supply the grid may have relevant market implications in Texas, where there is significant price volatility, as seen in Figure 5. Allowing firms to both supply to the grid and produce green hydrogen within the model, is a logical extension of our work.

Regarding the counterfactual scenarios, first, our simplified electricity market model does not take into account intra-regional transmissions constraints within ERCOT, and therefore may overestimate the impacts of additional renewable generation. Second, our current analysis assumes that all investment in renewable generation is in the form of new wind generation in Texas, and does not account for the possibility of new renewable investment within the WECC subregions. Future updates to the model could allow us to explore the optimal investment in each generation technology across all regions, providing insights into how increased transmission impacts the optimal generation mix. Third, our modeling does not consider the possibility of adding batteries to the ERCOT grid, which could further increase the ability to add renewable power, even in isolation. Fourth, political economy considerations regarding the feasibility or public interest in integrating Texas to neighboring grids is not explicitly considered.

Finally, as shown in the previous sections, we restrict our analysis to adding green hydrogen to Texas, where this industry's development exhibits a significant opportunity cost. However, other regions of the world have a high potential for renewable generation with a low opportunity cost. For example, chilean Patagonia has some of the highest potential for wind generation in the world[24], that is currently unexploited due to the absence of significant electricity demand in the neighboring areas. Considering the lower cost of electricity, and thus of producing hydrogen, the absence of alternative uses, and the possibility of transporting hydrogen internationally by way of ammonia, it may be feasible to invest in developing the green hydrogen industry internationally, still taking advantage of its decarbonizing potential but at a lower cost. Figure 12 presents the route connecting the ports of Cabo Negro (Patagonia, Chile) and Houston (Texas, US), which we estimated to be 11,303 km. Our preliminary results show that the cost of covering this route ranges between US$0.5 and US$1 per kg of hydrogen, suggesting that investing in green hydrogen development in Patagonia might be profitable. However, these results are not robust and require further research.

[24]Capacity factors exceed 0.7 in parts of the region, according to Global Wind Atlas.

Figure 12: Shipping lanes and shortest path connecting Punta Arenas and Houston



Source: Own elaboration

9 Final remarks

The United States has committed substantial resources towards developing a domestic green hydrogen industry, inspiring a deeper analysis of the potential emissions reductions and associated costs of an emerging green hydrogen economy. Our analysis contributes to the literature by providing a novel comparison of investments in green hydrogen and transmission infrastructure, based on emissions reductions and cost of abatement; quantifying the opportunity cost of devoting new renewable generation to hydrogen production in Texas.

In our most conservative cost scenario, we find that the relative abatement cost of allocating new wind capacities in Texas to green hydrogen production is roughly ten times higher than that of supplying renewables directly to the grid with increased transmission capacity. In terms of total abatement, with an equivalent increase of 30 GW of wind capacity, emissions reductions are over four times higher when electricity is supplied to an interconnected Texas-WECC grid, compared to our green hydrogen scenario.

Our analysis underscores the importance of investing in transmission infrastructure and enhancing grid interconnection in Texas. We find that the ERCOT electricity market operates almost at equilibrium, with very limited margin to add renewables without associated drawbacks, such as increasing curtailment or lowering prices that could make investment recovery unfeasible. These findings suggest that, from a policy perspective, it could be desirable for Texas to prioritize the investment in transmission infrastructure to connect ERCOT with surrounding electricity systems, such as the WECC case presented in this paper. This could allow Texas to further take advantage of its renewable potential, and contribute in decarbonizing the US power sector.

Further research could include efficiency improvements to reduce green hydrogen production costs over time, and address other political economy considerations, such as industrial policy or geopolitical motivations.

10 References

References

Acciona. What Are The Colours Of Hydrogen And What Do They Mean?, 2022. URL https://www.acciona.com.au/updates/stories/what-are-the-colours-of-hydrogen-and-what-do-they-mean/www.acciona.com.au/updates/stories/what-are-the-colours-of-hydrogen-and-what-do-they-mean/?_adin=02021864894.

