

# Water Electrolysis & Renewable Energy Systems



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Used for decades to produce hydrogen for industrial processes, water electrolysis is now attracting much interest for energy applications. The technology is well-suited to being coupled with variable sources of renewable energy such as wind and solar power as electrolyzers can operate effectively with fluctuating electrical input, can run intermittently, and can be implemented at a range of scales.

In water electrolysis, an electric current is used to split water into hydrogen and oxygen; the gases can be produced under pressure. There are two commercially available technologies: proton exchange membrane electrolyzers and alkaline electrolyzers, which offer different advantages. Solid oxide electrolyzers are under development but are relatively untested.



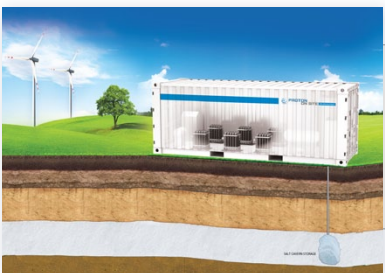
Electrolysers can be used with **distributed** electricity generation to facilitate true independence from the electricity grid, by providing the means for time-shifting energy production. Using excess solar power during the day, for example, electrolyzers generate hydrogen that is stored on site. This can then be converted back to electricity when needed at night, eliminating the need to resort to grid electricity.

At **grid-scale**, growing proportions of wind and solar power in the electricity supply pose a challenge in maintaining grid stability, ensuring an adequate supply, and balancing supply and demand. The challenge can be managed if the electricity system has sufficient flexibility in the form of dispatchable (on-demand) power generation, demand-side management, energy storage, and interconnection to allow export.



Electrolysers can provide all four of these resources. Instead of being curtailed, excess output from a wind farm can be routed through a megawatt-scale electrolyser installation to generate hydrogen which is stored. This can be used to fuel a power plant to generate electricity on demand, providing firm capacity to the grid and a source of renewable **dispatchable power**.

Excess renewable electricity can also be fed through the grid to smaller, distributed electrolyzers that are ramped up in response. Electrolysers on hydrogen refuelling station forecourts, for example, can convert low-value electricity to high-value transportation fuel at the point of use, and can be contracted by the grid operator to provide **demand-side management**.



As wind and solar power capacity increases there is a pressing need for **energy storage** with seasonal capacity. The hydrogen produced by electrolyzers is a clean energy carrier that, unlike electricity, can be stored cost-effectively in large quantities for long periods. Compressed hydrogen stored in underground salt caverns could be crucial to Europe meeting its 2050 renewable energy targets.

Instead of simple interconnection between electricity grids, hydrogen produced by electrolysis can allow **integration** of electricity with the other 'energy silos': heating and transportation. Using hydrogen as a common energy carrier creates flexibility in the energy system as a whole, allowing for better energy efficiency and synergistically increasing renewable energy content in all three silos.



The hydrogen can be used to generate grid **electricity**. Combined cycle gas turbines are an efficient means of gas-fuelled electricity generation and hydrogen-fuelled versions are becoming available. Installations of fuel cell power plants in South Korea and the USA show megawatt-scale electricity generation is possible with fuel cells, for which hydrogen is the ideal fuel.

Hydrogen from electrolysis can be injected into existing gas networks, referred to as 'power-to-gas'. The gas network has considerable energy storage capacity and is an effective way to distribute large volumes of energy; blending in hydrogen increases the renewable content of gas used for **heating**. Hydrogen can be introduced directly, subject to limits, or converted to synthetic natural gas first.



The sale of hydrogen for use in **transportation** is becoming a realistic prospect as automakers gear up for the commercialisation of fuel cell electric vehicles from 2015 onwards. Electrolysis will be critical in the creation of refuelling infrastructure, particularly as there is a strong drive for the provision of renewable hydrogen to fully realise the emissions-reduction capability of these vehicles.

Hydrogen can be recombined with carbon to produce **synthetic hydrocarbon fuels** such as methane and methanol. This has practical advantages for distribution and use in conventional equipment, as well as for energy security. In environmental terms, however, it has the greatest benefit when the hydrogen is used to renewably upgrade the carbon dioxide content of biogas and biomass-derived syngas.



Hydrogen is also used in large quantities in many **industrial processes**, but currently ~95% of this hydrogen is derived from fossil fuel and is a substantial contributor to man-made carbon dioxide emissions. If hydrogen were to be produced in bulk using excess renewable electricity, it could become cost-competitive and displace 'fossil' hydrogen in industry, reducing emissions.

There are many benefits to linking electrolyzers to renewable energy systems and these are enhanced by hydrogen's versatility as an energy carrier. However, the market drivers are still unclear and will differ from case to case. Numerous demonstration projects are now underway and will provide much-needed performance data and validation to potential investors, stakeholders and policymakers.



## 1. Introduction

This report describes how the electrolysis of water to generate hydrogen can be used in conjunction with renewable energy sources to provide a number of benefits. It begins with a brief summary of the fundamentals of water electrolysis and the available electrolyser technologies. It then looks at how electrolysis has been applied in the past and its applicability to, and suitability for, energy use.

One of the chief advantages of electrolysis is that it can be applied at a great range of scales. The report first examines its use at smaller scales, in off-grid or localised power generation, where it is a key component to enable smart, secure and flexible distributed energy systems that include renewables such as wind and solar power. True independence from the grid is difficult to achieve and in many instances electrolysis can be the crucial missing link.

One of the most exciting aspects of the technology currently is its emergence as a candidate for large-scale renewable energy storage – without a doubt one of the biggest challenges facing society in its efforts to move away from fossil fuels. Many nations support an increased contribution from wind and solar power, which are difficult to harness but potentially ‘unlimited’, unlike bioenergy. However, these sources provide a variable output which is difficult for the electricity grid to accept while maintaining its stability, and this places a real and fundamental limit on how much of this energy can currently be incorporated into the supply.

This limit can be circumvented if the renewable energy can be stored at times of excess production, buffering the effect of variability on the grid and providing a more predictable supply. But energy storage at the scale needed for a global shift away from carbon is a significant technological challenge that cannot be satisfactorily met with existing technology. As this report describes, using clean electricity to drive water electrolysis and produce hydrogen in large quantities as an energy storage medium is in fact one of the most viable options available to us. The use of the technology to facilitate the integration of renewable energy into the electricity supply is the subject of a dedicated chapter of this report.

Hydrogen’s advantages as a clean energy carrier are numerous because it can link all forms of energy use, allowing for greater integration, greater flexibility and greater efficiency overall. As Figure 1 illustrates, hydrogen can be produced by electrolysis driven by either distributed renewables or grid electricity and then stored (in small or terawatt-hour-scale quantities and in a variety of ways). From there, it can fuel on-demand electricity or combined heat and power (CHP) generation, or it could instead be used in other ways: for example, as a vehicle fuel, or supplied to industry as a commodity or feedstock, or chemically combined with carbon to produce synthetic hydrocarbon fuels.

There are synergies to be explored; for example if hydrogen from electrolysis is used to renewably upgrade the carbon dioxide (CO<sub>2</sub>) fraction of biogas. Hydrogen can also be injected into the natural gas network, either in methanated form or directly, to increase the proportion of renewable energy in grid gas. Gas has been combusted for many years to generate electricity and heat, but electrolysis and hydrogen for the first time provide a link between the electricity and gas grids in the opposite direction.

These connections and synergies are the central theme of this report.

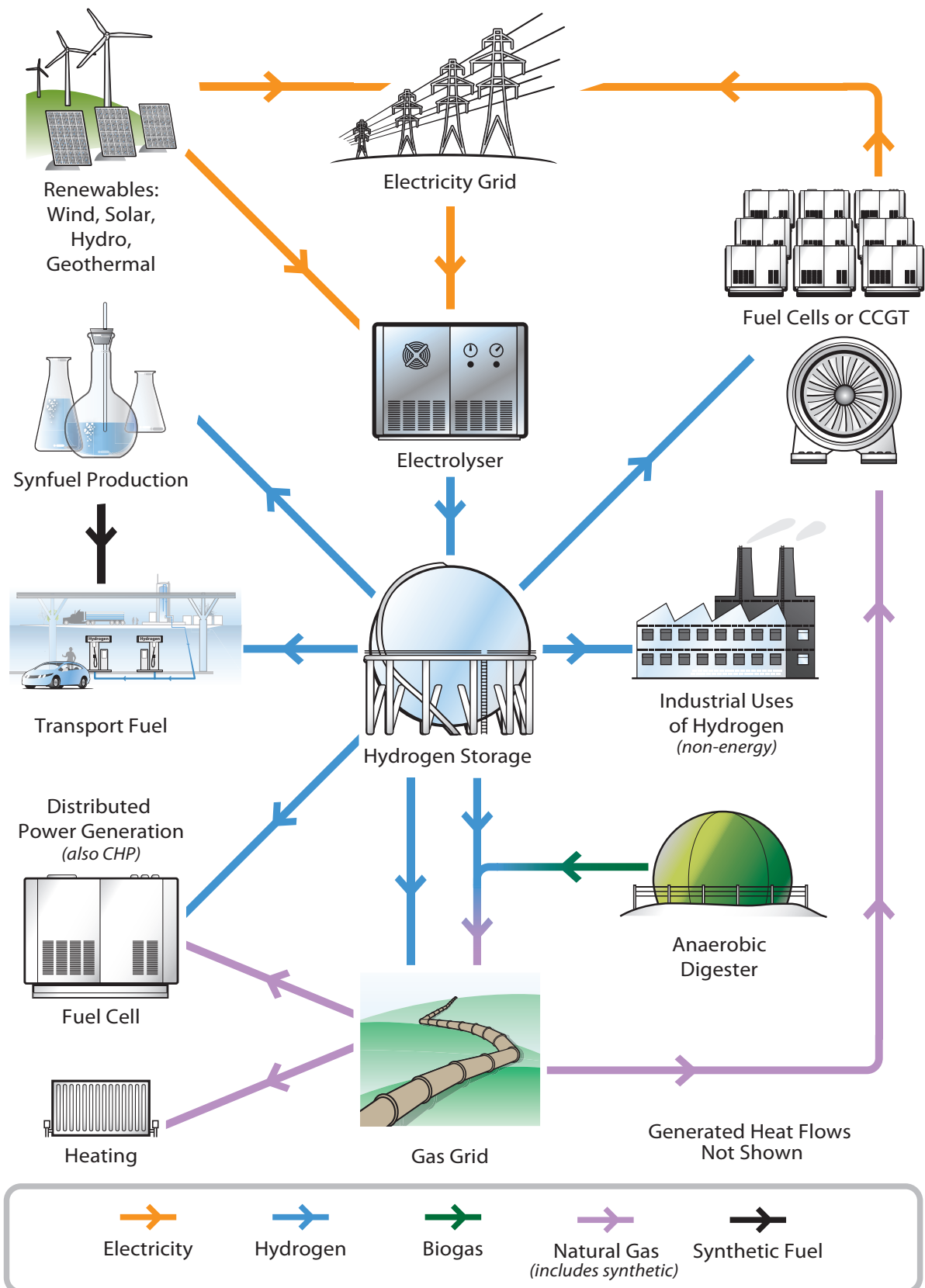
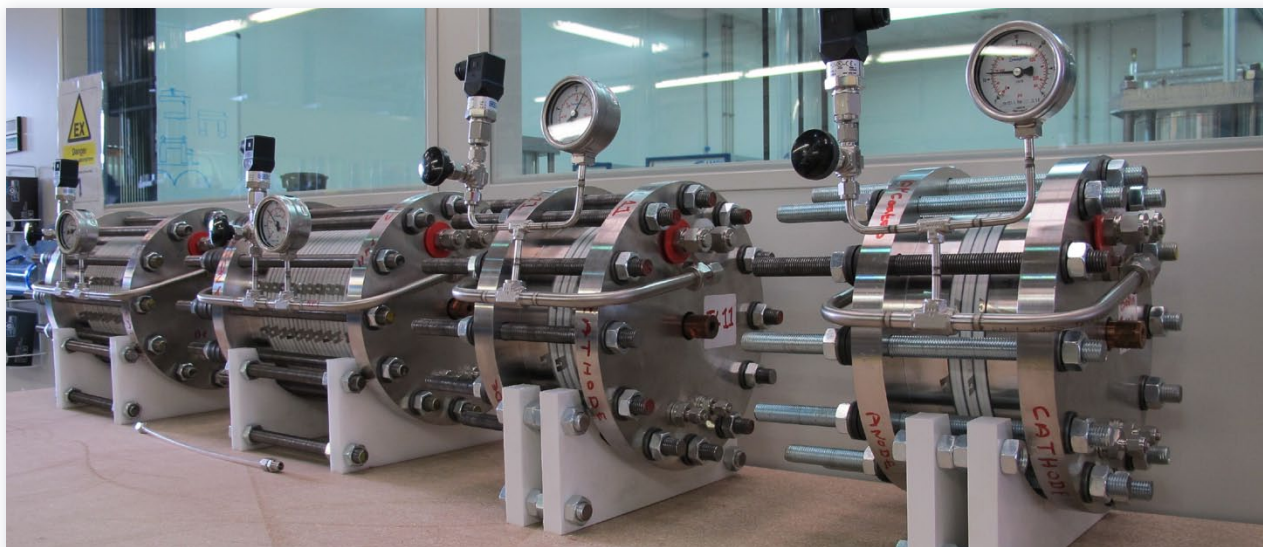


Figure 1: The integrated energy network created by using water electrolysis to produce hydrogen as an energy carrier



## 2. Electrolyser Technology



This section discusses the principles of water electrolysis and the available technology.



The discovery of electrolysis and its use to split water dates back to the 1800s when William Nicholson and Anthony Carlisle observed the evolution of gases during early experiments to replicate the voltaic pile (the world's first battery, invented by Alessandro Volta).<sup>1</sup> There are two main technologies for water electrolysis in use today: alkaline electrolytic cells (AEC) and proton exchange membrane electrolyser cells (PEMEC). High-temperature water electrolysis is a third method which is currently in the research and development stage; this type of cell is known as a solid oxide electrolytic cell (SOEC). These three technologies share a number of similarities with their fuel cell counterparts and in simple terms an electrolyser can be considered as a fuel cell operating in reverse. Indeed PEMEC systems have been made which can also operate in reverse as fuel cells.

### 2.1 General Principles

In electrolysis, an electrical current is passed through a conductive substance (the electrolyte) in order to drive a non-spontaneous reaction. In the context of this report, the reaction we are interested in is the decomposition of water into hydrogen and oxygen; this reaction is endothermic, requiring an input of energy. For all practical purposes, pure water does not conduct electricity, so an electrolyte is added to facilitate the reaction. A water electrolyser consists of a series of electrochemical cells, with the main components of each cell being two electrodes and the electrolyte.

1 Royal Society of Chemistry, 'Chemistry World', August 2003, accessed 23rd January 2013: <http://www.rsc.org/chemistryworld/Issues/2003/August/electrolysis.asp>



### 2.1.1 Gas Production and Efficiency

When an electric current is applied to the electrodes, hydrogen gas is formed at the cathode and oxygen gas at the anode. In general terms, the amount of gas produced per hour is directly related to the current passing between the electrodes.

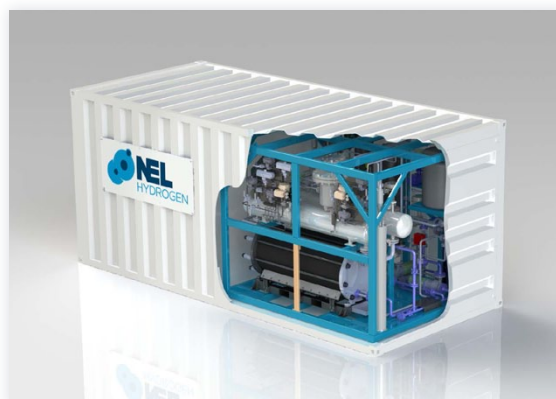
Producing larger quantities of hydrogen and oxygen is not as simple as increasing the current density, however: other factors must be taken into consideration. The operation of an electrolyser is a trade-off between energy efficiency and productivity. There is a minimum theoretical voltage required to split water (about 1.48 V for the cell to remain thermally neutral), but in practice higher voltages are required to overcome inefficiencies in the system; this additional energy is known as the overpotential. As the current density is increased between the electrodes, the overpotential increases, which causes heat to be generated and results in a loss of efficiency. But at low current densities too little gas is produced to be practical, so a fine balance is required.

Reducing this overpotential allows for improved production while maintaining efficiency. There are a number of ways to do this, which include engineering the electrodes to maximise the surface area (and therefore contact) between the electrodes and the electrolyte, and using catalytic materials on the electrodes. With the cost of electricity accounting for the largest proportion of electrolyser operating cost, minimising the overpotential contributes to lowering running costs.

