Role of Hydrogen in a Decarbonized Future

Bank of America 2023 Hydrogen Conference

PREPARED BY

Josh Figueroa

Andrew W. Thompson

Metin Celebi

DECEMBER 19, 2023

Brattle

Disclaimer

The views expressed in this presentation are strictly those of the presenters and do not necessarily state or reflect the views of The Brattle Group or its clients.

Agenda

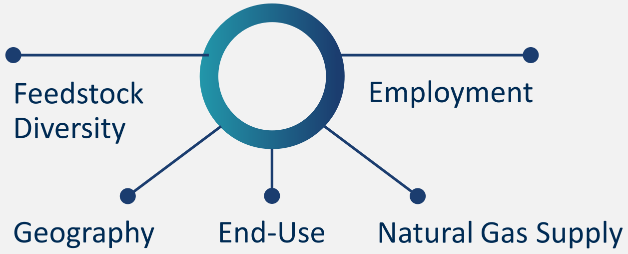
- U.S. Hydrogen Policy Landscape
- Hydrogen End Uses
  - Hydrogen in the Power Sector
  - Hydrogen Blending for Heating
- Questions

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

Hydrogen Hubs (2021)

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)
- Department of Energy (DOE) is administering the funding in 50% cost-sharing agreements
- Seven hubs selected Oct 2023, each receiving about $1 billion and targeting a mix of H_2 feedstocks and end-uses
- DOE expects projects to be executed over 8 to 12 years



Inflation Reduction Act (2022)

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 (48)
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)

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

Selected Clean Hydrogen Hubs

On October 13, 2023 the U.S. government announced the decision to allocate $7 billion in DOE funds to seven Clean Hydrogen Hubs, plus $1 billion for hydrogen demand-side initiatives within the hubs. $40 billion in private funds will increase total H2Hubs investments to almost **$50 billion**.

Selected Hydrogen Hubs are:

1. Appalachian Hydrogen Hub (West Virginia, Ohio, Pennsylvania)
2. California Hydrogen Hub (California)
3. Gulf Coast Hydrogen Hub (Texas, Southwest Louisiana)
4. Heartland Hydrogen Hub (Minnesota, North Dakota, South Dakota, Wisconsin)
5. Mid-Atlantic Hydrogen Hub (Pennsylvania, Delaware, New Jersey)
6. Midwest Hydrogen Hub (Illinois, Indiana, Michigan)
7. Pacific Northwest Hydrogen Hub (Washington, Oregon, Montana)

The hubs involve a mix of **green** (solar, wind), **blue** (natural gas + carbon capture), and **pink** (nuclear) hydrogen and target a wide range of end-use sectors.

Selected Regional Clean Hydrogen Hubs

Source: U.S. Energy Dept., Office of Clean Energy Demonstrations.

Overview of Selected Hubs

DOE Project Name	Selectee Name	States	Type of H_2	DOE Funds	Target Sectors
Appalachian Hydrogen Hub	Appalachian Regional Clean Hydrogen Hub (ARCH2)	WV, OH, PA	Green, Blue, Biohydrogen	$925 million	Ammonia, chemicals, industrial, heavy-duty transport, mining, data centers, distribution centers, sustainable aviation fuel (SAF), gas utility blending, residential fuel cells
California Hydrogen Hub	Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES)	CA	Green, Biohydrogen	$1.2 billion	Heavy duty-transport, power generation, port operations
Gulf Coast Hydrogen Hub	HyVelocity H2 Hub	TX, LA	Green, Pink, Blue	$1.2 billion	Ammonia, refining and petrochemicals, industrial, heavy-duty transport, transit authorities, ports, SAF, marine fuel (eMethanol), power generation
Heartland Hydrogen Hub	Heartland Hydrogen Hub (HH2H)	MT, ND, SD, MN, WI	Green, Pink, Blue	$925 million	Fertilizer, industrial, SAF, power generation, gas LDC blending
Mid-Atlantic Hydrogen Hub	Mid-Atlantic Clean Hydrogen Hub (MACH2)	PA, DE, NJ	Green, Pink, Blue	$750 million	Industrial, refineries, heavy-duty transportation, transit authorities
Midwest Hydrogen Hub	Midwest Alliance for Clean Hydrogen (MachH2)	IL, IN, MI	Green, Pink, Blue	$1 billion	Agriculture, industrial, manufacturing, heavy-duty transportation, SAF, gas utility blending
Pacific Northwest Hydrogen Hub	Pacific Northwest Hydrogen Hub (PNWH2 Hub)	WA, OR, MT	Green	$1 billion	Fertilizer, refiners, industrial, heavy-duty transport, SAF, marine fuel, long-duration energy storage

Notes: States based on information provided by selected hubs.

