Modeling Hydrogen in U.S. Energy Systems

US-REGEN Approach

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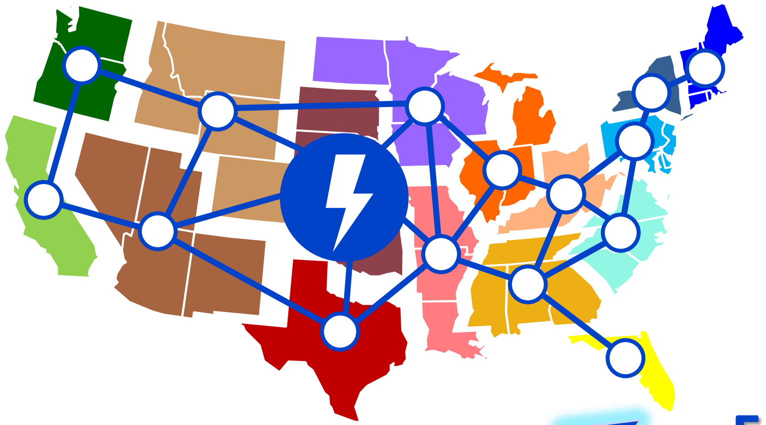
US-REGEN

Regional Economy, GHG, and Energy

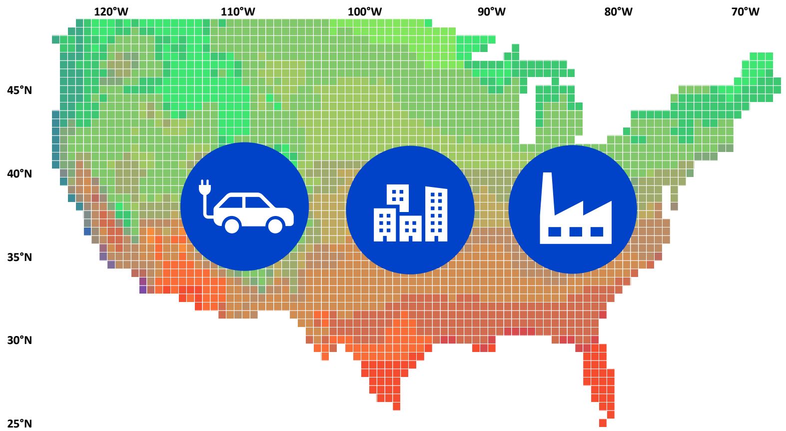
More information at

https://esca.epri.com

Electric Generation

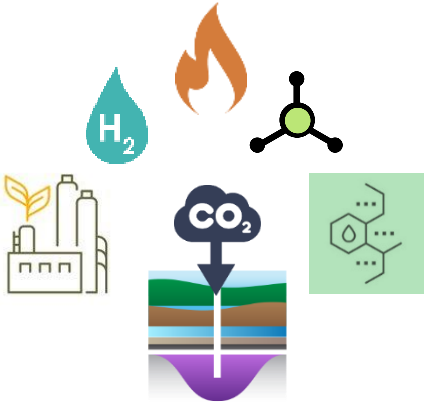


Energy Use



Synchronized prices/supply/demand

Fuel Supply/Conversion



Model Inputs:

Service demands, technology costs, resource availability, policy constraints, climate

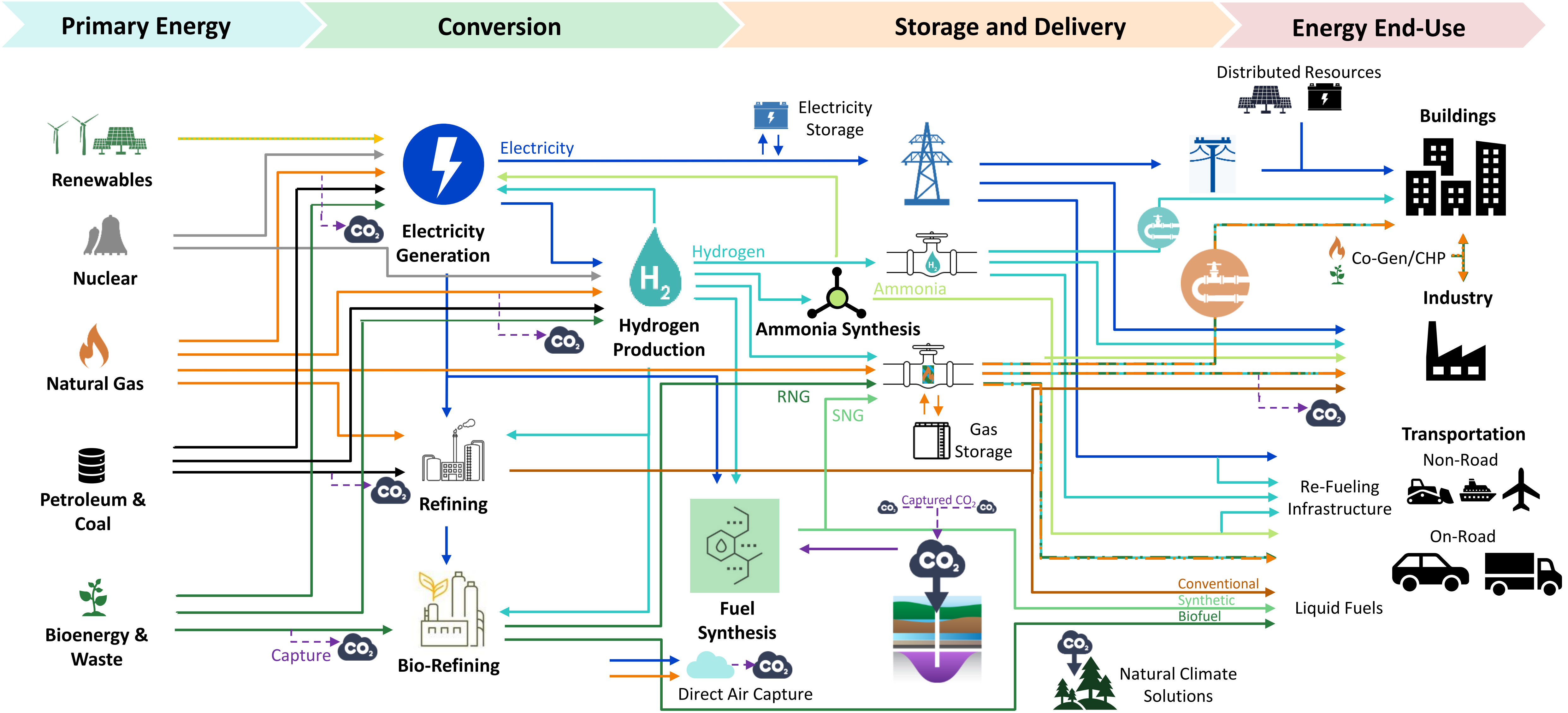
Model Outputs:

