Energy 299 (2024) 131576

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

An assessment of current hydrogen supply chains in the Gulf Cooperation Council (GCC)

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ARTICLE INFO

Handling editor: Henrik Lund

Keywords:
GCC
Hydrogen
Supply chain
Optimisation
Energy transition
Renewables

ABSTRACT

The Gulf Cooperation Council (GCC), comprising: Saudi Arabia, United Arab Emirates, Kuwait, Qatar, Oman, and Bahrain, is home to an abundant number of resources, including natural gas and solar and wind energy (renewables). Because of this, the region is favourably positioned to become a significant player in both blue and green hydrogen production and their export. Current dependence on fossil fuels and ambitious national targets for decarbonisation have led the region and world to research the feasibility of switching to a hydrogen economy. This literature review critically examines the current advantages and strategies adopted by the GCC to expedite the implementation of hydrogen supply chains, as well as investigation into the methodologies employed in current research for the modelling and optimisation of hydrogen supply chains. Insight into these endeavours is critical for stakeholders to assess the inherent challenges and opportunities in establishing a sustainable hydrogen economy. Despite a substantial global effort, establishing a solid hydrogen supply chain presently faces various obstacles, including the costs of clean hydrogen production. Scaling-up storage and transport methods is an issue that affects all types of hydrogen, including carbon-intensive (grey) hydrogen. However, the current costs of green hydrogen production, mostly via the process of electrolysis, is a major obstacle hindering the widescale deployment of clean hydrogen. Research in this literature review found that compressed gas and cryogenic liquid options have the highest storage capacities for hydrogen of 39.2 and 70.9 kg/m3, respectively. Meanwhile, for hydrogen transportation, pipelines and cryogenic tankers are the most conventional and efficient options, with an efficiency of over 99 %. Cryogenic ships to carry liquid hydrogen also show potential due to their large storage capacities of 10,000 tonnes per shipment, However, costs per vessel are currently still very expensive, ranging between $ 465 and $620 million.

Abbreviations

GCC=Gulf Cooperation Council
MT=Million Tonnes
STP=Standard Temperature and Pressure
CCUS=Carbon Capture, Utilisation and Storage
SMR=Steam Methane Reforming
CSRE=Catalytic Steam Reforming of Ethanol
MTPA=Million Tonnes per Annum
GHGs=Greenhouse Gases
LOHCs=Liquid Organic Hydrogen Carriers
LH_2=Liquid Hydrogen
MOFs=Metal Organic Frameworks
AEM=Anion Exchange Membrane
PEM=Proton Exchange Membrane

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SOE=Solid Oxide Electrolysis
WGS=Water Gas Shift
PSA=Pressure Swing Adsorption
MILP=Mixed Integer Linear Programming
GIS=Geographic Information Systems

1. Introduction

Presently, 85 % of the world's total energy consumption is obtained from fossil fuels, namely natural gas, oil, and coal [1]. The release of GHG emissions from the combustion of these energy sources, especially

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https://doi.org/10.1016/j.energy.2024.131576
Received 12 February 2024; Received in revised form 26 April 2024; Accepted 5 May 2024
Available online 6 May 2024
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CO_2, which is reputed for its adverse environmental impacts, is influencing a global effort to obtain energy from different sources. This urgency is causing a universal shift towards renewables as energy sources-particularly solar and wind. This is to accelerate the electrification of the transport and heat sectors, which is deemed one of the most critical components of the global energy transition [2]. Policymakers worldwide are also implementing acts and targets to expedite progress towards the adoption of clean energy.

As a result of this, hydrogen has in recent years become a very attractive candidate for achieving a zero-carbon future. The current global demand for hydrogen stands at approximately 90 million tonnes per year, but according to reports [1], in a net-zero scenario, hydrogen demand will need to reach 530 to 810 million tonnes (MT) per year to accommodate global needs. 20–40 % of this hydrogen is expected to be blue, while the remaining hydrogen will come from green energy sources [3–5]. 'Grey' hydrogen, which is presently the world's most abundant, is mainly produced via the process of steam methane reforming (SMR), utilising fossil fuels such as natural gas. This method releases between 8 and 12 kg of CO_2 per kg of hydrogen produced as a by-product into the atmosphere [6], contributing largely to the carbon footprint associated with hydrogen production. 'Blue' hydrogen also describes hydrogen produced via SMR, however this method integrates Carbon Capture, Utilisation and Storage (CCUS) technologies within the SMR process. CCUS facilitates the capture and sequestration of CO_2 emissions generated during hydrogen production, mitigating some of the environmental impact associated with grey hydrogen. 'Green' hydrogen describes hydrogen produced entirely via renewable energy sources, such as solar power, and uses mostly electrolysis technologies to split water into hydrogen and oxygen. This method produces hydrogen without generating carbon emissions, positioning green hydrogen as the front-runner to zero-emission fuels. Current developments in specific types of electrolysis however, such as redox water splitting, also show promising potential for the production of green hydrogen [7]. In this method, like electrolysis, water is directly split into hydrogen using electricity, without any direct emissions of CO_2. Unlike electrolysis however, redox water splitting involves two half-reactions (oxidation and reduction) occurring simultaneously in separate compartments of an electrochemical cell [7]. Oxidation occurs in one compartment where water is oxidised to produce oxygen gas and protons, while reduction occurs in the other compartment where protons are reduced to produce hydrogen gas, resulting in an overall redox reaction that splits water into H_2 and O_2 [7]. Deng et al. [8] also determined the possibility of green hydrogen being produced via the catalytic steam reforming of ethanol (CSRE), with this method achieving a maximum hydrogen yield of over 95 % [8]. This method has shown vast potential to reduce the cost of hydrogen production, where the study [8] concluded that the cost of hydrogen produced via CSRE was ~ \$3/kg-H_2, compared to the ~ \$6–8/kg-H_2 costs in current electrolytic hydrogen production. Despite this potential however, this method faces challenges in the GCC region, due to the limited agricultural resources available and heavy reliance on desalination [9].