Alternative end uses for hydrogen

- **A** Industry
- **B** Transportation
- **C** Power
- **D** Buildings & Appliances

Currently H_2 being developed mostly for end-use applications where there are few substitutes or they are expensive.

Priority should be based on cost/availability and carbon reduction benefits relative to the Next Best Alternative (NBA):

- Few clean alternatives to H_2 for high heat industrial applications (possibly CCS)
- Some transportation methods have high ordinary fuel costs so H_2 could be useful even if expensive
- Power production has many clean alternatives, but competing technologies to some key H_2 capabilities (particularly long duration storage) are under development or emerging techs
- End-use electrification (e.g. heat pumps) viable and competitive for residential and commercial

Hydrogen in the Power Sector

Hydrogen potential end-uses in the power sector

Hydrogen-fired Generation	Hydrogen Fuel Cells	Long Duration Energy Storage	Load Flexibility
Hydrogen can be used in gas turbines either with gas blends or 100% H_2 fuel in either retrofitted or new plants	Hydrogen fuel cells operate like batteries at higher efficiencies than combustion turbines (<60%) without air pollutants	By creating hydrogen with VRE and later using it to produce electricity, H_2 can be effectively a source of grid storage	Schedulable hydrogen production with flexible electrolyzers that can operate in response to grid conditions
Source of clean dispatchable generation and capacity	Source of capacity and fast ramping clean energy for ancillary services	Source of long-duration (weekly to seasonal) storage and other "grid firming" capabilities	Source of load flexibility to reduce VRE curtailments and enable greater penetration of VRE

Hydrogen's potential role in a highly renewable future

Like other emerging clean dispatchable techs, H_2 can provide some of all the future needs, but capability and cost-effectiveness to do so will depend on how it is configured.

1. Ensuring **reliability** and resource adequacy -- requires peak availability which H_2-fired generation should be able to provide with very modest storage

2. Ensuring **quick-ramping/flexibility** for diurnal low VRE periods – a low H_2 volume application, so easy to meet with H_2-fired generation and storage; also supported by flexible H_2 electrolyzers being turned on and off

3. Ensuring **replacement energy** adequacy during seasonal low VRE – harder for H_2 absent lots of geologic H_2 storage since green H_2 may suffer from low output at same time

4. Supplying **resiliency** energy for renewable droughts and extreme storm events – requires modest H_2 storage, likely feasible on-site. A post-2030 need.

5. Maintain **reserves** for ancillary services – technically easy with H_2 generation (and potentially H_2 fuel cells), but will compete with batteries.

EPA's proposed rule sets GHG rate standards in part based on H_2 co-firing

Co-firing combustion plants with hydrogen is a permissible pathway to reduce GHG emission rates in the recently proposed (May 9, 2023) EPA rule

- EPA's model finds that it is cost-competitive to adopt this pathway and co-fire new NGCCs with hydrogen (to some extent) in 2030
- Existing NGCC plants limit capacity factor to <50%, remainder switch to CCS to meet their standards (as per EPA assumption)
- A key assumption of the EPA model relies on is Hydrogen being available at **$1/kg** (as per DOE's "Earthshot" goal)

	Phase I	Phase II/III
New gas e.g., natural gas combined cycle facilities (NGCCs)	Efficient operations starting immediately	In the 2030s, must either: • Use carbon capture and storage (CCS) • Co-fire with H_2 – requirement goes from 30% co-fire to 96% in later years • Limit capacity factor to 20%
Existing gas	N/A	Requirement pending, except: • Units > 300 MW and >50% capacity factor (CF) ~follows new gas • Size threshold applied to combustion turbine (CT) plus pro rata share of steam turbine (ST)
Existing coal	N/A	In the 2030s, must either: • Retire by 2034 maintaining emissions no worse than today • Convert to gas and then retire by 2039 • Use CCS

