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# CARBON MANAGEMENT AND HYDROGEN: POTENTIAL SOLUTIONS FOR HARD-TO-DECARBONISE SECTORS

## INTRODUCTION

The May 2021 edition of the *Oxford Energy Forum* covered the role of hydrogen in the energy transition in some detail,[1] starting from an observation that the decarbonized energy system was expected to see an increase in the share of electricity in final consumption rising from its current 20 per cent to around 50 per cent by 2050. If anything, in the intervening 18 months, the perceived role of electricity has strengthened further, with advances in battery technology and rapid uptake of electric vehicles, such that the 2023 update to the International Energy Agency's Net Zero scenario sees the share of electricity in final consumption at 53 per cent, up slightly from the 49 per cent in the 2021 edition.[2] There has been a corresponding slight reduction in the envisaged role of hydrogen, now seen to be at 8 per cent of final consumption by 2050, compared to a projection of 10 per cent previously. While such projections more than 25 years ahead are extremely uncertain, it remains clear that there will be several hard-to-abate sectors which are not suitable for electrification and where other decarbonization solutions will be required.

Hydrogen remains a key technology for such sectors along with other carbon management activities, such as the deployment of carbon capture and storage (CCS) technologies, whether that be from industrial emission sources or to drive carbon removals compensating either for historic emissions or those which cannot otherwise be avoided. In January 2022, OIES published an edition of the *Forum* examining trends in CCS and exploring the regulatory and commercial barriers limiting the deployment of CCS at large,[3] including regional and country experiences, and the increasing role of carbon dioxide removal (CDR) technologies in net-zero paths. In June 2022, this was followed by an issue of the *Forum* focussed on carbon markets, evaluating global trends in compliance and voluntary market developments,[4] including the role of complementary mechanisms such as carbon border adjustments.

As part of its increasing focus on the energy transition, the Oxford Institute for Energy Studies established two additional research programmes in 2022, one on carbon management and one on hydrogen. For this edition of the *Forum,* it is therefore timely for these two programmes to come together to consider how carbon management and hydrogen can play a role in decarbonization of the energy system.

In the first article, with a focus on hard-to-abate sectors, *Toby Lockwood* provides an overview of the main strategies to cut emissions from heavy industry such as cement, iron and steel, and chemical production, as well as shipping and aviation. Broadly, the author categorizes these strategies into three: first, reducing dependency on carbon-intensive sectors by reducing consumption or increasing material efficiency; second, replacing fossil fuels with cleaner alternative fuels such as hydrogen; and third, adopting breakthrough low-carbon technologies such as CCS. In focus on the latter, the author highlights that CCS still lags far behind where it needs to be according to climate change pathways by the Intergovernmental Panel on Climate Change and International Energy Agency, attributing slow developments to lack of financial incentives to deployment. This is now beginning to change as governments give greater attention to decarbonizing hard-to-abate sectors, with examples of support for CCS including direct subsidy from the Norwegian government and carbon pricing under the EU Emissions Trading Scheme—some of which are further complemented by long-term carbon contracts for difference on a national level, such as in the Netherlands. Across the pond in the US, significant subsidies are provided for CCS projects under the newly enacted Inflation Reduction Act (IRA), including a credit of $85 for every tonne of $CO_2$ captured and permanently stored. The author concludes on an optimistic note that while the cost of CCS may seem eye watering, it is expected to come down significantly as companies gain experience from frontrunner projects.

Further examining the US landscape, *Nnaziri Ihijerika* comprehensively appraises the new changes under the IRA and its support for carbon capture, utilization, and storage (CCUS) and hydrogen production projects. For carbon capture, the IRA enhancement improves the original tax credit (tax code section 45Q) with a steep increase in credit value for direct air capture

[1] Oxford Institute for Energy Studies (2021, May), *Oxford Energy Forum,* 127, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2021/05/OEF-127.pdf.
[2] International Energy Agency, *Net Zero Roadmap: A Global Pathway to Keep the 1.5 °C Goal in Reach*, *2023 Update*, https://www.iea.org/reports/net-zero-roadmap-a-global-pathway-to-keep-the-15-0c-goal-in-reach, Table 2.1.
[3] Oxford Institute for Energy Studies (2022, January), *Oxford Energy Forum,* 130, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/01/OEF-130.pdf.
[4] Oxford Institute for Energy Studies (2022, June), *Oxford Energy Forum,* 132, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/06/OEF-132.pdf

(DAC) projects, and sizeable increases for $CO_2$ stored geologically or used for enhanced oil recovery (CCS-EOR). In addition, the minimum plant capacity threshold to qualify for the credits was decreased significantly, opening the investment space to smaller firms and others developing pilot-scale plants for new CCUS technologies. The IRA also introduced a new tax credit (tax code section 45V) for clean and low-intensity hydrogen production. In the author's view, combined with the potential for both technologies' costs to decrease through economies of scale and cost learning, there is a high level of enthusiasm about the potential for the IRA to create an inflection point in the development of both technologies. The 45V tax credit provides a significant level of support for hydrogen production, with particular emphasis on clean (or green) hydrogen, defined as having an emissions intensity lower than 0.45 $kgCO_2/kgH_2$. Despite this, several factors—including the cost of renewable energy production, lack of clarity around eligibility for the maximum 45V credit, and the inherent advantages of blue hydrogen from fossil fuel production—may be stalling the momentum of green hydrogen development in the US. The author calls to attention that for both CCUS and hydrogen (blue or green), there is an ongoing concern about revenue streams. Combined with the IRA being valid for 12 years or less, project developers remain hesitant to sanction projects without some level of assurance that there will be a market for significantly higher amounts of $CO_2$ and hydrogen than are produced today.

