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Sailing towards sustainability: offshore wind's green hydrogen potential for decarbonization in coastal USA†

Rishi Kaashyap Balaji [a] and Fengqi You *[abc]

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In the pursuit of achieving net-zero emissions to combat climate change, green hydrogen is expected to be an important decarbonization vector for hard-to-abate sectors. Scaling up green hydrogen production necessitates significant resources such as renewable energy and water, presenting an opportunity for a synergistic integration with offshore wind—a largely untapped energy source with abundant potential and declining costs. In this study, we employ a systematic assessment, utilizing an optimization framework and life cycle assessment, to evaluate the economic and environmental implications of green hydrogen production offshore. We examine the two delivery pathways of direct hydrogen transport – liquefied hydrogen and compressed gaseous hydrogen for 30 coastal states in the United States and further extend the analysis to the regional level, conceptualizing offshore hydrogen hubs. Our findings reveal that under optimistic scenarios of hydrogen uptake, 75% of the nation's serviceable consumption potential of hydrogen can be fulfilled through the deployment of 0.96 TW of offshore wind capacity. This leads to a significant increase in the utilization of offshore wind resources from 1% at present to over 22% of its technical resource potential. Our assessment predicts a delivered cost range of \$2.50–\$7.00 per kg H_2 and life cycle greenhouse gas emissions below the 4 kg CO_2e per kg H_2 benchmark at the coast for hydrogen produced offshore. These estimates are robust over a large range of demand scenarios. Furthermore, we delve into the factors that lead to the spatial differentiation in these metrics and discuss key policy support measures to bolster the growth potential of these nascent sectors.

Broader context

Tackling climate change urgently demands global carbon neutrality. While electrification remains a cornerstone in the race for decarbonization, propelled by the widespread adoption of renewable energy sources such as solar and wind, the focus is now extending to the ''hard-to-abate'' sectors. These sectors present greater technical challenges, with emissions deeply embedded in fundamental processes and technologies that are challenging to electrify or often beyond the direct reach of renewable energy's Midas touch. Clean hydrogen is poised to play a crucial role here, emerging as a molecular carrier of energy with capabilities for storage, transformation, and trade, bearing structural similarities to our traditional energy systems. However, unlocking its potential hinges on establishing scalable strategies for hydrogen production and utilization in cost-effective and environmentally sustainable ways. Integration of offshore wind energy and green hydrogen production could be a pivotal step in this direction, enabling opportunities for deep-decarbonization and promoting a sustainable and carbon-neutral future.

Introduction

Achieving the ambitious target of attaining net-zero carbon emissions by 2050 to rein in climate change could necessitate a global annual demand of more than 500 million metric tons (MMT) of clean hydrogen,[1–3] with North America accounting for approximately 100 MMT.[1] While the US currently produces about 10 MMT of grey hydrogen annually, new projects totaling 10 MMT of additional capacity of green and blue hydrogen have been announced, aligning with the national clean hydrogen

[a] *Systems Engineering, College of Engineering, Cornell University, Ithaca, New York 14853, USA. E-mail: fengqi.you@cornell.edu; Fax: (607) 255-9166; Tel: (607) 255-1162*

[b] *Robert Frederick Smith School of Chemical and Biomolecular Engineering, Cornell University, Ithaca, New York 14853, USA*

[c] *Cornell Atkinson Center for Sustainability, Cornell University, Ithaca, New York 14853, USA*

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strategy roadmap until 2030.[4,5] However, beyond 2030, a market gap of up to 86 MMT per year presents opportunities for a transformative expansion predicated on shifting supply reliance on fossil fuels from 98%[6] at present to a composition composed primarily of cleaner sources to realize deep decarbonization goals in the United States. This is particularly significant because the US Department of Energy forecasts a growth in demand for clean hydrogen across nine different markets, most of which are known as hard-to-abate sectors.[7] Influenced by factors such as availability, price, ease of adoption, and competition with alternative technologies, this growth could vary significantly, potentially reaching the serviceable consumption potential (SCP) of 106 MMT per year, representing the upper bound of the market size of hydrogen. Though multiple low-carbon hydrogen production pathways such as steam methane reforming with carbon capture,[8–11] methane-pyrolysis[12–14] and biomass based thermochemical routes[15–17] exist, electrolysis with renewables is expected to be most widely adopted to meet this growing demand, potentially accounting for over 60% of future supply,[18] but its water usage and land requirements necessitate careful consideration for large-scale implementation. In addition to facing significant local resistance in siting new wind energy projects,[19,20] a recent study indicates that land scarcity could arise from the potential use of wind power to meet the 2050 targets of hydrogen production in the US while maintaining adequate forest and agricultural coverage, despite the US's vast geographical expanse.[21] Such competing requirements for land and water resources can lead to renewable energy infrastructure having environmental consequences, such as habitat destruction and a reduction in biodiversity, with repercussions reaching far beyond the confines of the land they occupy, impacting various species and their ecosystem interactions.[21] Therefore, exploring alternative approaches to generate clean energy that powers electrolysis is essential to scale and sustain clean hydrogen production.

Offshore wind offers a promising solution to scale up green hydrogen production in the US, leveraging abundant resources and high capacity factors.[22–26] Although the United States possesses significant offshore wind energy potential of over 4.3 TW[27,28] and a large number of areas with sustained high wind speeds over 7 m s^{-1},[29] the nation has lagged significantly in the utilization of these resources. Global offshore wind power capacity reached 64.3 GW in early 2023, with less than 0.1% of this capacity currently operational in the US.[30] Ongoing projects for 2030 account for less than 1% of the country's potential, with 2050 targets reaching up to 3%,[31] while Europe and China have already surpassed the planned future capacity of the US. Recent studies suggest that achieving 10–25% of US electricity supply from offshore wind by 2050 is feasible and offers substantial benefits, utilizing 250–750 GW of capacity,[32,33] but it is still less than 20% of the available technical resource potential. Integrating green hydrogen production with offshore wind emerges as a promising strategy, synergistically increasing offshore wind utilization while eliminating challenges like high transmission costs, losses, and coastal grid congestion, associated with offshore wind energy.[34] Further, directly producing hydrogen offshore enables the conversion of an otherwise untapped, variable energy resource which faces major hurdles in grid connection into a decarbonization vector capable of extended storage and cost-effective transportation at higher capacities, with minimal losses of 1% through pipelines, as opposed to the 3% losses in electricity transmission.[35]

While the concept of harnessing the ocean's vast resources for hydrogen production has been contemplated for a long time, recent technological advancements have propelled us closer to transforming this vision into reality. These advancements include floating wind turbines, which extend our reach into deeper ocean waters for access to superior wind resources and breakthroughs in catalysts and electrode materials enabling direct seawater electrolysis.[36,37] In tandem, the cost of offshore wind energy has also seen a rapid decline, a trend which experts predict will persist in the future.[38] Yet, there is a lack of systematic investigation of the life cycle energy, economic, and environmental impacts related to offshore green hydrogen production and transportation pathways. Notably, there is also a significant knowledge gap concerning delivered cost projections for offshore wind-based hydrogen in the US, as previous research[39–43] has primarily focused on different regions[44–49] or its combined use with other renewable generators,[24] leaving the specifics of the American context underexplored. Existing studies also focus solely on production costs, rely on general assumptions about facility size neglecting location-specific demand data, and predominantly examine smaller 2–8 MW wind turbines[42] despite the industry's move towards larger 11–15 MW turbines.[50,51] It is crucial to tackle these knowledge gaps to quantify the costs and environmental impacts of offshore hydrogen production, compare it to onshore alternatives, identify the barriers to its adoption, and synthesize insights necessary for science-based policy development, informed investment decisions, and strategic infrastructure planning in the pursuit of a sustainable energy future.

Addressing these knowledge gaps presents three primary challenges: first, the systems design and optimization of the entire offshore wind-to-hydrogen supply chain, encompassing decisions related to facility location, production scheduling, and transportation planning. This involves accommodating wind speed variations for flexible system operations, effectively managing trade-offs in capacity utilization, onsite inventory, and fleet sizing and usage. Second, systematic analysis of the environmental impacts of offshore wind-based hydrogen production across the life cycle, distinct from offshore wind energy assessments as it focuses on hydrogen transport impacts rather than those from electricity transmission. Third, the development of location specific insights on the effect of delivery pathways and scale on the economic and environmental performance of offshore wind to hydrogen infrastructures for the US.

Bridging these gaps, this study offers detailed systems-level insights into the energy, economic and life cycle environmental implications associated with offshore wind-based green hydrogen for the United States (Fig. 1). It presents a comprehensive