Hydrogen Blending for Heating

LDC H_2 blending pilots are gaining speed: about 30 projects, nearly 50% on the West Coast, mostly evaluating electrolytic H_2

Utility	Pilot Project Name	Status (Start date)	H_2 Source (electricity type)	Blend %	Number of Customers
CenterPoint Energy (MN)	River Building Pilot Project	Active (April 2022)	Electrolysis (grid + RECs)	1% - 5%	N/A
Dominion Energy (UT)	ThermH2	Active (April 2023)	Steam methane reforming	5%	1,800
National Grid (NY)	HyGrid Project	Active (December 2021)	Electrolysis (on-site solar)	N/A	800
PG&E (CA)	Hydrogen to Infinity	Inactive (2025)	N/A	5% - 30%	Isolated System
SDG&E (CA)	H_2 Blending Demonstration	Delayed (Fall 2024)	Electrolysis (grid)	5% - 20%	400
SoCal Gas (CA)	H_2 Blending Demonstration	Delayed (Fall 2024)	Electrolysis (grid)	5% - 20%	N/A
	Angeles Link	Under Development	Electrolysis (N/A)	N/A	N/A
Southwest Gas Corp. (CA)	H_2 Blending Demonstration	Delayed (Summer 2024)	Electrolysis (grid)	5% - 20%	2-16

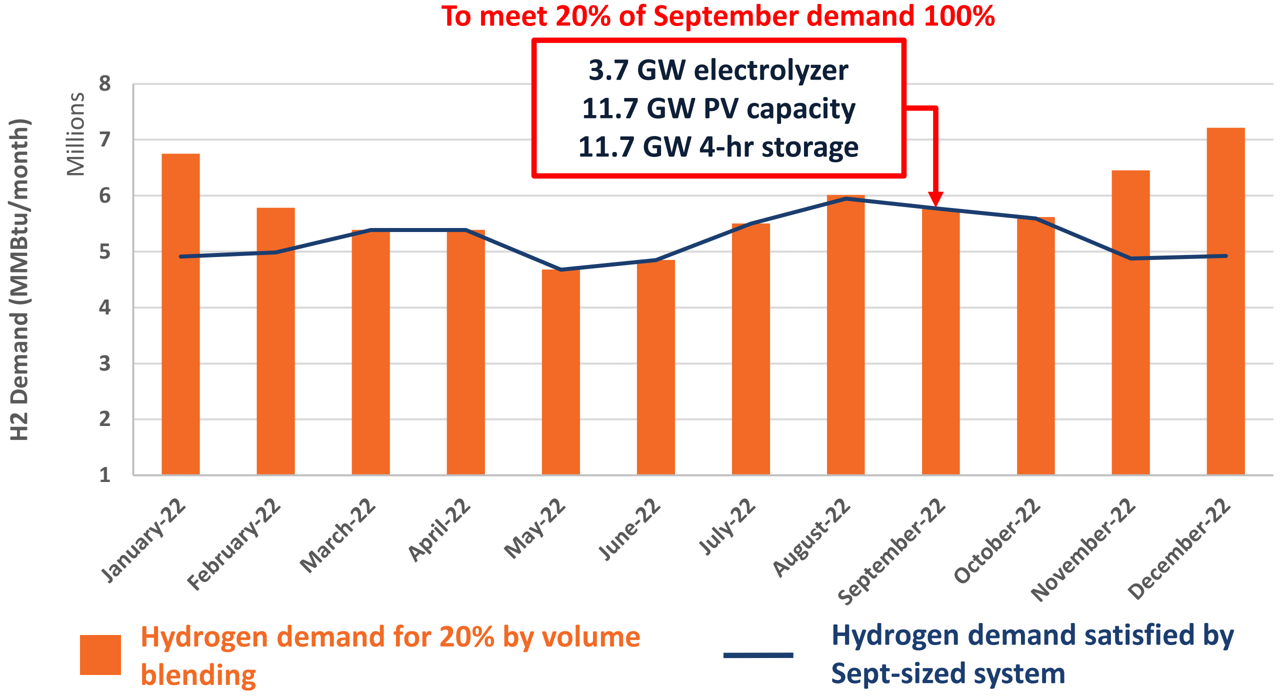
Other active blending pilots include ongoing blending with Hawai'i Gas, the Green Hydrogen Project with New Jersey Natural Gas, two pilots (Georgetown and Takoma) with Puget Sound Energy, two additional pilots (Tempe, AZ and Henderson, NV) with Southwest Gas Corp, and others in New York (ConEd), Pennsylvania (NiSource and Peoples Gas), New Jersey (Public Service Enterprise Group), and Texas (ONE Gas). **Details on size and cost of, customers served by, and results from these pilot projects are generally unavailable.**

Coping with seasonal variation in LDC gas demand

Because of highly seasonal heating load, *neither steady baseload nor purely intermittent renewable power and resulting H_2 production may be serviceable for an LDC*.