In accordance with the Paris Agreement of 2015, several countries have set ambitious targets towards decarbonisation, with many of them involving renewable energy deployment [10]. Renewable deployment is considered the primary catalyst towards the electrification of transport and heat – i.e. total 'net-zero'- which many countries aim to commence around 2030 and fully achieve from 2050 onwards [11,12]. In a net-zero scenario, total blue and green hydrogen use would equate to about 10–20 % of global energy demand [13]. However, a question that arises in this case is how much should be green and how much blue. According to Durakovic et al. [14], the choice between green and blue hydrogen has a substantial impact on cost, particularly between now and 2030. Their study examined the coexistence between blue and green hydrogen in Europe and concluded that too early a deployment of green hydrogen (i.e. between now and 2030), leads to higher hydrogen costs, and that blue hydrogen is more favourable in the short term due to being able to produce hydrogen at a much lower cost. Results from their study determined that in 2030, the cost of hydrogen is reduced by more than 55 % in a case where blue hydrogen is also utilised, as opposed to only green. Whereas, in the long term (~2050), green and blue hydrogen are able to coexist without negatively influencing one another. However, in Ref. [15], it was concluded that government subsidies for renewable energy deployment can significantly reduce the cost of green hydrogen production.

Out of the current annual hydrogen demand of 90 million tonnes, the main consumption comes from the refineries sector, which account for approximately 45 % of global use. Ammonia for fertilisers constitutes ~38 % of hydrogen use, and methanol ~12.5 %. In 2020, 0.3 MT of total hydrogen demand in these sectors was satisfied with low-carbon hydrogen, mainly due to hydrogen plants integrated with CCUS units, as well as electrolysis units in the chemical sector [16]. Although not a significant amount, this represented an almost 20 % increase in low-carbon hydrogen production compared to 2019.

Hydrogen as an energy carrier has been a topic of discussion for some time. Because it can be generated from both renewable and non-renewable energy sources, the prospect of hydrogen as an energy carrier is very promising in current literature [17]. Aside from its generation from both renewable and non-renewable sources, hydrogen possesses various other advantageous characteristics that have drawn attention to it as a potential energy carrier. First, at STP conditions, hydrogen has a low density of approx. 0.09 g/L [18]. This shows promise for hydrogen fuel, as due to the lower density, less space may be required to transport or store the same volume of hydrogen compared to gasoline or other fuels. Second, hydrogen is the most abundant gaseous element in the world, accounting for more than 90 % of the world's total [18]. Although abundant, however, the problem lies in that the abundance does not lie within hydrogen in its gaseous state, but instead combined with water and other hydrocarbons. Hydrogen is also environmentally friendly and sustainable, which makes it advantageous from the point of view of decarbonisation targets. Other notable advantages include hydrogen's high energy density, which is double that of conventional fossil fuels, and its versatility: hydrogen can be stored as a fuel to be used in various energy sectors to produce heat, power, and electricity, or it can be used as feedstock for various industrial processes, such as the synthesis of ammonia.

Several research papers [13,16,17] have analysed hydrogen's potential as an energy carrier. A common feature of all of them was the issue of hydrogen storage being one of the main limitations towards the establishment of a hydrogen supply chain. Based on the current literature, compressed gas and cryogenic liquid options have the highest storage capacities for hydrogen of 39.2 and 70.9 kg/m3, respectively [17]. However, these methods present safety concerns due to the high flammability of hydrogen. Metal Organic Frameworks (MOFs) present safer hydrogen storage option, but research on these materials is presently still very limited. For hydrogen transportation, pipelines and cryogenic tankers are the most conventional and efficient options, with an efficiency of over 99 %. Cryogenic ships to carry liquid hydrogen are also promising due to their large storage capacities of 10,000 tonnes per shipment [17]. However, these again present safety concerns due to the high risk of spillages, which can have adverse environmental effects. Additionally, the costs per vessel range between \$ 465 and \$620 million, making them an unattractive investment for stakeholders [17].

Considering the entire supply chain, several papers [18–21] have analysed the value of the hydrogen chain from all parameters, namely hydrogen production, storage, transportation, and end-uses. The papers have also addressed the challenges regarding the feasibility of a hydrogen economy, which again emphasised storage as a crucial issue. Usman [18] and Ratnakar et al. [13] specifically highlighted that the challenges are more associated with large-scale liquid hydrogen (LH_2) storage and transport, rather than hydrogen as an entire entity [12]. Abohamzeh et al. [14] and Abdalla et al. [15] addressed the hydrogen supply chain while also considering the safety challenges associated with hydrogen storage, transportation, and end-use applications. These studies also identified current developments in all these parameters, including the techno-economic barriers hindering the commercialisation of hydrogen.

For the GCC specifically, the region has vast comparative advantages, particularly abundance in solar energy and natural gas reserves to be able to shift towards blue and green hydrogen technologies. Wind speed is not as abundant in the region as compared to global benchmarks. However, Oman possesses average wind speed values between 11 and 16 m s^{-1} making it a suitable contender for wind energy developments. Alharbi and Csala [22] evaluated the GCC's resources and concluded the following: Oman has the highest regional annual solar radiation of up to 2500 kWh/m^2; United Arab Emirates (UAE) has the second highest annual solar radiation at 2285 kWh/m^2 and Kuwait and Saudi Arabia have equal annual solar radiations at 2200 kWh/m^2 [23]. Annual global average solar radiation ranges between 640 and 2400 kWh/m^2 [24], so the region lies among the highest globally for solar radiation. This presents various opportunities for green hydrogen development in the region, mainly from solar energy but also from wind in Oman's case. In implementing strategies to exploit their natural resources, the region has the ability to accelerate the transition towards a low-carbon economy. Policymakers in the region have also declared ambitious decarbonisation targets for the transition towards low-carbon supply chains. According to Khan and Al-Ghamdi [16], GCC decarbonisation targets are as follows: Saudi Arabia and Bahrain are aiming for total net-zero by 2060, UAE and Oman are aiming for total net-zero by 2050, Qatar is aiming for a 25 % reduction in emissions by 2035 and Kuwait is aiming for a 7.4 % reduction in emissions by 2035. Aside from their natural comparative advantage in terms of resources, the imposition of these targets is also steering the need towards an economy where energy and fuel generation is low-carbon and clean.

As is the case for all current global hydrogen supply chains, the challenge for a GCC supply chain lies within techno-economic, safety, and social aspects. To model this, research [25,26] concluded that simulating supply chains combined with optimisation has proven to be an effective method of identifying optimal combinations of feedstock, transportation and biorefineries prior to the construction of the plants. However, this model was conducted for fuel production via biomass, rather than solar and wind energy. The modelling of hydrogen supply chains in the current literature is reviewed in greater detail in Section 4.

