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GREEN HYDROGEN IN DEVELOPING COUNTRIES

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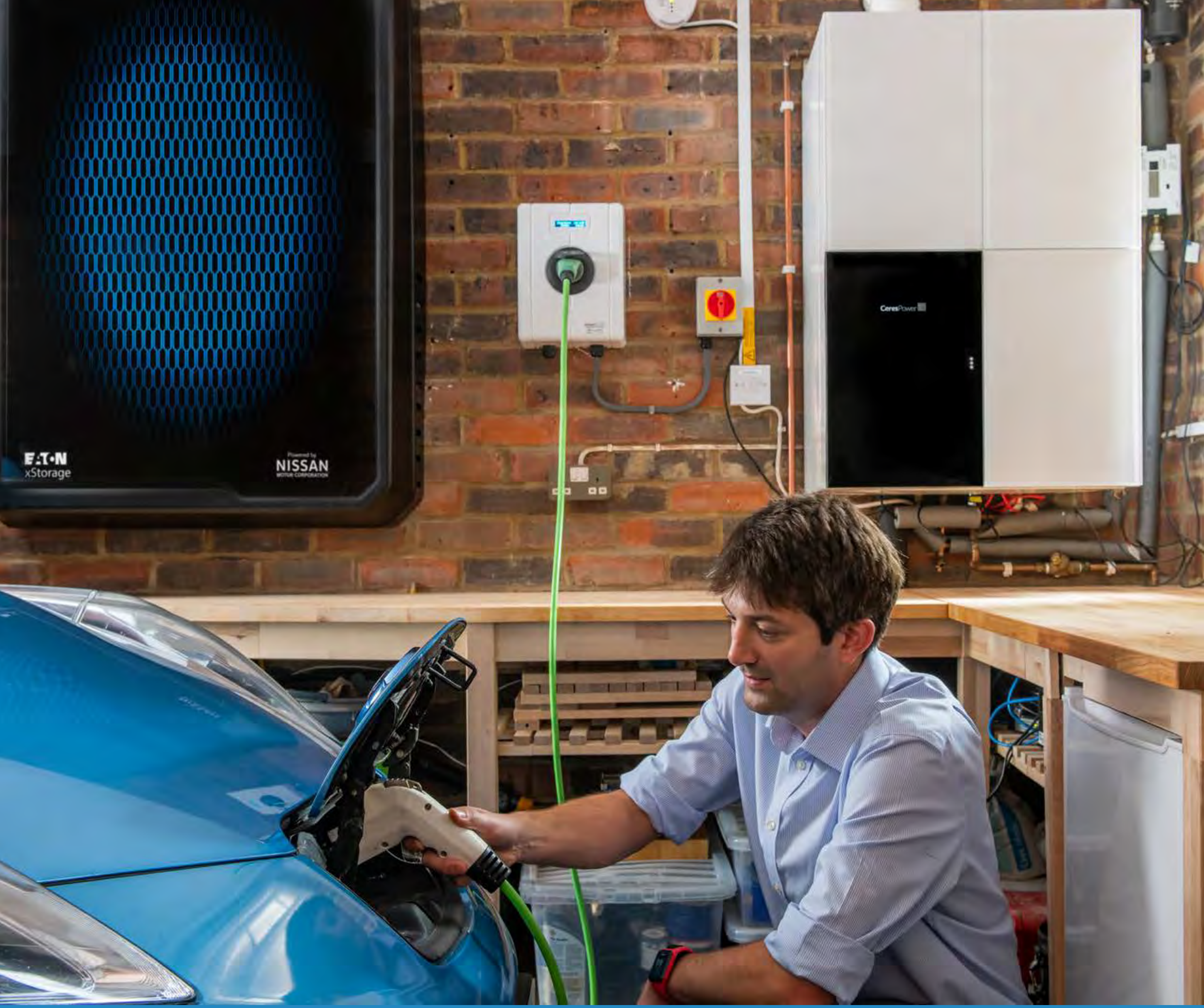

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ESMAP MISSION

The Energy Sector Management Assistance Program (ESMAP) is a global knowledge and technical assistance program administered by the World Bank. ESMAP assists low- and middle-income countries in increasing their know-how and institutional capacity to achieve environmentally sustainable energy solutions for poverty reduction and economic growth.

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ABBREVIATIONS AND ACROYNYMS

AEM	anion exchange membrane
AFC	alkaline fuel cell
AHP	African Hydrogen Partnership Association
BEV	battery electric vehicle
CAGR	compound annual growth rate
capex	capital expenditure
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CCU	carbon capture and use
CEOG	Centrale Électrique de l'Ouest Guyanais (French Guiana) (Western Guiana Power Plant)
CHP	combined heat and power
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CNG	compressed natural gas
CO_2	carbon dioxide
DMFC	direct methanol fuel cell
DOE	Department of Energy
EGAT	Electricity Generating Authority of Thailand
EJ	exajoule
ESMAP	Energy Sector Management Assistance Program
EU	European Union
EV	electric vehicle
FCEB	fuel cell electric bus
FCEV	fuel cell electric vehicle
FCH JU	Fuel Cells and Hydrogen Joint Undertaking
GHG	greenhouse gas
GW	gigawatt
HRS	hydrogen refueling station
HTAP	Hydrogen Technology Advisory Panel
HySA	Hydrogen South Africa
IEA	International Energy Agency
IOC	Indian Oil Company
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
kg	kilogram
kW	kilowatt
LNG	liquefied natural gas
LCOE	levelized cost of energy
LOHC	liquid organic hydrogen carrier
MCFC	molten carbonate fuel cell
MEA	membrane electrode assembly
MJ	megajoule
Mtoe	million tonnes of oil equivalent
MW	megawatt
MWh	megawatt-hour
NASA	National Aeronautics and Space Administration
NDC	Nationally Determined Contribution
NREL	National Renewable Energy Laboratory
OEM	original equipment manufacturer
PAFC	phosphoric acid fuel cell
PEM	proton exchange membrane
PPA	power purchasing agreement
PV	photovoltaic
R&D	research and development
RD&D	research, development, and deployment
SMR	steam methane reforming
SOE	solid oxide electrolysis
SOFC	solid oxide fuel cell
VRE	variable renewable energy

All dollar figures denote US dollars unless otherwise noted.

GLOSSARY OF TERMS

Alkaline electrolyzer—This is the oldest established technology for creating hydrogen from water and electricity. The name is derived from the electrolyte used, which is typically based on either potassium hydroxide (KOH) or sodium hydroxide (NaOH).

Alkaline fuel cell—This is one of the oldest and cheapest fuel cell technologies. Because of this fuel cell's highly conductive electrolyte and highly reactive electrodes, manufacturers have been able to assemble larger units, and thus reduce losses and provide higher general electrical efficiencies than other fuel cells. Despite these features, relatively few have been deployed.

Blue hydrogen—This term is used for hydrogen produced using low-carbon processes. It is almost exclusively used to refer to hydrogen produced via natural gas or coal gasification but combined with carbon capture storage (CCS) or carbon capture use (CCU) technologies in order to reduce carbon emissions significantly below their normal levels for these processes. It can, however, also refer to hydrogen produced via pyrolysis, by which hydrogen is separated into hydrogen and a solid carbon product colloquially called "carbon black."

Black hydrogen—Hydrogen produced from coal via coal gasification and extraction.

Brown hydrogen—Hydrogen produced from lignite (see black hydrogen).

CHP—An abbreviation that stands for combined heat and power. A term used to describe a technology that produces both heat and power for commercial uses.

Coal gasification—A process through which coal is deconstructed into a gas via a combination of high pressure and high temperature steam, and by external heat. This process transforms the complex hydrocarbons from a solid state into a gaseous one, thus facilitating the reforming of the hydrocarbon gas and allowing hydrogen to be extracted.

DMFC—An abbreviation that stands for direct methanol fuel cell. This technology is based on a PEM fuel cell design, which can accept methanol directly.

Electrolyzer—A technology that converts water and electricity into hydrogen, oxygen, and heat. The technology has differing names depending on the electrolyte used to facilitate the chemical reaction.

FC—An abbreviation for fuel cell, which is a technology that converts hydrogen into water, heat, and electricity through a chemical reaction that combines hydrogen with oxygen, usually from the filtered ambient air. The abbreviation "FC" is frequently added to the end of a descriptor—for example, PEMFC stands for proton exchange membrane fuel cell. Fuel cells can range from a few watts in size to multimegawatt units. They can be used for stationary, mobile, and portable applications, with differing performance lifetimes, efficiencies, and operating temperatures available, depending on the specific fuel cell technology.

FCEV—An abbreviation for fuel cell electric vehicle. The main body of the vehicle remains electric, but the primary propulsion fuel is hydrogen, which is consumed by a fuel cell within the vehicle. Frequently, a battery component is also included with the fuel cell for quick-start functions and actions when the vehicle is not running.

FCEB—An abbreviation for fuel cell electric bus. These vehicles build on existing bus or even electric bus designs by adding a fuel cell and hydrogen fuel supply equipment, installed by a specialist systems integrator.

Green hydrogen—This term is used for hydrogen produced from 100 percent renewable sources. It most commonly refers to hydrogen created from a process called electrolysis, which can use 100 percent renewable power and water to create pure hydrogen and oxygen. Other green hydrogen production methods include hydrogen extraction from reformed biogas and hydrogen extraction from waste.

Gray hydrogen—This term usually refers to hydrogen produced via steam methane reforming (SMR), and it is the most common type of hydrogen produced globally. Gray hydrogen can also refer to hydrogen that is created as a residual product of a chemical process—notably, the production of chlorine from chlor-alkali plants.

Hydrides—A hydrogen storage technology that is able to absorb hydrogen into differing solids, including certain metallic compounds and porous nanoparticles. The hydrogen stored in this form can then be released back via changes in pressure, decomposition over a catalyst, or an increase in heat. The storage unit can be recycled and does not require regular replacement.

Hydrogen—The lightest element in the periodic table and the most common in the universe. Because of its natural tendency to form bonds with other molecules, it is rarely found unbounded in nature. It can therefore be considered as a storage of energy because the molecules can be easily encouraged to form bonds with other elements through either chemical or combustion processes. The products of these processes are water and energy (which, depending on the reaction, can be in the form of electricity and heat, or simply heat). It is a widely used commercial gas, with a broad range of applications in the energy transition.

LOHC—An abbreviation for liquid organic hydrogen carriers, which are (usually) hydrocarbon molecules, such as methylcyclohexane or dibenzyltoluene and can be used to absorb large quantities of hydrogen for long-duration storage or for transportation.

MCFC—An abbreviation for molten carbonate fuel cell. This is a higher-temperature fuel cell that is predominantly deployed in the Republic of Korea and the United States, largely running on natural gas from the grid.

PAFC—An abbreviation for phosphoric acid fuel cell, which has been deployed globally and is considered to operate at intermediate temperatures, with a long operating lifetime.

PEM—An abbreviation for proton exchange membrane, a chemical solution used for the electrolyte in either a fuel cell or an electrolyzer that shares the name. PEM fuel cells are the most widely deployed fuel cell technology today and are the overwhelmingly preferred technology for fuel cell mobility applications. PEM electrolyzers are much newer and less developed than alkaline electrolyzers are. However, they are showing fast signs of scaling and typically produce higher-purity hydrogen with greater flexibility in production than alkaline solutions.

SMR —An abbreviation for steam methane reforming, a process by which hydrogen is extracted from natural gas or methane.

SOFC—An abbreviation for solid oxide fuel cells. These are among the most efficient and longest-duration fuel cells commercially available. While there are emerging solid oxide electrolyzers (SOEs) that promise higher efficiencies and lifetimes than are available via PEM and alkaline electrolyzers, for now SOEs remain at the pilot stage with limited units in the field, all of which are below the 1 megawatt scale.

EXECUTIVE SUMMARY

KEY TAKEAWAYS

- In the future, green hydrogen—hydrogen produced with renewable energy resources—could provide developing countries with a zero-carbon energy carrier to support national sustainable energy objectives, and it needs further consideration by policy makers and investors.
- Developing countries with good renewable energy resources could produce green hydrogen locally, generating economic opportunities, and increasing energy security by reducing exposure to oil price volatility and supply disruptions.
- Green hydrogen solutions could decarbonize hard-to-abate sectors such as heavy industry, buildings, and transport while catalyzing renewable-based energy systems in developing countries.
- Electrolyzers and fuel cell technologies are experiencing significant cost, efficiency, and product quality improvements, with green hydrogen steadily closing the cost gap with fossil fuel-derived hydrogen in certain contexts and geographies. Still, further cost reductions are needed for green hydrogen to scale up.
- The technologies necessary to provide a systemic transition pathway for supplying hydrogen-based low-emissions heat, seasonal energy storage, firm power, and heavy-duty mobility solutions already exist today.
- Green hydrogen could provide energy systems with a long-term energy storage solution capable of mitigating the variability of renewable resources, thus increasing the pace and penetration of renewable energy.
- Deployment of green-hydrogen–based systems can facilitate "sector coupling" among different economic sectors, minimizing the cost of meeting sectors' combined decarbonized energy needs.
- Fuel cells may have immediate applications in developing countries, particularly providing decentralized solutions for critical systems, powering equipment in emergency responses, and increasing energy access in remote areas.
- Despite the many years of experience handling hydrogen in industry, risks throughout the hydrogen value chain still require specific knowledge and capabilities to ensure the safe production, storage, transport, and use of hydrogen.
- In developing countries, there is a shortage of qualified engineers who can install, monitor, operate, and maintain integrated fuel cell and hydrogen systems.
- Support from development finance institutions and concessional funds could play an important role in deploying first-of-a-kind green hydrogen projects, accelerating the uptake of green hydrogen in developing countries, and increasing capacity and creating the necessary policy and regulatory enabling environment.

OVERVIEW

Hydrogen produced using electrolysis powered by renewable energy—green hydrogen—and its use in fuel cells has a long history of promising a pathway to a global clean energy economy yet failing to deliver. But mounting evidence suggests that this time the script could be different. As the costs of producing green hydrogen and its use in fuel cells steadily decreases, the global urgency to deliver clean energy alternatives and decarbonize is growing. Accordingly, green hydrogen's extraordinary versatility could play an important role in this transition, particularly in developing countries where access to local fuels and other firm[1] low-carbon resources such as geothermal and large hydro may be limited.

The impact of scaling in the green hydrogen market and improvements in the performance of electrolysis and fuel cell technologies has yet to be translated into actions and implications for developing countries. Despite a significant volume of literature on the global hydrogen market, and the market's latest progress in developed countries, the potential applications for green hydrogen and fuel cells in developing countries have not been fully explored. Hydrogen is a complex technology to operate that requires specific knowledge and capabilities to ensure that its production, storage, transport, and use remains safe. In developing countries these requirements may produce implementation challenges that have to be well understood. This report seeks to advance the understanding of opportunities and challenges of green hydrogen in developing countries by describing examples of green hydrogen pilot applications that have already been deployed in developing countries, bringing to light potential use cases and strategic value, and highlighting technology risks and implementation challenges.

WHAT HAS CHANGED IN THE HYDROGEN TECHNOLOGY LANDSCAPE?

At a global level, there are four key reasons that hydrogen is now emerging as a viable energy technology for the energy transition:

1. **Increased urgency to stop climate change:** The global commitment to mitigate climate change and focus on climate regulations is much stronger now than at any time previously in history. This commitment is gradually pushing countries to find and support low-emission technologies that can reliably supply their growing energy demands. Consequently, as countries increase pressure on energy suppliers to find low- and zero-carbon solutions, significant new funding is being allocated by companies, governments, and investors to overcome the historic barriers that hydrogen technologies have faced.

2. **Reduced renewable energy costs and increased need to firm up renewable energy resources:** Renewable energy costs have declined dramatically and are continuing to fall, significantly reducing the price gap between hydrogen from electrolysis and hydrogen derived from fossil fuels. Moreover, variable renewable energy (VRE) sources alone cannot provide firm energy solutions, which are necessary to guarantee that demand can be met at all times. Hydrogen storage could therefore emerge as a widely deployable solution to contribute to mitigating renewable seasonal variability and to maximizing renewable use in a national energy system.

3. **Significant advancement in hydrogen and fuel cell technologies:** Hydrogen and fuel cell technologies have experienced significant technical progress in their efficiency, durability, reliability, and cost reduction.

[1] The term "firm" refers to energy technologies whose availability is guaranteed at all times, in contrast with variable renewable energy resources such as wind and solar photovoltaics, whose availability is constrained by instantaneous wind speed and sunlight, respectively.

Despite requiring further cost reductions to scale up globally, modern fuel cells are now considerably cheaper, more durable, and more efficient than during the last fuel cell boom cycle in the early 2000s.[2] Thus, companies have begun to shift their focus away from exclusively concentrating on research and development toward developing the capacity to increase manufacturing output. In certain locations, these improvements are helping to close the price gap between electricity generated by fuel cells using green hydrogen and electricity provided from fossil alternatives such as diesel generators.

4. **Global transition towards electric mobility solutions:** The transition to electric mobility has helped develop enabling technologies that hydrogen and fuel cells are using to provide solutions for long-range zero-emission applications: trucks, trains, maritime shipping, buses, commercial vehicles, and perhaps even aviation. With the use of electric drivetrain architecture and supportive air quality requirements established by policy makers and regulators, hydrogen and fuel cells soon could be well placed to reach the scale needed to significantly drive down systems costs and mitigate the heavy pollution common in many cities in developing countries.

GREEN HYDROGEN MARKET TODAY

While, the global market for green hydrogen remains nascent, it could play a more prominent role in the energy transition. The modular nature of electrolysis and fuel cells combined with the widespread availability of zero carbon renewable energy resources makes green hydrogen a particularly interesting option for bringing sustainable hydrogen solutions to developing countries. Green hydrogen is the only known clean energy molecule that can be produced at any scale and in almost any location on earth, a characteristic that is not comparable for other synthetic green fuels. Accordingly, green hydrogen could offer almost any community, company, or country the potential to generate their own fuels, with the flexibility for multiple end uses, including applications in industry, buildings, and transport.

Despite its potential, hydrogen production today is a fossil fuel–intensive process, and significant scaling up is needed to decarbonize existing production. The most common methods to extract hydrogen are through the reforming of natural gas—a process that accounts for around 6 percent of global natural gas demand—and gasification—for which about 2 percent of total coal production is allocated, most of which is in China. Together, these processes are estimated to account for between 96 and 99 percent of global hydrogen production. Thus, hydrogen generation from electricity and water through electrolysis is currently estimated to provide as little as 4 percent of global hydrogen supply. This situation, however, is set to change as green hydrogen costs fall further.

Growing global demand for green hydrogen is driving significant cost declines for electrolyzer equipment. Global water electrolysis deployments have risen from a cumulative 32.7 megawatts (MW) of installed capacity between 2000 and 2013 to over 260 MW of installed and committed capacity between 2014 and 2019 (IEA 2019b). The size of electrolyzer orders is also rising from ITM and Shell's world-record proton exchange membrane (PEM) order of 10 MW in 2017 (ITM 2018) to Hydrogenics's 20 MW order in February 2019, and new feasibility studies announced since March 2019 for 250 MW

[2] Current systems have demonstrated operating lifetimes of over 34,000 hours in the field, with certain technologies reporting electrical efficiencies over 60 percent and combined heat and power (CHP) efficiencies in the 90+ percent range. More generally, capital expenditures for proton exchange membrane (PEM) fuel cells have fallen from \$4 per watt in 2003 to under \$2 per watt today for stationary applications.

electrolyzer capacity in the Netherlands and 12 gigawatts (GW) in Pilbara, Australia. These new market developments indicate that scaling is occurring at a significant rate. Manufacturing capacity (currently about 2.1 GW annually) is responding to this growing demand and moving to fully automated production lines, with future public manufacturing expansion commitments already exceeding 4.5 GW. This scaling is important not simply for keeping up with demand. Crucially, the scaling of manufacturing is also leading to significant cost declines, with the estimated cost of PEM electrolyzers falling from over \$2,400 per kilowatt (kW) in 2015 to under \$1,100 per kW in 2019.[3] Moreover, alkaline electrolysis costs are falling below \$500 per kW for orders above 10 MW, and some market sources suggest that costs below \$300 per kW could now be realized from \$800 per kW in 2017.

Along with the cost reductions in electrolyzers, the rapidly declining cost of renewable electricity is translating into lower costs for green hydrogen production. In markets where wholesale electricity prices fall below \$45 per megawatt-hour (MWh), the cost of green hydrogen production could range between \$2.5 and \$6.8 per kilogram (kg). Although it may seem high compared with a range of \$1–\$3 per kg for hydrogen from steam methane reforming (SMR) for markets that can access natural gas below \$8 per million British thermal units, this price excludes transportation, distribution, liquefaction, and gasification costs, which could add up to \$4 per kg of hydrogen, depending on the transportation mode (pipeline or ship) and location of supply and demand. Accordingly, local green hydrogen production could already be cost competitive in isolated locations with good renewable resources, particularly in those that do not have local hydrocarbon resources and are far from natural gas exporting regions. If renewable energy and electrolyzer costs continue to decline, green hydrogen could eventually become cost competitive in a larger number of locations and in a wider range of applications.

Fuel cells are also becoming cheaper, more durable and more efficient, enabling low-carbon applications for transport, critical systems, and energy access in remote areas. The total capacity deployed of fuel cells worldwide is above 2GW, with PEM and alkaline fuel cells reaching costs below \$2,000 per kW and \$700 per kW, respectively, and efficiencies above 50 percent and 60 percent, respectively. These improvements are helping to close the price gap between electricity generated by fuel cells using green hydrogen or other green hydrogen–derived fuels and electricity provided from fossil alternatives such as diesel generators. The transition to electric mobility has also helped develop enabling technologies that vendors are integrating with fuel cells to provide solutions for long-range zero-emission applications such as trucks, trains, maritime shipping, buses, and commercial vehicles.

The declining price of green hydrogen production and fuel cells opens the door to its wider adoption as a decarbonization vector for energy sector transition. Significant cost declines in green hydrogen production could help to expand its market share in the existing \$135.5 billion a year global industrial hydrogen market (Markets and Markets 2018), which is estimated to release 830 million tonnes of carbon dioxide (CO_2) per annum (IEA 2019b)—a figure equivalent to the combined annual emissions of Indonesia and the United Kingdom. Given the scale of emissions from existing industrial demand sources for hydrogen, it is unsurprising that one of green hydrogen's greatest appeals is its ability to provide a zero-emission energy vector for decarbonization of industrial feedstock.

3 Figures are an average from market data points and numbers cited in the broader literature. For a range of current estimates of alkaline and PEM electrolyzer prices, see table 3.6.

This decarbonization path would also open the door for green hydrogen production to expand into industrial heat displacing carbon intensive fossil alternatives, as the early scaling brings green hydrogen costs toward (and eventually below) fossil parity.

The rapid proliferation of innovative green hydrogen applications is capturing the imagination of international media and policy makers, creating a feedback loop that is boosting awareness and support for green hydrogen technologies. A significant number of countries and companies have begun to develop policies and support pilot projects geared toward exploiting near-term green hydrogen opportunities. These have focused largely on either decarbonizing existing hydrogen applications or using green hydrogen as an alternative to heavy fuels in transport and more recently in industrial heat. In developed countries, exploiting existing gas infrastructure, developing green hydrogen hubs and trade routes, and decarbonizing freight transportation could represent transformational opportunities. Lessons from initial pilots could cascade into other sectors, increasing the experience with green hydrogen technology and further driving down costs. Development of the green hydrogen market could offer a particular advantage to developing countries that have pressing infrastructure needs and exposure to high fuel prices—and that also require solutions to address energy security and resiliency considerations.

GREEN HYDROGEN APPLICATIONS IN DEVELOPING COUNTRIES

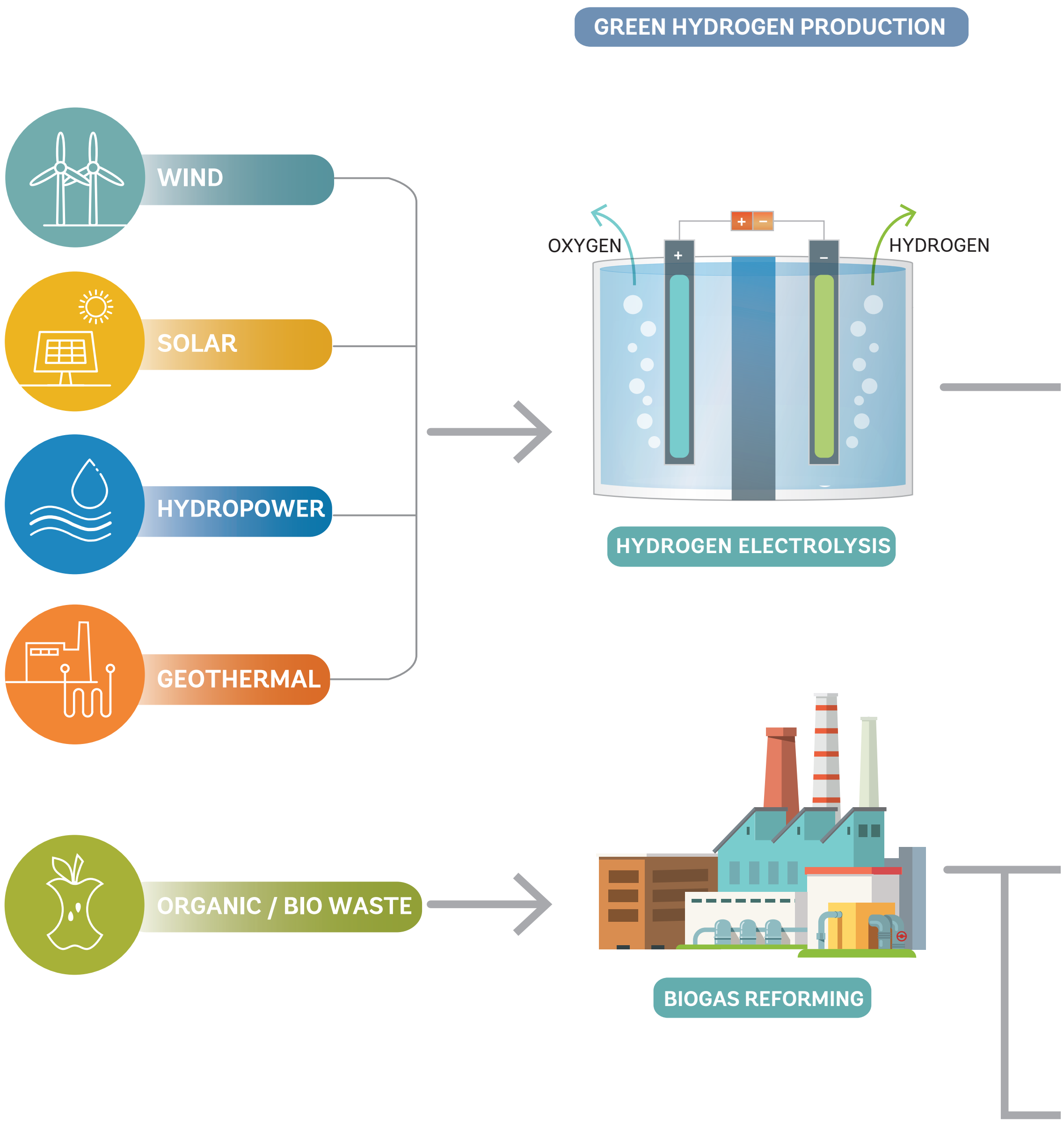
Green hydrogen could provide developing countries with a powerful technology to support national sustainable energy objectives and decarbonization strategies. Green hydrogen could enhance national energy security by reducing the exposure to oil price volatility and supply disruptions where it is produced locally, while also lowering energy sector costs over time in countries that rely heavily on diesel. It could also provide an array of decentralized services that could cover all energy needs in buildings, transport, and industry, while helping to shield critical infrastructure from power supply disruptions, therefore bolstering climate and extreme weather resiliency.

At the core of the appeal for developing countries is the versatility that green hydrogen and its derived fuels offer as a clean energy vector. Today, green hydrogen is a technological solution that can facilitate sector coupling by enabling solar, wind, and other renewable sources to be converted into an energy vector that can decarbonize industry, mobility, and electric power. Moreover, hydrogen and hydrogen-derived fuels are easier to store, transport, and repurpose across an array of energy needs than electricity. The existing infrastructure in developing countries that supports the supply, storage, and transportation of methanol and ammonia could be leveraged by green hydrogen applications (figure ES.1).

Existing demand for fossil-derived hydrogen in developing countries is concentrated in the production of ammonia for fertilizers; the refining of petroleum products for domestic use, exports, or both; the production of methanol; the production of iron, glass, and polysilicon in manufacturing; and the treatment of certain food products and other smaller industrial requirements. Given the existing demand, green hydrogen may offer an economic opportunity for policy makers to develop local industry through domestic green hydrogen production. If fully exploited, domestic green hydrogen production could enhance food and energy security.

Green hydrogen could also help address key challenges in bringing excellent- quality renewable resources to market while increasing renewable penetration rates. VRE resources such as wind power (both onshore and offshore) and

FIGURE ES.1 Primary hydrogen and fuel cell applications and ecosystem for developing countries



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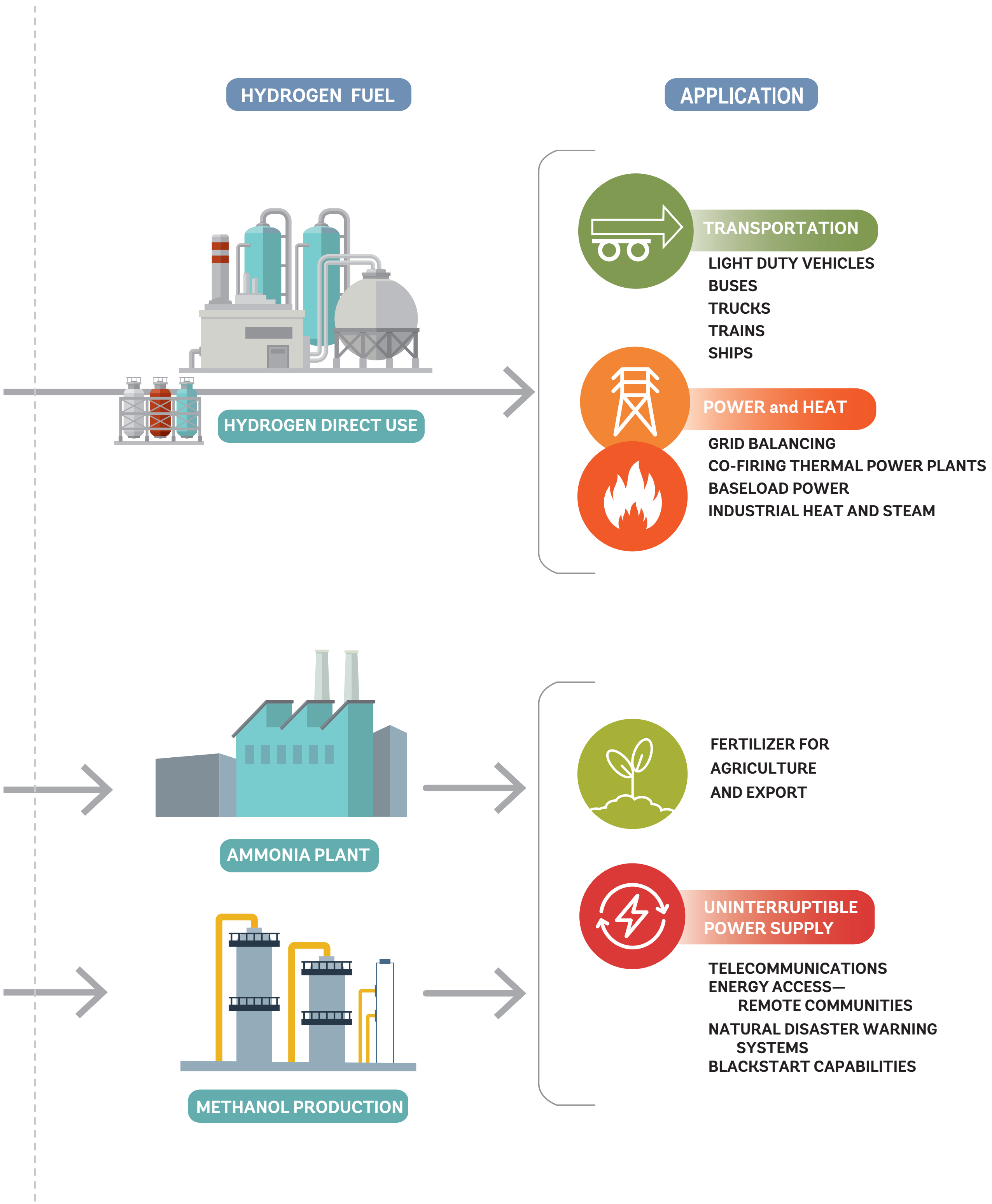

HYDROGEN FUEL
APPLICATION
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LIGHT DUTY VEHICLES
BUSES
TRUCKS
TRAINS
SHIPS
HYDROGEN DIRECT USE
POWER and HEAT
GRID BALANCING
CO-FIRING THERMAL POWER PLANTS
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NATURAL DISASTER WARNING
SYSTEMS
BLACKSTART CAPABILITIES
METHANOL PRODUCTION

solar photovoltaic (PV) are frequently located away from large population centers and not available on demand, making them costly to deploy and integrate into the power grid. The ability to bypass these constraints by creating green hydrogen on-site and either storing it for later use in a fuel cell or transporting it to demand centers holds considerable appeal, especially if it can could be produced at sufficient scale and use existing pipelines or transportation routes. Exploiting the synergies between VRE resources and green hydrogen production could help leverage high-quality resources and significantly increase VRE deployment rates.

Yet, further cost declines will be needed to meet existing hydrogen demand in developing countries. Harnessing the opportunities presented by green hydrogen to supply existing hydrogen demand will require further electrolyzer cost declines, particularly in countries with access to natural gas or cheap coal. If long-term predictions are realized, green hydrogen costs could fall below US$2 per kg by 2030 in countries with high-quality renewable resources such as China, Bangladesh, the Arab Republic of Egypt, India, Kenya, Mexico, Morocco, Nepal, Pakistan, Somalia, South Africa, and Turkey (IEA 2019b). At such a price point, the cost of green hydrogen production could be comparable, and in many cases lower, than on-site hydrogen generation from natural gas using SMR.

