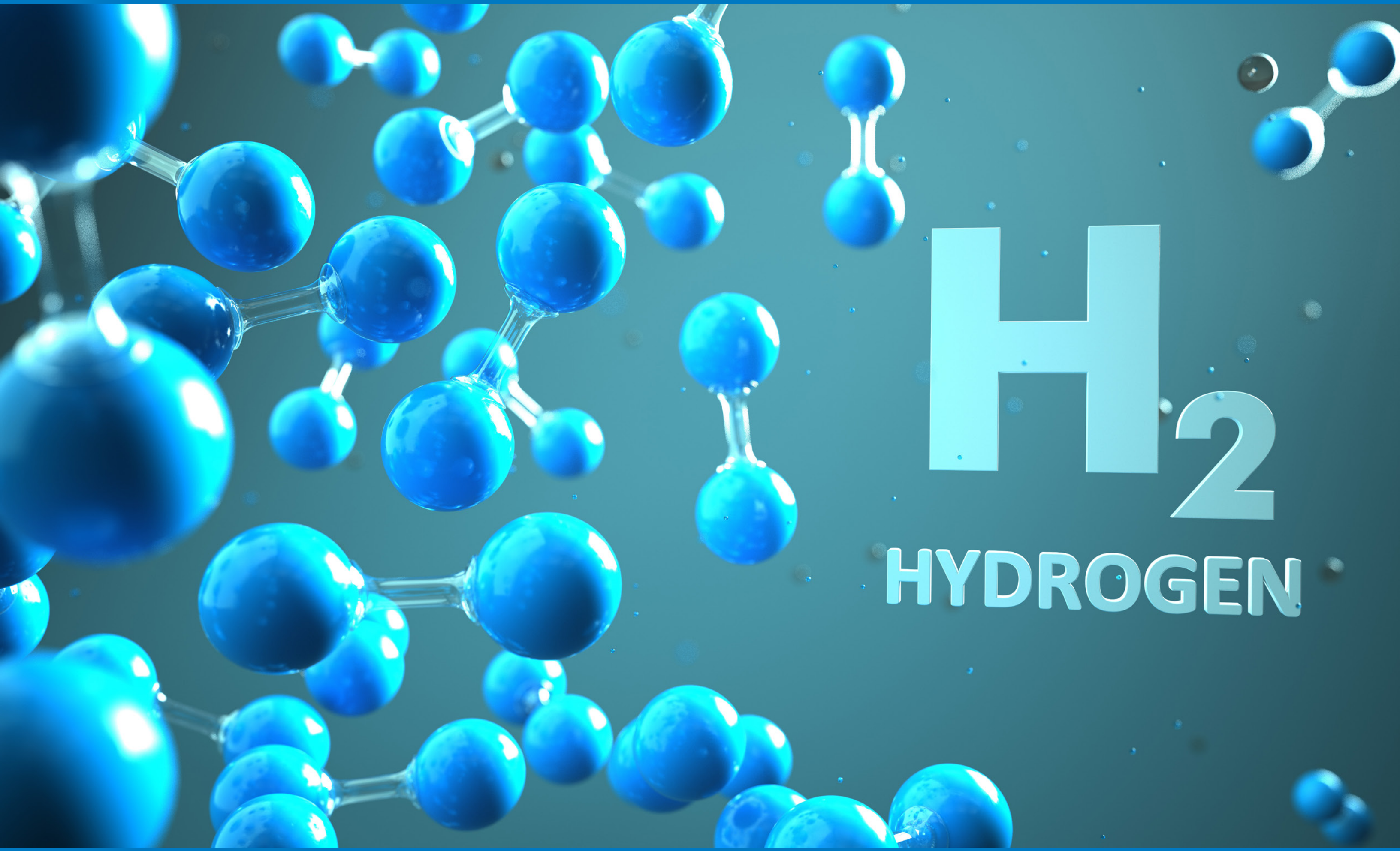
IN Front

BMO Capital Markets Equity Research

Hydrogen: The Science and The Investment Opportunities



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BMO Capital Markets

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Hydrogen: The Science and The Investment Opportunities

In this report, we do a deep dive into the science of hydrogen, the challenges that remain for the energy transition, and how the future of hydrogen will affect BMO's global equity research coverage universe.

The BMO Edge

- Built on our previous proprietary global cross-sector analysis
- Technological deep dives beyond what has been widely reported
- A cross-department and cross-border collaboration

Top Proprietary Takeaways

The report begins with a scientific deep dive into hydrogen. The conclusions are significant and include four core takeaways:

- It is the flexibility of hydrogen fuel that will allow it to become a viable fossil fuel replacement.
- Emerging water electrolysis technologies have evolved to the point that they are considered a key component of the green energy transition.
- To achieve global CO_2 reduction targets, electrolysis might be preferred, but carbon capture will also be necessary.
- The transportation sector will lead the way in building a viable hydrogen infrastructure, and other sectors will follow.

From a sector lens, our covering analysts provide critical takeaways that we expect to play out over the coming years:

- Global integrateds are all involved in hydrogen, and we expect this to become a more material business unit in the future. European integrateds are moving more aggressively than U.S. peers, while targeting both green and blue hydrogen generation, and aiming to capture double-digit market shares in core markets.

- U.S. integrateds note the need for improved cost competitiveness from hydrogen, and while still pursuing numerous opportunities across different value chains, are generally planning less significant strategic and portfolio repositioning than European peers, with oil and gas likely to remain the dominant business well into the future.

- In Canada, a hydrogen transition would be leveraged by blue hydrogen potential in Western Canada, including U.S. fuel exports. In turn, this would have positive implications for Canadian natural gas production and benefit both large, low-cost gas producers and CCUS-exposed oil companies like **Canadian Natural Resources** (CNQ, $38.57, Outperform), **Tourmaline Oil** (TOU, $23.92, Outperform), **ARC Resources** (ARX, $7.65, Outperform), and **Whitecap Resources** (WCP, $5.62, Outperform).

- Oilfield service companies are likely to see meaningful future revenue opportunities develop across the hydrogen value chain. Hydrogen, and other energy transition markets, should help offset structural headwinds from reduced upstream capital spending over the mid-to-long term, although we expect near-term oil and gas activity to trend higher. Hydrogen today is most impactful for **Baker Hughes** (BKR, $20.11, Market Perform) and Chart Industries (GTLS, $143.91, Not Covered), although **Schlumberger** (SLB, $26.76, Outperform) is also pursuing green hydrogen opportunities.

- Canadian energy infrastructure companies should see hydrogen as an attractive lever to drive organic growth. Currently, **ATCO** (ACO.X, $42.15, Outperform)/**Canadian Utilities** (CU, $34.13, Market Perform), **Brookfield Renewable Partners** (BEP, $43.52, Market Perform), and **Enbridge** (ENB, $46.22, Outperform) are the only companies investing in hydrogen projects, but we expect the broader sector to all be involved over the long term.

- Green hydrogen's role in the final leg of decarbonization of the utility sector is undeniable, however, given current economics, we do not see material capex opportunities for the sector until the end of the decade. Most positively impacted is **NextEra Energy** (NEE, $77.94, Outperform).

- The hydrogen economy provides several opportunities for long-term growth across the chemical sector, particularly the specialty chemical and industrial gas players. We see the most obvious potential beneficiaries as **Air Products & Chemicals** (APD, $284.36, Outperform) and **Linde PLC** (LIN, $284.80, Outperform).

- New demand opportunities and premium pricing tiers are expected to develop for ammonia if it is established as an efficient hydrogen carrier. This would benefit incumbent producers **CF Industries** (CF, $46.01, Outperform) and **Nutrien** (NTR, $54.92, Outperform) and **Yara** (YAR, NOK426.70, Market Perform). The potential for methanol to have the same hydrogen opportunity set as ammonia (and benefit **Methanex** (MEOH, $39.79, Outperform) seems more limited.

- In metals and mining, to facilitate hydrogen production and use, platinum group metals-heavy catalysts are required, with PGM producers set to benefit from re-rating. We see **Sibanye-Stillwater** (SBSW, $18.27, Outperform) as best placed to benefit.

- Utilising hydrogen to replace fossil fuels in logistics and refined metal output has potential to help the metals and mining sector reduce its carbon footprint amid rising one-upmanship between major producers as to who can hit carbon neutrality first.

- For the auto parts suppliers, investors appear more focused on the risks that hydrogen and electric propulsion presents rather than the opportunities. In particular, suppliers that currently provide parts for the internal combustion engine powertrain are most subject to change.

- Almost all of **Linamar's** (LNR, $74.64, Outperform) auto parts business is supplying parts to the powertrain, and accordingly its business will face greater disruption but also potential opportunity. **Magna** (MGA, $89.50, Outperform) appears to offer a balance of traditional parts that will still be required notwithstanding propulsion type while at the same time is positioning itself to capitalize on electrification opportunities.

- The market for fuel cell electric vehicles is set to scale up this decade. **Ballard Power Systems** (BLDP, $23.28, Outperform) is the leading developer of proton exchange membrane fuel cell systems for use in vehicle applications. As a result, the market's development should create opportunities for rapid long-term revenue growth for Ballard.

- From an ESG perspective, it will be imperative that companies participating in the 'hydrogen economy' shore up their overall ESG strategy, including health and safety management, approaches for community engagement, and corporate diversity.

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1. Hydrogen Fuel's Flexibility Makes It a Viable Fossil Fuel Replacement

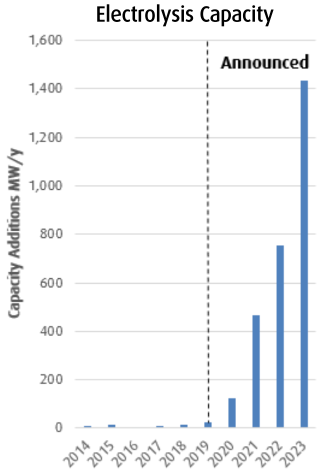
The path to find and develop alternatives to fossil fuel has been filled with many false starts and broken promises, and hydrogen fuel is just one of the many future possibilities (biofuels, biomass energy, geothermal, etc.). Interest in hydrogen will continue because it can carry a lot of energy on a per molecule basis and can be produced and stored in numerous ways. As a result, hydrogen has enjoyed renewed popularity as countries plan their net neutral carbon futures and look to adapt existing infrastructure to new decarbonization realities. While numerous technologies can be used to achieve national and international climate change goals, we believe that hydrogen's versatility will make it a key component in a clean energy future should public and private support continue. Part of our enthusiasm stems from the fact that hydrogen fuel can be produced by many different feedstocks, and there are many paths for cleaner wide-scale hydrogen production being proposed. Furthermore, hydrogen production can be incorporated into existing infrastructure and can be installed onsite, thereby eliminating the need to solve the pressing transportation, storage, and availability problems.

In this section, we contrast hydrogen to traditional fuels and introduce the various categories of hydrogen based on the amount of CO_2 emissions produced through its production. Given the many pieces required to complete the hydrogen economy puzzle, we believe that at this juncture, the main indicators to evaluate the progress of its development are listed below. This is by no means an exhaustive list, but it creates an initial framework that we believe investors need to demystify the hydrogen space.

1. **Cross-cutting decarbonizing technologies — Not a one-size-fits-all approach.** The success of the hydrogen economy will be predicated on how hydrogen production technologies such as electrolyzers and carbon capture systems are intertwined in varying combinations that will be unique to a particular region's energy generation mix and overall capacity needs.

2. **Increased hydrogen fuel demand in new sectors — Still a niche market.** Currently, the ~70Mt in annual pure hydrogen demand is split equally between oil refining and chemical production (mainly ammonia and methanol). However, new applications, such as transportation, energy generation and storage, and heat and processing, are expected to become new markets from 2021 onward and drive global hydrogen demand from 70Mt today to over 1,000 Mt by the next decade based on government policy announcements to date.

Electrolysis Capacity



Source: IEA

3. **Growth in renewable energy infrastructure — A necessary element to green hydrogen.** According to the IEA, global renewable electricity generation is expected to increase by 127% by 2030 and 283% by 2040 from 2018 levels. Furthermore, 2.8GW of planned electrolysis capacity is expected to come online over the next three years. This dramatic growth in renewable demand, along with government policies designed to encourage the scaling up of electrolysis technologies, will be essential for the development of the green hydrogen economy and its progress will be a key indicator.

4. **The pace of decarbonizing conventional energy generation methods — A necessary element to the blue hydrogen story.** The development of blue hydrogen fuel is seen as essential to decarbonizing *existing* infrastructure and is especially important for assets that still have many years of useful life. However, the transition from carbon-intensive grey hydrogen production to low-carbon blue hydrogen production is predicated on improving carbon capture systems and storage techniques, which have not yet reached technical maturity, to achieve the efficiencies required for large-scale applications.

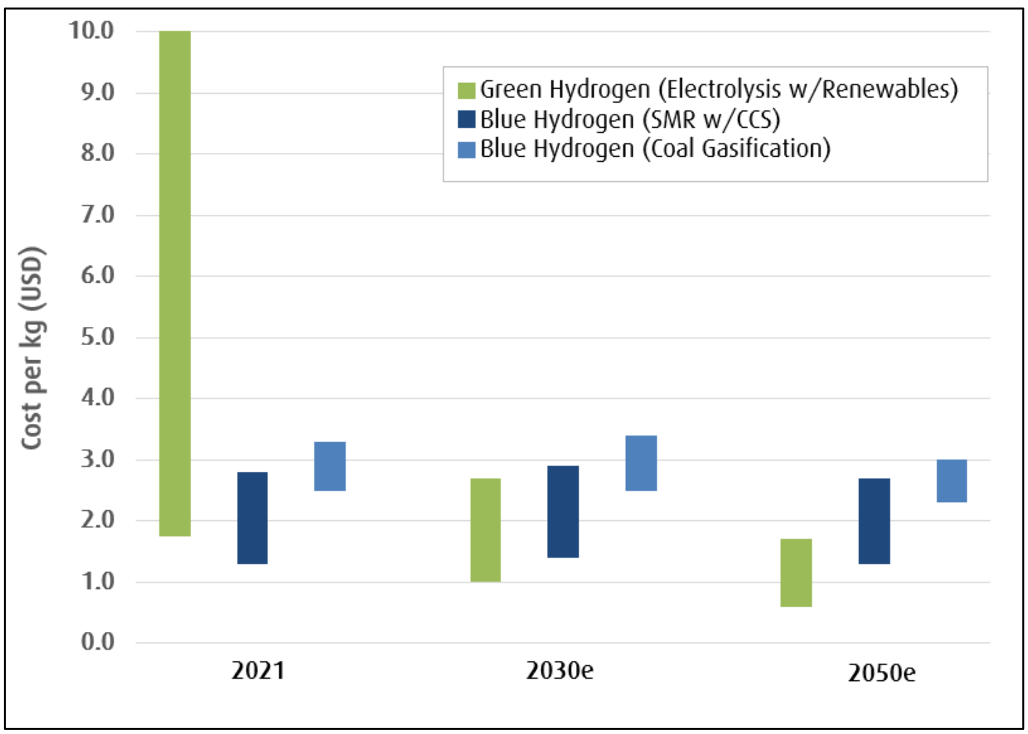
5. **Development of transport and storage technologies — Ammonia-based hydrogen transport, and storage.** While ammonia is being considered as an alternative fuel for jets and ships, it can

also be used as a stable and practical hydrogen carrier and could resolve many of the infrastructure issues that we discuss in this report.

The costs of low to zero CO_2 emission technologies vastly improve — Current methods are cheap, but highly polluting. While globally, green hydrogen is forecast to be the winner, the reality is that it depends on a number of factors, and the forecasts in Exhibit 1 could look very different in another country due to a number of economic and geopolitical implications. Furthermore, the focus of many forecasts has been on hydrogen generation costs, but the transport and storage part of the equation will also differ from country to country. Today, highly polluting hydrogen production methods, such as SMR and coal gasification without carbon capture, can range from US$1 to US$3 per kilogram while the costs for cleaner blue hydrogen (with carbon capture) range from US$1.30 to US$3.30 and for green hydrogen (electrolysis with renewables) range from US$1.75 to US$10.10 per kilogram, depending on the jurisdiction, natural resources, and energy generation mix. However, green hydrogen is expected to reach cost parity by the end of the decade.

The bottom line is that the outlook for prices suggests that over the next 30 years green hydrogen costs will drop dramatically, as electrolysis capacity increases, the supply of green electricity rises, and the expected technology improvements come to fruition. Forecasts show that by 2050, the price of green hydrogen is estimated to drop by 60-80%, bringing green hydrogen costs to between US$0.60 and US$1.70/kg. Meanwhile, blue hydrogen is expected to experience a relatively minor drop in cost on a global basis; however, that could change depending on the infrastructure built and lower natural gas prices in the future. For now, blue hydrogen's cost (SMR and coal gasification with carbon capture) is expected to drop only slightly to US$1.30 to US$3.00/kg by 2050.

Exhibit 1: Forecasts for Global Cost of Hydrogen Production See Green Hydrogen as the Winner



Source: Noussan *et al.,* 2021, BNEF, BMO Capital Markets

A Primer on Grey, Blue and Green Hydrogen Fuel Production

Hydrogen fuel is generally classified as grey, blue, turquoise, yellow, or green, depending on the feedstocks used and the amount of carbon dioxide emissions released during the conversion process. Hydrogen may be abundant in the environment, but it does not exist in nature in molecular form and must be extracted and processed from various sources (fossil fuels, coal, biomass, electricity, etc.). How to efficiently extract hydrogen from these compounds in an economical and sustainable manner is the pressing challenge, as the cost and the amounts of CO_2 emitted during fuel processing depend on the conversion efficiency and the carbon intensity of the underlying feedstock. Therefore, for hydrogen to be regarded as a low- to zero-emissions alternative to fossil fuels, the end product has to be produced in a low- to zero-emissions manner.

Hydrogen fuel is a flexible energy carrier compared with alternatives and is more than just a transportation fuel. It can serve as an energy grid stabilizer as electrolyzers can be used to manage loads and deal with the intermittency issue from renewable energy, can replace natural gas in domestic applications, can be used in power generation, and can be an industrial feedstock for key chemical commodities such as ammonia.

Hydrogen production categories keep expanding to offer a better delineation between feedstock and methods. The 'colours,' blue, turquoise, yellow, and green, represent the low- to zero-carbon options that will be needed to make the hydrogen economy a reality. Given that elemental hydrogen is part of many compounds, it is no surprise that new, low-carbon ways of producing hydrogen are becoming more prominent. However, the colour categorization is not standardized, with nuclear often classified as green instead of yellow and pyrolysis often classified as blue instead of turquoise. However, we have decided to break yellow and turquoise out for clarity. Turquoise hydrogen is similar to blue hydrogen in that natural gas feedstocks are used; however, pyrolysis is used instead of methods that require carbon capture and the byproduct is solid carbon that is already used in multiple applications. By contrast, yellow hydrogen (sometimes called purple) is hydrogen produced by production technologies such as electrolysis that is connected to nuclear power plants.[1]

[1] Noussan, M., Raimondi, P., Scita, R., and Hafner, M. (2021). *The Role of Green and Blue Hydrogen in the Energy Transition – A Technological and Geopolitical Perspective.* Sustainability; 11: 298.

Exhibit 2: The Different Hydrogen Classifications Show its Versatility: Grey → Blue → Turquoise → Yellow → Green

Grey Hydrogen	**Fossil fuels → reforming and gasification processes → grey hydrogen.** The 'grey' classification (sometimes called brown, black, or industrial hydrogen) means that it is produced from fossil fuel sources without the use of carbon capture. This method accounts for 90-95% of the hydrogen produced in the world today. Grey hydrogen is currently the cheapest hydrogen production option at ~€1.50 per kilo, and the price is highly correlated to natural gas prices. However, as more and more jurisdictions adopt regulations that could establish carbon pricing mechanisms, grey hydrogen's cost effectiveness will diminish. For example, the European Union's emissions trading system will price CO_2 emissions from hydrogen production in the €20 to €25 per ton range. However, this cost could be offset through the use of carbon capture technologies and that would transition grey hydrogen to blue hydrogen.
Blue hydrogen	**Fossil fuels and biomass → reforming and gasification processes (or grey hydrogen) combined with carbon capture → blue hydrogen.** The 'blue' classification pertains to hydrogen that is produced in a way that meets the low-carbon threshold but is still generated from nonrenewable sources such as fossil fuels or carbon-intensive biomass. While the price of blue hydrogen mirrors natural gas prices, the cost of carbon capture systems and distribution comes into play. According to the IEA, current carbon capture system costs are in the range of €50-70 per ton of CO_2 , and therefore, carbon prices would have to be in the range of €55-90 per ton of CO_2 to make blue hydrogen cost competitive with grey hydrogen today. Even if technologies that capture 100% of the CO_2 emitted via reforming and gasification processes are available, blue hydrogen would still not be considered 'green hydrogen' because the conversion of non-fossil fuel feedstocks does not produce CO_2 emissions in the first place. Finally, these capture technologies need to advance enough to the more than 95% efficiency predicted (currently estimates are anywhere from 30% to 90%) to meet net carbon neutral goals.
Turquoise hydrogen	**Natural gas → pyrolysis → turquoise hydrogen.** While pyrolysis is still in the early research phase, it is widely seen as a promising low-carbon method of utilizing natural gas infrastructure without being reliant on carbon capture systems. The main reaction produces hydrogen gas and solid carbon, which is easier to handle and omits the conversion steps required to manage, store, and use the gaseous CO_2 emissions that would be acquired via carbon capture in blue hydrogen case. C-Zero, Inc. has raised $11.5 million to advance this technology and is surely one to watch as it could facilitate the conversion of natural gas infrastructure at a quicker pace.
Yellow hydrogen	**Nuclear energy → steam methane reforming, thermo-chemical water splitting, high-temperature electrolysis → yellow hydrogen.** Nuclear energy generates about 10% of the world's electricity supply with ~440 operable reactors (and >50 under construction, WNA estimate) and is the second-largest source of low-carbon power after hydroelectric power. This type of energy, which generates power through nuclear fission, does not generate air pollution and CO_2 emissions while in operation, has a much smaller land footprint compared with solar, and produces minimal waste compared to other energy generation methods. However, that waste remains radioactive for tens of thousands of years and can pose numerous threats to society if not handled correctly, and the impact of low-level radiation is still being assessed. Regardless, it is considered one of the safest forms of electricity generation. Finally, there are multiple pathways to produce hydrogen from nuclear energy, including steam methane reforming.
Green Hydrogen	**Renewable sources → electrolysis, gasification, or pyrolysis → green hydrogen.** Hydrogen fuel classified as 'green' automatically meets the low-carbon threshold as the feedstock is not as carbon intensive and is generated from renewable energy sources such as wind and solar. This means that carbon emissions are not produced in the first place and, therefore, do not incur the carbon pricing and carbon capture costs associated with grey and blue hydrogen. However, the cost of green hydrogen depends on the cost of electrolysis (the process whereby hydrogen is produced from water using renewable energy) and the price of the green electricity that is used in the electrolysis process. The bottom line is that green hydrogen would be much cheaper in areas with abundant sun and wind but very expensive in regions without such renewable resources; therefore, other low-carbon production methods would need to be considered.

Source: IEA, H2FCSupergen, Noussan *et al.*, 2021, European Commission, BMO Capital Markets

The Majority of Hydrogen Is Produced Using Carbon-Intensive Methods

Current Status:
Grey = ↑ emissions; ↓$
Blue = ↓ emissions; ↑$$
Turquoise = ↓ emissions; ↑$$
Yellow = ↓ emissions; ↑$$$
Green = zero emissions; ↑$$$$

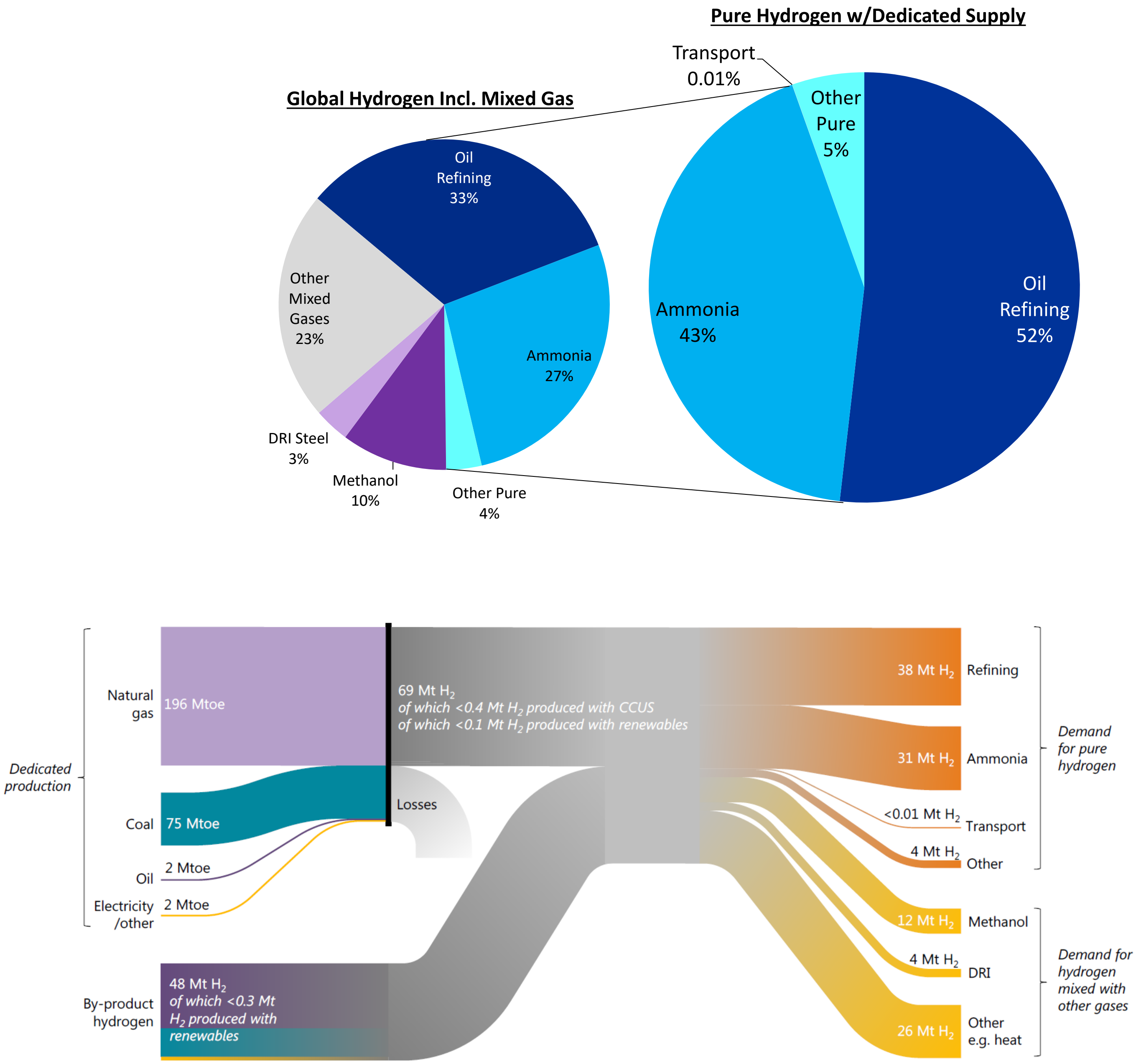
Of the 70Mt of pure hydrogen produced in the world today, 90-95% is classified as 'grey hydrogen,' 'brown hydrogen,' or 'industrial hydrogen' and comes from natural gas (75-80%) using around ~205 billion cubic meters (bcm), or 6% of global natural gas demand, and coal (18-20%), which uses ~ 107 MT, or 2% of global coal demand. The production methods used include mainly steam methane reformers (SMRs), coal gasification processes, and to a lesser extent, autothermal reformers (ATRs).[2] Unfortunately, these methods are highly energy and carbon intensive, and according to the International Energy Association (IEA) and the International Renewable Energy Agency (IRENA), pump more than 830 Mt of CO_2 emissions into the atmosphere annually. To break this down, SMRs have an emission factor of

[2] Dehganimadvar, M., Shirmohammadi, T., Sadeghzadeh, M., Aslani, A. and Ghasempour, R. (2020). *Hydrogen production technologies: Attractiveness and future perspectives.* DOI: 10.1002/er.5508.

As more government support and a robust hydrogen infrastructure come to fruition, market demand will shift toward transportation and other industrial applications.

285 grams of CO_2 per kilowatt hour (kWh) of hydrogen, while coal gasification, which is dominant in China, has an emission factor of 675 grams of CO_2 per kilowatt hour (kWh) of hydrogen and has lower efficiency. This means that unless hydrogen production is decarbonized, this fuel alternative won't help meet emission reduction goals.

Exhibit 3: Hydrogen Production Pathways Currently Favour the Refining and Ammonia Industries

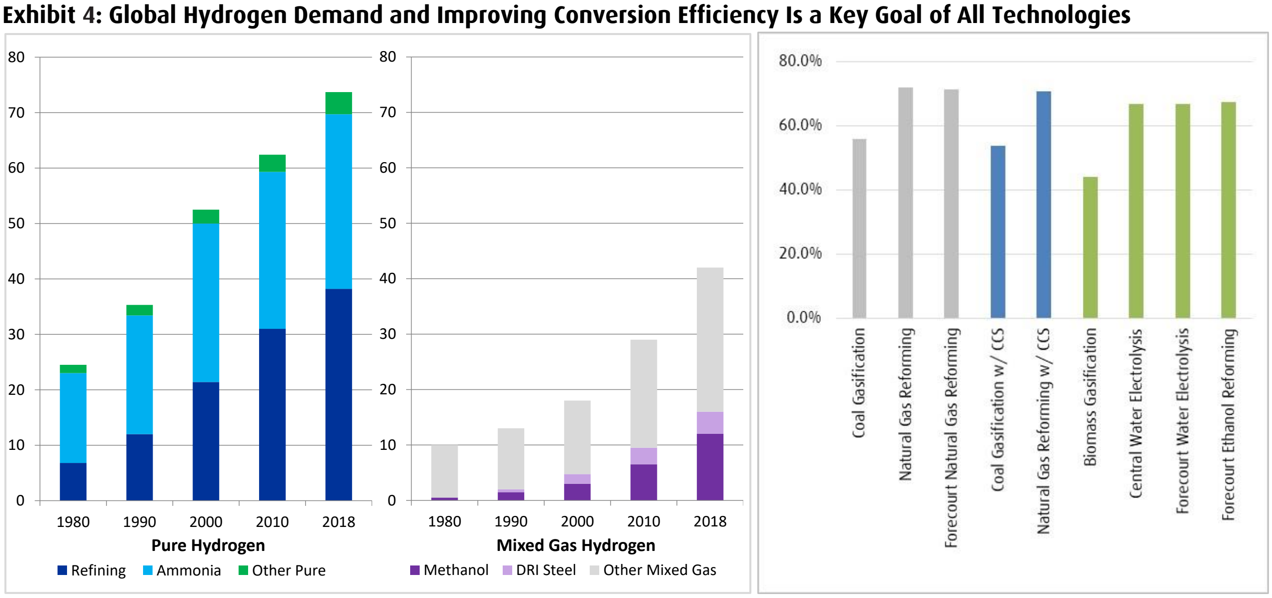


Source: IEA, BMO Capital Markets

Hydrogen can be produced using existing infrastructure via cleaner methods that either offset the emissions or eliminate the problem altogether. Carbon capture systems can be used to offset the emissions from carbon-intensive feedstocks and processes (grey → blue), but although there is merit in decarbonizing existing infrastructure that has many years of useful life, this method of hydrogen production doesn't necessarily fit into the fossil fuel energy free narrative. The more popular alternative, at least in Europe, is using water electrolysis (green hydrogen) to produce hydrogen from renewable resources (solar, wind, etc.) without releasing carbon emissions in the first place. However, some argue that producing hydrogen via electrolysis is an inefficient use of renewable energy on a wide-scale basis and, therefore, may not be as practical as has been suggested. Regardless, it is going to be part of this narrative going forward. Furthermore, both technologies for producing blue (carbon capture) and green hydrogen (electrolyzers) are evolving, have not yet matured technologically, and stand at 3-4x the cost to produce grey hydrogen. The conversion efficiencies of grey hydrogen methods with carbon capture are pretty-equivalent, but biomass gasification and water electrolysis efficiencies need improvement.

The bottom line is that carbon capture methods, storage, and utilization will need to be developed in unison for a hydrogen economy to gain traction. Looking at patent activity, many of the granted patents have been mostly for blue hydrogen processes such as fossil fuel reforming (37.9%) and coal gasification (31.2%); however, electrolysis (20.7%) is starting to gain traction. Therefore, we see this as strong indication that blue and green hydrogen production technologies will be part of the future.[3]

Exhibit 4: Global Hydrogen Demand and Improving Conversion Efficiency Is a Key Goal of All Technologies



Source: h2Tools, NREL, IEA , BMO Capital Markets

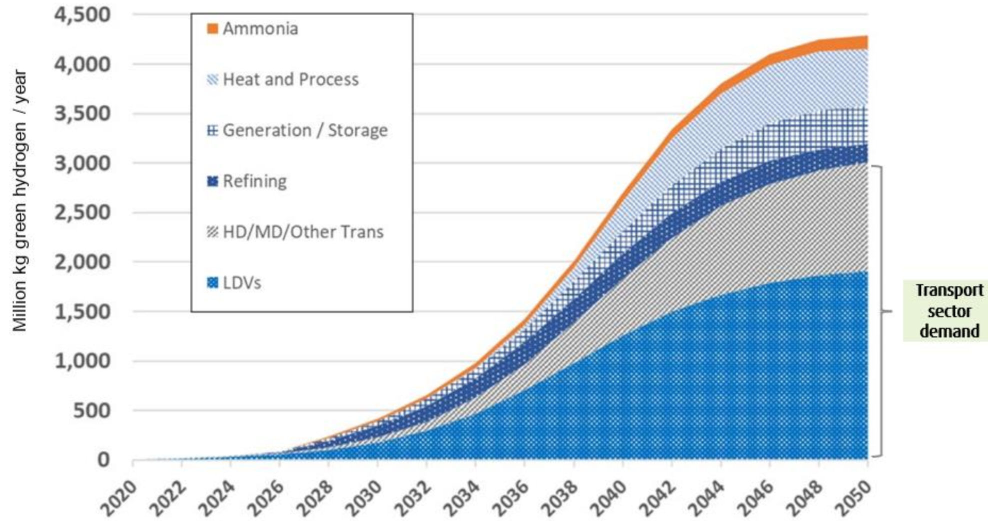
[3] Dehganimadvar, M., Shirmohammadi, T., Sadeghzadeh, M., Aslani, A. and Ghasempour, R. (2020). *Hydrogen production technologies: Attractiveness and future perspectives.* DOI: 10.1002/er.5508.

Current hydrogen demand in California is split between oil refining (46%) and ammonia production (45%)...

...but that is expected to change with increasing transport sector demand and infrastructure growth.

Using California as an example, future green hydrogen production demand is expected to be dominated by the transportation sector. According to the recently released *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California*, hydrogen production from renewable energy in the state is expected to grow from ~2 million metric tons per year to ~470 million and ~4,300 million metric tons per year by 2030 and 2050, respectively, in the most optimistic scenario.[4] Like most markets, hydrogen produced in the state is classified as 'grey' and predominantly used in petroleum recovery and refining. However, hydrogen demand in the transportation sector (LDV, MDV, and HDV)[5] is expected to account for ~47% total hydrogen demand in 2030 and ~67% in 2050 compared with negligible levels now and, therefore, will make up the bulk of the demand growth in the future. These forecasts show the changing dynamics of the hydrogen industry and that change will be predicated on infrastructure growth and the decarbonization of the production process.

Exhibit 5: Transportation Expected to Be ~67% of Green Hydrogen Demand in 2050



Source: California Energy Commission

Multiple Pathways for Hydrogen Production — Not a One-Size-Fits-All Approach

As there are multiple pathways for hydrogen production and the methods employed will vary from country to country and region to region, a lot of assumptions need to be made to formulate the many hydrogen mandates we describe in Appendix 1. Topography, existing infrastructure, waste management, water supply, and much more come into play, and the complications that arise cannot be understated. While many hydrogen plans seem myopically focused on green hydrogen, decarbonizing existing infrastructure in an economically supportive way is also being proposed, and in the next five years, we should see a more complete picture of how hydrogen will be incorporated into the energy mix. But for now, we can say with confidence that it will not be a one-size-fits-all approach, and the key short-term indicator will be how these technologies are integrated into existing infrastructure.

Furthermore, dealing with waste streams is now becoming part of the conversation. Some of the methods, such as partial oxidation, produce waste streams that are hard to use in secondary applications. This will also be a concern as companies move toward environmentally stable strategies.

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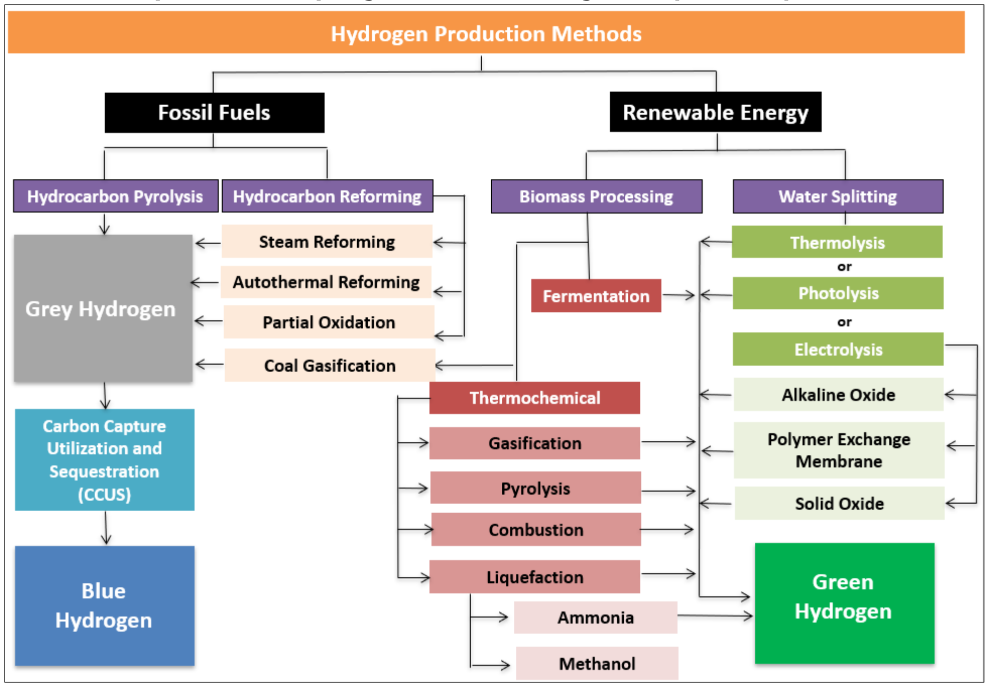
[4] California Energy Commission Clean Transportation (June, 2020). *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California*. Prepared by the UC Irvine Advanced Power and Energy Program. cafcp.org.

[5] LDV = light-duty vehicles; MDV = medium-duty vehicles; HDV = heavy-duty vehicles

These long-term forecasts are based on global numbers and do not take into consideration unique regional and national energy grid characteristics.

