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Review article

Renewable-based zero-carbon fuels for the use of power generation: A case study in Malaysia supported by updated developments worldwide

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ABSTRACT

The existing combustion-centered energy mix in Malaysia has shown that replacing fossil fuels with zero-carbon alternative fuels could be a better approach to achieve the reduction of the carbon footprint of the power generation industry. In this study, the potential of zero-carbon alternative fuels generated from renewable sources such as green hydrogen and green ammonia was addressed in terms of the production, transport, storage, and utilization in Malaysia's thermal power plants. The updated developments associated to green hydrogen and green ammonia across the globe have also been reviewed to support the existing potential in Malaysia. Though green hydrogen and green ammonia are hardly commercialized in Malaysia for the time being, numerous potentialities have been identified in utilizing these fuels to achieve the zero-carbon power generation market in Malaysia. The vast and strategic location of natural gas network in Malaysia has the potential to deliver green hydrogen with minimal retrofitting required. Moreover, there are active participation of Malaysia's academic institutions in the development of water electrolysis that is the core process to convert the electricity from renewables plant into hydrogen. Malaysia also has the capacity to use its abundance of depleted gas reservoirs for the storage of green hydrogen. A large number of GT plants in Malaysia would definitely have the potential to utilize hydrogen co-firing with natural gas to minimize the amount of carbon dioxide (CO_2) released. The significant number of ammonia production plants in Malaysia could provide a surplus of ammonia to be used as an alternative fuel for power plants. With regard to the energy policy in Malaysia, positive acceptance of the implementation of renewable energy has been shown with the introduction of various energy policies aimed at promoting the incorporation of renewables into the energy mix. However, there is still inadequate support for the implementation of alternative zero-carbon fuels in Malaysia.

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1. Introduction

Malaysia, a developing country, is located in Southeast Asia and divided into two areas by the South China Sea, where the nation occupies parts of the Malay Peninsula and the island of Borneo (Lim and Goh, 2019). There are 13 states in Malaysia, 11 of which are in Peninsular Malaysia (Lim and Goh, 2019). Two other states, Sabah and Sarawak, known collectively as East Malaysia, are located on the island of Borneo (Lim and Goh, 2019; Oh et al., 2018). Peninsular Malaysia shares land and sea frontiers with Thailand and sea frontiers with Singapore, Vietnam, and Indonesia. Borneo's East Malaysia shares land and sea frontiers with Brunei and Indonesia and a sea frontier with the Philippines and Vietnam. The population of Malaysia is approximately 32 million (Michel Devadoss et al., 2021) and the area of Malaysia is 329,847 km^2 (Tan et al., 2020). Due to the location of Malaysia near the Earth's equator, the local climate is equatorial with tropical weather all year round (Lim and Samah, 2004). In addition, due to its proximity to water, Malaysia's climate can be considered a high humidity maritime climate (Lim and Samah, 2004). Annual precipitation is often abundant in tropical climates and has a seasonal rhythm to varying degrees (Lim and Samah, 2004). In tropical climates, there are usually only two seasons, a wet season and a dry season (Lim and Samah, 2004). The weather in Malaysia is therefore never too hot, with temperatures ranging from an average of 20 °C to 30 °C throughout the year (Lim and Samah, 2004).

Malaysia's population has increased dramatically and the urban population has increased at a higher rate than the rural population at the same time (Anon, 2021i). One of the main indexes for economic development and growth of production is urbanization (Alias et al., 2010). Malaysia is one of Southeast Asia's most urbanized countries at present, and also one of the world's most rapidly urbanized regions (Alias et al., 2010). For the last nine decades, Malaysia has experienced rapid urban population growth, but more particularly during the 1980s and 1990s, when there was a period of rapid economic growth and urbanization (Chong et al., 2019). This urban growth and development has been due to the country's rapid socio-economic development since more than five decades. This growth is expected to continue as people migrate from rural areas to urban areas due to the continuing shift of the economy and employment from agriculture to industry and services (Chong et al., 2019). Pretty much across the board, energy demand is rapidly increasing as socio-economic development progresses (Oh et al., 2018; Nepal and Paija, 2019). Therefore, sustainability and a clean environment should be considered in the definition of energy supply policies in order to guarantee people's health and secure energy supplies (Groissböck and Gusmão, 2020).

Indeed, the main case of unsustainability is a development strategy based exclusively on exports of hydrocarbons. Today, most of the world's energy comes from different kinds of fossil fuels, such as coal, oil, and natural gas (Mendonça et al., 2020; Zeppini and Van den Bergh, 2020; Yin, 2021). Approximately two-thirds of the world's required electricity is generated from the use of fossil fuels (Zeppini and Van den Bergh, 2020). Malaysia's economy relies heavily on the oil and gas industry and fluctuations in oil prices have an impact on the country's development (Lim and Goh, 2019; Shangle and Solaymani, 2020; Tang et al., 2017). Oil reservoirs are unequally divided between the countries of the world so that 42 nations account for more than 98% of oil production and less than 2% of oil production is related to 70 countries and there are no oil reservoirs in the remaining 70 countries (Hosseini et al., 2013). Malaysia is benefiting from an enormous oil and gas reservoir (Lim and Goh, 2019; Oh et al., 2018; Shangle and Solaymani, 2020; Tang et al., 2017). As one of the key oil and gas producers in the Asia-Pacific region, Malaysia's average daily output in 2018 is more than 1.7 million barrels of oil equivalent (Anon, 2021h). Malaysia's remaining oil and natural gas commercial reserves in 2017 are estimated at more than 5 billion barrels of oil equivalent and 83 trillion standard cubic feet (TSCF) respectively (Energy Commission, 2019), as shown in Fig. 1.

Commercial reserves are contained in more than 400 fields, with natural gas accounting for about three-fourths of the mix (Anon, 2021h). Malaysia is also one of the biggest liquefied natural gas (LNG) exporters in the world (Vivoda, 2019) and, as recently as 2019, was the world's fifth biggest exporter of LNG (Anon, 2021d). This well-established landscape is among the driving factors behind the Malaysian economy's development, with oil and gas responsible for around 20% of the country's gross domestic product (GDP) (Anon, 2017). The combination of natural gas, crude oil, and petroleum products accounting for approximately 72% of the country's total primary energy supply by fuel type (Energy Commission, 2019).

In some countries, such as China and the US, coal plays a vital role in energy source (Zhang et al., 2020b), as it is known to be one of the cheapest and most abundant fossil fuels available (Clark et al., 2020). The same is true of Malaysia, where coal accounts for around 20% of the total energy supply (Energy Commission, 2019). Unlike China and Indonesia, which have abundant coal resources (He et al., 2020; Kang et al., 2021; Friederich and Van Leeuwen, 2017) and currently two of the world's largest coal exporters, Malaysia's coal reserves are approximately 1279.30 million tonnes (Energy Commission, 2019) — comparatively small compared to Indonesia's coal reserves of approximately 37560 million tonnes (Anon, 2020g). Thus, to meet Malaysia's demand for energy supply, approximately 98% of the coal needed has been imported from other nations (Oh et al., 2018; Energy Commission, 2019). Malaysia's reliance on coal combustion has increased substantially in recent decades, including a fourfold increase in its share of the energy mix between 1996 and 2016 (Clark et al., 2020). Hence, with rising demand for cheap electricity which act as a key driver to the growth of coal-fired power generation in Malaysia (Clark et al., 2020), along with abundance of Malaysia's oil and natural gas reserves, Malaysia relies heavily on fossil fuel-based power plants as they make up a significant share of the energy mix (Oh et al., 2018). Figs. 2–4 show the fossil fuel-based power plant infrastructure in Malaysia.

Henceforth, the firing of fossil fuels continue to play a vital role in Malaysia's generation of electricity in order to attain sustainable socio-economic growth for the industrial sector (Oh et al., 2018; Groissböck and Gusmão, 2020). As shown in Fig. 5, electricity demand in Malaysia was reported to be 33,991 megawatt (MW) in 2018, which is about 80% of what was generated by fossil fuel consumption (Energy Commission, 2019). It has been projected that Malaysia 's final energy demand will grow at an average annual rate of 1.7%, reaching 103 million tonnes of oil equivalent (Mtoe) by 2035 (Anon, 2021c).

Obviously, there is a high chance that fossil fuel resources will not cover this percentage in 2035. Heavy fossil fuel consumption has raised concerns about energy security, as global reserves of oil and natural gas are expected to be drained within 60 years if used

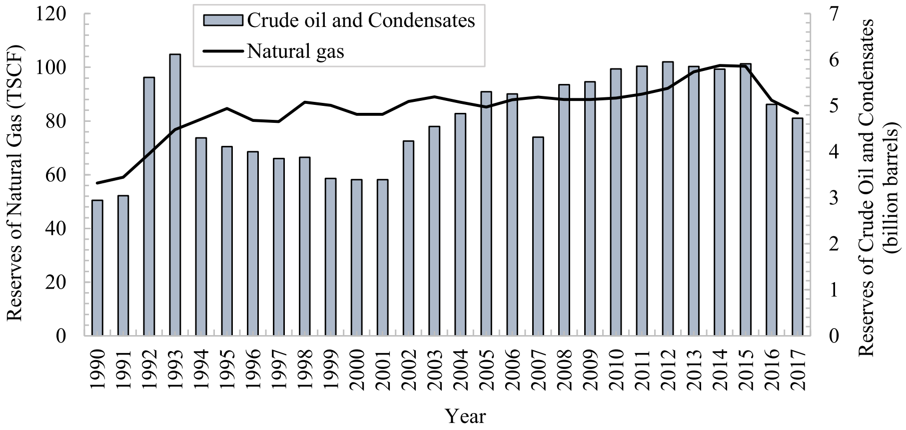


Fig. 1. Malaysia's reserves of crude oil, condensates, and natural gas.
Source: Adapted from Energy Commission (2019).

at the same rate (Mah et al., 2019). Moreover, as energy demand continues to increase and fossil fuel consumption is expected to increase, it will results in a further increase in carbon dioxide emissions (CO_2) (Welch and Prasad, 2018). The largest contributor to CO_2 emissions is electricity generation, which accounts for nearly half of global CO_2 emissions, as shown in Fig. 6.

CO_2 is one of the main greenhouse gases, which absorbs and emits radiant energy within the thermal infrared range, resulting in a greenhouse effect (Mendonça et al., 2020; Mohammadpour et al., 2021; Nordenstam et al., 2018). As shown in Fig. 6, with global electricity still largely generated from the combustion of fossil fuels, a significant amount of anthropogenic CO_2 emissions is being released to the atmosphere (Hu et al., 2020; Khallaghi et al., 2020). Due to exorbitant fossil fuel consumption, the rising rate of global greenhouse gas (GHG) generation has a serious impact on human life and especially on global warming phenomena (Karmaker et al., 2020; Nunez, 2021). In addition, about one-third of CO_2 emissions are adsorbed annually by oceans that create acidic conditions and have adverse effects on the marine ecosystem's biodiversity (Ahmed Bhuiyan et al., 2018). CO_2 is the main GHGs generated by an upward trend during the last decade in Malaysia and total CO_2 emission from energy consumption has been reported to be 258.783 million tonnes in the year 2017. As most of Malaysia's energy demand has been provided by fossil fuels (Hanif et al., 2019), this country has been introduced as the 27th worldwide country in CO_2 generation in the year of 2017 (Team, 2019). Fig. 7 shows the trend of CO_2 constitution in Malaysia (Etokakpan et al., 2020; Team, 2019).

As the impact of global climate change has become significant due to the fast-growing population and industrialization (Karmaker et al., 2020), most countries have agreed on the urgency of controlling energy-related GHG emissions (Chong et al., 2019). Several major international treaties have been implemented over the years in order to engage countries to participate in the reduction of GHG emissions (Mendonça et al., 2020). The Kyoto Protocol, for example, is an international treaty extending the 1992 United Nations Framework Convention on Climate Change (UNFCCC), which commits states to reduce GHG emissions (Kuriyama and Abe, 2018). Following the signing of the Kyoto Protocol in 1997, most of the countries around the globe have had to comply with, and aim to achieve, this principle. Developing nations voluntarily play a vital role in maintaining and adhering to GHG emission reductions (Miyamoto and Takeuchi, 2019). Energy policies and relevant regulatory frameworks play a pivotal role in meeting the objectives of the Kyoto Protocol, as nearly all GHG emissions come from the energy sector (Lim and Goh, 2019). The Paris Agreement is yet another agreement signed in 2016 within the UNFCCC, dealing with the reduction, adaptation, and finance of GHG pollution (Liu et al., 2020b). The main objective of the Paris Agreement is to reduce GHG emissions as quickly as possible in order to achieve the long-term global average temperature target of well below 2 °C above pre-industrial levels and to pursue efforts to reduce the increase to 1.5 °C (Liu et al., 2020b). These objectives have been established to reduce the risks and effects of climate change. Eventually, it will help to achieve a balance between both the anthropogenic emissions from sources and the elimination of greenhouse gas sinks in the second half of the 21st century (Vrontisi et al., 2020). Under the Paris Agreement, each country must identify, plan, and report regularly on the contribution it undertakes to reduce global warming (Vrontisi et al., 2020). A country is to set a specific emission target by a specific date, but each target should go beyond the previously set targets (Vrontisi et al., 2020). Malaysia has also offered to devote itself to both the Kyoto Protocol and the Paris Agreement in order to reduce the carbon footprint (Anon, 2021o,p). One of the main strategies highlighted in these agreements is to increase the market share of renewable and sustainable energy (RSE) resources (Miyamoto and Takeuchi, 2019; Liu et al., 2020b).

As RSE development not only plays a key role in GHG mitigation, but also has a major impact on the global energy strategy (Mohammadpour et al., 2021), Malaysia has therefore focused on promoting the implementation of RSE through various national initiatives (Mendonça et al., 2020). Since 2000, when the Four-Fuel Diversification Policy was revised to the Five-Fuel Diversification Policy, the government has endorsed the use of RSE in Malaysia. RSE was introduced as the fifth fuel in the energy supply mix after oil, natural gas, coal, and hydropower (Mendonça et al., 2020). RSE was targeted in the 8th Malaysia Plan (2001–2005) to supply 5% of energy demand (about 500 MW) by 2005. The Small Renewable Energy Power Program (SREP) has been launched to promote private sector investment in small-scale energy generation projects using RSE sources (Mendonça et al., 2020). However, under SREP projects, RSE's energy capacity accounted for only 0.3% of the energy mix in 2005, which was far from the original goal (Mendonça et al., 2020). Eventually, RSE targets were also not met in the 9th and 10th Malaysia Plans. Although the installed RSE capacity increased from 53 MW in 2009 to 243 MW in 2014 following the launch of a 1% feed-in tariff, a great deal of effort is still necessary to accomplish the RSE capacity mix target (Mah et al., 2019). It can thus be noticed that while RSE has excellent potential to disrupt the heavy reliance on fossil fuels, the advancement in assimilating with the Malaysia's energy mix has been slow (Zeppini and Van den Bergh, 2020).

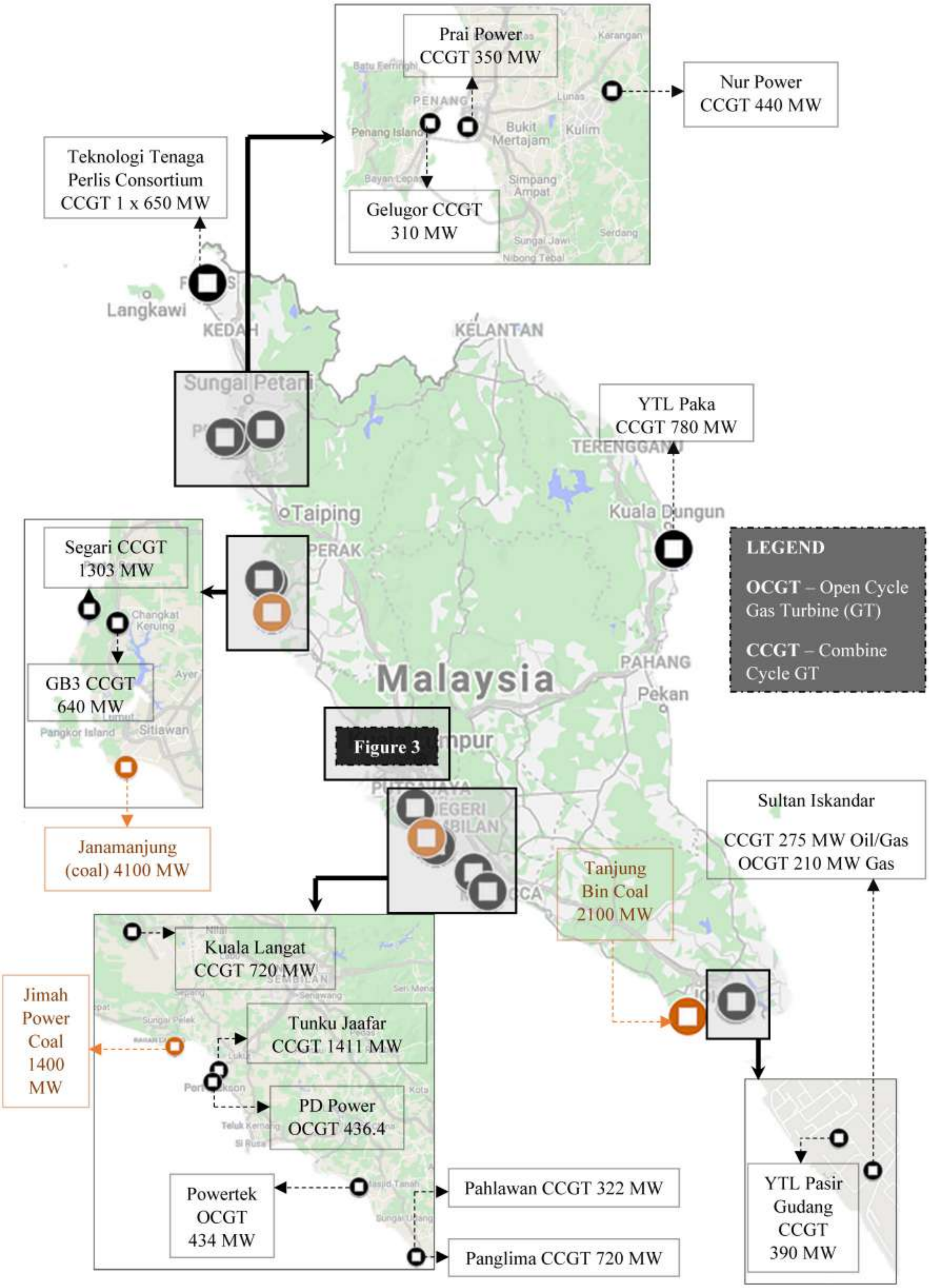


Fig. 2. Fossil fuel-based power plants in Peninsular Malaysia.
Source: Adapted from Energy Commission (2019).

However, efforts to promote the implementation of RSE have begun with key decision-makers to work together to expand the RSE portfolio in the nation's energy mix. Tenaga National Berhad (TNB), Malaysia's largest power utility company, has recently announced that they have taken a strict position not to build any new coal-fired power plants, the last of which was recently commissioned Jimah East (Aman, 2020), as low-carbon energy systems largely fixate on the deep decarbonization of the power industry (Anon, 2021b). Petroliam Nasional Berhad (PETRONAS), the sole manager of Malaysia's oil and gas reserves,

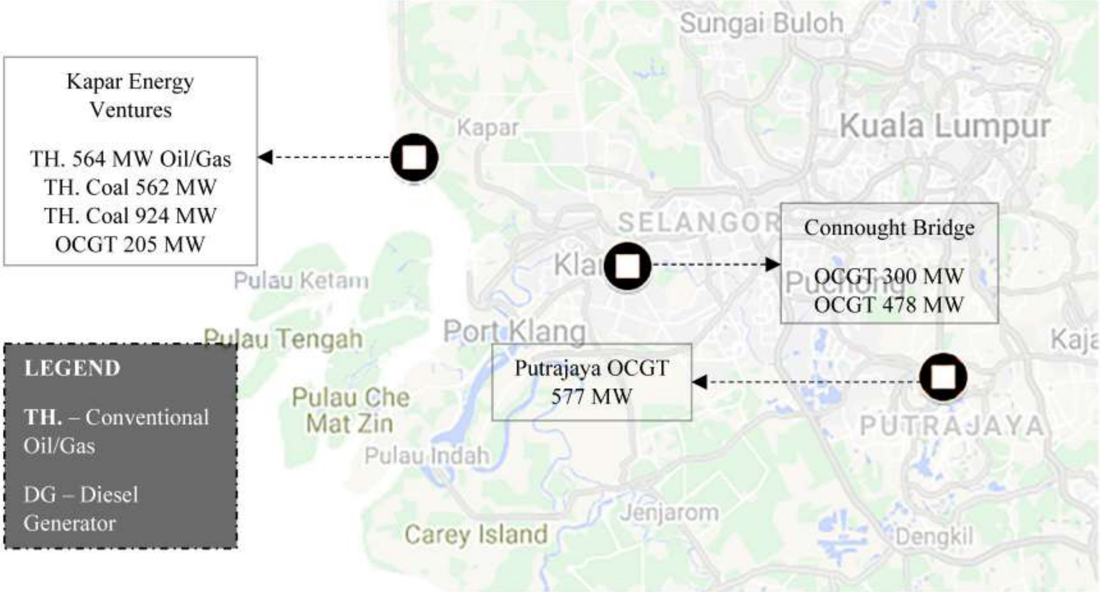


Fig. 3. Fossil fuel-based power plants in Klang Valley.
Source: Adapted from Energy Commission (2019).

