Hydrogen Council

Baringa

Hydrogen in Decarbonized Energy Systems

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Key messages from this report

Hydrogen brings system benefits in addition to decarbonising hard-to-abate sectors

- Resource-rich regions need to prioritize connecting renewable resources to demand centres via hydrogen pipelines
- Resource-poor regions need to focus on maximising the value of limited renewables available, and can use curtailed power to make hydrogen
- Islanded power systems need to pay extra attention to flexibility, which electrolyzers and hydrogen turbines can provide

Renewable hydrogen production will add flexibility to energy systems and consequently reduce the cost to decarbonize

- Electrolyzers can respond to market prices to help alleviate supply-demand crunches in systems relying on high levels of intermittent wind and solar
- Hydrogen to power provides resilience against most challenging part of the year when renewable load is low and energy demand is high. It complements the role of batteries and CCS in doing so

Network infrastructure and sensible market design rule are critical enablers for decarbonisation using hydrogen

- Hydrogen and CO_2 pipelines will enable production while storage is key to unlocking flexibility benefits
- Allowing electrolyzers to respond to prices will ensure lower overall energy costs and less price volatility

57 GW
Electrolyzer capacity in Texas by 2050

$247 bn
Investment in hydrogen infrastructure in Texas

10 – 15%
Added value to renewable power projects from electrolyzers

> $14 bn
Annual 'flexibility' benefit to systems identified

> 100 kt per day
Hydrogen piped through Central-West Europe in 2050

$50 bn
Conversion, network and storage infrastructure required in Texas

Much of the additional system benefits of hydrogen reside in the power system where flexibility is a challenge: In three contrasting energy systems hydrogen adds flexibility and reduces cost to the power system

Net Zero 2050 system	Japan	Texas	CW Europe
Annual power system benefit of hydrogen	$6.0 bn	$2.5 bn	$5.9 bn
Hydrogen share of power generation	14%	3%	1%
Hydrogen share of flexible power capacity	57%	9%	11%

Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Key messages for three regions assessed

Texas

Hydrogen can allow Texas to continue to be an energy exporter, adopting both renewable and low-carbon hydrogen production to take advantage of relatively low-cost solar, wind, and natural gas resource, and carbon sequestration potential.

Growth in renewable hydrogen production means electrolyzers and hydrogen-to-power peakers can help stabilize the power system, requiring proportionally less batteries and natural gas firing to offer flexibility for every unit of intermittent wind and solar. If incentives are structured appropriately, this should not require temporal correlation rules, as prices alone should promote electrolyzers to run when it is best for the system to do so.

Low-carbon hydrogen offers some insurance against any decline in natural gas production that could arise from decarbonization. Repurposing of pipelines and storage infrastructure will bring benefits through extended asset life, avoiding stranded network infrastructure.

$247 bn

Investment in Hydrogen infrastructure in Texas by 2050

$2.5 bn

Annual benefit from electrolyzers and peakers in Texas power grid by 2050

$5 bn

Cumulative benefit of extending life of natural gas infrastructure to facilitate hydrogen

Central-West Europe

There is a role for both renewable and low carbon production in Central-West Europe, across scenarios of low or high gas prices, though the share of each will depend on whether long term gas prices are more tied to LNG imports or pipeline gas. To enable rapid scale-up of production capacity, 'no regrets' development of storage and transport infrastructure is required.

Allowing electrolyzers to respond to market power prices will lower system costs versus forcing electrolyzers to link to individual renewable power assets. Production rules such as additionality and temporal correlation intended to prevent market distortions increase the overall cost of the system by reducing flexibility within the system that comes from hydrogen, forcing other sources of flexibility to overbuild.

2.5 – 3.4 Mt

Electrolyzer capacity in Europe by 2050

$5.9 bn

Annual system Benefit from allowing electrolyzers to operate freely

Japan

Hydrogen is a bigger part of Japan's decarbonisation journey than elsewhere as indigenous renewable resource is more limited. **This will require a major expansion of port space** – Japan will need two-thirds more terminal footprint relative to today to deal with storage requirements for liquid and gaseous hydrogen and provide flexibility in the absence of geological storage potential.

Hydrogen and derivative fuels such as ammonia will provide flexibility required to decarbonize Japan's power system alongside the development of renewable wind and solar. Japan's limited renewable resource means hydrogen and ammonia will be more important than batteries in providing flexible, dispatchable power, particularly in areas like Tokyo, Chubu and Kansai, where renewable resource is most scarce.

Electrolyzers running on excess power from wind and solar could add value to renewables projects, while still producing hydrogen that matches the import price. This domestic hydrogen production will play a minor role relative to imports but will make more renewable power capacity viable for Japan

2/3

Additional port terminal footprint required versus today to accommodate fuel imports

$6 bn

Annual system benefit from power generation from hydrogen and derived fuels

10 – 15%

Additional value to renewable projects selling curtailed energy to electrolyzers

Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Introduction

Context for the report

Hydrogen creates stronger links between electric, gaseous and liquid energy flows which bring benefits not captured in levelized cost

The world's energy system continues to be based on fossil fuels, which are either burned directly, or transformed into electricity. As our energy system decarbonizes to meet the shared goal of limiting global warming, these fuels will be increasingly replaced through electrification. However, sectors which are difficult to electrify will continue to require liquid and gaseous fuels, and these fuels can be produced using hydrogen.

To fulfil this role, hydrogen fuels must be sustainable. This means hydrogen will be made from solar, wind or nuclear power through the electrolysis of water, or from natural gas using carbon capture and sequestration infrastructure. If not used to provide flexible and reliable energy directly, hydrogen will be processed into liquid fuels using recycled carbon dioxide or nitrogen.

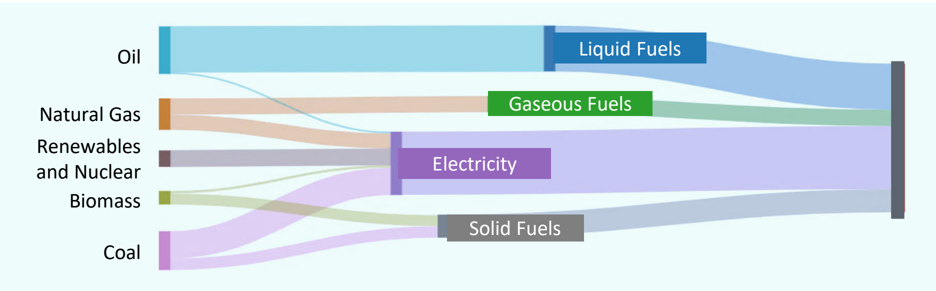
The presence of hydrogen will result in stronger links across the energy system by providing a bridge between electric, gaseous and liquid energy mediums. These links will allow areas with abundant renewable energy generation to meet energy demand in the power, heating, industrial or transport sectors where renewable energy is more limited. They will however therefore place additional demand on the power sector to serve the production of fuels.

The benefits and challenges provided by hydrogen will therefore vary depending on whether the system is a net exporter or importer of energy, and the extent to which it is already connected to other systems via existing power, gas, and liquid fuel networks.

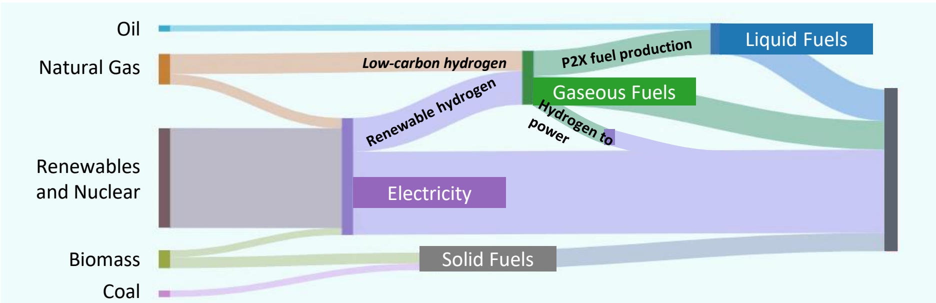
Previous studies, including our Hydrogen for Net Zero report have assessed the direct abatement potential of hydrogen as a low-carbon fuel. In this report we build on that direct benefit by demonstrating that irrespective of the type of system in place, there are quantifiable system benefits to introducing hydrogen infrastructure that go beyond the 'levelized-cost' value of using hydrogen-derived fuels versus the next best alternative.

We do so by accounting for system effects arising from linking power, gas, and liquid systems, particularly in providing flexibility, security and resilience to the wider energy system. These benefits have historically been provided by liquid and gaseous fuels which are inherently more flexible and easier to manage than electricity.

Exhibit 1: Conceptual energy flows today versus in a decarbonized energy system



Today's Energy System, little interconnection between energy vectors



Future Energy Systems, hydrogen enables extensive interconnection

Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Focus on three contrasting systems

The report provides insights on energy system evolution and the benefits of hydrogen through analysing three different regional energy systems

Energy systems have different underlying fundamentals and different starting points for decarbonising which influence their preferred pathway. To highlight both the evolution of the system as it decarbonizes, and the benefits of hydrogen to the system on that journey, we have assessed three regional systems with contrasting features. By modelling the energy system of each region as a set of zones with their own resource potential, demand, and price, we show that each system will evolve differently, but that each highlights system benefits that hydrogen brings.