Implication: what works in one energy grid does not work in another, therefore, this chart could look different in Canada compared with Germany.

Exhibit 6: Many Methods of Hydrogen Production Being Developed and Optimized



Source: Dincer, 2012; Kumar and Himanbindu, 2019; BMO Capital Markets

As there are multiple pathways, the hydrogen economy in Germany will look very different than the one in Japan....

...and in North America, it will vary from region to region.

Hydrogen quality is a key issue with most of the commercial production methods currently used. The costs involved in producing the fuel standards that end users need are largely predicated on the carbon intensity and impurities in the feedstock. While there are various purification methods such as pressure swing absorption (PSA), membrane separation, or liquefaction, these extra steps add to hydrogen production delivery costs. Focusing on purification and using fuel cell vehicles as an example, the hydrogen fuel provided at the pump will require a certain purity level to perform as expected and meet our total cost of ownership estimates that we detail in Hydrogen Fuel Cells – The Clean Energy Answer to Heavy-Duty Applications. This is because the gold standard fuel cell used in this sector, the proton exchange membrane (PEM), requires the use of platinum catalysts, which tend to corrode in the presence of carbon monoxide impurities. While we go into more detail in Appendix 2 of this report, the required purity can be achieved using any of the methods shown in Exhibit 7; however, the production costs increase with each extra step required to meet end user demands. The bottom line is that certain fuel cell types will be more expensive to fuel if the main production method is coal gasification versus steam methane reforming, depending on their sensitivities.

The impurities present in the feedstock can affect the overall costs as fuel cells on the market require a certain level of purity to meet performance and longevity requirements.

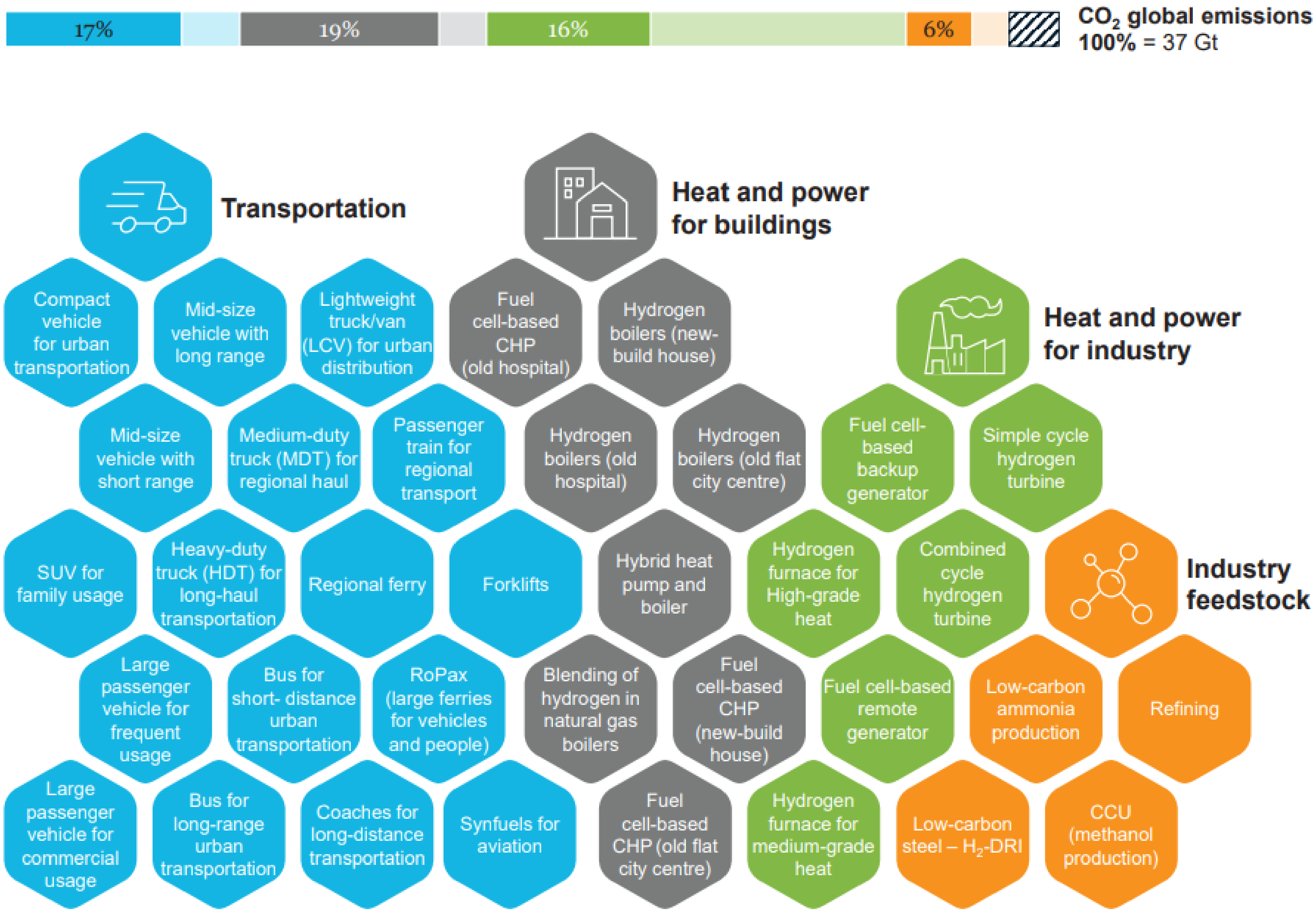
Exhibit 7: Impurities Present From Different Fossil Fuel-Based Hydrogen Production Methods

	Steam Methane Reforming (SMR)	O_2-Blown Autothermal Reforming	Coal Gasification	Ease of Removal With PSA [2]
Hydrogen (H_2) yield	94.3%	93.2%	87.8%	n/a
Impurities: [(1)]				
Carbon Monoxide (CO)	0.1%	1.4%	2.6%	Medium
Carbon dioxide (CO_2)	2.5%	1.7%	3.9%	Easy
Nitrogen (N_2)	0.2%	0.7%	5.0%	Easy
Methane (CH_4)	2.9%	2.4%	0.01%	Medium

1. The level of impurities in the feed streams entering the pressure swing absorption (PSA) purification unit produced by SMR, ATR, and coal gasification.
2. Medium means that there is an impact to PSA recovery and increased capital costs.

Source: Besancon *et al.*,2009; Ohi *et al.*, 2016

Exhibit 8: The Uses for Hydrogen Are Significant and Growing — Its Versatility Is Never Ending



Hydrogen can also be used for container ships, tankers, tractors, motorbikes, planes, auxilliary power units, large-scale CHP for industry, mining equipment, metals processing, and many more applications.
Source: Hydrogen Council

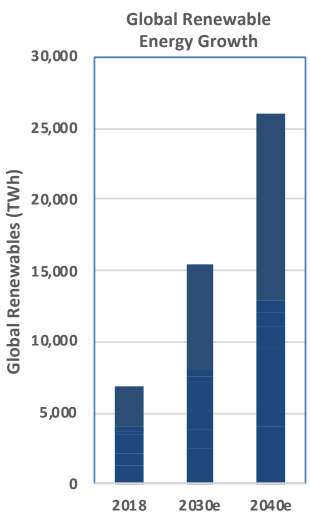
Exhibit 9: The Advantages and Disadvantages of Hydrogen Production Methods in Use and in Development

Hydrogen Production Methods	Advantages	Disadvantages	Key Technical Goals	Efficiency/ Cost
Steam methane reforming (SMR). Hydrocarbons react with high temperature steam over a catalyst to produce syngas (H_2+CO). **Grey and blue hydrogen**	• Most developed technology • Can be used in existing infrastructure • Can use natural gas, methanol, and oxygenated hydrocarbons • Does not require oxygen • Low operating temperature • Best hydrogen/CO ratio • High CO_2 capture rates (70%)	• Produces high amount of CO_2 (7.05 kg CO_2/kg H_2) • Removing CO creates more CO_2 • Second stage (post syngas) requires sulfur-free material • Susceptible to catalyst poisoning • Relies on fossil fuels • Needs to be paired with carbon capture system	• Reduce reformer footprint and costs • Optimize carbon capture technology • Manage variable demand • Designing stable catalysts	70-85% **Baseline:** $1.00 – 3.30/kg
Partial oxidation (PO). Hydrocarbons partially combusted with oxygen to produce syngas (H_2+CO). **Grey and blue hydrogen**	• Established technology • No catalyst and, therefore, not susceptible to catalyst poisoning • Not sensitive to sulfur	• Produces mostly heavy oils and petroleum coke, which is hard to treat and use in secondary applications • Requires extra step to ↑ H_2 yields • Produces more CO than SMR • High operating temp. (>800°C)	• Increase yields in fewer steps • Reduce the heat required to catalyze reactions	60-75% $1.50 – 3.50/kg
Auto-thermal reforming (ATR). A combination of steam and partial oxidation to produce syngas (H_2+CO). **Grey and blue hydrogen**	• Established technology • Can be used with existing infrastructure • Does not require heat • Higher CO_2 capture rates (90%)	• Produces CO and CO_2 that needs to be removed via water-gas shift reaction • Relies on fossil fuels • Require air or oxygen	• Decrease costs • Diversify feedstock via new catalysts	60-75% $1.50 – 3.30/kg
Coal gasification. Using a high-temperature vessel where oxygen and steam feed coal to produce syngas (H_2+CO). **Grey and blue hydrogen**	• Well-established technology • Can be used with existing infrastructure • Abundant and cheap feedstock	• Prone to tar formation • H_2 content depends on impurities • Needs to be paired with carbon capture system or highly polluting	• Optimize the gasification process • ↓ emissions and ash from coal gasification • Increase efficiency with CCS	60% $2.50 – 3.30/kg
Electrolysis.. Using electrolyzers to split water molecules into hydrogen and oxygen via water oxidation. **Green and yellow hydrogen**	• Established technology • Zero emissions if paired to renewable energy • Can be used with existing infrastructure • Oxygen is a byproduct	• Fuel storage and transportation problem unless used onsite • Energy intensive • Most expensive method on the market	• Bring operating costs down • Improved conversion efficiency	60-80% $1.75 – 10.00/kg
Biomass gasification. Using a high-temperature vessel where oxygen and steam feed organic waste (e.g., animal wastes) to produce syngas (H_2+CO). **Green hydrogen**	• CO_2 neutral when organic waste used • Assists in waste recycling • Simple reactor technology • High production rates	• Fluctuating H_2 yields because of feedstock impurities • Organic feedstock is expensive • Formation of tar and high emissions of CO, CO_2, and nitrogen • Needs large-scale centralized plants	• Reduce costs • Optimize the gasification process	35-50% $6.60/kg
Biomass pyrolysis. Heating biomass to temperatures ranging from 650K to 800K at 0.1-0.5MPa. **Green and turquoise hydrogen**	• Abundant and cheap feedstock • Can be CO_2 neutral • Can be adapted to numerous feedstocks • Oil products can be separated out	• Tar formation if hydrocarbons used • Fluctuating H2 amounts because of impure feedstock • Seasonal availability • Different catalysts need to be used	• Reduce number of steps • Improve catalyst stability	35-50%
Dark fermentation. Uses anaerobic bacteria on carbohydrate-rich substrates without using light. **Green hydrogen**	• Hydrogen is produced without light • No oxygen limits • Assists in waste recycling	• Early phase of development • Methane can also be produced • Low yields that vary widely • Needs large-volume reactors	• Generate 10 moles H_2/mole glucose • Improve selectivity • Improve fermentation	60-80% $50-60/kg
Thermolysis. Splitting water using high heat (500°C – 2,000°C). **Green hydrogen**	• Clean and sustainable • O2 byproduct • ubiquitous feedstock	• High capital costs • Elemental toxicity • Corrosion problems	• Still in the early research phase	20-45% n/a
Photolysis. Uses microorganisms such as green algae or cyanobacteria and sunlight to split water. **Green hydrogen**	• O_2 is a byproduct • abundant feedstock • no emissions	• Low efficiency, non-effective photocatalytic material, requires sunlight	• Still in the early research phase	20-45% n/a
Photo fermentation. Solar energy + organic acids + nitrogenase = photosynthetic bacteria that produces hydrogen. **Green hydrogen**	• Involves waste water recycling • CO_2 neutral method	• low efficiency & production rate • sunlight required • needs expensive, large volume reactors • oxygen sensitivity	• Still in the early research phase	0.1% n/a

Source: Kalamaras and Efstathiou, 2013; James *et al.,* 2016; U.S. Drive Partnership, 2017; Abdalla *et al.,* 2018; Kumar and Himanbindu, 2019; Newborough and Cooley, 2020; BMO Capital Markets

2. Water Electrolysis Depends on Renewable Energy

We start our in-depth analysis with electrolysis as it is often viewed as the Holy Grail of clean technology that will allow us to break away from our fossil fuel dependence. The successful integration of green hydrogen production via water electrolysis into the energy generation mix will rely on technological development to improve efficiencies, the cost of water electrolysis or electrolyzer technology, and the growth of renewable energy infrastructure. According to the IEA, global renewable electricity generation is expected to increase by 127% by 2030 and by 283% by 2040 compared with 2018 levels (left). This dramatic growth in renewable power generation, along with government policies designed to encourage the scaling up of water electrolysis technology, will be essential for the development of the green hydrogen economy.



Source: IEA

In this chapter, we discuss emerging water electrolysis technologies have evolved to the point that they are considered a key component of the green energy transition.

A Versatile Means of Power Generation With an Inexhaustible Energy Supply

The benefits of using electrolyzers are not necessarily tied to green hydrogen production and can be used in a variety of ways that include:

1. **Power to fuel.** On-site hydrogen production at refueling stations for a wide variety of fuel cell vehicles would be highly beneficial for public busses and commercial trucking as an electrolyzer can be installed in bus depots and delivery centres. Electrolyzers can be used in refineries in the desulfurization process from fossil fuels and can be used for residential and industrial heating purposes.
2. **Power to industry**. Electrolyzers can produce hydrogen that will be used directly as an industrial gas in the steel industry, flat glass plants, and the semiconductor industry. It can also be used to decarbonize natural gas applications.
3. **Power to gas.** Based on the conversion of electricity to hydrogen to power other sectors to meet decarbonization goals, electrolysis can be used in the production of methanol, ammonia, and even jet fuel, along with many other chemicals and materials.

Electrolyzers only produce zero-carbon hydrogen if they are connected to renewable, hydroelectric, or nuclear power; however, most grids produce GHG-intensive electricity.

As the only inputs are water and electricity, electrolysis can provide immediate GHG emission reductions of the energy grid as well as achieve synergistic economic benefits between hydrogen producers and energy grid operators. Furthermore, electrolysis can be implemented off-grid in regions with significant amounts of renewable resources and can be implemented incrementally to transform existing infrastructure that will meet national policy goals.

Renewables and hydroelectric may not be the only option — the case for yellow hydrogen. For countries that have significant nuclear capacity such as the U.S. (98.2GW), France (63.1GW), China (47.5GW), and Japan (32GW), connecting large electrolyzers would provide significant operational advantages. The U.S. Department of Energy estimates that ten 1,000 MW nuclear reactors could produce more than 200,000 tonnes of hydrogen annually or about one-fifth of the hydrogen currently used in the country. This production method would also be able to take advantage of regional hydrogen demand differences without the need to purify the end product for use in certain applications, such as fuel cell vehicles, that require rigid hydrogen fuel specifications without impurities.

A Primer on Splitting Water Molecules to Produce Hydrogen Fuel

Water electrolysis technology has developed substantially over the past 15 years, and a number of large-scale electrolysis installations are being piloted. Similar to fuel cell technology that we describe in Appendix 2, electrolyzers consist of an anode and a cathode, separated by an electrolyte, and are differentiated by (and named after) the electrolyte used. The electrolysis of water to produce hydrogen fuel is ideal as the output does not have the impurities that affect the performance and longevity of the fuel cell stacks, and water itself is a renewable commodity. Furthermore, the process is carbon free (no need for carbon capture), produces only pure oxygen as a byproduct, and produces hydrogen that is >99.5% pure. In other words, there is no need for further purification steps. However, the energy intensity of the process and the composition of the electricity grid, especially if there is a high amount of coal-powered energy generation in the mix, need to be evaluated from a total emissions perspective.

While solid oxide electrolyzer technology is gaining traction, alkaline and proton exchange membrane (PEM) electrolyzer technology will dominate this landscape over the next five years. On top of being the most technologically advanced, alkaline and PEM electrolyzer technologies have a number of unique advantages that will ensure their place in the hydrogen economy. For one, alkaline electrolyzers are much cheaper to run than PEM electrolyzers, and their simplicity means that they have a longer lifetime. They are also more flexible as a deionized water and alkaline solution can be used, while PEM electrolizers can only use deionized water. By contrast, PEM electrolyzers have higher current densities, are about one-third of the size relative to alkaline electrolyzers, and have benign waste products. While not the most toxic byproduct, lye, or sodium hydroxide, from alkaline electrolyzers is corrosive at high concentrations and can have immense environmental repercussions (e.g., changing the pH levels of fresh water lakes) if not disposed of properly in jurisdictions that do not have the appropriate regulations in place. That said, it can be used to neutralize acidic waste water making them environmentally benign. In other words, it is just more complicated.

The application and project costs will dictate electrolysis type. Hydrogen production by alkaline electrolysis is well established and commercially available up to the megawatt level, and PEM electrolysis may be installed at those levels by 2025 should current pilot projects be validated. While electrolysis technology has an efficiency of 60-80%, which is more or less similar to the current production methods, hydrogen produced in this manner faces storage and transportation problems and, therefore, is currently economically unfeasible.[6] Alkaline electrolyzers may have cheaper upfront costs, but PEM electrolyzers are better able to adapt to the intermittencies of renewables because there is a slower response due to the electrolyte. The platinum catalyst used in PEM electrolyzers allows them to absorb the energy better during intermittency and more easily perform forward and reverse reactions. Theoretically, this means that when wind and sun are present, hydrogen can be produced, and when not present, the PEM electrolyzer can act like a fuel cell and generate electricity easier than an alkaline electrolyzer at greater efficiencies.

Both technologies will need to be supplied with DC voltages and DC currents, and therefore, AC-DC converters are needed for the typical AC power supply from power grids and wind turbines, and for high current applications, rectifiers may also be required, further adding to the cost.[7]

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[6] Kumar, S. and Himanbindu, V. (2019). *Hydrogen production by PEM water electrolysis – A review.* Materials Science for Energy Technologies; 2(3):442-454.

[7] Yodwong, B., Guilbert, D., Phattanasak, M., Kaewmanee, W., Hinaje, M. and Vitale, G. (2020). *AC-DC Converters for Electrolyzer Applications: State of the Art and Future Challenges.* Electronics; 9(6):912.

The first step in driving down zero-carbon hydrogen production costs is to reduce electrolyzer technologies and enhance efficiencies...

...while alkaline electrolyzers are the least costly option, PEM electrolyzers will be critical to making widespread use of green hydrogen a reality.

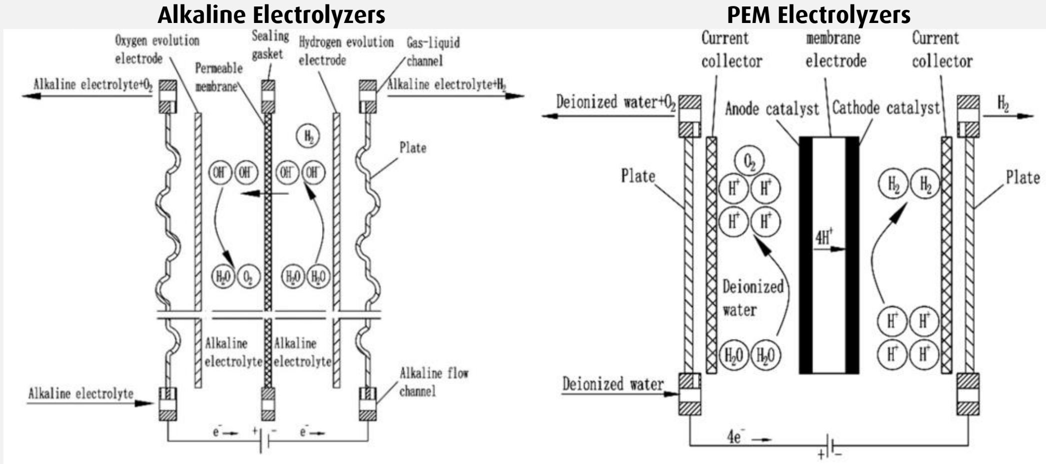
A Little More Detail for the Scientifically Inclined

Electrolyzers split water molecules to form hydrogen and oxygen gas →green hydrogen. The main technology being considered for large-scale production of green hydrogen involves electrolysis of water or water oxidation that uses electricity to split water into hydrogen and oxygen. However, regardless of the type of electrolyte used, the only byproducts are hydrogen and oxygen.

- **Alkaline electrolyzers.** In this the less costly alternative, water goes into the cathode side of the electrolyzer and is reduced to hydrogen and hydroxyl ions ($2H_2O + 2e^- \rightarrow H_2\uparrow + 2OH$-). The hydrogen ions form hydrogen gas, which is released, while the hydroxide ions are pushed to the anode side where oxygen is released ($2OH^- \rightarrow H_2O + 2e^- + ½O_2\uparrow$). Alkaline electrolyzers are the most technologically mature and the most common type used commercially as the process is well known, has an electricity-to-fuel energy efficiency of ~70-80%, and uses cheaper more ubiquitous catalyst materials (e.g. nickel, cobalt, and iron). However, as they use a liquid alkaline electrolyte solution, KOH or NaOH, the response to the fluctuating electrical input nature of wind and solar energy generation leads to energy wastage and makes them more susceptible to leakage, causing extra maintenance.

- **Polymer electrolyte membrane (PEM) electrolyzers.** Water goes into the anode side of the electrolyzer where it is split into hydrogen and oxygen ($H_2O \rightarrow ½O_2\uparrow + 2H^+ + 2e^-$), and the hydrogen ions move through the membrane to the cathode side of the electrolyzer to produce hydrogen ($2H^+ + 2e^- \rightarrow H_2\uparrow$). PEM electrolyzers have an electricity-to-fuel energy efficiency of ~60-80% and are expected to reach 82-86% by 2030; however, their need for expensive platinum catalysts and electrolyte membrane (Nafion®) are key factors contributing to their higher costs.

Alkaline Electrolyzers **PEM Electrolyzers**



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- **Solid oxide electrolyzers.** Although still at the research stage of development, solid oxide electrolyzers use a solid ceramic material as the electrolyte that selectively allows the passage of negatively charged oxygen ion (O^{2-}) and produces hydrogen in a slightly different way. First, water combines with electrons to form H_2 and O^{2-}, and then, the O^{2-} travels to the other side to form oxygen at the anode. This technology has more favorable thermodynamics and faster kinetics and, thus, is gaining traction. The U.S. DOE has invested $34 million to validate syngas production, and numerous companies are looking to commercialize this technology in the next couple of years.

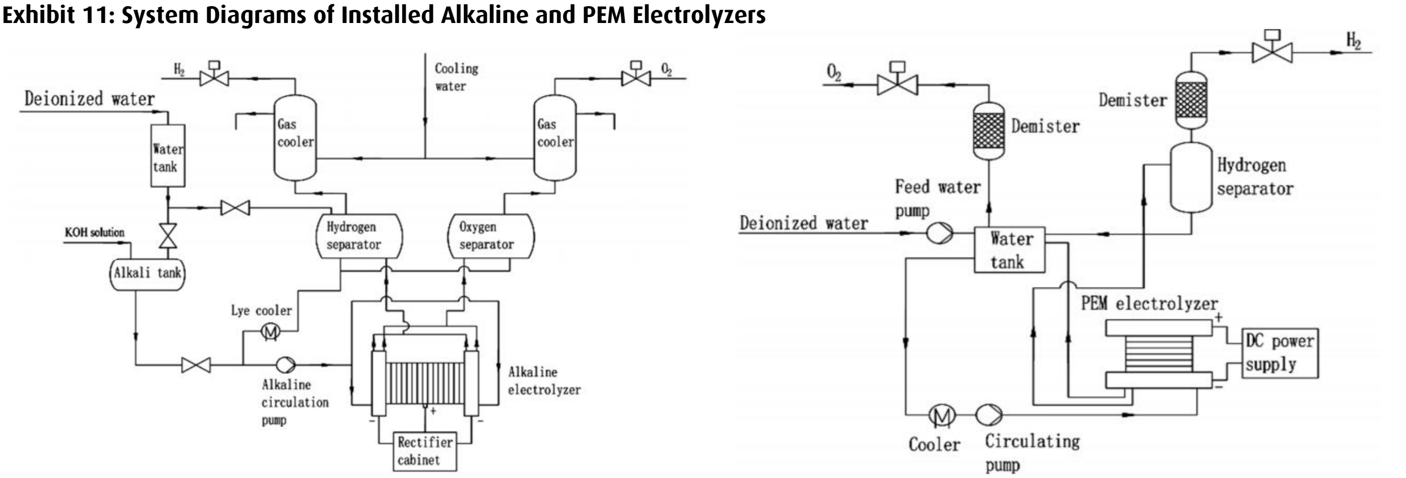
Source: US DOE, Dincer, 2012; Grond and Holstein, 2014; NIRAS, 2019, Guo *et. al.*, 2019, Gul and Akyuz, 2020; Brauns and Turek, 2020; Yodwong *et al.*, 2020

Exhibit 10: The Key Differences Between Alkaline and PEM Electrolyzers

	Alkaline	PEM
Current density	2,000-4,000 A/m^2	10,000-20,000 A/m^2
Working pressure	$\leq$3.2MPa	$\leq$5MPa
Operating temperature	80-90 °C	50-80 °C
Hydrogen purity	$\geq$99.8 %	$\geq$99.99 %
Export component	O_2 + lye, H_2 + lye	O_2 + deionized water, H_2 + trace deionized water
Raw material	Deionized water and alkali	Deionized water
Corrosion	Alkaline corrosion	None
Operating characteristics	Isobaric operation	Differential pressure operation
Volume and weight	Very large	1/3 the size of alkaline electrolyzers
Manufacturing cost	Low	High
Lifetime	10 years	3-4 years

Source: Guo *et al.*, 2019

Exhibit 11: System Diagrams of Installed Alkaline and PEM Electrolyzers



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Electrolyzer Costs and Capex Are Expected to Come Down Quickly

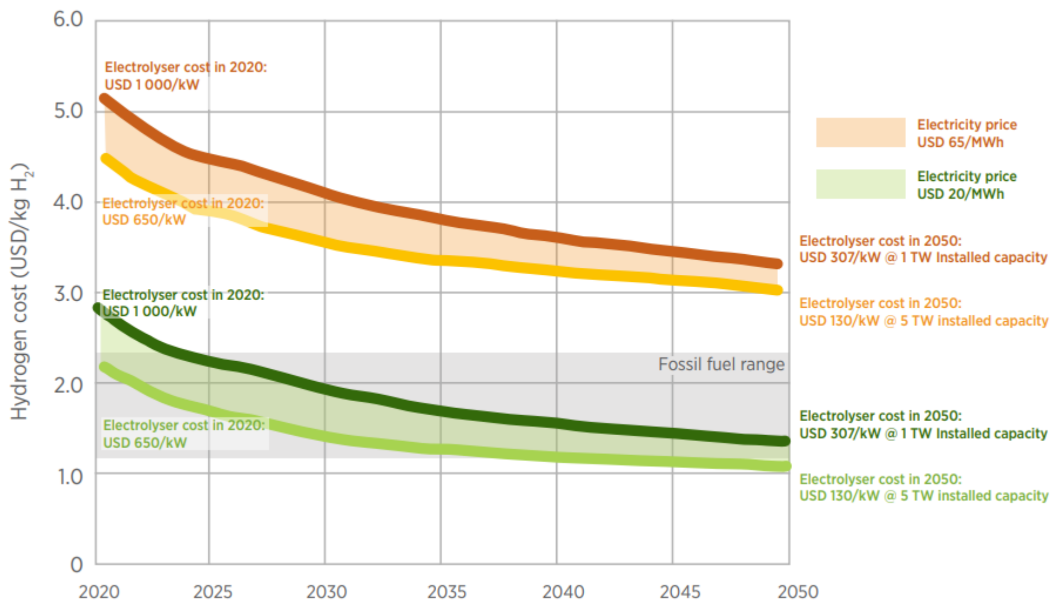
The cost of green hydrogen production is a function of electrolyzer deployment and electricity prices. Capital requirements for green hydrogen can be fairly-significant today and can vary depending on the technology. According to the IEA, for alkaline electrolyzers, the capital costs are in the range of US$500-1,700/KWe, while more expensive PEM electrolyzes can fall in a range of US$1,100-1,800/KW. The IEA and IRENA estimate that costs for electrolyzers will drop by more than 50% over the next decade.

	Alkaline Electrolyzer			PEM Electrolyzer		
	Today	2030	Long-Term	Today	2030	Long-Term
Electrical Efficiency (% LHV)	63-70	65-71	70-80	56-60	63-68	67-74
Capex (US$/KWe)	500-1700	400-850	200-700	1100-1800	650-1500	200-900

Source: IEA, BMO Capital Markets

Should electricity prices remain fairly low (~US$30/MWh) and rapid scale-up takes place in the next decade, then Exhibit 12 shows that green hydrogen could become cost competitive with grey and blue hydrogen by 2030. However, this is a highly optimistic scenario.

Exhibit 12: Electrolyzer Costs Are Expected to Come Down Significantly



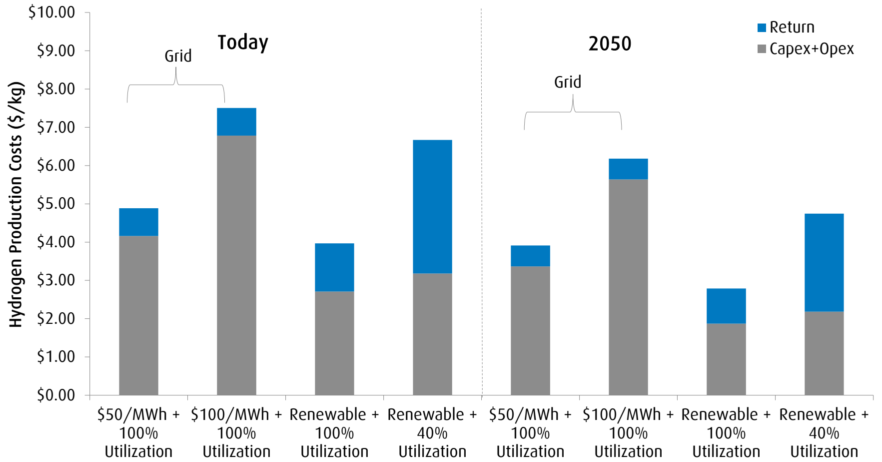
Note: Efficiency at nominal capacity is 65%, with a LHV of 51.2 kilowatt hour/kilogramme of hydrogen (kWh/kg H2) in 2020 and 76% (at an LHV of 43.8 kWh/kg H2) in 2050, a discount rate of 8% and a stack lifetime of 80 000 hours. The electrolyser investment cost for 2020 is US$650-1000/kW. Electrolyser costs reach US$130-307/kW as a result of 1-5 TW of capacity deployed by 2050.
Source: IRENA

Hydro accounts for 67.5% of the renewable energy in Canada followed by solid biomass at 23.3%, wind at 5.2%, and others at 4%.

Cost per kilogram will depend on electricity costs and runtime on a fully loaded basis. Using Canada as an example, Exhibits 14 and 15 show that the levelized cost of hydrogen is highly dependent on the operating hours of the electrolyzer, and as operating hours increase, levelized cost falls. At the same time, as operating hours increase, total electricity costs rise. Furthermore, the levelized cost of hydrogen under electrolysis is highly dependent on the area of operations and cost of electricity in the regional grids. As we have repeatedly stated, the use of any technology, including renewables, is not a one-size-fits-all endeavour. As Canada is not as well endowed with sunlight compared with other countries, we believe the overall cost of green hydrogen in many areas in Canada will be significantly higher. However, areas where hydroelectric power is plentiful (Quebec, BC, and Manitoba) have an acute advantage and could act as a national "hydrogen" hub, providing for a low-cost source of electricity.

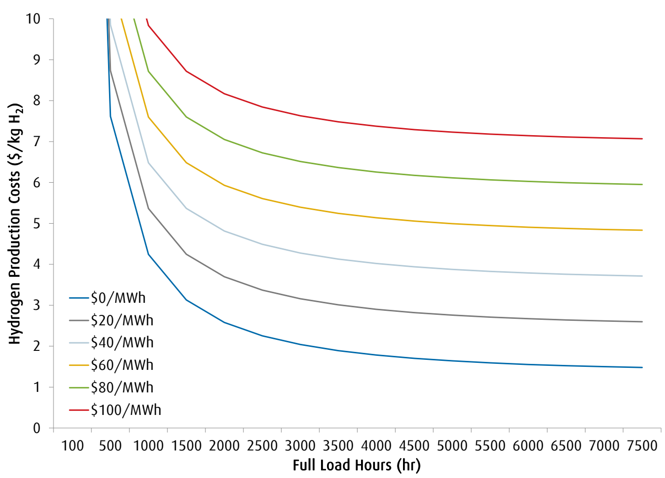
Inputting an 8% return assumption into this scenario, we estimate the all-in hydrogen production costs using electrolysis would currently range from C$4.00 to $7.50 per kg of hydrogen in Canada, and although the cost could come down if offshore wind enters the picture (projects of more than 3.6GW have been proposed), having dedicated renewable power with electrolysis can result in lower hydrogen production costs over time. We estimate that hydrogen production costs under a renewable plus electrolysis framework could reach as low as C$2.75-4.70/kg of hydrogen, although the C$2.75/kg production cost is under the assumption of 100% utilization. Furthermore, these costs are expected to come down if electrolysis costs come down as expected.

Exhibit 13: Hydrogen Production Costs Using Electrolysis



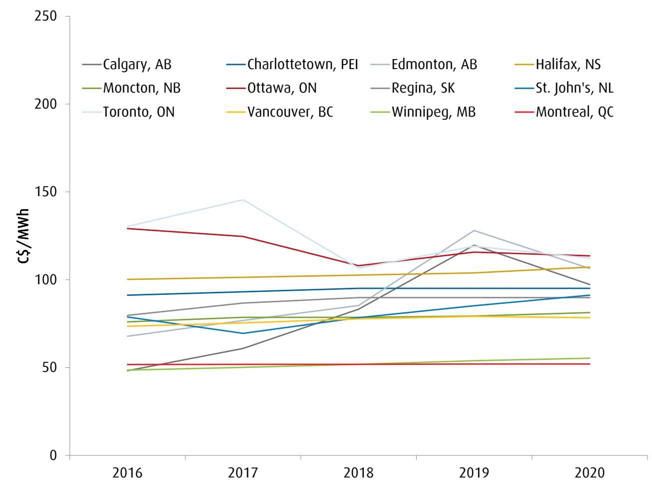
Source: BMO Capital Markets *Today's assumptions: LVH efficiency of 64%, Capex cost of US$900/KW, operating hrs of 95,000 ** 2050 assumptions: LVH efficiency of 74%, Capex cost of US$450/KW, operating hrs of 100,000 ***Renewable power costs assume wind power only of ~US$1,450/KW in 2021 and ~$1,100/KW in 2050

Exhibit 14: Hydrogen Production Costs vs. Full Load Hours



*US$1,500/KWe Capex, 60% Efficiency (LHV), assumes PEM electrolyzer.
Source: BMO Capital Markets

Exhibit 15: Average Price for Large-Power Customers by City



*Large Power Customers (Power Demand of >5,000 KW or monthly consumption of 3.1mm kWh).
Source: Quebec Hydro, BMO Capital Markets

Exhibit 16: Leading Alkaline and PEM Electrolyzer Technologies

Manufacturer	Series and Operating Pressure	Hydrogen Flow Rate ($Nm^3 \cdot h^{-1}$)	Energy Consumption ($kWh \cdot Nm^{-3}$ H_2)	Load Range (%)	Electrolyte	Power
Alkaline Electrolyzers						
Hydrogenics	HYSTAT/10–25 bar	10–60 max. 15/stack	4.9–5.4 (AC system all included)	40–100 (25–100 as an option)	H_2O + 30% wt. KOH	100–515 kVA
McPhy	McLyzer/10–30 bar	10–800	4.43–5.25 DC system at nominal flow rate	-	-	57 kW–4 mW
Teledyne Energy Systems	TITAN HMXT 10 bar	2.8–11.2	-	-	-	-
Teledyne Energy Systems	TITAN EL-N 10 bar	56–78	-	-	-	-
Wasserelektro-lyse Hydrotechnik	EV 50–EV 150 Atmospheric 4 bar	75–220	5.28 depending on the operating temperature and the load	20–100	30% KOH	-
NEL	A Series 1–200 bar	50–3880	3.8–4.4	15–100	25% KOH Aqueous Solution	up to 2.2 mW
Nuberg PERIC	ZDQ 5–600 15 bar to 20 bar	5–600	4.6 DC system	-	30% KOH (by weight)	23.7 kW–2.74 mW
Sagim S.A.	M-series 7 bar	1.5–5	5	-	-	14–42 kVA
Tianjin Mainland Hydrogen Equipment	FDQ series 3 bar to 5 bar	2–1000	4.4–4.9 DC system	40–100	30% KOH	-
Green Hydrogen	A-Series 35 bar	2.7–8.1	4.63–4.81	-	-	125–390 kW
Proton Exchange Membrane (PEM) Electrolyzers						
Proton OnSite	S Series 13.8 bar	0.265–1.05	6.7	0–100	Nafion ®membranes	-
Proton OnSite	H Series 15–30 bar	2–6	6.8–7.3	0–100	Nafion ®membranes	-
H-TEC Systems	H-TEC Series-S	0.22–1.1	No details	No details	Nafion ®membranes	1–5 kW
H-TEC Systems	ME unpressurised 30 bar	13–210	4.9	No details	Nafion ®membranes	225 kW–1 mW
Areva h_2 gen	E series Up to 35 bar	10–200	4.7–5.3	No details	Nafion ®membranes	80–1600 kVA
Hydrogenics	HyLYZER 0–7.9 bar	1–2	6.7	0–100	Nafion ®membranes	-
ITM Power	HPac, HCore, HBox, HFuel 15 bar	0.6–35	4.8–5.0 (system)	No details	Nafion ®membranes	2 mW
Siemens	SILYZER 200 35 bar	225	No details	No details	Nafion ®membranes	1.25 mW
Green Hydrogen	P-series/15–50 bar	1	No details	25–100	Nafion ®membranes	4.95 kW
NEL	M Series 30 bar	103–413	4.53	0–100	Nafion ®membranes	0.5–2 mW

Source: Yodwong *et al.,* 2020

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3. Carbon Capture Will Be Part of the Clean Energy Future

Realizing the decarbonizing impacts of hydrogen relies on a variety of factors; however, bringing the costs of producing both blue and green hydrogen down is the first step to achieving cost parity with grey hydrogen. While green hydrogen is seen as the Holy Grail, blue hydrogen can be thought of as an important stepping stone to that reality and a means of utilizing the full potential of existing infrastructure with many years of useful life. Therefore, more efficient, less costly, larger-scale, and agile carbon capture systems that can be readily adapted to today's reality are important pieces of the hydrogen puzzle. According to the Global CCS Institute, 51 large-scale carbon capture units are in operation or under construction; however, similar to electrolysis, carbon technologies are still evolving and have yet to achieve the technological maturity required for large-scale applications. The bottom line is that although the concept of carbon capture is not as popular as electrolysis, CO_2 emissions will not be reduced in the regulatory timeframes without it.