An optimal hydrogen value chain for the GCC requires the careful evaluation of feedstock, production technologies, storage options, transportation routes, and end-user applications. Policy intervention and national strategies to accelerate the implementation of clean hydrogen also need to be assessed.

The rest of this review paper is structured as follows: Section 2 provides a literature review of the GCC's current approach to hydrogen in terms of resources, strategy, investment, and policy intervention; Section 3 discusses the region's current hydrogen supply chain and its limitations; Section 4 discusses the models being used to optimise present clean hydrogen supply chains and Section 5 discusses hydrogen's future and challenges.

2. The GCC's potential and approach to hydrogen

As this review paper is intended to assess all aspects of a hydrogen economy, this section covers the comparative advantages in terms of resources, technologies, and strategies that the GCC region has implemented or is in the process of implementing. The GCC is one of the world's largest suppliers of oil and gas, holding approximately one-third of global oil reserves and one-fifth of the world's natural gas reserves [27]. Steam-methane reforming is currently the most utilised method for grey hydrogen production, both globally and regionally. SMR is the favoured due to its high efficiency of 74 % and low hydrogen cost of ~ $2/kg-H2. Electrolysis on the other hand, has an efficiency of 60 % and a higher cost of ~$10/kg-H2. As such, significant research and development is required for this method of hydrogen production to become more commercially competitive. The petrochemical industry accounts for most of the grey hydrogen produced via SMR in the region, with an annual production of ~10 MTPA [28]. However, in recent in years the adoption of CCUS technologies has aided in a significant reduction of carbon emissions in the SMR process. Alternative methods for hydrogen production include using renewable sources to produce green hydrogen using water electrolysis or biomass gasification. Due to their abundance in renewables and natural gas, the region has the potential to produce both blue and green hydrogen at competitive rates. National strategies in Saudi Arabia and Qatar are already aiming to use these advantages effectively to achieve low-carbon hydrogen [29,30].

Aside from the technologies, higher funding availability in the region and alignment with national diversification strategies are positively contributing to the transition towards clean energy. GCC countries are committed towards allocating investment towards projects that will aid in accelerating the deployment of clean energy. These are presented in Table 1 below.

These high investments can be credited to GCC countries' substantial financial reserves from their oil and gas economies, which are often steered by national sovereign funds, such as the Saudi Public Investment Fund (PIF) and Abu Dhabi Investment Authority (ADIA). This is advantageous because it means that the allocation of these funds is guided by the primary policymakers in the country. When policies such as clean energy are classed as a crucial national target, the amount of financial investment going into the deployment of clean energy will be sufficient to accelerate its progression. Because there is a national alignment between the amount of investment that goes into a project or technology and the associated policies or strategies, this can lead to a more rapid advancement of projects or novel technologies. For example, Saudi Arabia's $186.5 billion plans for renewable energy complements the government's plan to transition 50 % of its domestic energy supply to renewable sources by 2030 [37]. This harmonisation between the availability of high cash reserves and the associated policies advocating clean energy can lead to a significant acceleration in regional hydrogen developments. Policies and strategies can also help to exploit the region's inherited comparative advantages for hydrogen. Not only can this again accelerate progress, but beneficial policies can also maximise the use of already available resources which can lead to a greater quantity of the clean energy produced. Regional policymakers are implementing various action plans to facilitate a GCC transition towards clean energy (Table 2).

The complementarity between the GCC's abundance in resources and the associated investments and strategies position the region, from an economic perspective, in a very favourable position to be able to foster an entire clean hydrogen supply chain.

3. The current hydrogen supply chain

When compared to other global players, the GCC has already

Table 1
GCC clean energy investments.

GCC Country	Clean Energy Investment	
Saudi Arabia	$ 186.5 billion planned in renewable energy (production and distribution) projects by 2030.	[31]
United Arab Emirates	$ 63 billion investment towards clean and renewable energy sources by 2050.	[32]
Qatar	$ 1 billion ammonia-to-hydrogen plant announced in 2022.	[33]
Oman	$ 20 billion worth of hydrogen agreements signed in 2023.	[34]
Kuwait	$ 6.3 billion worth of ongoing clean energy projects underway in 2022.	[35]
Bahrain	In 2023, signed deals to construct a 72-MW solar park that will include rooftop and ground-mounted solar power systems and EV charging stations.	[36]

Table 2
GCC clean energy policies and strategies.

GCC Country	Clean Energy Policies/Strategies	
Saudi Arabia	Plans to generate 50 % of electricity from renewables and 50 % from gas by 2030. Saudi Arabia is undertaking various projects to accelerate this transition, such as: Sudair solar PV plant: this plant is projected to be one of the largest global solar PV plants with an installed capacity of 1500 MW, capable of powering 185,000 homes and offsetting nearly 2.9 MT of emissions annually. NEOM green hydrogen facility: commencing operations in 2026, the plant will produce 660 tonnes per day of green hydrogen, the equivalent of current total annual global production.	[37]
United Arab Emirates	National green hydrogen strategy: The UAE is targeting a production of 1.4 million tonnes per annum of low-emission hydrogen by 2031, with 71.4 % being green hydrogen. By 2050, the UAE aims to scale up this production tenfold, reaching 15 million tonnes per annum. This hydrogen strategy also includes a hydrogen infrastructure expansion: The UAE is planning the establishment of two hydrogen oases (hubs) and a hydrogen centre for R&D by 2031. By 2050, the UAE aims to transform the establishment into globally renowned innovation centre.	[38]
Qatar	The Qatar National Vision aims to generate 20 % of electricity from renewable energy sources by 2030 by means of solar PV projects with an 800 MW capacity.	[39]
Oman	Oman's national energy strategy aims to derive at least 30 % of electricity from renewables by 2030. To achieve this, Oman has embarked on various projects, including: a wind farm in Dhofar; two solar IPPs in Manah; 11 solar-diesel hybrid facilities; and the 'Sahim' initiative to install small-scale solar panels on residential and commercial buildings, among others.	[40]
Kuwait	Kuwait is aiming to produce 15 % of its power supply, estimated at around 4.5 GW, from renewable energy by 2030. By 2035, Kuwait plans to reduce its carbon emissions by 7.4 % by 2035 (in a business-*as*-usual scenario). Kuwait plans to do this by harnessing its renewable energy potential, reducing electricity demand through higher efficiencies, switching from oil to more natural gas use, and using CCUS technologies.	[41]
Bahrain	Bahrain has set national energy efficiency and renewable energy 2025 targets at 6 % and 5 %. Bahrain aims to increase this target to 10 % by 2035. Bahrain has ventured into various national solar projects to help achieve these targets. These projects include: 100 MW of renewable power from Askar landfill; a 50 MW initiative to install solar panels on the roofs of hundreds of state-owned buildings and the potential installation of "floating solar" technologies to be deployed for power generation in Bahrain's territorial waters to address the issue of land scarcity for larger solar farms.	[42]

extensively catalysed the deployment of clean hydrogen. In 2020 for example, Saudi Arabia exported the first shipment of 'blue' ammonia (ammonia produced via carbon capture, utilisation, and storage) to Japan.