Selma Atilhan, Sunhwa Park, Mahmoud M El-Halwagi, Mert Atilhan, Margaux Moore, and Rasmus B Nielsen. Green hydrogen as an alternative fuel for the shipping industry. *Current Opinion in Chemical Engineering*, 31:100668, March 2021. ISSN 22113398. doi: 10.1016/j.coche.2020.100668. URL https://linkinghub.elsevier.com/retrieve/pii/S221133982030071X.

Abhinav Bhaskar, Mohsen Assadi, and Homam Nikpey Somehsaraei. Decarbonization of the Iron and Steel Industry with Direct Reduction of Iron Ore with Green Hydrogen. *Energies*, 13(3): 758, February 2020. ISSN 1996-1073. doi: 10.3390/en13030758. URL https://www.mdpi.com/1996-1073/13/3/758.

John Bistline, Geoffrey Blanford, Maxwell Brown, Dallas Burtraw, Maya Domeshek, Jamil Farbes, Allen Fawcett, Anne Hamilton, Jesse Jenkins, Ryan Jones, Ben King, Hannah Kolus, John Larsen, Amanda Levin, Megan Mahajan, Cara Marcy, Erin Mayfield, James McFarland, Haewon McJeon, Robbie Orvis, Neha Patankar, Kevin Rennert, Christopher Roney, Nicholas Roy, Greg Schivley, Daniel Steinberg, Nadejda Victor, Shelley Wenzel, John Weyant, Ryan Wiser, Mei Yuan, and Alicia Zhao. Emissions and energy impacts of the Inflation Reduction Act. *Science*, 380(6652):1324–1327, June 2023a. doi: 10.1126/science.adg3781. URL https://www.science.org/doi/10.1126/science.adg3781. Publisher: American Association for the Advancement of Science.

John Bistline, Neil Mehrotra, and Catherine Wolfram. Economic Implications of the Climate Provisions of the Inflation Reduction Act, May 2023b. URL https://www.nber.org/papers/w31267.

James B. Bushnell, Stephen P. Holland, Jonathan E. Hughes, and Christopher R. Knittel. Strategic Policy Choice in State-Level Regulation: The EPA's Clean Power Plan. *American Economic Journal: Economic Policy*, 9(2):57–90, May 2017. ISSN 1945-7731, 1945-774X. doi: 10.1257/pol.20150237. URL https://pubs.aeaweb.org/doi/10.1257/pol.20150237.

Espen Flo Bødal, Dharik Mallapragada, Audun Botterud, and Magnus Korpås. Decarbonization synergies from joint planning of electricity and hydrogen production: A Texas case study. *International Journal of Hydrogen Energy*, 45(58):32899–32915, November 2020. ISSN 03603199. doi: 10.1016/j.ijhydene.2020.09.127. URL https://linkinghub.elsevier.com/retrieve/pii/S0360319920335679.

Ralph A. Cantafio and Miles C. Nowak. Solving the Interconnection Problem Oil & Gas Survey. *Texas A&M Journal of Property Law*, 7(3):526–538, 2021. URL https://heinonline.org/HOL/P?h=hein.journals/txamrpl7&i=526.

CBO. Congressional Budget Office. 2022. "Summary Estimated Budgetary Effects of Public Law 117-169, to Provide for Reconciliation Pursuant to Title II of S. Con. Res. 14 (September 7, 2022)." Congressional Budget Office and Joint Committee on Taxation., 2022.

Fangwei Cheng, Hongxi Luo, Jesse D. Jenkins, and Eric D. Larson. Impacts of the Inflation Reduction Act on the Economics of Clean Hydrogen and Synthetic Liquid Fuels. *Environmental Science & Technology*, 57(41):15336–15347, October 2023. ISSN 0013-936X. doi: 10.1021/acs.est.3c03063. URL https://doi.org/10.1021/acs.est.3c03063. Publisher: American Chemical Society.