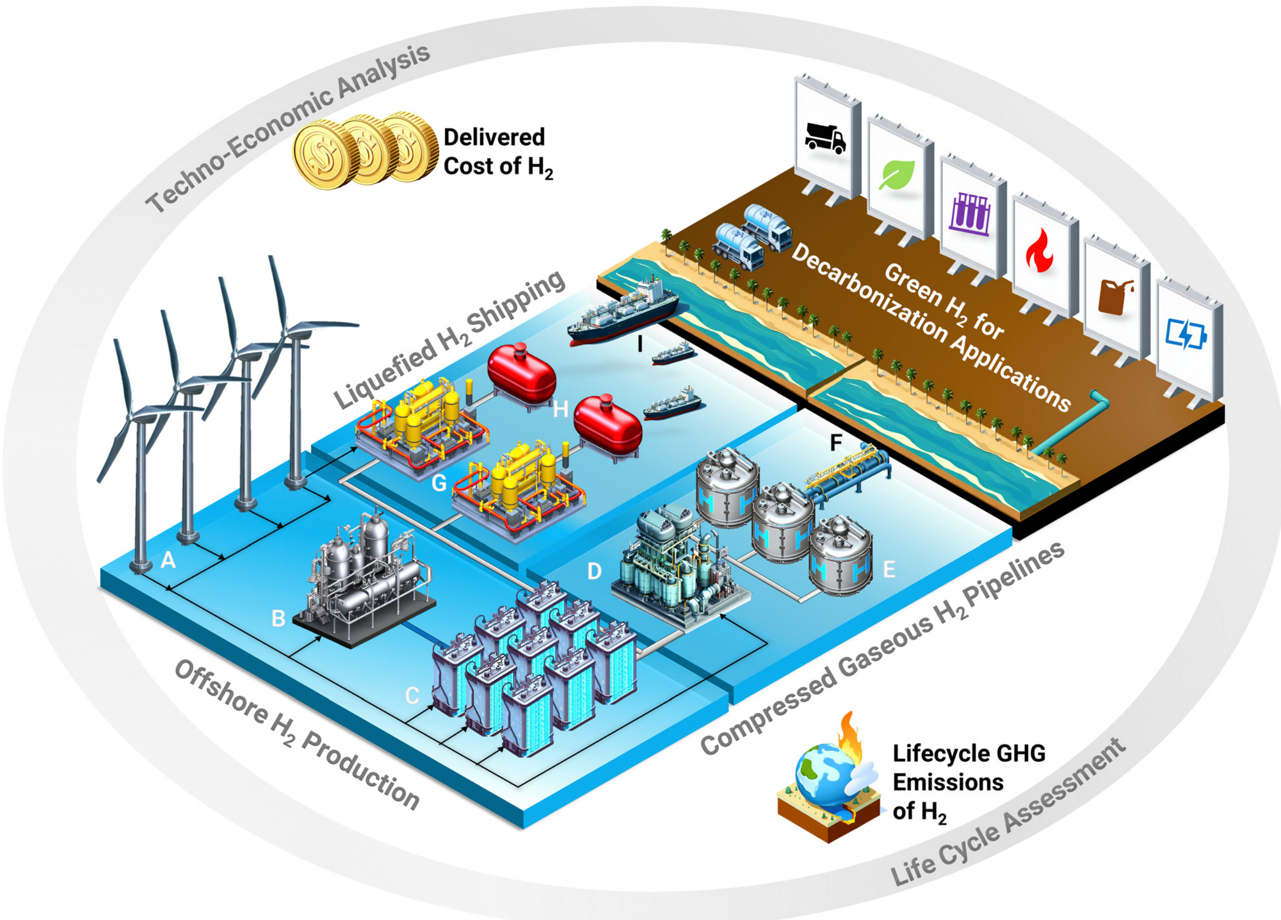

Fig. 1 Schematic of offshore wind to hydrogen systems highlighting the two delivery pathways—liquefied hydrogen shipping and compressed gaseous hydrogen pipelines analyzed for economic and environmental performance through the framework integrating optimal systems design and life cycle assessment. Offshore hydrogen production involves generation of variable renewable energy through floating offshore wind farms (A) which is subsequently used for desalination (B) of sea water and electrolysis (C). In the compressed gaseous hydrogen pipelines pathway (D)–(F), the green hydrogen produced is compressed (D), stored on site (E) and transported to the shore *via* subsea pipelines (F), while in the liquefied hydrogen shipping pathway (G)–(I), it is liquefied (G), stored on site (H) and shipped using liquefied hydrogen tankers (I) to ports on the shore. Green hydrogen finds applications across hard-to-abate sectors such as refineries, metals production, chemicals, ammonia and fertilizer production, fuel cell electric vehicles (medium and heavy duty), biofuel/synthetic fuel production, natural gas supplementation and long-term storage critical for decarbonization.

systems analysis approach that employs an optimization framework to effectively address trade-offs like proximity to demand, resource variability and quality, and scalability for design considerations spanning strategic, tactical, and operational facets within the offshore wind-to-hydrogen supply chain, with the overarching aim of minimizing the total delivered costs of hydrogen produced offshore to coastal areas. Two hydrogen delivery pathways – liquefied hydrogen (LH_2) shipping and compressed gaseous hydrogen (CGH_2) pipelines are explored through this framework. While ammonia and other liquid organic hydrogen carriers (LOHC) have emerged as alternative pathways for hydrogen delivery, offering cost-effectiveness and reduced losses for long-distance transportation applications like intercontinental trade, the hydrogen-to-carrier conversion and reconversion processes involve significant costs and energy requirements that may outweigh their benefits for the distances and volumes pertinent to this study,[52,53] due to which they are not considered. The optimization framework is further augmented with life cycle assessment, facilitating environmental impact quantification by way of estimating the life cycle greenhouse gas (GHG) emissions. Furthermore, through a multi-scale spatial analysis approach, the study analyzes individual states and extends to the regional level, clustering states into hubs based on geographical proximity—an alignment with the US Department of Energy's localized clean hydrogen hubs initiative,[54] which defines hydrogen hubs as regional networks comprising all the necessary infrastructure for production, storage, delivery, and end-use of clean hydrogen. This study builds upon the existing literature by offering spatially resolved insights into delivered costs and life cycle impacts of hydrogen, providing reliable benchmarks for onshore comparisons, inputs for future analyses and revealing opportunities for offshore hydrogen competitiveness. Additionally, this study delves into variations in these impacts and the factors driving them, shedding light on crucial considerations for planning and locating offshore wind to hydrogen facilities.

This study's key findings reveal that meeting 75% of the US's hydrogen consumption potential in coastal states would require installing 0.96 TW of offshore wind capacity. This approach could channel 22% of the nation's offshore wind resource potential toward deep decarbonization. The study emphasizes the significance of the hydrogen delivery pathway, showing that the choice of transportation method significantly affects costs and emissions. Regional hubs with centralized offshore hydrogen production could achieve cost savings of up to 30% through shared infrastructure and optimized facility siting. However, longer transportation distances from centralized hubs may double GHG emissions for some states. The East Coast stands out as a prime region for offshore wind-based green hydrogen production, thanks to its high capacity factors, regional demand, surplus potential, and export opportunities to European markets. These findings suggest that policy actions are needed to integrate offshore green hydrogen into the US energy portfolio, address resource and workforce requirements, focus on technology development, and establish long-term contracts and support for new hydrogen applications.

Results

Offshore wind resource availability and quality

Fig. 2a illustrates the regional distribution of the technical resource potential of offshore wind in the United States. With approximately 4.3 TW of capacity along its coastline (including the Great Lakes region),[27] the United States has among the highest offshore wind potential in the world.[55] It can be observed that this potential, which is dependent on a region's wind capacity factors and area available for offshore wind resource development is also well distributed, promoting equitable access and opportunities across the regions. Notably, the

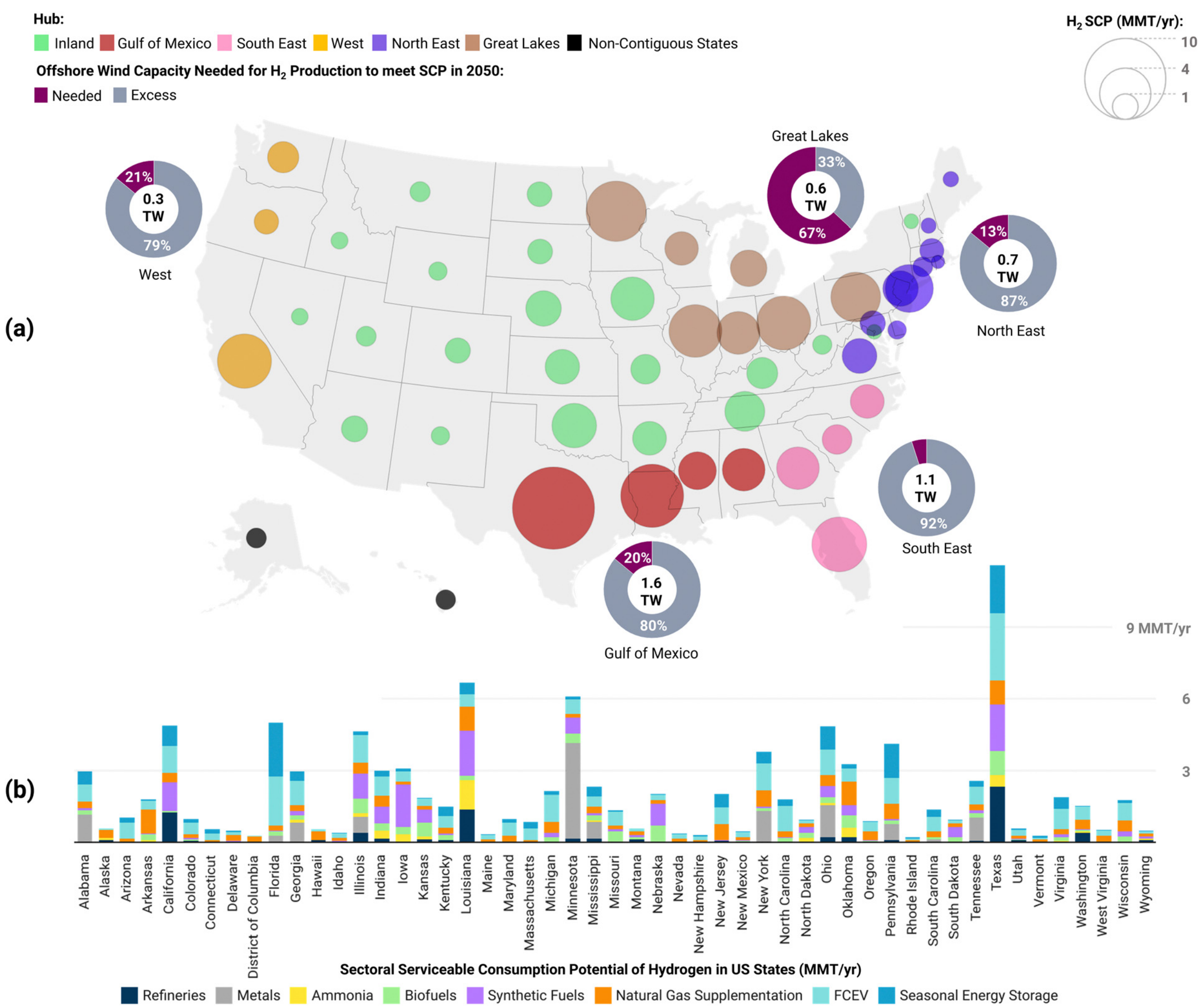

Fig. 2 (a) Regional offshore wind capacity and utilization illustrated through donut charts, alongside state-wise annual serviceable consumption potential of hydrogen presented in a bubble chart, with bubbles grouped by regions/hubs. Figure highlights the availability of adequate offshore wind capacity across regions for hydrogen production. (b) The sectoral split of serviceable consumption potential of hydrogen in US states shows varied use cases across regions, with conventional applications like refineries and ammonia dominating demand in the Gulf of Mexico region, while emerging decarbonization applications contribute to increased demand share in other regions.

coastal states also contribute to a substantial 75% of the nation's SCP of hydrogen.[7] Nine of the top ten states with the highest SCP of hydrogen are also coastal. The concentration of hydrogen demand along the coast is a trend that aligns with the higher population density and economic development along coastal regions, with US coastal counties housing over 128 million people, nearly 40% of the nation's total population, and collectively boasting a GDP that is higher than that of most countries.[56] Developing an offshore wind-based hydrogen infrastructure is therefore a strategic approach to meet the majority of the nation's hydrogen potential that is concentrated in coastal regions. Our analysis suggests that by integrating offshore wind and green hydrogen production to meet the optimistic hydrogen demand represented by the SCP of the coastal states, a substantial 0.96 TW of offshore wind capacity can be harnessed, equivalent to around 22% of the nation's offshore wind potential. Correspondingly, at low levels of future hydrogen uptake, the increase in offshore wind capacity utilization to meet the hydrogen demand is estimated to be at least 6%. The wind resource requirements for meeting these hydrogen demands were determined as part of the overall optimal design of offshore wind-to-hydrogen facilities (See Methods, Optimal design) conducted for four cases comprising of two delivery pathways – liquefied hydrogen shipping and compressed gaseous hydrogen pipelines, and two scale pathways – state-level and regional hub-level infrastructure. The illustrated utilization results correspond to the SCP & Low Case demand scenarios (See Methods, Hydrogen Demand) of the hub-wise pipelines case, which is estimated to have the lowest cost and environmental impact. Furthermore, our analysis reveals that there is sufficient offshore wind capacity at the regional level to fulfill the hydrogen production requirements of the states as substantiated by the donut charts presented in Fig. 2a. These charts depict the limiting case of the percentage utilization of offshore wind resources required for meeting the SCP.