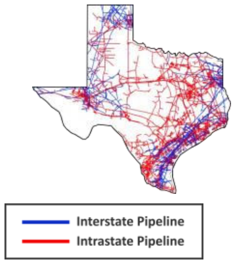
Exhibit 2: Rationale for three energy systems studied

Texas

Texas is resource rich, grid-islanded, and has demand clusters located far away from resource zones

- Produces 25% of US gas, over 40% of U.S. oil, and has built 28% of US wind capacity
- Solar, wind, and gas needs to move from rural areas to 'Texas triangle' of demand in the East and South where > 70% of GDP occurs
- Energy exports from Texas and Louisiana represented $315 billion in 2022, and 83 percent of U.S. energy exports
- Currently Potential to export 9 Mt of hydrogen and derived fuels by land and sea

Texas gas pipelines today

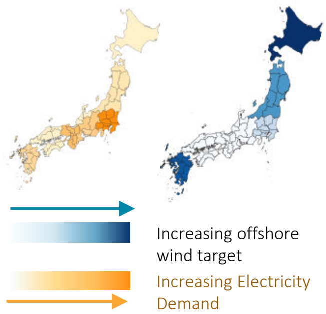


Japan

Japan is an islanded system that will rely heavily on imports to support limited solar and wind resource

- 88% of the country's primary energy supply is met with either coal, gas or oil, and over 98% of all fossil fuels are imported. Minimal national gas grid but the world's largest LNG import capacity
- Limited access to onshore renewable energy or geological CO_2 sequestration to help decarbonize heavy industry and power
- Over 30% of the government's 30 - 45 GW offshore wind target is planned in Hokkaido, one of Japan's least energy intensive region

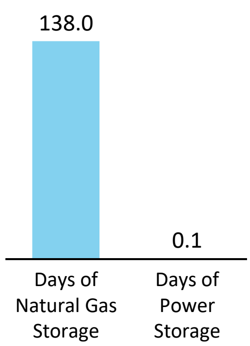
Japan renewable supply targets and demand centres



Central Western Europe

Central-West Europe (Germany, Benelux, and France) is highly connected and will rely on imports and domestic resources to decarbonize

- Today Central-West Europe has 60 GW of power connection capacity – 43% of average demand
- The proportion of hydrogen and derived fuels imported through four major corridors will rise from 14% in 2030 to 86% by 2050
- Targeting net zero power systems by 2035-2040, but relying on 32% fossil fuels for energy needs today
- Increasingly harmonized energy regulation under EU, but different system visions among member states



Source: Hydrogen Council - Global Hydrogen Flows (2022), Baringa Japan Power Market Model, US. Bureau of Labour Statistics, U.S. Energy Information Administration, American Clean Power Association,

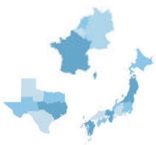
Introduction to energy system analysis

The long-term evolution of the energy system is modelled under a scenario consistent with the vision for hydrogen demand and global trade set out in our previous reports

Understand energy system benefits requires energy system models that can simulate how the needs of the whole system are met both on a long term and short-term basis. The shape of supply and demand over hours, days, weeks and years need to be accounted for, as should the impact of continuing or decommissioning existing infrastructure. We have employed a modelling platform that uses today's system as a starting point and then determines the optimal mix of infrastructure to serve the system's demand, and then simulate how that system meets demand hour to hour over a 30+ year time horizon.

The analysis within this report focuses on 'transmission' level system with the aim of informing infrastructure decisions at state or multi-state level. 'Distribution' level questions associated with last-mile delivery and delivering an energy transition at the metro area infrastructure are equally important to understand in selecting the right decarbonisation pathway. They present challenges, such as how to scale up zero-emissions heavy-good-vehicle refuelling , which liquid and gaseous fuels may be able to address more readily than electrification. As with most modes of civic infrastructure planning, they require a different, tailored system analysis versus what is required to assess whole regions or large countries.

Exhibit 3: Scenario assumptions for Energy System Study



Base case scenario for system evolution - our base case scenario builds on our previous reports detailing overall hydrogen demand, directions of hydrogen trade (**Global Hydrogen Flows**) and our view on cost of various elements of the hydrogen value chain detailed in our annual **Hydrogen Insights**.

Using reference scenarios from this prior work as a starting point, we simulate how the combined hydrogen, power, and gas system will evolve to meet expected levels of hydrogen demand and broader energy demand and emissions targets in the wider system by 2050. We assume the system reaches deep decarbonisation by that point and that both demand for power increases steadily through electrification of heating and transport, while gas demand peaks in 2030s and then decreases to 2050.

For Central-West Europe we have also tested a high gas price scenario in which gas flows from Russia do not return and consequently prices into Europe reflect much higher reliance on LNG from the US and Middle East, competing with continued gas demand growth in developing markets.

Our 2050 base case assumptions	**Potential hydrogen demand**	**% imported (exported)**	**Energy System emissions**	**Renewable LCOE**	**Emissions price**	**Gas price**
Texas	16 Mt	(55%)	Net Zero	18 - 96 $/MWh	158 $/t CO_2	2.0 $/mmbtu
CWE	33 Mt	86%	Net Zero	30 - 84 $/MWh	250 $/t CO_2	4.3 $/mmbtu
Japan	25 Mt	100%	Net Zero	80 – 183 $/MWh	207 $/t CO_2	4.2 $/mmbtu
Additional 'High gas price' test case						
CWE	33 Mt	80%	Net Zero	30 - 84 $/MWh	250 $/t CO_2	10.5 $/mmbtu

Assessing system benefits - to determine system-benefits, we compare our base case scenario to a test scenario in which a particular asset or behaviour is restricted. The per-unit-energy total system cost of each scenario is then compared to derive the system benefit.

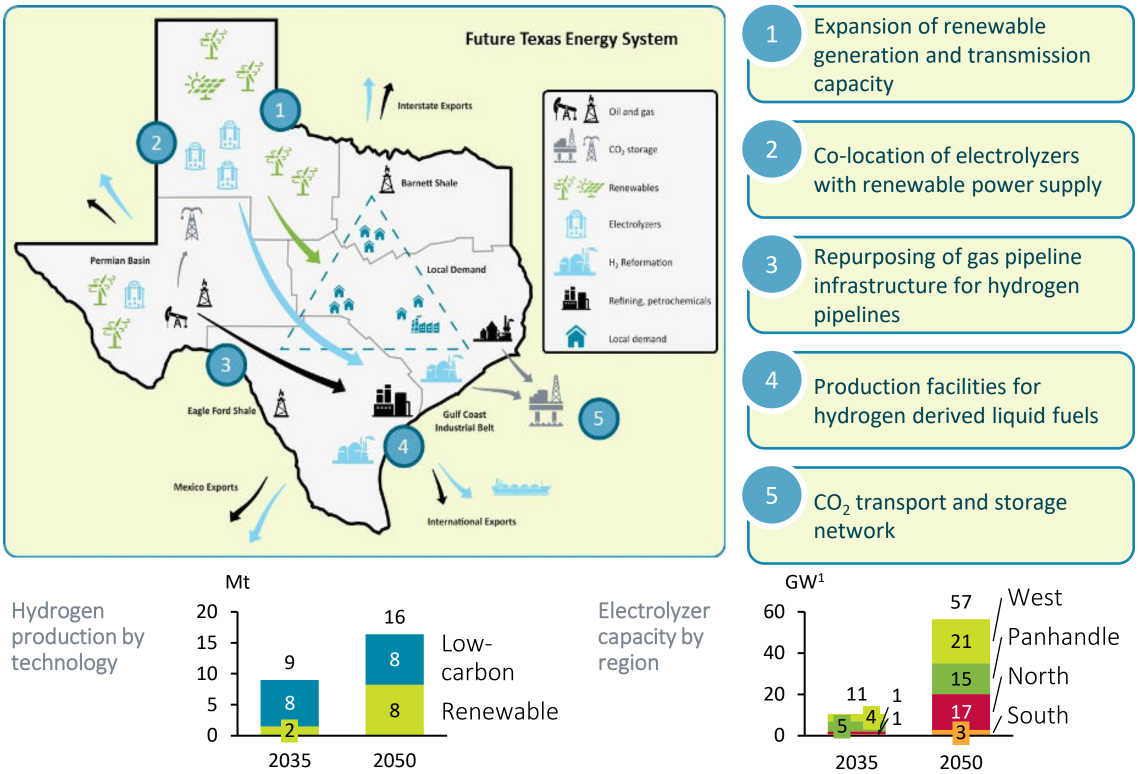
Please see Annex for further details of assumptions

Source: Hydrogen Council - Global Hydrogen Flows (2022)

How energy systems will evolve using hydrogen to decarbonize

Texas will continue to be an energy exporter but with much more coming from solar and wind via hydrogen

Exhibit 4: Vision for a highly decarbonized and export-led energy system in Texas



Texas is endowed with some of the richest energy resource in the world. In addition to an abundance of oil and natural gas, it provides some of the U.S.'s lowest cost solar and wind energy and geology suited to sequestering carbon. This means that Texas can abate emissions using hydrogen from both natural gas and its renewable power resource. This will result in six key developments within the energy system shown in Exhibit 4.

Firstly, renewable transmission capacity from wind sources to demand centres will expand as the power system relies less on thermal generation and demand for electricity in transport and buildings increases. Over 50 GW of electrolyzers could be located with renewable power supply and will be connected to demand and export centres via 16 Mt of hydrogen pipeline capacity repurposed from natural gas pipelines.

