Decarbonizing power generation through the use of hydrogen as a gas turbine fuel

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Abstract

The power generation industry has a major role to play in reducing global greenhouse gas emissions, and carbon dioxide (CO_2) in particular. There are two ways to reduce CO_2 emissions from power generation: improved conversion efficiency of fuel into electrical energy, and switching to lower carbon content fuels.

Gas turbine generator sets, whether in open cycle, combined cycle or cogeneration configuration, offer some of the highest efficiencies possible across a wide range of power outputs. With natural gas, the fossil fuel with the lowest carbon content, as the primary fuel, they produce among the lowest CO_2 emissions per kWh generated. It is possible though to decarbonize power generation further by using the fuel flexibility of the gas turbine to fully or partially displace natural gas used with hydrogen. As hydrogen is a zero carbon fuel, it offers the opportunity for gas turbines to produce zero carbon electricity. As an energy carrier, hydrogen is an ideal candidate for long-term or seasonal storage of renewable energy, while the gas turbine is an enabler for a zero carbon power generation economy.

Hydrogen, while the most abundant element in the universe, does not exist in its elemental state in nature, and producing hydrogen is an energy-intensive process. This paper looks at the different methods by which hydrogen can be produced, the impact on CO_2 emissions from power generation by using pure hydrogen or hydrogen/natural gas blends, and how the economics of power generation using hydrogen compare with today's state of the art technologies and carbon capture. This paper also addresses the issues surrounding the combustion of hydrogen in gas turbines, historical experience of gas turbines operating on high hydrogen fuels, and examines future developments to optimize combustion emissions.

Nomenclature

AM	Additive Manufacturing
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
COG	Coke Oven Gas
DLE	Dry Low Emissions
EU	European Union
g	gram (mass)
H_2	Hydrogen
IEA	International Energy Agency
Kg	Kilogram (mass)
kWh	kiloWatt hour
lb	Pound (mass)
mg/Nm^3	Milligrams per Normal Cubic Meter
mmBtu	million British thermal units
MW_{th}	MegaWatt thermal
MWh	MegaWatt hour
NG	Natural Gas
NO_x	Oxides of Nitrogen
OEM	Original Equipment Manufacturer
ppm	Parts per million
RES	Renewable Energy Systems
SMR	Steam Methane Reforming
UK	United Kingdom

Introduction

Energy production is a major contributor to global greenhouse gas emissions. According to the IEA, total global CO_2 emissions in 2016 were 32.31GT, an increase of 40% over 2000 data, and CO_2 emissions in 2017 are estimated to have risen 1.5% over 2016 figures [1].

Electricity and heat production in 2016 was the single CO_2 largest contributor to man-made global CO_2 emissions,

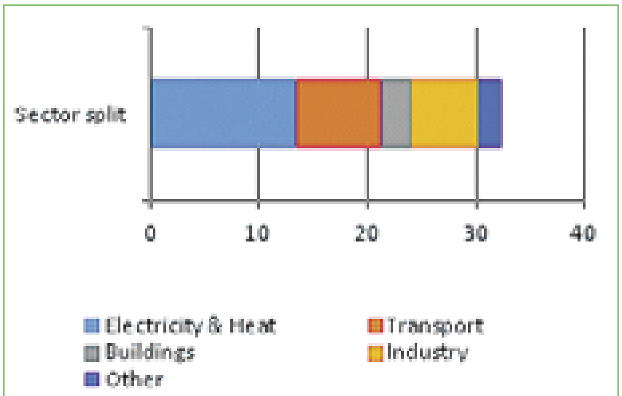

Figure 1: Split of global CO_2 emissions in 2016 by sector [1]

CO_2 accounting for 42% of total CO_2 emissions. Figure 1 shows the breakdown of global CO_2 emissions by sector [1]. Despite forecast global growth in electricity demand, the power generation sector has been identified as a key target sector for CO_2 reduction, with some countries aiming for deep de-carbonization, an 80% reduction or more by 2050 compared to current levels.

The power generation industry now faces the challenge of reducing its carbon footprint, while maintaining security of supply and ensuring electricity remains affordable so as not to adversely impact economic growth or quality of life.

The de-carbonization challenge

There are four ways to reduce the CO_2 emissions from power generation: using renewable energy sources, such as wind and solar; increasing the efficiency of power generation; switching to lower carbon fuels; and carbon capture.

