Emerging Economics of Hydrogen Production and Delivery

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Purpose and Scope

This study reviews how the production and delivery costs of hydrogen are changing under the influence of recent strong tax incentives, DOE support for hydrogen research and hub development, rapidly growing commercial scale, and projected technology improvements.

We compare costs under a few different modes of production, or "colors," of hydrogen including green pink and blue, but most focus is on green hydrogen.

- We compare costs if H_2 is produced intermittently (when wind or solar power are available) versus if it is produced in "steady state" at a uniform level throughout the year (which requires overbuilding the renewable power and including storage).
- Comparisons are between 2023 and 2030, when many developers hope to be bringing announced projects to market (for which they also project technology improvements used herein).
- Due to pronounced differences in feedstock costs, H_2 costs will vary by region. We compare California to the Gulf Coast and to New York, which correspond to where most H_2 development projects are being pursued at this time.
- Delivery costs are evaluated for pipelines and trucking, but not for distribution scale pipes or conversion expenses of hydrogen customers. Focus is on getting hydrogen to market areas, not on end-use demands or priorities.

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Findings

Results indicate that public programs, especially the recent Clean Hydrogen Production tax credits for green H_2 can offset around half of H_2 production costs, making it close to competitive with conventional (grey) H_2. Projected large reductions in electrolysis costs could achieve comparable reductions, potentially reaching or beating DoE's "hydrogen shot" goal of $1/kg by 2030.

- Indeed, 2030 costs with tax shields could be negative in some places.
- A $1/kg price is equivalent to about $7.44/MMBtu, i.e. close to natural gas, esp. if the latter were penalized by a CO_2e emissions charge reflecting the social cost of carbon.

Midstream and downstream delivery and storage costs for moving H_2 appear to be less than $1/kg, but there are significant unresolved technical limitations (esp. leakage) on bulk shipping and storing

- The small size of H_2 molecules makes remote delivery and storage challenging
- There are regional hydrogen pipeline networks in the Southeast, and some hub projects include new pipes, but at present no natural gas pipeline company is (publicly) considering expansion or conversion to hydrogen
- Only salt-dome storage seems well suited to hydrogen, which are mostly located on the Gulf Coast; long term seasonal storage (akin to natural gas storing summer for winter) seems unlikely

As a result, a national market for H_2 may be slow to develop; instead H_2 will tend to be made more locally, close to end use, under differing technologies and costs that suit those locations.

Long run demand for H_2 is projected to be high, but there is a fairly clear "ladder" of priority for best-use (hence most likely realization) across industries, with hard-to-electrify industrial applications and some heavy duty transportation the strongest.

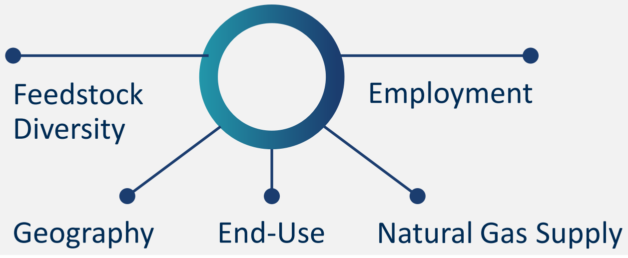
The clean power requirements for making the quantities of H_2 that are sometimes projected for 2040-2050 (30-50 million metric tons per year) could be huge: perhaps as much as 700GW of renewable power just to serve this demand.

Recent U.S. policy is driving investment and focus on H_2

Hydrogen Hubs (2021)[1]

Congress appropriated $8 billion to award “networks of clean H_2 producers, consumers, and the connecting infrastructure.”

- Part of the Infrastructure Investment Job Act (IIIJA)
- DOE is administering the funding in 50% cost-sharing agreements
- Seven hubs selected Oct 2023, each receiving about $1 billion and targeting mix of H_2 feedstock's and end-uses
- An additional $1 billion is targeted for demand-side initiatives.
- DOE expects projects to be executed over 8 to 12 years



Inflation Reduction Act (2022)[2]

Congress introduced major incentives for clean energy production, including expanded tax credits for carbon capture utilization and storage (CCUS) and direct air capture (DAC), and novel tax credits for clean hydrogen production.

Tax Credit	Amount	Description
45V (new)	Up to $3/kg H_2	Production tax credit for “clean” hydrogen, developers allowed to choose between ITC and PTC
45Q (extended and augmented)	Up to $85/t$CO_2$ stored	Production tax credit for capture *and* sequestration; Cannot be stacked with 45V
45Z (new and augmented)	$0.2 to $1/gal. x emission factor $0.35 to $1.75 x emission factor (aviation fuel)	Clean transport. fuel production credit; higher amount available for meeting wage and labor criteria; Cannot be stacked with 45V

EPA Section 111 (2023)[3]

EPA proposed updates to New Source Performance Standards for new stationary combustion turbines:

Establishes both (a) 90% carbon capture and **(b) 30% hydrogen co-firing with natural gas** as best available technology beginning in 2032

Establishes both (a) 90% carbon capture and **(b) 96% hydrogen co-firing with natural gas** as best available technology beginning in 2038

IRA: a watershed for US H_2 economy

The 2022 Inflation Reduction Act provided $369 billion of spending for climate protection provisions. Among these, the outsized clean production tax credits for H_2 are stimulating the development of a US H_2 economy.[4]

- 45V clean H_2 tax credits can be $3/kg – about half the size of recent production costs, or $22.30/MMBtu, and these tax credits can be monetized
- In response, there have already been announcements of at least 25 industry H_2 projects, many of which project very substantial IRRs.[5]

Many specifics for the IRA are unresolved, which creates a number of uncertainties for H_2 development.

- One critical area is the resolution of the proposed 45V regulations which aims to ensure that power used for making H_2 is not inducing new GHG emissions, deemed the "additionality problem":[6]
  - Preliminary 45V rules state that power for electrolysis needs to be on-site *or* temporally aligned with H_2 production ("hourly matching"), within the same deliverability region ("deliverability"), and from new renewable resources ("additivity").
  - Affects costs and locations of potential projects (more feasible with less additionality)
  - Also unresolved are the extent of allowable stacking of different types of energy tax credits, and how to deal with fugitive emissions
- *Herein, we assume strict additionality is required;* no remote, partially clean power used
  - But, H_2 use has additional positive and negative side effects from changing methane leakage and its own possible leakage as a GHG on delivery
  - Still reduces GHGs, but not 100%

Department of Energy Hydrogen Programs: Hydrogen Hubs

2021's Infrastructure Investment and Jobs Act appropriated $8 billion in funding to the DOE for awards to between six and ten hydrogen hubs.[1]

Overview:

- Awards are intended for networks of clean H_2 producers and consumers, and the infrastructure connecting the two
- Hubs must include capabilities for all stages of a H_2 supply chain, including production, processing, delivery, storage, and end-use.

Criteria:

- DOE was required by law to selected seven hubs such that, together they meet the following requirements:
  1. Feedstock diversity: renewable, natural gas with CCS, and nuclear
  2. End-use diversity: power generation, industrial, heating, and transportation
  3. Geographic diversity
  4. At least two hubs must be located in natural gas producing regions
  5. Create employment requirements

Timeline:

- Projects were selected in Fall 2023
- DOE expects project execution over 8 – 12 years

Applicant Hubs:

- **Northeast:** CT, NY, NJ, ME, RI, VT and MA to compete jointly for a $1.25 billion hydrogen hub funding. Hub will focus on clean electrolytic production for hard to decarbonize sectors *i.e.* transportation and heavy industry.
- **California:** State-wide hub application led by the Alliance for Renewable Clean Hydrogen Energy Systems
- **Texas:** Three hub proposals- Gulf Coast Hydrogen Transition Hub, HyVelocity Hub, Corpus Christi Horizons Clean Hydrogen Hub
- 21 projects, including the five above, were encouraged to and submitted full applications to the DOE.

Selected Clean Hydrogen Hubs

	States	Type of H_2	Funds	Target Sectors[a]
Appalachian Hydrogen Hub	WV, OH, PA	Green, Blue, Biohydrogen	up to $925 million	Ammonia, chemicals, industrial, heavy-duty transport, mining, data centers, distribution centers, Sustainable aviation fuel (eSAF), gas utility blending, residential fuel cells
California Hydrogen Hub	CA	Green, Biohydrogen	up to $1.2 billion	Heavy duty-transport, power generation, port operations
Gulf Coast Hydrogen Hub	TX, LA	Green, Pink, Blue	up to $1.2 billion	Ammonia, refining and petrochemicals, industrial, heavy-duty transport, transit authorities, ports, eSAF, marine fuel (eMethanol), power generation
Heartland Hydrogen Hub	MN, ND, SD, MN, WI	Green, Pink, Blue	up to $925 million	Fertilizer, industrial, eSAF, power generation, gas LDC blending
Mid-Atlantic Hydrogen Hub	PA, DE, NJ	Green, Pink, Blue	up to $750 million	Industrial, refineries, heavy-duty transportation, transit authorities
Midwest Hydrogen Hub	IL, IN, MI	Green, Pink, Blue	up to $1 billion	Agriculture, industrial, manufacturing, heavy-duty transportation, eSAF, gas utility blending
Pacific Northwest Hydrogen Hub	WA, OR, MT	Green	up to $1 billion	Fertilizer, refiners, industrial, heavy-duty transport, eSAF, marine fuel, long-duration energy storage

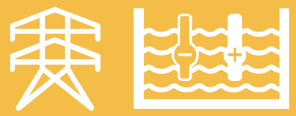
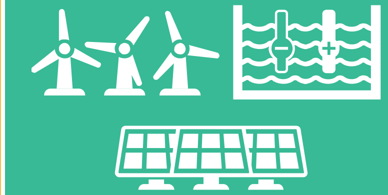
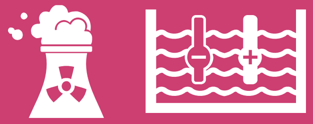
[a]: Targeted sectors are not all or mostly yet committed as offtakers, i.e. demand is not fully assured.

Recent industry project announcements targeted mostly at industrial uses[5]

No.	Firm(Partner)	Type of Project	Location	Production /Size	Type of Supply	CCS	Midstream	Type of Offtake	Offtake Agreement
1	CF Industries	NH3 - Blue	Donaldsonville, LA	1.7 MMst NH3/yr.	Steady	Yes	None	Brownfield	None
2	CF Industries(Mitsui)	NH3 - Blue	LA	1.35 MMst NH3/yr.	Steady	Yes	None	Brownfield	None
3	CF Industries	NH3 - Blue	Yazoo, MS	-----	Steady	Yes	None	Brownfield	None
4	Nutrien(Mitsubishi)	NH3 - Blue	Geismar, LA	1.35 MMst NH3/yr.	Steady	Yes	-----		-----
6	Enbridge/Yara	NH3 - Blue	Ingleside, TX	1.3 MMst NH3/yr.	Steady	Building CO2 Storage	-----	Greenfield; online 2028	100% to Yara
5	Air Products	Blue H2 & NH3	Eastern LA	4 MMst NH3/yr.	Steady	Yes	Air Products H2 P/L	Greenfield; online 2026; 50% H2 & 50% NH3	-----
7	ExxonMobil	Blue H2 & NH3	Baytown, TX	1 BCFD H2	Steady	Building 10 MMmt CO2 Storage		Greenfield; online 2028	Baytown refinery & adjacent Sk, Inc NH3 plant
8	NextEra/CF Industries	Green NH3	Verdigris, OK		Steady	No	-----	450 Mw co-located renewables for 100MW electrolyzer	-----
9	CF Industries	Green H2 & NH3	Donaldsonville, LA	20 Mst H2/yr.	Steady	No	-----	Uses 20 MW alkaline electrolyzer	Japanese utility to co-fire with coal
10	Air Products(AES)	Green H2	Wilbarger Cty, TX	78 MMmt H2/yr.	Intermittent	No	Building liquefier; trucks; won't build H2 P/L	Greenfield; serve transportation sector	
11	Air Products	Green H2	Casa Grande, AZ	3.65 Mmt H2/yr.	Steady	No	-----	Greenfield; online 2023; 300 MW solar for 120 MW electrolyzer	-----
12	Air Products(World Energy)	Green H2	Paramount, CA	-----	Intermittent	No	SoCal H2P/L; can store 400 kg H2 onsite	Greenfield; online 2028; Includes aviation fuels plant	World Energy
13	Air Products	Green H2	Massena, NY	12.5 Mmt H2/yr.	Intermittent	No	Building liquefier; trucks	Greenfield; serve transportation sector; online 2027; hydro power at $20/MWh	-----

Hydrogen Production

Hydrogen can be produced via many system configurations

					
	Grey	**Blue**	**Yellow**	**Green**	**Pink**
Technology	Steam Methane Reforming (SMR)	SMR with Carbon Capture and Sequestration (CCS)	Electrolyzer - Alkaline, Polymer Electrolyte Membrane (PEM)	Electrolyzer - Alkaline, Polymer Electrolyte Membrane (PEM)	Electrolyzer - Alkaline, Polymer Electrolyte Membrane (PEM)
Feedstock /Fuel	Natural Gas/Electricity	Natural Gas/Electricity	Water/ Grid Electricity	Water/Renewable Electricity	Water/Nuclear Electricity

Other production processes such as pyrolysis (turquoise hydrogen) and partial oxidation are also being developed but are commercially unproven thus far and less prevalent in industry discussions today.

Wholesale hydrogen cost chain

Upstream
Hydrogen Production

- **Electrolysis**
  - *Feedstock* – Water;
  - *Fuel* – Electricity from renewables, nuclear, grid power
- **Steam Methane Reforming with Carbon Capture**
  - *Feedstock* – Methane
  - *Fuel* – Methane, Electricity

→ **Midstream** Transportation → **Storage** → **City Gate or End-User**

In this report, costs added to here but not beyond, i.e. no local delivery or end-use conversion costs considered.