Economic equilibrium across energy production and use

Emissions, air quality, and water

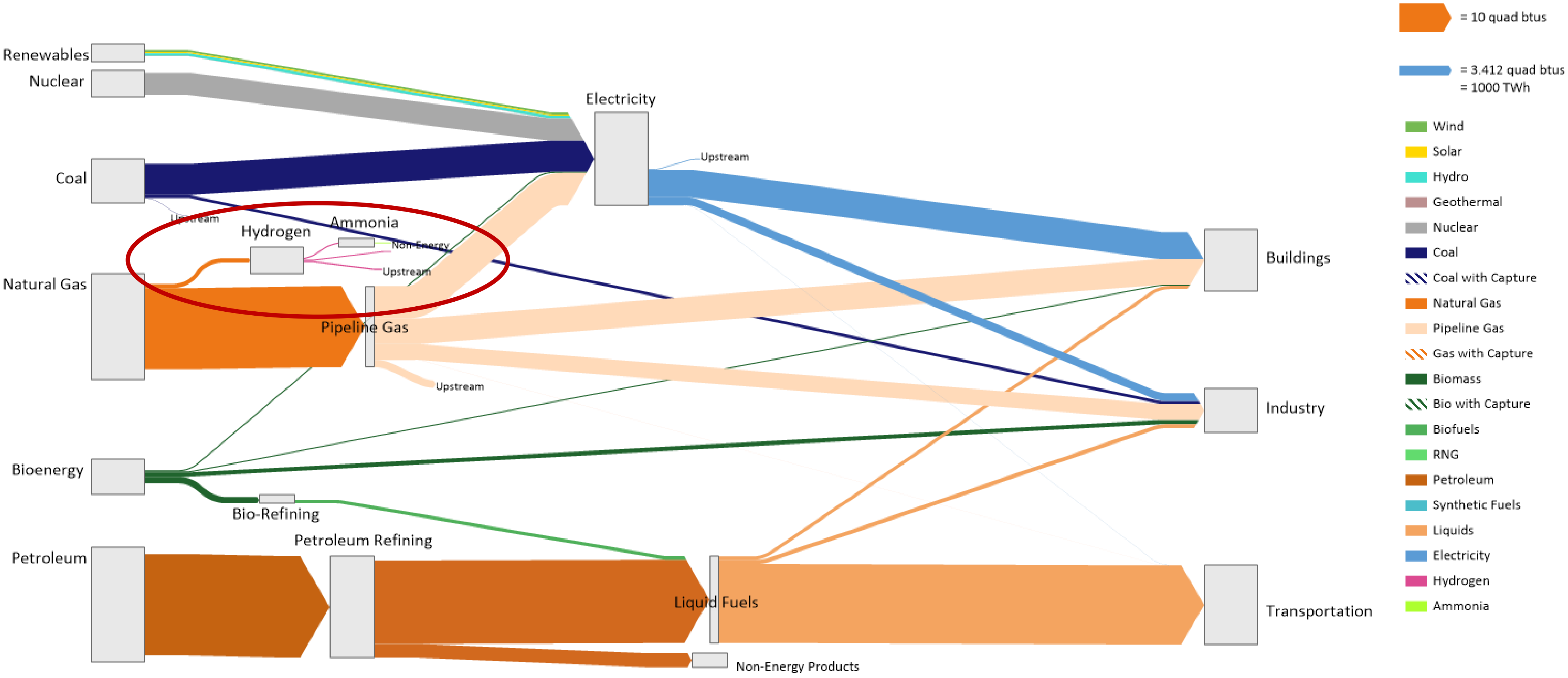
- Framework for understanding drivers of change in the electric sector and energy system
- Supported by EPRI engineering expertise and technology projections