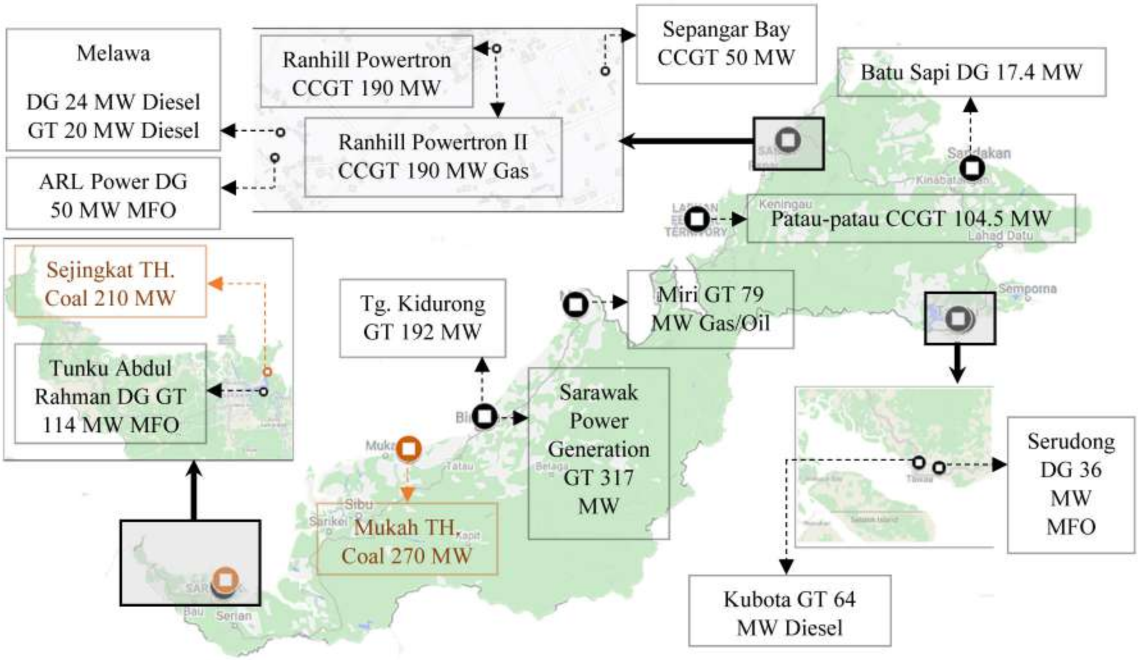


Fig. 4. Fossil fuel-based power plants in East Malaysia.
Source: Adapted from Energy Commission (2019).

has announced its goal of achieving Net Zero Carbon Emission by 2050 as part of its integrative approach to achieving a sustainable future (Hicks, 2020).

A significant number of fossil fuel power plants in Malaysia have shown that replacing fossil fuel with carbon-neutral fuel could be a better approach to promoting carbon footprint reduction. Displacement of fossil fuels with zero-carbon alternative fuels is a feasible means of enabling a carbon neutral power plant to operate as it does not produce CO_2 (Anon, 2021f). Furthermore, the implementation of zero-carbon alternative fuels generated from RSE resources, such as green hydrogen and green ammonia, could be the optimal solution for Malaysia's combustion-centric energy mix to accelerate the downward trend in Malaysia's carbon footprint. With regard to the potential of green hydrogen and green ammonia to act as transport and storage media for the RSE, efforts to expand the RSE portfolio in the nation's energy mix could be encouraged. The switch from fossil fuel to zero-carbon alternative fuel is a reasonable means for thermal power plants, as existing thermal power plant facilities can be used with relatively small modification work. The current review therefore seeks to contextualize the potential approaches to the production, storage, distribution, and the use of zero-carbon alternative fuels in Malaysia from the perspective of the electricity generation.

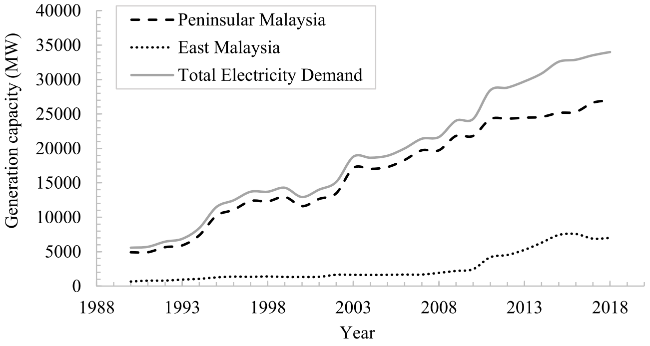


Fig. 5. Malaysia's generation capacity.
Source: Adapted from Energy Commission (2019).

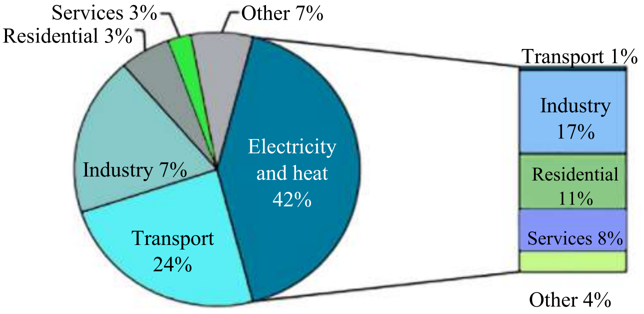


Fig. 6. Global CO_2 emission by sector.
Source: Adapted from Welch and Prasad (2018).

2. Overview on the growth of green hydrogen economy

A massive interest in zero-carbon alternative fuels is triggered by economic and environmental issues. Hydrogen is among the most promising carbon-free alternative energy carriers which can be generated from both fossil energy resources and RSE resources (Wijk and Chatzimarkakis, 2020; Hosseini and Wahid, 2016). Hydrogen is believed to be the future energy that could help to decarbonize global energy use. In its elemental form on earth, hydrogen does not naturally occur. It must be produced from hydrogen-containing substances that require considerable energy to achieve. Broadly speaking, production of hydrogen can be classified into several types, including brown hydrogen (hydrogen production generating CO_2 emissions), blue hydrogen (CO_2 generating hydrogen production combined with carbon capturing), and green hydrogen (electrolysis from surplus renewable energy) (Welch and Prasad, 2018).

Green hydrogen, which includes the use of excess renewables to produce hydrogen, will permit RSE to be stored in hydrogen form and converted to electrical energy when necessary. It could therefore act as among the energy storage technologies as seen in Fig. 8.

Power-to-gas hydrogen is a major interest for hydrogen economy roadmaps, considering the need to bring more RSE energy online (Hu et al., 2020; Anon, 2021b; Widera, 2020; Uchman et al., 2020; Walker et al., 2017). While RSE, such as solar, wind, and wave power, would provide eco-friendly alternatives to fossil fuels, the intermittency of such energy sources necessitates an energy storage form of media that enables for consistent energy supply (Hu et al., 2020; Uchman et al., 2020; Walker et al., 2017). Currently, the primary provider of such energy storage is batteries (Palys and Daoutidis, 2020; Burton et al., 2021; Khosravi et al., 2018). Although the infrastructure is in place for the manufacture and the use of batteries, as well as battery efficiencies are hailed to be as high as 90%, current battery technology, regardless of the amount of power drawn from them, has the issue of energy leakage and capacity deterioration over time (Burton et al., 2021; Chen et al., 2021; Gunsal et al., 2018). In addition, materials required for the production of batteries, such as lithium, are costly and limited in availability (Zubi et al., 2020). The life expectancy of batteries is also limited (Khosravi et al., 2018), and at the end of their life cycle, the dumping of batteries results in environmental waste which is costly to safely dispose of, with plenty of battery waste materials having no sustainable way of disposal (Burton et al., 2021). In addition, depending on batteries alone limits the potential to use RSE in the energy mix since their relatively low energy density makes them impractical for long-term energy storage of high capacity (Palys and Daoutidis, 2020; Khosravi et al., 2018). As a replacement to batteries, RSE can supply the energy required to generate hydrogen from water which can be stored as an energy carrier for electricity generation, enabling the continuous production of energy necessary to satisfy the consumption requirements of modern society (Widera, 2020; Burton et al., 2021).

Hydrogen is a clean energy carrier which has the potential to replace fossil fuels as a global energy source (Burton et al., 2021). Hydrogen is light and non-toxic as an energy storage medium, and hydrogen has minimal to negligible negative impact on the environment when used as a fuel source (Burton et al., 2021). Hydrogen also is the lightest and most abundant element in the universe (Kudria et al., 2021), accounting for 75% of all matter by

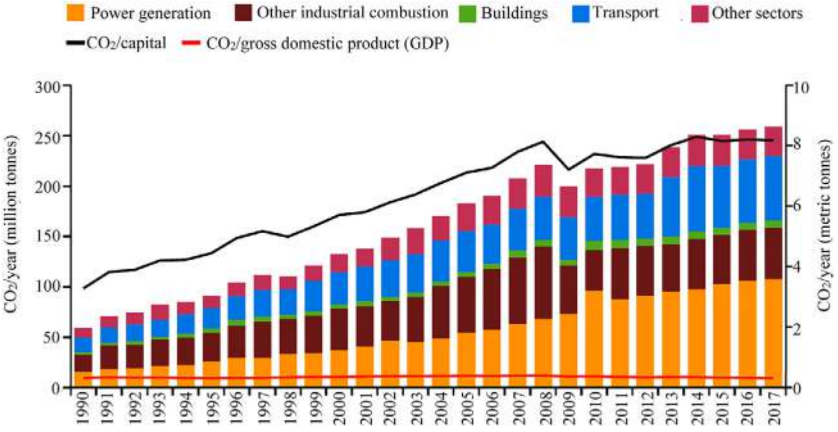


Fig. 7. Malaysia's CO_2 emission by sector (Team, 2019).

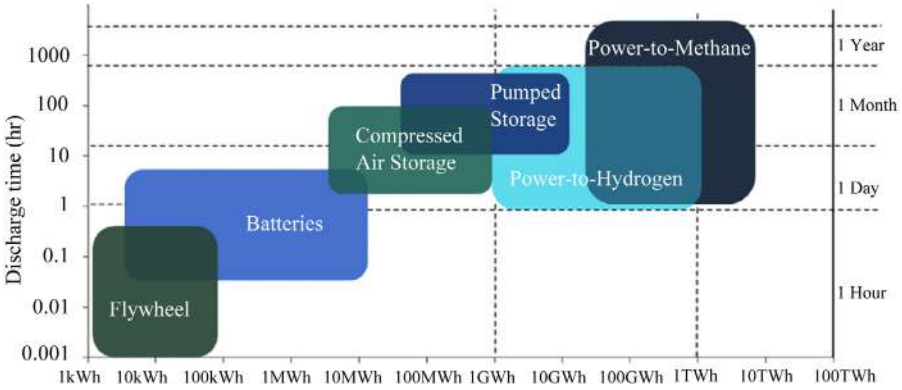


Fig. 8. Storage capacity by the type of energy storage technologies.
Source: Adapted from Anon (2021b).

mass and 90% when the number of atoms is taken into consideration (Burton et al., 2021). Even though hydrogen exists in great abundance throughout the universe, the Earth's atmosphere contains only around 1 ppm of hydrogen per volume (Burton et al., 2021). Even so, hydrogen is one of the two elements in water that covers 75% of the Earth's surface and it is also frequently found in various carbon-based chemical molecules, such as organic matter and petrochemicals (Burton et al., 2021).

Because of its versatility, hydrogen has the potential to be an outstanding energy carrier that can be used in internal combustion engines, steam engines, and fuel cells, as hydrogen can be rapidly translatable into mechanical, thermal, and electrical energy (Burton et al., 2021; Kudria et al., 2021). With relatively low-cost modifications, hydrogen could also be used in many of the currently available internal combustion engines (Burton et al., 2021). As hydrogen is the cleanest burning fuel and burns more effectively than petrochemicals (Pandey et al., 2020), vehicles using hydrogen as an energy source have a very low level of environmentally damaging emissions (Burton et al., 2021). In addition, of all fluids, hydrogen has the lowest viscosity, resulting in decreased friction, which otherwise contributes to an overall loss of efficiency in the form of heat Burton et al. (2021). In domestic and industrial heating applications, hydrogen is also a good fuel to be used (Burton et al., 2021). As the combustion of hydrogen and oxygen produces the highest amount of energy per fuel weight, hydrogen has demonstrated its ability to provide an outstanding energy source within the aerospace industry (Burton et al., 2021). For instance, compared to petroleum producing a heat energy of 35.15–43.10 kilojoules per gram (kJ/g) and wood producing 17.57 kJ/g, the heat energy produced by the combustion of hydrogen is 142.26 kJ/g (Burton et al., 2021). It is also worth noting that although hydrogen, compared to gasoline and methane, has both higher and lower ignition limits and lower ignition energy, it also has lower explosion energy (Burton et al., 2021). In addition, hydrogen is far less poisonous as a fuel than gasoline and methane, produces less harmful emissions after combustion, has a higher ignition temperature, and lower flame emissivity, resulting in the categorization of hydrogen as a safer fuel than both gasoline and methane (Burton et al., 2021).

The increased efficiency of hydrogen storage systems when compared to batteries is another advantage of hydrogen as an energy carrier. For instance, deep discharge of metal hydride or hydrogen gas cylinders does not have any damaging consequences, whereas deep discharge of batteries is known to negatively affect the capacity of the batteries (Burton et al., 2021). Mediums for hydrogen storage also have extended life cycles and do not have the problem of leakage discharge that batteries have. When the backup storage capacity is equal, existing metal hydride systems are more efficient and similar in weight to lithium-ion batteries, and the benefits only increase with extended backup storage capacity (Burton et al., 2021).

Because of the ease of transport and greater energy content than pure hydrogen, there is also seems to be a recent interest in storing the generated green hydrogen in the form of liquid ammonia (Wan et al., 2021; Aziz et al., 2019). Having said that, the future prospect of hydrogen economy is the cornerstone of many studies (Hosseini and Wahid, 2016). Nevertheless, hydrogen generation from non-renewable resources such as coal, oil, and natural gas is currently dominating the production of hydrogen (Mah et al., 2019; Hosseini and Wahid, 2016). More than 99% of currently produced hydrogen is generated from fossil fuels or electricity generated from fossil fuels, while 96% of commercially available hydrogen, as shown in Table 1, is directly sourced from fossil fuels.

The use of fossil fuels to produce hydrogen invalidates many of hydrogen's environmental benefits as a source of fuel, as this process produces as much as 2.5–5 tonnes of CO_2 per tonne of hydrogen produced (Burton et al., 2021). Nearly half of all hydrogen generated is produced from gasification and thermo-catalytic processes of natural gas, followed by heavy oils, naphtha, and coal (Hosseini and Wahid, 2016; Liu and Liu, 2021; Ayodele et al., 2019). Green hydrogen could be used in all applications where 'standard' hydrogen can be used, but when the infrastructure is in place to generate green hydrogen, very little to no environmentally destructive by-products, such as CO_2 and carbon monoxide (CO), are produced during the production and the use of green hydrogen (Mah et al., 2019; Hosseini and Wahid, 2016; Burton et al., 2021). When a life-cycle study is done to evaluate hydrogen production methods, green hydrogen production has minimal impact on the environment compared to hydrogen produced with fossil fuels (Burton et al., 2021). Out of all green hydrogen production technologies, only water electrolysis has approached commercial readiness (Burton et al., 2021; Piraino et al., 2021). Projects have been developed around the globe which will transform the way hydrogen is produced by using RSE sources to generate water-electrolysis hydrogen instead of steam-reformed natural gas.

2.1. Worldwide

For the most part, the hydrogen economy roadmaps centered on two main points which include improve technology efficiencies and reduce investment costs (Anon, 2021b; Aziz et al., 2019; Kazi et al., 2021; Milani et al., 2020). A number of investigations have been conducted to analyze the feasibility of the transition to a hydrogen economy in different countries in

Table 1
Global output of hydrogen by source (Burton et al., 2021).

Source	Billion m^3/year	Share (%)	Advantages	Disadvantages
Natural Gas	240	48	• Low production cost • Accessible infrastructure	• Environmental impacts during extraction of natural gas • Production of GHG
Oil	150	30	• Low production cost • Accessible infrastructure	• Environmental impacts during extraction of oil • Production of GHG
Coal	90	18	• Low production cost • Accessible infrastructure	• Environmental impacts during extraction of coal • Production of GHG
Electrolysis	20	4	Can be produced with low GHG emissions when using RSE sources	• Low efficiency • High cost of production • Limited infrastructure • Production of GHG when powered with fossil fuels
Total	500	100		

order to achieve these two main points (Hosseini and Wahid, 2016). As the European Union (EU) has made the decision to achieve 33% of its installed energy capacity from RSE, the strong solar targets have pushed green hydrogen development potential to bolster its RSE drive to permit seasonal energy storage and sector coupling (Anon, 2020d). The transition to a low-carbon economy has become a prime concern for European member states (Alonso et al., 2016) and the EU Energy Roadmap is planning to produce 2250 terawatt hour (TWh) of hydrogen in Europe by 2050 (approximately 24% of final energy demand) (Anon, 2021b). Indeed, many European countries have begun to develop ways to produce green hydrogen to position themselves as a hub for the hydrogen economy (Anon, 2020e). When it comes to developing a hydrogen economy, European nations are considered to have several advantages. These include the presence of current leaders throughout the hydrogen value chain who can promote implementation, research strengths in terms of universities with hydrogen expertise and mature research, industrial capacity that can implement a green hydrogen system quickly and cost-effectively, development programs at different levels of government, a solid policy dedication to carbon reduction, and its abundant supply of good RSE resources (Hu et al., 2020; Anon, 2021b; Wijk and Chatzimarkakis, 2020). Moreover, with excellent RSE resource areas generally far from energy demand at industrial sites and urban areas in Europe, the conversion to hydrogen at solar and wind farms provides the opportunity to transmit solar and wind energy fairly cheap and without losses over large distances (Wijk and Chatzimarkakis, 2020).

For example, in Denmark, there is a plan to build a 1.3 GW electrolyzer powered by offshore wind (Anon, 2020e). If the development of the electrolyzer mentioned is successful, it could be one of the largest, if not the largest, green hydrogen plants in the world. In the UK, a first stage implementation project to determine the effectiveness and scale of the deployment of green hydrogen electrolyzer plants powered by offshore wind in the North Sea for industrial energy consumers in Immingham was granted to ITM Power and Element (Anon, 2020a). Glomfjord Hydrogen, a Norwegian company, has proposed the construction of large-scale processing and liquefaction of green hydrogen in Glamfjord, Norway (Anon, 2020e). Nel Hydrogen Electrolyzer, another Norwegian company, has entered into a framework agreement for the supply of up to 60 MW of electrolyzers for green hydrogen production to Lhyfe Labs in Nantes, France. (Anon, 2021b, 2020a). VNG, Uniper, Terrawatt and DBI are building a 40 MW wind farm coupled with electrolyzers near a chemical industry site in Germany, including 50 billion cubic meters of storage and a designated hydrogen pipeline, with a potential expansion to 200 MW by 2030 (Kakoulaki et al., 2021). Another large-scale green hydrogen project in Europe is the Green Hydrogen @ Blue Danube project, focusing on the production, transport and usage of green hydrogen by industrial users and the mobility sector (Anon, 2020f). The project is currently being led by Verbund, the leading energy provider in Austria and one of Europe's largest producers of hydroelectricity (Anon, 2020f). Even oil and gas companies have begun to expand their portfolio of businesses to develop the green hydrogen sector. Shell Netherlands, which is currently working with partners to build a wind-powered green hydrogen plant at one of the major ports in Rotterdam, is a case in point (Anon, 2020e). According to another study, 4.6% of the current fueling stations in the Netherlands can be converted into on-site wind-powered hydrogen fueling stations (Chrysochoidis-Antsos et al., 2020). The percentage was identified by evaluating several key factors, including the potential for annual output of hydrogen, the demand coverage, and the potential for connection to existing gas grids (Chrysochoidis-Antsos et al., 2020).

In order to generate green hydrogen in European countries, it seems that the use of wind energy has gained considerable interest in powering the water electrolysis operations (Berg et al., 2021). In Ireland for instance, wind energy has gained momentum, and there has been a 309% increase in installed capacity from 2008 to 2018 (Chandrasekar et al., 2021). As in 2019, wind energy contributed to 29.3% of the total electricity production in Ireland (Chandrasekar et al., 2021). Large-scale onshore and offshore winds can be produced in several parts of Europe at competitive and subsidy-free prices (Kakoulaki et al., 2021). As shown in Fig. 9, large-scale offshore winds have great potential in the North Sea, Irish Sea, Baltic Sea, and parts of the Mediterranean Sea (Wijk and Chatzimarkakis, 2020).

Coupling offshore wind with the development of hydrogen will offer many advantages to both technologies (Babarit et al., 2018). Without paying for grid access feeds or taxes, hydrogen can be directly connected to an electricity source that provides good capacity factors (Franco et al., 2021). In addition, when combined with hydrogen, offshore wind potential would be untapped, accessing areas with large energy resources that will further decarbonize the economy (Franco et al., 2021). Geothermal energy has also been used to produce green hydrogen, in addition to the use of wind energy. Iceland, for example, has an operational geothermal plant producing green hydrogen and

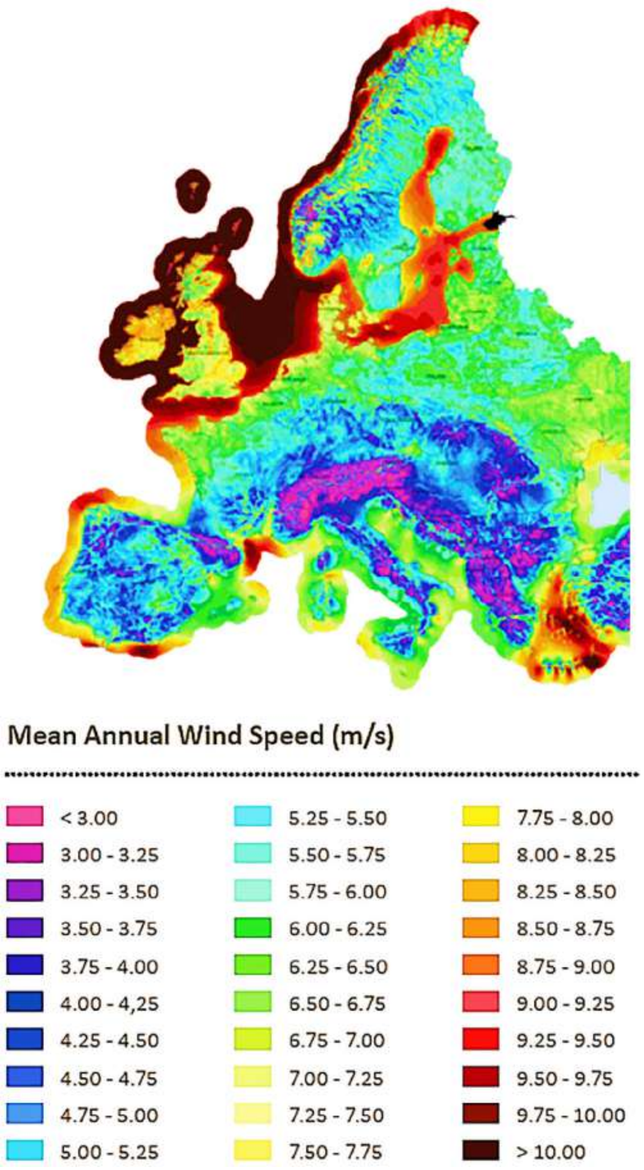


Fig. 9. Wind speed at 80 m height in Europe (Wijk and Chatzimarkakis, 2020).

then using it to produce methanol (Kauw et al., 2015). With an electricity price of EUR 30/MWh ($48/MWh), it is claimed to be cost-competitive (Anon, 2021b). Kakoulaki et al. (2021) conducted a study to evaluate the replacement of fossil fuel-based hydrogen with green hydrogen by electrolysis in the Europe, in which they found that the current electricity produced from RSE resources in Europe is easily sufficient to cover all the current electricity needed for green hydrogen production, as well as the additional demand for green hydrogen in the future (Kakoulaki et al., 2021).