Here we assume that hydrogen production is either by electrolysis of water (renewables - green, nuclear - pink, or grid power—yellow) or by steam methane reform (SMR) + carbon capture and storage (CCS) of natural gas (blue) to determine the cost of production in three regions – CA, Gulf Coast, and Northeast (NY) – across different time periods.

Electrolysis is assumed to be by Polymer Electrolyte Membrane (PEM) technology unless otherwise indicated.

All required electrolysis power is assumed to be local and synchronous with H_2 production; no sub-additivity.

We use nominal levelized cost of hydrogen (LCOH = lifecycle breakeven flat price per kg) as comparison metric.

Current green H_2 production costs

For green H_2 today, electricity costs are by far the lion's share, i.e. 70-90%, of total costs.

Power costs in turn depend strongly on how it is produced (renewable, nuclear, grid, etc. – shaded blue bars at right depict alternative power sources)

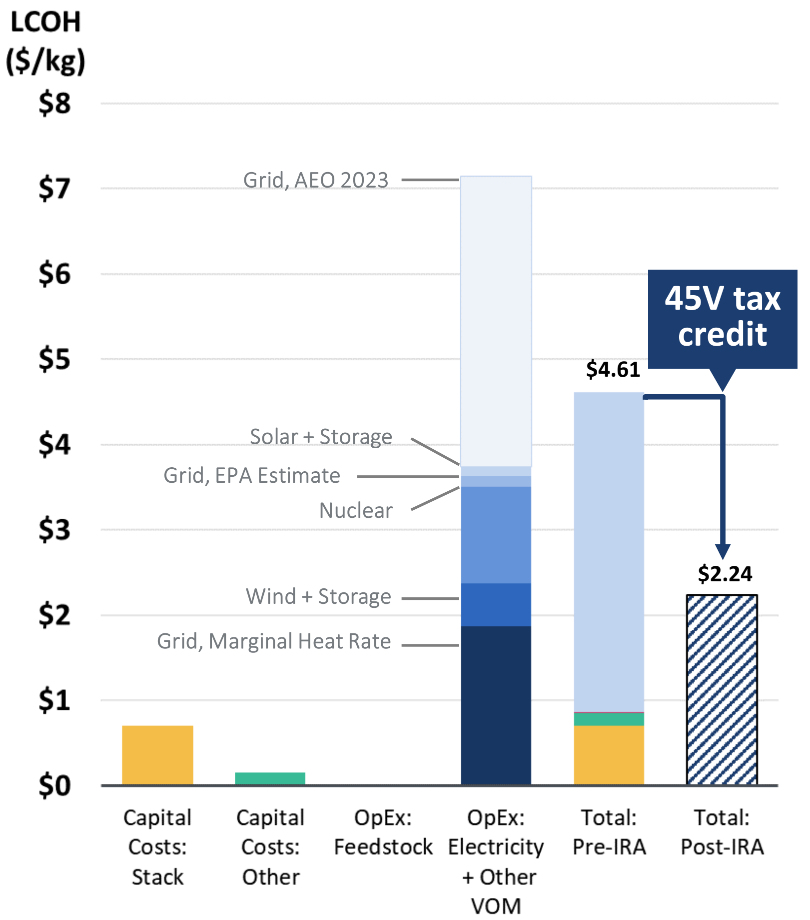
Under the Clean Hydrogen Production Tax Credits, green H_2 receives a \$3/kg credit for production in the first 10 years of plant life, cutting net costs by as much as half.

Capital costs and efficiency of electrolyzers are projected by developers to improve rapidly over next few years.

- PEM costs about \$1,000-1,500/kW today, but recent industry projects cite around \$250/kW by 2030 and requiring 20% less electricity per kg
- Also, many other electrolyzer technologies emerging and improving
- Renewable power costs also likely to fall over the coming decade, if past trends are indicative.

H_2 at \$1/kg corresponds to \$7.44/MMBtu

2023 California Costs for Steady State H_2 via Electrolysis using PEM



Note: 45V tax credit converted from larger initial 10-year value to equivalent net benefit over entire life of the plant

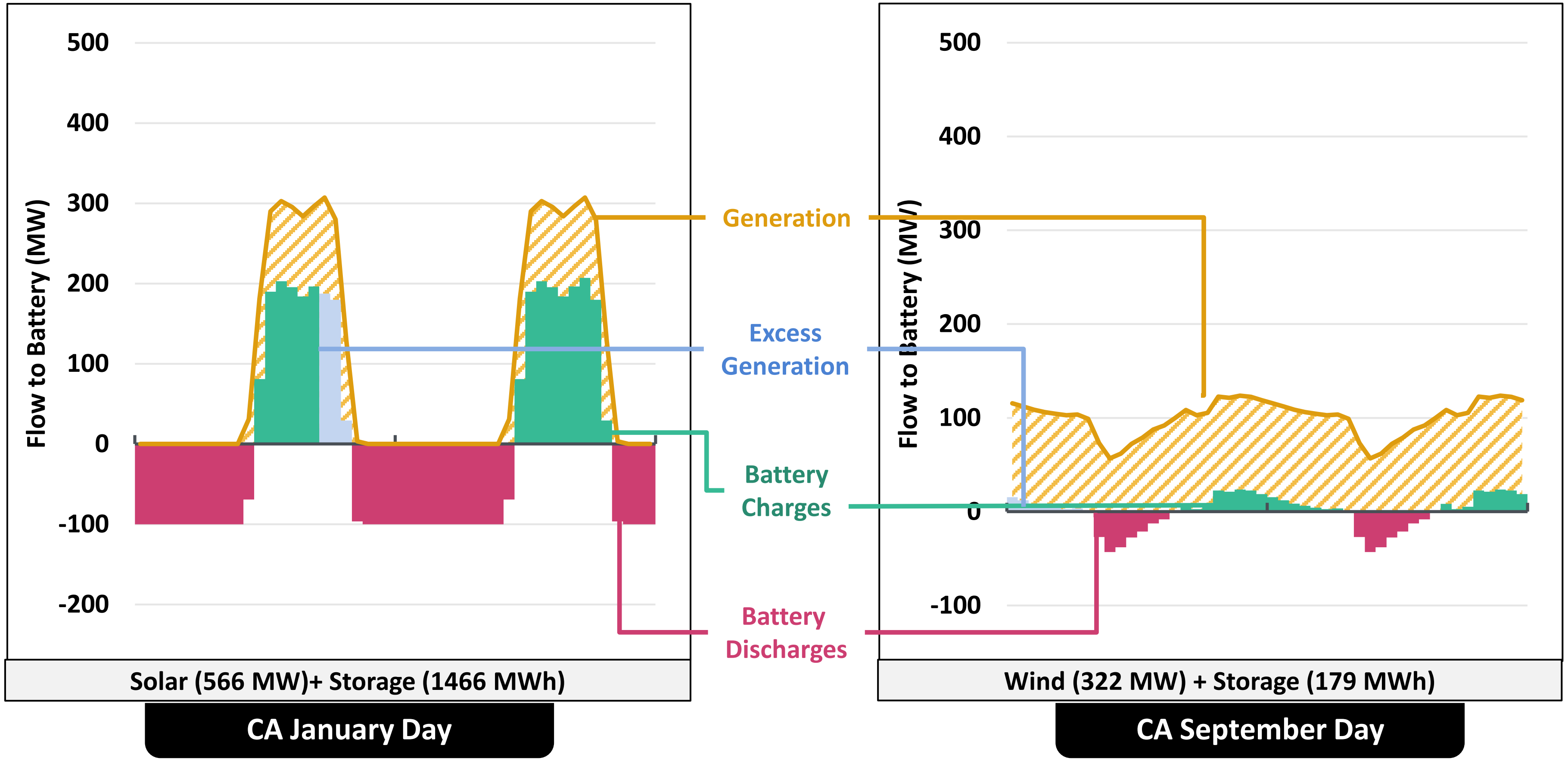
Technology assumptions – improvements by 2030

Process	Input	Units	2023	2030	Sources
Electrolysis	Electrolyzer CapEx	$M	**$1,263**	**$202**	2023: [8] 2030: [9]
		$/kW	**$1,000**	**$250**	
	Electrolyzer Capacity	MW	**1,263**	**809**	Assumption
		kg/day	**474,000**	**474,000**	
	Efficiency	kWh/kg_{H2}	**64**	**41**	2023: [10] 2030: [11]
	Lifetime	Years	**15**	**15**	Assumption
	Utilization rate	%	**Reflects source of electricity**		
Steam Methane Reform with Carbon Capture & Sequestration	SMR CapEx	$M	**$216**	**$216**	[12]
	CCS CapEx	$M	**$140**	**$135**	[13]
	SMR Capacity	kg/day	**500,000**	**500,000**	[13]
	Efficiency	$MMBtu_{CH4}/kg_{H2}$	**0.171**	**0.171**	[13]
	Lifetime	years	**15**	**15**	Assumption
	Utilization rate	%	**90%**	**90%**	[13]
	Carbon intensity	kg_{CO2}/kg_{H2}	**8.5**	**8.5**	[13]
	Carbon capture rate	%	**90%**	**90%**	[13]

*Cost improvements based on DOE Liftoff report, consistent with several industry projections

Sizing of electricity for steady state H_2

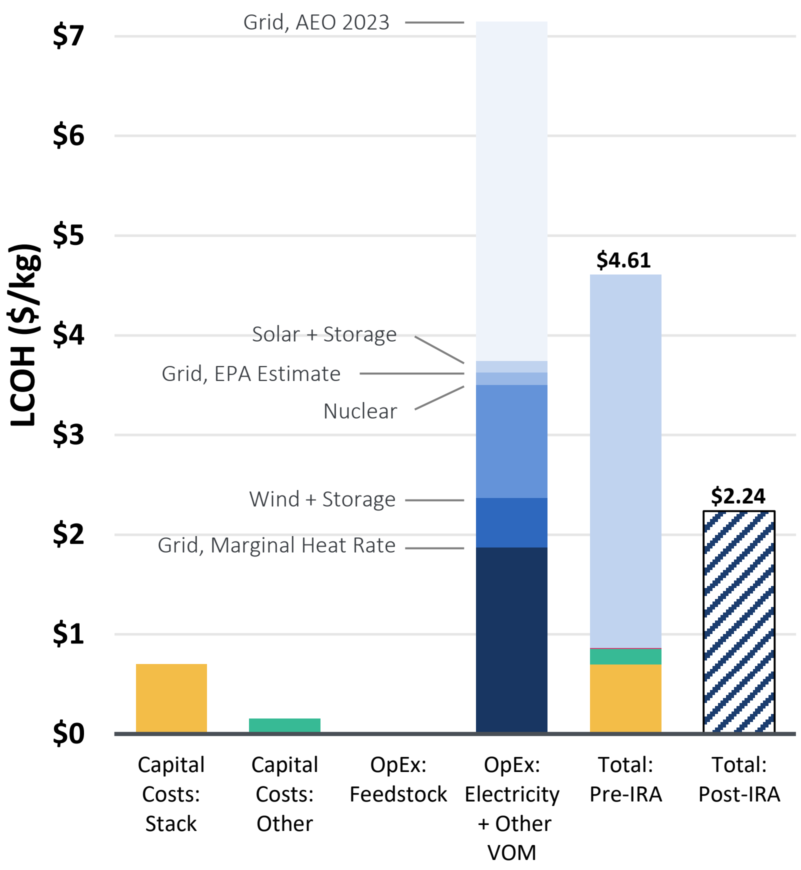
To produce H_2 year-round at 100% load factor, renewable power must be sized at $\frac{\text{Electrolyzer capacity (in MW)}}{\text{VRE Daily Capacity Factor}}$ for, e.g., two consecutive days of poor to average sun or wind, and corresponding battery storage added. Result can be many multiples of electrolyzer size (here assumed to be 100 MW, under California RE power conditions).



Note: Sizing for poor seasonal (e.g. solar winter) capacity factor results in large **power supply** with considerable **excess generation in some months** that can be sold into wholesale power market (at seasonal spot prices) to defray some H_2 costs.

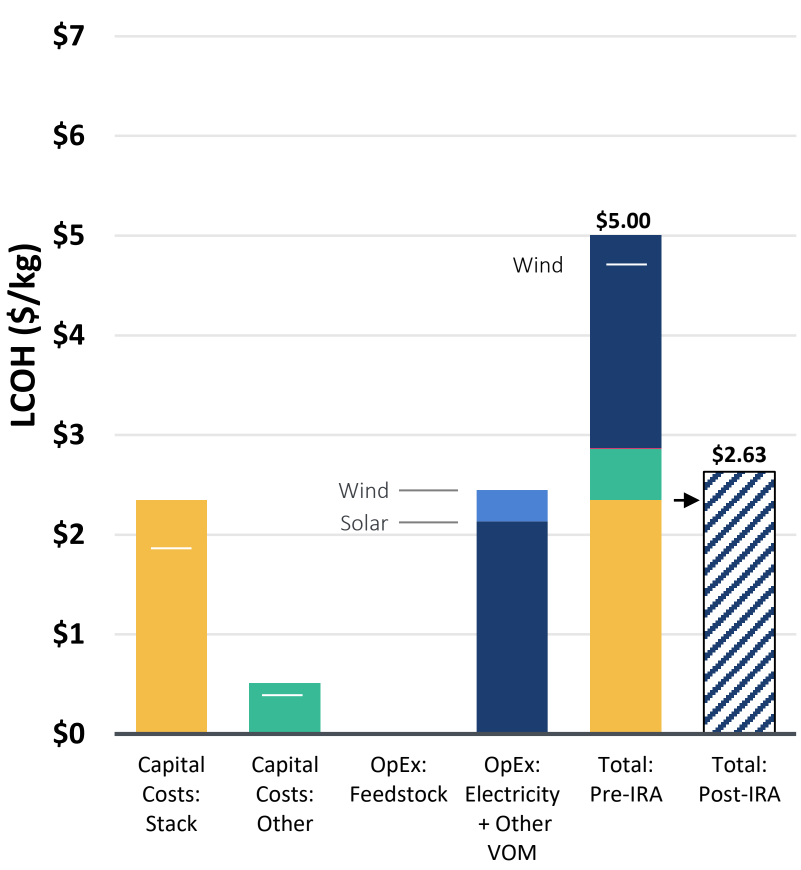
2023 Intermittent vs. Steady-State Green H_2 – CA production

Steady-State Electricity



*Total Costs shown for solar + storage power scenario

Intermittent Renewable Supply



*Total Costs shown for solar power scenario

Steady state production is slightly cheaper per kg than intermittent, at around $4.60 vs. $5/kg.

