Creating Demand for Low-Carbon Hydrogen for Industry Decarbonization: Lessons from the Electricity Sector

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October 2023

Doi: 10.30573/KS--2023-DP22
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Many policymakers now see the use of low-carbon hydrogen as a strong contender in terms of how to achieve climate neutrality goals. Currently, hydrogen is used in refinery processing, ammonia production, or methanol production as feedstock, where no other alternatives exist. However, new uses for hydrogen are being explored in the industry, transport, and electricity sectors, which together account for approximately 85% of global energy-related CO₂ emissions. This paper analyses the readiness of the use of low-carbon hydrogen to decarbonize industries in the Middle East/North Africa (MENA) region and Europe. While the former aims to become a leading producer and exporter of low-carbon hydrogen, the latter wants to leverage the enabling role of renewable hydrogen in fulfilling its climate neutrality goals by 2050 or earlier. Furthermore, lessons from other sectors, including instances of the growth in popularity of renewables and emerging climate policy instruments, that can help create demand for low-carbon hydrogen to decarbonize difficult-to-abate sectors are also considered. The key findings are as follows:

If industrial users have to switch to hydrogen (on an equivalent heat content basis) from natural gas in industry, then the current estimated cost of renewable hydrogen production will decrease by approximately 78% in the UAE and 90% in Saudi Arabia to achieve cost parity with natural gas.

As the average natural gas retail tariff for industrial customers falling under consumption slab Band I4 (100,000 gigajoules (GJ) < annual consumption < 1,000,000 GJ) in European Union (EU) countries is higher, only an approximately 30% cost reduction in renewable hydrogen is needed to break even. Thus, the encouraging fuel-switching in the industrial sector will pose considerable challenges to governments in most regions and require innovative ways in which to spur the demand for low-carbon hydrogen locally.

The current focus is largely directed at the supply side of hydrogen; however, how to create demand in domestic and international markets, which is equally important, has yet to be much debated. A lack of demand could render a capital-intensive investment in hydrogen production risky. Push and pull policies are needed to incentivize sectors and applications best suited to transition from fossil fuels to low-carbon hydrogen.1

Globally, renewable purchase obligations (RPOs)/renewable portfolio standards (RPSs) have played a vital role in fueling the growth of renewable energy (RE). Similar to the case of renewables, setting hydrogen-related decarbonization targets in the form of hydrogen purchase obligations (HPOs) for specific end-use sectors can be pivotal in creating demand for low-carbon hydrogen. However, an effective monitoring and compliance mechanism with requisite penal provisions would be necessary to achieve the desired policy objectives of HPOs.

Carbon pricing will be crucial for stimulating demand and reducing the degree of price differences to unlock growth for low-carbon hydrogen. However, those countries where natural gas is currently inexpensive will require a significantly higher carbon tax of approximately $290/tCO₂ to achieve parity with green hydrogen produced at $2/kg, while only approximately $60–70/tCO₂ of the carbon tax may be sufficient to break even with the gas priced at $14/mmbtu. Furthermore, the adoption of new market-based instruments, such as carbon contract for difference (CCfD), can help lessen the market risks associated with cap-and-trade carbon pricing schemes by providing more predictable terms for producers and end users.

Key Points
1. Introduction

In 2021, global energy-related CO₂ emissions from energy combustion and industrial processes reached a record high level of 36.3 gigatonnes (Gt) (Figure 1) (IEA 2022). Sectorwise, electricity production, transport, and industry are the largest contributors to global energy-related emissions, while countrywise, China, the US, and India remain the world’s major emitters (Figure 1).

In an effort to tackle the climate crisis, a growing number of countries have announced their commitment to becoming net-zero economies by 2030–2065 (ECIU 2023) through law, policy documents, and declarations. As a result, nearly 90% of global emissions are now covered under such net-zero targets set forth by many countries (Figure 2). In the race to become net-zero economies, policymakers are paying considerable attention to hydrogen energy as a potential substitute for oil, natural gas, and coal in difficult-to-abate sectors. Since 2019, interest in using hydrogen as a fuel and feedstock to decarbonize energy use has seen an uptick, which has not been witnessed by other forms of clean energy in the past.