Economy-Wide Low-Carbon Energy Pathways

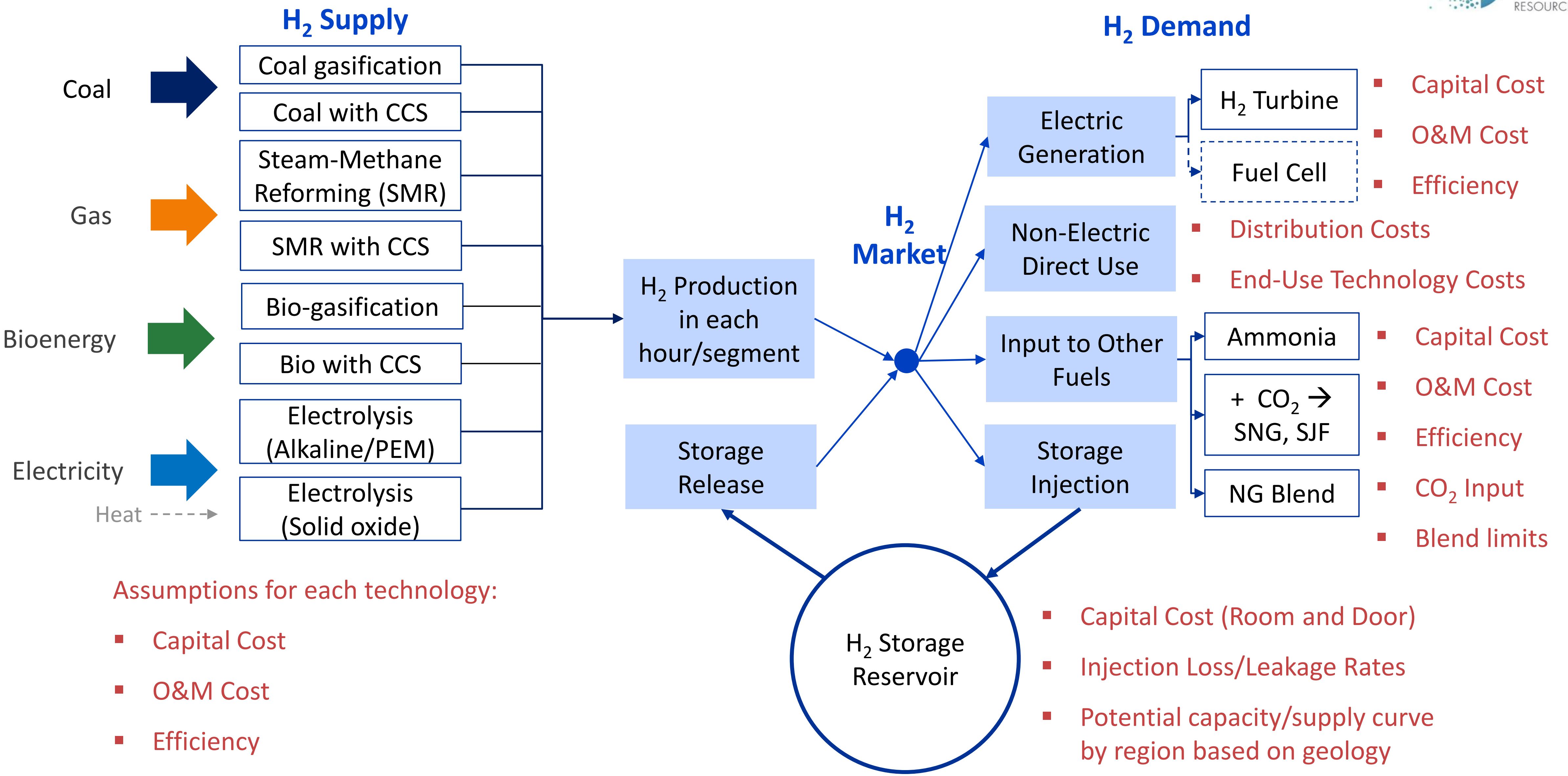


Hydrogen’s role in current energy industry

US 2019 Energy Flows (quad btus)



Hydrogen Module in US-REGEN



H_2 Supply

Coal
- Coal gasification
- Coal with CCS

Gas
- Steam-Methane Reforming (SMR)
- SMR with CCS

Bioenergy
- Bio-gasification
- Bio with CCS

Electricity
- Electrolysis (Alkaline/PEM)

Heat
- Electrolysis (Solid oxide)

H_2 Production in each hour/segment

Storage Release

H_2 Market

H_2 Demand

Electric Generation
- H_2 Turbine
- Fuel Cell

- Capital Cost
- O&M Cost
- Efficiency

Non-Electric Direct Use
- Distribution Costs
- End-Use Technology Costs

Input to Other Fuels
- Ammonia
- $+ CO_2 \rightarrow$ SNG, SJF
- NG Blend

- Capital Cost
- O&M Cost
- Efficiency
- CO_2 Input
- Blend limits

Storage Injection

H_2 Storage Reservoir
- Capital Cost (Room and Door)
- Injection Loss/Leakage Rates
- Potential capacity/supply curve by region based on geology

Assumptions for each technology:
- Capital Cost
- O&M Cost
- Efficiency
- Emissions / Capture rate

Hydrogen Production Technology Assumptions (1/2)

“Breakthrough” PEM scenario

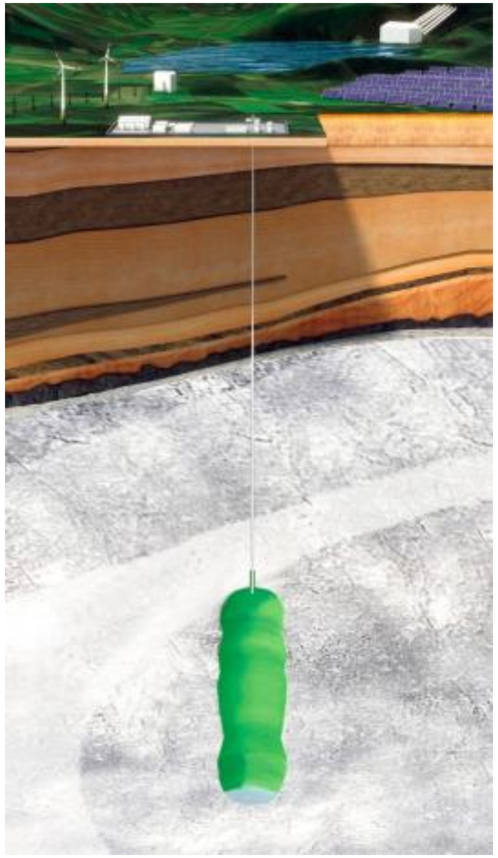
	Current	2035	2050
Capital Costs ($/mmbtu H2/year)			
Conventional Steam methane reforming (NG → H2)	23.6	23.6	23.6
“Blue” hydrogen (NG → H2 with carbon capture)	53.9	44.6	34.8
Biomass gasification	31.4	24.7	21.5
Biomass gasification with carbon capture	37.1	29.1	25.4
Electrolysis (alkaline)	60.6	37.1	28.7
Electrolysis (central-scale PEM)	87.1	38.1 | *24.8*	14.3 | *6.0*
Electrolysis (distributed-scale PEM)	87.1	47.8 | *31.1*	22.5 | *9.3*
Electrolysis (high-temp solid oxide)	269.7	77.1	22.0
Energy Consumption (mmbtu fuel in/mmbtu H2 out)			
Conventional Steam methane reforming (NG → H2)	1.31 (NG)	1.31 (NG)	1.31 (NG)
“Blue” hydrogen (NG → H2 with carbon capture)	1.47 (NG)	1.47 (NG)	1.47 (NG)
Biomass gasification	2.25 (Bio)	2.25 (Bio)	2.25 (Bio)
Biomass gasification with carbon capture	2.25 (Bio)	2.25 (Bio)	2.25 (Bio)
Electrolysis (alkaline)	1.43 (Ele)	1.43 (Ele)	1.43 (Ele)
Electrolysis (central-scale PEM)	1.50 (Ele)	1.39 (Ele)	1.38 (Ele)
Electrolysis (distributed-scale PEM)	1.50 (Ele)	1.39 (Ele)	1.38 (Ele)
Electrolysis (high-temp solid oxide)	1.20 (Ele) + 10% heat	1.09 (Ele) + 10% heat	0.98 (Ele) + 10% heat