Steady state cheaper despite much higher total power supply capital requirements, due to much higher volume of H_2 (roughly 3x) to bear those fixed costs

With the 45V tax credit, green H_2 becomes competitive with gray hydrogen (assuming a grey LCOH of $1-1.50/kg).

Assumptions:
- Technology: PEM
- Region: California
- Electricity Source: Solar PPA ($28/MWh)
- CapEx Cost: 1,000/kW
- PEM Efficiency: 64 kWh/kg

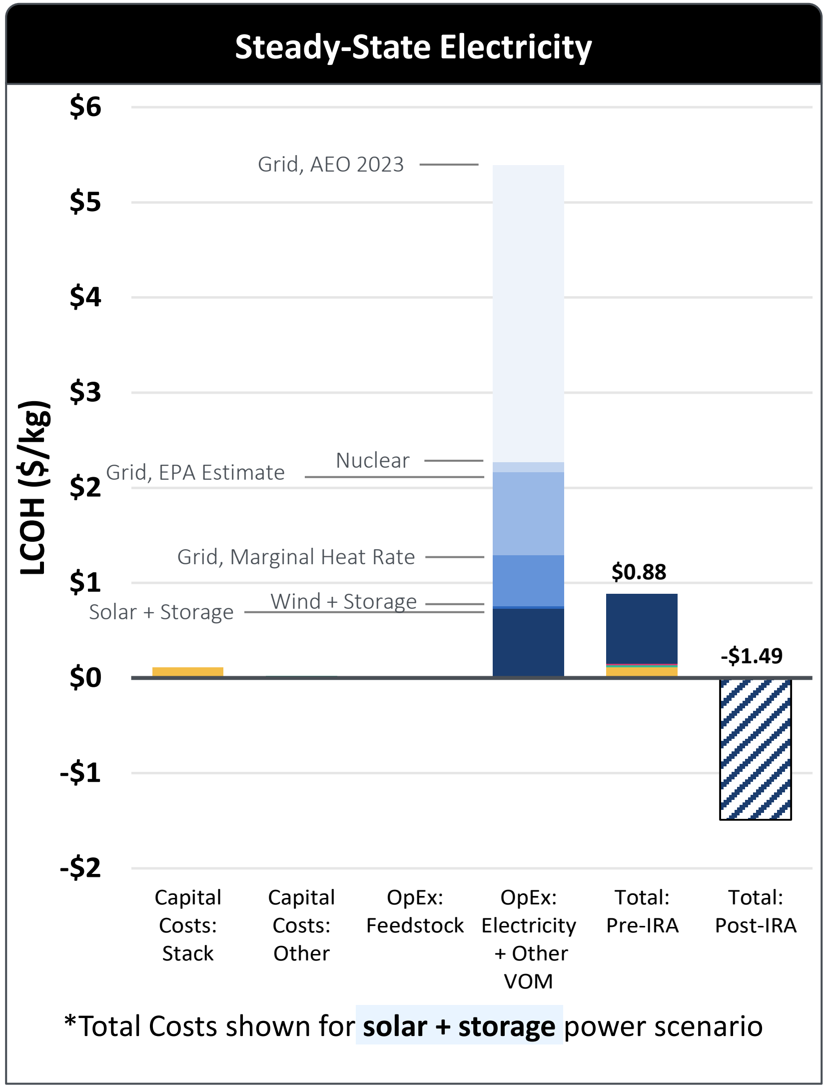
Note: Each portion of the "OpEx: Electricity + Other VOM" bar corresponds to the incremental cost of that contribution to the LCOH under each electricity supply scenario. The blue section of the "Total: Pre-IRA" bar matches the full height of the corresponding portion in the bar to its left.

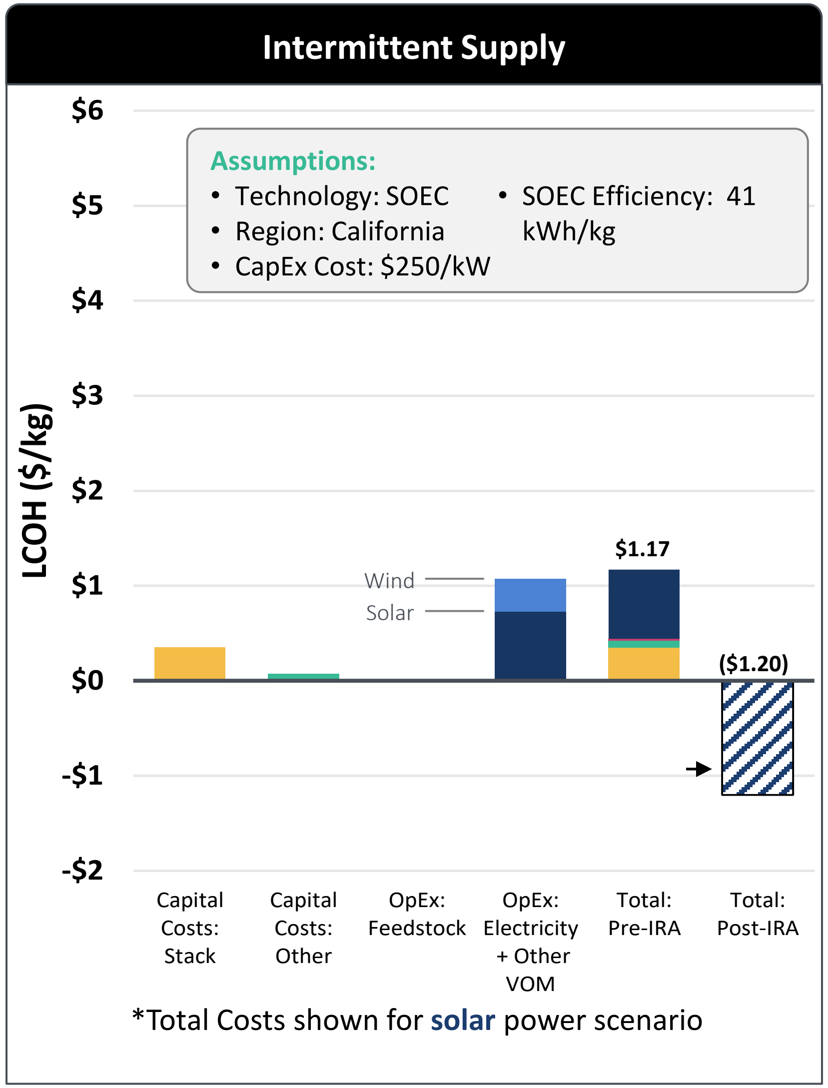
Industry electrolyzer improvement outlooks

Type	Unique Characteristics	Drawbacks	Commercial Availability	Major Vendors	Other Notes[a]
Proton Exchange Membrane (PEM)	• Fastest cycle times • Pairs well with intermittent renewables	• Uses precious metals (platinum & iridium), which could adversely impact future costs	• Dominated the market in the recent past	• Plug Power, • Siemens • Cummins	• Plug Power forecasts PEM cost decline of 50%
Anode Exchange Membrane (AEM)	• CapEx is 25% less than PEM (Uses steel/titanium instead of iridium) • AEM pairs well with intermittent VRE	• Relatively small scale (often referred to as the perfect fit for small consumers)	• Available	• Enapter (Europe)	• Enapter's patented dry cathode improves compactness, makes scale-up & maintenance easier.
Alkaline	• CapEx is lower than PEM or AEM	• Slow start times • Does not pair as well with intermittent renewables as a result	• Available	• Longi (China) • Nel (Europe)	• Longi forecasts cost decline to as low as $250 per kW
Solid Oxide Electrolyzer Cell (SOEC)	• 25% more efficient than PEM • Does not use precious metals • Uses steam instead of water	• Nascent technology that only recently became commercial	• Only demo plant to date (size is about 1/10th of PEM units) • Commercially available by 2024 • $10B in orders	• Bloom Energy	• Bloom predicts costs a cost decline of 10% to 15% per year

[a] Electric Hydrogen thinks costs will decline to <$500/kW by 2030. Linde and Air Products foresee costs as low as $200/kW.

Potential production costs in 2030 – CA example



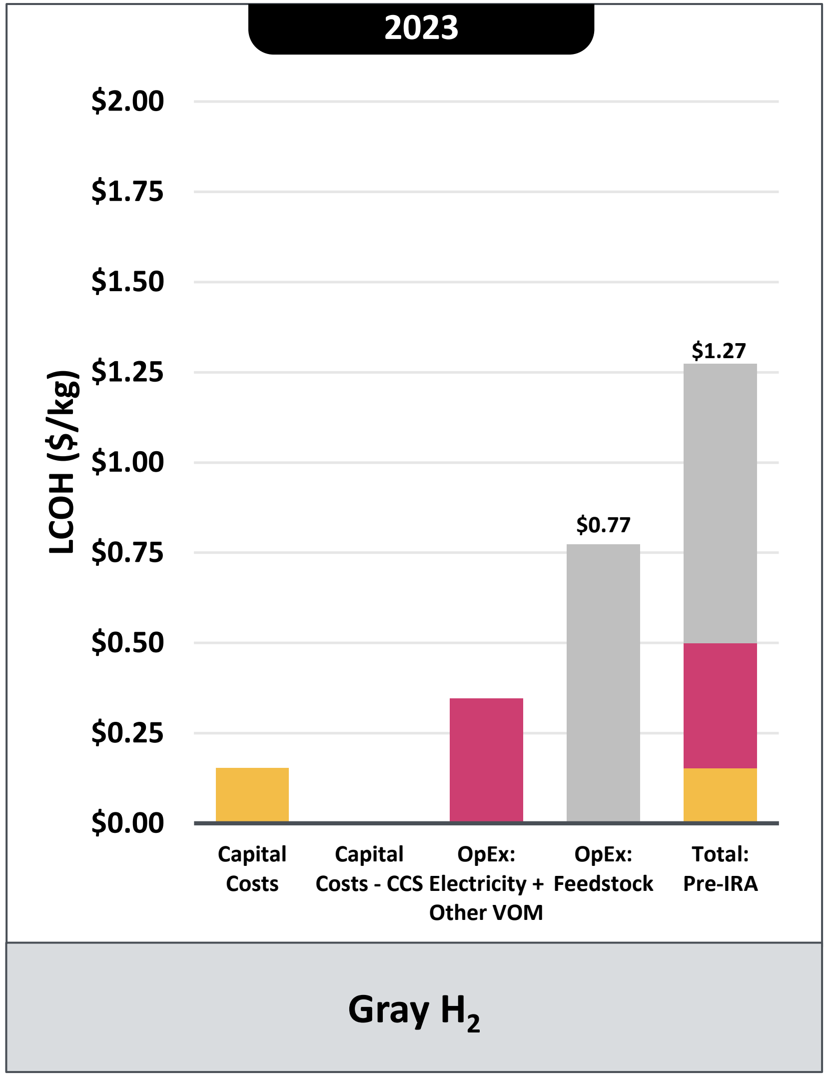


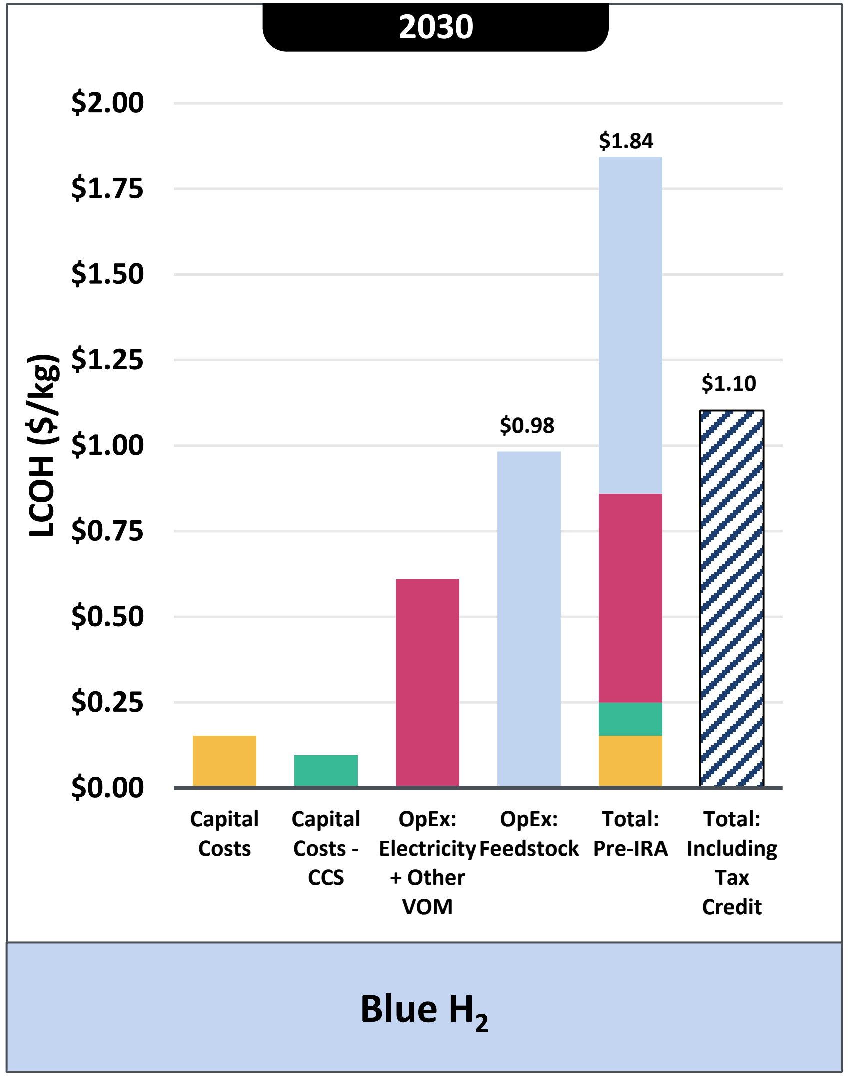
Even without IRA tax benefits, green H_2 reaches cost parity with, or beats, gray hydrogen by 2030 (assuming gray stays around $1-1.50/kg).