Australia has also begun to make use of its abundant RSE resources and the potential resources available to boost its economy through the production of green hydrogen (Li et al., 2020). The nation currently has 95 large renewable energy infrastructure projects in construction (or due to start construction soon) due to Australia's large investment in renewable solar and wind energy (Wandel, 2020a). In Burrup Peninsula, Western Australia, the Yara Pilbara Renewable Ammonia Feasibility Study will examine the possibility of creating green hydrogen through on-site solar PV powered electrolysis (Wan et al., 2021; Wandel, 2020a). Currently, by using natural gas as a feed stock for its steam methane reforming process, Yara's Burrup Peninsula facility produces fossil fuel-based hydrogen (Wandel, 2020a). Their objective for the feasibility study is to ensure that up to 3% of the total hydrogen generated by the facility comes from RSE resources (Wandel, 2020a). While the percentage may seems minuscule, the feasibility project will help to unlock the potential for producing hydrogen entirely through RSE resources. Australia has recently embarked on the construction of its first commercial-scale wind and solar-powered green hydrogen plant, with initial production scheduled for Q4 2022 (Anon, 2020a).

In the US, the Wind2H2 project (2008–2009) was launched with the main aim of optimizing the production of green hydrogen powered by electricity from wind farms (Widera, 2020). The project was carried out as part of research at the National Wind Technology Center (NWTC) by the National Renewable Energy Laboratory (NREL). Optimization elements include the reduction of electrolysis capital costs and the development of strategies to produce low-cost green hydrogen through utility coordination (Widera, 2020). The high proportion of RSE resources in Canada has driven the implementation of several green hydrogen projects. Since 2018, a 2.5 MW power-to-gas facility run by a collaboration between Enbridge Gas and Hydrogenics has been in operation in Markham, Ontario (Lemieux et al., 2020). Next, a 20 MW hydrogen electrolyzer device for hydrogen production is under development, scheduled to begin operations in Mississauga, Ontario in late 2020 as part of a partnership between Air Liquide and Hydrogenics (Lemieux et al., 2020).

With a view of creating a hydrogen society, Japan is already leading the world with its technological solutions. Japan is also the first country to adopt a basic hydrogen strategy as early as 2017 (Khan et al., 2021; Anon, 2021g). The domestic hydrogen market is projected to expand 56-fold to JPY 408.5 billion (roughly US$ 4 billion) by 2030 (Anon, 2021g). The world's largest green hydrogen production facility has been completed in Fukushima, Japan, in March 2020 (Anon, 2020b). A 20 MW solar array, backed up by renewable power from the grid, is used by the Fukushima Hydrogen Energy Research Field (FH2R) to run a 10 MW electrolyzer at the site in Namie Town, Fukushima Prefecture (Anon, 2020b). The FH2R system can produce up to 100 kg of hydrogen per hour (Anon, 2021g). Accomplishing a hydrogen society also means promoting the overall integration of production, storage, transportation, and utilization of hydrogen. When hydrogen is produced from RSE sources that vary according to the weather and other variables, a particularly critical problem is responding to fluctuations in electrical power. The verification tests at FH2R will address this issue, helping to establish a total management system that incorporates optimizable operating procedures (Anon, 2021g). In addition to expanding its green hydrogen portfolio, the Japanese government has also prepared itself to be the leading exporter of green hydrogen and its supply chain technologies by working to significantly reduce green hydrogen production costs over the next several decades (Anon, 2021b, 2020i). Although water electrolysis is advantageous as it could transform intermittent RSE resources into green hydrogen as a form of energy carrier/storage, the production cost is still relatively expensive compared to other methods as shown in Table 2.

PEM is one of the electrolysis techniques. It can be seen that even though hydrogen gas has the lowest levelized expenditure ($3.0 per kg), it encompasses zero use of RSE resources (Anon, 2021b). In the production of green hydrogen, the capital costs are primarily from the electrolyzers (Hu et al., 2020). Green hydrogen is especially attractive if production costs for water electrolysis can be reduced, as it potentially allows 'sector coupling' whereby the generated green hydrogen can be utilized to decarbonize not only the power generation sector, but also other sectors such as industry and transport.

In terms of the use of hydrogen, the feasibility of green hydrogen with current thermal power plants, particularly gas turbine (GT) fleets, is another key factor that needs to be considered. By retrofitting existing GT combustors and boilers, high temperature heat can be produced from hydrogen (Wijk and Chatzimarkakis, 2020). Hydrogen can therefore replace natural gas in existing power plants after minor modifications have been made (Anon, 2021b). A cooperation agreement was recently signed between the German-based energy utility Uniper and Siemens Gas and Power to create projects relating to the decarbonization of power generation and the use of green hydrogen (Anon, 2020a). The focus of this new agreement includes the assessment of the potential of Uniper's existing GTs and gas storage facilities for the use of green hydrogen. A joint venture of European companies, research institutes, and universities has also launched the world's first demonstration of a completely integrated power-to-hydrogen-to-power project on an industrial scale and in the real-world application of power plants (Anon, 2021q). The four-year project is to demonstrate HYFLEXPOWER, which has accomplished a technology readiness level of 7, by converting a 12 MW combined heat and power (CHP) plant at Engie Solutions' Smurfit Kappa pulp-and-paper industrial site in Saillat-sur-Vienne, France (Anon, 2021q). Siemens Gas and Power, which will play a key role as project coordinator for the HYFLEXPOWER pilot, will provide an electrolyzer system for the production of hydrogen from surplus RSE in the region. While some of that hydrogen would be used for storage, Siemens will also modify the existing SGT-400 industrial GT at the CHP plant to combust a variety of natural gas and green hydrogen mixtures for power generation, working to continually raise the hydrogen fuel volume to at least 80% and eventually to 100% (Anon, 2021q). Fig. 10 below shows the workflow for the HYFLEXPOWER project.

Another major problem nowadays is the lack of RSE plant dispatchability, which pushes GT fleets to provide highly variable outputs at any moment to meet the load. In view of the need for GT fleets to improve their flexibility and efficiency in providing grid balancing services, Mitsubishi Power launched its first 'standard package' of green hydrogen called the Hydaptive and Hystore packages in the US to provide flexibility for RSE by acting as a near-instant power balancing resource to improve the ability of a SCGT or CCGT plant to ramp output up and down to provide grid balancing services (Jones, 2020). It integrates a GT power plant fueled by hydrogen and natural gas with electrolysis to produce green hydrogen using 100% renewable power and green hydrogen storage on site (Jones, 2020). Three key elements are included in the green hydrogen energy storage system. First, excess renewable energy is converted into hydrogen by electrolysis plants. Next, storage mediums store green hydrogen for hours to seasons, depending on the needs of the grid. Finally, hydrogen-enabled SCGT or CCGT power plants transform green hydrogen into centralized dispatchable electricity. Together, this storage system allows further balancing of renewable energy (Jones, 2020).

With all these latest situations showing significant green hydrogen growth, it is not surprising that green hydrogen developments will have a strong impact on the global energy transition in the near future. Latest developments have also shown the potential of green hydrogen to significantly improve the flexibility of the power plant and make 'hydrogen ready' power plant as hydrogen facility matures and requirements for renewable storage increase.

2.2. Malaysia

Numerous studies have been conducted in Malaysia on green hydrogen production technologies, such as biomass gasification, bio-liquid reforming, biogas reforming, dark fermentation, photoelectrochemical splitting of water, and microbial electrolysis cells (Mah et al., 2019). Since the 8th Malaysia Plan, Malaysia's government has identified hydrogen as a priority in research and development (R&D) (Mah et al., 2019). TNB has placed hydrogen under the Proactive Environmental Management Theme as one of the enablers (Mah et al., 2019). From 1997 to 2013, the Ministry of Science, Technology and Innovation (MOSTI) allocated RM40 millions of R&D funds to hydrogen-based research (Mah et al., 2019). Several universities in Malaysia have been actively involved in hydrogen research, especially in the field of fuel cells. This can be demonstrated by the establishment of the Institute of Fuel Cell at Universiti Kebangsaan Malaysia (UKM) and the Centre of Hydrogen Energy (formerly known as the Institute of Hydrogen Economy) at Universiti Teknologi Malaysia (UTM) (Mah et al., 2019). Malaysia's Eco-House, located in UKM, is a great example of green hydrogen economy (Mah et al., 2019). In the Eco-House, solar energy from sunlight is transformed to electrical energy and then used for water electrolysis. The generated hydrogen produced will be stored and then used to run a fuel

Table 2
Costs of production for hydrogen technologies excluding compression, storage and delivery costs.
Source: Adapted from Anon (2021b).

Pathway	Renewable level (%)	Technology	Input	Plant capacity (kg/day)	Levelized cost of production (US$/kg)
Solar PV and grid electricity to hydrogen	32	Proton Exchange Membrane (PEM)	Grid and solar electricity, water	398	8.02 ($11.0)
100% Solar PV generation to hydrogen	100	PEM	Grid electricity, water	126	15.43 ($21.2)
Biogas to hydrogen	100	Steam-methane reforming (SMR)	Landfill, wastewater or dairy biogas	1500	2.94 ($4.0)
Tri-generation biogas to hydrogen	100	Tri-generation	Biogas	1500	5.99 ($8.2)
Natural gas to hydrogen	0	SMR	Natural gas	398	2.17 ($3.0)

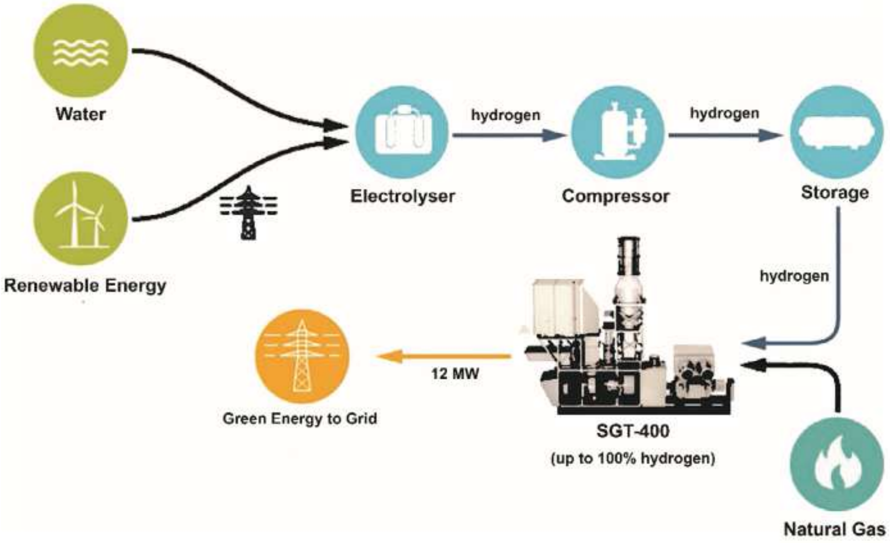


Fig. 10. The overview of HYFLEXPOWER project (Anon, 2021q).

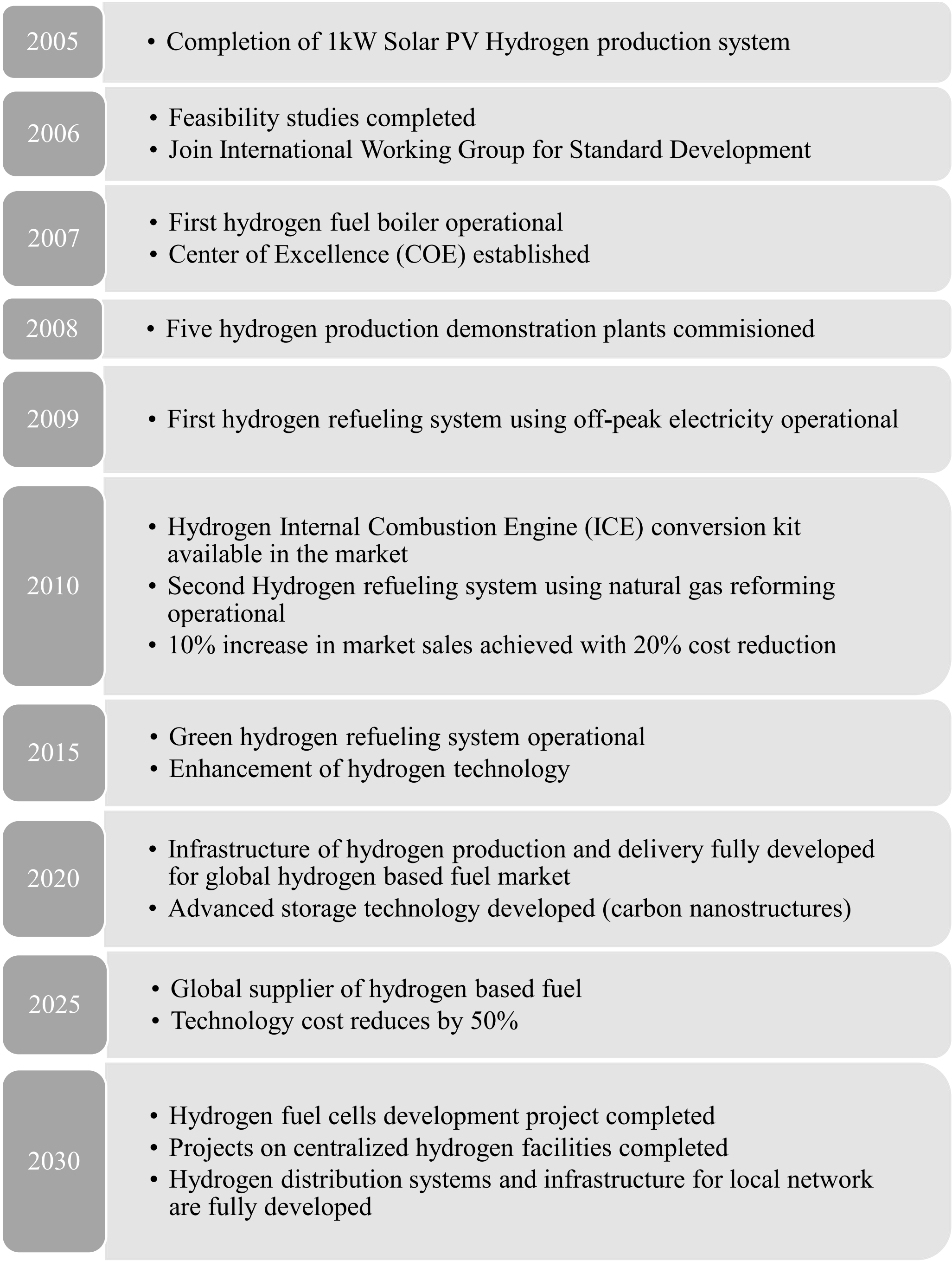
cell, a cooking stove, and a boiler for absorption of the air conditioning system. In 2008, UTM successfully demonstrated their “H2Motive” hydrogen fuel cell motorcycle (Mah et al., 2019). A 7-kW fuel cell system is the core of the motorcycle powertrain that generates electricity for the electric motor to operate the back wheel. UKM unveiled Malaysia’s first indigenous fuel cell hydrogen vehicle in 2014, which is a golf buggy (Mah et al., 2019). Using a device known as a PEM Fuel Cell/Supercapacitor Hybrid Power, the vehicle is powered by a fuel cell engine (Mah et al., 2019).

Despite the actions taken by Malaysia to encourage hydrogen, the progression of hydrogen economy continues to be slow. Fig. 11 shows the hydrogen roadmap developed during the 8th Malaysia Plan in Malaysia, where hydrogen is intended to become an attractive and efficient source of energy by 2030.

As per the roadmap, the first hydrogen refueling device using off-peak electricity is expected to be operational in Malaysia by 2009 and a green hydrogen refueling system by 2015 (Mah et al., 2019). Nevertheless, the development of Malaysia’s hydrogen economy is indeed very poor, and some of the expected roadmap milestones have failed to meet the targeted years as a result (Mah et al., 2019). However, there has recently been an interesting development associated to the development of Malaysia’s green hydrogen infrastructure. This progress is being led by Sarawak, one of the states in Malaysia, with the launch of the first integrated hydrogen production plant and refueling station in Southeast Asia (Anon, 2018b). Developed by Sarawak Energy Bhd. (SEB), with the cooperation of Linde EOX Sdn. Bhd., the facility includes a hydrogen-producing plant through electrolysis and a refueling station for the state’s first hydrogen-powered vehicles (Anon, 2018b). The stations will be established by the state-owned Petroleum Sarawak Bhd. (Petros) and Sarawak Economic Development Corporation (SEDC), and will initially service three SEDC-operated hydrogen fuel cell buses and two SEB corporate fleet vehicles. SEB also discussed the potential collaboration on hydrogen energy with Japan, which is considered to be one of the pioneering steps towards green hydrogen development in Malaysia (Anon, 2021l).

3. Malaysia’s prospective landscape in the green hydrogen potentiality

Unlike a number of developed countries which have abundant RSE resources and leading renewables technology that could assist in the translation into green hydrogen, Malaysia however, is still lacking in terms of RSE integration in the energy mix as shown in Fig. 12.



2005	• Completion of 1kW Solar PV Hydrogen production system
2006	• Feasibility studies completed • Join International Working Group for Standard Development
2007	• First hydrogen fuel boiler operational • Center of Excellence (COE) established
2008	• Five hydrogen production demonstration plants commisioned
2009	• First hydrogen refueling system using off-peak electricity operational
2010	• Hydrogen Internal Combustion Engine (ICE) conversion kit available in the market • Second Hydrogen refueling system using natural gas reforming operational • 10% increase in market sales achieved with 20% cost reduction
2015	• Green hydrogen refueling system operational • Enhancement of hydrogen technology
2020	• Infrastructure of hydrogen production and delivery fully developed for global hydrogen based fuel market • Advanced storage technology developed (carbon nanostructures)
2025	• Global supplier of hydrogen based fuel • Technology cost reduces by 50%
2030	• Hydrogen fuel cells development project completed • Projects on centralized hydrogen facilities completed • Hydrogen distribution systems and infrastructure for local network are fully developed

Fig. 11. Malaysia's Hydrogen Roadmap (Mah et al., 2019).

Although Malaysia's RSE integration is small in comparison to fossil fuel-based energy, Malaysia has abundant renewable resources, particularly solar, biomass, and hydropower. Malaysia has obtained adequate sunlight and irradiance levels due to the geographical position of Malaysia near the equator (Lau et al., 2020), as seen in the irradiance map in Fig. 13. Several studies have already measured the irradiance levels of several major cities in Malaysia where there is a clear potential for solar energy usage across the country (Mohammad et al., 2020). At these high levels of sunlight and irradiance, cheap but intermittent solar energy can be generated (Vaka et al., 2020), which could produce solar-powered electricity nationwide (Lau et al., 2020). In the solar power industry, Malaysia plays a key role and is currently in third place in the development of solar photovoltaic (PV) cells and modules (Vaka et al., 2020). Via solar PV panels, the sun's rays can be transformed into electricity by utilizing the photons of light from the sun (Lau et al., 2020). It is possible to produce electricity and make it available to every corner of the country with the aid of PV technology. Thanks to the decrease in the cost of solar panels, not only is the price of electricity reduced, but it is also becoming more available to everyone (Vaka et al., 2020). As a result, solar PV installations in Malaysia have increased significantly, as shown in Table 3.

The development of green hydrogen through the coupling of PV panels with electrolyzers is one promising source of green hydrogen that could be economically efficient and commercially viable in the near future. In such systems, the energy provided by PV panels is used for electrolysis and is often referred to as

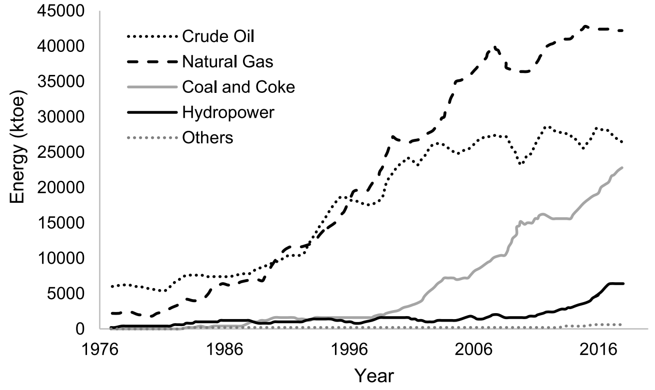


Fig. 12. Malaysia's energy mix (Energy Commission, 2019).

Table 3
Installed capacity of solar in Malaysia compared to the rest of the world (Vaka et al., 2020).

Year	Installed capacity, MW (Malaysia)	Installed capacity, MW (Rest of the world)
2011	0.54	72,029.69
2012	25.10	101,511.21
2013	97.12	135,740.15
2014	165.78	171,518.92
2015	229.10	217,242.54
2016	278.80	290,961.18
2017	370.07	383,597.83
2018	536.02	483,078.20
2019	882.02	580,159.00

solar–hydrogen hybrid systems (Burton et al., 2021). A variety of feasibility studies and pilot solar–hydrogen plants across the globe are already underway, showing that the proposed system is technically and economically feasible (Burton et al., 2021). For example, an experimental investigation of the solar–hydrogen plant was carried out in the regions of the Algerian Sahara, where the efficiency of the solar–hydrogen system was found to be between 18 and 40% (Khelfaoui et al., 2020). The techno-economic investigation of the production of green hydrogen from solar energy systems in Morocco is also investigated, in which a number of locations in Morocco can be considered favorable for the production of green hydrogen (Touili et al., 2020).

