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King Abdullah Petroleum Studies and Research Center

Commentary

How Realistic Is Hydrogen for Electrification?

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The Growing Importance of Hydrogen as a Future Energy Vector

Hydrogen has gained considerable global support in the energy policy discourse on how to meet decarbonization targets. Due to its clean-burning properties and versatility, hydrogen is being examined as an alternative fuel source to reduce greenhouse gas (GHG) emissions in various sectors, including transport, industry, building, and power. Blending hydrogen with natural gas in existing networks is considered an attractive proposition to reduce hydrocarbon use and subsequent carbon emissions while scaling up demand for hydrogen. Several demonstration projects worldwide have been experimenting with injecting hydrogen into the gas grid, using hydrogen concentrations as high as 20%. However, the long-term impact of this on pipeline materials and end-use equipment remains unclear (NREL 2020). Once blended, hydrogen can be separated from natural gas at the point of delivery using downstream extraction technologies, or a blended hydrogen-methane mix can be used directly for combustion. In this commentary, we examine the economic viability of the latter, specifically for use in gas turbines in the electric power sector.

While hydrogen blending is increasingly discussed as a means of decarbonizing electricity production, most projects currently remain at trial stages

Driven by environmental, social, and governance motives, utility companies are increasingly incorporating low-carbon technologies and fuels into their portfolios to win contracts, signaling a shift to hydrogen as a component of their net-zero plans (Jones 2021). In addition, regulatory approvals for new gas plants are becoming difficult to come by in some regions as political support for moving away from hydrocarbons gains traction (Jones 2021).

For example, as a part of the European Union's draft proposal, gas plants are only allowed to be a part of its Sustainable Finance Taxonomy if they have "the potential to use low-carbon fuels in the future and emit no more than 270 grams of CO_2 equivalent per kWh of energy" (EURACTIV 2021). Gas turbine manufacturers are responding by developing turbines capable of firing a significantly higher concentration of hydrogen than what is technically feasible today. GE plans to advance its current 50% hydrogen capability to 100% by 2030 (EURACTIV 2021). Mitsubishi Power has successfully tested a 30% hydrogen-blended fuel but aims to achieve a 100% hydrogen-fired gas turbine by 2025 (Mitsubishi Power 2018). It is also developing a 40-MW class gas turbine that can directly combust 100% ammonia for power generation, which is due in or around 2025 (Patel 2021).

Several other projects are also currently underway to study the combustion characteristics of hydrogen-blended gas for power generation. In the U.S., the Intermountain Power Project in Utah is converting its existing 1,800 MW coal plant into an 840 MW gas-based combined-cycle facility. It should have the capability of blending up to 30% hydrogen by 2025 and will transition to 100% hydrogen by 2045 (IPA 2020). The Palomar Green Hydrogen Systems Project, undertaken by San Diego Gas & Electric (SDGE) in California, plans to demonstrate the blending of hydrogen with natural gas for power generation (Mandel 2021). SDGE's second demonstration project, the Borrego Springs Green Hydrogen Project, is examining the use of hydrogen for long-duration energy storage to support grid reliability. In this project, an on-site electrolyser will produce hydrogen using solar energy, and the fuel cell will convert hydrogen energy to electricity when it is needed by the grid. While the desire to reduce GHG emissions is a key driver of this push to use hydrogen for power, hydrogen's economic viability and technical capabilities are yet to be established.

Emissions Come From Many Sectors, But Power Generation Remains the Largest Contributor

Despite the rapid growth of renewables in the past decade, the electricity sector remains the largest contributor to energy-related CO_2 emissions globally. As shown in Figure 1, the electric power and heat sectors emitted 13.5 gigatonnes (Gt) of CO_2 in 2020, or about 40% of global emissions. The power sector remains dominated by fossil fuels, comprising nearly 61% of the total electricity generation, while non-hydro renewables captured only a 12% share (BP 2021). Over the last decade, renewable energy's contribution to the generation mix has increased significantly. Yet, fossil fuels remain the dominant source of energy for electricity production. This is mainly the result of a rise in the use of natural gas and coal. These have collectively seen an uptick in consumption (from 90.5 exajoules [EJ] in 2009 to 112 EJ in 2019) for electricity production, resulting in an increase in CO_2 emissions from 7.5 Gt in 2009 to 8.9 Gt in 2019 (IEA 2021). While efforts are being made to decarbonize the electricity grid in the long term, demand for natural gas for power generation is likely to increase in the near future, with a decline beginning around the 2040s (IEA 2021a).

