# APPENDIX B: FINANCIAL VIABILITY ANALYSIS OF EXPORT-ONLY ELECTROLYZER PROJECTS

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This appendix details the methodology and findings of our financial viability analysis of export-only electrolyzer projects. This project configuration consists of an electrolyzer that can only buy power from co-located new clean energy resources rather than the grid while also allowing the opportunistic sale of clean energy to the grid. We find that these types of projects—which are more restrictive than detached projects[2] but clearly compliant with the three principles of additionality, deliverability, and hourly time-matching—are competitive from the outset across large swaths of the United States. This in turn implies that rigorous 45V guidance that accurately measures lifecycle greenhouse gas emissions from electrolysis would not harm electrolyzer deployment or the development of the clean hydrogen industry. Instead, it would encourage development of competitive zero-carbon hydrogen production in much of the country, laying the foundation for rapid electrolyzer growth and further cost reductions.

## METHODOLOGY

We chose three U.S. test sites with readily available data and good wind and solar resource quality to conduct our analysis of the financial viability of export-only projects:

- **West Texas,** which we selected as having some of the best wind and solar resources in the U.S., with abundant land for siting large projects—though revenues may need to be comparatively higher to fund hydrogen transport to offtakers due to the region's remoteness;
- **Near Houston, Texas,** which we selected for its good solar resource, decent wind resource, and proximity to industrial offtakers (e.g., petrochemicals); and
- **Southwest Minnesota,** which we selected for its good wind resource, decent solar resource, abundant land for siting large projects, and agricultural presence, which could be ideal for new ammonia production.

For these sites, we used wind and solar resource production data from Renewables.ninja. We used historical 2021 levelized cost of electricity (LCOE) data from the 2022 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[3] and applied a $24.01 per megawatt-hour (MWh) production tax credit (PTC) from the Inflation Reduction Act.[4] We also included a conservative case that adds $5/MWh to all LCOEs.

We used historical zonal hourly day-ahead power prices from the Electric Reliability Council of Texas (ERCOT) and the Midcontinent Independent System Operator (MISO) for Texas and Minnesota, respectively. We picked a low-price year (2020) so that grid sales revenues would be conservative and have more upside than downside

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[1] This appendix complements an April 2023 Energy Innovation paper titled "Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow the Industry," found here: https://energyinnovation.org/publication/smart-design-of-45v-hydrogen-production-tax-credit-will-reduce-emissions-and-grow-the-industry/.

[2] "Detached" projects site clean energy and electrolyzers on different points on the grid, requiring proof of compliance with the three principles to ensure accurate greenhouse gas emissions accounting.

[3] See: https://atb.nrel.gov/electricity/2022/index.

[4] We assumed projects met the prevailing wage and apprenticeship requirements to earn the 5x credit multiplier, but we did not assume they met domestic content or energy community conditions to receive additional bonuses. We started with a $26.68/MWh tax credit and applied a 10 percent haircut for monetizing the tax credit (e.g., selling it to a party with a higher tax burden), making the effective PTC value $24.01/MWh over 10 years.

potential; this also guards against value deflation risks (i.e., lots of these projects coming online and pushing down power prices in the same sets of hours).[5]

We assumed these export-only projects could make money in three ways:

- Selling **hydrogen** at a fixed rate of $1 per kilogram (kg), which would be low enough to outcompete conventional hydrogen production via steam methane reformation, while collecting the $3/kg tax credit;
- Selling clean electricity produced in **excess** of what the electrolyzer can consume to the region's power market rather than curtailing it; and
- Shutting down the electrolyzer and selling all available clean electricity to the region's power market when prices are at a **premium**—that is, above $80/MWh[6]—which simultaneously benefits the grid by making more energy available during periods of tight supply (improving reliability and reducing power prices for customers).[7]

We then modeled project operations, summing the three revenue streams and netting out the price of power from the renewable projects for an estimate of gross profit. As part of this process, we iterated the size of the co-located wind and solar projects to test designs that derived most of their value from a 1 megawatt (MW) electrolyzer, as we wanted to keep the focus on the value of hydrogen production.[8] While we did not set a hard limit, we generally iterated to ensure hydrogen revenues were upward of 70 percent of the total project value and electrolyzer load factors were upward of 80 percent.[9]