NEAR-TERM OPPORTUNITIES FOR GREEN HYDROGEN IN DEVELOPING COUNTRIES

Opportunities exist today to pilot both green hydrogen for low-emission transport solutions and fuel cells for remote power provision in developing countries. China, India, Indonesia, the Philippines, and South Africa are starting to gain experience using ammonia-based and methanol-based fuel cell systems for the telecommunications sector. Meanwhile, smaller stationary fuel cell systems have also started to be piloted for residential and tourism consumers in Namibia and Thailand. Other larger hydrogen or fuel cell projects are being piloted to provide stationary power solutions in Argentina, Mali, Martinique, and Uganda. On the mobility side, fuel cell buses have been piloted in China, Costa Rica, and Malaysia, with orders placed in Bulgaria, Indonesia, and India. China and South Africa also have begun to pilot hydrogen and fuel cell systems for forklifts used in material handling. The motivating benefits of these projects are context dependent, but they broadly reflect the fact that for some applications hydrogen could be more attractive than electricity-based storage systems given hydrogen's higher energy density (figure ES.2).

The transition to modern fuels in industry could also be a major area of potential near-term growth for green hydrogen. Developing countries that are in the process of building the means to supply their rapidly growing industrial demand for energy will also need to transition away from traditional fuel sources—notably, biofuels, coal, and petroleum-based fuels—toward clean energy sources. Given that 25 percent of global carbon emissions could come from industrial heat demand in 2040 (Bellevrat and West 2018), green hydrogen represents a significant opportunity for investors and policy makers seeking to lock out heavy CO_2-emitting energy sources from becoming the foundation for industrialization in many developing countries.

Island locations, remote communities, countries with existing gas infrastructure, areas with poor air quality, and areas with excellent renewable resources or with severe seasonal renewable variability could offer the most attractive opportunities for near-term deployments of green hydrogen and fuel cell projects. Given the high energy prices, synergies with other infrastructure, and environmental challenges that these territories face, the applicability of green hydrogen solutions could be initially explored in these cases:

FIGURE ES.2 **Hydrogen South Africa solar plus battery, hydrogen electrolysis, and fuel cell system**

© HySA.

1. **Islands and remote communities that are energy importers could use green hydrogen as a decarbonization vector across heat, transport, and power.** Given the ability to produce and store hydrogen in large quantities for long periods of time, as well as the limited physical requirements for fuel cell systems, islands and remote communities represent an obvious initial opportunity for green hydrogen. Initial analysis suggests that green hydrogen combined with fuel cells may already provide cost-competitive power against diesel alternatives in certain conditions.

2. **Middle-income countries with existing gas infrastructure have clear incentives to explore green hydrogen.** Countries such as Argentina, Egypt, Malaysia, and Thailand have made significant investments in gas and now risk stranding assets as they seek to decarbonize. However, existing natural gas assets could be repurposed to support green hydrogen production, minimizing the risk of stranded assets. Short-term opportunities may also exist for blending green hydrogen into gas grids, thereby requiring no changes to existing assets but leading to reduced emissions. Green hydrogen also offers countries a route to repurpose existing turbine base power systems, thus avoiding the need to retire assets early.

3. **Heavily polluted metropolitan areas in developing countries could benefit significantly from fuel cell bus transport solutions.** These areas often have large public sector–owned transport fleets that could be repurposed to help improve local air quality and reduce emissions. Because all fuel cell vehicles require air filters, a citywide fleet could help reduce particulate emissions while emitting only water. Fuel cell options also offer longer ranges than battery electric alternatives, creating alternative clean solutions for transport activities that rely on long-haul fleets.

Areas with excellent renewable resources or with a high degree of seasonality in their renewable power production profiles could consider green hydrogen as a seasonal energy storage solution. In this regard, green hydrogen could provide opportunities for increasing the deployment levels of VRE technologies in these locations, further reducing demand for fossil fuel alternatives and eventually enabling green hydrogen exports with sustained declines in production cost.

REMAINING TECHNOLOGY AND IMPLEMENTATION CHALLENGES

Some significant safety and technical risks still need to be understood and addressed before countries can leverage all the opportunities that green hydrogen could offer. Hydrogen is a complex molecule to contain, store, and transport. It has unique safety properties that can be challenging to address and that require technical awareness that may be lacking in countries that do not have domestic hydrogen production capabilities. Even in countries that do have some expertise, knowledge of how electrolyzers operate, how to maintain fuel cell systems, and how to avoid leakages from high-pressure storage (or cryogenic storage) is essential.

Hydrogen technologies are capital intensive, and further cost reductions and efficiency gains need to be realized to scale up green hydrogen solutions. High maintenance requirements in some regions might also increase costs, because hydrogen technologies are very prone to damage and deterioration if input quality does not meet required specifications—for example, impurities in water for the electrolyzer or impurities in hydrogen for fuel cells. Moreover, as with some existing battery technologies, few systems have been tested to their full anticipated stack lifetime and, as a result, performance has not been fully assessed at scale for all current technology providers. Additional efficiencies could be gained with current hydrogen storage systems, most of which require pressurization or liquefaction. Other hydrogen storage technologies based on solid-state compounds are being explored and eventually could bring more efficient solutions to store and transport hydrogen.

Integration of green hydrogen technologies and labor capacity constraints are still significant barriers to the wider deployment of green hydrogen and fuel cell technologies, especially in developing countries. Few engineering companies have experience in developing and installing green hydrogen or fuel cell technologies, especially in developing countries. Lack of sufficient training programs on hydrogen installation is a constraint, especially when many of the suppliers have a limited number of staff members who can offer installation support. The integration of hydrogen technologies into other systems also poses a challenge, as suppliers may have limited experience optimizing their units to fit within a new application. Electrolysis and fuel cell systems require regular maintenance visits, which could pose a barrier in remote locations and even in markets where the number of installed units is too low to justify a permanent resource from the manufacturer. There is also a need to guarantee that maintenance work is done properly and to market specifications.

The initial rollout of green hydrogen will require countries to develop national strategies that clearly identify both a pathway toward meeting the infrastructure needs and the sectors where green hydrogen solutions could become commercial. The development of green hydrogen energy systems will require countries to think carefully about whether to make strategic investments into pipeline infrastructure or whether to rely on road transportation and storage across multiple locations. In some instances, the repurposing of existing infrastructure may be possible, thus avoiding stranded assets and potentially lowering deployment costs. However, that option will not be applicable in all developing countries. Further, local capacity to install, maintain, and handle hydrogen and its associated technologies would have to be developed, a task that would require a long-term commitment to education programs in developing countries. Consequently, the decision to initiate the development of green hydrogen energy systems should be considered within a clear framework and roadmap that help all stakeholders (including consumers and government) plan and adjust their investments and actions accordingly.

The equipment used in producing green hydrogen is capital intensive and, as such, requires high utilization rates to economically justify investments. Accordingly, developing countries must assess at a system level whether green hydrogen production is appropriate given the existing resources available and the energy needs from different sectors. Strategies for large-scale deployment of green hydrogen should also consider the systemwide impacts of a transition, notably where other energy storage solutions may offer greater system efficiencies. Coordination among all energy sector stakeholder, including the public sector to develop these strategies into a favorable regulatory environment, and with development finance institutions working in tandem to provide concessional financing that mobilizes private capital, will be essential to ensuring a successful initial rollout of green hydrogen.

Moreover, financial constraints derived from technology and regulatory risks may inhibit the near-term development of green hydrogen in developing countries. These constraints include the insufficient scale or track record of some hydrogen system components, investors' lack of awareness of green hydrogen's potential role in the energy transition in developed countries, and the lack of clear national strategies and regulatory frameworks for some hydrogen applications, coupled with a perception that new technologies deployed in developing countries may pose higher risks. Innovative cofinancing and concessional funds could play an essential role in supporting first-of-a-kind green hydrogen projects in developing countries, in particular those with technology components that do not have a sufficient scale or track record. For example, investors could use commercial financing for renewable power projects such as wind and solar assets dedicated to producing green hydrogen, benefiting from blending with concessional funds to reduce the financing cost of the electrolysis plant.

Despite existing challenges, the potential uses for green hydrogen make it an essential area for further consideration and analysis by policy makers and investors in developing countries (box ES.1). Green hydrogen is increasingly drawing interest from governments in all regions, with valuable near-term applications in some contexts and a predominant decarbonization role in hard-to-abate sectors. Over the next 5 years, early evidence suggests that mobility and power provision could provide the main source of growth for green hydrogen and fuel cell technologies in developing countries. This forecast largely reflects the fact that further cost declines are essential for green hydrogen production to reach commercial-equivalent cost points to alternative energy vectors in developing countries. Efforts are therefore needed today to ensure that the opportunities available to scale up green hydrogen and fuel cell deployments in developing countries are researched and capitalized on before alternative carbon-intensive energy systems are locked in.

BOX ES.1

HYDROGEN FUNDAMENTALS

Hydrogen is the most abundant molecule in the universe and the lightest element in the periodic table. It is rarely found unbounded in nature, and it is almost always extracted from another source. Hydrogen production typically comes from the extraction of hydrogen from water and electric power or from hydrocarbons, most notably by using natural gas and coal.

As an energy carrier, hydrogen can be used for a wide array of energy and industrial applications and can be stored for long periods of time in various forms. Hydrogen is already one of the most widely produced industrial gases in the world, and it is a significant source of carbon dioxide emissions because of its typical production through extraction from fossil fuels. However, the production of zero-emission hydrogen through renewable energy sources could become a commercial alternative to fossil fuel–derived hydrogen in a wide array of applications. Producing hydrogen from renewable electricity is done through a process called *electrolysis*, in which electricity is channeled through a device called an *electrolyzer*, which splits oxygen from hydrogen in water, creating pure oxygen and pure hydrogen with zero carbon emissions. Approximately 50 kilowatt-hours of electricity and 9 liters of deionized water are required to produce 1 kilogram of hydrogen using an electrolyzer of 80 percent efficiency.

Fuel cell technologies offer a method to generate electricity by combining hydrogen with oxygen in a chemical process. This is typically much more efficient than a combustion process, while also being considerably quieter and producing zero carbon emissions (if pure hydrogen) or zero nitrogen oxide emissions when using hydrocarbon fuels. When hydrogen reacts in a fuel cell to generate electricity, the only products are electricity, a small amount of heat, and water. Approximately, 42 kilograms of hydrogen are needed to produce 1 megawatt-hour of electricity using a fuel cell of 60 percent efficiency.

Hydrogen's specific energy is the highest among conventional fuels, but its energy density is the lowest, so pressurization or liquefaction is required for hydrogen to be used as a fuel. These fundamental characteristics of hydrogen are the primary drivers of its value as a fuel.

Table BES.1.1: Specific energy and energy density comparison of commonly used fuels

FUEL	SPECIFIC ENERGY (MJ/kg) (1kWh = 3.6 MJ)	ENERGY DENSITY (MJ/L)
Hydrogen	142.0	0.01 (1 atm); 7.10 (1,000 bar); 10.00 (liquid)
Methanol	20.0	15.90
Ammonia	22.5	15.60
Gasoline	47.1	35.00
Diesel	42.8	40.40
Heavy fuel oil	42.4	40.70
Biodiesel	42.2	33.00
Natural gas	50.0	0.04
LNG	50.0	22.20

Source: World Bank compilation of higher heating values obtained from multiple sources.
Note: atm = atmospheres; kg = kilogram; kWh = kilowatt-hour; L = liter; LNG = liquefied natural gas; MJ = megajoule.

1: INTRODUCTION

KEY TAKEAWAYS

- Green hydrogen, produced using electrolysis powered by renewable electricity, is emerging globally as an energy solution for a diverse array of challenges, including climate change mitigation and adaptation and energy security.
- Green hydrogen could contribute to the decarbonization of activities in industry (zero-emission industrial heat supply), transport (clean mobility solutions), and buildings (climate-resilient firm power generation), increasing the scalability of renewable energy use.
- The current hydrogen market is already significant and carbon intensive, thus providing an opportunity for investors and policy makers to reduce emissions and develop national strategies for green hydrogen's future production and for uses that are compatible with Nationally Determined Contributions (NDCs).
- Green hydrogen could represent a clean alternative fuel for developing countries as they transition from a heavy reliance on fossil fuels and look for modern, low-emission, and locally produced energy vectors.
- Hydrogen production technologies and fuel cells are well established, with research and innovation efforts focusing mostly on cost reductions per unit.
- A number of technology challenges remain surrounding the cost efficiency of transport and storage of hydrogen, and further work on alternative hydrogen storage technologies (such as, solid-state storage, liquid organic hydrogen carriers [LOHCs], and small-scale hydrogen conversion technologies) is needed.
- Knowledge of green hydrogen as a potential energy vector in developing countries is low, making capacity building and training essential to support green hydrogen deployments in developing countries.

Hydrogen is not a new commodity, nor are fuel cells a new technology. The global hydrogen market in 2018 was valued at over $135.5 billion, with an estimated compound annual growth rate (CAGR) of 8 percent until 2023 (Markets and Markets 2018). Estimates for the volume of hydrogen produced vary, but a significant number of documents suggest that 55 million tonnes[4] to 70 million tonnes (IEA 2019b) of hydrogen are commercially produced annually.[5] Given its existing scale, hydrogen production and storage are well understood. But what is new is the growing interest around a hydrogen production process called *electrolysis*, which is reaching a point of cost parity with hydrogen derived from fossil fuel sources in certain contexts and geographies. The prospect of producing a zero-emission energy vector through electrolysis with a wide array of applications in many sectors could be transformative to economic development that is aligned with national and global climate goals.

Consistent findings across available literature and consultations with market players indicate that hydrogen technologies have been progressively improving throughout the past decade and systems have been developed that are more efficient and safer to operate than those in the past. If progress in cost and performance continues, and the scaling up of electrolysis equipment over the next decade further pushes costs down, green hydrogen production could eventually become a viable commercial alternative to existing fossil-based solutions. As the International Renewable Energy Agency (IRENA) concluded in its 2018 hydrogen report: "The technologies are ready. A rapid scaling up is now needed to achieve the necessary cost reductions and ensure the economic viability of hydrogen as a long-term enabler of the energy transition" (IRENA 2018).

This report attempts to draw attention to areas of current success and areas in which green hydrogen could provide a compelling solution to address the current and anticipated energy challenges faced by developing countries. In this way, this report focuses on how green hydrogen and fuel cell technologies could be initially rolled out in developing countries by presenting a series of applications that could be initially deployed in some locations and that could scale up in the future.

This report also focuses on some of the technology risks, implementation challenges, and knowledge gaps that are emerging as new hydrogen projects and technologies are being deployed and tested in greater numbers. Crucially, the report seeks to draw attention to where these challenges are universal and where they are more specific to developing countries.

Although other methods of hydrogen production do exist, this report will focus largely on hydrogen produced from electrolysis with renewable sources (figure 1.1).[6] Electrolysis is simply the process of chemically separating hydrogen and oxygen molecules from water using electricity. When the source of electricity is renewable, this process is referred to as *green hydrogen*.[7] The most obvious appeal of green hydrogen is its ability to decarbonize the current global hydrogen market while also

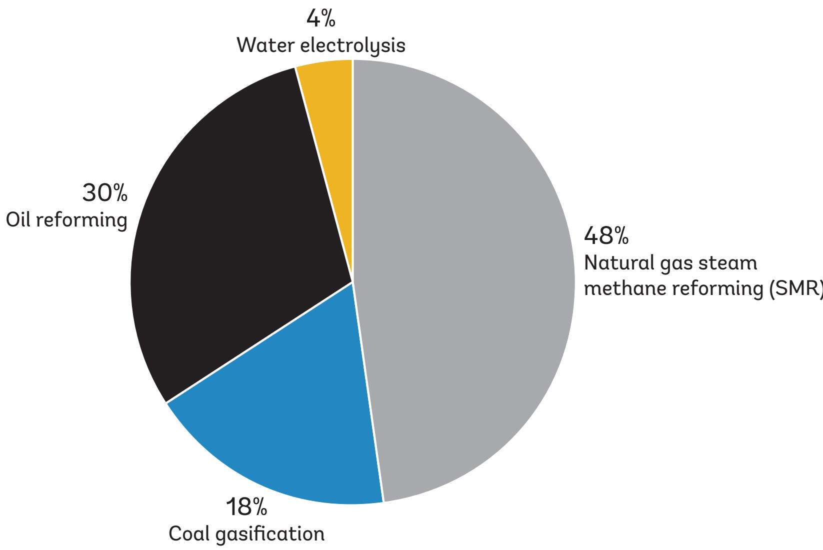
4 While 55 million tonnes is a broad representation from the available literature, it has also been used recently by the Canadian Hydrogen Fuel Cell Association. See LePan 2019.

5 DNV GL's 2019 paper for the Norwegian government quoted 55 million, as did the Hydrogen Council (2017), IRENA (2018), and Siemens (2019). World Energy Council—Netherlands cited 45 million–50 million using 2010 data in its 2019 report.

6 Other World Bank reports are under development that will address gray and blue hydrogen in more detail.

7 The term *green hydrogen* can also refer to hydrogen created from biogas; however, few projects or pilots have been proposed and developed to date. This report therefore does not focus on that technology.

FIGURE 1.1 **Global hydrogen market, by production method**



Sources: Ajayi-Oyakhire 2012 and IRENA 2018.

creating a flexible clean energy carrier that can be used for a wide array of energy applications. The decarbonization potential of a broader use of green hydrogen is significant.

In 2019, about 96 percent of global hydrogen production came from fossil fuel sources, with 4 percent from electrolysis, 48 percent from natural gas via steam methane reforming (SMR), and 48 percent from coal gasification, oil, or other chemical processes (such as chlorine production).[8] These types of hydrogen are typically referred to as *gray, black,* or sometimes *brown hydrogen*. Today, hydrogen accounts for 6 percent of global gas consumption and 2 percent of global coal consumption, a primary energy demand equivalent to 330 million tonnes of oil equivalent (Mtoe), which as the International Energy Agency (IEA) notes is larger than Germany's primary energy demand (IEA 2019b, 17). Moreover, this demand is growing as the world requires ever more hydrogen as an industrial feedstock, the primary uses of which are for ammonia production, followed by refining, methanol production direct iron reduction, and various other products (such as glass production and hydrogenation of fats). Therefore, green hydrogen production (figure 1.2a) offers policy makers a route to removing 830 million tonnes of carbon dioxide (CO_2) (IEA 2019) from global annual emissions and preventing any increase in emissions from this sector. Achieving this reduction is as crucial in the developed world as it is in developing countries, especially where hydrogen and hydrogen-derived products are essential for the health of local industries (notably, ammonia used in the production of fertilizers).

Given the size and anticipated growth of the existing hydrogen market, the development of green hydrogen projects could present a significant investment opportunity for investors in developing countries. Not only do many developing countries enjoy some of the most abundant renewable resources, but they also are often the countries that are most in need

8 Ajayi-Oyakire 2012, citing Ogden 2004; IEA 2015, 10; IRENA 2018, 13; and Siemens 2019, slide 8.

of new and clean forms of energy to support economic development. IEA data illustrate one area of immediate interest: Roughly 4.5 percent of the global energy supply in 2015 (approximately 28.24 exajoules, EJ[9]) was sourced from traditional biomass, which is entirely consumed in developing countries. Further, all 28.24 EJ of developing country energy consumption that is currently derived from traditional uses of biomass must be replaced by more modern alternative fuels as consumer purchasing power grows in these markets. Ensuring that the alternative fuels create zero emissions, are affordable, and are convenient to use is essential to avoid locking developing countries (and ultimately global CO_2 emissions) into a trajectory that leads to significant climatic warming by the middle of the century.

But hydrogen applications do not come without challenges. Hydrogen is a notoriously complex and expensive gas to store, with a range of properties that require careful consideration to ensure safe usage (these are explored more in chapter 7). Although technologies and procedures do exist to minimize leaks and to ensure that, where necessary, hydrogen is released in a controlled manner, these elements are not universally understood outside the petrochemical industry. Indeed, where there have been safety incidents involving hydrogen, the cause has often been a fault in the assembly of the units, demonstrating the importance of having access to experienced installers and engineers. Access to such skills is also important for the ongoing maintenance of fuel cell systems, notably those operating at higher temperatures for which suppliers are advising some form of basic maintenance every three months. But storage and assembly concerns are not unique to hydrogen and are also considerations for the handling of other fuels such as ammonia—a toxic chemical—or new technologies such as electric battery storage, for which fires from poor assembly are also a concern. Indeed, the key takeaway is not that safety is an insurmountable barrier or that the issues are not sufficiently understood; rather, the knowledge around hydrogen needs to be more widely disseminated and practiced as these new applications gain traction.

Beyond the safety, cost, and convenience of deployment remain the two key factors that determine the pace of technology adoption in developing countries. It is notable that hydrogen and its derived products are already being used for a wide array of applications in some developing countries without the need for large-scale government support. The reasons for this are explored in detail in chapter 2 of this report but, broadly speaking, consumers in developing countries often pay higher than average prices for energy than their peers in developed countries do, and commercial and industrial consumers in developing countries often face problems with the reliability of the energy supply. These factors can negate some of the challenges that face hydrogen deployments in developed markets, where green hydrogen in power-to-power applications has struggled to provide a commercially compelling proposition at current costs. Furthermore, hydrogen production and fuel cell technologies are often deployed in prefabricated containers at the distributed scale, making installation relatively fast and reducing the construction time.

Further, some developing countries simply lack the ability to develop extensive domestic renewable energy resources because of physical constraints such as the lack of access to land on which to deploy renewable plants or the poor quality of local renewable resources. In these cases, the ability to import a clean fuel from a variety of suppliers and provide reliable power

[9] This amount is the product of the 55.4 percent of traditional biomass used for energy in 2015 multiplied by 51 EJ. IEA, Bioenergy website, https://www.iea.org/topics/renewables/bioenergy/.

without requiring large amounts of space is essential. Green hydrogen can be produced and stored for long periods of time, then dispensed when needed. Electrolyzers can even provide services to grid operators, adjusting their hydrogen output as they do in markets such as the United Kingdom, where six 330 kilowatt (kW) electrolyzers will follow a demand optimization profile provided by a software provider called Open Energi (*FuelCellWorks* 2019c).

One significant barrier to the deployment of green hydrogen in developing countries is a lack of awareness. Few business and utilities in developing countries have a clear understanding of the potential applications for green hydrogen inside their businesses, and thus they have not sought to engage with suppliers, financiers, or the government to promote its use. Concurrently, many policy makers have not sought to develop a policy framework or national strategy to support the uptake of green hydrogen and fuel cells because they may be unaware of the role hydrogen could play in their national energy strategy and industrial objectives. In addition, the technical expertise for hydrogen systems is frequently low and in many cases nonexistent. Because training may take several years for workers in developing countries to gain the necessary skills to support these technologies, developing countries will have to rely on a small pool of qualified international workers who will be in high demand within their own markets. This requirement may increase short-term deployment costs and increase the timetables for deployment in developing countries.

With regard to fuel cells, the technology itself was first developed in 1839, and today over 1.6 gigawatts (GW) of stationary fuel cell capacity has been deployed globally (IEA 2019b). In developing countries, the bulk of deployed fuel cell systems are small scale and have been used to provide an uninterruptible power supply for telecommunications and emergency services. Although the size of each unit may be small (typically below 10 kW, but it can vary depending on the site) the absolute number of systems deployed is significant and growing.[10] On the larger stationary side, fuel cells are beginning to gain traction for commercial uses (below 5 megawatts [MW]) in developing countries, with countries such as India and South Africa both deploying high-temperature systems. Typically, these larger units will make commercial sense where there is already access to natural gas, which remains globally the preferred fuel for stationary fuel cells. Nevertheless, current deployment levels are low and further cost declines will likely be needed before stationary fuel cells in other markets are able to replicate the deployment scales achieved in the Republic of Korea and the United States (figure 1.2b).

On the mobility side, there are over 12,000 fuel cell electric vehicles (FCEVs) globally,[11] with hydrogen buses, trucks, trains, drones, and bicycles all available for commercial purchase. Further, hydrogen and fuel cell prototypes have been developed or first units ordered for ferries and small aircraft. Developing countries have gradually begun to deploy fuel cell buses, notably in Asia, funded primarily through the support of either local government or large national utilities. In the long term, the appeal of hydrogen is clear, with local governments in Indonesia (Borneo), Brazil, China, Costa Rica, India, Malaysia,

[10] One of the leading providers of methanol fuel cells, CHEM Corporation, stated that it has deployed over 3,000 systems, mostly located in the Caribbean, China, India, Indonesia, Japan, Malaysia, South Africa, and other smaller markets (*Engineering News Online* 2019).

[11] The California Fuel Cell Partnership (CAFCP) reports 9,789 FCEVs in California as of September 2019 and 3,386 in Japan. This combined with over 500 FCEVs announced in the EU under the Hydrogen Mobility Europe initiative and the recently announced sales of 1,106 FCEVs for China in 2019 (from data provided by the Power Battery Application Branch of China Industrial Association of Power Sources) provides the basis for the greater than 12,000 figure. Including Australia, Korea, and other markets will increase the numbers modestly. Sources: CAFCP 2019, Sampson 2019, and Xinhua News Agency 2019.

FIGURE 1.2 **Green hydrogen generation and fuel cell examples: Electrolyzer and community wind site, Shapinsey, Orkney Islands, United Kingdom (left) and Bloom Energy commercial unit, United States (right)**

Source: ESMAP (left). © Bloom Energy (right).

Nepal, Thailand, and South Africa all expressing interest or actively investing in fuel cell mobility projects.

Although there are varying methods for classifying the different applications for green hydrogen and fuel cell technologies, this report will group potential uses into three core areas of interest:

- Green hydrogen for power and heat,
- Green hydrogen for mobility, and,
- Green hydrogen for industry.

Within these areas, the types of potential green hydrogen projects can be extremely diverse, both geographically and with respect to their application. For example, a 250 MW electrolyzer has been proposed by BP for refining gasoline for vehicles in the Netherlands, while a 20 MW electrolyzer project for producing green ammonia is being deployed in Quebec and a 12 GW project is under consideration in Pilbara (Australia) for hydrogen exports to Asian countries. For fuel cells the uses are just as diverse, with a 50 MW fuel cell in Korea being deployed to generate power for Daesan Industrial Complex (Hanwha 2018), a hybrid renewable energy and energy storage system in French Guiana to provide 24-hour dispatchable power, and a fuel cell bus program announced in Borneo (Indonesia). Nonetheless, these classifications do help provide an analytical reference point, given that mobility applications typically represent the most expensive form of energy, followed by power and heat and then by hydrogen for industrial uses. Accordingly, the categories help influence assessments about when certain applications are likely to become commercially viable and competitive against alternatives, and what conditions are needed to achieve this.

This report is structured to provide readers first with an overview of why green hydrogen has gained traction in recent years, why that is relevant for developing countries, and what implementation challenges remain. In chapter 2, the report offers a historical context to the development of the current global hydrogen and fuel cell market and then explains what has changed and provides examples of how these technologies are being used by consumers in developing countries. That chapter, in turn, is designed to shed light on where current opportunities for market growth in green hydrogen exist and to draw attention to applications that have been neglected. To help frame the discussion of green hydrogen within the global context, chapter 3 provides a recap of how hydrogen technologies work and details costs and the size of global markets today. Chapters 4, 5, and 6 then explore the current array of applications for green hydrogen and fuel cell technologies in power and heat, transport, and industry, respectively, illustrating the areas in which developing countries have already begun to deploy hydrogen and fuel cell technologies. These chapters also show the wider array of potential applications as the technologies develop and costs decline further. Chapter 7 provides a list of implementation challenges for green hydrogen and fuel cell projects—including safety, transport, and storage—with the aim of helping readers understand some of the technical factors involved in developing projects and of assisting policy makers, developers, and investors who are considering these types of projects in developing countries. Finally, chapter 8 suggests areas for further research to help developing countries assess the potential for green hydrogen projects.

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2: WHY GREEN HYDROGEN, WHY NOW, AND WHY DEVELOPING COUNTRIES?

KEY TAKEAWAYS

- Hydrogen is a well-understood gas that could offer solutions to certain energy, climate, and public health requirements while contributing to decarbonizing economic activities.
- Historically the majority of hydrogen was green, produced from water and power from hydroelectric sites, but this method was subsequently replaced by hydrogen from fossil fuel sources.
- The historically high cost of electrolyzers and variable renewable energy technologies prevented green hydrogen from emerging as a significant clean energy technology during its first major commercialization wave in the late 1990s and early 2000s, but the circumstances today are different.
- Electrolyzer costs have declined by over 50 percent in the past five years, while efficiencies and system lifetimes have also increased considerably. Meanwhile, the cost of renewable electricity has fallen dramatically, with solar PV power purchasing agreements (PPAs) signed for under $20 per MWh.
- There is an emerging national and corporate consensus that hydrogen is essential to supporting decarbonization pathways in developed and developing countries.
- Developing countries that experience high electricity prices and reliability problems could provide more appealing commercial opportunities for green hydrogen and fuel cell technologies in the near term.
- Hydrogen is not a new technology for developing countries. Large-scale green hydrogen production has previously occurred in developing countries, such as Egypt, India, and Zimbabwe, and its reestablishment could create local economic opportunities for industry while facilitating higher rates of VRE deployments.
- Energy storage solutions based on green hydrogen could help increase grid resiliency, addressing concerns that may arise from challenges posed by VRE integration, climate disasters, or challenges in managing grid load requirements.
- Long-term investment decisions taken today will define the design and structure of future energy systems, which must already consider how to reduce greenhouse gas (GHG) emissions. A failure to identify and develop strategies to incorporate green hydrogen today could lock fossil fuels in and green hydrogen out of national energy systems for decades, potentially hindering CO_2 reduction efforts.

2.1. WHY GREEN HYDROGEN?

Given the increasing urgency to meet global climate commitments under the Paris Agreement and to seek even faster reductions as reflected in the Intergovernmental Panel on Climate Change (IPCC) 1.5-degree scenario, the wide variety of applications for green hydrogen make it an essential part of the decarbonization toolkit. Indeed, hydrogen is a flexible energy carrier that can be transformed into electricity and heat for use in decarbonizing activities in industry, transport, and buildings. Analysis conducted by McKinsey for the Hydrogen Council in 2017 suggested that a transition toward a hydrogen economy could lead to 7.5 gigatonnes of annual CO_2 abatement by 2050 (equivalent annually to 20 percent of the total emissions in 2018) (McKinsey & Company 2018). Further, as policy makers seek to encourage a transition to clean energy, there is a growing awareness of the essential need to find technical solutions that allow for the decarbonization of economic activities while leveraging existing assets whenever possible. In this context, green hydrogen could offer a value proposition to a wide array of stakeholders, including gas companies, utilities, consumers, developers of renewables, and policy makers. Because hydrogen is a well-known industrial gas that the world has produced for over 60 years, there is significant global expertise on the production and handling of hydrogen, as well as regulatory guidance, safety standards, and established training programs. Hydrogen can be used through upgrades to existing gas networks, adjustments to existing gas turbine technologies, and modifications of boilers and to existing commercial vehicles. Accordingly, hydrogen is seen as particularly appealing to markets with sizeable existing gas infrastructure, notably in Argentina, China, Europe, the Gulf Cooperation Council countries, Japan, Korea, Indonesia, Malaysia, North America, and Thailand.

But hydrogen's importance to the energy transition goes beyond its convenience for existing gas consumers. Green hydrogen is one of the few technologies that currently offers the capability of delivering seasonal energy storage in all markets—notably, in those that cannot develop large pumped hydro solutions. Further, green hydrogen and its derivative fuels, such as ammonia and methanol, are among the few technical solutions that are capable of reducing emissions in heavy-duty transportation sectors such as rail, shipping, trucking, and even aviation. Today there are fuel cell trains actively deployed or under consideration in China, Japan, Korea, France, Germany, the Netherlands, Russia, the United Kingdom, and the United States, while hydrogen-powered fuel cell ferries will begin operation in 2021 in Norway and the United Kingdom. In trucking and the urban mobility space, hydrogen is also a powerful partner to battery-based electric solutions. Nearly all fuel cell electric buses today operate in tandem with a battery, while the flagship Nikola fuel cell trucks also incorporate lithium ion batteries alongside fuel cells. In this context, green hydrogen and fuel cells should be seen less as threats to the development of electric mobility solutions and more as additional configurations that can help optimize solutions for long-range or high-energy applications.

Since 2018, energy agencies such as IRENA and the IEA have concluded that "clean hydrogen is currently enjoying significant political and business momentum, with the number of policies and projects around the world expanding rapidly. . . . now is the time to scale up technologies and bring down costs to allow hydrogen to become widely used" (IEA 2019b). The importance of scaling has thus become the focus for companies in this sector, driven by assessments that by creating an enabling environment for green hydrogen production, costs could fall between 30 percent to 70 percent by 2030 in aggregate (Hydrogen Council 2020; IEA 2019b), and that prices could fall even further in certain project contexts. At that level, green hydrogen could not only reach cost parity with fossil-derived hydrogen—thus becoming a powerful mechanism for decarbonizing the existing energy and carbon intensive industrial hydrogen commodity market—but it could also become an important energy vector for decarbonizing the wider energy sector.

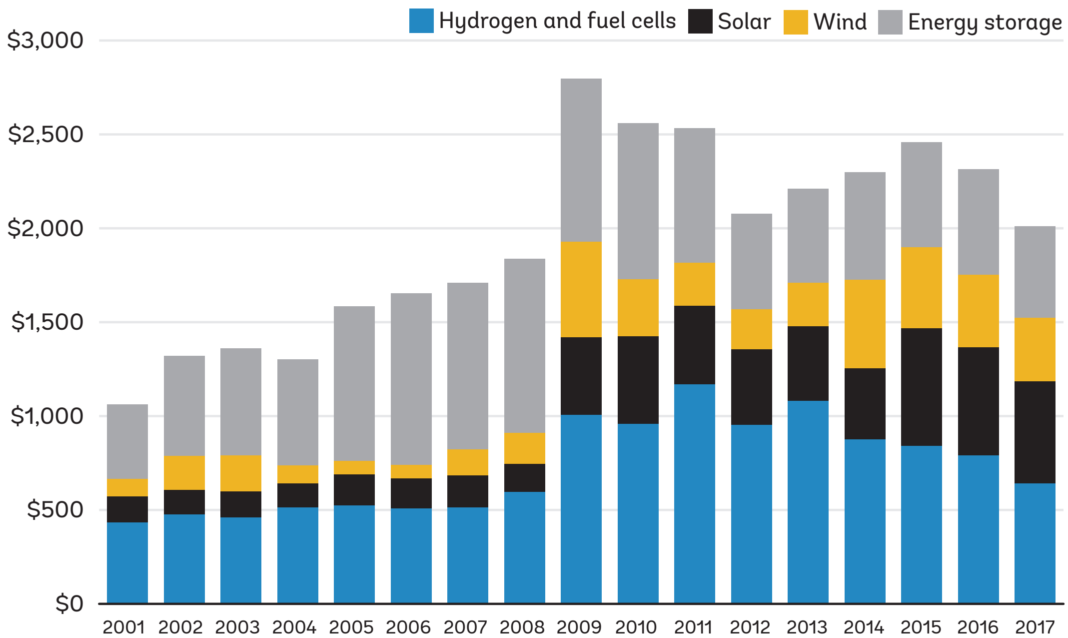
2.2. WHY NOW?