CO_2 emissions from electricity production have risen globally, despite the uptick in renewable energy usage

Figure 1. Global energy-related CO_2 emissions in 2020 (in Gt).

Source: (IEA 2021a).

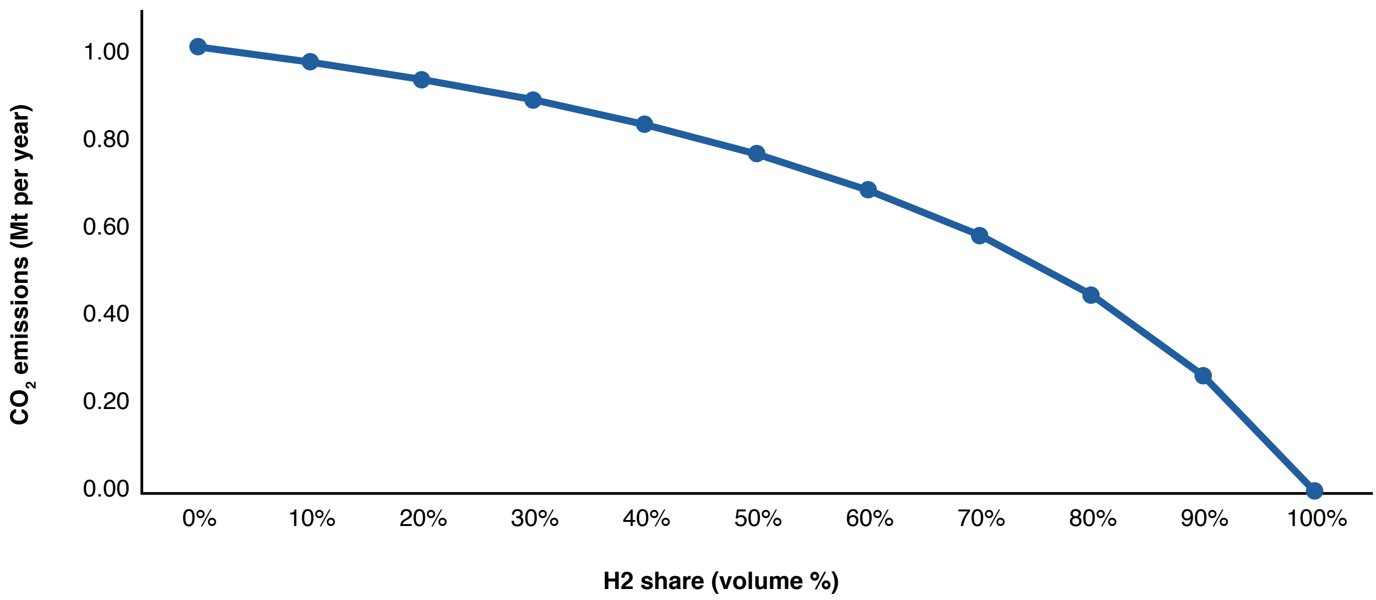
Retrofitting existing gas-fired power plants with carbon capture utilization or sequestration (CCUS) technology, building new gas power plants with CCUS or co-firing hydrogen-blended fuels can reduce the emissions intensity of the gas-fired generation fleet while providing the flexibility needed to operate the grid reliably. As CCUS technologies remain at an early stage of commercialization, co-firing of hydrogen-blended gas could offer an easy pre-combustion decarbonization alternative in the short term.

Hydrogen for Electrification: Has the Moment Arrived?

Blending Hydrogen With Natural Gas To Reduce Carbon Emissions

On a volumetric basis, natural gas has more than three times the energy density of hydrogen. Thus, blending hydrogen with natural gas reduces the overall calorific value of the fuel blend. This would mean that a higher volume of blended gas would be required to provide the requisite heat content to produce a unit of electricity. Further, because of differences in the energy density, attaining a 50% reduction in CO_2 emissions would require a blend that is ~77% (by volume) hydrogen (Figure 2). Using 100% hydrogen as a fuel for gas turbines will eliminate all CO_2 emissions relative to operation with natural gas. This would also mean that if hydrogen is priced higher than natural gas, the short-run marginal cost (SRMC) of running a power plant would also increase (discussed in the next section).

Figure 2. Relationship between CO_2 emissions and hydrogen/methane fuel blends (volume %).