The forecasted gross profits provide a rough estimate of the funds a developer would have available to cover two classes of uncertain costs—hydrogen production and hydrogen storage or transport. The biggest determinant of hydrogen production costs (other than the price of power) is capital costs for the electrolyzer and the rest of the system. These total system costs for highly flexible proton exchange membrane (PEM) electrolyzers can range from $700 to $1,400 per kilowatt (kW).[10] We tested three capital cost assumptions, deriving net profits for our projects by subtracting total hydrogen production costs from gross profits; while this included a "high" case of $2,000/kW, nearly all sources of electrolyzer costs today fall within or near the range of $700/kW to $1,400/kW.[11]

[5] There is likely a limit to how bad value deflation would get. For example, at low enough power prices, batteries would likely come online to soak up excess energy, acting as a price floor; this would have co-benefits of helping to clean the grid in peak hours and improving reliability.

[6] This threshold assumes revenues of $4/kgH_2$ ($3/kgH_2$ from the 45V tax credit plus the $1/kgH_2$ hydrogen sale price) and an electrolyzer with an efficiency of 50 $kWh/kgH_2$ (which translates to 20 $kgH_2/MWh$). See: https://resources.plugpower.com/electrolyzers/ex-4250d-f041122.

[7] There is a fourth element we did not model. Namely, when renewable energy availability falls below a certain level (roughly 10 percent of the electrolyzer's capacity), the electrolyzer might need to shut down. This power can then be sold to the open market, though it may generate less revenue than if it could produce hydrogen (and 45V tax credits).

[8] The 1 MW electrolyzer size should be understood as an index that can scale linearly; that is, a 1 MW electrolyzer with a 2 MW solar farm and 3 MW wind farm would have the same operational dynamics as a 10 MW electrolyzer with a 20 MW solar farm and 30 MW wind farm.

[9] In reality, hydrogen project developers would optimize profitability of the total system using more sophisticated methods that account for the risk of value deflation (i.e., changes in market power prices over time), potential offtake contracts for the hydrogen and clean power, and other factors outside the scope of this feasibility assessment.

[10] See Table 1: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Green_Hydrogen_breakthrough_2021.pdf.

[11] See: https://zenodo.org/record/7948769#.ZGZ7n3bMLo8.

**Table B1. Electrolyzer cost assumptions**

| Parameter | Low | Central | High |
|---|---|---|---|
| **PEM electrolyzer capital costs ($/kW)** | 800 | 1,400 | 2,000 |
| **Capital recovery factor** | 7%/10 years | 7%/10 years | 7%/10 years |
| **PEM electrolyzer capital cost amortization ($/kW-yr)** | 112 | 196 | 280 |
| **Operations & maintenance ($/kW-yr)[12]** | 90 | 90 | 90 |
| **Finance & tax shield ($/kW-yr)[13]** | 90 | 90 | 90 |
| **Total system costs ($/kW-yr)** | 292 | 376 | 460 |

Our analysis ends with calculating net profits, though these margins can be used for investment in hydrogen storage or transportation services. These costs are highly dependent on a wide range of factors, including how much storage capacity you need; how long you are storing hydrogen at a time; whether you are sharing the costs of a storage system with other developers; how sensitive your offtaker is to fluctuations in supply; whether you are located near salt caverns or need higher-purity options like above-ground storage tanks; whether you have access to a shared hydrogen pipeline network; and how much you can store within any such pipelines. Therefore, we do not test specific storage or transport cost scenarios—though available net profits allow developers to be creative in funding the specific services they need to deliver hydrogen to offtakers.[14]

## RESULTS

Table B2 details the results of our modeling of export-only projects, including selecting capacities of solar and wind projects that drive relatively high electrolyzer profits (limiting how much revenue can come from excess power sales). We chose renewable project capacities that are five to six times larger than the electrolyzer capacity, which helps support electrolyzer load factors of 82-88 percent while selling 47-61 percent of generation to the grid.