In this chapter, we describe why carbon capture should not be overlooked and why we believe that its development and commercialization constitute an important step to realize a clean energy future. While steam methane reforming (SMR) and coal gasification are the leading technologies in this field, they need to be paired with carbon capture to reduce CO_2 emissions. However, carbon storage and the use of the CO_2 captured in other industries still need to be determined as pathways are murky.

A Primer on Carbon Capture for Decarbonizing Hydrogen Production

Green hydrogen may be viewed as the ultimate goal, but blue hydrogen is the 'low-hanging fruit' to decarbonizing existing energy infrastructure ...

Carbon capture sequesters a concentrated stream of CO_2 emitted from industrial processes and captures it *before* it is released into the atmosphere. Given that the leading methods of producing hydrogen are carbon intensive, we believe that carbon capture is a key ingredient in this transition, and we have evaluated the leading technologies based on their technology readiness levels (TRL 1–9). To give context to this measurement, TRL 1 covers basic principles at the benchtop level or lab, while at the highest level, TRL 9, the technology has been proven in a real-world application. A TRL of 5-8 means that there is higher developmental risk due to design errors, technological failure, or operational fault, while TRL 9 means that the technology is verified but the business case still needs development.

...however, carbon capture technologies are still in early development and efficiencies need to be improved.

Grey hydrogen + carbon capture system (CCS and CCUS) → blue hydrogen. Carbon capture generally involves capturing CO_2 produced during the industrial process and permanently storing it (CCS) or using it to make fuels or other products (CCUS). There are three main routes: 1) pre-combustion (integrated combined cycle); 2) post-combustion (CO_2 is sequestered from the flue gas); and 3) oxy-fuel combustion (the use of pure oxygen to produce highly CO_2 concentrated flue gas). While other industrial carbon capture processes that differ from these routes are used to in cement or steel production and to purify natural gas and produce hydrogen-containing syngas for the manufacture of ammonia, alcohols, and synthetic fuels, most of the CO_2 captured is released into the atmosphere anyway, because there is no financial incentive or regulation to store or utilize it again in another application.

There is a wide variety of carbon capture techniques, but the preferred method is the absorption amine process, which has a TRL 9 rating and is the type installed in small refineries in Norway, Japan, and the Netherlands. The absorption amine process involves passing the flue gas through an amino scrubber, which is then heated and transferred to a stripper. This allows CO_2 gas to be released from solution, which is then compressed and transferred through a pipe or stored. Other carbon capture methods include temperature swing absorption (TRL 6-7), cryogenic carbon capture (TRL 5), and calcium looping (TRL 6-7). The first steps to the successful deployment of carbon capture systems involve vastly improving real-world capture yields and developing more efficient physical and chemical separation techniques. This is ongoing research in laboratories worldwide.

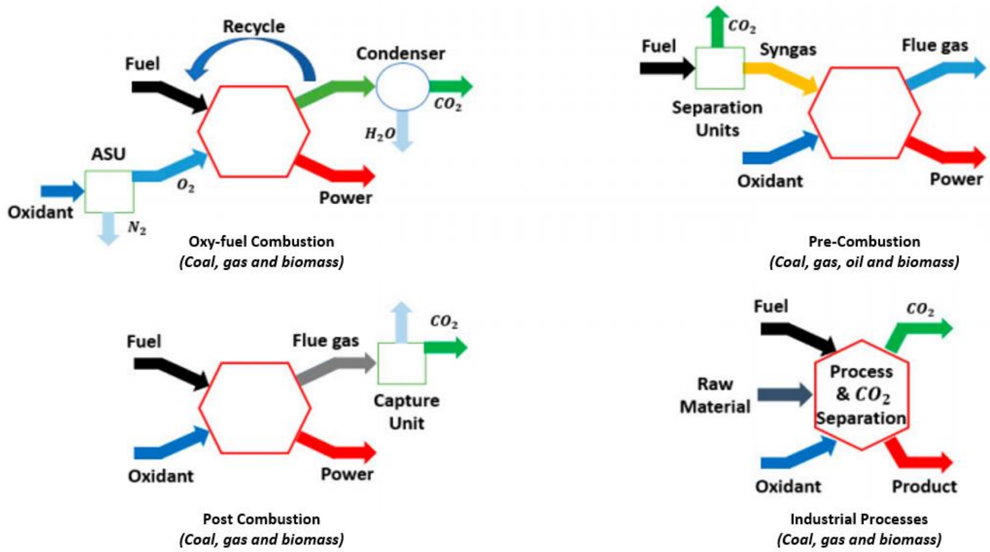
For oxy-fuel combustion, fuel is burned in a nearly pure oxygen environment rather than air and that results in a more concentrated CO_2 emissions stream that is easier to capture...

...however, as carbon capture is in its infant stages, mitigating investment risk is a key industry issue.

Comparing green hydrogen to blue hydrogen is like comparing apples to oranges where no direct comparisons can be made...

...the choice between them depends on which is the most economically feasible option.

Exhibit 17: Methods of Carbon Capture That Can Be Adapted Based on Inputs



Source: Cannone, S., Lanzini, A. and Santarelli, M. (2021). *A Review of CO2 Capture Technologies with Focus on CO2 Enhanced Methane Recovery from Hydrates.* Energies; 14:387. @Creative Attribution License

There is a large disparity in the data that needs to be resolved to make proper comparisons, but in general, a reduction in life cycle emissions by 55-90% is a reasonable benchmark. According to a report by IRENA, CCS pilot projects have been shown to be only ~30% effective, citing the Boundary Dam project in Canada and the recently decommissioned Petra Nova project in Texas as examples.[8] However, other accounts state that both projects captured 90-95% of CO_2 emitted from these respective coal plants. This large disparity is likely due to the different methods used to measure CO_2 capture efficiency (there are four methods to calculate capture efficiency), but this lack of a standardized metric has created some uncertainties surrounding this technology that will need to be resolved to make proper comparisons.[9]

For now, there are 43 commercial large-scale CCS installations around the world that, according to the IEA, capture more than 30 million tons of CO_2 every year. Furthermore, Dr. Julio Friedman, a leading researcher from the Center on Global Energy Policy at Columbia University, notes that CCS technology has been proven, has been shown to reduce life cycle emissions by 55-90%, and there are no technological barriers to effectively store CO_2 permanently on a large scale at a cost of $40 per tonne.[10] This, in our view, is a realistic benchmark at this juncture. The bottom line is that the success of the hydrogen economy is predicated on how both carbon capture systems and electrolyzer technologies are intertwined in varying combinations that are unique to a particular region's energy generation mix, climate, and topography.

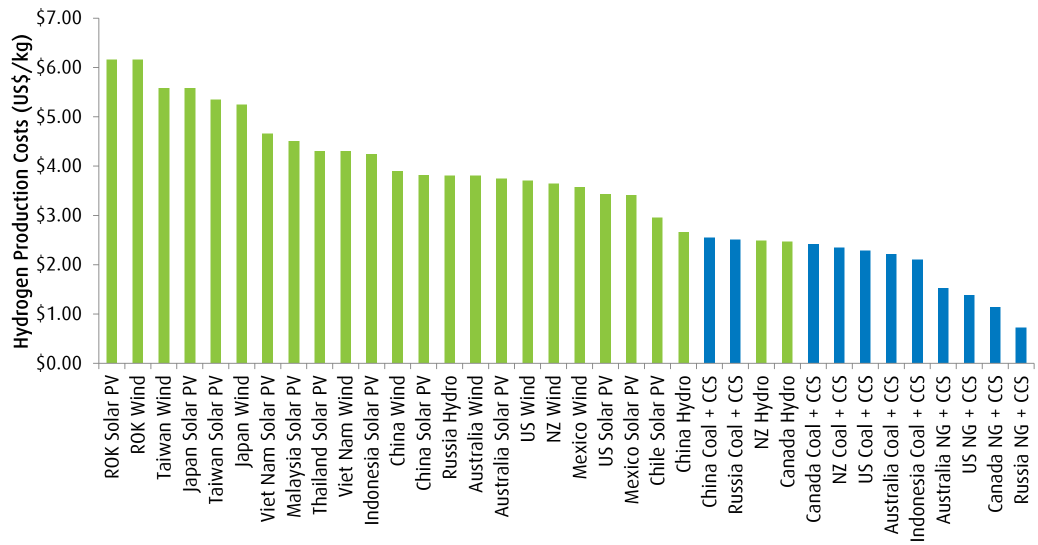
Using Canada as an example, it is clear from comparing the costs of the various electrolyser and carbon capture installations in Exhibit 18 that a predominately blue hydrogen strategy is in the country's best interest to decarbonize energy generation. However, this may not be the case for other countries, and although public opinion favours green hydrogen, it may not be the most cost-effective choice.

[8] International Renewable Energy Agency (2019). *Hydrogen: A Renewable Energy Perspective, A Report Prepared for the 2nd Hydrogen Energy Ministerial Meeting in Tokyo, Japan.* www.irena.org.

[9] Cents, A., Brigman, N., Askestad, I., and Fostas, B. (2014). *Results from MEA testing at the CO2 Technology Centre Mongstad. Part II: Verification of baseline results.* Energy Procedia; 63:5994-6011.

[10] Varanasi, A. (September 27, 2019). *You Asked: Does Carbon Capture Technology Actually Work?* State of the Planet: Earth Institute, Columbia University. https://blogs.ei.columbia.edu/2019/09/27/carbon-capture-technology/

Exhibit 18: Canada Places Among the Lowest in Green vs. Blue Hydrogen Production Costs



Source: APERC, BMO Capital Markets

While CO_2 emissions are the primary regulatory target, the plans in place to reduce it will also reduce other problematic emissions that affect climate change and toxins proven detrimental to human health.

A Little More Detail for the Scientifically Inclined

Why Carbon Dioxide (CO_2) Is the Baseline for Measuring the Impact of GHG Emissions

We often receive questions about why there is so much attention on CO_2 emissions and carbon capture systems that only focus on CO_2 when other greenhouse gases (GHGs) are equally important and perhaps more harmful. The reason is that CO_2 is by far the most abundant of these gases, and even though CO_2 is the least efficient heat-trapping gas on a per mole basis, its weaker radiative efficiency (RE), with an RE of 1.4×10^5 compared with 3.7×10^4 for methane CH_4 and 3.03×10^3 for N_2O, means that it is responsible for ~60% of the observed heat warming effects Furthermore, its rate of atmospheric decay is about 120 years compared with ozone and methane, which decay in 0.1 year and 10 years, respectively. For these reasons, CO_2 sets the standard for the global warming potential (GWP) scale and is the focal point for regulators to formulate policy. Excessive CO_2 emissions also dissolve in seawater to form carbonic acid, leading to the acidification of oceans and decay of essential ecologies around the world, and increasing atmospheric CO_2 has been linked to rising sea levels.

Source: Rodhe, 1990; Cherubini et al., 2011; Zickfeld et al., 2017

We Have Prevented CO_2 From Being Emitted, Now What?

Since publishing our first reports on the hydrogen economy, we have been asked about what happens to the CO_2 gas after it has been captured. For one, carbon capture can decrease a plant's efficiency and increase water use and that could be a geographical issue in areas that are facing water shortages. Furthermore, there are transportation and storage challenges that need to be overcome.

- **Transportation.** If the site of capture is far from the site of storage, then transportation is required. There are significant energy costs to compressing CO_2 and keeping it compressed throughout the transportation process. Similar to hydrogen where we see many of the same issues, the CO_2 pipeline will need to be specifically designed as existing infrastructure cannot be used. Furthermore, impurities in the CO_2 stream could lead to leaks and, although the risk is low, explosions.

- **Storage.** In regions that have the appropriate geological formations such as saline aquifer formations, depleted oil and gas reservoirs, and deep un-mineable coal beds or has established oil and gas infrastructure where CO_2 can be stored during enhanced recovery, then storage is a much easier and more economical endeavor.[11] These formations are able to more securely trap CO_2 via physical trapping (hydrostratigraphic or by capilliary), which traps CO_2 for about a century, or by geochemical trapping, whereby CO_2 is dissolved into a brine. Although these methods have attracted a fair amount of controversy, scientists are analyzing possible outcomes and finding that properly managed sites are *unlikely* to induce felt seismicity that would lead to a leak.[12] But the risk remains real. Finally, if these formations are not within a reasonable distance, then transportation and, possibly, political negotiations add to the cost.

- **Utilization.** Luckily, CO_2 has multiple industrial and commercial uses and we touch upon only a few of the possible ones here as it is part of many chemical transformative processes. CO_2 in solid and liquid form can be used in for refrigeration and cooling, to manufacture casting molds, as a propellant in aerosol cans, and it is a raw material in many chemical processes such as methanol and urea. Furthermore, CO_2 can be used in the food and beverage industry to make carbonated drinks and decaffeinated coffee and to purify volatile flavor and fragrance concentrates. However, the logistics of transportation and temporary storage come into play.

The bottom line is that carbon capture is, in our view, an important part of decarbonizing hydrogen production in the short term and is a technology that can be applied to decarbonize other CO_2 emission-intensive industries. Our reason is that although energy generation is shifting toward renewables, there are also industrial and energy generation plants with many years of useful life. Furthermore, the uses of CO_2 are endless and could be an important piece of creating sustainable consumer products from legacy industrial processes. The scale required to decarbonize hydrogen fuel production only amplifies the capital investment required.

Further cost implications and uncertainties of carbon capture still need to be addressed. The methods to produce hydrogen from natural gas are well-established mature technologies, while carbon capture is not. At this point, we do not know how extensive the infrastructure will need to be to transport CO_2, and aside from technological risk, there are other cost implications and uncertainties that still need to be addressed. Namely, the legal responsibilities and liabilities will need to be ironed out, and insurance for high-pressure CO_2 pipelines will be required. Finally, CO_2 is not the only concern as upstream methane leaks, a much more potent greenhouse gas, is also a possibility.

Therefore, government subsidies will likely be needed to establish a clear business model and garner the public support necessary as well as to establish auditing methods to verify that blue hydrogen is indeed a low-carbon hydrogen production method.

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[11] Ajayi, T., Gomes, J. and Bera, A. (2019). *A review of CO2 storage in geological formations emphasizing modeling, monitoring and capacity estimation approaches.* Petroleum Science; 16: 1028-1063.

[12] Vilarrasa, V. and Carrera, J. (2015). *Geologic carbon storage is unlikely to trigger large earthquakes and reactivate faults through which CO2 could leak.* PNAS: 112(19):5938-5943.

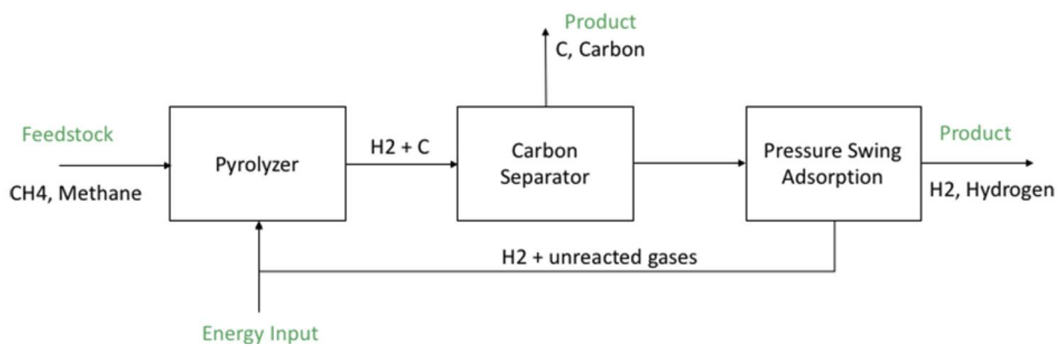
Turquoise Hydrogen: Pyrolysis Is an Important Emerging Technology

Although we believe that the use of SMR, coupled with carbon capture, will remain the dominant method to produce hydrogen from fossil fuel feedstocks, research is under way to find alternate methods that perhaps don't require technology add-ons to reduce carbon emissions. Methane pyrolysis is the leading candidate at the moment, and this hydrogen production method is subdivided into thermal, plasma, and catalytic pyrolysis. Dubbed 'turquoise' hydrogen, pyrolysis technology has not been used at a commercial level; however, Gazprom has developed pyrolysis technology that is being considered as part of a potential hydrogen production plant at the German terminus of the Nord Stream 2 natural gas pipeline. That said, costs and hydrogen purity continue to be challenges, and carbon residue can clog up the reactors, reducing their longevity and increasing costs.

A decarbonized method of using fossil fuels to produced hydrogen that does not require carbon capture. The thermal decomposition of natural gas (CH_4) into its constituent elements, hydrogen gas (H_2) and solid carbon (C), is not a new technology as it has been used to produce carbon black since the1930s in the rubber industry. However, this technology can also be adapted to become a hydrogen production method whereby methane is converted via a high-temperature process into hydrogen gas and solid carbon in the presence of a catalyst. Some companies, such as start-up C-Zero, believe that this technology can be used if catalysts that favour high-purity hydrogen rather than a high-quality carbon solid that can be used in other industries are used. However, this could mean disposal issues (it is possible to store or safely dispose of the solid carbon as it is not considered a hazardous material) or extra steps to produce quality raw carbon inputs required for tires, plastics, paints or inks.

Another example includes the Cancarb facility in Medicine Hat, Alberta, which uses the hydrogen gas produced as a fuel to heat the reactors in the production cycle as shown in Exhibit 19. In 2001, the facility installed a waste heat recovery unit to capture exhaust gases/heat to produce steam that drives a power generation plant, providing a source of clean electricity to the local grid. With a finite market for carbon black (3.75kg produced per kg of H_2), technologies are being developed to find alternate uses for the produced byproduct (C) or improve the efficiency of the process to enhance economics of hydrogen production through pyrolysis without carbon sales.

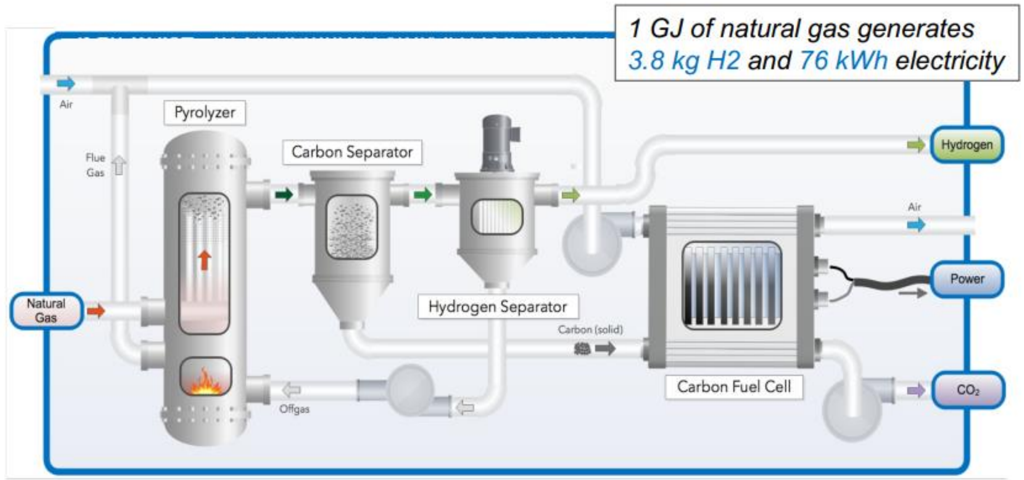
Exhibit 19: Thermal Pyrolysis



Source: BCBN Hydrogen Study

Tri-generation pyrolysis (TGP). Canadian-based startup Ekona Power has developed a process that combines thermal pyrolysis of natural gas to fuel a 'direct carbon fuel cell' to generate electricity. However, CO_2 is produced as a byproduct of this power generation, but it is at an estimated 90% greenhouse gas reduction compared with SMR. This technology is in the early stages of development; however, Ekona projects commercial hydrogen production costs as low as C$0.60/kg when factoring in electricity sales. In tandem, Ekona is also developing a pyrolysis technology called pulse methane pyrolysis (PMP), which injects pulses of thermal and mechanical energy into the system and is scalable for industrial applications. Assuming no carbon sales, the company sees hydrogen costs as low as C$1.36/kg at a commercial level.

Exhibit 20: Tri-Generation Pyrolysis

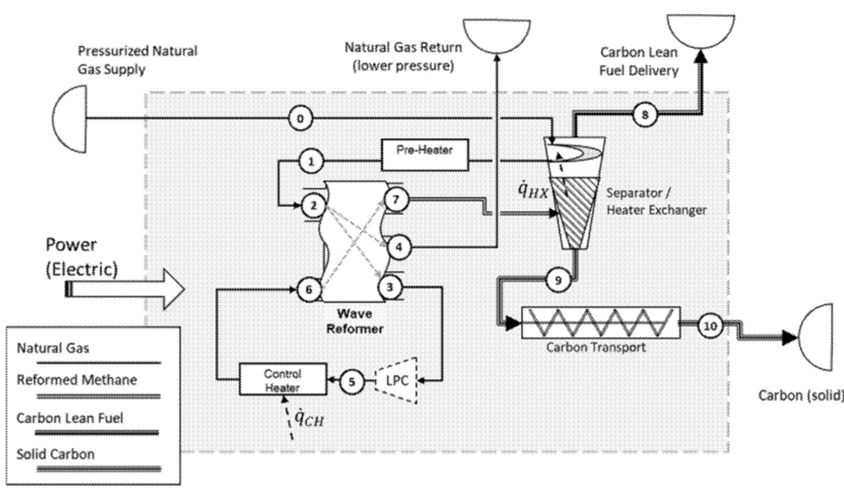


Source: Ekona Power

Molten metal thermal pyrolysis. Technology is being developed to improve the methane conversion rate in thermal pyrolysis to create a more efficient process and strengthen hydrogen production economics. Using molten gallium or a liquid alloy such as nickel-bismuth as a heat transfer agent and catalyst, for example, can maximize the methane conversion efficiency to as high as 95%. Assuming conversion of ~90%, studies have calculated hydrogen production costs as low as C$1.68/kg using liquid metal thermal pyrolysis technology.

Shock wave thermal pyrolysis. Calgary-based New Wave Hydrogen (formerly Standing Wave Reformers) has developed technology that utilizes shock waves or compression energy to create the heat necessary for thermal methane pyrolysis without the need for catalysts. The company claims its systems can be installed in any pressurized pipeline to decarbonize the natural gas stream.

Exhibit 21: Hydrocarbon Wave Reformer



Source: Standing Wave Reformers

Plasma pyrolysis. The plasma torch was invented in the 1990s in Norway and represents an alternate method of forming carbon black and hydrogen gas from natural gas. The plasma torch generates the required heat through the combination of electric power and recirculated hydrogen. It is estimated that electricity requirements are 80% lower than for PEM electrolysis. A Canadian company, Atlantic

Hydrogen, built a prototype using this technology in the 2010s with the aim of blending the local natural gas grid with up to 20% hydrogen, but it went bankrupt before a larger-scale pilot was completed.

Catalytic pyrolysis. Converted carbon is released as CO_2 during combustion in this process, so it isn't considered a viable alternative in the context of this report.

4. Delivery, Storage and Refueling Issues Need to Be Solved

While the U.S. DOE has mainly focused on reducing fuel and dispensing costs for retail consumption in the transportation sector, the same efficiencies will apply in other applications. Whether it is refueling hydrogen tanks on-site for manufacturing purposes or even home and transportation use, the new hydrogen infrastructure needs to be able to accommodate multiple applications in a similar fashion to the fossil fuel industry. The ultimate price target for hydrogen fuel is a high market volume price of $2.05 by 2030-2035, and to reach this target, research and development needs to focus on reducing the costs of key components (transportation, storage, etc.), and that could mean enabling liquid hydrogen transport in lieu of using compressed gaseous transport tanks as long-term storage options remain elusive.[13] The bottom line is that these constraints will likely first be overcome in the transportation sector, creating the necessary foundations to expand hydrogen into other sectors and industries.

In this chapter, we evaluate the key constraints that need to be removed to build a viable hydrogen infrastructure that can support all end users. This is a necessary ingredient to deliver on hydrogen's clean energy promises. We also discuss on-site hydrogen fuel power generation and consumer apprehension about hydrogen fuel in general.

Transportation and Storage Remain Missing Pieces in This Elaborate Puzzle

Hydrogen fuel at the pump is just too expensive for mass vehicle adoption, and costly and complicated delivery issues need to be solved for its expansion to other sectors and industries.

Large-scale use of hydrogen will require effective and safe delivery from the production site to end users, and right now, it is a costly and time-intensive endeavor. We know from our previous research that the cost and availability of hydrogen fuel will continue to be a major factor in the deployment of fuel cell vehicles unless the issues with hydrogen transportation and storage are solved. Studies from the Argonne National Laboratory assessed the impact of refueling configuration and market parameters on the total cost of ownership of FCEVs and found that there is a fairly large discrepancy between the production costs of hydrogen and the dispensing costs. Using California as an example, the cost of producing hydrogen through steam reforming methane (SMR) was about $2-3 per kilogram of hydrogen, while the dispensing cost to retail customers was about $13-15 per kilogram of hydrogen.[14] For the medium- and heavy-duty vehicle segment, dispensing costs would be lower given that there are fewer locations to consider and compression costs are typically lower compared with light-duty passenger vehicles which require keeping a higher-pressure environment within the onboard tanks as well.

Delivery is a major constraint to achieving a viable and effective hydrogen infrastructure. While delivery methods are available, they are too expensive and inefficient to support widespread hydrogen demand and currently represents the largest cost component of the delivery part of the equation as gaseous compression, pipelines, liquid hydrogen conversion, etc., require complex technologies. These difficulties stem from the fact that hydrogen is the smallest and lightest element on earth, and one gallon of hydrogen has a mass of only 0.00075kg compared with 2.75kg for gasoline. Furthermore, the materials used for storage and transport cannot have a strong reaction with hydrogen or be susceptible to hydrogen corrosion, and the storage containment technology needs to be able to contain hydrogen until it is ready to be released. This is called the hydrogen reversibility of the containment unit, and the ability to efficiently contain and release hydrogen when needed is of tremendous importance.

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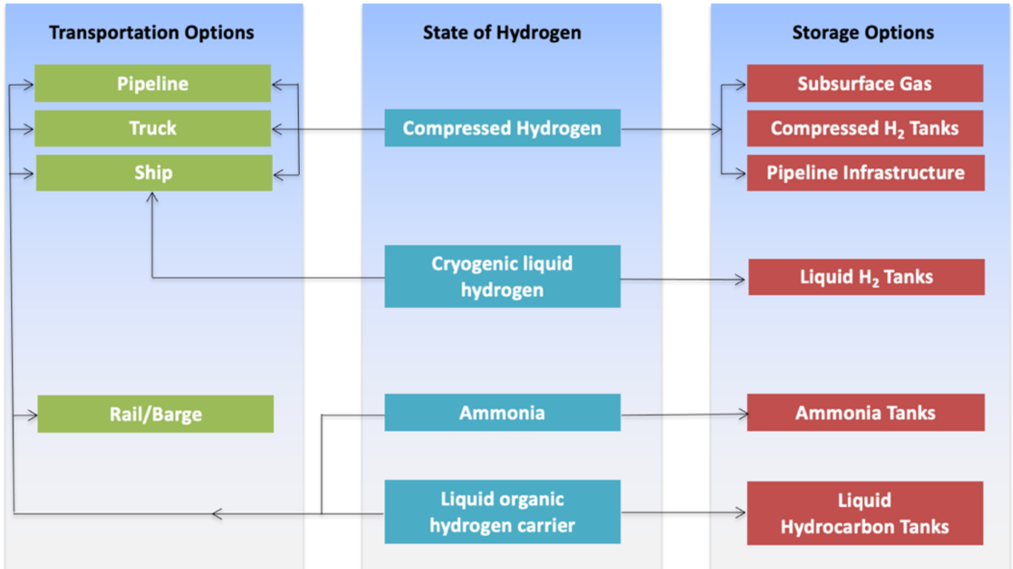
[13] Rustagi, N., Elgowainy, A. and Vickers, J. (2018). *DOE Hydrogen and Fuel Cells Program Record.* DOE: Record 18003.

[14] Reddi, K., Elgowainy, A., Rustagi, N. and Gupta, E. (2017). *Impact of Hydrogen Refueling Configurations and Market Parameters on the Refueling Cost of Hydrogen.* International Journal of Hydrogen Energy; 42(34): 21855-21865.

Gas compression, especially from delivery with gaseous tubes, currently represents 53% of the total delivery and dispensing costs...

...liquefaction may be a less costly, more practical solution that could solve many issues.

Exhibit 22: Required Hydrogen Fuel Infrastructure for Transportation and Home Heating



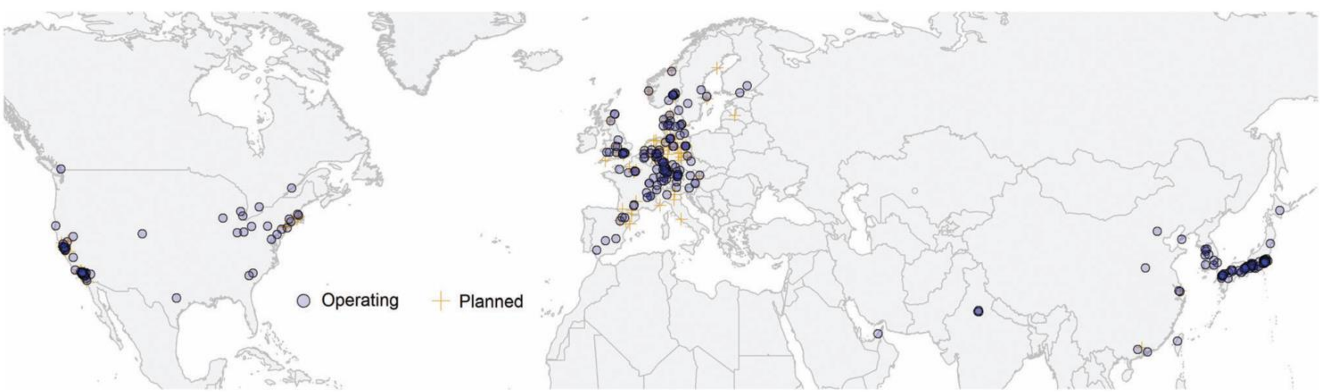
Source: DNV GL, BMO Capital Markets

Exhibit 23: The Ultimate DOE Goal for High-Volume Hydrogen Fuel Delivery and Dispensing is $2.05/kg by 2030-2035

	2017	2025e	% Cost Decrease
Hydrogen Supply Mode	Gaseous tube and liquid trailers	Liquid trailers	-
Station Capacity	530 kg/day	1,000 kg/day	-
Early Market Pricing	$11.80 – 12.70/kg	$7.95 – 8.80/kg	-31% to -33%
High Volume Market Pricing	$4.90/kg	$4.15/kg	-15%
R&D Requirements to Achieve these cost reductions			
Cost of Dispensers	$100,000 per unit	$50,000 per unit	-50%
Cost of High-Pressure Storage (875-bar)	$1,780 per kg	$600 per kg	-66%
Capital cost of high-pressure cryopumps	$760 per unit	$380per unit	-50%
Capital cost of liquefier	$38 million per unit	$19 million per unit	-50%

Source: Rustagi *et al.,* 2018

Exhibit 24: The Market Potential of Hydrogen Is Tied to Refuelling Infrastructure



Source: Stafell, I., Scamman, D., Abad, A., Balcombe, P., Dodds, P., Ekins., P., Shah, N. and Ward, K. (2019). *The role of hydrogen and fuel cells in the global energy system.* Energy & Environmental Science; 12:463. © Creative Commons License.

Gaseous, Liquid, and Pipeline Delivery Cost Is Expected to Come Down

According to the Hydrogen Council, the current cost for dispensing hydrogen, excluding the production costs, can range from US$6.30 to US$7.7/kg, depending on the process (liquid trucking, gaseous trucking, or pipeline) and if fueling is necessary. Over time, with a large number of retail refueling stations and hydrogen fuel vehicles, estimates are that dispensing could fall to US$2.1-2.2/kg. Still, the creation of a hydrogen distribution network will require large capital investment, and it will take a number of years to develop the necessary infrastructure that will suit the demand and supply dynamics projected. Furthermore, the type of infrastructure employed will vary from country to country and region to region. For long-distance transport, the shipping and storage methods and related costs depend on the hydrogen chemical state.

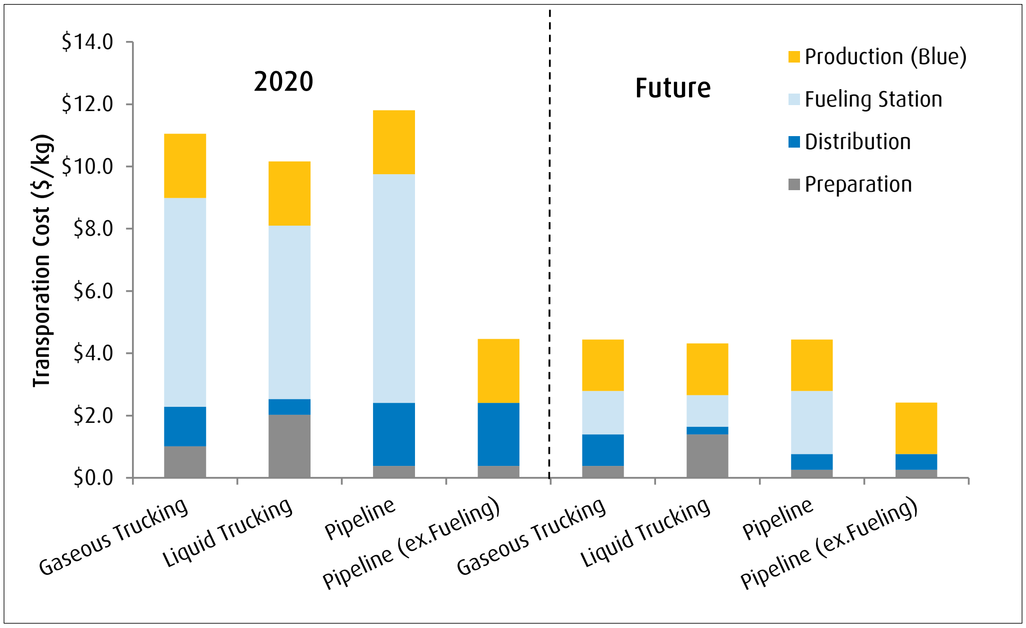
- **Compressed gas via trucking.** The most common method of storage and transport via trucking is through compressing hydrogen in its gaseous state in high-pressure gas cylinders or tubes at about 200-500bar, which translates to 420-1,050kg of hydrogen. Key issues is that the weight of the cylinders is high, and while lighter tank materials are being tested, safety concerns loom large.

- **Cryogenic liquid hydrogen.** Gaseous hydrogen is liquefied by cooling it below -253°C (-423°F) in a process called liquefaction. This is a costly and energy-intensive process, and some of the stored hydrogen is lost through the evaporation process. However, this is the preferred method for long-distance trucking and shipping, and the hydrogen can easily be vaporized to a high-pressure gaseous state on-site for dispensing.

- **Liquid organic hydrogen carrier (LOHC).** LOHCs are organic compounds that can readily absorb and release hydrogen and keep fuel in a liquified state until it is ready to be dispensed. This is by no means as easy as it sounds as different carriers can be hydrogenated and dehydrogenated easier than others, and long-term stability over many cycles is strongly dependent on the applied reactor configuration.

- **Ammonia.** There are a number of possibilities for ammonia in the hydrogen economy including hydrogen production, but at the moment, the most intriguing use is as a transportation and storage vessel. Ammonia can be liquefied under mild conditions, can be stored in standardized and inexpensive storage tanks, and has a large fraction of hydrogen (hydrogen constitutes 17.65% of the mass of ammonia).

Exhibit 25: Hydrogen Cost for Transportation



Note: When combining the cost of transportation/distribution, we estimate the full-cycle blue hydrogen costs can range from $4.50/kg for pipeline distribution and preparation only, and up to $12/kg, if including fueling stations. Interestingly, as a comparison, the average refueling retail price of hydrogen in California in 2019 was around US$16.51/kg (or ~C$21/kg) and ~US$7-8/kg for high-volume transportation applications.
Source: Hydrogen Council, BMO Capital Markets

Pipeline transportation would be the most economical option, especially for countries with robust infrastructure in place. We believe that in many countries, the most economical avenue for hydrogen fuel delivery is by blending natural gas streams with up to 20% hydrogen by volume through existing pipeline infrastructure. This mix is required because if hydrogen is present at higher concentrations, new infrastructure or significant retrofits would be required at a substantial cost.

- **Hydrogen embrittlement.** Hydrogen can degrade metal at high concentrations and pressure with prolonged exposure. Natural gas transmission pipelines are made with high-strength steel, and this, combined with their high-pressure nature, leaves them susceptible to hydrogen embrittlement. A hydrogen concentration of 5% is thought to pose a low risk to pipeline integrity in transmission lines. A 15% concentration by volume may be acceptable but could shorten the operating life of the line. At the distribution level, lower pressures within lower-strength steel and polyethylene pipes are able to safely handle higher concentrations of up to 25% hydrogen.

- **Appliance tolerances.** End-use applications have a range of tolerances, but most industrial and residential appliances are able to handle hydrogen of 5-20% of the gas mix by volume. Of note, all gas appliances sold in the U.K. after 1996 have been designed to operate at hydrogen concentrations of up to 23%.

- **Leakage and safety.** Hydrogen is more mobile than natural gas and has an estimated three times higher leakage rate. Therefore, while gas leakage from pipelines is considered minimal, there is elevated safety risk in a confined space at the service level. Although hydrogen ignites more readily than natural gas, at concentrations of 20% or lower, the safety risk is deemed to be acceptable.

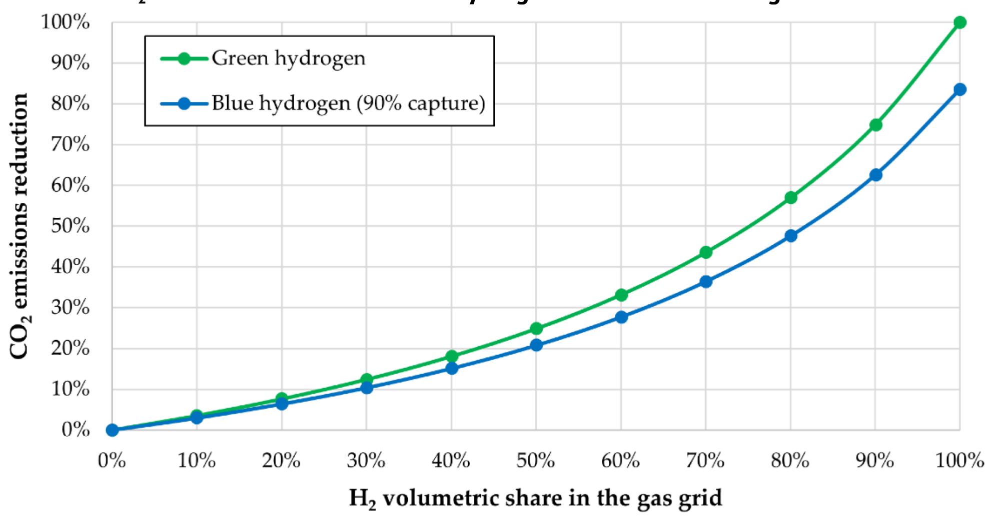
- **Lower heating value.** As hydrogen has lower volumetric energy density relative to natural gas, additional compression is required to increase the flow velocity to deliver the same energy.