Natural gas demand will eventually decrease but gas pipeline infrastructure will still be needed to move over 3 bcf/d gas from production fields to where over $40 bn of low-carbon hydrogen production investment could be centred along the Gulf Coast.

Production facilities for hydrogen derived liquid fuels (kerosene and ammonia) could make up close to 30% of all hydrogen demand and can replace existing refineries along the Gulf Coast as demand for hydrogen increased while global demand for petroleum products declines and oil production becomes more oriented towards petrochemical products.

Over $8 bn of investment in CO_2 transport and storage networks could enable hydrogen production and industrial processes in the refining belt and is likely to expand to encompass thermal power generation from natural gas.

Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023), Hydrogen Council – Hydrogen for Net-Zero (2021), Hydrogen Council – Global Hydrogen Flows (2022)

Note: 1) Measured in GW of electricity input

Central-Western Europe will evolve to mix both imported and domestically produced hydrogen and renewables

The Central West Europe (CWE) region could need up to 32.5 Mt of hydrogen by 2050. It will develop a mix of both renewable and low-carbon hydrogen production, as well as a mix of both imports and domestic production. As we have demonstrated in our previous Global Hydrogen Flows report, hydrogen-derived liquid fuels such as ammonia and e-kerosene will largely be imported from outside of Europe where renewable energy is cheaper to produce into major ports such as Rotterdam, Antwerp, and Hamburg, where import terminal projects are already in development.

Hydrogen gas will be piped into the region from four corridors envisaged by the European Hydrogen Backbone initiative and just over 100 kt per day of pipeline capacity will be needed by 2050 to enable transport of hydrogen imported into the region as well as between markets within the region. This will support existing connectivity provided by cross-border power transmission interconnectors and allow hydrogen production to more easily access large-scale salt-cavern storage potential which is concentrated in Germany.

Imports will be augmented by domestic production of both low-carbon and renewable hydrogen. To 2030 this will be driven by domestic policy aimed at kickstarting renewable hydrogen production. Beyond 2030 low-carbon hydrogen, enabled by mature natural gas infrastructure and the ability to sequester CO_2 in the North Sea, could increase its share if the region prioritises delivering hydrogen at minimum cost and ensures security of supply of natural gas through diversified imports of liquefied natural gas.

By 2050 both imported renewable hydrogen and domestic low-carbon hydrogen could have similar shares of domestic supply. Notably given the large share of demand served by imports, domestic production required in 2050 is not materially larger than 2030 targets for production set by countries within the region and amounts to 5 - 6 Mt annually over 2040-2050. By contrast transport and storage infrastructure will be substantially larger than what is currently in progression given the overall level of hydrogen consumed within the region.

2/1

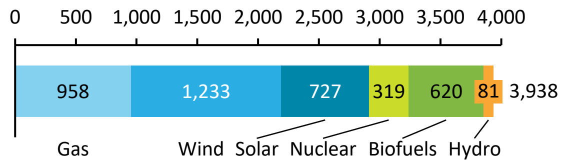
Ratio of renewable energy to natural gas as primary energy source in 2050

44 GW

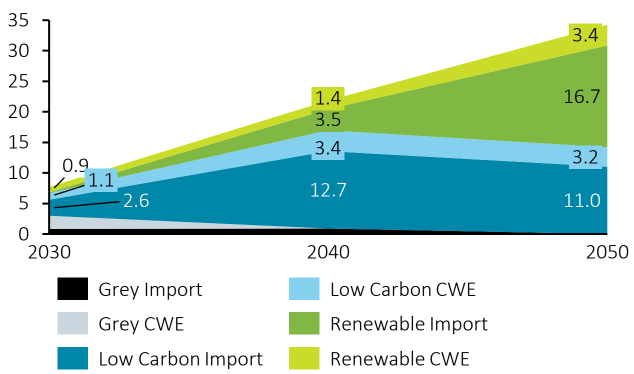
Electrolyzers required in CWE by 2050[1]

Exhibit 5 – evolution of Central-West Europe energy system

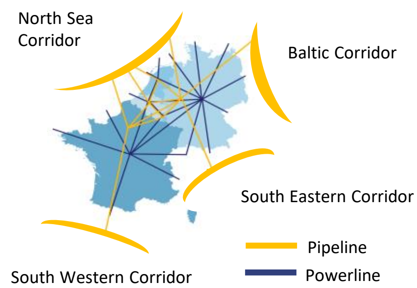
Primary fuel mix for power, hydrogen and HDF demand in 2050, TWh



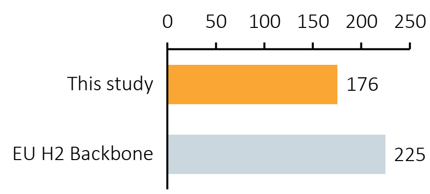
Hydrogen Supply (2030-2050), Base Case Scenario, Mt of H_2 equivalent



Hydrogen pipeline and power transmission corridors in CWE



Cross-border hydrogen pipeline capacity required by 2050 , GW



Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023) , Hydrogen Council – Global Hydrogen Flows (2022)

Note: 1) Measured in GW of electricity input

Japan will need new import infrastructure to deliver decarbonized energy using hydrogen and ammonia

As Japan decarbonizes, it will largely replace imported LNG and coal with hydrogen and derived fuels such as ammonia alongside development of wind and solar potential. This will result in three major changes to the system.

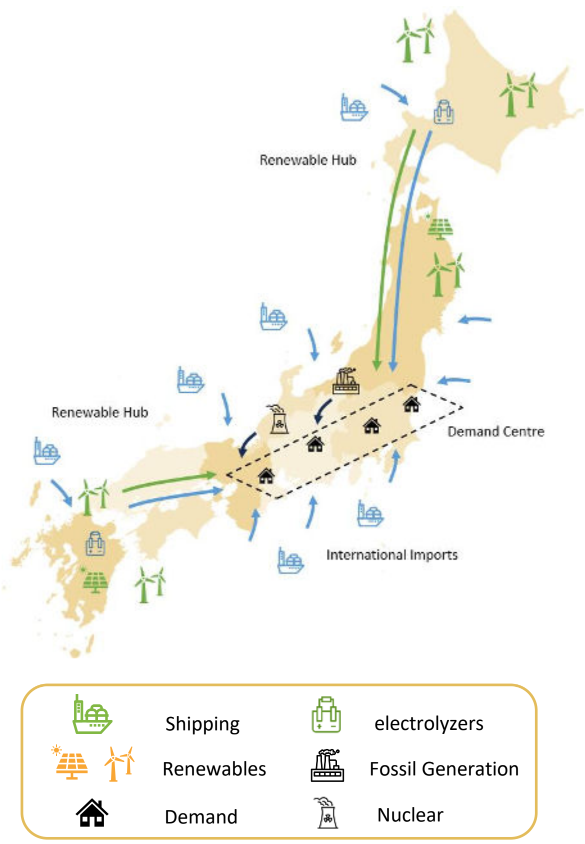
First, there will be a phase out of coal with renewables within the power system, followed by phase out of gas with hydrogen and ammonia. Existing gas-fired power generation capacity will need to be re-purposed to take hydrogen and ammonia for power.

Secondly, more renewables will mean a much larger transmission grid to facilitate moving power from renewable zones into the central prefectures.

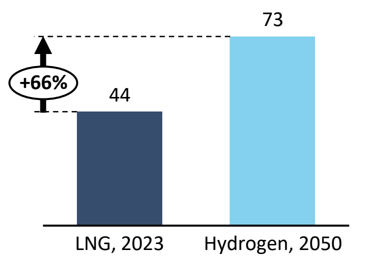
Finally, LNG import infrastructure will need to be repurposed to develop ammonia and hydrogen import infrastructure. Additional footprint will be needed to accommodate above-ground liquid hydrogen storage terminals. Hydrogen pipelines may be needed but in far less quantities than regions such as CWE and Texas as consumption for power and industrials will be centred around port terminals, as is the case with LNG today.

Exhibit 6: Evolution of Japan's energy system

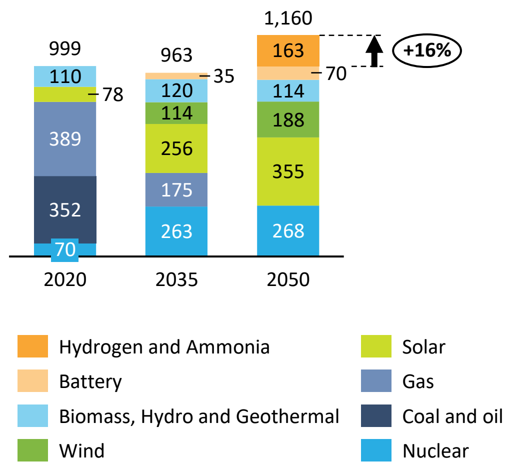
Future Japanese Energy System



Japan's import terminal footprint, km²



Japan's optimal power generation mix for achieving Net Zero by 2050, TWh



Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Benefits of hydrogen in decarbonized energy systems

Each system presents challenges in ensuring affordable, reliable, low carbon systems, which hydrogen can enable

Well-developed energy systems are the pillars of well-developed economies and highly decarbonized systems will need to display three over-arching characteristics to function well: the flexibility required to respond to routine fluctuations in supply and demand, the resilience needed to respond to more acute or extreme shocks, and a level of affordability that ensures the economy is competitive.