To be used in solar–hydrogen hybrid systems, it is vital to build low cost, high performance PV panels and electrolyzers. In addition, the highest efficiencies of solar–hydrogen hybrid systems can only be reached if the full power output of the PV panels can be used by the electrolyzers while the electrolyzers operate as efficiently as possible (Burton et al., 2021). Since hydrogen production is always proportionate to input energy, which is typically not constant from RSE sources due to RSE's intermittent nature, it is important to develop a system that pairs electrolyzers with RSE systems in such a way that the specific operating parameters of renewable energy systems are effectively combined with the power requirements of electrolyzers (Burton et al., 2021). For instance, a solar–hydrogen hybrid system that generates hydrogen effectively when supplied with a highly variable power input, such as power from a PV panel on a day with scattered clouds or on a day with high cloudiness (Burton et al., 2021). The variability of solar intensity presents challenges due to fluctuating solar irradiance and the strict power requirements of the electrolyzers (Anon, 2021b). Although solar PV systems are one of Malaysia's most promising RSE sources for green hydrogen production due to the strategic location of Malaysia around the equatorial region, the country is warm and surrounded by the South China Sea and Malacca Straits, where a large amount of clouds are produced and passed through the region (Lim and Tang, 2014). Therefore, the power production of the PV system is highly intermittent in Malaysia (Lim and Tang, 2014).

Most of the findings from previous publications have provided valuable information on potential methods for improving the efficiency of solar–hydrogen hybrid systems. However, the coupling efficiency of existing commercially feasible solar–hydrogen hybrid systems is typically less than 12%, with the efficiency of some systems found to be as low as 2.3%. Such low efficiency of solar–hydrogen systems significantly increases the total cost of power generation, thereby limiting the usefulness of such systems (Burton et al., 2021). The low performance of solar–hydrogen hybrid systems can partly be due to losses in the efficiency of PV panels and electrolysis cells, as well as electronic control and temperature control power consumption (Burton et al., 2021). Most of the inefficiency, however, is due to inadequate coupling mechanisms between the PV and electrolyzer plates (Burton et al., 2021). In addition, as the electrolyzers shut down whenever the incoming power from the PV panel fluctuates outside the permissible power requirements of the electrolyzer, the number of bearable shut-downs and start-ups of the electrolyzers before premature cell deterioration happens is also a key consideration (Burton et al., 2021). Moreover, the quality of hydrogen generated by many of the current electrolysis systems is also responsive to a decline in input power, and a rise in input power results in an increase in operating temperature, which may contribute to a decline in hydrogen production in some systems (Burton et al., 2021).

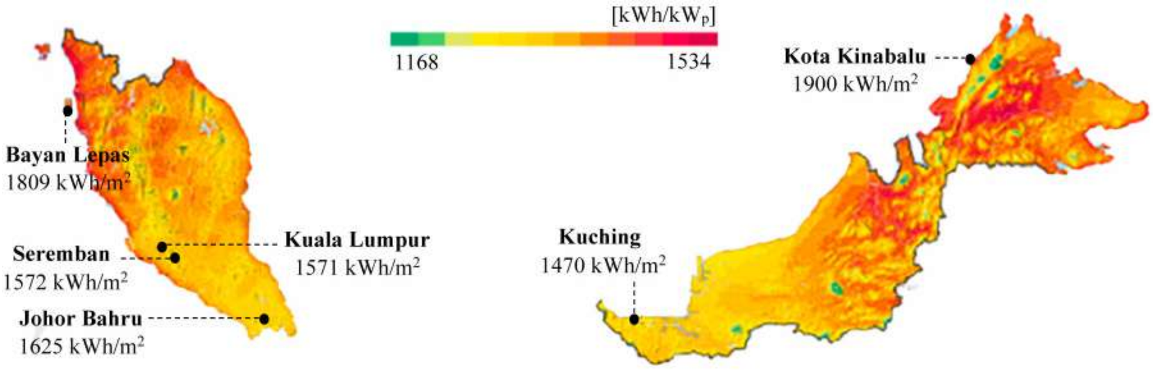


Fig. 13. Solar irradiance level of different towns in Malaysia.
Source: Adapted from Vaka et al. (2020) and Malik and Ayop (2020).

It was difficult to increase the performance of the solar–hydrogen hybrid system, but recent advances have shown that there is a glimmer of light at the end of the tunnel. One study has demonstrated a 95% efficiency solar–hydrogen coupling system (Burton et al., 2021). Even so, the unit was tested for less than 3 h and only recorded data at peak solar irradiance. Since PV panels are capable of collecting energy outside peak time, it is expected that there will not be sufficient power to run their electrolysis bank effectively during periods of low solar irradiance, as the electrolyzers function effectively only within their respective energy requirements (Burton et al., 2021). The research does, however, indicate that 95% of the power produced by the PV panel can be supplied to the electrolyzer and suggests that, when the output of the PV systems matches the necessary input of the electrolyzer, the setup can obtain up to 95% efficiency (Burton et al., 2021). It has therefore demonstrated that there are opportunities to further enhance the efficiency of such a system and, apparently, as stated before, a number of existing and under construction solar–hydrogen pilot plants around the globe will be used to evaluate the potential of this system to further enhance its efficiency.

The use of hydroelectric power with electrolysis for the production of green hydrogen is also an ideal method. Not only could it accelerate the transition to a green hydrogen economy, it could also increase the potential to match electricity production with power demand and increase the flexibility of the hydropower plant (Anon, 2016). The Sarawak Renewable Energy Corridor (SCORE) is one of the corridors of economic development which is a "success story" from the RSE policy in Malaysia with the aim of developing low-cost and clean renewable energy options through hydropower development (Tang, 2020; Mullan, 2018). Currently, hydropower is leading the renewables category in Malaysia's energy mix as shown in Fig. 12. Blessed with high rainfall, favorable geographical terrains (Oh et al., 2018), and abundance of rivers, Sarawak, one of the states in Malaysia, has the potential to deliver affordable hydropower and under the SCORE plan, twelve mega hydropower plants in the Sarawak were proposed at the beginning (Tang, 2020; Mullan, 2018). The current state of development of hydropower in Sarawak includes three dams in operation with one under construction. Two of the operational dams are mega-dams, including Bakun and Murun, both generating 2400 MW and 944 MW of power respectively (Mullan, 2018). With the help of these policies, hydropower has enjoyed considerable expansion and has become one of Malaysia's three vital electricity sources, along with thermal and co-generation stations (Tang, 2020). With most of the hydropower constructions are under way, the significant expansion of renewables in Malaysia is inevitable. There are already several feasibility studies related to the hydrogen production plant powered by hydropower stations, though not as much as solar–hydrogen hybrid plants (Anon, 2016; Posso et al., 2015). Hence, there is a potential to convert some of the hydropower abundances in Malaysia into green hydrogen.

3.1. Electrolyzer development in Malaysia

It has been shown that the core of any power-to-green hydrogen plant is the electrolyzer (Uchman et al., 2020). As a potential strategy to generate hydrogen as a RSE carrier with high energy density, electrocatalytic water splitting is currently attracting tremendous research attention (Widera, 2020; Xie et al., 2021). Three methods are presently available for water electrolysis, including alkaline electrolysis (AEL), PEM, and solid oxide electrolysis (SOEL) (Uchman et al., 2020). A summary of the operating conditions for these three methods is shown in Table 4.

Based on Table 4, it can be shown that AEL and PEM electrolyzers operate at relatively low temperatures. Originally, AEL was the most advanced and cheapest technology, and therefore the most widely used (Leeuwen and Zauner, 2018). The common structure for the AEL setup comprises of two or more electrodes which are immersed in an electrolyte consisting of distilled water and typically 5%–40% sodium hydroxide or potassium hydroxide (Leeuwen and Zauner, 2018). The electrodes have an electrical potential applied across them to cause a direct current (DC) flowing through the electrolyte as seen in Fig. 14. The water disassociates into gaseous hydrogen and oxygen when the energy is high enough (Leeuwen and Zauner, 2018).

This happens when electrons at the cathode decrease the water molecules to create hydrogen gas and hydroxide ions. The negatively charged hydroxide ions subsequently travel to the anode and are oxidized to create oxygen gas and water while introducing electrons into the current flow (Burton et al., 2021).

However, PEM is now a strong alternative to AEL and is used in several power-to-green hydrogen pilot plants (Leeuwen and Zauner, 2018; Shiva Kumar and Himabindu, 2019). Electrolysis with PEM technology is similar to AEL, but instead of liquid electrolytes, a catalyst coated membrane is typically used (Xie et al., 2021), as shown in Fig. 14. In addition, in PEM electrolysis, water is introduced on the anode side of the electrolysis cell and an electrical potential is introduced between the electrodes (Burton et al., 2021). The water disintegrates into oxygen gas, protons and electrons when the power is high enough. Subsequently, the oxygen is released from the system and the electrons are discharged into an external electrical circuit. Protons move through the proton exchange membrane to the cathode at which point they recombine with electrons and other protons to create hydrogen gas (Burton et al., 2021). PEM can achieve greater efficiencies than AEL and can handle fast load variations, which can be very advantageous for green hydrogen production applications (Leeuwen and Zauner, 2018; Dubent and Mazard, 2019). However, recent advancements in AEL technology have resulted in similar efficiencies in both methods (Leeuwen and Zauner, 2018). In addition, as shown in Table 4, PEM has a higher price associated with the required components, such as platinum (Xie et al., 2021) and titanium (Dubent and Mazard, 2019), due to its highly corrosive medium within the electrolyzer as the reaction occurs around a pH of 2 (Burton et al., 2021). PEM also requires equipment to be capable of dealing with high-pressure gases, while guaranteeing that such high-pressure gases are not subject to an environment suitable for combustion (Burton et al., 2021). As a result, AEL was predicted to remain the most crucial electrolysis technology in the near future (Leeuwen and Zauner, 2018).

As it operates at high temperatures and uses steam instead of water, SOEL differs from the other two technologies (Tucker, 2020). The technology is the least developed of the three and has not yet been widely used on a commercial basis (Leeuwen and Zauner, 2018; Tucker, 2020). The most significant benefit of SOEL is the low demand for electricity, as shown in Table 4, and thus the high efficiency potential (Uchman et al., 2020). Rapid material degradation, limited long-term stability because of high operating temperatures, lower electrochemical performance, and high capital costs are the main issues currently associated with the SOEL technology (Leeuwen and Zauner, 2018; Kim et al., 2021). Most of the current research focuses on reducing material degradation and enhancing electrochemical performance, and it is already possible to find some promising results (Kim et al., 2021; Lei et al., 2020). While SOEL may in the future become a very important competitor for AEL and PEM, the technology is still not relevant when reviewing the current capacity of power-to-hydrogen power plants (Leeuwen and Zauner, 2018).

Since the efficiency of the water electrolysis system is the greatest concern for the production of green hydrogen, studies on water electrolysis have been widely carried out by academic

Table 4
A comparison of the operating conditions of AEL, PEM and SOEL (Burton et al., 2021).

Operational conditions	AEL	PEM	SOEL
Temperature (°C)	40–90	20–100	650–1000
Pressure (bar)	<30	<200	<20
Cell region (m^2)	<4	<0.13	<0.06
Current density (Acm^{-2})	0.2–0.4	0.6–2.0	0.3–2.0
Voltage (V)	1.8–2.4	1.8–2.2	0.7–1.5
Production (N m^3/h)	<1400	<400	<10
Gas purity (%)	>99.5	>99.9	>99.9
Stack energy consumption (kWh/N m^3)	4.2–5.9	4.2–5.5	>3
System energy consumption (kWh/N m^3)	4.5–6.6	4.2–6.6	3.7–3.9
Stack efficiency (% LHV)	63–71	60–68	100
System efficiency (% LHV)	51–60	46–60	76–81
Stack lifetime (kh)	60–120	60–100	8–20
Deterioration (%/a)	0.25–1.5	0.5–2.5	3–50
Capital cost (USD/kW)	880–1650	1540–2550	>2000
Maintenance cost (% of investment/year)	2–3	3–5	Not available
Strengths	• Low cost of capital • Smooth operation	• High purity of hydrogen • Quick start-up • Lightweight system	• Highly efficient • Low cost of capital
Weaknesses	• Corrosive • Low purity of hydrogen • Prolong start-up	• Elevated cost of membranes and electrodes • Acidic • High pressure	• Instability that causes safety problems
Technology readiness	Commercial	Near commercial	Demonstration

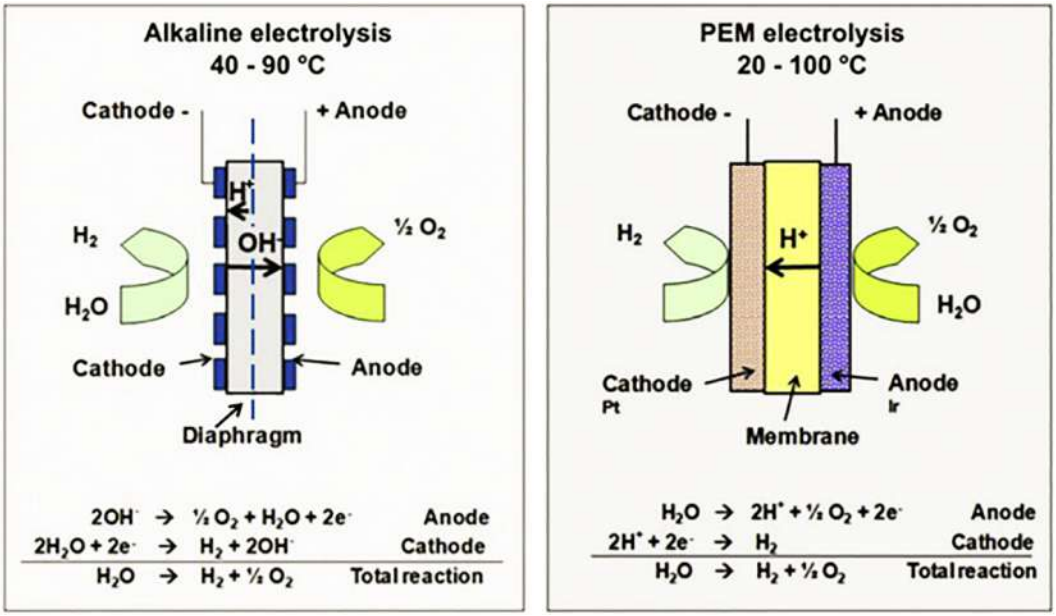


Fig. 14. Illustration of the basic operating parameters of an AEL and a PEM electrolyzer (Burton et al., 2021).

institutions in Malaysia, mainly focused on improving the efficiency of such a system by analyzing the factor that affects the production of hydrogen. Both UTM and Universiti Tun Hussein Onn Malaysia (UTHM) have been actively involved in the development of water electrolysis, and some of the factors studied by the UTM–UTHM collaboration are sunlight, magnetic, and optical field (Bidin et al., 2017a,b). Because of the residue electrical field that reduces the performance of the electrolysis, the collaboration proposed using sunlight to overcome the problem. Several sets of experiments were conducted where they discovered that the production of hydrogen from electrolysis-assisted sunlight was 53% higher compared to conventional light and dark fields (Bidin et al., 2017a). For magnetic and optical field effects, the result of hydrogen production due to magnetic field was found to be higher compared to the optical field (Bidin et al., 2017b). More notably, the combination of both fields produced a superior effect in which, compared to conventional water electrolysis, hydrogen production was found to be nine times higher (Bidin et al., 2017b). In yet another study, a collaborative effort between Universiti Putra Malaysia (UPM) and UTM has proposed a composite membrane electrolysis based on high-temperature copper chloride for hydrogen production (Kamaroddin et al., 2019). The above-mentioned method of electrolysis is proposed with a view to enhancing the associated parameters, which include fuel diffusivity, thermal membrane, and mechanical stability in hydrogen production. The findings have shown that all the aforementioned parameters were improved by the proposed composite membrane. A collaborative work between UKM, UPM, and Kyungpok National University, South Korea, has proposed a highly efficient microbial electrolysis cell (MEC) enhancement catalyst. MEC is a technology for the production of green hydrogen from organic materials (Kadier et al., 2015). In this experiment, a non-noble nickel mesh cathode was evaluated in the MEC setup. The results of the experiment show the great potential of using nickel mesh cathode for the production of hydrogen via MEC. Universiti Malaya (UM) has not been left out in the electrolysis field as they have contribute a number of research studies in the realm of water electrolysis. For example, Ng et al. (2017) from the Nanotechnology and Catalysis Research Center (NANOCAT) in UM have presented scalable and cost-effective water electrolysis using cobalt oxide platelets backed by iron oxides as a novel electro-catalyst system (Ng et al., 2017). It has been shown that the above-mentioned electro-catalyst system could improve the electrochemical performance of water electrolysis, which could then serve as a cost-effective route for the large-scale commercialization of electrolyzers.

The active participation of Malaysia's academic institutions towards water electrolysis development has shown that there is a clear decarbonization pathway in Malaysia as they have begun to build an in-house water electrolysis expertise to help the future progression of the green hydrogen economy. Particularly in the current scenario, when Malaysia is on the verge of getting its first commercial electrolysis plant in Sarawak, the future of the green hydrogen economy in Malaysia seems bright. Nevertheless, the interest and investment in hydrogen production as an energy carrier, the efficiency and economic viability of water electrolysis still need to be improved in order for hydrogen to compete with existing renowned energy carriers (Burton et al., 2021). When Malaysia has successfully developed strong links with the global hydrogen network in the future, this cost can be significantly reduced and, at the same time, the number of research and expertise in green hydrogen production can be further increased to assist the rapidly growing hydrogen-based economy in the future.

3.2. Utilization of the existing Malaysia's gas pipeline network for hydrogen transportation

Hydrogen can be shipped as gas in high-pressure containers, as liquid in thermally insulated containers, as processed methanol or ammonia, or as a chemical carrier medium (Anon, 2021m). Nevertheless, the most economically viable method by far is via the pipeline, where a very high energy transportation capacity can be achieved (Anon, 2021b,m; Obara and Li, 2020; Witkowski et al., 2017). The cost of hydrogen transport by pipeline is 10–20 times cheaper than the cost of electricity transport by cable (Wijk and Chatzimarkakis, 2020; Zivar et al., 2020). The capacity of the infrastructure is a critical distinction between the transport of electricity by cable and the transport of hydrogen by pipeline. The electricity transport cable has a capacity of 1–2 gigawatt (GW), while the hydrogen pipeline can have a capacity of between 15 and 30 GW (Wijk and Chatzimarkakis, 2020). In addition, the transport of electricity via cables leads to losses, while the transport of hydrogen via pipelines does not result in losses. Thus, the re-use of the existing natural gas pipeline to transport green hydrogen could be a major solution to cater the limitation of electricity grid capacity due to the rapid expansion of renewable energy without necessarily requiring tremendous upgrades to the electricity grid (Wijk and Chatzimarkakis, 2020; Liu et al., 2020a).

Malaysia, especially in the Peninsular region, already has a vast gas infrastructure that could be used to transport green hydrogen (Lim and Goh, 2019). In 1983, PETRONAS Gas Berhad (PGB) was founded as a wholly owned subsidiary of PETRONAS with the aim of building the backbone of Malaysia's natural gas transport system, the Peninsular Gas Utilization (PGU) project (Anon, 2021d). The PGU project is one of the long-term strategies and integrated planning in PETRONAS' 1981 Gas Masterplan Study to further grow the natural gas industry in Malaysia. (Kumar and Stern, 2020). The 2613 km PGU pipeline network was completed in 1998 and delivers gas for the consumption of power plants and other industrial customers across the Peninsular Malaysia (Lim and Goh, 2019; Oh et al., 2018; Anon, 2021d; Kumar and Stern, 2020; Anon, 2021n). At current situation, the PGU pipeline network is capable of transporting up to 3000 to 3500 million standard cubic feet per day (mmscfd) of gas (Kumar and Stern, 2020; Anon, 2021n). The existing PGU infrastructure can therefore be converted relatively easily and quickly to accommodate green hydrogen at a sensible cost. The current natural gas delivery workflow in Peninsular Malaysia via PGU is shown in Fig. 15.

Via the City Gate Stations, the existing PGU network supplies natural gas (Kumar and Stern, 2020). There are 33 City Gate Stations in Peninsular Malaysia at the moment. In order to odorize natural gas as part of the safety requirements, each City Gate Station consists of an odorant injection (Anon, 2021n). Natural gas is then transmitted throughout the district stations via feeder lines and distributions lines situated throughout Peninsular Malaysia. Based on the volume and pressure of natural gas needed, the pressure in these pipelines is lowered at district stations, service stations, area stations or regulating stations (Anon, 2021n). When the gas pressure has been lessened to the acceptable level, it can then be delivered to the consumer's internal piping system (Anon, 2021n).

Another benefit of PGU is the strategic location of the network, where it is currently located close to the majority of renewable energy plants in Peninsular Malaysia, in particular solar power plants as shown in Fig. 16.

In addition, one of the original applications of PGU is the supply of natural gas to most of the GT power plants in Malaysia. Assuming that the electrolysis facilities are located in the renewable power plants themselves, the delivery of green hydrogen from renewable power plants to GT power plants can be carried out relatively easily and cheaply by utilizing the existing large-scale PGU networks. If the envisaged situation can be successfully realized, an extensive opportunity for optimizing the production and supply of green hydrogen in Malaysia could be unlocked. In the long run, the success of utilizing the PGU network could unlock another huge potential market which is to become one of the pioneering green hydrogen hubs in Southeast Asia as the PGU already provides a vital gas network that links Peninsular Malaysia to the gas pipeline grid in Thailand and Singapore (Lim and Goh, 2019; Kumar and Stern, 2020).

While Peninsular Malaysia has a long PGU network which could cover almost an entire Peninsular Malaysia, Sabah and Sarawak (East Malaysia) have relatively short gas networks to cover both states (Oh et al., 2018). Sabah–Sarawak Gas Pipeline (SSGP) is a 512 km, 36 inch natural gas pipeline linking the Sabah Oil and Gas Terminal (SOGT) in Kimanis to PETRONAS LNG Complex in Bintulu, Sarawak (Nordin and Ishak, 2018; Ng, 2013). In order to cover both states, which are also two of the largest states by land area in Malaysia, it could therefore be expensive to achieve a wide pipeline accessibility. However, a number of hydropower plants scattered throughout these two states could provide significant cost savings in the construction of additional pipeline infrastructure. If there is a need to construct new gas infrastructure for the green hydrogen project, construction costs are 10–20 times cheaper than building the same energy transport capacity with the new electricity infrastructure (Wijk and Chatzimarkakis, 2020).