Going into detail on CCS-EOR specifically, *Hossa Almutairi* and *Axel Pierru* seek to evaluate the potential for the practice to contribute to emission reductions. The authors note that EOR has been the largest industrial user of captured $CO_2$ and, given the revenue from increased oil production, EOR has long been regarded as the most readily deployable CCUS technology. To design incentives that enable EOR projects by rendering them financially attractive, governments must ascertain whether implementing the projects reduces global $CO_2$ emissions, and if so, by how much. Here, determining whether the $CO_2$ emissions of the additional oil production should be attributed to the EOR process is crucial in adequately addressing this question. However, there is no consensus on this issue in the literature on lifecycle assessment, which attempts to estimate the greenhouse gas (GHG) emissions associated with industrial processes. The authors show that the impact of EOR on overall emissions is a function of three factors: (1) EOR reduces emissions through the capture and storage of $CO_2$, though operational emissions (such as energy consumption for the CCS facility and emissions from $CO_2$ transport) should be taken into account and deducted from the overall emission reductions reported; (2) EOR leads to increased emissions from the additional EOR oil produced; and (3) emissions are saved due to the displacement from the global oil market by the EOR oil. The authors apply their formulas to three scenarios: conventional EOR, advanced EOR (where oil recovery and $CO_2$ storage are simultaneously optimized), and maximum EOR (where long-term storage of $CO_2$ is maximized). In the three cases, CCS-EOR remains a mitigation technology, since capturing and storing a ton of $CO_2$ leads to a net reduction in global emissions, even after accounting for the full decarbonization of the additional EOR oil produced.

Delving into other carbon management solutions, *Alex Luke* appraises the role of CDR technologies in tackling climate change. The author emphasizes that in order to meet net-zero targets it will not be enough to reduce global emissions, but emissions would have to be actively removed from the atmosphere, whether through technological or nature-based solutions. It is estimated that around 10 billion tonnes of $CO_2$ will need to be taken out of the atmosphere, and stored, every single year by 2050. The author especially highlights the role of engineered CDR methods, such as DAC, in meeting these targets, and notes several advantages that such technologies have over nature-based solutions, including reduced land requirements, longer storage periods, and capacity to accurately measure the sequestered $CO_2$. Despite their importance, the author warns that engineered CDR deployment needs to rapidly scale up—by a factor of 2,500 over the next two and a half decades—and underscores the role of potential cost reductions in achieving this scale-up. The author also believes that to scale effectively, it is critical that engineered CDR methods can back up their removal claims through robust monitoring, reporting, and verification, while also unlocking finance for projects and developers by creating a market for the credits they sell. To unlock finance at the scale required, CDR needs to assure investors of project quality, which can be measured through carbon credit ratings, representing independent third-party assessments of the likelihood that a given credit achieves a tonne of carbon avoided or removed. Within the CDR sector, ratings can help the market to better understand how risk differs between CDR technologies and across individual projects.

Further tackling the issue of scale-up of tech-based CDR solutions, *Peter Webb*, *Mark Fulton,* and *Nigel Curson* assess the technical and political requirements which are needed to scale DAC technology to the gigatonne level. From an engineering and infrastructure perspective, the authors break the challenge into three areas: capture, power, and storage. They delineate different capture methods, namely the liquid sorbent and solid adsorbent methods, which are leading technologies in the market today. The authors evaluate land and operational requirements for each solution, including water, heat, power, materials and chemicals, and staffing. They estimate that approximately 2 terawatt hours of energy will be required to capture and store 1 megatonne of $CO_2$, with power options including solar, wind, hydro, geothermal, industrial waste heat, nuclear, and natural gas with CCS, each with different levels of inherent intermittency. The authors argue that to scale from a few megatonnes per year of capture capacity in 2030 to 1 gigatonne in 2050, early indications from interviews with experts and a review of published studies are that no showstoppers exist. Where there are constraints, there is every chance that mining, commodity, and technology markets could find solutions. The challenge with DAC is that currently the cost in its various applications is set in a broad range around $800–1,000 per tonne of $CO_2$. Significant policy incentives will be crucial to enable innovation, and scale up, to bring costs down.

One such vehicle to mobilize investments in CDR projects is the voluntary carbon market (VCM). In their article, *Andrea Bonzanni* and *Antoine Diemert* shed light on the challenges and opportunities for growth of the VCM. The VCM has witnessed steep growth in recent years, growing in market size from approximately $300 million in 2019 to $2 billion in 2021. Despite its relatively small size and after operating under the radar for many years, the VCM has received a lot of attention lately. Media reports have investigated some shortcomings in how the market operates, exposing flaws in both methodologies and specific projects that led to over-crediting or double counting of emission reductions. This has led regulators to introduce new measures to help tackle these issues, including the European Commission's legislative proposals on 'green claims' and on 'empowering consumers in the green transition', with strict rules around the claims associated with the use of carbon credits. The need to improve market integrity and credit quality in the VCM had been identified by industry long before it attracted the attention of external stakeholders. The authors especially underline the role of two initiatives—the Integrity Council for the VCM and the Voluntary Carbon Market Integrity Initiative—in market self-regulation and discipline, by defining what constitutes high-integrity carbon credits and what claims can be made using those credits. Lastly, the authors caution that a new phase of consolidation and steady expansion is what the VCM needs to mature and contribute to global efforts to reduce emissions and meet the UN Sustainable Development Goals.

Setting the scene for the role of hydrogen in the decarbonized energy system, *Erik Rakhou* considers the potential 'battles' between the competing alternatives of electrification, biofuels, and hydrogen. He does so by taking an innovative approach of looking back from the future and reflecting how a current ideological discussion on the technical merits of hydrogen and alternatives may look from a perspective closer to the end of the decade. In doing so, he highlights the possible tension between technology-driven and policy-driven choices, the latter in the context of a second 'battle' between countries and regions for green investment and green jobs. He concludes that collaboration (and not battles!) is the key topic for the future of hydrogen, a theme which notably is picked up by several other authors in this issue.

Forming a bridge between carbon management and hydrogen, *James Dallimore* contributes a fascinating article regarding one of the classic hard-to-abate sectors: international shipping. He starts by noting the revised strategy adopted at the Marine Environment Protection Committee meeting in July 2023 aiming for net zero GHG emissions by 2050, as a great improvement from the previous target of 50 per cent reduction by 2050. The article outlines the key approaches being considered to meet this objective, including increased efficiency, various hydrogen derivatives, and onboard CCS. He highlights some of the challenges to meeting these targets, noting in particular the urgency for action given the typical 25–30 year vessel lifespan, meaning that vessels being built today will most likely still be in service beyond 2050. He ends on an optimistic note that through partnerships and collaboration the ambitions can be achieved.