Carbon capture, while offering the greatest CO_2 reduction potential at the source of emissions, is the most problematic of the three options. As well as increasing the CAPEX of the power plant, it increases the operational costs and reduces the efficiency of conversion of energy in the fuel into electricity, thus creating the paradox of requiring more fuel to produce less electricity than an unabated power plant of the same configuration. Once captured, the CO_2 then has to be disposed of in a safe and environmentally friendly manner, which usually incurs additional costs, although if used in enhanced oil recovery, at least some additional revenues can be generated as opposed to storage only which is a pure cost adder.

Increasing amounts of electricity are being generated from renewable sources, primarily wind and solar. However, these sources are intermittent, leading to phenomena like the 'California Duck Curve' (Figure 2), where during daylight hours there is over-generation potential, while in the evening rapid ramp up from non-solar sources is required. The available renewable resources are also variable depending on geographic location, which can limit the contribution renewables can make to decarbonization. To ensure security of electricity

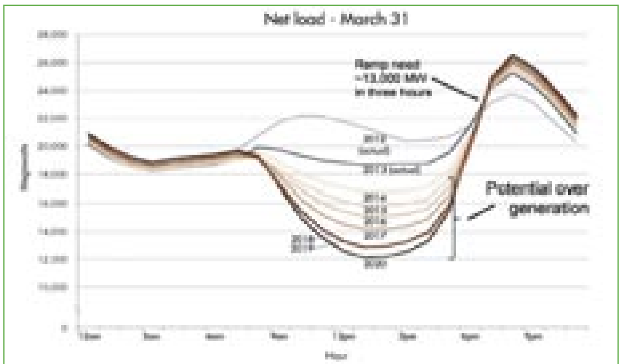

Figure 2: The California Duck Curve

Table 1: CO_2 emissions by fuel type (source US EIA) [2]

Fuel Type	CO_2 Emissions (lb/mmBtu fuel combusted)
Coal (Anthracite)	228.6
Lignite	215.4
Sub-bituminous coal	214.3
Bituminous coal	205.7
Diesel and heating oil	161.3
Propane	139.0
Natural gas	117.0

supplies, both energy storage and a back-up source of power generation are likely to be necessary.

Although CO_2 emissions from power generation have risen since 2000, the rate of increase has slowed due to switching to lower carbon fuels. In many countries old coal-fired or oil-fired power plant have been replaced by natural gas-fired combined cycle gas turbine power plant (CCGT). Assuming the efficiency of electricity production is the same, the lower carbon content of natural gas creates an immediate impact on CO_2 emissions, being able to generate the same amount of power for around half the CO_2 emissions as shown in Table 1.

Improving the efficiency of power generation, especially when combined with fuel switching, also reduces the CO_2 emissions.

Older and smaller sub-critical coal power stations typically have power generation efficiencies in the 32% to 35% range. Improvements in material technology have allowed increases in steam temperatures and pressures to be obtained, so that today's super critical coal-fired power stations can achieve power generation efficiencies of around 42% and ultra super critical units efficiencies in the 45% to 48% range. Replacing an old sub-critical bituminous coal power plant with a state of the art ultra super critical unit will reduce CO_2 emissions on a lb/MWh electrical basis by 33%. Similarly, technology improvements on gas turbines and combined cycle plants have enabled CCGT efficiencies to increase from 50% in the early 1990s to 63% today, reducing CO_2 emissions by 20% on a lb/MWh basis. The target for gas turbine OEMs is 65% combined cycle efficiency by the early 2020s, which will lead to an additional 3% reduction in CO_2 emissions.

However, further efficiency improvements and switching to reduced carbon fuels alone will not achieve the deep de-carbonization targets desired. One potential route to achieve the de-carbonization targets is to fully or partially displace fossil fuels with a zero carbon fuel such as hydrogen (H_2). With zero CO_2 emissions when combusted, replacing natural gas with hydrogen or blending hydrogen into natural gas can have a much more significant impact on CO_2 reduction than efficiency improvements alone. Blending hydrogen into natural gas