Hydrogen concentration levels may be constrained by pressure ratings on pipelines as part of the transmission and distribution network.

- **Downstream extraction.** If extraction is necessary, there are challenges to removing the hydrogen economically and in an uncontaminated form, depending on the end-use requirements. Decompression may be required to separate the hydrogen before recompressing the remaining stream. In addition, the efficiency of current hydrogen extraction technology is proportional to the concentration, so costs could rise exponentially with increased hydrogen in the mix.

We expect that blending will start at very low concentrations and climb over time, as safe distribution and use are demonstrated. The amount of hydrogen permitted in natural gas infrastructure is set by regulations that vary from country to country; however, we see a drastic CO_2 reduction as hydrogen becomes a larger part of the gas grid.

Exhibit 26: CO_2 Emissions Reduction Versus Hydrogen Volumetric Blending



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Safety concerns and negative attitudes are a critical barrier to adoption. Hydrogen fueling stations have adopted the same safety parameters as gasoline (no smoking, not using cell phones, etc.) but have additional safety measures, given it is compressed gas, to vent the hydrogen to a safer location in the case of an emergency and keep a tightly locked seal on the nozzle during refueling. However, apprehension about hydrogen's safety persists even though it is far less flammable and dangerous than gasoline, which also tends to pool on the ground and can result in long-lasting, difficult to extinguish fires that can easily carry through to gutters and drains.

This hydrogen fear, which was founded by the Hindenburg disaster, has only intensified with a few more recent instances such as when multiple hydrogen tanker trucks caught fire at a reforming station in California, and separately, a refueling station operated by Nel Hydrogen in Norway caught fire in June 2019. Therefore, the idea of hydrogen trucks moving through residential zones is increasingly unappealing, especially as general knowledge about hydrogen energy is very low.

Section 2: The Impact of Hydrogen Adoption by Sector

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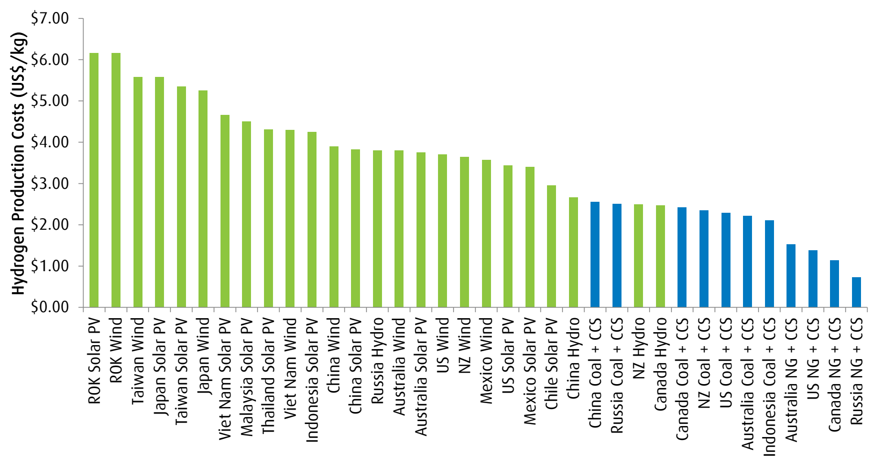
Canadian Oil & Gas

- **Bottom Line: Canada Poised to Be a Low-cost Blue H_2 Leader, Supported by its Oil & Gas Sector**. In a recent industry thematic report, we took an in-depth look at scenarios for a future hydrogen economy in Canada and its implications for the O&G sector (see "The Bold and the Blue-tiful"). With Canada's goal to reach net zero by 2050, we expect interest in hydrogen to accelerate and see the Canadian sector playing a lead role in sourcing "Blue" hydrogen using natural gas with Carbon Capture Utilization and Storage (CCUS), supported by key regional influences, policy advancements and relative costs. *In the end, we believe a hydrogen transition could be net positive for Canadian natural gas demand – a view that is contrary to prevailing market assumptions.*

- **Canadian Blue H_2 Costs Among the Lowest.** Combined with current and future government carbon policies in Canada, we believe that the levelized cost of western Canadian blue hydrogen will be competitive as an energy transition fuel, allowing the natural gas industry to play a key role in de-carbonizing Canada, and the world. We estimate the levelized cost for blue hydrogen via Steam Methane Reforming (SMR) and CCUS is currently ~$2.00/kg H_2. With improvement in technology and capital synergies, this could fall by at least 20% or to <$1.65/kg by 2050. Green hydrogen costs in Canada should also see rapid deflation, from an estimated range of $4.00-7.50/kg currently to as low as $2.75/kg-$4.70/kg by 2050, but are likely to remain above blue sources in western Canada. Independent studies have supported this view, indicating Canada as one of the lowest cost blue hydrogen sources globally given an abundance of low cost gas (see Exhibit below).

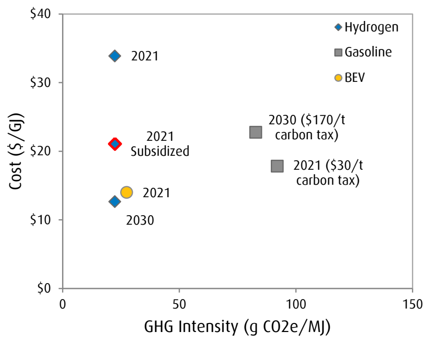
Exhibit 1: Canada Ranks Among the Lowest Blue Hydrogen Production Costs



Source: APERC, BMO Capital Markets

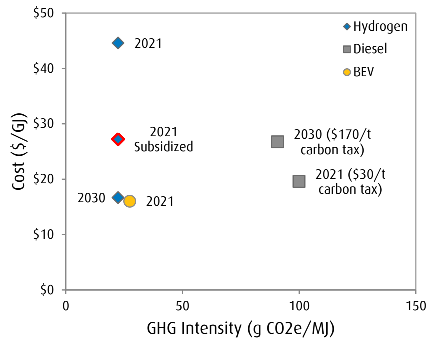
- **Provincial and Federal Support for Blue Hydrogen.** Both levels of government recognize that Canada and Alberta hold all the qualities needed to become a major producer and exporter of low carbon hydrogen including a robust energy sector, unique geology and land title structure allowing for large scale CCS. We believe the largest policy impacts for blue hydrogen will come from the federal carbon tax, proposed Clean Fuel Standard, and Alberta's Technology Innovation and Emissions Reduction (TIER) regulation. Together, the carbon performance/emission credits accrued could effectively reduce the levelized cost of blue hydrogen by over 40% on a full cycle basis and allow hydrogen to compete with existing gasoline/diesel fuel costs. We see hydrogen facing more challenges competing with natural gas in residential heating without further government incentive.

Exhibit 2: LDV Fuel Comparison



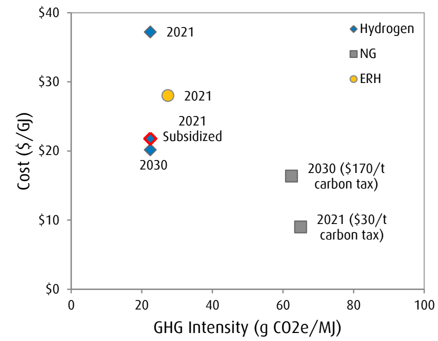
Source: NRCan, BMO Capital Markets

Exhibit 3: HDV Fuel Comparison



Source: NRCan, BMO Capital Markets

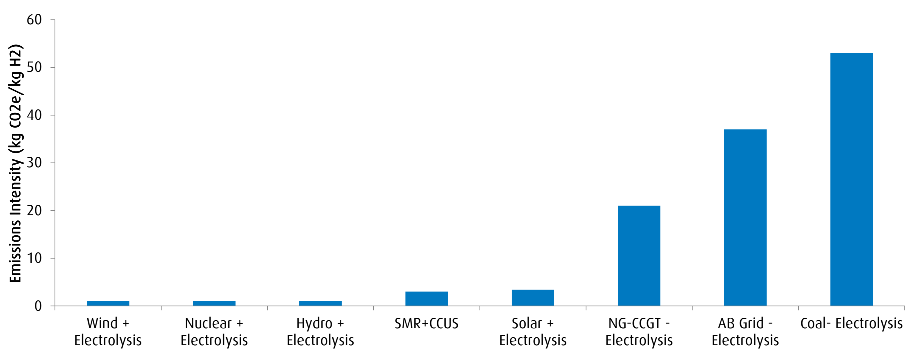
Exhibit 4: Space Heating Fuel Comparison



Source: NRCan, BMO Capital Markets

- **Canadian Blue H_2 Can Be Carbon Competitive.** We estimate the upstream emissions intensity for a typical natural gas producer including infrastructure/processing, equates to roughly 1.3-1.5 kg CO_2e/kg H_2. An SMR unit without CCUS emits up to 8-10 kg CO_2e/kg H_2, but <1 kg assuming 90% CO_2 recovery. All told, including an additional 20% for transport, we believe Canadian blue H_2 has a total emissions intensity of just 2.7-3.0 kg CO_2e/kg H_2. This compares more favourably to green hydrogen than many believe, depending on the source of power for electrolysis. Based on the work of the Transition Accelerator, green hydrogen from nuclear, wind, and hydro have intensities of <1 kg CO_2e/kg H_2. However, Canadian solar is ~3.4 kg CO_2e/kg H_2 while electrolysis using grid electricity can be as high as 20-50 kg CO_2e/kg H_2. We believe this lends support to blue hydrogen in western Canada given a relative lack of renewable power options.

Exhibit 5: Canadian SMR-CCUS Emission Intensity versus Other Processes



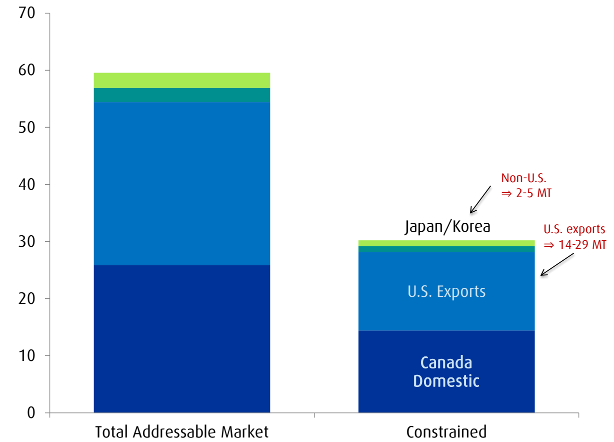
Source: The Transition Accelerator, BMO Capital Markets

- **Canada's H_2 Potential Is Relatively Large, Domestic & Exports >30 MT/Year.** Our survey of global energy use outlooks suggests that worldwide hydrogen potential may be anywhere between 60 MT/year and 400 MT/year, or 3-20% of final energy demand by 2050. Applied to Canada's relative position, our analysis identified constrained market potential of >14 MT/year or 21% of end-use demand based on a risked market assessment, and a Total Addressable Market (TAM) of >25 MT/year versus current Canadian production of ~3 MT. Furthermore, exports to the U.S. and Asia could overshadow Canada's domestic potential. If you consider current natural gas, refined product and crude oil exports to the U.S. market, and new opportunities in select Asian markets, Canada's total H_2 opportunity could be >30 MT/y on a risked basis, and double this from a TAM standpoint.

- **Most De-carbonization Potential for H_2 in Western Canada.** Our in-depth evaluation of Canada's energy use further indicates that >60% of the Canadian market opportunity for H_2 resides in western Canada given its sectoral makeup weighted toward Industry and an energy mix leveraged to natural gas and diesel fuel – which represent primary end-use de-carbonization opportunities. Overall, western Canada holds ~70% of de-carbonization potential in traditional gas markets and

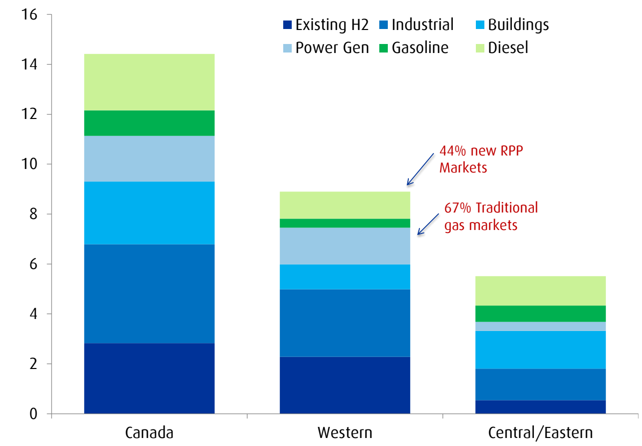
44% in refined products. That said, uptake in eastern Canada's commercial transport sector will also be an important driver of overall potential and net impact on WCSB natural gas demand.

Exhibit 6: Summary of Canada's H_2 Potential (MT/y)



Source: EIA, NRCan, BMO Capital Markets Estimates

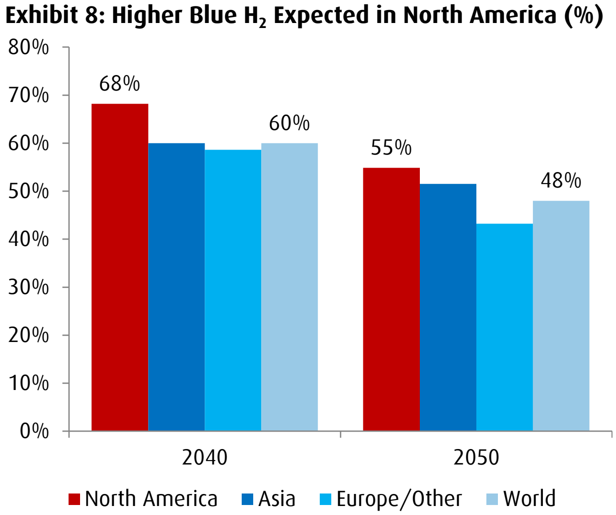
Exhibit 7: Canada's Risked H_2 Potential by Region (MT/y)



Source: NRCan Comprehensive Energy Use Database, BMO Capital Markets

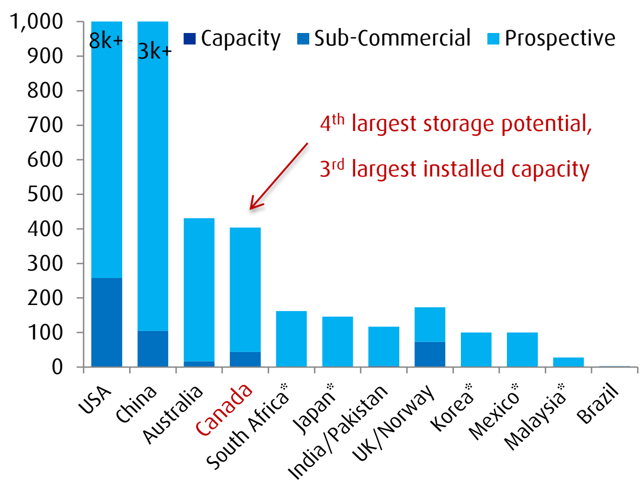
- **The Case for More Blue H_2 in Canada.** Our survey of industry consensus showed that global hydrogen demand will be met by roughly a 50/50 split of blue/green supply long-term, with emphasis on blue hydrogen in the early transition to 2040 and more blue in North America's long-term mix. Our work further suggests meaningfully higher blue hydrogen in western Canada's mix specifically given key regional influences including existing blue hydrogen expertise, abundant gas resource, and world class CCUS potential. Alberta is already an established leader in blue hydrogen with ~25% of its supply using CCUS while Western Canada also holds the fourth-largest carbon storage potential and third largest installed capacity globally, with Alberta alone representing 5x Canada's cumulative output through 2050. In our view, this has important implications for the hydrogen pathway in Canada. In our analysis, we assume a 75%/25% blue/green mix in Western Canada, and 50/50 split in the East (in line with global average expectations).

Exhibit 8: Higher Blue H_2 Expected in North America (%)



Source: BP Energy, DNV Transition Outlook (2020), BMO Capital Markets

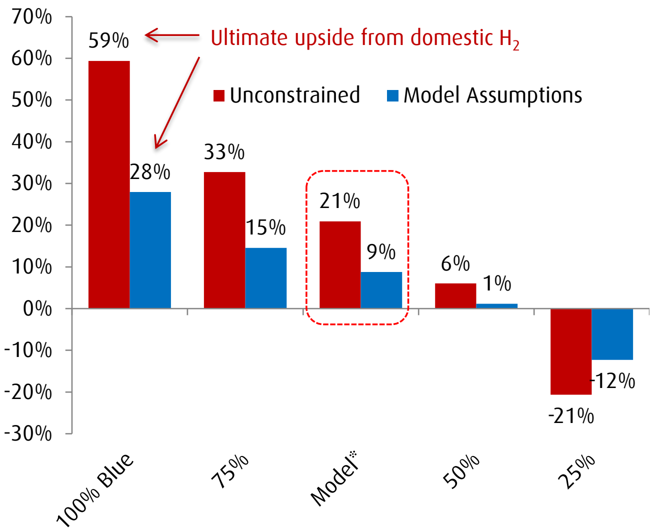
Exhibit 9: Canada's CCS Storage Resource (GT)



Source: CCS Institute, Global CO2 Storage Resource Catalogue

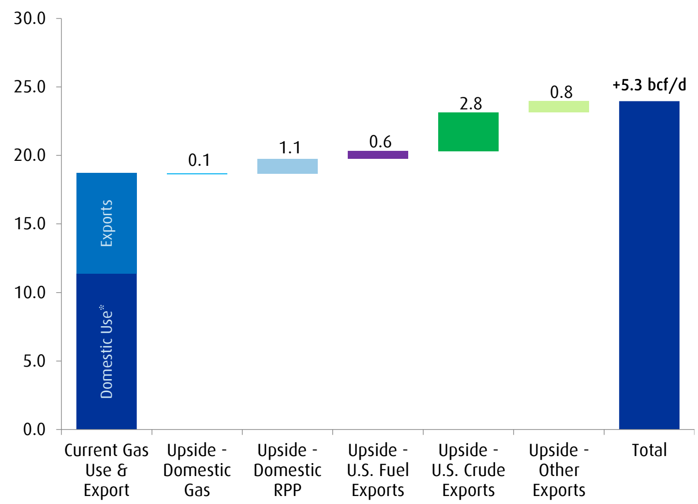
- **Net Positive Outlook for WCSB Natural Gas.** Conversion losses associated with the SMR-CCUS process require about 30% more natural gas to produce the equivalent energy in hydrogen form using SMR (assuming 90% Carbon capture efficiency), which means that blue hydrogen drives net gains in gas demand, all else equal. In addition, hydrogen uptake in new transportation markets is pure upside for gas use, assuming at least some portion comes from blue sources. Given our blue-hydrogen weighted assumption for western Canada, we infer that a hydrogen transition in Canada would have a net positive impact on WCSB natural gas demand, amounting to 1 bcf/d or a 9% increase in our risked scenario, but as much as 7 bcf/d or a ~60% increase TAM with 100% blue supply. This compares to current Canadian gas supply of ~19 bcf/d (~17 bcf/d Western Canada). As we demonstrate in Exhibit 11, including both domestic use and export markets, our constrained model suggests that >5 bcf/d or a 30% increase in current marketed gas supply is possible.

Exhibit 10: Gas Demand Sensitivity to % Blue H_2 Supply



Source: BMO Capital Markets Estimates

Exhibit 11: WCSB Natural Gas From H_2 – Risked Model (bcf/d)



Source: EIA, NRCan, BMO Capital Markets Estimates

- **Massive Investment Is a Meaningful Hurdle.** We estimate that as much as 185 MT/year of new CCUS capacity would be required to handle the volume of blue hydrogen outlined in our risked model scenario. While western Canada retains abundant storage (~400 GT) to handle this output, the level of investment required is staggering at more than $250 billion for CCUS capacity alone, and possibly $500 billion including SMR. While our work suggests that a green hydrogen pathway would cost even more, we see costs for both as a meaningful hurdle to hydrogen's ultimate success without meaningful policy support from the Canadian government.

- **Unique Opportunities in Canada's Oil Sands.** One of the unique opportunities within Canada's heavy industry includes de-carbonizing the oil sands sector, which currently uses nearly 3 bcf/d of natural gas and generates substantial emissions. Several industry studies have shown feasibility of blending H_2 in SAGD steam boilers, and we believe there are numerous other applications where diesel and natural gas use could be replaced, including mobile truck fleets in mining operations. In addition, the industry is closely evaluating use of Molten Carbonate Fuel Cells (MCFC) as a multi-faceted solution to reduce industrial carbon emissions and produce low carbon electricity on site. One primary benefit may be its ability to be deployed in modular scale to address CCUS and power needs in remote and smaller scale industrial applications. Alberta Innovates led a joint industry study evaluating the use of MCFCs. As a result of this feasibility work, Canadian Natural Resources is leading a follow-up project to pilot a 1.4 MW MCFC at its Scotford upgrader with planned startup by 2022. Industry proponents of the joint study include Cenovus, Canadian Natural, Suncor and MEG, while ExxonMobil (parent to Imperial Oil) has also expressed considerable interest in the technology. We reiterate that the oil sands sector has been an industry leader in R&D over past decade, which supports the view that H_2 is likely to play some role in the sector's future.

Key stocks impacted: We believe that large-scale, low-cost natural gas producers such as Canadian Natural, Tourmaline and ARC, as well as services providers like Enerflex, Mullen and Precision

Drilling, and CCUS/CCS experts such as Whitecap and Canadian Natural, may all play a material role in a Canadian blue hydrogen transition.

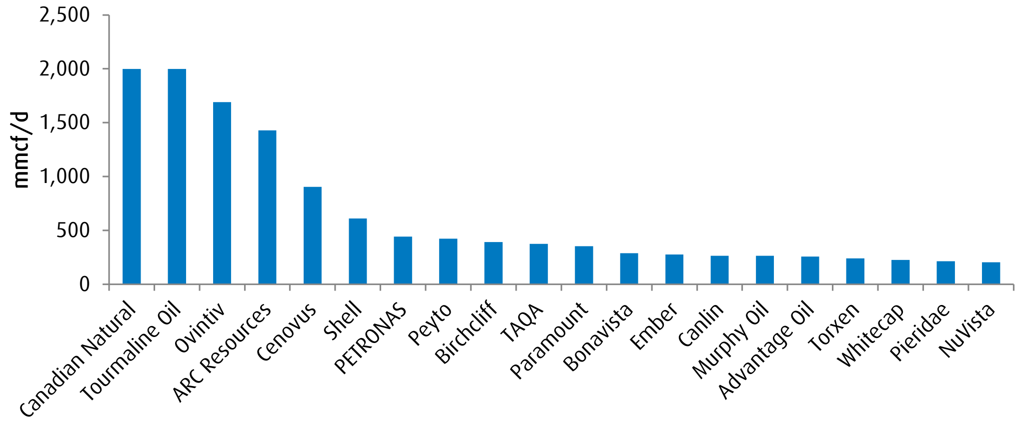
- **Canadian Natural Resources (CNQ, $38.57, Outperform, $52 Target Price)**: Canadian Natural is currently the largest natural gas producer in western Canada with output of >2 bcf/d, and holds abundant low-cost resources to support long-term supply to a hydrogen economy. Its industry-leading operating performance, scale, and flexibility combined with its long life, low-decline asset base has translated into the lowest WTI breakeven within its peer group at US$30-31/bbl. As a result, we believe the company's unique ability to generate meaningful free cash flow will also allow it to maintain leading investment in R&D and new technology in support of its long-term net zero goal. Canadian Natural is also currently the largest owner of CCUS capacity (and by extension, blue hydrogen) in Canada, as well as sixth largest CCUS owner among oil & gas producers globally given interests in nearly 2 MT/year between the Quest project, Sturgeon refinery and its Horizon hydrogen plant. We believe its FCF potential, leading R&D investment and CCUS expertise positions the company well to capitalize on future hydrogen opportunities.

- **Tourmaline (TOU, $23.92, Outperform, $33 Target Price):** Tourmaline is currently our top recommendation among the Canadian natural gas producers, and we believe may also be well positioned to benefit from a broader transition toward a blue hydrogen economy in Canada. Tourmaline is poised to become the top, low-cost natural gas producer in western Canada (currently second largest), in our view, which positions it very well as a top supplier to a blue hydrogen buildout. The company has a history of disciplined financial management and accretive acquisitions which have allowed the company to deliver growing returns to shareholders. At current prices, we believe that the shares are undervalued.

- **ARC Resources (ARX, $7.65, Outperform, $11 Target Price):** ARC Resources is the fourth largest natural gas producer in western Canada, with an attractive, low-cost asset base. We believe the company would be well positioned to leverage opportunities in a hydrogen transition given its strong balance sheet, sales market diversity, and higher margin asset portfolio. Furthermore, its recent merger with Seven Generations has given the company significant liquids exposure, further bolstering natural gas production economics.

- **Whitecap Resources (WCP, $5.62, Outperform, $8 Target Price):** We believe Whitecap could play a leading role in a hydrogen transition given its CCUS expertise. The company is currently a leader in carbon capture via its 65.3% W.I. ownership in the Weyburn unit, which is the largest sequestration project globally and has so far sequestered ~36 MT of CO_2 (or ~2 MT/year). In fact, the Weyburn unit alone has the potential to sequester a total of 52-81 MT, nearly 2-3x more than currently stored volumes. Ultimately, we wouldn't be surprised to see the company leverage its deep CCUS expertise to capitalize on the hydrogen trend. Notably, Whitecap has recently created a new business unit to evaluate "low carbon solutions and other new energy opportunities" to bring in additional revenue streams.

Exhibit 12: Top Natural Gas Producers in Western Canada (mmcf/d)



Source: APERC, BMO Capital Markets

Canadian Oil & Gas Services

- **How a Shift to Hydrogen Could Impact the Sector**: While it remains very early days, Canada's transition towards hydrogen could benefit and/or impact the oilfield service sector through a few different avenues. If Canada is to shift towards greater usage and production of cleaner technologies such as hydrogen, adequate infrastructure will be needed in order to support this adoption. However; capital intensity is high, particularly around hydrogen processing and the required facilities. We expect this transition will include the emergence of new companies focused on hydrogen purification, blending, storage and transportation as well as a shift in focus from existing energy service companies in Canada and abroad. Additionally, those companies with solid market positions in drilling, completions and well servicing in Canada could benefit from the increased need for natural gas production. The Steam Methane Reforming (SMR) landscape is also still in its infancy, although we are seeing more public and private companies expand into the space.

  Key stocks impacted:

  - **Enerflex (EFX, $8.10, Outperform, $11 Target Price):** EFX recently appointed a Chief Energy Transition Officer who has been tasked with formulating a plan to address the renewables market, including green hydrogen. Green hydrogen projects have historically lacked the proper economics needed for customers to enter the space, although government incentives are creating a shift in thinking. The company holds the proper in-house capabilities to address the hydrogen market and we wouldn't be surprised to see EFX enter the green hydrogen world (either organically or inorganically) in the medium-term given its processing/manufacturing capabilities.

  - **Mullen Group (MTL, $12.38, Outperform, $15 Target Price):** MTL has engaged in some hydrogen initiatives in the Fort Saskatchewan, Alberta region, and would be highly impacted from a shift towards fuel cells, although again it remains early days on this front. While the company is currently leaning towards the electrification of smaller units (i.e., delivery vans and less-than-truckload vehicles), it could shift towards hydrogen fuel cells for its long-hauler trucks.

  - **Precision Drilling (PD, $30.52, Outperform, $45 Target Price):** PD would benefit from increased adoption of hydrogen, as natural gas drilling will play an even greater role going forward. PD is the largest driller in the WCSB, controlling ~30% of the market.

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U.S. Energy and Global Integrateds

- **Bottom line.** The development of the hydrogen economy has the potential to have meaningful implications for oil and natural gas demand, while also opening up new market opportunities across the hydrogen value chain, including generation, transportation, storage, and usage. We expect most energy subsectors to play a role in the latest iteration of hydrogen with European integrateds aiming to capture significant market share, while hydrogen and carbon capture could become significant business units for oilfield service companies and the need for significant infrastructure buildout involves midstream and downstream players.

- **Hydrogen creates both threats and opportunities**. In *Oil Demand to 2040: Beyond the Hype*, Randy Ollenberger estimated that increased penetration of fuel cell electric vehicles (FCEV) could reduce future oil demand by roughly 0.8 million b/d and a further one million b/d of potential demand losses could be realized if the heavy-duty market achieves similar zero-emissions vehicle market share as the passenger segment as a result of hydrogen FCEV success. The potential oil demand loss due to hydrogen over the next 20 years is estimated to be as high as roughly 4.5 million b/d by 2040 in the most optimistic scenario, which is BP's "net zero" outlook but more likely in the range of 2 million b/d. Hydrogen's penetration into the transportation market (road, aviation, rail, and marine) is expected to accelerate post-2040 as the technical and infrastructure challenges are resolved.

  By contrast, natural gas demand has the potential to benefit from increased production of blue hydrogen, which BP estimates will have a roughly equal split to green hydrogen production by 2050. Gas-fired capacity could be retrofitted to combust hydrogen and be equipped with carbon capture. Hydrogen and Co_2 pipeline networks will also be needed, although hydrogen can be blended into natural gas and transported on existing gas pipelines and hydrogen production facilities can be located close to industrial consumers. Increased hydrogen usage will also advance the carbon capture, utilization, and sequestration (CCUS) market as blue hydrogen is produced from natural gas with CCUS. CCUS has become a major focus area for energy companies with Exxon believing the addressable market could grow to $2 trillion by 2040, while Oxy Low Carbon Ventures has generated significant investor interest with the construction of its direct air capture facility in the Permian Basin and a Valero and BlackRock partnership recently announced an open season to develop an industrial-scale CCUS pipeline system, which spans five Midwest states with the capability to store up to 5-8 million metric tonnes of Co_2 per year.

- **Path forward**. U.S. oil services companies such as Baker Hughes have a long history with hydrogen with application in its compression technology and hydrogen blend turbines for mechanical drive in LNG, while Schlumberger has established a green hydrogen technology venture with several notable partners. Both companies are also pursuing CCUS opportunities, with Baker recently acquiring Compact Carbon Capture (3C) and Schlumberger and LafargeHolcim forming a partnership to explore the development of CCS solutions in the cement industry. The global integrateds are also pursuing hydrogen opportunities, although the energy transition strategies of the European (Rotal Dutch Shell, Total) and U.S. (Exxon, Chevron) majors is diverging as to the pace and magnitude of evolving business models. Both Royal Dutch Shell and BP expect to capture double-digit market shares in core hydrogen markets, with Royal Dutch seeing parallels to its global integrated LNG business and planning to use LNG, chemicals, refining, and products assets as the platform for future hydrogen and biofue facilities.

  Key stocks affected:

  - **Baker Hughes (BKR, $20.11, Market Perform, $27 Target Price)**. Baker Hughes is pursuing multiple concepts and business models across the hydrogen, CCUS, and energy storage value chains and industries. Baker has participated in hydrogen since 1962, engaging in more elementary uses and implementation with its compression technology where 2,000 compressors utilize hydrogen applications today. The company is seeing increased applications for hydrogen blend turbines for mechanical drive in LNG. Baker has turbines running on 100% hydrogen as well as blended hydrogen in several power generation applications across its fleet, which consists of an installed base of 5,000 gas turbines and 8,000 compressors. LNG operators are increasingly seeking to reduce the carbon footprint of their projects, and this should increase the use of hydrogen blend applications as the infrastructure becomes more efficient. While Baker currently plays on the compression and generation side of hydrogen, it sees additional opportunities in movement, storage, liquefaction, and end destination of hydrogen. Over the next ten years, we can see these new energy opportunities representing ~25% of Baker's Turbomachinery & Process Solutions segment revenues.

- **Schlumberger (SLB, $26.76, Outperform, $33 Target Price)**. Schlumberger's New Energy business includes ventures in hydrogen, CCUS, lithium, and geo-energy. The company's Genvia venture focuses on clean hydrogen production technology and is partnered with the CEA, VINCI Construction, Vicat, and AREC. Genvia will accelerate the development and industrial deployment of CEA's high-temperature reversible solid oxide electrolyzer technology. The technology provides the flexibility to switch between electrolysis and fuel cell functions and aims to lower the electricity usage per kg of hydrogen produced. Schlumberger believes that toward 2030 the global market could reach 70 gigawatts of installed capacity of electrolyzer. Technology demonstration and delivery of prototypes to partners will occur in coming quarters, and in the next two to three years, Genvia will decide whether to build and expand into large-scale manufacturing.

- **Chart Industries (GTLS, $143.91, Not Covered)**. Chart Industries recently signed a MOU with Ballard Power Systems (BLDP) to jointly develop integrated system solutions that include a fuel cell engine with onboard liquid hydrogen storage and vaporization for the transportation industry with a focus on heavy-duty applications. Chart will provide liquid hydrogen expertise, truck LNG experience, and an existing liquid hydrogen onboard vehicle tank prototype design. In addition, Chart, Baker Hughes, and Plug Power are cornerstone investors in the formation of the FiveT Hydrogen Fund, which is a new clean-hydrogen-only private infrastructure fund dedicated to delivering clean hydrogen infrastructure at scale, with a focus on production, storage, and distribution applications. Chart and Baker will commit $60 million each, while Plug will invest $200 miliion, with the fund having the ambition to reach $1.2 billion from both financial and industrial investors.

- **Exxon (XOM, $55.87, Not Covered)**. Exxon currently produces 1.3 million tonnes of hydrogen per year and is focusing its research on lower-cost hydrogen and carbon capture, along with advanced biofuels. In the Netherlands, Exxon is participating in a study of large-scale production of low-cost, low-carbon hydrogen while capturing Co_2. Exxon believes the hydrogen addressable market could grow to $1.0 trillion by 2040 with further advances in technology, distribution, and production to reduce the cost of low-carbon hydrogen, along with increased capital investment. ExxonMobil Low Carbon Solutions is working on more than 20 new CCUS opportunities globally and has an equity share in one-fifth of global carbon capture capacity.

- **Chevron (CVX, $102.92, Not Covered)**. Chevron recently announced the launch of its $300 million Future Energy Fund II, which is focused on investing in low-carbon technologies, including hydrogen and carbon capture. Today, Chevron uses hydrogen in its refineries and has hydrogen refueling stations, while also being involved in the California Hydrogen Highway, which was initiated in 2004 and is a series of hydrogen refueling stations. Chevron believes hydrogen holds great promise for use in hard to decarbonize sectors and is focused on generation and transport, but notes that the generation cost needs to be reduced to be commercial. Transportation and infrastructure advancements are also needed to build the market for hydrogen.

- **Royal Dutch Shell (RDS, $38.91, Not Covered)**. Shell sees its future energy product mix dominated by low- and no-carbon energy, such as renewable power, biofuels, and hydrogen. The company's LNG, chemicals, refining, and products assets would be the platform for future hydrogen and biofuel facilities. By 2030, Shell believes it can increase the amount of low-carbon fuels like hydrogen and biofuels from 3% to 10%, while its retail sites will expand into hydrogen, along with electric charging, LNG, and renewable gas. At its Rotterdam energy hub, an offshore wind farm could supply power beyond its core applications to make green hydrogen at a 200-megawatt electrolyzer. Shell has announced a number of green hydrogen projects with combined production capacity of more than four gigawatts to come on stream this decade. The company aims to capture a double-digit market share of global clean energy sales and believes it can build an integrated global hydrogen business, similar to its leading LNG position. Toward the end of the decade, Shell expects hydrogen to become a more significant business and believes that trading optimization will be important, along with the ability to produce the cheapest green and blue hydrogen and having the right logistical control points.

- **BP (BP, $24.39, Not Covered)**. BP estimates that by 2050, hydrogen could account for more than 15% of global final energy consumption under its net-zero scenario and that blue and green hydrogen will account for roughly equal amounts. Green hydrogen production complements the company's growth in renewables, and blue hydrogen is enabled by its scaling up of CCUS. BP believes an overreliance on green hydrogen could constrain the pace at which the hydrogen economy can grow, require an even faster expansion of wind and solar capacity, and divert renewable energy from decarbonizing everyday uses of electricity rather than hard to decarbonize sectors such as heavy-duty trucks and high-temperature processes in industry. The company is developing business models to scale up hydrogen refueling stations across the U.S. and Europe and for heavy-duty vehicles, believing hydrogen demand could reach 16 million tonnes (>800,000 Bbl/d of oil) by 2040. Ultimately, BP aims to capture a 10% share of hydrogen in core markets by 2030 and build positions in the U.S., U.K., Europe, China, and Australia.

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Legal Entity: BMO Nesbitt Burns Inc.

Canadian Utilities

- **Natural progression for utilities.** The Canadian utility sector is in the early innings of a multi-decade grid greenification and energy transition wave, in our opinion. A sharp ESG focus by stakeholders (customers, regulators and investors), to the extent of calls to phase out natural gas transmission, increasingly incentivizes utilities to not only be ambitious, but also to be innovators with decarbonization efforts. A natural step forward exists in hydrogen – why? Since hydrogen combustion emits only water, blending with natural gas reduces the greenhouse gas (GHG) intensity of natural gas streams, delivering lower carbon energy for utility customers. We see a perk for utilities in the pairing of grid stability and greenification: gas turbines are being developed which could use hydrogen in peaking power applications, reducing the GHG intensity of a solution for when the sun isn't shining or the wind isn't blowing. We also believe adoption ease will be a hydrogen growth driver for utilities – at low blending levels, hydrogen does not require changes to existing natural gas infrastructure. While natural gas utilities will increasingly blend hydrogen into natural gas streams, we note Canadian utilities within our coverage for now are contemplating limited hydrogen blending levels (5-15%). Over time, there may be opportunities for utilities to invest in upgraded natural gas assets, e.g., via modifications to turbines to accommodate higher hydrogen blend levels. Overall, we view hydrogen as an attractive lever to drive organic growth for Canadian utilities, while delivering an avenue to achieve both operational (grid stability) and ESG (grid greenification) objectives, which, net, supports further valuation expansion.

- **Pathway forward.** Per BloombergNEF, hydrogen could be cost competitive by 2035 vs. fossil fuels – scale matters in bringing costs down, and we believe, recognizing this reality, utilities and regulators are sizing up. In October 2020, Sempra Energy announced two long-duration green hydrogen projects (2022 est. COD), while Ohio's Long Ridge Energy Terminal is to convert a 485MW combined-cycle gas power plant to run on 100% green hydrogen. Alberta recently released its Natural Gas Vision and Strategy, with a Hydrogen Roadmap to be issued in spring 2021. Many European nations have also established goals to replace natural gas with ~20% green hydrogen, with Germany aiming for 60%!