Covering another classic hard-to-abate sector, *Abdurahman Alsulaiman* contributes an excellent article on the role of hydrogen in decarbonization of aviation. He highlights three different measures seen by the industry as key to decarbonization: efficiency, sufficiency (i.e. lower demand), and fuel/propulsion innovation. He considers the ways in which hydrogen could be used directly on aircraft, either in hydrogen-compatible jet engines or by generating electricity in hydrogen fuel cells. He points out the regulatory and practical challenges of having hydrogen aircraft coexisting with traditional aviation fuelled aircraft, leading to a consensus that so-called sustainable aviation fuel is more likely to play a significant role. Here too, low-carbon hydrogen plays an important role in the various potential production routes for sustainable aviation fuel, which can then be blended in increasing percentages with traditional aviation fuel.

Moving on from hard-to-abate sectors, Japan perhaps represents a good example of a hard-to-abate economy. As *Hendrik Gordenker* explains in his very well-reasoned article, energy conversion, mainly electricity generation, accounts for around 40 per cent of Japan's direct GHG emissions, a larger share than in many other developed countries. While the country has set bold targets of reducing GHG emissions by 46 per cent compared to 2013 levels by 2030, including increasing the share of renewables in power generation from 18 per cent in 2021 to 36–38 per cent in 2030, achieving these targets will be challenging, largely on account of Japan's geography, with limited available land and limited scope for fixed-bottom offshore wind. This leads to an envisaged role for hydrogen and derivatives such as ammonia, much of which will need to be imported. He then goes on to explain the significant challenges facing the adoption of clean hydrogen in Japan, including transport, storage, infrastructure, cost, and scale. He ends on the positive note that despite the challenges, pursuing the road to clean hydrogen seems to be Japan's best alternative.

Finally, providing more detail on one of the key aspects of policy and regulation, *Alex Barnes* describes the challenge of developing a consistent approach to measuring and certifying the emissions along specific hydrogen value chains, moving beyond such ambiguous terms as 'clean', 'green', 'blue', 'renewable', and 'low carbon' hydrogen. He describes the complexity of aligning on key topics such as the scope of emissions to be included and a common methodology for measuring them. This goes well beyond hydrogen itself, touching on such topics as fugitive methane emissions along the natural gas supply chain, the assumed carbon footprint of electricity taken from a grid (citing for example that the carbon footprint of the German electricity grid is about 25 times that of Sweden's). He argues that the current regulatory approach in the EU potentially leads to higher costs and lower reduction in emissions than could otherwise have been the case. Overall, though, the first priority is for a system of robust carbon accounting and standard accepted methodologies—as he comments in the article, 'if you can't measure it, you can't manage it.'

Reflecting on the diverse range of articles contributed to this issue of the *Oxford Energy Forum*, it is clear that significant challenges remain to be overcome to meet the key roles for carbon management and hydrogen on the pathway to a decarbonized energy system. The theme of collaboration has been mentioned several times as a key success factor; in an increasingly fragmented world, the prospects for achieving that global collaboration are, sadly, not looking particularly promising. We hope that in a small way, this collection of articles may help make the case for that collaboration, and in any case that readers find this edition of the *Forum* thought-provoking and informative. We would like to thank all of the contributors, Amanda Morgan for copy editing, and Kate Teasdale and Harvey Grazebrook for their usual attention to detail in finalizing the publication. If you would like to discuss any of the points raised or find out more about the OIES Carbon Management and Hydrogen Research programmes, please contact hasan.muslemani@oxfordenergy.org or martin.lambert@oxfordenergy.org.

## THE ROLE OF CARBON CAPTURE AND STORAGE IN DECARBONIZING HARD-TO-ABATE SECTORS

***Toby Lockwood***

Clean power generated by wind turbines and solar panels is the first thing most people associate with efforts to reduce greenhouse gas emissions. There is also growing awareness of new ways of using that power to decarbonize daily life, such as electric cars and residential heat pumps. For most of the 21st century, climate policy has focused on these solutions—building renewable energy and, more recently, electrifying applications that currently use fossil fuels. And as supportive policy has helped drive remarkable cost reductions in renewable energy, there is ever greater interest in using these technologies to decarbonize as much of society as possible. But can we electrify everything? And will there be enough low-carbon energy available to take on such a monumental task?

The uncompromising climate arithmetic of net-zero emissions targets is now forcing governments and industries to give serious consideration to these questions and examine those parts of the economy which are often labelled hard to abate. This concept is poorly defined, but broadly describes those sectors that are difficult or impossible to run on low-carbon electricity. These typically include heavy industries such as iron and steel, cement, and chemical production, as well as aviation and shipping.

Heavy industry is the major offender, contributing over 17 per cent of global $CO_2$ emissions, including a colossal 8 per cent from cement production and 7 per cent from iron and steel. Each of these sectors accounts for more than twice as much $CO_2$ as shipping (3 per cent) and aviation (2.5 per cent). Hard-to-abate heavy industries rely on very high temperatures produced by fuel combustion, which are difficult or impossible to reproduce with electricity. Some sectors, such as cement, also produce $CO_2$ as part of the fundamental chemistry of the process, as carbon contained in input materials is converted to other forms.

Strategies to cut these hard-to-abate emissions can typically take three approaches. First, we can reduce our dependency on carbon-intensive sectors by reducing consumption, perhaps by changing behaviours, increasing material recycling, or finding alternative, less carbon-intensive materials and products that fulfil the same need. Second, fossil fuels can be replaced by alternative fuels such as hydrogen, which could potentially be created using renewable energy. Third, the $CO_2$ emissions can be separated and stored deep underground—a process commonly known as carbon capture and storage, or CCS. As emerging economies develop and urbanize, global consumption of steel, cement, and plastics is expected to continue rising, meaning that we cannot rely on the first approach alone. We will need to lean heavily on all three methods if we are to have any chance of meeting our challenging climate goals.

CCS is particularly important to accelerate as it currently lags so far behind where it needs to be, according to climate change mitigation pathways modelled by the Intergovernmental Panel on Climate Change, the International Energy Agency, and other expert bodies. Today, only around 40 million tonnes of $CO_2$ per year are captured and geologically stored worldwide, although at least four times this is captured and used temporarily in products. The International Energy Agency's net-zero roadmap indicates that over six billion tonnes of $CO_2$ should be captured annually, with one billion tonnes reached by 2030. The Intergovernmental Panel on Climate Change's *6th Assessment Report* projects an average of over 650 billion tonnes of $CO_2$ stored between now and 2100 across 1.5°C-compatible scenarios. Tellingly, the only one of this report's 'Illustrative Mitigation Pathways' to exclude CCS also sees global energy demand nearly halved by 2050.