Within each of these pillars there are several ways hydrogen can help address more specific system challenges such as resilience to price shocks, counterbalancing the intermittency of renewables, and effectively linking areas of resource to areas of demand.

Exhibit 7: The benefits of hydrogen infrastructure in addressing system challenges

	System challenges in decarbonising	Benefits of hydrogen
Flexibility	• **Power system flexibility** - How will short term and seasonal fluctuations caused by large amounts of intermittent solar and wind be dealt with? • **Regulation of supply and demand** - how do systems create the right incentives for rewarding system flexibility?	electrolyzers can offer a source of demand-side flexibility to power systems, provided they are free to respond effectively to market price signals and not isolated from the wider system through regulatory rules
Security and resilience	• **Resilience in isolated systems** - how will power systems deal with more acute supply/demand imbalances caused by weather events? • **Import / export security** - how will regions with large net energy balances maintain security of supply and demand? • **Price shocks** - How will systems deal with unexpected changes in commodity prices?	Hydrogen offers a form of long-duration energy storage where it can be burned to produce power at times where there is a prolonged supply shortage that batteries will not be able to cover cost-effectively Hydrogen can be sourced from a variety of countries with strong renewable supply potential, reducing risk of energy cartels capable of controlling prices
Affordability	• **Optimal use of limited resources** - how can systems with limited renewable resources keep the cost of decarbonized energy to a minimum? • How does the system effectively **link resources to demand**? • How do we reduce **the risk of stranded assets** used to serve fossil fuels and extend asset lifetime?	Hydrogen can be produced from both renewable power and natural gas, offering opportunities to hedge against shocks to either gas or power prices Ammonia derived from hydrogen can provide a major source of power where there is low renewable resource Hydrogen pipelines can be an optimal means of moving energy across a region as well as a means of prolonging the lifetime of natural gas network and storage infrastructure

Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Challenges are both universal and unique to different energy systems

Different regions have different energy system characteristics which determine the range of challenges they face in decarbonising. Each system will need to be flexible to respond to routine fluctuations in demand while also having resilience to more extreme shocks. Systems will also need to carefully regulate how supply and demand participate in order to ensure level playing fields and avoid additional system costs caused by restricting freedom to operate. On top of these challenges, our three regions highlight different challenges faced by different systems.

Central-West Europe will need to accommodate both high levels of domestic renewable energy generation as well as a need to secure imported energy from lower-cost supply locations. Texas also needs to accommodate high penetration of renewables as the grid is isolated from neighbouring markets and therefore requires higher levels of flexibility that in CWE is partially provided through cross-border interconnectors. By contrast Japan will need to decarbonize with relatively low amounts of economically feasible renewable development potential and must find ways to maximize the utility of its limited resources, while still providing adequate system flexibility, security, and resilience.

These regions serve as exemplars because they contain challenges that feature across all energy system, and these challenges are applicable to both emerging markets seeking to grow sustainably, as well as developed markets aiming to decarbonize quickly. In both contexts the energy system needs to ensure flexibility, security, and affordability increasingly without using fossil fuels.

Exhibit 8: Three different geographies highlight the challenges and benefits of hydrogen infrastructure within the system



	Analogous regions	*New England; China, California*	*Chile, Australia, Gulf region, Argentina, Norway, South Africa*	*South Korea, New Zealand, Ireland*
Flexibility	**Power system flexibility**	✓	✓	✓
	Regulation of supply and demand	✓	✓	✓
Security and resilience	**Resilience in isolated systems**		✓	
	Security of imports	✓		✓
	Security of exports		✓	
	Resilience to price shocks	✓	✓	✓
Affordability	**Optimal use of limited resources**			✓
	Linking resources to demand	✓	✓	✓
	Extending life of network assets	✓	✓	

Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

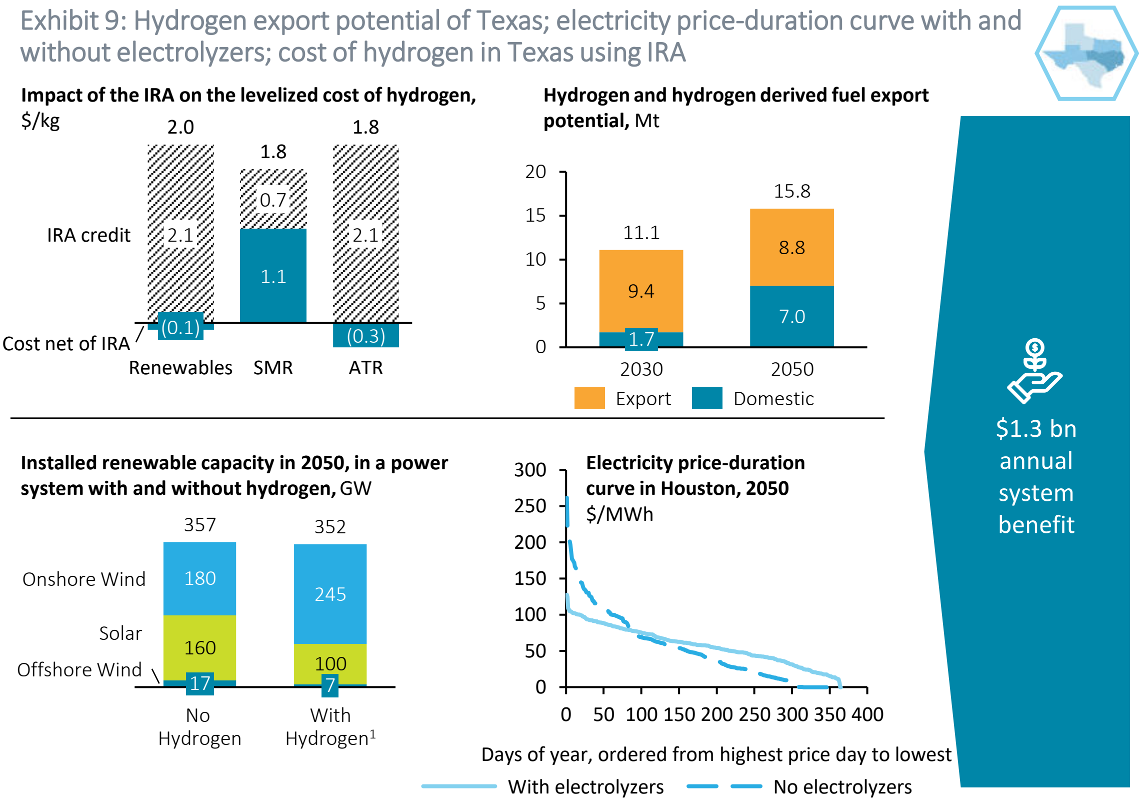
System benefit: renewable hydrogen production offers a critical source of flexibility to power grids that promotes decarbonisation

Energy systems need flexibility to cope with routine changes in supply and demand, otherwise prices become volatile, there are greater opportunities for rent seeking, and consumers pay more as a result. This is especially important in power systems as electrical energy is more difficult to store than chemical energy contained in liquid and gaseous fuels. Traditionally fossil-fuelled power generation has provided various flexibility benefits, including short-term grid balancing, coping with daily peaks and troughs in demand, as well as monthly or seasonal variations in demand. As fossil fuels get phased out, this flexibility needs to come from elsewhere, with electrolyzers, batteries, hydrogen-fired generators, pumped storage, and demand response all playing important roles.

Texas is home to abundant energy resources, with much of the U.S's exported oil and gas moving through the Gulf Coast, and large amounts of land with low commercial value suitable for both solar and wind energy. This makes Texas ideal for producing both renewable and low carbon hydrogen and with the addition of the Inflation Reduction Act (IRA) offering up to $3 / kg in tax credits, both renewable and low carbon hydrogen could be produced very competitively. This will greatly help enable Texas's potential to produce up to 9 Mt of hydrogen for export potential identified in our Global Hydrogen Flows study as well as meeting up to 7 Mt of domestic demand.

However, the Texas power system is largely islanded from the rest of the U.S., which can lead to periods of very high prices for consumers when demand peaks during very hot or very cold weather, or when supply shortages occur during period of low solar and wind output. Electrolyzers can help stabilize prices by offering a flexible source of demand. If the Texas power system is to decarbonize without needing to serve any demand from electrolyzers, this will mean price spikes up above $250 / MWh on some days and will result in several weeks where prices are above $100 / MWh. However, if Texas were to produce 16 Mt p.a. then prices would stabilize considerably, as electrolyzers are incentivized to turn down when prices are high and turn up when prices are low, insulating the system against price shocks. Overall, we estimate this flexibility will reduce the cost of decarbonising the energy system by approx. $1.3 bn annually ($23 bn cumulatively) between now and 2050.