Deep decarbonization of economic activities will require a multifaceted technology approach to develop a holistic strategy that provides affordable, reliable, low- or zero-emission energy for developing countries. Within these emerging frameworks, green hydrogen must now be considered when previously it may have been discounted as too expensive. This is not the first time that hydrogen has been identified as a potential energy source for the future—and, accordingly, the rapid growth in interest and investments in green hydrogen have been met with some skepticism. However, four significant differences in the market today contrast with the conditions existing during the failed first hydrogen phase in the early 1990s and mid-2000s:

1. **Climate regulations are much stronger.** The Paris Climate Agreement, the European Union's (EU) 2030 Climate and Energy Framework, and the commitment to Net Zero in 65 nations (United Nations 2019) are a testimony to the transformation in public attitudes on climate change. Growing concern to avoid the IPCC's 1.5-degree scenario has encouraged policy makers and companies to find energy solutions that can decarbonize hard-to-abate sectors and to invest resources to deploy them. In this context, few alternative technologies can demonstrate such a breadth of technically viable decarbonization solutions as green hydrogen can to reduce emissions in sectors such as maritime, rail, and trucking; to provide a route to seasonal energy storage; and to decarbonize the heating needs for industrial and residential consumers.
2. **The cost of producing hydrogen from clean sources has fallen dramatically.** The advent of solar PV and onshore wind prices that reach levelized cost of energy (LCOE) points below \$25 per MWh in Chile, Portugal, Saudi Arabia, the United States, and other leading markets is enabling some electrolyzer companies to quote a green hydrogen production total cost of below \$3.50 per kg. Thus, decentralized green hydrogen production could soon become cost competitive against delivered gray hydrogen from trailer tubes or cryogenic tanks.
3. **Hydrogen technologies have improved in cost and performance.** Electrolyzers and fuel cell solutions now have significantly better operating lifetimes and system efficiencies than their predecessors, while they also cost considerably less and have been tested extensively in the field and across a wide array of applications. This creates a powerful positive feedback loop in which green hydrogen production costs continue to benefit from a downward cost spiral on both the renewable power supply side and the electrolyzer equipment side. This progress has unlocked new funding streams for hydrogen technologies, which in turn enables suppliers to provide more attractive solutions to end customers.
4. **The technological infrastructure to support a hydrogen energy system is now available.** The clearest example of this point would be the fuel cell mobility sector, in which the advent of battery electric vehicles has ensured that electric drivetrains are now widely available, effective, and increasingly affordable. These drivetrains are essential for a fuel cell vehicle, which at its core is an electric vehicle that simply derives its power from hydrogen and which frequently uses a battery alongside the fuel cell system.

The impact of these four changes has been profound, and understanding them is key to understanding why this time the discussions

FIGURE 2.1 **OECD RD&D Spending, US$, millions, 2001–17**



Source: IEA, "RD&D Budget." IEA Energy Technology RD&D Statistics (database), accessed March 7, 2019, https://doi.org/10.1787/data-00488-en.
Note: OECD = Organisation for Economic Co-operation and Development; RD&D = research, development, and deployment. The dataset includes statistics on energy technology research and development (R&D) and dissemination as well as R&D budget for International Energy Agency countries. It presents shifts in R&D expenditures associated with investments and further analyzes budget allocations in terms of flow.

around hydrogen are different. To assist in this process, this report reviews the context behind the first phase of using hydrogen as an energy solution to explain the early barriers and market failures.

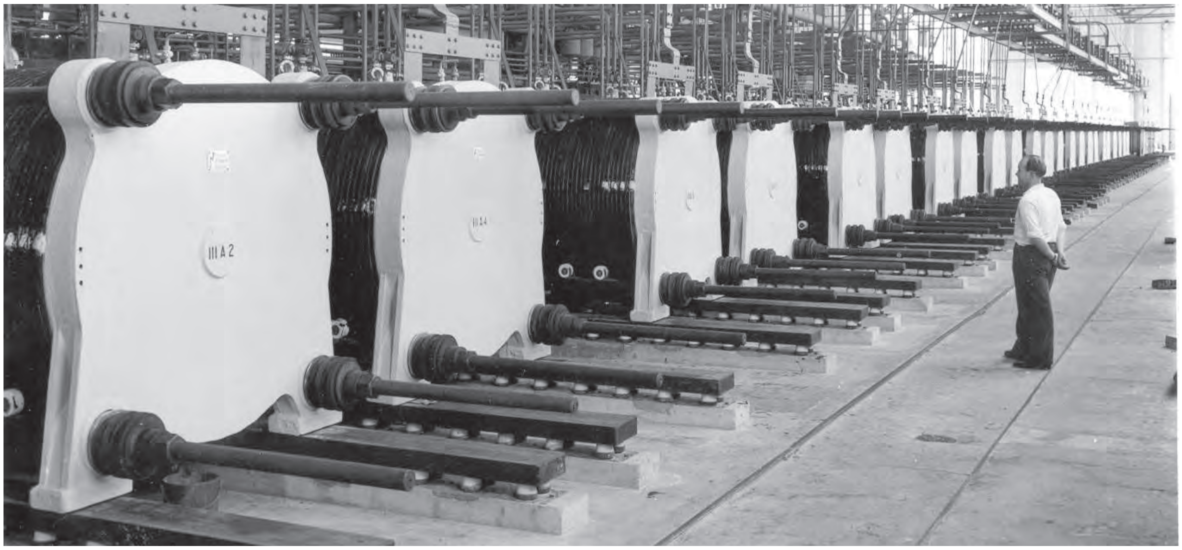
2.2.1. Historical context

Although the dates are contested, the first significant attempts to deploy hydrogen as an energy solution began in earnest in the 1990s. In the United States the best initial starting point is the 1998 Hydrogen Technology Advisory Panel (HTAP) review of the state of hydrogen technologies, which was submitted to the US Congress. In it, the authors wrote:

> "Hydrogen is an important energy option for the Nation and the world. Based on fossil fuels in the near term and renewable energy sources in the longer term, hydrogen can contribute significantly to each of the five goals stated in the DOE's *Comprehensive National Energy Strategy* (April 1998) regarding energy efficiency, energy security, the environment, the expansion of future energy choices, and international competitiveness" (HTAP 1998, 1).

The authors of the HTAP report were not alone in their conclusions. Over the next decade governments around the world invested heavily in research, development, and deployment (RD&D) of hydrogen and fuel cell solutions. The IEA estimates that between 2000 and 2010, the sector received on average 7 percent of global energy RD&D (OECD 2019) (see figure 2.1). Yet, the technologies failed to gain commercial traction,

FIGURE 2.2 **World's Largest Electrolyzer: Norsk Hydro 135 MW Electrolyzer, Glomfjord, Norway**



Source: Nel 2018c, slide 4. © Nel.

and from 2009 to 2017 global funding roughly halved, falling from 9.2 percent of world energy RD&D in 2009 to 5.2 percent in 2017.

There are four key reasons why green hydrogen and fuel cell technologies failed to gain traction:

1. There was no market demand for green hydrogen from industry.
2. Hydrogen from electrolysis was not cost competitive against alternatives.
3. Fuel cell technologies were still emerging, with short operating lifetimes, low efficiencies, and high system costs.
4. Enabling technologies, such as electric drivetrains, were almost nonexistent.

The lack of green hydrogen demand from industry was a function of both economics and limited regulatory incentives to switch to lower-carbon solutions. In the early years of the hydrogen sector (pre-1950s), when transportation of ammonia and other products was technically challenging and prohibitively costly, those markets that lacked access to coal and natural gas frequently turned to alkaline electrolyzers. Those electrolyzers were often used in conjunction with large hydropower resources and reached significant sizes, notably Nel's (Norsk Hydro) world record 135 MW electrolyzer in Glomfjord (Norway), which was built in 1953 and operated until 1991 (Nel 2018c) (figure 2.2).

This early market for green hydrogen lost its cost-competitive edge once the global maritime industry expanded and vessel designs became more advanced. This development made it considerably easier and cheaper for smaller countries and consumers to import ammonia that had already been created elsewhere rather than to install electrolyzers and smaller-scale Haber-Bosch units themselves.[12] These changes ensured that by the early 1990s to late 2000s, there was almost no cost advantage to using hydrogen from electrolysis except in very

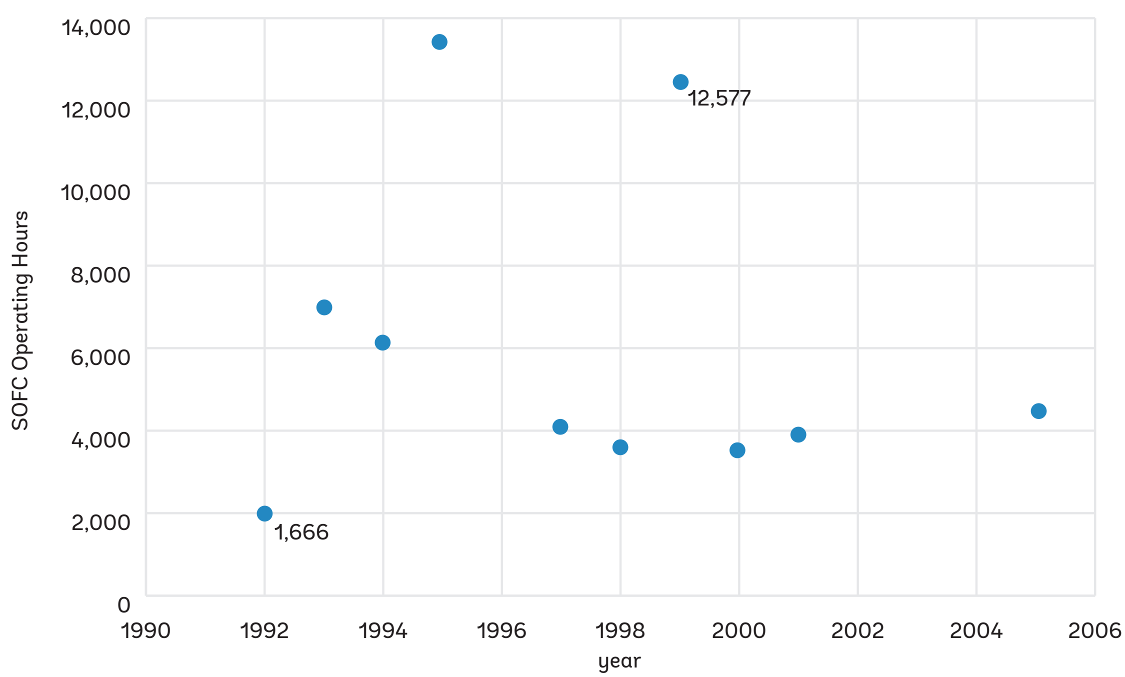
12 Haber-Bosch is the process of creating ammonia through combining hydrogen with nitrogen from the atmosphere to make NH_3. A good explanation is on the Encyclopaedia Britannica website: https://www.britannica.com/technology/Haber-Bosch-process.

location-specific contexts. Accordingly, industry needed either a regulatory incentive to supply green hydrogen or demand for an energy service that only hydrogen could provide. In the early 1990s and 2000s, the sector found neither.

The challenges faced by the green hydrogen sector in finding an energy service to drive demand for the product were amplified by the challenges facing the development of fuel cell technologies, which were seen as the primary mechanism to consume hydrogen for energy applications. While fuel cells had existed since 1831 and had been deployed by the National Aeronautics and Space Administration (NASA) in the early Gemini space programs, the considerable investments made between the 1990s and early 2000s were not able to create a minimally commercially viable product before hydrogen's first phase ended and it was overtaken by solar, wind, and electrochemical batteries. A key challenge for many companies involved in the early efforts was that fuel cell systems had poor stack system lifetimes and low system efficiencies. Consequently, substantial amounts of investment in research and development (R&D) were needed to improve lifetimes to the level expected for commercial operations. The scale of money sums involved wiped out many early venture capital investors and inflicted heavy losses on some of the world's largest industrial corporations.

A good illustration of this challenge was the case of Siemens-Westinghouse's funding for solid oxide fuel cell (SOFC) systems (figure 2.3). Early SOFC systems had very poor stack lifetimes, making them unsuitable for most power, and many mobility applications. Improving the lifetimes of SOFCs required significant and sustained investment. Accordingly, it was estimated that Westinghouse and the US Department of Energy (DOE) spent $150 million on SOFC research from the late 1980s until the 1990s, when

FIGURE 2.3 **Lifetime Performance of Siemens-Westinghouse SOFC Units, Test Results**



Source: OECD/IEA 2005.
Note: SOFC = solid oxide fuel cell.

Siemens acquired the business for $1.53 billion in 1998. Yet, despite additional investments and work with the DOE, Siemens closed its SOFC unit and sold the assets in 2008, a decade later (Olson 2008).

In addition, fuel cell systems required other enabling technologies to be developed and scaled in tandem, with the best example being the automotive sector. In the 1990s and early 2000s, most investors, policy makers, and researchers thought that the most attractive business case for hydrogen and fuel cell scaling was light duty vehicles. At the time, this was intuitive because of rising fears about peak oil prices; concerns in Europe, Japan, and the United States about reliance on the Middle East for petroleum products; and the potentially higher efficiencies promised by fuel cell systems. Yet, despite these considerations, manufacturers quickly realized that to run a fuel cell, they also needed to build an electric car,[13] which created a major problem because the electric vehicle (EV) sector in the ’90s was nonexistent, and even in 2005 there were barely more than a few hundred electric vehicles globally (Plummer 2016).

The final issue was that fuel cells required original equipment manufacturers (OEMs) not only to support additional R&D to improve the stack time of fuel cells but also to find and develop hydrogen storage, hydrogen compressors, and hydrogen safety mechanisms for vehicles from scratch. For the few that did persevere to develop fuel cell electric vehicles (FCEVs), this process simply created expensive vehicles that were considerably less efficient than their potential.[14] In part because PEM fuel cells were much less efficient during this period than they are today, but also because electric drivetrain technologies and innovations such as regenerative braking were far less efficient, the overall system efficiency was well below what is expected from a modern FCEV.

2.2.2. Present day

While the decline in the cost of renewable power is becoming essential to improving the commercial viability of green hydrogen, other changes are also playing a key role in facilitating the initial deployment of green hydrogen and fuel cell technologies. Principally, the global pressure for clean energy technological solutions and the emergence of enabling technologies—such as batteries, electric drivetrains, the “internet of things,” and high-speed internet access—are transforming the competitive landscape for green hydrogen and for fuel cell technologies. In tandem to these changes, electrolyzer and fuel cell technologies are now better, with the bulk of initial technical challenges having been addressed and cost becoming the largest remaining barrier to widespread commercialization.

The results of these changes are becoming clear. Currently there are more than 20 GW of globally announced electrolyzer projects in varying stages of project development, including from prefeasibility to firm orders, covering almost every continent. In less than three years, more than 82 of the world’s largest companies, controlling over $2.6 trillion in revenue, have joined the Hydrogen Council, the flagship industry initiative for industries fostering hydrogen as an energy solution (*FuelCellWorks* 2019b). Although many of these partners are focused on hydrogen generation from fossil fuels, possibly combined with carbon capture technologies, almost all of them are also exploring electrolyzer business models, including those with existing and substantial natural gas

13 While there is some debate about why this shift occurred, the main issues appear to have been linked to safety concerns around gas leaks and questions about the costs of adding hydrogen storage and petroleum storage in a vehicle.

14 Research from the IEA in 2005 noted that the assumed fuel-to-wheel efficiency of FCEVs at that time was around 28 percent (IEA/OECD 2005), compared with figures that McKinsey & Company provided for FCEVs in 2017 that showed efficiencies above 44 percent (Hydrogen Council 2017). Indeed, Toyota in 2019 announced that its latest FCEV would achieve above 60 percent efficiency.

resources. Countries are now channeling significant financial resources into this space, with China alone allocating an estimated $12.4 billion in subsidies for deployments and R&D for fuel cell–powered vehicles in 2018 to be distributed across local, state, and central government budgets and through state-owned enterprises (Sanderson 2019).

As a result of these developments, hydrogen today is recognized by many of the world's leading economies and corporations as a key component in enabling the energy sector transition. In 2018 the world's first Hydrogen Energy Ministerial summit was hosted in Tokyo, and a second event was held in September 2019. At the first ministerial summit, participants announced the "Tokyo Statement," which consisted of four actions:

> (1) Promote technical collaboration and encourage standardization and harmonization of standards and regulations between countries and businesses; (2) define the direction of research and development that countries should collaborate to achieve hydrogen energy society including securing hydrogen safety and development of hydrogen supply chain; (3) study and assess potential economic effects of hydrogen energy use and effects of CO_2 reduction in order to attract investment and create business; and (4) emphasize the importance of education and public relations activities which allows all citizens in the world to widely understand and accept hydrogen energy. (METI and NEDO 2018)

Energy ministers also agreed that the outcome of the meeting would be an input for the G20 Summit in June 2019. At this second event in 2019, the IEA launched its "Future of Hydrogen" report (IEA 2019b), which concluded, "The time is right to tap into hydrogen's potential to play a key role in a clean, secure and affordable energy future." This report further proposed a draft of policy measures and identified areas in which technological breakthroughs were essential to see the sector flourish. These developments have subsequently been built on during the second Hydrogen Energy Ministerial in September 2019 and further supported through the release of the report "Hydrogen: A Renewable Energy Perspective," which IRENA produced to provide countries with help developing supportive policy frameworks to accelerate the deployment of green hydrogen (IRENA 2019).

2.3. WHY DEVELOPING COUNTRIES?

Developing countries are responsible for more than half of the world's GHG emissions, and their carbon footprint is growing in both absolute and proportional terms.[15] Accordingly, there is an increasing need to identify, assess, and deploy low- to zero-emission fuels such as green hydrogen to support developing countries in meeting their development targets and climate commitments. The reemergence of hydrogen as a solution for the energy sector has largely been discussed in the context of developed markets such as Australia, the European Union, Japan, and the United States. While this is unsurprising given investor familiarity with these markets and the financial resources available to policy makers in those countries, there are unique features that make developing countries extremely enticing for investors in green hydrogen technologies and that perhaps have not been given sufficient consideration.

2.3.1. Hydrogen can help increase energy security

Green hydrogen allows developing countries to locally produce an extremely versatile fuel

[15] World Bank, "CO_2 Emissions (kt)," dataset, https://data.worldbank.org/indicator/EN.ATM.CO2E.KT; Center for Global Development (CGD) 2015, https://www.cgdev.org/media/who-caused-climate-change-historically.

that can be stored over long time periods and requires only renewable power and water. This is transformative for countries that are dependent on costly energy imports, typically petroleum, and that are exposed to both oil price volatility and energy security risk if the fuel supply is partially or fully disrupted. These fuel supply disruptions could be caused by regional conflicts, geopolitical tensions, the financial situation of local utilities, or corruption—all of which undermine economic growth and development objectives. It is crucial that developing countries can count on reliable and affordable resources to power their economic activities and meet their national development objectives. Although renewable resources are widely available in many developing countries, they cannot be dispatched on command and require storage to meet instantaneous demand. Green hydrogen could thus help support the development of renewable energy systems by providing the long-duration energy storage capability and flexibility that fossil fuels have traditionally provided to the power sector.

Currently the import demand for oil-derived fuels can be a source of significant economic and political instability, in part because of the volatility of global oil prices combined with the low elasticity of fuel consumption, which can amplify price spikes and have a severe negative local impact on competitiveness and economic growth. While developing countries have traditionally attempted to mitigate these issues through subsidies, the consequences include significant fiscal pressure on finance ministries, economic inefficiencies, and political pressures to maintain or expand the subsidies. Green hydrogen production could play a major role in providing a decentralized form of fuel production that is driven not by the volatility of global prices, but rather by local renewable power pricing and local supply and demand. This option could also reduce the need for subsidies and the need to draw from foreign exchange reserves to pay for fuel imports.

2.3.2. Electric power in developing countries can be extremely expensive

In many developing countries electric power is more expensive than in developed ones, a feature which is especially concerning given the lower relative purchasing power of consumers in these countries. Because of fuel price volatility and additional costs incurred by many developing economies in importing natural gas, coal, and petroleum products such as diesel, the economics for green hydrogen and fuel cell solutions could be significantly more appealing in developing countries than for developed ones. This is certainly the case in remote islands like Kiribati or Vanuatu, where retail power prices exceed \$400 per MWh (UNECLO Engie 2019), and even countries with close proximity to large petroleum producers, such as Mali, can face electric power prices exceeding \$230 per MWh (World Bank 2018). Although solar PV, wind power, and other renewables could help reduce these prices and their underlying generation costs, the grid integration of VREs can be challenging at high penetration rates, and their value may be limited when it comes to providing firm capacity. Accordingly, there could be opportunities for countries to provide dispatchable, renewable power leveraging the flexibility of green hydrogen, particularly in systems in which access to low-cost fuels may be limited. In small diesel-based power grids, hydrogen hybrid systems in conjunction with solar power and batteries could also be a potential solution for providing locally produced electricity and fuels, thus reducing cost and diversifying fuel supply to mitigate supply risk from any specific company or country (box 2.1).

2.3.3. Developing countries already have experience with large-scale hydrogen projects

Hydrogen is not a new commercial product and electrolyzers are not new to developing countries. Hydrogen has long been an important

BOX 2.1

HYBRID ENERGY STORAGE SYSTEMS IN FRENCH GUIANA

Remote systems have long been attractive to renewable energy developers, owing to the high cost of imported power and the need to provide resiliency in the event of grid outages, whether from weather events, theft, or grid imbalances. Still, integrating VRE into small grids can be challenging, despite the compelling economics of solar PV compared with diesel alternatives. The past few years have seen the proliferation of hybrid solar PV, diesel, and battery solutions, operating concurrently in different configurations, as potential alternatives to decarbonize remote energy systems. But in French Guiana, HDF Energy believes that green hydrogen and fuel cells could be part of the answer to displacing diesel entirely and providing longer-duration storage than batteries alone.

The Centrale Électrique de l'Ouest Guyanais (CEOG) project is seeking to deploy a 55 MW solar PV site, in conjunction with a 20 MW battery, a 20 MW electrolyzer, and a 3 MW fuel cell, to provide what the company calls a "RE-new stable" solution for its customers. In effect, the company will provide 10 megawatt-hours (MWh) of dispatchable power during peak daytime hours, dropping down to 3 MWh during the off-peak evening times. The project size is significant when compared to the country's national grid capacity of just over 300 MW. The project has already secured 60 percent of the equity funding from French investment house Meridiam and was due for financial close in December 2019. While the project has not disclosed its pricing publicly, the company has confirmed that the project will not rely on subsidies and thus is expected to come in around (or below) the latest solar and battery project in the region, which secured a power purchase agreement at EUR 260 per MWh.

Given the ability to provide dispatchable base load power at prices below or at least comparable with diesel, the CEOG project offers a unique approach to decarbonizing remote energy systems.

Note: The project data is from HDF Energy 2019. The source of the greater than 300 MW installed capacity figure for French Guiana is U.S. Energy Information Administration data for 2016, https://www.eia.gov/opendata/qb.php?category=2134409&sdid=INTL.2-7-GUF-MK.A.

industrial gas for developing countries, owing to its role in the production of ammonia for fertilizers. In the period before the advent of advanced modern ship designs, which made ships capable of storing and transporting large volumes of ammonia, hydrogen production from domestic sources was essential to helping emerging markets increase domestic food production. Accordingly, there have been units as large as 106.0 MW installed in India (1958), 74.6 MW in Zimbabwe (1975), and 115.0 MW installed at the Aswan dam in Egypt in 1960 (Buttler and Spliethoff 2018). Given these experiences, hydrogen electrolyzer projects are not a new concept for the development finance community. To meet the need to produce local fertilizers, often from ammonia (via hydrogen), multilateral organizations like the World Bank were extensively involved in projects that required the consumption and production of hydrogen from domestic sources. Examples of projects financed by the World Bank in the fertilizer sector include

FIGURE 2.4 **World's largest current electrolyzer (25 MW), polysilicon plant, Sarawak, Malaysia**

© Nel 2018a, slide 5. © Nel.
Note: ESMAP research suggests that this is the largest currently operating unit as of 2019.

the IGSAS fertilizer project in Turkey in 1980 (World Bank 1980), the Talkha II fertilizer project in Egypt in 1983 (World Bank 1983), and the Fauji fertilizer plant in Pakistan in 1986 (World Bank 1986).

Even today, countries like Malaysia, which have access to natural gas and SMR, still use alkaline electrolyzers to support manufacturing. In the case shown in figure 2.4, a 25 MW electrolyzer is used in Malaysia in the production of polysilicon. In Costa Rica, hydrogen from renewable power and electrolysis is also used for certain commercial applications. These experiences create a starting base from which a scaling up of green hydrogen production for industrial decarbonization can be built into the policy discussion and in the national green hydrogen strategies in developing countries.

2.3.4. Integrating large shares of variable renewable energy requires long-duration storage

Although many developing countries have significant renewable resources, integrating large amounts of VRE into local grids can be technically complex for any power system. As electric power systems grow, so does their peak demand, requiring countries to increase the amount of generation capacity available during the peak or when it is needed most. This type of capacity is known as "firm." The amount of firm capacity provided by VRE technologies (also known as *capacity value*) is very limited given the technologies' uncontrolled variability. In countries with no access to firm generation technologies (typically large hydro or generators running on fossil fuels), meeting peak demand with renewables requires the deployment of different forms of long-duration energy storage to "firm up" the output from VRE plants and guarantee that there will be sufficient energy available to meet the peak.

Integrating VRE into grids is difficult regardless of location, but developing countries face particular difficulties posed by unreliable grids with insufficient back-up generation capacity and a lack of automated supervisory control and data acquisition systems. Grids in developing countries can be more sensitive to sudden changes in demand and supply and less able to maintain grid stability than in developed countries. Further, regulators and utilities in these markets often have limited technical capacity to address the impacts of VRE on their systems, and so investors may experience an aversion to deploying large VRE projects.

In this context, energy storage, including batteries and green hydrogen, can help provide additional balancing mechanisms to support VRE integration. Green hydrogen is one of the few technologies that can mitigate the long-term variability of renewable resources (weekly and seasonal) because hydrogen can be stored for long periods of time and subsequently used for power generation in a fuel cell (or turbines). This feature could create opportunities to develop firm renewable-based solutions or renewable microgrids that can meet a predefined generation profile, or fully adapt to the variability of electricity demand. Although this option may be a longer-term ambition, the existence of hydrogen gas caverns in the United Kingdom and the United States and pilots to use hydrogen for seasonal renewable energy storage in Austria[16] show that green hydrogen could be an option worth exploring for developing countries that are planning the future of their energy systems over the next 30 or even 50 years. The ability to firm up renewable generation, or to develop what one developer has called, "a re-new stable solution,"[17] therefore can unlock markets for VRE technologies that have thus far been reluctant to scale up deployments or can further increase renewable use in locations that have reached their maximum penetration levels.

Additionally, electrolyzers are already providing grid-balancing services in a number of territories, and the early experiences can serve as case studies for how hydrogen can support further VRE deployments. In Canada, for example, the Markham Energy Storage project uses a 2.5 MW electrolyzer to provide secondary frequency control for the Independent Electricity System Operator, while in the United Kingdom ITM Power's 3 MW bus refueling station in Birmingham provides demand response services to the utility, National Grid.

2.3.5. Green hydrogen offers local industry development opportunities

One of the most compelling reasons that green hydrogen has significant potential as a resource

16 This was derived from discussions with Verbund staff members about the company's hydrogen plans in 2019.

17 Comments from Jean-Noël de Charentenay of HDF Energy, July 2019.

BOX 2.2

BALANCING WIND IN THAILAND: SOUTHEAST ASIA'S FIRST MEGA-WATT-SCALE ENERGY STORAGE PROJECT

Thailand has emerged as one of the most dynamic markets for renewable energy, driven by the relative lack of domestic oil and gas resources and the relative abundance of wind and solar resources. Nevertheless, like many countries, Thailand has been managing the challenges associated with balancing variable renewable energy within a national grid system that was designed for dispatchable power resources. While batteries provide grid operators and developers with a powerful resource to address a number of these challenges, the Electricity Generating Authority of Thailand (EGAT) has also been exploring the role that hydrogen and fuel cell integrated solutions can play in grid balancing.

In 2016 the Lam Takhong Wind Hydrogen Hybrid Project was announced. The project combines a 22 MW onshore wind site in Nakhon Ratchasima Province, Thailand, with a 1 MW proton exchange membrane (PEM) electrolyzer and a 300 kilowatt PEM fuel cell. The electrolyzer converts excess power from the wind site during off-peak hours, allowing the fuel cell to provide clean power to EGAT's Learning Center building, as needed. In total, the system provides 3 megawatt-hours of compressed hydrogen storage (250 bar), allowing for up to 10 hours of continuous power supply. The cost for the electrolyzer and fuel cell system was EUR 4.3 million.

in developing countries is that nations without access to fossil fuel resources—such as natural gas, oil, or coal— but with good renewable resources could use locally produced green hydrogen to develop both their national energy system and an industrial market simultaneously (box 2.2). Green hydrogen could thus hold out the possibility for some developing countries to create a domestic, renewable fuel that could contribute to local job creation (such as in hydrogen infrastructure, transport, construction, and agriculture) and new social opportunities (by providing access to heat, reducing local pollution, enhancing the livelihood of local communities, and addressing existing gender gaps).

Green hydrogen also offers developing nations the ability to exploit sector coupling opportunities, in which greater economic efficiencies are achieved by using the same assets in processes that belong to different sectors. For example, the agricultural sector, the water sector, and the power sector could be interconnected through the use of water and renewable-generated electricity to produce green hydrogen, which could in turn be used in the synthesis of ammonia. As the cost of electrolysis continues to decline and renewable energy costs continue to fall, it would be reasonable to anticipate in the future an increase in the volume of green hydrogen production within emerging markets, a process that could transform domestic industries and disrupt major established markets. As noted previously, many developing countries did historically produce their own hydrogen and ammonia domestically, before production moved to lower-cost markets as global pricing became linked to the ability to access cheap domestic natural gas resources.

A key challenge for developing countries has been that the unit sizes that have been ordered for electrolyzers, fuel cell vehicle fleets, and stationary power solutions in the first projects have been smaller than in developed markets (with China being an exception). That scale

FIGURE 2.5 **Fuel cells for critical infrastructure in Indonesia**

© Cascadiant Indonesia.

leads to higher costs and puts further pressure on the commercial appeal of the technologies. Accordingly, greater commercial hydrogen deployment in developing countries will require broad strategic pathways and wide partnerships to aggregate demand and justify investments at scale. Initiatives that have begun to develop these elements are under way. An example is the African Hydrogen Partnership, which is helping investors, policy makers, and companies view hydrogen production as part of a wider energy ecosystem that can underpin regional economic development, regional transportation, and deeper economic integration (box 2.3).

2.3.6. Reliable power supply for critical systems, climate resiliency, and industry

Power supply interruptions are a major inhibitor of economic growth in developing countries. Accordingly, fuel cells are a technology that could help reduce the risk of power losses to crucial sectors, even when the grid experiences disruption. Fuel cell systems are due to supply over 800 telecommunications stations in Kenya through the local telecom company Adrian Kenya, while today there are already over 800 fuel cell systems providing power to telecommunications and other critical systems in Indonesia (figure 2.5). The number of fuel cell systems deployed in China and India is harder to track, but some market participants estimated it to be in the low thousands and growing. Suppliers are also commenting that fuel cell systems are being used to provide power for applications such as wildlife surveillance systems to prevent poaching and for powering wind meter measurement towers in developing countries across Asia and Africa. Some systems are even being used in drones to monitor deforestation.

Fuel cells could offer significant benefits for developing countries that are seeking climate-resilient energy solutions, because they can provide long-duration power supply (in some cases up to six months without refueling if ammonia or methanol is used) as well as minimal required maintenance and lower risk of theft. These attributes are particularly relevant in settings that face fragility, conflict, and violence, where fuel cells could address some of the impacts derived from the fragility of the situation. In the aftermath

BOX 2.3

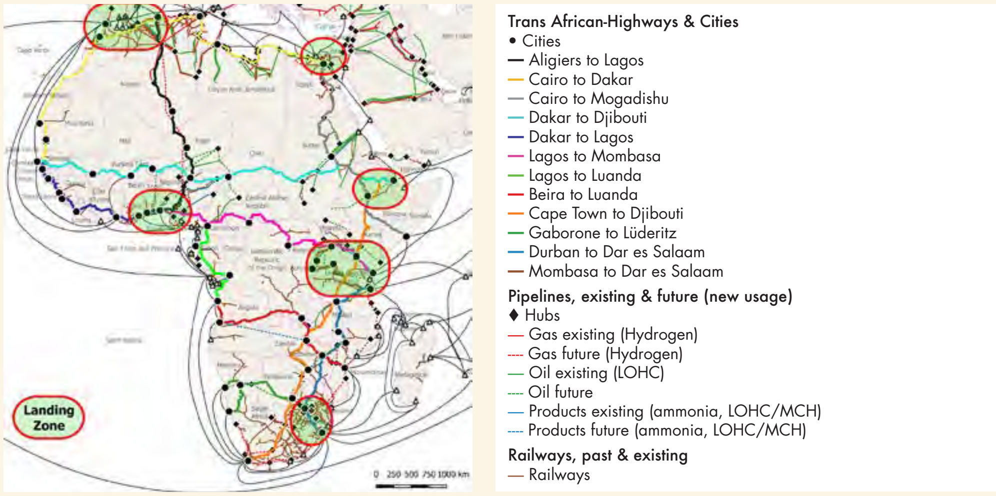
A STRATEGIC VISION FOR AFRICA'S HYDROGEN ECONOMY

Ensuring that Africa is able to obtain affordable, reliable, and clean energy resources is essential not only to the continent's economic development but also to the world's ability to stay under the 1.5 degrees increase threshold set by the IPCC. Energy access remains a pressing concern for policy makers, businesses, and communities, while even consumers with access to electricity can still suffer from frequent blackouts. Energy is also expensive for many African consumers, who may have a heavy reliance on imported petroleum even in countries that might be net exporters of crude oil products.