In addition, pipeline networks are under construction that could link Peninsular Malaysia and East Malaysia. The ongoing construction of the pipeline referred to above is part of the Trans-ASEAN Gas Pipeline project as shown in Fig. 17 (Kumar and Stern,

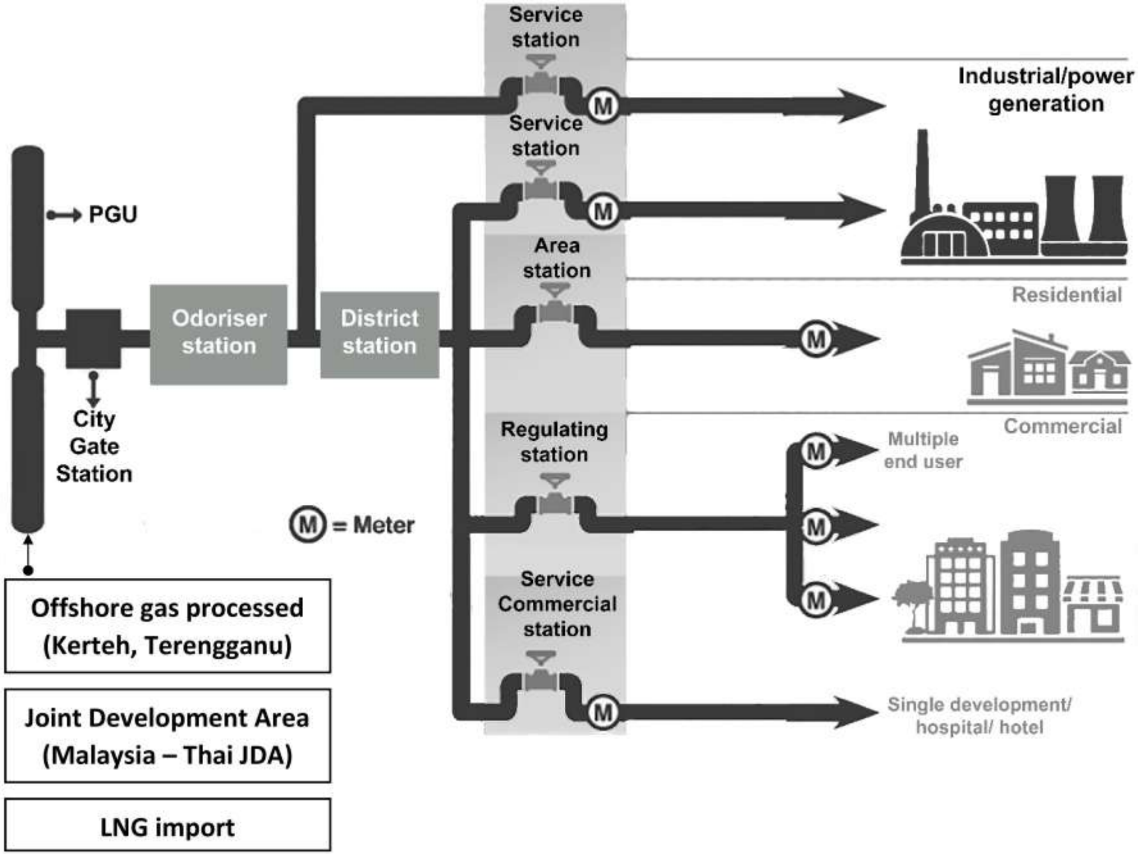


Fig. 15. The delivery workflow of natural gas in Peninsular Malaysia.
Source: Adapted from Lim and Goh (2019), Anon (2021n).

2020; Shi et al., 2019; Kurnia, 2002). The primary goal of the project is to improve the security of energy supply throughout the Southeast Asia countries by establishing interconnection structures for the natural gas transportation (Shi et al., 2019; Kurnia, 2002; Khattak M. A et al., 2018).

The future pipeline interconnections between Peninsular Malaysia and East Malaysia, as shown in Fig. 17, could serve as a backup plan against any scenario that may affect the production of green hydrogen from one of the regions, as the production of green hydrogen from another region could support the affected supply region in order to ensure the continued reliability of the supply of green hydrogen to satisfy the load demand.

Retrofitting the existing Malaysia's gas pipeline network to deliver green hydrogen safely is one of the keys to realize the development of the green hydrogen economy in Malaysia (Anon, 2021b). The success of retrofitting the gas network will also help to prolong its life span in a low-carbon future. A number of studies worldwide have already been conducted to address any technical concerns related to the transport of hydrogen via the existing natural gas pipeline (Liu et al., 2020a), as many industries have realized this low-cost option of delivering hydrogen without the need for high initial capital costs to build new pipeline structures. An example of such studies is the H21 Leeds program funded by the UK government to conduct hydrogen transport research and testing in the UK's existing natural gas networks (Anon, 2021b; PG&E GAS R&D and Innovation, 2018). One of the main objectives of the project is to generate quantitative safety-based evidence to corroborate the potential of the vast existing UK gas pipeline to transport hydrogen at a comparable safety risk to the current supply of natural gas (Anon, 2021b). In China, the surplus of RSE electricity from the northwest provinces has driven several economical studies to utilize the existing natural gas pipeline to transport its RSE surplus via hydrogen to the eastern provinces with developed economies (Obara and Li, 2020; Liu et al., 2020a). The technical and economic studies have revealed the feasibility of these projects (Anon, 2021b; Liu et al., 2020a). Nevertheless, before the natural gas networks can be fully transformed to cater for the delivery of hydrogen, there are a few concerns that need to be considered. The main concern about the use of the current pipeline network is that the networks have been optimized to deliver mostly methane-containing natural gas, and the introduction of large-scale hydrogen would require at least some modification of the current pipeline system, particularly pipeline monitoring and integrity management practices (PG&E GAS R&D and Innovation, 2018).

Based on previous research work related to the use of natural gas pipelines for the transport of hydrogen, the compatibility of the pipeline material with the properties of hydrogen is one of the crucial issues (Bouledroua et al., 2020). Hydrogen's physical and chemical properties differ from natural gas, and therefore it may impact the diffusion into pipeline materials and the carbon steel oxidation (PG&E GAS R&D and Innovation, 2018). In essence, hydrogen can also be corrosive and has a certain embrittlement effect on certain metals (PG&E GAS R&D and Innovation, 2018; Bouledroua et al., 2020). The phenomenon is called as hydrogen-environment embrittlement (H-E) or cracking in steel transmission pipeline welds (Bouledroua et al., 2020; Lankof and Tarkowski, 2020). It is when the mechanical properties are degraded when the metal is exposed to the hydrogen environment (Bouledroua et al., 2020; Hafsi et al., 2018). It happens when the metal is under stress and cracks are present. A number of studies have found the negative impacts of increasing the

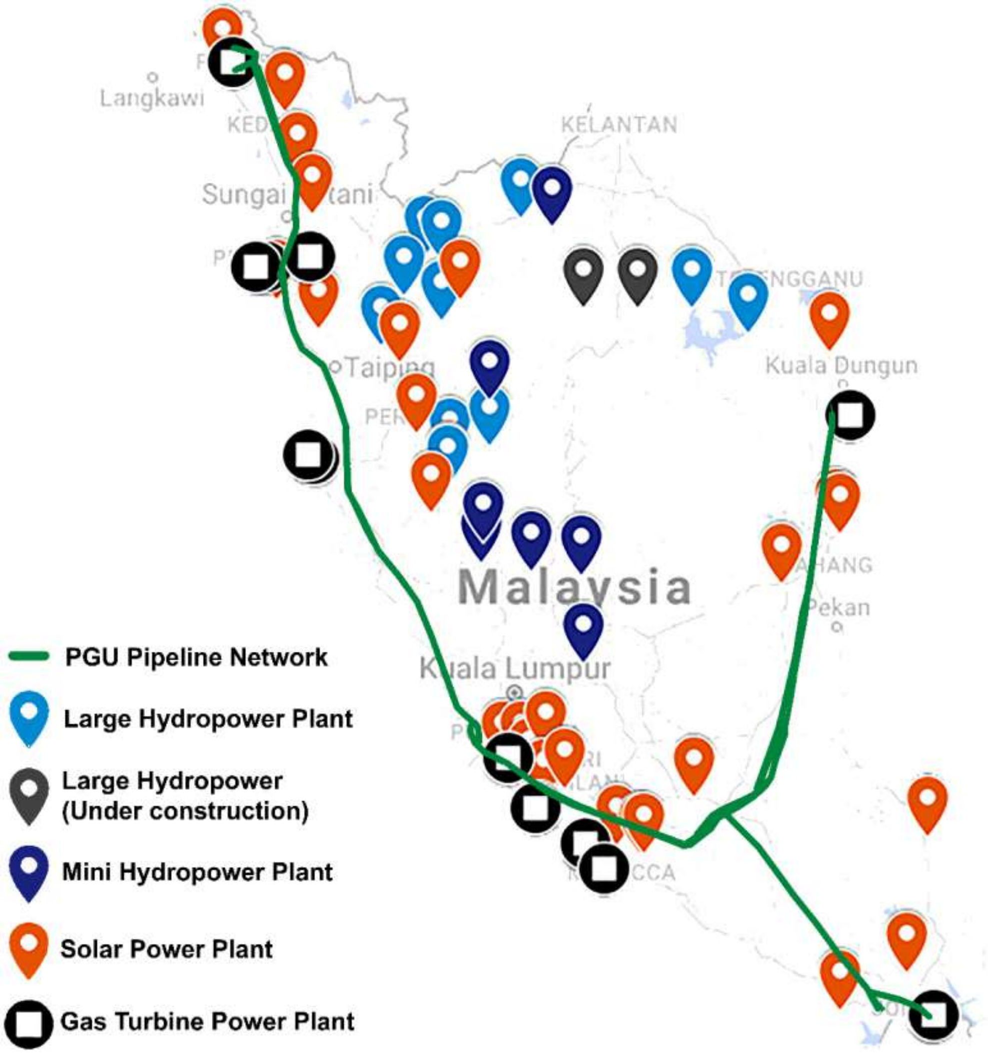


Fig. 16. Locations of PGU, renewables, and GT power plants in Peninsular Malaysia.
Source: Adapted from Energy Commission (2019).

amount of hydrogen in the natural gas pipelines where it could provoke the pipeline brittle fracture (Bouledroua et al., 2020; Hafsi et al., 2018). Plus, the transient condition of hydrogen flow in pipelines due to the sudden changes in gas flow parameters can be a triggering factor for serious operational issues (Bouledroua et al., 2020). In principle, embrittlement can accelerate the propagation of cracks, depending on the quality of the steel and potential exposure to atomic hydrogen, thereby reducing the service life of the pipeline by 20 to 50% (Anon, 2021m). All in all, hydrogen gas decreases fracture strength, crack propagation resistance, and ductility (as measured by area reduction), and increases the growth rates of fatigue crack for pipeline steels and their welds (PG&E GAS R&D and Innovation, 2018; Bouledroua et al., 2020; Hafsi et al., 2018). An experimental study has shown the effect of the proportion of hydrogen in natural gas on the degradation mechanism of X80 pipeline steel, where 5% hydrogen volume already affects the tensile strength and yield strength of the pipeline steel (Zhou et al., 2021). Ergo, to deliver hydrogen, the integrity of the steel pipes and fittings must be considered, with necessary modifications are needed to boost the reliability and the durability of the pipeline (PG&E GAS R&D and Innovation, 2018; Bouledroua et al., 2020). Numerically tracking the concentration of hydrogen along the inner wall of the pipeline on the basis of pressure fluctuations due to the dynamics of transient gas is also one of the approaches suggested by researchers to predict the amount of hydrogen diffused in the pipeline metal to prevent leakage of hydrogen (Hafsi et al., 2018). In terms of mitigating the corrosive issue, corrosion inhibitors have emerged as an effective technique, and in recent years, the technique has gained increasing attention among researchers (Bouledroua et al., 2020).

Next is the leakage issue. If the pipeline is impaired and an uncontrollable leakage of hydrogen occurs, the transport of hydrogen via pipelines presents a possible hazard to humans and the surrounding environment (Witkowski et al., 2017). Since the hydrogen molecule is so small, mobile, and has low molecular weight, it is highly diffusive and it can penetrate seals and plastic pipes more easily than methane (Witkowski et al., 2017; Zivar et al., 2020; Lankof and Tarkowski, 2020; Tarkowski, 2019; Taamallah et al., 2015). The physico-chemical properties of hydrogen and methane are shown in Table 5.

The volume of hydrogen leakage is generally estimated to be approximately triple than that of natural gas, which is marginal on an economic scale (Anon, 2021e). In a confined area, however, one or many concentrated leaks could raise the hydrogen levels to an intolerably high level, which would be a major safety concern (Froeling et al., 2021). Plus, with hydrogen having a much lower density than natural gas, the leakage of hydrogen

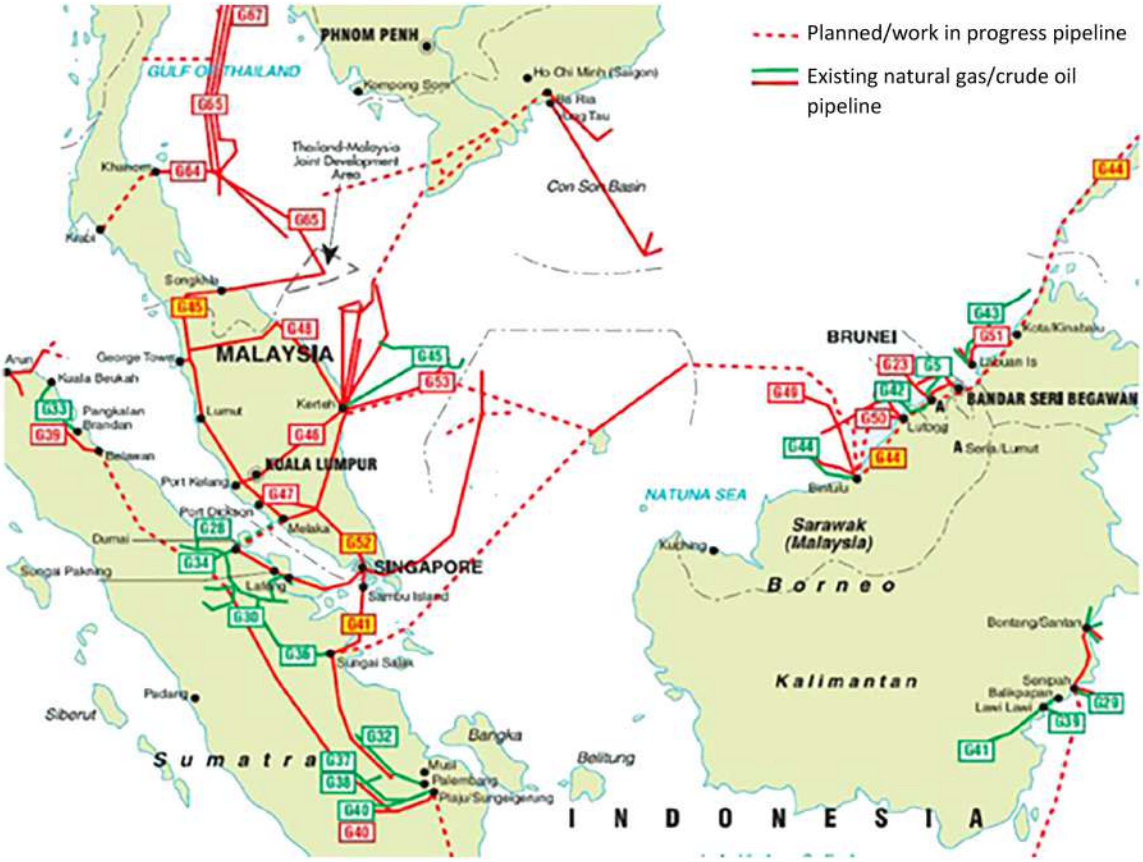


Fig. 17. Southeast Asia pipeline map (Abdul Rahman et al., 2016).

Table 5
Comparison of physico-chemical properties of hydrogen and methane.
Source: Adapted from Zivar et al. (2020) and Tarkowski (2019).

Properties	Hydrogen	Methane
Molar mass	2.016	16.043
Density at NTP (kg/m^3)	0.08375	0.6682
Viscosity at NTP (Pa s)	0.89×10^{-5}	1.1×10^{-5}
Heating value (kJ/g)	120–142	50-55.5
Flammability limits [vol% in air]	4–75	5.3–15
Minimum ignition energy [mJ]	0.02	0.29
Autoignition temperature [°C]	585	540
Detonability limits [vol% in air]	11–59	6.3–13.5
Diffusion coefficient in air at NTP [cm^2/s]	0.61	0.16

may disperse faster than the leaked natural gas (Anon, 2021e). Most importantly, there is currently no odorant for hydrogen, which makes it very difficult for consumers, employees, or the public to detect significant or dangerous hydrogen concentrations (Verleysen et al., 2020). Therefore, as hydrogen levels in the pipeline increase, hydrogen monitoring and leak detection tools are becoming increasingly important (PG&E GAS R&D and Innovation, 2018). There are already a number of studies exploring the harmful effects of hydrogen transport associated with unintended pipeline failure, with the phenomenon of hydrogen jet fire being one of the main concerns (Froeling et al., 2021). However, a numerical analysis has predicted that hydrogen jet fires are less deadly than natural gas jet fires. The degree of lethality of hydrogen jet fires is predicted to decrease faster than natural gas jet fires along the pipeline distance (Froeling et al., 2021). The study should be further validated with the experimental results, but the information from this numerical work is important to provide preliminary insights on the subsequent impact of hydrogen leakage, especially on the basis of fire hazards.

Hydrogen much lower density as compared to natural gas has another concern. To generate the same amount of energy as natural gas, a greater volume of hydrogen is needed. To provide the same energy to the customer, the flow rate of hydrogen needs to be significantly increased. In pipeline network, the flow velocity of hydrogen with its smaller density is up to three times greater than that of methane (Anon, 2021m). This means that the same pipeline necessitates three times the amount of hydrogen to be transported at the same pressure during a given period, while the capacity for energy transport is only slightly lower (Anon, 2021m; Zivar et al., 2020). Henceforth, the hydrogen compression in pipelines is another important issue (Palys and Daoutidis, 2020; Witkowski et al., 2017; Yee Mah et al., 2021). If the hydrogen compressors could be employed to meet the similar pressure necessities as those used for natural gas compressors, it can be expected that hydrogen pipe diameters to approach common values of natural gas pipelines (Witkowski et al., 2017). Nevertheless, hydrogen compression in pipelines will increase the potential for chocking to take place at certain distances along the pipeline (Witkowski et al., 2017). Therefore, the decompression of hydrogen at the correctly selected transport distance will be needed (Witkowski et al., 2017).

Despite the above-mentioned concerns, the use of natural gas pipeline networks has remained one of the best low-cost options for transporting green hydrogen to meet load demands and, ultimately, to create a zero-carbon economy. Situated at the heart of Malaysia's energy system, the dense PGU pipeline infrastructure for natural gas provides unique opportunities to figure out how the most economical conversion of the PGU infrastructure to deliver hydrogen could work. With the recent declaration from PETRONAS to be carbon neutral by 2050 (Hicks, 2020), the utilization of gas pipeline network to deliver green hydrogen could be one of the major initiatives to achieve the zero-carbon goal. TNB, PETRONAS, Sarawak Energy, and the Malaysian government, all of which are key decision-makers for Malaysia's energy industries, could begin to collaborate on the green hydrogen project by first using all of their existing infrastructures to launch the feasibility study, and then commercializing green hydrogen at modest costs. While the network conversion to cater hydrogen will takes considerable time where major stages include several years of preliminary works, the right strategies and policies, along with the support from all the key-decision makers will help to accelerate the realization of hydrogen economy in Malaysia.

3.3. Availability of Malaysia's depleted gas reservoirs for green hydrogen storage

Energy storage is considered to be a key component of the energy supply chain for the 21st century (Tarkowski, 2019) as it ensures the reliability of supply to meet the needs of consumers (Wijk and Chatzimarkakis, 2020). Furthermore, the implementation of energy storage will create a wide range of potentials, particularly in terms of improving the use of RSE resources, grid stability, efficiency of energy systems, while at the same time reducing the use of fossil fuels and, subsequently, reducing the environmental impact of power generation (Tarkowski, 2019). Energy storage would also help to prevent the RSE power abandonment phenomenon that is still extreme at the moment (Wu et al., 2021). Energy storage can be categorized into four groups, based on how RSE energy is stored as mechanical, electrical, thermal, and chemical (Wu et al., 2021). Green hydrogen storage is classified as the chemical-based energy storage (Yee Mah et al., 2021; Wu et al., 2021), where in the sense of the application of green hydrogen, would not only serve as an RSE energy storage, but also as a buffer between transport and distribution (Wijk and Chatzimarkakis, 2020). In addition, if the electrolyzer is not continuously operated but instead adapts to the fluctuating supply of energy from renewable farms such as solar or wind, a storage facility is required to buffer the fluctuating production of green hydrogen (Widera, 2020; Palys and Daoutidis, 2020; Leeuwen and Zauner, 2018; Zivar et al., 2020; Liu and Du, 2020). Therefore, one potential way to adapt to the fluctuation of green hydrogen produced by RSE is to use hydrogen storage, which accumulates surplus RSE energy via hydrogen at the time of overproduction and effectively transfers stored hydrogen to the network during its shortage (Uchman et al., 2020; Yee Mah et al., 2021; Lankof and Tarkowski, 2020). It will also be used as insurance against any unforeseen accidents, natural catastrophes or other events which may affect the production or distribution of green hydrogen (Wijk and Chatzimarkakis, 2020).

Hydrogen storage costs can be inexpensive. The cost of storing hydrogen in depleted gas reservoirs is at least 100 times cheaper than the cost of storing electricity in batteries (Wijk and Chatzimarkakis, 2020) and it is suitable to store a large amount of hydrogen gas (Widera, 2020; Zivar et al., 2020; Colbertaldo et al., 2019). Originally, natural gas deposits occur in so-called geological traps (Tarkowski, 2019). These traps typically consist of a reservoir (abundance of hydrocarbons in the pore space of rocks such as sandstone or carbonate), its seal, and an underlying aquifer (Tarkowski, 2019). The trap-sealing rocks (low permeable and non-fractured) keep the natural gas in the reservoir and do not permit it to move beyond its boundaries (Tarkowski, 2019). Exploitation removes a portion of natural gas, but not all of it (Tarkowski, 2019). Thus, the depleted gas reservoirs are the remnants after such natural gas extraction has occurred.

The depleted gas reservoir is currently one of the potential techniques for the application of underground gas storage (Colbertaldo et al., 2019). In general, reservoirs of this type are equipped with the necessary surface and subsurface installations that can be used for hydrogen storage application (Zivar et al., 2020; Tarkowski, 2019). This is a big advantage, compared to another form of underground hydrogen storage such as the salt cavern, where high investment outlays are needed for the construction of related facilities (Lankof and Tarkowski, 2020). The adaptation of depleted gas reservoir to the requirements of underground hydrogen storage makes it possible to reduce costs (Colbertaldo et al., 2019). For a depleted gas reservoir to be used as an underground hydrogen storage site, some geological criteria have to be met. It is necessary to carry out a fully integrated assessment of the processes involved in the conversion of such reservoirs to store hydrogen, covering geological and technical aspects, including those relating to boreholes (type of casing, type of steel and cement used), surface installations, and others (Zivar et al., 2020; Tarkowski, 2019).