McKinsey & Company. Unlocking clean hydrogen in the US Gulf Coast | McKinsey. Technical report, August 2023. URL https://www.mckinsey.com/industries/oil-and-gas/our-insights/unlocking-clean-hydrogen-in-the-us-gulf-coast-the-here-and-now#/.

Rafael d'Amore Domenech, Teresa J. Leo, and Bruno G. Pollet. Bulk power transmission at sea: Life cycle cost comparison of electricity and hydrogen as energy vectors. *Applied Energy*, 288:116625, April 2021. ISSN 03062619. doi: 10.1016/j.apenergy.2021.116625. URL https://linkinghub.elsevier.com/retrieve/pii/S0306261921001604.

Daniel DeSantis, Brian D. James, Cassidy Houchins, Genevieve Saur, and Maxim Lyubovsky. Cost of long-distance energy transmission by different carriers. *iScience*, 24(12):103495, December 2021. ISSN 25890042. doi: 10.1016/j.isci.2021.103495. URL https://linkinghub.elsevier.com/retrieve/pii/S2589004221014668.

EIA. Transmission limits and capacity in the united states: Summer 2023, 2023. URL https://www.eia.gov/electricity/markets/quarterly/archive/2023/transmission_limits_07_2023.pdf.

EPA. Emissions & generation resource integrated database (egrid), 2022. Technical report, Office of Atmospheric Protection, Clean Air Markets Division, Washington, DC, 2024. URL https://www.epa.gov/egrid.

Jamil Farbes, Ben Haley, and Ryan Jones. Marginal Abatement Cost Curves for U.S. Net-Zero Energy Systems. Technical report, Environmental Defense Fund, August 2021. URL https://www.edf.org/sites/default/files/documents/MACC_2.0%20report_Evolved_EDF.pdf.

Meredith Fowlie, Claire Petersen, and Mar Reguant. Border Carbon Adjustments When Carbon Intensity Varies across Producers: Evidence from California. *AEA Papers and Proceedings*, 111: 401–405, May 2021. ISSN 2574-0768. doi: 10.1257/pandp.20211073. URL https://www.aeaweb.org/articles?id=10.1257/pandp.20211073.

Antonio Galván, Jannik Haas, Simón Moreno-Leiva, Juan Carlos Osorio-Aravena, Wolfgang Nowak, Rodrigo Palma-Benke, and Christian Breyer. Exporting sunshine: Planning South America's electricity transition with green hydrogen. *Applied Energy*, 325:119569, November 2022. ISSN 03062619. doi: 10.1016/j.apenergy.2022.119569. URL https://linkinghub.elsevier.com/retrieve/pii/S0306261922008790.

Sushant S. Garud, Fanlok Tsang, Iftekhar A. Karimi, and Shamsuzzaman Farooq. Green hydrogen from solar power for decarbonization: What will it cost? *Energy Conversion and Management*, 286:117059, June 2023. ISSN 01968904. doi: 10.1016/j.enconman.2023.117059. URL https://linkinghub.elsevier.com/retrieve/pii/S0196890423004053.

Gunther Glenk and Stefan Reichelstein. Economics of converting renewable power to hydrogen. *Nature Energy*, 4(3):216–222, February 2019. ISSN 2058-7546. doi: 10.1038/s41560-019-0326-1. URL https://www.nature.com/articles/s41560-019-0326-1.

Luis E. Gonzales, Koichiro Ito, and Mar Reguant. The Dynamic Impact of Market Integration: Evidence from Renewable Energy Expansion in Chile, May 2022. URL https://www.nber.org/papers/w30016.

Iberdrola. Difference between green and blue hydrogen, 2024. URL https://www.iberdrola.com/about-us/what-we-do/green-hydrogen/difference-hydrogen-green-blue.

IEA. World Energy Outlook 2023 – Analysis. Technical report, October 2023a. URL https://www.iea.org/reports/world-energy-outlook-2023.

IEA. Energy Statistics Data Browser – Data Tools, 2023b. URL https://www.iea.org/data-and-statistics/data-tools/energy-statistics-data-browser.