Hydrogen Production Technology Assumptions (2/2)

	Current	2035	2050
Annual Fixed Operating Costs ($/mmbtu H2/year)			
Conventional Steam methane reforming (NG → H2)	1.69	1.69	1.69
“Blue” hydrogen (NG → H2 with carbon capture)	3.84	3.18	2.48
Biomass gasification	2.26	1.77	1.55
Biomass gasification with carbon capture	2.62	2.06	1.80
Electrolysis (alkaline)	2.75	0.88	0.68
Electrolysis (central-scale PEM)	1.74	0.68	0.33
Electrolysis (distributed-scale PEM)	1.74	0.96	0.45
Electrolysis (high-temp solid oxide)	5.39	1.54	0.44
Variable Non-Fuel Operating Costs ($ per mmbtu H2)			
Conventional Steam methane reforming (NG → H2)	0.28	0.28	0.28
“Blue” hydrogen (NG → H2 with carbon capture)	0.28	0.28	0.28
Biomass gasification	3.93	3.09	2.70
Biomass gasification with carbon capture	4.91	4.06	3.66
Electrolysis (alkaline)	1.76	0.56	0.40
Electrolysis (central-scale PEM)	2.63	1.49	0.79
Electrolysis (distributed-scale PEM)	2.63	1.49	0.79
Electrolysis (high-temp solid oxide)	4.27	2.33	0.39

Hydrogen Storage Technology Assumptions

	Estimate 1	Estimate 2	
Storage energy capacity ("room") ($ per kg)	24	12	Geology, excavation, brine disposal, cushion gas
Storage withdrawal capacity ("door") ($ per kg per day)	120	240	Compression, well drilling and completion
Total cost of benchmark facility of 500 tH_2 "room"; 50 tH_2/day "door"	$18M	$18M	10-day storage
Total cost of benchmark facility of 1000 tH_2 "room"; 50 tH_2/day "door"	$30M	$24M	20-day storage



https://www.sciencedirect.com/topics/engineering/salt-cavern

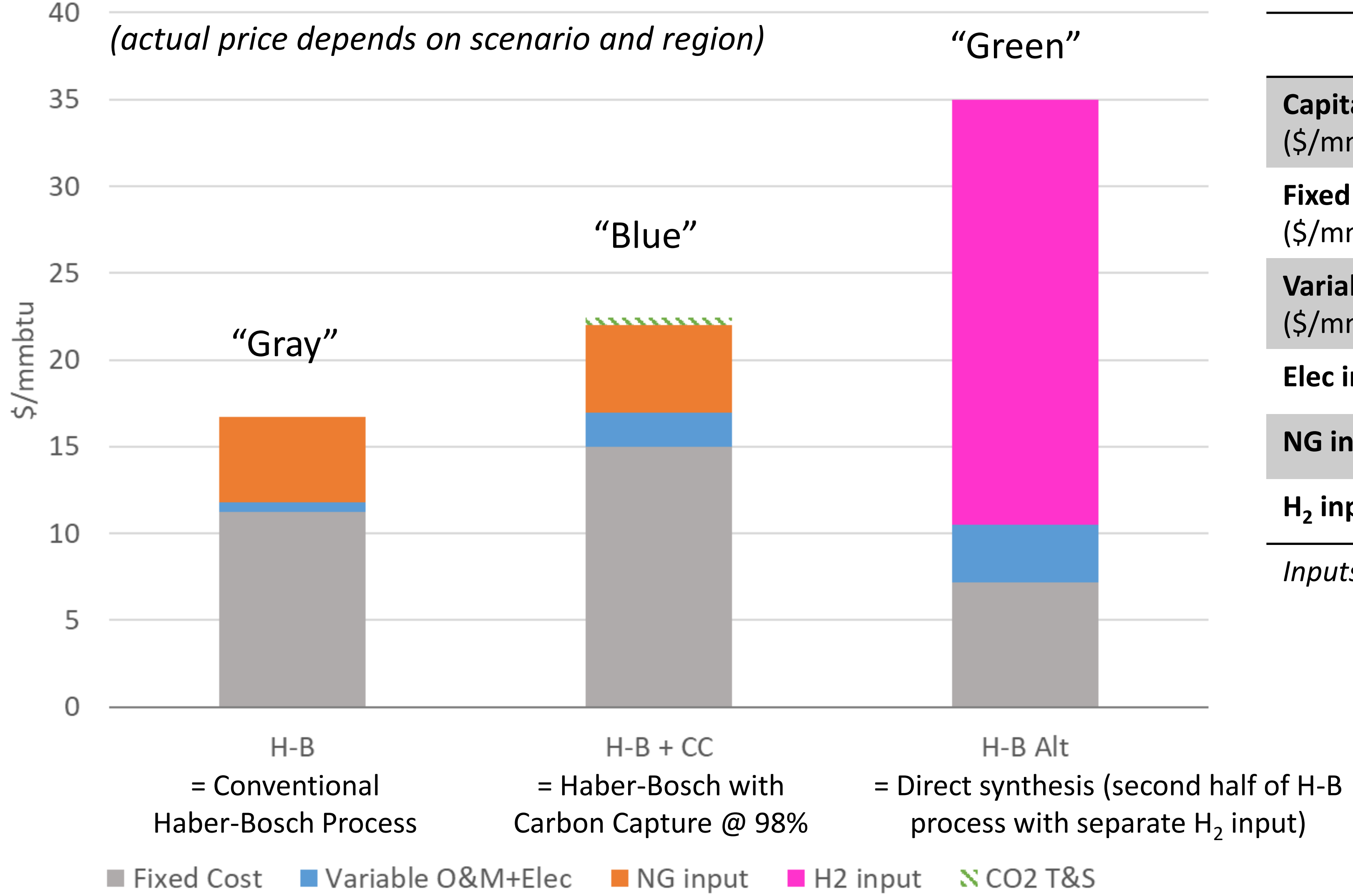
Uncertainty/ambiguity about break-out between "room" and "door": different studies suggest different allocations