While Fig. 2 establishes the availability of wind resources, Fig. 3 offers an additional perspective into the quality of the available resources by examining the annual offshore wind capacity factors (CF) at the candidate offshore locations (See Methods, Offshore wind energy model). The Gulf of Mexico stands out as the region with the largest offshore wind potential and also boasts the highest hydrogen demand of 24 MMT per year. Texas takes the lead in SCP singularly accounting for 12 MMT per year. Nevertheless, Fig. 3 reveals that all Gulf of Mexico states experience lower offshore wind capacity factors in the range of 40% to 45% as compared to the other regions, primarily due to slower wind speeds. This region is also prone to higher risk of hurricanes and storms, which may have to be mitigated through measures such as siting farms in areas of lower risk, adoption of more robust designs and increased design loads.[57,58] Alaska and Hawaii, though distant from the mainland, exhibit some of the highest wind capacity factors, though most of these areas are reported to be cost prohibitive or restricted completely due to their protected status as national wildlife sanctuaries, conservation areas, and other sensitive habitat designations.[59] The Great Lakes region also displays a strong potential for hydrogen uptake, with a combined SCP of 27 MMT per year distributed across three hubs

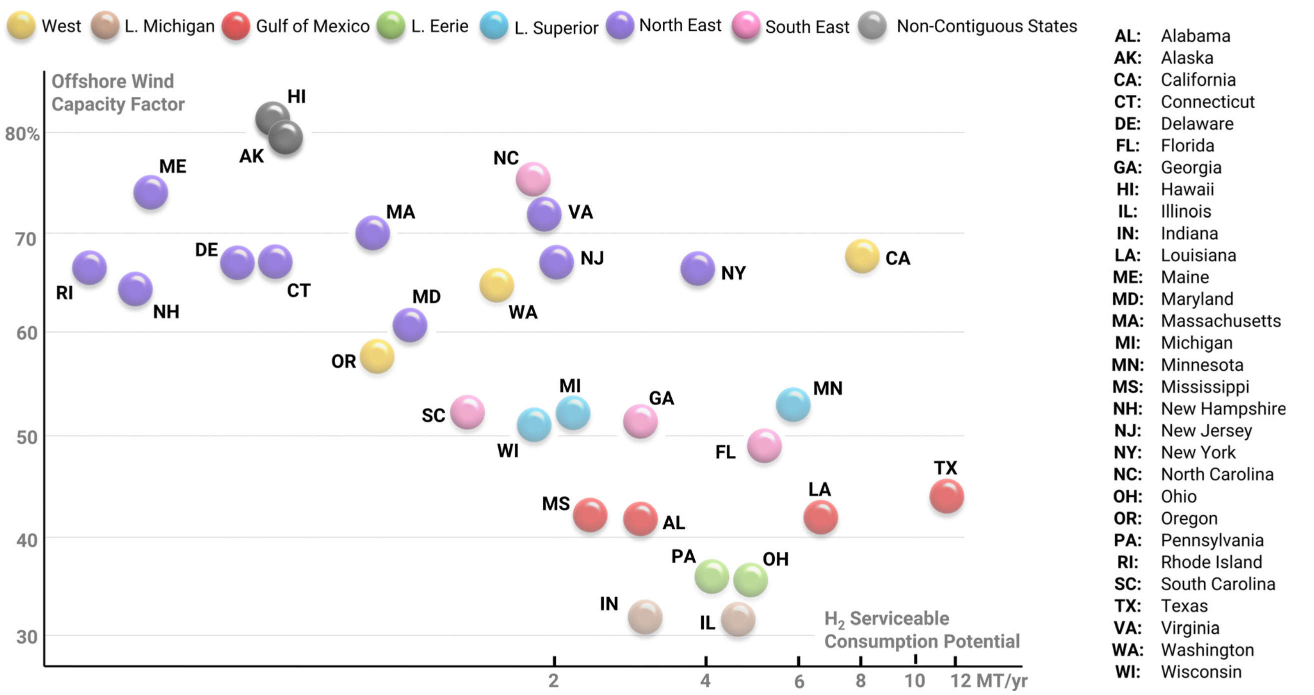

Fig. 3 Annual offshore wind capacity factors *vs.* serviceable hydrogen consumption potential for coastal states in the US, grouped by hubs to illustrate variations within and among the different regional hubs. Most coastal states have high quality wind resources, but concentration of multiple states with high CF and small demands in North–East and large intra-regional variations in South–East and West regions highlight potential for centralization through hub formation.

centered around Lake Erie, Lake Superior, and Lake Michigan. However, an analysis of the existing data suggests that the quality of wind resources in this area tends to be on the lower end of the spectrum, particularly for the Lake Erie and Lake Michigan hubs. Furthermore, this region is expected to face unique challenges, such as blade icing and additional structural loading on the wind turbines caused by the wind driving large sheets of surface ice through stationary wind arrays.[60] While our strategic assessment does not account for these regional constraints, detailed location-specific mitigation strategies could be a topic of future research.

The East coast, which holds 40% of the US's offshore wind capacity, is particularly noteworthy for its surplus potential that is available at high capacity factors of over 60%, as shown in Fig. 3. This surplus potential, coupled with its advantageous position along the transatlantic trade route, positions the East coast as a promising destination for the development of export-oriented facilities aimed at serving net hydrogen importers in Europe. While the West Coast also boasts high-quality wind resource regions, its technical resource potential of 0.3 TW is less than 50% of the resource potential in the North East. The excess capacity on the West Coast, at 0.24 TW, would be one-third of the excess capacity in the North East. Despite this, regions on the West Coast could be developed to serve as export-oriented facilities, targeting markets in Japan and South Korea, where local hydrogen production is expected to be expensive due to resource availability and regulatory constraints that challenge the generation and sourcing of renewable energy.[61]

As new offshore wind projects are typically known to have capacity factors in the range of 40%–50%,[62] a capacity factor greater than 50% can be considered indicative of a high-quality resource suitable for development. As shown in Fig. 3, most coastal states meet this criterion. Recent studies that obtain an offshore wind energy atlas for higher altitude wind turbines also substantiate these findings.[59] However, the variations in CF across states, coupled with different levels of SCP, have tangible impacts on both the economic and environmental aspects of offshore wind-based green hydrogen production. In the subsequent sections, we delve into the nuanced implications arising from the variations in CF and SCP, emphasizing how these translate into the economic and environmental impacts.

Delivered costs of hydrogen produced offshore

Fig. 4 shows the estimates of delivered costs of hydrogen (in 2022 USD per kg H_2) for coastal states across all four cases. This metric encompasses the levelized midstream costs linked to compression and pipelines in the compressed gaseous hydrogen pipelines pathway, and liquefaction and shipping in the liquefied hydrogen shipping pathway, alongside the levelized offshore hydrogen production costs. It serves as a valuable tool for analysis, facilitating a closer comparison with hydrogen produced from inland resources by accounting for the added expenses of point-to-point transport of hydrogen produced offshore to coastal locations. In practice, hydrogen produced offshore must attain cost competitiveness or even surpass onshore production costs to establish its market viability, despite these additional midstream costs. Fig. 4 further dissects these costs by subsystem components, representing the total capital and operating costs of each system for a more detailed assessment. As the costs related to desalination and storage are minimal, contributing less than 5%, they are not explicitly illustrated. Additionally, the delivered costs depicted in Fig. 4 correspond to meeting the optimistic hydrogen demand, represented by the SCP. Fig S2a and b (ESI†), which illustrate these values for the other scenarios also show that the sensitivity of the delivered costs across the demand scenarios is

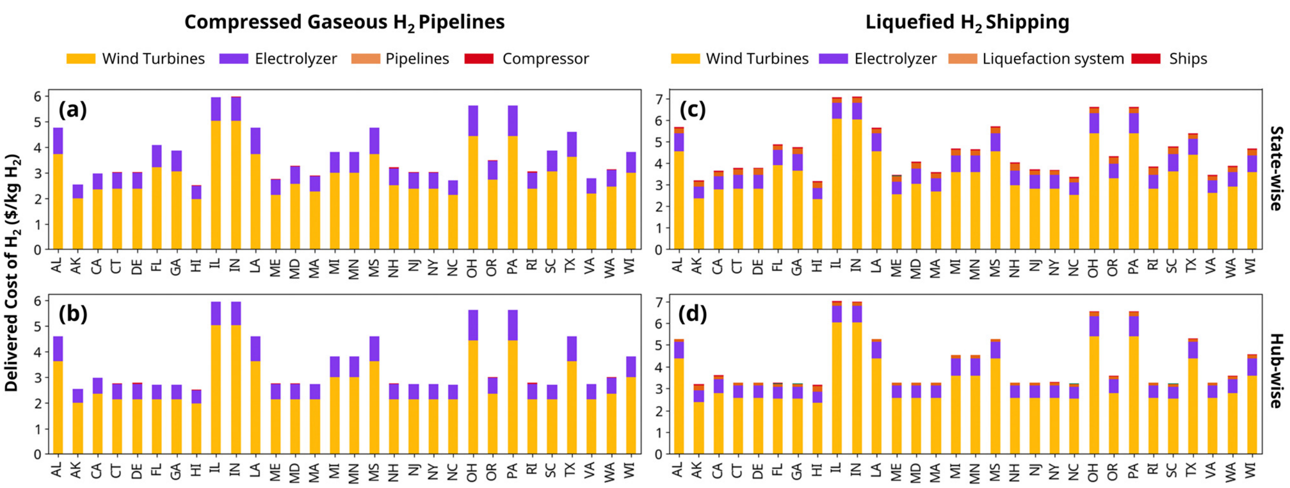

Fig. 4 The delivered costs of green hydrogen for the coastal states based on meeting the SCP through the four cases investigated (a) state-wise and (b) hub-wise configurations of compressed gaseous hydrogen pipelines and (c) state-wise and (d) hub-wise configurations of liquefied hydrogen shipping. Compressed gaseous hydrogen costs range from \$2.50 per kg H_2 to \$6.00 per kg H_2 and liquefied hydrogen costs range from \$3.00 per kg H_2 to \$7.00 per kg H_2. The legend shows the breakdown of total capital and operating costs by each subsystem. The pipeline based compressed gaseous hydrogen pathway emerges to be economically favorable.

limited. Considering this, further discussion on the delivered costs is based on the results of the limiting case presented in Fig. 4.