### 2.1.2 Operation Under Pressure

In many applications, the production of hydrogen under high pressure offers benefits in terms of cost and efficiency as this pressurised gas can be used directly for its intended application. This can reduce or eliminate the cost of compressors and other balance of plant, thereby lowering overall cost and increasing system efficiency. Typically, electrolyzers will produce both hydrogen and oxygen at equivalent pressures and this can be problematic because oxygen under pressure is a very reactive substance that can be difficult to handle. Oxygen lowers the ignition temperature of materials and high pressure amplifies this effect, creating a fire risk. Organic substances, such as those used in seals, pump valves or grease, are particularly susceptible to combustion in this environment. As such the generation of pressurised oxygen is generally not as desirable as generating pressurised hydrogen.

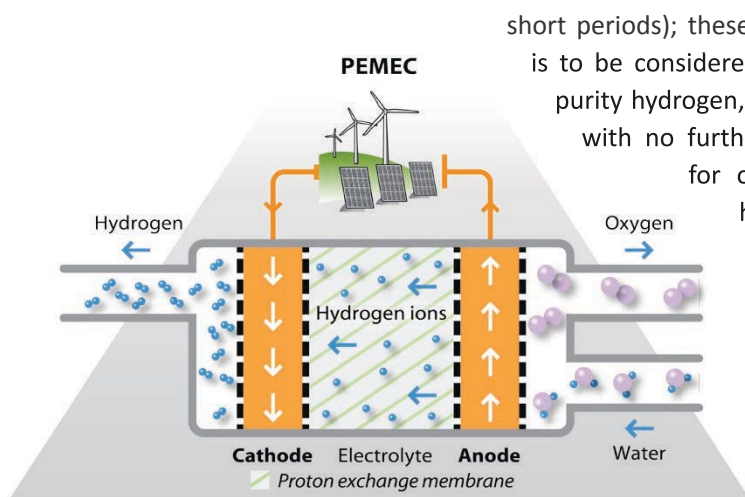
In certain types of electrolyzers the whole unit must be pressurised to produce high-pressure hydrogen, but other units can operate at a differential pressure, where high-pressure hydrogen is produced at one electrode and lower-pressure (or ambient pressure) oxygen at the other. These differential pressure systems avoid the use of expensive materials needed to handle high-pressure oxygen.



## 2.2 Proton Exchange Membrane Electrolyzers

Proton exchange membrane electrolyser cells have been available commercially for many years, but historically not at a large enough size to be suitable for energy storage. Recently, a number of companies have announced their intention to develop large-scale electrolyzers and target this market.

PEMEC have fast response times to fluctuations in electrical input and they can also be operated anywhere between zero and 100% of nominal capacity (or higher for



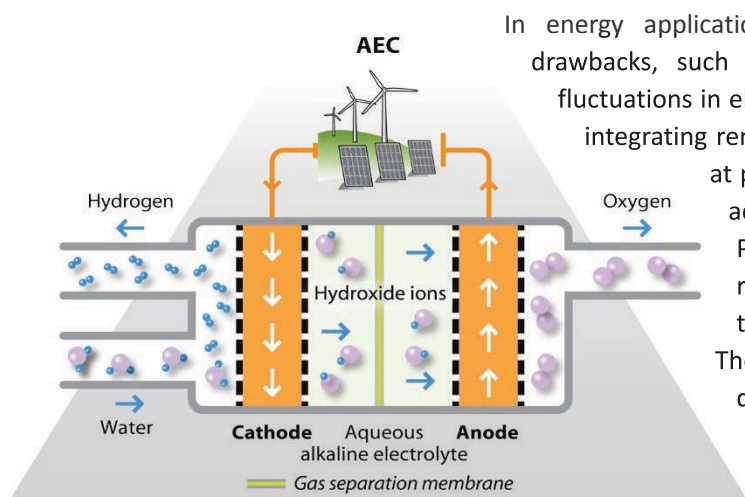
short periods); these are important considerations if the technology is to be considered for grid balancing. PEMEC also produce high-purity hydrogen, which can be used directly in many applications with no further purification required. The technology allows for operation under differential pressure, meaning hydrogen can be produced at a higher pressure than oxygen.<sup>2</sup>

Current drawbacks to PEMEC include their relatively high capital cost, resulting from the use of expensive membranes and electrode materials, and their unproven durability and scalability. The modular nature of these systems may help to overcome problems of scale to some extent.

## 2.3 Alkaline Electrolysers

Alkaline electrolyser cells have been in commercial use in industrial applications since the 1920s and it is the most mature electrolyser technology available today. The electrolyte is an aqueous alkaline solution containing either sodium hydroxide (NaOH) or potassium hydroxide (KOH) and electrodes are commonly made of nickel-coated steel.<sup>3</sup>

AEC technology is well understood and has a reputation for being robust, with units in reliable operation for decades.<sup>4</sup> It is the current standard for large-scale electrolysis and systems have been successfully built at megawatt-scale, producing up to 200 Nm<sup>3</sup>/h of hydrogen, making them well suited to the storage of large quantities of energy. AEC also tend to use cheaper materials than PEMEC, due to their alkaline chemistry, which is also a consideration when raising the capital for a new installation.



In energy applications, conventional AEC technology may have drawbacks, such as a relatively limited ability to respond to fluctuations in electrical input, something commonly found when integrating renewables such as wind and solar. To produce gas at pressure, the entire unit needs to be pressurised, adding cost. Gas purity is also lower than with PEMEC technology, as traces of the electrolyte remain which must be scrubbed out in order to produce hydrogen of the necessary purity. These limitations are the subject of technology development aiming to improve the performance of AEC when linked to renewable energy, and new products targeting this application are being released.

<sup>2</sup> Information based on discussion between Fuel Cell Today and Proton OnSite, November 2012.

<sup>3</sup> IEA HIA, 'Alkaline Electrolysis', accessed November 2012: <http://ieahia.org/pdfs/Task25/alkaline-electrolysis.pdf>

<sup>4</sup> NEL Hydrogen, 'Company History', accessed 22nd June 2013: <http://www.nel-hydrogen.com/home/?pid=54>

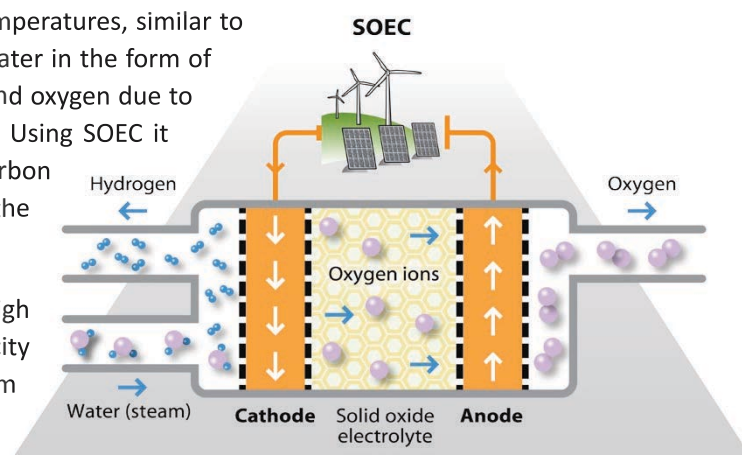
## 2.4 Solid Oxide Electrolysers

Solid oxide electrolytic cells operate at high temperatures, similar to solid oxide fuel cells. At these temperatures, water in the form of steam can be split more easily into hydrogen and oxygen due to the added energy contribution from the heat. Using SOEC it is also possible to generate synthesis gas (carbon monoxide, CO, and hydrogen, H<sub>2</sub>) through the co-electrolysis of steam and carbon dioxide.

Advantages of this technique are the high efficiencies achievable, especially if the electricity and heat can be sourced renewably, such as from a solar thermal collector plant, where high-grade heat and electricity are produced.

The synthesis gas can be used to produce synthetic hydrocarbon fuels or as a feedstock for the chemicals industry. Manufacturing liquid fuels from SOEC-produced syngas could provide a viable route to the long-term storage and distribution of solar energy.

Drawbacks to this technology would be the limited availability of renewable high-grade heat and electricity in the same location. This technology is still relatively young and untested when compared to PEMEC and AEC. There are no SOEC systems commercially available yet.



## 2.5 Reversible Fuel Cells

Fuel cells can, in theory, be operated in reverse to perform electrolysis. Much research has been carried out in this field due to the belief that using a single device for both operations could save on capital cost. However there are drawbacks to this approach. Dedicated fuel cell or electrolyser systems are optimised for maximum efficiency, but reversible systems cannot operate at maximum efficiency in both modes, which impacts on operating cost. Also on a technical level, the electrode materials used in each system tend to be subtly different, and so failure modes such as delamination of electrodes are not uncommon in reversible systems.

Versa Power Systems has investigated reversible solid oxide fuel cell (SOFC) systems as part of a DOE-supported project, but does not currently offer any commercial systems. In fact, a number of companies are marketing autonomous fuel cell systems for long run-time telecommunications backup power, but these systems include dedicated fuel cells and electrolyzers packaged in a single system. The fact that units such as these are commercially available underlines the challenges associated with reversible systems.

Technology	Electrolyte	Temperature (°C)	Electrode catalyst
AEC	KOH or NaOH	50–100	Nickel-based
PEMEC	Humidified polymer membrane	20–100	Platinum/Iridium
SOEC	Ceramic	500–1,000	Nickel cermet

Table 1: Comparison of water electrolysis technologies

### 3. Application of Water Electrolysis



Water electrolysis has for many years provided hydrogen and oxygen on demand for a number of customers in various industries around the world. This provides a profitable business platform for manufacturers of the technology and is funding development of electrolyser to enable their deployment in the renewable energy sector.

#### 3.1 Existing Markets

While the majority of the world's hydrogen comes from the steam reforming of fossil fuels, on-site production using electrolysis has been used for decades to provide hydrogen in places where pipelines and tube trailers cannot reach.

The products of electrolysis can be used in a wide variety of different applications. Oxygen generation is useful on-board submarines, and during manned space missions. Hydrogen finds many more uses, including as a chemical reagent, a fuel and a lubricant; its fundamental properties are also of use because it is lighter than air. The ability to generate hydrogen at the point of use is a key selling point of electrolyser, and 4% of current global hydrogen demand<sup>5</sup> is met in this way. Key applications for hydrogen from electrolysis are discussed below.



##### 3.1.1 Chemical Feedstock

Hydrogen from electrolysis has been used for a wide range of industrial chemical reactions for many years. Possibly the earliest use was for the production of ammonia-based fertilisers by Norsk Hydro, with a test reactor set up in Notodden, Norway in 1927.<sup>4</sup> This application also claims one of the world's largest electrolyser installations, at Sable Chemicals in Zimbabwe. Its array of 28 electrolyser consumes 80 MW

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5 International Energy Agency, 'Energy Technology Essentials', accessed 14th January 2013:  
<http://www.iea.org/techno/essentials5.pdf>



per hour, producing around 21,000 Nm<sup>3</sup>/h of hydrogen. Here electrolyzers can compete if cheap sources of electricity are available and natural gas for steam reforming is relatively expensive.



### 3.1.2 Power Plant Generator Cooling

Hydrogen is a common coolant used in power station applications. It has a low density and high heat conductivity, which are important properties to increase the efficiency of generators. The flammability of hydrogen is less of a concern here as these systems operate above the upper flammability limit. Using electrolysis to produce hydrogen on-site allows generators to operate using a purity of >99% hydrogen, which maximises efficiency, and can reduce or eliminate hydrogen deliveries.

### 3.1.3 Semiconductor Fabrication

During the manufacture of silicon wafers, used in semiconductors, hydrogen is used in the carrier gas as a reducing agent. It can facilitate silicon growth during chemical vapour deposition and also scavenges oxygen, preventing damage to expensive components. Use of electrolyzers for on-site and on-demand hydrogen production minimises the quantity of hydrogen that must be stored at a facility, thereby reducing the risks associated with the storage of hazardous chemicals.



### 3.1.4 Meteorological Monitoring

Electrolyzers are used at some weather stations to produce hydrogen as a lift gas to fill weather balloons. The balloons carry instruments into the atmosphere to gather temperature, humidity and wind data. Electrolyzers provide a decentralised source of hydrogen eliminating the need for deliveries and this is particularly useful if the customer is in a remote location (such as in Antarctica).

## 3.2 Energy Applications

Water electrolysis is a well-established technology, but energy applications have very different requirements from the traditional industrial applications – so is electrolysis technology up to the challenge? These requirements and the ability of electrolyzers to fulfil them are summarised below.<sup>6</sup>

### 3.2.1 Dynamic Operation

Dynamic operation is required to follow the fluctuating electrical input characteristic of variable renewable energy (VRE) such as wind and solar power. Misconceptions that the technology has limited capability in this regard have arisen because dynamic operation has not been necessary in industrial applications. However, even standard industrial electrolyzers have 40–100% operability, and new AEC and PEMEC products offer as much as 0–100% in standard operation; the technology lends itself to dynamic operation. An electrolyser system can also comprise a number of stack modules that can be stopped and started independently, offering further flexibility to meet different levels of input.

### 3.2.2 Cold Start Capability

Electrolysers in energy applications will have fewer operating hours a year than those in industrial applications, and thus good stop–start capability is necessary. An electrolyser that runs only when excess renewable electricity becomes available must be able to start up quickly in response to a signal to take advantage of as much of this excess as possible. Starting an electrolyser immediately from standby is possible with both PEMEC and AEC. However, gas specifications are important as initial output after start-up may not comply to required gas quality, so some gas would have to be discarded. This would depend on the intended use of the hydrogen and may only apply for a few seconds.

### 3.2.3 Overload Regime

As stated above, if electrolysers are required to run only when excess VRE is available, they may operate only for short periods intermittently through the day. Instead of sizing the electrolysers for peak input, capital expenditure can be minimised by selecting smaller electrolysers and equipping them to run in overload (i.e. at more than 100% of rated input) for short periods. Both alkaline and PEM electrolysers can do this, the latter to greater extent (up to 200%), but generally the larger the unit the more heat generated during overload can be tolerated. However, power equipment must be sized for overload which does add some cost upfront.

### 3.2.4 Appropriate Capital Cost

In energy applications where operating cost is likely to be low due to the availability of (relatively) cheap electricity, capital cost will be the more important deciding factor for the business case; currently this is the greatest obstacle, as electrolysers are expensive pieces of equipment. The reason for this is the low economy of scale: the industrial market adds or replaces less than 100 MW of electrolyser capacity annually. However, there are two ways in which extending the technology into energy applications will facilitate cost reduction. The first is by greatly increasing the number of units deployed (a total electrolyser capacity of 1,000 MW is projected for Germany in 2022, for example) and the second is by increasing the size of the units themselves. As this report discusses, multi-megawatt electrolyser installations will be required and by scaling units up a significant reduction in cost-per-kilowatt can be realised.

How water electrolysis can be used in energy applications and the benefit it brings are the subjects of Sections 4 and 5.



## 4. Electrolysers in Distributed Applications



### 4.1 Distributed Electricity Generation

One of the key advantages of electrolyzers is their suitability to different scales of energy input. On the smaller end of the scale, distributed electrolyzers can be used to produce hydrogen for use in the same location. Before looking at how electrolyzers are used in these systems, it is worth examining the drivers for distributed *electricity* generation, which in application tend to overlap.

In many instances distributed generation (DG) is used because the electricity grid is not available or is unreliable, or because independence from the grid is sought for some other reason. That said, the grid itself can incorporate DG for reasons including energy efficiency and as a means to add capacity, and it has become a core component of the smart grid concept.

In other cases, DG is attractive primarily because it offers lower emissions, joule-for-joule, than using grid electricity: transmission losses are eliminated and often the technology used is more efficient at energy conversion than conventional power stations. This is particularly true in combined heat and power generation, where electricity generation is accompanied by the production of usable heat.

If a local energy source such as biogas or biomass is available, it often makes more sense to use it for local electricity generation than to truck it to a central power station. As the rapid spread of microgeneration technologies underscores, sun and wind power can also be harnessed at the point of use. On-site generation using these energy sources increases the consumer's energy security and freedom from fossil fuels.

Broadly speaking then, energy efficiency and energy independence are the major motivations for investing in DG. But electrolyzers use electricity and, like any energy conversion technology, are net consumers of energy: there must thus be compelling reasons for their inclusion in DG systems. These are discussed below for the major application types and a few examples are given to illustrate the concept in each case. (Please note these are by no means a definitive list.)



## 4.2 Household and Building Energy

A typical household in the developed world uses energy in three ways: as electricity, as heat/hot water (which may be produced using electricity or from other fuels such as natural gas), and – for vehicle owners – in the form of transportation fuel. Energy independence would mean finding alternatives to the distribution grids serving each of those three needs. These alternatives would have to be available on demand, and micro-renewables such as solar photovoltaic (PV) and wind power cannot fulfil this requirement. Thus the household must have the capacity for energy storage, and the means to turn that stored energy into heat or electricity as needed – a microgrid, in other words.