- Continuing 45V tax credits, *if extended then*, lead to **negative** production costs.
- The decline in the capital cost of electrolyzers significantly reduces the contribution to LCOH ($0.11 for steady state, $0.35/kg for intermittent)

Note: Each portion of the "OpEx: Electricity + Other VOM" bar corresponds to the incremental cost of that contribution to the LCOH under each electricity supply scenario. The blue section of the "Total: Pre-IRA" bar matches the full height of the corresponding portion in the bar to its left.

Blue H_2 produced in the Gulf Coast by SMR w/CCS could cost around $1.80 per kg by 2030 without 45Q, and $1.10 per kg with it, at or below gray.





- The vast majority of hydrogen currently produced is gray H_2 at low costs ($1 - $1.5/kg) but high emissions (8.5 kg CO_2/kg)
- The 45Q tax credit for CCS, along with low forecasts for natural gas prices (specific to the Gulf Coast) means blue H_2 also likely to reach cost parity with gray H_2 by 2030.
- *No assessment herein of CCS technology risk*

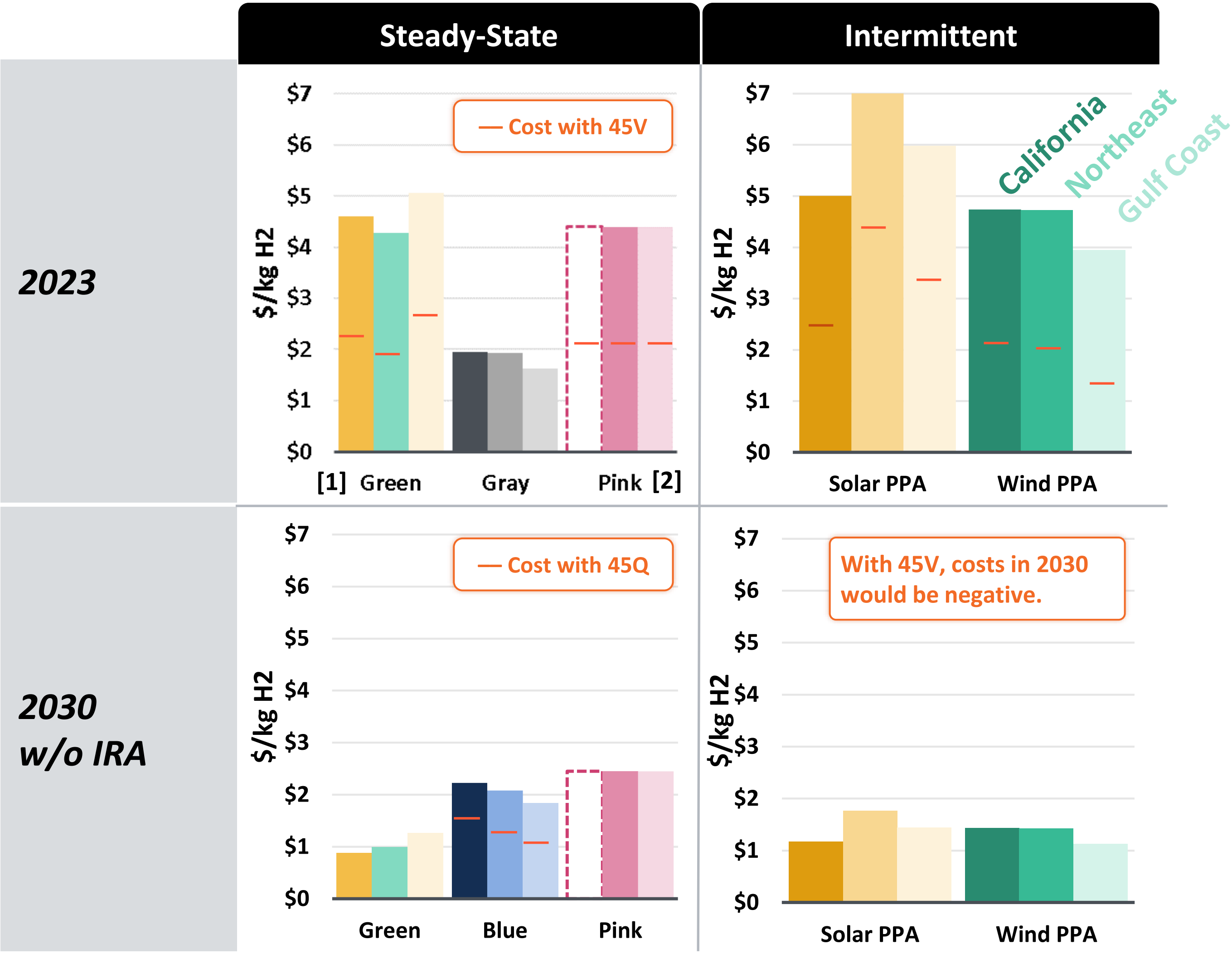
Assumptions:

- Technology: SMR
- Region: Gulf Coast
- Electricity Source: Solar PPA
- 45Q credit: $1/kg CO_2
- Cost of CO_2 transport and storage: $20/kg CO_2 (2023 dollars)[13]
- No penalty on CO_2 residual emissions from SMR
- Efficiency: 0.171 MMBtu/kg H_2
- Facility Lifetime: 15 years
- CCS CapEx: $135 M in 2030; 96% Capture
- Cost of Natural Gas (changes Y-over-Y): 2023: $5.86/MMBtu 2030: $4.06/MMBtu

Current vs. 2030 Production costs by region and technology

- Bars to the right compare H_2 techs under steady-state (left) and intermittent (right) approaches.
  - For green H_2 bars, all **shades of yellow indicate solar** supply, all **shades of green wind**. From darkest to lightest shade, the bars represent California, the Northeast and the Gulf Coast in that order.
  - Blue and pink H_2 assumed to operate only in steady-state mode.
  - All bar heights show costs without tax benefits. Orange lines in mid-bar indicate cost with 45V or 45Q savings
- Steady-state modes are generally cheaper than intermittent in both 2023 and 2030.
- Green H_2 appears cheapest in 2030 even before tax benefits.

Cost estimates assume all H_2 produced is immediately consumed, i.e. no storage, curtailment, or H_2 demand load-following.



[1] Cases for green hydrogen reflect the following PPA resources: CA and GC – Solar; NY – Wind.
[2] Given the lack of new nuclear generation and barriers to development, we do not anticipate pink hydrogen will be viable in California.

By 2030, green, pink and blue H_2 could be competitive with conventional natural gas

By 2030, hydrogen costs could decline to between $0.9 and $2.4 per kg, or $6.7 to $17.8 per MMBtu

- In comparison, the average natural gas citygate costs in the three regions ranged from $3.60 to $4.80 per MMBtu from 2020 to May 2023, and the current cost is around $3 to $4.50/MMBtu.[14]
- If a $190/ton carbon price (recent EPA social cost of carbon) were to apply to natural gas in 2030, the total cost in use of $4.50 gas would exceed $15.2/MMBtu.
- In addition, the $190/ton carbon price would raise the cost of gray hydrogen by $1.62/kg, improving the attractiveness of clean H_2

	2023 Cost Estimates (per kg)		2030 Cost Estimates (per kg)	
Steady Electricity Supply	Solar + Storage	$4.6 ($2.2)	Solar + Storage	$0.9
	Wind + Storage	$3.2 ($0.9)	Wind + Storage	$0.9
	Nuclear	$4.4 ($2.0)	Nuclear	$2.4
Intermittent Electricity Supply	Wind Only	$4.7 ($2.4)	Wind Only	$1.4
	Solar Only	$5.0 ($2.6)	Solar Only	$1.2

Data for Green H_2 in CA. All in 2023 dollars.

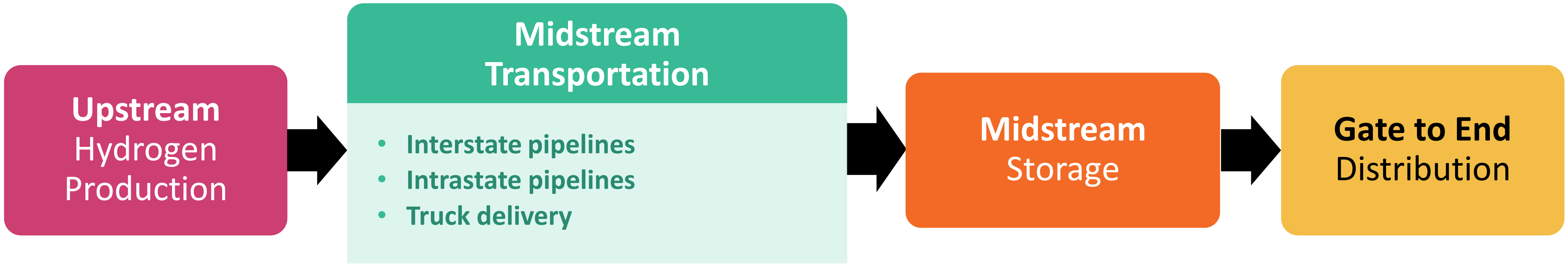
Data for Green H_2 in CA. All in 2030 dollars.

Costs shown inside parentheses are the LCOH after applying the tax credit benefits of 45V.

Tax benefits **not** shown in the 2030 estimates, as all scenarios eligible for the tax credit then become negative

Hydrogen Midstream – Transport

Transporting hydrogen



This section considers whether H_2 will mostly be produced close to end-use, i.e. at the citygate or at industrial end-user site, vs. transported from remote bulk production centers.

- Development of midstream infrastructure will depend on: whether hydrogen is materially cheaper to produce in some locations, the scale and geographic concentration of large demands, and how much hydrogen delivery adds to total costs versus producing on-site
- There are unresolved technical impediments to midstream H_2 transport and storage, but notwithstanding their uncertainty, we evaluate long-haul systems with storage to determine the impact of that handling on total delivered costs.

Midstream costs not limiting with production near end uses

Midstream costs (for H_2 transportation and storage) are likely to have a limited impact on the overall costs of end-use H_2 (≈10% increase today). However, with future lower H_2 production costs, midstream handling costs may become significant (i.e., ≈20% to 30%) to regional advantages.

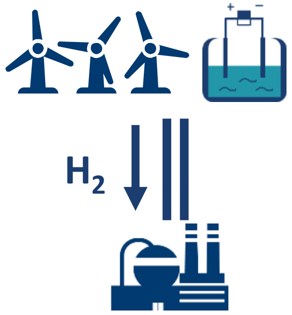
Transportation - No strong natural advantage for green hydrogen production in one region vs. another (unlike natural gas). This will diminish or delay any development of a national H_2 delivery network

- **Costs of transporting** often exceed production cost differences between low and high cost regions ➔ most H_2 will be made very near its end use.
- **Technical/economic barriers** of leakage, corrosion, pressure management for flowing gaseous H_2 in bulk over long distances
  - No major US natural gas transmission pipeline is publicly considering upgrading or retrofitting gas pipes at this time
  - Also because no market destinations yet of appropriate scale (chicken-and-egg problem)

- **Medium size local**, lower volume networks may evolve if/once substantial industrial use in a region, e.g. Gulf Coast already has 900 miles of H_2 pipelines;[15] CA next most likely
- **Distribution by truck** (over a few 100s of miles) will be needed for H_2 in HDV transport, in order to reach filling stations – expensive and relatively higher leakage rates, but there is no good alternative and the avoided diesel is also expensive
- **Transport as ammonia** – NH_3 is produced for export to foreign markets and transported by tanker; mostly for use as ammonia, not for conversion back to H_2

New pipelines – cost- and time-intensive solution that may only be suitable for moderate ranges

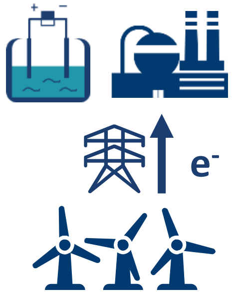
- Per ACER (2021),[16] new H_2 pipes could cost about 110-150% of corresponding new natural gas pipelines (so adding around $1 or more per MMBtu to delivered H_2 costs)
- Building new hydrogen pipelines for **moderate** ranges of 100 or so miles is part of a few recent industry proposals
- Building H_2 pipes may be economical (quicker and cheaper) to accelerate development if/where H_2 production can use existing power grid infrastructure near pipeline input, thereby avoiding long interconnection delays for new power at end-use location.