Fig. 4a and b show that the delivered costs for state-based and hub-based configurations range from \$2.50 per kg H_2 to \$6.00 per kg H_2 in the compressed gaseous hydrogen pipelines pathway. Maine, North Caroline, Virginia, Hawaii, Alaska, exhibit the lowest costs, while Illinois, Indiana, Ohio, and Pennsylvania have costs towards the higher end. Fig. 4c and d display the delivered costs for the liquefied hydrogen shipping pathway, showing that the costs range from \$3.00 per kg H_2 to \$7.00 per kg H_2. Similar to the previous case, states with high CF such as Alaska, Hawaii, Maine, and North Carolina continue to demonstrate the least costs, while Indiana, Iowa, Ohio, and Pennsylvania are among those with the highest costs. Notably, this points to a strong dependence on the wind capacity factors.

Comparing the distribution of costs among states in all four cases reveals that the pipeline based compressed gaseous hydrogen pipelines pathway emerges as the economically favorable option, consistent with previous analyses[4,63–66] that explore factors affecting hydrogen delivery costs, including transportation distance and volume. The higher delivered cost of the liquefied hydrogen shipping pathway can be ascribed to increased energy requirements for liquefaction and elevated unit costs associated with liquefaction technology. Furthermore, it is observed that the hub-based approach generally leads to cost reductions, primarily due to favorable offshore wind-to-hydrogen facility locations with higher capacity factors. This results in substantial cost reductions for hubs like the Southeast, whereas the Gulf of Mexico hub experiences only modest cost reductions due to similar wind speeds and capacity factors among all the states within the hub. In the hub-wise liquefied hydrogen shipping case, the proportion of costs attributed to liquefaction is reduced due to non-linear scaling of liquefaction costs. Conversely, in the hub-wise compressed gaseous hydrogen pipelines scenario, the fraction of costs associated with pipelines is more significant for states situated at a greater distance from the hub, indicating potential cost challenges related to longer transportation distances.

While Fig. 4 shows that the primary cost driver in all scenarios is the construction and operation of offshore wind farms, redistributing the costs of the offshore wind farms across the energy-consuming processes using a levelized cost of energy approach reveals the actual costs of individual process steps, including those related to their energy demands. Fig. 5 provides a visual representation of this insight, presenting the range of percentage contributions of various process steps to the levelized delivered cost of hydrogen. The additional costs in offshore hydrogen production, such as desalination and midstream costs covering compression/liquefaction, pipelines/shipping, and storage, constitute only 2–7% of the delivered costs in the case of compressed gaseous hydrogen pipelines and 18–23% of the delivered costs in the case of liquefied hydrogen shipping. Notably, liquefaction stands out as the most expensive midstream process, with individual contributions ranging from 16% to 20% of the delivered costs. This high cost of liquefaction is attributed to the current scale at which liquefaction plants are designed and implemented. Liquefying hydrogen is particularly challenging due to its extreme conditions, requiring a temperature of −253 °C (in comparison to −160 °C for liquefied natural gas).[67] Achieving such low temperatures necessitates multiple refrigerant cycles, contributing to significant energy losses during the process. These losses occur during various stages of the process, including heat exchange, *ortho–para* conversion, hydrogen gas purification, compression and expansion, nitrogen liquefaction processes, and insulation.[67] Presently, the energy consumption for liquefaction is roughly 30% of the lower calorific value of hydrogen. However, it is anticipated that advancements in technology will substantially reduce this figure by more than 50%,[53] bringing up to 8%–10% reductions in the delivered cost of liquefied hydrogen. This progress is crucial for establishing a liquid hydrogen value chain with distributed hydrogen demand, particularly in sectors like transportation, aviation, and shipping, where significant inland transportation of hydrogen may be necessary, as liquefied hydrogen trucks are best suited for long-range transportation with low throughput.[64,65] It also holds strategic significance in the absence of an extensive hydrogen pipeline infrastructure for distribution, which may take several years to develop.

Overall, the range of delivered costs for hydrogen produced offshore, spanning \$2.50 per kg H_2 to \$7.00 per kg H_2, is well above the current hydrogen costs (\$1.50 per kg H_2)[1,68] in a market dominated by grey hydrogen and future US targets[69] which have been announced in the range of \$1.00 per kg H_2. However, this projection aligns with other latest estimates for hydrogen produced using offshore wind[68] and with some estimates for green hydrogen produced on land, which take into account additional costs related to electrical grid or renewables connections, hydrogen storage, compression, and distribution and project an expected total green hydrogen cost of approximately \$3.00–7.00 per kg H_2 for a typical end-user.[70] More ambitious estimates of green hydrogen costs,[71–73] often below \$1.50 per kg H_2, have been reported, but they are likely to be contingent on specific conditions, including exemption from renewable connection charges, the absence of storage requirements, and immediate hydrogen utilization post-production, in addition to assumptions of substantial cost reductions and efficiency improvements in renewable energy generation and electrolysis.[70] Nevertheless, economic support measures for the production and uptake of green hydrogen is a key intervention that might be required to enable its adoption at scale.

Life cycle GHG emissions of offshore hydrogen at the shore

Fig. 6a and b show the life cycle GHG emissions at the coastal states for the state-based and hub-based configurations of the compressed gaseous hydrogen pipelines pathway. The emissions are further categorized by life cycle emissions generated from the construction and operation of each of the subsystems. The trends observed here closely mirror those of the delivered costs.

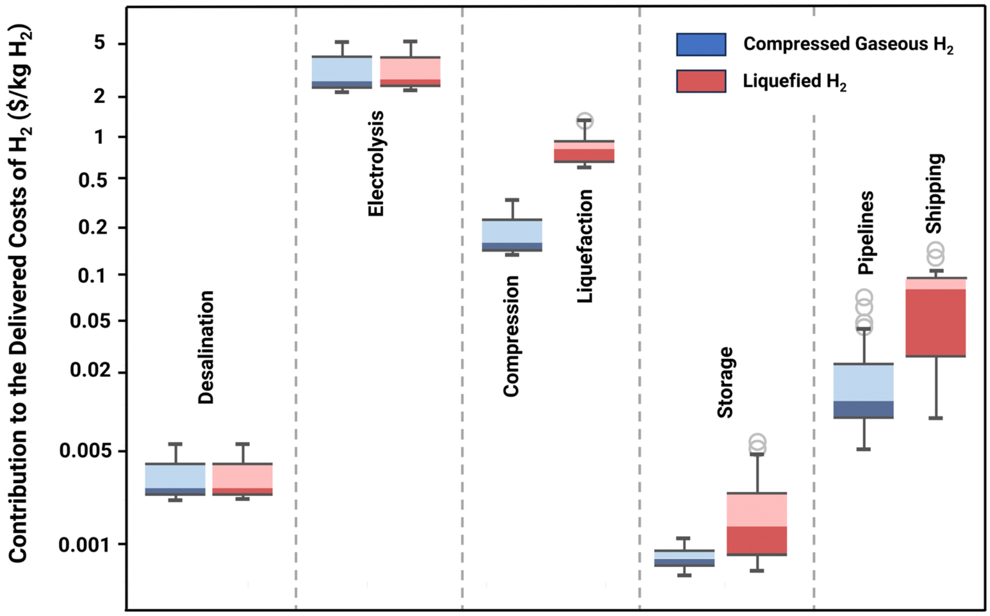

Fig. 5 Breakdown of the delivered costs of offshore hydrogen showing the range of contributions at the process level, accounting for energy costs from offshore wind based on consumption ratios. The costs of hydrogen production offshore are similar across both the pathways. The boxes show the dispersion of process costs across all the scenarios investigated, representing the minimum, maximum and median values. The Midstream costs associated with liquefaction, storage, and shipping lead to higher overall costs in the liquefied hydrogen shipping pathway with liquefaction emerging as the most expensive midstream process.

Facilities located in high-capacity factor regions exhibit higher capacity utilization rates, while those in low-capacity factor regions are often oversized, resulting in elevated material burdens and higher GHG emissions. States with the lowest GHG emissions include Alaska, Hawaii, Maine, North Carolina, and Virginia, while Indiana, Illinois, Ohio, and Pennsylvania top the list with the highest GHG emissions.

Fig. 6c and d focus on the liquefied hydrogen shipping pathway, displaying the distribution of life cycle GHG emissions for states under state-based and hub-based configurations. Notably, the states with the lowest GHG emissions include Maine, Delaware, and Rhode Island, while Texas, Louisiana, Ohio, New York, and Florida exhibit the highest GHG emissions. These trends also generally align with wind capacity factors, similar to the compressed gaseous hydrogen pathway, but deviations arise due to shipping, which contributes to higher emissions in specific states in the state-wise scenario. The hub-based approach, employing a mixed-fleet associated with the hub, mitigates these variances to some extent. However, states located farthest from the offshore facility within hubs still experience the highest GHG emissions, primarily due to higher transportation-related emissions.

Fig. 7 breaks down the percentage contributions of various process steps in the system to the life cycle GHG emissions of hydrogen. Similar to Fig. 5, these estimates are based on the re-distribution of the offshore wind farm's emissions to the energy consuming processes. Interestingly, it reveals that life cycle GHG emissions contribution of desalination, and midstream processes, such as compression/liquefaction, pipelines/shipping, and storage, account for only 5–7% of GHG emissions in the case of compressed gaseous hydrogen pipelines. In contrast, in the case of liquefied hydrogen shipping, midstream processes contribute significantly more, ranging from 16% to 81%. Particularly, operational emissions from transport powered by traditional fuels emerge as the largest contributor to the life cycle GHG of liquid hydrogen. Though this estimate has been obtained conservatively based on highly carbon-intensive fuels that are in use at present, in the future, the decarbonization of the maritime industry through the adoption of lower-carbon liquid or gaseous biofuels, e-fuels such as methanol, ammonia, or even hydrogen will bring reductions to shipping related emissions,[74] improving the overall environmental impact of the liquefied hydrogen shipping pathway substantially.