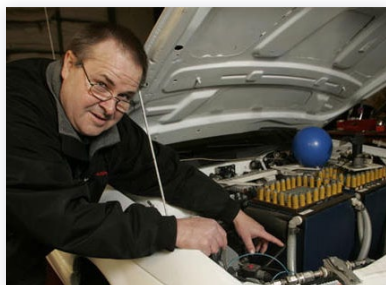


In a microgrid, an electrolyser serves an important function in time-shifting energy generation. For example, when a building's solar PV panels are generating electricity that is not required at the time, it can be used to produce hydrogen which is then stored. When PV output stops, as it does at night, but hot water or electricity is needed, the hydrogen can be used to fuel a micro-CHP fuel cell system, providing energy on demand.

The electrolyser would also allow the building to generate vehicle fuel, should it have a vehicle equipped to run on hydrogen – and this will generally only become a practical reality following the commercial rollout of fuel cell vehicles from ~2015 onwards (see Section 6.3). 'Fuelling' a car at home is of course nothing new, following the introduction of battery electric vehicles in many countries, but hydrogen has an advantage over battery storage in terms of the amount of energy that can be practically stored.

### Examples

In March 2012, Honda Motor Company unveiled a solar-powered hydrogen station on the grounds of the Saitama Prefectural Office in Japan. A high-pressure water electrolysis system draws power from solar PV panels and can produce 1.5 kg of hydrogen within 24 hours; this is sufficient for an FCX Clarity fuel cell electric vehicle (FCEV) to run approximately 150 km or 90 miles, making the station ideal for personal use. Honda intends to develop the system to offer clean energy sources for the home of the future.



In the USA, the Hydrogen House Project succeeded in creating a fully off-grid house in Hopewell, New Jersey. The project received grants from the New Jersey Board of Public Utilities, as well as personal funds from the owner, Mike Strizki. He refers to it as "the first solar-hydrogen residence in North America", as it is powered exclusively by solar panels and hydrogen generated *via* electrolysis. The latter is used in his car, which has been converted to run on fuel cells, and in the fuel cell system installed in the house. Strizki offers educational tours so that people can see the concept in practice.



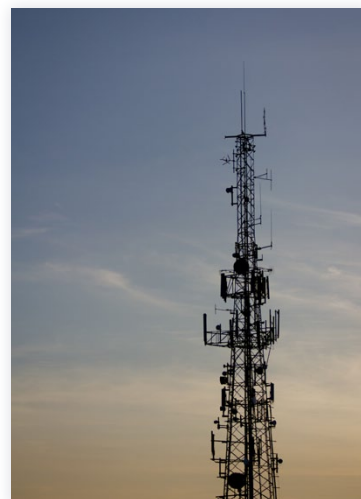
### 4.3 Autonomous Backup and Remote Power

Worldwide wireless telecommunication is supported by extensive networks of thousands of base transceiver stations (BTS). To ensure reliable service, grid-connected BTS usually have on-site battery backup power, sometimes coupled with diesel or gasoline generators. BTS are also installed in many parts of the world where there is no grid available and are then exclusively powered by electricity generated on-site, conventionally with diesel generators.

In both cases, a better solution for on-site power is sought. Batteries are expensive, bulky and provide very limited runtime. Diesel generators offer longer runtimes but have a significant environmental impact – a single BTS can account for as much as 20,000 litres of diesel per year – and are also subject to theft. There is also a need for a low-maintenance solution: BTS are often installed in remote locations and are accessible only with difficulty; even where this is not the case, the number of BTS and the distances between them mean that service costs mount quickly for the network operator.

For these reasons, alternative energy sources such as micro-scale wind and solar power are of much interest for BTS, but because of their variability they need to be implemented along with some form of energy storage. Fuel cell backup power is also seeing increasing commercial success in this application, using fuel stored on site: either packaged hydrogen or methanol which is reformed to produce hydrogen. Fuel deliveries are still required but usually at much longer intervals as the efficiency of fuel cell technology coupled with energy storage in the form of hydrogen or methanol allows for extended runtimes.

But by incorporating an electrolyser with fuel cell backup power, the need for fuel deliveries can be eliminated. The electrolyser draws power from the grid when available, replenishing the hydrogen storage at the site, ready for future grid outages, or can be connected to on-site microgeneration for a fully renewable, grid-independent system.



#### Examples



Launched early in 2010, the ElectroSelf from Electro Power Systems was the first commercially available system of this type and has been installed at numerous base station sites. It is described as a 'self-recharging' fuel cell system that can effectively guarantee power, and is optimised for use with renewables such as wind and solar power but can also work with the grid. Power output ranges from 1.5 kW to 12 kW, depending on the model, and electrolyser power rating is 5.5 kW.

A similar system is now available from German fuel cell company FutureE. The Jupiter Independence system has two 2 kW rack-mounted fuel cells integrated with a water tank, an electrolyser (power input up to 1.8 kW), two cabinet-sized hydrogen storage cylinders and a small battery for power management. Hydrogen storage capacity is 700 litres, sufficient to sustain power during outages of several hours. FutureE's development of back-up systems for the telecoms industry has been customer-driven, with Deutsche Telekom taking a particular interest. Acta has recently launched its version of an autonomous fuel cell and electrolyser hybrid system, the Acta Power. It uses its own electrolyzers and incorporates fuel cells from its partner, FutureE. The two companies are targeting different initial markets for telecommunications backup power in order to maximise their production volumes.



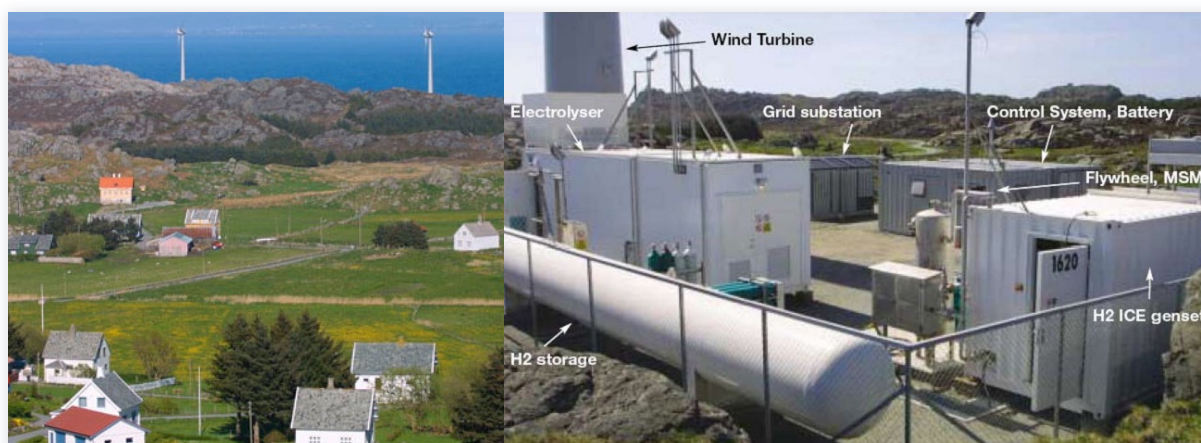
## 4.4 Stranded and Localised Grids

Localised grids can be isolated from the centralised national electricity grid for a number of reasons. Island grids and remote areas are separated geographically and often cannot benefit from regional interconnection between neighbouring networks. Other grids may be 'isolated' by some other means, for example military installations or critical infrastructure like emergency response centres. These grids may not be able to rely fully upon centralised energy supply and instead choose to run autonomously. Similar to the examples above, all of these types of stranded grids can benefit from using electrolysis and hydrogen for energy storage.

Localised grids can also suffer from limited flexibility by being smaller in extent, so adding a component that links electricity and heating (often in combination with biogas) as well as transportation can be helpful. In the case of islands, the opportunity to fully decarbonise transportation can be a simpler task using hydrogen than it might be on the mainland. An island's vehicle fleet can effectively operate in a return-to-base model with a small number of hydrogen refuelling stations providing full coverage due to the limited driving range on the island. In this mode the electricity and transportation networks can be developed in harmony utilising renewables to increase energy security and decarbonise local energy.

### Examples

An early use of water electrolysis in a practical energy application was in the Utsira Wind Power and Hydrogen Plant, on the small island of Utsira just off the south-west coast of Norway. This landmark project demonstrated the concept of wind-to-hydrogen production at full scale, under real-life conditions. An integrated renewable energy system was constructed on Utsira to demonstrate reliable power provision to local households, which have a weak grid connection to the mainland. Excess electricity generated by the 600 kW wind turbine was used in the 48 kW electrolyser to produce hydrogen at 10 Nm<sup>3</sup>/h. This was compressed and stored, and fed through a generator or fuel cell when electricity was required and wind power was not sufficient. Over four years of operation, from 2004 to 2008, the concept was successfully proven as energy for ten households was exclusively supplied by the pilot plant. However, it was concluded that further technical improvements and cost reductions were needed for commercial viability.



On the island of Corsica, AREVA has been running a trial since 2010 to store the energy generated from a 550 kWp array of solar PV panels. Known as MYRTE (Mission hYdrogène Renouvelable pour l'intégration au réseau Electrique; Renewable Hydrogen Mission for Integration into the Electric Grid), the installation uses a combined electrolyser and fuel cell system from AREVA, called the Greenenergy Box. This unit compensates for drops in PV production or can replace the mains supply in the event of a power cut. Surplus PV energy can be stored during the daytime using the electrolyser and the hydrogen and oxygen are stored in tanks. This energy can then be returned to the grid when required using the fuel cell.



The initial aim of the project was to prove the concept, but the system has always been earmarked for further development with a second phase to increase the overall power capabilities of the fuel cell and electrolyser systems.

A clean energy project for the Isle of Wight, called Ecoland, was launched in November 2011. The project aims to position the Isle of Wight as a net energy exporter (to the UK mainland) by 2020 *via* the integration of its renewable energy supplies through a smart grid to intelligent distributed power devices and clean transportation. Hydrogen production and storage solutions will be linked to renewable energy produced on the island and storing this energy will enable the provision of clean hydrogen to fuel vehicles. The project took a step forward in July 2012 with an infusion of funding in the form of a £4.66 million grant from the Technology Strategy Board (TSB) for the building of a hydrogen energy system, its integration into the power system and a hydrogen vehicle refuelling system. There are a large number of companies working as partners on the project, contributing to different aspects of the vision including the smart grid and hydrogen vehicle fleet; these include household names such as IBM, Vodafone and Toyota.

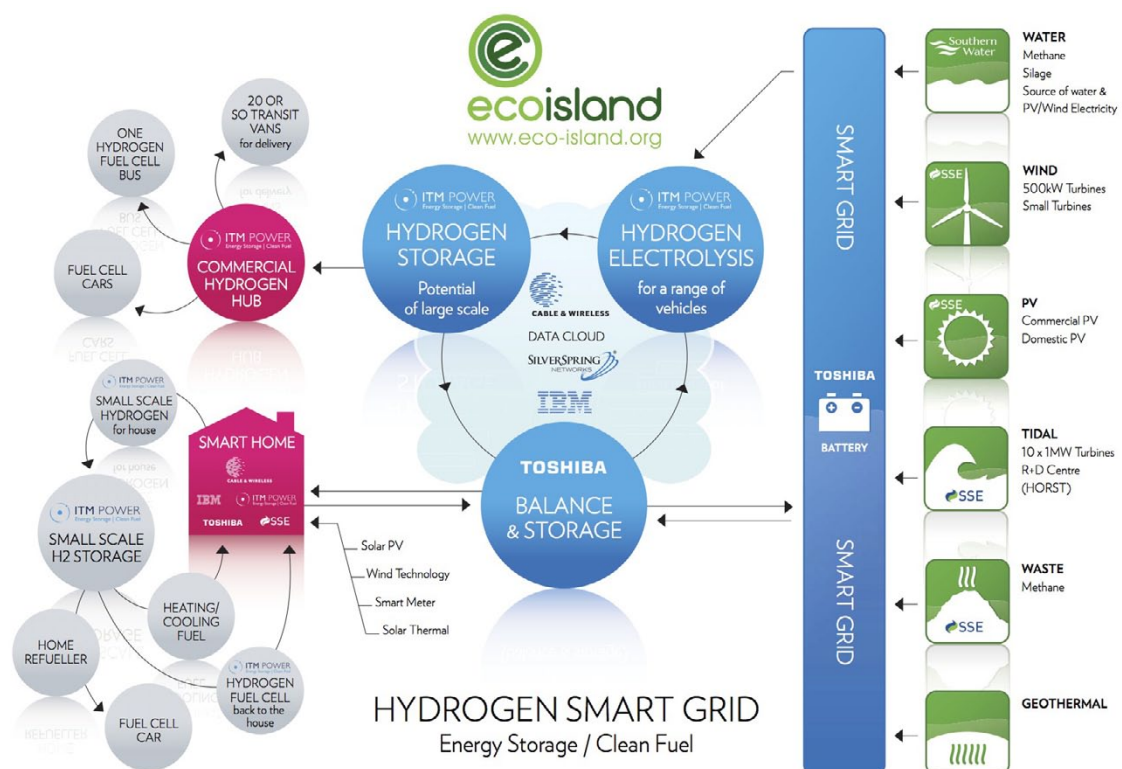


Figure 2: The integration of hydrogen in the Ecoland project (Source: ITM Power)



## Background and Funding

The ENERTRAG *Hybridkraftwerk* hybrid power plant in Prenzlau has been established to prove the viability of producing and effectively utilising renewable energy, including its integration into existing power infrastructures. The project required over €4 million of direct investment and €3 million of research investment for its hydrogen technologies and a further €21 million for the accompanying wind farm. It is sponsored by the Federal State of Brandenburg under the Gemeinschaftsaufgabe Ost (Joint Task East), which sees federal funding allocated to improving areas of East Germany that are economically or structurally weak. Other organisations involved in the project are: TOTAL Deutschland GmbH; ELT GmbH; The Brandenburg Technical University of Cottbus; The University of Applied Sciences of Stralsund; NOW GmbH.

## Configuration

- A 500 kW alkaline electrolyser with an output (at nominal load) of 120 Nm<sup>3</sup>/h H<sub>2</sub> at 99.997% purity and 60 Nm<sup>3</sup>/h O<sub>2</sub>.
- Two 60 Nm<sup>3</sup>/h hydrogen compressors, outputting at 30 bar, and three pressure vessels with a total storage capacity of 1,350 kg of hydrogen.
- Three wind turbines, with a combined nominal power of 2 MW, directly linked to the electrolyser through a medium-voltage grid, which in turn supplies energy to Vattenfall's 220 kV high-voltage grid *via* a transformer station at Bertikow.
- A 625 kW biomass plant and accompanying storage.
- Two CHP units, with a nominal electrical and thermal power of 350 kW and 155 kW each, and capable of running on mixes of 30–100% biogas, with hydrogen making up the rest. The units can be run grid-independently if necessary.

## Operation

The plant opened in October 2011; in full operation it can generate 16 GWh of sustainable electricity per annum, enough to meet the needs of 4,000 German households. It is designed to intuitively respond to demand forecasts in order to support the grid, and serves four primary functions: hydrogen generation *via* electrolysis; electricity and thermal energy production *via* CHP; providing a stabilised renewable power supply to the electricity grid; allowing for an enhanced certainty in forecasting energy supply to the electricity grid. It responds to its differing needs with four operation modes:

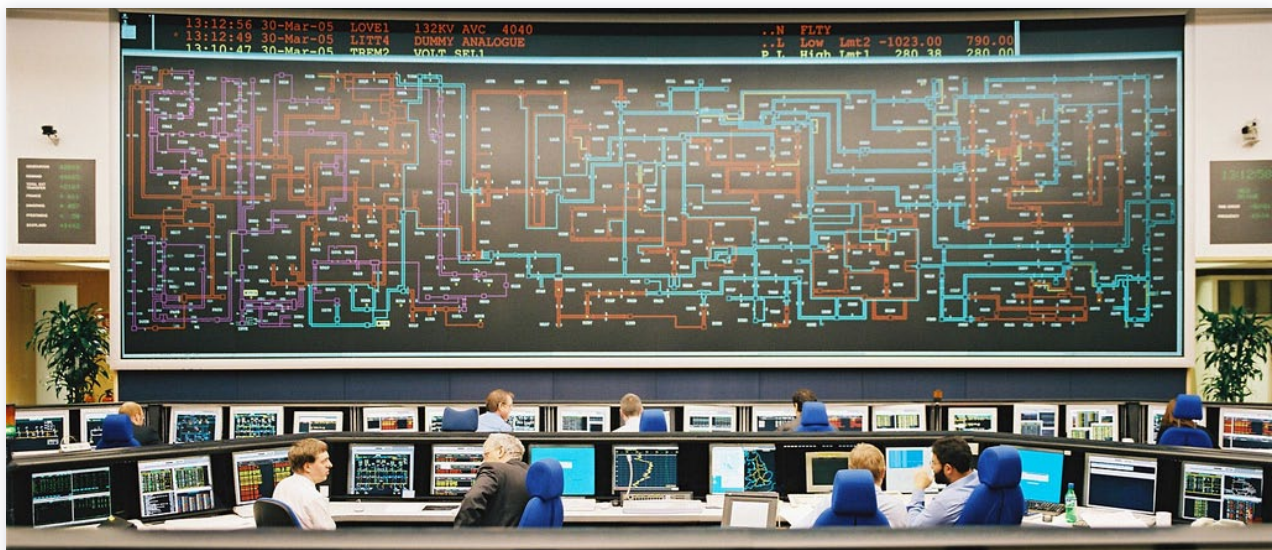
- **Hydrogen production**  
Under this mode the maximum possible amount of hydrogen is generated, up to the maximum capacity of the hydrogen storage vessels. During low wind periods, the CHP units can supply electricity to the electrolyser. If there is an abundance of wind, additional electricity will be sent to the grid. This mode suits a demand for decentralised hydrogen production, particularly for the fuelling of FCEV.
- **Base load**  
This mode allows for a constant, reliable electricity supply, regardless of variations in wind supply. Any excesses in the wind supply are sent to the electrolyser for storage as hydrogen; during times of deficit the stored hydrogen is mixed with biogas and fed to the CHP units for electricity production. This allows for the hybrid power plant to act as a base load power station.
- **Wind forecast**  
In this mode the hybrid power plant tracks forecasted wind production levels, allowing the grid operator to rely on previously changeable forecasts. The forecast is sent to the power plant eight hours in advance and, during the production hours the forecast covers, any deficits or excesses in wind production are balanced by the CHP units and the electrolyser, respectively.
- **Generation against peak demand or best tariffs**  
In this mode the plant enters production only once a predefined minimum electricity tariff level is attained. Below this threshold wind energy is used to produce hydrogen *via* the electrolyser.