Exhibit 9: Hydrogen export potential of Texas; electricity price-duration curve with and without electrolyzers; cost of hydrogen in Texas using IRA



Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023), Hydrogen Council – Global Hydrogen Flows (2022)

Note: 1) Includes hydrogen to power infrastructure. Adding electrolyzers alone will result in increase in total renewable generation capacity, though investment required per unit of demand is lower

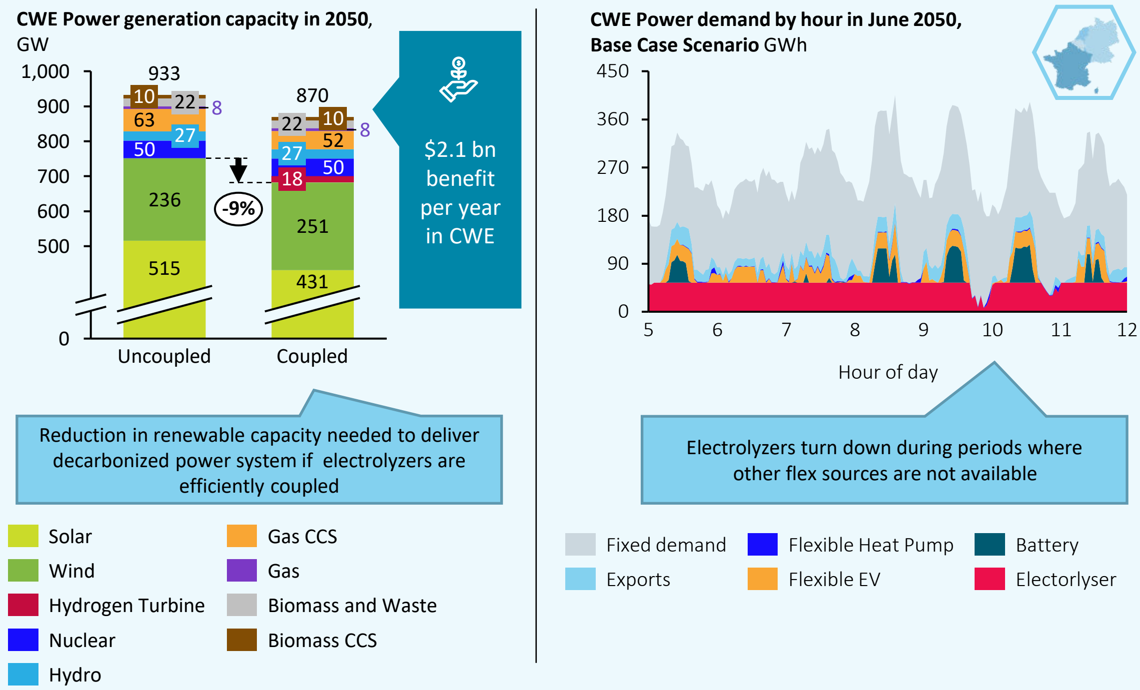
System benefit: Allowing electrolyzers to respond to system prices is needed to enable the value of flexibility

Regulatory criteria to qualify renewable hydrogen can support the decarbonisation of the energy system. For example, in Europe these criteria mandate that electrolyzers contract only with newly built renewable assets ('additionality') and must match the generation profile of those assets to the hour or less ('temporal correlation'). These criteria were introduced to ensure hydrogen production goes hand in hand with new renewable electricity generation capacities ('additionality') and that hydrogen is produced when and where renewable electricity is available ('temporal and geographical correlation')[1]. At the same time, our analysis shows that restricting electrolyzer generation can reduce system flexibility in two ways: firstly, by removing some of the freedom electrolyzers must respond to prices and secondly by reducing the pool of renewable assets they can contract with. This price response can be beneficial when supply is short, for example on prolonged overcast periods with low wind where batteries are unavailable and other sources of flexible power are more expensive. If electrolysers are locked into hourly-correlated power supply agreements with individual renewable generation assets then they are not incentivized to turn down when the wider system is more carbon intensive, or conversely to turn up when renewable power generation is high in other parts of the system.

We have evaluated this flexibility restriction by comparing scenarios where electrolyzers and their required renewable power are either separate or integrated with rest of the system. In Central-West Europe, we estimate the cost of this restriction to be $2.1 bn per annum in a scenario where the region produces 7 - 8 Mt of hydrogen by 2050, equivalent to $0.30 for every kg of renewable hydrogen produced. This benefit arises from allowing electrolyzers to obtain electricity outside of the renewable asset they are directly contracted with and results in less renewable power capacity being required to serve the same level of demand as there is more flexibility within the system.

This validates the provisions within EU rules that allow for relaxing temporal correlation in some circumstances e.g., when prices are lower or when renewable generation would otherwise be curtailed. However, it also highlights that additionality rules can result in overbuild of renewables. There will be similar benefit from integration of electrolyzers with grid in Texas as it becomes more decarbonized, allowing them to benefit from system prices rather than renewable LCOEs. Similarly in Texas, where low-cost gas-fired power generation can be produced at < $40 / MWh, linking subsidies to carbon intensity (as has been done in the IRA) will ensure electrolysers do not frequently dispatch at periods of higher grid carbon intensity.

Exhibit 10: How electrolyzers reduce renewable capacity required in coupled energy system



Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Note: 1) This page has been updated on October 25th 2023 to reflect that EU regulatory criteria for green hydrogen production have been finalized in the EU Delegated Act for Renewable Fuels of Non-Biological Origin

System benefit: Pipelines and storage prolong asset lifetimes while linking wind/solar to areas of demand

Network infrastructure needs in regional energy systems present one of the greatest challenges of the energy transition. Gas and electricity networks which have taken shape over several decades are now required to transform in half that time.

Transmission wires will remain the primary means of moving electricity from where it is produced to where it is consumed. But hydrogen pipelines will be needed alongside them to move energy from solar and wind sites co-located with electrolyzers to areas of demand. For distances of 100s of km, this is generally lower cost than moving the same energy in the form of transmission wires and electrolyzers are therefore better located near supply locations rather than demand locations.

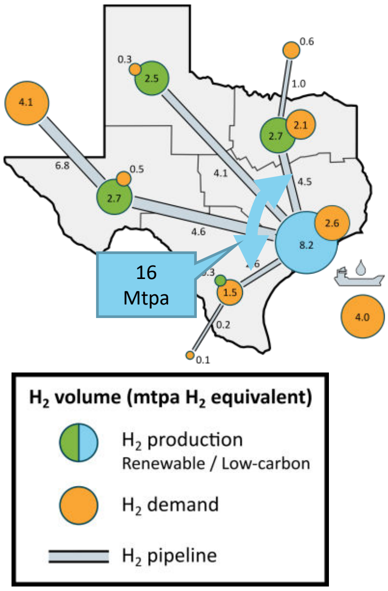
In Texas this could result in 16 Mt of pipeline capacity needed by 2050 to move renewable hydrogen from areas with low LCOEs into the Texas triangle and gulf coast belt of fuel refineries. Additionally there could be a $3.9 bn system benefit to using repurposed natural gas pipelines that would otherwise have a reduced asset lifetime, as well as $2.0 bn potential benefit from repurposing existing gas storage infrastructure.

Similarly, CWE could need nearly 20kt per day of hydrogen pipeline capacity by 2030, and over 100 kt per day by 2050 to import renewable hydrogen from the North Sea, Southern and Eastern Europe, and North Africa. By contrast, production of low-carbon hydrogen from natural gas requires less new pipeline infrastructure, as gas pipelines can continue to be the used to move energy from well source to methane reformers, which can be in industrial demand clusters. This will necessitate carbon transport and sequestration infrastructure around low-carbon hydrogen hubs which can serve other CCS use cases in addition to hydrogen production. In Texas and Central-West Europe's case, adequate CO_2 storage potential exists in shallow seabed near-shore to facilitate this.

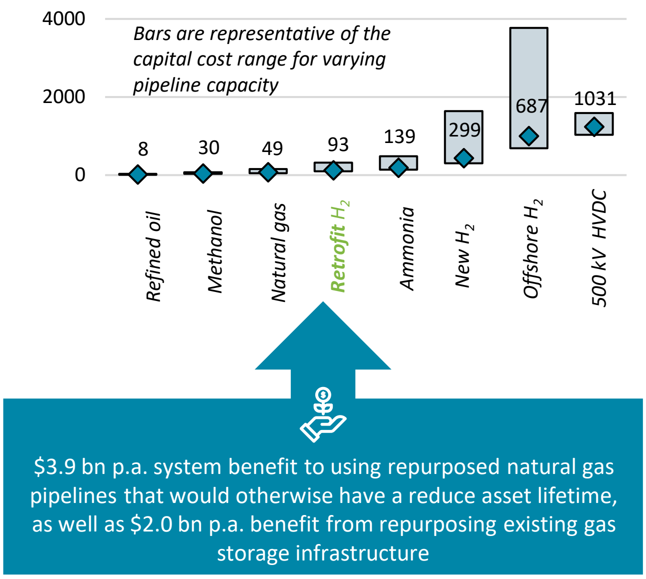
Finally, existing refined fuel pipeline infrastructure may continue to be the best option for moving aviation fuel. Today the Colonial pipeline carries 3m barrels of refined oil per day from the Gulf Coast refinery belt through the South-East to New York and as aviation fuel decarbonizes this can take kerosene derived from hydrogen produced in Texas as a drop-in fuel alongside kerosene derived from crude oil.

Exhibit 11: energy transmission costs and hydrogen pipeline capacity in Texas

Hydrogen pipeline capacity in Texas by 2050 (Mt p.a.)