  Key stocks impacted:

  - **ATCO/Canadian Utilities (ACO.X, $42.15, Outperform, $46 Target Price; CU, $34.13, Market Perform, $35 Target Price)**: ATCO is well poised to capitalize on hydrogen opportunities, being engaged in multiple pilots in Canada and Australia. Efforts include blending hydrogen into a subsection of its Fort Saskatchewan natural gas distribution system, and a study to potentially develop Australia's first commercial-scale green hydrogen ecosystem (10MW electrolyzer, 4.6 tons/day hydrogen production). R&D efforts coupled with ATCO's natural gas systems, along with operational expertise in Alberta (home to abundant natural gas reserves) should allow ATCO to become an active participant in the hydrogen value chain. About 35% of ATCO's earnings are from gas utilities.

  - **Emera (EMA, $56.44, Outperform; $60 Target Price)**: While noting no active projects related to hydrogen given current unattractive economics, management has noted this could change in the future and instead is more focused on renewable natural gas opportunities (particularly in Florida). That all said, we believe the combination of a proactive, observant management team at the reins, significant existing gas infrastructure, and clear incentives to decarbonize will result in EMA participating meaningfully in the hydrogen story over future periods. About 20% of EMA's earnings are from gas utilities.

  - **Fortis (FTS, $54.79, Outperform, $60 Target Price):** Management has noted that hydrogen is in the "feasibility and pilot stage," and efforts are focused around two key areas: 1) the blending of hydrogen to decarbonize natural gas streams; and 2) closed-loop systems, industrial applications to displace natural gas with hydrogen. For now, FortisBC is FTS's only utility involved in hydrogen projects: conducting feasibility studies and actively exploring ways to add hydrogen to its natural gas supply, including a partnership with Lonsdale Energy Corporation to determine the feasibility of injecting hydrogen into the energy system in the District of North Vancouver. We believe momentum will build, as recently evidenced by FTS's ambitious renewable targets (e.g., FTS exiting all coal-fired generation in Arizona by 2032). About 20% of FTS' earnings are from gas utilities.

Canadian Renewable Power

- **Next leg of the renewable power saga.** A decade ago, renewable energy was a divisive topic amongst the contracted power industry – with bears contending fossil-fuels would remain more cost-efficient and dominant well into the 21st century. In a stunning evolution, the levelized cost of energy for wind/solar now approaches the cost of fossil-fuels. A similar trajectory may be in play for hydrogen – for energy companies that stayed on the sidelines with renewables, hydrogen is an opportunity they hope not to miss. As large-scale, global operators, we believe our Canadian renewables power coverage is ideally positioned to capitalize as opportunities to invest economically in hydrogen as they emerge.

- **Why hydrogen?** We believe there are multiple factors that will catalyze hydrogen participation by renewables:
    - First, we anticipate the power sector will evolve to increasing hydrogen blending/participation levels via upgrades to legacy gas-fired turbines and development of turbines that support hydrogen combustion. We believe using "green hydrogen" with existing gas-fired infrastructure is exciting, as this could allow for plants to decarbonize and perhaps drive valuation expansion for contracted power names with fossil-fuel exposure.
    - Second, we anticipate continued secular growth in demand for corporate PPAs and a growing realization that potential customers (data centers, Amazon, Walmart, Silicon Valley) desire green electricity, creating significant incentives to minimize fossil-fuel exposure. We believe this will drive demand for "green hydrogen" and create opportunities – either via production of hydrogen or providing clean energy to hydrogen producers.
    - Third, energy storage: renewable projects can power electrolyzers that use water to produce "green hydrogen," energy which may be stored for later use or sold to other customers. This could enable achieving the renewable holy trinity: good economics, clean generation, and storable energy. Energy storage is a significant value-add with renewables, as it could offset earnings drag from curtailments and negative power pricing.
    - Fourth, we believe capital deployment will naturally follow declines in the levelized cost of hydrogen, as the fuel becomes more cost competitive (especially as scale is achieved and more hydrogen infrastructure is in-place). Once the levelized cost of hydrogen approaches natural gas, we believe the opportunity could be immense: 38% of the U.S. electrical grid was natural gas based in 2019 (source: EIA).

  Key stocks impacted:

    - **Brookfield Renewable Partners (BEP, US$43.52, Market Perform, US$42.00 Target Price)**: Within our coverage, BEP has been the most active on the hydrogen front, announcing in September 2020 an agreement to supply Plug Power (PLUG, US$32.20, Not Covered) with 100% renewable electricity. We believe this arrangement will provide management with excellent visibility into the production of "green hydrogen" and, combined with BEP's operational expertise, positions BEP well for future investments in hydrogen as the fuel becomes more commercially viable at scale.

- **Boralex (BLX, $42.47, Outperform, $48 Target Price):** BLX has noted interest and demonstrated operational expertise in relation to energy transition technologies (first energy storage asset commissioned on March 1, 2020, with installed capacity of 2MW at a wind farm in France). Given a solid existing foothold in France via its onshore wind platform, and ambitious European Union hydrogen objectives, we think BLX is a natural fit as hydrogen opportunities emerge in France.

- **Innergex Renewable Energy (INE, $22.48, Outperform, $27 Target Price)**: To date management has not commented on hydrogen opportunities, but we note that INE has been active in battery storage, via its solar and battery storage projects in Hawaii and the Tonnerre project in France (uses a battery developed by EVLO – a subsidiary of Hydro-Quebec). Given expertise with nascent energy transition technologies, we would not be surprised to see INE participate in hydrogen projects in the near to medium term.

- **Northland Power (NPI, $46.64, Market Perform; $49 Target Price)**: Per the recent 2021 investor day, management underlined keen interest in hydrogen/renewable green fuels, noting the initial entry strategy is to acquire an existing platform. NPI is expected to build a dedicated hydrogen team, initially focused in Europe but with a global purview: consideration will be given to both providing renewable electricity and direct involvement in production.

Canadian Pipeline & Midstream

- **Even hydrogen requires infrastructure.** While hydrogen continues to entrench itself as a cornerstone of the clean energy transition conversation, the Canadian pipeline and midstream sector is showing signs of being ready to adapt existing steel in the ground as the fuel source becomes a bigger part of the energy mix. We expect pipelines will continue to have a competitive advantage (in cost and safety) over other energy transportation means such as liquid tanker trucks and rail when it comes to hydrogen. In addition to pipeline transportation, we expect midstream infrastructure (i.e., gas processing plants, storage facilities) to also play a useful role in the hydrogen production lifecycle (especially for as long as natural gas and oil remain the predominant feedstocks for hydrogen production). Currently, "grey hydrogen" produced from fossil fuels accounts for 90-95% of the hydrogen produced in the world and remains the cheapest hydrogen production method. As costs come down, we'd expect the Canadian midstream and pipeline sector to invest and explore in technologies such as carbon capture and adapt existing energy infrastructure to move towards more emissions-friendly and efficient "blue-hydrogen" blending opportunities.

- **Altering the terminal value assumption.** In our January 24 sector comment, "Canadian Midstream - What Is the Right Energy Transition EV/EBITDA Multiple?", we discussed how the long-term value of midstream infrastructure assets has recently come into question given the global push to a lower carbon future and how terminal value risk is more than reflected (and in some cases, overdone) in current valuations. Though we noted the potential for the Canadian Midstream and pipeline sector to mitigate energy transition risk in our comment, we did not ascribe any value or upside/useful life extension from retrofitting pipelines or adapting processing plants for hydrogen use. The potential to adapt existing energy infrastructure assets would change the terminal value discussion for the sector, as it would limit the likelihood of a costly change in corporate strategy/business mix (i.e., through large-scale M&A or altering capital allocation priorities) and could extend existing infrastructure asset life at a more reasonable cost of capital.

Key stocks impacted:

- **Enbridge (ENB, $46.22, Outperform, $53 Target Price)**: ENB management has noted that it expects hydrogen-related opportunities to become a source of organic growth in the future. At the moment, ENB is mainly testing the waters with hydrogen with pilot projects, but we expect this could lead to larger investments in the future: (i) $5.2M project with Cummins (CMI, US$259.38, Market Perform rated by Joel Tiss, BMO Capital Markets Corp.) announced on November 20, 2020, at its power-to-gas facility in Markham, Ontario, which would produce renewable hydrogen for distribution to the city's existing gas network in Q3/21 (maximum 2% blend); (ii) at its Quebec gas utility Gazifere, a partnership was announced on February 25 with Brookfield Renewable to build and operate one of Canada's largest green hydrogen injection projects in Quebec. $90M is expected to be invested in a 20MW electrolyzer facility built at Gatineau, Quebec (near BEP's existing hydro facilities). This green hydrogen would then be injected into the natural gas distribution network through a new 15km pipeline.

- **Keyera (KEY, $26.11, Market Perform $27 Target Price)**: Though noting it remains early days with respect to its hydrogen opportunity set, KEY management has noted its Central Alberta gas processing footprint makes for a logical fit for future hydrogen production. The company also has existing competency in hydrogen production that could be leveraged in future opportunities (its AEF plant currently produces some hydrogen). Management noted that it hopes to work with the Alberta government (which is providing a grant of up to 12% of eligible project capital costs for facilities that produce hydrogen) as it evaluates the opportunity set moving forward.

- **TC Energy (TRP, $58.68, Outperform, $70 Target Price):** At its most recent investor day, TRP highlighted opportunities for hydrogen within its existing North American energy infrastructure footprint, including the potential for transporting hydrogen within both its Canadian and U.S. natural gas pipeline systems. Additionally, the company is exploring mass production of hydrogen using nuclear technology at its Bruce Power facility.

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U.S. Utilities

Bottom line: The importance of green hydrogen's role in the final leg of decarbonization of the utility sector is undeniable. However, given the technology's current economics, we do not see the capex opportunities for the sector becoming material until the end of the decade unless there are significant technological breakthroughs. Importantly, however, we see the sector's participation as an integral component of the move away from primarily grey hydrogen towards green hydrogen given the sector's existing infrastructure and proximity to the end use customer. Overall, the investment opportunity set is most visible for the integrated electric utilities, but cost-effective hydrogen could begin to address the ESG and terminal value questions surrounding gas distribution utilities as well.

Where does hydrogen fit in today with the utility sector? Similar to the acceleration in investment in both wind and solar generation by the U.S. utility sector, we see the cost of green hydrogen production as the next key phase to its integration in the sector's energy supply portfolio. Globally, initial decarbonizing efforts have focused on the power sector in tandem with the transportation sector as they account for nearly 2/3 of the carbon intensity on an industry basis. In the U.S., the movement began with state-level renewable portfolio standards for power supply, but carbon reduction targets have continued to become more aggressive through additional state-level legislative actions (California, Massachusetts, New York, and Virginia among others), proposed federal targets under the Biden Administration for the power sector (2035), and corporate carbon reduction pledges as ESG awareness and investor demands escalate.

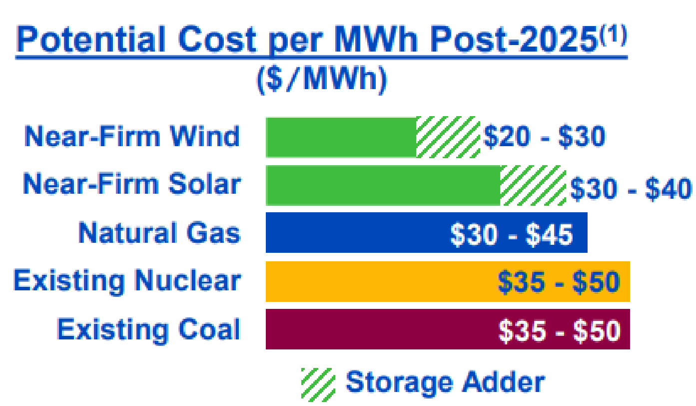
Utilities have continued to pull forward their carbon reduction targets with pledges ranging from 50-80% by 2030 and nearly all, albeit aspirational, at "net-zero" by 2050 (Exhibit 1). SRE's SoCalGas recently made the first pledge by a gas distribution company to reach carbon neutrality by 2050. For most integrated utilities, their carbon reduction plans began with an acceleration in coal retirements which are now able to be replaced economically by wind and solar given the declining cost curve for renewables. However, within the industry, we are seeing a noticeable pivot towards natural gas-related emission reductions both on the power supply side as well as on the gas distribution side.

Exhibit 1: Carbon Reduction Targets

Symbol	Carbon Reduction Target	Base Year
AEE	50% reduction by 2030, 85% by 2040, net-zero by 2050	2005
AEP	80% reduction by 2030, net-zero by 2050	2000
CMS	Net-zero by 2040	
CNP	70% reduction by 2035	2005
D	70-80% by 2035, net-zero by 2050	2005
DTE	Net-zero by 2050	
DUK	50% reduction by 2030, net-zero by 2050	2005
ES	Carbon neutral by 2030	
ETR	50% reduction by 2030, net-zero by 2050	2000
LNT	50% reduction by 2030, net-zero by 2050	2000
NEE	67% reduction by 2025	2005
NI	50% reduction by 2025	2005
NRG	50% reduction by 2025, net-zero by 2050	2014
PEG	80% reduction by 2046, net-zero by 2050	2005
SO	50% reduction by 2025, net-zero by 2050	2007
SRE	Net-zero by 2046 (CA mandate)	
VST	60% reduction by 2030, net-zero by 2050	2010
XEL	80% reduction by 2030, carbon free by 2050	2005

Source: BMO Capital Markets, Company Reports

Exhibit 2: NextEra Energy Outlook for the Cost of Power by Generation Type

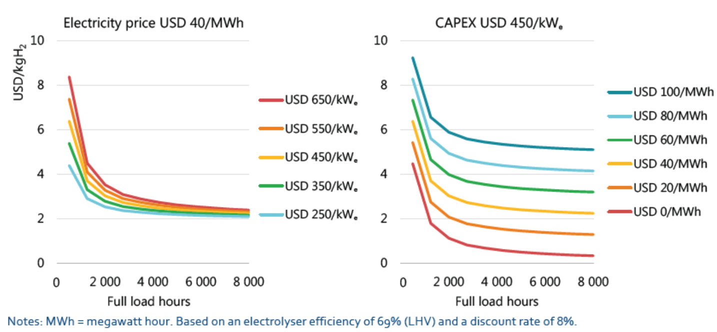


Source: BMO Capital Markets, Company Reports February/March 2021 Presentation (1) Represents projected cost per MWh for new build wind, solar, and natural gas; excludes PTC for wind and assumes 10% ITC for solar; projected per MWh operating cost including fuel for existing nuclear and coal; based on NextEra Energy internal estimates

Dispatchability/reliability and energy cost parity are the primary challenges facing a more accelerated phase out of natural gas-related emissions. Given the intermittent nature of renewable energy and the dual peak demand profiles of many utilities in the US, we think the need for natural gas for heating and as a component of dispatchable, flexible fuel gas-fired generation will continue to be needed for reliability until the cost of scalable energy storage including hydrogen is economic. Distributive generation solutions via roof-top solar, batteries, and hydrogen fuel cells are increasingly promising but cost remains the primary hurdle to adoption. According to an S&P Global Ratings report, it could be another 10 years before hydrogen can compete on price. Even if green hydrogen pricing could fall by over 50% by 2030 to ~$2/kg, S&P estimates that the energy-equivalent natural gas cost would be between $17-18/MMBtu, which would be the equivalent of over $100/Mwh compared with the outlook for near-firm wind with no PTC of $20-30/Mwh and near-firm solar of $30-40/mwh with a 10% ITC (Exhibit 2).

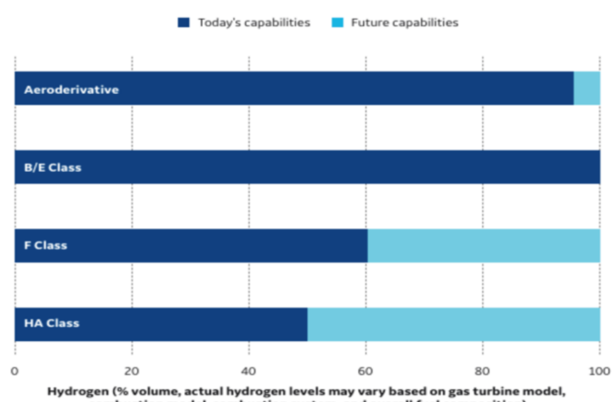
Both the S&P and the IEA see hydrogen becoming cost competitive if solar or wind production costs continue to fall below $30/MWh, and the capital cost of electrolysers continue to improve through technology (electrode/membrane costs), economies of scale (multi-stack systems) and importantly utilization (Exhibit 3). The IEA estimates the electrolyzer stack is responsible for 50% and 60% of the capex costs of alkaline ($500–1,400/kWe) and PEM electrolysers ($1,100–1,800/kWe). The power electronics, gas-conditioning, and plant components account for most of the rest of the costs. To achieve this would require even more aggressive government policies/support (stricter RPS, expanded tax credits, and potentially a formal carbon policy) and a supply portfolio made up of at least 70-80% renewable energy. As this is unlikely to occur before the beginning of the next decade, large-scale adoption of hydrogen for heating and power generation is still a way off, in our view.

Exhibit 3: IEA Future Levelized Cost of Hydrogen Production by Operating Hour for Different Electrolyser Investment Costs (left) and Electricity Costs (right)



Source: IEA "The Future of Hydrogen" June 2019

Exhibit 4: General Electric Gas Turbine Hydrogen Blending Capabilities by Turbine Class



Source: GE Power (https://www.ge.com/power/gas/fuel-capability/hydrogen-fueled-gas-turbines)

But the utility industry continues to move forward with various pilot programs to begin the integration of the use of this carbon-free energy and storage medium into its energy supply portfolios. NextEra Energy (NEE) has said it has nearly 50 pilot programs underway, including both regulated and non-regulated applications, which expand its market opportunity for renewable's development activities. We have also seen various announcements from CNP, EXC, D, ETR, SRE, XEL, PNW, and SO among others regarding pilot applications for hydrogen. Given the sector's existing infrastructure and proximity to the end use customer, we see utilities as an integral component to the commercialization of green hydrogen.

So where do we see the current focus in Utilities? The sector's various pilot programs have been focused primarily across three main fronts: 1) blending hydrogen into the natural gas supply for generation and energy storage applications; 2) natural gas distribution emissions reduction through hydrogen blending; and 3) green hydrogen production from wind and solar as well as nuclear generation.

Hydrogen Blending in Gas-fired Generation: To achieve long-term zero carbon or carbon neutrality objectives while still maintaining supply reliability in the intermediate term, several utilities are using green hydrogen blending pilots that can both reduce the CO_2 emissions from their existing gas fleets and have the potential to become economically scalable energy storage solutions. As one example, NEE's proposed $65mm Okeechobee pilot program would utilize solar energy, which would otherwise been clipped, to produce green hydrogen though a 20MW electrolysis system and replace up to 10-15% of the natural gas consumed at one of the plants three gas turbines. Although most gas turbines have some degree of fuel flexibility, hydrogens volumetric energy density is about 1/3 of natural gas, consequently 3x the flow of gas is required, and H_2 burns hotter and is much more reactive. This means the fuel system needs to be adjusted to accommodate this higher level of flow as well as the combustion components. GE has a fuel system that can be retrofitted to burn fuel blends up to 50% hydrogen but also has turbines that can run up to 100% hydrogen (Exhibit 4). Unlike battery applications, hydrogen is "scalable" and storage capability can be added through larger storage tanks at relatively low cost to make these natural gas plants more dispatchable.

Natural Gas Distribution: In addition to the use of renewable natural gas (RNG) to reduce GHC emissions (methane), managements are looking at green hydrogen pilot programs as an additional $C0_2$ emission reduction tool. Hydrogen produced via renewable electricity is blended into the existing gas supply via pipeline systems for distribution to customers. In addition to the challenge of energy cost parity with currently low spot natural gas prices, there is a physical limitation to the amount of hydrogen that can currently be introduced into the gas supply due to pipe embrittlement issues. According to the International Energy Agency (IEA), for gas distribution applications a blend of up to 20% on a volumetric basis requires minimal/potentially no modifications to grid infrastructure (as well as consumer appliances) but for gas transmission, the limit with the current gas pipeline infrastructure is lower at ~10%. Over time and likely though the adaptation of their current reliability-based pipeline replacement programs, utilities will likely be able to upgrade their systems to accommodate the distribution of green hydrogen.

Green Hydrogen from Nuclear: EXC, XEL, and PNW have all been awarded funding from the DOE for projects aimed at bolstering the long-term viability of carbon-free nuclear power as well as producing green hydrogen using polymer electrolyte membrane (PEM) technology and onsite storage. As electrolyzer utilization improves, the impact of capital costs on the levelized cost of hydrogen should decline increasing the impact of electricity costs on the cost of green hydrogen. Nuclear power can provide reliable, low-cost electricity that allows the electrolyzer to operate at these high full-load hours. By producing hydrogen economically, a nuclear plant could create an additional revenue stream helping to offset the downward pressure on power prices these assets have witnessed as solar and wind power get dispatched first in wholesale electricity markets because they have a near-zero marginal cost.

Pathway forward: Given the sector's existing infrastructure and proximity to the end use customer, we see utilities not only as a key player in the commercialization of green hydrogen production, but also as part of the logistics solution including storage, transportation, and distribution. We see the utilities opportunity set continuing to develop across the following areas:

Growth in low-carbon supply: The most obvious intersection for utilities and green hydrogen is the continued decarbonization of its power supply portfolio through the increased deployment of wind, solar and solar + storage. In addition to their regulated renewable investments, utilities such as NEE, D, AEP, DUK, WEC, ALE, and ED, among others, also have non-regulated investments in contracted renewable projects that will help facilitate increased penetration and availability of carbon-free power. Similarly, nuclear-based electrolysis could be a win-win for both the nuclear owners as well as the supply and cost of green hydrogen.

Storage & Distribution: Both integrated gas and electric utilities and natural gas distribution utilities have existing infrastructure that could ultimately be converted to store and deliver green hydrogen to end use customers. Gas distribution systems can provide the backbone to deliver green hydrogen to customers for both heating and cooking and eventually distributive generation applications. Similarly, the salt cavern storage facilities now used to storage natural gas can be repurposed to store hydrogen, which can be used for both retail as well as wholesale customers including power generation. The investment and/or the repurposing of these assets could help assuage investor's ESG and terminal value concerns for gas transmission and distribution systems.

Transportation: Similar to the current proliferation of electric vehicle (EV) charging stations, utilities could also play a large role in hydrogen refueling stations for longer-haul transportation applications. As discussed above, utilities existing infrastructure provides it with not only the storage and distribution capabilities but also existing assess to the end-use customer.

- **Key stocks affected:**
  - **NextEra (NEE, $77.94, Outperform, $89 Target Price)**: The scale of NextEra's renewable development operations and market leadership in creating both economic and reliable renewable supply places it at the heart of the commercialization of green hydrogen. With 22GW of wind and solar in operation and another 11GW in its backlog, NEE management sees its low cost, near-firm renewables creating significant long-term demand in the power sector. Green hydrogen should provide the company with yet another market to deploy additional renewables resources while also helping the power sector meet its longer-term zero-carbon targets as well as the electrification of the transportation and industrial sectors. NEE has already discussed one potential project that includes a solar tracker combined with an electrolyzer that can not only produce green hydrogen as feedstock for the industrial customer, but any excess power produced can be used to reduce the customer's electricity use while also reducing its carbon footprint. Over the course of 2021 we would expect to get additional announcements on the conversion of the company's more than 50 pilot programs across the US.
  - **Entergy (ETR, $101.14, Outperform, $110 Target Price)**: Entergy's gulf coast-centric service territory positions it at the heart of both the petrochemical and major refineries both of which utilized hydrogen as feedstock. The company is targeting 7,000-8,000MW of new generation (2022-2030) of which up to half could be renewables. Additionally, its Orange County Power Station (2026 in-service) will be located between two existing hydrogen pipelines and can blend up to 30% hydrogen as currently configured. The company also has a decarbonization-focused collaborative with Mitsubishi Power to explore several hydrogen-related applications including 1) CCGT gas turbine innovations including hydrogen flex; 2) CCGT expansion potential using renewables to produce green hydrogen with battery application; 3) nuclear-supplied electrolysis with storage; and 4) evaluation of storage and storage conversion projects.
  - **Exelon (EXC, $44.83, Outperform, $46 Target Price)**: Exelon is the largest nuclear owner and operator in the U.S. with 12 facilities located in the central and eastern regions of the country (Illinois, Maryland, New York, Pennsylvania, and New Jersey) totaling over 18.7GW of carbon-free generation. Producing over 155mm/Mwhs annually, EXC's nuclear fleet produces roughly 20% of the nation's electricity and more than 60% of its clean, zero-carbon energy. As discussed above, low-cost electricity available at a level to ensure the electrolyzer can operate at relatively high full load hours is essential to produce low-cost hydrogen. While still in the pilot phase, EXC could announce as early as this April

whether it will proceed with the 1MW electrolyzer project. If successful, we would see this as a long-term positive for EXC's and other nuclear plants by creating an additional revenue stream that would help bolster the economics of the assets that have been challenged by low power prices.

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U.S. Chemicals

- **Bottom line**: The chemical industry has a number of ways that it can and will be needed to participate in the emergence of the hydrogen mobility industry from the material science required for improved production around electrolysis to broader manufacturing and distribution and carbon capture/sequestration.

- **Industry Participation/Overview**: The chemical industry promises to be an integral part of the broader global push for hydrogen to become a "greener" alternative fuel source to more traditional "dirty" fossil fuels. Their participation will range from helping in part to provide the technology to produce green/blue hydrogen as well as handling the transportation and distribution of the product. Those with the greatest exposure and potential appear to be the industrial gas producers as they: 1) have broad experience with hydrogen given their decades of grey hydrogen production and transportation; 2) have invested in green/blue hydrogen capabilities through their own development and/or have acquired technology to facilitate significant production of green/blue hydrogen and ammonia; 3) possess the global scale to assist in distribution/logistics; and 4) also have the technology to participate in carbon capture and sequestration as parts of the industry push toward blue hydrogen.

  At the same time there are other aspects of the industry that will also participate such as those producing separation membranes (that separate hydrogen and oxygen during water electrolysis), catalysts, etc. In the end, with their material science capabilities as well as production and manufacturing skills, the industry is poised to not only participate, but also to facilitate the emergence of a clean hydrogen fuel industry.

- **Pathway Forward.** The chemical industry is already investing in various stages to help prepare for this emerging energy technology. Over the past decade, green hydrogen as an energy source had an obvious "chicken and egg" issue with potential users not willing to invest in hydrogen vehicles with no obvious source of "fuel" or green/blue hydrogen, while many potential producers of green hydrogen were not comfortable making the investment in production without an obvious market for the product. That said, with the help of government stimulus and proposals as well as participants like Air Products (APD) which "took the plunge" and committed to a large-scale green hydrogen/ammonia facility (the APD NEOM project), the industry appears to have reached a tipping point and investment is being committed. This has also been facilitated by lower renewable fuel source pricing.

  However, the industry is still significant distance away from having this "greener" energy reach cost parity with more traditional fuel sources. It will be imperative to monitor not only how the technology develops (and which companies may lead the charge with innovation), but also the focus on capital allocation and deployment for those targeting the industry—early movers may be rewarded if successful, but may also face greater risk of return damage if not successful/careful.

  Key stocks impacted:

  - **Air Products & Chemicals (APD, $284.36, Outperform, $310 Target Price)**: APD is one of the leading producers of industrial gases in the world as well as hydrogen (largest producer in the world), and has assembled substantial infrastructure, expertise, and customer relationships to maintain/expand its market share as demand grows, with a particular focus on the hydrogen arena. Their industry-leading grey hydrogen position is anchored by their significant pipeline systems in the USGC and in Europoort, Netherlands, as well as relatively smaller systems in the U.S. (Los Angeles), Canada (Edmonton and Sarnia), Thailand, U.K., and Brazil, as well as an emerging pipeline enclave in Saudi Arabia. In its goal to begin allocating capital to the green/blue hydrogen arena to help drive long-term growth, APD has started to work with many established players to unite expertise across the hydrogen energy chain.

Their commitment is exemplified in their NEOM project, a green hydrogen/ammonia project with enough expected hydrogen production to power 20K busses. This project includes a partnership with ACWA Power (energy generation) in Saudi, various technological agreements with Haldor Topsoe (ammonia production) and their latest strategic cooperation agreement with ThyssenKrupp (TKA, €11.11, Not Covered) (exclusive collaboration in certain regions for electrolysis tech), which when combined will result in the world's first large-scale green hydrogen/ammonia plant with zero carbon emissions (scheduled to ramp in 2025). The $7B project includes a $5B JV where the venture will utilize solar- and wind-powered electrolysis (producing hydrogen using ThyssenKrupp tech) and ASU (APD tech) to produce 1.2MT of green ammonia (Haldor Topsoe tech). Then APD will solely invest $2B of capital to create new logistics infrastructure (capital for truck/delivery fleets, facilities to convert the ammonia to hydrogen and filling stations for their hydrogen vehicles—trucks/buses) to eventually deliver ~650 tons per day of green hydrogen from 2025 (in this part of the business they are currently looking to lock in customers to 10- to 15-year contracts and have admittedly taken on some commodity risk to do it).

Beyond this large-scale project, APD continues to get significant interest in its blue hydrogen solutions, particularly blue ammonia (where carbon is captured) from countries like Japan where the focus is on low-carbon power generation. They expect to use their hydrogen experience as well as carbon capture capabilities to drive their growth in the business.

- **Linde Plc (LIN, $284.80, Outperform, $320 Target Price)**: We see LIN as an active participant in the fast-evolving hydrogen for mobility space both in green and blue hydrogen production. Like APD, LIN has extensive experience with hydrogen tied to their massive grey hydrogen tonnage/pipeline business with a global footprint including significant assets throughout the U.S. We expect LIN to take an active role in facilitating blue hydrogen production/growth not only with its experience in hydrogen, but also with its ability to participate in the area of carbon sequestration.

  With regard to investing in the green/blue hydrogen space, LIN has taken a selective/surgical approach to the market with the goal of maintaining high returns while deploying capital into this growth opportunity—as such they make commitments to sizeable investment in the segment only when the pricing and costs are locked in to ensure limited risk around returns (similar to traditional industrial gas ventures). Examples of their approach can be seen in a number of recent announcements including: 1) green hydrogen projects in California (green hydrogen-powered mobility); and 2) U.K. (first hydrogen-powered ferry) and numerous MOUs signed with regional players to target the emerging industry including with Beijing Green Hydrogen Technology Development Co. and CNOOC for the development and promotion of green hydrogen in China, Hyosung in South Korea, and with Snam in Europe. Equally exciting, LIN also announced plans to build/own/operate the world's largest PEM electrolyzer plant in Germany. We expect to hear more in this space from LIN in 2021 (which thinks that in the long term this is a multi-billion opportunity for the company).

  Air Liquide (AI, €140.84, Not Covered): Like the U.S. industrial gas companies, Air Liquide will be an active participant in the green/blue hydrogen mobility arena. Air Liquide has been a major player in the hydrogen industry for decades including production, storage and distribution with its sizeable grey hydrogen platform. Looking forward they expect to participate in the industry meaningfully both in the green and blue hydrogen markets (with their carbon capture/sequestration capabilities).

Some of the more recent examples of their commitment to the area include the initiation and start of the world's largest membrane-based electrolizer unit in Canada; the completion of the first phase of an ultra-high purity low-carbon hydrogen plant in Tiawan, and the company's investment with a 40% stake in the French company H2V Normandy, which is building a large-scale electrolizer complex of up to 200MW of renewable and low-carbon hydrogen in France.

- **Chemours (CC, $27.85, Outperform $38 Target Price):** CC expects to participate in the green hydrogen industry as part of the water-electrolysis process. Specifically, their Nafion membranes provide the separation of hydrogen and oxygen during the electrolysis process. While the company's Nafion business tied to electrolysis is currently small, their material can be instrumental as the electrolysis industry accelerates and looks for greater and greater efficiency (CC claims its membrane works with low voltages and can work over a broad temperature range).

- **Evonik Industries (EVK, €30.01, Not Covered)**: Evonik expects to participate in the water-electrolysis arena as well. They have developed ion-exchange membranes for the electrolyzers. Specifically, while current membranes used in the electrolysis platform are AEL membranes (used in alkaline electrolysis) or PEM (proton exchange membranes), which require incorporate precious metals, Evonik has developed an AEM (anion exchange membrane) that doesn't require precious metals, thereby potentially bringing down the costs significantly.

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Legal Entity: BMO Nesbitt Burns Inc.

Fertilizers (Nitrogen Producers)

Hydrogen is a key input to the production of ammonia (basic building block of nitrogen fertilizer, and a fertilizer itself), and a push to decarbonize ammonia and establish it as an efficient hydrogen carrier may create multiple new demand opportunities and premium pricing tiers for the commodity. We expect incumbent ammonia and nitrogen producers (such as YAR, CF, and NTR in our coverage universe) would see increased benefits given existing ammonia infrastructure as well as production/handling/transport/storage expertise (important since ammonia is classified as hazardous). The upside for these producers would be more attainable if low-carbon blue ammonia (i.e., still produced from gas and coal as today, but with carbon capture and sequestration) can be deemed sufficient to not require large capital spends to change or add production for green, carbon-free ammonia. Consideration to not raise farmer fertilizer costs and thus possibly contribute to food inflation will need to be scrutinized.

- We believe on average ~2.4 tonnes of CO_2 is produced per one tonne of ammonia, though if that ammonia unit is integrated downstream with a urea or nitrate fertilizer plant, it serves as a sink for about a third of the carbon.

Potential for many multiples of ammonia demand growth over time. Ammonia is typically produced through the combination of nitrogen and hydrogen, in which the hydrogen component is primarily sourced from natural gas, but also from coal in China. Ammonia is about a 200Mt market with ~80% of this for fertilizer markets (direct application, as well as upgraded to other nitrogen and phosphate fertilizer) and ~20% for industrial markets. We have seen estimates of up to an order of magnitude of greater ammonia demand assuming different new applications for ammonia (e.g., we've seen 2050 third-party hydrogen demand forecasts of ~200-600M tonnes, implying ammonia demand of ~1-3B tonnes).

- *The emergence of ammonia as an efficient way to transport and store hydrogen would significantly boost ammonia demand.* Hydrogen's low energy density makes it challenging to store and transport. As an alternative, hydrogen can be converted to liquid ammonia (boasting a ~50% higher volumetric energy density than liquid hydrogen) via well-established technology and making use of existing ammonia infrastructure for transport and storage. However, the ammonia must then be decomposed back into hydrogen for end-market use, requiring additional (low-carbon) energy and costs.

- *Potential new demand opportunities in marine fuels*. Emissions reduction is a key focus of the maritime industry considering the IMO's commitment to reducing greenhouse gas emissions by at least 50% by 2050 (from 2008 base). While a tiny fraction of ships today use ammonia as a fuel, ammonia is already globally traded and some of the infrastructure required (distribution to ports, storage tanks, etc.) to use it as a fuel are already in place with existing ammonia producers. This said, a significant scale up of ammonia infrastructure would still be needed, with estimates suggesting ~500Mt of ammonia would be required long term to satisfy shipping needs. Plus, it would require a revamp of the global shipping fleet for ammonia compatible engines, though we have seen some interest in this with MAN Energy, Samsung Heavy Industries, Yara, and others part of a joint development project to develop the first ammonia-fueled oil tanker by 2024, and shipping giant Maersk recently backing plans to build Europe's largest green ammonia unit (expected 2026).

Pathway forward – it will take time for opportunities to materialize and we're not sure how blue vs. green ammonia prices and project ROI will evolve.

- Lower-carbon blue ammonia could act as a transition product, with some estimates suggesting blue ammonia costs are similar to those of conventional ammonia (given tax credits), some producers already producing blue product (via CCS practices), and suggestions that blue ammonia may be deemed sufficient (in terms of carbon reduction) in the near term in certain industries (e.g., marine fuel). However, it is unclear what premium or tiered price could be charged for blue (or even green) ammonia quite yet, and may depend on various carbon credit plans in different jurisdictions. Plus, growers wouldn't likely want to pay higher for blue or green ammonia, as farmers want ammonia solely for nitrogen nutrient content, unless some sort of carbon credit program was available to subsidize growers. A key ammonia benchmark price, Tampa, has averaged $270/t, $405/t and $360/t over five year, ten years, and twenty years.

- Capex and opex for green ammonia remain prohibitive, and there is still much work that needs to be done to figure out the best technology. Capex estimates suggest new green ammonia capacity could cost $2,000-5,000/t vs. $1,000/t for a conventional world scale 1Mt grey ammonia plant. We've so far only seen capex estimates for small pilot projects of 20-50kt plants, but costs would presumably scale down as technology advances (e.g., CF's first 20kt green ammonia unit at Donaldsonville for $100 million capex, with the next 20kt unit seen costing ~$60-70 million). On the opex side, assuming $3 gas, ammonia cash costs are ~$140/t, but we've seen cash costs estimates for green ammonia of ~$450-500/t. As such, we don't expect to see widescale green ammonia production until regulation (subsidies, carbon pricing, etc.) and technology advances (electrolyzers, renewables, etc.) improve the cost differential for no-carbon ammonia. Plus, in order to justify such spends, beyond carbon credits, green hydrogen prices likely need to be at least ~$7-8/kg, which some may view as too lofty.

Key stocks impacted:

- **Yara (YAR, NOK426.70; Market Perform, NOK425 Target Price)**. Yara is emerging as one of the early movers in the space, having already announced three green ammonia projects for potential commissioning over the next two to seven years (though this will still only contribute a small part to its overall ammonia footprint). The company is partnering with Ørsted in the Netherlands on the development of a 100MW electrolyzer plant for renewable hydrogen production, generating ~70kt/year of green ammonia at YAR's Sluiskil plant (this is a relatively small project, but one has to start somewhere). As well, there's a collaboration with Engie exploring green ammonia production at YAR's Pilbara Plant in Australia. Finally, Yara (along with partners Statkraft and Aker Horizons) plans to fully electrify hydrogen production at its Porsgrunn plant in Norway, generating ~500kt/year of green ammonia – this would shift the feedstock from natural gas to renewable power sources from the Norwegian grid. We understand Porsgrunn is one of Norway's largest stationary carbon dioxide sources today. We believe YAR's existing ammonia production footprint (~8.5Mt) including handling expertise, its 20% global ammonia trade share (with own back-up supply system), and its robust ammonia maritime fleet and storage capacity leaves the company well-positioned to participate in the green ammonia/hydrogen evolution. Plus, the company is gearing up for this, recently separating its ammonia trading business into a separate corporate segment. However, we note that it remains early, with announced projects small in the context of YAR's overall production. Additionally, YAR has stated that any new green ammonia projects would only make sense with some level of public/government funding (it should be noted the Norwegian government owns ~36% of YAR shares).