$CO_2$ capture and storage is not only used to decarbonize heavy industry in these decarbonization pathways. The same technologies can also be used to remove $CO_2$ from the atmosphere—either by capturing it from biomass or sucking it directly from the air. The further we fall behind on our emissions-cutting targets, the more we are likely to need these $CO_2$ removal technologies to get atmospheric $CO_2$ to a safe level. They are also needed to cancel out any emissions which may be simply too difficult or costly to prevent by other means, such as in aviation—effectively putting the 'net' in net zero.

The idea of storing $CO_2$ underground can be hard to conceptualize, but it requires thinking on geological scales. At depths of more than 800 metres, the pressure keeps the greenhouse gas in a dense state, where it takes up around 300 times less space. This fluid is trapped within the microscopic pores of rocks like sandstones, and prevented from escaping by thick layers of impermeable rocks such as shales. We know that these geological formations can hold $CO_2$ for millennia, as there are many natural reservoirs of $CO_2$ that have done just this, in the same way as similar rocks have trapped oil and natural gas.

As society comes to terms with the reality that $CO_2$ is effectively a hazardous waste when allowed to enter the atmosphere, it needs to develop an appropriate waste management solution. When other wastes or pollutants are visibly damaging the environment, we usually don't wait for the offending industries to transition or disappear—we try to deal with the problem however we can. However, CCS has progressed so slowly to date because there is no money to be made in this kind of waste management. Nearly all the large CCS projects operating today are using $CO_2$ to increase production from oil reservoirs, which generates revenue. The few projects that are storing $CO_2$ for the purpose of cutting emissions have been required or incentivized to do so by policies such as carbon taxes, subsidies, or making CCS a basic requirement of operation.

The $CO_2$ that is captured and stored today is also mostly from processes where this is relatively easy to do or already carried out for commercial reasons. For instance, natural gas often contains $CO_2$ which needs to be removed regardless before the gas can be used. Many fertilizer plants need to remove $CO_2$ that is produced during the conversion of natural gas to ammonia. For many of the heavy industry processes that will need CCS to decarbonize, it is not so easy to separate the $CO_2$ from other gases, usually because it is at lower concentrations, at lower pressures, or emitted in several places.

For example, cement kilns, in which limestone and clay are heated to several hundred degrees, produce exhaust gases that are only around 10 to 20 per cent $CO_2$. Steel plants are complex facilities with several $CO_2$-emitting processes, with concentrations ranging from 5 to 30 per cent. Oil refineries also include a number of carbon-intensive processes where CCS could be applied, including hydrogen production and the catalytic cracking of heavier oils into lighter hydrocarbons.

Capturing $CO_2$ from these industrial facilities can use gas separation technologies that are fundamentally similar to those that have been used for decades in natural gas processing or fertilizer production. Many leading technologies react the $CO_2$ with a chemical solution that binds the molecule; heating this solution then releases a stream of pure $CO_2$. However, tackling more dilute $CO_2$ sources mean that these capture processes consume more energy and need bigger equipment. This cost barrier, and a lack of adequate policy support, has meant that there are very few full-scale CCS projects operating in heavy industry today, mostly tacking the relatively concentrated $CO_2$ emitted during hydrogen production in oil refineries.

This is now beginning to change as governments give greater attention to decarbonizing hard-to-abate industries and policies are introduced to meet the challenge. In Norway, construction is nearing completion on a project to capture 400,000 tonnes per year from the Brevik cement plant, which will send liquid $CO_2$ by ship to be stored deep below the North Sea. Kicking this off required the Norwegian government to fund the storage site and cement plant with €1.7 billion, which will cover capital investment and operational costs for 10 years. In future, European governments hope that the carbon price set by the EU's Emissions Trading System (ETS) could drive companies to invest in CCS without so much support. This price has remained high since soaring in 2021, reaching a record of €100 per tonne in February 2023, but is still below the cost of installing CCS in many industries that need it. The EU uses some of the revenues from the ETS to fund its Innovation Fund for novel decarbonization projects, selecting 13 CCS projects over the past two years.

Some national European governments have also chosen to give the carbon price a helping hand by awarding individual projects with long-term contracts that effectively top up the ETS. Thanks to such a scheme in the Netherlands, the Porthos CCS project took a positive final investment decision in October 2023. This will initially gather $CO_2$ from activities related to oil refineries in the Port of Rotterdam, for storage just offshore. In the UK, seven industrial facilities and one power plant have been selected for long-term support through a £20 billion fund set aside for CCS.

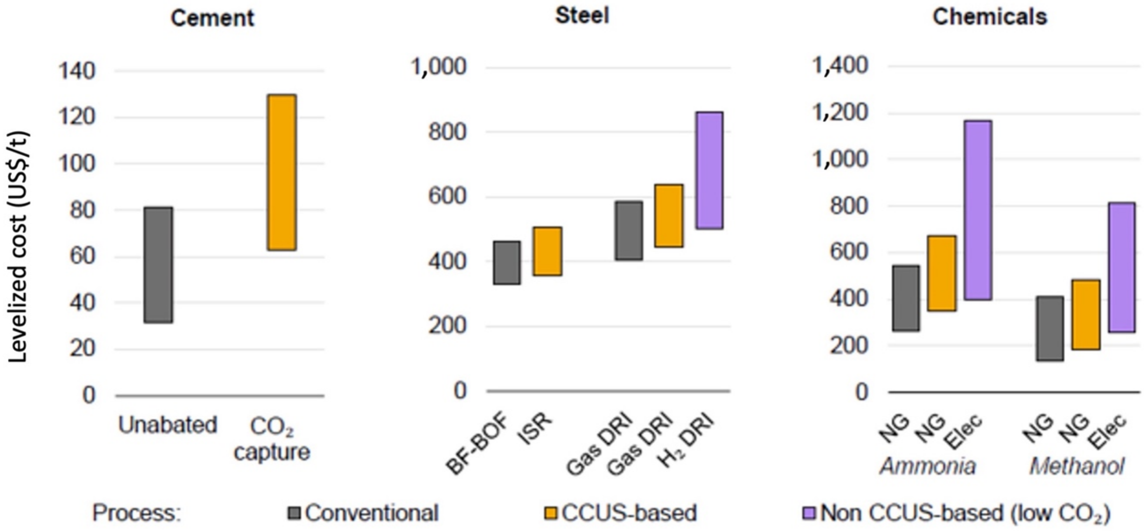
In the US, significant subsidies for industrial decarbonization technologies form a key part of the Biden administration's Inflation Reduction Act, including a credit of up to $85 for every tonne of $CO_2$ stored. Much like the EU's carbon price, this is still not enough for many heavy industry sectors to invest in CCS, and the Department of Energy is providing additional funding for demonstrating the technology with more challenging applications like cement.