Capital cost of energy transmission infrastructure
$/km/MW



Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

System benefit: Hydrogen to power adds system resilience through ‘peakers’ in high-renewable systems

Most highly decarbonized systems will have high levels of intermittent solar and wind generation providing the bulk of the systems’ emissions-free energy. In addition to coping with more regular periods of tight supply-demand balances, these systems will also need flexibility to cope with infrequent but prolonged periods where the supply-demand balance is even tighter. A typical example is a prolonged period of high pressure with high cloud cover where both wind and solar are low but energy demand is high, likely in summer in hotter climates such as Texas, or in winters in the northern half of Europe.

While batteries, electrolyzers, and pumped storage have a major role to play in dealing with periods lasting hours, they will not adequately cover such periods if lasting several days or weeks. Conversely, using CCS to enable continued gas-fired generation will be useful for serving more predictable seasonal changes in supply-demand, as their capital-intensive nature makes them more suited to running with higher utilisation, stopping only during periods of renewable over-supply. Geothermal power production can also provide dispatchable power but typically only where heat sources are accessible at low cost. Biomass also offers dispatchable generation but only provided feedstock is sustainable.

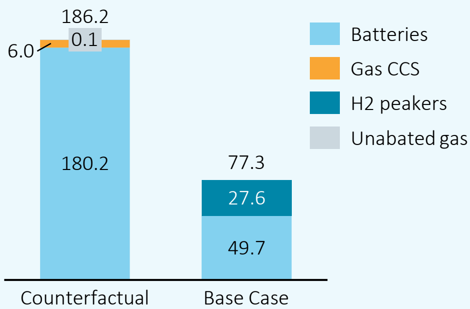
As a result, there is a role for hydrogen-to-power ‘peakers’ similar to that played by open-cycle-gas-turbines and gas engines today. This form of generation has lower capital costs versus CCS-CCGTs but can run for weeks if needed to. This effectively uses hydrogen as a form of long-duration energy storage.

We estimate that in order to reach deep decarbonisation, systems such as Texas and CWE will need 11 GW and 18 GW of this hydrogen to power capacity, respectively. It is likely to run between 5 and 15% of the time, when the system is at its most strained.

Beyond these regions, hydrogen can be expected to play this role in any system without very large amounts of interconnecting or hydro or nuclear power that reduce intermittency of supply. Such prolonged flexibility is very challenging to provide through other non-chemical forms of energy storage.

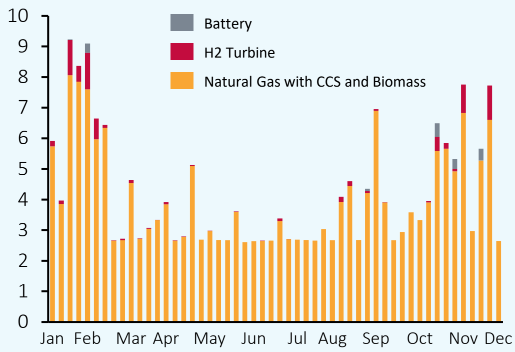
Exhibit 12: Flexible power supply in Texas and CWE

Flexible Generation in Texas in 2050, in a power system with and without hydrogen, TWh



$1.2 bn p.a. system benefit to 2050 in Texas

Sources of power by week in CWE in 2050, High Gas Price Sensitivity, TWh



$3.8 bn p.a. system benefit in CWE

Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

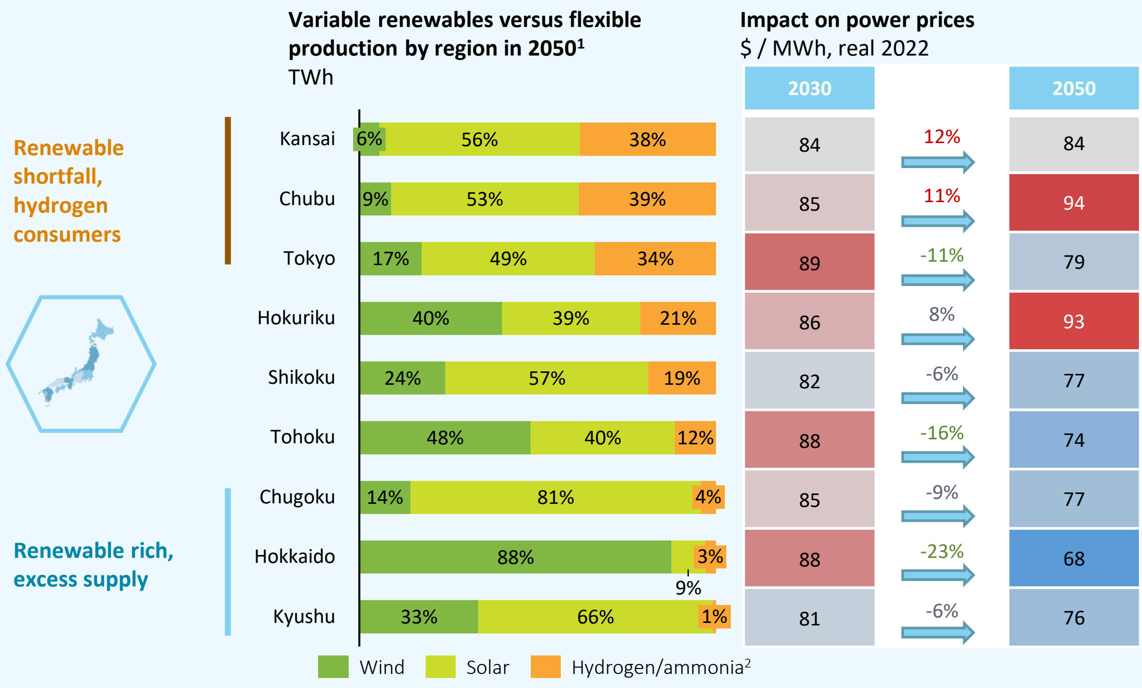
System benefit: Imported hydrogen is key to providing reliable dispatchable power where less renewables are available

Systems with limited renewable resource potential such as Japan will need to import hydrogen to produce power, as there is little alternative given the lack of CO2 sequestration potential. Therefore, in contrast to Texas and CWE where hydrogen-to-power acts as low-utilisation 'peaking' capacity, hydrogen-to-power can play a more central role in Japanese power system, particularly in regions such as Tokyo, Chubu and Kansai where there is less renewable resource. In 2050 over 16% of Japan's generation capacity could come from hydrogen or derived fuels such as ammonia, complementing wind and solar as the primary lever of decarbonisation.

Our analysis shows that this will result in only modest increases in the cost of energy in these regions going from 2030 to 2050, while prices in other regions may actually fall through pursuing decarbonisation via combination of domestic renewable power supported by hydrogen and ammonia to power generation.

The overall benefit to the Japanese energy system of using hydrogen in this way will be worth just over $5 bn p.a. versus a scenario in which Japan opts not to decarbonize but offsets its emissions elsewhere. At this stage it is too early to tell whether this will be largely enabled through hydrogen or derived fuels such as ammonia or synthetic methane, and utilities and OEMs are pursuing the development of each of these options.

Exhibit 13: Japan's power mix and impact on power prices by region



$5.1 bn p.a. system benefit from both new build and repurposed turbine capacity for hydrogen and ammonia

Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Note: 1) Nuclear and geothermal generation have been omitted from this view for clarity as they provide baseload generation and consequently have lower impact on flexibility requirements 2) Synthetic methane has not been modelled in this study but would provide similar flexibility benefit if used and sourced at similar cost to hydrogen or ammonia

System benefit: hydrogen can improve the business case for renewables where they are expensive

Curtailment of power occurs both when supply is in excess of demand, and when transmission lines have reached their peak export capacity, causing power generation to be wasted. Curtailment of solar and wind power is forecast to be up to 30% in particularly islanded grids or where transmission grid congestion is an issue.

The renewable-rich regions of Hokkaido, Kyushu and Tohoku experience prolonged periods of curtailment in a decarbonized system. This is true even in a system which has been optimized to reduce curtailment through the deployment of batteries, and implementation of the government's grid expansion plans.

In Hokkaido, power is curtailed for over a quarter of the year in 2050. electrolyzers can exploit these periods of low power price to produce hydrogen which is competitive with global imports. Up to 25 GW capacity running on curtailed / spilled energy could be economically viable.

Using this curtailed power can serve 2 – 5% of hydrogen demand in Japan while adding 10 – 15% to the value of renewable assets by providing an outlet for otherwise curtailed renewable energy.