Source: Authors' estimation.
Notes: Based on (i) 400 MW combined-cycle gas turbine (CCGT) power plant size, (ii) 34,200 KJ/m3 and 10,809 KJ/m3 calorific values of natural gas and hydrogen, respectively, and (iii) an emission factor of 56.10 kg CO_2/GJ (~53.08 kg of CO_2 per MMBtu) for natural gas (Gómez et al. 2006).

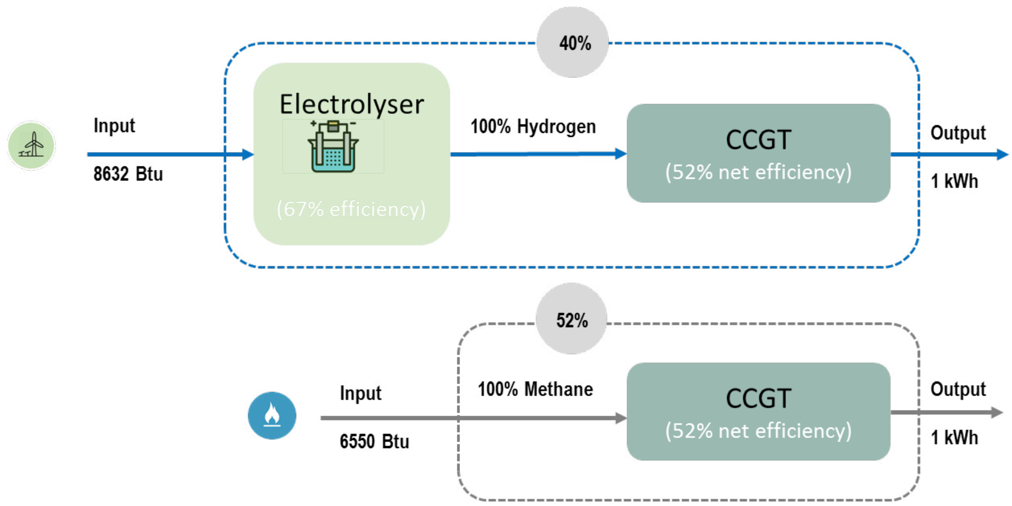
100% Hydrogen-fueled Gas Turbine Will Lower the Overall Round-trip Efficiency of Electrification

Natural-gas-fired turbines usually come in two modes: open-cycle gas turbines (OCGT) or combined-cycle gas turbines (CCGT). An OCGT has a much simpler configuration than a CCGT, and it is typically used to meet peak loads and offers moderate electric efficiency. CCGT, in contrast, is far superior in terms of its efficiency and is a preferred choice for meeting base-load power, but it has a higher capital cost than OCGT. Both options can ramp up and ramp down the generation output, with OCGT having a higher ramping rate, thereby enhancing the operational flexibility of a power plant in the grid. However, the higher thermal efficiency of the CCGT technology has become the driving force behind its adoption, reaching a range of 50-60%, which is a substantial improvement over the efficiency of a simple OCGT, which is around 33% (IPIECA 2013).

Power-to-X applications allow renewable power to be used to produce gaseous energy carriers, such as hydrogen, which are then used as fuel to generate electricity through gas turbines. However, these applications would lower the overall round-trip efficiency because of the multiple energy transformation stages involved in the process. Figure 3 illustrates this impact, where the efficiency of a natural gas combined-cycle power plant is reduced from 52% to ~40%, if 100% hydrogen is used as a fuel for electricity production. This is because the energy requirement for water electrolysis to produce hydrogen is considerable, and re-using this hydrogen to generate power reduces the round-trip efficiency.

From an efficiency standpoint, direct electrification with renewables is a much better option to decarbonize the power grid

Figure 3. Illustration of round-trip efficiency for 100% hydrogen in Power-to-X application.



Source: Authors' illustration.

Hydrogen-blended Natural Gas To Upset the Economics of Electricity Production

Depending upon the renewable energy generation costs in different markets, green hydrogen produced with renewable resources could cost between $3/kg to $6.5/kg (European Commission 2020). This translates to gas priced between $26/MMBtu and $57/MMBtu on an energy-equivalent basis, making green hydrogen much more expensive than natural gas in most jurisdictions.