[43]. For the GCC, another advantage is that much of their oil and gas infrastructure can be utilised for hydrogen production [44,45].

3.1. Production

Globally, the most utilised method for hydrogen production is steam methane reforming, followed by electrolysis. SMR involves the catalytic conversion of a hydrocarbon and steam into hydrogen and carbon oxides and requires three crucial steps: reforming feedstock, water-gas shift (WGS) and methanation or gas purification. The feedstock used in SMR is mainly either methane or natural gas but can include other methane containing gases through various combinations of light hydrocarbons, such as propane, butane, pentane, and light and heavy naphtha [46]. To produce the desired purified hydrogen product and prevent the formation of coke on the catalyst surface, the operational parameters of reforming are selected at high temperatures, pressures up to 3.5 MPa and a steam-to-carbon ratio of 3.5 [47]. Following the reformer, the gas mixture passes through a heat recovery step and is fed into a WGS reactor, where the CO reacts with steam to produce additional hydrogen. The mixture then passes either through CO_2-removal and methanation, or through a pressure swing adsorption (PSA) that leaves hydrogen with a higher purity of near 100 %. Presently, almost all global hydrogen demand (~97 %) is produced via SMR, due to its low cost and high efficiency [48,49]. However, this process generates 'grey' hydrogen, which emits a significant amount of CO_2 emissions into atmosphere (9 kg of CO_2 is generated for every kg of hydrogen produced using SMR) [50]. This significant emission limits hydrogen's ability to be classed as 'clean'. As such, there has been growing interest in capturing CO_2 from these SMR plants to create low emission 'blue' hydrogen [51,52].

According to Damen et al. [53], CO_2 emissions can be significantly reduced by means of Carbon Capture, Utilisation, and Storage (CCUS), through which CO_2 is captured and either re-utilised or injected into storage sites such as geological reservoirs or the ocean. This method can accelerate the transition towards blue hydrogen. However, carbon capture processes are currently still capital-intensive, and do not yet operate at the required levels to be able to compete with grey hydrogen in terms of costs and process efficiency [54,55].

'Green' hydrogen, on the other hand describes an entirely environmentally friendly category of hydrogen which is produced primarily via water electrolysis. Here, an electric current is used to split water into hydrogen and oxygen with no emission of GHGs, so long as the electricity used to power the process stems entirely from renewables [56]. In electrolysis, surplus electricity generated from renewable energy sources, i.e., solar and wind, can also be utilised for the electrolysis, which produces green hydrogen. Pure hydrogen is produced at the cathode and is separated from water and oxygen. Because of its zero-emissions nature, electrolysis is the favoured candidate for clean hydrogen production. There are four main types of water electrolysis technologies, namely: (i) Alkaline water electrolysis, (ii) Anion exchange membrane (AEM) water electrolysis, (iii) Solid oxide water electrolysis (SOE), and (iv) Proton exchange membrane (PEM) water electrolysis. These methods differ based on the electrolyte used, operating conditions, and ionic agents. In all cases, electrolysis requires substantial electrical energy (~40 kWh per kg of H_2) and has a maximum efficiency of 73 % [57]. However, the issue with electrolysis is that in all four technologies, for every advantage there lies a greater counterpart challenge.

3.1.1. Alkaline water electrolysis

Alkaline water electrolysis is a well-established technology for industrial hydrogen production, reaching up to 2.2 MW in commercial applications globally [58]. It is a highly favoured system for large-scale hydrogen production, particularly due to the investment cost ranging between USD 500–1000/kW, which is competitive with SMR [59]. However, the major challenge associated with alkaline water electrolysis is that it operates at limited densities, and the corrosive KOH electrolyte used in this method reacts with external CO_2, which produces low purity hydrogen.

3.1.2. AEM

Anion exchange membrane water electrolysis works similarly to conventional alkaline water electrolysis [60]. However, the primary difference lies in the ionic agent used. The main advantage of AEM water electrolysis is that cost-effective and abundant transition metal catalysts are used instead of noble metal catalysts. Despite this, AEM is an emerging technology for green hydrogen production, and it still requires substantial R&D to become stable, efficient, and commercialised [61–63].

3.1.3. SOE

Solid oxide water electrolysis involves the conversion of electrical energy into chemical energy, and typically operates with water (steam) at high temperatures between 500 and 850 °C. The fact it operates at high temperatures dramatically reduces the power required to split the water into hydrogen and oxygen, which in turn increases energy efficiency. This improvement in energy efficiency can lead to a strong reduction in hydrogen production cost, due to power consumption being the main cost in electrolysis [64]. The high operating temperatures also increase conversion efficiency, making SOE more favourable. Another advantage of SOE, which is particularly beneficial for the GCC, is that SOE is easily integrable with the downstream chemical industry, one of the region's most prominent. Specifically, SOE can be integrated into the production of ammonia, methanol, and dimethyl ether [61,65]. Furthermore, SOE does not require the use of noble metal electrocatalysts, which aside from high operating temperatures is another factor that allows for high conversion efficiency. However, SOE technology is still not sufficiently stable long-term to be commercialised.

3.1.4. PEM

Proton exchange membrane water electrolysis works in a similar manner to the PEM fuel cell technology being developed for green hydrogen end-use. Here, the sulfonated polymer membrane can be used as an electrolyte. PEM water electrolysis operates at low temperatures (30–80 °C) and high densities (1–2 A/cm^2) and produces 99.99 % high purity hydrogen [66]. PEM is also advantageous because it is safer than other electrolysis technologies and works faster due to the highly active area of the metal surface of Pt electrodes and lower pH of the electrolyte. However, a major challenge preventing the widescale implementation of PEM technology is the high cost of the various components, namely the electrode materials, current collectors, and bipolar plates [67].