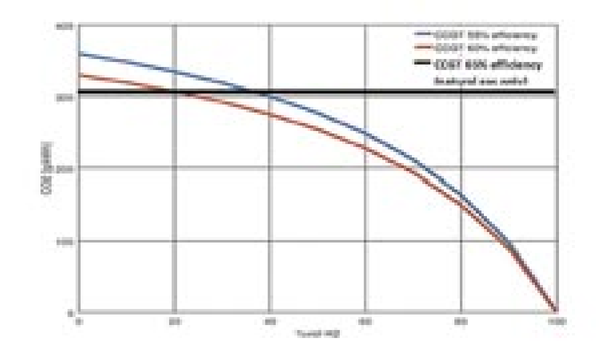

Figure 3: CO_2 emissions from CCGT on a g/kWh basis for increasing hydrogen volumes blended into natural gas (source: Siemens)

also has the benefit that existing CCGT assets could potentially be modified to run on the fuel blend, reducing the overall investments required to achieve de-carbonization. As shown in Figure 3, a 55% efficient CCGT operating on a 60% natural gas/40% H_2 fuel gas blend (volume basis) will emit less CO_2 per MWh of electricity generated than a 65% efficient CCGT operating on 100% natural gas.

Hydrogen as a gas turbine fuel

Combustion challenges

The ability of a gas turbine combustor to burn a fuel depends on a number of factors associated with the fuel composition, but the key factors are [3]:

- Wobbe Index
- Flame speed
- Flashback potential
- Dew point

In the case of hydrogen or hydrogen/natural gas blends, the concerns are dominated by flame speed and flashback potential. Hydrogen has a significantly higher flame speed than most other gases commonly found in fuel gas streams, as shown in Table 2.

Table 2: Comparison of flame speeds of common constituents in fuel gases

Gas	Chemical Formula	Maximym Flame Speed (cm/s)
Methane	CH_4	37.3
Ethane	C_2H_6	44.2
Propane	C_3H_8	42.7
Carbon Monoxide	CO	42.9
Hydrogen	H_2	291.2

The higher flame speed leads to the possibility of flashback, where the flame front moves closer to the injector leading to the possibility of combustion occurring at the burner tip or within the fuel injector causing rapid and catastrophic component damage [4]. The burner design and fuel delivery systems therefore need to be modified to ensure the flame is correctly positioned within the combustion chamber.

Hydrogen also has a much wider flammable region than methane, the main constituent in natural gas. As hydrogen will combust over a much wider range of fuel/air ratios, combustion may appear in areas within the combustor not normally considered when the gas turbine is operating on natural gas. Thus the combination of increased flame speed and wider flammable region change the flame shape, as shown in Figure 4 [4].

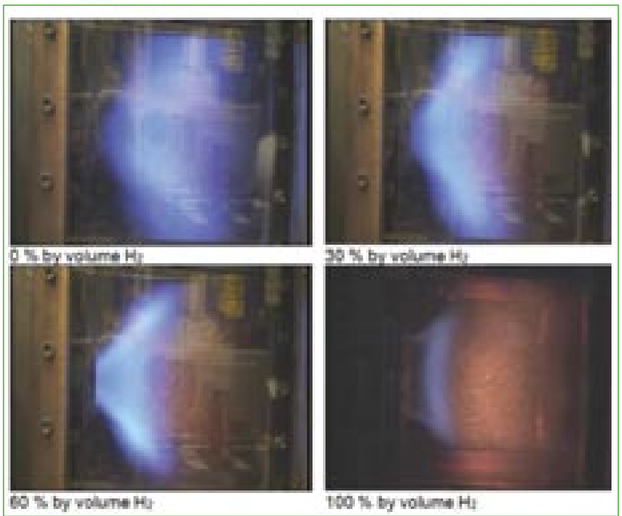

Figure 4: Variation in flame shape with increasing hydrogen volumes blended into natural gas [4]

While combustion is the major challenge, the need for package modifications to the fuel systems and safety systems to ensure safe and reliable operation cannot be overlooked. It should be noted though that using fuel gases with high hydrogen content is not a new application for gas turbines: millions of operating hours experience have been gained on units of all sizes on hydrogen-containing fuels such as Coke Oven Gas (COG), syngas from gasification processes and offgases from refineries and petrochemical processes over the past 50 years. Therefore the system design modifications and material selections to avoid leakage or hydrogen embrittlement are well understood.