IEA. Towards hydrogen definitions based on their emissions intensity – Analysis. Technical report, April 2023c. URL https://www.iea.org/reports/towards-hydrogen-definitions-based-on-their-emissions-intensity.

IEA. Global Hydrogen Review 2023 – Analysis. Technical report, September 2023d. URL https://www.iea.org/reports/global-hydrogen-review-2023.

IEA. CO2 Emissions in 2023 – Analysis. Technical report, March 2024. URL https://www.iea.org/reports/co2-emissions-in-2023.

IPCC. AR6 Synthesis Report: Climate Change 2023 — IPCC, 2023. URL https://www.ipcc.ch/report/sixth-assessment-report-cycle/.

G. Keith and W. Leighty. Transmitting 4,000 MW of new windpower from North Dakota to Chicago - New HVDC electric lines or hydrogen pipeline. In *40th AIAA Aerospace Sciences Meeting & Exhibit*, Reno,NV,U.S.A., January 2002. American Institute of Aeronautics and Astronautics. doi: 10.2514/6.2002-1029. URL https://arc.aiaa.org/doi/10.2514/6.2002-1029.

David A. King. Interregional Coordination of Electric Transmission and Its Impact on Texas Wind. *Texas Journal of Oil, Gas and Energy Law*, 8(2):309–348, 2012. URL https://heinonline.org/HOL/P?h=hein.journals/texjogel8&i=327.

Ryoichi Komiyama, Takashi Otsuki, and Yasumasa Fujii. Energy modeling and analysis for optimal grid integration of large-scale variable renewables using hydrogen storage in Japan. *Energy*, 81:537–555, March 2015. ISSN 03605442. doi: 10.1016/j.energy.2014.12.069. URL https://linkinghub.elsevier.com/retrieve/pii/S0360544214014492.

Johanna Ivy Levene, Margaret K. Mann, Robert M. Margolis, and Anelia Milbrandt. An analysis of hydrogen production from renewable electricity sources. *Solar Energy*, 81(6):773–780, June 2007. ISSN 0038092X. doi: 10.1016/j.solener.2006.10.005. URL https://linkinghub.elsevier.com/retrieve/pii/S0038092X06002635.

Alexandra Lüth, Paul E. Seifert, Ruud Egging-Bratseth, and Jens Weibezahn. How to connect energy islands: Trade-offs between hydrogen and electricity infrastructure. *Applied Energy*, 341:121045, July 2023. ISSN 03062619. doi: 10.1016/j.apenergy.2023.121045. URL https://linkinghub.elsevier.com/retrieve/pii/S0306261923004099.

Ella M. Morton, Thomas A. Deetjen, and Shadi Goodarzi. Optimizing hydrogen production capacity and day ahead market bidding for a wind farm in Texas. *International Journal of Hydrogen Energy*, 48(46):17420–17433, May 2023. ISSN 03603199. doi: 10.1016/j.ijhydene.2022.12.354. URL https://linkinghub.elsevier.com/retrieve/pii/S0360319922062395.

Alexandra M Oliveira, Rebecca R Beswick, and Yushan Yan. A green hydrogen economy for a renewable energy society. *Current Opinion in Chemical Engineering*, 33:100701, September 2021. ISSN 2211-3398. doi: 10.1016/j.coche.2021.100701. URL https://www.sciencedirect.com/science/article/pii/S2211339821000332.

Nigel Rambhujun, Muhammad Saad Salman, Ting Wang, Chulaluck Pratthana, Prabal Sapkota, Mehdi Costalin, Qiwen Lai, and Kondo-Francois Aguey-Zinsou. Renewable hydrogen for the chemical industry. *MRS Energy & Sustainability*, 7(1):33, July 2020. ISSN 2329-2229, 2329-2237. doi: 10.1557/mre.2020.33. URL http://link.springer.com/10.1557/mre.2020.33.