## 5. Electrolysers and the Electricity Grid



Electrolysers can be integrated with the electricity grid in a number of ways, to provide a service to the grid. To understand the value of this service it is important to understand how the grid operates in principle and why the variability of renewable energy supply is a problem.

### 5.1 Grid Requirements

The International Energy Agency (IEA) states that the fundamental requirements of an electricity grid system are that it be stable, balanced, and adequate.<sup>7</sup>

Grid stability requires control of voltage and frequency, both of which are affected by fluctuations in supply and demand. It is not possible to store alternating current and hence supply to the grid has to be matched to draw from the grid instantaneously (second-by-second) and on a continuous basis. Matters are further complicated by the fact that both active (actual) power and reactive power (power that circulates in the grid but does no work) need to be controlled, to maintain a set frequency and voltage respectively.

A balanced grid is a grid that has load-following capability: i.e. supply to the grid can be ramped up or down as required to meet demand over minutes and days.

To be adequate, the grid must have sufficient production capacity available to it so that it can meet peak demand with an acceptable level of reliability. This is a longer-term requirement, coming into play over months and years.

### 5.2 The Renewables Challenge

The electricity supply is generated by a variety of means from a range of energy sources in each country, referred to as the generation mix. The integration of renewable energy sources such as wind and solar

<sup>7</sup> International Energy Agency, 'Harnessing Variable Renewables: A Guide to the Balancing Challenge', © OECD/IEA, 2011



power into this mix poses a number of challenges for the grid operator, the impact of which increases in line with the proportion of these sources in the mix.

To begin with, energy sources such as solar and wind power are inherently variable: wind power is only available when the wind blows and the wind speed controls power output. Wave power is similarly affected by the wind. Solar electricity is only generated during daylight and weather conditions will also influence how much solar power can be generated on a given day. These fluctuations in supply tend to increase the variability of the grid's net load (demand less supply) and thus have an impact on both balance and stability.



However, variability on its own can be managed if it can be predicted with accuracy – the earlier the better. Weather forecasts give a good indication of trends in wind speed and sunshine, for instance, but are always subject to some uncertainty which increases the further out the forecast is made. This degree of unpredictability in renewable energy output adds another complication in managing its direct integration to the grid.

The final issue is installed capacity. To the power system operator, a nuclear power plant with a 600 MW rating generally represents reliable capacity of 600 MW (stoppages tend to be planned well in advance). A wind farm with 600 MW installed capacity, by contrast, is subject to the weather and cannot be relied upon to always produce a full 600 MW when required. Thus a wind farm may have the same installed capacity as a conventional power plant but will have a significantly lower firm capacity and make less of a contribution to system adequacy. To ensure that a grid incorporating a high proportion of renewables has adequate capacity available at any given time to meet peak demand, some form of backup capacity may thus be required.

## 5.3 Managing the Integration

The problems of variability and uncertainty can be managed – and the disadvantages mitigated – if the power system incorporates sufficient flexibility. A highly flexible system can support a larger proportion of variability. Flexibility can be quantified as the power that can be ramped up or down over a given time period: megawatts per minute for instance. The IEA lists four main categories of flexible resources: dispatchable power generation, demand-side management, energy storage, and interconnection between grids.

### 5.3.1 Dispatchable Power Plants

The term 'dispatchable' refers to power plants that can ramp output up or down in response to the needs of the system operator; they can thus be used as supply-side management. These plants fall into three categories and are used in different ways to meet the grid demand curve.

**Baseload plants** run continuously and require hours or days to ramp their output up or down. These are used to meet the grid's minimum load throughout the day and include predictable power sources such as hydroelectric, coal-fired and nuclear power plants which are expensive to build but relatively cheap to run. Typically, baseload plants have limited load-following capability (under 20%) while operational.

**Mid-merit plants** have much greater load-following capability and provide flexibility on an hourly basis. This category includes newer biomass- and coal-fired plants and combined-cycle gas turbines, as well as some hydropower plants. They can often be ramped down to minimal output while remaining operational.

**Peaking plants** are those that can be started up and shut down very quickly in response to minute-by-minute variability and to make up for forecast uncertainty. These can be the most expensive to operate, although they tend to run only for relatively short periods to meet peak demand. This category includes open-cycle gas turbines, diesel turbines and reservoir hydropower.

Power system operators also maintain an emergency operating reserve in case of unforeseen stoppages or load changes. Operating reserve comprises spinning reserve, provided by increasing the output of plants that are already operating and connected to the grid, and non-spinning reserve, plants that are not running but can be started up rapidly.

### 5.3.2 Demand-Side Management

Another way of decreasing variation in the net load on the grid is by using demand-side management; currently this is mainly done by either postponing or curtailing consumer demand. Large customers (or groups of customers) can be contracted in advance to reduce their consumption when required by the system operator, or consumers may respond on an *ad hoc* basis to changes in the electricity supply (reflected by its price). The latter is more difficult to manage, but both have the advantage of being able to change the net load almost immediately.

An example of demand-side management is the difference in electricity tariffs for day and night usage, intended to shift some consumption from peak periods during the day to quieter periods at night (peak shaving). Rolling blackouts (load shedding) are a more extreme example. Both these examples are typical, as most demand-side management today involves decreasing consumption during peak demand periods; it can also take the form of increasing consumption during peak *supply* periods – such as on a very windy day.



### 5.3.3 Energy Storage

Excess production can also be dealt with by storing it instead of sending it to the grid. This usually takes the form of pumped hydro storage: excess electricity is used to pump water from low-lying reservoirs to higher reservoirs where it is stored. When demand increases and the energy is needed again it can then be rapidly released back to the grid in the form of hydroelectricity. The other form of storage in general use today is compressed air energy storage (CAES).

The restriction here is storage capacity, whether reservoir volume for pumped hydro or underground cavern volume for compressed air storage. This volume translated back into electricity may only be able to supply peak demand for a number of hours. If periods of excess supply run into days and weeks it is likely that available storage capacity will be exceeded and plants will then have no alternative but to shut down.

Apart from the energy that is lost, there may be a cost penalty associated with this curtailment. In the UK in 2011, for example, operators of Scottish wind farms were paid to constrain their supply so as to not overload the electricity grid. The total energy lost was 75,000 MWh, for which customers paid 21p/kWh – a total of £15.8 million.<sup>8</sup>

### 5.3.4 Interconnection

The more extensive a power system is – the more elements it includes and the greater the variety in those elements – the more flexible it is likely to be, as there are more options available for maintaining balance.

8 Dr G. Cooley, 'Hydrogen Energy Storage – Nextgen', presented 11th October 2012: <http://www.itm-power.com/wp-content/uploads/2012/10/NextGen-11102012.pdf>



Geographical extent is an important factor: an electricity grid that covers a greater area can more easily absorb a spike in wind speed in one region, for example, because other regions may be experiencing different weather. And if demand in one region goes up, elsewhere it may go down. Interconnection between the national grids of different countries is not unusual and allows for a sharing of resources, but this needs to be carefully coordinated and there must be sufficient interconnectivity between the grid systems to facilitate energy transfer.

Denmark and Norway are good examples as the two countries have a high proportion of renewable energy in their generation mixes; in Denmark's case this is wind power and in Norway's it is hydropower. Denmark exports excess wind energy to Norway *via* a subsea cable when hydro output drops, while during periods of high rainfall Norway exports hydroelectricity to Denmark. The UK and Ireland are also working on a deal that would allow new wind farms in Ireland to export power to the UK, increasing the cost effectiveness of these installations.



There is a limit to how far this can be taken, particularly when all of the countries in a region are greatly increasing their proportion of renewables, as is the case in Europe. Exporters need to be matched with importers, but no country can rely solely on importing energy from a neighbour when needed. Hence all countries will continue to add domestic generating capacity to the point where they are likely to experience surplus simultaneously.

## 5.4 The Role of Electrolysers

So what role can electrolysers, hydrogen and fuel cells play in facilitating the integration of renewable energy into the generation mix? This section will examine the potential benefits of these technologies to the electricity grid.

### 5.4.1 Supply-Side Management

The inclusion of VRE in the grid generation mix requires the provision of operating reserve and dispatchable power – likely fossil fuelled – to minimise the impact of variability and unpredictability. This pushes up the cost of renewable energy and reduces its effectiveness in cutting carbon emissions. But what if the renewable capacity itself could provide part or all of the reserve? Or, to put it another way, what if part of the capacity of a wind farm or solar power installation could be guaranteed as firm capacity, available at any time regardless of the weather?

Electrolysers provide the means for doing so. To continue with wind as an example, a certain proportion of a wind farm's output could be diverted through large electrolysers located on site. The resultant hydrogen can then be stored at the point of production and used to fuel power plants that run on demand to dispatch electricity to the grid. Hydrogen can be used directly in specially designed turbines or in fuel cells, or alternatively can be blended with natural gas before combustion; either way, the hydrogen is still contributing renewable energy to the grid.

To make this work, a wind farm would have to be more than just a wind farm. Instead it would be a power plant that incorporates wind turbines, electrolysers, hydrogen storage and fuel cells (or gas turbines) on the same site, or over several local sites. Design studies before construction would determine the optimal control strategy for managing the integration of these components. A key question would be when to divert wind power output to the electrolysers – during periods of excess supply, certainly, but the economic case for doing so routinely must be assessed because of the reliability and rapid response that can be gained.

There is of course a sacrifice in overall energy efficiency and a loss of energy at every conversion stage, but to some extent this doesn't matter. For energy sources such as wind and solar power that are 'free' and not finite, efficiency of use applies not to the energy source but to the equipment that is installed to harness it. It is the *firm* capacity of a plant that matters, and this is reflected in the capacity credit that is allocated to the plant; this is currently very low for wind power (<30% – meaning less than a third of the capacity is actually recognised). The use of hydrogen from electrolysis to supplement electricity generation should facilitate an increase in this credit, with an associated financial benefit. This would then provide the business case for installing the additional equipment.

The benefit to the grid is that VRE capacity is being backed up renewably instead of being supported with carbon-intensive capacity. Almost counter-intuitively, for a given investment in VRE capacity, and despite energy losses, the routing of some renewable electricity through electrolyzers to generate hydrogen would thus potentially increase the renewables proportion of the generation mix.

#### 5.4.2 Demand-Side Management

As stated, most demand-side management currently takes the form of curtailing consumption during peak demand periods. However, in terms of the integration of variable renewables, it would be useful if consumption could also be increased during peak supply periods (because of the lower firm capacity of VRE plants, peak output from these plants is more likely to be surplus to requirements).

This is where electrolyzers can come into play. In this scenario, excess renewable energy is fed through the grid as electricity and is drawn off by grid-connected electrolyzers that have been started up or ramped up in response to the spike to keep the grid in balance. The electricity is used to electrolyse water, generating hydrogen which can be stored or used directly on-site (and of course oxygen, which can be captured or vented as required). Because electrolyzers have a broad operational range (anywhere between 0% to 100% of rated output or higher for short periods) and can respond very quickly to changes in input (often in less than a second) they have excellent dynamic capability. Thus they offer a more nuanced form of demand-side management than simple peak shaving.



For demand-side management to work, the grid must have sufficient transmission capacity to carry the excess energy. There are also transmission losses to consider, and the inherent energy loss during the conversion from electricity to chemical energy, but these are immaterial if the alternative is to simply lose the renewable energy altogether. Reflecting this probable wastage, the electrolyser owner/operator would benefit from a lower – or even a negative – electricity price.

There is, however, a second benefit that could well outweigh this: by siting the electrolyser at the point of hydrogen use, the grid performs the function of energy distribution, saving the customer the cost of hydrogen distribution. This could be particularly beneficial for hydrogen refuelling stations, which can and do use forecourt electrolyzers to generate hydrogen on site. The hydrogen is being generated 'little and often', rather than arriving in single, widely-spaced deliveries, so savings in on-site hydrogen storage capacity can also be realised.

The amount of flexibility electrolyzers provide to the grid operator will depend on capacity. Forecourt electrolyzers could be contracted through the refuelling station operators as aggregate capacity (growing in line with the FCEV fleet) and larger grid-connected electrolyzers, even with megawatt-scale rating, can also be used if there is a suitable application for the hydrogen on site (or hydrogen distribution costs are less punitive). Electrolyzers operate automatically and can be integrated into a smart grid, giving the grid operator a manageable, dependable resource to call upon for grid balancing.

### 5.4.3 Energy Storage

Globally, renewable energy has the potential to meet our annual electricity requirements many times over. Estimating global wind power potential in a similar manner to the systems used for fossil fuel reserves is difficult. Many studies have been published on the subject, but a consensus has not yet been reached. One recent paper<sup>9</sup> revisited the topic and concluded that previous estimates had overestimated wind resource by not accounting for geographical constraints, low capacity factors and the impact on wind speeds from large wind farms. It did not put a figure to the potential for wind but commented upon previous studies to the effect that global wind potential could be on the order of 158,000 TWh in a single year. Despite the authors' reductions in estimated capacity, this would be sufficient to meet the world's electricity requirements eight times over.<sup>10</sup>

If we consider just solar energy, the US Department of Energy (DOE) states that "enough energy from the sun hits the earth every hour to power the planet for an entire year."<sup>11</sup> But harnessing this energy is difficult.

Put simply it is a matter of timing and location. The sun only shines during the daytime and wind tends to blow strongest at night. Also, wind and solar farms are not often located close to population centres. Fossil fuels have provided convenience for many years because, as energy carriers, they can be used whenever we need them and can be relatively easily stored and transported. Due to the millennia of high temperatures and pressures, these fuels also have a relatively high energy density, making it difficult for alternative energy sources to displace them when compared on a simple cost basis.

The ability to store renewable energy would allow us to average out its inherent variability, and there is more than enough renewable energy available to compensate for efficiency losses during its storage and use. This would maximise the opportunity for decarbonisation, but the business case must be argued to include the many other benefits available, such as grid stabilisation.

Energy storage has become a high-profile topic in recent years due to the increasing penetration of renewable energy sources contributing to the electricity grid. Currently, the majority of our installed generation capacity runs on fossil fuels and other predictable sources of energy, such as hydroelectric generation. These have provided a schedulable supply of electricity to the grid. In recent years an increasing percentage of renewable energy generation is being installed in order to meet future emissions reduction targets; an example of this trend is illustrated in Figure 3 showing capacity additions in the USA over the last decade. Between 2005 and 2010, the contribution to new capacity each year from wind energy rose, accounting for a maximum of 47% in 2008. As discussed above, this poses a problem for grid operators in terms of compensating for variable inputs with conventional sources to maintain grid stability.