NO_x emissions

Hydrogen burns with a hotter flame than natural gas, and so operating a gas turbine on hydrogen-rich fuels generates higher levels of thermal NO_x than on natural gas fuel. This creates a challenge to meet legislative requirements, even where legislators recognize the issue and higher NO_x levels are potentially permitted,

Table 3: Comparison of maximum permitted NO_x emissions within the EU [5][6]

NO_x Emission Limit Values (mg/Nm^3) for new engines and gas turbines (applicable for 70 – 100% operating load)		
	Natural Gas	Gaseous Fuels other than natural gas
1 to 50MW$_{th}$ fuel input	50	120
>50MW$_{th}$ fuel input	50	75

depending on the location of the installation. Table 3 shows the comparison of maximum NO_x levels permitted within the European Union (EU) for gas turbines operating on natural gas and gaseous fuels other than natural gas.

The vast majority of operational experience to date on gas turbines using high hydrogen content fuels has been in conventional diffusion flame combustors. Even with in theory higher permissible NO_x emissions, it is unlikely that these values can be achieved even with 'wet' emission control technology such as steam or water injection. Figure 5 shows the comparison of calculated NO_x emissions of a 5MW gas turbine with a diffusion flame combustor for operation on 100% natural gas or 100% hydrogen. The maximum permitted NO_x levels stated in Table 3 cannot be met in either fuel case when a diffusion flame combustion system is used. Therefore it is necessary to investigate the acceptability of high hydrogen content fuels in Dry Low Emissions (DLE) combustion systems.

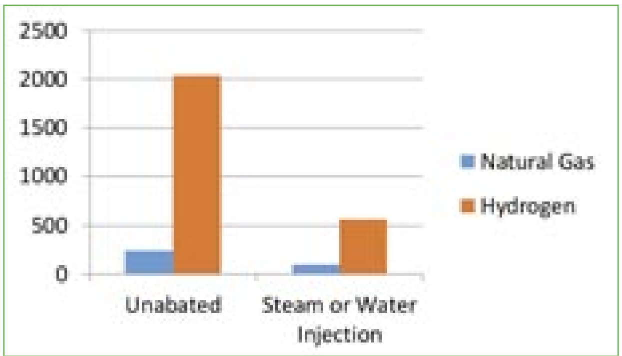

Figure 5: Comparison of calculated NO_x emissions for a 5MW class gas turbine for natural gas and 100% hydrogen fuel

Combusting gaseous fuels containing hydrogen in DLE combustion systems has not proven straightforward, although some injector designs have proven to have more flexibility than others. Some OEMs have with just minor modifications achieved levels up to 60% hydrogen by volume and sub-25ppm NO_x with no noticeable or acceptable performance derates, whilst others struggle to achieve a 20% hydrogen content by volume which many observers see as being the minimum level as the hydrogen economy develops.

Most modern gas turbines base their DLE combustion systems on the lean premix concept, where, unlike the diffusion flame combustors, fuel and air are mixed prior to injection into the combustion zone. While pre-mixed combustion reduces the flame temperature compared to diffusion combustion, the stable combustion range is narrower and there is a higher tendency for flashback to occur. Development work undertaken by Mitsubishi Hitachi Power Systems (MHPS) on their standard lean premix injector identified that the swirl used to pre-mix the air and fuel created a low pressure, low flow velocity

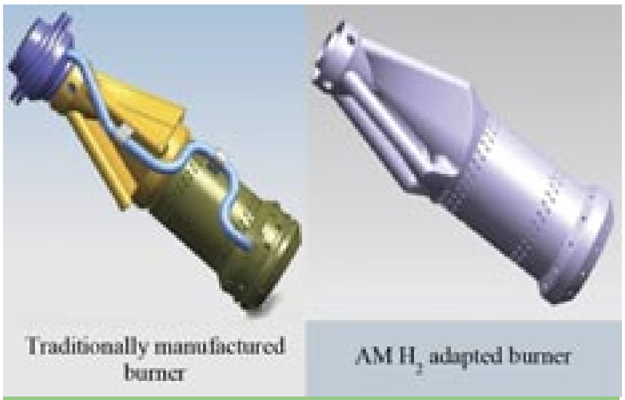

Figure 6: Comparison of a traditionally manufactured burner machined from 13 parts with 18 welds with a single piece Additive Manufactured burner design [4]

region at the center of the swirl, leading to a very high risk of flashback on hydrogen contents in natural gas as low as 10% by volume. By modifying the injector design to increase the flow velocity at the center of the swirl, the risk of flashback occurrence was reduced and the permissible hydrogen content increased to 30% by volume [8].