A range of forecasts exist for future global hydrogen demand (Figure 3). These estimates differ due to, for example, different assumptions of global climate change ambitions, energy-efficiency measures, sector-specific activities, and the availability and use of carbon-capture technologies. According to the IEA, global hydrogen demand will reach 290 million tonnes (Mt) by 2050 under the sustainable development scenario of its Global Energy and Climate (GEC) model (Figures 3 and 4). However, if the world has to attain net-zero emissions, then the demand for hydrogen would need to reach 528 Mt globally by 2050 (Hunter 2021; IEA 2022a). The Hydrogen Council’s estimates are more optimistic and expect hydrogen demand to be 660 Mt by 2050 (Hydrogen Council 2022).

Figure 1. Global energy-related CO₂ emissions by fuel, sector, and region – 2021

1. Introduction

Figure 2. Global emissions covered under net-zero goals


Figure 3. Global hydrogen demand
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1. Introduction

Among those industries considering potential hydrogen end-use applications, difficult-to-electrify industries are the most primed to explore the use of hydrogen. One-fourth of global hydrogen demand by 2050 will likely come from difficult-to-abate energy-intensive industries such as the iron, steel, and chemical sectors. Currently, as will be shown, hydrogen is more expensive than are counterfactual fuels used in energy-intensive industries in the Middle East/North Africa (MENA) region as well as worldwide. Unfavorable economics will remain a major challenge in spurring demand and fuel switching in difficult-to-abate industrial sectors.

This paper analyses the relative economics of renewable hydrogen compared to natural gas for industrial users in two potential regions: the MENA region and Europe. The former aims to become a leading producer and exporter of renewable and low-carbon hydrogen, while the latter wants to leverage the enabling role of hydrogen in fulfilling its climate neutrality goals by 2050. We also discuss the potential policy/ regulatory tools, and learnings from other sectors that can help stimulate demand for low-carbon hydrogen in its early adoption years.

Figure 4. Hydrogen demand forecasts for various end-use applications (IEA, Sustainable Development Scenario).

Approximately 95% of hydrogen is presently used as a feedstock in oil refining, ammonia, or methanol production (IRENA 2022), where it is largely produced in-house by companies using their own on-purpose (i.e., captive plant) hydrogen production facilities. Refineries also produce some byproduct hydrogen from catalytic reforming processes, but this supply meets only a fraction of the demand for hydrogen. In such applications, both hydrogen production and use-case technologies where hydrogen is consumed as a feedstock are well proven. Moreover, there is no alternative to hydrogen as a feedstock in such applications.

However, if energy-intensive industries such as iron and steel, nonferrous metal, cement, glass, pulp, and paper industries have to embrace hydrogen as an alternative to fossil fuels, then it is likely that their production processes will require new technologies that are either not (yet) available or not cost competitive. Even if we set these two factors aside,

**Figure 5. Competitiveness of renewable hydrogen vs. natural gas**

<table>
<thead>
<tr>
<th>Year</th>
<th>Region</th>
<th>Energy Source</th>
<th>Price per MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020 S1</td>
<td>Europe</td>
<td>Natural gas end-use price</td>
<td>$0</td>
</tr>
<tr>
<td>2020 S2</td>
<td>Europe</td>
<td>Natural gas, TTF (avg)</td>
<td>$50</td>
</tr>
<tr>
<td>2021 S1</td>
<td>Europe</td>
<td>Green H2</td>
<td>$100</td>
</tr>
<tr>
<td>2021 S2</td>
<td>Europe</td>
<td>Natural gas, TTF (max)</td>
<td>$150</td>
</tr>
<tr>
<td>2022 S1</td>
<td>Europe</td>
<td>Natural gas end-use price</td>
<td>$200</td>
</tr>
<tr>
<td>2022 S2</td>
<td>Europe</td>
<td>Natural gas, TTF (avg)</td>
<td>$250</td>
</tr>
<tr>
<td>Saudi Arabia</td>
<td>GCC</td>
<td>Natural gas end-use price</td>
<td>$200</td>
</tr>
<tr>
<td>UAE</td>
<td>GCC</td>
<td>Natural gas, TTF (max)</td>
<td>$250</td>
</tr>
</tbody>
</table>


Notes: (a) EU-wide average natural gas price (excluding taxes and levies) applicable to nonhousehold consumers (industry Band I4, 100 000 GJ <Consumption<1000 000GJ per year) has been used for comparison purposes, (b) Dutch Title Transfer Facility (TTF) prices are the wholesale gas prices (average and maximum) during the first (i.e., S1) and remaining six (i.e., S2) months of the year, (c) no hydrogen transportation and delivery costs have been assumed, (d) green hydrogen production costs are computed using the H2 cost production model developed by the author. There are several gas hubs operating in Europe; however, Dutch TTF has been chosen as an example as it dominates in Europe in terms of traded volume.
the gap between the cost of renewable hydrogen and what industrial users pay for using natural gas will prevent them from switching to hydrogen as fuel or feedstock.