Co-locating electrolyzer near existing power lines remote from H_2 end-use
+
Siting and development of a pipeline to demand center

Or

Co-locating power for electrolyzer near end-use demand center
+
Upgrade of transmission for new renewable facility



- However, key challenges include permitting hurdles and upfront capital risks, esp. while waiting for a strong end-use market to develop potentially

Midstream transportation costs – literature estimates

Repurposing existing transmission pipelines appears to be feasible for 10-35% of the cost for a new hydrogen pipeline (ACER 2021,[16] Hydrogen Council 2021[17]) – *however, no major pipeline is (publicly) considering this as yet*

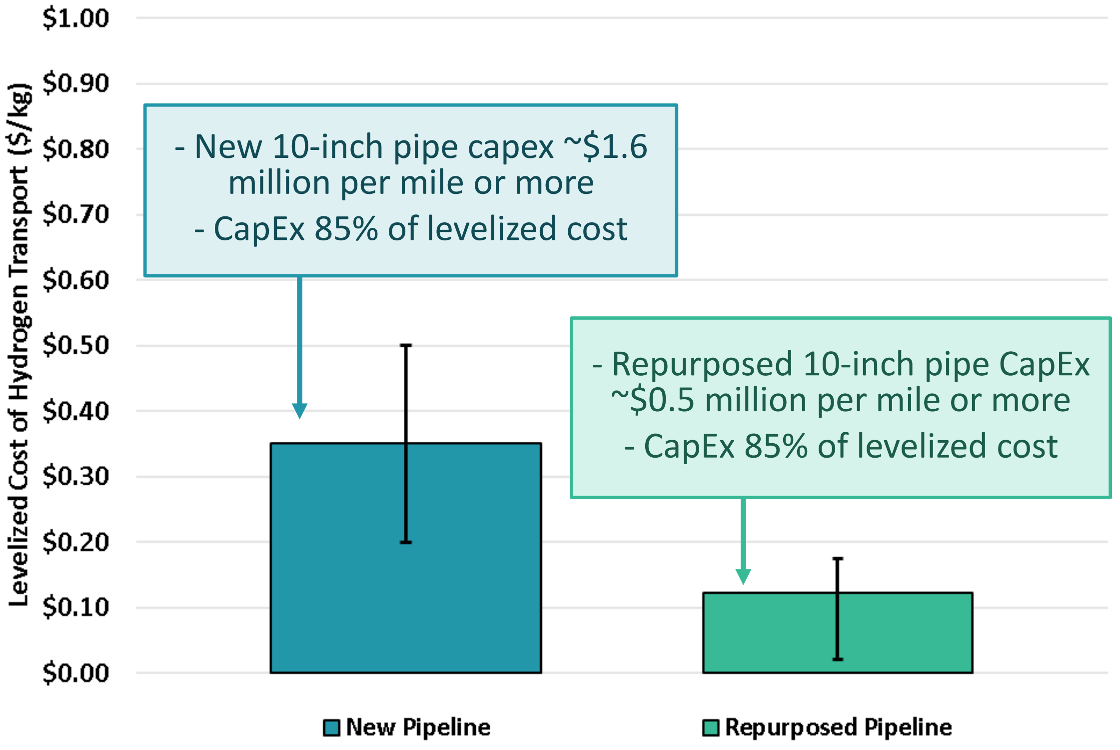
- Adaptation costs per mile increase with pipeline diameter and pressure (the higher the pressure, the higher the risk of cracking)
- Transportation networks more likely to be intraregional, as in Gulf region today

Costs modelled here for only smaller, regional pipes

Variable	Assumptions
Volume transported	600 ton per day
Pipeline length	186 miles
Pipeline diameter	6 to 14 inch
Pipeline pressure	1160 psi

- Diameter suitable for moderate length pipelines (not long haul, like LA HyBuild which assumes 24” pipeline)

2030 Levelized Costs per kg H_2



Source: DOE, Pathways to Commercial Liftoff: Clean Hydrogen.[18] DOE, Hydrogen_Delivery_Scenario_Analysis_Model_(HDSAM)_V3.1.xlsm.[19]
Notes: DOE does not display levelized cost for repurposed pipeline. In line with Hydrogen Council, we assumed a repurposed pipeline might cost one-third of the cost building a new pipeline

Transporting hydrogen via trucks

In areas where hydrogen pipelines do not exist, or are challenging to build, hydrogen can be transported via truck from production site to end-user.

- Gaseous H_2 compressed to >180 bar (2,600 psig) into steel tubes carried on a trailer; approximately 560-900 kg H_2 per trailer[20]
- Or, cryogenic Liquid hydrogen is transported via tankers at temperatures below 20 degrees Kelvin, carrying approximately 4,000 kg H_2 per trailer; requires regasification facility at point of delivery[20]

This is mainly suitable for low to moderate demand levels served from a fairly local or regional H_2 production facility

- Requires on-site storage at end-use and nearly round-the-clock deliveries to maintain steady supply of hydrogen
  - E.g., serving a green steel facility's demand of 350,000 Kg of H_2[21] [22] per day requires 380 gaseous or 86 cryogenic truck deliveries per day
  - Amazon expects to serve the energy needs at 100 fulfillments centers with by 2025[23] hydrogen[23]

Trucking hydrogen is 2-6.5x more expensive than pipelines, but may be worth it if costs of building/repurposing a hydrogen pipeline is prohibitively or not feasible.

  - **Gaseous:** \$0.9-\$1.9/Kg, ideal for small volumes (<20 tones per day) and shorter distances due to lower capex costs than pipes[18]
  - **Liquid:** \$2.7-\$3.2/kg, better suited for larger volumes and longer distances to minimize number of trips and labor costs[18]

- Federal and State regulations may limit ability to transport hydrogen via trucks
  - *E.g.*, U.S. DOT limits hydrogen trailers to 250 bar of pressure; local limitations on transporting hydrogen on critical road infrastructure (tunnels, bridges, etc.)

Source: DOE, "Hydrogen Tube Trailers" and "Pathways to Commercial Liftoff: Clean Hydrogen"

Midstream transportation costs: literature estimates

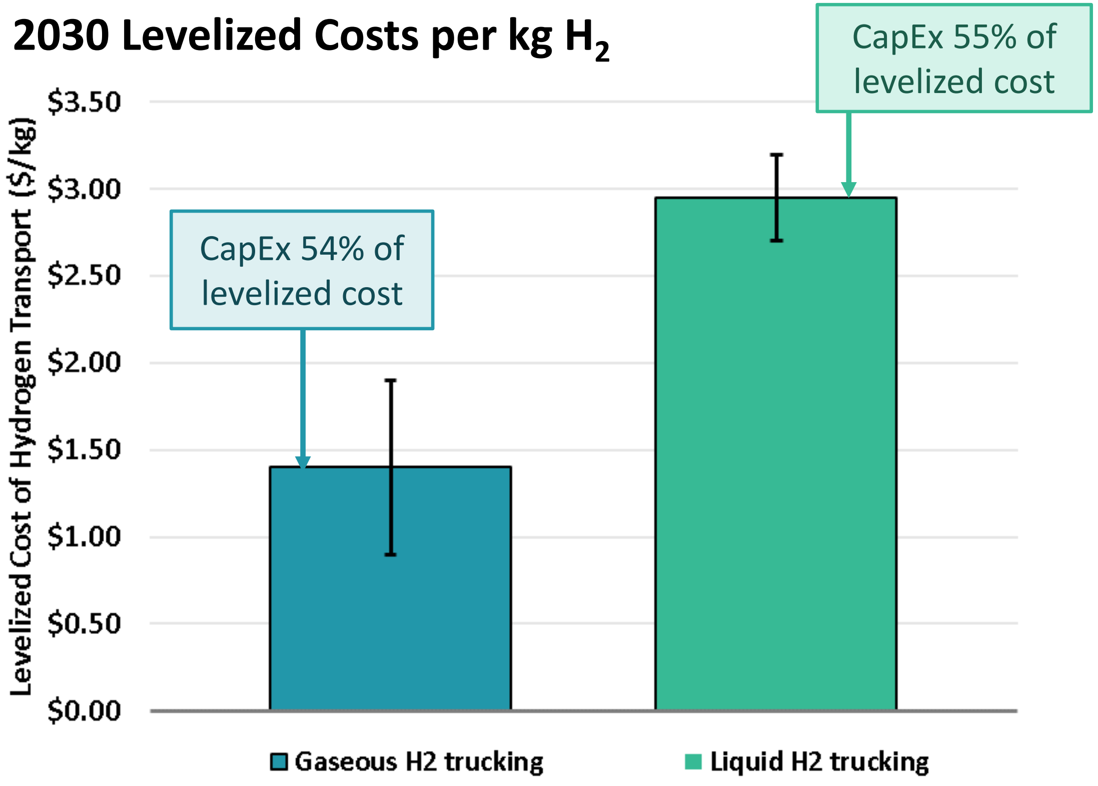
- **Compressed Gaseous Trucking:** Suitable for small volumes and short distances, esp. HDV vehicle depots
- **Liquid Hydrogen Trucking:** More economical for medium distances, but requires higher CapEx for liquefaction; likely users include aviation and maritime industries

Gaseous H_2 trucking	Assumptions
Volume transported	<20 ton per day
Distance length	<150 miles
Tank pressure	500 bar

Liquid H_2 trucking	Assumptions
Volume transported	<50 ton per day
Distance length	>150 miles

Source: [18] DOE, Pathways to Commercial Liftoff: Clean Hydrogen

2030 Levelized Costs per kg H_2



Source: DOE, Pathways to Commercial Liftoff: Clean Hydrogen[18]
Notes: levelized cost of liquid H_2 trucking includes the cost of liquefaction

Announced infrastructure for proposed H_2 projects: Transportation

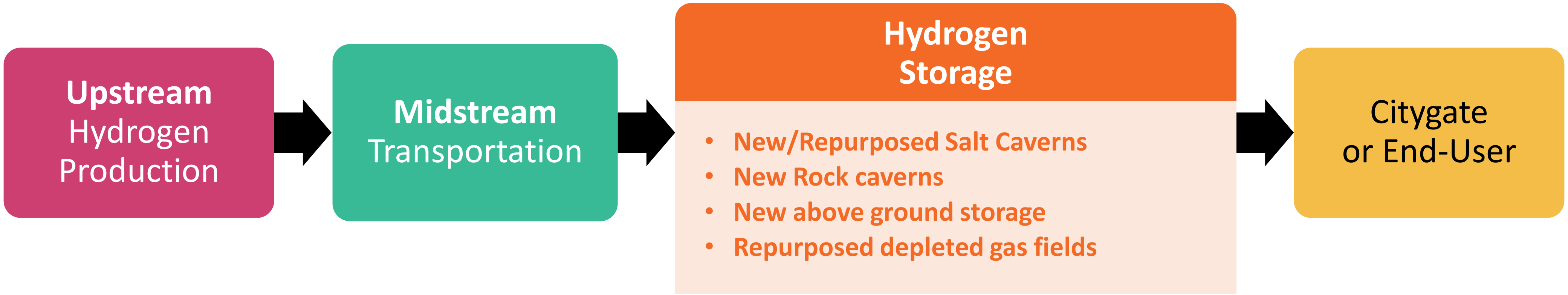
Only a handful of announced projects identify any associated transportation plans or facilities.

	Company	Location	Transportation	Other Notes
1	Green Hydrogen International	Corpus Christi, TX	Yes, no data on miles	Region already has 110 miles of existing H_2 pipelines.
2	SoCal Gas	Los Angeles, CA	Yes (Angeles Link), no data on miles	Announced delivery of green H_2 in an amount equivalent to almost 25% of the NG SoCalGas delivers today.
3	Air Products/AES Corporation	Ascension Parish, LA	Will use existing Gulf Coast pipeline system	Largest hydrogen pipeline system in the world,> 700 miles; can supply more than 1.6 Bcf per day.
4	Air Products	Paramount, CA	10 miles of transport pipelines to extend network	Output to be used for sustainable aviation fuels production.
5	HyVelocity Hub	Gulf Coast, TX and LA	Retrofitting existing ~35,000 miles gas network in TX;, ~1,500 miles in 2030 and ~5,200 miles in 2040	Plans to first blend as much as 20% hydrogen to avoid retrofitting pipes & cluster physical assets around production and demand to increase utilization while decreasing costs.
6	HyBuild LA	Los Angeles, CA	1,300 miles of pipes to be built/repurposed, 620 MW of compressor stations (+ 310 MW of compressor capacity at upstream injection). Spend estimated: $4.2 billion on pipes, $1.2 billion for compression stations	Closest commercially-proven geologic salt cavern site is located in Delta, Utah. Designed to serve a total demand of 1.4 MMT GH_2, is estimated to require a total capital expenditure (CapEx) of $34 billion through 2030
7	Air Products	Massena, NY	Distribution by truck to fueling stations[a]	Will add H_2 liquefaction and distribution capacity. To be stored above ground and be distributed using trucks.

[a]: Project is one example of a transportation end use. Other transportation projects have been announced, but were not surveyed exhaustively.

Hydrogen Storage

Hydrogen storage



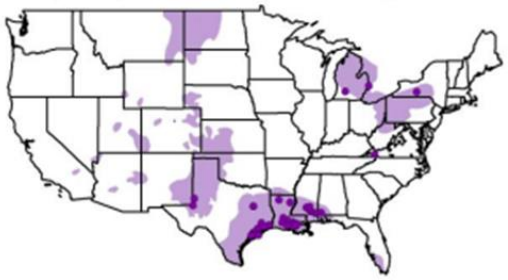
- We assess the cost of storing hydrogen using different commercially available technologies including geologic storage (salt caverns, rock caverns), depleted natural gas fields and in newly-built, above-ground storage facilities.
- Depleted gas fields exist in California and North East regions, whereas both depleted fields and salt caverns exist in the Gulf Coast region.

