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# The Alchemist


## Hydrogen: Applications in Mining and Metals

From Fuel Cell Electric Vehicles to Green Explosives - The Alchemist takes a dive into hydrogen's potential role in decarbonising the mining and metals industry

### Introduction

Interest in hydrogen and the development of a green hydrogen economy is rapidly gaining momentum due to its potential to decarbonise many difficult-to-abate industrial processes and heavy transportation. Whilst the concept of a hydrogen economy has existed for decades, it is only recently that the substantial investments required to make the concept a reality have started to flow, with over US$80bn of mature investment expected through to 2030 (Source: Mckinsey). Investment has been turbocharged by government policies, regulation, and net zero ambitions. As a result, green and low carbon hydrogen production is projected to reach around 7Mtpa by 2030.

So, is hydrogen a potential solution to enable mining and metals companies to achieve ambitious decarbonisation objectives? This issue of *The Alchemist* will take a closer look at hydrogen applications in the mining and metals industry, the status of technology developments and highlights key obstacles to their potential uptake.

### Hydrogen Overview

#### Why the interest now?

Readers of *The Alchemist* will be well versed in the broad macroeconomic themes encompassing decarbonisation and will no doubt be aware of increased focus on emissions from government and broader society alike. Electrification has emerged as a relatively low-cost abatement option across many industries (as discussed in *The Alchemist Issue 38 – Decarbonisation The Mining and Metals Industry Reaction – Is It Smoke and Mirrors*). However, electrification struggles to compete technically and economically as a decarbonisation method for many industrial processes – and this is certainly true in the mining and metals industry.

As a result, the mining and metals industry will need to explore decarbonisation options beyond electrification and look at higher cost abatements to meet ambitious emissions targets – enter hydrogen. When combined with the increasing adoption of carbon pricing mechanisms worldwide and technological advances in hydrogen production, storage and transportation, the forecast economics for certain applications stack up.

#### Why Hydrogen?

Hydrogen can be effectively produced, transported and exported to anywhere in the world and thus has the potential to emerge as a global energy carrier. As a carrier, hydrogen has the highest specific energy of any common fuel by weight (~3x petrol/gasoline), it can be produced readily from water, can be stored for extended periods of time with minimal losses and finally it only produces water vapour and heat as by-products when used in fuel cells or directly combusted. Hydrogen is already a globally significant commodity in its own right, around 70Mtpa of hydrogen is produced each year (well over U$100bn p.a.). However, around 95% is captive to the chemical industry (~60% ammonia and methanol production) and the petrochemical industry (~30%). Hydrogen for transport comprises <1% of uses, owing to the low volumetric energy density of hydrogen (~7x less than gasoline even when compressed to 700bar).

#### How is Hydrogen produced?

Critically, if society is considering hydrogen to assist with decarbonisation then the source of hydrogen production and the corresponding emissions intensity matters - a useful way to conceptualise this is the hydrogen colour wheel in Figure 1.

Additional colours seem to be added to the wheel on a regular basis and some inconsistencies exist as to the classifications, so do not be surprised if additional colours are mixed up for marketing purposes or to support a particular industry viewpoint in energy debates. For our purposes we will base our discussion on the use of 'green' hydrogen, but equally noting any zero or low emission hydrogen source can be viable for decarbonisation.

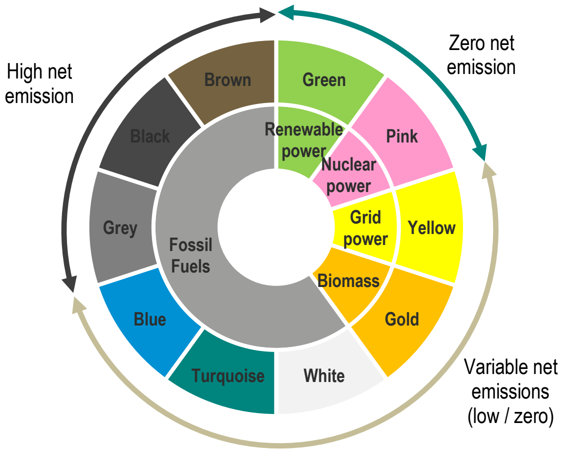


Figure 1. Hydrogen 'colours' (middle ring), corresponding source (inner) and typical net emissions intensity (outer). Source: RFC Ambrian

**Green** – produced by the electrolysis of water powered by any renewable energy source.

**Brown/Black** – the original hydrogen production source, produced by gasification of coal (in-situ or on-surface) creating a syngas which can contain $H_2$, $CO$, $CO_2$, $CH_4$ and various other gases. Brown vs. Black is used to further distinguish the rank of coal gasified.

**Grey** - The most common source today, produced from steam methane reforming of natural gas, $CH_4$ is split into hydrogen gas and $CO_2$. For every 1t of $H_2$ produced, around 10t of $CO_2$ is emitted.