Given these challenges, the African Hydrogen Partnership (AHP) believes that hydrogen might be the key to address some of Africa's energy problems.. Working in partnership with governments, private sector companies, and financial institutions, the AHP has drafted a series of high-level strategic documents to help policy makers and investors visualize an Africa-wide hydrogen strategy. The core challenge is achieving significant scale as soon as possible. Accordingly, the AHP recommends a strategy of establishing "landing zones/bridgeheads," where initial green hydrogen projects could be developed before expanding into other clusters (figure B2.3.1). The first nine markets include Djibouti, the Arab Republic of Egypt, Ethiopia, Ghana, Kenya, Morocco, Nigeria, South Africa, and Tanzania. Specific plans are set for each city and use cases for each market, most notably the coordinated procurement of fuel cell buses across several cities to reduce costs. To finance this vision, the AHP is proposing a green bonds program for Africa and is working alongside stock exchanges in Africa and Europe to design a framework for investors and gauge initial appetite.

While the AHP initiative might appear abstract, evidence from other markets has shown that developing strategic concepts is essential to helping policy makers, investors, and consumers understand the role that hydrogen might play.

Figure B2.3.1. African Hydrogen Partnership landing zones and operational planning outline



Source: African Hydrogen Partnership 2019.

of Hurricane Katrina, the U.S. DOE noted that fuel cells had played an essential role in ensuring backup power provision for critical communications equipment and substation functions. Indeed, in 2012 fuel cells were credited with keeping the emergency 911 service functional in Barbados after Hurricane Sandy (*Renewable Energy Focus* 2012). Fuel cell systems have also been deployed for monitoring earthquake tremors and for ensuring that medical supplies—critically, those that require cooling—have access to reliable power. Similarly, GenCell (a leading provider of fuel cells for resiliency applications) recently announced its entry into the Philippine market with a specific focus on ensuring business continuity and support for critical infrastructure during severe storms and earthquakes (GenCell 2019).

While large-scale stationary fuel cells may take longer to arrive in emerging markets, several notable examples have already been deployed. Bloom Energy has sold its first units in India (figure 2.6), while HDF Energy has installed a 1 MW unit in Martinique (France). Hybrid renewable minigrids in developed countries include hydrogen and other storage technologies and may provide a model for developing countries in the future. Notable among these are the Raglan Mine project in Canada, the Cerro Pabellón minigrid in Chile, and the Daintree hydrogen microgrid in Australia (Maisch 2019).

2.3.7. Urban mobility solutions to reduce air pollution

Hydrogen for mobility is a growing area of focus for countries. The IEA's latest research illustrates that only 2 countries in the world have policies to incentivize hydrogen in industry, but 5 have policies to promote fuel cell trucks, 10 have policies for fuel cell buses and refueling stations, and 15 have policies to encourage hydrogen in passenger vehicles (IEA 2019b). Indeed, for urban mobility applications fuel cell buses provide a complementary solution for urban planners seeking to reduce localized air pollution and also to integrate battery-electric solutions into a congested grid. Hydrogen for mobility has long been of interest to developing countries with bus programs; it was considered in Brazil in 2012, while New Delhi had a fleet of fuel cell rickshaws developed around 2012 (Yee 2012). Between 2008 and 2012, the

FIGURE 2.6 **Commercial fuel cell installation in India**

© Bloom Energy.

BOX 2.4

FUEL CELL BUSES IN INDIA

India has been closely monitoring hydrogen as a domestic alternative to lithium ion battery–based systems for mobility. Given the abundance of domestic biowaste that can be converted into biomethane (and reformed for hydrogen), coupled with significant local air quality challenges and the desire to promote local manufacturing, hydrogen has become a logical route for policy makers to explore. One of the most prominent actors in this move toward hydrogen for mobility in India is the Indian Oil Company (IOC), which has already trialed Tata buses using Ballard fuel cells on its R&D Campus. Recently IOC has also submitted a bid to provide hydrogen and to develop four Indian-manufactured fuel cell buses for operation in Delhi, following a tender by the Ministry of New and Renewable Energy (Gupta 2019).

India is exploring blending hydrogen into existing buses that already run on compressed natural gas (CNG), with a pilot commissioned in Delhi to run up to 50 buses on an 18 percent hydrogen/22 percent CNG blend. IOC estimates this could cut carbon dioxide emissions from these CNG buses by up to 70 percent (Gupta. 2019).

United Nations Development Programme was involved in a series of activities to bring hydrogen mobility solutions to Turkey, which was followed by a $10 million grant to the program in China in 2017 to advise the local government of Rugao. Today, five developing countries have either ordered or deployed fuel cell mobility solutions, including Indonesia, China, Costa Rica, India (box 2.4), and Malaysia. The development finance community has also supported some of these efforts. For example, the Interamerican Development Bank provided financial support to the fuel cell mobility provider Ad Astra to support a local fuel cell bus and hydrogen refueling station project in Costa Rica, while the Asian Development Bank invested in 10 fuel cell electric buses for the 2022 Beijing Winter Olympics.

2.4. SHORT-TERM, MEDIUM-TERM, AND LONG-TERM OPPORTUNITIES FOR GREEN HYDROGEN

A wide array of compelling reasons explain why green hydrogen production and fuel cell technologies may become commercially and technically appealing to developing countries in the near future. But despite the significant potential for green hydrogen deployments in developing countries over the medium and long term, in the short term observers anticipate that the deployment of electrolyzers and large-scale production of green ammonia could be slow, particularly in countries with access to low-cost natural gas. This situation is largely due to the low cost of hydrogen derived from natural gas and to the expectation that companies will focus on lower-hanging opportunities elsewhere in the energy sector of developed markets and will wait for green hydrogen prices to fall further before expanding into developing countries. Yet, developing countries may start deploying green hydrogen systems early if they have excellent renewable resources, unique energy requirements, or a high level of synergy between the development of green hydrogen for industry, mobility, power, and heat. These early deployments or first-of-a-kind projects may be considered in regions with exceptionally good renewable resources and where the lack of preexisting infrastructure creates a clear incentive to engage policy makers and investors sooner rather than later to avoid technology lock-in to high-carbon-emitting energy alternatives.

Similarly, fuel cell deployments are likely to accelerate in developing countries, as the systems continue to decline in cost and provide a number of key benefits to consumers who face an array of energy challenges, such as reliability of supply, local air quality issues, high cost of diesel or other fossil fuels, and the need for long-duration power supply. It also remains likely that fuel cell mobility solutions will continue to interest developing countries.

3: STATE OF THE MARKET

KEY TAKEAWAYS

- In 2019, the global hydrogen market was worth $135 billion, with over 70 million tonnes produced that year and 10 million tonnes of the demand coming from China.
- Global electrolyzer manufacturing capacity is currently above 2 GW per annum, and it is forecast to exceed 4.5 GW on the basis of current expansion commitments.
- Global fuel cell manufacturing capacity is currently about 1.5 GW per annum. Fuel cell demand has grown dramatically, to 1.6 GW stationary installed capacity and over 300,000 units deployed, most of which are based on proton exchange membrane (PEM) systems.
- Similar to development of the lithium-ion battery market, PEM fuel cell manufacturing capacity and cost declines are being driven by the transport sector. However, the market focus for fuel cell in transport is moving toward larger uses—trucks, buses, trains, and ships—rather than light-duty cars.
- In some contexts and geographies the production of green hydrogen could already be cost competive with fossil alternatives.
- If hydrogen demand were to scale at the pace anticipated by analysts, the likely consequence would be to have a short-term increase in coal and natural gas demand for hydrogen production.
- In the medium to long term, demand for fossil fuel–produced hydrogen will depend on whether expected electrolysis and renewable power cost declines are realized.
- Key factors that will drive green hydrogen prices are the quality of the renewable resource, renewable and electrolyzer capital expenditures, and load factors that extend above 3,500 hours per annum.
- Fuel cell technologies come with different costs, efficiencies, operating temperatures, and lifetimes. Therefore, capital exenditures alone will not always be the key driver of technology choice.

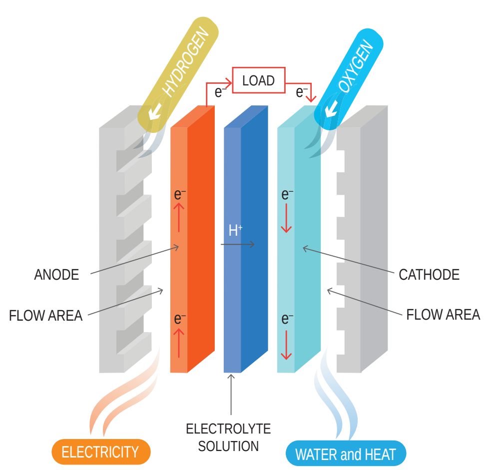
3.1. HOW FUEL CELL AND ELECTROLYZER TECHNOLOGIES WORK

3.1.1. Fuel cells

Fuel cells are energy conversion devices that combine hydrogen with oxygen to produce water and energy (electricity and heat). Inside the fuel cell, hydrogen is passed through the anode, where hydrogen is oxidized producing hydrogen ions and electrons that move to the cathode through an electric circuit. An electrolyte solution allows hydrogen ions to move from the anode to the cathode, where they react with oxygen and electrons from the anode, producing water (figure 3.1).

The first fuel cell was invented in 1831 in the United Kingdom, and fuel cell systems were deployed in several of the early NASA space programs in the 1950s and 1960s—notably, in the Gemini missions. The earliest and most established fuel cell solutions are proton exchange membrane (PEM) fuel cells and alkaline fuel

FIGURE 3.1 Simple diagram of a proton exchange membrane fuel cell



Source: ESMAP, adapted from various sources.

cells (AFC). Two core components of a fuel cell are the membrane electrode assembly (MEA) and the plates that are used to enclose them, which typically are either steel or ceramic. The MEA is where most companies hold their intellectual property, and it remains the most complex part of the unit. A fuel cell system can use multiple types of electrolytes to facilitate a chemical reaction, and individual fuel cell technologies gain their names from the types of electrolytes used.

Fuel cells can be used for a wide range of applications, including stationary power, portable power, and mobility. They are commercially deployed in a range of geographies and applications, with a current scale range of several watts up to 50 MW (under consideration). Today there are five core fuel cell technologies that are commercially available. These are PEM, AFC, molten carbonate fuel cells (MCFCs), solid oxide fuel cells (SOFCs), and phosphoric acid fuel cells (PAFCs). In the stationary power market, units above 1 MW are typically PAFC or MCFC, while units between 100 kW and 1 MW are typically SOFC or PAFC.

The two key differences between the primary fuel cell technologies are their input fuel(s) and their operating temperatures. Typically, PEM and AFC solutions operate under 100°C, thus limiting their usage for combined heat and power (CHP) services, but other fuel cells can operate between 500°C and 650°C. High-temperature fuel cell systems typically have higher electrical (and thermal) efficiencies and run almost continuously, making them better suited for baseload power provision and well suited for CHP applications. By contrast, PEM and AFC can provide more adaptive power provision, making them suitable for balancing applications. For mobility applications, only PEM fuel cells have been used commercially, with SOFC considered thus far only as a potential source of auxiliary power for larger mobility applications.

Four primary fuel sources are used in fuel cells: hydrogen, ammonia, methanol, and natural gas (and biogas).[18] All fuel cells ultimately consume hydrogen, but most applications (except for PEM) extract their hydrogen from another feedstock first. This is important because the extraction process often reduces the overall system efficiency below the fuel cell system's quoted electrical efficiency, leading to a trade-off between efficiency and convenience in the fuel source chosen. Today almost all SOFC, MCFC, and PAFC units run on natural gas, with some also consuming biogas.

PEM fuel cells can only run on hydrogen, but many systems have been adapted to use other hydrogen-derived fuels, such as methanol and ammonia. This allows the operator to store and transport the fuel (methanol or ammonia) easily and at lower cost than hydrogen. These solutions, however, appear to have shorter lifetimes and higher upfront capital expenditures (capex) than other PEM solutions that directly use hydrogen or alternative fuel cell technologies.

3.1.2. Green hydrogen generation—electrolyzers

The electrolysis process uses water and electricity to produce hydrogen and oxygen. It does so by using a device called an electrolyzer, in which a molecule of water is split into oxygen and hydrogen using an electric current. This process is the only commercially proven technology that has been deployed widely and that can produce *green hydrogen*—hydrogen produced entirely from renewable energy sources.[19]

Electrolyzers perform essentially the opposite chemical reaction of that of a fuel cell. An electrolyzer takes electrical power and water and then uses an electrolyte and a membrane to facilitate the separation of hydrogen molecules (generated in the cathode) from oxygen molecules (generated in the anode). A typical electrolyzer consists of 100 plate cells that are grouped together to form a *stack*, which also includes the anode and cathode. These stacks are added together to reach the required nameplate capacity for the unit and are then added to a system that adjusts the heat, moisture, and pressure of the hydrogen to suit the specific application. Because the stacks can be mounted in parallel using the same balance of plant infrastructure, costs decline quickly with scale, thus making electrolyzers highly modular systems (IEA 2015, 29) (figure 3.2).

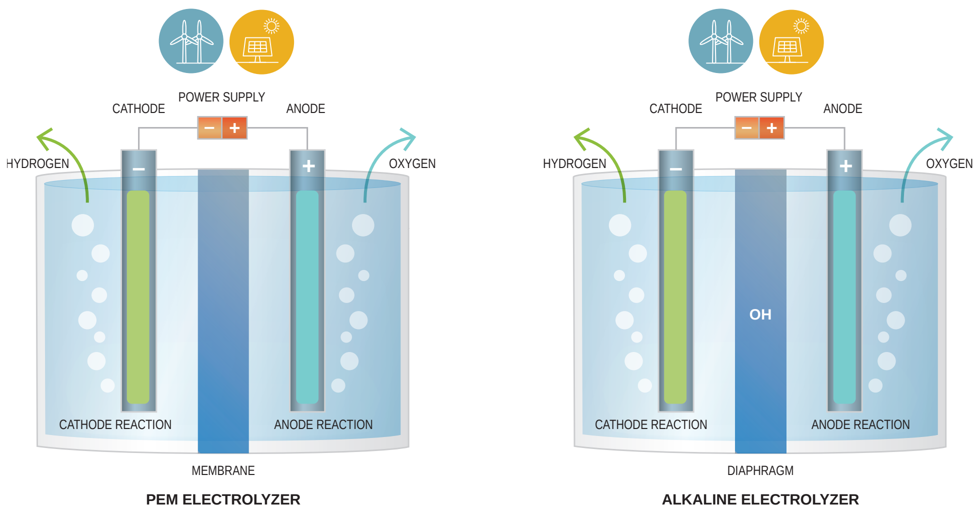
Other mechanisms to produce hydrogen—notably through steam methane reforming (SMR) or coal gasification—are not covered in this report. This is primarily because those technologies create what is called *gray hydrogen*, which has significant carbon emissions associated with it. Although a third type of hydrogen called *blue hydrogen* exists, it is essentially the same production process as gray hydrogen, but it relies on carbon capture and use (CCU) or carbon capture and storage (CCS) so the production process could be considered carbon neutral. The potential applications for blue hydrogen in developing countries are not covered in this report but remain a significant area of interest for developed and some developing countries, particularly those with access to natural gas resources.

The most established electrolyzer technology is the alkaline electrolyzer, which has existed commercially since the 1940s. Despite its long existence, the technology has experienced a sharp cost decline curve in recent times as system efficiencies have improved and interest in

18 Some fuel cells can also run on other hydrocarbons; however, because these are not created as derivatives from the SMR hydrogen production process, they are outside the scope for this report.

19 There are preliminary pilot projects under way that seek to create hydrogen from waste and that could theoretically be considered as green hydrogen generation sources. However, they are not considered significant in the broader literature on the sector at this time.

FIGURE 3.2 **Simplified diagrams of a PEM and alkaline electrolyzer**



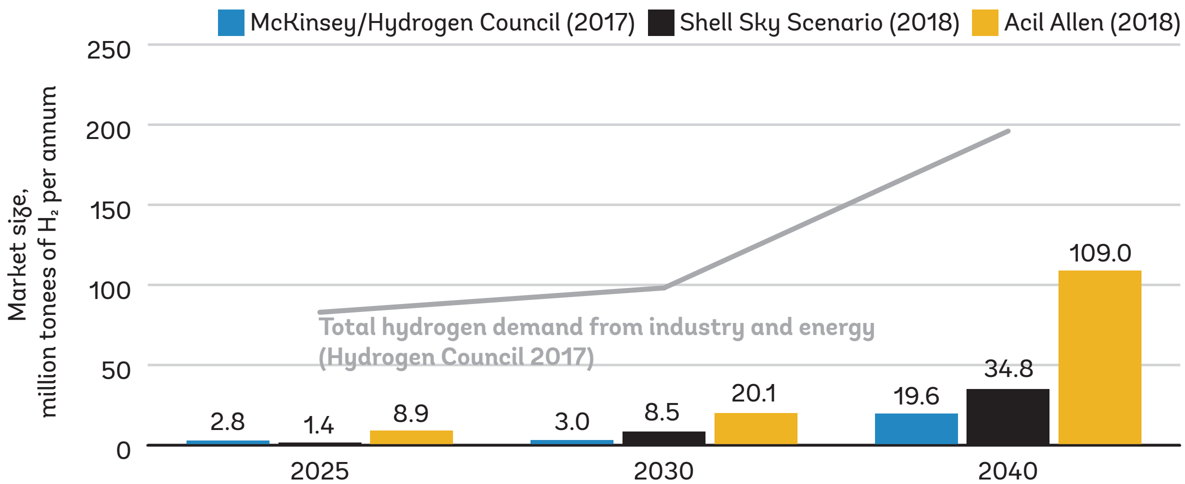
Source: ESMAP, adapted from various sources.
Note: OH = hydroxide ions; PEM = proton exchange membrane.

hydrogen from electrolysis has grown, increasing orders. Nonetheless, the fastest-growing electrolyzer technology is based on PEM electrolysis, which is considered to be more dynamic and responsive to changing power input requirements than alkaline units are. While the largest currently deployed PEM unit is a 6 MW unit in Austria, units for 20 MW have already been ordered in Germany and Canada, with feasibility studies and concept designs under way to examine the deployment of a 250 MW unit in the Netherlands and a project of up to 12 GW in northern Australia. Typically, PEM units have been small, and the interest has largely focused around their role as either a mechanism to absorb constrained power in an area with significant renewable resources or a form of distributed generation for hydrogen refueling stations. This picture may change in the future if PEM units can reach lower capex costs than alkaline electrolyzers as the market expands.

Two additional electrolyzer technologies have become commercially available in the past two years—namely, anion exchange membrane (AEM) technology and solid oxide electrolysis (SOE). AEM technology is seen as a potential breakthrough, given its ability to achieve alkaline electrolysis–level efficiencies with the flexibility of PEM and with the use of platinum, a key component in most PEM designs. Yet, few units have been deployed and today only two companies offer this product. Meanwhile, SOE, a high-temperature electrolysis technology, has displayed the highest theoretical efficiency across electrolysis technologies and is being closely studied by large industrial consumers. SOE, however, still remains a very-early-stage emerging technology, with a total installed capacity below 300 kW globally as of September 2019; the bulk of these deployments are at two pilot sites operated by Sunfire GmbH with German and EU grant funding.

Last, several companies have advocated for technologies that reform or extract hydrogen from waste. Although such technologies hold out an attractive option for municipal authorities seeking to reduce waste and provide low-cost fuel for public transit, none of these technologies have been deployed outside of testing environments.

FIGURE 3.3 Projections and roadmaps for global hydrogen demand in the energy sector



3.2. MARKET SIZE

3.2.1. Hydrogen and electrolyzers

The global hydrogen market is valued at over \$135.5 billion, with an estimated CAGR of 8 percent until 2023 (Markets and Markets 2018). While exact figures for the volume of hydrogen produced vary, the literature suggests 55 million tonnes up to 70 million tonnes (IEA 2019b) of hydrogen are produced annually.[20] As previously illustrated in figure 1.1, around 96 percent of global hydrogen production comes from fossil fuel sources, with 48 percent from natural gas via SMR and 48 percent from either coal gasification or other chemical processes (such as chlorine production). Only 4 percent comes from electrolysis.[21] Given the wide range of potential applications, determination of the potential market size for hydrogen is extremely contentious. Assessing this myriad of use cases, McKinsey & Company in a report for the Hydrogen Council (2018) determined that the future hydrogen energy market could amount to up to \$2.5 trillion a year by 2050. It is worth noting though that other analysts have come up with significantly smaller figures.

Four of the most often cited growth scenarios for the hydrogen sector are from the Hydrogen Council (2017), Acil Allen (2018), IRENA (2018), and Shell's Sky Scenario (2018). Although the studies do not compare like for like, they do illustrate the scale of hydrogen as a potential fuel source. Given that in their modeling Acil Allen, IRENA, and Shell do not appear to account for nonenergy uses of hydrogen (such as ammonia production and use as a process agent in refining), an assumption for the value of the global hydrogen market for chemical and process applications must also be made to arrive at a global hydrogen market demand in 2050. Consumption of hydrogen for energy and mobility is assumed to be below 1 percent of total demand, so about 99 percent of hydrogen demand today is for chemical and industrial process applications. This figure can then be subtracted from these estimates to produce an estimate of global hydrogen demand for energy applications (see figure 3.3).

20 The IEA (Philibert 2017) quoted 60 million tonnes in 2017. DNV GL's paper for the Norwegian government (2019) quoted 55 million tonnes, as did Siemens (2019), the Hydrogen Council (2020), and IRENA (2019). In its 2019 report, WEC Netherlands cited 45 million tonnes–50 million tonnes using 2010 data.

21 Hydrogen Council 2020, citing IEA 2017; Ajayi-Oyakhire 2012, citing Ogden 2004; IRENA 2018, 13; Siemens 2019, slide 8; and IEA 2015, 10.

FIGURE 3.4 **Power to gas, wind to hydrogen in Germany**

© Energiepark Mainz, Siemens.

Despite a wide variation in estimated annual hydrogen demand from the energy sector, it is clear that the demand for hydrogen in industrial applications will remain significantly larger than the market for hydrogen in the electric power sector. This observation not only illustrates how quickly the market could absorb additional hydrogen demand, but it also illustrates the potential scale of investment for green hydrogen to decarbonize existing hydrogen demand. (See figure 3.4 for an example of a renewable power to gas investment.)

None of these scenarios provide an explicit split between what would be green hydrogen, gray hydrogen, and blue hydrogen at each milestone, so it is more difficult to provide an indication of how large the market for green hydrogen could be. However, current estimates suggest that between 0.7 million tonnes and 2.8 million tonnes of hydrogen come from electrolysis today.

The obvious questions raised by the growing interest in the potential use of hydrogen are where the hydrogen will come from and whether electrolysis companies will be able to meet the scale of demand at a cost-competitive level. Answering these questions requires obtaining clear data on the current size of the market today, which is very challenging.

For pure electrolysis solutions, current research estimates that global electrolyzer sales in 2017 reached 100 MW for the year (DOE 2018), with 2018 sales estimated at $286 million for water-based electrolyzers and growth forecast at a CAGR of 5.67 percent during 2019–25 (GII Research 2019). The most recent publicly available estimate for water-based electrolysis deployments globally is from the IEA (2019b), which estimates that the global installed-water electrolysis capacity today is over 100 MW electrical, while current orders for water electrolysis (alkaline and PEM) will see the installed capacity reach 285 MW by the end of 2020. By geography, Asia appears to be the world's largest market for electrolyzers, with China assumed to have a market share of about 47 percent (Market Watch 2019). It is worth noting that China's annual electrolyzer demand has grown from roughly 160 units in 2013 to 2,014 units by 2017, although no information is available on whether the average size of units has changed (GII 2018). If chlor-alkali electrolysis plants are included, then certain sources indicate global

TABLE 3.1 Estimated global manufacturing capacity for electrolyzers (PEM and alkaline), 2019

TECHNOLOGY	CURRENT MANUFACTURING CAPACITY (MW PER ANNUM)	FUTURE COMMITTED MANUFACTURING CAPACITY, ESTIMATED DELIVERY 2025 AND AFTER (MW PER ANNUM)
PEM electrolysis	> 300 MW	> 1,500 MW
Alkaline electrolysis	> 1,800 MW	> 3,000 MW

Source: ESMAP research and correspondence with suppliers.
Note: MW = megawatt; PEM = proton exchange membrane.

installed electrolysis capacity could be between 1.5 and 3.0 GW.[22] Other higher-end estimates by BNEF have suggested that global installed capacity could be as high as 20 GW of electrolysis, but with only 2 GW installed since 2000 (BNEF 2019).

Public sources estimate that 4 percent of global hydrogen production comes from electrolysis, so green hydrogen will have to scale up significantly or CCU technology will have to grow rapidly, or both, to ensure that emissions from hydrogen production are reduced. To put this challenge in context, if the market demand for hydrogen in 2018 stood at 55 million tonnes until 2050 and current production from electrolysis was 2.2 million tonnes in 2018, then the electrolysis market would have to grow by 11 percent annually to achieve 100 percent hydrogen generation from electrolysis by 2050. Thus, given the significant scale-up of green hydrogen required to decarbonize existing hydrogen demand, a number of analysts have become concerned that the development of a hydrogen market may perpetuate the use of natural gas reforming or coal gasification, albeit combined with CCU. The IEA, for example, notes that less than 0.4 million tonnes of hydrogen is produced with CCU and less than 0.1 million tonnes from renewables, amounts that illustrate the scale of the challenge to simply decarbonize the existing hydrogen market in the industrial sector (IEA 2019a).

Today, exact global electrolyzer manufacturing capacity figures are challenging to obtain. In early 2019 Nel, a market leader in the electrolysis market, claimed that the global market manufacturing capacity was around 90 MW per annum (Nel 2018b). Yet, this figure did not appear to reflect the considerable manufacturing capacity of electrolyzer companies in China and the existing capacity in Europe. Accordingly, ESMAP analysis suggests that current market capacity across alkaline and PEM is above 2.1 GW per annum and is scaling fast (table 3.1).

These figures are subject to a number of assumptions, but what is clear is that the global market is scaling rapidly. Two examples of electrolyzer manufacturing are Nel, which has committed to increasing its current manufacturing capacity 10-fold to 360 MW (with a 1 GW site identified in August 2019), and ITM Power, which also has publicly committed to a 10-fold increase in its manufacturing warehouse space (figure 3.5). Thyssenkrupp also has publicly acknowledged it has 1 GW of alkaline electrolysis capacity, while John Cockerill also has confirmed its capacity increased to 350 MW as of Q4 2019.

22 This estimate is informed by data from an H21 (2018) study, which claims that about 5.5–7.0 GW of hydrogen production capacity is installed per year over the last 40–50 years. This amount would average to 137 MW per annum of hydrogen electrolyzers. If the maximum electrolyzer lifetime is assumed to be 20 years, the theoretical ceiling of global installed capacity is thus implied to be a spread of between 1.5 GW and 3.0 GW (H21 2018). However, the H21 study also includes chlor-alkali and sodium/chlorate units, which have longer lifetimes. Nouryon, for example, already has a 1 GW electrolysis portfolio.

FIGURE 3.5 **Electrolyzer gigafactory under construction in Sheffield, United Kingdom**

Despite this growth, research conducted for this report indicates that under current practice a significant scale-up of hydrogen demand globally is still likely to increase short-term demand for fossil fuel–based hydrogen production, though the medium- to long-term outlook will be determined by the pace of growth, green hydrogen scale-up and the dynamics of hydrogen production pricing across the available technologies. Even taking a longer time horizon, current evidence suggests that to achieve the Hydrogen Council's vision of hydrogen demand reaching 18 percent of final energy demand by 2050 while minimizing the carbon footprint of hydrogen production, significant scale-up of green hydrogen will need to occur.[23] The implication to policy makers considering hydrogen applications, especially in developing countries, is that it is essential to develop a clear roadmap for how the hydrogen can be sourced in a climate-sustainable manner to ensure that zero-emission sources of hydrogen production are scaled up.

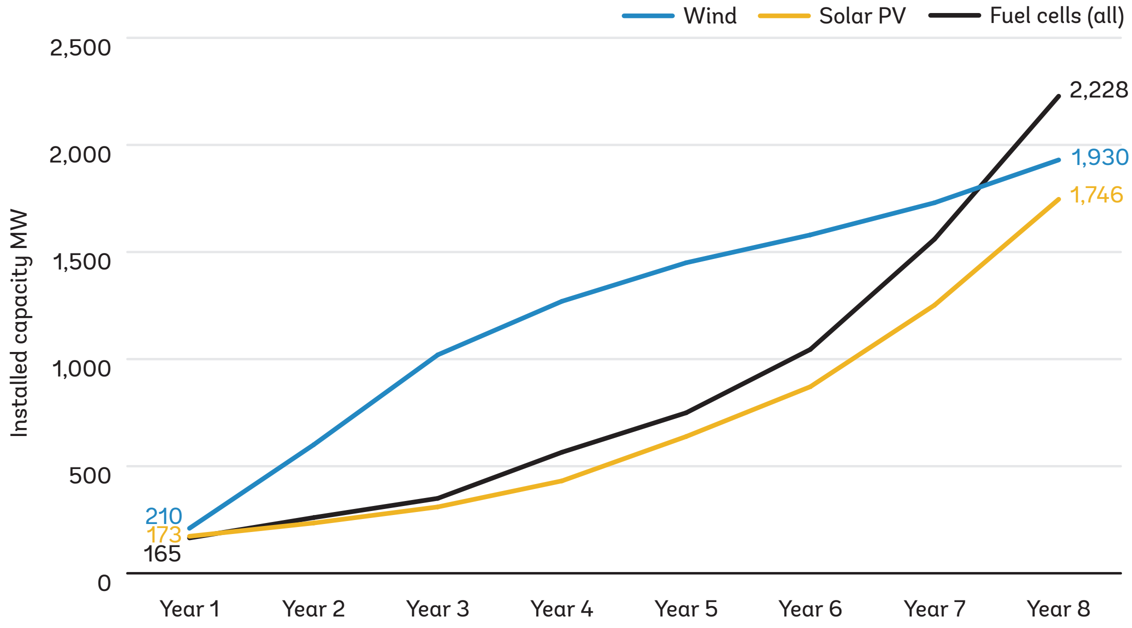
3.2.2. Fuel cells

Sources complied by ESMAP suggest that the global fuel cell market exceeds $2 billion per annum and that more than 2 GW of fuel cell systems have been shipped since 2000. To place this pace of deployment in context, note that the growth rate of various technologies in the five years after they reached 100 MW installed or shipped per annum indicates that fuel cells (portable, stationary, and mobility applications) have scaled faster than solar PV and onshore wind (figure 3.6).

The big drivers of this change have been the rapid improvements in the cost of fuel cell units, combined with improvements in efficiencies and in the operational lifetimes of fuel cell stacks (figure 3.7). For example, the previous SOFC lifetime record was under 20,000 hours in 2005. Today, Bloom Energy, which produces SOFC technology, estimates that its systems can operate for 40,000 hours before the stacks may need

23 This figure assumes that by 2050 hydrogen will provide 550 terawatt-hours of seasonal power storage, fueling 400 million light-duty vehicles, 15 million to 20 million trucks, and 5 million buses (Hydrogen Council 2017).

FIGURE 3.6 Technology deployment curves for fuel cells versus wind, and solar photovoltaic



Sources: U.S. Department of Energy market analysis reports, https://www.energy.gov/eere/fuelcells/market-analysis-reports; E4tech, "Fuel Cell Industry Review," various years; and Klippenstein 2017, compiled by ESMAP.
Note: MW = megawatt; PV = photovoltaic.

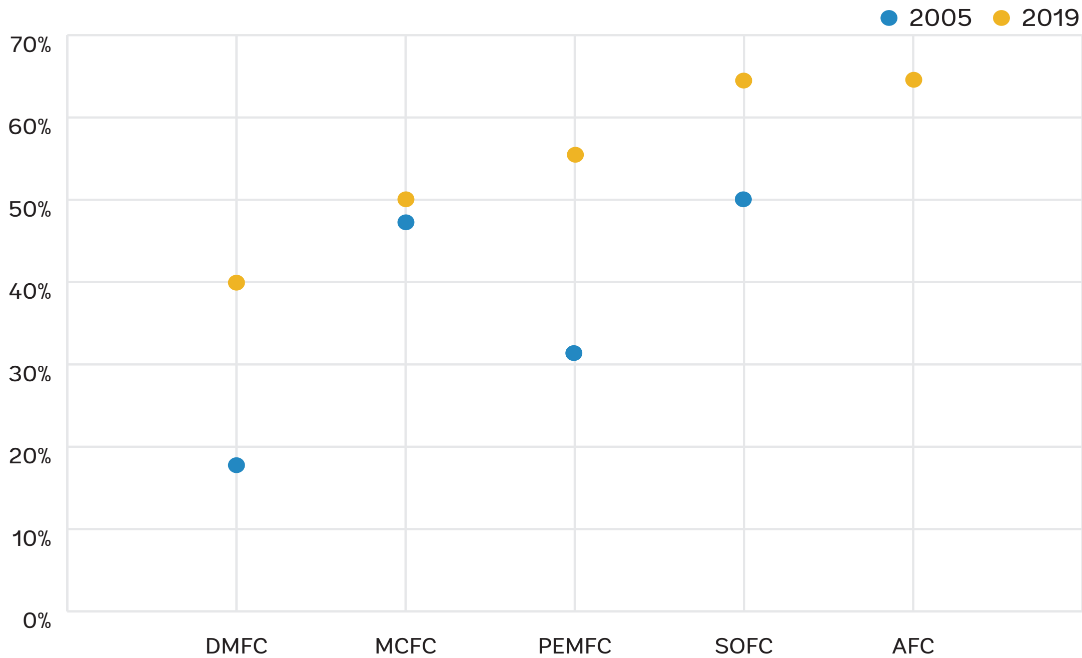
replacement. Meanwhile, Ballard, which specializes in PEM fuel cells, has provided a warranty that its latest stationary fuel cell systems will perform for over 34,000 hours, while Doosan fuel cells have reported over 70,000 hours of operational lifetime for their PAFC units.

Increasing system efficiencies also has played an important role in improving the economics of fuel cell applications. These efficiencies include not only general improvements to the chemistry but also commercial innovations such as adapting units to provide CHP solutions in stationary contexts and recycling heat in vehicles to improve efficiency.

These incremental gains in efficiency and rapidly declining costs (figures 3.7 and 3.11) have therefore led some industry analysts to ask whether the market has sufficient manufacturing capacity to meet the rapid increases in demand. This is an important but complex question. Finding publicly available sources for global fuel cell manufacturing capacity is extremely challenging, especially because many companies are privately held and few public market reports provide granular information. Notwithstanding these challenges, by using publicly available sources and making reasonable assumptions, one can establish a "baseline" production capacity. Analysis conducted for this report suggests that significant capacity for PEM fuel cell manufacturing already exists and that plans are in place for a significant expansion. Other fuel cell technologies seem to be considerably more constrained (table 3.2), and that situation may lead to supply issues if these technologies experience a short-term surge in demand.