Hydrogen storage costs based on underground salt cavern reservoir, may not be available in all regions; other formation types could be used, with higher costs.

Ahluwalia et al (2019), System Level Analysis of Hydrogen Storage Options, DOE
Lord et al (2014), Geologic storage of hydrogen: Scaling up to meet city transportation demands, Intl Journal of Hydrogen Energy

Ammonia Technology Inputs

Illustrative levelized cost of NH_3



Model Inputs

	H-B	H-B+CC	H-B Alt
Capital Cost ($/mmbtu/yr)	66	88	42
Fixed O&M ($/mmbtu)	5.7	7.4	3.5
Variable O&M ($/mmbtu)	0.31	0.40	0.23
Elec input (kWh)	4	26	51
NG input (mmbtu)	1.65	1.68	
H_2 input (mmbtu)			1.36

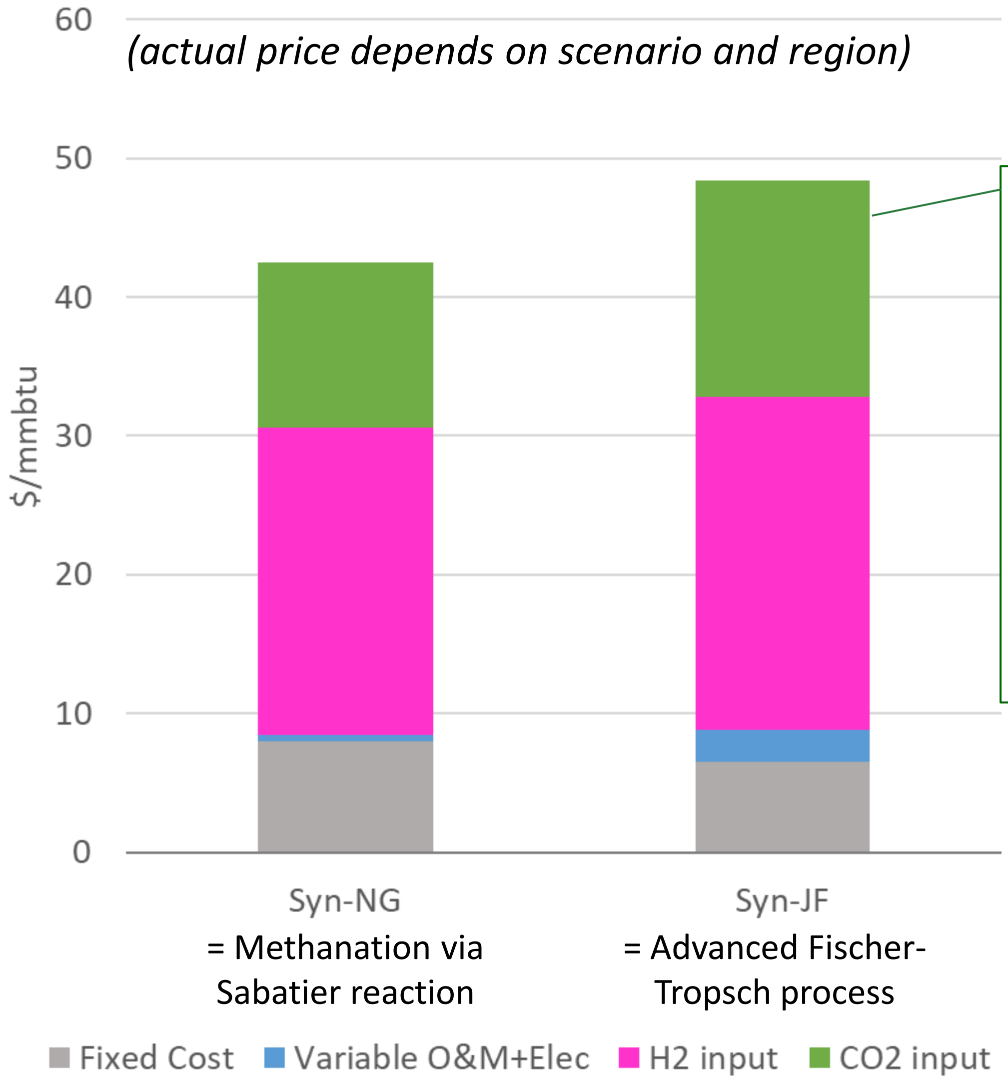
Inputs normalized per mmbtu of NH_3 output