While the cost of CCS may seem eye watering, it is expected to come down significantly as companies gain experience from these frontrunner projects. There is already evidence of this trend based on some of its early uses on coal power plants, although current projects face strong inflationary headwinds. Carbon capture plants can be huge installations, with towers over 100 metres high used to react $CO_2$ with the active chemicals; but even large equipment can be standardized and mass produced, and new, more compact and modular technologies are emerging.

The cost of the energy needed to run the process is more challenging to drive down further, with current technologies consuming at least 2 GJ per tonne of $CO_2$ they capture; for comparison, producing that energy by burning gas would itself produce around 120 kg of $CO_2$ that would also need to be captured. This presents a particular challenge for cement plants, which have very little waste heat energy available to run the process. However, several carbon capture technologies run on electricity alone, and could in theory be powered using low-carbon energy sources.

Despite the cost, CCS is still being seriously pursued by many industrial facilities because either there are no other routes to eliminate emissions or the alternatives are even more expensive. This is illustrated in Figure 1, which compares decarbonization options for cement, steel, and chemicals. While cement and some chemicals are reliant on CCS, steel and ammonia production could, in theory, decarbonize by replacing fossil fuels with low-carbon hydrogen. Hydrogen can be cleanly produced from the electrolysis of water using low-carbon power. The steel sector is particularly interested in this route, with many of Europe's steel plants making plans to replace their existing coal-dependent processes with alternatives that could run on hydrogen. But producing enough hydrogen to decarbonize global steel production would require an enormous amount of renewable energy: nearly half Europe's current wind and solar output would have to be dedicated to the region's steel plants. With renewable energy still in relatively short supply, some steel plants are turning to hydrogen made from natural gas with CCS—at least in the near term.

**Figure 1: Simplified levelized costs of producing low-carbon cement, steel, and chemicals. Note: BF-BOF, blast furnace-basic oxygen furnace; ISR, innovative smelting reduction; DRI, direct reduced iron; NG, natural gas; Elec, electrification**




Source: International Energy Agency (2020) CCUS in Clean Energy Transitions.

As tough as industrial decarbonization will be in the EU and the US, China presents a challenge on another order of magnitude. Over half the world's steel and cement production is concentrated in China, most of which has been built up over the past 20 years. As the country's built infrastructure ages, there will be a growing supply of recycled steel, which can help reduce the reliance on carbon-intensive steel produced from iron ore. Ambitious targets to produce green hydrogen for hard-to-abate sectors are driving rapid growth in electrolyser capacity. But the government also recognizes a need for CCS, with several large projects kicking off in the past two years, including some of the biggest ever seen in cement and steel. Although suitable geology for $CO_2$ storage is fairly widespread in China, developing this resource on the scale required could be challenging given the country's proportionally small oil and gas production sector.

There are no easy answers for decarbonizing heavy industries: they are literally hard—and expensive —to abate. But the colossal scale of the emissions from these sectors means that it is a problem that must be solved, with just as much urgency, political effort, and investment as has been concentrated on cleaning up the power sector. While the cost of both CCS and hydrogen is expected to come down over time, future low-carbon cement, steel, and plastics will undoubtedly carry a significant 'green premium' for consumers. Forward-looking climate and industrial policies should ease this transition by building consumer demand for low-carbon products—for instance, by committing to buy low-carbon cement and steel for public infrastructure, or regulating end-users such as the construction and automotive industries to lower their embedded carbon footprint.

The higher cost of conventional materials will help limit excessive consumption and push society towards alternative materials that can offer the same function at lower overall cost. But we cannot afford to wait for this transition to take place by itself. There are solutions for cutting carbon pollution available to society today, and we need to step up efforts to deploy and optimize these technologies in the hard-to-abate industries where they are most needed.

# ASSESSING CARBON CAPTURE AND STORAGE AND CLEAN HYDROGEN ACCELERATION UNDER THE US INFLATION REDUCTION ACT

***Nnaziri Ihijerika***

**The Inflation Reduction Act's ambitions for decarbonized industry**

The signing into law of the Inflation Reduction Act (IRA) in August 2022 by the Biden administration in the United States was a monumental moment in the energy transition. The IRA includes significant tax credits for a suite of clean technologies, notably carbon capture and sequestration (CCS) and clean hydrogen. Both technologies have been identified as key to the decarbonization of hard-to-abate sectors, particularly the petrochemical, cement, ammonia, and steel industries. For carbon capture, the IRA enhancement improves the original Internal Revenue Code Section 45Q tax credit with a steep increase in credits for $CO_2$ captured from direct air capture (DAC), and sizeable increases for $CO_2$ stored geologically or used for enhanced oil recovery (EOR). In addition, the minimum plant capacity threshold to qualify for the credits was decreased significantly, opening the investment space to smaller firms and others developing pilot-scale plants for new carbon capture, utilization, and storage (CCUS) technologies.

The announced support for clean hydrogen development was even more substantial. In 2021, the Bipartisan Infrastructure Law (BIL) was signed, promising up to $9.5 billion in support for clean hydrogen, including electrolysis, manufacturing, and the establishment of regional hydrogen hubs. The IRA built upon this by introducing a new tax credit (Section 45V) for clean and low-intensity hydrogen production. In lieu of the 45V credit, clean hydrogen producers can choose to receive an investment tax credit worth up to 30 per cent of the project cost. Tables 1 and 2 highlight key features of both credits.