To illustrate this point, this paper analyses the economics of renewable hydrogen relative to natural gas on an equivalent heat content basis for industrial consumers. The price parity between renewable hydrogen and natural gas has been examined for two geographic regions: the MENA region and Europe. The examples highlight the gap between the cost of domestically produced renewable hydrogen and the natural gas tariff paid by industrial users in select countries in the Cooperation Council for the Arab States of the Gulf (GCC) region (Case I) and Europe (Case II) in the first and second half of 2022. The results are shown in Figure 5.

The key observations are summarized below:

a) **Case I**: As Saudi Arabia and the UAE host some of the lowest-cost renewable energy (RE) projects (700 MW Al Rass PV in Saudi Arabia at $15/MWh, and 2 GW Al Dhafra Solar PV in UAE at $13.5/MWh) (Reuters 2020; Shetty 2021) in the world, the GCC region is uniquely positioned to produce renewable hydrogen at the most competitive rates in the world. RE projects in this price band can produce green hydrogen close to $2/kg (~$60/MWh). Natural gas prices for industrial users range from $1.75 to 3.5/mmbtu, which translates to ~$6–12/MWh. Thus, even if we do not account for the hydrogen transportation and delivery costs, the green hydrogen cost must decline by 78% in the UAE and 90% in Saudi Arabia to achieve parity between hydrogen energy and the prevailing natural gas prices for industrial users.

b) **Case II**: The story differs for EU countries, where the average RE price was ~$55/MWh in 2022, nearly 3.6 times that of GCC countries. The cost of renewable hydrogen at this average RE price will be ~$4.1 per kg ($124/MWh). In contrast, the average natural gas end-use price for industrial consumers (Band I4) remained in the range of $21.7/MWh to $24.4/MWh during 2020–2021 S1 (first half of the year) but increased to $43/MWh in 2021 S2 (second half of the year) and $80.3/MWh in 2022 S1, triggered by the Ukraine-Russia conflict. Therefore, the renewable hydrogen cost must decline by approximately 35% to match the current natural gas end-use prices. This value may reach approximately 11% by 2030 if RE costs are reduced by 25% from the current level while assuming no change in end-use gas prices. Any future increase in end-use gas tariffs will only reduce this gap.

European wholesale gas prices surged postconflict when Russia deepened its supply cuts. Postconflict, Dutch TTF natural gas spot prices became more than ten times the average between 2010 and 2021. Using Dutch TTF wholesale spot prices as a benchmark, it can be seen that renewable hydrogen was close to the average in 2022 S1 but 66% less expensive than the maximum TTF prices observed during the 2022 S1 and S2. Thus, the production of renewable hydrogen appears more competitive than that of natural gas. However, such high wholesale gas prices are unlikely to prevail in the long term. Already, current Dutch TTF prices have fallen to the levels of the preconflict period.

It is clear from this example that encouraging fuel-switching in the industrial sector will pose considerable challenges to governments in most regions and will require innovative approaches to spur the demand for hydrogen locally. In this regard, lessons from the development of other low-carbon energy technologies can be suitability adapted to signal the creation of hydrogen demand.
3. Building up Hydrogen Demand

Policies around renewable hydrogen target mainly the supply side –

In the last four years, policymakers’ interest in fitting hydrogen energy into the energy mix to combat climate change has soared to new heights. However, the focus is more skewed toward the supply side, especially outside the EU. During the 27th edition of the UN Conference on Climate Change, held at Sharm El-Sheikh, low-carbon hydrogen energy was in the spotlight during various side events and discussions organized by several participating countries and organizations. A slew of announcements on the launching of new mega projects, partnerships, and programs also clearly signaled the future role of low-carbon hydrogen and its derivatives in fulfilling climate change commitments.