The ability to provide PEM fuel cell solutions to the mobility sector is a key driver of scaling capabilities and, in turn, will likely drive costs down and increase uptake, despite the potential

FIGURE 3.7 Average fuel cell electrical efficiencies between 2005 and 2019



Sources: IEA, OECD 2005 and data from multiple sources compiled by ESMAP.

for other fuel cell technologies to provide solutions with higher efficiencies and longer stack lifetimes. Further, because the MCFC, SOFC, and PAFC markets are dominated by one or two companies, the success of these applications will likely be far more closely tied to the companies' own decisions than to the fate of the broader fuel cell industry. This may create another driver for consumers to focus on PEM technology, where they are more likely to be able to find alternative suppliers.

3.3. COSTS

3.1.1. Hydrogen and electrolyzers

The actual cost of hydrogen production and the price paid by most end consumers are difficult to determine because of the lack of publicly available data. Reports frequently state that hydrogen from electrolysis is more expensive than from steam methane reformation and from coal gasification. Yet that observation is far too simplistic. As noted by the EU's Fuel Cells and Hydrogen Joint Undertaking (FCH JU in Fraile and others 2015), hydrogen prices can vary from EUR 1.5 per kg to EUR 60 per kg in the EU market, a range that remains true today, according to ESMAP's discussions with current market participants. This range is also noted in other large hydrogen markets outside the EU.

The most commonly quoted figure for hydrogen pricing is derived from steam methane reforming technologies, which can produce hydrogen from natural gas at around $1.00–$1.50 per kg. But this price is typically linked to large-scale SMR units, with access to low-cost natural gas such as those in the United States and Northern Europe. Further, these costs often refer to already existing assets and do not reflect the

TABLE 3.2 **Estimated global manufacturing capacity for fuel cells across all technologies, 2019**

FUEL CELL TECHNOLOGY	CURRENT MANUFACTURING CAPACITY (MW PER ANNUM)	FUTURE COMMITTED MANUFACTURING CAPACITY (MW PER ANNUM)
PAFC	126[a]	> 126
MCFC	100[b]	> 200
SOFC	> 120[c]	> 120
PEM	> 1,100[d]	> 12,000

Note: MCFC = molten carbonate fuel cell; PAFC = phosphoric acid fuel cell; PEM = proton exchange membrane; SOFC = solid oxide fuel cell.

a. Moon 2017; Doosan Fuel cell website, http://doosanfuelcell.com.en/intro/manufacturing.

b. FuelCell Energy 2018.

c. Public filings show that Bloom Energy has deployed over 300 MW since 2011, which on a linear scaling would equate to at least 30 MW a year. It is also known that Bloom's manufacturing site is over 210,000 square feet and, given the capacity of competitor FuelCell Energy—which reports a 64 MW capacity from a 60,000 square foot site—and Ballard Power Systems (Ballard 2017)—which reported that its Synergy Ballard JVCo could achieve an annualized production capacity of approximately 20,000 fuel cell stacks (80 MW) from 50,0000 square foot—it could be estimated that Bloom Energy can produce at least 120 MW per annum. Bloom data, Bloom Energy 2011; FuelCell Energy 2018.

d. Hyundai currently can produce 3,000 fuel cell stacks per year. It could scale to 40,000 annually by 2022 and aim for 700,000 per annum by 2030. Each Toyota Mirai is 114,000 kW; therefore, there is 342 MW current capacity, due to reach 4,560 MW by 2022. Toyota currently can produce 3,000 fuel stacks per year, with plans to reach 30,000 by 2020 (Toyota 2018). Given that Toyota's fuel cell stack is around 100 kW, scaling is from 300 MW to around 3 GW. Plug Power is quoted as having capacity in 2019 to produce 20,000 fuel cell units per annum. In 12 months, from September 2017 to Septempber 2018, it produced more than 5,000 stacks. The average unit is 2 kW to 4 kW. It could be estimated that the company produces around 40 MW to 80 MW per annum, averaged to 60 MW. These numbers are comparable with those given in correspondence with the company. Longer term, Zhongshan Broad-Ocean Motor Co., already Ballard's largest shareholder, is building three manufacturing facilities using Ballard technology. Thus three assembly lines will make 10,000 units of 35 kW to 85 kW (or 3.5 GW–8.5 GW) (Broad-Ocean Motor Group 2017, slide 13). So 5 GW additional capacity is assumed. In addition to these sources, market intelligence from various suppliers has helped inform the baseline.

costs of capital expenditure in their pricing. As shown in table 3.3, sources suggest that hydrogen production costs from SMR are closely correlated to moves in natural gas prices, with a recent study by WEC Netherlands observing that natural gas costs correspond to 70–80 percent of the total hydrogen production cost. According to this source, a EUR 6 per gigajoule price increase in natural gas corresponds to a hydrogen production cost increase of EUR 1 per kilogram (WEC Netherlands 2019).

Nevertheless, these figures are in many senses limiting because they almost exclusively provide the cost only for consumers who are colocated and who represent the primary off-taker for the SMR operator. The reality for smaller-scale consumers is that hydrogen costs vary considerably, and calculating what the pricing should be of hydrogen delivered to customers is challenging. The simple reason is that transportation and storage of hydrogen remain expensive and cost varies depending on the volume of hydrogen demanded by customers and their distance from the hydrogen production site. How broad the spread can be is illustrated by the publicly available Hydrogen Demand and Resource Analysis tool (HyDRA) from the National Renewable Energy Laboratory (NREL) (figure 3.8).

As can be seen from figure 3.8, the cost of delivering hydrogen to customers is considerably more than the production cost; thus there

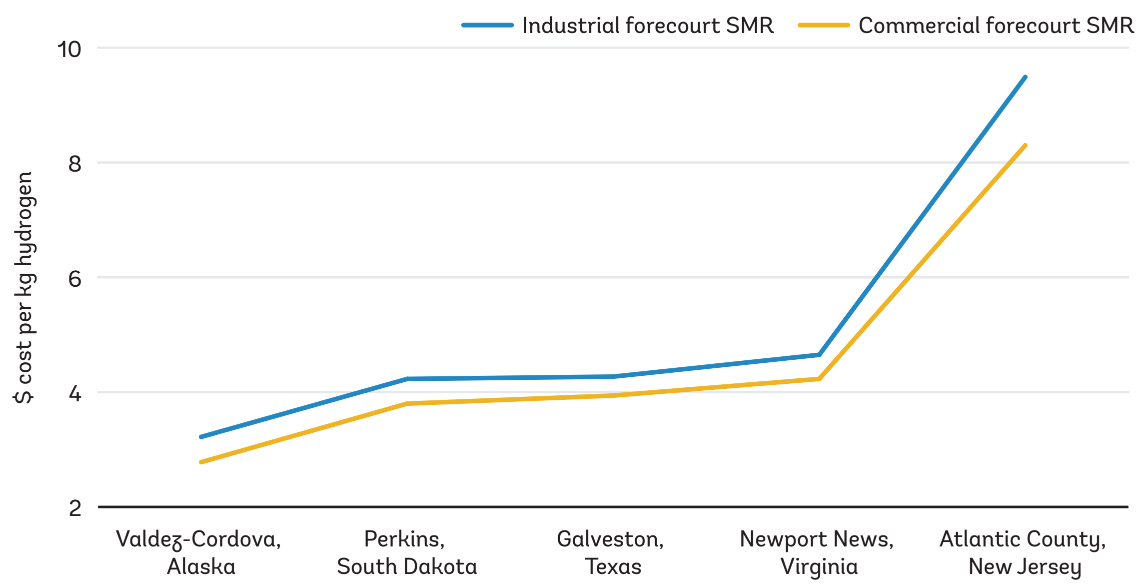
TABLE 3.3 **Production cost estimates of hydrogen from steam methane reforming and coal gasification (excluding transport and storage costs)**

ORGANIZATION/LOCATION	PRODUCTION METHOD	COST (US$/KG)
IGEM 2012, United Kingdom	SMR	3.00[a]
IGEM 2012, World	SMR	0.80–6.00[b]
IEA 2015, United States	SMR	0.90
IEA 2015, Europe	SMR	2.20
IEA 2015, Japan	SMR	3.20
IEA 2017, World	SMR	1.00–3.00[c]
WEC 2018, Netherlands	SMR (Large scale)	1.10–1.70[d]
WEC 2018, Netherlands	SMR (Small scale)e	4.60—5.75[f]
CSIRO 2018, Australia	SMR + CCS	2.27–2.77[g]
CSIRO 2018, Australia	Brown coal gasification +CCS	2.57–3.14[g]

Note: CCS = carbon capture and storage; SMR = steam methane reforming; IGEM = Institution of Gas Engineers and Managers; IEA = International Energy Agency; WEC = World Energy Council; CSIRO = Commonwealth Scientific and Industrial Research Organisation.

a.Ajayi-Oyakhire 2012. b. Ajayi-Oyakhire 2012. c. Philibert 2017. d. WEC 2019. e. Producing 200 kg–600 kg per day. f. WEC Netherlands 2019. g. Bruce and others 2018.

FIGURE 3.8 **Spread in United States hydrogen prices from HyDRA, April 2019**



Source: NREL 2019.
Note: HyDRA = Hydrogen Demand and Resource Analysis (tool); NREL = National Renewable Energy Laboratory; SMR = steam methane reforming.

remains a significant cost advantage to being able to produce hydrogen on-site. This dynamic has underpinned much of the growing interest in electrolyzers, and it is worth noting that as early as 2015 the IEA, citing the US DOE, argued that the cost of distributed hydrogen production via electrolysis using off-peak electricity could be $3.90 per kg (IEA 2017). On this basis, hydrogen created from an electrolyzer on-site could be cheaper than the price of commercial forecourt hydrogen from SMR in all the locations shown in figure 3.8 except in Alaska.

The question then is what drives the cost of hydrogen from electrolysis, and can these solutions consistently deliver green hydrogen at prices that are below those prices currently accessible to existing hydrogen consumers, excluding the largest captive producers (for whom there is no need to transport hydrogen because it is produced and consumed on-site). Historical analysis of the cost of hydrogen from electrolyzers has typically considered capex and electricity costs to be around 50:50 with regard to their impact on the cost of hydrogen. That is especially true for units below 1 MW. Yet, as the market has expanded and electrolyzer costs have fallen, companies have begun to argue that electricity costs now account for around 75 percent of hydrogen's cost (Nel Asa 2017). Nevertheless, capex clearly is still an important consideration, especially at the smaller, decentralized scale. Thus, achieving load factors above 3,500 hours per annum is essential to securing low hydrogen prices, even when the cost of power might be low (or free when curtailed).

To illustrate some of the current green hydrogen cost estimates, table 3.4 consolidates assessments from a wide array of sources, under differing sets of assumptions. As the table shows, there is considerable variation in hydrogen pricing points. That variation reflects two sources of uncertainty: (a) considerable variation in electrolyzer cost assumptions and efficiency values and (b) considerations around the LCOE of electricity used and load profile/capacity factor of the electrolyzer, reflecting the use of the asset. One source of discrepancy on cost assumptions is whether the capex figure given includes only the electrolyzer, or the balance of plant, installation, or both. Yet, even with these considerations, the pricing range remains large.

Evidence from projects that are publicly available appears to corroborate feedback from suppliers, suggesting that alkaline units above 20 MW can be expected to cost below $700 per kW on an equipment-only basis. For PEM electrolyzers the deployment amounts have been much smaller and therefore pricing remains extremely varied (table 3.5). However, equipment costs below $1,200 per kW appears to be an accepted benchmark for these solutions. The other aspect to note is that literature sources and suppliers commonly assume electrolyzer efficiencies to be at least 65 percent today, with many using 70 percent as the base case. See figure 3.9 for examples of PEM electrolyzer units for mobility applications.

From the evidence available it is reasonable to conclude that hydrogen from electrolysis cannot be currently produced more cheaply than from large existing-scale SMR in areas with access to low-cost natural gas. Yet, cost estimates shown in table 3.4 suggest that, for customers with access to the grid and falling wholesale power prices, hydrogen from on-site electrolysis can be cheaper than the cost from large-scale SMR facilities plus transport costs. It also appears to be the case that even where off-takers have access to natural gas at low prices, smaller SMR units (those producing less than 4.5 kg of hydrogen per hour) would only be able produce hydrogen at a cost that would be comparable to that produced via electrolysis (IEA 2015; WEC Netherlands 2019). Looking forward, if wholesale power prices, renewable costs, and electrolyzer costs

TABLE 3.4 Cost estimates of hydrogen generated via water electrolysis

ORGANIZATION	ELECTROLYSIS COST RANGE ($/KG)	ASSUMPTIONS
Siemens 2016	4.40–7.70[a]	Based on data analysis from the Energiepark Mainz project.
IEA 2017	2.00	Alkaline electrolyzer, $850/kW capex, WACC 7%, lifetime 30 years, efficiency 74%, 4,500 full load hours
Nel ASA 2017	2.70–4.00[b]	Alkaline electrolyzer, capex below $700/kW, and a solar PPA $40–$60/MWh
Nel ASA 2017	1.30–2.70[b]	Alkaline electrolyzer, capex below $500/kW and solar PPA is $20/MWh–$40/MWh
IRENA 2018	5.00–6.00[c]	Alkaline electrolyzer; 2017 Danish electricity prices that include all grid fees, levies, and taxes; load factor above 40%
IRENA 2018	4.20–5.80	PEM electrolyzer, Chile; wind + solar, with an LCOE $20/MWh–$50/MWh and 6,840 full load hours
Tractebel Engie and CORFO 2018[d]	1.80–3.00	Northern Chile, 2023; electricity cost $28.40–$56.20/MWh
CSIRO 2018 (base case)[e]	4.80–5.80	Alkaline electrolyzer, 44 MW, 85% capacity factor, 57% efficiency, $60/MWh, capex $1,347/kW
CSIRO 2018 (base case)[e]	6.10–7.40	PEM electrolyzer, 1MW, 85% capacity factor, 62% efficiency, $60/MWh, capex $3,496/kW
ESMAP 2020 (base case)	4.5–4.8	Alkaline electrolyzer, 1 MW, 75% capacity factor, 80% efficiency, $30/MWh, capex at $800/kW
ESMAP 2020 (base case)	5.00 – 5.80	PEM electrolyzer, 1 MW, 95% capacity factor, 72% efficiency, $30/MWh, capex at $1,100/kW
ESMAP 2020 (lowest price)	3.70 – 4.00	Alkaline electrolyzer, 1MW, 95% capacity factor, 80% efficiency, $30/MWh, capex at $800/kW

Source: As shown, and ESMAP.

Note: All sums have been converted to U.S. dollars at prevailing exchange rates. capex = capital expenditure; CSIRO = Commonwealth Scientific and Industrial Research Organisation; CORFO = Chilean Economic Development Agency; ESMAP = Energy Sector Management Assistance Program; IEA = International Energy Agency; IRENA = International Renewable Energy Agency; LCOE = levelized cost of energy; PEM = proton exchange membrane; PPA = power purchasing agreement; WACC = weighted average cost of capital.

a. Siemens 2016—converted from EUR to US$. b. Nel Asa 2017. c. IRENA 2018. d. Tractebel and Chilean Solar Committee 2018. e. Bruce and others 2018.

continue to decline, it appears conceivable that electrolysis could become a commercial alternative to SMR or coal gasification for large-scale centralized production.

These findings suggest avoiding the assumption that most of the growth in global hydrogen demand will be met by SMR deployments, because green hydrogen prices may well reach parity with fossil-derived hydrogen sooner than anticipated in locations with exceptionally good renewable resource.

3.1.2. Fuel cells

One of the best illustrations of the historic decline in the cost of fuel cell technologies comes from observing the cost declines for PEM fuel cell systems (figure 3.10). That is because PEM systems have been developed since the 1950s and remain the most commonly procured fuel cell technology in aggregate across sectors (largely driven by mobility applications).

It is important to note that costs for PEM fuel cells in mobility have always been lower than

TABLE 3.5 Sample of electrolyzer capital expenditure estimates

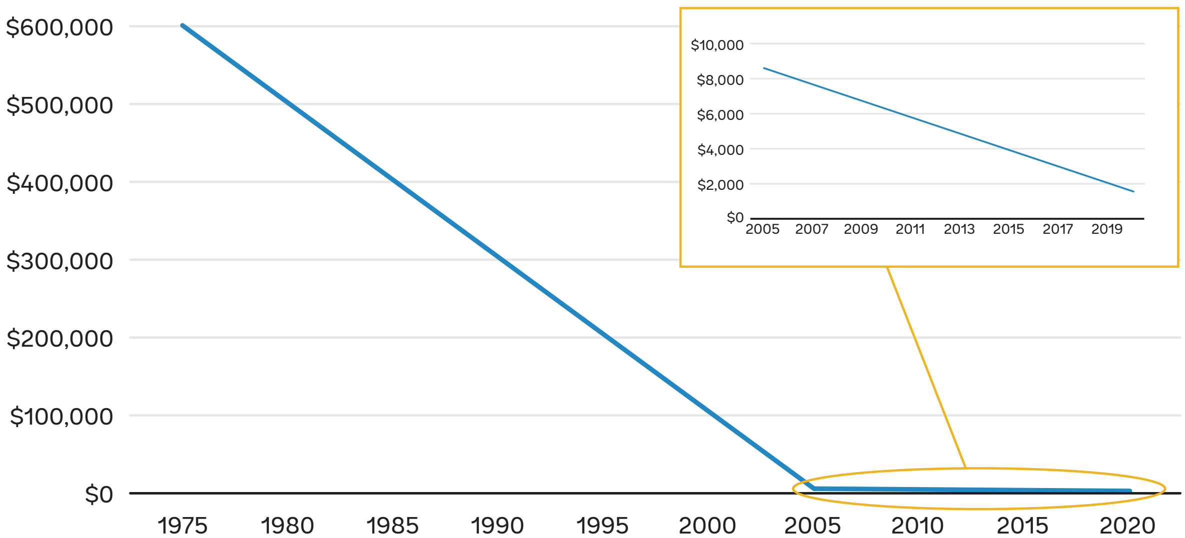
ORGANIZATION	TECHNOLOGY	CAPEX (US$/KW)
IEA (2015)	PEM	2,650[a]
CSIRO (2018)	PEM	3,496[b]
H2I (2018)	PEM	2,800 –3,400[c]
IRENA (2018)	PEM	1,380[d]
ESMAP (2020)	PEM	1,100
IEA (2015)	Alkaline	1,150[e]
IEA (2017)	Alkaline	850f
CSIRO (2018)	Alkaline	1,347[g]
H2I (2018)	Alkaline	1,300–1,700[h]
IRENA (2018)	Alkaline	860[i]
ESMAP (2020)	Alkaline	800

Source: As shown, and ESMAP.
Note: PEM = proton exchange membrane.

a. IEA 2015. b. Bruce and others 2018. c. H2I 2018. d. IRENA 2018. e. IEA 2015. f. Philibert 2017. g. Bruce and others 2018. h. H2I 2018. i. IRENA 2018.

FIGURE 3.9 ITM PEM electrolyzer National Physics Lab,United Kingdom, 2019 (left) and Siemens Silyzer 3000, Mainz Park, Germany, 2019 (right)

FIGURE 3.10 **Stationary PEM fuel cell cost per kW**



Source: ESMAP.
Note: PEM = proton exchange membrane.

for stationary applications, owing to different stack lifetime requirements. Therefore, there are PEM fuel cells available today that suppliers will quote for below $2,000 per kW. Typically, the higher stack lifetime requirements for all stationary fuel cells lead to higher costs, part of the reason that stationary systems have a higher capex than mobility solutions.

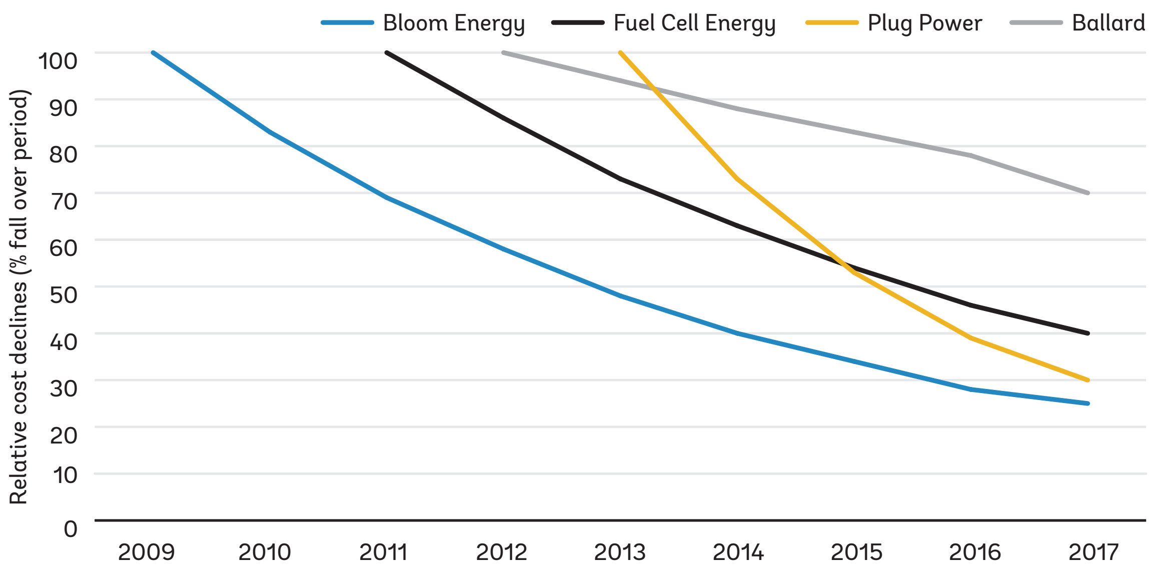
PEM fuel cell suppliers are not the only ones seeing significant cost declines. Publicly available data also show that manufacturers across other fuel cell technologies are reporting significant cost declines as orders scale up (figure 3.11).[24] These companies are often well-established businesses, a fact that indicates not only the time it has taken to develop products that are commercially available to go to market, but also the importance of achieving scale to drive down costs and improve the economics of fuel cell projects.

But not all fuel cell system costs are starting from the same position. Fuel cell technologies have different applications, stack lifetimes, electrical efficiencies, and fuel sources that drive their overall cost structures (tables 3.6 and 3.7).

Assessing fuel cell costs, therefore, requires more than a simple analysis of capital expenditures. For example, PEM fuel cells rely on high-purity hydrogen, which is more expensive and more complicated to transport and store than other fuel alternatives such as ammonia, methanol, or natural gas. Further, it is important to consider the application. Where fuel costs are cheap or maintenance is a concern, there may be an incentive to switch toward longer-duration and lower-cost systems, such as PAFC or MCFC units instead of SOFCs. For customers who may value a CHP application, high-temperature fuel cells can provide a more compelling solution and a

24 The figures are derived from annual reports that indicate declines in price over a fixed period but do not provide exact prices for each year. Accordingly, the "midyear" data has been extrapolated between the start year and 2017 figures.

FIGURE 3.11 **Reported equipment cost decline curves from leading fuel cell suppliers**



Source: Extrapolated from company-reported declines 2018/19.

much higher system efficiency than lower-temperature fuel cells. For example, Transport for London installed a CHP (PAFC) unit in its Palestra building to help provide power as well as heating and cooling.

In short, choosing the most appropriate fuel cell solution requires companies to make a variety of assessments and judgments when scoping the technology solution and the application for the end customer. Capex alone is not always the key driver of technology choice.

TABLE 3.6 **Overview of primary fuel cell technologies**

TECHNOLOGY TYPE	$/kW	SYSTEM EFFICIENCY (%)	STACK LIFETIME (HOURS)	SYSTEM LIFETIME (YEARS)	PRIMARY APPLICATIONS
Proton exchange membrane fuel cell (PEM)	Stationary: 1,400–4,000 Mobility: 1,000–3,000	Stationary: 45–58 Mobility: 45–60	Stationary: 20,000–40,000 Mobility: 6,000–20,000	20	All mobility, UPS, residential power, peaking power provision.
Molten carbonate fuel cell (MCFC)	Stationary: 3,000–4,000	Electric only: 45–55 CHP: 70–85	Stationary: 60,000–80,000	20	Baseload power generation, UPS, CHP uses.
Alkaline fuel cell (AFC)[a]	Stationary: 700	Electric only: 55–65 CHP: 80–90	Stationary: 5,000–6,000	20	Baseload power generation and UPS.
Solid oxide fuel cell (SOFC)	Stationary: 3,000–6,500	Electric only: 45–65 CHP: 80–90	Stationary: 25,000–40,000	20	Baseload power generation, UPS, range extender for larger mobility applications, CHP uses.
Phosphoric acid fuel cells (PAFC)[a]	Stationary: 4,000–5,000	Electric only: 45–55 CHP: 85	70,000–80,000	20	Baseload power generation, UPS, CHP uses.

Source: IEA, ESMAP, various suppliers.
Note: CHP = combined heat and power; kW = kilowatt; UPS = uninterruptible power supply.
a. IEA 2015.

TABLE 3.7 **Methanol and ammonia fuel cells**

FUEL SOURCE	COST PER KW ($)	SYSTEM EFFICIENCY (%)	STACK LIFETIME (HOURS)	SYSTEM LIFETIME (YEARS)	WHERE USED?
Methanol fuel cell	4,000–10,000	Electric only: 50, Whole system 35–40	Stationary: 5,000–10,000	20	Uninterruptible power supply
Ammonia fuel cell	10,000	Electric only: ~50 Whole system: 35-40	Stationary: 5,000–8,000	20	Uninterruptible power supply

Source: ESMAP.
Note: kW = kilowatt.

4: ENERGY APPLICATIONS AND COMMERCIAL SOLUTIONS

KEY TAKEAWAYS

- Variable renewable energy deployments, balanced by electrolyzers, hydrogen storage, and fuel cells, can achieve a levelized cost of energy for the provision of power that could be below the cost of diesel alternatives in some developing countries and remote areas.
- There is an abundance of applications for which green hydrogen could provide solutions for industries, commerce, utilities and policy makers to help decarbonize existing fossil-based energy systems.
- Not every application for green hydrogen will be appropriate in every country context, and careful analysis will be needed to ensure the solutions are suitable.
- Developing countries are already ahead of developed countries in the use of certain hydrogen and fuel cell applications today because they make commercial sense in their contexts.
- Green hydrogen and fuel cells could become a building block of fully decarbonized grids, complementing existing renewable energy technologies and facilitating their further deployment by addressing constraints such as long-duration storage and transportation.
- Green hydrogen storage, electrochemical batteries, and other forms of energy storage offer different value propositions and in most cases can be regarded as complementary.

Hydrogen and fuel cell technologies are aleady being used in a wide array of stationary power applications at the utility, industrial, commercial, and residential level (table 4.1). On the fuel cell side, the applications range from sub-1 kW units to systems over 50 MW, and by late 2019 there were estimated to be 363,000 stationary fuel cells in operation globally (IEA 2019b). A significant proportion of stationary power applications below 3 kW are located in developing countries—notably in Asia, where they play an increasingly important role in power provision for off-grid sites that require high availability and are at risk from diesel thefts. These applications typically include telecommunications towers, but in Japan customers also include residential CHP units. The majority of units of 100 kW or larger are located in Korea and the United States, largely for commercial consumers and a few large industrial customers, with the overwhelming majority of these units using natural gas as their primary fuel. While fuel cells remain the primary consumer of hydrogen for energy, there is also growing interest in retrofitting or designing combustion turbines and reciprocating engines to also run on hydrogen.

4.1. RESIDENTIAL APPLICATIONS

One of the areas of focus for hydrogen technologies in the residential sector is the installation of residential fuel cell combined heat and power units, which have transitioned in recent years from PEM to SOFC because of the higher efficiency and operating temperature of SOFC. The largest of these rollouts is the Japanese Ene-Farm project, which in over a decade has seen more than 300,000 units deployed domestically, making it the largest market by far. Other

TABLE 4.1 **Overview of stationary fuel cell applications**

APPLICATION	TECHNOLOGY	UNIT SIZE (kW)	COMPLIMENTARY TECHNOLOGIES	EXAMPLES
Residential combined heat and power	PEM and SOFC	< 5	Solar PV, batteries	Ene-Farm, Ene-Field
Back-up power	PEM, methanol and ammonia	< 100	Solar PV, batteries, micro-wind	Adrian Kenya, PT Telekom, U.S. state of Maryland, Bahamas, Danish emergency broadcast system
Off-grid power provision	PEM fuel cells, mostly.	< 1	Solar PV, wind, batteries, geothermal	Tiger Power, Cerro Pabellón geothermal plant, Raglan Mine, BIG HIT
Commercial office power	Mostly SOFC and PAFC	< 5	Solar PV, batteries, micro-wind	Apple HQ, Morgan Stanley Manhattan, PG&E campus, South African Ministry of Mines
Baseload power generation	SOFC, PAFC, MCFC, retrofit gas turbine	> 400	Power grid	Daesan Green Energy JV, CEOG, North Chungcheong Province (Korea Western power)

Note: MCFC = molten carbonate fuel cell; PAFC = phosphoric acid fuel cell; PEM = proton exchange membrane; PV = photovoltaic; SOFC = solid oxide fuel cell.

FIGURE 4.1 **Sunfire GmbH 2019 Residential SOFC (left) and Ceres Power Ltd 2019 residential SOFC (right)**

© Sunfire (left). © Ceres Power Ltd. (right).
Note: SOFC = solid oxide fuel cell.

suppliers in Europe, notably CERES Power and SunFire GmbH, are due to begin rollouts of their residential SOFC CHP units as part of a grant from the EU called Ene-field. These innovations could be particularly interesting for developing countries in Europe and Central Asia whose existing gas grid could be repurposed accordingly.

Fuel cells are being considered primarily as residential power sources to help promote distributed generation and enhance system resiliency (figure 4.1). Japanese and EU programs that already provide feed-in tariffs to support micro-CHP include support for fuel cell units.

While some of these systems are focused on natural gas consumption for the present, in Thailand a company called Enapter has already built the world's first 100 percent renewable home with green hydrogen and fuel cells. The Phi Suea house in Chiang Mai (figure 4.2) is entirely off the grid and provides 100 percent renewable power 24/7, using 86 kW of solar PV and four modular electrolysis units, to convert excess solar PV into stored energy for use during the day and in the evening.[25]

Recently a number of schools and office buildings have also begun to look at green hydrogen production and fuel cell systems, alongside on-site (typically rooftop-mounted) solar PV, to provide 24-hour renewable power. In Singapore a local company, SP Group, has converted its training center at Woodleigh Park to a 100 percent renewable, off-grid, hydrogen-based system. This pilot is unique not only for being the first fully zero-emission office in Southeast Asia, but also because it uses solid-state hydrogen storage on the premises. This system significantly reduces concerns around storage and leakage of hydrogen gas (SP Group 2019).

[25] Information provided courtesy of correspondence with the supplier in September 2019.

FIGURE 4.2 Phi Suea off-the-grid house, Thailand, hydrogen systems

© Enapter.

Another area of interest is the distribution of green hydrogen through the existing gas grid to be used by existing heating technologies such as boilers, burners, and CHP fuel cells. One method is to simply blend hydrogen with natural gas inside the grid, a process that is being piloted by Keele University in the United Kingdom (HyDeploy n.d.). The other concept is to convert gas grids to 100 percent green hydrogen and convert appliances accordingly. Although that conversion may seem dramatic, it is worth noting that from 1967 to 1977, 14 million customers and 40 million appliances in the United Kingdom were converted from town gas (about 50 percent hydrogen and 50 percent methane) to natural gas (Bruce and others 2018). A number of hydrogen appliances and hydrogen upgrade kits are commercially available to enable residential consumers to use grills and ovens, water heaters, cook tops, and gas heaters. As an example, hydrogen boilers have already been installed at a school on the island of Shapinsey in the United Kingdom (figure 4.3). These applications could offer developing countries—particularly those with an existing gas infrastructure—an interesting pathway to achieve emission reductions in their residential sectors.

4.2. BACK-UP POWER APPLICATIONS

The primary market for back-up power has been the telecommunications sector, which has long been a popular focus area for fuel cell systems. The need for continuous operation of telecommunication towers, the frequent lack of access to power from the grid, and significant security issues related to theft of diesel have encouraged many developed and developing countries to deploy these solutions. While early fuel cell solutions for the telecommunications industry often focused on providing PEM units that required pure hydrogen, initial operating experience has shown that this combination creates significant logistical and performance issues for early adopters. Those issues were almost entirely related to securing hydrogen of sufficient purity and having it delivered consistently to the telecom sites when needed, a challenge compounded by the complexity of storing pure hydrogen in large

FIGURE 4.3 **Hydrogen boilers deployed at Shapinsey School, Kirkwall, United Kingdom**

Source: ESMAP.

quantities over long periods. Accordingly, most telecom tower systems today use methanol- or ammonia-based fuel cell solutions, with companies such as GenCell and Cascadiant leading the rollout in emerging markets. In Indonesia there are already over 800 fuel cell systems in the telecom space, including more than 40 units in Papua New Guinea, whereas Adrian Kenya recently ordered more than 800 ammonia fuel cells to replace diesel gensets (GenCell 2018). In Europe companies such as Ballard, SFC Energy, and Siqens have deployed various solutions, ranging from airport systems in Norway to the Danish emergency broadcasting frequency systems.[26] These projects remain small in absolute numbers, but the number of projects is increasing.

The key to expansion is the ability to combine green hydrogen with direct air capture/carbon capture techniques to produce ammonia. This capability is important because ammonia (and methanol) can be more easily procured and can be stored for longer periods of time than hydrogen, and thus they are more appealing for telecommunications companies (box 4.1). By way of illustration, the two plastic containers in the image of the SFC Energy unit in figure 4.4 (center and right) can provide up to 30 days of power at continuous operation. This ability has enabled fuel cells to overcome some of the initial fuel supply issues that hampered the early adoption of fuel cells for telecom providers in the early 2000s.

4.3. OFF-GRID POWER APPLICATIONS

Providing power to remote areas through minigrids has long meant an increased reliance on diesel generators. Historically, these generators have provided the only reliable means of firm energy supply, through the use of a multifaceted fuel that could be used for both power generation and transport. But today green hydrogen and

[26] In 2007 Ballard was chosen the start providing solutions for the Danish TETRA Network alongside Motorola. Additional details can be found on Ballard's website, https://blog.ballard.com/motorola-fuel-cell-backup-power.