Kevin Rennert, Frank Errickson, Brian C. Prest, Lisa Rennels, Richard G. Newell, William Pizer, Cora Kingdon, Jordan Wingenroth, Roger Cooke, Bryan Parthum, David Smith, Kevin Cromar, Delavane Diaz, Frances C. Moore, Ulrich K. Müller, Richard J. Plevin, Adrian E. Raftery, Hana Ševčíková, Hannah Sheets, James H. Stock, Tammy Tan, Mark Watson, Tony E. Wong, and David Anthoff. Comprehensive evidence implies a higher social cost of CO2. *Nature*, 610(7933):687–692, October 2022. ISSN 1476-4687. doi: 10.1038/s41586-022-05224-9. URL https://www.nature.com/articles/s41586-022-05224-9. Publisher: Nature Publishing Group.

Joshua D Rhodes. A Roadmap for Modernizing Texas' Electricity Infrastructure. 2023.

Hannah Ritchie and Max Roser. Sector by sector: where do global greenhouse gas emissions come from? *Our World in Data*, September 2020. URL https://ourworldindata.org/ghg-emissions-by-sector.

A. Taieb and M. Shaaban. Cost Analysis of Electricity Transmission from Offshore Wind Farm by HVDC and Hydrogen Pipeline Systems. In *2019 IEEE PES GTD Grand International Conference and Exposition Asia (GTD Asia)*, pages 632–636, Bangkok, Thailand, March 2019. IEEE. ISBN 978-1-5386-7434-5. doi: 10.1109/GTDAsia.2019.8715900. URL https://ieeexplore.ieee.org/document/8715900/.

Feng Wang, Ross Swinbourn, and Chao'en Li. Shipping Australian sunshine: Liquid renewable green fuel export. *International Journal of Hydrogen Energy*, 48(39):14763–14784, May 2023. ISSN 03603199. doi: 10.1016/j.ijhydene.2022.12.326. URL https://linkinghub.elsevier.com/retrieve/pii/S0360319922061870.

Sarah Wang, Brian Tarroja, Lori Smith Schell, Brendan Shaffer, and Scott Samuelsen. Prioritizing among the end uses of excess renewable energy for cost-effective greenhouse gas emission reductions. *Applied Energy*, 235:284–298, February 2019. ISSN 03062619. doi: 10.1016/j.apenergy.2018.10.071. URL https://linkinghub.elsevier.com/retrieve/pii/S0306261918316398.

Enakshi Wikramanayake, Palash V. Acharya, Mark Kapner, and Vaibhav Bahadur. Green hydrogen-based energy storage in Texas for decarbonization of the electric grid. In *2021 IEEE Green Technologies Conference (GreenTech)*, pages 409–415, Denver, CO, USA, April 2021. IEEE. ISBN 978-1-72819-139-3. doi: 10.1109/GreenTech48523.2021.00070. URL https://ieeexplore.ieee.org/document/9458551/.

A Appendices

A.1 Levelized cost of electricity

Levelized cost of energy (LCOE) is calculated according to the following equation:

$$LCOE_{i,j} = \frac{CAPEX_j + \sum_{t=1}^{N} \frac{OPEX_j}{(1+i)^t}}{\sum_{t=1}^{N} \frac{Q_{i,j}}{(1+i)^t}} \tag{17}$$

Where i represents the region and j the technology.

$Q_{i,j}$ is the annual production of electricity in region i using technology j, which is itself a function of the average capacity factors (acf) as expressed in the following equation:

$$Q_{i,j} = acf_{i,j} * 8,760$$

And $CAPEX$ and $OPEX$ are the capital and operational expenditures, respectively.

We calculated the LCOE of wind in Texas using the following parameters and sources in Table 8:

Table 8: Parameters for LCOE of wind in Texas

Parameter	**Value**	**Description and Source**
r	5%	Interest rate, source: IRENA (2022)
CAPEX	1150	CAPEX of wind, source: NREL
OPEX	27	OPEX of wind, source: NREL
t	25	Economic life of wind generation, source: IRENA

Source: Own elaboration.