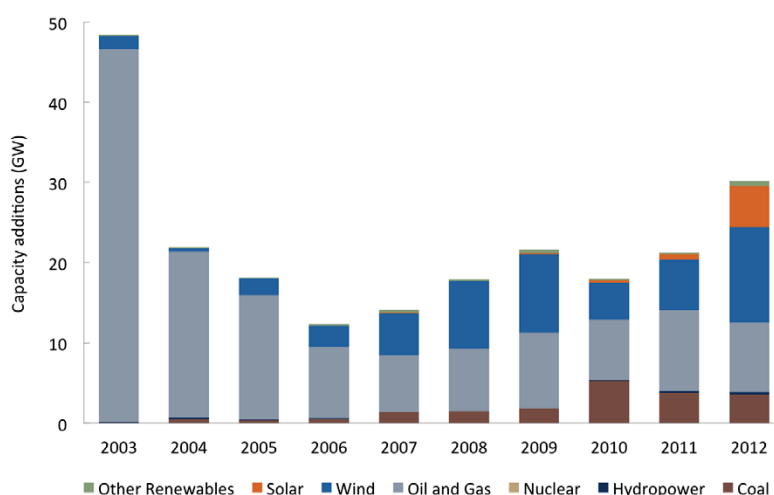


Figure 3: US electricity generation capacity additions (Source: US EIA)

9 Adams & Keith, 'Are global wind power resource estimates overstated?', *Environ. Res. Lett.*, **8** 015021, February 2013: <http://iopscience.iop.org/1748-9326/8/1/015021/article>

10 US CIA, 'The World Factbook', accessed May 2013: <https://www.cia.gov/library/publications/the-world-factbook/>

11 Department of Energy Office of Energy Efficiency and Renewable Energy, 'Energy 101: Solar PV', April 2013: [http://www1.eere.energy.gov/multimedia/video\\_energy101\\_pv.html](http://www1.eere.energy.gov/multimedia/video_energy101_pv.html)

Technology to store energy over long periods of time has been investigated for many years and, to date, pumped hydro has been the most popular option. However, significantly growing storage capacity using this method is not feasible because it relies upon favourable geographic conditions in order to form the water reservoirs necessary to store the energy. Norway is one country which has a suitable geography and hence currently derives 95% of its electricity from hydro power. This would not be an option in a flatter country, such as Holland.

Compressed air energy storage is another option, but like hydropower it requires access to suitable geographical conditions for large-scale energy storage, in this case large underground caverns to store the energy. The low energy density of CAES restricts the extent to which it can be exploited. Small-scale CAES can use high-pressure cylinders, but unless the heat generated during compression is also stored, the energy required to expand the air for use negates its stored energy.

Other methods such as batteries and supercapacitors have been used, and these are less geographically restrictive. For example the world's largest battery energy storage system (BESS) is located in Fairbanks, Alaska and consists of 13,760 nickel cadmium batteries. This BESS can provide up to 26 MW of power for fifteen minutes. It currently holds the Guinness world record for most powerful battery, once supplying 46 MW for five minutes.<sup>12</sup> While impressive, it is clear this type of storage is only feasible for short time-scales and the facility is also very large, covering more than 10,000 square feet (930 m<sup>2</sup>).

Storing energy over long timescales requires a stable storage medium, which can be scaled up and which is not subject to restrictions on its location. Chemical storage is one such possibility and specifically hydrogen can meet all of these requirements. It is a stable chemical which can be stored for long periods of time and will not degrade. It can be stored in a gaseous or liquid form, or in some instances adsorbed onto a solid. It is miscible with other gases, so is suitable for injection into the existing natural gas grid. It can also be used as a reagent for further chemical transformations, for example to re-use fossil CO<sub>2</sub> as synthetic natural gas. Hydrogen can also be used directly to generate electricity, or to power fuel cell electric vehicles. The many end uses for hydrogen are discussed in more detail in Section 6.

Placement of energy storage infrastructure is something which must be considered on a case-by-case basis as it can offer a number of benefits. Placing storage close to areas of grid congestion can help to alleviate this and allow best use of connected assets. More isolated parts of the grid can use storage for energy arbitrage, and storage sited close to demand (i.e. near to metropolitan areas) can be used to bridge the gap between the electricity, heat and transportation fuel networks.

Storage of hydrogen for long periods is something which can be done on both small and large scales, using existing technology. On the small scale, standard cylinders of compressed hydrogen can be used, similar to those used in the industrial gas industry worldwide. This is best suited to stationary applications due to the weight of hydrogen cylinders, although the automotive industry is also committed to high-pressure hydrogen storage using lighter, modern carbon fibre pressure vessels. Metal hydride technology is another option; one high-profile application is in the portable market for fuel cells in consumer electronics. Hydrogen storage in a chemically combined or adsorbed form is also used for applications when small quantities of the gas are needed periodically.

Liquid hydrogen has been researched as a possibility, but finds limitations on a small scale when required for long-term storage. The liquid inevitably produces what is known as boil-off gas, which raises the pressure in the storage vessels. Not being built to retain high pressures, the vessels release the excess using pressure relief valves and this can lead to loss of the hydrogen over prolonged periods of time. On a larger scale,

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12 Guinness World Records, 'Most Powerful Battery', 10th December 2003:  
<http://www.guinnessworldrecords.com/records-4000/most-powerful-battery/>





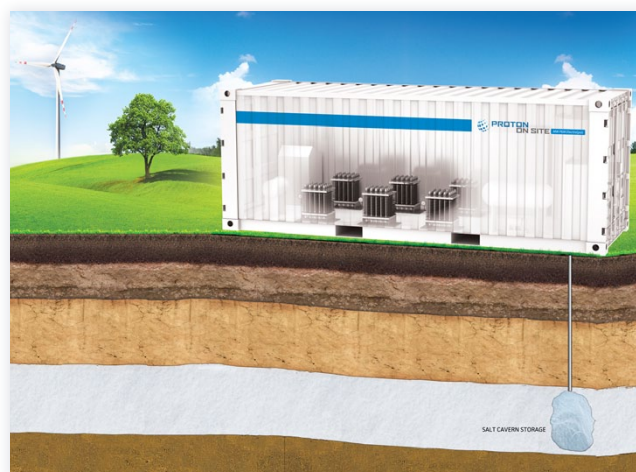
liquid storage becomes more feasible. NASA, the world's largest user of liquid hydrogen, has a liquid storage facility that contains 3,800 m<sup>3</sup> hydrogen and it claims this loses only 0.03% per day, allowing hydrogen to be stored in this way for years. Generally the energy used to liquefy hydrogen is more justifiable when the hydrogen is to be transported and used as a liquid in a high-value application, as is the case with the rocket fuel used by NASA.

In the context of seasonal storage of large quantities of hydrogen produced using renewably driven electrolysis, salt caverns and aquifers provide the most viable option, and these methods are being exploited for industrial purposes by the petrochemicals industry today. Large underground hydrogen storage facilities are in operation in both North America and Europe, clustered around petroleum refining facilities, where hydrogen is produced and consumed in large quantities.

In Europe, an EU supported project called HyUnder began in 2012 and is planned to run for two years. The project's aim is to assess the potential and business case for large-scale (seasonal) storage of renewable electricity by hydrogen underground storage. There are various geological options here, and the project is considering storage in salt caverns, depleted gas fields and aquifers, with salt caverns identified as the most likely to be implemented first.

Working from the EU's 2050 renewable energy targets and energy consumption data, analysis has produced an estimate of required energy storage capacity of 400–480 TWh (60% wind, 40% solar). This cannot be achieved with either pumped hydro or compressed air energy storage, neither of which allows for energy densities that are high enough; hydrogen under pressure allows for a volumetric energy storage density almost two orders of magnitude higher. To service a fully renewable electricity generation system in the EU by 2050, a hydrogen storage system would have to have around 50 TWh energy capacity and 220 GW discharge power (assuming 60% in–out efficiency for the underground storage process). These figures equate to only around 85 salt caverns being needed to service the entire European renewable electricity storage requirement, for which potential exists in salt formations across Europe.

This is a compelling and by no means unrealistic proposition: large-scale underground gas storage is relatively mature in both economic and technical terms and this expertise can be applied to hydrogen. In fact, as mentioned above, hydrogen is already being stored in three salt caverns under Teesside in the UK, and in two underground salt caverns in the USA, with another under construction. The obvious question is how safe and secure such storage is as the hydrogen is under pressure ranging from 60–180 bar. But it is important to note that salt caverns are very far down at depths between 800 m and 1.4 km and are geologically stable; if properly constructed and managed, leakage and losses are minimal (below 0.1% per year).



In addition to comparing the options for underground hydrogen storage to each other and to other storage technologies, the HyUnder project is undertaking geological mapping to identify the most viable sites. Above- and below-ground plant technologies are being analysed with the emphasis on safety and case studies will be produced for Germany, Spain, the UK, Romania, France, and the Netherlands. A pilot project is on the horizon.

Another hydrogen storage option would be to use the existing gas network infrastructure to store hydrogen alongside natural gas. The currently installed gas grid has the capacity to store large quantities of hydrogen with minimal alterations, and therefore cost, required; this concept is discussed in Section 6.2.

#### 5.4.4 Integration of Energy Use

In Section 5.3.4, the use of interconnection between power grids to allow excess electricity to be exported is discussed. This connection increases flexibility in the respective grids, mitigating the effect of variable, intermittent energy supply on each. However, electricity export is not easily accomplished, particularly if the energy flows in question are large, such as peak output from an extensive wind farm would be. In many cases, even with the low penetration of VRE to date, existing power lines are proving insufficient and this is hampering export. Clean energy is thus wasted despite the fact that there is demand for it. In Europe, for example, this is becoming enough of a problem that the overlay of an entirely new high-voltage electricity network to cover Europe by 2050 – at an estimated cost of around €200 billion – is being considered.<sup>13</sup>

However, the principle of interconnectivity can be extended to the integration of the electricity system with the other ‘energy silos’, namely energy for heating and for transportation. This requires energy carriers that can be shared between the different silos. For example, with the introduction of battery electric vehicles, electricity has become an energy carrier for transportation. This commonality means that it is theoretically possible to transfer some excess renewable electricity through the grid and store it in the batteries of vehicles to help restore balance, although storage capacity carried on board vehicles will of course be subject to practical limitations.

There is a very strong motivation for connecting electricity generation with heating and transportation, and that is the great need for renewable capacity that can cater to these sectors. In 2011, the IEA reported<sup>14</sup> that roughly half the energy we consume globally is actually used in the form of heat. Transportation accounts for around 30% while only about a fifth of our energy consumption is in the form of electricity – yet in many countries the main thrust of efforts to cut carbon is directed at cleaning up the electricity supply. This is because, despite the attendant difficulties, a large-scale introduction of renewable sources into electricity generation is still easier to accomplish in the near term than a wholesale conversion to renewable heat or climate-neutral transportation fuel. Once electricity is decarbonised, the hope is that it will be possible to achieve further emissions cuts by electrifying heat and transportation.

But doing so is not a straightforward prospect and would place a further burden on an already strained electrical infrastructure. Ideally, what is needed is a carbon-free energy carrier that can connect electricity with heating and transportation in a form that is more readily usable for the latter two. Hydrogen generated by electrolysis is the only possible candidate here (and has the further advantage that it is widely used as an industrial commodity). As is made clear in the discussion above, it also provides the means to store energy in a clean form in very large quantities, something that will become increasingly important for all sectors as existing fossil fuel storage reservoirs (natural and otherwise) become unusable.

Integrating electricity, heating, transportation, and even some industrial processes through the medium of hydrogen will create flexibility not just in the electricity grid but in the energy system as a whole. It will allow for synergies to be exploited, increasing renewable capacity in all three energy silos as well as overall energy efficiency. There is no doubt that it could be an enormously powerful tool for reduction of greenhouse gas emissions in the near future – if the use of hydrogen is a realistic prospect. This is the point that will be addressed in the next section.

<sup>13</sup> Dr E. Gaxiola, ‘Infrastructure Roadmap for Electricity Networks in Europe’, presented 20th March 2013.

<sup>14</sup> International Energy Agency, ‘Cogeneration and Renewables: Solutions for a low-carbon energy future’, © OECD/IEA, 2011

## 6. Markets for Hydrogen



In Section 3.1 we discussed the existing industrial markets for hydrogen production from electrolysis, but these use a fairly limited amount of hydrogen. If hydrogen is to be produced in appreciable quantities as a clean energy carrier, as is discussed above, it will have to find new markets. In fact, hydrogen is actually used in massive quantities in industrial process, but this is fossil hydrogen mainly produced from the reforming of natural gas. Displacing this with hydrogen from electrolysis is certainly a possibility, discussed in Section 6.5. However, other ways to use this hydrogen are emerging, and it is hoped these new applications will enable decarbonisation of not just the electricity grid, but also of heating and transportation. They are the subject of Sections 6.1 to 6.4.

### 6.1 Centralised Power Generation

If electrolyzers are to be implemented on a large scale, at a major onshore wind farm for example, then there are options for using the vast quantities of hydrogen produced directly and in a centralised fashion. This local usage approach is beneficial as it avoids potential transmission and further conversion losses. As we are dealing with the handling of excess electricity, it makes sense to consider the centralised storage and later use of this energy in the context of electricity generation.

There already exist in many nations large-scale combined cycle gas turbine (CCGT) plants used for power generation from natural gas. CCGT are commonplace in the energy industry, often used as spinning reserve, and are well-suited for high-power applications. At a distributed level, many CCGT would be able to process natural gas from the grid with some hydrogen present (as discussed in Section 6.2), but to put high concentrations of hydrogen directly into a CCGT presents some problems. Chiefly, hydrogen is known to embrittle metals, and its continued use at high purities in conventional systems is likely to damage them. However, hydrogen-compatible CCGT are under development and the centralised use of these is a viable option for direct power generation from hydrogen.





In 2010 Enel, Italy's largest utility, inaugurated a 12 MW 100% pure hydrogen fuelled combined cycle gas turbine in Fusina, near Venice – the first of its kind in the world.<sup>15</sup> When fully integrated with the existing coal-fuelled plant at the site, efficiency can reach over 40% and electrical output 16 MW.<sup>16</sup> Operating at full capacity the plant uses 1.3 metric tonnes of hydrogen per hour, piped as by-product from a nearby petrochemical complex, and generates 60 GWh a year – enough to meet the needs of 20,000 households. In doing so it avoids the emission of more than 17,000 metric tonnes of CO<sub>2</sub>. At least in its infancy, this is a relatively expensive option: a total investment of €50 million was needed for the creation of the Fusina plant and the electricity produced there is up to six times more expensive than conventional electricity.<sup>15</sup> That said, all new and nascent technologies come at a cost and this will always decrease over time, as is also the case with fuel cells.

Another option for generating electricity from hydrogen is to use fuel cells. Although large-scale stationary fuel cell power plants are relatively uncommon at present, not least due to their high price, much progress is underway both in cost reduction and deployment. There are large stationary fuel cells installed across the world, historically featuring most strongly in the USA, where the majority of these plants have been manufactured, but more recently South Korea has become an equally prominent market.

Interest in fuel cells in South Korea has accelerated in recent years, driven by the government's Renewable Portfolio Strategy (RPS) – a strict renewables implementation plan that mandates 350 MW of additional renewable power capacity per year through 2016, and 700 MW per year through 2022. The RPS also decrees that electricity producers with an annual capacity greater than 500 MW must generate 2.5% of their electricity using new and renewable energy (NRE); this rises to 7% by 2019 and 10% by 2022. NRE types are ranked to calculate the purchase price per kilowatt-hour; fuel cells benefit from the highest ranking among NRE technologies and this has been a major driver for rapid growth in fuel cell imports. The NRE subsidy that fuel cells receive may make them particularly attractive to operators of wind or solar farms, which receive a lower subsidy; excess electricity from the turbines or panels could be converted into hydrogen, stored, and then processed in a fuel cell and sold for a higher price per kilowatt-hour in times of deficit.

Thanks to the increasing demand from South Korean utility POSCO Energy for FuelCell Energy molten carbonate fuel cells, having now cumulatively installed over 100 MW, we are beginning to see larger and larger centralised fuel cell 'power parks'. In May 2012 FuelCell Energy announced that it was to provide fuel cells for an 8.4 MW power park in Samcheok and a 58.8 MW park in Hwaseong – by far the world's largest fuel cell installation.<sup>17</sup> A series of large fuel cell installations are also planned for Seoul which, along with 102

15 Svetlana Kovalyova/Reuters, 'Enel to start major plant conversion to coal 2011', 12th July 2010: <http://www.reuters.com/article/2010/07/12/us-enel-idUSTRE66B4KB20100712>

16 Enel SpA, 'The world's first hydrogen-fuelled power plant', accessed April 2013: [http://www.enel.com/en-GB/innovation/project\\_technology/thermal\\_power\\_plants/co2\\_capture/ccs\\_project3.aspx](http://www.enel.com/en-GB/innovation/project_technology/thermal_power_plants/co2_capture/ccs_project3.aspx)

17 FuelCell Energy, Inc., 'FuelCell Energy Highlights Advances With the Development of a 59 Megawatt Fuel Cell Park in South Korea', 17th October 2012: <http://fcel.client.shareholder.com/releasedetail.cfm?ReleaseID=714163>



residential fuel cells, the Seoul Metropolitan Government hopes will be providing 230 MW of electricity by 2014.<sup>18</sup> Although the RPS is a very obvious driver for the adoption of large centralised fuel cell installations, the model is beginning to become viable elsewhere. In December 2012, FuelCell Energy announced the sale of a 14.9 MW fuel cell power park to Dominion, one of the USA's largest producers and transporters of electricity, for installation in Bridgeport, Connecticut.<sup>19</sup> Ground was broken on 3rd May 2013 and the plant should be operational by the end of 2013.<sup>20</sup>

All of the installations exemplified currently run on some form of natural gas, but large fuel cell power plants also have the option of running on hydrogen. In 2011, a 1 MW PEM fuel cell power plant from Nedstack was installed at Solvay's chlor-alkali plant in Lillo, Belgium, and this runs on by-product hydrogen from the chlor-alkali process.<sup>21</sup> In October 2012 Ballard Power Systems commissioned a 1.1 MW ClearGen PEM fuel cell system – the largest of its kind – at Toyota Motor Sales USA's premises in Torrance, California.<sup>22</sup> The system runs on hydrogen, supplied through a dedicated pipeline and generated by Air Products through reforming of natural gas. Siting a fuel cell power park next to a large renewables site with electrolyser makes sense: in times of excess renewable power the plant could run on hydrogen and in times of deficit it could run on natural gas.