Other OEMs have successfully tested modified natural gas DLE burner designs and permitted commercial release on levels up to 60% hydrogen by volume blended in natural gas. Test and development work undertaken by Siemens [4] on up to 100% hydrogen has identified three main combustion regimes for hydrogen/natural gas blends:

- Less than 60% hydrogen by volume, where a slight increase in flame velocity is seen and the chemistry is hydrocarbon dominated
- An intermediate regime from 60% to 90% hydrogen by volume
- A hydrogen-dominated chemistry regime for over 90% hydrogen content by volume, where a dramatic increase in laminar burning velocity occurs.

The shape of the fuel injector can also influence the possibility of flashback occurring, with sharp edges in particular exacerbating the possibility of flashback. Additive manufacturing has been used by Siemens [4] to create rapid prototypes to allow testing of different burner designs, and enabled revised burner front profiles to be printed to a smoothness and precision previously unachievable in traditionally manufactured burners.

Optimized combustion and gas turbine performance are unlikely to be achieved using a modified natural gas DLE combustion system in this hydrogen-dominated regime. However, developments based on designs with multiple fuel injection points, such as multi-cluster type concepts, which create multiple small flames show promise in attaining the goal of burning 100% hydrogen as a fuel with low NO_x emissions and without excessive gas turbine performance derate.

Sources of hydrogen

Hydrogen (H_2) does not occur naturally in its elemental form on earth. It must be produced from substances that contain hydrogen, which requires considerable energy to achieve. Broadly speaking, production of hydrogen can be classified into: brown hydrogen (ie hydrogen production generating CO_2 emissions), blue hydrogen (eg CO_2 generating hydrogen production combined with carbon capturing) and green hydrogen (eg electrolysis from surplus renewable energies) [7].

Brown hydrogen: Some industrial processes, such as propane dehydrogenation, refining and ethane cracking, produce offgases that contain some hydrogen which can be separated from the other constituents, but the majority of hydrogen is produced by thermochemical processes. Most hydrogen produced in Europe comes from steam methane reforming (SMR) of natural gas: while this can produce H_2 at a cost as low as €2/kg between 8 and 10kg of CO_2 are released for every 1kg of H_2 according to a study by Shell in 2017 [9]. This offsets a significant portion of the CO_2 savings made by introducing hydrogen into the fuel mix for power generation.

Blue hydrogen: As well as SMR, hydrogen can also be produced through the gasification of biomass, or coal when steam or water is introduced into the process. Gasification produces a 'syngas' containing predominantly hydrogen and carbon monoxide (CO), so processes can be introduced to produce a pure hydrogen stream for use as a fuel. If combined with carbon capture storage, the produced hydrogen can be considered as blue. This approach is part of the Equinor climate roadmap.

Green hydrogen: Electrolysis of water is another option for hydrogen production. If the electricity required for this is taken from the existing grid infrastructure, then CO_2 is still emitted to produce the hydrogen. The 2017 Shell study indicates that using the current EU energy mix, CO_2 emissions are between 220 and 230g per MJ of H_2 produced. If, however, the electricity is obtained from renewable/carbon free sources, the produced hydrogen can be considered as virtually CO_2 free and thus green. There are several different types of electrolysis system available: Alkaline Electrolysis (AE) systems have been around for around 100 years, while Proton Exchange Membrane (PEM) and Anion Exchange Membrane (AEM) systems are also available. Solid Oxide Electrolysis (SOE) is currently in the experimental stage.

Future applications for hydrogen-fueled gas turbines

As Governments around the world seek to meet their CO_2 reduction goals, it is clear that renewables, especially wind and solar, will play an increasing role in power generation. However, as these resources are not evenly distributed around the world, the proportion of power generated from renewable energy systems (RES) will vary. According to material presented by the reciprocating engine manufacturer Wärtsilä [10] once the grid penetration of RES reaches 20%, the need for traditional 'inflexible' baseload thermal power generation reduces and to ensure grid stability needs to be replaced by more flexible thermal power generation, able to operate efficiently over a wide load range. Once RES penetration reaches 80%, there is no role for the traditional baseload plant and thermal power generation needs to highly flexible in order to maintain overall grid system stability.