With attributional lifecycle GHG emissions ranging from 0.6 kg CO_2e per kg H_2 to 3.00 kg CO_2e per kg H_2, green hydrogen produced offshore is a substantially cleaner alternative to currently used grey hydrogen, which is estimated to have a well-to-gate GHG emissions of between 10–11 kg CO_2e per kg H_2 in USA.[75] However, another crucial finding established from this analysis is that the life cycle GHG emissions of hydrogen produced offshore and delivered onshore also remain well below the 4 kg CO_2e per kg H_2 benchmark set by the US Department of Energy for the well-to-gate GHG emissions of "clean" hydrogen through the clean hydrogen production standard (CHPS).[75] This signifies that green hydrogen produced offshore retains its environmentally friendly status even when considering additional burdens, such as those arising from transportation, emphasizing the decarbonization potential of green hydrogen produced offshore even in the face of transportation-related emissions.

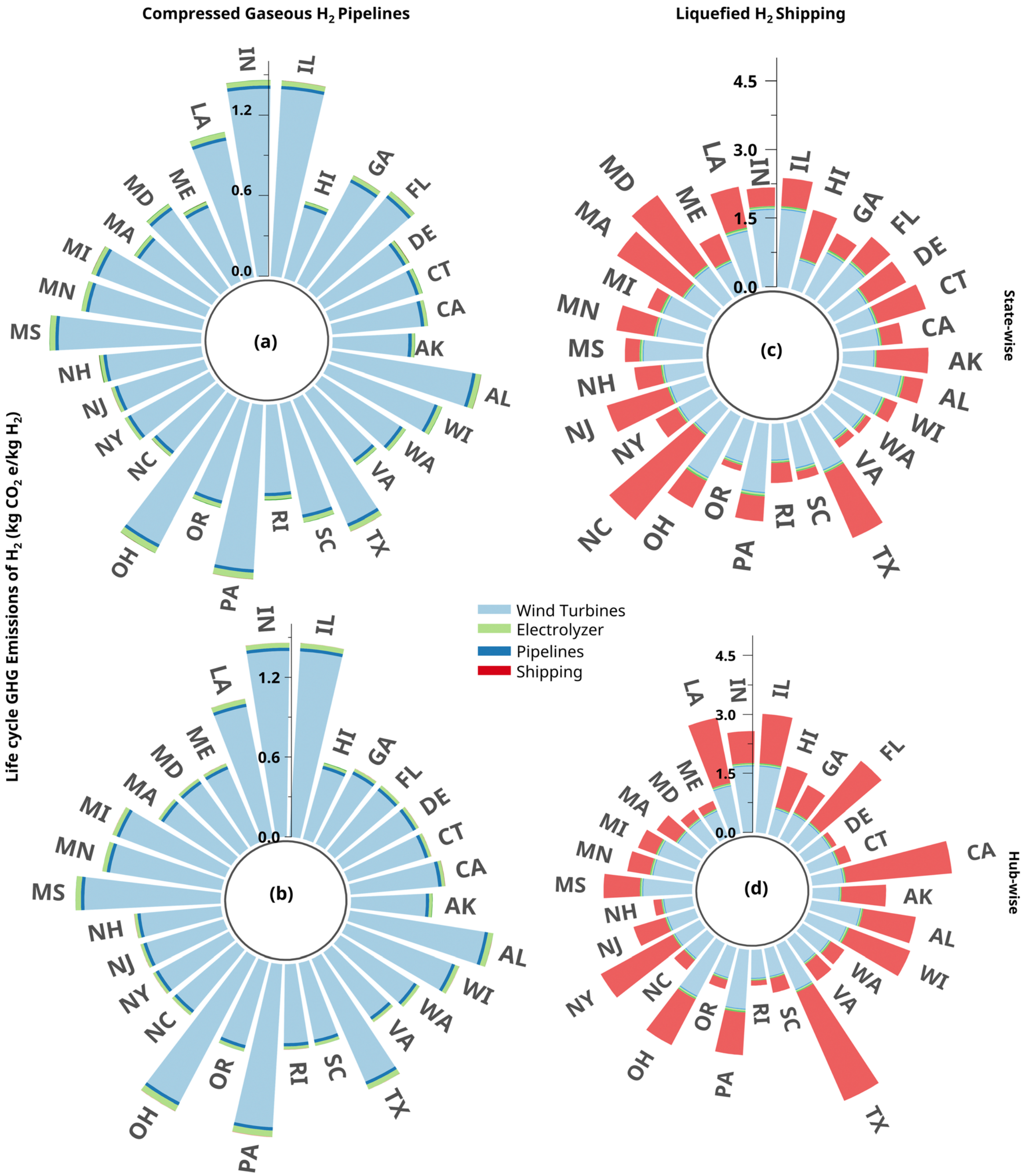

Fig. 6 The life cycle GHG emissions of green hydrogen for the coastal states based on the four cases investigated (a) state-wise and (b) hub-wise configurations of compressed gaseous hydrogen pipelines and (c) state-wise and (d) hub-wise configurations of liquefied hydrogen shipping. Emissions in the compressed gaseous hydrogen pipelines pathway range from 0.60 kg CO_2e per kg H_2 to \$1.50 kg CO_2e per kg H_2 and emissions in the liquefied hydrogen shipping pathway range from 0.97 kg CO_2e per kg H_2 to \$3.15 kg CO_2e per kg H_2. The legend shows the breakdown of total GHG emissions from construction and operation of each subsystem. The pipeline based compressed gaseous hydrogen pathway emerges to be environmentally favorable.

Regional offshore hydrogen hubs: costs and emissions trade-offs

Fig. 8 presents an overview of the delivered cost of hydrogen and the life cycle GHG emissions for all four scenarios, encapsulating the key findings from our previous analyses. Notably, states such as Florida, Georgia, New Hampshire, Maryland, and South Carolina experience significant cost reductions resulting from hub formation across both delivery pathways. Moreover, these states along with states such as Delaware, Connecticut, Rhode Island, Massachusetts, and New Jersey also witness reductions in the life cycle GHG emissions of hydrogen. The regionalization of facilities through hub formation emerges as

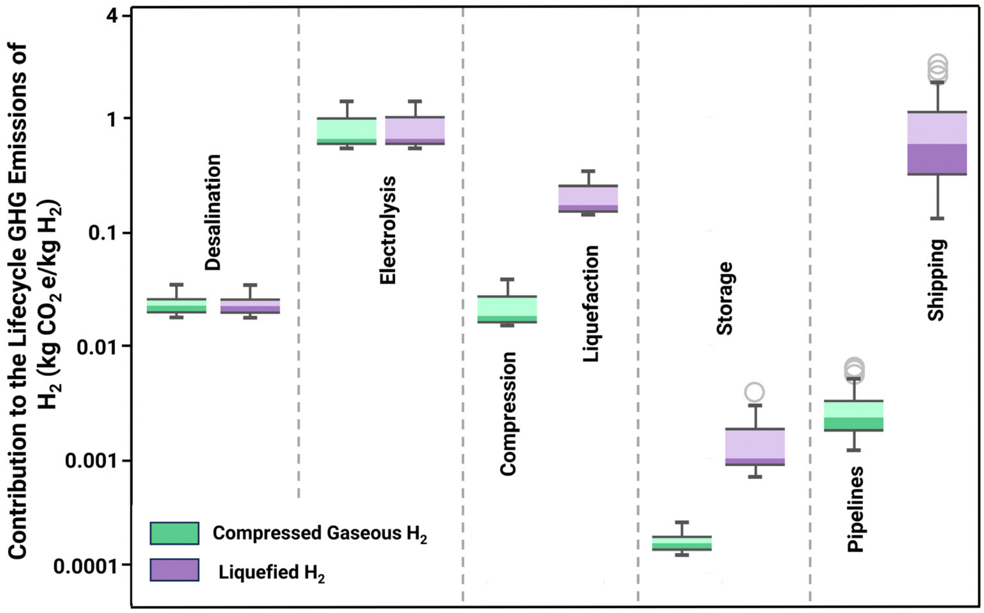

Fig. 7 Breakdown of the life cycle GHG emissions of offshore hydrogen showing the range of contributions at the process level, accounting for energy related emissions from offshore wind based on consumption ratios. The boxes show the dispersion of process costs across all the scenarios investigated, representing the minimum, maximum and median values. While midstream processes in the liquefied hydrogen shipping pathway generally exhibit higher emissions compared to their counterparts in the compressed gaseous hydrogen pipelines pathway, shipping powered by traditional fuels emerges as a major contributor, resulting in higher emissions overall in the liquefied hydrogen shipping pathway.

a strategy generally favorable for cost and GHG emissions reductions, with some exceptions, such as New York, California, Wisconsin, and Texas, where life cycle GHG emissions exhibit significant increases, particularly in the case of liquefied hydrogen shipping. Fig. 8i and j offers deeper insights into the factors contributing to these overall effects, visualizing the percentage change in costs and environmental impact at a more granular sub-system level to discern overall trends.

The trends observed in Fig. 8i and j indicate cost reductions in all hydrogen production aspects like wind turbines, desalination, compression, storage, and liquefaction for both the pathways. Increases are primarily observed in delivery costs due to extended transportation distances for some states from the centralized production facility of the hub. Despite increased distances in some cases, the costs of shipping consistently show a reduction due to shared fleet utilization. However, in instances such as New York, California, Wisconsin, and Texas, the overall life cycle GHG emissions show an increase. This increase can be attributed to higher shipping emissions which primarily stem from variations in fleet usage, such as the employment of smaller-sized ships leading to an increased number of round-trip movements thereby leading to higher emissions.

It is worth noting that the hub-based approach exerts a more pronounced influence on the liquefied hydrogen shipping as compared to the compressed gaseous hydrogen pipelines. This distinction is attributed to the impact of liquefaction costs and shipping emissions, which constitute a significant proportion of the costs and emissions associated with this pathway, respectively. The pooling of demand leads to a noticeable reduction in costs of liquefaction, which scales non-linearly, contributing to the cost reductions observed in the liquefied hydrogen shipping pathway. In the case of pipelines, the effects of hub formation are more constrained. Pipelines and compressors, whose costs do not scale linearly, still require capacity corresponding to the individual state's demand, even when hub formation is considered. As a result, the benefits derived from economies of scale are somewhat limited in this scenario.