BOX 4.1

DISPLACING DIESEL IN INDONESIA'S TELECOMMUNICATIONS SECTOR

Indonesia is one of the world's fastest-growing telecommunications markets, with the number of mobile phones in the country rising from 124 million in 2014 to an estimated 184 million in 2018. Yet, ensuring that the world's fourth most populous nation stays online is not easy. A report by PWC in 2016 (PWC 2016) concluded that grid blackouts cost Indonesian businesses $415 million every year, while the country's electricity consumption per capita stood at 1.02 MWh in 2018, below Vietnam but slightly above the Philippines. Although the national electrification rate stood at 98.0 percent in 2017, the existence of 18,000 separate islands means that access can vary, from 59.9 percent to 99.9 percent.

To ensure that Indonesians can stay connected, the country's telecom operators have typically resorted to back-up diesel generators to guarantee continuity during grid blackouts and coverage in off-grid areas. These assets are frequently targeted for diesel theft and contribute to local air and noise pollution. However, one company is addressing this problem. Cascadiant develops and operates methanol-based fuel cells for Indonesia's largest telecom provider, PT Telkom Indonesia (figure B4.1.1). The fuel cells enjoy efficiencies above 40 percent and run continuously in all conditions, with a 99.6 percent uptime reported across 815 sites in Indonesia and Timor-Leste since 2010 and extremely limited maintenance required. Cascadiant's fuel cell units rely on methanol, which is produced from domestic hydrogen and then blended partially with water. The blending has a limited effect on efficiency but makes the methanol undesirable for thieves, in contrast to the challenges faced by diesel operators. Since 2013, the company has deployed 800 fuel cell units across Indonesia and Timor-Leste, with no reported thefts since its first contract in 2013.

Cascadiant's use of methanol instead of diesel also has avoided over 17,000 tonnes of carbon dioxide emissions and prevented the import and use of over 6 million liters of diesel fuel by replacing it with domestically produced hydrogen and methanol fuel stocks. Although Indonesia produces its hydrogen from reforming natural gas, this method could be replaced or complemented by the production of green hydrogen from domestic renewable resources.

Figure B4.1.1 Methanol fuel cells in Indonesia's telecommunications sector

© Cascadiant.

FIGURE 4.4 **Snapshot of portable fuel cells for telecom applications: GenCell A5 2019 (left), SFC Energy methanol fuel cell 2019 (center), and SFC Energy methanol fuel cell back-up for lighting system 2019 (right)**

© GenCell (left). © SFC Energy (center and right).

its derived fuels are increasingly seen as potential alternatives.

In Uganda, a Belgian company called Tiger Power has provided off-grid power via a hybrid solar PV and green hydrogen solution, with the hydrogen produced from excess PV and stored for use by a fuel cell during the evening. Within the mining sector, NRCAN worked with GlenCore to develop a hybrid energy storage system at Raglan mine in Canada that incorporated hydrogen and fuel cells. The minigrid forms only part of the mining site's total demand of 20 MW capacity, but it reduced diesel demand by 3.4 million liters and avoided the release of 9,110 tons of GHG during its first 18 months of operation (NRCAN 2019). The full system combines a 3 MW turbine with a 200 kW flywheel, a 200 kW Li-Ion battery, a 315 kW electrolyzer, and a 198 kW fuel cell (NRCAN 2019). Other remote areas have included national parks, such as Cerro Pabellón geothermal plant in Chile's Atacama Desert, where hydrogen is used as a long-duration storage solution, and Australia's Daintree microgrid project. Some projects, such as Hychico in Patagonia, have also used green hydrogen production to blend with an existing natural gas turbine to provide another form of renewable energy storage in a remote area (Hychico n.d.).

By combining the different elements in hybrid applications, these projects maximize the use of the capex invested and provide enhanced services (box 4.2).

4.4. COMMERCIAL APPLICATIONS

Because most fuel cells in the commercial segment run on natural gas, they are considered similar to conventional boiler and CCGT technologies and therefore have been established in urban environments for many years (figure 2.7). Noteworthy projects include a 300 kW CHP fuel

BOX 4.2

POWERING SCHOOLS IN SOUTH AFRICA

South Africa is a major proponent of green hydrogen production and fuel cell technologies through its Hydrogen South Africa (HySA) program. The country is estimated to hold 75 percent of global platinum group metal resources globally, an important component of proton exchange membrane technology. Thus, South Africa sees green hydrogen as a solution to provide clean power solutions domestically while creating a new market for platinum group metals.

At Poelano High School in Ventersdorp, HySA has partnered with multiple organizations, including the Council for Industrial and Scientific Research, North-West University, University of Cape Town, Mintek, and University of the Western Cape, to develop a 2.5 kW hydrogen fuel cell system (figure B4.2.1). The unit derives its power from a rooftop solar photovoltaic array at the school and provides continuous renewable power to the currently off-grid location, allowing the 486 students to have access to reliable communication technologies and lighting.

The South African Ministry of Science and Technology launched a ZAR 10 million ($590 thousand) renewable energy program in April 2018 to expand energy access to approximately 5,000 schools and clinics that have little to no access to reliable electricity. The program aims to help reduce the costs of providing electricity access to facilities that are often located more than 20 kilometers from the Eskom grid and thus require costly transmission expansions in the absence of a compelling distributed generation alternative.

Figure B3.2.1. Pressurized hydrogen storage (left) and Rooftop solar PV system (right)

Source: Courtesy of Hydrogen South Africa.

cell in London's 20 Fenchurch Street building, called the "Walkie Talkie" skyscraper (Logan Energy 2019), and a 750 kW fuel cell on the roof of Morgan Stanley's New York office (Bloom Energy 2016). As previously discussed, fuel cells that run on pure hydrogen require higher pressures and more exhaustive safety measures to store and may require more developed infrastructure to deploy than other fuels.

The majority of fuel cell units in Korea and the United States operate under a leasing structure in which the manufacturer has entered into a relationship with an existing equipment finance provider or the manufacturer has raised debt to provide the service to the commercial client. The other alternative is one in which manufacturers offer an equipment-only PPA to commercial customers. These PPAs mirror a lease model to an extent, with modifications to terms of use, duration of contract, and other parts of the agreement. In both cases the manufacturer will usually also sign a service contract with the commercial off-taker in which the manufacturer agrees to operate the fuel cell system. The fuel is typically then provided separately, with most off-takers in Korea and the United States working with their existing natural gas provider. At this time some specialized gas companies, such as Air Liquide, Air Products, or Linde, can provide hydrogen if requested, but there has been limited interest in this at the commercial level to date.

Fuel cell suppliers contacted in the preparation of this report corroborate the estimate that fuel cell systems using natural gas can deliver power at between $103 and $152 per MWh, with natural gas currently accounting for $25–$28 per MWh of the cost (Lazard 2018). Other interesting applications include the use of fuel cell units in conjunction with waste sites, such as wastewater treatment plants. For SOFC and MCFC units, the systems have a higher tolerance for carbon dioxide and therefore can run biogas mixtures of more than 40 percent carbon dioxide. This application does reduce the efficiency of the systems, and major suppliers have suggested that it is reasonable to have a ceiling of about 10 percent of deployed stationary commercial fuel cell units using biogas.

It is important to note that stationary fuel cells can be retrofitted at low cost to run on pure hydrogen solutions. That option could enable countries to future-proof investments by using fuel cells with natural gas or biogas today, then transitioning the fuel cells to consume green hydrogen in the future.

4.5. UTILITY-SCALE APPLICATIONS

One of the main appeals of stationary fuel cells is their ability to provide utility-scale firm power in low-carbon grids to complement renewable energy output, including ancillary services, given their fast response. As was shown with commercial applications, power grids with access to natural gas (figure 4.5) could achieve lower electricity costs with fuel cells running on natural gas than with generators running on heavy fuel oil. These fuel cells can rapidly adapt their output to complement renewable variability and contribute to meeting instantaneous electricity demand. Yet, despite having lower carbon emissions than electricity generated by a CCGT, natural gas–based solutions are not emissions free.

Conversely, fuel cells running on green hydrogen could demonstrate the same performance and could complement renewable variability to meet instantaneous demand, but without producing any carbon emissions (box 4.3). Moreover, green hydrogen could provide power grids with a long-term energy storage solution, capable of mitigating the long-term and seasonal variability of renewable resources, and could become a building block of fully decarbonized power grids, particularly in countries without access to other firm low-carbon resources such as large hydro projects or geothermal or thermal plants

FIGURE 4.5 **Utility-scale fuel cell solutions: Solid oxide fuel cell units in the US**

© Bloom Energy.

with carbon capture and storage. By storing green hydrogen for long periods of time and subsequently using it for power generation in a fuel cell (or even in turbines adapted to run on hydrogen), countries gain opportunities to develop firm clean power solutions.

The hybridization of solar power generation, wind power generation, or both with electrolyzers, fuel cells, green hydrogen storage, and batteries could provide firm generation solutions that rely solely on renewables as the primary energy source. One of the largest examples of such hybrid configuration is the CEOG project in French Guiana, which will combine a 55 MW solar PV generator with a 20 MW battery, 20 MW electrolyzer, and 3MW fuel cell (HDF Energy n.d.), with the goal to provide a dispatchable green power source for the utility. Another example is Electricity Generating Authority of Thailand's (EGAT) wind-hydrogen system, which consists of a 1 MW electrolyzer linked to a 24 MW onshore wind site, with a 300 kW fuel cell to help balance the variable power output from the wind farm and to help EGAT manage the impact of variable output on the grid.

Some PEM electrolyzer units also operate on excess hydrogen production from industrial sites, by consuming the hydrogen for power and feeding it back into the grid. An example is HDF Energy's 1MW unit at Sara refinery in Martinique (figure 4.6).

Ambitious plans have been announced to convert large existing natural gas turbines to run on hydrogen, in an attempt to use existing hydrogen production from SMR sites in the short term, before transitioning to green hydrogen once the market has developed. The best-known example of this use case is the 400 MW Magnum CCGT site operated by Equinor in the Netherlands, which is due to be 100 percent hydrogen by 2023.

4.6. LEVELIZED COST OF ENERGY ILLUSTRATIVE MODELING: GREEN HYDROGEN PRODUCTION AND FUEL CELL SYSTEM

To illustrate the current economics of fuel cell and green hydrogen hybrid power systems,

BOX 4.3

GREEN HYDROGEN STORAGE AND BATTERIES

Energy storage is a fundamental component of fully decarbonized power systems, particularly those relying on variable renewable energy resources, to meet firm power needs. Energy storage allows for the increased use of wind and solar power, which not only can increase access to power in developing countries, but also increase the resilience of power systems, improving grid reliability, stability, and power quality.

Improvements in battery technologies driven primarily by the transport sector have lowered battery costs to the point at which they have become cost competitive in many stationary power applications. However, most commercial battery technologies can deliver their rated power only during a few hours (such as two-to-four hours in the case of lithium ion). This characteristic is not a limitation when it comes to mitigating the short-term variability of renewables, but it requires oversizing the battery pack to address daily or weekly variability phenomena and to guarantee power availability during longer periods without renewable resource. The economic implication of oversizing batteries is that their average utilization is lower, and their average cost increases.

The question then arises about whether it is more cost efficient to use green hydrogen or batteries to meet the storage needs in a fully decarbonized power system. The answer to this question requires evaluating the energy storage needs in the system on the basis of load profile and the renewable resources available. Because the spectrum of demand and renewable variability is broad, the most likely outcome is that power systems could simultaneously benefit from all forms of storage. Batteries would address short-term and medium-term renewable variability and green hydrogen or other forms of long-term storage, such as hydro reservoirs, would address long-term and seasonal variability, particularly in systems that lack other firm low-carbon resources. The optimal share between these and other forms of storage will depend on their relative performance and their relative cost, and it is analogous to determining the optimal share of different thermal generation options in a thermal-dominated system. This optimal share will be a moving target as fuel prices and technologies evolve, with cost curves decreasing at different paces.

ESMAP has constructed an illustrative LCOE analysis of a hydrogen electrolyzer unit linked to a PEM fuel cell system to provide a reference point for system costs (figure 4.7). This power-to-power application could be used to complement a VRE plant, thus providing a stationary power supply for periods of low or zero output from the primary VRE source. The model is driven by a fixed MWh output from the fuel cell, and thus the electrolyzer utilization is driven by the role of the fuel cell in meeting demand. At low levels of utilization, the system shows signs of providing peaker capacity, while at 55 percent or above it is providing a residual base-level generation.

With the rapid scaling of both fuel cell technologies and electrolyzers, the economics of green hydrogen hybrid systems are expected to become increasingly favorable when viewed against diesel generation alternatives.

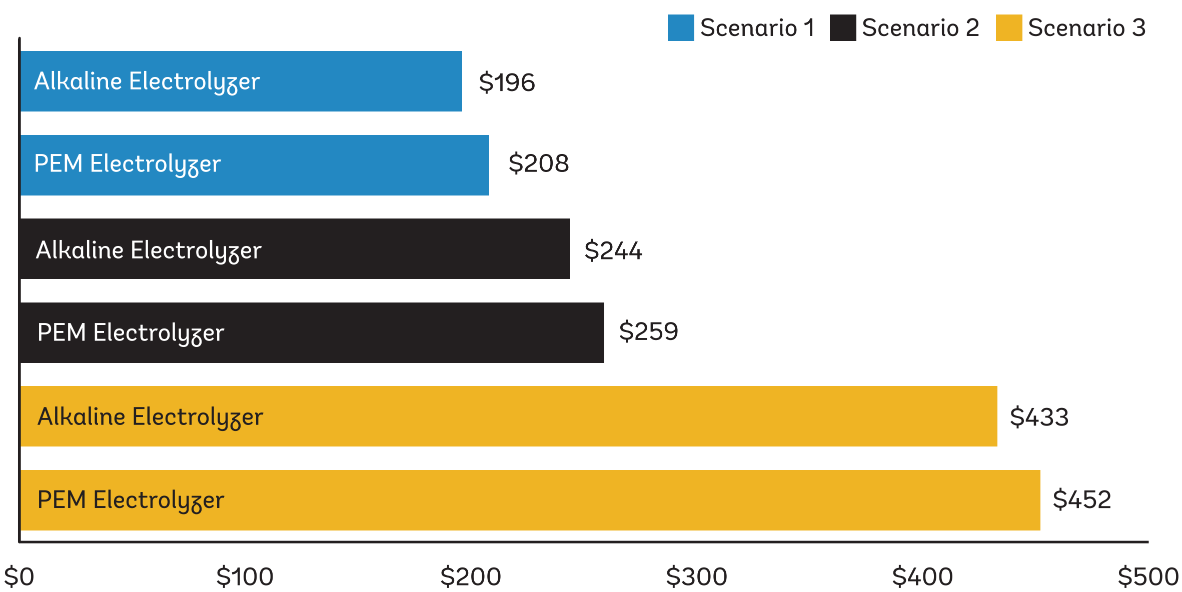
Assumptions

- 1 MW PEM fuel cell and a 1.2 MW electrolyzer
- 1 tonne of on-site pressurized storage (canisters) assumed for each scenario
- Installation costs are 1.6 × equipment capex
- Weighted average cost of capital is 10 percent

FIGURE 4.6 PEM fuel cell 1 MW unit using excess hydrogen from island refinery, Martinique, 2019

© HDF Energy.

FIGURE 4.7 Illustrative levelized cost of energy of green hydrogen-based electricity, modeling under three scenarios, \$/MWh



Note: PEM = proton exchange membrane.

- Amortizing initial capex in 10 years and stack replacements over a project life of 20 years
- $30 per MWh price of power.
- PEM fuel cell capex is $3,450 per kW
- Alkaline electrolyzer capex is $800 per kW
- PEM electrolyzer capex is $1,200 per kW

The modeling operates under three scenarios, all of which have assumed access to the grid.

- Scenario one: fuel cell utilization at 70 percent
  - Alkaline electrolyzer utilization at 50 percent
  - PEM electrolyzer utilization at 50 percent
- Scenario two: fuel cell utilization at 55 percent
  - Alkaline electrolyzer utilization at 40 percent
  - PEM electrolyzer utilization at 40 percent
- Scenario three: fuel cell utilization at 30 percent
  - Alkaline electrolyzer utilization at 20 percent
  - PEM electrolyzer utilization at 20 percent

Several benchmark reference points inform the LCOE analysis. For example, CSIRO 2018 research suggests that under that study's base case modeling for a green hydrogen and fuel cell system in 2018, LCOE would be $330–$410 per MWh, which could be expected to fall to $120–$150 per MWh by 2025 (Bruce and others 2018). Another reference was Hinicio's 2016 study of a hybrid 115 MW solar PV unit, a 40 MW electrolyzer, and a 7 MW fuel cell system, which estimated an LCOE of $360 per MWh (Hinicio 2016). These results appear ready to be tested by a French developer called HDF Energy, whose project for the Centrale Électrique de l'Ouest Guyanais (CEOG) will install a 55 MW solar PV unit with a 20 MW battery, 20 MW electrolyzer, and 3 MW fuel cell in French Guiana. Although HDF Energy has not officially released economic information for this CEOG project, it has been stated that the project will not require subsidies, and we have thus assumed that the analysis must have arrived at an LCOE equivalent to or below the utility rate.

Because a core consideration in assessing the economic feasibility of green hydrogen in power systems applications is to see if such a hydrogen hybrid system can displace diesel and heavy fuel oil as a firm generation solution, a benchmark target to beat is around $140–$440 per MWh for heavy fuel oil and $250–$440 per MWh for diesel. Set against this benchmark, it appears that green hydrogen production and fuel cell hybrid solutions today could provide power at comparable or lower cost than diesel gensets in certain contexts, while also complementing VRE deployments for developing countries. Important contextual considerations for early deployments of these systems include areas where VRE resources can be deployed below $50 per MWh (ideally below $30 per MWh), grid resiliency and climate resiliency are areas of concern, the locations are not too remote from air access (especially for maintenance work), and there is the ability to access (or produce) water.


甲铺岭路
Jiapuling Rd.
九龙湖街
方向选定车道
359
鄂A 13999F

5: MOBILITY APPLICATIONS

KEY TAKEAWAYS

- Green hydrogen offers an immediately deployable technological solution toward achieving decarbonization of heavy-duty and freight transport sectors in developing countries.
- Fuel cell and green hydrogen mobility solutions could address immediate air quality issues while improving system energy efficiencies and reducing the strain on power grids.
- Batteries and fuel cells are complementary to each other in the mobility sector, especially in heavy-duty applications in which both technologies could be used in tandem.
- The use of existing infrastructure in green hydrogen and fuel cells transportation systems could reduce the risk of generating stranded assets.
- As deployments grow in China and other countries—notably, the United States, Korea, and Japan—the cost of fuel cell mobility solutions will rapidly decline.
- A significant constraint for the initial scale-up of hydrogen mobility applications is the availability and cost of refueling stations.

Mobility has long been seen by hydrogen and fuel cell proponents as the key sector to generating significant market demand and scaling technologies so that costs can fall. Currently a wide array of hydrogen-based mobility applications is available across the sector—including cars, buses, trucks, trains, planes, and ships—with the most attractive market segment for current market participants in the heavier-duty use cases (that is, greater than 2 tons carrying capacity) and freight transport, including maritime shipping. While fuel cells are often portrayed as competitors to battery electric solutions, it is more helpful to consider them as partner technologies that complement one another. Most fuel cell vehicles use batteries to provide immediate

BOX 5.1

FUEL CELL VERSUS BATTERY ELECTRIC VEHICLES

The question of whether fuel cells or batteries will dominate the electric vehicle market often emerges during discussions of the future of electric transport. Battery electric vehicles (BEVs) have come a long way, representing a non-negligible share of total passenger car sales in many countries, while the number of FCEVs on the road remains much lower, with only a few models available. Yet, the relative strengths and weaknesses of these two electric vehicle types indicate that they will likely have complementary roles in the future.

Technically, the main difference between storing electricity in a battery and storing hydrogen in a tank lies in their different specific energy and energy density. Although batteries can store a large amount of energy in a small volume, batteries are heavy and require more energy to be transported with the vehicle. Achieving long ranges with BEVs therefore involves carrying an increasingly heavy battery that reduces the overall fuel efficiency of the vehicle. Conversely, hydrogen has a much higher specific energy (approximately 150 times more energy than batteries for the same weight) but very low energy density (it takes a larger volume and requires very high pressures to be contained in a small volume).

Another important difference is the current availability of recharging and refueling stations and the recharging/refueling time. BEVs can be recharged at home, and public charging infrastructure has improved continuously over the past decade, with a network of charging stations already available in many countries. In contrast, FCEVs cannot be refueled at home, and the number of public refueling stations is much more limited than for BEVs (for a reference, in 2017 it was 328 versus 90,000, according to Unicredit 2019). However, a growing number of countries have ambitious plans to develop new hydrogen refueling stations in the near future. Also, FCEVs can be refueled in just a few minutes, whereas it might take hours to recharge a BEV.

In terms of cost, BEVs offer a lower total cost of ownership than FCEVs (4.44 cents/km for BEVs versus 9.50 cents/km for FCEVs, according to Unicredit 2019). However, this factor is directly dependent on the use of the vehicle, and vehicles that are meant to operate over longer distances, such as FCEVs, could see this figure reduced.

Because of these factors, the current expectation is that, for most passenger cars, BEVs will continue to significantly outnumber fuel cell vehicles, but for longer-range applications, freight transportation, buses, maritime, and air transport, FCEVs could have a strong competitive edge in the future.

TABLE 5.1 **Overview of notable currently available and announced passenger fuel cell electric vehicle models**

MODEL	COMPANY	COUNTRY	RELEASE DATE	CONFIGURATION	RANGE (km)[a]	COST ($)[b]
Mirai	Toyota	Japan	2014	114 kW	499	57,500
Kangoo	Renault	France	2017	varies	100 (est.)	Order dependent
iX-35	Hyundai	Korea, Rep.	2015	100 kW	594	65,000
Clarity	Honda	Japan	2018	130 kW	616	60,000
GLC F-Cell	Mercedes	Germany	2019	155 kW	475	Not released
Nexo	Hyundai	Korea, Rep.	2019	135 kW	795	58,000d
5 Seriesc	BMW	Germany	2020	180 kW	480	Not released
i8	BMW	Germany	2020	Unknown	496	Not released

a. Converted into kilometers. b. All converted into U.S. dollars at XE rate on September 17, 2019. c. Hydrogen Cars Now n.d. d. Crosse 2019

power response, especially for heavier-duty applications. Fuel cells, however, can have higher specific energy than batteries and can extend the range of vehicles more effectively than batteries because of their lower total system weight and quicker refueling time. Additionally, fuel cells are less affected by external temperatures and thus are less likely to experience range reductions owing to abnormal conditions. At the time of writing this report, it is estimated that there are 3,000 fuel cell buses and trucks deployed globally (Obiko Pearson 2019) and over 12,000 fuel cell passenger vehicles.

5.1. FUEL CELL ELECTRIC VEHICLES

Today more than 12,000 FCEVs are on the roads globally, with the overwhelming majority in Japan and the United States. Most of these units are purpose-built hydrogen models, but in some markets, such as Europe, a significant number of FCEVs are essentially modified electric vehicles in which the fuel cells function as a range extender (table 5.1). While a considerably smaller market than the battery electric vehicle (BEV) market, FCEVs are gaining popularity among users who either have considerably longer average driving distances (such as California) or customers whose high rate of vehicle use places a premium on the availability of power.

A clear example of the second group is the taxi industry, with FCEV taxis now being used in China, Denmark, France, Germany, the Netherlands, and the United Kingdom. Another example is the ride-sharing industry. The first such program announced publicly was by Grove—a Chinese automotive company—which announced a 200-vehicle first run in the Chinese city of Rugao in 2019 that will expand to 10,000 FCEVs by 2020–21 (New Mobility 2019). Grove has also announced initial discussions with partners in Minas Gerais, Brazil (Green Car Congress 2019) and with DSM Global to deploy FCEVs to Nepal (Kreetzer 2019). Recently, FCEVs have also been deployed in British Columbia as a ride-share solution, with early signs that the cars have proved popular with consumers (McCredie 2019).

The growing interest in passenger FCEVs is driven by several factors. The first is the recognition that low-emission technologies are essential for the automotive sector. FCEVs have no tailpipe emissions—only water. The second is customer experience. Although FCEVs today may lack a wide refueling network, they do provide significantly longer ranges than can typically be found in battery electric vehicles, and they refuel in under five minutes.

FCEV manufacturers have also identified other benefits to highlight. For example, because fuel cells require access to clean oxygen to react with hydrogen, all FCEVs require some form of air purifier on board. On that account, Hyundai has recently begun to market its latest FCEV sport-utility vehicle, the "Nexo," as "an air purifier on wheels" that claims to leave the air even cleaner than it was when it entered the car. The vehicle has a filter system to separate the oxygen before it is compressed and filtered into the fuel cell (The Wheel Network 2018), thus Hyundai argues that the Nexo is actually better for addressing localized air pollution than BEVs are.

Declining fuel cell vehicle costs are also likely to be a significant contributing factor in rising global FCEV deployments. For example, the cost of a Toyota FCEV launched in 2015 was expected to be 95 percent lower than an equivalent model available in 2008 (Millikin 2014). Nevertheless, fuel cell vehicle sales are still starting from a low base, with no fuel cell vehicle ever having entered the top 50 most popular models (JADA 2019), despite strong government support (box 5.2).

Few FCEVs are purchased directly today because of the limited number of refueling stations and the lack of widespread technical capability to address car servicing needs, both of which make individual ownership challenging. To address those issues, manufacturers have ensured that almost all FCEVs are leased today, with the Toyota Mirai available for lease in the United States at $349 per month (IEA 2017). As refueling capacity is rolled out further and as automotive dealerships see sufficient demand to train their staff to service FCEVs, it is anticipated that more FCEVs will be purchased directly by consumers. California offers one example of the growth of the FCEV market over the past five years in an early-adopting market (figure 5.1).

5.2. FUEL CELL ELECTRIC BUSES

The number of fuel cell applications for buses is currently significantly larger than the number of FCEVs deployed globally. Ballard Power Systems delivered its first fuel cell bus in 1993. Today there are several hundred fuel cell buses (FCEBs) in operation, notably in Europe, with increasing growth in China, Japan, Korea, and North America (figure 5.2). The advantages of fuel cell buses are their range, quick refueling times, and, increasingly, their declining cost versus battery alternatives. Developing countries are catching up quickly, with Brunei, Costa Rica, India, and Malaysia among the first movers.

As of 2019, FCEBs have demonstrated operating times above 20,000 hours in multiple countries. In fact, Transport for London's eight FCEBs procured for the Olympics in 2012 have exceeded 34,000 hours operating time and remain on the roads today. In Aberdeen, Scotland, the 10 FCEBs procured in 2014 have demonstrated remarkable performance, with all units exceeding 1 million miles and demonstrating ranges of up to 250 miles per day, refueling in only five to seven minutes (Ballard Power Systems 2019a). Consequently, the Aberdeen City Council confirmed financial support for an additional five FCEBs in 2019 (*FuelCellWorks* 2019a) on the basis of the performance of the existing units, which tests suggest have proved to be almost four times more fuel efficient than their diesel equivalents (IMechE 2016). Newer units are targeting even higher performance. For the 2022 Winter Olympics in China, Toyota is partnering with Beiqi Foton Motor and Yihuatong Technology to provide a fleet of FCEBs. These will have a 60 kW

BOX 5.2

HYDROGEN MOBILITY IN CHINA

Following China's rise to become the world's premier market for battery electric mobility solutions, the battery electric transport leasing market is switching its focus increasingly toward fuel cell mobility solutions. In 2018 alone, China is reported to have invested over US$12 billion in research, development, and deployment of hydrogen and fuel cell solutions, almost exclusively within the transportation sector. All of China's major car companies have announced fuel cell vehicles under development, while the city of Rugao, backed by technical support through a US$10 million program with the United Nations Development Programme, has committed to purchasing 10,000 fuel cell vehicles from Chinese start-up Grove.

The fastest-moving sectors of the fuel cell industry in China have been in the bus and logistics segments. Alibaba has already begun to use fuel cell vehicles to support its logistics operations in and around its vast warehouses, while several Chinese cities have procured and are expanding their fleets of fuel cell buses. In Beijing, the government recently procured 10 fuel cell buses to support the 2022 Olympics, with financing partly provided by the Asian Development Bank. Meanwhile in Shanghai, SAIC and the Shanghai Chemical Industry Park opened the world's largest hydrogen refueling station in June 2019. The site supports the refueling of 74 fuel cell buses, dispensing around 1.5 tonnes of hydrogen daily on a 24/7 basis. As of December 2019 alone, it was reported that Ballard and its joint venture partners in China (Foshan Feichi Bus and Yunnan Wulong Bus) secured 354 fuel cell bus orders.

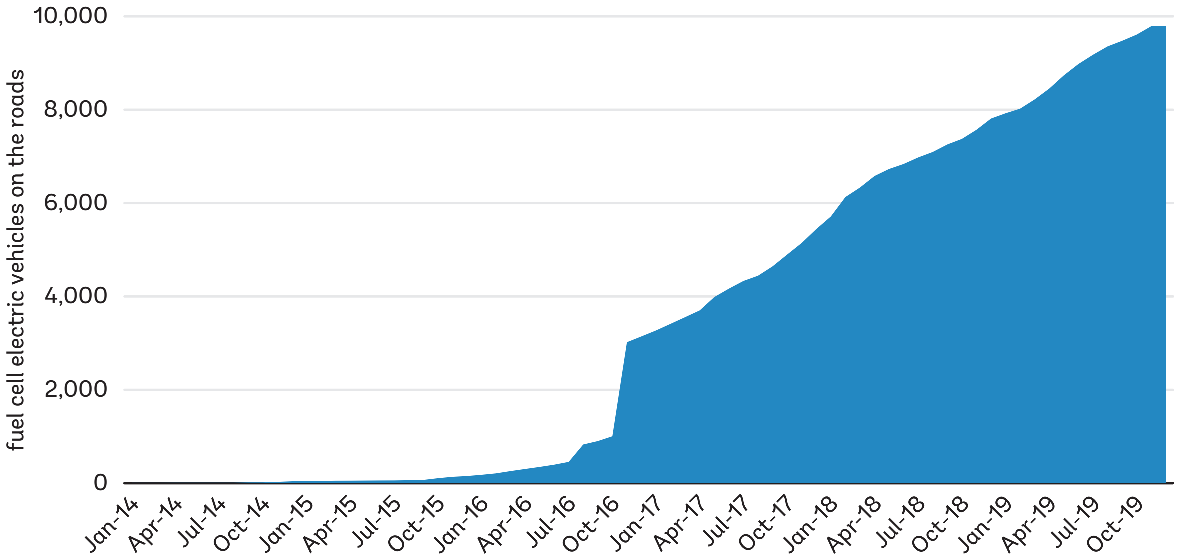
State support has proved to be essential in accelerating deployments. SAIC's Maxus FCV80 was originally launched at a price tag of RMB 1.3 million, but with subsidies the actual cost was estimated to come in closer to RMB 300,000. Meanwhile, fuel cell buses were expected to receive a subsidy worth in excess of US$100,000, reducing the cost of fuel cell buses from US$500,000 to below US$400,000 before local and regional subsidies. Further, most of China's hydrogen is sourced from hydrogen produced as a non-core product of another chemical or industrial process and thus it is often sold below the price point of US$10–US$14 per kg commonly seen in developed markets. Furthermore, fuel cell costs and electric vehicle costs are clearly falling, suggesting that the Chinese government's planned phaseout of subsidies by 2023 could mark the point at which fuel cell vehicles will reach commercial viability in the domestic market.

Sources: Sanderson 2019 and ESMAP correspondence with suppliers.

fuel cell, and Foton claims that its fourth-generation buses will provide a range of 450 kilometers (Xu 2019). It is important to note that FCEBs are not limited to developed markets. Indeed, Ad Astra deployed the first FCEB in Central America in 2018, using solar PV and electrolyzers to generate green hydrogen on-site for its two refueling stations (Kazmier 2018) (box 5.3).

Existing experiences show that the costs of FCEBs are a constraint in certain markets, as is access to refueling units. For example, electric buses in the United States appear to be less expensive than the most recent publicly quoted price for an FCEB, at roughly $1.1 million for an FCEB in California versus $750,000 per battery electric bus (Stromsta 2019). Further,

FIGURE 5.1 California monthly fuel cell electric vehicle market, January 2014–December 2019 (number of sold and leased units)



Source: Energy.gov and California Fuel Cell Partnerships, compiled by ESMAP 2020.

FIGURE 5.2 Past and present fuel cell bus examples, 1993 (right) and 2014 (left)

© Ballard Power Systems.

BOX 5.3

CLEAN MOBILITY IN COSTA RICA USING CENTRAL AMERICA'S FIRST FUEL CELL BUS

Costa Rica is frequently recognized as a global leader in sustainability, ecotourism, and clean power, but decarbonizing the country's transportation sector has remained a challenge. Local grids are often ill suited to rapid charging requirements that battery electric drivers expect (as of April 2018 there were 20 electric vehicle charging stations in the entire country). Further, the country's population depends on the bus network to commute to work and school, particularly in poorer communities. In this context, U.S.-based Ad Astra Rocket deployed Central America's first fuel cell electric bus (FCEB), hydrogen refueling station, and green hydrogen electrolysis unit. The project was partly funded by IDB Invest, the private sector arm of the Inter-American Development Bank, and is intended to demonstrate that fuel cell buses can be a serious solution to help decarbonize the transportation sector in Costa Rica, throughout the wider Latin America region, and beyond.

At a cost of $4.4 million to date, the project has demonstrated that the technology is technically viable, that it is clean, and that it could be a powerful contribution to Costa Rica's decarbonization efforts. The bus itself was deployed in 2017 in Liberia, Guanacaste, and has a range of up to 340 kilometers (210 miles) on 38 kg (83 lbs.) of compressed hydrogen. The capacity of the vehicle is about 35 passengers, and it can reach a speed limit of up to 110 km per hour (68 mph). As a public-private partnership, the project has benefited from the collaboration of the government of Costa Rica, Ad Astra Rocket Company, Air Liquide, Cummins Inc., Sistema de Banca para el Desarollo, Relaxury S.A., and US Hybrid Corporation. The power is generated by a combination of solar photovoltaic panels and an onshore wind turbine located next to the company's Costa Rican office. The site now also refuels the country's first four fuel cell electric vehicles, three of which are leased to tourists at a local ecotourist hotel, as a zero-emission solution capable of driving long distances without range concerns.