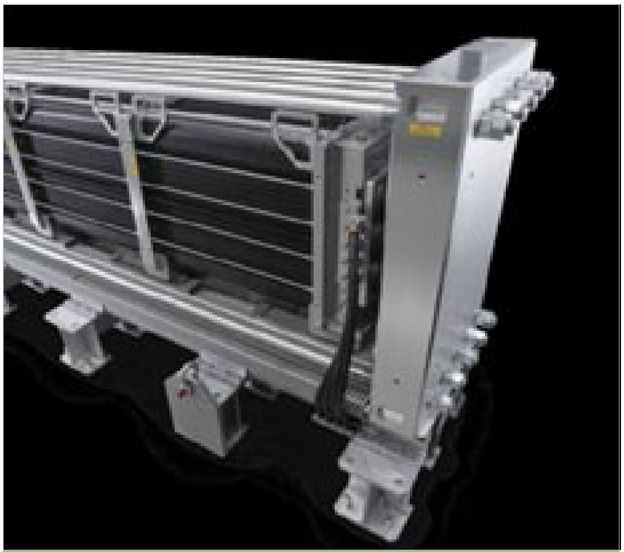

Figure 7: Siemens Silyzer Proton Exchange Membrane (PEM) Electrolyzer

Heat production is also a major contributor to global CO_2 emissions, and RES do not fully address this issue. Electrification of heat production is unlikely to be widely adopted due to the high investment costs required to generate the additional electricity that would be required, and in the necessary expansion in electricity transmission and distribution systems – the United Kingdom for example currently uses five times as much fossil fuel energy for heat production as it does for electricity generation.

Therefore three different potential routes are emerging for the deployment of gas turbines with high hydrogen fuel capability.

Blending hydrogen into the natural gas network

The simplest and most cost effective way to reduce CO_2 emissions is to reduce the carbon content of natural gas by admixing hydrogen in small amounts. This would impact every piece of equipment connected to the natural gas network, leading to the decarbonization of heat production as well as electricity generation for both existing assets and new units. However, the percentage of hydrogen that can be blended with natural gas must be at a level which does not cause negative impacts on the tens of millions of domestic and industrial appliances connected to the network, nor impact the safe operation of the natural gas network. Currently permissible levels of hydrogen in natural gas are very low, ranging from less than 1% by volume to a maximum of 5% by volume.

Many studies on this approach have been undertaken, and some demonstration schemes proposed. Under proposals for two such demonstration projects in the United Kingdom – HyDeploy and HyNet – hydrogen concentrations of up to 20% by volume will be injected into 'closed loop' low pressure gas networks to prove the ability of domestic and industrial equipment to operate safely on natural gas/hydrogen blends. Most gas turbines in the chosen regions though will be unaffected as they are connected to higher pressure gas systems.

While the impact on CO_2 emission reduction is limited by adopting this approach, the relatively low quantity of hydrogen required will only have a minor impact on the cost of fuel, while cost of modifications to gas-consuming equipment, including gas turbines, is minimized.

Dedicated high hydrogen flexible baseload power plants

While blending small quantities of hydrogen with natural gas helps decarbonize energy usage for millions of small-scale gas consumers economically, its global CO_2 reduction benefit is limited. Significantly greater CO_2 reductions can be achieved by targeting large-scale energy users and creating dedicated hydrogen production facilities or a centralized hydrogen production facility feeding into a local dedicated pipeline network, so that these energy consumers can operate on as close to 100% hydrogen fuel as possible.

This concept allows low carbon electricity generation or cogeneration by using hydrogen as a gas turbine fuel. For continuous operation, the source of hydrogen is most likely to be chemical, such as SMR or gasification, so carbon capture will be required at the hydrogen production facility to achieve the overall reduction in carbon footprint desired. Therefore there needs to be a solution in place for transportation and storage of the CO_2 captured, although there is a small market for CO_2 so in some instances it is possible to create an additional revenue stream.

In this scenario baseload or flexible baseload power generation to be operated to complement low penetrations of RES on a network, allowing power generation to be carbon neutral even when renewables are unable to provide the majority of energy required. The high energy efficiencies of gas turbine-based CHP plants and CCGTs reduce the quantities of hydrogen that needs to be produced, and hence the volumes of CO_2 that need to be disposed of. Renewable power generation technology could even be incorporated into the power plant, to create hybrid solutions such as Integrated Solar Combined Cycle (ISCC).

High hydrogen peaking power plants

Once the penetration of RES onto the electricity grid reaches high levels, the role for supporting power generation assets switches from the flexible baseload scenario to a 'peaking' role, requiring daily or multiple daily start/stop cycles and low annual operating hours – a role becoming increasingly common for grid support today, but replacing natural gas peaking plant with hydrogen-fueled peaking plant.