Among others, the EU and Egypt signed a bilateral Memorandum of Understanding (MoU) to step up their cooperation on renewable hydrogen and prepare the ground for a just energy transition in Egypt (European Commission 2022b). The UAE’s Masdar-led consortium announced its partnership with Egypt to develop a 4-gigawatt (GW) electrolyzer plant with the capacity to produce up to 480,000 tons of green hydrogen annually by 2030 (Masdar 2022). The World Bank launched its Hydrogen for Development (H4D) Partnership to help catalyze financing for hydrogen investments in developing countries (World Bank 2022). On the sidelines of COP27, and as part of its Saudi Green Initiatives (SGI), Saudi Arabia highlighted the country’s roadmap to combat climate change in the coming years, which, among other action points, includes the launching of the Circular Carbon Economy Knowledge Hub. Furthermore, if we add up the respective targets of countries with hydrogen strategy, 90 GW of electrolyzer capacity is expected to be in place by 2030 (BloombergNEF 2023). Through the Inflation Reduction Act (IRA), passed in 2002, the US is also aiming to fully unlock the potential of developing a future hydrogen economy and accelerate its energy transition. The act introduced a clean hydrogen production tax credit and extended the investment tax credit to hydrogen projects and standalone hydrogen storage technology. Such lucrative incentives are targeted to encourage investments and position the US as one of the smallest green hydrogen producers in the world (Bansal 2023).

While, for all the right reasons, the need to set up needed supply-side (hydrogen and manufacturing) capacities remains the key focus of discussions and developments globally, how to create demand for hydrogen energy in domestic markets has yet to be much debated. The predictability in hydrogen demand is a crucial prerequisite to reducing investment risks among first movers, especially when this commodity is more expensive than are other counterfactual fuels in potential industrial use cases.

Creating demand for renewable hydrogen will require focused attention –

The ongoing issues surrounding hydrogen demand and supply create a so-called chicken--and-egg situation for low-carbon hydrogen. While building the required hydrogen production infrastructure is needed to use hydrogen for energy transition, a lack of demand could render the wide-scale investment in hydrogen production risky. Thus, focused attention is necessary to incentivize the creation of hydrogen demand in sectors and applications best suited to transition from fossil fuels to renewable hydrogen. Promoting the use of renewable hydrogen will require carefully crafted
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policy and regulatory interventions, especially at the infancy stage of hydrogen energy deployment, when hydrogen energy is prohibitively more expensive than are the currently used fossil fuels in energy-intensive industries. In addition to the popular prescription of offering fiscal and financial incentives to reduce the costs and provide tax credits, other policy and regulatory tools that can support hydrogen uptake and improve its economic viability are discussed below.

**Building up hydrogen demand through production/consumption obligation:**

*Experience from the electricity sector* – Two decades back, when RE started its journey, it was also very expensive compared to other conventional sources of electricity; we face a similar situation now with green (or low-carbon) hydrogen. However, RE exhibited phenomenal growth in the past 20–25 years. The uptake of RE technologies did not occur organically but was influenced by may support policies including the renewable portfolio standards (RPSs), also referred to as renewable electricity standards (RESs) or renewable purchase obligations (RPOs) in some countries. Such policies required or encouraged electricity suppliers to provide their customers with a stated minimum share of electricity from eligible renewable resources. Later, in some countries, large electricity consumers were also placed under such a quota system to further increase the contribution of RE.

RPSs/RPOs have played a vital role in driving the increases in the amount of renewable electricity generation in the US (EIA 2022b). In a recent assessment, the Lawrence Berkeley National Laboratory (LBNL) highlighted that RPSs have contributed to 45% of the total US RE growth since 2000 (Barbose 2021). Europe, which has also been at the forefront of promoting and integrating RE resources, considered the need for binding and ambitious RE targets (through Directive 2001/77/EC) at the national level, which they considered essential for obtaining results and achieving renewable targets. In India, Australia, and several other countries, such policies also played a catalyst role in promoting RE when such energy resources were not economically viable compared to fossil-fuel-based electricity generation. In June 2022, the Ministry of Power in India amended its “Green Energy Open Access Rules,” which now allow the obligated entities, including industries, to achieve their RPOs by purchasing green hydrogen along with RE (Ministry of Power 2022). The above experience suggests that a top-down approach may be successful in terms of accelerating the hydrogen market with binding hydrogen-related decarbonization targets for specific end-use sectors.