- **CF Industries (CF, US$46.01; Outperform, US$54 Target Price)**: CF is active at the pilot/exploratory stage for green ammonia/hydrogen. Late last year, the company announced a 20kt green ammonia project at its Donaldsonville (Louisiana) nitrogen complex for ~$100 million capex. Beyond this, management has indicated that it will "walk not run" when it comes to green ammonia, so we expect the pace of future green ammonia expansions to be relatively cautious. However, CF expects to be able to scale its blue ammonia production much faster given more favourable cost economics for blue ammonia, plus the company has already invested in CCS capabilities. Management has indicated it could ramp to ~2Mt of blue ammonia (~20% of annual ammonia capacity) within a couple of years by adding some compression and dehydration facilities, accessing geological sequestration (caverns), etc. Overall, similar to YAR, we believe CF is well-positioned to participate in low-carbon hydrogen/ammonia story over time given its existing ammonia infrastructure and handling expertise including its 23 distribution facilities, ~1.5Mt of storage capacity, five deep water docking facilities, pipeline access, etc. CF recently presented on its approach to blue and green ammonia.

- **Nutrien (NTR, US$54.92; Outperform, US$62 Target Price)**: To date, NTR's comments around its blue/green ammonia strategy have been relatively limited (with the company appearing more focused so far on its farm carbon sequestration program). Management has simply indicated it is currently investigating green ammonia pilot projects. However, we note that one-third of NTR's ammonia is already blue (carbon sequestration at Geismar, Redwater, etc.) and low-carbon (sourcing nearby by-product hydrogen for production at Joffre). As we understand it, NTR sells a portion of this carbon for enhanced oil recovery as well as other industrial applications. Similar to other incumbents, NTR benefits from an existing ammonia infrastructure and know-how, and so as momentum for low-carbon products builds, we wouldn't be surprised to see NTR announce investment into the space, ultimately allowing the company to become an active participant in the upside potential.

Methanol

- **We see methanol as having a similar hydrogen opportunity set as ammonia (potential storage medium for hydrogen and as a marine fuel); however, in our view, as carbon is emitted when methanol is combusted as a fuel, this could limit the commodity's attractiveness in these markets unless the carbon used in methanol production is derived from green sources.**

- **Demand growth opportunities appear more limited given methanol's carbon content.** Methanol, a ~90Mt market today, is used for a diverse range of applications including plastics, paints, formaldehyde production, fuels, and olefins production (i.e., methanol-to-olefins). Methanol is typically produced from a combination of carbon dioxide, carbon monoxide, and hydrogen, sourced from natural gas or coal. As such (and as with ammonia), the methanol industry is well-positioned for decarbonization via blue/green hydrogen creating growth opportunities in existing markets as customers demand a greener supply chain, and evolving markets such as the clean energy space for marine fuel (already has applications in fuel blending and industrial boilers/kilns to reduce emissions). Similar to ammonia, methanol as a fuel/hydrogen carrier benefits from existing infrastructure; however, there are drawbacks that could limit adoption.

    - *Green methanol production is significantly more expensive than conventional production.* Plus, the need for companies using green hydrogen-based methanol production to source the necessary carbon dioxide separately (unlike conventional methanol production in which carbon dioxide is generated as part of the process), potentially adds further costs (i.e., carbon capture and storage costs) as well as carbon sourcing challenges (i.e., ability to source non-fossil based carbon).

    - *Given methanol's carbon content, if used directly as a fuel it can lead to greenhouse gas emissions unless the carbon is from non-fossil sources such as direct air capture (DAC).* Beyond this, methanol has also been touted as a potential carrier of hydrogen given its high energy density (80% higher than liquid hydrogen). However, we also see limits to the adoption of this application since the process of reconverting methanol to hydrogen usually involves steam reforming and the release of carbon dioxide (likely rendering methanol a less favourable alternative to ammonia as a hydrogen carrier).

- **Pathway forward – as with ammonia we view the hydrogen-related opportunities for methanol as taking time to play out.** Plus, we expect some incremental limitations to methanol's roll-out into new applications given issues related to its carbon content. Near term, we see the potential for an increase in conventional or low-carbon methanol demand as an alternative to conventional marine fuel given its existing favourable sulphur profile (and IMO 2020's 0.5% cap on sulphur content in marine fuels), estimated ~20% lower carbon dioxide emissions, and dual methanol/heavy fuel oil engines already available today (MAN Energy, Wärtsilä, etc.). Indeed, methanol producer Methanex has seen some early success in proving out methanol as a marine fuel with its fleet of ~11 methanol-fueled ships (growing to 19 by 2023). However, longer term it remains to be seen whether green methanol or green ammonia will emerge as the preferred green marine fuel, with the industry currently seeming undecided between the two (e.g., shipping giant Maersk is investing in both technologies). Though we believe the production of zero-carbon methanol may prove more challenging given the added need to source non-fossil based carbon (e.g., DAC).

Key stocks impacted:

  - **Methanex (MEOH, US$39.79, Outperform, US$55 Target Price)**: As the world's largest producer and supplier of methanol, MEOH stands to benefit significantly if the low-carbon hydrogen related growth opportunities for methanol (in particular for marine fuel) play out. As already mentioned, the company has made significant strides towards proving out methanol as a viable marine fuel with a not insignificant fleet of its own methanol-fueled vessels (using MAN Energy's dual fuel engines). As well, MEOH is a shareholder (with board representation) of Carbon Recycling International, which operates a renewable methanol plant in Iceland and leverages renewable energy from the Icelandic grid to produce hydrogen as well as waste carbon dioxide from a nearby geothermal power station. However, this represents a relatively small opportunity at ~4kt/year of methanol. Beyond this, the company also supports various pilot projects including opportunities with cruise ships, ferries (e.g., Stena Germanica), barges, etc., and is working on a number of projects in China to demonstrate methanol as a marine fuel.

Canadian Small-Cap Chemicals (Chlorate Producers)

- **Unlocking a new revenue stream for sodium chlorate producers**: Sodium chlorate (a pulp bleaching agent) is produced via electrolysis from water, salt, and electricity with hydrogen gas created as a by-product (~55kg of hydrogen is generated per tonne of chlorate). This hydrogen can be captured and stored for commercialization. Importantly, where the electricity used in the process is generated from renewable sources (e.g., hydroelectricity) the resulting hydrogen is considered green and so commands a premium price. Overall, we view hydrogen as an attractive lever to drive incremental revenue for chlorate producers (such as Olin, Chemtrade, and Erco) as they seek to commercialize this hydrogen co-product amid a growing hydrogen market.

Key stocks impacted:

  - **Chemtrade (CHE.UN, C$7.08, Market Perform, $7.50 Target Price)**: CHE is pursuing opportunities with a recently signed partnership with Hydra Energy (a hydrogen-as-a-service provider for commercial fleets) whereby excess hydrogen generated by CHE's ~80kt Prince George (British Columbia) chlorate plant will be supplied to Hydra (at no capital cost to CHE) for use as a fuel in truck fleets. This represents an incremental opportunity since currently CHE is not getting value for this ~5kt of hydrogen. However, we believe it will be some time before CHE sees any material earnings from this source with earnings from the Hydra deal not expected before 2027 (i.e., until Hydra recovers the capital costs for the project). Over time, the real opportunity for CHE lies in the much larger Brandon (Manitoba) plant (though challenging given its more isolated location), which has chlorate capacity ~320kt (suggesting a ~17.5kt hydrogen opportunity).

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Global Metals & Mining

- **Metals & Mining both facilitates and benefits from the hydrogen economy**: Hydrogen has two potential roles in the metals and mining sector which are currently being explored. Firstly, it can help mining operations and associated logistics decarbonize amid rising one-upmanship between major producers as to who can hit carbon neutrality first. Furthermore, it can reduce dependence on fossil fuels in refined metal output, most notably in iron and steelmaking. Meanwhile, increased hydrogen use would boost demand for certain metals, such as carbon and stainless steel for the associated infrastructure, but more notably the platinum group metals, in particular platinum and iridium.

- **Steelmaking is under pressure to reduce emissions, and hydrogen is a potential solution.** While increased use of scrap in lieu of virgin raw materials is a quick and easy fix for carbon reduction, it is not a universal solution, particularly in scrap-short emerging economies. To move towards a net-zero carbon scenario, replacement of coal as a reductant for iron ore would be required. And this is where the push towards hydrogen is gaining traction, with utilization either in blast furnace alternatives or in the blast furnace itself.

- **Direct-Reduced Iron:** DRI production is a well-established industry, with 92Mt produced last year representing ~4% of all metallic units consumed in steelmaking. This can be coal based (mainly in India) but generally utilises natural gas to reduce high-grade, low-impurity iron ore. Gas-based DRI production is already less carbon intensive than blast furnace ironmaking, and various firms including Tenova and Kobe Steel-owned Midrex have now developed technology to allow increased volumes of hydrogen to be blended into reduction gas over time, showing a staged approach to further reducing emissions. Already, LKAB and ArcelorMittal have committed to hydrogen-based DRI facilities, while in November of last year a contract for a DRI plant powered by hydrogen-enriched gas has been signed between China's Hebei Iron & Steel Group – the country's second-largest steelmaker - and Tenova. Phase 1 of this 1.2Mtpa facility is scheduled to begin production by the end of 2021 (though based solely on natural gas rather than hydrogen), with a longer-term aim of 70% hydrogen concentration resulting in 125kg/CO2 per tonne of emissions. However, the economics remain a long way away from parity with incumbent processes, with Wood Mackenzie estimating the hydrogen price would have to be approximately one-third of current levels, and the carbon price higher, to compete with blast furnaces with all other things being equal. A push towards hydrogen-based DRI would be a net positive for high-grade iron ore, particularly pellets or pellet feed, but bad for coking coal and lower-grade iron ore.

- **Blast Furnace Hydrogen Injection:** A less-developed technology than that outlined above, hydrogen injected into the bottom of the furnace acts as an energy source and a reductant, partially replacing pulverised coal. Unfortunately, hydrogen's cooling effect limits injection rates, leading to emission reductions of only ~15%. Gas co-injection is already used in many North American blast furnaces and is an incremental solution towards carbon reduction with limited change to existing equipment.

- **Hybrid Truck Fleets:** Most mine trucks are already diesel-electric and some operations use trolley assist to reduce diesel consumption and for faster ramp climb rates, but the move to full electrification could lead to significant emission reductions at the mine site. Given the remote nature of mining, and continuous operation, it is well suited to fuel cell technology provided limitations around vibration and impact shock can be successfully overcome. With this, both OEMs and the mining companies are researching full electrification of the mine fleet, which could include hybrid hydrogen/battery power, so this has potential to impact many of the mining companies under coverage in the longer term.

- **The infrastructure required for hydrogen is steel intensive.** While existing pipelines can be converted, a widespread hydrogen economy would need dedicated infrastructure. Given these will be pressurized systems, high-strength low alloy steel linepipe will be needed, with alloy additions of chrome, molybdenum, and potentially vanadium and niobium. Hydrogen tanks for cars and trucks would also utilize high-tensile strength steel. Meanwhile, the gas conversion plants needed would be a benefit to stainless steel demand.

Platinum is central to hydrogen catalysis: Platinum group metals (PGM) producers are highly involved with hydrogen developments, given it has potential to be a significant source of future demand. In terms of electrolysis, the polymer electrolyte membrane electrolysis (PEM EL) method, is fast becoming the leading technology in this area particularly as new processes to cut iridium use (but not eliminate it completely) have proven successful. Porous platinum membranes are also utilized in fuel cell technology. From ~50koz currently (<1% of total demand) we anticipate total fuel cell plus electrolyzer platinum demand growing to 180koz by 2025 and ~400koz by 2030, by which point they will account for ~6% of platinum demand. In our view, PGMs need to find new end-use markets over time to offset losses to electric vehicles, and hydrogen offers good potential as a complementary energy transition strategy (rather than necessarily just a competing one).

Key stocks impacted:

- **Sibanye-Stillwater (SBSW, $18.27, Outperform, $25/ADR Target Price, covered by Raj Ray):** Sibanye-Stillwater is well positioned to capitalize on hydrogen opportunities given application of PGMs (specifically platinum, iridium and ruthenium) in proton exchange membrane (PEM) technology and hydrogen fuel cells. Sibanye-Stillwater is amongst the world's leading producers of platinum, iridium and ruthenium. Particularly, platinum accounts for ~51% of the metals prill-split of the company's South African (SA) PGM production. Sibanye-Stillwater also remains at the forefront of future technological innovation in the hydrogen fuel cell space through its research arm, SFA (Oxford), which works with clients on projects from assessing the role of fuel cell vehicles in underground mining, to understanding the supply and pricing dynamics of PGMs to assess the long-term viability of the hydrogen market.

- **Anglo American (AAL, £30.83, Outperform, £34 Target Price, Mining Top Pick, covered by Alexander Pearce)** is planning to deploy a proof-of-concept battery and hydrogen fuel cell hybrid mine truck to its Mogalakwena PGM mine in South Africa around the end of this year. Further, the company is a major producer of platinum group metals, a key component of hydrogen fuel cells (and catalyst for conventional I/C engines).

- **Fortescue Metals Group (FMG, A$20.89, Market Perform, A$22 Target Price, covered by Alexander Pearce)** is also looking at a potential hybrid "green" truck at its iron ore operations in Australia. Further, as part of a wider investment in hydrogen via its new investment vehicle Fortescue Future Initiatives (FFI), Fortescue is exploring opportunities within green hydrogen including a potential 250MW hydrogen (250ktpa green ammonia) plant in Tasmania. An investment decision is expected in 2021, with potential to support its existing operations and provide domestic and international export opportunities for green hydrogen.

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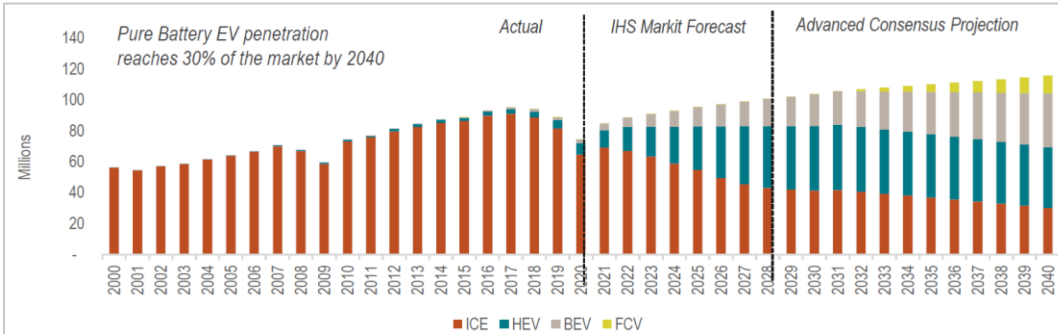
Canadian Auto Parts

- **Bottom line**: Powertrain suppliers will face opportunities and risks as the global automotive industry transitions from internal combustion engine (ICE) vehicles to hybrid electric vehicles (HEV) to battery electric vehicles (BEV) and finally to fuel cell electric vehicles (FCV).

- The transition among the propulsion types will happen on a continuum and will likely transpire over the next 30 years. As illustrated in Exhibit 1 below, the dramatic change over the next 20 years will be related to the penetration of HEVs and BEVs at the expense of ICE vehicles. By 2040, FCVs is expected to account for only 10% of global vehicle production.

Exhibit 1: Global Vehicle Production Forecast by Propulsion Type



Notes: i) 2000-2028 forecasts based on IHS Markit
ii) 2029-2040 forecasts based on consensus average of external industry expert forecasts
iii) production share projections in 2040: 26% ICE, 34% HEV, 30% BEV, 10% FCV
Source: Linamar Investor Presentation

- Notwithstanding that there is considerable skepticism regarding FCVs now, we believe a faster-than-anticipated introduction of FCVs is certainly possible. We believe the transition from BEVs to FCVs should be relatively seamless and rapid since both types of vehicles are based on electric propulsion technologies. The difference lies in that BEVs derive the necessary electricity to propel the vehicle from batteries while FCVs derive the electricity from fuel cells.

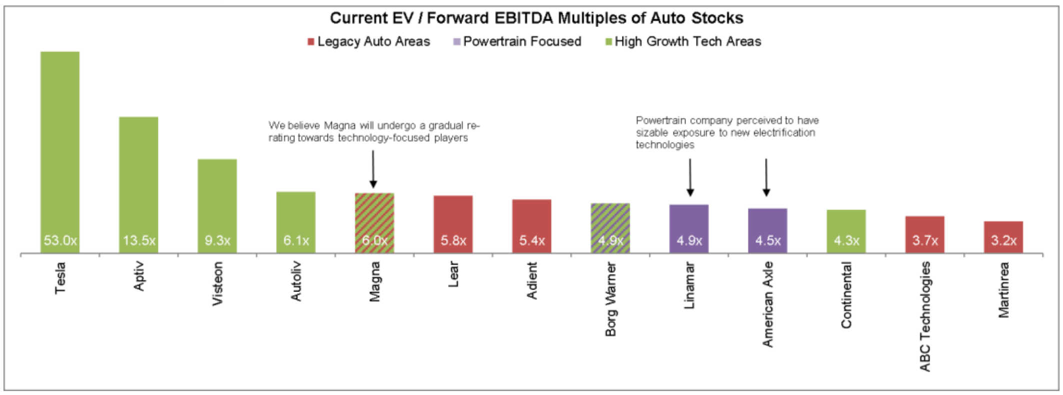
- The opportunity and risk profile for each auto parts supplier will differ and will largely depend on the supplier's current powertrain exposure. Many auto parts suppliers provide parts that are unrelated to the powertrain and these suppliers are considered powertrain agnostic. For example, whether a vehicle is powered by an ICE or by fuel cells, it will still need seats, bumpers, windows, latches, interior panels, etc. As a result, powertrain agnostic businesses should see limited impacts as the transition towards greener powertrain types take place. Conversely, auto parts suppliers that provide powertrain parts, such as parts for the engine and transmission for an internal combustion engine will be subject to rapid changes as the traditional powertrain parts (sprockets, gears, shafts, engine blocks, cylinder heads, etc.) will no longer be required, and hence the risks.

- For powertrain suppliers, the opportunity will be to supply parts for the electric propulsion system and other unique aspects of electrified vehicles. On the electric propulsion system, suppliers will pursue the electric axle, which is the electric drivetrain. This is a module that comprises the electric motor, a gearbox (gears, shafts, and housing), and the associated electronics (software) of the module. A tier one supplier of the electric axle will be selling the module to auto OEMs at about $1,000 per unit. There will be many competitors in the space, with the obvious candidates being Magna, Linamar, GKN, and BorgWarner, as well as, the auto OEMs themselves.

- In addition, lightweighting (i.e., reducing the weight of the vehicle) will be an important consideration for electrified vehicles as the weight of the vehicle contributes to its potential driving range. As a result, most powertrain suppliers are also expanding into lightweight materials, such as aluminum castings. One area of interest for these suppliers is the battery tray, which is an aluminum cast structural part that holds the battery module and it also provides for the front-end structure of the vehicle. A supplier will sell this module to auto OEMs for about $600 to $700. Overall, most powertrain companies believe that potential powertrain content on an electrified vehicle will between $2,000 and $3,000, regardless if it is a BEV or FCV.

- Interestingly, based on the valuations of Canadian auto parts stocks, it appears that investors at this time are more focused on the risks as opposed to the opportunities. Exhibit 2 below, which depicts the current EV/forward EBITDA multiple for many North American auto parts supplies and Tesla, indicates that powertrain related stocks (purple bars) are generally attributed lower multiples.

Exhibit 2: Current EV/Forward EBITDA Multiples of Auto Stocks



Notes: i) Multiples are based on consensus 2022 EBITDA forecasts, except BMO's coverage (Magna, Linamar, Martinrea, ABC Technologies)
Source: BMO Capital Markets, Company Reports, FactSet

Key stocks impacted:

- **Magna International (MGA, $89.50, Outperform, $96 Target Price):** About 20% of Magna's revenues are related to the powertrain, while the rest is powertrain agnostic. Magna's ultimate electrification exposure is difficult to predict as the exposure is over several parts categories and the evolution of vehicle electrification is still in its infancy with supply chains still to be sorted out and determinations made of what the auto OEMs will do in-house and what will be outsourced to suppliers like Magna. In any event, the list of where Magna will play a role in vehicle electrification, whether BEVs or FCVs, is lengthy and includes the following:
  - Specialized dual clutch transmissions for hybrid vehicles.
  - Electric drivetrains, Magna currently has joint ventures in China and Korea to supply these drivetrains.
  - Engineering and design work for electric vehicles, Magna does this at its campus in Austria and through a joint venture in China.
  - Contract assembly of electric vehicles, Magna already assembles the Jaguar I-Pace electric vehicle in Austria and assembles a Chinese BEV through a joint venture in China. Magna will also be assembling the first Fisker BEV called the Fisker Ocean.
  - Electric vehicles will incorporate numerous autonomous driving features, Magna is an industry leader in sensors such as cameras, radar, and LIDAR.

- **Linamar (LNR, $74.64, Outperform, $95 Target Price)**: Of the Canadian auto parts suppliers, Linamar has the highest powertrain exposure. In 2020, the auto parts segment accounted for approximately 80% of Linamar's sales. Within the auto parts segment, almost all of the exposure is related to the powertrain. The other 20% of Linamar's revenues are derived from its mobile access equipment business, Skyjack, and its agricultural equipment business, MacDon. For BEVs and FCVs, Linamar will be aggressively pursuing the modules and related parts that we have noted above: electric axles, battery trays, and other aluminum cast parts.

- **Martinrea International (MRE, $12.82, Market Perform, $17 Target Price)**: While Martinrea is predominately a metal stamping company, it does have a significant aluminum casting business called Honsel that uses various casting methodologies to manufacture engine blocks and structural parts within the vehicle. Honsel represents about 20% of Martinrea's sales. Clearly, as electrification displaces ICEs, the engine block business, which we believe is the most significant business within Honsel, will wind down and Martinrea will be required to replace the lost revenues with aluminum casted lightweight structural parts for HEVs and BEVs.

- **ABC Technologies Holdings Inc. (ABCT, $8.43, Market Perform, $11 Target Price)**: ABC is the classic powertrain agnostic supplier with only about 10% of its revenues related to the powertrain. However, as BEVs and FCVs proliferate over the coming decades, auto OEMs will be compelled to lightweight to address issues related to range. Lightweighting will directly benefit ABC as the company's plastic auto parts are lighter, and auto OEMs will desire to increase the amount of plastic used in the vehicle at the expense of alternative metals.

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Fuel Cell Developers

- **Demonstrated technology attracting support and investment.** There is broad public and industry interest in de-carbonizing transportation. Governments of 18 countries, in aggregate representing approximately 70% of global GDP, have formal hydrogen roadmaps, including targets for fuel cell electric vehicles and hydrogen fueling stations. Hydrogen provides practical advantages over large batteries including higher gravimetric density (lighter mass) resulting in lower impact to vehicle revenue capacity (payload), faster refueling times, and greater range. These advantages are particularly important for certain heavy-duty transportation applications, including buses, commercial trucks (particularly long-haul tractors), marine vessels, and rail. Hydrogen fuel cell technology has been demonstrated on-the-road. Fuel cell electric vehicles powered by the fuel cell engines and components of Ballard Power Systems alone have driven over 75 million kilometers. From an ESG perspective, fuel cells are also highly recyclable and offer potential for lower well-to-wheel emission, depending on the hydrogen fuel energy source and distribution method. A number of major vehicle manufacturers and engine manufacturers have announced fuel cell vehicle development programs and we expect continued investment into promising applications for fuel cells in heavy-duty transportation.

- **Markets for fuel cell electric vehicles set to scale up this decade.** We have conservatively estimated the total addressable market for engines used in buses, commercial trucks, marine, and rail, to be about US$107 billion globally. Heavy-duty trucks are the largest opportunity, representing nearly three-quarters of this estimate. Today, the primary applications for fuel cell vehicles are transit buses and forklifts. Transit authorities in California and Europe alone are expected to order thousands of fuel cell buses over the next decade to comply with California's Zero-Emission bus regulations and Europe's Clean-Vehicle Directive. Starting in approximately 2023 or 2024, the market for fuel cell commercial vehicles in China is expected to scale up to the tens of thousands of units annually supported by the world's strongest fuel cell vehicle support policy and industry investment including by Weichai, the world's largest engine manufacturer. China's central government has targets for 50,000 fuel cell electric vehicles on the road by 2025 and one million fuel cell electric vehicles on the road by 2030. The commercial truck market in Europe also appears set for rapid growth from 2023-2030 with several OEMs including Daimler, Volvo, and Iveco developing long-haul fuel cell electric trucks in coordination with industry associations and government groups, in anticipation of coming large-scale electrolyzer deployments supported by the European Commission.

Exhibit 1: Total Addressable Market Estimate (by Vehicle Type)

Engine Sales by Vehicle Market	Units (000s)	Engine (Avg)	Revenue
Buses	141	72 kW	$5,040
Heavy-duty trucks	1,705	225 kW	$76,796
Medium-duty trucks	513	83 kW	$8,534
Rail	9	600 kW	$4,000
Marine	8	2,000 kW	$13,000
Total			**$107,370**

Source: BMO Capital Markets

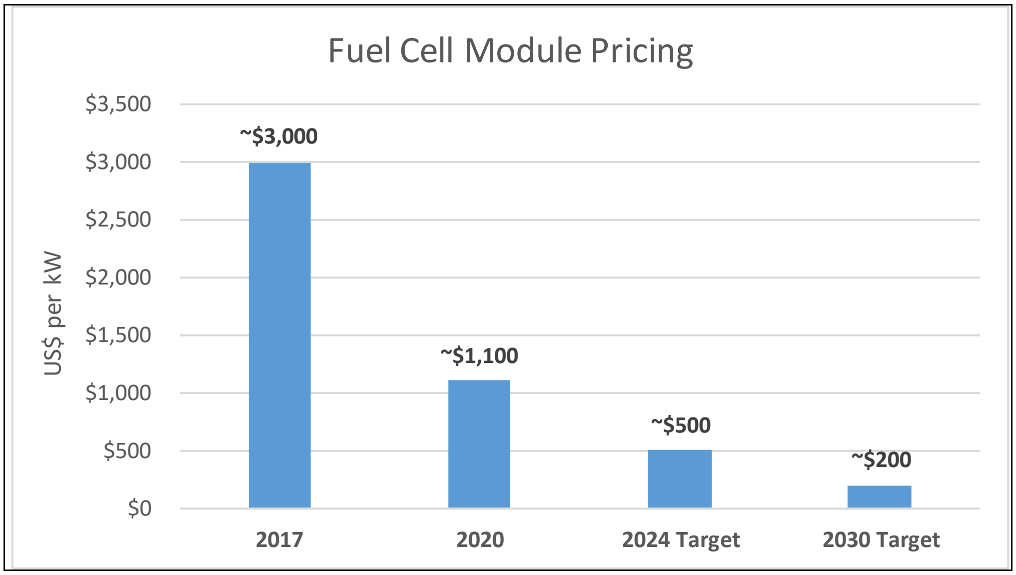
Exhibit 2: Total Addressable Market Estimate (by Geography)

Engine Sales by Geography	Units (000s)	Revenue
China	1,525	$63,664
Europe	415	22,324
U.S.	434	21,381
Total	**2,375**	**$107,370**

Source: BMO Capital Markets

- **Developers driving down fuel cell system costs.** Fuel cell system costs for buses have been reduced by nearly two-thirds since 2017, from $3,000 per kWh to approximately $1,100 per kWh, on relatively low volumes. Fuel cell propulsion systems have at their core one or more fuel cell stacks, representing approximately 30% of the cost of a total fuel cell system onboard a bus today. Leading global developer Ballard Power Systems plans to reduce fuel cell stack costs 70% by 2024, through engineering efforts and leveraging volume growth, while simultaneously improving performance characteristics. At the fuel cell system level, prices are also expected to decline rapidly as manufacturing of the other "balance-of-plant" components scales and becomes commoditized.

Exhibit 3: Fuel Cell System Prices Rapidly Declining

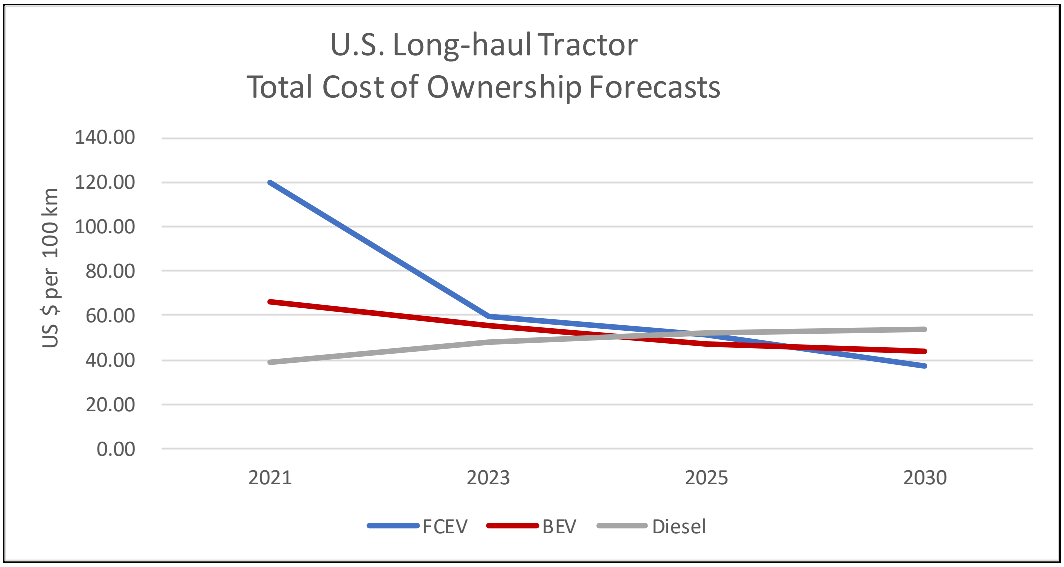


Source: Ballard, DOE, BMO Capital Markets Research

- **Hydrogen fuel prices expected to continue declining.** Hydrogen production capacity appears set to scale up in many global jurisdictions supported by government targets and programs, including investments to produce hydrogen derived from renewable sources (aka "green" hydrogen). Production costs for green hydrogen produced from electrolysis have fallen by approximately 60% since 2010 to the range of approximately US$1.75-10.10 per kg, and are expected to continue to decline to a range of approximately US$1.00-2.75 by 2030, and then to as low as US$0.60 per kg over time, according to Bloomberg New Energy Finance. This would place green hydrogen costs below carbon-intensive "grey" hydrogen (approximately $1-1.50 per kg, depending on the jurisdiction), as eletrolyzers are installed in certain regions including Europe, much of North America, and in Asia, supported by government targets and programs. Prices at the pump are also expected to decline. For example, fuel cell transit buses in California today pay about US$7-8 per kg for hydrogen fuel (minimum 33% from renewable sources), and we expect this could decline to the range of US$3 per kg by about 2030, as distribution scales and becomes more efficient.

- **Total cost of ownership trending toward parity with internal combustion engine options.** Fuel cell electric buses already offer total cost of ownership to the customer below diesel-powered and battery-electric alternatives in certain regions of Europe and according to at least one transit agency in California. The superior range of fuel cell electric buses over lithium-ion battery variants means fleets can service the same number of routes with fewer vehicles. As hydrogen fuel prices and fuel cell system costs continue to decline, total costs of ownership could drop below diesel and battery alternatives for other higher-volume vehicles. For long-haul trucks (a particularly large global market), we estimate TCOs for fuel cell electric could be below battery-electric and diesel alternatives once volumes scale to the 100,000s.

Exhibit 4: U.S. Long-Haul Truck: Total Cost of Ownership Forecasts



Source: BMO Capital Markets Research, with inputs from public materials.

Ballard Power Systems (BLDP, US$23.28, Outperform, US$35 Target Price): Leading fuel cell developer set for rapid long-term demand growth. Ballard Power Systems is the leading developer and manufacturer of proton-exchange membrane (PEM) fuel cell systems globally for use in vehicle applications, and is set for rapid long-term growth. Ballard is the market leader with fuel cell modules and/or stacks in approximately 45% of fuel cell electric buses and trucks on the road in China today, 80% of fuel cell buses on the road in Europe, and approximately 80% of fuel cell electric buses in California. Ballard has a joint venture in China to produce fuel cell engines with Weichai Power, the world's leading manufacturer of heavy-duty engines with approximately 30-40% share of China's commercial vehicle engine market. Ballard has approximately 400 engineers, scientists, and technologists on staff including world leaders in fuel cell development, and has invested over $1.5 billion to get to where it is today.

Today, the company's business primarily consists of orders to supply fuel cell modules for buses and consulting services to Audi and Weichai. Buses are a relatively smaller portion of Ballard's TAM and experiencing more mature growth, with relatively predictable deployments over the next decade in Europe and the U.S. Revenue growth is expected to be subdued near term until China implements its fuel cell vehicle subsidy program, potentially over H2 2021. Ballard records revenue on sales of MEAs and other fuel cell components to the joint venture. As the JV ramps up, Ballard will record some revenue on prior MEA shipments and (more significantly) should receive additional MEA orders. In addition, Ballard will benefit from the JV's eventual earnings once gross profits exceed fixed costs. As fuel cell electric commercial truck markets in China and Europe scale up, we expect Ballard's revenue growth should accelerate to the range of approximately 40-60% annually, potentially as soon as 2023. For example, Ballard is currently developing with partner MAHLE a 240-kW fuel cell engine for heavy-duty truck markets in Europe, North America, and elsewhere, which we expect to be at prototype phase by the end of 2021 and potentially ready for commercial scale production by the end of 2022. Our target price for Ballard is based on 36x EV/revenue (2023). As Ballard's revenue growth accelerates, we expect it will be valued at a premium to the global fuel cell sector. Public fuel cell development and manufacturing stocks we track have a median two-year forward EV/revenue (2022) multiple of 31x and a median two-year visible revenue growth (2019-2021) of 44%.

Exhibit 5: Forecast Summary

Ballard Power US$ million, Year-end: Dec	FY 2019 Dec.	FY 2020 Dec.	FY2021E Q1E Jun.	Q2E Sep.	Q3E Dec.	Q4E Dec.	FY 2021E Dec.	FY 2022E Dec.	FY 2023E Dec.
Weichai-Ballard JV									
Revenue (100%)	$7.0	$15.8	$6.0	$15.0	$15.0	$24.0	$60.0	$91.9	$153.6
Net income (loss) (100%)	($21.6)	($25.5)	($5.8)	($3.8)	($3.8)	($1.7)	($15.0)	$2.7	$4.6
Ballard Power									
Heavy-duty Motive Revenue	$35.4	$47.7	$8.3	$18.8	$22.0	$20.3	$69.3	$110.8	$205.1
Backup Power Revenue	$3.0	$5.6	$1.2	$1.3	$1.0	$2.1	$5.6	$7.8	$11.0
Material Handling & Other	$11.4	$5.3	$0.7	$2.2	$1.4	$0.9	$5.3	$0.0	$0.0
Product & Services Revenue	$49.7	$58.6	$10.2	$22.3	$24.4	$23.3	$80.2	$118.7	$216.0
Technology Solutions Revenue	$56.6	$45.3	$8.6	$8.8	$9.2	$12.3	$38.9	$40.5	$42.1
Consolidated Revenue	**$106.3**	**$103.9**	**$18.8**	**$31.1**	**$33.7**	**$35.6**	**$119.1**	**$159.2**	**$258.1**
Revenue growth (y/y %)	10.1%	-2.3%	-21.7%	20.3%	31.3%	25.2%	14.7%	33.6%	62.2%
Gross profit	$22.6	$21.0	$3.6	$5.7	$6.0	$6.2	$21.5	$32.7	$59.4
Gross margin (% of sales)	21.3%	20.2%	19.2%	18.2%	17.8%	17.4%	18.0%	20.5%	23.0%
Cash Opex	$40.6	$50.0	$17.4	$17.5	$16.9	$22.0	$73.8	$76.9	$88.9
(% of sales)	38.2%	48.2%	92.4%	56.5%	50.3%	61.7%	62.0%	48.3%	34.4%
Adjusted EBITDA (before equity loss)	**($15.2)**	**($26.0)**	**($13.0)**	**($10.6)**	**($9.6)**	**($14.3)**	**($47.6)**	**($39.5)**	**($24.3)**
(% of sales)	-14.3%	-25.0%	-69.2%	-34.3%	-28.4%	-40.3%	-39.9%	-24.8%	-9.4%
Equity (Loss) Earnings	($11.1)	($12.6)	($2.7)	($1.7)	($1.7)	($0.7)	($7.0)	$1.7	$2.6
Adjusted EBITDA (net of equity loss)	**($28.2)**	**($38.9)**	**($15.8)**	**($12.4)**	**($11.3)**	**($15.1)**	**($54.5)**	**($37.8)**	**($21.6)**
(% of sales)	-26.5%	-37.5%	-83.7%	-39.9%	-33.6%	-42.4%	-45.8%	-23.7%	-8.4%
Reported EPS (diluted)	($0.17)	($0.20)	($0.05)	($0.04)	($0.03)	($0.05)	($0.17)	($0.17)	$0.21
Wtd. Avg. Shares (diluted, millions)	232.8	248.5	289.6	297.1	297.1	297.1	295.2	297.1	297.1
Financial Metrics									
Net Cash (Net Debt)	$148	$746	$1,294	$1,267	$1,251	$1,259	$1,259	$1,134	$1,135
Free cash flow	-$26	-$55	-$4	-$29	-$19	$6	-$46	-$119	$12

Source: BMO Capital Markets, Company Filings

Exhibit 6: Ballard Trading in Line With Sector Despite Leading Development Capabilities

Company	Ticker	Currency	Price	Mkt Cap.	Enterprise Value	Revenue	EV/Revenue			Revenue CAGR		EV/EBITDA	Gross Margin	Debt / Cap
			9-Apr-21	(US-equiv mm)	(US-equiv mm)	(US$ M, 2021E)	2021E	2022E	2023E	2019-2021E	2021-2023E	2023E	2020	Latest
Transportation Market Focus:														
Ballard Power System	BLDP	USD	23.30	$6,179	$4,905	$119	47.5x	36.4x	22.4x	6%	47%	nm	20.2%	1.9%
Plug Power	PLUG	USD	32.30	$20,703	$20,043	$461	43.5x	27.7x	17.8x	41%	56%	108.0x	nm	32.2%
PowerCell Sweden AB	PCELL	EUR	243.50	$15,017	$14,607	$217	56.7x	33.7x	23.2x	80%	56%	nm	12.8%	13.7%
Median				**$15,017**	**$14,607**	**$217**	**47.5x**	**33.7x**	**22.4x**	**41%**	**56%**	**108.0x**	**16.5%**	**13.7%**
Electrolyzer Market Focus														
ITM Power	ITM	GBP	4.91	$3,749	$3,701	$30	89.3x	33.6x	19.0x	203%	117%	nm	nm	10.5%
McPhy Energy SA	MCPHY	EUR	33.64	$1,122	$896	$27	27.4x	18.0x	8.6x	55%	79%	nm	nm	3.6%
Nel	NEL	USD	25.33	$38,559	$36,347	$988	36.8x	22.4x	14.2x	32%	61%	nm	nm	2.2%
Median				**$3,749**	**$3,701**	**$30**	**36.8x**	**22.4x**	**14.2x**	**55%**	**79%**	**nm**	**NA**	**3.6%**
Stationary Power Market Focus														
Bloom Energy Corp	BE	USD	24.84	$4,511	$5,125	$979	5.2x	4.2x	3.4x	3%	25%	62.3x	20.3%	92.1%
Ceres Power [(1)]	CWR	GBP	12.50	$3,344	$3,210	$32	72.1x	67.1x	59.6x	46%	10%	nm	67.3%	3.5%
FuelCell Energy	FCEL	USD	12.46	$4,054	$4,090	$80	50.8x	34.2x	25.6x	15%	41%	nm	nm	43.4%
Sinohytec	688339	CNY	281.48	$3,026	$2,861	$1,392	13.5x	9.7x	6.7x	59%	41%	121.9x	nm	0.0%
Median				**$3,699**	**$3,650**	**$530**	**32.1x**	**22.0x**	**16.2x**	**30%**	**33%**	**92.1x**	**43.8%**	**23.5%**
Median - All Fuel Cell Developers & Manufactur				**$4,282**	**$4,498**	**$168**	**45.5x**	**30.6x**	**18.4x**	**44%**	**52%**	**nm**	**20.3%**	**7.0%**

Notes: (1) Ceres Power has identified future opportunities in Transportation markets, in addition to its near-term focus on SOFC.