**Table 1: Key IRA features for carbon capture**

| Feature | Sector | DAC | DAC-EOR | CCS-Storage | CCS-EOR |
|---|---|---|---|---|---|
| Credit value ($/t$CO_2$) | All | 180 | 130 | 85 | 60 |
| Volume threshold (t$CO_2$/year) | Industrial | 1,000 | 1,000 | 12,500 | 12,500 |
| | Power generation | | | 18,750 | 18,750 |

Source: US Department of Energy.

**Table 2: Key IRA features for clean hydrogen**

| Carbon intensity (kg$CO_2$e/kg$H_2$) | Hydrogen production tax credit ($/kg$H_2$) |
|---|---|
| 4–2.5 | 0.60 |
| 2.5–1.5 | 0.75 |
| 1.5–0.45 | 1.00 |
| 0.45–0 | 3.00 |

Source: US Department of Energy.

Like the 45Q, the 45V incentivizes the timely construction of projects, and allows eligible projects to be stacked with jointly announced tax credits for renewable energy and zero-emission nuclear projects. Both credits are also production credits. This suggests that they have been structured as a way to provide a return on investment, but only if the facilities meet programme guidelines, not only for production but also in terms of the economic benefits (wages and other labour requirements) provided.

Notable in the support levels provided to both CCUS and clean hydrogen is that the tax credit values significantly subsidize the break-even costs for both energy transition pathways. It is estimated that a typical onshore CCUS project in the US Midwest or Gulf coast averages $82/t$CO_2$,[5] while the market price for hydrogen from electrolysis (green hydrogen) in California is around $4.5/kg$H_2$.[6] Combined with the potential for these prices to decrease through economies of scale and cost learning, there is a

[5] Findlay, P., 'What's shaping CCUS project costs?', https://www.woodmac.com/news/opinion/ccus-project-costs/.
[6] S&P Global (September 2023), *Platts Hydrogen Assessment*.

high level of enthusiasm about the potential for the IRA to create an inflection point in the development of both technologies. While the tax credit for hydrogen produced from carbon capture (blue hydrogen) is much lower than that of green hydrogen, its current costs ($1.5/kgH_2$) are also lower. Crucially, blue hydrogen projects cannot leverage both 45Q and 45V—only one can be applied for.

From an investment perspective, the BIL and IRA reflected the government's intent to rebuild the post-Covid industrial economy on a foundation of clean technologies. Additionally, both programmes buttress the position of the US as a leading hub of global CCUS and hydrogen activity. Even before the IRA, CCUS investors viewed the country positively because EOR was a supported use under the 45Q credit. This allowed projects that would otherwise have been uneconomic to provide a quicker return on investment, depending on oil prices, than comparable projects in other jurisdictions, particularly Canada and the EU. On the hydrogen front, the US produces over 10 per cent of the global production of 94 million tonnes per year. Given the preponderance of the country's automotive, marine, steelmaking, and automotive industries, growth in global hydrogen demand is unlikely without significant influence from the US market. The combination of BIL and IRA is a significant driver of the over 115 hydrogen projects that have been announced since Joe Biden assumed the US presidency in 2021. However, despite the IRA's promise as a game changer, neither CCUS nor clean hydrogen development is much further ahead in the US over one year after the bill's passage.

**CCUS: a scale-up and financing challenge**

The IRA places a premium on DAC rather than CCUS, but CCUS is viewed as a key pathway for the scaling of two components required for DAC to be successful: transportation and storage. Some environmentalists view CCUS as a means of maintaining oil and gas production, rather than a meaningful attempt at emissions reduction. However, there is widespread acknowledgment that it remains one of the most viable options for sectors with hard-to-abate emissions. On its own, CCUS provides no revenues outside of EOR and other utilization avenues, so the backstop offered by the IRA is an opportunity for investors to recoup a portion of their investment while allowing crucial industrial sectors to maintain their social license to operate. For the IRA to enable this in a meaningful way, further investment de-risking will be required.

CCUS is a relatively mature technology, having existed in various forms since the 1970s. Its original—and in many places, continuing—use for EOR enabled continued production from mature oil fields that would have otherwise been abandoned. This history reflects the reality that there is no one single CCUS technology, due to unique aspects related to location, geology, industry, and where emissions are captured from in the chemical process. There are at least 25 documented carbon capture technologies, at various stages of maturity,[7] not including technologies associated with storage and transportation. In addition, the incorporation of CCUS into brownfield assets often requires unique solutions that cannot always be replicated in other facilities. Some of these may work at scale, but when combined with designs that do not work or are completely bespoke, overall cost learning and scale is likely to occur at a modest rate.

Sectors that are among the hardest to abate—cement and steel—must contend with carbon capture costs that are much higher than for those processes with purer streams of $CO_2$. There is a wide range of costs at these facilities, from under $10/tCO_2$ to over $200/tCO_2$, but the credit value provided by the IRA is significant enough to accelerate investment. The actual rate of return will depend on whether such plants have access, at a favourable price point, to $CO_2$ pipelines and either dedicated storage or utilization like EOR. For EOR, investment value can be provided through the facilities receiving a share of the revenues from oil sales, which combined with tax credits should provide positive cash flow. Larger incentives or technological innovations may be required to drive costs down even further for projects that derive no economic value from utilization.

**Clean hydrogen: green dreams, blue reality**

Clean hydrogen, particularly green hydrogen produced from electrolysis, is expected to play a major role as an energy carrier in the push to net zero. The 45V tax credit provides a significant level of support for hydrogen production, with particular emphasis on clean (or green) hydrogen, defined as having an emissions intensity lower than 0.45 $kgCO_2/kgH_2$. Despite this, several factors—including the cost of renewable energy production, lack of clarity around eligibility for the maximum 45V credit, and the inherent advantages of blue hydrogen from fossil fuel production—may be stalling the momentum of green hydrogen development in the US.

[7] Global CCS Institute, *Technology Readiness and Costs of CCS*.

The 45V credit supports a price point ($3/kgH_2$) that appears within the realm of reductions expected through scaling and learning by doing, but there is a relative lack of clarity about how emissions intensity from green hydrogen production will be calculated. These cost calculations do not take into consideration the added costs of building incremental renewable energy supply, either to power the electrolysers or to make up the power deficit for other consumers. In addition, they generally do not include other post-electrolysis production costs, including storage, compression, and distribution of hydrogen. Thus, there is a risk that full lifecycle costs—and associated emissions if the costs are avoided—will be passed on either to hydrogen buyers or to residential and other small commercial consumers.