[12] Estimated from pages 12 and 16 of "Hydrogen Carbon Intensity Temporal Analysis," Wood Mackenzie, February 2023. These values also lined up with conversations with other industry consultants and project developers.
[13] "Hydrogen Carbon Intensity Temporal Analysis," Wood Mackenzie, at 12, 16.
[14] For more detail on cost considerations, see the "Midstream: Distribution and storage" section of the U.S. Department of Energy's *Pathways to Commercial Liftoff: Clean Hydrogen* report starting on page 14: https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

### Table B2. Export-only project cost assumptions and results

| Parameter | West Texas | Near Houston | Southwest Minnesota |
|---|---|---|---|
| **Solar costs and operations** | | | |
| Solar capacity (MW) | 3.0 | 3.5 | 2.0 |
| Solar LCOE – central case ($/MWh) | 16.20 | 19.32 | 27.47 |
| Solar LCOE – conservative case ($/MWh) | 21.20 | 24.32 | 32.47 |
| Solar capacity factor (%) | 25.9 | 20.8 | 21.2 |
| Solar production (MWh/yr) | 6,824 | 6,392 | 3,722 |
| Solar share of total renewable production (%) | 47 | 43 | 19 |
| **Wind costs and operations** | | | |
| Wind capacity (MW) | 2.0 | 2.8 | 4.0 |
| Wind LCOE – central case ($/MWh) | 19.20 | 23.93 | 16.39 |
| Wind LCOE – conservative case ($/MWh) | 24.20 | 28.93 | 21.39 |
| Wind capacity factor (%) | 43.6 | 34.5 | 45.2 |
| Wind production (MWh/yr) | 7,661 | 8,496 | 15,877 |
| Wind share of total renewable production (%) | 53 | 57 | 81 |
| **Electrolyzer operations** | | | |
| Total renewable production (MWh/yr) | 14,485 | 14,888 | 19,599 |
| Electrolyzer capacity (MW) | 1.0 | 1.0 | 1.0 |
| Electrolyzer consumption (MWh/yr) | 7,654 | 7,095 | 7,642 |
| Electrolyzer load factor (%) | 88.1 | 81.8 | 87.0 |
| Excess energy sales (MWh/yr) | 6,628 | 7,520 | 11,958 |
| Premium energy sales (MWh/yr) | 203 | 273 | 0[15] |
| Share of production sent to electrolyzer (%) | 53 | 48 | 39 |

Table B3 details the financial results for these export-only projects. Hydrogen sales—which include the $3/kg tax credit—dominate project revenue, accounting for 72-79 percent of all income. This reflects the influence of the tax credit on oversizing the renewable resource build-out—slight increases in electrolyzer load factors can have big impacts on profitability.

[15] Power prices never rose above $80/MWh in MISO Minnesota Hub in 2020.

### Table B3. Export-only project financial assumptions and results

| Parameter | West Texas | Near Houston | Southwest Minnesota |
|---|---|---|---|
| **Revenue** | | | |
| Median day-ahead power price ($/MWh) | 16.41 | 18.18 | 17.23 |
| Revenue from excess energy sales ($/yr) | 123,434 | 173,973 | 188,040 |
| Excess energy sales share of total revenue (%) | 16 | 22 | 24 |
| Revenue from premium energy sales ($/yr) | 41,236 | 46,584 | 0[16] |
| Premium energy sales share of total revenue (%) | 5 | 6 | 0 |
| Revenue from hydrogen sales ($/yr) | 612,289 | 567,570 | 611,337 |
| Hydrogen sales share of total revenue (%) | 79 | 72 | 76 |
| Total revenue ($/yr) | 776,959 | 788,127 | 799,377 |
| **Renewable power costs** | | | |
| Cost of renewable power – central case ($/yr) | 257,638 | 326,772 | 362,533 |
| Cost of renewable power – conservative case ($/yr) | 330,062 | 401,243 | 460,530 |
| **Gross profit** | | | |
| Gross profit – central case ($/yr) | 519,321 | 461,355 | 436,844 |
| Gross profit – conservative case ($/yr) | 446,897 | 401,243 | 338,847 |
| Gross profit – central case ($/kW-yr) | 519 | 461 | 437 |
| Gross profit – conservative case ($/kW-yr) | 447 | 387 | 339 |
| **Electrolyzer costs** | | | |
| Electrolyzer costs – low case ($/kW-yr) | 292 | 292 | 292 |
| Electrolyzer costs – medium case ($/kW-yr) | 376 | 376 | 376 |
| Electrolyzer costs – high case ($/kW-yr) | 460 | 460 | 460 |
| **Net profit** | | | |
| Net profit – central-low ($/kW-yr) | 227 | 169 | 145 |
| Net profit – central-medium ($/kW-yr) | 143 | 85 | 61 |
| Net profit – central-high ($/kW-yr) | 59 | 1 | (23) |
| Net profit – conservative-low ($/kW-yr) | 155 | 95 | 47 |
| Net profit – conservative-medium ($/kW-yr) | 71 | 11 | (37) |
| Net profit – conservative-high ($/kW-yr) | (13) | (73) | (121) |