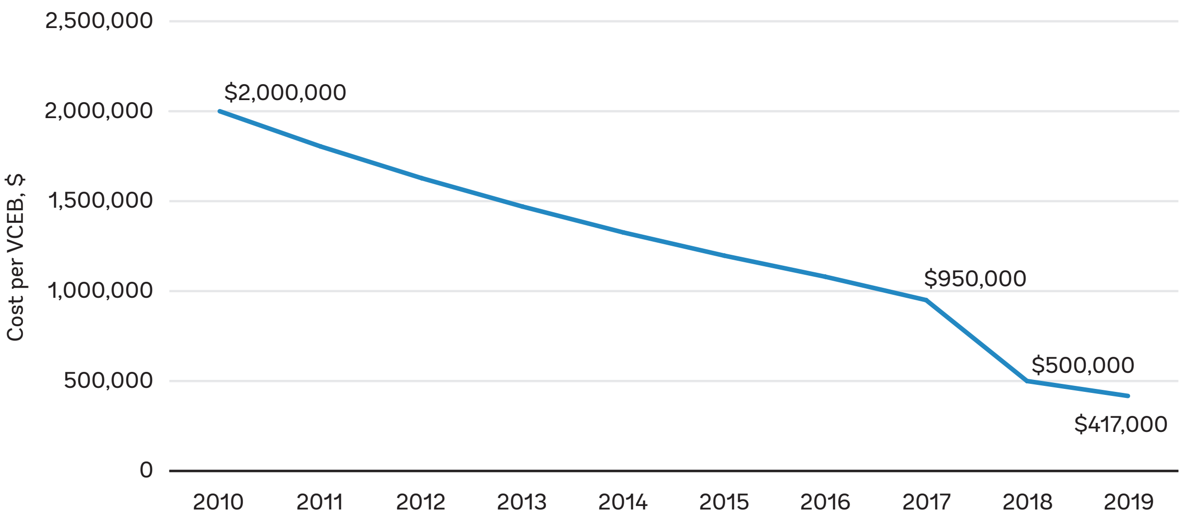
Source: ESMAP correspondence with suppliers.

significantly fewer hydrogen refueling stations than electric charging locations have been installed. Yet, the cost advantage of batteries over FCEBs does not hold in all markets. For example, in public filings Ballard provided cost estimates of US$500,000 per FCEB in China, while sources all suggest that EU target prices of EUR 650,000 (GBP 520,000) set in 2016 have been met in the United Kingdom market today (Pocard and Reid 2016). At these price points, FCEBs may look attractive even compared with conventional diesel buses in certain markets (figure 5.3), particularly where diesel bus prices of US$500,000 per unit have been reported (Stromsta 2019). It is also the case that most FCEBs now are delivered alongside hydrogen refueling stations at their base of operations, thus addressing some of the concerns around access to fuel supply (figure 5.4). Nevertheless, with respect to charging or refueling, hydrogen refueling stations remain more expensive to install than pure electric alternatives.

5.3. Fuel Cell Trucks

Fuel cell trucks are one of the most promising areas of growing demand for fuel cell solutions in the mobility sector. As of 2020, government agencies and companies in China, Japan, Korea, Norway, and Switzerland all have pledged to

FIGURE 5.3 Declining cost of fuel cell electric buses



Source: Ballard data 2019 and Bloomberg 2019, reconstructed by ESMAP.

FIGURE 5.4 Fuel cell bus refueling in Wuhan, China

procure and deploy over 1,000 fuel cell trucks over the next decade.

Thus far China has been the dominant market for actual deployments of fuel cell trucks. As of December 2019, Horizon Fuel Cells through its joint venture with Ford Motor Company in China had deployed over 400 fuel cell trucks (ranging 8 tons to 42 tons), notably the first 42-ton hydrogen trucks delivered in the world (Gu 2019). Meanwhile, Ballard and its partners have deployed over 1,400 fuel cell trucks in China, ranging from 500 three-ton trucks in Shanghai to larger 12-ton units (Ballard 2018, 2019b). Numerous other companies are now entering the sector, contributing to an estimated 4,000 fuel cell commercial vehicles in China by 2018 (Ballard 2018).

However, although China is the largest current market for fuel cell trucks, the rise of a company called Nikola in the United States has captured the bulk of investor and media interest recently. Nikola Corp. is currently one of the market leaders in terms of orders and scale for hydrogen trucks, and it has plans to offer three truck products: Nikola One, Nikola Two, and the Nikola Tre (European model). The flagship model is the Nikola One, which offers up to 2,000 pounds of torque, up to 1,000 horsepower, a 500–700 mile range, and a 15–20 minute refueling time. Across all three models, Nikola claims to have a backlog of 13,000 orders (Wiles 2019). Powerful strategic partnerships underpin the Nikola proposition. Electrolyzers have been ordered from market leader Nel, for a 1 GW initial order, to provide initial 50 x 20 MW electrolyzer units for refueling. Bosch is the OEM provider (with fuel cells likely to be from Ballard, though that is not yet confirmed). Confirmed clients include Anheuser Busch, which has already committed to taking more than 600 trucks. In total, Nikola claims to have $11 billion in preorders and has raised over $450 million in financing in the past five years.

It is important to note that Nikola's business model differs significantly from current market practices and that Nikola's solution, at least in the United States, will operate under an integrated leasing structure, in which a single monthly payment will cover vehicle rental, hydrogen refueling, warranty, and maintenance. The pricing is based on an estimated distance traveled, and owners will have the option to trade in for a new Nikola vehicle every 700,000 miles or 84 months, whichever comes first (Nikola n.d.).

Despite the potential for Nikola to transform US trucking, the only deployed hydrogen and fuel cell trucks in the US today are run in Long Beach, California, where Toyota is using two hydrogen trucks for drayage operations, with Shell providing the hydrogen for refueling (PR Newswire 2018). Toyota has partnered with Kenworth for the project, and their two pilot trucks are due to expand to 10 units by 2020. Thus far the trucks have logged more than 14,000 miles of testing and drayage operations (Babcock 2019). Mike Dozier, the general manager of Kenworth, stated, "The performance of the 10 Kenworth Class 8 trucks being developed under this program … is targeted to meet or exceed that of a diesel-powered truck, while producing water as the only emissions byproduct" (Babcock 2019). In addition to those units, Toyota/Kenworth have orders from UPS, whose first three deliveries were due at the end of 2019 (Abt 2019) (figure 5.5). Box 5.4 describes a heavy transport case involving green hydrogen.

5.4. SHIPPING AND TRAINS

Two of the largest potential sources of green hydrogen demand in the mobility sector are freight and maritime applications.

The first hydrogen vessel was a retrofitted German ferry for internal waterways commissioned in 2006, and new ocean-capable vessels being designed today have received provisional classifications and may be in service by 2021. These new vessels include a green hydrogen ferry for

FIGURE 5.5 **Current fuel cell truck concepts: Kenworth/Toyota fuel cell electric truck (top), Nikola One (bottom left), and Horizon fuel cell in JMC truck (bottom right)**

Sources: a. Courtesy of Toyota via Toyota newsroom. b. Courtesy of Nikola Corp. c. Courtesy of Horizon Fuel Cells.

BOX 5.4

HYDROGEN FOR MINING MOBILITY OPERATIONS IN CHILE

Mining is an energy-intensive business. The World Bank's Climate-Smart Mining Facility reports that mining operations consume around 11 percent of total energy demand worldwide, with 4 percent used for crushing rocks alone. Yet, the sector's heavy reliance on diesel for mobility and remote power provision indicates that the sector's emission profile may be even worse than the headline numbers. In Chile, a country where mining accounts for 10 percent of gross domestic product and copper alone accounts for 50 percent of exports, the desire to replace expensive fuel imports for mining operations by lower-cost locally produced energy is encouraging early investments.

In 2017 the country's leading research agency, CORFO, announced that a consortium of leading mining, fuel cell, hydrogen, and renewable project development companies would work together to develop hydrogen mobility solutions for mining operations in Chile. The approximately $6 million investment, backed by up to $6 million of investment from the project's private sector partners, is designed to help examine the technical and economic viability of hydrogen as a clean fuel source in the large mining vehicles that operate in the country's northern regions. Alongside this effort in Chile, AngloAmerican has invested in 900 kW of proton exchange membrane fuel cells from Ballard to power a retrofitted Ultra heavy-duty mining truck in South Africa that will begin its pilot operations in 2020 (Ballard 2019c). Further on, hydrogen may also be able to help provide remote energy storage, as it does in one of Chile's microgrids in the Atacama Desert, and it may even be able to help with processing ore after its extraction.

A key reason that Chile has emerged in recent years as a hotspot for green hydrogen projects is the country's exceptional renewable resources, complemented by a strong regulatory framework and investment environment. A study by Tractebel and the Chilean Solar Committee (2018) concluded that green hydrogen could be produced at between $1.80 per kg and $3.00 per kg as soon as 2023, making the fuel competitive with hydrogen from natural gas imports, if not cheaper. This forecast further aligns with research conducted by the International Renewable Energy Agency in 2018, which concluded that Chile could produce hydrogen from renewable resources today at between $4.00 per kg and just under $6.00 per kg, declining to between $2.50 per kg and $4.00 per kg by 2030. Given these anticipated cost declines, and market expectations that hydrogen in mobility can compete with diesel at below $7.00 per kg at the point of delivery, Chile appears well positioned to lead the deployment of low-emission technologies to reduce heavy transport emissions in the mining sector.

Source: Tractebel and Chilean Solar Committee 2018; ESMAP correspondence with suppliers.

the Orkneys, being developed under the HySeas III program in Scotland, and several projects in Norway. Initially, the focus for hydrogen in shipping has been to provide auxiliary power. During the FellowSHIP program in Norway in 2009, the Viking Lady installed a 330 kW molten carbonate fuel cell from MTU Onsite Energy that ran on natural gas without pre-reforming (Fuel Cell Today 2013). During the trial, the fuel cell logged 18,500 successful operating hours, providing supplementary power to the ship at an electrical efficiency of over 52 percent at full load (Fuel Cell Today 2013). Now the sector is looking to power all operations via hydrogen, with some configurations using pure PEM units and others considering PEM to power the turbines while auxiliary power might be handled by other technologies such as SOFC units. For example, Bloom Energy has announced a partnership with Samsung Heavy industries to examine SOFC use in shipping as of September 2019 (Business Wire 2019). Noteworthy partnerships in this space include PowerCell and Siemens (Siemens 2018), Ballard and ABB (Green Car Congress 2018), as well as Nedstack and General Electric (Terpilowski 2019). Given the intensive use of heavy and light hydrocarbons as bunker fuels in maritime shipping and the large potential environmental benefits of decarbonizing this sector, the World Bank through its trust fund Problue has begun a program to support developing countries in their ambitions to switch to zero-carbon bunker fuels, and to develop sustainable marine resources. Initial steps have been taken to explore the potential demand for zero-carbon bunker in the ports of a few selected countries, and the resources required to meet that demand.

With respect to trains, only two countries currently operate them: one hydrogen train in Germany and a hydrogen tram in China (Yang 2017). Germany's train is developed by Alstom and Hydrogenics (Railway Technology n.d.). But other companies are catching up, with Ballard and Siemens working together on a hydrogen train based on the Mireo platform. Ballard already received an order from Porterbrook (a leading participant in the UK rail leasing market) to provide fuel cells for 100 carriages that will operate in the United Kingdom under the "HydroFLEX Train" banner (Songer 2018). Interest in hydrogen trains has also been expressed in Canada and North Carolina (United States) and in France and other EU markets.

5.5. HYDROGEN REFUELING STATIONS

A significant constraint for hydrogen mobility applications is the availability of refueling stations. Relatively few stations are in place globally, with the IEA estimating that 432 stations were operating at the end of 2019. But this situation is forecast to change rapidly, and as of 2017 global cumulative announcements for hydrogen refueling stations (HRSs) exceeded 1,100 new units by 2020, 3,000 by 2025, and about 15,000 by 2030 (Hydrogen Council 2017). These figures are being revised upward, with Agrola, AVIA, Migros, Migrol, and Coop in Switzerland committing to support the deployment of 1,500 HRSs alone, and KOGAS committing over $4 billion to hydrogen production and refueling station infrastructure in Korea between 2019 and 2030. Hydrogen refueling stations are also moving out from traditional markets like China, France, Germany, Japan, Norway, the United Kingdom, and the United States (figure 5.6). In 2018 the first HRS units were installed in Austria, Canada, Costa Rica, Iceland, Spain, and the United Arab Emirates; meanwhile, Malaysia announced plans to expand its hydrogen refueling station network from one to seven in December 2019, making it one of the largest networks in the world announced outside of Japan, Germany, France, the United Kingdom, and the United States (FuelCellWorks 2020).

In addition to the number of stations deployed, hydrogen refueling stations are also scaling in their capacity. While early sites may have been able to refuel only a small number of cars per day, new stations can provide fueling for potentially hundreds of vehicles, with the world's largest refueling station in China providing hydrogen for 74 fuel cell buses a day, dispensing 1.5 tonnes of hydrogen (Haskel 2019).

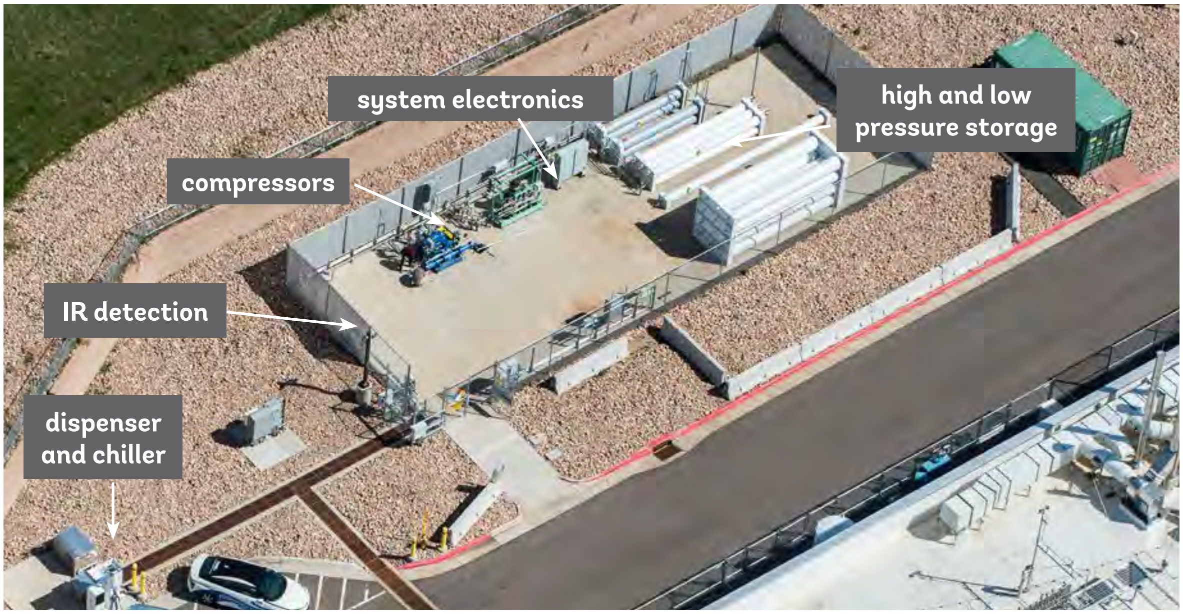
Possibly the largest constraint for HRS units is their cost. Estimates suggest that without on-site refueling (hydrogen brought in externally), HRS can be developed for around $1.1 million in the United States[27] and for around $1.5 million

[27] ESMAP discussions with suppliers, 2019.

FIGURE 5.6 **Green hydrogen refueling, with on-site hydrogen generation from rooftop photovoltaic: Freiburg, Germany, in 2012 (left) and Emeryville, California, in 2011 (right)**

Source: Courtesy of Nel.

FIGURE 5.7 **Example of hydrogen refueling station configuration (no on-site production)**



Note: IR = infrared.
© NREL. Notes added by ESMAP.

in China (Wanyi 2018). (See figure 5.7.) A study by the Hydrogen Council noted that the CEP/H2Mobility program in Germany saw HRS costs fall from EUR 2 million (US$2.4 million) per station in 2008 to EUR 1 million (US$1.2 million) as of 2017 (Hydrogen Council 2017). The same year, the IEA reported, "The cost of early market HRS ranges from US$2.1 million to US$3 million in California" (IEA 2017). HRS units today employing on-site green hydrogen generation can add US$2 million–US$4 million to the site's cost depending on the electrolyzer size and the technology used (box 5.5). It has been noted that PEM electrolyzer units in the United Kingdom can qualify for ancillary service provision under the UK's "demand on" program run by National Grid, which may provide an additional revenue stream to improve the commercial viability of on-site generation for HRS locations.

5.6. MATERIAL HANDLING AND FORKLIFTS

One of the world's leading companies in material handling units is Plug Power, a US-listed fuel cell manufacturer with over 30,000 fuel cell forklift trucks deployed globally, mostly in the United States (Plug Power 2020). Currently, hydrogen and fuel cell technologies

BOX 5.5

ENERGY STORAGE AND GREEN HYDROGEN REFUELING ON SINGAPORE'S SEMAKAU ISLAND

The island of Semakau in Singapore lies 8 kilometers away from the mainland and operates as an entirely separate microgrid. While the island is largely used as a landfill site for ashes from Singapore's waste incineration plant, it has also deployed several renewable resources, including an onshore wind turbine, and is now the pilot site for the REIDS initiative (Renewable Energy Integration Demonstrator—Singapore). The island is a test case for the government to show that hydrogen and fuel cells can help work alongside the other renewable technologies on the island to enhance grid stability and provide innovative solutions to the island's energy needs.

Led by Engie via its Sustainable Powering of Off-Grid Regions (SPORE) project, Semakau has deployed a specially designed onshore wind turbine, supported by a 200 kW Ineo battery, which functions as the primary energy storage solution for the island. To provide additional storage beyond the several-hour timeframe and to provide an energy solution for vehicles on the island, an electrolyzer provided by McPhy that can store up to 2 MWh (80 kg) of hydrogen has been deployed. This hydrogen can then be used either by the hydrogen refueling station on the island to power a modified Renault Kangoo electric van or to provide additional energy storage for periods that exceed the storage capacity of the battery.

Although Semakau is small island with only 2 square kilometers, the project itself has demonstrated that green hydrogen can be a useful contributor to maintaining grid stability, mitigating renewable variability, and providing multiple energy end applications for off-grid or remote energy systems.

FIGURE 5.8 **Hydrogen forklift refueling**

© Grove Hydrogen Automotive.

are extremely appealing to material handling businesses because they require significantly less space than battery alternatives and they have a higher operational availability (figure 5.8). Major customers of hydrogen and fuel cell forklift units include Amazon (an investor in Plug Power) and Walmart, both of which are estimated to use Plug Power units in over 25 percent of all their US warehouses. Outside of the United States, Carrefour, Alibaba, and Toyota are also scaling up their use of hydrogen and fuel cell forklifts.

6: INDUSTRIAL APPLICATIONS

KEY TAKEAWAYS

- Gray hydrogen is widely used in industry today. The scaling up of green hydrogen provides companies and policy makers with a powerful tool to decarbonize existing and new sources of industrial energy demand and industrial processes.
- Ammonia production, refining processes and methanol production constitute over 90 percent of the total hydrogen demand today.
- Green hydrogen could be a clean alternative to coal in the reduction of iron ore, and could replace natural gas as a source of high-temperature heat in the iron and steel industry.
- Hydrogen carriers such as methanol, ammonia and synthetic methane are easier to store and transport than hydrogen but come with higher efficiency losses. Still, their physical properties make them more appropriate than hydrogen for specific industrial applications
- Producing green ammonia in developing countries, using low cost renewable energy and electrolysis, create a more distributed production model, reducing transport costs and creating opportunities for local industrial development.

6.1. IRON AND STEEL

Industrial and chemical uses remain the core market for hydrogen today. Broadly, the current market can be split into production of ammonia, refining of gasoline, and production of methanol. However, as industries increasingly look to decarbonize their industrial heat requirements, a number of companies are examining the role of green hydrogen in processes such as steel and glass manufacturing.

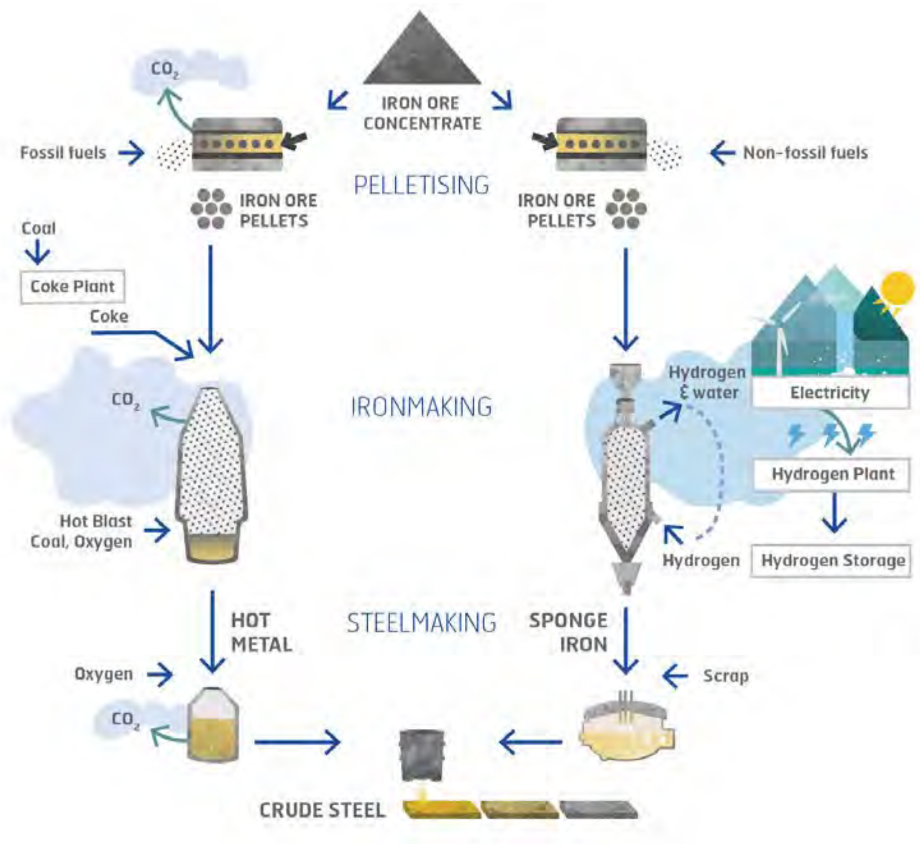
Steel production is a particularly interesting area for hydrogen because of the process's high carbon emissions and the relative lack of viable alternatives. Currently hydrogen is already partly used in metal processing to yield iron reduction, and Air Liquide estimates that the typical hydrogen consumption in this type of plant is between 36 tonnes per year and 720 tonnes per year (Fraile and others 2015). Thus, steel represents an addressable market by electrolysis and green hydrogen. Indeed, there are companies using hydrogen as the protection gas in the production of steel plate, with a unit supplied by THE China providing this service to a site in Bulgaria (THE n.d.a.). Hydrogen is also used in the iron industry to prevent partial oxidation of iron ore while the ore is in the furnace. Some sites will flood the furnaces with hydrogen, so that it will react with any fugitive oxygen molecules and prevent oxidation (figure 6.1).

The bigger question that researchers are attempting to assess is whether hydrogen can play a greater role by replacing coal and other heating fuels. Three flagship projects operate in this space: Tata, ThyssenKrupp, Nouryon, and the Port of Amsterdam project; HYBRIT in Sweden; and H2FUTURE in Austria. By far the largest of these is the Port of Amsterdam, which is at the feasibility study phase and is looking at a 100 MW electrolyzer that would produce 15,000 tonnes of green hydrogen a year and create oxygen for the steel site as well. The first pilot that is actually installed and operating is H2FUTURE in Austria, where a 6 MW PEM electrolyzer provided by Siemens is working on a Voestalpine steel site, using power from Verbund's almost entirely renewable-based portfolio (Voestalpine 2018).

For the HYBRIT project, SSAB, LKAB, and Vattenfall are using a 4.5 MW alkaline electrolyzer to operate in Luleå, Sweden, from 2021 until

FIGURE 6.1 **Electrolyzer at an Indian iron production plant**

FIGURE 6.2 **HYBRIT concept image**



© Hybrit Development, 2019.

2024, before the project enters a demonstration phase with the goal to have an industrial process in place by 2035. The HYBRIT process is based on direct reduction of iron ore using renewable energy and hydrogen; the hydrogen reacts with the oxygen in the iron ore, thus creating metallic iron and water (Cision 2019) (figure 6.2). At this time, in the absence of supporting policies, evidence from HYBRIT studies suggests that the costs from electrolysis remain too high. The capital expenditure required for setting up a direct iron processor, an electrolyzer, and a hydrogen storage facility is estimated at EUR 1,000 per tonne of crude steel, comprising almost 80 percent of the total production costs and yielding a steel price of EUR 1,200 per tonne (WEC Netherlands 2019).

6.2. AMMONIA

As previously indicated, ammonia is the largest demand source for hydrogen today and a prime option for decarbonization efforts with green hydrogen. Two large-scale projects that are being considered for investment are a 20 MW electrolyzer unit at Air Liquide's ammonia site in Quebec (Air Liquide 2019) and a 100 MW solar PV combined with a 50 MW electrolyzer for YARA's ammonia site in Western Australia (ENGIE 2019). These projects are following pilot hydrogen-from-wind to ammonia projects that already have been deployed and which provide evidence of the technical feasibility and cost considerations for such an application (figure 6.3).

FIGURE 6.3 **World's first wind-to-ammonia project**

Source: Nel electrolyzer at Morris, Minnesota, United States. Courtesy Nel.

Ammonia as a market for green hydrogen is particularly appealing because of the scale of demand. A study for the FCH JU in 2015 estimated that a typical ammonia plant has the capacity to produce between 1,000 and 2,000 tonnes of ammonia per day, thus requiring 57,500 to 115,000 tonnes of hydrogen per year (Fraile and others 2015), while Thyssenkrupp suggests a traditional plant would produce closer to 3,000 tonnes per day (Thyssenkrupp n.d.). Such a level would require electrolyzer units significantly larger than those currently commercially deployed, and a single site would likely absorb many manufacturer's annual capacity for several years, given the current installed capacity of electrolyzer suppliers.

The other appeal is that if the cost of hydrogen from electrolysis were to fall below the cost from SMR, it would be conceivable that the centralized ammonia production process itself would change and move toward a more distributed production model. Such a situation would reduce transport costs and would also create the opportunity for many countries to produce greater volumes of ammonia domestically, creating jobs. It is for this reason that companies such as Thyssenkrupp have begun to market smaller-scale ammonia solutions based on systems that can run on a 20 MW power input, with modular scaling up to 120 MW. Regarding the use cases for smaller designs, the company noted, *"at landlocked locations with low power costs, installation of a green ammonia plant may well be an interesting option, not least for the fertilizer or chemical industry. Not surprisingly, economies of scale favor conventional plants at higher production capacities. But besides its economically feasible existence as a niche product, green ammonia is becoming increasingly interesting to renewable energy producers as a suitable energy storage and carrier medium."* (Thyssenkrupp n.d.).

While the primary interest in ammonia is its use as a fertilizer, it can also be used as a mechanism for storing energy hydrogen cheaply and for long periods of time, before the hydrogen is extracted out of the ammonia again. Although this process entails high efficiency losses, with round-trip efficiency figures around 20–30 percent, depending on the initial efficiency of the electrolyzer/SMR used, it may still be viable in areas where the production of hydrogen is low. In addition, more recent research has examined whether ammonia can be used directly as a fuel, whether with a reformer on a fuel cell or combusted in a turbine. Some companies in the power sector already use ammonia. The largest user of ammonia for fuel cell applications is GenCell, whose units provide off-grid power supply using ammonia with a reformer (GenCell n.d.). These units have lower system efficiency than typical hydrogen or SOFC cells, but they can store ammonia easily on-site for up to six months at a time. Companies such as Baker Hughes and MAN Group have also been working to develop and commercialize turbine technology that could generate power from 100 percent ammonia fuel. This is being closely monitored by officials in countries with existing natural gas turbines installed, who see green ammonia as a potentially more convenient hydrogen-derived fuel for zero-carbon-emission power.

6.3. REFINING

One of the most immediate sources of potential industrial demand for green hydrogen is refining. A typical refinery might require between 7,200 tonnes and 108,800 tonnes of hydrogen per year, with new and complex large-scale refineries requiring up to 288,000 tonnes per year (Fraile and others 2015). Accordingly, a growing area of interest for industry in the short to medium term is whether emissions from refining and gasoline consumption in mobility can be reduced by using green hydrogen. Although the economics at this time appear challenging, the segment may be driven by policy if it is accepted that the use of green hydrogen can be counted toward reduction in national transportation emissions. Thus, the first big test is likely to be ITM Power's 10 MW unit inside Shell's Rhineland factory, closely followed by BP's 250 MW feasibility study in the Port of Rotterdam that is looking at producing up to 45,000 tonnes of green hydrogen per annum (Port of Rotterdam 2019).

6.4. GLASS, FOOD, AND OTHER AREAS

Other segments of interest for green hydrogen in industry include the food industry and glass industry. Hydrogenation of fats is the core area of application for the food industry, with the demand profile suitable for electrolyzer units between 0.5 MW and 2 MW. This amount is based on estimates from the FCH JU that on average hydrogenation of fats sites require hydrogen production of up to 28 kg per hour,[28] corresponding to 672 kg a day if operating 24 hours.

Glass manufacturing is also a growing area of interest for green hydrogen, with suppliers indicating growing awareness in Asia, Europe, and North America. Given the low demand for hydrogen from a typical glass plant, around 3.95 kg per hour, this market segment is well suited to on-site generation via electrolysis.[29] In Slovenia, one company is using rooftop solar PV to create hydrogen that is blended with natural gas into the glass site furnaces (Willuhn 2019). A company in Vietnam has been using hydrogen within its glass processes (THE n.d.b.).

Other notable areas not explored here are the use of green hydrogen in the semiconductor industry as a heat transfer fluid (when kept in a vacuum) and as rocket propellant for the aerospace industry.

[28] Converting 320 normal cubic meters per hour at 0.08988 kg per 1 normal cubic meter per hour, using http://www.uigi.com/h2_conv.html with source data from Fraile and others 2015, 16.

[29] Converting 44 normal cubic meters per hour at 0.08988 kg per 1 normal cubic meter per hour, using http://www.uigi.com/h2_conv.html with source data from Fraile and others 2015, 16.

FIGURE 6.4 Sunfire synthetic green fuels from hydrogen in Germany

© Sunfire GmbH, Dresden/Rene Deutscher, 2019.
Note: Units in the photo are marked raw naphtha, raw diesel, and raw wax.

6.5. OTHER HYDROGEN FUELS

Although hydrogen itself is a valuable and effective fuel, several alternative fuels can also be created from green hydrogen. These fuels have differing properties from hydrogen that can sometimes be more attractive than pure hydrogen for specific use cases and applications. Examples commonly include methanol, ammonia, and, increasingly, synthetic methane, all of which are considerably easier to store and transport than hydrogen but come with higher efficiency losses in generation (figure 6.4).

6.5.1. Methanol

By some estimates, methanol production accounts for around 10 percent of global hydrogen demand. Although it is used in a wide array of applications, methanol is particularly useful for fuel cell units that provide uninterruptible power supply services, especially in off-grid areas. One liter of methanol is approximately 4.8 kWh, or 1 kg is about 5.6 kWh. This is a significant reduction from the 33.33 kWh held in a kg of hydrogen. Nonetheless, the fuel is a very light liquid and can be easily stored and carried. Further, it is readily available across both emerging and developed markets, making it attractive for locations where hydrogen infrastructure and safety capabilities are low. Today, methanol is largely created via natural gas and is the result of a two-stage process that requires both the production of hydrogen and its subsequent bonding with carbon inside a new molecular structure. The average plant capacity is around 5,000 tonnes per day with a yearly hydrogen consumption of 266,104 tonnes. Key industrial players include Methanex and Sabic (Fraile and others 2015).

6.5.2. Synthetic Methane

One of the largest areas of interest, particularly for European companies and policy makers who are exploring green hydrogen applications, is the ability to synthesize hydrogen with carbon to create methane. Creation of synthetic methane can be enormously appealing because it allows for the continued use of current natural gas infrastructure and avoids the need to replace or retire existing natural gas assets. Synthetic methane also has the added advantage of being easier to generate at larger scales and across a wider range of locations than biogas, which has long been seen as a means of “greening” the gas supply.

Only a few pilot projects are currently generating synthetic methane. Most of them extract their carbon from anaerobic digesters linked to agricultural waste or landfill waste. But a pilot in Italy sources its carbon from direct air capture technology, and both options can be considered carbon neutral.

The largest approved project is the Underground Sun Conversion project in Austria, which will combine solar PV with a 13 MW alkaline electrolyzer. The project will produce and store synthetic methane in an underground cavern and will then release the methane directly to customers as needed (McPhy 2017). Two other flagships are in Germany and France. This includes Uniper’s “STORE&GO” project in Germany, which uses wind power and electrolysis to produce up to 1,400 cubic meters of synthetic methane a day, or approximately 14,500 kWh of energy (Eckert 2019). In France, the Jupiter 1000 program aims to use a hybrid of alkaline and PEM electrolysis, with carbon capture storage, to create and distribute synthetic methane (Jupiter 1000 n.d.).

7: IMPLEMENTATION CHALLENGES

KEY TAKEAWAYS

- Hydrogen is a well-established industrial gas, but leveraging the full potential of green hydrogen in developing countries requires building local capacity and increasing access to expertise that, at the global level, remains limited.
- Safety is paramount for all green hydrogen applications: although hydrogen has been safely produced, stored, handled and used for decades, it is a gas with unique properties and specific safety considerations.
- Hydrogen-derived fuels like ammonia and methanol can be easier to transport and store than hydrogen but pose additional safety and environmental considerations that should be clearly understood and factored in when designing projects.
- Costs of transporting small volumes of hydrogen can potentially double or triple the end-user cost of hydrogen. Demand aggregators that exploit economies of scale and distributed production closer to demand locations could in many instances reduce transportation cost.
- Green hydrogen storage will likely remain focused on gaseous storage—either pressurized, pipeline or gas cavern—unless significant breakthroughs reduce the cost and increase the efficiency of alternative storage methods.
- Use of liquid organic hydrogen carriers (LOHCs) is a promising storage method to meet larger-scale hydrogen transportation needs, such as those from international hydrogen transport; and solid state hydrogen (hydrides) could offer interesting solutions for urban areas and for mobility applications.
- High-purity water is an impotant input for green hydrogen production, and access to it might pose a barrier in many countries.