**Blue** – Same as Grey hydrogen or Brown hydrogen, however the $CO_2$ is captured via a Carbon Capture and Storage (CCS) process.

**Turquoise** – produced from methane pyrolysis; splitting the methane molecule to produce hydrogen gas and solid carbon. Differs from Grey hydrogen as no water/steam is used. Considered a low emission hydrogen source as the carbon can be used for other applications.

**White** – or natural hydrogen, produced from reservoirs in the earth's crust, usually alongside helium and methane (rare at economic concentrations). May also refer to hydrogen produced from in-situ processes in hydrocarbon reservoirs such as in-situ gasification.

**Gold** – gasification of biomass feedstock. Considered low emission hydrogen (on a net basis), can be combined with CCS for zero net emissions.

**Yellow** - produced by the electrolysis of water powered by the electricity grid and therefore the emissions intensity associated with its production is dependent on the local grid.

**Pink** – produced by the electrolysis of water powered by nuclear energy.

## Hydrogen Applications in Mining and Metals

### Green Steel

Steel is generally produced via two methods; the Blast Furnace (BF) and Basic Oxygen Furnace (BOF) route or the Direct Reduced Iron (DRI) and Electric Arc Furnaces (EAF) route.

BF's rely on coking coal which provides heat and carbon that indirectly reduces iron oxide ore. The carbon in coal reacts with the oxygen in iron ore to produce carbon metallic iron with carbon dioxide produced as a by-product. The metallic iron is then placed in a BOF, oxygen and fluxes are added to lower the carbon content and produce low-carbon steel. Approximately 74% of steel globally is produced via BOF.

The use of hydrogen in BF's involves the injection of hydrogen (or hydrogen rich gases) in the process to act as a reducing agent and also provide a source of heat. Simulations indicate injection rates are limited due to the cooling effect of $H_2$ in the blast furnace, capping emissions intensity reduction to around 15-20%. Thus, hydrogen can at best offer only a reduction in emissions for the BF-BOF pathway.

The DRI pathway uses a reducing gas or elemental carbon to convert ore to metallic iron without melting it. The reducing agents are carbon monoxide and hydrogen, which can be provided from a number of feedstock materials such as natural gas (most common), coal or syngas. As DRI occurs below the melting point of iron, it is considered more energy efficient when compared with BOF and is the key feedstock for EAF, being used to dilute scrap steel impurities. DRI and scrap steel is added to an electric arc furnace where high current electricity is used to produce liquid steel for casting. Current DRI technology is also impacted by impurities in the iron ore feedstock (silica, alumina and phosphorus) and thus requires higher quality iron ore feed.

As hydrogen is a reducing agent for the DRI process the use of green hydrogen to displace reformed (Grey) hydrogen is readily possible but requires plant reconfigurations and significant on-site hydrogen production in addition to a source of carbon monoxide to make up the reductant gas. Consequently net zero emission green steel using the DRI-EAF pathway is theoretically possible.

An established company developing green DRI is Midrex (US based). Midrex are building a 100% hydrogen based direct reduction demonstration plant for ArcelorMittal in Hamburg which was announced in 2019. The plant will produce approximately 100ktpa of DRI. The technology is an evolution of their natural gas DRI plants, with an intermediate phase allowing for extra hydrogen to be added to the methane feedstock in concentrations up to 30%. The hydrogen undergoes pre-heating before entering the shaft furnace. Reduction occurs around 900°C and temperature control is highly important. Hydrogen consumption is approximately 550-650 $Nm^3$/t DRI (~50-

60kg$H_2$/t DRI), with an additional 250 $Nm^3$/t DRI of $H_2$ or an equivalent heat source added to maintain the reaction.

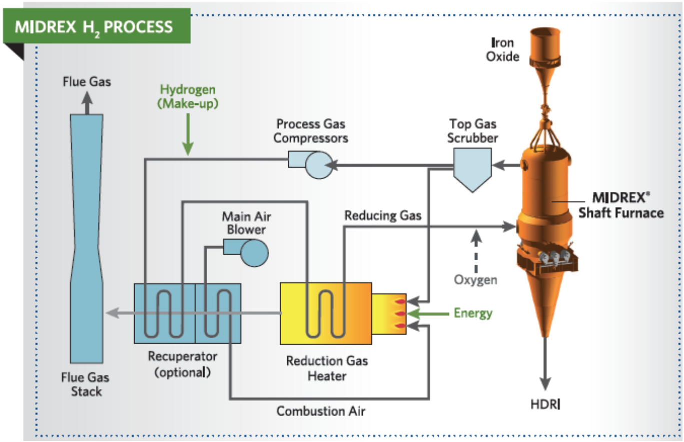


Figure 2. Midrex $H_2$ Process. Source: Midrex

Another green DRI project is the HYBRIT project, a partnership between LKAB, Europe's largest iron ore producer, and Vattenfall to replace existing BOF facilities in Sweden and Finland with EAF. A pilot plant has been launched in Lulea, Sweden to produce DRI at a rate of 1tph using green hydrogen as the reducing agent and fossil-fuel free iron ore pellets. Following the pilot plant, a demonstration plant is slated for construction in 2023 and expected to produce steel by 2026.