Storage Types

Storage may help achieve desired end-use load factors, and allow greater use of intermittent production, but many technical and geographic limitations on possibilities:

- **Below ground geological storage** akin to natural gas not technically viable – too much loss to penetration and absorption into cavern; microbial reactions with H_2
  - This also implies seasonal storage of H_2 in caverns will not be viable
- **Salt dome caverns** appear to be the only viable bulk storage approach because of small H_2 molecule size.
  - Their economics also depends on nearly monthly cycling (so high inventory turns per year)
  - *Appears to add roughly 0.2 $/kg to production costs*
  - Most salt caverns located in Gulf Coast, giving it an advantage over other regions (with a few exceptions, e.g. Utah)
- **Modest scale above ground storage** may be useful/necessary for intermediate/somewhat flexible load factor uses of H_2 – e.g. for heavy duty vehicles and perhaps power resiliency
- **Ammonia as storage** – H_2 converted to liquid NH_3 for easier transport, but developers note penalty cost of ≈15% of energy to disassociate the H_2
- **New projects** – Only four of the recently announced projects using H_2 storage – three serving transportation sector likely using above ground and one using below ground for a power plant

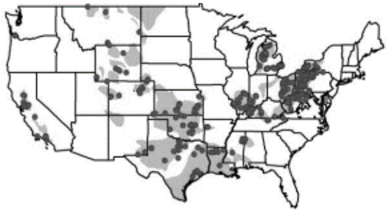
Overview of hydrogen storage technologies



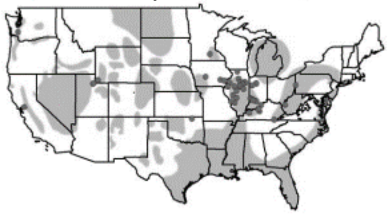
Salt Caverns

- Artificial structures constructed in underground rock salt formations
- Proven to be suitable for H_2 at field scale
- Concentrated near the Gulf Coast, with some also in central and northeastern USA

Depleted fields



Aquifiers



Depleted Fields and Aquifiers

- Depleted fields - Underground geological structures that once naturally contained hydrocarbons , used for natural gas storage after depletion; Aquifers – porous sedimentary rock structures previously contained water
- Untested for H_2 storage
- Present across the country

Hard Rock Caverns

- Artificial structures created in metamorphic and igneous rock formations, requiring relatively less cushion gas
- No existing hard rock caverns in the US; technology still immature

Above Ground Storage

- Hydrogen can also be stored in new above-ground facilities either as compressed gas or in liquid form
- Compressed gas storage usually implemented at smaller scales, thus has high unit costs,
- Liquid hydrogen storage not suitable for long term storage; additionally liquefaction uses >30% of H_2 energy content

Sources and Notes: Maps from DOE-NETL Study (2022)[24] ; shaded area represents development potential, circles represent locations of existing storage facilities

Availability, loss rates, allowed cycling, and capital costs factor into storage technology decisions for hydrogen

Likelihood of adoption

		Investment Cost	Loss/ Leakage	Availability	Cycling
1	Salt Caverns	⬇ Low	⬇ Low	Limited (Regional)	Months
2	Above Ground Storage	⬆ High	⬇ Low	High	Days-Weeks
3	Depleted Fields and Aquifers	⬇ Low	⬆ High	High	Seasonal
4	Hard Rock Caverns	▬ Mid	⬇ Low	Very Limited	Months-Weeks

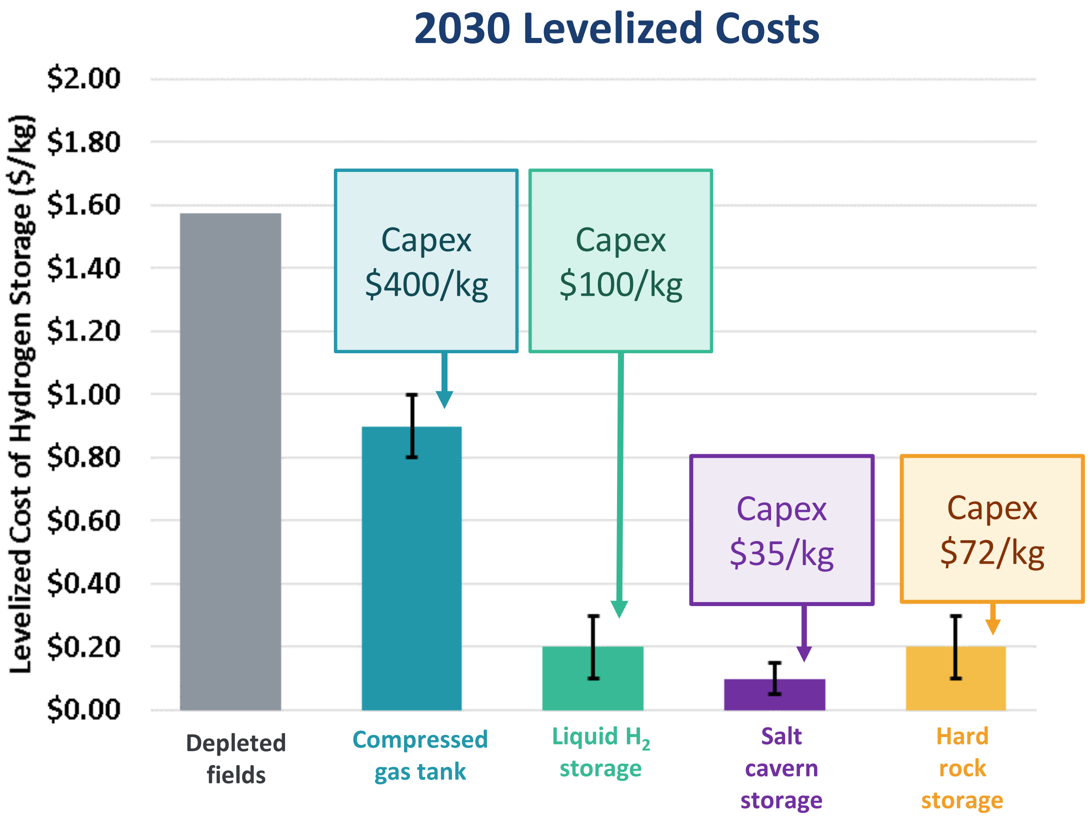
Midstream storage costs

Salt caverns storage are the cheapest storage and most viable option due to low capital cost, relatively frequent cycling, and the lowest leakage rate. This gives the Gulf Coast a unique operating advantage.

- Limited cycling capability makes depleted fields the most expensive technology on a levelized cost basis. There are also large loss concerns with this approach.
- Liquid storage can be economical but is preceded by expensive H_2 liquefaction ($2.7/kg at 50 ton per day, per DOE) and can only be stored for short durations (up to 10 days) due to H_2 boil-off.[18]

Technology	Volume*	Pressure	Cycles
Salt cavern	4,200 T (range based on 350-14,000 T)	80 bar	1/week
Hard Rock cavern	-	150 bar	1/week (range based on 0.5-2 cycles per week)
Depleted Fields	1,912 ton	138 bar	1-2/year
Compressed gas storage	950 kg	500 bar	1/week
Liquid H_2 Storage	50 TPD	-	1/week (range based on 0.5-2 cycles/week)

* Volume assumptions are not related to national potential capacity but to the expected average project size in the US by 2030



Source: DOE, Pathways to Commercial Liftoff: Clean Hydrogen;[18] Sandia National Laboratories,[25] Geologic Storage of Hydrogen: Scaling up to Meet City Transportation Demands.

*Range of costs for salt caverns cover 50-2,000 TPD volume. Range of costs for liquid storage and hard rock storage based on 0.5-2 cycles/week

*Depleted field "capex" costs not available; reflects only typical ongoing cost

Planned infrastructure additions for proposed hydrogen projects: Storage

Very few of the announced hydrogen projects in the US explicitly indicate plans for hydrogen storage.

Company	Location	Storage	Other Notes
Green Hydrogen International	Corpus Christi, TX	6 TWh salt dome storage	Region already has 110 miles of existing H_2 pipelines.
Air Products	Massena, NY	Small above ground storage	Will add H_2 liquefaction and distribution capacity. to be stored above ground and be distributed using trucks.
HyBuild LA	Delta, UT	130 kT H_2 of salt dome storage, $2.4 billion spend	Closest commercially-proven geologic salt cavern site is located in Delta, Utah. Project designed to serve a total demand of 1.4 MMT H_2 per year, with overall costs estimated to reach $34 billion through 2030

- Salt caverns are the most likely to be used, but just for short term storage. They are mostly available in the southeast.
- Long-term seasonal storage is expensive due to low cycling (costs must be recovered over one turn of stored H_2) and loss prone. It may be more economical to overbuild capacity then vary behind the meter H_2 production than to store seasonally.

Implications for H_2 market

Total H_2 delivered 2030 cost ranges

The supply cost of H_2 is likely to fall considerably with stimulus monies and learning improvements. But the total cost of H_2/kg will vary substantially depending on how it is produced (color, location, intermittency vs. steady state) and how much handling it requires. It could be fairly close to natural gas for some applications and locations by 2030.

Upstream Hydrogen Production		**Midstream** Transportation		**Storage**		**Citygate or End-Use**
0.7 – 2.4 $/kg	+	0 – 3 $/kg	+	0.1 – 1.5 $/kg	=	0.8 – 6.9 $/kg

* Costs presented in 2030 nominal dollars. Production costs span the range of costs to produce clean hydrogen (green and pink) across NY, CA and Texas in 2030 without PTC. Midstream varies from $0 if production is onsite to $3 if by truck.

It appears unlikely there will be a single representative or reference price/marginal cost for H_2 that determines whether users will produce it for themselves or attempt to buy it from the market. Regional production and use with differing costs is more likely, more akin to coal markets than natural gas.

Ladder of H_2 Demand Applications

Approximately $60B of expenditures are announced for hydrogen development through 2030, with the majority of those anticipating H_2 offtake to industrial and feedstock applications.

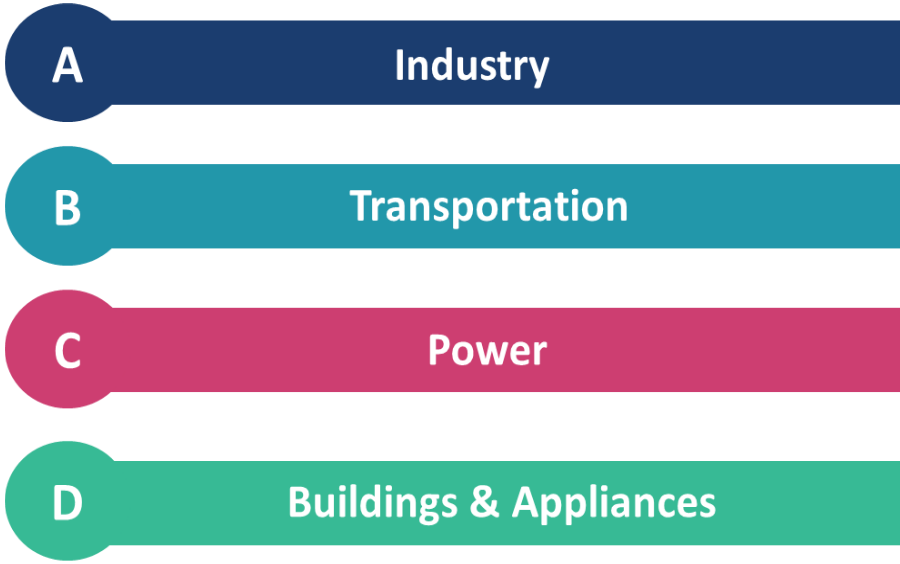
This is consistent with studies that have found the highest and best use of hydrogen to be in hard to decarbonize industries with few or expensive options to use electricity or other clean fuels. Priority should be based on cost/availability and carbon reduction benefits relative to the Next Best Alternative (NBA). While this prioritization is a moving target (as technologies change for H2 and other fuels), the fairly consistent ladder is:

Very few clean alternatives to H_2 for feedstock or high heat industrial applications makes using H_2 for the decarbonization of the **industrial sector** a priority

Some heavy duty commercial **transportation** has high ordinary fuel costs, so H_2 could be useful even if expensive.

For the **power** sector, H_2 is a form of long duration energy storage, offering firm power that qualifies under proposed EPA GHG emission limits. But the sector has many other carbon reduction alternatives. Also, round trip efficiency losses are huge and unattractive, except if used to supply resiliency power to back up renewables.

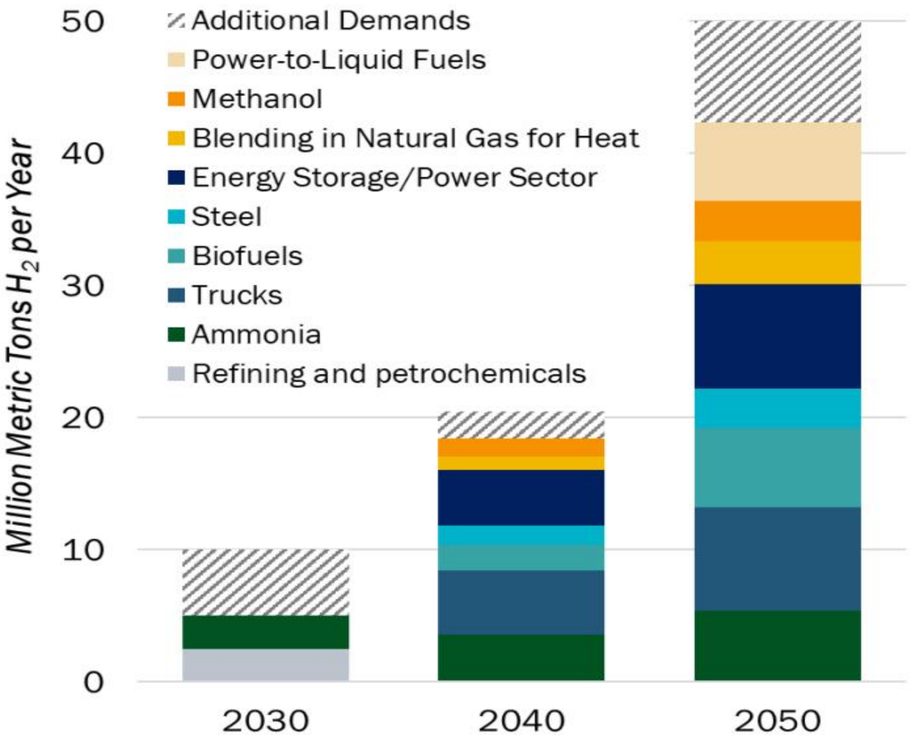
For **building** heating, H_2 is under review by LDCs for blending at small quantities in distribution gas (<= 7% of energy content), but technical /economic feasibility is unresolved. Long run usage at higher blending looks much more problematic, requiring massive, highly coordinated conversions of distribution infrastructure and customer appliances. Electrification is a competitive and viable alternative.