3.2. Transport and storage

Aside from production, the future of a hydrogen supply chain depends on determining a safe and feasible system for hydrogen transport and storage [68]. Current literature has proposed various options for hydrogen transport, namely: (i) Liquid Organic Hydrogen Carriers (LOHCs) for both transport and storage, (ii) compressed hydrogen storage in salt caverns combined with pipelines, (iii) compressed hydrogen gas transported via trucks, and (iv) cryogenic hydrogen storage. As is the case with production, each hydrogen transport and storage method still faces challenges which do not yet allow for widescale deployment.

3.2.1. LOHCs

Liquid Organic Hydrogen Carriers describe a technology where hydrogen is chemically bonded to a stable hydrogen organic liquid carrier, which eliminates the need for compression [66]. This makes it a safe, practical, and more cost-efficient method to transport hydrogen. However, various reports [69–71] have concluded that LOHC transport is the least favourable from an environmental and ozone depletion perspective.

Despite being the most economically favourable hydrogen transport option for short distances, LOHCs have higher environmental impacts than pressurised gas, especially in the case of low hydrogen demand and high transport distance [72].

3.2.2. Compressed hydrogen

Compressed hydrogen storage is the most established hydrogen storage technology and involves the physical storage of compressed hydrogen gas in high-pressure vessels. Hydrogen is typically produced at relatively low pressures (20–30 bar) [73]. As such, it must be compressed prior to transport or storage. Because of its density <0.1 g/L, hydrogen needs to be compressed before it can be stored. The most economically feasible method of densifying the hydrogen is by compressing it at high pressure (between 180 and 900 bar) for storage or transport [73]. Following compression, the hydrogen can then be transported or stored.

3.2.3. Salt caverns

Salt caverns are formed out of existing salt bed deposits, and these can be utilised as storage vessels. For the GCC, this is particularly advantageous as salt caverns work best on flat desert land and can also be made in depleted oil and gas reservoirs [74,75]. The cavern is made by drilling a well down into the formation, where water is pumped through the well to dissolve the salt [76]. For hydrogen storage, this presents various advantages, namely, the walls of the cavern are resilient against reservoir degradation, which increases the longevity of the salt cavern as a storage system. Salt caverns are also open vessels, meaning they offer very high deliverability and flow rates [77]. The issue, however, is that salt caverns are not suited for long term seasonal storage, due to hydrogen leakage losses caused by unsuitable salt cavern permeability and biochemical reactions in the case of oil and gas reservoirs. According to existing studies, the interlayer permeability of a salt cavern must be greater than 10−17 m^2 to prevent hydrogen leakage [78]. However, permeability is generally less than 10−20 m^2, making hydrogen leakage highly likely [79]. According to various studies [80–82], hydrogen leakage loss ranges between 10 and 61 % due to biochemical reactions that occur within the reservoir, again making them unsuitable short term. Nonetheless, salt caverns show vast potential for short-term hydrogen storage.

3.2.4. Pipelines

The transportation of this compressed hydrogen would usually occur via pipelines. One of the main concerns with pipelines is their capital cost. The total installed capital cost of the pipeline includes not only the cost of the materials for the pipeline but also costs related to installation and rights of way (ROW), fusion and leak testing. These can vary significantly with location [83] and can in turn differ between the different GCC countries.

Existing pipelines that transport natural gas are also not yet a developed option for hydrogen transportation. Although converting natural gas pipelines to carry a blend of natural gas and hydrogen (approx. 15 % hydrogen) is possible given slight pipeline modifications, converting existing natural gas pipelines to deliver pure hydrogen requires substantial modifications and costs [84–87]. There also lies the issue of inefficiency in the physical transportation of hydrogen through natural gas pipes. Transportation efficiency defines the correlation between the pressure drop caused by the transportation distance and the heat transfer value of the substance [88]. According to various studies [89–91], hydrogen takes approximately four times more energy to move through a pipeline than natural gas. This is a challenge that must be addressed for pipelines to become a viable option for hydrogen transport, particularly for long-distances.

3.2.5. Trucks

The transportation of compressed hydrogen can also occur via trucks. Following compression at pressures of 180 bar or higher in long cylinders, these cylinders are stacked on a trailer that is then hauled by the truck. An issue with this, however, is that the high weight of the cylinders or tubes limits the maximum hydrogen load that can be transported.

A tube trailer with steel cylinders can store up to 25,000 L of hydrogen compressed to 200 bar, equating to approximately 420 kg of hydrogen [92]. This is a relatively beneficial capacity. On average, a fuel cell electric vehicle (FCEV) requires about 5 kg of hydrogen per 300 miles of transport [93]. Considering this, a 420 kg capacity yields approximately 25,200 miles of transport. The problem with this again, however, is the maximum load that can be transported via truck using these cylinders. The average capacity per truck is 600 kg of hydrogen per day [94]. On the other hand, gasoline tank trucks can carry up to 73 times this parameter, where daily capacity can equate to 11,600 gallons or ~43,964 kg [95]. This causes complications in terms of the scalability of this method of hydrogen transport, as well as cost concerns regarding the extra number of trucks required to transport the equivalent amount of daily gasoline capacity. As such, substantial R&D is required for hydrogen transportation via trucks to become commerciable.

3.2.6. Cryogenic/liquid hydrogen

Cryogenic (liquid) hydrogen has a density that is nearly double that of compressed hydrogen at 700 bar. Liquid hydrogen is stored in specially insulated cryogenic tanks under pressure which have facilities for cooling, heating, and venting. However, the liquefaction of hydrogen is an energy-intensive process. According to research, 12.5–15.0 kWh/kg is required for liquefaction compared to approx. 6.0 kWh/kg required for compression [96].

The energy-intensive liquefaction process also results in higher operational costs for cryogenic tanks. Typical liquefaction capacities can range from 100 kg/h to 10,000 kg/h and cost US$ 9–10/kg LH_2 [97]. Meanwhile, onsite storage capacities are much higher, typically ranging from 115,000 kg to 900,000 kg [98].

Although cryogenic tanks have high initial costs, particularly larger tanks with higher liquefaction capacities, cryogenic storage presents economies of scale. Here, the cost of hydrogen and the energy needed to liquefy hydrogen decreases per kg of hydrogen liquefied, so that large-scale cryogenic units can become cost effective.

Regionally in the GCC, there are currently no operating cryogenic tanks. As such, for the cryogenic storage of hydrogen to be adopted in the region, new storage facilities would need to be developed. The initial capital investment for these new facilities would be high, due to the need for liquefaction equipment as well as storage.