Source: BMO Capital Markets, FactSet

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ESG

- **Bottom line**: Hydrogen offers enormous potential as a clean energy solution that can help the global economy meet the Paris Agreement's ambitious climate reduction goals. However, investors are increasingly scrutinizing the wholesale ESG practices of companies in the clean tech sector, and we think it will be important for companies participating in "the hydrogen economy" to shore up their overall ESG strategy, including health and safety management, approaches for community engagement, and corporate diversity.

- **Hydrogen has burst onto the clean energy scene.** Hydrogen has been used commercially for over 40 years, but it suddenly has become a centrepiece in the broader energy transition discussion. Green hydrogen in particular has captured investors' imagination, even though other shades of hydrogen production will be needed to decarbonize existing infrastructure, as noted throughout this report.

- **Rise of interest in hydrogen can be traced to the Paris Agreement.** Surging interest in hydrogen as an emissions reduction solution is driven by many factors, including improving economics and increased awareness about hydrogen's remarkable versatility to abate emissions in multiple industries. However, we think it's also important to highlight the role of the Paris Agreement in hydrogen's resurgence. Signed in 2016, the Paris Agreement created a flexible but ambitious global policy framework for countries to pursue emissions reductions, with a view to keeping the increase in global average temperature from pre-industrial levels to well below 2 degrees Celsius. The agreement provides a critical backdrop to many national policy efforts that today drive much of the hydrogen agenda, including the EU's plan to become climate neutral by 2050.

- **Investors are increasingly scrutinizing the ESG practices of clean tech companies.** We think many ESG investors historically have been inclined to give a "free pass" to renewable energy and clean tech companies, including solar and wind project developers and component manufacturers. The rationale was that those companies were providing essential products to enable energy transition and mitigate climate change, arguably the most material ESG issue. However, as we recently observed, this is no longer the case. As the renewable energy space has grown and to some extent matured, investors have begun assessing wholesale ESG practices of renewable energy and clean tech firms, including health and safety management, community engagement strategies, and corporate diversity. Despite the nascent development of green and blue hydrogen, we think new entrants in the hydrogen economy should be prepared for comprehensive scrutiny from ESG investors.

- **Hydrogen's sustainability characteristics likely to come under the microscope.** Although hydrogen's versatility as an emissions reduction solution is well established, we expect increased discussion and analysis of the element's sustainability attributes as hydrogen projects increasingly come online. Inquiries are likely to include the environmental benefits of fuel cells from a lifecycle perspective and questions about the safety of long-distance hydrogen transportation.

- **For a deeper dive into our ESG work on hydrogen, please reference:** Hydrogen Fuel Cells – The Clean Energy Answer to Heavy-Duty Applications.

Appendix

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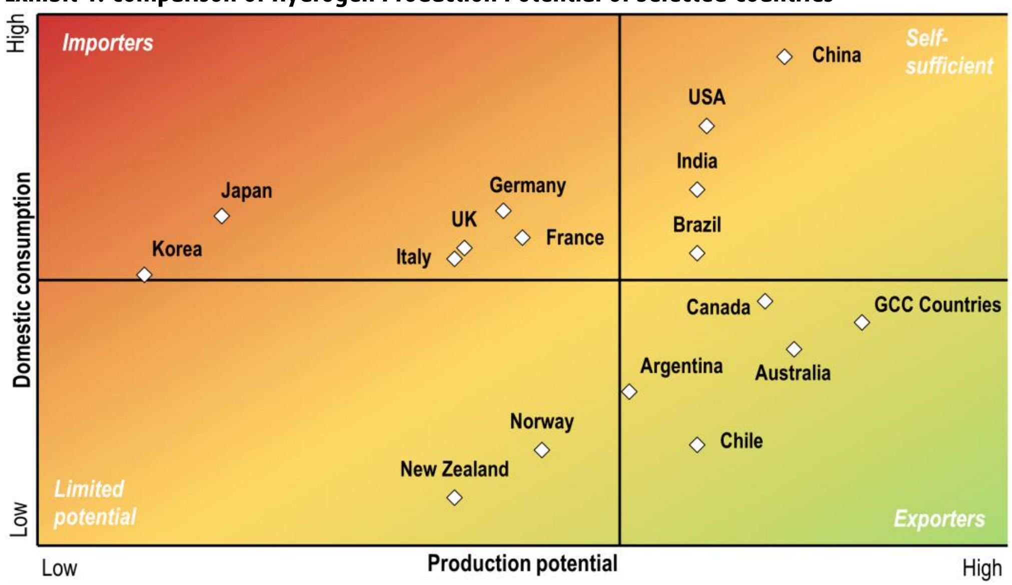
Appendix 1. Hydrogen Is Significantly Attracting Public Capital

Given that there are multiple pathways to decarbonize hydrogen fuel production, at this nascent stage of development, we view infrastructure spending and government regulation as the primary litmus tests for the future large-scale deployment of hydrogen fuel cell vehicles. While a number of carbon capture systems are in development to aid in the transition from grey hydrogen to less polluting blue hydrogen production, the ultimate goal of the industry and many regulators remains achieving emission-free green hydrogen fuel production from renewable resources. However, this does not mean that hydrogen fuel derived from hydrocarbons will be eliminated altogether, nor does it mean that there is a one-size-fits-all approach. We see a blend of green and blue hydrogen pathways that takes advantage of the existing infrastructure while planning for a carbon-neutral future. This is what we believe will be the framework as other national carbon-neutral plans come to fruition.

Exhibit 1: Comparison of Hydrogen Production Potential of Selected Countries



Source: Noussan, M., Raimondi, P., Scita, R. and Hafner, M. (2021). *The Role of Green and Blue Hydrogen in the Energy Transition – A Technological and Geopolitical Perspective.* Sustainability; 11: 298. @Creative Attribution License

Europe: Green Hydrogen Essential to Achieve Carbon Neutrality by 2050

The European strategy includes allocating €65B to develop hydrogen infrastructure for the transportation sector.

In the European hydrogen strategy paper, hydrogen's share of Europe's energy mix is projected to grow from less than 2% in 2018 to 13-14% by 2050. The European Commission has set out three phases to accomplish this goal with 40GW of planned green hydrogen production capacity by 2030.[15] Furthermore, the EU plans to invest €24-42 billion in electrolyzer technology and production and €220-340 billion to scale production up and connect 80-120GW of solar and wind energy to the electrolyzers from now until 2030 (the end of phase 2). Furthermore, €65 billion will be invested in hydrogen infrastructure for the transportation sector, which will involve developing a transport, distribution, and storage system and installing hydrogen refueling networks. In total, all three phases through to 2050 are expected to require €180-470 billion of public investment.

Assuming renewable electricity becomes cheaper in the next decade (end of phase 2), the commission estimates that electrolyzer costs will be halved to €450/kW or less (€180/kW by 2040), an increase in carbon capture costs pushes natural gas reforming from €810/kWh to €1,512/kWh, and finally, grey hydrogen will be €2-2.5/kg versus €1.1-2.4/kg from 2030 onward.

[15] European Commission (2020). A Hydrogen Strategy for a climate-neutral Europe. Brussels, 8.7.2020; COM(2020) 301 final. ec.europa.eu.

Exhibit 2: Three-Phase Plan to Decarbonize Hydrogen Production

Phase	Timeline	Capacity	Green Hydrogen Production	Focus/Goal
1	2020 →2024	~6GW	1 million tonnes	Decarbonize existing hydrogen production in the chemicals sector and facilitate green hydrogen consumption in industrial processes and possibly heavy-duty transport.
2	2025→2030	~40GW	10 million tonnes	Help to decarbonize the steel-making industry, heavy-duty truck and rail sectors, and some marine applications. During the second phase, green hydrogen production is expected to gradually become cost-competitive with grey or blue hydrogen. Achieving this goal will involve the development of local hydrogen clusters in remote areas and development of regional hydrogen ecosystems called "hydrogen valleys."
3	2031→2050	~80GW	?	Green hydrogen production is expected to reach maturity and be deployed at large scale and decarbonize all hard-to-reach sectors. The ultimate goal is to have 40GW of electrolyzer capacity within Europe and 40GW outside of Europe selling into Europe.

Source: European Commission

Blue hydrogen will be a crucial stepping stone to Europe's lofty green hydrogen goals. To meet market demand and scale up hydrogen infrastructure, blue hydrogen will be needed to facilitate carbon-neutral goals. As a result, a group of 11 European gas infrastructure companies has proposed building a 23,000 km dedicated hydrogen pipeline network by 2040 with 75% consisting of retrofitted natural gas pipelines. However, this has created a divide with Czechia, Finland, France, Hungary, the Netherlands, Poland, and Romania supporting this "low-carbon" alternative while Austria, Ireland, Latvia, Luxembourg, Portugal, and Spain support green hydrogen only.

Many countries have introduced their own hydrogen strategies. In addition to the hydrogen initiatives, many countries have also recently released national low- to zero-carbon hydrogen production strategies, and the U.K. is expected publish its plans in early 2021:

(In alphabetical order)

France is leading with 6.5GW of hydrogen by 2030, followed by Germany and Italy with 5GW of planned capacity by 2030 as well.

- **France.** Following the 2015 Paris climate agreement, France has set goals to become carbon neutral by 2050. With a few hydrogen pilot projects already in place, France has announced that an additional €7.2 billion will be invested in lowering emissions from hydrogen production processes and will produce 6.5GW of hydrogen by 2030. Of this, €1.5 billion has been earmarked for the development and manufacturing of electrolyzers and includes provisions for blue hydrogen infrastructure that will utilize its natural gas grid and decarbonize existing industries.

- **Germany.** Germany aims to become GHG neutral by 2050 and has set preliminary targets to cut 55% by 2030 compared with 1990 levels. A country with a long history of hydrogen and fuel cell technology, Germany has committed €9 billion for low- to zero-emission hydrogen production development and setting up the necessary infrastructure. Of that amount, €7 million is earmarked for its national hydrogen strategy, and plans are in place to ramp up green hydrogen production capacity to 5GW by 2030 and 10 GW by 2040. Finally, €2 billion will be reserved for international projects, and the country has recently given grants to develop a 20MW alkaline electrolyzer for green and ammonia production in Saudi Arabia and a synthetic fuel project in Chile. On the blue hydrogen side, there have been strategy talks with the chemicals and steel sectors to utilize carbon capture technology as a decarbonization tool.

  Most of the hydrogen will be provided by offshore wind farms, and the government has approved 11 demonstration projects, including a 50MW electrolyzer at BP's Lingen Refinery that will be powered by a North Sea wind farm operated by Orsted, which could be in operation by 2024. Finally, several German companies have partnered together in a $1.5 billion project that will see the integration of hydrogen into the energy generation mix of the northwestern coastline.

- **Italy.** Italy recently launched an ambitious plan to install 5GW of electrolyzer capacity by 2030, increasing hydrogen penetration into its energy mix from 1% to 2%. The current goal is to have hydrogen account for 50% of the energy production mix by 2050. Furthermore, Snam has been experimenting with delivering a 10% mix of hydrogen within its natural gas network, and Enel and Eni have been developing their own hydrogen plans. Finally, the development of the country's first 'hydrogen valley' that will be located outside of Rome has commenced with an initial investment €14 million.

- **The Netherlands.** The Dutch government aims to cut CO_2 emissions by 49% by 2030 and 95% by 2050 from 1990 levels and plans for gaseous energy carriers, such as hydrogen, to account for 30-50% of the country's energy usage by 2050. An ambitious hydrogen plan was released last April to create large hydrogen infrastructure projects that will focus primarily on renewables and green hydrogen. This plan aims to have 3-4GW of installed electrolyzer capacity by 2030, and the development of a 2GW conversion park is under way in Rotterdam harbor, along with several other initiatives. Plans are also under way for a 20MW plant (that could be expanded to 60MW) for methanol and synthetic fuel in the Groningen province.

- **Norway.** The long-standing beacon of environmental regulation and the zero-emission transformation of the passenger vehicle market, Norway has vowed to become a low-emission society by 2050, targeting a 90% to 95% reduction in emissions compared with 1990 levels.[16] Last summer, hydrogen became a key component of that goal and is a key part of the NOK 3.6 billion (€330 million) 'Green Transition Package' announced in early 2020. Furthermore, Yara International signed a letter of intent with Statkraft and Aker Horizons to establish Europe's first green ammonia project (500k tonnes per year), which is thought to be an important stepping stone to the transition to green hydrogen. Finally, a pilot project is under way to test high-temperature electrolyzers to produce 8kt of synthetic fuel from hydrogen and CO2, and Equinor and Engie are looking to exploit established pipelines and offshore wind to establish blue hydrogen production.

  Port operations cause a number of negative environmental impacts for local air, water, and surrounding lands, particularly from oil and gas storage facilities, storm water runoff, and oil spills. As a result, the number of zero-emission ports and diesel bans from protected natural habitats, such as the Fjords in Norway, will increase drastically in the future and perhaps become part of national policies.

- **Poland.** Poland announced plans for 2GW of hydrogen electrolysis capacity by 2030 earlier this month that is set to be approved in Q1/21. Poland is committed to the EU's carbon-neutrality goal but believes that 2056 is a more realistic target given its ~ 80% reliance on coal for electricity production. However, plans are in the works to reduce the share of coal in the energy mix to 56-60% by 2030, and that transition could be accelerated. Realistically, this could be accelerated should blue and turquoise hydrogen become more a part of the equation as Poland is already a major hydrogen producer and has three installations for natural gas reforming and one hydrogen recovery installation that produces 15.5 tons of hydrogen per hour.

- **Portugal.** Portugal aims to achieve carbon neutrality by 2050 and considers hydrogen key to achieving that goal. The Portuguese government released its hydrogen strategy last spring, totaling €7 billion in both public and private investment. The plan includes 2-2.5GW of electrolysis capacity, and the government has stated that existing pipelines are 70% ready to distribute hydrogen.

- **Spain.** With new proposed legislation cutting carbon emissions to net zero by 2050, hydrogen is set to become a leading contributor to achieve those goals. Spain's hydrogen plan, which was released last fall and is estimated to cost €8.9 billion, aims to install 4GW of electrolyzer capacity by 2030 with 200-300Mw to be up and running by 2024. Repsol plans to build a green/blue hybrid that would see green hydrogen from wind power combined with CCS at its nearby Petronor refinery.

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[16] Norwegian Ministry of Petroleum and Energy (2020). *The Norwegian Government's Hydrogen Strategy Towards a Low Emission Society. www.regjeringen.no*

U.S.: California Is Only State With a Meaningful Hydrogen Strategy

California already mandates that 33% of hydrogen production be green, and this is considered key to achieving the state's target of 5 million zero-emission vehicles (ZEVs) on the road by 2030. The state already regulates that 33.3% of hydrogen production comes from renewable sources (40% to be eligible for the low carbon fuel standard (LCFS) infrastructure credit) on a per kilowatt basis, and the percentage of green hydrogen for the transport sector to be required is 50% by 2030 and 90% by 2050.[17] The California Hydrogen Business Council estimates that actually 37-44% of the hydrogen used in the transportation sector is from renewable sources, and there have been a number of hydrogen infrastructure announcements over the past year. For example, SGH_2 Energy Global, a subsidiary of the Solina Group, has proposed building the world's largest green hydrogen plant near Los Angeles, which will transform 40,000 tons of plastics and recycled paper waste into 3.8 million kilograms of hydrogen fuel annually.

According to the recently released *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California*, hydrogen production from renewable energy in the state is expected to grow from ~2 million metric tons per year to ~470 million and ~4,300 million metric tons per year by 2030 and 2050, respectively, in the most optimistic scenario (high-volume case).[18] Currently, the hydrogen produced is classified as 'grey' and predominantly used in petroleum recovery and refining. However, hydrogen demand in the transportation sector (LDV, MDV and HDV)[19] is expected to make up ~47% in 2030 and ~67% in 2050 compared with negligible levels now.

While California may be the only state with a hydrogen policy, investment from the private sector is expected to boom. In the summer of last year, NextEra Energy (NEE, $77.94, rated Outperform by James Thalacker) proposed a US$65 million pilot plant through its Florida Power & Light utility that will see the installation of a 20GW electrolyzer to produce green hydrogen from solar. Cummins recently announced its five-megawatt PEM electrolyzer to convert surplus hydro to clean hydrogen for the Douglas County Public Utility District in Washington State (USA).

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[17] California's definition of renewable sources include fuel cells using renewable sources, biomass, digester gas, geothermal, landfill gas, municipal solid waste, ocean wave, ocean thermal, tidal current, solar voltaic, small hydroelectric, solar thermal, and wind.

[18] California Energy Commission Clean Transportation (June, 2020). *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California*. Prepared by the UC Irvine Advanced Power and Energy Program. cafcp.org.

[19] LDV = light-duty vehicles; MDV = medium duty vehicles; HDV = heavy duty vehicles

Exhibit 3: Green Hydrogen Demand Scenarios for California Will Initially Be Dominated by the Transport Sector

Applications	Base Volume Case	High Volume Case	Low Volume Case
Light-duty vehicles (1)	500,000 FCEVs by 2030 and 35% LDV market penetration by 2050 (12.3 million vehicles)	1 million FCEVs by 2030 and 50% LDV market penetration by 2050 (17.5 million vehicles)	250,000 FCEVs by 2030 and 20% LDV market penetration by 2050 (7 million vehicles)
Medium- and heavy-duty transport (2)(3)	Hydrogen serves 30-35% of the medium- to heavy-duty on-road renewable diesel demand and 10-12% for off-road vehicles	Hydrogen serves 50% of the medium- to heavy-duty on-road renewable diesel demand and 20% for off-road vehicles	Hydrogen serves 20-25% of the medium- to heavy-duty on-road renewable diesel demand and ~5% for off-road vehicles
Petroleum refining	50% decarbonized H_2 by 2050 with production beginning in 2025	100% decarbonized H_2 by 2050 with production beginning in 2025	none
Process and heat	5% of current natural gas (NG) demand in 2050 with H_2 blending in 2025	10% of current natural gas (NG) demand in 2050 with H_2 blending in 2025	none
Ammonia production	15% decarbonized H_2 by 2030	100% decarbonized H_2 by 2030	none

1) In the transport sector, green hydrogen is expected to continue to make up 33% of production in 2025 and ramp up to 100% by 2050.
2) The high case assumes that 50% of the diesel demand for medium to heavy-duty vehicles and 20% for off-road vehicles such as ocean-going vessels and locomotives.
3) Green hydrogen for non-LDV transport accounts for ~1,100 million kg annually in the high-volume case and only 100 million kg annually in the low-volume case.

Source: California Energy Commission

Other Regions: Plans to Create Hydrogen Societies Are Taking Shape

With companies such as Toyota and Hyundai strongly committed to hydrogen fuel cell technology, it is no wonder that their respective home countries, Japan and South Korea, have also committed to building the necessary infrastructure. We are also seeing that China has put a renewed spotlight on hydrogen now as part of its national strategy to strengthen energy security.

- **Japan: An ambitious hydrogen plan that complements the world's largest refueling infrastructure is in place.** Long considered a hydrogen economy frontrunner with more than 135 hydrogen refueling stations to support 3,800 fuel cell vehicles and 91 fuel cell buses currently on the road, Japan's investment in building a hydrogen economy (80 billion yen was budgeted in FY2020) is starting to bear fruit.[20] With an aim to achieve net-zero GHG emissions by 2050, the Government of Japan released its third version of its Strategic Roadmap for Hydrogen and Fuel Cells in March 2019, which includes demonstrating hydrogen storage and transportation from abroad by 2022 and introducing full-scale hydrogen generation by 2030 and domestic use of green hydrogen by 2050. These goals also include bringing the cost of green hydrogen to US$ 3/kg by 2030 and US$ 2/kg by 2050.

- **China: Already producing a fifth of global hydrogen capacity**. The world's largest industrial hydrogen producer — it produces 22 million tons of hydrogen per year (one-third of global capacity) — China does not have a specific green hydrogen strategy but rather lofty ambitions to create a hydrogen economy. This is partly because of its continued reliance on coal-powered electricity generation and because coal gasification currently contributes to more than 60% of the country's hydrogen production and, therefore, leaning toward a blue hydrogen strategy makes sense. However, China currently has installed one-third of the global renewable capacity, and 2020 also saw a surge of renewable power to gas (P2G) project announcements that will likely use electrolysis to produce hydrogen. Furthermore, oil and gas giant Shell (RDS.A, $38.91, Not Covered) signed off on its first commercial hydrogen project last fall, and hydrogen refueling stations are expected to be built in Zhangjiakou City, one of the host cities for the 2022 Beijing Winter Olympics. We also highlight that

[20] Nagashima, M. (2020). *Japan's Hydrogen Society Ambition: 2020 Status and Perspectives.* www.ifri.org.

the Guangdong Synergy Hydrogen Power Technology Co. built a 13MW plant in 2016 to produce green hydrogen used in fuel cell busses in China, which we visited in 2018 as part of a site tour to China hosted by Anglo Platinum.

The small-scale, rapid-growth model is a throwback to China past. When developing nascent industries, China's model is to bypass (or buy) the lab and move directly to practical optimisation. In recent times, Chinese cities have been competing to be hydrogen hubs, with those chosen including Yunfu in Guangdong and Rugao, northwest of Shanghai. In these cities, all parts of the hydrogen and fuel cell supply chains are setting up in close proximity to minimize logistics and costs, and to maximize recoveries. China has previously successfully used this local "pilot" model across various industries before being rolling them out regionally and nationally. In essence, the Chinese government is 'venture capital' seeding these firms and creating a competitive environment to find winners, which will then be charged with being national leaders. Subsidy reliance is still high, and even the post-subsidy profits at present mean the fuel cell industry will struggle to service its debt. However, development of a functional hydrogen economy plays into a lot of the core themes laid out for China's recently published fourteenth Five-Year Plan, including decarbonisation, technology innovation, reducing dependence on imported energy, and infrastructure building.

- **South Korea: Laying the groundwork for a hydrogen ecosystem with its FCEV Vision 2030.** As South Korea is dependent on imports for 98% of fossil fuel demand and is home to one of the leading fuel cell vehicle manufacturers, it makes sense that the country would invest in hydrogen infrastructure as a means of gaining energy security and meeting its Paris Climate Accord Submission that pledged a reduction in emissions by 37% below 2030 projected rates of growth.[21] In early 2020, the country's National Assembly passed the Hydrogen Economy Promotion and Hydrogen Safety Management Law, which provided the legal framework to develop the necessary hydrogen infrastructure to meet energy demands.

  However, the country has 60 coal-fired plant units in commission and, according to the IEA, limited solar potential. Despite having offshore wind potential, South Korea's plan is most focused on producing low-emission grey and blue hydrogen. The Korea Gas Corporation has also developed a hydrogen plan to invest US$4.1 billion in R&D, the construction of 25 hydrogen facilities, and 700km of new pipeline.

- **Canada's federal government (Natural Resources Canada)** released the "Hydrogen Strategy for Canada" in late 2020, which serves as a broad roadmap for hydrogen's potential in achieving Canada's net-zero ambitions by 2050, and a guide for deployment, starting with early development in condensed geographical locations or 'hubs,' followed by rapid growth and expansion. Hubs identified include areas that have existing hydrogen production, transportation corridors, and marine hubs, including Alberta's Industrial Heartland, which houses nearly 30% of Canada's existing production. In the end, Canada hopes to become a top three global producer of low-carbon hydrogen. Canada's strategy outlines two scenarios for deployment, 'Transformative' and 'Incremental.' Under the Transformative scenario, which is consistent with net zero by 2050, NRCan believes hydrogen may contribute 31% of Canada's delivered energy by 2050 at just over 20 MT/y and abate 190 MT/year of emissions. The 'Incremental' scenario assumes less aggressive policy action with production of 8.3 MT/y by 2050.

  As we highlighted in our in-depth review of hydrogen opportunities in Canadian oil & gas, *The Bold and the Blue-tiful: Canadian Oil and Gas's Role in the Hydrogen Economy*, the Canadian government recognizes that it holds all the qualities needed to become a major producer/exporter of low-

[21] Stangarone, T. (2020). *South Korean efforts to transition to a hydrogen economy.* Clean Technologies and Environmental Policy; DOI: 10.1007/s10098-020-01936-6.

carbon hydrogen, including a robust energy sector and unique geology and land title structure allowing for large-scale CCS, and it has vowed policy support for a rapid transition. We believe the largest policy impacts for blue hydrogen will come from the federal carbon tax of $170/T by 2030 and a proposed Clean Fuel Standard, as related credits could reduce the levelized cost of blue hydrogen by more than 40% on a full-cycle basis and allow it to compete with existing transportation fuels.

- **Australia: Introduced plans to become a leading hydrogen exporter to Japan and Korea.** Australia, along with the Asian Renewable Energy Hub, is planning a $36 billion project to build wind and solar to generate 26GW of green hydrogen in Canberra, Western Australia. Construction is expected to begin in 2026, and hydrogen will be converted into ammonia to transport the fuel to domestic and international markets.
- **Saudi Arabia, the United Arab Emirates (UAE), and Oman have all announced hydrogen plans.** In July 2020, Air Products, Saudi ACWA, and Neom signed a joint-venture agreement to develop the largest green ammonia plant powered by 4GW of solar and wind that is expected to come online in 2025. While UAE is developing a hydrogen roadmap, Dubai is looking to take advantage of its solar park to implement a 5GW green hydrogen project by 2030 that will initially target the transportation sector. Finally, Oman announced construction of a 250-500 MW green hydrogen facility at the Duqm port and is expected to release its own hydrogen strategy shortly.

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Appendix 2. Our (Very) Deep Dive on Fuel Cell Technologies

Hydrogen fuel cells have faced a "chicken or egg first" problem for some time despite being invented in 1838 and successfully deployed in a variety of niche applications. While fuel cells are often linked to the transportation sector, they are now being designed for a number of other applications such as power storage and onsite hydrogen generation. This deep dive unveiled some realizations about the continued cost and performance impact of precious metal electrocatalysts (particularly platinum) and the ongoing sensitivity to impurities from feedstocks produced from the leading way to produce hydrogen. While we focused on the impact of platinum on proton exchange membrane (PEM) fuel cells in previous work Hydrogen Fuel Cells – The Clean Energy Answer to Heavy Duty Applications, as it is the gold standard technology for the transport sector, other fuel cell technologies also rely on this noble metal. The bottom line is that reducing the reliance on platinum or removing it altogether would solve many of the issues plaguing this technology. Furthermore, the use of non-hydrocarbon feedstock could see a reemergence of the alkaline fuel cell (AFC) as its sensitivity to carbon dioxide has derailed its prospects.

Developers continue to drive down fuel cell system costs by reducing platinum content and realizing economies of scale. Fuel cell costs also need to come down to more reasonable levels, and while there are several manufacturing and design elements that can accomplish this, to us, the continued reliance on platinum is the key factor hindering market uptake. Understandably, research over the past two decades has involved, reducing platinum content in the gold standard fuel cell for the transport sector, PEMFCs, as even slight reductions in content have led to sizeable cost reductions. Furthermore, while finding a replacement has unveiled some possibilities, these materials have not yielded the results needed in wider-scale testing. That said, overall costs have come down pretty-quickly despite the persistence of platinum dependence.

Fuel Cell Basics: Simple Designs + Complex Catalytic Reactions = Energy

Fuel cells resemble normal batteries in that they consist of an electrolyte sandwiched between a cathode and an anode; however, the reactions within the system are not standardized among the different types. One side of the system takes in hydrogen fuel while the other side supplies the oxidant that causes the chemical reactions to produce energy, and the three-dimensional electrodes are intricately designed to allow the transit of the necessary electroactive reactants and reaction products throughout the cell. Furthermore, the key components, the flow of energy conversion, the operational temperature, and the purity of hydrogen fuel that can be used differ among the kinds of fuel cells we describe in Exhibits 2 and 3. Together, these characteristics dictate the application.

Fuel cells are categorized by the electrolyte employed as it dictates the electrochemical properties, electrodes, catalysts, and hydrogen fuel that can be used. The type of electrolyte material determines the design of the electrodes, the internal electrochemical reactions, the electrical efficiency, and the operational temperature range of the cell.[22] Fuel cells that operate at temperatures below 480°F or 250°C (PEMFCs and AFCs) need expensive catalysts to accelerate the redox processes shown in Exhibit 2 to efficiently produce the power needed. Of the five types of fuel cells we describe in this section, polymer electrolyte membrane fuel cells (PEMFCs) are the industry gold standard in the transportation sector and will be the focus of our discussion in this report. However, alkaline fuel cells (AFCs) and solid oxide fuel cells (SOFCs) have also been piloted in the transportation sector to a small degree and warrant our attention. Phosphoric acid fuel cells (PAFCs) and molten carbonate fuel cells (MCFCs) are exclusively used in stationary storage applications due to lower efficiencies given the same weight and

[22] The different electrolytes for each fuel cell type: polymer electrolyte membrane (PEM) = perfluorosulfonic acid; alkaline (AFC) = aqueous potassium hydroxide soaked in a porous matrix or alkaline polymer membrane; solid oxide (SOFC) = yttri stabilized zirconia; phosphoric acid soaked in a porous matrix or imbibed in a polymer membrane; (MCFC) = molten lithium sodium and/or potassium carbonate, soaked in a porous matrix.

volume (PAFCs are 37-42% efficient at generating electricity) and durability (MCFCs operate at high temperatures in a corrosive environment).

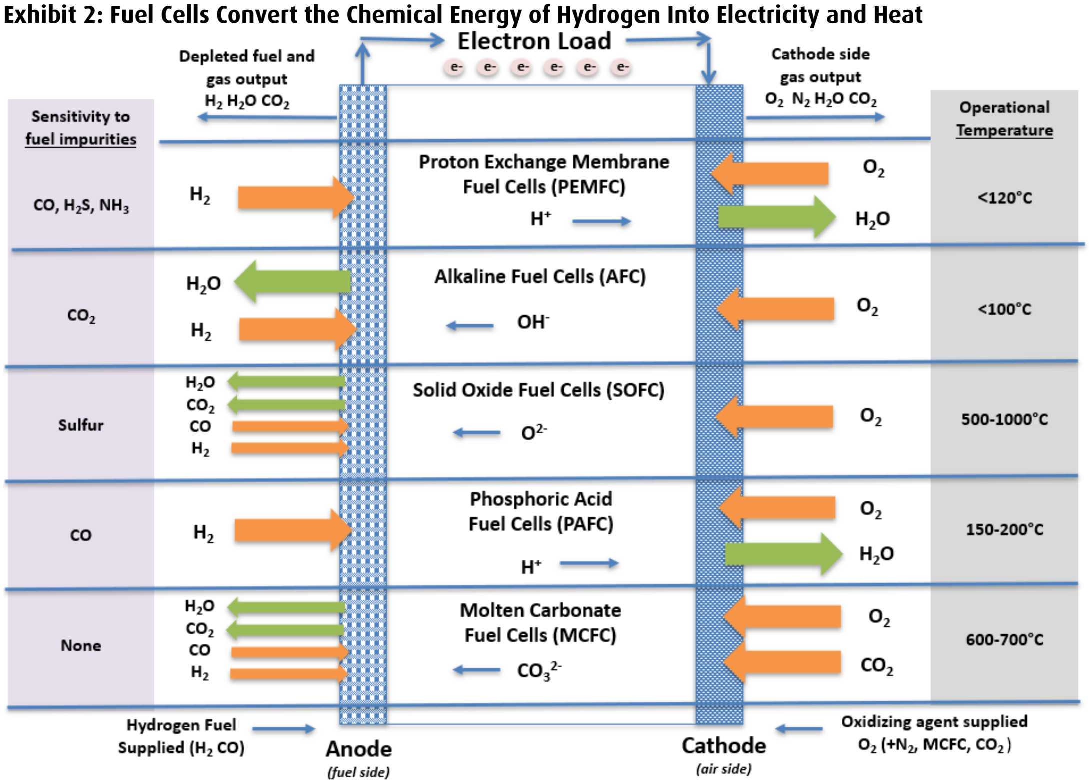
The processes of each type of fuel cell are balanced and dynamic, and the gases move through the grooves of the porous electrodes. Lower operating temperatures mean that the crucial chemical reaction at the electrodes, particularly at the cathode, needs an electrocatalyst. Of these fuel cell types, proton exchange membrane and phosphoric acid fuel cells are probably the most similar in the direction of ionic flows and the need for platinum catalysts, but a liquid electrolyte of hydrogen phosphoric acid is used instead of a membrane makes it largely unsuitable for transportation. Similarly, solid oxide's rigid structure has also made it unsuitable for transportation, although it is now being considered. The bottom line is that their individual characteristics dictate the application, and once chosen, end users are essentially locked in to that technology.

Exhibit 1: Despite the Many Advantages, the Disadvantages Have Impeded Market Uptake in Many Applications

Advantages	Disadvantages
No toxic tailpipe emissions or pollution. Only water and heat.	**Fuel sensitivity.** Depending on the fuel cell, hydrogen fuel needs to meet certain specifications and be free of certain impurities.
Higher thermodynamic efficiency. Fuel cells do not rely on the inefficient combustion process that occurs with ICE vehicles, and therefore, operating temperature does not influence efficiency.	**Hydrogen is costly to manufacture and store**. Current hydrogen production methods are highly carbon intensive and infrastructure to deliver and store fuel is lacking.
Very part-load efficient. The efficiency does not drop with a decrease in power plant size.	**Costly precious metal catalysts.** The key fuel cells used in automotive applications, PEMFCs, need platinum-based catalysts.
Useful in co-generation applications. Fuel cells have solid state properties and, therefore, can react instantly to changes in voltage load.	**Moisture issues.** Because pure water is generated through the fuel cell membrane, uncontrolled water state changes (drying or freezing) can negatively affect performance and life span.
Low operating temperatures. Fuel cells that have low operational temperatures (PEMFC, AFC, PAFC) have quick start-up times.	**Fuel cells typically need compressed air and a high-speed compressor.** This extra load on the system reduces efficiency and output.
Faster refueling times. Unlike other BEVs that have lengthy charge times, FCEVs are filled up in a similar way as gas- or diesel-powered vehicles.	**Fuel cell systems are heavier and bulkier than ICE vehicle systems.** Compared with an ICE engine, FCEV requires more space and structural components to accommodate fuel cell systems.

Source: Olabi *et al.*, 2021, BMO Capital Markets

Exhibit 2: Fuel Cells Convert the Chemical Energy of Hydrogen Into Electricity and Heat



Source: Ehsani *et al.*, 2010; Di Sia (2018), Coralli *et al.*, 2019, BMO Capital Markets

Exhibit 3: Fuel Cell Types Are Named After the Electrolyte — PEMFC Is the Dominant Technology in Transportation Applications

Fuel Cell Type	2019 Shipments	Applications	Advantages	Disadvantages
Used and Researched in the Transportation Sector				
Polymer electrolyte membrane fuel cells (PEMFC) (1) Operating temp.: 50-120°C Typical stack: <1kw – 100kw Electrical efficiency: • 60% transportation • 35-40% stationary	934.2 MW (82.7%)	• Backup Power • Portable power • Distributed generation • **Transportation** • Specialty vehicles • Toys	• Solid electrolyte reduces corrosion and electrolyte management problems • Low operational temperature • Low weight and volume • Quick start-up (1 second) • Quick load following • Allows direct use of methanol without a fuel processor	• High catalyst costs (platinum) • Sensitive to CO (50 ppm), sulfur and ammonia fuel impurities • Water elimination problem • High cost of the PEM electrolyte
Solid oxide fuel cells (SOFC) (2) Operating temp.: 700-1000°C Typical stack: 1kw – 2kw Electrical efficiency: 60%	78.1 MW (6.9%)	• Auxiliary power • Electric utility • Distributed generation • **Transportation (new)**	• Higher operating heat removes the need for expensive catalysts • Fuel flexibility (tolerant to fuel impurities) • Wide # modular configurations	• High temperature corrosion • Breakdown of thin ceramic components of the electrolyte • Long start-up time • Intolerant to Sulfur (50 ppm)
Alkaline fuel cells (AFC)(3) Operating temp.: <100°C Typical stack: <1kw – 100kw Electrical efficiency: up to 70%	0 MW (0%)	• Military applications • Space travel • Backup power	• Quick start-up & easy to operate • Wider range of stable materials • Lower component costs • Highest efficiency • Low operational temperature • Low weight and volume	• Highly susceptible to CO_2 (350 ppm max) and CO poisoning • Requires pure H_2 and O_2 • Corrosive, liquid electrolyte • Lower electrolyte conductivity • Water produced on the fuel side • Short lifespan
Fuel Cells Exclusively Used for Electric Utility and Generation				
Phosphoric acid fuel cells (PAFC)(4) Operating temp.: 150-200°C Typical stack: 5kw – 400kw Electrical efficiency: 40%	106.7 MW (9.4%)	• Distributed generation • Being tested in submarines	• Cheap electrolyte and low operating temperature • Suitable for combined heat and power (CHP) cogeneration • Increased tolerance to fuel impurities (higher operational temperature)	• Highly acidic electrolyte (H_3PO_4) • High catalyst costs (platinum) • Highly susceptible to CO catalyst poisoning • Long start-up time • Low power density
Molten carbonate fuel cells (MCFC)(5) Operating temp.: 600-700°C Typical stack: <0.3MW –3MW Electrical efficiency: 50%	10.2 MW (1.0%)	• Electric utility • Distributed generation	• Megawatt scale • Fuel flexibility (tolerant to impurities) • Suitable to CHP • Hybrid/gas turbine cycle	• High temperature corrosion and breakdown of cell components • Long start-up time • Low power density

1. Also called proton exchange membrane fuel cells, PEMs are favoured in the transportation industry due to faster start-up times and favorable power-to-weight ratios. The process within a PEM fuel cell represents the classic combustion of H2 as the membrane allows for the transfer of H+ ions from the anode to the cathode. A polymeric perfluororinated-sulfonic acid membrane (100 micrometers) has high chemical and thermal stability and remains stable against chemical attack from bases. **Fuel:** hydrogen (green), reformed hydrogen (grey and blue) with low-carbon monoxide content.
2. Solid oxide (SOFC) is essentially a solid-state energy system with an electrolyte that consists of zirconium oxide doped with 8-10% molar of yttrinium oxide (Y_2O_3) or (yttri stabilized zirconia). **Fuel:** hydrogen, biogas, methane, low sulfur diesel.
3. AFCs were the first fuel cell technologies developed and widely used in the space program to deliver electricity and water onboard spacecraft. The electrolyte used in an AFC is an aqueous potassium hydroxide soaked in a porous matrix or alkaline polymer membrane. **Fuel:** hydrogen, cracked ammonia.
4. PAFCs use a phosphoric acid electrolyte soaked in a porous matrix or imbibed in a polymer membrane. **Fuel:** hydrogen, reformed hydrogen
5. MCFCs use a molten lithium sodium and/or potassium carbonate, soaked in a porous matrix. **Fuel:** hydrogen, biogas or methane.