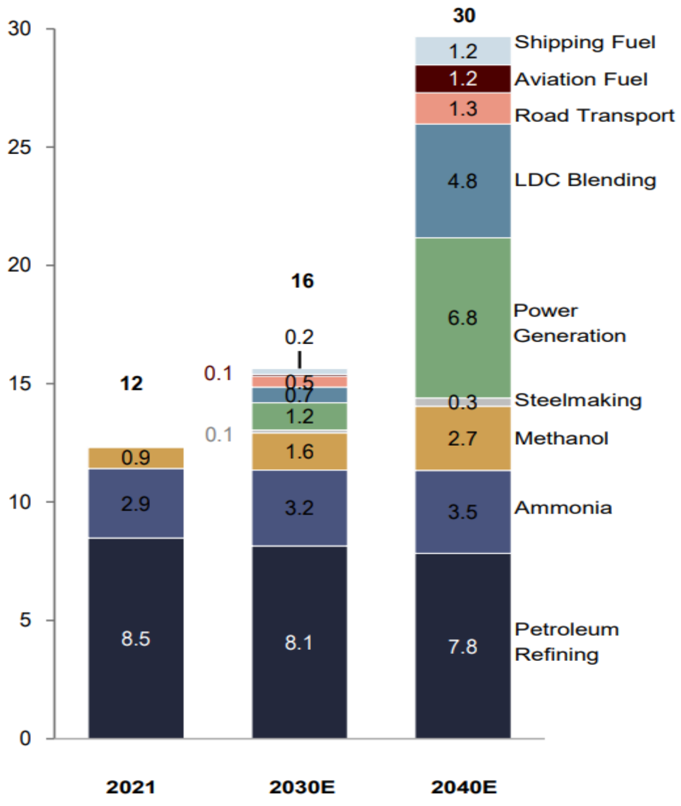
Projections of Future H2 Demand in All Sectors

Demand for H_2 is projected to be mostly in industrial applications, but even low supply costs may not attract green H_2 demand if there are large end-use conversion costs (NOT quantified in this study).

U.S. DOE ESTIMATES (US DOMESTIC) WITHOUT IRA INCENTIVES[26]



LAZARD'S ESTIMATES (US DOMESTIC) WITHOUT IRA INCENTIVES[27]



- Fertilizer has sunk cost capacity in place for using natural gas, rather than taking clean H_2
- Converting steel to H_2 requires significant investments in new furnaces
- Chemical applications may choose to stick with grey (or blue, gas + CCS) because of also needing the heat energy from the SMR process

There may need to be additional subsidies or incentives (e.g., CO2e pricing) for demand to match emerging supply.

Electricity Implications of H_2 Demand in 2050

Electricity may not become a dominant user of H_2, but hydrogen production will greatly affect that industry.

How much power will hydrogen-fired generation **supply?**

The amount of electricity that hydrogen can produce will depend on the technology that is used (CT vs CC vs fuel cell).

<u>2030 Power Sector Hydrogen Demand</u>: The DOE (June 2023) predicts a **1 MMT/yr demand for H_2 in the power sector in 2030**

- This is **enough to fire 8.5 GW of CTs operating at a 20% annual CF**

<u>2050 Power Sector Hydrogen Demand</u>: DOE (June 2023) predicts **7.8 MMT/yr demand for H2 in the power sector in 2050.[26]**

- Enough for about **66 GW of CTs** operating at 20% CF (≈116 TWh)
- Equivalent to about **2-4%[26] of then-expected total US power capacity**

How much power will making US hydrogen **require?**

The power required to make hydrogen depends on whether electrolyzers will be operated as **baseload** or **intermittent** production.

<u>Baseload Hydrogen Production Example</u>: **1 MMT of baseload H_2 production (Load factor: 90%) would require 5.7 GW of electrolyzers.**

- This level of production would need ~**19 GW of PV** (18% current PV capacity) operating at 30% CF, with additional battery storage.

<u>2050 Total Hydrogen Production:</u> DOE (June 2023) predicts a H_2 demand of **50 MMT/yr for all sectors.**[26]

- If 75% of this is produced via electrolysis and half of that demand is met by **baseload** H_2, **107 GW of electrolyzers powered by ~360 GW of PV with storage** would be needed (3.5x current PV deployment).

How much **flexibility** will electrolyzers provide?

Intermittent H_2 production via electrolyzers may be a HUGE flexibility resource.

<u>Intermittent Hydrogen Production Example:</u> **1 MMT of intermittent H_2** production (Load factor: 30%) **would require ~17 GW of electrolyzers**.

- This level of production would need ~**19 GW of PV** operating at 30% CF.

<u>2050 Total Hydrogen Production</u>: Using the same assumptions as the baseload example

- **Intermittent** H_2 to satisfy 2050 demand would need ~**321 GW of electrolyzers** and ~**350 GW of PV with storage** (≈920 TWh)
- This 321 GW of electrolyzer capacity would be flexible load (4.5x current available flexible load).

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[35] NREL's Renewable Energy Potential (reV) model

Appendix I: Model Assumptions

Electricity from the grid

California:

A. EPA Post-IRA Reference Case
   - 2023 – 2050 average industrial rate: $45/MWh
   - Source: EPA's Power Sector Modeling Platform v6, as-of April 5, 2023, and inclusive of the Inflation Reduction Act Provisions.[28]

B. Marginal Heat Rate:
   - 2023 – 2050 average industrial rate: $25/MWh
   - For this profile, we assumed a gas unit is on the margin in the long run. The market clearing price is calculated by multiplying the projected natural gas price from EIA's Annual Energy Outlook 2023 by the forecast market heat rate from the CPUC's avoided cost calculator.[29]

C. EIA Annual Energy Outlook Case;
   - 2023 – 2050 average industrial rate: $126/MWh
   - Source: EIA's Annual Energy Outlook 2023 forecast for the *Pacific* census region[30]

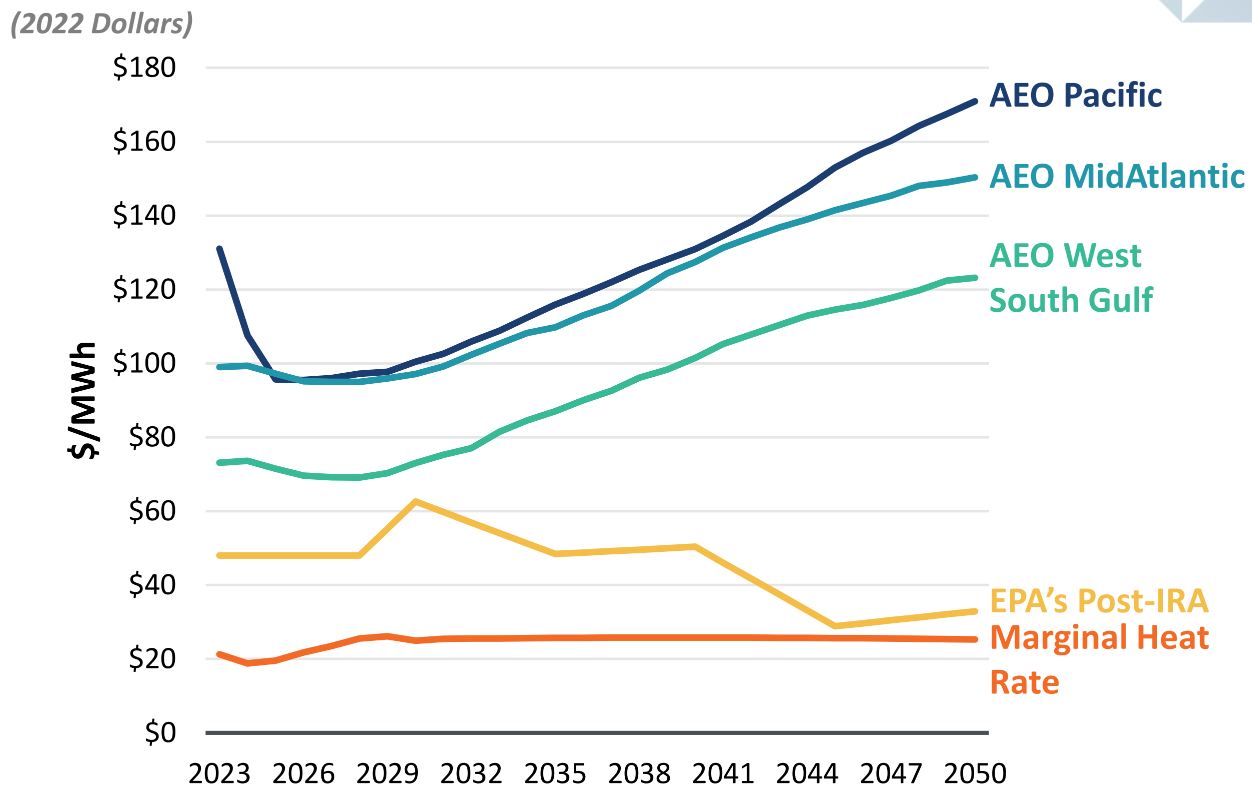
New York:

- 2023 – 2050 average industrial rate: $118/MWh
- Source: EIA's Annual Energy Outlook 2023 forecast for the *MidAtlantic* census region[30]

Texas:

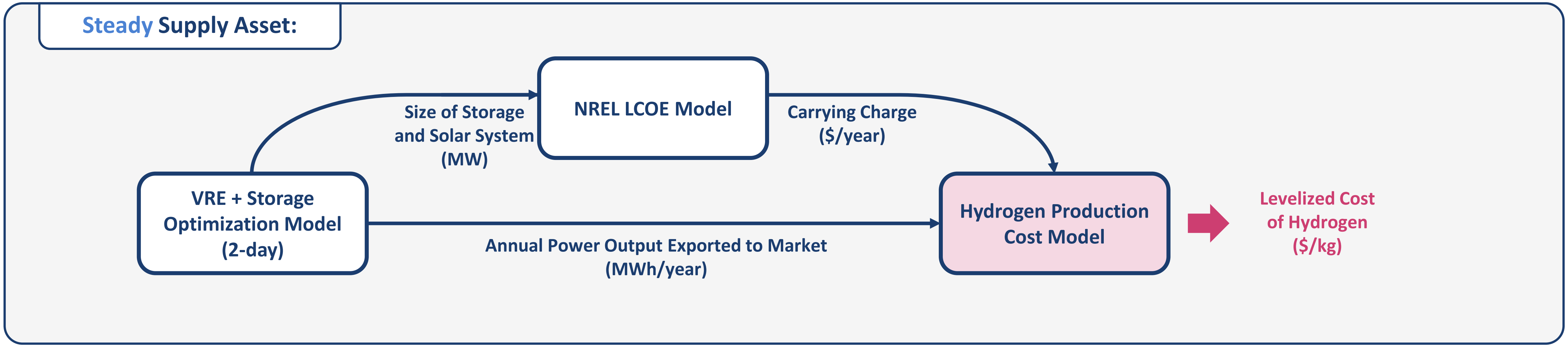
- 2023 – 2050 average industrial rate: $93/MWh
- Source: EIA's Annual Energy Outlook 2023 forecast for the *West South Central* census region[30]

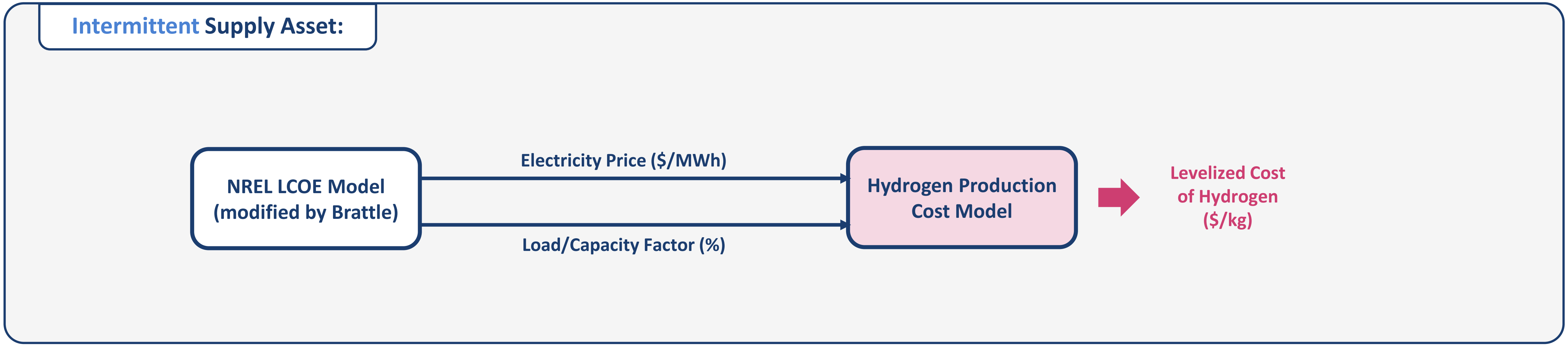
ELECTRICITY PRICE FORECASTS BY REGION



All AEO values have been adjusted for inflation assuming a 2% annual inflation rate, and thus reflect the nominal price per MWh.