Based on these observations, the benefits of hub formation can be summarized as follows: firstly, hub formation enhances scale of hydrogen production through demand pooling, delivering benefits from improved economies of scale. Secondly, it promotes the efficient utilization of shared infrastructure, leading to high levels of facility utilization and the distribution of common infrastructure costs across multiple states, and thirdly, it facilitates access to hydrogen produced from regions with superior wind resource quality, characterized by higher capacity factors, thus improving cost-effectiveness, especially for states with lower capacity factors.

In summary, these findings underscore the pivotal role of hub formation in optimizing the cost-efficiency of offshore wind-based green hydrogen production. While there are notable advantages in different scenarios and pathways, it is essential to consider the specific circumstances of each state to evaluate the extent of these benefits. Additionally, future research should investigate the synergies from hub-based configurations further. These analyses could evaluate the technical parameters such as the number of hubs and their sizes to determine optimal hub configurations, study more integrated architecture that includes further packing of hydrogen into its

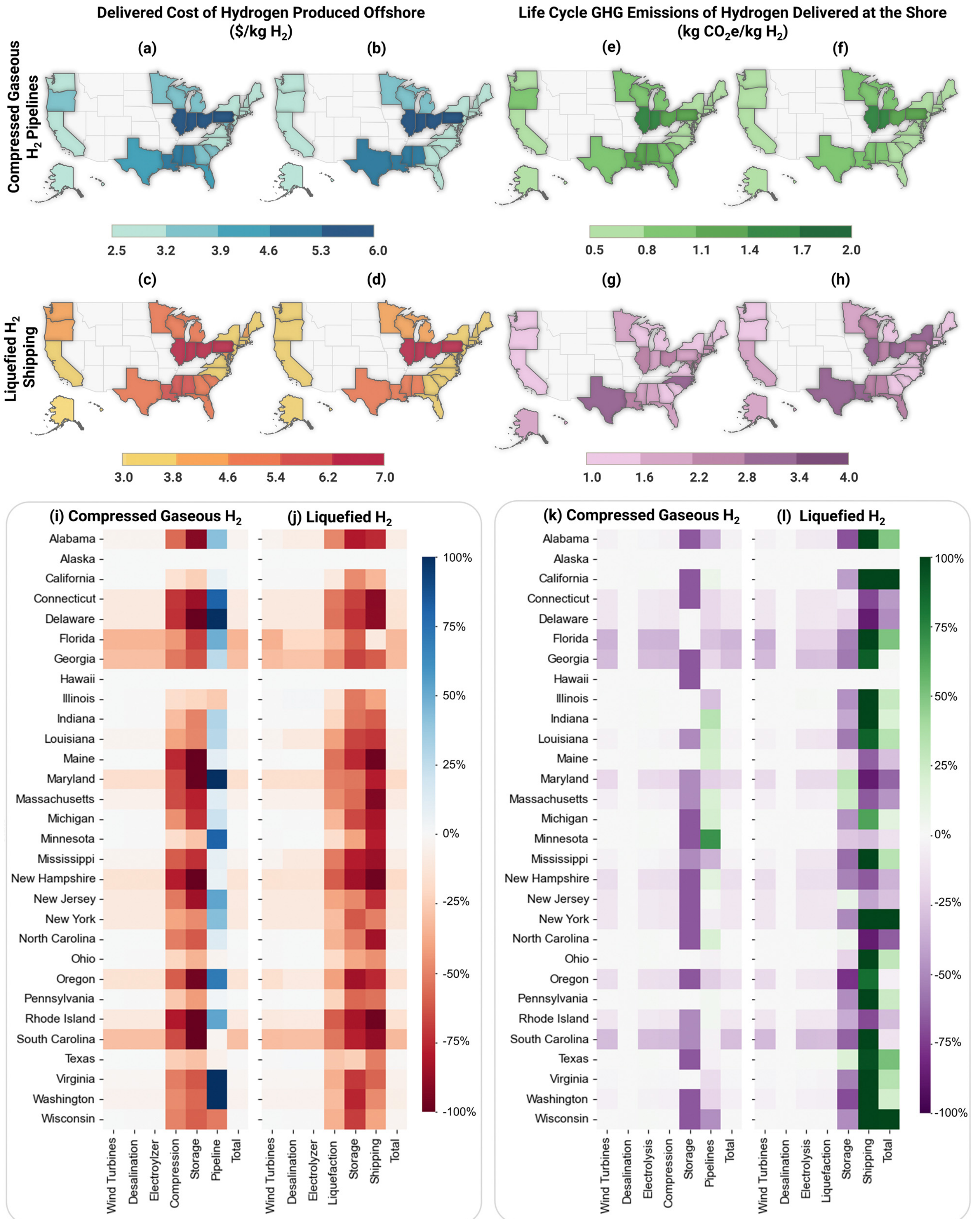

Fig. 8 The maps (a)–(d) illustrate the delivered costs and maps (e)–(h) illustrate the life cycle GHG emissions for the following cases: Statewise compressed gaseous hydrogen pipelines, hubwise compressed gaseous hydrogen pipelines, statewise liquefied hydrogen shipping and hubwise liquefied hydrogen shipping respectively. Comparative analysis of the four cases reveals key variations among coastal states and common trends emerging from hub formation in delivered costs and life cycle GHG emissions for the two delivery pathways. Percentage changes in the cost (i) and (j) and life cycle GHG emissions (k) and (l) contribution of the various steps as a result of hub formation for the two delivery pathways show the source of the variations arising from hub formation. All estimates are based on meeting the optimistic H_2 demands represented by the SCP.

carriers for drawing on synergies between domestic applications and export needs and delve into policy related implications of investing and operating facilities in a partnership composed of multiple states or even countries, in the context of Europe. Such analyses will greatly benefit the goal of advancing successful multi-regional partnerships cutting across various sectors of the economy.

Discussion

The key findings from this study can be summarized as follows:

• Meeting the serviceable consumption potential of hydrogen in coastal states of the US (75% of the national potential) entails installing 0.96 TW of offshore wind capacity, highlighting a green pathway to channel 22% of the nation's offshore wind resource potential towards deep-decarbonization applications.

• The hydrogen delivery pathway significantly influences midstream costs and GHG emissions associated with the transportation of hydrogen to onshore locations, with the cost-intensive liquefaction and emissions-intensive shipping of liquefied hydrogen accentuating the economic and environmental advantages of the compressed gaseous hydrogen pipeline-based approach.

• Regional hubs can demonstrate self-sufficiency in hydrogen production enabled by adequate offshore wind potential across the coastal regions; however, variability of the offshore wind capacity factors is a key factor leading to differentiation in costs and GHG emissions.

• Regional hubs with centralized hydrogen production offshore bring cost savings up to 30% through shared infrastructure, optimized facility siting, and economies of scale; however, longer transportation distances from centralized hubs may double GHG emissions for some states.

• The East coast emerges as a prime region of interest for offshore wind-based green hydrogen production, propelled by high capacity factors, significant regional demand, abundant surplus potential, and promising prospects for establishing export-oriented facilities to serve net-importers of hydrogen in European markets.

These findings underscore the synergies of integrating offshore wind and green hydrogen production in the United States. Meeting the serviceable consumption potential of hydrogen within coastal states offers significant growth potential for the offshore wind energy sector and also provides a sustainable pathway to incorporate green hydrogen into the country's hydrogen supply mix, reducing its longstanding dependence on fossil fuels. By fulfilling the demands of emerging decarbonization applications concentrated along the coast, this approach circumvents potential land and water use constraints associated with electrolytic green hydrogen production onshore. However, it is crucial to recognize that both offshore wind and the green hydrogen landscape in the US are still in their infancy. To fully realize their growth potential, supportive policies are essential.

A concrete effort to establish a robust and consistent supply chain, which includes domestic manufacturing of materials, equipment, and facilities, alongside the development of a skilled workforce to support these endeavors, is crucial. Such a localized supply chain can serve as a bedrock support system to safeguard against escalating costs related to materials, labor, and logistics, which have burdened numerous developers of offshore wind projects in the recent past.[76,77] At the same time, there are also opportunities to re-evaluate long-standing regulations. For instance, the Jones Act, established a century ago to protect the United States' maritime industry has already posed complications for offshore projects by requiring that ships that transport cargo between domestic points in the United States must be constructed locally and crewed by American citizens.[78] However, as recently as 2020, there were no US-flagged ships capable of performing specialized tasks such as assembling turbines miles out at sea.[79] Advocating for flexible policies to overcome such practical challenges while creating a nurturing ecosystem for the evolving industry is of paramount importance.

Our results emphasize a significant influence of location on the costs and environmental impacts associated with green hydrogen production offshore, highlighting the need for well-defined strategies to facilitate implementation. This location dependency is primarily attributed to the high contribution of offshore wind energy, which is significantly affected by capacity factors, to the delivered costs and life cycle GHG emissions of hydrogen. Future studies should further study the impact of offshore facility locations by focusing on the relationship between offshore wind speeds, distances from shore and water depths based on highly granular spatial data. While strategic siting optimizes capacity utilization and cost efficiency, it is observed that regions with strong conventional demand, such as the Gulf of Mexico, may face elevated costs. Conversely, regions with substantial potential, such as the East and West coasts, where a significant part of demand stems from newer decarbonization applications, may need technical and economic support from both the demand and supply sides to stimulate adoption and demonstrate readiness for large-scale commercial use. This is particularly important as offshore hydrogen production costs are anticipated to remain higher than some onshore alternatives due to the additional midstream costs involved. The introduction of economic support provisions, such as the production tax credits (PTC) under the Inflation Reduction Act (IRA),[80] is a notable step on the supply side. Due to low life cycle GHG emissions below the 4 kg CO_2e per kg H_2 benchmark, green hydrogen produced offshore qualifies for PTC under the IRA Act 45 V. This can help increase the market competitiveness, particularly if producers meet prevailing wage and apprenticeship requirements, qualifying them for the 5× multiplier offering up to \$3 per kg of clean H_2. In addition to the PTC, carbon pricing mechanisms may also become necessary to sustain competitiveness. On the demand side, it is important to stimulate green hydrogen uptake, especially for emerging applications. The establishment of long-term contracts for green hydrogen adoption, combined with technical and economic assistance to address the transitional challenges in new decarbonization applications can be a key demand side support. This can also offer the stability and predictability essential for investors and developers to expedite the development of regional-scale offshore hydrogen projects, fostering the creation of sustainable hydrogen value chains at scale.