The benefit of the depleted gas reservoirs is that they have been well recognized during their exploration and exploitation (Lemieux et al., 2020). As natural gas has remained there for millions of years, the tightness of a depleted gas reservoir is guaranteed by its existence (Lemieux et al., 2020). There is usually some amount of remnant gas in a depleted gas reservoir that can be used as a cushion gas. It is essential to cease gas extraction at the optimum time when planning to set up a hydrogen storage facility in a depleted gas reservoir (Zivar et al., 2020). This enables the storage to be created in a shorter time at a lower cost (Zivar et al., 2020). Newly formed underground gas storage facilities tend to meet their planned exploitation parameters in about 5 years (Zivar et al., 2020; Tarkowski, 2019). During this time, formation waters that invaded the gas deposit after the cessation of its exploitation are expelled (Zivar et al., 2020; Tarkowski, 2019). The maximum pressure in underground storage located in the depleted gas reservoirs commonly exceeds the original reservoir pressure (Zivar et al., 2020; Tarkowski, 2019). This makes it possible to store more gas than was initially present in the deposit (Zivar et al., 2020; Tarkowski, 2019).

Next advantage is the safety of storage. It has already been established that depleted gas reservoirs can be used for gas storage because of their imperviousness over geological time frames (Donadei and Schneider, 2016). Underground gas reservoirs are less susceptible to fire due to the absence of contact with atmospheric oxygen (Zivar et al., 2020), which is a very important scenario for high-reactivity gases, such as hydrogen, as well as the reduce risk for terror acts or military operations (Tarkowski, 2019). The next benefit is the space handling. The conventional storage of surface tanks would have to use large areas to store the same amount of gas as in depleted underground gas reservoirs (Tarkowski, 2019). It is therefore more profitable to store gas in underground reservoirs than to construct an equivalent surface tank (Khilyuk et al., 2007). In addition, with the existing depleted gas reservoir facilities, which are usually already equipped with gas injection and withdrawal installations, together with gas processing and transport preparation systems in the transmission system, converting the depleted gas reservoir into a green hydrogen storage facility means lower financial expenditure (Tarkowski, 2019). Another benefit is that these reservoirs have already been very well studied as part of previous exploration and production activities (Donadei and Schneider, 2016). Last but not least, there is a vast availability of depleted gas reservoirs around the globe (Tarkowski, 2019). Fig. 18 shows the capacity of three common underground storages — depleted gas reservoir, depleted aquifer, and salt cavern (Zivar et al., 2020; Brey, 2020), where it can be seen that the depleted gas reservoirs accounted for an approximately 75% of the total underground storage capacity worldwide.

Underground hydrogen storage does not differ greatly from underground natural gas storage, which for years has been

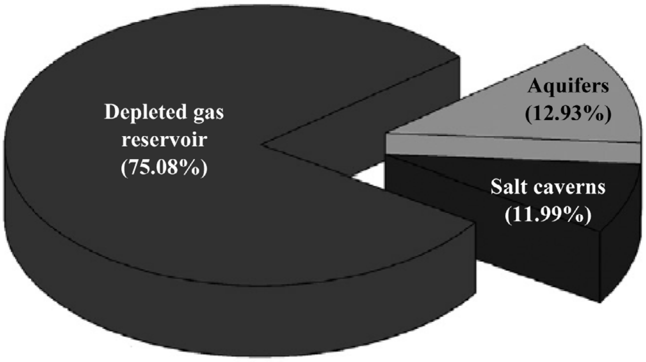


Fig. 18. Share of worldwide underground storage by storage type in 2010 (Tarkowski, 2019).

widely used by oil and gas (O&G) companies (Zivar et al., 2020; Tarkowski, 2019). Malaysia is already recognized as one of the nations with a flourishing upstream, midstream, and downstream O&G sector due to its long historical development of the O&G industry that began more than a century ago (Lim and Goh, 2019; Islam et al., 2012; Ramli, 1985). Malaysia is one of the world's largest LNG exporters (Zainul, 2019). Therefore, Malaysia has a number of depleted gas reservoirs that could be used to store large volumes of green hydrogen underground.

Nevertheless, not all depleted gas reservoirs are best suited for transformation into a gas storage facility. The depleted gas reservoirs are of pore fracture type, where geological aspects and conditions are crucial for storage and the technical requirements are of secondary importance (Tarkowski, 2019). The criteria for suitability include structural depth, thickness, tightness, reservoir pressure, reservoir characteristics–porosity and permeability, geo-mechanical characteristics, and the proper attributes of insulating roof rocks (Zivar et al., 2020; Tarkowski, 2019; Donadei and Schneider, 2016). Because of the depleted reservoir mechanical characteristics, they tend to have a lower injection and withdrawal flexibility, so gas storage facilities built using this reservoir tend to be best used for seasonal applications (Donadei and Schneider, 2016). Therefore, for the selection of depleted reservoirs for safe green hydrogen storage, there is a need to implement a certain practice. Successful storage requires a wise choice of appropriate wells in depleted gas reservoirs to minimize the risk of leakage and contamination of subsurface resources (Raza et al., 2017). One of the critical elements to unlocking the immense potential of green hydrogen storage in Malaysia is a certain guideline that can be followed to provide a deeper understanding of depleted gas reservoirs chosen for green hydrogen storage practices.

All the requisite guidance goes back to the relationship between hydrogen properties and the geological structures of depleted gas reservoirs. Depending on the temperature and pressure, hydrogen may be present in different states, as shown in Fig. 19.

Hydrogen is a solid with a density of 70.6 kilogram per cubic meter (kg/m^3) at −262 °C. It is a gas with a density of 0.089 kg/m^3 at 0 °C at a pressure of 1 bar (Tarkowski, 2019). The extent of the liquid state of hydrogen is shown by the narrow zone between the triple point and the critical point at −253 °C, with a density of 70.8 kg/m^3 (Tarkowski, 2019). As mentioned before, the storage of hydrogen essentially involves reducing the enormous volume of hydrogen gas. One kilogram of hydrogen covers a volume of 11 m^3 at ambient temperature and at atmospheric pressure. It needs compression or cooling below the critical temperature in order to increase the hydrogen density for storage applications (Zivar et al., 2020). Alternatively, the repulsion needs to be lowered by the interaction of hydrogen with another material. The reversibility of hydrogen injection and withdrawal is another critical aspect in a hydrogen storage system (Tarkowski, 2019). However, higher gas mobility can be achieved due to the low viscosity of hydrogen relative to methane, and higher hydrogen withdrawal efficiency is therefore expected later on (Zivar et al., 2020).

As previously mentioned, the necessary condition for the design of an underground hydrogen storage facility is its geological tightness, which is also ensured by the tightness of the roof rocks (Zivar et al., 2020). This should not raise any concerns and hydrogen should not be leaking behind the storage space limits. As mentioned before, the hydrogen particle is the smallest chemical particle known. As a result, gaseous hydrogen has an elevated penetrability where it diffuses in solids several times faster than natural gas or pure methane, as shown in Table 5. This may create issues with underground storage. Fortunately, in depleted gas reservoirs, hydrogen tightness is boosted by the presence of water in the pore space of the rocks combined with a low hydrogen solubility in water, equal to 0.00018 mol/mol at 25 °C and a pressure of 100 bar, and a low diffusion coefficient of 10^{-9} m^2/s in pure water and 10^{-11} m^2/s in water-soaked argillaceous rocks (Tarkowski, 2019). The tightness of argillaceous rocks with respect to hydrogen, that is the loss of hydrogen by diffusion in these rocks and its solubility in reservoir water, has been guesstimated at 2% during one storage cycle (Tarkowski, 2019). Hence, the effective operation of underground green hydrogen storage facilities through depleted gas reservoirs will have a high advantage of ensuring that sufficiently large quantities of injected hydrogen are withdrawn without losses caused by hydrogen leakage.

The prospect of mixing the stored hydrogen with the remaining natural gas in depleted gas reservoirs, which could affect the purity of hydrogen, is another factor that must be considered (Zivar et al., 2020; Lord, 2009). Simulation studies could be used to offer insight into how the mixing of various gases stored underground can be minimized, which is already reflected in numerous technical publications (Lord, 2009). In contrast, a hydrogen-natural gas blend inside the depleted gas reservoir has a substantial advantage where the caprock's permeability has been found to be reduced, which can be a desirable scenario for a storage operation (Zivar et al., 2020).

Also important are the technical, environmental, legal, and economic aspects. The tightness of the boreholes drilled on the site and of the surface equipment are part of the technical tightness of the facility (Tarkowski, 2019). It is also of key importance to choose adequate exploitation parameters, to take into account the individual characteristics of the reservoir and to choose injection and withdrawal pressures that do not exceed the pressure of rock fracturing (Tarkowski, 2019). In a few scenarios, up to the time of production, reservoirs that once held gas continuously lost gas over geological time. In other situations, gas loss occurred until the pressure fell below the cap rock threshold pressure, which is the pressure required for capillary water to be displaced by gas. Consequently, once operating pressure has been increased, hydrogen gas loss can occur. 50% of the reservoir volume should contain cushion gas to maintain depleted reservoir temperature to enable adequate injection and withdrawal rates at all times (Zivar et al., 2020; Lord, 2009).

As far as the feasibility analysis on the use of depleted gas reservoirs to store hydrogen was concerned, such study was carried out in a small depleted gas reservoir in the Molasse Basin in Upper Austria. For the first time, the Integrated Pilot Project "Underground Sun Storage" tested the storage of hydrogen created from surplus RSE resources in a depleted gas reservoir (Zivar et al., 2020; Hassannayebi et al., 2019). The main objective of

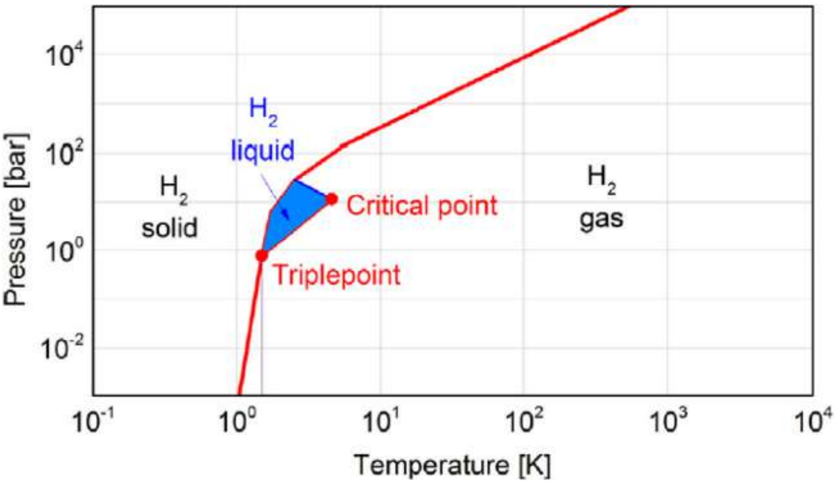


Fig. 19. Hydrogen phase diagram (Tarkowski, 2019).

the project is to develop a workflow to analyze hydrogen-brine-mineral interactions through geochemical modeling in order to quantify possible geochemical processes that could contribute to the loss of hydrogen in a depleted gas reservoir. The chemical reactivity of hydrogen with minerals is one of the highlighted issues associated with underground hydrogen storage (Lemieux et al., 2020; Zivar et al., 2020). The result of geochemical modeling has shown that hydrogen could potentially compromise the integrity of the reservoir as all possible reactions could raise the pH of the reservoir. Even so, given the full range of uncertainties mainly due to the lack of reliable kinetic data, the hazard of hydrogen loss, as well as the disruption of reservoir integrity associated with geochemical interactions with hydrogen cannot necessarily be ruled out (Hassannayebi et al., 2019). There is also a study that has already examined the potential of the Rough Gas Storage Facility — currently Great Britain's largest gas storage facility, to store hydrogen (Amid et al., 2016). The Rough Gas Storage Facility is a depleted gas reservoir located under the Southern North Sea bed (Amid et al., 2016). The assessment shows that there is no insurmountable technical barrier to the storage of hydrogen in a depleted gas reservoir (Amid et al., 2016). Dissolution and diffusion losses of hydrogen could be reduced to less than 0.1% (Amid et al., 2016). Even with calcium carbonate dissolution, losses from biological conversion of residual CO_2 were limited (Amid et al., 2016).

While the interest in hydrogen storage in geological structures is growing, as reflected in numerous technical publications (Tarkowski, 2019), there is still a lack of studies involving the storage of hydrogen in depleted gas reservoirs. Much of the research focused mainly on CO_2 storage for the application of carbon capture and storage (CCS) in depleted gas reservoirs (Zivar et al., 2020; Raza et al., 2017). For example, Raza et al. (2017) have provided a guideline that can be implemented to provide a clear grasp of depleted gas reservoirs chosen for the practice of CCS. Japan Oil, Gas and Metals National Corporation (JOGMEC) has recently signed an agreement to evaluate the development of high CO_2 gas reservoirs in Malaysia using CCS technology with JX Nippon Oil & Gas Exploration and PETRONAS (Anon, 2020h). The partnership would pave the way for Malaysia to use a large number of depleted gas reservoirs that have been found but left undeveloped because of technological and economic reasons. The feasibility study would certainly influence the development of future storage reservoirs, even if the initial concept is for CCS applications, because the underground storage of hydrogen does not vary greatly from the underground storage of CO_2 (Tarkowski, 2019). With a view to the eventual commercialization of green hydrogen, the partnership will serve as a first step towards maturing the depleted gas reservoir storage system before it can be considered for the application of green hydrogen. Several feasibility studies will be needed before depleted gas reservoirs can be fully converted to store pure hydrogen, including tightness monitoring and pressure control, reactivity (chemical, mineralogical, and biological) between hydrogen and reservoir rocks (Yekta et al., 2018), sealing overburden, and, last but not least, detailed characteristics of the storage site along with the creation of a digital model (Tarkowski, 2019).

The location of the depleted gas reservoirs in Malaysia is another significant factor. In order to clarify that the depleted gas reservoir is beneficial for the underground hydrogen storage in Malaysia, the reservoir should favorably positioned with respect to the distribution system. Most of Malaysia's oil and gas comes from offshore fields (Mohd Zaki et al., 2016). The continental shelf is divided into three production basins, including the Malay basin located in the western Peninsular Malaysia, and the Sarawak and Sabah basins in the eastern region, as shown in Fig. 20 (Mohd Zaki et al., 2016).

Specifically, Malaysia's natural gas reserves are primarily found in Sabah and offshore Sarawak (Oh et al., 2018; Anon, 2021d,j). The vast natural gas pipeline connections across the offshore fields of Malaysia and much of the metropolitan area of Malaysia would certainly be advantageous for the storage and transport of green hydrogen to customers.

In summary, the potential for green hydrogen underground storage in Malaysia exist which have been supported by several factors including the number of depleted gas reservoirs in Malaysia along with its flourishing O&G sector, the initiation of feasibility study related to the gas storage in Malaysia's depleted gas reservoirs, and some of impactful studies worldwide which have proved the feasibility of converting depleted gas reservoirs to store pure hydrogen. Needless to say, it will take years to fully realize the potential of underground hydrogen storage in Malaysia as the current development is still in the early phase. Plus, with the rapidly growing research scenario related to the green hydrogen storage worldwide, there is a possibility to have better solutions (technically and costly) in storing the green hydrogen in the future. Yet, the utilization of depleted gas reservoirs is currently one of the best options to store a large amount of hydrogen in Malaysia due to its modest cost based on the surplus of reservoirs and the preparedness in well technologies. Being said that, the compatibility of underground storage method differs for each regions. For example in Europe and the US, they have a large amount of salt caverns which can be used to store

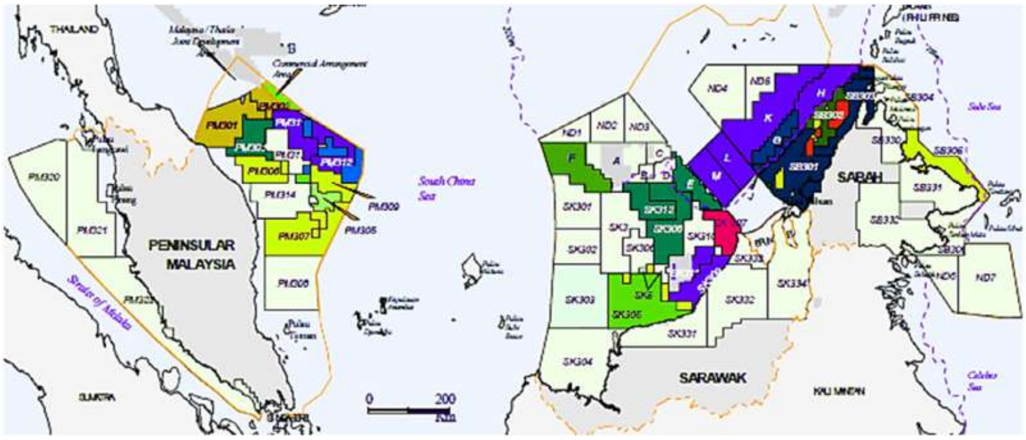


Fig. 20. Malaysia's exploration and production blocks (Mohd Zaki et al., 2016).

the hydrogen (Lemieux et al., 2020; Lankof and Tarkowski, 2020; Tarkowski, 2019). Hence, the use of salt cavern and depleted gas reservoir primarily depends on the surplus of both underground storage types at a particular region.

3.4. The firing of hydrogen in Malaysia's thermal power plants

The adoption of hydrogen in thermal power plants, especially GT, is one of the most important milestones that needs to be accomplished in order to fully realize the power-to-hydrogen-to-power system. GTs are considered as the cleanest options of conventional thermal power plant technologies (Anon, 2021f). As carbon neutrality becomes a key long-term priority for countries and organizations, the replacement of hydrogen from natural gas fuel is a viable means of enabling the operation of carbon neutral power plants as practically no CO_2 is produced by hydrogen combustion (Anon, 2021f). In addition, the blending of natural gas and hydrogen will significantly reduce carbon emissions (Anon, 2021f; Meziane and Bentebbiche, 2019). For hydrogen and natural gas mixtures, the relationship between the reduction of CO_2 and the hydrogen content is non-linear since the hydrogen molecule is 2.5 times the energy content of methane by mass, but one third by volume. CO_2 emissions are assessed by the hydrogen mass content of the fuel, while mixtures of hydrogen and natural gas are usually described on a volumetric basis, as shown in Fig. 21.

Based on Fig. 21, approximately 80% hydrogen fuel content is required in order to achieve a 50% reduction in CO_2 emissions by mass. With smaller quantities of hydrogen in the fuel, substantial emission reductions can still be achieved. For instance, adding just 10% of hydrogen to the fuel will reduce CO_2 emissions by 2.7%, resulting in a reduction of 1.26 million metric tonnes of CO_2 for a reference 600 MW CCGT that operates at an average efficiency of 60% for 6000 hr a year (Anon, 2021f). Most significantly, hydrogen firing would allow GT to participate in the power-to-hydrogen-to-power system and, subsequently, enter the journey to carbon neutrality. With a number of GT plants in Malaysia, as seen in Figs. 2 to 4, the ramification of hydrogen firing will help to achieve the growth of the green hydrogen economy at a moderate cost and will avoid stranded GT assets due to potential emission reduction regulations.

Excessive flame speed is one of the most common hydrogen firing difficulties in GT (Cappelletti and Martelli, 2017). Hydrogen is known to have a higher laminar flame speed compared to natural gas, which predominantly contains methane (Cappelletti and Martelli, 2017; Anon, 2018c). The laminar flame speed of hydrogen is more than three times that of methane and hydrogen's autoignition delay time is more than three times lower than methane, as shown in Fig. 22 for 1600 °C flame temperature (Anon, 2021f). Hydrogen's excessive laminar flame speed is largely due to the higher molecular diffusivity of hydrogen radicals during chemical reactions (Taamallah et al., 2015).

With these attributes, hydrogen is a highly reactive fuel and controlling the flame is a major challenge for research and development to preserve the integrity of the combustion system

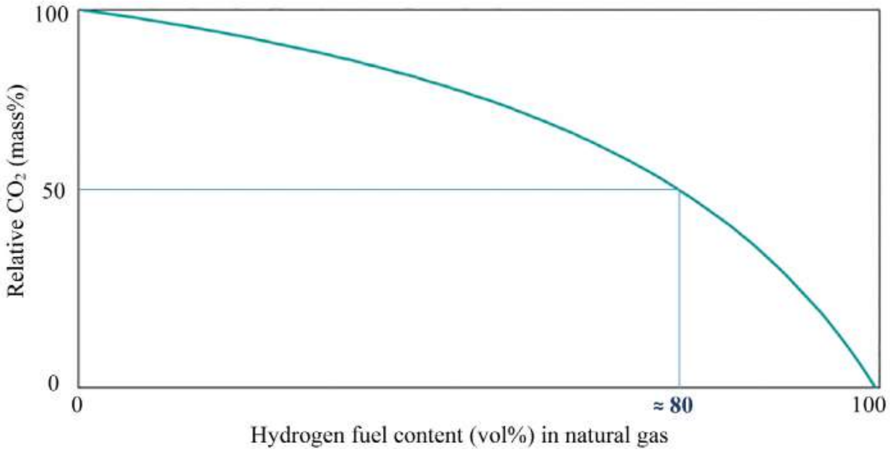


Fig. 21. Percentage of hydrogen volume in the fuel versus the relative emissions of CO_2 from the combustion process.
Source: Adapted from Anon (2021f).

and achieve the required level of emissions (Anon, 2021f). Higher hydrogen flame speeds raise the likelihood that the flame burns closer to the injection points and spreads to the mixing passages (Anon, 2021f; Taamallah et al., 2015; Funke et al., 2019; Liu et al., 2021). This is known as the flashback phenomenon (Taamallah et al., 2015; Cappelletti and Martelli, 2017; Anon, 2018c). Flame speed is the key element for combustion stability as it defines the flashback behavior (Cappelletti and Martelli, 2017; Liu et al., 2021). The chance of flashback increases as the hydrogen content of the fuel increases and the combustion inlet and flame temperature rises (Anon, 2021f). Hence, the addition of hydrogen would raise the probability of the flashback phenomenon, as opposed to the case of burning only natural gas (Anon, 2018c). The common method for flashback prevention is to apply high flow velocity to balance the hydrogen's excessive laminar flame speed (Taamallah et al., 2015; Liu et al., 2021). Nevertheless, the application of high flow velocity would have a negative effect on the combustor pressure drop (Cappelletti and Martelli, 2017).