## 6.2 Hydrogen Injection into the Natural Gas Grid

### 6.2.1 Advantages



This application, often referred to as 'power-to-gas', is the focus of serious consideration because there are a number of reasons why injecting hydrogen from electrolysis into the gas network is an attractive idea. Gas transmission pipelines offer a significantly more effective means of moving large quantities of energy over distances than power lines do and are subject to lower losses, as are distribution pipelines. In addition, gas end-use can be over 90% efficient, which could compensate for the losses incurred in converting electricity to gas. But the chief advantage is the considerable energy storage capacity of the natural gas network: even hydrogen injected at relatively low concentrations can equate to terawatt-hours of energy that can be stored for months.

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- 18 Fuel Cell Today, 'Seoul Government to Build 29 Hydrogen Fuel Cell Power Plants by 2014', 16th May 2012: <http://www.fuelcelltoday.com/news-events/news-archive/2012/may/seoul-government-to-build-29-hydrogen-fuel-cell-power-plants-by-2014>
- 19 FuelCell Energy, Inc., 'FuelCell Energy Announces Sale of a 14.9 Megawatt Fuel Cell Park in Bridgeport, Connecticut to Dominion', 14th December 2012: <http://fcel.client.shareholder.com/releasedetail.cfm?ReleaseID=726932>
- 20 Fuel Cell Today, 'Groundbreaking for Dominion Bridgeport Fuel Cell Power Station', 30th April 2013: <http://www.fuelcelltoday.com/news-events/news-archive/2013/april/groundbreaking-for-dominion-bridgeport-fuel-cell-power-station>
- 21 Fuel Cell Today, '2012 Fuel Cell RCS Review', 13th November 2012: <http://www.fuelcelltoday.com/analysis/legislation/2012/2012-fuel-cell-rcs-review>
- 22 Fuel Cell Today, '1 MW Ballard Fuel Cell System Now Operating at Toyota USA Headquarters', 18th October 2012: <http://www.fuelcelltoday.com/news-events/news-archive/2012/october/1-mw-ballard-fuel-cell-system-now-operating-at-toyota-usa-headquarters>

The gas network primarily serves energy demand for heating, so adding hydrogen generated by renewably driven electrolysis connects electricity and heating, increasing the flexibility of the energy system as a whole. While the benefits to the electricity grid are clear (as discussed in Section 5), there is also a considerable benefit for the gas grid. Renewable alternatives to natural gas are currently restricted to bioenergy, which has limited availability, but wind or solar power could provide a potentially limitless source of renewable gas that doesn't conflict with food supply. If the existing gas network can be reinvented as a means of distributing renewable energy, it also gains a 'second life': taking the long view, fossil fuel infrastructure has an expiry date on it unless it can be repurposed.

Hydrogen can either be injected into gas pipelines as hydrogen or be converted to a more conventional fuel by reacting it with carbon dioxide to produce synthetic methane. This methanation would allow for better matching of properties with utility gas so that injection limits could be increased (although there are still some technical issues with injecting synthetic methane in large quantities that would have to be addressed). Using hydrogen to produce methane is subject to an energy loss in conversion and this reduces overall efficiency, whereas direct hydrogen injection can be accomplished at high efficiency using existing technology. Nonetheless, there are advantages to methanation, particularly when the carbon is sourced from biomass; it is discussed further in Section 6.4 on the production of synthetic fuels.

This section only considers the direct injection of hydrogen into the gas network. So how much hydrogen can the network accept and what is the likely effect on network management and gas end-use? The below discussion focuses on results to date from some major studies but it should be noted that a number of multi-stakeholder projects investigating various aspects of this concept in more depth are in progress. In Europe, two major collaborative platforms to further the power-to-gas concept have been launched in 2013, one centred around the North Sea and the other around the Mediterranean.

### 6.2.2 Effect on Materials

The first issue is whether hydrogen will affect the durability of the materials used in gas pipelines and other components, as it is well known that some metals degrade and become brittle when exposed to hydrogen. This is generally only a problem with exposure over prolonged periods at high concentrations and elevated pressure, when it can lead to failure and reduced service life. A recent technical report on blending hydrogen into natural gas networks from the US National Renewable Energy Laboratory (NREL)<sup>23</sup> concluded that this is unlikely to be a problem in the US gas distribution system under normal operating conditions, but is more of a concern for transmission pipelines which have higher operating pressures. The report drew on the work done under the European NaturalHy project<sup>24</sup> (2002–2006), which concluded that, depending on the steel used, high-pressure pipelines can be used for gas blends containing up to 50% by volume hydrogen, although evaluation on a case-by-case basis is necessary. The NaturalHy project also led to a recommendation that, to ensure the integrity of steel pipelines in the gas network, more frequent inspection and adjustments to the pipeline integrity management systems may be required. These are modifications that are relatively easy to accomplish, and are not, in the NaturalHy report's words, 'showstoppers'.

It is important to note that there is no fundamental bar to the transport of even pure hydrogen in pipelines over long distances; this is something that has been done safely and efficiently for many years to serve industrial demand for hydrogen (for petroleum refining for example; see Section 6.5). The issue is not hydrogen *per se*, but rather the change in the gas composition from what was specified when materials were selected and the infrastructure was designed and installed.

23 Melaina, Antonia & Penev, 'Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues', NREL/TP-5600-51995, March 2013

24 NaturalHy Project, 'About NaturalHy', accessed 23rd April 2013: <http://www.naturalhy.net>

### 6.2.3 Safety

The NREL report examined the impact of hydrogen on safety, which is subject to a range of factors and would differ on a case-by-case basis.

In low-pressure lines, polymers such as polyethylene (PE) are increasingly being used for gas distribution networks and while these do not corrode like steel they are subject to some permeation of gas through the pipe walls. Permeation losses are negligible for natural gas but will increase if hydrogen is added, because hydrogen is a smaller molecule. The NREL report concluded that permeation of hydrogen through the walls of PE pipes is four to five times faster than methane but is still low and “acceptable from a safety, economy and environmental point of view”.

In terms of accidental leaks, the broad conclusion was that hydrogen concentrations up to 20% do not lead to a significant increase in either the risk of ignition or the severity of explosions resulting from gas leaks. Above 20% hydrogen content, the increased risk can be mitigated by better risk management. Blends containing more than 50% hydrogen in distribution mains and service lines do, however, lead to a significantly increased risk overall – with existing pipelines. New infrastructure designed with high hydrogen content in mind could negate this risk.



The NaturalHy project studied the increased risk of gas escape and ignition in buildings due to the addition of hydrogen. Increases in gas accumulation and volume are slight for hydrogen addition up to 50%. The increase in the severity of explosions is minimal up to 20% hydrogen. The research did find that the frequency of gas explosions in buildings could be doubled by the addition of 20% hydrogen but the point is made that the existing risk is very low so the increased risk is still within acceptable limits. Again, improvements in gas monitoring and other technology mean that this risk can be managed.

### 6.2.4 Energy Content

The hydrogen content of utility gas is also subject to limitations that arise from the fact that hydrogen's properties as a fuel gas differ from those of conventional fuel gases such as methane. In Germany, where this has been most studied, the technical standard for gas quality theoretically allows for single-digit concentrations of hydrogen to be admissible in both the low-calorific (L-gas) and high-calorific (H-gas) natural gas networks in the country. For concentrations above 10% hydrogen, however, certain components of the gas network would have to be modified or replaced and these act like bottlenecks preventing higher levels of hydrogen injection.

Because hydrogen has a lower volumetric energy content than natural gas it has the effect of ‘diluting’ the gas somewhat, leading to a moderate decline in the energy transport capacity of the pipeline (energy content shifted per unit of time). This is manageable: it is likely to be felt only at periods of peak gas demand and hydrogen injection can be coordinated with demand. But the gas network consists of more than pipelines: gas compressors tolerate hydrogen well but are sized for a specific throughput capacity, so higher concentrations of hydrogen may require higher compressor capacities.

### 6.2.5 Effect on End Use

Hydrogen burns differently from natural gas (with a higher flame speed) and addition of hydrogen also lowers the Wobbe index of the gas (which is based on calorific value and specific gravity), reducing the energy output of the combustion process. The effect of hydrogen blending is thus likely to be most severe on end-use appliances and industrial facilities and it is likely this will be the limiting technical factor for hydrogen injection. As the NREL report noted, the effect is dependent on the proportion of hydrogen, the type of appliance and its age; acceptable limits determined by various studies to date fall within the range



of 5–20% hydrogen. The NaturalHy project concluded that for properly adjusted appliances where the local gas quality specification is favourable in terms of the allowed range of the Wobbe index, domestic appliances could feasibly tolerate up to 20% hydrogen. In reality, phased replacement of the ageing domestic gas burner fleet would probably be necessary as hydrogen concentration is gradually stepped up.

Fuel cells in small-scale combined heat and power applications in homes and other buildings have an advantage here, in that they do not burn the gas and are thus unaffected by the changing flame speed. Although of course this has not yet been tested in practice, it is probable that micro-CHP fuel cells will prove quite tolerant of blends containing about 5% hydrogen – at the stack level the ideal fuel for any fuel cell is hydrogen, after all. At 20% hydrogen some impact on performance can be expected,<sup>25</sup> due to the variation from the gas specification the fuel cell system was calibrated for. In theory, if the gas blend is consistent, all that would be required is recalibration of the fuel cell system and possibly some modification to the balance of plant (depending on the type of fuel cell technology). The impact on performance of a fluctuating blend will be more difficult to manage.

At industrial scale, recent research by the German Technical and Scientific Association for Gas and Water (DVGW) concludes that gas engines are quite tolerant of hydrogen – there even appears to be an improvement in efficiency and exhaust gas composition at around 8% hydrogen. Gas engines that work well with up to 20% hydrogen should be possible with some modification. Gas turbines, by contrast, are more challenging. Currently these are limited to less than 3% hydrogen; R&D is increasing this to 9% or more. Higher concentrations should be technically possible – Siemens has gas turbines that can run with 15% hydrogen – but again the challenge here may lie more in operating the turbines with a fluctuating gas composition. See Section 6.1 for more discussion on hydrogen-fuelled turbines.

Theoretically, gas pipelines could also be used as a means of distributing hydrogen that is then separated from the natural gas at the point of extraction, so that the blend is of less relevance to end use. The required purity of the extracted hydrogen would be dictated by the intended application. Hydrogen separation from gas mixtures using pressure swing adsorption (PSA) is routinely conducted at industrial scale, but typically with higher hydrogen concentrations than would be the case in hydrogen extraction from gas pipelines. According to NREL, PSA systems that can operate with hydrogen content as low as 20% are technically feasible but the units would be overly large; the recommendation is that the technology be employed only at pipeline pressure reduction stations to exploit the pressure drop.

Low hydrogen content in the blend also poses a challenge for commercial membrane separation technologies because of the high differential pressure that would be imposed across the membrane. For this reason, NREL concluded that membrane technologies would be best used for extracting hydrogen from transmission pipelines where the higher pressure in the pipeline could aid hydrogen recovery. However, the NaturalHy project conducted much investigation into hydrogen-selective membranes for high-purity hydrogen and found that wider use of membrane separation systems is potentially feasible in both economic and technical terms. Palladium membranes are expensive but new techniques can manufacture very thin membranes to reduce cost and increase flux. Cheaper carbon-based membranes can be used when only 98% pure hydrogen is required, or can be used for first-stage separation in a hybrid system, with palladium membranes reserved for the second stage. Cost estimates produced by the project suggest that membrane technology could be more cost-effective than PSA for blends containing less than 40% hydrogen.

A third technology considered by NREL was electrochemical hydrogen separation (EHS) using either a Nafion-based membrane or a polybenzimidazole (PBI) system; the former technology is more mature but PBI requires less compression. It was concluded that EHS systems are likely to be too complex to compete with PSA or membrane technology at this stage.

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25 Information based on discussion between Fuel Cell Today and Ceramic Fuel Cells Limited, April 2013.

### 6.2.6 Currently Permissible Limits

For the USA, NREL concluded that hydrogen concentrations of 5–15% could be viable without significantly increasing the negative impact on end-use devices, overall public safety, or the durability and integrity of the existing natural gas pipeline network. In Europe, the NaturalHy project concluded that the maximum hydrogen concentration would be limited by, and dependent on, the effect on end-use appliances and should be determined individually for each distribution region using a methodology developed by the project. This also reflects the fact that hydrogen injection need not necessarily apply to an entire gas network and can be implemented only in those sections where it would be well tolerated.

In Germany at least, the DVGW study has shown 10% hydrogen in the gas grid is within reach, if the few bottlenecks are addressed. 10% hydrogen already equates to considerable energy storage potential and would allow for better integration of existing wind and solar power capacity in the near term. To put this into context, Germany Trade & Invest states that Germany's existing gas network holds around 220 TWh of energy (assuming 55% conversion efficiency) and that this is equivalent to 3,000 times Germany's current pumped storage capacity.<sup>26</sup> Even 10% of this would completely eclipse existing energy storage capacity in the country.

However, there are usually regulatory limits on how much hydrogen can be contained in grid gas, and in many countries these restrict hydrogen injection to below what could technically be tolerated. In many cases these are probably over-cautious, but much technical verification and demonstration of the safety of blending hydrogen into grid gas would be needed to relax these limits. Currently, the most generous limit in Europe is in the Netherlands, where up to 12% hydrogen is allowed. France is next at 6% and Germany's current limit is 5% by volume.

#### Example

A 2 MW power-to-gas plant is being constructed at Falkenhagen in Germany to demonstrate the concept of gas-grid injection in a flagship project for energy utility company E.ON. At the time of writing, six alkaline electrolyzers from Hydrogenics had been shipped to the site (see photo, right); Hydrogenics will deliver the plant to E.ON as a turnkey project and it is expected to be in operation in late 2013.



E.ON chose this location for the pilot project because of the proximity to grid-connected wind turbines. The output of these frequently exceeds local consumption, with very high peaks and steep power gradients. Instead of curtailing this, E.ON plans to demonstrate the benefit of using the excess electricity to produce hydrogen for injection into the local natural gas network, which is well developed with a central 900 mm pipeline that can transport as much energy as six high-voltage power lines. The power-to-gas plant will be connected to the nearby gas pipeline operated by ONTRAS, which will accept up to 360 cubic metres of hydrogen per hour from the plant once it starts up.

With the plant, which will be owned by its gas storage arm, E.ON aims to demonstrate the power-to-gas process chain and optimise the operating regime for such a facility. Validating the technology and proving the concept is a first step to creating the market for power-to-gas, which need not be a 'bolt-on' to the electricity or gas grid, but can exist separately to provide a valued service to both.

26 Germany Trade & Invest, 'Green Hydrogen and Power-to-Gas technology: Mass Energy Storage for the Future Energy Market', May 2012: [http://www.gtai.de/GTAI/Content/EN/Invest/\\_SharedDocs/Downloads/GTAI/Fact-sheets/Energy-environmental/fact-sheet-green-hydrogen-mass-energy-storage-for-future.pdf](http://www.gtai.de/GTAI/Content/EN/Invest/_SharedDocs/Downloads/GTAI/Fact-sheets/Energy-environmental/fact-sheet-green-hydrogen-mass-energy-storage-for-future.pdf)

## 6.3 Hydrogen for Transportation

An option to directly valorise hydrogen from electrolysis is to sell it as a transportation fuel. This prospect is closer than some may think: Hyundai has already begun a limited production run of 1,000 fuel cell electric vehicles for lease between 2013 and 2015,<sup>27</sup> after which it, Honda, Nissan, and Toyota will begin early market commercialisation of FCEV. Daimler will follow in 2017 and further major OEMs are expected to have launched vehicles by 2020. By 2025 the total cost of ownership for new internal combustion engine vehicles, plug-in hybrid electric vehicles (PHEV), battery electric vehicles (BEV) and FCEV is expected to converge (for passenger vehicles),<sup>28</sup> leading to increased take up and market penetration of the latter.