Another crucial factor in the effectiveness of cryogenic storage tanks lies in their design.

Cryogenic tanks are usually made with double walls and several layers of heat shielding between them, mainly aluminium or mylar [99]. Large storage tanks are also sometimes coated with liquid nitrogen to reduce heat transfer by lowering the temperature gradient within the outer wall of the tank. Cryogenic hydrogen tanks are typically large and either cylindrical or spherical. An advantage is that both cylindrical and spherical tanks have similar surface-to-volume ratios, which makes them easier to construct and more economically beneficial to operate [100].

This design also minimises hydrogen evaporation losses. Although cryogenic storage minimises losses, it does not eliminate them entirely. Hydrogen can either be released, built up within the tank, or captured and returned to be used back in the liquefaction process.

However, this is again very energy intensive. The liquefaction of hydrogen typically results in energy losses of up to 40 % compared to the 10 % energy loss in compressed hydrogen [101].

The very high energy requirement of current hydrogen liquefaction and high rate of hydrogen loss due to boil-off (~1–5%) pose two critical challenges that need to be addressed prior to the commercialisation of LH_2 storage technology.

4. Optimisation models for hydrogen supply chains

In an ideal scenario, hydrogen supply chain optimisation aims to minimise the cost, time, and distance of hydrogen with regard to each stage, namely: production, storage, and transportation. An ideal optimisation model considers all combinations for every method of production, storage, and transportation, while the output from this will determine the type, numbers, location, and capacity of each stage of production, storage, transportation. This is shown in Fig. 1.

Fig. 1 depicts the inputs, framework, types of optimisation models and desired outputs for a hydrogen supply chain. The aforementioned methods for hydrogen production, storage, and transport in Section 3 would be analysed and compared for an optimised GCC hydrogen supply chain in further research. Ideally, the optimised model will fulfil the objectives of minimising costs, environmental impacts, safety concerns and risks.

In the current literature, there are two main modelling methods utilised for hydrogen supply chain optimisation: mixed-integer linear programming (MILP) optimisation and geographic information systems (GIS) based optimisation. According to the literature cited in this review paper, these are the most effective models for designing and optimising a hydrogen supply chain. The aim of these methods is to obtain the outputs described in Fig. 1 and find out the optimal configuration in terms of production, storage and transport that minimises costs,

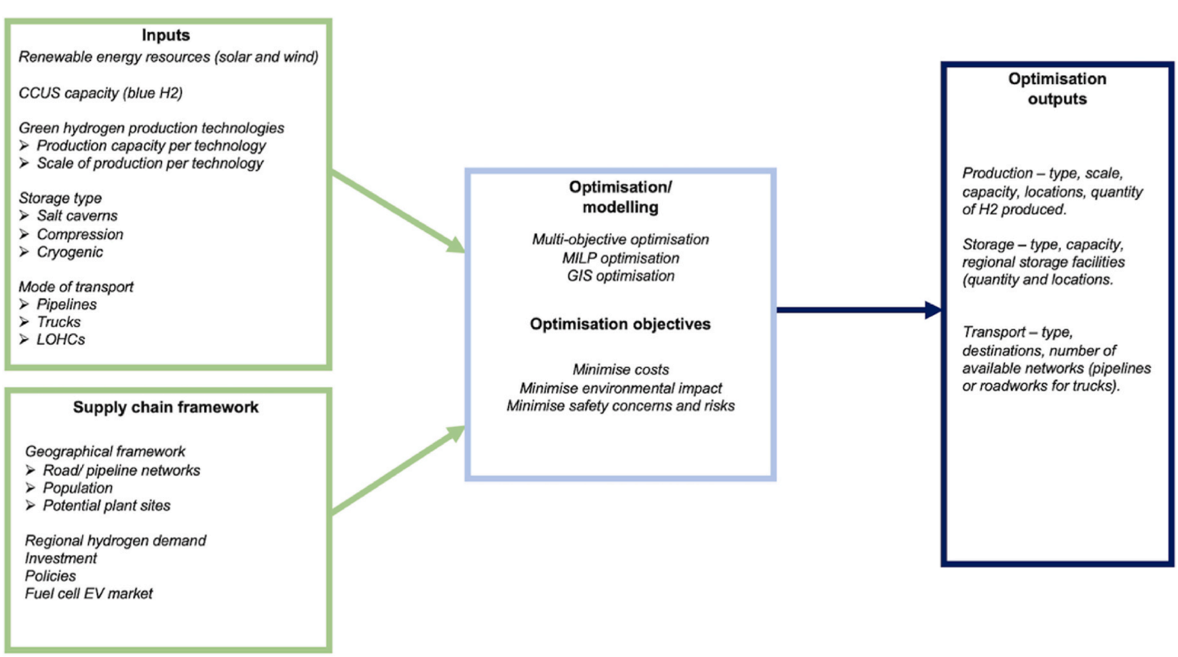

Fig. 1. Optimising a hydrogen supply chain.

environmental impact, and safety concerns.

4.1. Mixed-integer linear programming

MILP describes a mathematical modelling approach to solve complex optimisation tasks and to identify the potential trade-offs between conflicting objectives [102]. In the case a of hydrogen supply chain, safety and cost minimisation are conflicting objectives that require a trade-off [103]. MILP can provide a better understanding of energy transition scenarios and support decision-makers in determining sustainable pathways towards hydrogen targets while considering all aspects.

A study conducted by Ingason et al. [104] used MILP to determine the most cost-effective sites for hydrogen production technologies in Iceland. The study determined the best location for hydrogen production via electrolysis and the least expensive hydrogen production cost based on Iceland's existing and potential power plants and energy demand. In the work, it was concluded that the cost of hydrogen was relatively high at low demand due to the inefficient use of power plants and transfer lines, whereas costs at high demand were high due to the increased costs of constructing new plants and power transfer lines. Methods for how the total cost of hydrogen production can be minimised based on all aspects of production, transport and storage were also discussed. Another study by Almansoori and Shah [98] used MILP for the simulation of a hydrogen supply chain in the UK. The study used MILP solved via GAMS software to develop a hydrogen supply chain model which considers the availability of energy sources (solar and wind) and their logistics, as well as the variation of hydrogen demand over a given time period. The study concluded that with increasing demand, more plants of different sizes need to be constructed. The model was also able to determine the optimal method for hydrogen production, transport, and storage, which in the case of this study was liquid H_2 stored in different facilities.