The relevant learnings from the design and implementation of the RPO-driven approach in facilitating the demand for RE, which policymakers can suitably adapt to fit the requirements and complexities of renewable hydrogen, are as follows:

- **Distributional effect of RPOs:** As renewable resources are often not evenly spread across the country, a regional-level RPO within a country may have undesirable and adverse distributional effects on both utilities and consumers. Initially, both the US and India started with a state-based approach but soon graduated to a national-level RPO/RPS target to minimize the distributional effect and ensure ease in monitoring the compliance of policy goals at the national level (Hasan and Bhatt 2022; Rossi 2010).
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Drawing on the experience of many countries that adopted the RPO mandate, a nationwide mandate for renewable hydrogen production and consumption could be an effective tool in terms of developing and using renewable hydrogen resources in the nation's energy mix. While defining such goals, it is important to consider the national circumstances and economic effects. Nevertheless, learnings from the electricity sector suggest that low-level targets and less-stringent punitive measures for noncompliance with set targets have often failed to achieve the policy goals (Hasan and Bhatt 2022).

- **Equity and fairness in the cost recovery of RPO compliance**: Equity and fairness, while difficult to accurately define and devise policies around, are among the important considerations in electricity retail tariff design (Public Power 2019). However, in most jurisdictions, lower-income households are protected from likely tariff increases if the retail tariffs were to reflect the cost of providing electricity services. A tiered-rate structure, which is currently followed in several electricity markets, imposes an inequitable cost burden on customers. In such a tariff structure, those consuming higher amounts of electricity are billed at high-priced upper-tier rates, and the price of electricity is simultaneously subsidized to low-level-consumption customers (Petlin 2014) to ensure that utility revenues are kept stable. Thus, if an additional cost associated with RPO compliance, which comes as part of the utility’s overall cost of power purchase, is to be recovered from end users, then some of the best-paying consumers will likely take up a higher share of the cost of such decarbonization policies. While it may be politically challenging, can a similar approach be practical in pricing renewable hydrogen based on the type of end-use industrial customers? To achieve larger policy goals, the charging of a different retail natural gas price by power and ammonia producers is not uncommon in many countries such as China, Egypt, Indonesia, Pakistan, and India (Chen, Mollet, and Efird 2019; GASREG 2021; Government of Indonesia 2020; IEA 2021; SSGC 2023).

- **Obligated entity for implementing RPOs**: In the electricity sector, utilities are the first and main entities through which RPOs are enforced. They fulfill the mandated RPO requirements of procuring and supplying renewable electricity to their end consumers. Similarly, gas distribution companies supplying gas through their gas grid can be mandated to blend natural gas with a certain share of renewable hydrogen. Conceptually, both the gas grid and electricity grid represent network industries. While “electrons” from RE and conventional power have no distinction, the “molecules” from natural gas and renewable hydrogen possess different properties. Therefore, hydrogen embrittlement and leakages pose a technical challenge in terms of the durability of blending in existing pipelines. While such issues are being examined further to enable hydrogen to deliver its perceived potential in the energy transition, numerous studies suggest that up to approximately 5–10% of hydrogen blending by volume is possible without the need for major modifications to the transmission and distribution grid infrastructure and end-consumer installations (European Commission 2022a; IEA 2019; Topolski et al. 2022). Furthermore, a recent
study commissioned by the California Public Utilities Commission in 2022 concluded that hydrogen blends of up to 5% in the natural gas stream are generally safe. However, hydrogen blends above 5% may require some retrofitting to avoid leaks and equipment malfunction (CPUC 2022).

In most places, policymakers/regulators started with a small share of RPOs to be fulfilled by electric utility companies. Over the years, as RE technologies became more advanced and cost competitive, these targets progressively increased. Likewise, a modest HPO imposed on gas distribution companies, in the beginning, could be a step forward toward achieving the decarbonization of difficult-to-abate sectors and larger net-zero goals. Given the risks associated with investing in early-stage hydrogen infrastructure deployment, a hydrogen mandate can provide a degree of near-term demand certainty for the private sector. However, an efficient monitoring and enforcement mechanism is needed to ensure compliance and achieve policy goals (Hasan and Bhatt 2022; Sawhney 2022).

**Carbon pricing can accelerate energy transition and decarbonization** – Until renewable hydrogen becomes a cost-competitive alternative to the currently used fossil fuels, carbon pricing, as a climate policy tool, can foster energy transition and decarbonization by accelerating the diffusion of low-carbon technologies and encouraging fuel switching. In 1990, Finland became the first country to use a carbon tax of EUR 1.12 (USD 1.41) per ton of CO₂. Since then, over 70 carbon pricing initiatives have been implemented in various countries, covering approximately 23% of global GHG emissions (or 11.86 GtCO₂e) (World Bank n.d.) in 2022.