Our analysis reaffirms the economic and environmental advantages of the compressed gaseous hydrogen pipeline approach over the liquefied hydrogen shipping approach for offshore green hydrogen transportation. However, accurate hydrogen demand projections are needed to design and build pipelines, considering the challenges associated with their scalability. A pipeline built too conservatively may fail to efficiently handle increasing demand, resulting in costly upgrades that could render it economically inefficient. Conversely, overestimating hydrogen demand and constructing a pipeline with excessive capacity escalates the cost per unit of hydrogen, affecting overall economic feasibility.[64] The viability of the pipeline approach also relies on the presence of extensive pipeline networks for inland hydrogen transportation. While the USA has 1600 miles of operational hydrogen pipelines, they are operated and used by a few major consumers such as petroleum refiners & chemical manufacturers and are concentrated within the Gulf Coast region.[81] In other regions where infrastructure is still scarce or in the early stages of rollout, the liquefied hydrogen shipping pathway can be an efficient alternative, offering seamless integration with liquefied hydrogen tankers for inland transport, and avoiding onshore liquefaction through energy obtained from partially decarbonized grids. Therefore, research and development efforts are necessary to enhance efficiency and reduce the costs associated with liquefied hydrogen production, particularly in scenarios where pipeline networks are underdeveloped.

It is imperative to consider future scenarios where hydrogen is expected to play a substantial role in global energy trade, with some estimates suggesting its prominence rising to 25% of the energy traded.[82] North America, including the United States, is a leading energy exporter, primarily driven by the trade of liquefied natural gas (LNG) for immediate substitution of coal and other polluting fuels. However, as decarbonization efforts continue to intensify, the need for carbon neutral fuels will shift the focus to vectors such as hydrogen, which can be expensive to produce in some regions of the world. By leveraging the strategic position of the East Coast, not only for integrating offshore green hydrogen into the US energy mix, but also for tapping into the surplus potential for hydrogen exports, the United States can drive economic growth, enhance global energy access and security, and contribute to a diversified and decarbonized energy landscape.

In conclusion, the findings from this study offer multiple insights into the synergies of offshore wind energy and green hydrogen production, capitalizing on channeling abundant offshore wind resources into a decarbonization vector for hard-to-abate sectors. The technologies enabling this integration, spanning offshore wind energy generation, electrolysis, and hydrogen delivery, have witnessed considerable progress, and are reasonably established with pilot-scale implementations of offshore wind to hydrogen systems having commenced recently. Undoubtedly, there are multiple opportunities for further advancements; however, the technological readiness and prospects for growth in these sectors emphasizes the crucial importance of well-informed policies and strategic investments in infrastructure, research, and development. These measures are crucial for unlocking the full potential of offshore wind-based hydrogen production, while also advancing the nation's energy transition and contributing to global decarbonization efforts.

Methods

Our approach to systematically analyze the economic and environmental consequences of offshore wind-based hydrogen production involves a comprehensive process that encompasses data collection, optimization-driven system design, life cycle assessment, and a multi-scale spatial analysis. We examine two distinct delivery pathways: liquefied hydrogen and compressed gaseous hydrogen, with a specific focus on the 30 coastal states of the United States, including those with a Great Lakes coast.

Initially, we model offshore wind resource data using offshore wind speed information. Subsequently, we obtain hydrogen demand at the state level, providing essential parameters for our optimization frameworks which are instrumental in designing the offshore wind to hydrogen systems for both the delivery pathways. Once we establish the design and operational characteristics *via* a least-cost optimization approach, we proceed to estimate the life cycle environmental impacts based on a cradle-to-gate life cycle assessment approach. This analysis is applied to all the coastal states and is further extended to the regional level by applying the same methodology to 7 hubs created based on geographical proximity. The subsections that follow provide a more detailed description of the methodology outlined above.

Offshore wind energy model

Given the intermittent nature of offshore wind as the primary renewable source, the actual power output varies with time and frequently falls short of the maximum design capacity. To address the time varying nature of energy generation, capacity factors for offshore wind turbines must be calculated to serve as indicators of offshore wind energy availability, with actual power output determined by multiplying the capacity factor and the corresponding nameplate capacity of the wind turbines. The IEA 15 MW offshore reference wind turbine[51] is chosen as the basis for this as it is an open-source benchmark developed for use in studies to closely reflect the trends of commercial models. Hourly wind speed data from the years 1973 to 2022 is obtained from the National Data Buoy Centre (NDBC) website[83] for around 200 locations in the US coast. The data was pre-processed to remove erroneous records and outliers. Subsequently, hourly average wind speeds were calculated across the years to eliminate inter-annual variability and used for the estimation of daily average capacity factors. As the wind speed (v_t^w) data is available at a measured height (h_m), they are adjusted for the hub height (h_t) of the IEA 15 MW offshore reference turbine[51] using the one-seventh power law as shown in eqn (1)[28]

$$v_t^{w,h_t} = v_t^{w,h_m} \cdot \left(\frac{h_t}{h_m}\right)^{\frac{1}{7}} \tag{1}$$

The following power curve is then used to determine the time varying capacity factor as per eqn (2).[84] The superscripts ci, co, r denote the cut-in speed, cut-off speed and rated speed of the IEA 15 MW offshore reference turbine.[51]

$$\mathrm{CF}_t = \begin{Bmatrix} 0 & v_t^w \le v^{w,\mathrm{ci}} \\ \left(\dfrac{{v_t^w}^3 - {v^{w,\mathrm{ci}}}^3}{{v^{w,r}}^3 - {v^{w,\mathrm{ci}}}^3}\right) & v^{w,\mathrm{ci}} \le v_t^w \le v^{w,r} \\ 1 & v^{w,r} \le v_t^w \le v^{w,\mathrm{co}} \\ 0 & v_t^w \ge v^{w,\mathrm{co}} \end{Bmatrix} \tag{2}$$

In addition to the daily capacity factors, yearly average capacity factors are also determined to be used as the basis to compare multiple prospective sites and select one candidate location per coastal state.

Hydrogen demand

Recognizing that the potential applications of hydrogen for decarbonization are evolving, and large-scale uptake in commercial forms is just beginning to emerge, this analysis five considers demand scenarios. Primarily, the state level demand data is obtained from the SCP of hydrogen as per the "H_2@Scale Concept: Hydrogen Demand and Resources" data release through the Open Energy Data Initiative (OEDI) for each state.[85] The SCP is an estimation of the market size, considering factors like current energy usage in society, geographical considerations, system performance. In the United States, the SCP of hydrogen is projected to reach 106 MMT per year in 2050 and is the most optimistic projection amongst the five demand scenarios considered. Within this potential market estimated by SCP, approximately half is allocated to various industrial processes, encompassing synthetic hydrocarbon production (14 MMT per year), metals refining (12 MMT per year), oil refining (7 MMT per year), ammonia production (4 MMT per year), and biofuels production (9 MMT per year). fuel cell electric vehicles (FCEVs) contribute substantially, accounting for 29 MMT per year, while the rest is dedicated to hydrogen's role in supporting other energy systems, including seasonal electricity storage (15 MMT per year) and integration into the natural gas infrastructure (16 MMT per year). While other potential applications may emerge, adding to increased demand or competition with technological alternatives such as batteries and heat pumps may erode demand in a few sectors, the SCP serves as an upper bound of the market size for hydrogen under optimistic conditions and is in line with other projections such as "Princeton Net Zero America"[86] and the "US Roadmap to a Hydrogen Economy" study.[87] The four additional demand scenarios for 2050 considered are as outlined in the US Department of Energy's 'Pathways of Commercial liftoff: Clean Hydrogen'.[4] Of these four scenarios, the low case (27 MMT per year), base case (50 MMT per year) and high case (50 MMT per year) are based on the US National Hydrogen Strategy Roadmap[5] and the spike case(80 MMT per year) is based on the McKinsey Global Energy Perspective.[4] Additional details are provided in the ESI,† (See Note S1).

Technology costs

The capital and operating costs of various process technologies involved in the subsystem design are obtained from various sources in the literature based on projections for the year 2050 and are used to derive the total annualized cost (TAC), which is the sum of the annualized CAPEX and annual OPEX costs for the planning horizon of one year. The annualized costs for all technologies were estimated using eqn (3) based on a discount rate of 8% where AC represents the annualized CAPEX costs, OTC represents the one-time cost of investment, d is the discount rate in percentage and L is the asset lifetime in years.

$$\mathrm{AC} = \left(\frac{\mathrm{OTC} \times d}{1 - (1+d)^{-L}}\right) \tag{3}$$

Optimal design of offshore wind to hydrogen facilities

In this study, the design of offshore wind to hydrogen systems is approached using an optimization-based framework. Within this framework, crucial decisions encompass both strategic choices, such as the selection of suitable facilities and sizing of subsystems, and operational decisions, including dynamic production scheduling to accommodate fluctuating wind speeds and efficient transportation planning. The use of such an optimization framework to facilitate techno-economic analysis is one of the key contributions of the study as it overcomes the limitations in previous analyses on offshore wind-based hydrogen production systems which are based on generic assumptions of facility and component sizes. Optimization is pivotal to address inherent tradeoffs in the design of offshore wind to hydrogen systems and is especially important to accommodate the following: the need for optimal facility location selection, the balance between on-site inventory and dispatch methods like pipelines or shipping, the consideration of fleet selection and utilization in the case of shipping, the nonlinear cost curves associated with technologies, and the variable nature of wind resources, which necessitates maximizing capacity utilization. In particular, due to the time-variant nature of the offshore wind resource, multi-time period modeling is adopted to integrate scheduling and design, to optimize capacity utilization across time periods in a bottom-up approach. As integration with electricity grids is not considered, a daily time resolution is used to model the variability in islanded hydrogen production.[88,89] The presentation of two separate models, one for each technology pathway, is chosen to provide comprehensive insights into the entire spectrum of data and facilitate a thorough analysis of the differences between both delivery modes, recognizing that both these offshore wind to hydrogen systems are emerging areas of interest. The core objective of these models is to determine the optimal capacity and daily operational profiles of all system components (*i.e.*, wind turbines, electrolyzers, *etc.*) with the overarching goal of minimizing the total cost associated with delivering hydrogen to the shore while accommodating various operational constraints.