For electrification, hydrogen must compete on a heating value basis with natural gas

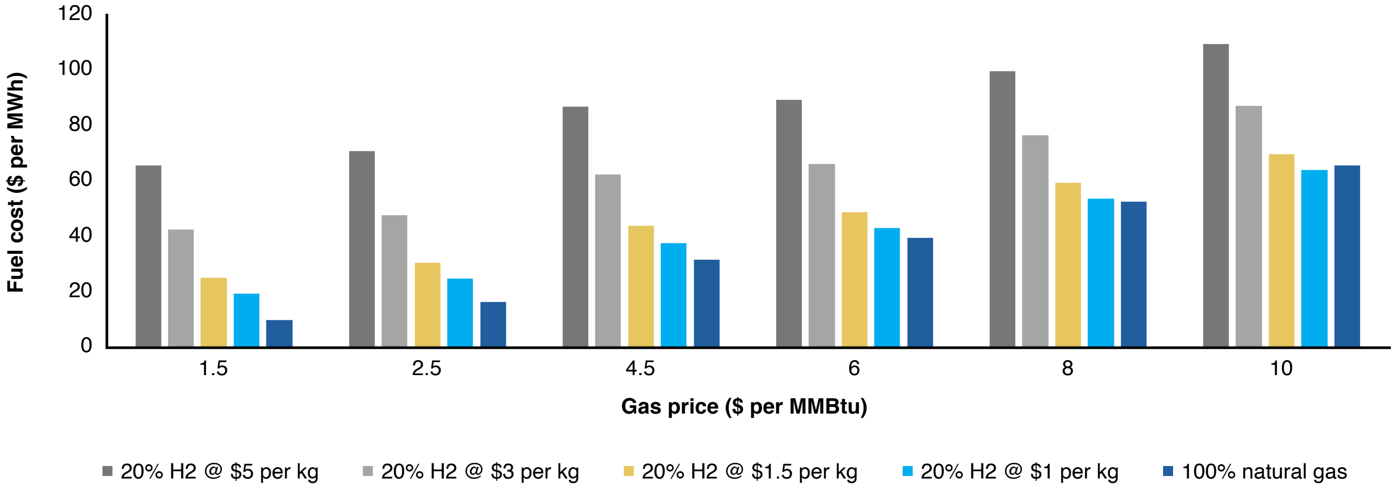
Thus, at an assumed gas price of $4.5/MMBtu, a 20% hydrogen blending by volume in a CCGT would increase the fuel cost (i.e., SRMC) of electricity production from $31/MWh (without blending) to $63/MWh (at a hydrogen price of $3/kg) or $87/MWh (at a hydrogen price of $5/kg), as shown in Figure 4. This is an increase of 100% to 175% in the fuel cost of electricity production for a resulting emissions reduction of 7%. The negative impact would be even more pronounced for producers using low-priced natural gas (e.g., $1.5 per MMBtu) due to the wider price differentials between green hydrogen and natural gas. A higher blending ratio of hydrogen would only exacerbate the cost of electrification (Figure 5).

Compared with this, the average wholesale day-ahead electricity prices remained below $60 per megawatt-hour (MWh) in Europe over the past three to four years (except for the current crisis that has been unfolding since April 2021 and has resulted in record-high wholesale electricity prices). In Spain and Portugal, prices have tripled in the past six months reaching €175/MWh ($203/MWh) in September 2021 (Hernández-Morales and Cienski 2021; BBC 2021). Around the same time, daily average wholesale electricity prices in the U.K. reached a record high of €277.30/MWh ($376.8/MWh) at the Nord Pool N2EX spot auction (Nord Pool 2021). Such high prices in the wholesale electricity markets may support hydrogen-based electrification. Prior to this year, prices have occasionally surged above $9/MMBtu due to tight market conditions. Between 2011 and 2014, liquified natural gas (LNG) imports into Asia were over $14/MMBtu (Corbeau, Shabaneh, and Six 2016). However, the current spike in wholesale electricity prices across Europe was largely triggered by the soaring gas prices in the run-up to winter 2021/2022. This surge resulted from tight gas markets in Europe and Asia (Eckert, Twindale, and Crellin 2021), which jolted gas prices in Europe and Asia to over $30/MMBtu. This price trend, however, is likely to be temporary, and natural gas prices are expected to come down as supply improves.

Thus, it would be unlikely for the use of hydrogen for electrification to make economic sense unless a heavy carbon price is imposed on fossil-fuel-based electricity production. However, in the long term, when green hydrogen is expected to cost under $1/kg, the economics of electrification through hydrogen may change in its favor, even more so in countries where natural gas prices reach around $10/MMBtu.