Several other studies have used MILP for determining a hydrogen supply chain from different angles. Hugo et al. [104] used MILP to optimise a hydrogen supply chain also considering investment strategies in each of their supply chain decision-making stages. The study classed cost, operability, reliability, environmental impacts, safety, and social implications all as crucial components that need to be considered when assessing the long-term implications of a hydrogen supply chain. Considering both investment and environmental criteria, the study concluded that to reach a high emission reduction target and minimise costs, the optimal supply chain design and investment strategy should start with small-scale reforming of natural gas (blue hydrogen). Lin et al. [105,106] used MILP in two studies. In the first [100], MILP was used to determine the lowest cost for hydrogen infrastructure design considering different technological alternatives in Southern California.

The model was analysed with regards to technology deployment, hydrogen cost, capital requirements, the subsidy needed, subsidy provided, and mitigation. The study concluded that using SMR for industrial hydrogen and the incorporation of CCUS is critical to facilitate the transition. This work also concluded that despite high capital investment, implementing the correct hydrogen technologies could return initial investment within 20 years.

The second study [107] used MILP to optimise the location of hydrogen stations in Southern California by analysing the distribution of the vehicle miles travelled. In this study, it was concluded that if station size constraints are relaxed, only 18 % of the existing gasoline stations are needed to achieve the current fuel accessibility of gasoline in the region. A further conclusion from this study is that stations should also be placed in low-demand locations for a balanced distribution. Kamarudin et al. [108] used MILP to determine the optimum hydrogen delivery network using transportation via trucks in Malaysia. The study used two methods to determine hydrogen demand. The first assumed hydrogen demand in Malaysia as a function of total vehicle numbers, average total distance travelled and vehicle fuel economy, while the second assumed hydrogen demand based on the current supply of gasoline and diesel from surveys on local petrol stations. The second method was utilised as it was more accurate, and the study concluded that liquefied hydrogen produced by natural gas via SMR and delivered via tanker trucks was the optimal hydrogen supply chain in terms of minimised cost.

As previously mentioned, safety concerns and cost minimisation are conflicting objectives of the hydrogen supply chain which require a trade-off. Kim and Moon [103] used MILP considering the trade-off between cost and safety of the hydrogen supply chain. The objective of this was to utilise MILP to determine a Pareto solution between minimising the costs of the supply chain while also accounting for the safety risks to the population. The study concluded, however, that changing the plant or any of the production, storage and transport does not result in any additional safety guarantees. Konda et al. [109] presented a multi-period optimisation for a hydrogen supply chain using MILP and GAMS software - the same software used in Ref. [98] - based on a techno-economic analysis in the Netherlands. The study investigated all spatial, economic, environmental, and energetic performances if hydrogen were to be adopted as a fuel in the Dutch transport sector. The study concluded that economically the transition towards large-scale hydrogen supply infrastructure is viable, however emission reduction potential is limited presently at ~30 % but can be improved to ~85 % through use of CCUS.

4.2. GIS-optimisation

Unlike MILP which describes a mathematical modelling approach, GIS describes a geo-spatial methodology which uses regional or national-specific conditions to determine an optimal hydrogen supply chain configuration [110]. Factors such as location, population, available resources, transportation network and policies are used to develop hydrogen demand scenarios. Because GIS is geo-spatial, it is usually used in conjunction with other techno-economic analyses for the simulation of a hydrogen supply chain. However, GIS can also be used alone to determine geographical systems for designing hydrogen-related infrastructure.

Nicholas et al. [111] used GIS to determine the siting for hydrogen stations in Sacramento, California. The study analysed average one-way driving time from home or work to a station as a metric to evaluate hydrogen station scenarios. The study concluded that the sites of current motorway gasoline stations would be the most effective. A further conclusion was that when the network reaches approximately 30 % of the size of the current gasoline station network in Sacramento, the entire existing gasoline network can be accurately estimated. A limitation to this work, however, is that the economics of supplying the stations with hydrogen was not evaluated. Strachan et al. [26] used GIS as a part of a wider economy systems model MARKAL to generate model scenarios that incorporate the spatial matching of supply and demand for optimal zero-carbon hydrogen deployment and distribution in the UK. In this work, it was concluded that liquid H_2 was the optimal solution for both deployment and distribution, whereas pipelines were restricted to <10 % of the national hydrogen supply. Melendez and Milbrandt [112] used GIS to propose hydrogen refuelling stations in various regions in the US. The study first calculated hydrogen demand in each region, and then proposed refuelling stations in areas that were high in hydrogen demand, closer to major retailers and significant in traffic volume. In this work, it was concluded that an optimal location for stations was in areas that provide access within 10 miles for at least 90 % of the population in the regions analysed. The study also determined that aligning optimisation between emerging hydrogen demand and emerging infrastructure in the correct locations is critical to a successful transition to hydrogen. Johnson et al. [113] combined GIS with a techno-economic model of hydrogen infrastructure components in Ohio, US, to determine the optimal infrastructure design, costs, CO_2 emissions, and energy use associated with hydrogen infrastructure combined with CCUS in each infrastructure pathway at different market penetrations. In this work, it was concluded that pipeline transportation was favoured compared to trucks even with low market penetration. However, production-related economies of scale decrease the levelised cost of trucks in time. Ball et al. [25] used GIS in conjunction with a MOREHyS model to optimise a hydrogen economy in Germany. In this study, GIS was to determine hydrogen demand based on the distribution of population and car densities nationally, while MOREHyS was used to model hydrogen infrastructure. The following was concluded in this study: the introduction of hydrogen in highly populated areas leads to economies of scale in hydrogen production; total supply costs when comparing natural gas and coal (for blue hydrogen) remain relatively level; the transport of gaseous hydrogen is the most favourable, however, high investment in liquefaction plants and liquid H_2 transport also result in economies of scale. Stiller et al. [114] used GIS to optimise regional hydrogen demand scenarios in Norway, considering the growth of regional hydrogen. The study also used GIS to determine the impacts of energy price and GHG emission constraints on hydrogen production and transport. The study concluded that electrolysis plays a crucial role in the energy transition in areas with low population density, and that the cost of hydrogen can become competitive at a market penetration level of ~5 %. Further conclusions determined that GHG emissions from hydrogen production stem mainly from the method of production, and can be influenced effectively by political intervention, including high carbon taxes or subsidies on renewable electricity. Kuby et al. [115] used GIS to develop strategies for initial hydrogen refuelling stations in Florida. In this work, it was concluded that clusters of refuelling stations in and near large metropolitan areas can refuel the high trip volumes between heavily populated areas. The study also determined that the clustering of stations also allows them to work together to refuel medium-length trips that require multiple stations along the travel route. However, spacing stations too far apart could lead to emergency situations and stranding of vehicles which could compromise safety and public perception.