The Bayonne Energy Center in New Jersey, USA, is an example of a natural gas fired peaking plant, using multiple aero-derivative gas turbines to help provide grid stability for New York City [11]. The gas turbines here can experience five or six start cycles per day, and operate for as little as thirty minutes at a time (Figure 8). In the future, this, and other plant like it, could be converted for hydrogen operation to eliminate the CO_2 emissions from peaking and grid support power plants.

With an uncertain operating gas turbine regime, a fast response requirement and few annual operating hours, producing H_2 by chemical means on or close to site is unlikely to be economic. For peaking plant the optimal solution is likely to be to transport and store H_2 on site. The transportation of hydrogen over long distances is

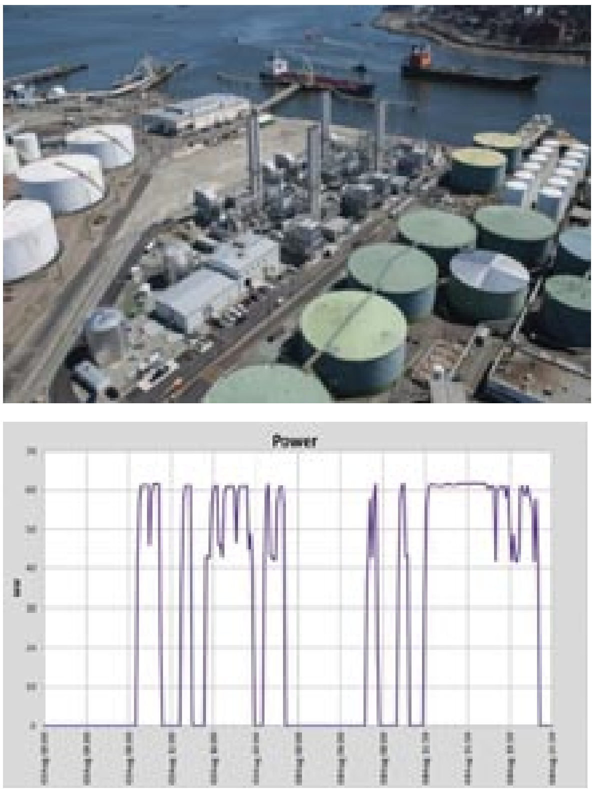

Figure 8: Bayonne Energy Centre, New Jersey and a typical daily operating profile for one of the aero-derivative gas turbines installed there [11]

expensive, and so alternatives are required. Using ammonia as a hydrogen transport vector appears to be an economically feasible option, and then cracking the ammonia on-site to produce the hydrogen required for gas turbine operation. Potentially ammonia could itself be considered as the gas turbine fuel, but ammonia combustion brings its own challenges with regards to flame speed. The toxicity of ammonia also needs to be considered, especially with regards to stack emissions from unburned fuel.

In many places zero carbon renewable energy generation (wind or solar) is constrained at times of maximum potential generation by transmission system capacity limits. By co-locating the peaking power plant with the wind farm, the surplus electricity generated by wind farms or solar fields in this instance could be used to power electrolyzers, and the hydrogen produced stored for later usage for power generation when required. Several such schemes have been proposed, and a 15MW project was recently announced by Hydrogen Utility (H_2U) at Port Lincoln in South Australia comprising a 30MW electrolyzer and a renewable ammonia plant, along with a 10MW hydrogen gas turbine and a 5MW fuel cell for reelectrification of the stored energy [12].

The economic challenge

While using hydrogen as a fuel source has undoubted environmental benefits from a carbon perspective, the speed of development of a hydrogen economy will depend on economic factors: can energy from hydrogen be produced at a similar cost to that from natural gas and coal.
A study for the European Union by SINTEF looked at current cost of hydrogen production from SMR and

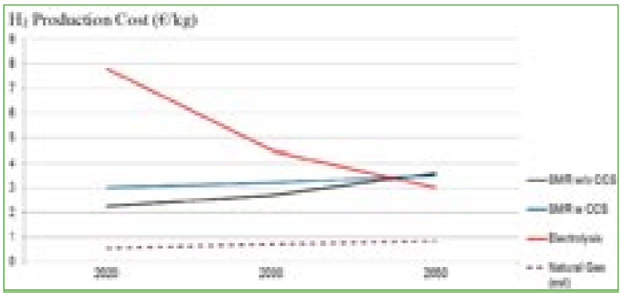

Figure 9: Estimated hydrogen production cost trend

electrolysis, and projected forward costs while taking into account the expected European trend of rising natural gas prices, falling electricity prices and rising carbon taxes [13]. On a €/kg basis, today even hydrogen produced from SMR without CCS is almost three times as expensive as natural gas. Correcting for calorific value to compare on a MJ/kg basis, the cost gap reduces but natural gas is still the lower cost fuel, and forward price forecasts suggest this will remain the case.