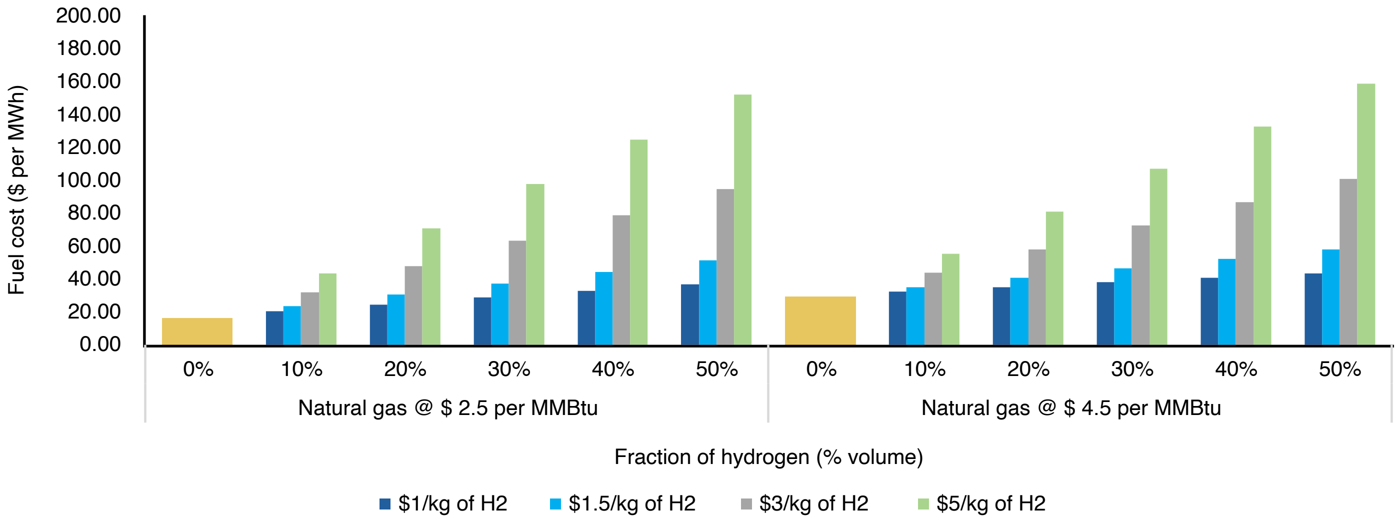
Japan has emerged as one of the countries targeting hydrogen use for power generation. It has one of the lowest energy self-sufficiency rates globally and has very few options for decarbonizing its industries with locally available and environmentally sustainable energy resources. As the country targets net-zero emissions by 2050, it plans to shift some of its fossil-fuel-based power to hydrogen, and it aims to make it cost-competitive against LNG (METI 2017). In 2020, Japan successfully imported a demonstration shipment of blue ammonia from Saudi Arabia for direct use in power plants.

Figure 4. Impact of hydrogen blending on short-run marginal cost for various gas and hydrogen prices.



Source: Authors' estimation.
Notes: Based on an assumed (i) net heat rate of 6,550 Btu/kWh (LHV), which corresponds to a net efficiency of 52% in CCGT mode, (ii) natural gas calorific value of 34,200 kJ/m3 and (iii) 75% plant load factor for a CCGT plant.

Figure 5. SRMC for various blends of hydrogen and fuel prices.



Source: Authors' estimation.

Conclusions

From an efficiency standpoint, direct electrification with renewables is a better option for decarbonizing the power grid than hydrogen. Hydrogen has a lower energy density than gas, and the long-term impacts of using it in existing natural gas pipelines and end-use applications are still under investigation. Electrification with 100% hydrogen has an end-to-end efficiency of 40% or lower. Given the premium green hydrogen has over other fuels, it would be better used in harder-to-abate sectors than for power generation. However, there may be a case for using hydrogen for peaking purposes, in places where gas prices are high or to provide needed flexibility services to operate the grid reliably. The variable cost of burning hydrogen for power generation can reach parity with natural-gas-based electricity production when the cost of natural gas is ~$10/ MMBtu and green hydrogen is around $1 per kg. Nonetheless, further developments in large-scale and cost-effective hydrogen storage would be necessary to tap this Power-to-X potential of hydrogen as a fuel for power generation.

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