Among other hydrocarbon fuels, natural gas has the lowest carbon footprint. Assuming a CO₂ emissions coefficient of 52.91 kg of CO₂ per mmbtu for natural gas (EIA 2022a), the scale of carbon prices needed for renewable hydrogen to break even is presented in Figure 6. The analysis suggests that in markets where natural gas prices are high (e.g., Europe, where natural gas prices averaged EUR48/MWh (~$14 per mmbtu) in 2021), a carbon price of $60–70 per tCO₂ can be sufficient to make the use of renewable hydrogen (with a local production cost of $2 per kg) viable. Regarding the use of hydrogen in specific end-use applications, a study by McKinsey & Company observed that with CO₂ prices of $75 per ton and green hydrogen at approximately $1.9 per kg of hydrogen, hydrogen-based steel production can become competitive with conventional steel production in Europe (Hoffmann, Van Hoey, and Zeumer 2020). In contrast, markets with low natural gas prices (e.g., countries in the Middle East and North America), a significantly higher carbon tax (~$290 per tCO₂) would be needed to compete with renewable hydrogen. Thus, carbon pricing is necessary to promote the use of renewable hydrogen for decarbonization in markets where natural gas prices are low and renewable hydrogen production is expensive.

There is a range of carbon pricing options available to policymakers. Emissions trading systems (ETSs) and carbon taxes are considered the essential bedrock for the needed transformation (Table 1). A carbon tax directly puts a price on greenhouse gas emissions or, more commonly, on the carbon content of fossil fuels. An ETS, sometimes called a cap-and-trade system, limits the total...
allowable greenhouse gas emissions and allows those industries with low emissions to sell their extra allowances to larger emitters. An ETS is a market-based mechanism, and thus, its prices are often volatile (Figure 7).

Since price volatility needs to be factored into investment decisions, volatile markets will render long-term capital-intensive investment decisions in hydrogen production and associated infrastructure riskier.

Figure 6. Impact of carbon pricing on the viability of green hydrogen

![Figure 6](image)

Source: Author’s assessment.

Figure 7. EU’s ETS carbon pricing, historical trends

![Figure 7](image)

Source: [www.investing.com](http://www.investing.com).
3. Building up Hydrogen Demand

However, regardless of the choice of carbon pricing instrument, its implementation in rentier states is often politically challenging, especially where existing policies directly counteract the price signal provided by a carbon price. Kazakhstan, a central Asian country whose economy relies heavily on fossil fuels (both exports and consumption), is a good example in this regard. First, the policy of providing subsidized fuels was a major barrier to carbon pricing implementation in the country. However, when, in 2013, Kazakhstan’s ETS was introduced as a primary tool for regulating and reducing carbon dioxide emissions in the energy sector, it was suspended for 21 months due to defects in the carbon pricing frameworks (ADB 2022). Nonetheless, the scheme was later relaunched with improved procedures and other necessary regulations. A major inhibiting factor for this scheme was the government’s decision to disable the pass-through cost mechanism, which could have otherwise resulted in electricity and heat price increases for local consumers (ADB 2022). Kazakhstan plans to develop its hydrogen economy to benefit the local and international community. However, the carbon price of $1.1/tCO$_2$ under its ETS for the current phase (CAT 2022b; ICAP 2022), which runs from 2022–2025, is insufficient for driving the hydrogen-based decarbonization locally or improving the competitiveness of its products by lowering its degree of carbon intensity when the carbon border adjustment mechanism (CBAM) comes into effect in the future.

Table 1. Overview of government-led carbon pricing instruments in the energy sector.