Hydrogen is being explored for the BF-BOF pathway as well, ThyssenKrupp has outlined plans to produce 400kt of green steel by 2025 increasing to 3Mt by 2030. To achieve these goals the company has announced plans for a 500MW electrolyser. The intention is to utilise hydrogen in the blast furnace and the company has completed the first stage of trials, stating the process has a theoretic potential to reduce carbon emissions by up to 20%.

ThyssenKrupp has also announced the potential integration of DRI into existing plants and will commission the first large scale plant in 2024, utilising blue hydrogen supplied by Equinor.

Europe's steel industry is strongly embracing hydrogen, with the US also demonstrating strong interest due to the large proportion of EAF mini-mills. In Australia, FMG, BlueScope and GFG's Whyalla steel works have also proposed potential green steel projects – however firm plans are yet to be announced.

Decarbonising steel production is a huge challenge, not just from a cost perspective, but from an infrastructure view-point as well 100's of TWh of electricity production is needed to displace coal in the process. Regardless, this is a windmill worth tilting at, given steel production is responsible for 7% of global $CO_2$ emissions (producing 1t of steel produces ~1.85t$CO_2$e).

Hydrogen based DRI-EAF seems likely to emerge as the only plausible low emission steelmaking process in the future. Hydrogen is already used as a reducing agent in DRI, and although utilising green hydrogen requires plant redesign, the approach overall is considered feasible. In fact, Midrex states their existing plants could be switched to up to 90% hydrogen with only minor modifications. The current challenges for green hydrogen are broadly cost and scalability – it is estimated that a 2Mtpa $H_2$ DRI plant would require a 900MW electrolyser for hydrogen supply (~144ktpa $H_2$) and up to 8.8TWh of electricity, based on current technology (Source: Mckinsey). To incentivise $H_2$ DRI-EAF production it is estimated a carbon price of at least US$65/t is required alongside a hydrogen price around US$2/kg.

Technology advances across the hydrogen supply chain should reduce the energy requirement, but there is still a very large amount of power required to electrify steel production. Also, an important note - a source of carbon is still required for the DRI-EAF process to provide the carbon content for steel!

| | Current Primary Steelmaking Processes | | | | Low-$CO_2$ Primary Steelmaking Processes | |
|---|---|---|---|---|---|---|
| Fuel and Feedstocks | BF-BOF | | Natural Gas DRI-EAF | | Natural Gas DRI-EAF w/CCUS | $H_2$ DRI-EAF (HYBRIT) |
| | Energy (GJ/ton steel) | Emissions (kg$CO_2$/ton steel) | Energy (GJ/ton steel) | Emissions (kg$CO_2$/ton steel) | Energy (GJ/ton steel) | Energy (GJ/ton steel) |
| Electricity | 0.7 | 87 | 2.5 | 312 | 2.7 | 2.9 |
| Coal | 18.0 | 1,592 | 0.5 | 44 | 0.5 | |
| Natural Gas | 1.0 | 50 | 10.1 | 508 | 10.1 | |
| Hydrogen | | | | | | 8.2 |
| Biomass | | | | | | 2.0 |
| **Total Energy and Emissions** | **19.7** | **1,730** | **13.1** | **864** | **13.3** | **13.1** |

Figure 3. Comparison of energy use for steel. Source: Mckinsey

## Hydrogen Powered Mining Fleets

Hydrogen is increasingly stated as a promising zero-emission alternative to diesel for heavy mining fleets, especially haul trucks and diesel-powered freight trains. Such applications would fall under the category of Hydrogen Fuel Cell Electric Vehicles (FCEV) that convert hydrogen to electricity via onboard fuel cells. FCEV fuel cells work by combining hydrogen and oxygen to produce electricity and water, the electricity is then used to power electric motors either directly, or indirectly via a battery – therefore their operation is similar to pure Electric Vehicles (EV's) but use a smaller capacity battery. Onboard high pressure (350-700bar) hydrogen tanks feed the fuel cells and can be refuelled at similar rates to Diesel (at pressure). Hydrogen can be produced either on-site via electrolysis or transported to site.