Modeling contracted renewables (via PPA or BTM generation)





Electricity price results – approach to LCOE estimates

Standalone Asset

$$\text{LCOE} = \frac{\text{PMT}(\sum \text{Discounted Cash Flows (e.g., Installed Cost, O\&M, Financing Costs)})}{\text{Capacity (MW)} \textbf{ x } \text{Capacity Factor (\%)} \textbf{ x } \text{8760 hours}}$$

Sized to match electrolyzer demand

Renewable Paired with Storage

$$\text{LCOE} = \frac{\text{PMT(Cost of Standalone Asset + Cost of Battery)}}{\text{Capacity (MW)} \textbf{ x } \text{Capacity Factor (\%)} \textbf{ x } \text{8760 hours}}$$

Sized to avoid interrupted operation

	2023 ($/MWh)			2030 ($/MWh)		
Resource Type	California	New York	Texas	California	New York	Texas
Solar	$28.44	$44.16	$35.37	$12.04	$22.86	$16.81
Wind	$33.33	$33.08	$25.66	$20.42	$20.23	$14.16
Solar + Storage	$53.61	$85.86	$60.56	$12.07	$34.60	$21.50
Wind + Storage	$32.13	$48.33	$29.68	$12.64	$14.86	$8.15

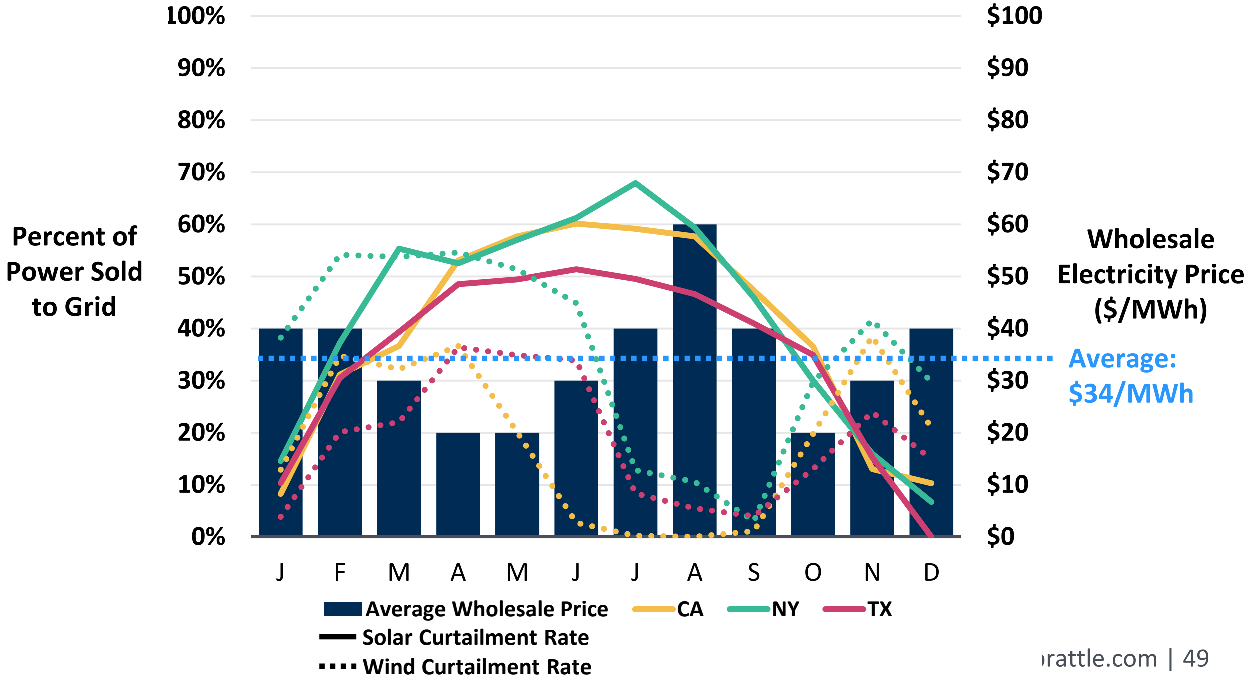
Standard financial assumptions for electricity cash flows

Standard Financial Assumptions

- Seasonal Market Price ($20-60/MWh)
- Debt/Equity ratio: 52%/48%
- Economic lifetime: 20 years
- Depreciation schedule: 20-year MACRS
- Debt rate: 4.2%
- Equity Rate: 9.6%
- Corporate tax rates:[31]
  - Federal: 21%
  - California: 8.84%
  - New York: 7.25%
  - Texas: 0.5%
- Annual inflation rate: 2.0%
- ATWACC: 6.54% (nominal)
- Applicable tax credit: PTC with no banking

The revenue from curtailed power is only relevant for renewable + storage configurations. The revenue is based on the simplification that all curtailed power is allowed to export to the grid at a wholesale rate. The volume of sold electricity is based on the average monthly curtailment rates of the system configurations detailed on the previous slide. Monthly wholesale prices reflect near-term estimates in the normal range for the regions considered.

Given the emphasis on hydrogen production, there were several limitations to the modeling of battery storage. The charge and discharge behavior is based on a reduced form model that does not consider the state of the battery charge, and estimates for reliably available wholesale prices were considered instead of calculating revenue based on long-term hourly forecasts.



Cost estimates for behind-the-meter assets and PPAs

- **Key assumption:** All of our cases model a 100% source of co-located or on-site clean power
  - Solar
  - Wind
  - Solar with Storage
  - Wind with Storage
- Parameters and operating characteristics are modeled state-by-state to reflect the physical and financial environment of the resources in each state
- Renewable resources were sized in two ways:
  a) For stand-alone solar and wind, the capacity is a function of the project's capacity factor, or the ratio of total generation over what the generation would be if the project operated at full capacity every hour of the year. It is sized equivalently to meet 100 MW of year-round use during an operating year.
  b) For solar and wind paired with storage, the asset size was co-optimized with 4-hour batteries to meet 100 MW of demand during every hour of the year
- Capital expenditure estimates are based on NREL's 2022 Annual Technology Baseline.[32]

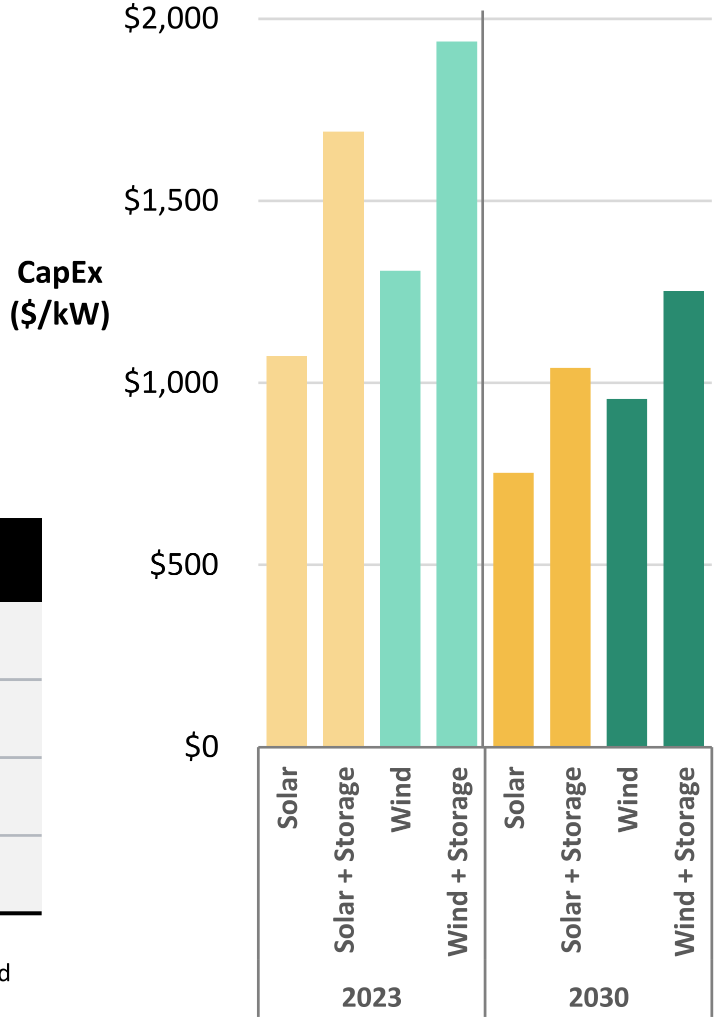
Capital expenditure estimates

- Capital expenditures are modeled as a linear function of the size of the asset. Prices scale based on the capacity of the project.
- The solar and wind asset sizes reflect the capacity factor of their regions:

		CA	NY	TX
Solar	**Class***	2	8	5
	Capacity Factor**	29.9%	22.0%	25.2%
Wind	**Class***	7	7	5
	Capacity Factor**	37.5%	37.5%	43.2%

Notes:
* Asset class corresponds to the average wind speed of the region. Regions were categorized based on NREL definitions. ([33], [34])
** The source for the capacity factors used to determine CapEx is NREL's 2022 Annual Technology Baseline. [32]

INSTALLED COST OF RENEWABLE ASSETS



	CapEx ($/kW)	
Resource Type	**2023**	**2030**
Solar	$1,074	$754
Wind	$1,308	$956
Solar + Storage	$1,690	$1,042
Wind + Storage	$1,938	$1,252

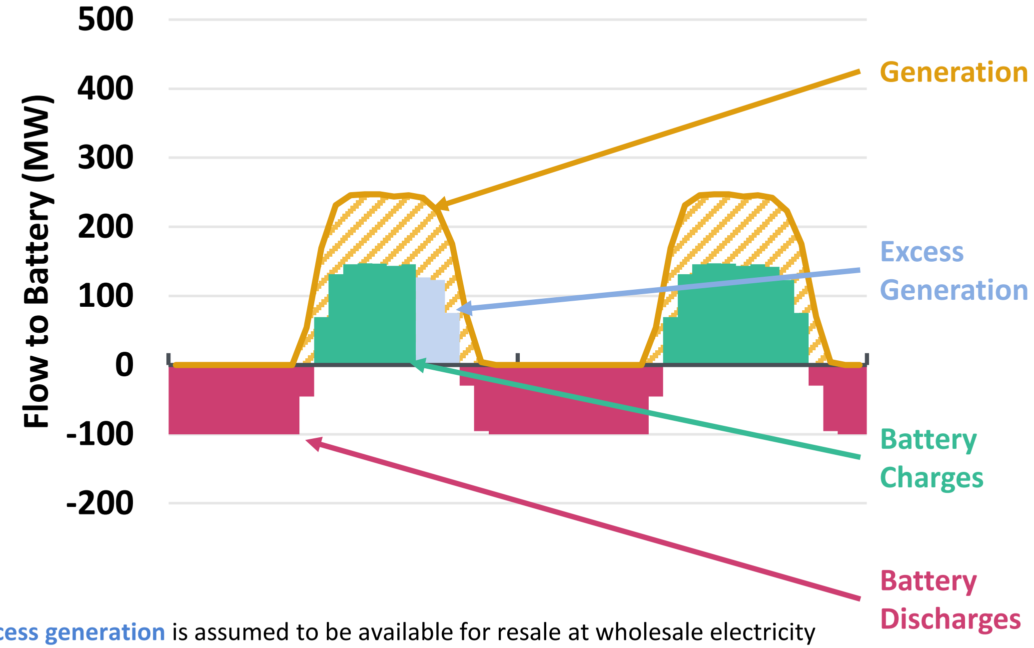
Source: [32]
Notes: The "Moderate" case was selected for all technologies.

Optimization of renewable assets with storage

- One objective of renewable systems paired with storage is to enable continuous operation of the electrolyzer. The combined system that achieves this must meet several conditions:
  - Utilization (met demand divided by total demand) must equal 100% (the electrolyzer operates continuously)
  - Electrolyzer demand precedes charging the battery
  - Electrolyzer demand that exceeds generation can only be met by energy discharged from the battery
  - Battery charge cannot exceed the capacity of the battery, and any generation that would otherwise exceed this limit is considered to be curtailed

Resource	Parameter	CA	NY	TX
Solar	**Month modeled**	January	January	January
	Average capacity factor (%)[35]	18%	12%	17%
Wind	**Month modeled**	September	September	September
	Average capacity factor (%)[35]	31%	18%	30%

The optimal configuration encounters several *modes* where the electrolyzer is being charged by the renewable asset, the electrolyzer is being charged by the battery, and when the battery is being charged by the renewable asset:



Note: Excess generation is assumed to be available for resale at wholesale electricity prices. See Slide 54 for the prices modeled.

Renewable sizing results

Steady-State

Resource	Parameter	CA	NY	TX
Solar + Storage	Solar Capacity (MW)	566	803	576
	Battery Size (MWh)	1,466	1,499	1,425
	Maximum Battery Discharge (MW)	367	375	356
Wind + Storage	Wind Capacity (MW)	322	560	332
	Battery Size (MWh)	179	287	359
	Maximum Battery Discharge (MW)	45	72	90

Intermittent

Resource	Parameter	CA	NY	TX
Stand-Alone Solar	Solar Capacity (MW)	100 (sized to electrolyzer)		
Stand-Alone Wind	Wind Capacity (MW)	100 (sized to electrolyzer)		

Two key methodological assumptions feed into the VRE + Storage Optimization Model to size the renewable asset:

1. The system configuration resembles two-day operation (48 hours of operation)
2. The systems are sized to provide adequate generation on the worst days (Solar & Wind: Winter)

These result in systems that are oversized the majority of the year, but avoid curtailment of H_2 production.

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- Lifecycle emissions assessment
- Emissions accounting standards
- Impact of H_2 hubs on state/regional emissions

Technological

- Impacts on power system from electrolyzer demand (flexible/ fixed)
- The value of H_2 as a clean firm, dispatchable generation resource
- Analyzing optimal hydrogen operations

Regulatory

- H_2 pipeline and storage siting and safety regulations
- H_2 procurement and risk management reviews
- Rate base and customer bill impacts
- Regulatory due diligence

Economics

- Impact of Inflation Reduction Act tax incentives (and their planned sunset in early 2030s)
- Regional H_2 market dynamics
- Economics of potential end-use pathways
- Economic impact assessments

Contracting

- Structure of H_2 offtake contracts

Markets

- Evolution of hydrogen markets – location, demand, type

To learn more: www.brattle.com/hydrogen

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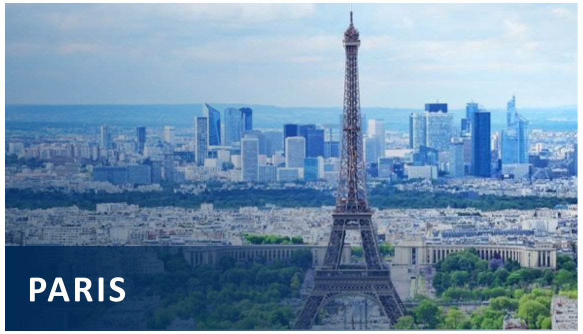

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