Prices in Hokkaido in 2050, from highest to lowest hour ($/MWh)

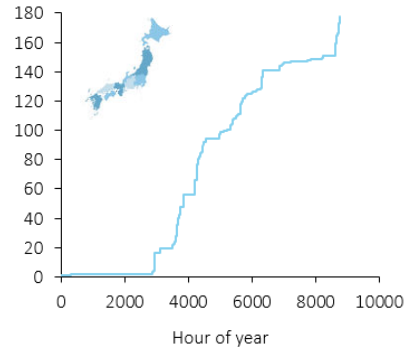
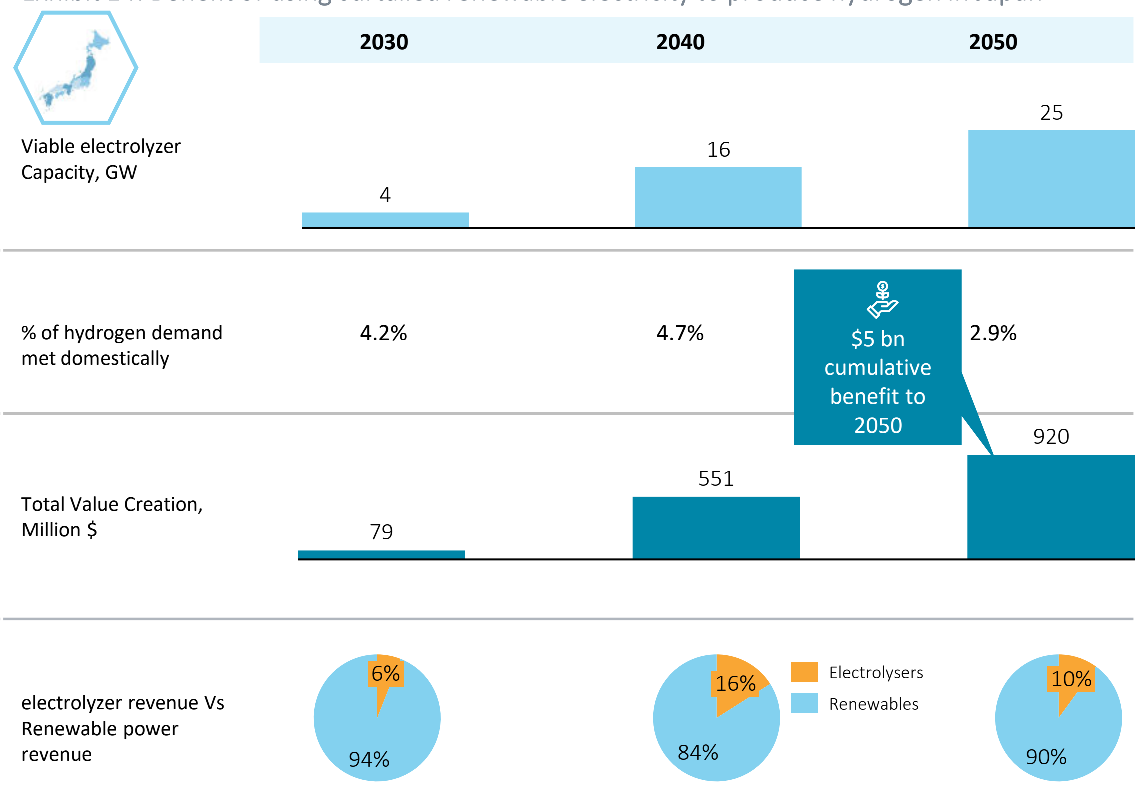


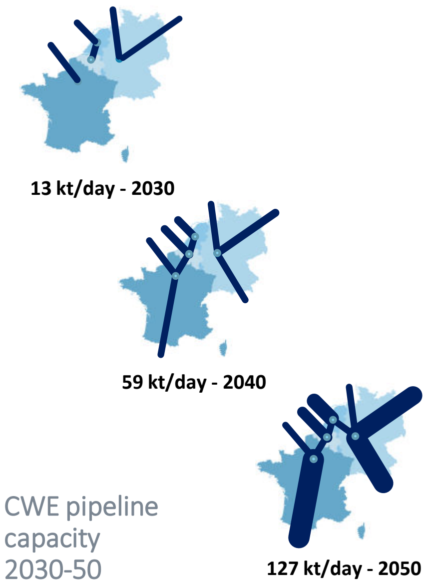
Exhibit 14: Benefit of using curtailed renewable electricity to produce hydrogen in Japan



Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Enabling infrastructure

Four types of enabling infrastructure are critical



Network infrastructure is needed to make any energy system work effectively: pipelines, ports, caverns and bunkers will all provide the flexibility and resilience the system needs to function.

Historically these networks and critical infrastructure have tended to evolve unevenly. In the early days of natural gas, pipelines linking Russia to Western Europe appeared gradually, underpinned by very large offtake contracts between producers and users.

Similarly, today Texas experiences occasional but severe power price spikes as a result of uneven reinforcement of the power grid in certain areas which prevent transmission between generators and demand centre.

Network projects also cover larger areas and consequently can require more extensive permitting and approval, taking longer to realize than generation projects as a result. For hydrogen this means careful policy and planning focus are required, as well as appropriate risk management by governments to accelerate the development of critical enabling infrastructure that can carry more investment hurdles for private capital if not managed and supported by public policy.

Four types of enabling infrastructure for adopting hydrogen into decarbonising systems

Hydrogen pipelines are essential to connect low-cost supply with proven demand. They will also reduce price volatility and extend the lifetime of existing natural gas infrastructure by connecting lower-price regions to higher-price regions, similar to how power and gas interconnectors function today

Seasonal hydrogen storage using salt caverns will balance seasonal variation in supply and demand in the same way gas storage does today and is essential to lowering LCOHs and allowing electrolyzers to benefit power systems by allowing them to operate more flexibly in response to cheap power prices

CO_2 transport and sequestration is needed to facilitate low-carbon hydrogen production and will require economies of scale through pooling hydrogen production with other CCS use cases in order to achieve expected cost reductions through economies of scale

Port terminals and bunkering will provide storage required to deal with interruptions and delays to shipping routes and will typically provide 1 – 2 weeks of storage coverage for ammonia, liquid fuels such as e-kerosene, and liquid hydrogen

Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Enabling infrastructure: hydrogen pipelines will be essential for connecting competitive supply to demand

Pipelines are essential to enabling hydrogen to grow within the power system. As previously shown, regions such as CWE and Texas may need to move hundreds of kt per day through pipelines as they are fundamentally lower cost mean of moving energy than transmission lines and therefore the primary means of linking renewable resources to hydrogen demand, in addition to providing system benefits through extending the life of gas network infrastructure.

As well as reducing overall cost of hydrogen, pipelines will be essential for minimising price volatility between markets, making for a fairer, more politically secure transition. In CWE, pipelines will ensure prices across Germany, France, and the Benelux countries will remain relatively aligned save for more severe price events caused by more severe weather.

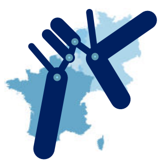
If regions rely more on renewable hydrogen, as in our 'High gas price' test case for CWE, more weather dependence will mean some seasonal price variation is likely even with an optimal amount of pipeline capacity as building enough pipelines to completely remove price differences would result in low asset utilisation and potentially high pipeline usage charges as a result.

4.8 Mt — Interstate pipeline capacity connecting Texas supply to U.S. demand

$2 / kg — Difference between summer and winter spot price for hydrogen in 2050 in CWE

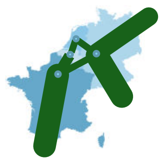
Exhibit 15: Hydrogen pipeline capacity and spot price in CWE under two scenarios

CWE Pipeline Capacity –Base case scenario
127 kt/day



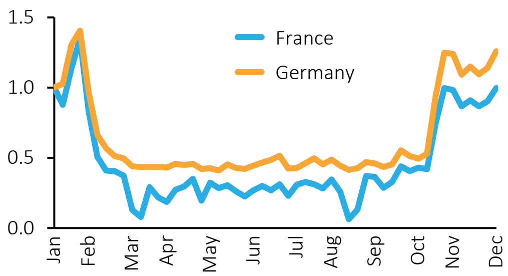
Pipelines will ensure prices across Germany, France, and the Benelux countries will remain relatively aligned save for more severe price events

Pipeline Capacity – High gas price case
111 kt/day

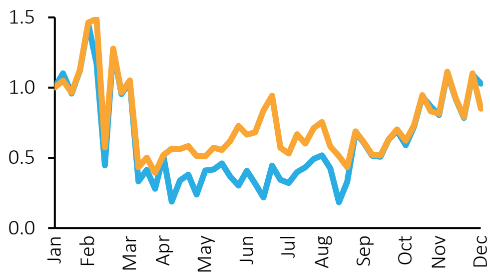


If relying more on renewable hydrogen, allowing for some seasonal variation in pricing is more optimal, through pipelines will prevent this being severe

Hydrogen Price Evolution in 2050 – Base case scenario
(Indexed, Jan 2050 = 1)



Hydrogen Price Evolution in 2050 - 'Higher gas price' case
(Indexed, Jan 2050 = 1)



Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Enabling infrastructure: hydrogen storage will enable integration of renewable hydrogen, it is the underlying source of flexibility

Different hydrogen consumers will carry different profiles: transport consumption varies considerably within day and over the week but remains reasonably flat over the year, while heating is highly seasonal and industry varies between seasonal (e.g., fertilizers delivering in time for farming season) and non-seasonal (e.g., 24/7 manufacturing processes).

Systems need to cater for this while potentially dealing with intermittent production of renewable hydrogen caused by intermittent solar and wind resource. This means overall peak hydrogen demand in a given year could be 1.6x of average demand and the system will need a combination of storage and production flexibility to cater for this. Peaks will occur at different times of year in different systems. In colder climates such as CWE, storage will fill up during summer/autumn and be drawn down during the winter in response to higher demand and lower solar output.

Seasonal storage is therefore a critical enabler of hydrogen in the energy system where domestic production occurs, with CWE and Texas each potentially needing 2 Mt worth of storage capacity by 2050 through developing salt cavern storage and repurposing natural gas storage. Europe currently has enough working salt cavern capacity to provide 1.5 Mt of storage while Texas can meet approximately 50% of its storage requirements in this way. Therefore, the development of new storage sites, as well as the repurposing of depleted gas fields will be needed long term to meet demand in our scenarios.