There are several aspects of FCEV's which advantage their use in a heavy mining fleet over light vehicle-oriented EV, principally owing to hydrogen's energy density;

1) The batteries used in FCEVs are significantly smaller and therefore lighter than an equivalent EV battery for a given capacity – a rough estimate indicates for a hypothetical 200t haul truck (~1,800kW / 2,400hp) to run continuously for 10 hours at 50% load would require a battery weighing around 45t (assuming a weight of 0.5t per 100kWh of battery). This additional weight would directly reduce payload;
2) As the primary fuel source is hydrogen, refuelling can occur rapidly – there is no need to recharge or swap batteries enabling continuous operations; and
3) The power required to rapidly charge a battery of any meaningful size is significant and a large mining fleet would quickly require hundreds of MWs of power, even when considering staggered charging.

Additionally, there are some positive aspects common with EV's - potential to integrate charging with a trolley system (say on the main haul road as First Quantum have done at the Kansanshi operation), less moving parts vs. diesel, fuel security, minimal impact from altitude and regenerative breaking. FCEV's principal drawback is the round-trip efficiency of producing hydrogen, storing and converting to back to electricity (also known as well to wheel efficiency). Currently this is around half the efficiency of EV's depending on the production method/technology, although technology improvements across the hydrogen supply chain are expected to close the gap.

The most advanced large scale hydrogen haul truck project is at Anglo American's Mogalakwena mine. Anglo American has partnered with Engie to convert a Komatsu 291t capacity 930E truck from diesel to a modular lithium-ion battery system with regenerative breaking, supplemented by a fuel cell module. The system is expected to produce similar power and range to a 3,500hp (~2.,600kW) diesel engine with the following major components:

- 1,100 kWh battery system developed by Williams Advanced Engineering
- 8x 100kW PEM fuel cell modules (800kW total) provided by Ballard Power Systems
- Hydrogen produced onsite via a 3.5MW electrolyser plant provided by Nel Hydrogen and a refuelling system installed by Plug Power

Details of the hydrogen storage capacity (and therefore the truck's range) have not yet been disclosed. Anglo American has stated the hydrogen powered truck will replace 900,000 L of annual diesel consumption, a 50-70% reduction in scope 1 and 2 emissions for open pit mines, and cost parity with diesel is expected by 2030. Anglo has indicated a 40-truck rollout and 320MW of solar power producing 1,000kg$H_2$/day at Mogalakwena starting 2024.

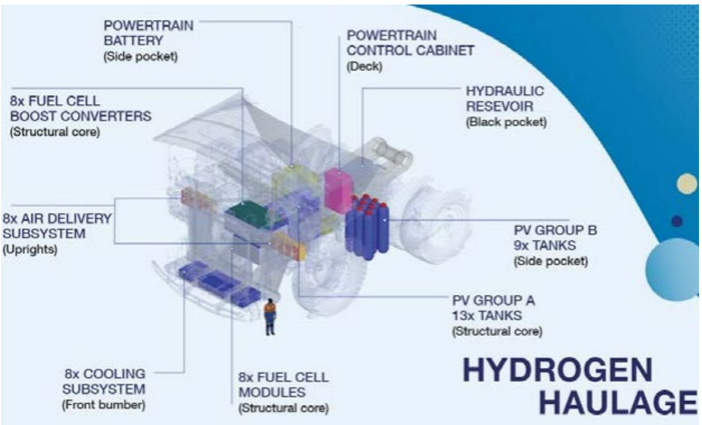


Figure 4: FCEV Haul truck. Source: Anglo American

Other FCEV mining specific projects also include:

- Fortescue Metals Group hydrogen fleet of 10 buses at their Christmas Creek operations. The fleet is custom built by HYZON motors with hydrogen generated onsite using the Chichester Solar Gas Hybrid Project. FMG also recently unveiled plans to consider hydrogen fuel cells to power a 240t prototype haul truck
- Weichai's 200t hydrogen demo fuel cell truck with 4x 85kW Ballard fuel cells; trucks suitable for mine site testing are expected to be produced sometime this year and use a total 800kW of fuel cells

The feasibility of FCEVs is edging forward with sectors of the market maturing; fuel cell powered forklifts in warehouses are already widely adopted, FCEV buses are progressing towards commerciality and the world's first hydrogen trains have completed trials and are set to provide regular service in Germany from 2022. Fuel Cells have experienced rapid growth in recent years - 908MW of Fuel Cells for transport applications were shipped in 2019 (source: Fuel Cell Industry Review 2019). However, the ability to scale the technology for large trucks and mining fleets is still being validated.

Whilst trials for mining fleets have started, commercial application, comparable pricing to diesel and widespread adoption is still years away. For reference, Komatsu plans to start their hydrogen development program in 2021 and aims to have commercial units by 2030, suggesting commercial scale up is approximately a decade away. However, increasing external pressure toward decarbonisation may accelerate commercial application, particularly for new mines.