- Flat annual output at 20% of any given month will be somewhat more or less than can be absorbed in other months.
- Heightened summer output of solar not very helpful to winter peaking LDC.
- LDC likely to have to size its electrolyzer for smallest monthly gross need, or size for more but curtail electrolyzer and sell power
  - Unless excess H_2 can be sold in spot market
  - Or, use very long term H_2 storage

HYDROGEN DEMAND FOR ONE CA UTILITY BLENDING AT 20%



Here, power and electrolyzer sized for September, then individual months blended up to:

Max of {power output, 7% of monthly gross gas MMBtu demand}.
with excess power sold to spot market when electrolyzer curtailed.

Behind-the-meter costs and feasibility considerations

Behind-the-meter equipment will need to be hydrogen-compatible in order to reach higher blending percentages.

Cost Considerations:

- Existing residential appliances can accommodate hydrogen only up to around 20%
- At higher blending levels, hydrogen-compatible appliances are required due to differences in combustion characteristics (see table)
- Behind-the-meter piping may need to be replaced depending on material composition and/or the presence of minor leaks
- An H_2 blending pilot in Leeds, UK estimated the cost of switching to H_2-compatible appliances was $3,913 per household

Feasibility Considerations:

- Customers may incur costs to convert (depending on incentives) and will be burdened by building conversion work
- Building and appliance codes will need to be updated
- Skilled labourers will need to be trained and certified to work with hydrogen

Comparison of Natural Gas and Hydrogen Appliances

	Natural Gas	Hydrogen	Implications for End-Use
Appliance Leaks	Less likely than Hydrogen	More likely	Because hydrogen is made up of smaller molecules, the supply leading to stoves will need to be more leak proof
Flammability Range (% of fuel needed for mixture to ignite)	7-20%	4-75%	Hydrogen will burn even at lower concentrations, which makes controlling combustion more difficult
Flame speed	30-40 cm/sec	200-300 cm/sec	Hydrogen's quick flame speed can require changes in combustion design (flames tend to move upstream). Stoves must be designed to reduce backfiring
Adiabatic flame temperature	1,937 ºC	2,182 ºC	Hydrogen combusts at a higher temperature, may need higher quality materials to withstand this (upgrading steel burner connections)
Water vapor (most relevant in boilers and ovens)	Equipment is designed around this standard	Generates 60% more water vapor/energy unit	If hydrogen levels are very high, most flame scanners available cannot distinguish the flame. Proper safety and safeguarding equipment is essential.

Hydrogen Appliance Labels – UK

Source: Heating & Hotwater Industry Council, Hydrogen Appliances, June 2022

System conversion process for higher blending amounts

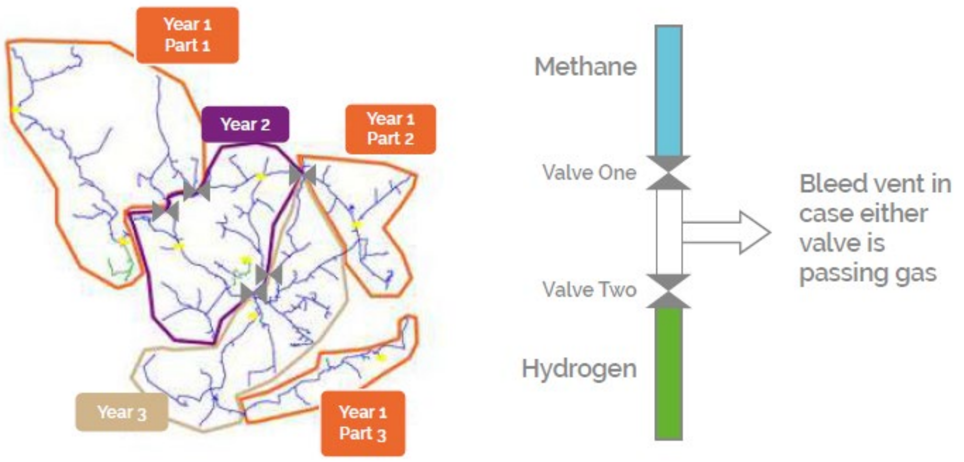
In order to pursue long-run higher blending percentages (approx. >20%), the coordination of system and customer adjustments becomes very challenging:

- Utilities will need a coordinated process that achieves simultaneous conversion of pipes with customer premises and appliances, while minimizing customer outage times, avoiding the heating season, and maintaining safe & reliable service.
- Blends >20% will require higher pressures to deliver the same amount of energy, which would exacerbate H_2 leak rates. While not resolved, addressing this is likely to require significant infrastructure upgrades and/or replacement.
- All customers on a segment must agree to convert to a blended H_2-system and have permits, contractors, and updated appliances *concurrently in place* to meet conversion schedule. (This coordination is not required for electrification).

In the past, utilities implemented zonal conversion processes to switch customers from town gas or heating oil to natural gas—a similar process could be used for hydrogen:

1. System divided into zones and scheduled for conversion – radial segments first, networked core second
2. Valves installed to isolate zones prior to start of conversion work
3. Distribution infrastructure in zone upgraded/replaced, H_2 supply interconnections constructed, and customers are reconnected to hydrogen system
4. Other zones also re-commissioned with hydrogen
5. Later, adjacent hydrogen zones are reconnected after their conversions

Illustrative Zonal Conversion Process



Source: H21 Leeds City Gate Report

Questions

Brattle's Hydrogen Expertise

Emissions

- 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

Contact Our Experts

Josh Figueroa

SENIOR ASSOCIATE | BOSTON

Josh.Figueroa@Brattle.com

+1 617 864 7900

Andrew W. Thompson

ASSOCIATE | MADRID

Andrew.Thompson@Brattle.com

+34 91 048 7121

Metin Celebi

PRINCIPAL | BOSTON

Metin.Celebi@Brattle.com

+1 617 234 5610

About Brattle

The Brattle Group answers complex economic, finance, and regulatory questions for corporations, law firms, and governments around the world. We are distinguished by the clarity of our insights and the credibility of our experts, which include leading international academics and industry specialists. Brattle has 500 talented professionals across four continents. For more information, please visit **brattle.com**.

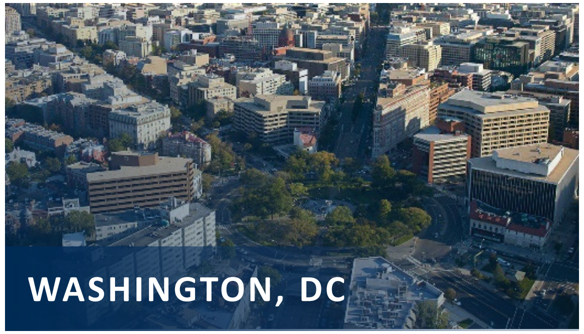
Our Services	Our People	Our Insights
Research and Consulting	Renowned Experts	Thoughtful Analysis
Litigation and Support	Global Teams	Exceptional Quality
Expert Testimony	Intellectual Rigor	Clear Communication

Our Practices and Industries

TOP 25 PRACTICES

- Accounting
- Alternative Investments
- Antitrust & Competition
- Bankruptcy & Restructuring
- Broker-Dealers & Financial Services
- Consumer Protection & Product Liability
- Credit, Derivatives & Structured Products
- Cryptocurrency & Digital Assets
- Electricity Litigation & Regulatory Disputes
- Electricity Wholesale Markets & Planning
- Environment & Natural Resources
- Financial Institutions
- Healthcare & Life Sciences
- Infrastructure
- Intellectual Property
- International Arbitration
- M&A Litigation
- Oil & Gas
- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Securities Class Actions
- Tax Controversy & Transfer Pricing
- Technology
- Telecommunications, Media & Entertainment
- White Collar Investigations & Litigation

A Global Firm



Brattle

Clarity in the face of complexity

Brattle