A.2 Levelized cost of hydrogen

The Levelized cost of hydrogen (LCOH) is calculated based on the following equation:

$$LCOH_i = \frac{CAPEX + \sum_{t=1}^{N} \frac{OPEX}{(1+r)^t} + \sum_{t=1}^{N} \frac{CostElectricity}{(1+r)^t}}{\sum_{t=1}^{N} \frac{QHi}{(1+r)^t}} + LCOW \tag{18}$$

Where r represents the interest rate, $CAPEX$ and $OPEX$ correspond to the costs associated to alkaline electrolizers, QH_i is the annual production of hydrogen produced in region i, $CostElectricity$ is the LCOE (cost of producing 1 MWh), and $LCOW$ is the levelized cost of water desalination.

The parameters and sources are the following:

Table 9: Parameters and their values with descriptions and sources

Parameter	**Value**	**Description and Source**
r	5%	Interest rate, source: IRENA (2022)
CAPEX	650	CAPEX of alkaline electrolyzer by 2030 according to IRENA (2020)
OPEX	2%	OPEX of electrolyzers in % of CAPEX according to IRENA (2020)
CostElectricity	35	LCOE in US$/MWh as explained in appendix A.1
LCOW	3.5	Levelised cost of water desalinization, source: IRENA (2022)

Source: Own elaboration.

A.3 Energy intensity of hydrogen demand

Table 10: Energy Intensity of Green Hydrogen Production

To produce 1 kg of Hydrogen	
Energy content	**33.3 kWh/kg h2**
Electrolyzer efficiency	66%
Electricity consumption (for electrolysis)	**50.35 kWh**
Water consumption	9 litres
Desalination efficiency	43%
Water required (litres)	21 litres
Water required (m3)	0.021 m3
Electricity per m3 of desalinated water	3.5 kWh/m3
Electricity consumption (Desalination)	**0.0735 kWh**
Total electricity consumption	**50.4235 kWh**

Source: Own elaboration.

A.4 Data

A.4.1 Sources

Table 11: Data used in our simulations

Data	Source
Hydrogen Energy Content (per kg H2)	IRENA
Alkaline Electrolyzer Efficiency	IRENA
Water Consumption of Electrolysis (per kg H2)	IRENA
Water Desalination Efficiency	IRENA
Electricity Consumption for Water Desalination	IRENA
Emission Intensity of Gray Hydrogen	IEA, Acciona, Iberdrola
Energy to Convert Hydrogen to Ammonia	EASE
Discount Rate	IRENA
Time horizon - Economic Life of Wind Generation	IRENA
CAPEX Electrolyzer	IRENA
OPEX Electrolyzer	IRENA
Electricity Demand	EIA through an API.
Electricity Generation	EIA through an API.
Prices	CAISO/ERCOT through the gridlock library (Python)
Costs	eGrid 2022
Installed capacity	eGrid 2022
Fuel Costs	EIA
CAPEX line	De Santis (2021)
CAPEX solar/wind	NREL
OPEX solar/wind	NREL

Source: Own elaboration.

A.4.2 Data process appendix

This appendix details how the data for our project was collected and processed. We followed the approach of Fowlie et al. (2021) closely, as we grouped Balancing Authorities by region following the classification presented in Table A.1:

The following sections briefly explain how each variable in our model was obtained, whereas a thorough explanation can be found in the attached Jupyter Notebooks.

A.4.3 Prices

- From CAISO, we download the dataset "TAC Area Map," from where we can identify the pairing of nodes and Transmission Access Charge (TAC) Zones.
- Following Table C.1 of Fowlie, Petersen, and Reguant (2021), we identify the nodes associated with each region, creating a list of nodes associated with each region.
- We downloaded hourly prices for every node associated with each region for 2023 using the Gridlock library from Python. Table A.2 summarizes the number of nodes identified contained in each region:
- Then, we grouped the data by region and calculated the median hourly price per region
- We assigned the Northwest sub-region electricity price to the Rockies sub-region.