### 6.3.1 Hydrogen as a Fuel



Hydrogen is an exceptionally energy-dense fuel by mass, higher than conventional fuels and substantially higher than batteries. However, volumetric densities are much lower so hydrogen in cars is compressed, most commonly to 700 bar. Currently, more than 90% of road fuel globally is manufactured from crude oil. Hydrogen, by contrast, is manufactured from a wide variety of sources, including water electrolysis, presenting the opportunity for many countries to reduce their dependence on imported energy.

The dominant industrial-scale production method at present is the steam reforming of methane (SMR), which can yield conversion efficiencies of up to 80%, but which generates CO<sub>2</sub> emissions. This footprint may be reduced in the future through the use of biogas as a feedstock and by the capture and storage of the CO<sub>2</sub> by-product. Gasification of biomass and waste may also be used to create hydrogen fuel, but water electrolysis is an increasingly compelling production method.

### 6.3.2 Renewable Fuel from Electrolysis

Hydrogen produced from large, centralised electrolyzers may be used as transport fuel in a number of ways: directly at a hydrogen refuelling station (HRS) at the renewables site, piped to local HRS or shipped on trailers to stations that are further afield or where hydrogen piping is not feasible. EU estimates for the sale of hydrogen as fuel stand at €5–10/kg. In more comparable terms, the US Department of Energy targets are for \$6/gge (gasoline gallon equivalent) by 2020, which equates to €1/£0.80 per gasoline litre equivalent. Once FCEV penetrate the market, fuel sale – either directly or to third party HRS operators – can add further profit for electrolyser operators on top of grid balancing payments. On a more distributed level HRS operators may wish to take the decarbonisation of hydrogen fuel into their own hands through the use of forecourt electrolyzers with renewable grid electricity; offering 100% renewable hydrogen could provide a competitive advantage. On-site electrolyzers are available from several manufacturers and are an increasingly popular feature in demonstration stations.

There is a strong drive for the provision of renewable hydrogen fuel as FCEV themselves only eliminate emissions at the point of use – they are not a truly zero-emission solution until there are no emissions from fuel production and distribution. (The same is of course true of BEV, which are



27 Hyundai, 'Hyundai Celebrates World's First Assembly Line Production of Zero-Emissions Fuel Cell Vehicles', 26th February 2013: <http://www.hyundaipressoffice.co.uk/release/379/>

28 Power-trains for Europe project, 'A portfolio of power-trains for Europe: A fact-based analysis', November 2010: [http://www.fch-ju.eu/sites/default/files/documents/Power\\_trains\\_for\\_Europe.pdf](http://www.fch-ju.eu/sites/default/files/documents/Power_trains_for_Europe.pdf)



only truly zero-emission if recharged with renewable electricity.) Fuel production was an issue addressed in some detail by the first phase of work of the UK H<sub>2</sub>Mobility coalition, which is assessing business cases for the introduction of FCEV into the UK from 2015. It notes that the decarbonisation of hydrogen fuel will be expected by fleet operators and the early FCEV consumer base. However, this must be balanced with cost, with the general principle being that the cost of hydrogen fuel should not be greater than current diesel prices (in terms of fuel required to travel a set distance).

To begin with, in 2015–2018 when FCEV volumes are at their lowest and electrolyser technology is still relatively expensive, more than 90% of the fuel mix (for an estimated demand of less than 1,000 tonnes per annum) is expected to come from existing hydrogen production capacities – predominantly SMR, as previously mentioned. As vehicle volumes increase and economies of scale improve, the UK H<sub>2</sub>Mobility coalition sees an increasing proportion of water electrolysis (WE in Figure 4) by 2020, supplemented in later years by new, more efficient SMR capacity, to provide for an expected demand of 51,000 tonnes per annum by 2025.<sup>29</sup> The increased share of renewable hydrogen would reduce CO<sub>2</sub> emissions to 60% lower than diesel by 2020 and 75% lower by 2030 with an aim to be 100% carbon-free by 2050. The use of electrolyzers with VRE is critical to achieving this.

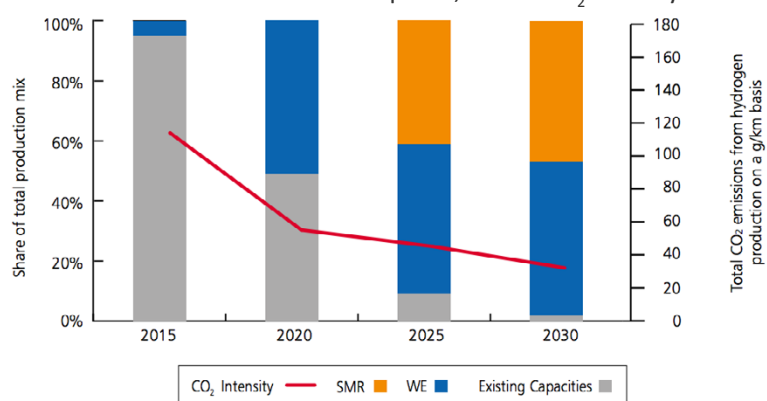


Figure 4: Proposed UK hydrogen fuel production mix over time <sup>29</sup>

### 6.3.3 Existing Electrolyser Hydrogen Refuelling Stations

Around the world there are a total of 80 HRS supplying hydrogen from electrolysis for the current fleet of fuel cell electric and hydrogen internal combustion engine vehicles. These stations make up 39% of all HRS and the majority of these are connected to, or use electricity from, renewable energy sources such as wind and solar power. Considering 95% of all hydrogen produced globally is manufactured from fossil fuels, the high percentage contribution from electrolysis in this application underscores the important role hydrogen from electrolysis plays in global aspirations to decarbonise transport.

Regionally, Europe and North America dominate in terms of installed refuelling stations using hydrogen from electrolysis: Europe has 33 electrolyser HRS (44% of Europe's total HRS) and North America has 35 (46% of its total). This is not surprising, since North America is home to many of the companies that manufacture electrolyzers for this market and it makes sense for them to service early markets close to home. In Europe, the strong push to adopt renewable electricity has paved the way for electrolyzers; indeed this report has shown how ideally suited electrolysis is to generating hydrogen using renewable electricity. Asia currently has nine electrolyser HRS in operation, spread between Japan, South Korea,

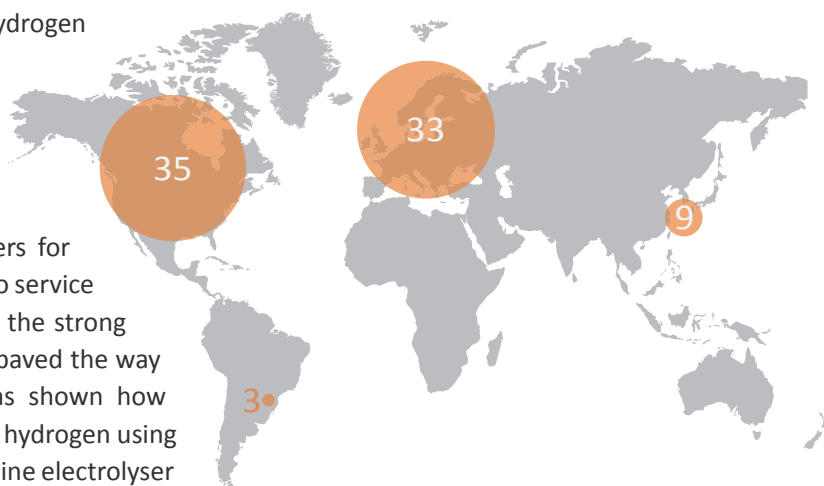


Figure 5: Existing electrolyser HRS by region

<sup>29</sup> UK H<sub>2</sub>Mobility project, 'UK H<sub>2</sub>Mobility: Phase 1 Results', April 2013: <https://www.gov.uk/government/publications/uk-h2mmobility-potential-for-hydrogen-fuel-cell-electric-vehicles-phase-1-results>

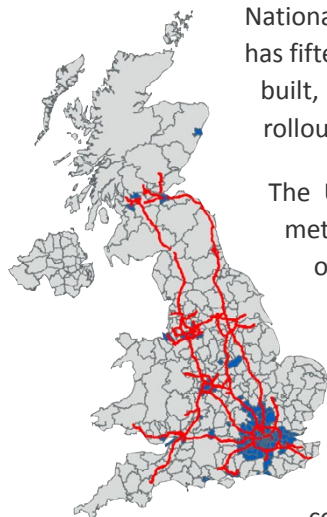
China and India, accounting for 18% of the region's total 50 HRS. More electrolyser HRS are planned: a total of 22 according to H2stations.org. Again, twelve stations in Europe and nine in North America account for all but one of the planned installations.

### 6.3.4 Rollout of Hydrogen Refuelling Stations

Although fuel mixes and production methods will vary from area to area and country to country, there will undoubtedly be an increasing demand for renewable hydrogen to support fuel cell vehicle fleets. According to the LBST and TÜV SÜD information website H2stations.org, 27 new hydrogen stations were opened worldwide in 2012, bringing the total number of hydrogen stations in service to 208 as of March 2013 – 80 in Europe, 49 in Asia, 76 in North America, and three elsewhere. A 15% increase in hydrogen refuelling stations in the space of a year is indicative of an industry drive towards market preparation for fuel cell vehicles. Of the 27 new stations, eight are in North America, three are in Asia, and sixteen are in Europe, of which five are in Germany.

The European FCEV movement has been led by Germany, with invested parties largely represented in the Clean Energy Partnership (CEP). Three of the five new German stations are CEP stations, in Hamburg, Berlin, and Dusseldorf. In June 2012, the German Federal Transport Minister Peter Ramsauer together with industry partners Daimler, Linde, Air Products, Air Liquide and Total signed a letter of intent to increase the network of hydrogen stations in Germany to 50 by 2015, supported by €20 million in funding from the National Hydrogen and Fuel Cell Technology Innovation Programme (NIP). Germany currently has fifteen public stations in operation and the country is on its way to achieving its goal. Once built, these 50 stations provide the skeleton infrastructure needed to support initial FCEV rollout across the nation.

The UK H<sub>2</sub>Mobility coalition states that a total of 65 HRS would be needed in major metropolitan areas and along national trunk roads by 2015 (left) to support an initial rollout of vehicles.<sup>29</sup> This would increase to 1,150 HRS by 2030 with a total funding requirement of £400 million through 2025 to support station construction and operation whilst utilisation is low.



In Japan in January 2011, the three major Japanese automakers – Honda, Nissan, and Toyota – signed a memorandum of understanding with ten Japanese oil and energy companies agreeing, amongst other things, that the fuel suppliers will construct a network of approximately 100 hydrogen refuelling stations by 2015.<sup>30</sup> These stations will be clustered in Japan's four main metropolitan areas: Tokyo, Nagoya, Osaka, and Fukuoka. According to HySUT, there are a total of nineteen publicly accessible HRS in Japan<sup>31</sup> (from an operational total of 26). A \$50 million government subsidy is being made available to support the construction of new hydrogen stations in 2013; the subsidy will cover up to 50% of a station's capital cost and could support 20 new stations in its first year. If the subsidy continues at this rate, and presuming that the maximum number of applicable stations are built, then Japan would have 86 stations by the end of 2015. However, the per-station subsidy may reduce from 50%, with private companies picking up the deficit; this would put the 100 station target within reach. JX Nippon



30 Toyota Motor Corporation, '13 Japanese Companies Eye Smooth Domestic Launch of FCVs', 13th January 2011: <http://www2.toyota.co.jp/en/news/11/01/0113.html>

31 Information based on discussion between Fuel Cell Today and HySUT, February 2013.

Oil & Energy Corp. and Iwatani have both recently announced plans to construct 40 and 20 stations, respectively, by 2015.

California continues to lead the USA in the adoption of FCEV. The Office of California Governor Edmund G. Brown published its zero-emission vehicles (ZEV) action plan in February 2013, which includes a roadmap towards putting 1.5 million ZEV on Californian roads by 2025. It mandates that by 2015 major metropolitan areas in California are to be 'ZEV ready', including suitable funding for infrastructure for both FCEV and BEV/PHEV, as well as streamlined permitting.<sup>32</sup> The plan incorporates the findings of a recent California Fuel Cell Partnership study, which suggests that 68 hydrogen stations would be needed for an initial launch of vehicles in 2015.<sup>33</sup> This Californian mandate is an important step forward for the country as thirteen other US states follow its more progressive air quality standards.

In terms of vehicle sales, Governor Brown's intention is for there to be 1.5 million FCEV on Californian roads by 2025. Across the Atlantic, in the UK sales of more than 300,000 FCEV are expected by 2030, at which point there could be up to 1.6 million FCEV on the road.<sup>29</sup> For reference, the UK currently accounts for 2.9% of global car sales, Germany for 4.2%, Japan for 5.8%, and the USA 18%.<sup>34</sup>



To summarise, as an increasing amount of VRE is added to electricity grids, there will be a growing demand for energy storage, and hydrogen from electrolysis (whether centralised or distributed) is uniquely positioned to provide this service. This growing demand for electrolyzers will lead to an increasing volume of clean hydrogen, which can be used to decarbonise the fuel mix needed for the commercialisation of FCEV. As the fleet grows, it creates a further need for hydrogen and electrolysis is the preferred low-carbon route, thus these two applications complement each other in a synergistic manner.

## 6.4 Production of Synthetic Fuels

Having gone to some length to produce hydrogen by electrolysis without generating any carbon dioxide emissions, what would be the point of combining that hydrogen with carbon again? But some companies are intent on doing just that: reacting hydrogen from electrolysis with carbon dioxide to produce synthetic hydrocarbon fuels. Depending on the process, this is either synthetic natural gas (i.e. methane) or liquid fuels such as methanol.

Hydrogen is produced as a form of energy storage, and these processes are employed as a further conversion step so that the energy carrier is a hydrocarbon instead. Because the original energy input occurs in the form of electricity, the concept is also often referred to as power-to-gas (methane rather than hydrogen in this case) or power-to-liquids.

There are immediately practical and operational advantages to this. In the first instance, methane can be injected and stored in the gas grid in greater quantities than hydrogen with fewer technical limitations

32 Office of Governor Edmund G. Brown Jr., '2013 ZEV Action Plan: A roadmap toward 1.5 million zero-emission vehicles on California roadways by 2025', February 2013: [http://opr.ca.gov/docs/Governor's\\_Office\\_ZEV\\_Action\\_Plan\\_\(02-13\).pdf](http://opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_(02-13).pdf)

33 California Fuel Cell Partnership, 'A California Roadmap: Bringing Hydrogen Vehicles to the Golden State', July 2012: <http://cafcp.org/carsandbuses/caroadmap>

34 LMC Automotive, 'Global Automotive Sales Forecast Q1 2013', April 2013: <http://www.lmc-auto.com/services/automotive-sales-forecasts/>





(at present) and, being indistinguishable from fossil methane, can more easily be burned in conventional equipment. It can also be used as vehicle fuel: CNG models or conversions are already on the market and are catered to by a growing CNG refuelling station network. So no need to wait for the commercial rollout of fuel cell vehicles and a hydrogen distribution infrastructure – the energy carried by the hydrogen can be accessed immediately.



Liquid fuels are even more easily distributed, particularly if blended with gasoline or diesel. Methanol, once used in thousands of fuel-flexible cars in the USA, is attracting renewed attention as a clean-burning and relatively safe transportation fuel, whether used in pure form in specially designed cars or in fuel blends; it can also be converted to diesel or gasoline equivalents.

So, by displacing fossil natural gas in the gas grid and fossil liquid fuels in the transportation sector, these processes may allow countries that have a large potential for renewable electricity generation but no fossil fuel reserves to increase their energy security. Synergistically, by opening a route to a readily-available market for the hydrogen, they would also facilitate the integration of further variable renewable energy in the electricity generation mix.

But the crucial question is where the carbon dioxide comes from. The possible sources are fossil fuels, atmospheric carbon dioxide, and biomass. These are all discussed below, but in our view the use of biomass is the only viable option from an environmental perspective.

Take carbon dioxide captured from the flue gas of a coal-burning power plant, for example. The best thing to do with this CO<sub>2</sub> once captured is to store it, to prevent its release into the atmosphere. Using this CO<sub>2</sub> in synthetic transportation fuels is not, however, a form of storage or sequestration as the CO<sub>2</sub> will be emitted through the car exhausts. Only if no option for secure long-term storage of the CO<sub>2</sub> exists, and the synthetic fuel does in fact displace fossil fuel and not renewables in transportation, there can still be said to be an environmental benefit. This is based on the fact that the hydrogen is carrying the carbon through a second 'energy cycle'. This would not strictly be recycling of the carbon, but rather reuse of the carbon and, theoretically, the production of synthetic fuels may allow you to emit one carbon atom instead of two for the same amount of usable energy.