To provide structure to the clean hydrogen buildout and ensure that there is no increase in emissions from power generation, US policymakers have proposed three pillars for the 45V credit: additionality, time-matching, and deliverability. *Additionality* is a requirement for hydrogen producers to build or obtain incremental renewable energy capacity for their electrolysers. This would ensure that electricity supply to neighbouring areas is not backed up by higher-polluting coal and natural gas plants during peak demand hours. The *time-matching* rule is designed to match green hydrogen production with peak renewable energy generation, to demonstrate that the hydrogen plant is not taking renewable power away from other users at the same time. *Deliverability* requires the incremental renewable energy generation to be located close to the hydrogen plant. The assumption is that if the incremental supply is proximal, it is less likely to draw power from existing supply elsewhere.

As a result of these proposed rules, and the significant overlaps between them, there is a concern that several projects could be ruled ineligible for the full 45V credit and may have to settle for a lower credit ($1/kgH_2$). This lower credit is likely to render electrolyser projects uneconomic in the near to middle term.

Although a greater number of green hydrogen projects have been announced since the BIL and IRA, the capacities of announced blue hydrogen projects are similar, reflecting their higher scale. Further, of the hydrogen projects that have received investment sanction for commissioning before 2030, up to 90 per cent of the capacity is blue hydrogen.[8] Blue hydrogen leverages carbon capture, a proven—if not fully scaled—technology. The technology can also be bolted onto steam methane reformers in existing hydrogen plants at relatively low costs, compared to green hydrogen's requirement for an electrolyser.

Existing grey hydrogen production (i.e. production without carbon capture) also has a ready market—refining, petrochemicals, and ammonia production—providing a firmer business case for additional investment in CCUS. Enhancing the value of blue hydrogen further, most of the announced projects are in industrial clusters, primarily around the Gulf of Mexico. This allows for the sharing of costs associated with technology development, transportation, and storage. Finally, although the 45V and 45Q credits cannot be combined for blue hydrogen projects, project developers can evaluate which credit provides them with better value, giving them more optionality for profit-taking than with green hydrogen.

**Fulfilling the IRA's potential**

For the IRA to fully enable the potential of CCUS in decarbonizing heavy industry, additional policy support and financial incentives may be required for projects located outside of the Gulf coast or other areas with ideal geological storage formations. The $2.1 billion loan programme for $CO_2$ pipeline construction that was announced as part of the Infrastructure Investment and Jobs Act is a starting point, but a greater imperative may be required to compel action. The US government could consider placing limits on the emissions produced from heavy industry or implementing a national carbon pricing scheme. Although the country tends to favour market-driven solutions, this may be an option to consider if the pace of adoption does not match the intent of the IRA and no other technologies are deemed sufficient to close the gap.

The combination of blue hydrogen's momentum and the uncertainties about how green hydrogen will be implemented have stalled the latter's progress. However, the IRA provisions for green hydrogen are still the most ambitious in the world. Some of the pillars that have been proposed create barriers to entry for project developers and should be re-examined, or at least redesigned. For example, if a developer can demonstrate additionality, there should be no further requirement for time matching or deliverability. In the short term, it should be recognized that additionality will increase the cost of green hydrogen compared to blue hydrogen. Some states like Colorado have offered demand-side incentives for industries that use clean hydrogen. The federal government may find value in enacting something similar. Renewable energy costs will also have to undergo a significant reduction to ensure that the post-IRA viability of electrolysers remains compelling for investors.

[8] Hydrogen Council, *Hydrogen Insights 2023*.

For both CCUS and hydrogen (blue or green), there is an ongoing concern about revenue streams. Combined with the IRA being valid for 12 years or less, project developers are hesitant to sanction projects without some level of assurance that there will be a market for significantly higher amounts of $CO_2$ and hydrogen than are produced today. Both CCUS and green hydrogen projects are very expensive, with no guaranteed economic returns for the delivered production beyond the value of the tax credits. Blue hydrogen does seem to close the gap by offsetting the high cost of CCUS with the brownfield replacement of relatively cheap grey hydrogen, but it faces ongoing scrutiny as a long-term decarbonization option. The US government could choose to extend both tax credits, or even enhance them further as has been done with the 45Q, but this is not a guarantee and is likely to be opposed by environmental groups who already feel that the IRA should be focused on dedicated renewable energy sources.

While they are widely acknowledged as the best options for decarbonizing heavy industry, neither CCUS nor clean hydrogen offers a guaranteed pathway for doing so. The IRA is a great first step towards enablement of both, offering a lower-risk way for these technologies to be implemented and scaled across the US. Given the challenge of managing the technology, complexity, and geographic issues, a high degree of coordination and standardization will be required if they are to be the game changer they have been purported to be. This will require the active participation of the government, industry, and investors, not just to agree on how the regulations should be implemented, but also to design tools that maintain the country's market-driven approach while ensuring a consistent outcome in its drive to net zero.

## WILL GOVERNMENT SUPPORT FOR CCS WITH ENHANCED OIL RECOVERY LEAD TO REDUCED EMISSIONS?

***Hossa Almutairi and Axel Pierru***

Carbon dioxide enhanced oil recovery ($CO_2$-EOR) involves injecting $CO_2$ into mature oil reservoirs to facilitate the flow of oil to the well. While $CO_2$-EOR was initially developed to increase hydrocarbon recovery, it can also serve as a method for underground $CO_2$ storage. When the $CO_2$ is captured from emissions-intensive sources such as power plants, manufacturing facilities, and industrial hubs, or directly from the air, the entire process is called CCS-EOR, representing a carbon capture, utilization, and storage (CCUS) activity.

CCUS technologies are expected to play a crucial role in reaching net-zero emissions targets. Nearly 20 percent of the world's $CO_2$ emissions arise from heavy industries.[9] For sectors like cement, steel, iron, and chemical production, CCUS often emerges as a practical and viable solution.