Source: U.S. DOE, Deloitte, Fuelcellswork, Ehsani and Emadi, 2010, Behling 2013, Di Sia, 2018, Wang *et al.*, 2020 Olabi *et al.*, 2021, BMO Capital Markets

PEMFC: This Well-Studied Fuel Cell Can Be Applied to Many Industries

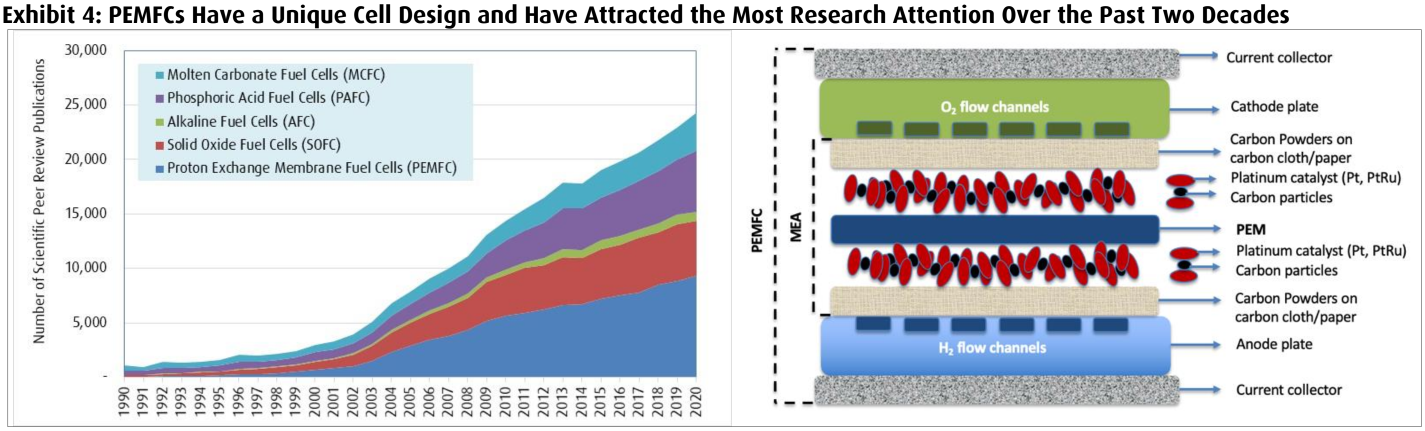
As the industry moves to decarbonize the transport sector, PEMFCs look poised to become the entrenched technology that will be difficult to displace.

The proton electrolyte membrane fuel cell (PEM fuel cells or PEMFCs) sets the standard for the fuel cell industry, and there have been impressive amounts of research and development over the past two decades. Moreover, the leading type of hydrogen fuel production, steam reforming methane (SMR), produces fewer poisonous impurities that could negatively affect performance, and this has given PEMFCs a significant competitive advantage over alkaline fuel cells. PEMFCs are by all means the gold standard for transportation applications but can also be readily applied to other sectors such as stationary storage. Other fuel cell technologies, SOFCs, PAFCs, and MCFCs, were developed for large-scale industrial purposes for a variety of reasons, but SOFCs are being evaluated for the transportation sector.

The use of platinum metal catalysts embedded on the electrodes is both a highlight and a limitation to market uptake. PEMFCs use a solid polymer membrane electrolyte made of perfluorosulfonic acid (also called Nafion from Dupont®), and given its highly acidic nature, hydrogen ions are transported from the fuel side (anode) to the oxidation reaction side (cathode) of the cell. By contrast, AFCs transport hydroxide, and therefore, a wider variety of catalysts can be used. The polymer electrolyte membrane itself is coated with a carbon-supported catalyst that is in direct contact with both the diffusion layer and the electrolyte for maximized efficiency. The catalyst essentially constitutes the electrode, and the assembly of the electrolyte, catalyst layers, and gas diffusion layers is referred to as the membrane–electrode assembly (MEA) or the 'heart' of the fuel cell. The PEMFC fuel cells are stacked layer by layer to produce the power required by the application, and the size of the stack depends on the energy efficiency of the cell.

We believe that PEMFCs will continue to be the dominant technology, especially in the transportation sector, for the foreseeable future due to their low operating temperature (faster start-up times) and ability to use ambient air as an oxidant. This technology is also a strong candidate for other applications such as stationary power. However, the key disadvantage of PEMFCs is that expensive platinum-based metal catalysts seem to be the only materials that have been shown to be able to withstand thousands of hours of operation within the highly corrosive and acidic conditions of the cell while accelerating the complex oxidation reaction required to produce energy. Since platinum metal is required to catalyze the internal reactions, the extra cost is a significant barrier to the widespread use of PEMFCs.

Exhibit 4: PEMFCs Have a Unique Cell Design and Have Attracted the Most Research Attention Over the Past Two Decades



Source: BMO Capital Markets, Huang et al., 2016

Race to Reduce or Eliminate Platinum From PEMFCs to Reduce Cost (and Degradation)

At one-third the cost of PEMFC stacks, platinum catalysts are a double-edged sword…

…they unlock the potential of fuel cells but inhibit power density and longevity if not embedded properly.

For fuel cells to achieve cost parity with gas- and diesel-powered vehicles, it is important to reduce the costs of all components in the system. However, a recent expert elicitation assessment concluded that the continued reliance on precious platinum group metals, particularly platinum, is considered key to inhibiting the US DOE goals for system cost, stack durability, and stack power density.[23,24] The US DOE has set an ultimate target for fuel cell costs to be $30-40/kWh, and most of the experts interviewed in the study expected this to be achieved by 2050. Median assessments for 2020 and 2035 were $62/kW and $40kWh, respectively.[25] The experts ranked the key technical barriers to achieve these goals and the top priority was overwhelmingly the cost of the platinum catalyst due to the high loadings still required.

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[23] This expert elicitation assessment involved interviews with 39 experts across academia, government, industry to assess system costs, stack durability and stack power density and characterize the technical and economic hurdles impeding market uptake of PEMFCs.

[24] Whiston, M., Azevedo, I., Litster, S., Whitefoot, K., Samaras, C. and Whitacre, J. (2019). *Expert assessments of the cost and expected future performance of proton exchange membrane fuel cells for vehicle.* PNAS: 116(11):4899-4904.

Furthermore, the high level of platinum activation loss that is embedded on the cathode is considered the most significant barrier to improving the power density and longevity of the fuel cell.

A platinum catalyst is required due to the low operating temperature and acidic nature of the electrolyte used in PEMFCs. Platinum is used as a catalyst for both the hydrogen oxidation reaction at the anode side of the fuel cell and the oxidation reduction reaction (ORR) at the cathode side. Of the two, the reaction at the cathode side is the more complicated because of the direction of the reaction (anode → cathode) and the fact that reducing oxygen is more difficult than oxidizing hydrogen. As a result, the cathode requires ten times the amount of platinum. The bottom line is that platinum catalysts can efficiently convert oxygen (O_2) to water in the presence of hydrogen ions, and catalyst materials that can't perform this reaction as effectively convert oxygen into hydrogen peroxide (H_2O_2) — an undesirable outcome that degrades the electrolyte membrane prematurely. However, platinum also tends to lose its catalytic abilities over time by either sticking together or via catalyst poisoning from carbon monoxide (CO) present in hydrogen fuel from processing natural gas. As a result, reducing or replacing platinum catalysts at the cathode as well as improving durability of the embedded catalyst is the current focal point of research.

Further technological improvements of the PEMFC are also needed. While we are currently focused on platinum reduction, there are also many other improvements that will need to be accomplished to achieve cost parity to both electric vehicles and diesel to some extent, which will involve several technological advancements and design changes. According to a study by Strategic Analysis Inc. in conjunction with the U.S. DOE, the main areas of advancement other than reducing platinum content and improving its durability are the MEA and the bipolar plates.[26] Currently, the membrane in the MEA is a 14-micron Nafion® film supported on expanded polytetrafluorethylene (ePTFE), and the 2025 goal would be to reduce the film to 10-microns and supported on electrospun polyphenylsulfone. Finally, the main goals with the bipolar plates are to reduce the size and the number of stamps and to vacuum coat them in one or two steps rather than in multiple steps.

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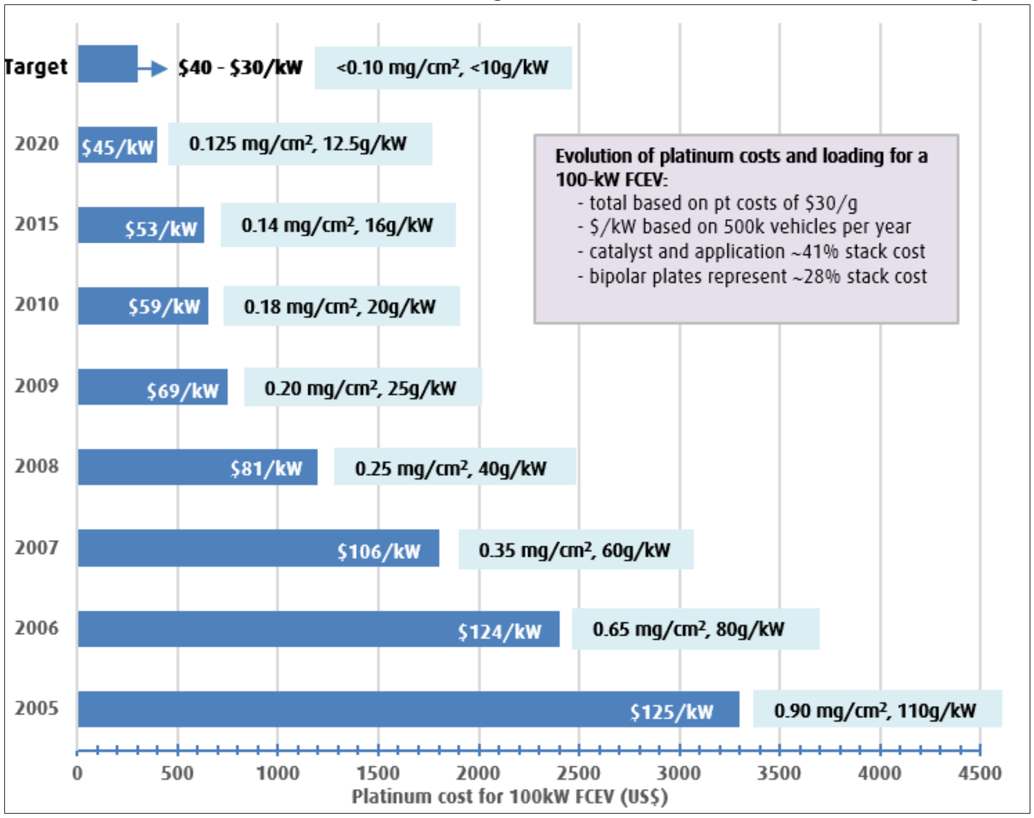
[25] The U.S. DOE does not specify whether their targets are in nominal or in real dollars, but the $30/kW ultimate fuel cell cost goal has remained unchanged since 2002.
[26] James, B., Huya-Kouadio, J., Houchins, C., and DeSantis, D. (2018). *Mass Production Cost Estimation of Direct H2 PEM Fuel Cell Systems for Transportation Applications: 2018 Update.* www.energy.gov. Creative Attribution License©

The acidic nature of the electrolyte and the difficult oxidation reaction at the cathode mean that PEMFCs are tied to costly platinum metal catalysts.

Considering the cost of platinum, the main research focus has been to reduce (<10g) or remove this necessity, a key goal since the 1990s.

Exhibit 5: Platinum Has to Be Reduced to < 10g for a 100kW FCEV to Meet U.S. DOE Cost Targets



Source: Pollet *et al.*, 2019, US DOE, BMO Capital Markets

The anode side of the PEMFC is fast and easy, while the cathode side requires ten times the amount of platinum…

…therefore, the key research focus has been to reduce the platinum content and improve integrity given the acidic nature of the MEA.

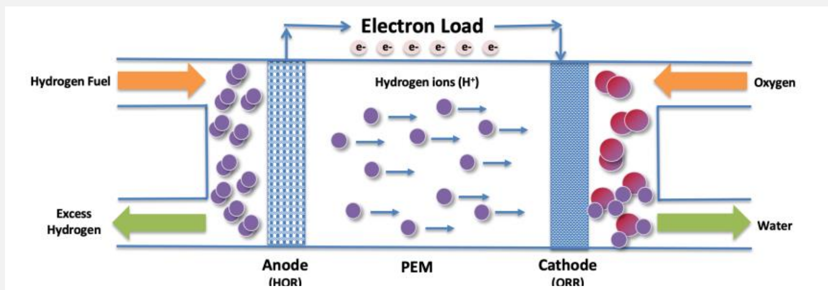
Researchers have yet to find a suitable replacement for platinum catalyst use in PEM fuel cells…

…but, many alternatives are being tested at the benchtop level.

A Little More Detail for the Scientifically Inclined

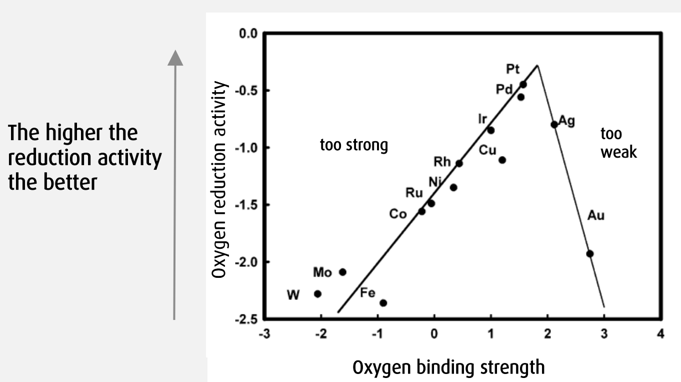
The HOR (fast) and ORR (slow and complex) reactions catalyzed by platinum hydrogen oxidation reaction (HOR) at the anode. At the anode side of the PEMFCs, hydrogen gas is fed into the cell where it is absorbed onto the platinum catalyst and then split into hydrogen ions and electrons. The electrons flow out of the cell and create the electrical current, and the hydrogen ions then flow to the cathode side of the cell. The kinetics at the anode side are fast and, as a result, require very few platinum loadings that effectively remain stable.

Oxygen reduction reaction at the cathode. After the HOR reaction, hydrogen ions flow through the very selective membrane to the cathode where the slow and complex ORR reaction occurs. Air comes into the cell on the cathode side, and oxygen is bound to the platinum catalyst where the incoming hydrogen ions are reduced to water. However, the catalyst used to do this must be able to resist the corrosive environment on the cathode side of the cell and be able to catalyze the oxygen, or peroxide can form and disrupt cell function. Furthermore, noble materials must be used to allow the easy release of water and free up the catalytic sites.



Four Main Characteristics for PEMFC Catalysts:

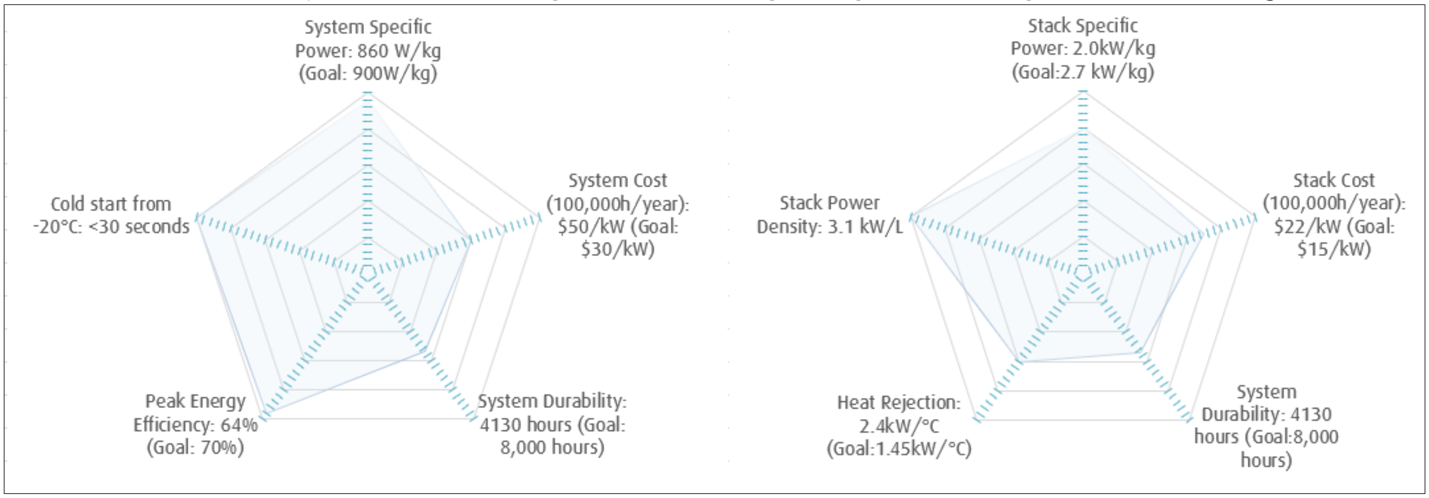
1. Ability for the catalyst to absorb the reactant in a manner that facilitates the reaction but is not too strong that the catalyst is blocked by the reactants or products – the catalyst can't be too strong or too weak.
2. Selective enough to minimize the production of undesirable compounds.
3. Stable enough to withstand operating in a highly acidic environment with strong oxidants and reactive radicals.
4. Able to resist being poisoned by impurities from hydrogen fuels such as carbon monoxide.



Reprinted (adapted) with permission from Norskov, J. *et al.* (2004). *Origin of the Overpotential for Oxygen Reduction at a Fuel Cell Cathode.* The Journal of Physical Chemistry B; 108(46):17886-17892.

Source: Norskov *et al.*, 2004, Holton and Stevenson, 2013, BMO Capital Markets

Exhibit 6: Platinum Is the Major Cost Barrier, but Improvements in Multiple Components Are Required to Meet DOE Targets



Source: U.S. DOE, BMO Capital Markets

AFCs are not dependent on expensive platinum-based catalysts...

...but stringent fuel requirements and fussy electrolyte diverted attention away from this once promising technology.

AFC: Will This Technology Fulfill Its Earlier Promise?

Alkaline fuel cells (AFCs) have been in development since the 1930s and were the first fuel cells that could deliver significant power in practical settings at the University of Cambridge 20 years later. Used as the electrical power source in the Apollo missions to the Moon and the space shuttle orbiter, this type of fuel cell is easy to handle and has high electrical efficiency. However, the stringent fuel requirements that needed to be free from carbonate, fussy electrolytes and the emergence of PEMFC, diverted research interest away from this once very promising technology. Yet, the widespread use of carbon-free green hydrogen will make the fuel purity requirements moot and perhaps relax the technological commitments that end users have to make to suppliers as key impurities will not be present in the fuel in the first place. But for now, the purity requirement imposes significant costs in the long term, and the development of more durable electrolytes that can be used in this system have not received the necessary funding.

Fuel cells that operate at lower temperatures require electro-catalysts that are expensive and can cause premature degradation depending on hydrogen fuel purity. The hydrogen collected from the types of processes currently used to produce hydrogen fuel shown in Exhibit 7 need to be further processed using a pressure swing absorption (PSA) purification system that can remove impurities with varying degrees of ease. Therefore, the lower the amount of impurities present in the beginning, the lower the cost of the hydrogen fuel depending on the fuel cell type used. Given that PEMFCs are highly susceptible to carbon monoxide impurities, the widespread use of steam methane reforming for hydrogen production is a competitive advantage given its low levels (0.1% compared with 2.6% for coal gassification) before PSA treatment. By contrast, AFCs are sensitive to carbon dioxide (CO_2) and, therefore, have been ruled out for widespread use in the transportation sector and have been supplanted by other fuel cell technologies in other applications. However, green hydrogen development would make this problem moot considering non-hydrocarbon feedstock.

SMR, the leading hydrogen production method, produces little CO before further purification...

...and this has given PEMFCs a competitive advantage over AFCs, because they are so sensitive to CO_2 impurities.

Exhibit 7: Carbon-Based Fuel Requirements for Principal Fuel Cells in the Transport Sector

Fuel Requirements (1)	Proton Exchange Membrane (PEMFC) (2)	Alkaline (AFC) (3)	Solid Oxide (SOF) (4)
Hydrogen (H_2)	Fuel	Fuel	Fuel
Carbon Monoxide (CO)	Poison (>10ppm)	Poison	Fuel
Carbon dioxide (CO_2) & water	Diluent	Poison	Diluent
Methane (CH_4)	Diluent	Diluent	Fuel
Sulfur (SO_2, H_2S and COS) (5)	Poison to cathode	-	Poison (> 1.0ppm)

1. The presence of carbon-based fuel impurities such as CO and CO_2 can cause coking or carbon to deposit on the fuel side electrodes of the system and in the case of PEMFCs, electrocatalyst poisoning.
2. Since the main hydrogen fuel method is SMR and that produces the least amount of CO, PEMFCs currently have a strong competitive advantage especially given its technological maturity.
3. The fact that CO_2 is poisonous to AFCs has ruled it out for wide-spread use in the transportation industry because CO reacts with H_2) producing H_2 and CO_2 via a shift reaction making it difficult to purify for this fuel cell.
4. SOFCs offer the most fuel flexibility, but the metallic interconnections within the fuel cell is highly susceptible to sulfur containing fuels and therefore, needs to be removed. Hydrogen sulfide (H_2S) has the greatest impact, but if there is minimal buildup (~10ppm), the damage can be reversed.
5. Sulfur has complicated effects on PEMFCs as the platinum catalyst is tolerant to sulfur compounds on the fuel side of the cell but not the cathode.

Source: Ziomek-Moroz and Hawk, 2004; Jayaraj et al., 2014

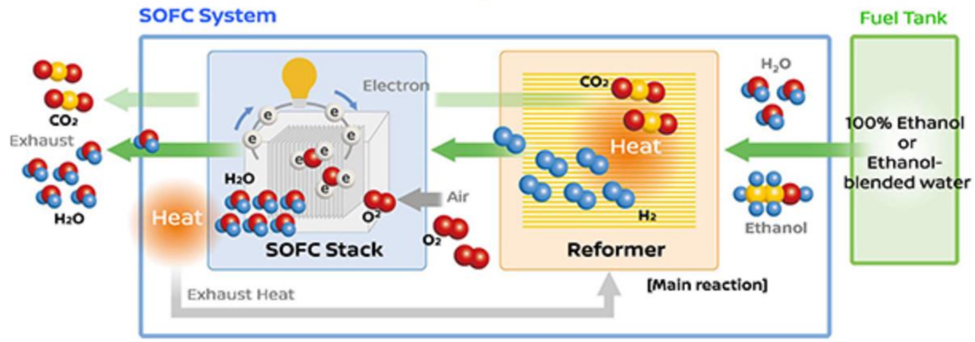
SOFC: Can This Technology be the Ultimate Winner?

Solid oxide fuel cells (SOFCs) are essentially solid-state energy systems that are similar to the solid-state lithium-ion batteries currently in development. For a long time, SOFCs were seen as a possibility for industrial and grid storage applications only as the ceramic electrolyte typically used was unable to withstand the typical vibrations from normal vehicle usage and requires a higher operating temperature compared with PEMFCs. Furthermore, SOFCs can use fossil-derived and bio-derived hydrocarbon fuels that readily react with oxygen, such as ethanol, ammonia, and even conventional fuels. However, while this higher operating temperature may remove the need for expensive platinum catalysts to accelerate the internal oxidation reaction and allow SOFCs to be more tolerable to impurities (CO, CO_2, etc.) typically present in fossil fuel-based hydrogen fuels, it also results in longer start-up times.

The major advantage of SOFCs, higher operating temperature, is also its disadvantage. The need for higher activation energy may allow fuel flexibility, but it also causes longer start-up times and rapid engine shutdowns, making this technology unsuitable for noncommercial applications as the vehicles need to run for 10 hours or more to make economic sense. The higher heat also causes internal degradation of the electrodes, and the presence of sulfur impurities in the fuel leads to reduced durability and performance. Moreover, the ceramics used in first-generation systems were much more brittle, making them vulnerable to the vibrational shocks that occur during normal vehicle operation. These technical hurdles are being ironed out, and there have been a few real-world tests of SOFC-powered vehicles over the past decade.

To realize this fuel flexibility, onboard reformers are needed to convert the fuel into hydrogen, or carbon will deposit, and eventually destroy, the anode that is typically made of nickel and yttria-stabilized zirconia (Ni/YSZ) cermet. This means that SOFC-powered vehicles can readily be paired with existing infrastructure or any other future options, making this technology feasible in markets where PEMFC, AFC, or even pure battery electric vehicles would not be zero emission or cost effective. However, this does not mean that SOFCs are completely out of the running for transportation applications, and we see this technology as one that could supplant PEMFCs as the transportation gold standard.

Exhibit 8: Fuel Flexibility Is a Strong Competitive Advantage for SOFCs



Source: Nissan Global

In 2016, Nissan launched a pilot project in Brazil to test the real-world driving capabilities of the first ethanol SOFC-powered light-duty vehicle. Nissan's e-Bio Fuel-Cell vehicle (based on the e-NV200) uses bioethanol (100% ethanol or an ethanol blended water) made from sugar cane and corn and has a 5kW SOFC stack and a 30L tank to produce a vehicle range of more than 600km. Although the conversion of bioethanol into electricity emits CO_2, CO_2 is absorbed by plants during the growth process, leading to a zero net CO_2 emission well-to-wheel classification. The initial testing phase ended in mid-2017, and despite plans to commercialize the vehicle by 2020, research is ongoing. Ceres Power became a research partner in 2018, and the immediate goal is to remove the onboard reformer needed to simplify the system and reduce vehicle weight.

Stationary Storage Holds Is the Most Promising Application

As SOFCs have electrical efficiencies of more than 60% compared with PAFCs or MCFCs that can be upped to 80-85% with a combined heat and power (CHP) system, along with the fuel flexibility and dynamic nature (able to supply both electricity and heat), they are particularly suitable for stationary storage applications such as on-site hydrogen production and off-grid applications.[27] This dynamic quality is due to their higher operating temperatures, and although high-temperature PEMFCs are being developed, SOFCs are the more mature technology for this application. Moreover, SOFCs can be structured in three ways (tubular, monolithic, and planar), depending on the applications. Finally, PEMFCs, PAFCs, and MCFCs have water management issues and degrade faster, giving them an economic disadvantage for these applications. That said, all of these fuel cell types are being piloted for these applications.

Key areas of research are to develop solid electrolyte materials that can operate in lower temperatures to more reasonable levels (less than 600°C) and enhance the performance of the anode and the cathode to minimize activation, concentration, and ohmic losses.[28] One major goal is to minimize the resistance at the cathode side of the equation at lower temperatures (below 700°C), and systems that include pairing them with a PEMFC unit have been proposed.

[27] Baldi, F., Wang, L., Perez-Fortes, M. and Marechel, F. (2019). *A Cogeneration System Based on Solid Oxide and Proton Exchange Membrane Fuel Cells With Hydrid Storage Membrane Fuel Cells with Hybrid Storage for Off-Grid* Applications. Frontiers in Energy Research; https://doi.org/10.3389/fenrg.2018.00139

[28] Song, C., Lee, S., Gu, B., Chang, I., Cho, G., Baek, J., Cha, S. (2020). *A Study of Anode-Supported Solid Oxide Fuel Cell Modeling and Optimization Using Neural Network and Multi-Armed Bandit Algorithm*. Energies; 13:1621.

PAFC: Acts Like PEMFCs, but With Higher Fuel Flexibility

Phosphoric acid fuel cells (PAFCs) have similar characteristics to PEMFCs in that they have the same gas flows, operate at similar temperatures, require platinum catalysts (albeit less), and are commercially available. The key differences are that PAFCs use a phosphoric acid liquid electrolyte, and because they use less platinum, can tolerate higher carbon monoxide impurities. While the acidic nature of the electrolyte has proven to be problematic in other fuel cell types and, in this case, also must be paired with cell components that can resist corrosion, phosphoric acid can operate at higher temperatures, removes the hydration requirement for the membranes used in PEMFCs, and can be used directly with a reformer. Even though there were a few pilot studies for vehicles, PAFCs have been used as an energy conversion technology for more than 30 years. First-generation PAFCs used a silicon carbide matrix for the MEAs that has since been replaced by a phosphoric acid-imbibed membrane system that has high proton conductivity, low gas permeability, and improved thermal stability.[29,30]

Key areas of research include improving stack life as performance can affected after long periods of operation, reducing platinum content and carbon electrode corrosion, and improving the stability and volume of the electrolyte.

MCFC: A Fuel Cell That Can Facilitate Carbon Capture? Really?

Molten carbonate fuel cells (MCFC) are a bit different from the other fuel cells listed in this chapter and consist of a porous, nickel-based cathode, which is a nickel oxide structure doped with 1-2% lithium, and the electrolytes consist of a mixture of lithium and potassium carbonates in a lithium aluminum matrix.[31] Furthermore, the carbonate ions are transported from the cathode to the anode instead of the usual hydrogen, oxygen, or hydroxide ions, and this has an important implication in that it has a duel power supply, meaning that it can be powered by both the cathode and anode side of the cell. The key issue is that because of the high operating temperature, MCFCs are strictly limited to stationary applications. However, due to their unique qualities, Canada's Oil Sands Innovation Alliance (COSIA) is exploring the use of MCFC to help in capturing CO2 from natural gas-fired processing units while generating electricity.

Key research issues include ensuring the stability of the components, especially in carbonate melts, and increasing the power density to become more economical in the long run.

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[30] Eapen, D., Suseendiran, S. and Rengaswamy, R. (2016). *Phosphoric acid fuel cells.* Compendium of Hydrogen Energy; Volume 3: Hydrogen Energy Conversion; 57-70.

[31] Di Sia, P. (2018). *Hydrogen and the State of Art of Fuel Cells.* Journal of Nanoscience with Advanced Technology; 2(3):6-13.

Appendix 3. The Hydrogen Economy Ecosystem

Green Hydrogen (Electrolysis)

Supply Providers

- BP (UK)
- Brookfield Renewable (Cdn)
- EDF (France)
- Enagas (Spain)
- Engie (France)
- Eni (Italy)
- Equinor (Norway)
- Doosan (S. Korea)
- Galp (Portugal)
- Iberdrola (Spain)
- Neste (Finland)
- Ørsted (Denmark)
- OMV (Austria)
- Repsol (Spain)
- Shell (Netherlands)
- Snam (Italy)
- Statoil (Norway)
- Total (France)

Equipment Providers

- 3M (US)
- Air Liquide
- Alfa Laval
- Anglo American
- Areva
- Asahi Kasei (Japan)
- Avalance (US)
- Electric Heating (US)
- Enapter (Italy)
- Cummins (Hydrogenics) (US)
- GE Global Research (US)
- Giner ELX (US)
- Green Hydrogen Systems (Denmark)
- Hydrigen Systems (Belgium)
- Idroenergy (Italy)
- ITM Power
- Johnson Matthey (UK)
- Linde
- Maire Techinmont
- McPhy (France)
- NEL Hydrogen (Norway)
- Oronzio De Nora (Italy)
- Plastic Omnium
- PowerCell
- Proton Energy Systems (US)
- Shinko Pantec (Japan)
- Space Systems (US)
- Stuart Energy (Canada)
- Sunfire (Denmark)
- Sunhydrogen/Hypersolar (US)
- Siemens
- ThyssenKrupp (Germany)
- Treadwell (US)

Source: BMO Capital Markets

Blue Hydrogen (SMRs with CCS)

Supply Providers

- Aramco (Saudi)
- BP (UK)
- Chevron (US)
- Chiyoda (Japan)
- Eni (Italy)
- Equinor (Norway)
- Fortum (Finland)
- Galp (Portugal)
- OMV (Austria)
- Petrobas (Brazil)
- Repsol (Spain)
- Shell (Netherlands)
- Sinopec (China)
- Taiyo Nippon (Japan)
- Technip (Netherlands)
- Texaco (Germany)
- Total (France)

Equipment Providers

- Air Liquide (France)
- Air Products (US)
- Alfa Laval
- Aker Solutions
- Brown & Root (US)
- Caloric (Germany)
- Doosan
- Foster Wheeler
- Haldor Topsoe (Denmark)
- Hydroge Burner Technology (US)
- International Fuel Cells (US)
- ITM Power
- Koch Process Technology Inc. (US)
- JGC Corp. (Japan)
- Johnson Matthey
- Linde
- Maire Techinmont
- Mahler (Germany)
- McDermott
- Mitsubishi
- The M.W. Kellogg (US)
- NEL Hydrogen
- Saipem
- Siemens
- Technip FTI
- ThyssenKrupp
- Uhde (Germany)
- Wood
- Xebec Absorption

Source: BMO Capital Markets

Fuel Cell Companies in Transportation and Stationary Storage

- 3M
- AFC Energy
- Ballard Power Systems, Inc.
- AFC Energy
- Ballard Power Systems
- Bloom Energy
- Bosch
- Ceramic Fuel Cells
- Ceres Power
- Doosan
- Great Wall Motor
- Hydrogenics/Cummins
- ITM Power
- Loop Energy
- Lubridizol
- Nedstack
- Mingtan Hydrogen
- Nuvera Fuel Cells
- Panasonic Corporation
- Plug Power
- PowerCell
- Proton Power Systems
- Toshiba Corporation
- Toyota
- Toray Industries
- Shouhang IHW Resources
- Solid Power
- Sunrise Power Co., LTD.
- Swiss Hydrogen
- Symbio (Michelin)
- SinoHytec
- Wuhan HydraV Fuel Cell

Hydrogen Fuel Cell Vehicles Companies

- ABB
- Airbus
- Alstom
- Audi
- BMW
- British Airways
- Chengu
- CNH Industrial
- Cummins
- Daimler AG
- Dayun Heavy Truck
- DongFeng
- ElringKlinger
- Esoro
- Faw Jiefang
- Fincantieri
- Foton
- Hino
- Honda
- Hornblower Yachts
- Hyundai
- Iveco (formerly Irisbus)
- General Motors
- Great Wall
- Grove Hydrogen Auto
- Jiangling
- Kawasaki
- Kenworth
- Mitsubishi
- New Flyer
- Navistar
- Nikola
- Renault
- Scania
- Sunline
- Symbio
- Thor Industries
- Toyota
- Traton Group
- VDL
- Weichai
- Wrightbus
- VanHool
- Yutong
- Xugong

Selected Hydrogen Producers (via Ammonia/Methanol)

- Asahi Chemical Industry Co. (Japan)
- Black & Veatch Pritchard (US)
- Caloric (Germany)
- C I Hayes (US)
- CF Industries
- China BlueChemical
- EuroChem
- Haldor Topsoe (Denmark)
- Institut Francais de Petrole (France)
- Johnson Matthey PLC (UK)
- Mahler AGS (Germany)
- Methanex
- Mitsubishi Gas Chemical Co. (Japan)
- M.W. Kellogg (US)
- Nutrien
- OCI NV
- Proman
- QAFCO
- Rolock Inc. (US)
- Sargent & Wilbur (US)
- Seco/Warwick Corp. (US)
- TogliattiAzot
- Yara

Auxiliary Equipment Providers for the Hydrogen Economy

- Chart Industries – cryogenic equipment
- Caterpillar (US) – distribution of fuel cells, data centers
- Hexagon Composite (Norway) – storage and distribution
- Mullen Group (US) – trucking an logistics
- Quantum Fuel (US) – hydrogen tanks
- Worthington Industries (US) – fueling and tanks
- Midrex – metallurgical process plant
- Tenova – metallurgical process plant

Catalyst Producers:

- BASF
- Clariant
- Entegris
- Umicore
- Johnson Matthey

Source: BMO Capital Markets

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ABC Technologies	ABCT	C$8.43	Mkt	64
Air Liquide	AL	€140.84	NR	53
Air Products*	APO	US$284.36	OP	52
Anglo American**	AAL	£30.83	OP	61
ARC Resources	ARX	C$7.65	OP	38
ATCO	ACO.X	C$42.15	OP	43
Baker Hughes*	BKR	US$20.11	Mkt	40
Ballard Power Systems	BLDP	US$23.28	OP	67
Boralex	BLX	C$42.47	OP	45
BP	BP	US$24.39	NR	42
Brookfield Renewable Partners	BEP	US$43.52	Mkt	44
Canadian Natural Resources	CNQ	C$38.57	OP	38
Canadian Utilities	CU	C$34.13	Mkt	43
CF Industries	CF	US$46.01	OP	56
Chart Industries	GTLS	US$143.91	NR	41
Chemours*	CC	US$27.85	OP	54
Chemtrade	CHE.UN	C$7.08	Mkt	58
Chevron	CVX	US$102.92	NR	41
Emera	EMA	C$56.44	OP	43
Enbridge	ENB	C$46.22	OP	46
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Evonik Industries	EVK	€30.01	NR	54
Exelon*	EXC	US$44.83	OP	50
Exxon	XOM	US$55.87	NR	41
Fortescue Metals Group**	FMG	A$20.89	Mkt	61
Fortis	FTS	C$54.79	OP	43
Innergex Renewable Energy	INE	C$22.48	OP	45
Keyera	KEY	C$26.11	Mkt	46
Linamar	LNR	C$74.64	OP	64
Linde Plc*	LIN	US$284.80	OP	53
Magna International	MGA	US$89.50	OP	63
Martinrea International	MRE	C$12.82	Mkt	64
Methanex	MEOH	US$39.79	OP	58
Mullen Group	MTL	C$12.38	OP	39
NextEra Energy*	NEE	US$77.94	OP	50
Northland Power	NPI	C$46.64	Mkt	45

Company Name	Ticker	Price (04/09/21)	Rating	Page #
Nutrien	NTR	US$54.92	OP	57
Precision Drilling	PD	C$30.52	OP	39
Royal Dutch Shell	RDS	US$38.91	NR	42
Schlumberger*	SLB	US$26.76	OP	41
Sibanye-Stillwater**	SBSW	US$18.27	OP	61
TC Energy	TRP	C$58.68	OP	46
Tourmaline	TOU	C$23.92	OP	38
Whitecap Resources	WCP	C$5.62	OP	38
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Hold	Market Perform	46.4 %	25.9 %	44.1 %	44.5 %	40.1 %	37.5%
Sell	Underperform	2.1 %	36.4 %	2.8 %	2.1 %	1.6 %	4.8%

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