Equally, the need to pay for storage to mitigate intermittency of renewable sources may lead to different patterns of consumption among industrial users of hydrogen (e.g., steel and fertilizer production) as well as rewarding renewable hydrogen producers who can reduce their intermittency through combining or oversizing renewable power purchase agreements that serve their plant.

Import dependent systems such as Japan may need less capacity if exporting countries provide some of the storage requirements but will pay a higher price for liquid or compressed hydrogen storage if underground resources are not available. This may impact which energy carrier is chosen as import, as ammonia and other derived liquid fuels such as kerosene will be easier to store for longer durations than hydrogen gas.

Exhibit 16: Demand shape, storage capacity, and storage balance in CWE

Annual demand and supply profiles in CWE (Jan 1st = 100)

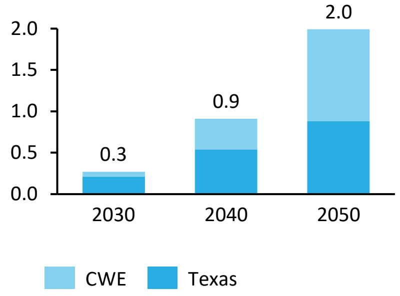
30 days

Estimated level of storage coverage required for a renewable hydrogen system

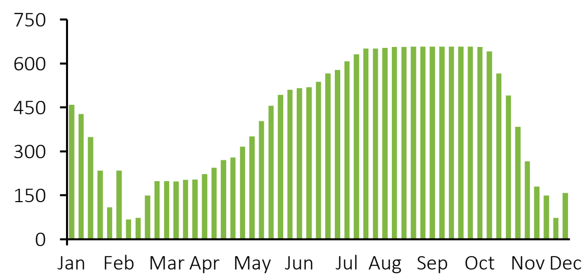
1.6x

Peak demand over baseline demand for hydrogen in 2050

Required underground hydrogen storage capacity (Mt)



Energy Stored by week in 2050, CWE (kt)



Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023), Gas Infrastructure Europe; U.S. EIA Field Storage Data

Enabling infrastructure: CCS infrastructure will enable low carbon hydrogen and can be pooled with broader CCS cluster

Low-carbon hydrogen using CCS is needed to make the transition to hydrogen more economically attractive, particularly where CO_2 sequestration potential is high and natural gas is cheap (as in Texas) or renewable hydrogen will be expensive (as in CWE).

However, as with other pipeline networks, building out CO_2 networks with multiple users delivering 10s of Mt volume p.a. each will be required to reach expected economies of scale. This will mean establishing CCS clusters to pool CO_2 supply within industrial clusters that go beyond low-carbon hydrogen production, capturing emissions from other major emitters such as refineries, crackers, cement plants, methanol plants, and power generators.

Usually, larger emitters are clustered together into regions with strong existing gas and power network infrastructure. Regions face a decision in how to link these clusters to CO_2 sequestration potential and developing storage offshore is generally more expensive than onshore. However, for Texas and CWE, sequestering carbon under the seabed may be competitive versus underground due to relative shallowness of respective seabed and proximity to emissions clusters versus suitable land-based alternatives.

Elsewhere, most of the estimated capacity is onshore in deep saline formations and depleted oil and gas fields and as such other clusters will require land-based CO_2 pipelines to link emissions clusters to storage. Regions such as the U.S. Midwest, as well as heavily industrialized parts of China and Russia will likely rely on land-based sequestration.

50 Mt

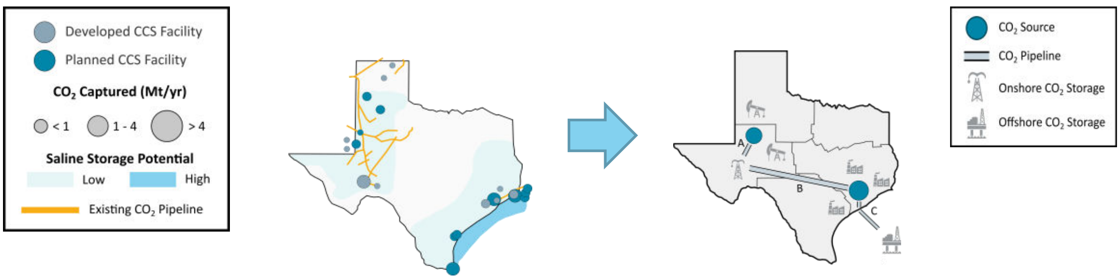
CO_2 storage capacity will be needed for low carbon hydrogen production in Texas

$9 bn

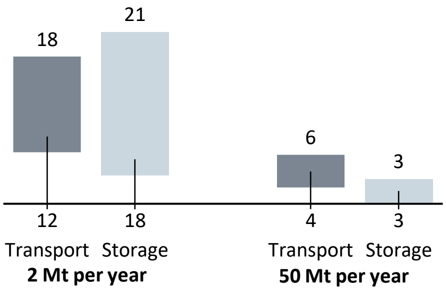
Required investment in CO_2 capture, transport and storage in Texas

Exhibit 17: CCS transport and storage current infrastructure, costs and vision in Texas

Conceptual evolution of CCS infrastructure in Texas versus today

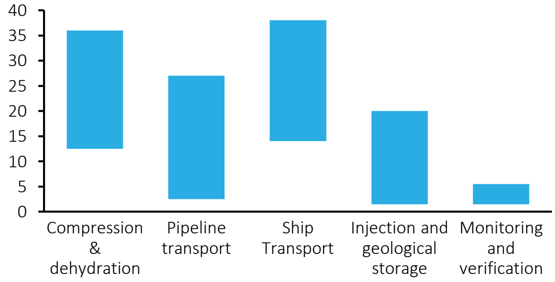


Economy of scale in CO_2 transport and storage costs ($ /tCO_2)



Cost ranges for CCS value chain components

($ /tCO_2)



Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Appendix of assumptions

Annex of assumptions

Technology costs

Power infrastructure costs are based on Baringa intelligence on each region and are summarized below. Otherwise, technology costs assumed are consistent with our previous assessment of infrastructure costs detailed in **Path to hydrogen competitiveness: A cost perspective** and updated annually through our **Hydrogen Insights** reports.

Base Case LCOE assumptions ($ / MWh) (2030 → 2050)	Solar	Onshore Wind	Offshore wind
Texas - Panhandle	29 → 24	28 → 18	n/a
Texas - South	33 → 27	34 → 24	96 → 77
Germany	54 → 33	52 → 40	72 → 41
France	50 → 30	54 → 40	84 → 43
Japan - Hokkaido	114 → 88	93 → 83	176 → 151
Japan - Kyushu	105 → 80	111 → 105	183 → 173

Low-carbon hydrogen is assumed to be produced using autothermal reformation with a capture rate of 90% while electrolyzer efficiency improves and capital cost declines over time. Salt caverns are assumed for storage and assessment of pipeline build is based on several standard diameters of pipe to capture increasing economies of scale.

Commodity pricing

Carbon and gas pricing is in Japan and Texas are consistent with the Net Zero case for our Global Hydrogen Flows. In Europe, gas prices for the base case and high gas price sensitivity are developed using the IEA's Sustainable Development Scenario and EIA's Low Oil & Gas Supply Scenario respectively, while carbon prices are based on the IEA's Net Zero Scenario.

Base Case Gas and carbon price assumptions (2030 → 2050)	Gas Price ($ / mmbtu)	Carbon Price ($ / tCO_2)
CWE	4.0 → 4.3	91 → 250
Texas	2.3 → 2.0	69 → 158
Japan	5.6 → 4.2	115 → 207
CWE, high gas price sensitivity	8.8 → 10.5	91 → 250

Subsidies

The impact of Production Tax Credits and the Inflation Reduction Act is incorporated into hydrogen, renewable power, and CCS infrastructure in Texas. Our estimation of IRA subsidy available to ATR of gas assumes negligible upstream emissions and a carbon capture rate of 95%. Subsidies are assumed to expire in 2032. Both Production tax Credits and Investment Tax Credits for renewable power generation are accounted for in addition to tax credits available for hydrogen production and are assumed to be stackable. Credits available for CCS under the 45Q are not considered stackable with IRA subsidies.

Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

Annex of assumptions

Energy system constraints

In each system hydrogen and power infrastructure are co-optimized. Power transmission capacity is fixed with future capacity additions based on latest development plans for transmission system operators. A system reserve capacity margin aligned with grid operator guidelines is used in each region.

Estimation of benefits

To determine system-benefits, we compare our base case scenario to a test scenario in which a particular asset or behaviour is restricted. The per-unit-energy total system cost of each scenario is then compared to derive the system benefit. For Japan, in the absence of a viable decarbonized power system without hydrogen we have estimated the system cost of an un-decarbonized system using a *global* carbon price of $275 / t based on IEA's SDS scenario for 2050

All costs are in real 2022 U.S. dollars and conversions from energy units to mass for hydrogen have assumed lower heating values.

Hydrogen demand and trade flows

For the base case scenario, hydrogen demand in heating, industry and transport and import and export flows for each region align with the Global Hydrogen Flows reference scenario. The high gas price test case for CWE aligns with the 'Renewable World' scenario from the same report. Hydrogen demand in power sector is an optimized output of this analysis.

Source: Hydrogen Council - Hydrogen in Decarbonized Energy Systems (2023)

End of report