7.1. IMPLEMENTATION CAPACITY AND INFRASTRUCTURE REQUIREMENTS

One of the most important factors in determining a country's existing capacity to implement green hydrogen solutions is its access to individuals with the technical knowledge and expertise to handle, install, and maintain hydrogen and hydrogen systems. Given the widespread use of hydrogen as an industrial gas, some countries already have the technical capacity to implement and operate hydrogen projects. This is the case particularly in countries, such as Argentina, Indonesia, or Malaysia, that also possess natural gas resources. Yet, the availability of individuals with the technical skills needed to assemble, install, and maintain hydrogen-associated equipment is usually confined to a few large companies that consume large volumes of hydrogen and are less common in regions that are looking to deploy smaller and more remote hydrogen solutions.

Moreover, while there are standards, procedures, and regulations already in place that govern the production, storage, and transportation of hydrogen in many developing countries, these are much less common for smaller-scale (decentralized) solutions and for fuel cells. The difference is that hydrogen is already an industrial market, with significant scale and several decades of development, that has created a pool of skilled workers and training resources, whereas the commercial fuel cell market is only now beginning to emerge, and green hydrogen production is scaling from a small base.

7.1.1. Systems integration

The most significant technical challenge facing the implementation of green hydrogen-based solutions is the integration of the hydrogen system with other systems that are part of the value chain. Applications using green hydrogen as an energy storage medium require different technologies and systems to work in tandem to procure, store, and deliver the hydrogen to an end solution. It is thus essential that project sponsors work with companies that are able to integrate all the different system components, while also accepting the engineering liability risk if the system they have designed does not perform.

For standalone electrolysis plants or fuel cell applications, most of these systems integration[30] issues can be addressed by the equipment supplier and rarely appear to pose significant challenges for end customers. However, multisectoral applications and country strategies involving large projects need to carefully plan how all the different systems will be working together. Examples might include systems in which electrolyzers are combined with a renewable power resource or a combination of battery, fuel cell, or hydrogen refueling infrastructure for mobility applications. Others include the retrofit or development of hybrid fuel cell and battery solutions for buses, trucks, or large industrial needs. It could also include incorporating hydrogen into existing internal combustion engine vehicles to provide a hybrid solution with a lower vehicle emission profile.

Systems integration is therefore important because although the individual components may work well individually, some configurations may not be appropriate, and the trade-offs between cost, sizing of different equipment, and system availability are complex and need to be better understood. For example, incorrectly sizing the compressor with the electrolyzer and using the wrong piping to connect the compressor, storage vessel, and fuel cell nozzles could create leakages and reduce the efficiency of the overall system. Similarly, in the *Clean Hydrogen in*

[30] Systems integration here refers to the development of energy solutions that use a range of individual technologies that may not have been initially designed to work in tandem but that have been adapted to meet a specific need.

FIGURE 7.1 **Hydrogen compressors for refueling in China: Compressor for Zhangjiekhou bus station (left) and compressor for Zongshan Dayang hydrogen bus refueling station (right)**

European Cities final summary report (Müller and others 2017, 29), the authors noted that "compressors are the single biggest cause of station failure," with several causes listed, including compressor head cracks, membrane failures, and connection leaks.

A common issue with stationary applications is the need to produce, store, and release green hydrogen within a system. Typically, hybrid systems store hydrogen generated on-site for later use. This approach requires the hydrogen to be released from the electrolyzer and then either pressurized or liquefied for storage. At all points in the process, the failure of a compressor, poor welding or configuration of the hydrogen piping, and lack of access to on-site basic spares—not to mention, a lack of local engineers—all could create significant risks for the successful implementation and operation of a hybrid hydrogen system.

For both mobility and some stationary applications, early findings from projects suggest that the single largest factor that affects the operational availability of a hybrid system is the method and equipment the project uses to pressurize hydrogen. The most common storage solution is to pressurize at least part of the hydrogen between 200 and 1,000 bar, so the original pressure at which hydrogen is released from the electrolyzer is too low for immediate use and thus requires additional compression. Typically, electrolyzers produce hydrogen at between 1 and 2 bar, but some systems produce at up to 35 bar or higher, which can significantly reduce the cost of the compression process but will affect the overall system capex.

The four main types of compression technologies then used are piston, hydraulic, diaphragm, and electromagnetic, with piston being the most common solution (figure 7.1). Most system integrators choose piston compressors because of their low cost. Yet, this comes with a trade-off because these units frequently have a lifetime of under 1,000 hours, because the seals are quickly worn out and will need replacing, which can significantly reduce the availability of the unit. This situation is especially true when the location is remote and an engineer needs to travel from outside the immediate vicinity to replace the seal. The design problem is that diaphragm compressors, which have much better lifetimes (over 5,000 hours), are more expensive and add to the initial project capex. Hydraulic compressors represent a hybrid option, while electromagnetic compressors are in their early deployment phase. Accordingly, some hybrid systems today have experienced lower availability than anticipated as a result of maintenance issues related to compression.

Creating new fuel cell mobility applications powered by green hydrogen is extremely challenging in part because most manufacturers offer only a one-year warranty as standard and in general cannot offer long-term warranties at commercial rates, combined with the issue that most manufacturers are unable to offer lease financing solutions. It is thus important to note that, excluding Nikola's trucks, Symbio's Renault Kangoo retrofits, and Arcola/Wrightbus's FCEBs in Liverpool, almost all mobility applications today are provided by major corporations that absorb risks on their balance sheets.

Understanding the needs of customers, the cost considerations required to make a project bankable, the ways that warranties of different components can be integrated to guarantee the adequate operation of new systems, and the level of resiliency required to meet regulatory requirements are essential skills that qualified systems integrators can bring to projects. However, even in developed markets, very few system integrators possess an established track record in deploying these types of hybrid green hydrogen production and fuel cell technologies, and most manufacturers now provide system integration services to customers as a means to address this shortage. This scarcity may be more acute in developing countries and it is an area that will require further investment to ensure the successful uptake of these solutions.

7.1.2. Safety considerations

As with any other flammable fuels, safety is of paramount importance for all hydrogen applications. Yet, hydrogen has unique properties that require special treatment compared with conventional fuels used for energy purposes. The first is that hydrogen is colorless and odorless. It burns with an invisible flame that releases little heat, and it can be challenging to handle for first responders who have not received adequate training. Hydrogen has a very wide flammability range, and the energy required to start a hydrogen/air explosion is considered low. It has also been noted that even small sparks produced from dropping a plastic-based pen would be sufficient to ignite hydrogen-air mixtures (Ajayi-Oyakhire 2012). Hydrogen also burns around eight times faster than natural gas, making it extremely difficult to contain especially in closed environments.[31] In its pure form, it burns no carbon and produces no hot ash and very little radiant heat, while burning fossil fuel produces hot ash, creating radiant heat (Hydrogen Europe n.d.).

As a result of these special properties and unique safety considerations, hydrogen safety remains a concern, as indicated by a survey conducted by the World Economic Council in 2019. In this survey only 49.5 percent of respondents considered hydrogen and its potential use as an energy source to be "safe," and 31.4 percent still considered hydrogen to be either dangerous/unsafe or extremely dangerous/very unsafe (WEF Netherlands 2019). This perception of hydrogen as a dangerous technology is often exemplified by the Hindenburg disaster in 1937

[31] Alternatively, this attribute can often enhance safety, because a rapid deflagration means that less heat is conveyed to surrounding areas than with other gaseous fuels. In a famous test when a conventional internal combustion engine car with gasoline was punctured with a 16 milimeter hole and an internal combustion engine car with hydrogen was also punctured, the gasoline car suffered severe damage while the hydrogen car was largely unphased (Ajayi-Oyakhire 2012).

and the explosion of the Challenger spacecraft in 1986.[32] Despite these two famous accidents, the safety risks associated with hydrogen are well known and well understood. Hydrogen has been effectively regulated by national and international standards for over 50 years, and there are established safety measures, protocols, and guidelines that can be implemented to address these aspects.[33]

The most significant safety considerations for hydrogen revolve around how the molecule is stored, how gas leaks are monitored, and how venting is conducted when a leak occurs. Because hydrogen has a very high diffusion coefficient, considered to be roughly four times that of methane, a common safety procedure is to vent hydrogen. Venting is a safe and practical safety measure because when hydrogen is released into the atmosphere, it quickly rises and dissipates. Thus, the primary safety mechanism for the majority of hydrogen units is to "vent" in the case of a major breach incident. The fact that hydrogen is not hazardous, nor radioactive, corrosive, carcinogenic, or self-igniting, further supports that venting is a sensible and environmentally friendly safety procedure. For on-site hydrogen storage, it is standard practice to store the hydrogen outside, with minimal amounts kept indoors. The hydrogen storage tanks themselves should be placed on nonstatic concrete and combined with fire walls, vent stacks, sensors, pressure-relieving devices, and clear labeling of equipment (tanks) and electrical devices for engineers (figure 7.2).[34]

The principle is similar for hydrogen electrolyzers. Infrared cameras combined with warning alarms are essential to notify those in the surrounding area that a leak has been detected. The electrolyzer units are installed on nonstatic concrete and have ventilation lines that head straight above the assets (figure 7.3).

For mobility applications, the question is whether hydrogen is stored in a pressurized unit, in a cryogenic form, or in a hybrid of both. Most tanks are covered with carbon fiber to increase the protection of hydrogen canisters against crashes. In 2018, for example, the Hyundai Nexo secured a maximum five-star Euro New Car Assessment Programme safety rating for its fuel cell vehicle (Attwood 2018). Even in extreme puncture events such as bullets piercing the tanks, evidence from the Toyota Mirai bullet tests shows that passengers remain safe.[35] The critical issue comes when hydrogen storage units are exposed to fires from an external source. For hydrogen stored in very-high-pressure tanks, the biggest concern is that the external temperature rises and causes hydrogen to expand. These issues have been known and addressed by the industry in a myriad of ways since 2006. For example, in a study by BMW on its BMW 7 hydrogen model:

> tanks filled with hydrogen were fully encompassed by flames at a temperature of more than 1,000 °C (1,830 °F) for up to 70 minutes. Even under such conditions, tank behavior did not present any problems, with the hydrogen in the tanks escaping slowly

32 In the case of the Hindenburg, the German Hydrogen and Fuel Cell Association has argued that the extremely flammable paint on the blimp was the key challenge, burning in 90 seconds and triggering the catastrophe. Meanwhile, for the Challenger aircraft, it has been argued that a defective seal in the auxiliary boosters was the cause of the flame damaging the fuel tanks, an issue that is not unique to hydrogen (Ajayi-Oyakhire 2012).

33 The primary international ISO is TC197, which comprises the technical committee that develops standards on hydrogen vehicles, fuel delivery, storage, measurement, and use of hydrogen (IEA 2017). There are also multiple national regulations that govern safety procedures and operations with hydrogen.

34 Feedback from asset operators, system integrators, and suppliers.

35 Toyota, 2016 YouTube demonstration, https://www.youtube.com/watch?v=jVeagFmmwA0.

FIGURE 7.2 **Safety measures installed for hydrogen leak detection, protection, and mitigation: Kirkwall Harbour Hydrogen tanks venting line (left), Kirkwall Harbour PEM fuel cell gas leakage monitoring sensor (center), and Shapinsey School pressurized hydrogen canisters stored in blast wall–covered area, outdoors with an infrared camera (right)**

FIGURE 7.3 **Warning system configuration for PEM electrolyzer at Shapinsey: PEM electrolysis unit infrared camera and warning alarms, Shapinsey, Orkney Islands, United Kingdom (left) and Shapinsey PEM electrolyzers on nonstatic concrete and with hydrogen ventilation shafts (right)**

Source: ESMAP.

FIGURE 7.4 **Shapinsey ferry hydrogen trailers and safety measures at sea: Orkney island hydrogen trailer (left); Orkney ferry to Shapinsey, United Kingdom (top right); and firehouse for hydrogen trailer (bottom right)**

Source: ESMAP.

> and almost imperceptibly through the safety valves. Following these most demanding tests and examinations, both TÜV South Germany and the fire brigade specialists acting as consultants arrived at the conclusion that the hydrogen car is at least as safe as a conventional gasoline car. (BMW 2006, 15–16.)

For larger mobility applications such as ships, trucks, and trains, safety procedures can be more complex. The current understanding is that hydrogen will continue to vent where possible during a fire safety event, with cryogenic hydrogen warmed by the ambient air temperature and vented. In confined spaces, an alternative solution is to use existing firefighting systems to keep storage units cool. For example, for transit by ferry of a custom-built hydrogen trailer carrying 250 kg of hydrogen in the Orkneys (UK), the unit is connected to the ferry sprinkler system. This unit can release up to 2,400 liters of water an hour to keep the pressurized containers cool and to eliminate the need for venting (figure 7.4).

7.1.3. Infrastructure considerations

Whether used in a small distributed application, or as a part of a large industrial scale system, green hydrogen has a number of essential infrastructure implications that must be considered and assessed at the very early stages of project design. These include avoiding physical damage to the equipment in place, assessing the impact on existing transportation and electricity networks, considering the potential of repurposing some of the existing infrastructure to avoid generating stranded assets, and complying with the maintenance requirements of the hydrogen equipment.

Ensuring the availability and use of appropriate equipment to handle hydrogen is key. Hydrogen can embrittle metals, and its buoyancy and molecular size require careful attention to potential leakages, including the deployment of the necessary systems to monitor and respond to potential leaks. Incorrect use of compression technologies (typically in situations where natural gas assets are simply repurposed with little to no modifications) can also provoke the degradation of materials, potentially leading to reduced efficiencies and safety issues. Another key aspect to consider is the correct assembly of hydrogen units, particularly the connections between pressurized storage tanks used for hydrogen refueling systems and the refueling nozzles.

Given the benefits of colocating electrolyzers next to renewable energy plants, it is essential to consider how the water required in the electrolysis and the green hydrogen produced will be transported to and from the production site if the hydrogen is not to be consumed on-site. In remote areas with low activity, a large green-hydrogen project may lead to increased road traffic and noise, as well as increased congestion and roadwork in the local road system that might ultimately require upgrades to the local infrastructure. These upgrades could be justified if there is a clear local benefit, such as the prospect of local job creation, energy security and resiliency, and additional revenue for local businesses and municipalities. These aspects must be addressed at an early stage to avoid unnecessary costs and delays as the project develops. It is also important to anticipate what impact a large green-hydrogen production facility may have on the local grid and on the existing water infrastructure, especially if further enhancements or upgrades are required, and who should cover these costs.

Last, as the world transitions toward a zero-emission energy system, a significant consideration will be the treatment of existing oil and natural gas assets that may become stranded. Green hydrogen in this regard can help mitigate some of the risk associated with stranded assets, by using some transportation and storage assets developed for the oil and gas sector. This does not mean that hydrogen is a silver bullet for existing asset owners. For example, most pipeline infrastructure today cannot support 100 percent hydrogen without risk of leakages and embrittlement. Similarly, natural gas storage tanks in their current state are not appropriate for storing pure hydrogen. However, green hydrogen can be blended into existing gas grids without further changes to existing assets, with several EU studies suggesting blends of up to 20 percent hydrogen are acceptable. Green hydrogen also can be blended into natural gas caverns. But the most significant potential for repurposing oil and gas assets may come from the successful development and rollout of liquid organic hydrogen carriers (section 7.3.2). LOHCs can be stored in existing oil facilities, bunkers, pipelines, and tanks. They can hold green hydrogen for months (or years) and do not require high pressure or low temperatures to keep hydrogen stable. In this way, LOHCs could provide a crucial lifeline for developing countries that intend to decarbonize their energy consumption and whose primary energy infrastructure is not the power grid, but rather fuels.

Box 7.1 examines operations and maintenance challenges that developing countries may encounter.

7.2. GETTING THE RIGHT INPUTS

7.2.1. Hydrogen purity

Not all hydrogen is created equal. The purity of hydrogen is very important for a number of applications, especially for fuel cells, and failure to ensure that the correct hydrogen purity is used can have negative consequences. The most sensitive issue is the use of hydrogen that is not of a high enough purity grade in PEM fuel cells. This can severely damage the stacks and shorten equipment life, as well as reduce system efficiency. In the European Union, the transport sector purity quality standards are specified in ISO 14687, with a level of 99.995 percent purity

BOX 7.1

OPERATIONS AND MAINTENANCE CHALLENGES FOR GREEN HYDROGEN IN DEVELOPING COUNTRIES

Unlike thermal generators, green hydrogen production and fuel cell systems have relatively few constantly moving parts that are subject to wear and tear. Those few moving parts, however, are sensitive components of the system and could provoke system failure if not operated and maintained correctly. Fans that drive the movement of gases, compressor valves, and components associated with the movement of water in the asset are among the most sensitive components and, while not necessarily expensive to replace, they can be highly disruptive where local capacity does not exist. Many companies have partially mitigated this exposure by developing modular systems, such that a fault in one unit does not incapacitate the entire system. This can be useful where larger multistacked systems are deployed, but this is less common for remote or distributed systems that are likely smaller and harder for technicians to access.

Another challenging issue is handling hydrogen fuels. Although hydrogen canisters are widely available in developed countries and considered safe to use, in remote areas of developing countries there is a greater likelihood that hydrogen fuels like ammonia or methanol will be used. The virtue of not using hydrogen is the fact that methanol and ammonia are less likely to escape containment. The tradeoff, however, is that these fuels are more hazardous to handle—notably ammonia, which is toxic and can be extremely problematic if leaked. A major ammonia leak would require coordination between local emergency services to ensure that as the ammonia is vaporized, members of the public are not exposed to the fumes and those who are can be treated carefully (Maryland Department of Agriculture n.d.).

needed (Fraile and others 2015). This quality requirement is higher than in the United States, where companies will provide hydrogen for fuel cells at more than 99.97 percent (United Hydrogen n.d.).

Typically, industrial grade hydrogen is the least sensitive with respect to purity and is supplied at 99.95 percent in both the European Union and the United States. But ultra-pure applications (such as PEM fuel cells) require hydrogen purities of greater than 99.999 percent (table 7.1).

It is important to note that different hydrogen production technologies deliver different purities of hydrogen. Typically, a standard PEM electrolyzer will deliver the highest hydrogen purity, followed by alkaline electrolysis and then SMR. For a standard alkaline electrolyzer, 99.95 percent purity from production is reasonable, while SMR can be as low as 95.00 percent. Still, hydrogen can be purified to achieve up to 99.999 percent purity requirements, either with modification made to the electrolyzer unit (if alkaline) or through a clean-up process after the hydrogen has been produced.

7.2.2. Water

All fuel cells require some water to achieve the humidity inside the stacks to optimize their operations, while electrolyzers require water as their primary feedstock. Access to water is therefore a commonly cited concern by some analysts who are evaluating the viability of hydrogen applications. However, discussions with fuel cell and electrolyzer suppliers and project developers suggest that the volume of water required for operations is in general less of a concern than typically assumed. Instead, water quality is a greater issue than is often understood.

TABLE 7.1 **Hydrogen purity requirements**

TYPE OF HYDROGEN	TYPICAL USES	HYDROGEN PURITY NEEDED (%)
Gaseous	General and industrial	99.950
Gaseous	Hydrogenation and water chemistry	99.990
Gaseous	Instrumentation and propellant	99.995
Gaseous	Semiconductor and specialty applications	99.999
Liquid	Standard industrial, fuel and standard propellant	99.995
Liquid	High purity: industrial, fuel and propellant	99.999
Liquid	Semiconductor	99.9997

Source: Fraile and others 2015.

The electrolysis process requires 9 liters of water to generate 1 kg of hydrogen. However, if the water is straight from the public water system, it must be deionized first. This means that actual water demands can be between 15 and 30 liters to filter 9 liters of deionized water for electrolysis. The remaining water can then be consumed or used as needed, but it cannot be used by the electrolyzer. Accordingly, there is a significant difference between actual water demand for electrolysis and actual water consumption. Given that the water is reusable after purification, the more reasonable assessment of water needs is water consumed; on that basis, hydrogen electrolysis has a fairly reasonable water demand profile relative to many alternative fuels. By means of comparison, hydrogen produced via SMR requires 4.5 liters of water per kg of hydrogen and coal gasification requires 9 liters of water per kg (Bruce and others 2018). This does not include the water actually required to extract the coal or gas, but it does reflect the water demands for hydrogen production technologies on-site. Thus, electrolysis production may require more water in its pure production than SMR does, depending on country context, but the amount required is comparable to producing hydrogen from coal gasification.

For fuel cells the picture is more complex. Because many fuel cells run on natural gas or methanol (often mixed with water), their actual water consumption is extremely low. Indeed, several suppliers claim that their units may require only a few liters per 100 kW every year. Other technologies such as PAFC require around 2,000 gallons a year for a 460 kW unit, with water use peaking at a gallon or two per hour during a 40°C day. Even assuming 2,000 gallons a year, a 460 kW fuel cell unit with 98 percent availability will consume only 4.8 liters per megawatt-hour (MWh) generated.[36] On a pure water demand basis, fuel cells therefore require less water for water withdrawal than all other forms of thermal power. On a consumption basis only, fuel cells require much less water than natural gas steam turbines or CCGT units, which consume between 757 and 1,461 liters per MWh and 150 to 400 liters per MWh, respectively (Union of Concerned Scientists 2013). Even for fuel cells consuming green hydrogen, the life-cycle water demands are between 545 liters per MWh and 725 liters per MWh, depending on system efficiencies.[37] An average nuclear plant

[36] Assumes a 460 kW PAFC running at 98 percent availability and 48 percent electrical efficiency and consuming 2,000 gallons a year (converted to liters at a ratio of 1 gallon = 4.54609 liters).

[37] Assumes 33.33 kWh per kg of hydrogen, requiring about 30 kg to reach 1 megawatt-hour, electric storage. At an electrical efficiency of

consumes 700–1,200 liters per MWh (Union of Concerned Scientists 2013).

In general, water quality is an underappreciated concern. PEM technologies remain the most sensitive to water quality issues, and PEM electrolyzers require deionized water that is usually processed through an additional built-in water-purification unit inside the electrolyzer.[38] For alkaline electrolyzers, water quality is also an issue, with certain suppliers setting a clean water target of conductivity lower than 20 microsiemens per centimeter. Most electrolyzer units include an option to add water purifiers to their solutions. These are a relatively low additional capex cost, and most manufacturers claim that water purity issues are addressable, providing the source of water is not heavily contaminated. Typically, most electrolyzer units have no problems accepting water from a public supply and then purifying it through the unit.

For fuel cells, although PEM units remain sensitive, other technologies such as SOFC, PAFC, and MCFC are less sensitive to water and can add reverse osmosis purifiers if needed. Most manufacturers of these technologies report that they have not faced noticeable water challenges in their operations thus far. Similar to electrolyzer units, most units will access water through a public source, though water can also be added externally where there is no access to a public water source.

7.3. TRANSPORT AND STORAGE

One of the main strengths of liquid fossil fuels is that they can be relatively easily transported and stored. Conversely, transporting and storing hydrogen has been for several decades one of the main constraints for broad-based applications. These constraints are fundamentally rooted in hydrogen's low energy density at atmospheric pressure, the efficiency losses associated with hydrogen pressurization and liquefaction, and the special conditions required to ensure that hydrogen transportation and storage are safe.

7.3.1. Transport

There are four modes of transport and four storage mediums to transport hydrogen. Depending on the specific market, hydrogen modes of transport today can include roads, rail, shipping, or pipeline. The storage mediums for transport include compressed hydrogen, liquid hydrogen, converted hydrogen (either to ammonia or methanol), or absorbed hydrogen (hydrides and LOHCs).

The most common method of transport is for hydrogen to be pressurized between 200 and 500 bar and moved via road (figure 7.5). Australia's CSIRO suggests that for journeys under 1,000 km or where demand is below 1.5 tonnes of hydrogen, pressurized hydrogen is most suitable (Bruce and others 2018), with cryogenic (liquid) hydrogen preferred for larger volumes and longer distances.[39] Hydrogen transit is less common by rail except when converted into ammonia. Hydrogen pipelines today can usually be found only in markets with established petrochemical infrastructure, such as China, Japan, Korea, and the United States, certain Gulf states, and Europe. Even in these markets, infrastructure remains limited. The longest hydrogen pipeline in Europe, which lies between Belgium and France, is only 400 km, while in 2011 the United

50 percent, this doubles to 60 kg, requiring between 10 and 12 liters per kg. Using an electrical efficiency of 60 percent for the fuel cell reduces demand to 54 kg.

38 One supplier, Peak Scientific, requires less than 1 microsiemens per centimeter or more than 1 megaohm-centimeter for their water purity.

39 Several reasons for this preference include convenience, ease of access to suppliers, and the fact that costs and risks are already known and regulations have already been drafted. Further, it is typically the case that at shorter distances, a lower amount of hydrogen will be needed (because for larger amounts, a company would typically consider building generation on-site). Thus pressured containers are a more logical choice.

FIGURE 7.5 **Pressurized hydrogen storage trailers**

© Hexagon.

Kingdom had only 25 km of hydrogen pipeline (Ajayi-Oyakhire 2012, 19). Ammonia shipping is common and has been established for many years. Companies have also begun to explore the technical and commercial viability of liquefied hydrogen shipping, with Kawasaki committed to developing at least one vessel for this purpose (Crolius 2017).

Transporting hydrogen is expensive. Using a Hinicio 2016 analysis, IRENA estimated that hydrogen compression, logistics, and distribution could add \$6–\$10 per kg for a hydrogen refueling station unit (IRENA 2018, 28).

One of the most anticipated innovations in hydrogen transportation lies in the ability to transport hydrogen by absorbing it into either a metallic composition (called a hydride) or into a liquid composition (liquid organic hydrogen carriers). Of the two, LOHCs are showing the greatest progress toward commercializing their solution. LOHCs are usually heat transfer fluids, such as toluene or dibenzyltoluene, which absorb hydrogen in a process that creates heat energy and then release hydrogen when exposed to heat at their point of use. There are two current commercial pilots using these solutions, one in Japan and one in Tennessee, United States. Other areas actively exploring the technology include Botswana (H_2-Industries 2018) and Germany. In Germany there are several pilot sites in operation, but most appear to be for research purposes.

See table 7.2 for an overview.

7.3.2. Storage

Hydrogen can be stored in pressurized, liquid, converted, or absorbed mediums. Most large industrial users consume hydrogen as it is produced, with SMR or gasification often colocated near the demand source, and most significant storage capacity is for either wholesale distribution or smaller on-site generation.

By far, the most common storage method for distributed hydrogen is pressurized containment. This process includes a series of tanks that are usually linked together to release pressure simultaneously as needed. For hydrogen refueling

TABLE 7.2 **Overview of hydrogen transportation methods**

TECHNOLOGY	VOLUME OF HYDROGEN PER TRUCK	TRANSPORT CAPEX (US$),TRACTOR AND TRAILER	ENERGY REQUIRED (KWH PER KG HYDROGEN, EXCL. TRANSPORT)	BOIL OFF (%)
LOHC–Hydrogenious LOHC Technologies	Up to 1,800 kg	180,000	1.5–10.0	0
Compressed gas hydrogen (@250 bar)	Up to 350 kg	>440,000	1.5–2.0	0
Compressed gas hydrogen (@500 bar)	Up to 1,100 kg	1.0 million–1.2 million	4.0–5.0	0
Liquid hydrogen (@ −250°C)	Up to 3,300 kg	750,000–1.7 million	10.0	1–3 per day
Pipeline	Size dependent	Initial Investment: 300,000–1.2 million per km (rural) and 700,000–1.3 million (urban)	n/a	0

Source: IEA 2015; ESMAP discussions with Hydrogenious LOHC Technologies; and market feedback.
Note: capex = capital expenditure; LOHC = liquid organic hydrogen carrier. n/a = not applicable.

systems, a hybrid of containerized and liquid hydrogen is also attractive. In these configurations, the majority of hydrogen is held in a liquefied tank that may be pressurized up to 30 bar. This is then converted from its liquid to gaseous form using ambient heat from the surrounding area. (Hydrogen needs to be below −423.17°F to stay fully liquid.) The hydrogen is then fed into a compressor to bring the pressure up to the requirement for nearby compressed storage tanks that usually distribute the hydrogen. Smaller sites may avoid this process by simply using pressurized hydrogen only, especially where on-site compression would add significant costs.

Very few providers of hydride storage exist—only Ardica, Hydrogen in Motion, and H2GOPower. But most have not deployed a large-scale pilot, let alone a commercial project to date, and all three companies have largely focused on storage applications for either the military, unmanned autonomous vehicles, or both. Nevertheless, in the long run the ability to store hydrogen in a solid state could be transformative to addressing safety considerations for stationary use cases as well as for mobility, especially in built-up areas. A recent example of the interest in solid-state hydrogen has been the announcement that SP Group will use solar PV, electrolysis, and solid-state hydrogen storage for its training center in Woodleigh Park, Singapore (Mohan 2019).

Conversely, it appears that LOHCs are starting to move toward commercialization and greater competition, with several leading LOHC providers already offering commercial solutions, including Chiyoda, Hydrogenious LOHC Technologies, Covalion, and H_2-Industries (figure 7.6).

For mobility applications, the most common method today is to pressurize hydrogen into carbon fiber tanks, in contrast to early hydrogen cars, such as the BMW 7, that used cryogenic hydrogen storage. Nonetheless, cryogenic hydrogen storage is now being reviewed for ferries,[40] ships, and trucks.[41] There are two advantages to cryogenic hydrogen for mobility platforms that require significant amounts of storage. The

40 Discussions with Orkney Islands Council Marine Services, part of the HySeas III hydrogen ferry delivery team, April 2019.

41 Correspondence with system integrators suggests that this may be optimal given refueling time priorities, April 2019.

FIGURE 7.6 **Liquid organic hydrogen carrier solution in operation, Tennessee, United States**

© Hydrogenious LOHC Technologies.

first is that cryogenic hydrogen is considerably more energy dense than pressurized hydrogen, which saves space (and weight) on the platform. The second is refueling time. To meet safety standards, the flow rate of hydrogen refueling is set by temperature bands, with 80°C being the upper safety limit, although most refueling stations aim to keep the temperature around the refueling nozzle to 50°C or lower. To keep the refueling time of hydrogen low, some engineers have suggested that cryogenic hydrogen would be faster than pressurized hydrogen because it would avoid the temperature constraint that is created by trying to push hydrogen into a fixed space (a process that generates heat).

Another area of research in hydrogen storage is around the use of ammonia as an energy storage method. Although this process leads to higher efficiency losses, ammonia is considerably easier to transport and store, making it a compelling proposition in an environment where the cost of diesel and other forms of stored energy may be comparatively expensive. The first pilot of this approach began in 2018 in Oxford, where Siemens, the Science and Technology Facilities Council (STFC), the University of Cardiff, and the University of Oxford have developed a demonstrator that creates green hydrogen from electrolysis in an on-site 12kW wind turbine and then combines it with oxygen to make ammonia (STFC. 2018). In some environments, this could become a compelling solution for off-grid renewables seeking an easy-to-store and easy-to-transport fuel, with no carbon emissions.

The largest storage application being considered is the use of hydrogen caverns. These already exist in the United Kingdom and United States, with a number of projects now examining the use of salt caverns to store hydrogen in and around the North Sea. In some developing countries this may be an existing opportunity for large-scale and low-cost green-hydrogen storage, particularly where existing oil and gas fields exist. Despite this potential, there is extremely limited public research available to date on the availability, technical challenges, and cost considerations of hydrogen caverns for green-hydrogen storage in developing countries.

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8: AREAS FOR FURTHER RESEARCH

This report has sought to illustrate current and potential areas of deployment for green hydrogen production and fuel cell technologies in developing countries. While the current focus in developing countries appears to be split between hydrogen applications for mobility, ammonia and methanol from remote power fuel cell systems, and some industrial uses, this scope will evolve as hydrogen technologies decline in cost and their complexity is better understood. Hydrogen is not and will not become a silver bullet for all energy challenges in developing countries. But what green hydrogen could provide is another powerful technological lever that policy makers and investors could use to develop clean solutions that are tailored to the energy context and to the unique challenges that the country is seeking to address.

For developing countries to be able to fully benefit from the investment opportunities that could be brought by green hydrogen, it will be increasingly important for organizations to work with investors and governments on developing national roadmaps to highlight areas of national focus and to assess the applications in which green hydrogen can deliver gains. These roadmaps will need to establish how hydrogen can be sourced in a climate-sustainable manner, leveraging local renewable resources whenever available. At the broader level, an area of work that has not been addressed in this report is a more in-depth assessment of how large the potential green hydrogen market might be in developing countries. This is a difficult endeavor partly because of the lack of data on current hydrogen production in different countries and because of the uncertainty around whether the green hydrogen market will become export driven like the global oil market is today or whether it will be more like natural gas, in which some international trade occurs but largely markets are regional not global. Further research and analysis of the drivers that would encourage domestic production versus imports of green hydrogen will be needed and could perhaps build on methodologies already adopted for assessing the scale of hydrogen and its sources for developed countries.

It is also important to consider further research that can help quantify nonmonetized benefits that green hydrogen can provide for developing countries. These include the ability to switch to a fuel with a wide diversity of potential suppliers, thus reducing the risk of concentrated energy supply among a few entities. Further, it could allow small-island developing nations to obtain a versatile, easy to store, and green energy source for their energy needs without inhibiting economic growth. The World Bank through ESMAP is supporting developing countries in factoring in these and other considerations in the development of national strategies that explore the role that green hydrogen could play in decarbonizing economic activities and pathways to leverage its full benefits.

This report also focused on hydrogen produced via electrolysis using variable renewable energy sources such as onshore wind and solar PV. Future studies may wish to consider what green hydrogen development could look like in countries that are endowed with other renewable power sources, such as geothermal, hydroelectric power, or offshore wind that typically have higher capacity factors than onshore wind and solar PV.

Understanding how green hydrogen technologies could be integrated within a blended portfolio of renewable energy distributed resources should also be a focus for multilateral development agencies and other energy organizations that are seeking to identify solutions for off-grid energy access. Notably, the use of batteries in tandem with variable renewables could help optimize the size of an electrolyzer by ensuring a consistent quality of power. Such solutions may also allow more developed alkaline technologies to overcome some of the concerns around their response speed that have typically encouraged renewable developers to consider PEM. If such solutions were technically feasible, they could provide a route to both reduce total system costs and reduce efficiency losses through the conversion to a hydrogen process.

Last, this report has focused exclusively on green hydrogen production via electrolysis. There are a number of pilots now under consideration to generate green hydrogen from waste, which are being piloted in some countries such as in Bangladesh. This pilot project funded by the government of Bangladesh will provide 5 MW of power to the grid from green hydrogen generated from waste in 2020 (Saha 2019). This is therefore another area worth exploring, especially given the potential economic benefits for municipal governments of turning waste into a resource for clean, local power provision.

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Energy Sector Management Assistance Program
The World Bank

1818 H Street, N.W.
Washington, DC 20433 USA
esmap.org | esmap@worldbank.org