### Dispatchable Power Solutions

The use of hydrogen for energy storage has significant potential for integration into remote power girds, enabling such systems to achieve higher use of Variable Renewable Energy ("VRE") without sacrificing availability or reliability of power supply by supplying a sizeable energy storage buffer. Excess electricity from VRE can be used to convert water to hydrogen gas via electrolysis before it is compressed and stored. When power demand exceeds supply, a fuel cell is used to produce electricity from the stored hydrogen, some electrolyser technologies can also be reversed to double as a fuel cell.

Most existing remote power grids supplying mine sites (whether captive or not) are powered by generator sets, burning diesel, natural gas or heavy fuel oil. Some sites have implemented hybrid systems - integrating VRE and batteries into their power supply, however these installation sites still require sizeable fossil fuel generation to balance VRE. For example Gold Field's Agnew gold mine has installed a microgrid with 18MW wind, 4MW solar 13MW/4MWh battery storage and 21MW of gas powered engines – Agnew's average load is around 15MW. Despite 22MW of VRE coupled with battery storage, renewable generation provides on average 50-60% of total load, and can experience material curtailment due to a mismatch between load and generation during peak periods of VRE generation.

The primary advantage of utilising hydrogen storage in a remote power grid is the ability to achieve much higher renewable penetration when compared to using batteries only. National Renewable Energy Laboratory (NREL) has concluded batteries are better suited to intraday storage for up to 15 hours of power storage, whereas hydrogen storage is suitable over a period of days, months and even seasons and consequently an excellent complement to battery installations. With adequate VRE, hydrogen storage can completely displace fossil fuel power generation, providing added fuel security. Hydrogen has the added benefit of mobility and can be transported to site if required to shore up supply.

Again, the primary disadvantage of hydrogen storage when compared to batteries is the round-trip efficiency of conversion, which is currently in the order of 35%. For this reason, it is optimal to utilise a small battery to manage smaller changes in VRE generation first, and then utilise hydrogen systems during periods of excess VRE production to capture energy production which would otherwise be curtailed. The economics of electrolyser utilisation will also need to be carefully considered.

Whilst there are an increasing number of mining projects utilising battery storage as a dispatchable power solution, hydrogen storage for remote sites is limited. The leading example is the Raglan nickel mine operated by Glencore in Arctic Canada which commenced production late 2015 and comprises the following:

- 6MW wind turbine generator for VRE generation (3MW in 2015 and 3MW added in 2018);
- 200kW/1.5kWh flywheel required to filter out short duration power variations and aid with system inertia;
- 200kW/250kWh Li-Ion battery to start up diesel generators or fuel cells for transition backup;
- 200kW/1MWh power system (315 kW Electrolyser coupled to a 198 kW PEM fuel cell) to minimise loss of wind energy over longer time periods.

The site is still dependent on diesel generation of 26MW for base load generation and a further 9MW for peak load.

Figure 5. Storage system at Raglan nickel mine, from left to right: hydrogen storage tanks, flywheel and substation, battery system, fuel cells and electrolyser. Source: Natural Resources Canada

The above hybrid system, whilst relatively small in scale compared to the total mine load still enabled a significant reduction in diesel use of 4.4ML p.a. The storage component resulted in wind power availability of 97% and roughly doubled the wind penetration level when compared to wind without the hybrid storage system (Source: Energy and Mines).

Whilst the technology to produce and store hydrogen via electrolysis, and then use fuel cells to generate power has existed for decades, new technologies are needed to drive costs down, principally via efficiency improvements. So, while existing commercial installations indicate the technology could be implemented, widespread adoption of integrated hydrogen storage is dependent on many technologies which are still in the development phase.

Commercially, hydrogen use for remote power systems requires advancement in technologies across the hydrogen supply chain – electrolysers, storage and fuel cells – to drive down costs. Electrolyser volumes are growing rapidly for stationary power generation, however growth is off a very low base - 221MW in 2019 (source: Fuel Cell Industry Review 2019). 100% renewable remote power grids with integrated hydrogen storage are still some time away.

## Heating

Many industrial processes require heat, in mining and metals common applications include kilns for drying ore, furnaces for steel production, boilers for steam production and Combined Heat and Power ("CHP"). Industrial sources of heat are predominantly provided by the combustion of either coal, oil or natural gas and represent an estimated 42% of industrial emissions globally – equal to 23% of global primary energy supply (Hydrogen Council 2017). Significant contributors include the cement and aluminium industries. Hydrogen represents a relatively simple technological swap for fossil fuels as the heat output from combustion can replace heat supplied by fossil fuels, either as pure hydrogen or hydrogen blended with natural gas. Hydrogen can burn at a temperature up to 2,100°C which satisfies most industrial processes, it also has a high heat flux, good heat availability and a high specific heat of combustion (>2x natural gas).