The six net profit results represent combinations of two renewable LCOE cases (with central and conservative cases reflecting NREL ATB data and a $5/MWh adder, respectively) and three electrolyzer capital cost cases (with low and medium cases reflecting the range of today's PEM electrolyzer market prices and the high case offering a pessimistic view).

With one exception, unprofitable outcomes are limited to combining the high-price renewable and electrolyzer cases. High net profit margins in West Texas allow for more spending on hydrogen storage and transportation. Near Houston and Southwest Minnesota have relatively tighter net profit margins but are also much closer to

[16] Power prices never rose above $80/MWh in MISO Minnesota Hub in 2020.

pipelines and industrial end users; for example, Houston is part of the existing U.S. hydrogen pipeline network and has plentiful petrochemical industry sites, while Southwest Minnesota is ripe for fertilizer production and has existing ammonia pipelines that flow all the way to the Gulf of Mexico.

As shown in Figure 15 of our main report, there are huge regions of the U.S. that meet similar conditions—namely, an average LCOE for wind and solar resources of $25/MWh or less. Net profit margins as well as proximity to storage options (e.g., salt caverns), hydrogen or ammonia pipelines, and end users will determine which project designs make sense and where developers will site them.[17] These projects will also overlap with hydrogen hub build-outs funded by the Infrastructure Investment and Jobs Act, which could provide shared storage or pipeline infrastructure at lower overall cost. Lastly, this analysis reflects today's electrolyzer and renewable energy costs—as prices fall over the next decade, these project configurations will likely become viable in many more places across the country and may only need one resource (i.e., wind or solar) to pencil out.

## CONCLUSION

There are a few takeaways from our financial viability analysis of export-only projects that are clearly compliant with the three principles of 45V guidance design:

- A combination of co-located wind resources, solar resources, and electrolyzers can easily sell hydrogen at $1/kg and pay off the cost of all electrolyzer equipment while making a profit today if located in parts of the country with decent wind availability.[18]
- Profit margins can help fund hydrogen storage or transportation investments, though these requirements are highly project specific.
- There is considerable profit upside not considered in this analysis, including building detached projects that can site renewable resources and electrolyzers in their most favorable locations (with low administrative costs of complying with the three principles),[19] capital costs falling over the next decade, state funding for hydrogen production,[20] and high power-price years.

In sum, projects compliant with the three pillars are financially viable in much of the U.S. today. Guidance that accurately measures lifecycle GHG emissions from electrolysis would not kill the industry or even meaningfully slow its growth. This finding has been corroborated by a range of other studies from independent developers, consulting groups, and academia.[21] The U.S. Treasury can have confidence that setting accurate 45V guidance will drive robust growth of the clean hydrogen industry, with projects that can survive and benefit the grid long after the tax credit expires.

[17] For example, see this project announcement from NextEra and CF Industries to build a zero-carbon hydrogen project in Oklahoma that would make ammonia: https://newsroom.nexteraenergy.com/2023-04-24-CF-Industries-and-NextEra-Energy-Resources-announce-a-memorandum-of-understanding-for-a-green-hydrogen-project-in-Oklahoma-to-support-decarbonization-of-the-agriculture-supply-chain.

[18] Wind resource quality varies much more than solar resource quality, so project viability mostly hinges on wind availability.

[19] Administrative costs would likely consist of providing proof of a power purchase agreement and demonstrating procurement and retirement of hourly renewable energy credits (though the cost of the power and credits themselves would be the same or less than the export-only project variant).

[20] For example, see Colorado's new law, which provides up to $1/kg for hydrogen that meets the three principles and is sold to prioritized end users: https://www.utilitydive.com/news/colorado-law-hydrogen-industry-tax-incentives/650460/.

[21] See: https://zenodo.org/record/7948769#.ZGZ7n3bMLo8.