Liquefied hydrogen shipping

In this pathway, the hydrogen produced offshore undergoes liquefaction at −253 °C and is subsequently transported using a mixed fleet of ships. The offshore facilities are assumed to be situated 100 km off the coast, near the midpoint of the US exclusive economic zone, allowing for a round trip travel time of approximately two days for ships, including loading and unloading. The optimization objective function is based on the total annualized CAPEX and annual OPEX cost for all the subsystems *viz.* offshore wind turbines, desalination, electrolysis, liquefaction, liquefied hydrogen storage, and shipping. Of note, the liquefaction cost is represented by a non-linear cost curve, capturing the economy of scale influence on liquefaction costs, and thus rendering the objective function non-linear, featuring a separable concave term. The overall structure of the problem P1 is shown below:

min	Total annualized costs	Eqn (S1)	
s.t.	Facility selection constraints	Eqn (S2)–(S9)	
	Capacity constraints	Eqn (S10)–(S13)	
	Energy balance constraints	Eqn (S14)–(S18)	
	Transportation constraints	Eqn (S19)–(S23)	
	Demand constraint	Eqn (S24)	(P1)

A key constraint pertains to facility selection, mandating the exclusive choice of a single facility from the available candidate locations for each state or hub, determined by a binary decision variable. Capacity constraints are in place to ensure that the capacity of each subsystem, measured in terms of flow rates or energy consumption, does not exceed the installed capacity within each time period. Energy balance constraints connect the unit energy consumption of all subsystems with their operating levels during each time period, ensuring that the total energy consumption remains equal to the energy generated at the same time period. Transportation scheduling constraints are essential for selecting a mixed fleet composed of three pre-defined sizes of ships. These constraints are designed to account for round-trip distances between the production facility and demand locations, thus optimizing fleet utilization. The decision variables corresponding to the transportation planning involve integer variables representing the number of ships selected, the number of dispatches of each ship type at each time period and the total number of trips for each type of ship. Inventory constraints describe the mass-balance relationships between the production, storage, and dispatch for each time period, maintaining consistency over time. Lastly, demand constraints ensure that the total production at a given facility aligns with the aggregated demand from all coastal locations it serves.

The detailed mathematical formulation of P1 is presented in the ESI,† (See Note S2).

Compressed gaseous hydrogen pipelines

In this pathway, hydrogen gas is compressed to 700 bar and transported *via* high pressure sub-surface pipelines to onshore sites. Such high-pressure pipelines have also been envisioned by the National Renewable Energy Lab for the HyLine system based on successful tests and use in Germany.[90] The offshore facilities are assumed to be located along the midpoint of the US exclusive economic zone, leading to offshore pipeline lengths of 100 km for each state. The goal of optimization is to minimize the total annualized CAPEX and annual OPEX across all subsystems *viz.*, offshore wind turbines, desalination, electrolysis, compression, compressed gas storage, and pipelines. Pipeline costs are represented by a non-linear cost curve, describing the relationship between pipeline diameter, length, and the costs. Additionally, the costs of compression and pumping are represented by non-linear cost curves that model the economy of scale. Thus, the objective function is non-linear, featuring both separable convex and non-convex terms. The overall structure of the problem P2 is shown below:

min	Total annualized costs	Eqn (S25)	
s.t.	Facility selection constraints	Eqn (S3)–(S5), (S26)–(S28)	
	Capacity constraints	Eqn (S10), (S11), (S13), (S29), (S30)	
	Energy balance constraints	Eqn (S16), (S17), (S31)–(S33)	
	Inventory and pipeline sizing constraints	Eqn (S34) and (S35)	
	Demand constraint	Eqn (S36)	(P2)

The constraints for facility selection, capacity and energy balance are of similar structure and significance of the previous model P1 discussed above. The notable changes are related to the delivery pathway. The maximum flowrate of hydrogen at each time is limited by the designed cross-sectional area of the pipe and the maximum permissible velocity of the gas, enabling the estimation of the pipeline diameter, which is a key decision variable for this pathway. As described earlier, the inventory constraints describe the mass-balance relationships between the production, storage, and dispatch for each time period, maintaining consistency over time and the demand constraints ensure that the total production at a given facility aligns with the aggregated demand from all coastal locations it serves.

The detailed mathematical formulation of P2 is presented in the ESI,† (See Note S3).

Solution approach for global optimization

The optimization problems originally formulated are non-convex mixed integer non-linear programs (MINLP), which are hard to solve to global optimality in a reasonable time frame using off-the-shelf solvers. Therefore, a tailored solution approach was adopted by recognizing that the non-linearity is solely due to the objective function and the non-convexity is due to the separable concave terms in the objective function. It has been demonstrated that MINLP problems with separable concave functions in the objective function can be effectively handled by a branch-and-refine algorithm.[91–93] Therefore, using the branch-and-refine method, the MINLPs solution challenge is addressed by sequentially solving a sequence of mixed integer linear programs (MILP) using piecewise linear approximators from the original MINLPs using the commercial solver Gurobi in about 60 s for 365-time steps to provide near global optimal solution within the pre-defined optimality tolerance.

Life cycle assessment

We perform a life cycle assessment to systematically evaluate the environmental impact of green hydrogen produced through an offshore wind-to-hydrogen system. In doing so, it is intended to understand the value proposition and competitiveness of hydrogen produced through this route as a green, renewable energy vector and commodity, contributing effectively to accelerate decarbonization.

The assessment encompasses the cradle-to-gate life cycle of hydrogen, from its production to delivery to the shore. Fig. 9 shows the system and process boundaries used for the life cycle assessment. The functional unit for analysis is set as 1 kg of hydrogen delivered to the shore. Given the limited external resource flows and emissions during the operational phase, the majority of environmental impacts stem from the project's initiation phase. Therefore, emissions from the project initiation phase are calculated and distributed across the entire project lifespan. The emissions from the project initiation phase include equipment manufacturing, subsystem construction, and installation for each of the sub-systems, while subsequent activities within the offshore hydrogen supply chain are considered operational emissions. Overall, the analysis encompasses the generation of wind energy through floating offshore wind turbines, seawater purification (desalination and deionization), gaseous hydrogen production *via* electrolysis, and the subsequent steps of liquefaction/compression, storage, and transportation *via* shipping or pipelines. Life cycle inventory data for the sub-systems and processes are sourced from existing literature. It is essential to highlight that all environmental consequences are attributed solely to the hydrogen produced, with oxygen, a by-product of electrolysis, not considered for commercial use. The life cycle assessment is

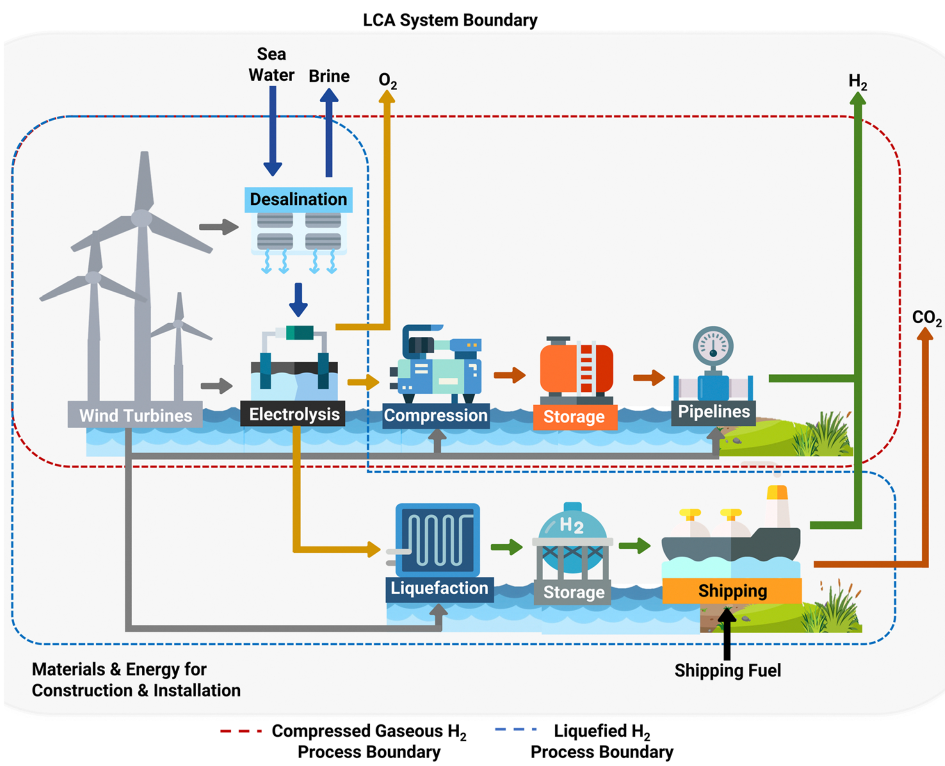

Fig. 9 The system boundary and process boundaries for compressed gaseous hydrogen pipelines and liquefied hydrogen shipping pathways used for the cradle-to-gate life cycle assessment of hydrogen produced offshore. This figure was designed using images from https://Flaticon.com.

conducted using OpenLCA 1.11.0 together with the ecoinvent 3.9.1 database. The life cycle impact assessment utilizes the ecoinvent – ReCiPe 2016 v1.03, midpoint (H) method, with a specific focus on the climate change and global warming potential (GWP100) impact category, which is most relevant to hydrogen related discussions in literature and policy.[75]

Multi-scale spatial analysis

To expedite hydrogen's use as a versatile, clean energy carrier aligning with broader clean energy goals, the US Department of Energy has initiated the promotion of localized clean hydrogen hubs.[54] These hubs encompass the complete hydrogen life cycle, spanning production, processing, delivery, storage, and eventual end-use. To investigate the impacts of extending this concept to offshore hydrogen hubs, the least-cost design and life cycle assessment-based analysis is applied to groups of states organized into 7 hubs based on the geographic proximity, as shown in Fig. 3. Consequently, the aforementioned analysis is employed across four distinct scenarios, as outlined below:

1. Statewise compressed gaseous hydrogen pipelines: in this scenario, individual states formulate autonomous infrastructure strategies to fulfill their SCP requirements, utilizing compressed gaseous hydrogen pipelines.

2. Hubwise compressed gaseous hydrogen pipelines: this scenario centers around the selection of a single site within each hub for the offshore wind-to-hydrogen production facility. This facility subsequently connects the remaining states within the hub through pipelines, following a hub-and-spoke model.

3. Statewise liquefied hydrogen shipping: states independently craft their infrastructure plans to meet SCP, with a primary focus on liquefied hydrogen shipping as the transportation method.

4. Hubwise liquefied hydrogen shipping: similar to the Hubwise compressed gaseous hydrogen pipelines scenario, this approach involves designating a central hub location for the offshore hydrogen production facility, which then connects the surrounding states *via* a shared fleet of ships, employing a hub-and-spoke model.

These scenarios represent diverse strategies that enable a comprehensive evaluation of the economic and environmental impacts of offshore hydrogen production. Results across these scenarios are summarized in Fig. 8a–h.

Data availability

Data supporting this article has been uploaded as part of the ESI.†

Author contributions

R. K. B and F. Y. contributed to the study design, data collection, data processing, analysis, and result interpretation. Both authors wrote, revised, and reviewed the manuscript.

Conflicts of interest

There are no conflicts to declare.

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