Hydrogen for residential heating is a relatively mature technology, particularly in Japan where government subsidies have assisted to drive over 300,000 residential fuel cells being installed from 2009 to 2019. These systems use natural gas to produce and store hydrogen which is then used in the fuel cell, producing both electricity and heat and effectively creating a microgrid.

Industrial heat applications utilising green hydrogen are less common, an example is Hyflexpower's integrated pilot project to provide heat and power for a paper factory in France. The 12MWe CHP system currently uses natural gas to power a gas turbine and recovery boiler – the steam is then used by the adjacent papermill. The project will initially trial a hydrogen natural gas blend and ramp up to a hydrogen percentage of at least 80%, with a target of 100%. Whilst applied in the paper and pulp industry, an equivalent system could effectively be used to provide steam or heat for mineral and metals processing.

The lack of hydrogen-to-heat projects is a function of technical and economic hurdles. Existing plants have been configured for combustion of a specific fuel across several parameters. The IEA notes several barriers for hydrogen substitution vs. natural gas, hydrogen has:

1. Higher combustion velocity and nonluminous flame - potentially requiring censors, controls, or added gases;
2. Lower radiation heat transfer - potentially requiring added material for heat transport and new burners; and
3. The potential to cause corrosion or brittleness in some metals – requiring the use of different metal alloys and/or protective coatings.

As a result, a complete swap from natural gas to hydrogen will most likely require extensive modification to existing plant depending on the application.

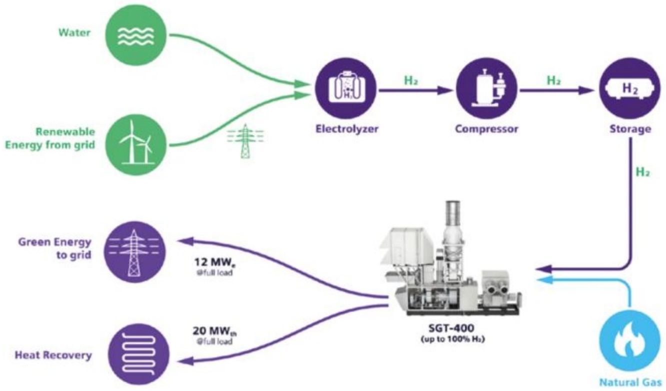


Figure 6. Power-H2-Power Pilot. Source: Siemens

Displacing heat from fossil fuels is certainly a high-cost abatement - BloombergNEF (BNEF) estimates that substituting zero-carbon hydrogen at a delivered price of US$1.00/kg$H_2$ for aluminium recycling would be cost-effective with a carbon price of US$90/t $CO_2$ (2020). Similarly cement production would require a carbon price of US$60/t $CO_2$. Given current green hydrogen prices generally range in estimates from US$5-10kg$H_2$ the industry is a long way off, so we expect progress in this area to be slow.

As industries scale their carbon abatement curves, Hydrogen will likely emerge as a promising candidate for decarbonising certain heating applications as other competing methods are predominately location dependent or logistically constrained, such as geothermal heat, carbon capture and storage, solar thermal and heat from biomass. Electric driven heating methods may also prove cost effective for low grade heat applications, such as heat pumps, electromagnetic heating (radio/micro/ultraviolet/infrared radiation, induction), electrical and resistance heating but struggle to supply high grade heat economically.

## Blending Hydrogen with Natural Gas

The concept of blending hydrogen into gas streams is not new – its use actually pre-dates natural gas distribution networks when coal was burnt to produce 'town gas' which typically contained 30-50% hydrogen in the mid-1800's. This method is a proposed means of reducing emissions by displacing a portion of natural gas – current estimates indicate 5-15% of hydrogen by volume is possible. While this amount seems small, global natural gas demand was just under

4,000Bcm in 2019 (source: IEA) (equivalent to ~1,200TWh), so displacing even a small amount of natural gas use with green hydrogen could have a large impact. Most existing appliances would not require any modification at a low concentration, however gas pipelines would most likely require some upgrading in monitoring and integrity at a minimum so some additional cost will need to be incurred.

Hydrogen blending affords an opportunity for the mining and metals industry to reduce the emissions profile of their natural gas use. For example, natural gas supplied via pipeline with a portion of hydrogen would reduce emissions from on-site electrical generation and heating. Blended gas streams can be combusted in both reciprocating engines and gas turbines, offering a ‘drop-in’ emissions reduction. One such blend is known as Hythane – a 20% hydrogen, 80% natural gas mix. At this ratio, minimal modifications are required to a natural gas engine and studies indicate a greater than 20% reduction in emissions. The addition of hydrogen enables combustion of ultra-lean air/fuel mixtures, improving fuel economy and providing a small boost in torque due to an improvement in energy density compared with natural gas alone.