<table>
<thead>
<tr>
<th>Geography</th>
<th>Name and type of instruments (and year of implementation)</th>
<th>Energy sector covered</th>
</tr>
</thead>
<tbody>
<tr>
<td>Europe and Central Asia</td>
<td>EU’s ETS (2005)</td>
<td>Power, industry, aviation</td>
</tr>
<tr>
<td></td>
<td>Kazakhstan’s ETS (2013)</td>
<td>Energy, industry</td>
</tr>
<tr>
<td>Latin America and the Caribbean</td>
<td>Argentina’s carbon tax (2018)</td>
<td>All</td>
</tr>
<tr>
<td></td>
<td>Chile’s carbon tax (2017)</td>
<td>Power, industry</td>
</tr>
<tr>
<td></td>
<td>Colombia’s carbon tax (2017)</td>
<td>All</td>
</tr>
<tr>
<td></td>
<td>Uruguay’s CO$_2$ tax (2022)</td>
<td>All</td>
</tr>
<tr>
<td></td>
<td>Mexico’s pilot ETS (2020)</td>
<td>Energy, industry</td>
</tr>
<tr>
<td></td>
<td>Mexico’s carbon tax (2014)</td>
<td>Fossil fuels</td>
</tr>
<tr>
<td>North America</td>
<td>Canada’s federal OBPS (2019)</td>
<td>Industry</td>
</tr>
<tr>
<td></td>
<td>Canada’s federal fuel charge (2019)</td>
<td>Fossil fuels</td>
</tr>
<tr>
<td>Africa</td>
<td>South Africa’s carbon tax (2019)</td>
<td>Industry, power, transport</td>
</tr>
<tr>
<td>East Asia and the Pacific</td>
<td>China’s national ETS (2021)</td>
<td>Power</td>
</tr>
<tr>
<td></td>
<td>Japan’s carbon tax (2012)</td>
<td>Fossil fuels</td>
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<tr>
<td></td>
<td>New Zealand’s ETS (2008)</td>
<td>All</td>
</tr>
<tr>
<td></td>
<td>Singapore’s carbon tax (2019)</td>
<td>Manufacturing, power, waste, water</td>
</tr>
</tbody>
</table>

Note: Europe has 24 total carbon pricing instruments in place, but only the EU’s ETS, as the main scheme, is highlighted in this review.
Source: Carbon pricing dashboard (last updated April 1, 2022), World Bank, and (Zholdayakova, 2022).
In conjunction with carbon pricing, the adoption of market-based instruments such as carbon contract for difference (CCfD), similar to the mechanism of contract for difference (CfD) used in the past, to enable developers of RE projects to stabilize their revenue at a pre-agreed-upon level (referred to as the strike price), can help address uncertainties arising out of future carbon prices, thereby providing predictable terms for both producers and end users. The ongoing energy crisis in Europe has resulted in several-fold increases in day-ahead spot electricity prices, leading to higher CfD payouts for renewable producers. Such developments have triggered a debate in terms of the redesign of the current CfD mechanism in the interest of all participating stakeholders. Nonetheless, these unfolding developments can offer a useful learning experience in designing CfD as a financial hedging instrument to safeguard the variability in future carbon prices needed to encourage the production and use of renewable hydrogen.

**Fulfilling cross-border hydrogen demand** –

The previous section discussed the importance of creating sustained demand for hydrogen energy and the policy and regulatory instruments that can help achieve this objective. This point discusses the relevance and implications of some emerging policy actions and their implications in creating and fulfilling hydrogen demand through cross-border hydrogen trade. Europe’s goal of importing and producing 10 million tonnes of renewable hydrogen by 2030 signals demand creation for hydrogen-producing countries. A detailed framework(s) governing the 10 million tonnes of bilateral hydrogen energy trade between the producing countries and the EU is yet to be developed. Moreover, the EU has adopted two Delegated Acts, as required under Articles 27 and 28 of the RE Directive (2018/2001), which call for the setting of legislative targets for renewable hydrogen for the industry and transport sectors (European Commission 2023a). The first Delegated Act defines the qualifying conditions for hydrogen to be considered a renewable fuel for nonbiological origin (RFNBOs). The second Delegated Act defines the methodology for estimating GHG emission savings, considering the full lifecycle of the fuels, from RFNBOs and recycled carbon fuels. However, the first Delegated Act also proposes the concept of “additionality,” whereby renewable hydrogen must be produced exclusively with additional RE capacities rather than with existing RE capacities, that is, to meet the RE targets with respect to final electricity consumption. Furthermore, there must be a temporal and geographical correlation between the electricity and fuel production units (i.e., renewable hydrogen) (European Commission 2023b).