Illustrative calculation assuming:

- $3/mmbtu NG
- $60/MWh electricity
- $18/mmbtu hydrogen (via electrolysis)
- $5/tCO$_2$ T&S
- 90% capacity factor
- 7.5% capital rental rate

Synthetic Fuel (H_2+C) Technology Inputs

Illustrative levelized cost of fuels



CO_2 input presumed to be "atmosphere neutral", e.g. from direct air capture (DAC) or from bioenergy with capture – in the latter case, a complex equilibrium emerges between biofuel, synfuel, and CO_2 markets

→ Synthesis of other liquid fuels also possible; REGEN currently includes only the JF pathway

Model Inputs (2050)

	Syn-NG	Syn-JF
Capital Cost ($/mmbtu/yr)	50	34
Fixed O&M ($/mmbtu)	4.8	3.3
Variable O&M ($/mmbtu)	0	0.20
Elec input (kWh)	7	34
H_2 input (mmbtu)	1.23	1.33
CO_2 input (tCO_2)	0.059	0.078

Inputs normalized per mmbtu of fuel output

Illustrative calculation assuming:

- $60/MWh electricity
- $18/mmbtu hydrogen (via electrolysis)
- $200/$tCO_2$ (e.g. from DAC)
- 90% capacity factor
- 7.5% capital rental rate

Hydrogen End-Use Technologies in US-REGEN

Buildings

- Space heating
- Water heating
- Other dual fuel appliances

Industry

- Direct reduced iron for steel making
- Process heat/steam in other manufacturing industries
- Existing use as industrial gas (non-energy)
- Existing use in petroleum refining

Transportation / Non-Road Vehicles

- Light-duty vehicles
- Medium- and heavy-duty on-road vehicles
  - Busses
  - Local freight/vocational trucks
  - Long-haul freight trucks
- Short-haul aviation
- Commuter, passenger, and freight rail
- Maritime
- Non-road vehicles and equipment in agriculture, construction, and mining

Details at https://us-regen-docs.epri.com

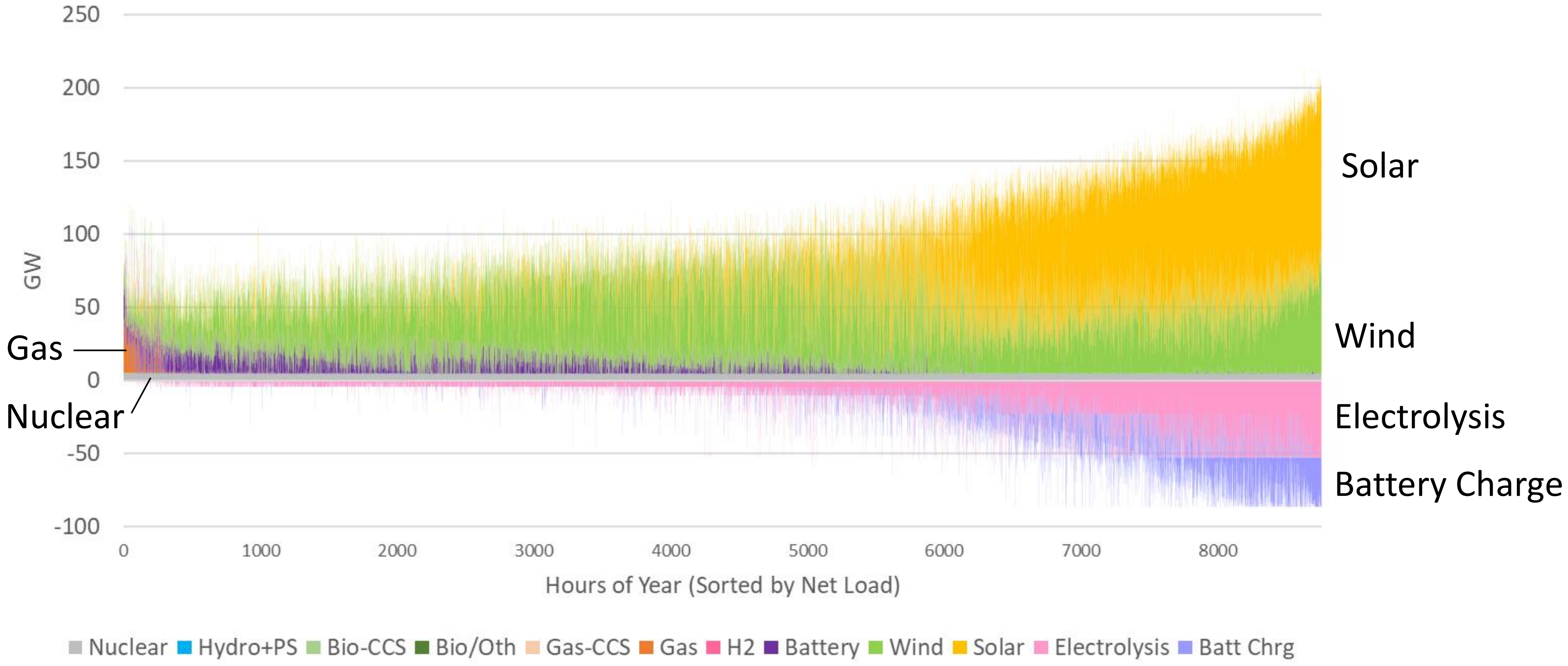
Fuel Delivery Cost Assumptions ($ per mmbtu)