There are dozens of pilots and trials worldwide which have demonstrated hydrogen blends up to 20% in natural gas networks and many pilots have been undertaken in the US, Europe and Australia. So, while proven effective, a key issue is the long-term implications for the natural gas network and end-use equipment. This is the key area of research as hydrogen results in pipeline embrittlement and therefore may cause premature failure, particularly at higher concentrations. Another important consideration is the marginal benefit of hydrogen blending vs. other applications, intuitively hydrogen has a greater environmental impact in displacing higher emitting fossil fuels such as coal and oil. For example, S&P Platts Analytics found that hydrogen blending with natural gas may have a lower impact on emissions vs. other uses, in particular green steel. Regardless, it creates another use case for hydrogen to assist with adoption and represents a genuine way for mining and metal companies to reduce their emissions.

### Green Explosives

Just as airlines market carbon offsetting for flights, explosives manufacturers could market ‘green explosives’ which mining companies purchase to reduce their scope 3 emissions (being those which occur up- and down-stream of the mine gate). Put differently, this will only reduce emissions in the production of explosives – and has no impact on emissions from detonating said explosives (unfortunately *those* emissions are rather unavoidable).

Ammonium nitrate is produced by reacting ammonia with nitric acid and forms the foundation of most bulk explosives, including ANFO and emulsion explosives. The ammonia feedstock is produced via steam methane reforming of methane gas to produce hydrogen which is then reacted with nitrogen to produce ammonia via the Bosch-Haber process. Consequently, green hydrogen production can directly substitute grey hydrogen produced via steam methane reforming – directly displacing emissions and giving rise to ‘green explosives’ – and a satisfying oxymoron in the process.

Multiple green ammonia to ammonium nitrate projects have been announced:

- Dyno Nobel will conduct a feasibility study into a green ammonia facility powered by 210MW co-located solar farm and a 160MW electrolyser at Moranbah, Australia
- Queensland Nitrates partnered with Neon and Worley to complete a Feasibility Study for a proposed 30MW electrolyser and a small-scale ammonia plant to produce 3,500tpa. of green hydrogen – yielding 20,000tpa of green ammonia for use in ammonium nitrate production
- Enaex in Chile have partnered with Engie to complete a feasibility study for a pilot plant to produce green ammonia from sea water at their Mejillones plant in northern Chile

Furthermore, dozens of green ammonia projects have been proposed and could provide feedstock to any ammonium nitrate producer for green explosives.

The technology to produce green explosives already exists, and as an existing demand of hydrogen (ammonia constitutes around 50% of hydrogen demand), adoption is only reliant on commercial scale up and cost-competitive production of green hydrogen.

### Synthetic Fuels (Synfuels)

Theoretically, all products derived from crude oil can be produced synthetically from syngas – a mixture of carbon monoxide and hydrogen. Today’s synfuel production is usually derived from coal, natural gas/methanol and more recently biomass gasification. However, synfuels could be produced from co-electrolysis of steam and $CO_2$ to produce green hydrogen and carbon monoxide - potentially allowing carbon neutral synfuels. As these fuels are identical in composition to their crude oil counterparts, they are sometimes referred to as ‘drop in’ fuels as they can substitute any crude derived product without modification to existing equipment. Furthermore, synfuels contain significantly fewer impurities than their crude derived counterparts and therefore combust more completely emitting less $CO_2$ and particulate matter. As a result, the synfuel industry has great potential to decarbonise heavy industry and transport (particularly aviation and shipping).

Synfuels have been produced for decades in South Africa and Malaysia and more recently in Qatar, however plants predominately use coal as feedstock and the market is still relatively small at ~250kbopd (<0.25% of global crude demand). Green synfuels projects using hydrogen are just starting to pop up – in 2020 Repsol announced a €60m investment to produce green fuels from hydrogen and captured $CO_2$.

Technically synfuels are already a mature market – the synthesis from green hydrogen instead of fossil fuels is proven but not yet scaled. Principally, cost is the primary barrier - IRENA estimate green synfuels for aviation are currently 8x more expensive than crude derived jet fuel.

### Notable Mentions

**Nickel processing –** Whilst steel is the largest potential application of hydrogen in metallurgical processes, hydrogen is used as a reducing agent in some HPAL processing circuits to produce nickel and cobalt briquettes (e.g. Murrin Murrin). We are yet to discover any proposals to utilise green hydrogen in HPAL plants.