In addition, most of the operating GTs currently use the Dry Low NO_x (DLN) combustor known for firing a premixed reactant to reduce the NO_x (nitrogen oxide) released (Anon, 2018c). Fuel and air are mixed prior to combustion in the DLN combustor in order to precisely regulate the flame temperature, which in turn enables the rate of chemical processes creating NO_x emissions to be controlled (Anon, 2018c). One of the driving factors for NO_x and flame stability is the relative fuel and air proportions. That being said, there is an existing concern with regard to the stable combustion range of the DLN combustor, which is narrower than that of the traditional non-premixed combustor (Anon, 2018c). The addition of hydrogen could therefore worsen the above-mentioned situation, because the higher reactivity of hydrogen presents unique challenges to the mixing technology in DLN systems (Anon, 2021f; Taamallah et al., 2015). The use of hydrogen as a fuel is therefore currently limited to GTs fitted with non-premixed (diffusion) flame combustors, where despite its wider combustion stability range, its non-premixed/inhomogeneous mixture contributes to the creation of elevated temperature at stoichiometric spots and, consequently, produces higher NO_x emissions compared to premixed combustors (Taamallah et al., 2015; Cappelletti and Martelli, 2017; Imteyaz et al., 2018). In addition, a number of publications have shown that the addition of hydrogen increases the emission of NO_x (Bouras et al., 2017). Due to its comparatively higher combustibility than methane, the addition of hydrogen has been found to move the reaction zone to upstream positions of the flame, creating an increase of hydroxide (OH) radical concentration (Bouras et al., 2017). The rise in the peak temperature subsequently causes the rate of NO_x formation to increase in the reaction zone (Bouras et al., 2017). Hydrogen firing may also alter the thermoacoustic noise patterns (Anon, 2021f; Taamallah et al., 2015). A scientific conception of thermoacoustic instability suggests that heat release oscillations serve as an acoustic source of energy if they are in phase with pressure fluctuations (Taamallah et al., 2015). The pressure fluctuations will therefore rise (Taamallah et al., 2015). Since most of the existing GT combustor is primarily intended for the firing of natural gas, hydrogen firing could affect the flame shape and local dynamics produced, which in turn alters the phase between heat release and pressure fluctuations (Taamallah et al., 2015; Nam et al., 2019). In fact, a study has shown that the fluctuation frequency is proportional to the fuel flame speed (Nam et al., 2019). Therefore, the higher hydrogen flame speed relative to methane would increase the oscillation frequency, resulting in a greater potential for strong combustion instability. The statement was supported by a study by Nam et al. (2019) where they have found that the response of the pressure oscillation is significantly enhanced when the hydrogen composition in methane is about 50% or higher (Nam et al., 2019).

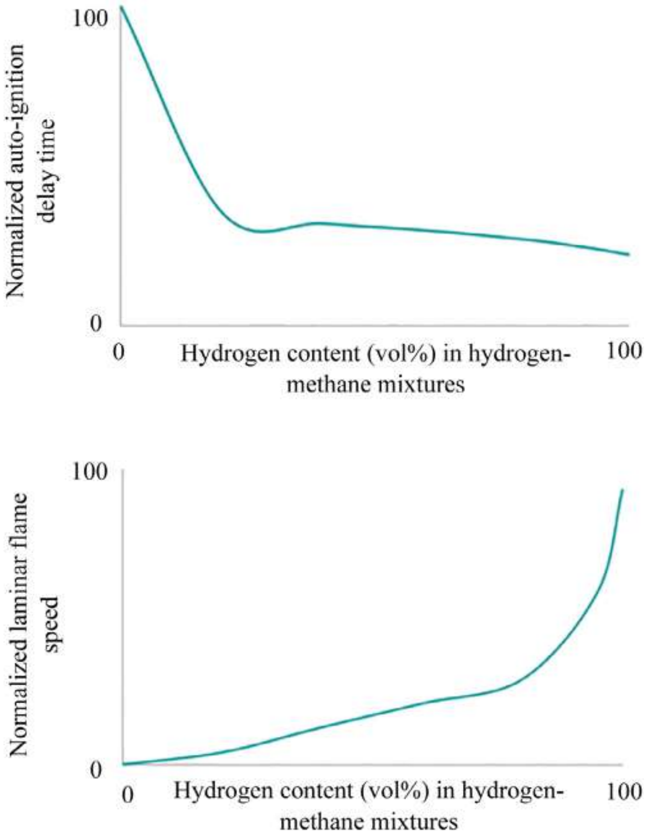


Fig. 22. Hydrogen's influence on auto-ignition delay and flame speed for hydrogen–methane mixtures.
Source: Adapted from Anon (2021f).

In order to address flashback concerns, pilot testing has been extensively carried out by both academia and commercial organizations, especially in relation to one of the proposed solutions that is to start the co-firing of hydrogen and natural gas in the GT combustor. For instance, Mitsubishi Heavy Industries (MHI) has embarked on the creation of GT co-fired hydrogen and natural gas to reduce the CO_2 released (Anon, 2018c). MHI has developed a new combustor to minimize the risk of flashback, which could suppress the low flow velocity generation in the center of the swirling region and consequently suppress the incidence of flashback during hydrogen and natural gas co-firing. The findings have shown that the new combustor succeeded to fire up to 30% volume of hydrogen stably (Anon, 2018c). Most of the commercial heavy duty GTs have been able to operate at a certain percentage of hydrogen volume (Anon, 2021f; Larfeldt et al., 2017). However, it depends primarily on the local conditions to which such operational restrictions can be apply, along with the need for advanced hardware and package modifications to safely accommodate the co-firing of hydrogen and natural gas (Anon, 2021f; Larfeldt et al., 2017). All in all, an increasing hydrogen concentration in methane leads to faster chemistry of combustion, a higher laminar flame speed, a thinner flame, and a shorter ignition delay time (Liu et al., 2021; Nam et al., 2019; Jiang et al., 2019).

Therefore, it can be seen that the well-established DLN firing system could not be directly applied to hydrogen firing because of the substantial difference in the properties of hydrogen compared to natural gas, in which several retrofitting works are needed to securely accommodate hydrogen firing (Jiang et al., 2019; Haj Ayed et al., 2015). For instance, in the numerical and experimental assessments by Cappelletti et al. (2017) to fire 100% hydrogen, a new swirler was developed in the premixer prototype adapted from an industrial GT device to strengthen the recirculation zone produced, along with a new mobile fuel injection system to increase the versatility of mixing control and flame flashback control (Cappelletti and Martelli, 2017). The DLN micromix principle of hydrogen combustion has also been tested by several researchers (Funke et al., 2019; Haj Ayed et al., 2015). The key aspect of the technique is the miniaturization of the combustion zone by inducing a jet in the cross flow configuration to reduce the residence time of reactants (Haj Ayed et al., 2015). Flame anchoring is one of the most critical aspects of stable combustion in GT, and most of the retrofitting techniques tested by previous researchers have actually been concerned with the manipulation of the resulting recirculation zones and vortices, as these two flow characteristics have a major impact on the behavior of flame anchoring (Haj Ayed et al., 2015). Furthermore, the interaction of the recirculation zone structure with the swirl-induced vortex-breakdown and its coupling with the flame-induced gas expansion, as well as the finite-rate chemistry effect near the lean blow-out limit, and the inherent flame instability in the presence of hydrogen, have a massive influence on the flashback and lean blowout phenomenon (Liu et al., 2021). Apart from recirculation zone-related enhancements, the implementation of sequential-combustion stages has also been tested where a recent development has shown that this combustion technique has managed to permit 50 to 70% of hydrogen volume in methane to be combusted, resulting in only slight efficiency de-rating (Jiang et al., 2019).

The progressive advancement of using hydrogen as a power generation fuel in thermal power plants has been demonstrated by a number of previous publications related to hydrogen combustion dynamics. Plus, with the growing participation of the major original equipment manufacturer (OEM) in the hydrogen GT market, it is not surprising that there is a promising future for the hydrogen economy as GT is one of the world's leading power generation technologies. The ability to expand the fuel flexibility of GT to cater for a higher percentage of hydrogen in fuel is a major game changer that accelerates the energy transition to be more hydrogen-centered. In January 2019, the EUTurbines industry association members dedicated to develop such GTs that capable of operating on 100% hydrogen by 2030 (Anon, 2021f). This demonstrates the commitment of the GTs industry to decarbonization and will make it possible to use GTs for entirely carbon-free operation.

As previously mentioned, natural gas dominates the total electricity generation mix in Malaysia, along with coal. With most of the global energy policies gradually averted from coal, the move to commissioning more GT plants is inevitable due to its cleaner option. The amount of GT power plants in Malaysia is one of the greatest potentials for the hydrogen economy to be realized as hydrogen co-firing in GT is currently possible. In addition, major OEMs and research institutions have tried to further push the hydrogen percentage cap in fuel so that more hydrogen can be burned and, finally, full hydrogen firing can be achieved. The readiness of Malaysia's power generation fleet to use hydrogen fuel can therefore be supported by a number of tests and risk assessments conducted by energy companies across the globe, associated with their desire to promote hydrogen either in co-firing or as the main fuel source for their current and future assets. The data from testing and simulation scenarios for hydrogen combustion can be drawn up and evaluated to accommodate the actual local and asset specific requirements.

3.5. Green hydrogen or green ammonia

Although green hydrogen at its point of use is a very clean fuel, its characteristics make it difficult to transport it over long distances (Guteša Božo et al., 2019; Mikulčić et al., 2021). Several initiatives are underway to look at ways of overcoming the transport problem, as stated in the previous chapter. The methods of embedding hydrogen in energy carriers, which facilitate transport and storage, are therefore pursued (Tamura et al., 2020; Valera-Medina et al., 2017). Liquid hydrogen, methyl-cyclohexane, and ammonia are suggested as hydrogen carriers (Aziz et al., 2019; Tamura et al., 2020). Out of all methods, ammonia is shown to have the least expensive form (Aziz et al., 2019; Tamura et al., 2020). Therefore, besides transporting green hydrogen directly via the existing gas pipeline, the conversion of green hydrogen to green ammonia is also one of the front runners in solving the transport problem (Welch and Prasad, 2018). Early work on ammonia fuel began more than half a century ago, but there has been a renewed interest in liquid green ammonia as an energy carrier, with its inclusion as a key technology for cross-sector decarbonization in recent studies by several international organizations (Guteša Božo et al., 2019; Cesaro et al., 2021; Keller et al., 2020). The use of green ammonia has the ability to streamline shipping processes around the globe and it can be stored as easily as petroleum products due to its ease of liquefaction (Palys and Daoutidis, 2020; Mikulčić et al., 2021; Keller et al., 2020). That being said, green liquid ammonia is cheaper to store and transport than green hydrogen, as existing facilities and equipment for liquefied petroleum gas (LPG) can be used (Mikulčić et al., 2021; Wandel, 2020b).

With regard to the production of ammonia, the steps towards achieving a global supply chain of green ammonia are driven by the decarbonization of the massive, already existing supply chain of ammonia fertilizers, currently at 180 million tonnes per year (Cesaro et al., 2021). At such scales, ammonia is already one of the most synthesized chemicals across the globe (Chisalita et al., 2020) and it is reasonable to believe that green ammonia will be available as an energy vector at most regions for the generation of electricity. Ammonia applications are already widely recognized and are critical for many applications, including fertilizer, chemical feed stock, clean-burning transportation fuel, refrigerant fluid, and power generator applications, among others (Chisalita et al., 2020; Fúnez Guerra et al., 2020). The typical ammonia production procedure is based on the Haber-Bosch process and is currently the main method for the industrial production of ammonia, accounting for 90% of the global ammonia production (Mikulčić et al., 2021; Chisalita et al., 2020). Usually, the procedure is executed at pressures above 10 megapascal (MPa) and between 400 and 500 °C, as the nitrogen and hydrogen gases are passed over four catalyst beds, with cooling between each pass to preserve a proper equilibrium constant. Only about 15% conversion takes place on each pass, but any unreacted gases are recycled, and an overall conversion of 97% is eventually achieved (Fúnez Guerra et al., 2020).

Although this method is proven to be effective today to meet the high demand for ammonia, purified nitrogen and hydrogen feeds are needed. In addition, although nitrogen is very abundant in our atmosphere, given the highly stable bond formed in this molecule, it is almost inaccessible (Fúnez Guerra et al., 2020). Hence, nitrogen is very unreactive. Nitrogen is typically produced by Cryogenic Air Separation (CAS), which is described as one of the most effective, developed, and economically sound technologies in the production of nitrogen (Chisalita et al., 2020; Fúnez Guerra et al., 2020). The hydrogen source is mainly from natural gas via the steam methane reforming (SMR) process (Chisalita et al., 2020). However, given the energy-intensive processes with a massive carbon footprint (Sajid and Bicer, 2020; Valera-Medina et al., 2019), ammonia processing based on water-electrolysis is more preferable than steam-based reforming production (Verleysen et al., 2020; Fúnez Guerra et al., 2020; Armijo and Philibert, 2020). Fig. 23 shows the general production routes of ammonia.

Ammonia plants around the world have begun to test the viability of generating green hydrogen to feed the ammonia production process. One such example is the Burrup Peninsula facility in Yara, Western Australia (Cesaro et al., 2021). The facility is currently producing ammonia by using natural gas as a raw material for its steam reforming process — the very same process used by most commercial ammonia plants around the world (Cesaro et al., 2021). Nevertheless, the facility has begun to explore the potential to generate and feed green hydrogen for its ammonia production process. In partnership with the global energy company ENGIE, the Yara Pilbara Renewable Ammonia Feasibility Study will examine the possibility of generating green hydrogen through on-site solar PV-powered electrolysis (Cesaro et al., 2021). Yara's goal is that up to 3% of the hydrogen used on site would be green hydrogen for the demonstration project (Cesaro et al., 2021). Subsequently, the blended hydrogen will be processed to ammonia and sold for further processing on domestic and foreign markets. The test pilot project would also explore the use of seawater for the electrolyzer (Cesaro et al., 2021). This project will be one of the ground breaking steps on the road to commercial development of green hydrogen and green ammonia. The outcome of this test pilot would be useful in providing some indication of the viability of upgrading existing ammonia plants to produce a higher percentage of green ammonia in the future. The feasibility assessment of industrial scale production of green ammonia in Chile, New Zealand, Norway, Saudi Arabia, Japan, and the UK is also underway (Verleysen et al., 2020; Cesaro et al., 2021). There are already a number of techno-economic studies focusing on obtaining the levelized cost of green ammonia, of which most studies have found that further cost reductions are feasible with the anticipated technological developments and increased RSE penetration, making it directly competitive with conventionally generated ammonia (Chisalita et al., 2020; Osman et al., 2020; Zhang et al., 2020a).

Malaysia has been recognized as one of the ammonia exporters with PETRONAS operating multiple ammonia plants across the nation (Anon, 2021k). The surplus of ammonia generated from all of these plants has been exported to various places in South and Northeast Asia (Wheeler, 2021). Several ammonia units operated by PETRONAS are situated in Kerteh (500,000 tonnes/year), Gurun (370,000 tonnes/year), Bintulu (400,000 tonnes/year), and Sabah (740,000 tonnes/year) (Anon, 2021k; Wheeler, 2021; Anon, 2018a). The production of ammonia in Malaysia is primarily for fertilization, where urea fertilizer is one of the most important products (Anon, 2021k). And as such, the potential for the production of green ammonia exists in Malaysia, as the current infrastructure of the ammonia plants already exists.

However, one of the key concerns is about the scope of green ammonia applications. Whether green ammonia is only for the transport of green hydrogen, or whether it would also be used as the burning fuel. Although the research of green ammonia is mainly based on the transport of green hydrogen, the recent momentum in the shipping industry's decarbonization using green ammonia is an indication that ammonia can be applied similarly to large-scale power generation because it is an energy-dense fuel with few technological barriers to the implementation (Aziz et al., 2019; Cesaro et al., 2021; Anon, 2020c; Al-Aboosi et al., 2021). Liquid ammonia has a major advantage over all other renewable energy carriers in terms of energy density, as seen in Fig. 24.

Studies around the world have begun to examine the feasibility of combusting ammonia in thermal power plants in order to investigate its subsequent effect on the output of the plant and the combustion dynamics produced. As the combustion intensity of ammonia is lower than that of conventional fossil fuels, co-firing of ammonia and fossil fuels is one of the alternatives to avoid the risk of loss of efficiency, while at the same time minimizing emissions of GHG to the atmosphere (Xia et al., 2020). One such study was conducted by Xia et al. (2020), which examined the fundamental mechanism of flame propagation in coal-fired boilers for co-fired pulverized coal and ammonia (Xia et al., 2020). Indeed, these mechanisms are necessary to fully understand the co-firing behaviors of pulverized coal and ammonia under various ammonia equivalence ratios as it will help to illuminate decision-making during the coal-fired process, whether to increase or decrease the amount of ammonia in the co-firing system. Nevertheless, since high-fuel-ratio coals were not used in many thermal power plants since their flame velocities were very low (Hadi et al., 2020), the addition of ammonia would definitely help to increase the speed of the flame and thus preserve the propagation of the flame in the coal-fired boilers.

The possibility of ammonia slip is another issue concerning the co-firing of pulverized coal and ammonia (Mikulčić et al., 2021). Ammonia slip is the escape of ammonia into the atmosphere (Tamura et al., 2020), which is not permissible due to its high toxicity (Wan et al., 2021; Guteša Božo et al., 2019; Mikulčić et al., 2021; Valera-Medina et al., 2015). IHI recently demonstrated the co-firing of coal with ammonia in a 1.2 MW pulverized coal firing furnace, and the properties of flue gas are constantly analyzed to ensure that no ammonia slip is observed (Tamura et al., 2020). The results show that stable combustion is accomplished without any ammonia slip, with a properly designed gas gun to allow efficient ammonia firing operation (Tamura et al., 2020). IHI also recently announced the co-firing of coal with 20% ammonia in the largest demonstration (10 MW) to date (Valera-Medina et al., 2019). Chugoku Electric Power Company has also completed a series of tests at its Mizushima power plant where ammonia was applied at a rate of 450 kilogram per hour (kg/hr) to the 155 MW coal-fired plant (Hadi et al., 2020). The company reported that adding ammonia did not cause the power efficiency of the plant to decrease (Hadi et al., 2020). The results of these studies have shown that green ammonia could be introduced as a CO_2-free energy carrier in the coal-fired boiler system. Not only could it help in the environmental sense, it could also pave the way for a reduction in the cost of solid fuel, as green ammonia would help to increase energy security through the use of high-carbon coal.

With the coal-fired boiler is one of the biggest electricity providers in Malaysia, the co-firing of ammonia and pulverized coal could be one of the major starting points to utilize the surplus of ammonia generated from a number of ammonia plants in Malaysia. There are already a number of studies which focusing on minimal retrofitting towards the existing coal-fired power plant facilities in order to generate stable combustion performance fueled by coal and ammonia. One such study is by Tamura et al. (2020), where stable combustion and the realization of NO_x emission reduction by stage combustion have been experimentally verified when ammonia is co-fired with pulverized coal (Tamura et al., 2020). The retrofitting focuses primarily on the ammonia injection position, injector designs, and sequences of air staging (Tamura et al., 2020). One of the ground breaking steps for achieving substantial carbon reduction from Malaysia's thermal power plants might just be the act of minimal retrofitting to co-combust ammonia. Once the confidence level of the power utility company is high enough for the implementation of ammonia co-firing, the green ammonia project could be carried

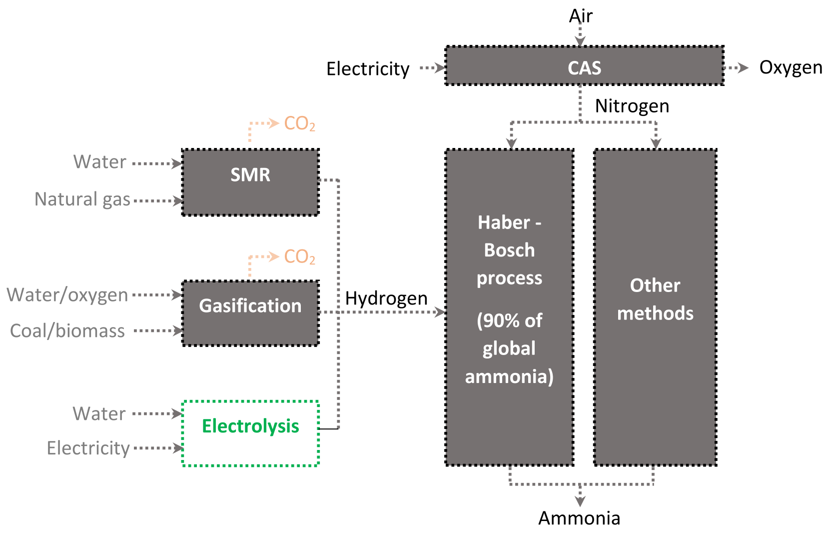


Fig. 23. The general production routes of ammonia. *Source:* Adapted from Chisalita et al. (2020), Fúnez Guerra et al. (2020).

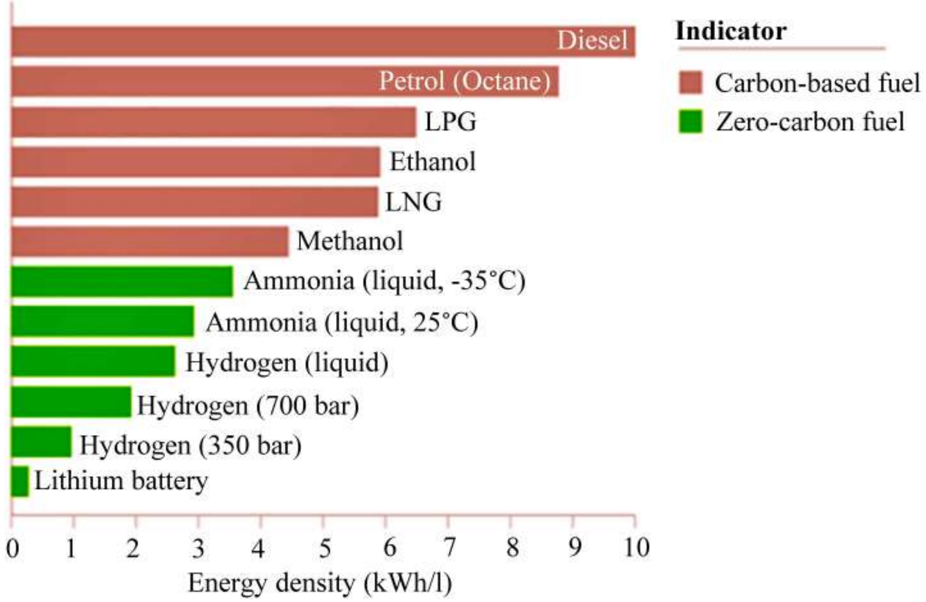


Fig. 24. Renewable energy carriers in terms of energy density Wandel (2020a).

out by converting Malaysia's ammonia plants from steam-based reforming production to water-based electrolysis production.