	Residential / Home Charging	Commercial / Public/Fleet Charging	Transportation Retail Fueling Stations	Transportation Depot Fueling	Industry Small	Industry Large
Electricity	19.6 (varies by region, US average)	12.9 (varies by region, US average)	N/A	N/A	4.6 (varies by region, US average)	4.6 (varies by region, US average)
Pipeline Gas (existing NG)	7.1 (varies by region, US average)	4.7 (varies by region, US average)	Commercial price + 8 compression +3-6 taxes		1.8 (varies by region, US average)	1.8 (varies by region, US average)
Hydrogen (new pipeline)	14	11	8 + 24 ($3/kg dispensing)	8 + 16 ($2/kg dispensing)	8	6
Diesel Gasoline	8	6	3 + 3-6 taxes (varies by region)	3 + 3-6 taxes (varies by region)	3	3
Jet Fuel	N/A	N/A	N/A	1	N/A	N/A
Ammonia	N/A	N/A	6	6	6	4

Dispatch of Electrolysis vs Renewables

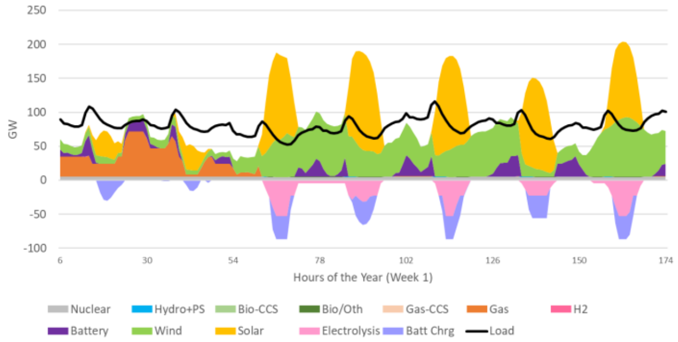
8760 Dispatch sorted by net load (= electricity demand – intermittent renewable output)

Texas, 2050, No CCS Net-Zero Scenario

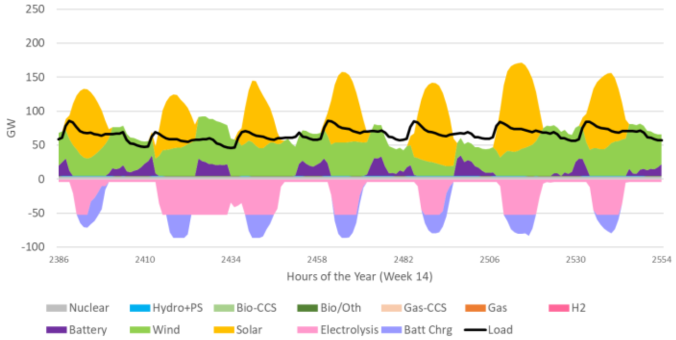


Hourly and Weekly Profiles of Dispatch

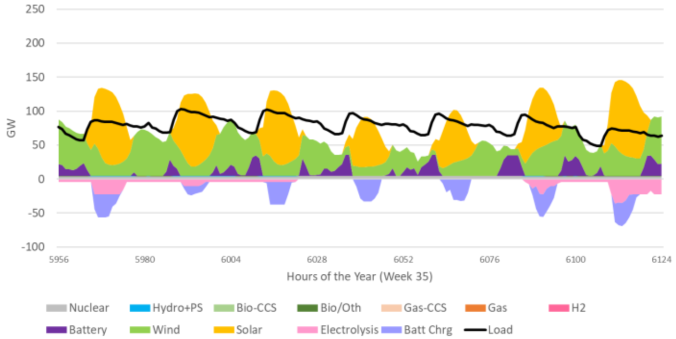
Texas, 2050, No CCS Net-Zero Scenario



Winter week (system peak)