This provision will apply equally to local producers of renewable hydrogen and those supplying this commodity from outside the EU. A lack of compliance with these conditions and criteria would prevent electricity from being used to produce renewable liquid and gaseous transport fuels from being considered fully renewable (European Commission 2023b). While the idea behind such a requirement is to support decarbonization and to complement electrification efforts, if the additionality concept is enforced on renewable-hydrogen-exporting countries, then the fulfillment of the EU’s goals of procuring 10 million tonnes of renewable hydrogen and, thereby, its progress toward energy transition goals could be impeded. In the past, “additionality” requirements were also introduced in the Clean Development Mechanism (CDM) of the Kyoto Protocol. However, several assessment studies pointed out the shortcomings of the “additionality
3. Building up Hydrogen Demand

test," loopholes, and challenges in providing real, measurable, and additional emissions reductions as part of their fulfillment (Cames et al. 2016; du Monceau and Brohé 2011).

Therefore, the proposed additionality conditions that need to be met to qualify as a renewable hydrogen import under the first Delegated Act needs to be more pragmatic.
There is currently unprecedented interest in renewable and low-carbon hydrogen to decarbonize difficult-to-abate sectors. As many as 42 countries have released national-level hydrogen strategies, with 36 other countries preparing similar strategies (BloombergNEF 2023). Most countries focus on creating hydrogen production facilities in a race to achieve net-zero goals or support decarbonization in other markets through exporting low-carbon hydrogen (or hydrogen derivatives).

While such strategic roadmaps are encouraging first steps and convey countries’ commitments to the utilization of hydrogen energy in their net-zero energy transitions, as evident from past RE growth, these frameworks might not necessarily signal the creation of hydrogen demand locally. The predictability of hydrogen demand is a crucial prerequisite for reducing the degree of investment risks of first movers, especially when hydrogen energy is more expensive than are other counterfactual fuels in potential industrial use cases. This situation requires tailored demand-pull policies to create demand for renewable hydrogen in new applications, especially for difficult-to-abate industries to switch from fossil fuels.

A lack of demand for renewable hydrogen could dampen the appetite of potential investors while rendering the investment decisions of early movers riskier. Therefore, setting HPO targets, similar to what was successfully used to promote renewables in the past, can be useful in creating demand for renewable hydrogen. When setting HPO targets, it is important to consider the national circumstances and economic effects. Nonetheless, putting in place an effective monitoring and compliance mechanism with requisite penal provisions will be necessary to achieve the desired policy objectives. The European Commission is emphasizing the need to propose subtargets for renewable hydrogen in the industry to boost demand and scale up production. A similar approach can help spur demand for renewable hydrogen in other markets.

Fiscal policies, such as carbon pricing policies, can encourage the use of hydrogen by reducing the current cost gap between fossil-fuel-based counterfactual fuels and renewable or low-carbon hydrogen. Nonetheless, adopting carbon pricing remains politically challenging in several countries, especially in rentier states that offer subsidized (or low cost) fossil fuels to their local end users. For example, the current Henry Hub natural gas spot price of $2.35/mmbtu would require a carbon tax of as high as approximately $290/tCO₂ to achieve parity with green hydrogen produced at $2/kg, while only ~$60–70/tCO₂ of the carbon tax may be sufficient for the company to break even with Dutch TTF’s gas price.

In the wake of volatile carbon prices, especially in the cap-and-trade kind of carbon pricing schemes, adopting new market-based instruments such as CCfD can help lower the degrees of such market risks by providing more predictable terms for producers and end users.

Undoubtedly, the concept of “additionality” to be imposed on domestic producers and those from other countries is to ensure that hydrogen is only derived from renewable sources and does not compromise the ongoing decarbonization efforts through renewable electricity. However, the strict adherence to the requirement that electricity for hydrogen must come from “new and dedicated renewable sources” will prevent the opportunity to effectively utilize the existing surplus RE wherever available from arising. Moreover, given the CDM’s past experiences, fulfilling such an additionality requirement will require a robust framework through which to assess additionality.
Endnotes

1 Unless specifically stated, low-carbon hydrogen in this document collectively refers to the hydrogen produced from water electrolysis using RE sources and hydrogen derived from nonrenewable sources where carbon dioxide (CO₂) emissions are captured.
References


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References


About the Author

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About the Project

This paper is part of the project “Innovations in electricity markets, network regulations, low-carbon investments and technologies” under KAPSARC’s Utilities and Renewables program. This project provides insights for the unfolding energy transition locally by discussing and learning from electricity markets worldwide, including their relevance for promoting clean hydrogen.