A number of projects have already demonstrated the high potential of ammonia as a fuel in GT applications (Valera-Medina et al., 2019). Meaningful projects were undertaken in the 1960s to evaluate the feasibility of ammonia as a fuel for GTs (Guteša Božo et al., 2019). Although the surge of low-cost fossil fuels put these ventures to an end, projects were reactivated several decades later, concentrating on the use of ammonia as a flexible fuel in GTs. A variety of methods for the introduction of ammonia as a flexible fuel in GTs have been demonstrated in several recent studies. For example, the Fukushima Renewable Energy Institute (FREA) has built fuel flexibility platforms to burn green ammonia generated from wind and solar sources in combination with kerosene in a 50 kW micro-gas turbine (Valera-Medina et al., 2019). Via the prototype bi-fuel combustor, diffusion combustion has been used because of the generated flame stability and it has been shown that the combustor can be operated using ammonia-kerosene blends at various concentrations (Valera-Medina et al., 2019). FREA and the universities leading this research are now on the verge of showing the ability of pure ammonia GT combustion through studies ranging from computational simulations to demonstration studies (Valera-Medina et al., 2019).

A variety of studies have also explored the use of ammonia-hydrogen/methane blends for GT combustion. The blending with hydrogen was done to enhance the ammonia reaction rate as ammonia fuel is known to have a relatively slow flame speed (Mikulčić et al., 2021), which during the start-up stage could lead to an early blowoff, ignition difficulty, and high emission generation (Guteša Božo et al., 2019; Valera-Medina et al., 2017). Previously, several research studies have shown that the inclusion of ammonia as a fuel in GT could leads to the formation of large quantities of NO_X, especially with current trends in GT development when OEMs continue to push the cap for the turbine inlet temperature produced (Keller et al., 2020). Yet, recent numerical research has shown that ammonia/hydrogen blends have the potential for large power generation with low NO_x emissions at high pressure conditions (Valera-Medina et al., 2019). Studies have found that a stable flame of ammonia co-fired can be produced within a limited range of equivalence ratios through a powerful swirl that creates coherent structures which could provide flame stabilization (Guteša Božo et al., 2019; Tamura et al., 2020; Valera-Medina et al., 2015). In different study, preliminary tests were conducted by using ammonia/hydrogen blend at 50/50% volume (Valera-Medina et al., 2017, 2019). From the preliminary tests, the ammonia/hydrogen mixture has shown to achieve comparable flame speed to methane (Guteša Božo et al., 2019; Valera-Medina et al., 2017). The NO_x emissions were also found to be prohibitive under lean conditions, while stability was impaired to a very narrow range of equivalence ratios (Valera-Medina et al., 2019). The narrow operating range stems from the high diffusivity of hydrogen as the high hydrogen swirl finds oxygen from the mix, creating a boundary layer flashback (Valera-Medina et al., 2017). The result set the way for further experiments at higher equivalence ratios above stoichiometric values.

In terms of advances towards industrial applications, companies such as NUON have initiated ambitious programs to improve their capabilities in the field of ammonia-fired systems. The most prominent is the Power-to-Ammonia program in which NUON works with TU Delft, Proton Ventures, OCI Nitrogen, AkzoNobel, ISPT, and the University of Twente (Valera-Medina et al., 2019). The NUON project sees ammonia as an energy that stores excess RSE on a large scale over a long period of time (Valera-Medina et al., 2019). Next, a project has also been developed by Skovgaard Invest, supported by Vestas, in order to build the world's first green ammonia plant at the commercial scale of 10 MW power where the plant will be located at Jutland, Denmark (Anon, 2021a).

That being said, the introduction of green hydrogen and green ammonia as fuels in commercial thermal power plants is promising, as positive findings have been found in many pilot tests across the globe, especially related to combustion dynamics and green ammonia/hydrogen productions. However, there is still a lack of studies on the performance of ammonia blended fuel for thermal power plants (Valera-Medina et al., 2019). It is currently a major problem that continues to affect the further propagation of the idea of green ammonia among industrialists. In addition, in order to obtain some in-depth comparisons between these two alternative green fuels, a detailed technical-economic study of the use of green hydrogen and green ammonia from production, transport, storage, and utilization is also crucial. Since the reduction of CO_2 emissions, which is one of the key contributors to the greenhouse effect, is one of the main drives for introducing a zero-carbon alternative fuel, many alternatives have been proposed to achieve CO_2 reduction from existing thermal power plants. Economic efficiency is therefore one of the essential criteria for helping to select which countermeasure technologies have the optimal CO_2 reduction. There are other methods for achieving CO_2 reduction in the case of coal-fired thermal power plants, other than the co-firing of coal with zero-carbon alternative fuels, such as post-combustion process and oxy-fuel combustion (Tamura et al., 2020). Despite the need to select the best CO_2 reduction countermeasure technology, some industrialists have argued that it is easier to have multiple choices for energy security purposes (Tamura et al., 2020). However, numerous studies have created simplified estimations that the electricity provided by the co-firing of coal with ammonia would be cheaper than the coal-firing with CCS (Tamura et al., 2020). Further feasibility studies are definitely needed to support these estimates. However, in the future, some researchers have predicted that the gap in the usage of green alternative fuel in thermal power plants would be narrowed not only by technological advances, but also by the presence of initiatives such as carbon taxation due to increased public interest in environmental issues (Tamura et al., 2020). That being said, political support from the government is still required to further promote the zero-carbon alternative fuel economy.

3.6. Malaysia's political support towards zero-carbon fuel economy

The political support and immense financial support necessary to develop the infrastructure needed to begin the commercialization of zero-carbon fuels are another aspects that needs to be highlighted. While some of the existing fossil fuel facilities can be converted to the commercialization of hydrogen or ammonia, it is predicted that there will be a similar need for investment and political support to begin the commercialization of zero-carbon alternative fuels (Burton et al., 2021). The production and implementation of zero-carbon fuel technology will be accelerated if similar financing is directed towards the creation of the infrastructure required to implement zero-carbon fuel as a primary energy carrier (Burton et al., 2021). Simply put, the production of genuinely RSE carrier, such as green hydrogen and green ammonia, must be appreciated by the private energy industry and policymakers on the basis of long-term benefits such as clean air, decreased environmental impacts of energy generation, and a more sustainable human life (Burton et al., 2021).

As Malaysia is recognized as one of the oil-rich countries, energy policies centered on petroleum resources in most of the 20th century, as policymakers were able to reasonably assume that the combination of high oil demand, lack of a real alternative, and limited supply of reserves provided their subsoil wealth with an intrinsic value (Anon, 2018d). Since the first discovery in Sarawak in 1910, the exploration and extraction of oil and gas has given rise to the country's GDP (Lim and Goh, 2019; Ghazali and Ansari, 2018). Shell and Esso began offshore oil exploration in Malaysian waters in the late 1960s, yet production was small, totaling to less than 10,000 barrels per day (Anon, 2018d). However, it had potential and the Malaysian government decided to restructure the legal system through the centralization of state regulatory and ownership rights, and the negotiation of new contracts with oil companies to raise oil production taxes (Anon, 2018d). The spirit of the time was expressed by PETRONAS, established in 1974 via the Petroleum Development Act (PDA) (Lim and Goh, 2019; Anon, 2018d). PETRONAS was set up as a national oil company and is responsible for the exploration, development, refining, manufacturing, production, marketing, and distribution of petroleum commodities (Lim and Goh, 2019). Next, in 1975, the Third Malaysia Plan (1976–1980) formulated the National Petroleum Policy (1975) (Lim and Goh, 2019) with the goal of making effective use of the resource for industrial growth, as well as ensuring that the nation retains majority control in the industry's management and operation (Jalal and Bodger, 2009). Its goal was to supervise and manage the rapidly growing petroleum industry in Malaysia, where significant production occurred between 1970 and 1975, with an average growth rate of about 40.5% per year (Jalal and Bodger, 2009). An overall energy policy, known as the National Energy Policy, was developed in 1979 (Lim and Goh, 2019) with broad guidance on long-term energy priorities and policies to ensure that energy resources are effective, secure, and environmentally sustainable (Jalal and Bodger, 2009). This is the key policy that regulates the energy sector in Malaysia. In order to support its goals and implementation, other policies were later introduced (Jalal and Bodger, 2009). Due to the rapid rise in crude oil demand, the National Depletion Policy 1980 (Lim and Goh, 2019) was introduced to safeguard the exploitation of natural oil reserves (Jalal and Bodger, 2009).

It was not until 1981 that the Four Fuel Diversification Policy (Lim and Goh, 2019) was implemented to avoid over-dependence on petroleum as the main energy resource (Dharfizi et al., 2020). Its goal was to ensure energy supply reliability and security by concentrating on four primary energy resources, including oil, gas, hydropower, and coal (Jalal and Bodger, 2009). This makes hydropower the first RSE recognized by Malaysia's energy policy. However, even after the implementation of the Four Fuel Diversification Policy in 1981, hydropower integration remained sluggish as shown in Fig. 12. Nevertheless, the reliance on oil has begun to be substantially reduced over the years, replaced by natural gas that is found to be abundant in Malaysia (Jalal and Bodger, 2009). When independent power producers (IPPs) came into the electricity market in 1993, the use of natural gas was further strengthened. Because of rapid plant uptime, lower capital costs, and simple operation, the IPPs have a greater propensity to build GT power plants (Jalal and Bodger, 2009). For the electricity sector, the key objective during the Seventh Plan period (1996–2000) was to ensure adequacy of capacity generation, as well as to extend and improve the transmission and distribution infrastructure (Jalal and Bodger, 2009).

The Four Fuel Diversification Policy 1981 was revised in 2000 to become the Fifth Fuel Policy (Eighth Malaysia Plan 2001–2005) (Lim and Goh, 2019), where RSE was declared as the fifth fuel in the energy supply mix (Jalal and Bodger, 2009; Dharfizi et al., 2020). The use of RSE, such as biomass, solar, and mini-hydro, was promoted in this amended policy (Jalal and Bodger, 2009; Kementerian Tenaga Teknologi Hijau dan Air (KeTTHA), 0000a). The SREP was launched in May 2001. Under the SREP projects, power plants can sell up to a maximum of 10MW of electricity to the National Grid (Jalal and Bodger, 2009). The Ninth Malaysia Plan reinforces the energy efficiency and RSE strategies put forward in the Eighth Malaysia Plan, which concentrated on optimizing the usage of energy resources (Jalal and Bodger, 2009). More attempts are being made to incorporate alternative fuels in order to further decrease the reliance on petroleum. Various tax exemptions for energy efficiency implementers and RSE generators have been implemented (Jalal and Bodger, 2009).

Accumulating all the results of the last eight years since the Fifth Fuel Policy was established, the National Renewable Energy Policy and Action Plan was established in 2009 (Lim and Goh, 2019) primarily to resolve the failure of the RSE market, policy contradictions, mixed investor signals, and the lack of robust and long-term sustainable development (Kementerian Tenaga Teknologi Hijau dan Air (KeTTHA), 0000b). The policy aims to increase the use of indigenous RSE to contribute to the security of the electricity supply and the independence of the fuel supply (Kementerian Tenaga Teknologi Hijau dan Air (KeTTHA), 0000b). The policy also seeks to increase RSE's share of the energy mix, encourage the growth of the local RSE manufacturing sector, ensure that the cost of generating RSE is acceptable, and protect the environment (Kementerian Tenaga Teknologi Hijau dan Air (KeTTHA), 0000b). In order to achieve its objectives, the Action Plan provides for the introduction of a feed-in tariff (FiT) mechanism to minimize the cost of funding transactions, create a favorable business environment for the growth of RSE enterprises, and build up local skills and capacities to attract skilled workers in the industry, as well as implement a long-term research and development program (Kementerian Tenaga Teknologi Hijau dan Air (KeTTHA), 0000b). Two legislative frameworks, including the Renewable Energy Act 2011 and the Sustainable Energy Development Authority Act 2011, have been established (Ministry of Energy, Green Technology and Water, 2015). The Renewable Energy Act 2011 is an act designed to allow for the development and introduction of a special tariff system to catalyze renewable energy production and to provide for related issues (Ministry of Energy, Green Technology and Water, 2015). The Sustainable Energy Development Authority Act 2011, on the other hand, is an act to provide for the creation of the Sustainable Energy Development Authority Malaysia (SEDA) and to provide for its duties and powers and matters related (Ministry of Energy, Green Technology and Water, 2015).

The Renewable Energy Act 2011 is the key legislation in Malaysia to govern FiT for renewable generation (Ghazali and Ansari, 2018). The FiT system in Malaysia obliges Distribution Licensees (DLs) to purchase electricity generated from renewable resources from Feed-in Approval Holders (FIAHs) and sets the FiT rate (Ghazali and Ansari, 2018). The DLs would pay for renewable energy supplied to the power grid for a specific period of time (Ghazali and Ansari, 2018). The FiT mechanism will make sure that renewable energy becomes a viable and sound long-term investment for both businesses and individuals by ensuring access to the grid and establishing a favorable price per unit of renewable energy (Ghazali and Ansari, 2018). SEDA is a statutory body constituted to oversee and manage the implementation of the FiT mechanism (Ghazali and Ansari, 2018). All in all, Fig. 25 shows the summary of the historical timeline for energy policies development in Malaysia.

Following these historical changes in Malaysia's energy policy, it can be seen that the Malaysian government has been encouraging the introduction of renewable energy since the 1980s. Nevertheless, despite the implementation of the Fuel Diversification Policies since 1981, the results have shown that the over-dependence of petroleum has been replaced by the over-dependence of natural gas (Dharfizi et al., 2020), demonstrating that the Malaysia's energy mix still relies heavily on fossil fuels. Moreover, there is still insufficient support for the introduction of alternative zero-carbon fuels in the Malaysian energy mix and a study once identified several flaws in the Renewable Energy Act 2011 due to its limitation in renewable energy support (Ghazali and Ansari, 2018). However, given that Malaysia's renewable energy policies are still 'green' relative to a number of developed countries worldwide, it will take some time to completely encourage the use of zero-carbon alternative fuels officially in future energy policies. In addition, the usage of renewable-based zero-carbon fuels for power generation takes the production, transport, storage, and utilization in power plants into account. With such a wide scope, amendments to the Renewable Energy Act 2011 may be required in order to extend its RSE support spectrum, which will explicitly support the introduction of zero-carbon fuels. Although several major organizations in Malaysia have already laid some groundwork for pilot projects on renewable-based zero-carbon alternative fuels, there is a particular need for government support, especially in terms of energy policy to officially recognize the potential of renewable-based zero-carbon alternative fuels and to gain the enormous financial support required to build the facilities in order to start zero-carbon fuels commercialization.

4. Conclusion

In conclusion, the existing combustion-centered energy mix in Malaysia has shown that replacing fossil fuels with renewable-based zero-carbon alternative fuels could be a better approach to supporting the reduction of the carbon footprint of the power generation industry. In this study, the potential of renewable-based zero-carbon alternative fuels in Malaysia was addressed in terms of the production, transport, storage, and utilization in thermal power plants. Though zero-carbon alternative fuels produced from renewable plants such as green hydrogen and green ammonia are hardly commercialized in Malaysia for the time being, numerous potentialities have been identified in realizing the zero-carbon power generation market in Malaysia. The

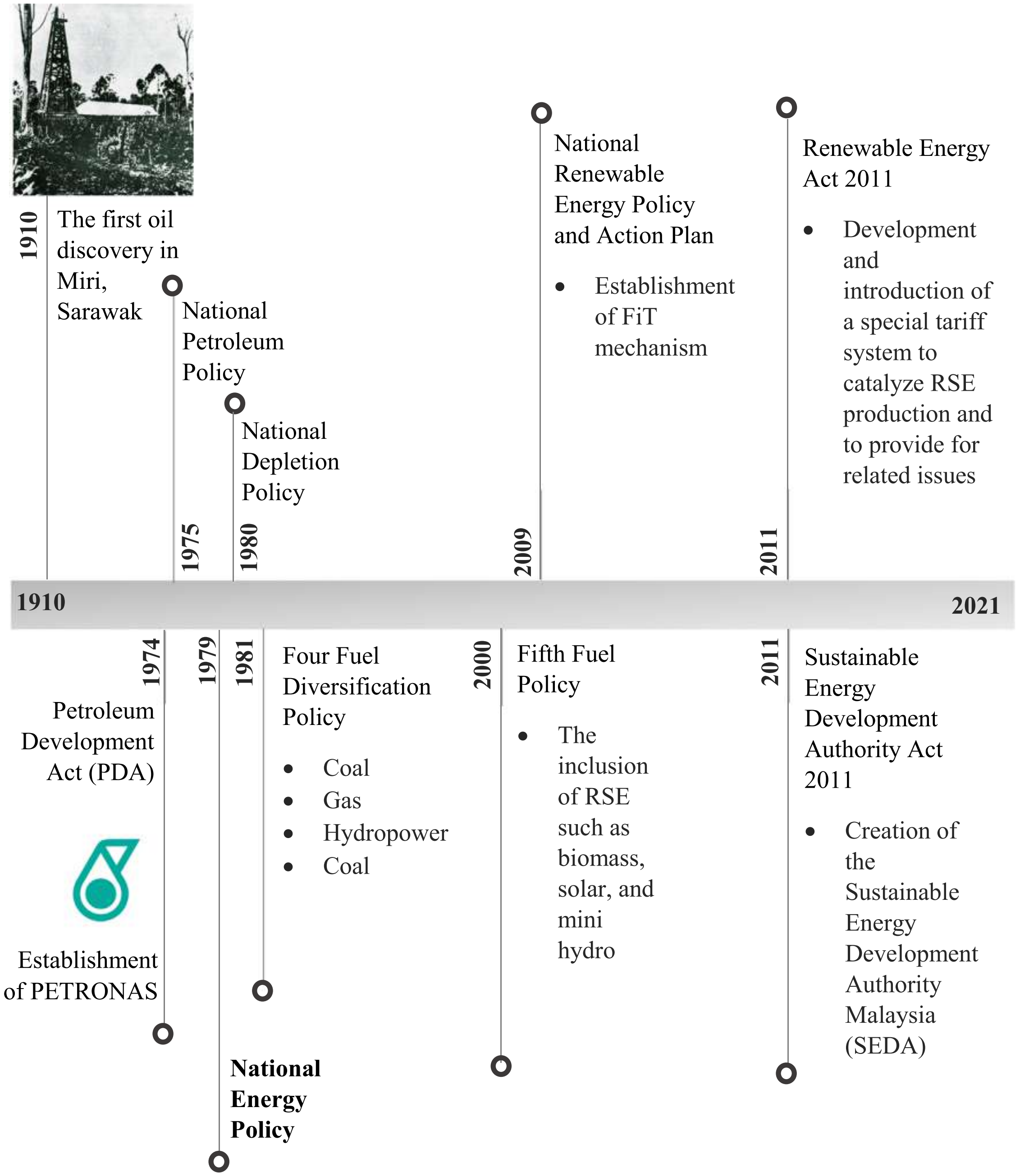


Fig. 25. The historical timeline for energy policies development in Malaysia. *Source:* Adapted from Lim and Goh (2019), Anon (2018d), Ghazali and Ansari (2018), Jalal and Bodger (2009), Dharfizi et al. (2020), Kementerian Tenaga Teknologi Hijau dan Air (KeTTHA) (0000a,b), Ministry of Energy, Green Technology and Water (2015) and Rasoul Sorkhabi et al. (2014).

updated developments associated to green hydrogen and green ammonia across the globe have been reviewed to support the existing potential in Malaysia. Malaysia's abundance of natural gas has provided a conducive infrastructure for natural gas system throughout Malaysia, especially in the Peninsular region. Malaysia's extensive natural gas pipeline network has the capacity to be used to deliver green hydrogen to most of Malaysia's thermal power plants. A number of pilot projects related to the transformation of the natural gas pipeline have been carried out by studies worldwide to deliver green hydrogen safely with minimal retrofitting required, and most of the research has shown that this feat is feasible. In addition, the strategic position of the natural gas pipeline, in particular the PGU, which is located near to most of Malaysia's solar power plants, has shown that there is a potential to smooth the process of transporting green hydrogen to thermal power plants. The active involvement of Malaysia's academic institutions in the development of water electrolysis has also shown that there will be a number of future electrolysis expertise that could provide a definite roadmap for decarbonization in Malaysia. As one of the oil-rich countries, Malaysia has the capacity to use its abundance of depleted gas reservoirs for the storage of green hydrogen. With Malaysia's booming O&G market, the use of depleted gas reservoirs is one of the best options due to its modest cost, based on the surplus of reservoirs and the preparedness of well technologies. Hydrogen firing in GT has already been extensively studied worldwide, with a large percentage of hydrogen can already be stably combusted in GT fleets. A large number of GT plants in Malaysia would definitely have the potential to utilize hydrogen co-firing with natural gas to minimize the amount of CO_2 released. The potential of green ammonia as a fuel to be used for power generation in Malaysia has also been reviewed in this study. The significant number of ammonia production plants in Malaysia could provide a surplus of ammonia to be used as an alternative fuel for power plants. As the co-firing of ammonia and pulverized coal has already shown its feasibility through a number of pilot projects, the implementation of this co-firing mechanism at a number of coal-fired power plants in Malaysia would surely beneficial for CO_2 reduction. With regard to energy policies in Malaysia, positive acceptance of the implementation of RSE has been shown with the introduction of various energy policies aimed at promoting the incorporation of RSE into the energy mix. However, there is still inadequate support for the implementation of renewable-based zero-carbon fuels in the Malaysian energy mix, and a study has found a number of shortcomings in the Renewable Energy Act 2011 due to its limitation in renewable energy support.

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CRediT authorship contribution statement

Mohammad Nurizat Rahman: Conceptualization, Formal analysis, Investigation, Resources, Writing - original draft, Writing - review & editing, Visualization. **Mazlan Abdul Wahid:** Writing - review & editing, Supervision.

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.

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