**Green Ammonia –** We have already covered the synthesis of green ammonia for ammonium nitrate production. However green ammonia has the potential to play an equally important role to hydrogen in decarbonising heavy industry, due to several important features making it more suitable than hydrogen as an energy carrier:

1) Ammonia is able to be stored as a liquid at moderate pressure and temperature compared to hydrogen – overcoming inefficiencies in compressing or liquifying hydrogen for transport (particularly over longer distances). Ammonia can be stored as a liquid at -33°C at atmospheric pressure or at 20°C at ~5bar
2) By volumetric density, ammonia counterintuitively stores ~70% more hydrogen per unit of volume (121kg$H_2$/m$^3$) vs. liquefied hydrogen (70.8kg$H_2$/m$^3$). This means a 50L ammonia fuel tank could store around 5kg of hydrogen
3) Ammonia is already the second most produced chemical globally at 180Mtpa, of which 18Mtpa is seaborne, implying substantial infrastructure and expertise already exists for ammonia production, storage and transportation

Various technologies are being developed to crack and separate ammonia and hydrogen at high efficiencies; enabling quick conversion on site or at the fuel pump (CSIRO has developed a membrane which operates at >80% efficiency). It is worth mentioning several liquid organic hydrogen carriers have also been proposed, such as methylcyclohexane, each with their own benefits and drawbacks.

**Chemical synthesis –** Similar to the manufacture of green explosives, hydrogen is an important precursor for some chemical synthesis processes which are part of the mining and metals supply chain – e.g., forming gas used for metal sintering. Therefore, the purchase of chemicals produced from green hydrogen would be considered 'green chemicals' and thus reduce Scope 3 emissions.

### Challenges

The key challenge for the uptake of hydrogen to drive decarbonisation in the mining and metals industry is principally an issue of cost – green and low emission hydrogen is currently expensive to produce (estimates range from 2x to >5x the cost of Grey hydrogen). As a result, hydrogen technologies sit relatively high within industry abatement curves. Carbon pricing can help bring these technologies into play, however the risk imposed of implementing new technology (perceived or actual) often pushes the industry to default back to the current incumbent technology.

The cost of hydrogen production is hindered primarily by the conversion efficiency of existing technologies. Technological advancements are needed to improve efficiencies and reduce the cost of manufacturing electrolysers, fuel cells and storage. This is a difficult challenge considering the most efficient and effective designs tend to incorporate more expensive materials such as platinum and various rare earths, thus pressuring the economics. Technology and economies of scale must work hand in hand to gradually bring down the cost of hydrogen production – this phenomenon has played out with a number of technologies in recent decades – solar panels, computer disk storage, battery storage, etc.

Another issue with hydrogen is the lack of dedicated infrastructure to enable the logistical challenge of producing, compressing, storing, and transporting hydrogen from low-cost production centres to demand centres. Whilst ammonia represents the leading logistical solution over longer distances, as with hydrogen, technology advances are required for reasonable efficiency and costs. Once enabled, network effects can then proliferate adoption as production, storage and distribution hubs emerge.

Beyond cost and logistics, HSE challenges will need to be considered and overcome. Green hydrogen production requires high purity water (one kg of hydrogen requires nine litres of water) and therefore a sustainable source of the water needs to be carefully considered if producing or procuring hydrogen. For most stationary applications, a large proportion of the water could be recycled. Hydrogen is also a highly flammable, odourless, and colourless gas and therefore needs to be safely integrated into existing operations.

### Conclusions

Despite the infancy of the hydrogen market and the numerous hurdles to be overcome, hydrogen is the leading candidate for decarbonising many difficult-to-abate processes within the metals and mining industry in the medium to long-term. Better hydrogen production technologies and improvements in efficiency will be required to produce low-cost hydrogen, which in turn will drive scalability and improve abatement economics. Government subsidies and carbon pricing can assist with first steps, but ultimately technology and scalability will drive adoption analogous to the growth in the solar industry on the back of declining costs and rising efficiency.

The uptake of hydrogen technologies across the mining and metals industry is likely to be slow. As the more impactful technologies will require rework of existing assets and infrastructure, it will be most logical to consider hydrogen technologies during pre-feasibility for new plant/operations or periodically as equipment reaches the end of its useful life. Industry participants serious about decarbonisation should seek to implement trials and pilots to accelerate learning of hydrogen applications in the mining and metals industry, well in advance of key asset management decisions. This can improve comfort around the hydrogen technologies and therefore alleviate some of the perceived and actual risks of technology implementation prior to major investment decisions.

Hydrogen is well placed to tackle difficult-to-abate emissions offering many advantages over pure electrification and other incumbent competing solutions. Given the ambitious decarbonisation targets of the mining and metals industry, increasing external pressures and current abatement curves, we see the uptake of hydrogen in key areas inevitable if industry intends to meet those targets and satisfy their social obligations. The pathway forward is not well described – many technologies exist with each promising to deliver on perceived cost targets required for widespread adoption. The industry needs to carefully consider their abatement curves and opportunity sets to ensure efforts are best placed into technologies and processes which can bring about the greatest impact, for many hydrogen will be the key piece of the puzzle.

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