However, in reality, this ratio will not be achieved due to the energy that is used and lost at various stages in the process: for one, carbon capture usually imposes a significant parasitic load on a power plant.<sup>35,36</sup> In fact the net reduction in CO<sub>2</sub> emissions could be much lower than expected so, ideally, newly-emitted fossil carbon would be used only during the transition to a fully renewable energy system. The hope is that perfecting this technique will lead to an effective way to produce hydrocarbons using atmospheric CO<sub>2</sub>, once an economically feasible way to capture this CO<sub>2</sub> is developed. CO<sub>2</sub> is of course continually extracted from the atmosphere by plants and other natural processes, but to extract 'fossil' CO<sub>2</sub> a net subtraction would be needed, requiring an effective man-made process to remove CO<sub>2</sub> from the air and counteract man-made emissions. The thermodynamics for such a process are not favourable due to the low concentration of CO<sub>2</sub> and it is likely to be highly energy-intensive.

35 Global CCS Institute, 'Post combustion capture progress in power generation', 10th October 2012: <http://www.globalccsinstitute.com/publications/global-status-ccs-2012/online/48276>

36 United States Government Accountability Office, 'Coal Power Plants: Opportunities Exist for DOE to Provide Better Information on the Maturity of Key Technologies to Reduce Carbon Dioxide Emissions', June 2010

The use of bio-carbon, then, is the best choice as it allows for a genuinely climate-neutral solution. One source is biogas produced in anaerobic digesters, only two-thirds of which is typically methane. The remainder is carbon dioxide and does not contribute to the energy content of the gas. Converting this CO<sub>2</sub> to methane using hydrogen from electrolysis upgrades the biogas in a completely renewable way.

Gasified biomass presents a similar opportunity. The desired product of gasification is syngas, a mixture of carbon monoxide (CO) and hydrogen that can be used as a feedstock for further processing into fuel and commodities. However, gasification of biomass also produces carbon dioxide in significant quantities, typically in concentrations upwards of 10%. Hydrogen can be used to convert this valueless CO<sub>2</sub> to methane or to CO, both of which are usable. The process thus maximises the benefit offered by two sources of clean energy: biomass and renewable electricity. As fossil fuel consumption dwindles in a country and energy efficiency becomes of growing importance, this route will offer the greatest potential for energy independence and emissions reduction.

## Examples

### Methanation $\text{CO}_2 + 4 \text{H}_2 \rightarrow \text{CH}_4 + 2 \text{H}_2\text{O}$

In September 2012, automaker Audi began construction of its e-gas plant on a site owned by energy utility EWE in Werlte, Germany. This plant is the first of its kind in the world, and in 2013 it will begin producing synthetic methane from carbon dioxide and hydrogen. The CO<sub>2</sub> comes from a nearby EWE biogas plant and the hydrogen is generated on-site by three electrolyzers with a total power rating of 6 MW. The plant's annual production of methane ('e-gas') will be about 1,000 metric tonnes and it will recycle around 2,800 tonnes of CO<sub>2</sub> per year. Waste heat from the processes will also be captured and used.

Audi says this quantity of e-gas is enough for 1,500 new A3 Sportback TCNG vehicles travelling 15,000 km annually (TCNG stands for 'turbocharged compressed natural gas'). This new model will be available at dealerships in late 2013 and Audi plans to launch a second TCNG model, based on the A4, in 2015. The e-gas will be fed into the existing gas grid and a certification procedure will verify that the amount of CNG purchased by Audi drivers at the pump is matched by e-gas injection into the grid.

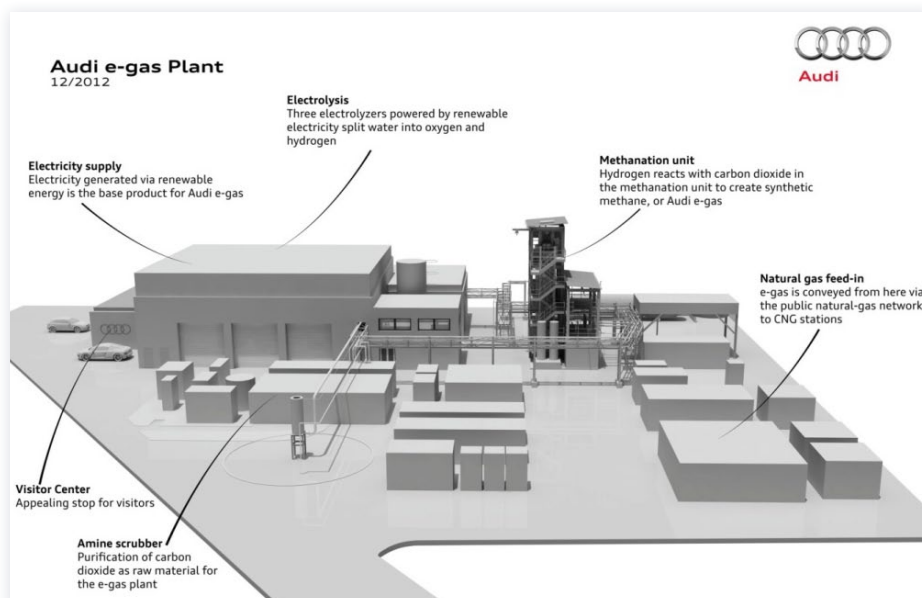


Figure 6: Configuration of Audi's e-gas plant (Source: Audi)

### Syngas production $\text{CO}_2 + \text{H}_2 \rightarrow \text{CO} + \text{H}_2\text{O}$

Hydrogen can be employed in the reverse water–gas shift reaction to convert  $\text{CO}_2$  to carbon monoxide. Along with  $\text{H}_2$ , CO is a component of syngas, a valuable feedstock for the production of liquid fuels and other commodities.



A 100 kW Siemens PEM water electrolyser is to be demonstrated at RWE's Coal Innovation Centre in Niederaussem, Germany (left), as part of a power-to-gas demonstration project. The CO2RRECT project, which is funded by the German Federal Ministry of Education and Research, brings together utility RWE, Siemens, chemicals firm Bayer, and a number of universities and research institutes. Its aim is to develop a process for converting  $\text{CO}_2$  from the flue gases of power stations into syngas using hydrogen.

The Niederaussem site is a testbed based around a coal-fired power station. The Siemens electrolyser will generate hydrogen using excess wind power. The electrolytic hydrogen and the power station flue gases will be studied at the site's catalysis facility with the goal of catalytically producing syngas. Other end-use options for the hydrogen, such as sale to the heating market, will also be investigated. The electrolyser will run initially from January to October 2013.

### Methanol production

Biofuel producer BioMCN has modified a traditional methanol plant in the Netherlands to produce bio-methanol. The feedstock for this process is for the most part crude glycerine, formed as a residue of biodiesel production; however, any form of biomass that can be converted to syngas is usable. BioMCN is also investigating the use of biogas from vegetable residues as an alternative feedstock to natural gas. Renewable fuel is not necessarily the same as sustainable fuel and, recognising this, the company says it only uses feedstocks 'derived from organic waste materials and crops other than those used for food consumption'. According to BioMCN's Eelco Dekker, the company's product emits 78% less carbon dioxide than conventional methanol on a life-cycle basis.

The European Commission has recently awarded €199 million in co-funding to a consortium that will construct a large-scale biomass refinery in the Netherlands. The Woodspirit refinery will gasify forestry and wood processing residue to produce syngas that is then converted to biomethanol.

With the use of appropriate catalysts and process conditions, methanol can also be produced directly from  $\text{CO}_2$  and  $\text{H}_2$  rather than *via* syngas. Icelandic-American company Carbon Recycling International (CRI) has patented a process for the direct production of liquid fuel from carbon dioxide and hydrogen at relatively low temperatures and pressures, what it calls the Emissions-to-Liquid (ETL) process.

In late 2011 it commissioned its first commercial facility, the George Olah Renewable Methanol plant at the Svartsengi geothermal power station in Iceland. The plant produces around 2 million litres of methanol annually, with plans to expand the plant to produce more than 5 million litres annually – equivalent to 2.5% of the Icelandic gasoline market. The  $\text{CO}_2$  is captured from the geothermal power station which also supplies electricity to produce the hydrogen. At full capacity, 4,500 tonnes of  $\text{CO}_2$  are used annually. CRI says that the methanol produced at the George Olah plant has a greenhouse gas emissions burden about 75% less than standard fuel. With the experience and validation gained at this plant, CRI has plans to build further commercial plants in Iceland and to export the concept to the rest of Europe. The plant has now received the first PLUS certificate for renewable fuel of non-biological origin issued by ISCC (International Sustainability and Carbon Certification).



### Liquid fuels production

Air Fuel Synthesis has a method for producing petrol, *via* methanol, using hydrogen, CO<sub>2</sub> and electricity. The company's ultimate intention is to harvest CO<sub>2</sub> directly from the air, making it a fully renewable process, but initial implementation will use CO<sub>2</sub> captured from point-source emitters like power stations. This approach has value in a number of areas. Aeroplanes are the source of a large proportion of carbon emissions and are not currently candidates for alternative drivetrains, so a synthetic liquid fuel using hydrogen from electrolysis and captured CO<sub>2</sub> can be a useful way to reduce emissions from air traffic. This is a high value application that could also offset, to some degree, the cost of scrubbing CO<sub>2</sub> from the air, which is possible but expensive in energy terms. Air Fuel Synthesis is also looking at producing racing car fuel.

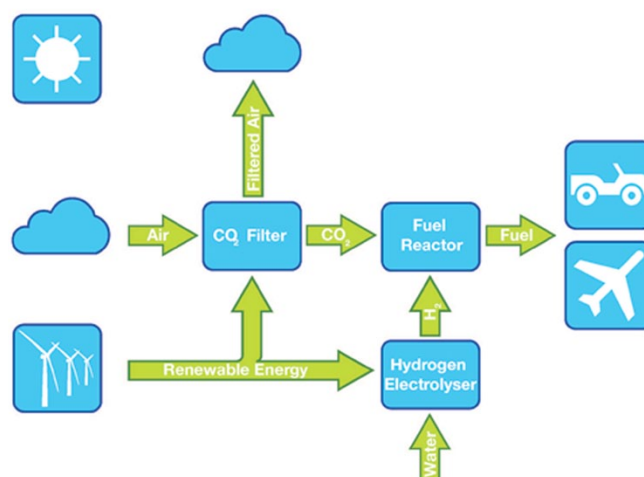


Figure 7: The Air Fuel Synthesis Method (Source: Air Fuel Synthesis)

## 6.5 Industrial Uses of Hydrogen

Hydrogen is used extensively in a number of industrial operations but currently around 95% of this hydrogen is produced by reforming fossil fuels, releasing CO<sub>2</sub>, because this is generally the most cost-effective option. However, if hydrogen were being produced in bulk using excess VRE, it could compete with 'fossil' hydrogen in terms of cost and availability. The point is that hydrogen is already a valued commodity that can find an established market and existing distribution infrastructure outside the 'energy silos' of electricity, transportation and heating, particularly as there is a growing awareness of sustainability in industry.

The largest consumers of hydrogen for industrial processes are the petroleum and chemical industries; two notable processes use hydrogen for the upgrading of fossil fuels and for ammonia synthesis. In these applications hydrogen is generally produced close to where it is required; however, over time, networks of pipelines have been built to transport the gas. As an example, Air Products has more than 950 km of pipeline in the southern US States of Texas and Louisiana connecting 22 hydrogen plants and with a capacity of 1.3 million Nm<sup>3</sup>/hr. In Europe, more than 1,500 km of hydrogen pipelines are in operation by the major global gas manufacturers.



The production of hydrogen from fossil fuel for manufacturing ammonia, used in vast quantities as fertiliser, is a significant contributor to global man-made CO<sub>2</sub> emissions (some estimates put it at almost 1%). Electrolysis has been used in this industry in the past, as mentioned in Section 3.1, but currently tends to lose out to fossil-derived hydrogen on cost. If hydrogen from electrolysis once again makes significant inroads into just this one application, displacing fossil fuel, it could make a measurable contribution towards a reduction in emissions.

Through the medium of hydrogen produced by renewably-powered electrolysis, there could be a time when renewable energy contributes to growing our food and to fuelling our cars – even before the widespread adoption of fuel cell electric vehicles.

## 7. Conclusions



In this report we have extolled the virtues of electrolyzers when linked to renewable energy systems and shown the many benefits they can provide. We have also discussed the existing and future markets for the hydrogen they produce. So is this a universal solution and if so why are electrolyzers not being installed in large numbers to solve the world's problems?

The market drivers supporting electrolyser installation are in many ways still unclear. These will differ from case to case and there are many questions to be answered to define them. Who will own and operate the assets on the ground? Should policies be written mandating renewable energy storage? Is there a push from grid operators keen to manage their operations in a stable and sustainable way, or is there a pull coming from customers wanting clean energy and hydrogen? These and other questions are still being debated, and while in theory the benefits of using electrolyzers in each of the sectors covered in this report are known, in practice people want proof. Installations of AEC for use in the energy sector are increasing and PEMEC installations will follow later in 2013: these will generate much needed performance data.

This is not to say electrolysis will take over the energy storage world once the benefits are recognised. Technology selection will depend heavily upon location, size of installation and duty cycles, among many other factors, and storage methods such as batteries and CAES will all find their place. But our intention in this report has been to show that there are unique advantages to using electrolysis that must merit its consideration as a powerful means to manage the introduction of renewable energy.

This applies to all energy use, not just electricity, and the discussion of electrolysis is of course closely bound up with the proposal to make wider use of hydrogen. The manifold benefits of hydrogen make it one of the most attractive energy carriers, with its ability to connect the energy silos of electricity, heat and transportation in a way no other energy storage solution can. Hydrogen production from electrolysis has such vast potential to help us reduce CO<sub>2</sub> emissions and use energy more efficiently that it must be considered as a holistic solution, with the modularity of the technology enabling it to work equally well on a small, distributed scale as in a multi-megawatt, centralised fashion.

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## GLOSSARY & ACRONYMS

AEC – Alkaline Electrolytic Cell.

BESS – Battery Energy Storage System.

BEV – Battery Electric Vehicle.

BTS – Base Transceiver Stations.

CAES – Compressed Air Energy Storage.

CCGT – Combined Cycle Gas Turbine.

CEP – Clean Energy Partnership (Germany).

CH<sub>3</sub>OH – Methanol.

CH<sub>4</sub> – Methane.

CHP – Combined Heat and Power.

CNG – Compressed Natural Gas.

CO – Carbon monoxide.

CO<sub>2</sub> – Carbon dioxide.

CRI – Carbon Recycling International (company).

DG – Distributed Generation.

DOE – Department of Energy (USA).

DVGW – Deutscher Verein des Gas- und Wasserfaches; German Technical and Scientific Association for Gas and Water.

EHS – Electrochemical Hydrogen Separation.

ETL – Emissions-to-Liquid.

EU – European Union.

FCEV – Fuel Cell Electric Vehicle.

GW – Gigawatt.

H-gas – High-calorific gas.

H<sub>2</sub> – Hydrogen.

H<sub>2</sub>O – Water.

HRS – Hydrogen Refuelling Station.

HySUT – Research Association of Hydrogen Supply/Utilization Technology (Japan).

IEA – International Energy Agency.

KOH – Potassium hydroxide.

kW – Kilowatt.

L-gas – Low-calorific gas.

MW – Megawatt.

MYRTE – Mission hYdrogène Renouvelable pour l'inTégration au réseau Electrique; Renewable Hydrogen Mission for Integration into the Electric Grid.

NaOH – Sodium hydroxide.

NASA – National Aeronautics and Space Administration (USA).

NIP – National Hydrogen and Fuel Cell Technology Innovation Programme (Germany).

Nm<sup>3</sup>/h – Normal metres cubed per hour.

NRE – New and Renewable Energy.

NREL – National Renewable Energy Laboratory (USA).

O<sub>2</sub> – Oxygen.

PBI – Polybenzimidazole.

PE – Polyethylene.

PEM – Proton Exchange Membrane.

PEMEC – Proton Exchange Membrane Electrolytic Cell.

PHEV – Plug-in Hybrid Electric Vehicle.

PSA – Pressure Swing Adsorption.

PV – Photovoltaic.

RPS – Renewable Portfolio Standard (South Korea).

SMR – Steam Methane Reforming.

SOEC – Solid Oxide Electrolytic Cell.

TCNG – Turbocharged Compressed Natural Gas (Audi marketing).

TSB – Technology Strategy Board (UK).

TW – Terawatt.

V – Volt.

VRE – Variable Renewable Energy.

W – Watt.

Wh – Watt-hour.

Wobbe index – A measure of the energy content of gas based on its calorific value and specific gravity.

Wp – Watt-peak.

ZEV – Zero-Emission Vehicle.





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