5. Challenges and the future of hydrogen

Blue and green hydrogen hold immense potential towards the future of the transport sector, particularly in the GCC who hold abundant resources and investment possibilities that can facilitate the transition. Both regionally and globally, hydrogen has the potential to acquire a significant market share in the coming decades if the cost and scalability of hydrogen supply chains are addressed, and effective political intervention incentivises a global push towards increasing efficiency and reducing CO_2 emissions. However, optimising a hydrogen supply chain, particularly in cases where infrastructural changes are required, such as the building of new plants, still poses challenges for hydrogen's commercial future. In terms of modelling, based on the current literature, choosing an optimal configuration for a hydrogen supply chain is also complicated, given the various options available for each of production, transport, and storage, as well as the different abilities of countries to implement them practically, from all economic, environmental, and political aspects.

According to this literature review, most studies developing optimisation models for a hydrogen supply chain focus on mathematical or combined mathematical and geo-spatial optimisation models. This is an advantageous approach; in the studies reviewed, these models allow for a simulation based on different inputs, such as hydrogen demand [112, 114] and existing infrastructure, such as pipeline networks and plants. The availability of one input or the other may differ per region in terms of modelling, so the advantage of using this approach lies in the versatility with which a hydrogen supply chain can be established.

In all the studies reviewed, the primary commonality lies in that the objective of optimisation was to minimise costs. Some studies [103,114] also considered other important factors such as the trade-off between economic optimisation and safety and the associated GHG emissions for the modelled hydrogen supply chain. However, in the present literature, very few studies have optimised a hydrogen supply chain based on an environmental or safety perspective.

An issue that may arise from this is that optimising a hydrogen supply chain from either environmental or safety perspectives may result in needing to compromise economic optimisation. This may prevent either maximised environmental benefits in supply chains that prioritise economic optimisation, or, vice versa, it can prevent widescale deployment of hydrogen due to high economic costs.

Nonetheless, environmental optimisation is particularly important when considering hydrogen production. As the entire nature of blue and green hydrogen revolves around them being low-carbon, future research should investigate hydrogen supply chains that operate via clean feedstock, either through CCUS or renewable sources. Another important factor with regard to production is that current electrolysis technologies still present challenges for large-scale hydrogen production. Aside from entire supply chain optimisation, future research should also focus on developing and optimising hydrogen production methods to accelerate widescale deployment. Establishing the cost reduction of hydrogen production, transport, and storage to the point where they become competitive with grey hydrogen is also a crucial factor towards clean hydrogen's success. In the GCC's case however, even with the global challenge of needing to establish a cost reduction, electrolysis methods such as SOE, can be integrated into downstream chemical production [61,65]. Saudi Arabia lies in the top five global chemical producers, so that in comparison to other global regions, this advantage may in future make electrolysis in the GCC cheaper compared to global benchmarks. Further research is required to better investigate the advantages of integrating electrolysis into the downstream chemical industry.

The adoption of new strategies, policies and initiatives will also accelerate research and development and advance both deployment and public perception of hydrogen as a fuel.

When this occurs, a more solid hydrogen market will be initiated, and hydrogen demand will be estimated based on real-life scenarios. This will allow for more accurate estimations of hydrogen demand, and will further optimise the hydrogen supply chain, as the estimations will come from a real-life market.

6. Conclusion

This literature review first presents an overview of hydrogen supply chains in the GCC, assessing all the comparative advantages, policies, strategies, and investments the region is undertaking to transition towards a hydrogen economy. From this section, it is noted that the region is allocating substantial investments towards clean hydrogen and has the potential to become an important global player in the clean hydrogen economy, based on their natural comparative advantages of solar abundance, high wind speed in the case of Oman, and flat desert land suitable for hydrogen storage. The next section analyses current hydrogen supply chains in terms of production, storage, and transport methods. The objective of this is to determine whether any method of production, transport or storage is at a higher level compared to others in terms of being closer to commercialisation. It is noted that for hydrogen production, SOE and PEM are overall the best candidates. SOE is favourable due to its high operating temperatures and conversion efficiency, as well as cost-effective catalysts being used in operation rather than noble electrocatalysts. PEM on the other hand works at low temperatures but produces the highest purity hydrogen. However, despite their advantages, SOE is still not a stable enough technology for long-term use, and requires more developments for long-term sustainability, whereas PEM incurs high costs. For storage and transport, cryogenic hydrogen shows vast potential due to the effective design of the tanks and potential of economies of scale. However, energy losses in the liquification process are much higher than in the other transport and storage methods. Lastly, this literature review assesses models being used in current research to optimise hydrogen supply chains. The two models assessed in this review are MILP - a mathematical model, and GIS - a geo-spatial model. The objective is to determine which type of model is more effective in hydrogen supply chain optimisation. It is observed that MILP is a more effective model for the design of a hydrogen supply chain, particularly from an infrastructural perspective. Studies that utilised GIS, used them in conjunction with mathematical models for a more substantiated supply chain simulation. In most of the reviewed studies, optimisation relates to cost minimisation, with only a few studies assessing other factors such as environmental impact and safety. Further research should focus on optimising hydrogen supply chains from environmental and safety perspectives. However, optimising a hydrogen supply chain from either environmental or safety perspectives may result in needing to compromise economic optimisation. This may prevent either maximised environmental benefits in supply chains that prioritise economic optimisation, or vice versa can prevent widescale deployment of hydrogen due to high economic costs.

Hydrogen holds immense potential in the future of the transport sector, and with the correct approaches and strategies it has the potential to acquire a significant market share in the coming decades if the cost and scalability of a hydrogen supply chain are addressed, and effective political intervention incentivises a global push towards increasing efficiency and reducing CO_2 emissions.

CRediT authorship contribution statement

Valentina Olabi: Writing – original draft, Validation, Data curation, Conceptualization. **Hussam Jouhara:** Writing – review & editing, Supervision, Resources, Funding acquisition, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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