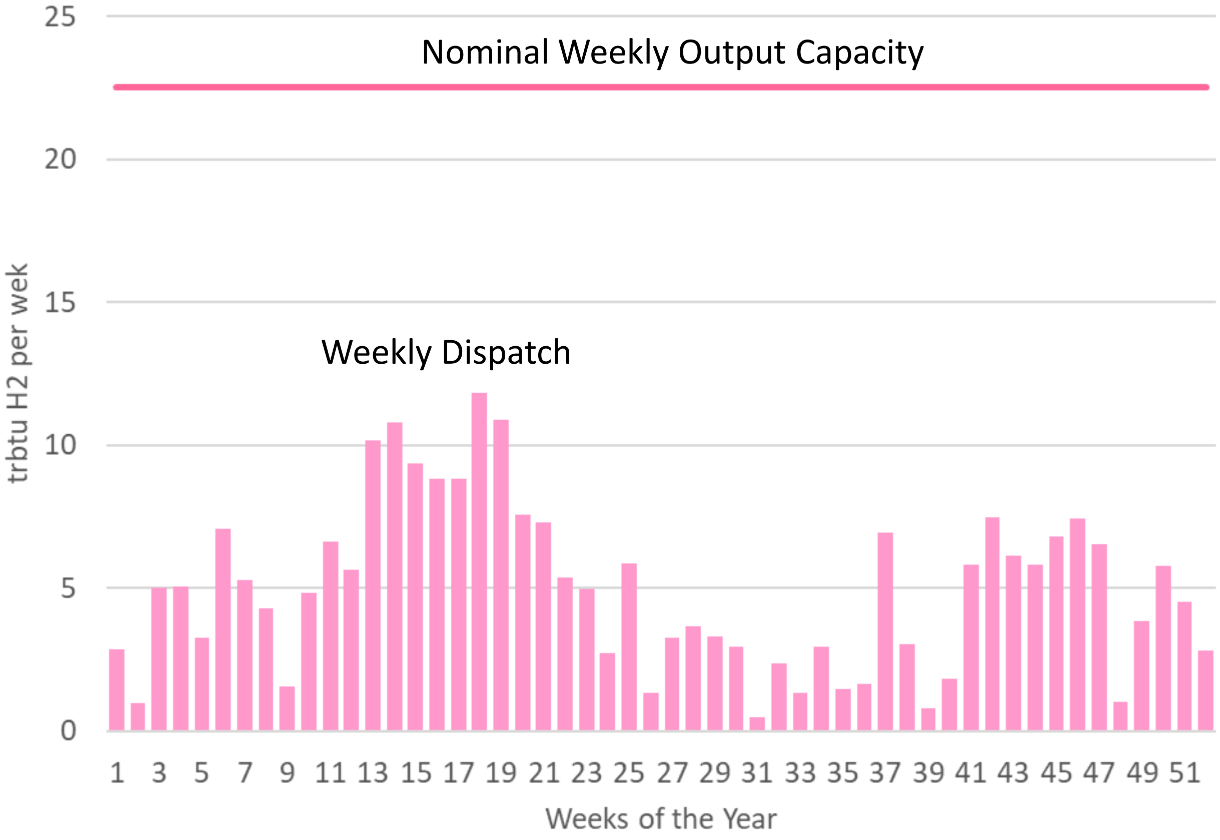
Shoulder week



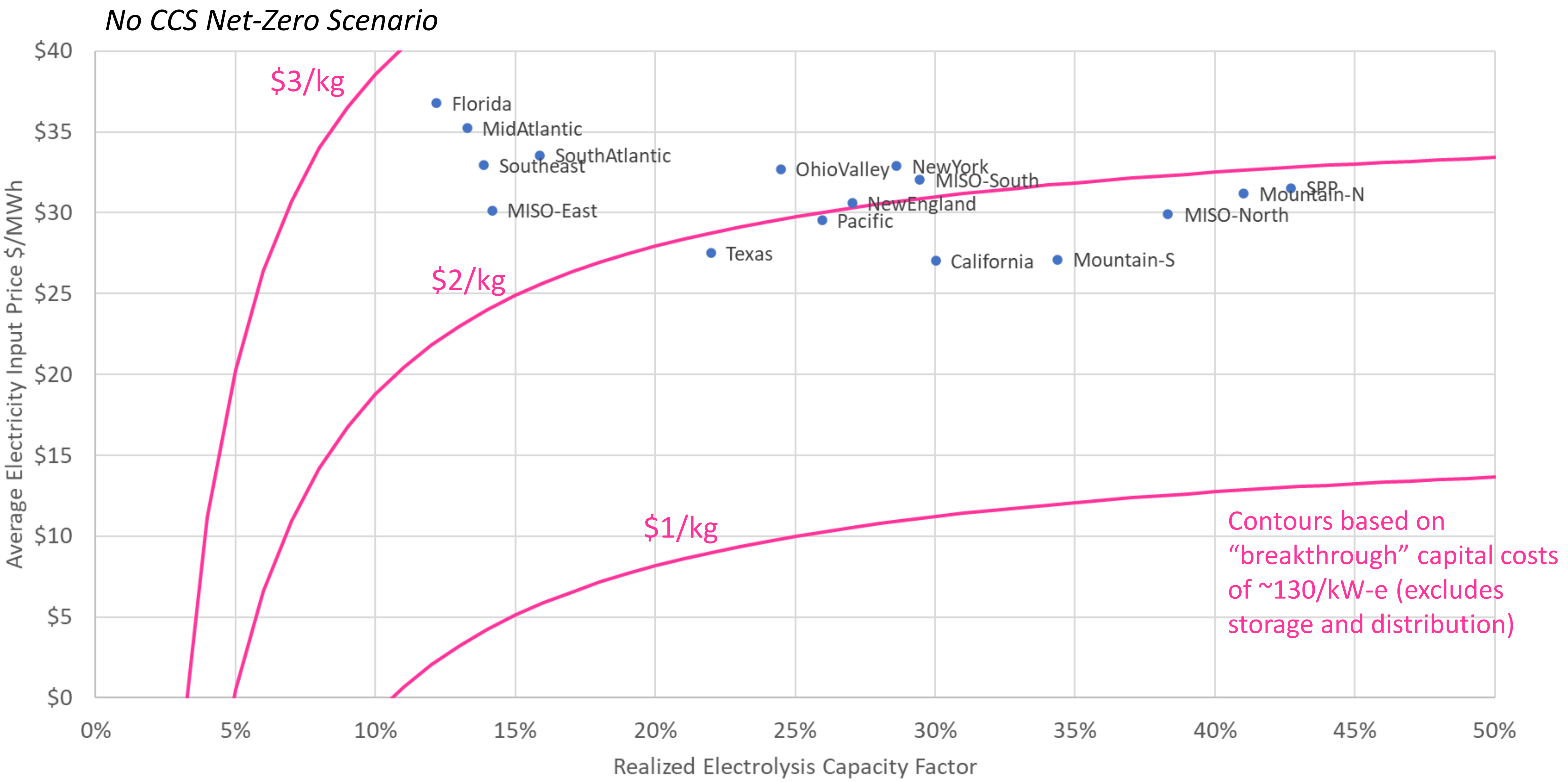
Summer week

Key Questions

- Can PEM electrolysis operate this flexibly?
- How widely available is underground bulk storage for hydrogen (e.g. salt caverns, other formations)



2050 Electrolysis CF vs Electricity Price



Contours based on "breakthrough" capital costs of ~130/kW-e (excludes storage and distribution)

Hydrogen Modeling Challenges

- Integrated energy system modeling needed to characterize potential role and value of hydrogen
- Electric sector interactions are particularly complex: cost of electrolysis and value of storage depend on dispatch profiles
- Uncertainty around many technology parameters, e.g.
  - Electrolysis capital costs
  - Fuel cell costs (and other end-use technologies, e.g. process heat)
  - Storage and delivery costs vary by region, scale and application
- Potential for global market interactions (e.g. shipping via NH_3)
- Impacts on water, land, air quality also need to be characterized

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