Table 4 compares the relative CO_2 emissions and fuel costs for a nominal 100MW power plant with varying efficiencies and also considering the impact of carbon taxes. Natural gas is considered to cost a typical UK price to industry of £22 sterling/MWh (€25.3/MWh), while £110/MWh (€126.5/MWh) is considered a standard cost for H_2 from electrolysis. The UK set a price for CO_2 at £16/tonne when the carbon price support mechanism was introduced in 2013, and this is set to rise to £30/tonne in 2020. However, these low levels for CO_2 pricing are insufficient to compensate for the high cost of hydrogen. The SINTEF study [13] projects CO_2 prices in 2050 to lie within a range of €50 to €150. Therefore €115/tonne (£100/tonne) was considered as the future the cost of CO_2, which is just over five times the current price for CO_2.

Table 4: Comparison of hourly fuels costs with varying fuel composition and efficiency for a nominal 100MW power plant

Fuel	Efficiency (%)	CO_2 Emissions (T/h)	Fuel Cost (£/Hour)	Fuel Cost + CO_2 Tax (£/h)
100% NG	40	49.5	5500	10450
100% NG	55	36	3982	7582
100% NG	60	33	3652	6952
40% NG/ 60% H_2	65	30.4	3388	6428
40% NG/ 60% H_2	55	24.5	9350	11600
100% H_2	55	0	19910	19910
100% H_2	65	0	16940	19910

It's clear from Table 4 that even with a dramatic increase in carbon taxes, the cost of hydrogen needs to fall considerably for power generation from hydrogen to be economic compared to natural gas without requiring significant Government subsidies. A study by Advanced Plasma Power and Progressive Energy for Cadent looked at the potential costs for producing bio-hydrogen by gasification of wastes, and estimated H_2 could be produced for £71/MW [14]. Even this cost, which is close to the cost of hydrogen from SMR processes, still means the hourly fuel costs are higher than natural gas, even with a high carbon tax. If carbon taxes are to stay at today's low levels, then the cost of hydrogen needs to be similar to that of natural gas for power generation to be economic without additional subsidies (Table 5).

If the cost of hydrogen production can be reduced to close to that of natural gas, then Table 5 shows that current 55% efficient CCGT technology fueled on 100% hydrogen can be competitive with natural gas with low levels of carbon taxation, even when compared to the future CCGT efficiency goal of 65% efficiency.

Table 5: Comparison of hourly fuel only operating costs with varying fuel costs and efficiency for a nominal 100MW power plant				
Fuel	**Efficiency (%)**	**CO_2 Tax (£/h)**	**Fuel Cost (£/MWh)**	**Fuel Cost + CO_2 Tax (£/h)**
100% NG	40	100	22	10450
100% NG	65	100	22	6428
100% H_2	55	100	71	12670
100% H_2	65	100	71	10780
100% NG	40	20	22	6490
100% NG	65	20	22	3996
100% H_2	55	20	22	3982
100% H_2	65	20	22	3388

Conclusions

Hydrogen potentially offers a solution for deep decarbonization of energy production, especially electricity. In the future, both open cycle and combined cycle gas turbine power plant can operate on 100% hydrogen efficiently and flexibly to provide the grid with the necessary power to support power grids with differing levels of intermittent renewable power generation. The emerging pathways for a future hydrogen economy allow for both new build plant and existing assets to utilize hydrogen to reduce the carbon footprint of energy production.

The technical challenge is to be able to combust 100% hydrogen without resorting to wet low emission control techniques to achieve NO_x emission limits, but ongoing research and development indicates that this goal can be achieved.

The greater challenge is economic, the ability to produce hydrogen at a cost that is competitive with natural gas, without requiring high levels of Government subsidy or carbon taxation. While it will be some time before electrolysis technologies can achieve this cost level, there are some interesting potential future developments in the gasification field that could produce hydrogen at a more competitive cost than SMR processes.

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