Table A.1: Balancing authorities mapped to their five sub-regions

California	**Northwest**	**Southwest**	**Rockies**	**Texas**
BANC	AVRN	AZPS	PSCO	ERCO
CISO	AVA	DEAA	WACM	
LDWP	BPAT	EPE	WAUW	
TIDC	TPWR	GRMA		
	GRID	GRIF		
	IPCO	IID		
	GWA	HGMA		
	WWA	PNM		
	NEVP	SRP		
	NWMT	TEPC		
	PACE	WALC		
	PACW			
	PGE			
	CHPD			
	GCPD			
	DOPD			
	PSEI			
	SCL			

Source: Own elaboration based on Fowlie, Petersen, and Reguant (2021).

Table A.2: Number of Nodes by Region

Region	**Number of Nodes**
California	2,777
Northwest	396
Southwest	108

Source: Own elaboration

- We complemented the data with the prices for Texas, which we downloaded directly from the ERCOT website.
- Finally, we adjusted the time zone of all prices, which were originally in their respective local time zones, to the Pacific Time Zone (PST), using the TimeZones package from Julia.

A.4.4 Generation and demand

- We downloaded the hourly demand and net generation by technology from the U.S. Energy Information Administration (EIA) for every Balancing Authority presented in Table A.1 using the EIA's API.
- We added the net demand by region, and the net generation by technology and region according to Table A.1.
- Finally, we adjusted the time zone of our data, originally in UTC, to PST.
- More details can be found in the Jupyter Notebook files.

A.4.5 Plant-level data from Egrid (heat rate, emissions and capacity)

To construct the vectors that are based on Egrid 2022 data at plant-level we made the following filters:

- Filter the balancing authority for each region (as in table A.1)
- Keep only plants with gas, coal or oil as main fuel.
- Drop plants with missing or zero value in capacity factor variable
- Replace missing values in heat rate variable with median value per region and fuel type (only few cases needed this correction).

These filtering was made separately for all regions. Since California was the region with the highest number of observations (311) our final vectors are merged to be of that size. In order to fill the vectors for the other regions (with less observations) we made the same assumptions as in Fowlie et al. (2021), namely:

- Marginal costs were set to 1,000 $/MWh
- Capacity factors and capacity in MW were set to zero
- Emissions rate was set to 20.

More details can be found in the Jupyter Notebook files.

A.5 Simulation of transmission line costs

To estimate the cost of the policy of Scenario 3, we need to estimate the cost of building a transmission line that connects WECC with ERCOT. We simulated two different transmission lines: a short line connecting two representative cities on either side of the border between the WECC and ERCOT (Odessa - El Paso), and also, for robustness, a longer line connecting the two larger population hubs in Texas and the Southwest (Austin - Phoenix). Estimates regarding the length of the line were obtained by applying geospatial tools, in particular least cost path methodology, constraining the line to go through the current electricity network in the region. This criteria rules out the possibility of the transmission line to be built in a more direct/shortest path, but it has the advantage of ensuring feasibility, discarding areas that could not support a line due to technical constraints or to social opposition. The length of both simulated lines are as follows:

1. Short line: Odessa to El Paso 348 mi (560 km)
2. Long line: Austin and Phoenix is 1,119 mi (1,802 km)

In our final model, we continue with the long line as a conservative estimate.

Once we calculated the length of the lines we used estimates from the literature to estimate the cost of building them. Following DeSantis et al. (2021), we used a base capital cost of $1.5 million per GW per mile (therefore $9 million per 6 GW lines per mile). Multiplying this by the length of the line, and calculating the annuity considering 30 years of duration per line (conservative calculation) and an 5% discount rate[25] we came with the following results:

Table A.3: Estimated Total and Annual Investment Costs for a 6 GW Transmission Line (M$)

Category	Short line	Long line
Total Cost	3,130	10,071
Annual Cost	204	655

Source: Own elaboration based on De Santis (2021).

[25] Calculation of annuity was done using formula $Annuity = \frac{PV}{\frac{1-(1+r)^{-n}}{r}}$