Historically, $CO_2$-EOR has been the largest industrial user of captured $CO_2$. Given the revenue from increased oil production, CCS-EOR has long been regarded as the most readily deployable CCUS technology. In addition, EOR provides the largest experience in storing $CO_2$ with a minimal risk of leakage.[10]

A significant challenge faced by CCS-EOR, however, concerns the public perception of the technology, as storing $CO_2$ to stimulate oil production does not have an obvious climate benefit when first presented. As a result, the status of CCS-EOR as a climate-change mitigation technology is often contested. This concern is regularly raised when projects storing captured $CO_2$ through EOR are discussed in the media.[11]

Addressing the question of the potential impact of CCS-EOR projects on global $CO_2$ emissions is therefore critical—since, presumably, the level of governmental support for these projects should align with the emission reduction they achieve. Therefore, to design incentives that enable CCS-EOR projects by rendering them financially attractive, such as tax credits or subsidies, governments must ascertain whether implementing CCS-EOR reduces global $CO_2$ emissions, and, if so, by how much.

[9] International Energy Agency (2020), *Energy Technology Perspectives*, https://www.iea.org/reports/energy-technology-perspectives-2020.
[10] Lyons, M., Durrant, P., and Kochhar, K. (2021), *Reaching Zero with Renewables: Capturing Carbon*, International Renewable Energy Agency Technical Paper 4.
[11] Ratcliffe, V. (28 September 2022), Europe's hunt for clean energy in the Middle East has a dirty secret, *Bloomberg,* https://www.bnnbloomberg.ca/europe-s-hunt-for-clean-energy-in-the-middle-east-has-a-dirty-secret-1.1824762; Jacobs, J. (20 October 2022), '"Put up or shut up": can Big Oil prove the case for carbon capture?', *Financial Times*, https://www.ft.com/content/b8d6848d-1e8a-4c57-b65b-52105b48b178.

Determining whether the $CO_2$ emissions of the additional oil production should be attributed to the CCS-EOR process is crucial in adequately addressing this question. However, there is no consensus on this issue in the literature on lifecycle assessment,[12] which attempts to estimate the greenhouse gas emissions associated with industrial processes. Some authors argue that the emissions from consuming the additional barrels produced by EOR should be attributed to the CCS-EOR technology. Others argue the opposite by invoking the 'full displacement assumption', i.e. that these additional barrels replace barrels that would otherwise have been produced by other oil suppliers, so the emissions from the EOR oil should not be attributed to the CCS-EOR process.

This article summarizes new analysis conducted by the authors that addresses the above questions from an economic perspective,[13] using a partial-equilibrium framework to develop formulas that evaluate the impact of incentivizing CCS-EOR projects on global emissions.

This analysis assumes that the global oil market is in equilibrium with supply equal to demand at a given price. Here, the oil supply represents the aggregated production of all projects profitable at this price point. The analysis then considers a new policy supporting CCS-EOR projects that, without intervention, would not be viable at the current oil price. The provided support, which can take different forms, such as fiscal incentives (i.e. subsidies) or public ownership, helps these projects materialize by rendering them profitable. The subsidies for CCS-EOR projects provided by the 2022 United States Inflation Reduction Act provide a good example of such a policy.

The incentivized CCS-EOR projects either capture the $CO_2$ emissions from industrial facilities or remove $CO_2$ from the atmosphere through a direct-air-capture installation, injecting the captured $CO_2$ into an oil field to increase its output. The introduction of this policy is assumed to result in the storage of a specific number of tons of $CO_2$ in oil fields, and consequently, to produce additional barrels of oil through $CO_2$-EOR. These extra barrels of EOR oil are sold on the global market, impacting the initial market equilibrium. By adding new oil production, the implementation of the policy results in reshaping of the oil supply curve, which shifts to the right. The adjustment to a lower equilibrium price results in a decrease in the volume of oil supplied by other producers. This decrease in other oil supplies represents the volume of oil 'displaced' from the global oil market by the EOR oil.

The analysis develops novel analytical formulas that quantify the volume of oil displaced by EOR oil and the resulting consolidated environmental benefits. Different perspectives can be adopted when measuring the impact on global emissions of capturing and storing a ton of $CO_2$. The analysis focuses on a broad economic perspective that, for the EOR oil produced, assesses emissions on a well-to-wheel basis and considers the displacement effect.

Well-to-wheel emissions include the oil producer's upstream emissions, as well as the midstream and downstream emissions per barrel of EOR oil (including the emissions from consuming the barrel). Note that a well-to-wheel analysis can be viewed as yielding values comparable to the sum of the oil producer's Scope 1, 2, and 3 emissions. However, Scope 3 is broader than what is usually considered in well-to-wheel analyses (because it includes, for instance, the emissions from manufacturing the equipment used to produce the oil).

From the well-to-wheel economic perspective, the total amount of global emissions attributable to implementing the incentivized CCS-EOR projects results from the addition of three effects:

1. **The reduction in emissions due to the capture and storage of $CO_2$.** Capturing a ton of $CO_2$ does not directly translate into an equivalent reduction in emissions at the source. For instance, facilities equipped with carbon capture tend to have a higher energy consumption per unit of output. Similarly, direct-air-capture installations are energy-intensive, potentially releasing $CO_2$ in their operational cycle. Emissions from $CO_2$ transportation to oil fields must also be taken into account. As a result, when considering the capture and transportation process, a ton of $CO_2$ captured and stored through EOR corresponds to a smaller actual reduction in emissions.

2. **The increase in emissions from the EOR oil produced.** This includes the well-to-wheel emissions associated with the EOR oil.

[12] For a review of lifecycle assessment studies for CCS-EOR, see Sekera, J., and Lichtenberger, A. (2020), 'Assessing carbon capture: public policy, science, and societal need', *Biophysical Economics and Sustainability* 5(3).
[13] Almutairi, H. and Pierru, A. (forthcoming), 'Mitigating Climate Change While Producing More Oil: Economic Analysis of Government Support for CCS-EOR', *The Energy Journal*.

3. **The emissions saved due to the oil displaced from the global oil market by the EOR oil.** These are defined as the well-to-wheel emissions of the displaced oil barrels, which include the upstream, midstream, and downstream emissions of displaced oil.

Using the formulas developed in the analysis, the reduction in emissions per ton of $CO_2$ stored can be calculated for three $CO_2$-EOR techniques summarized in an International Energy Agency report:[14]

1. Conventional EOR+ (standard practice that maximizes oil production and minimizes $CO_2$ use, with additional monitoring and verification practices).
2. Advanced EOR+ (simultaneous optimization of oil recovery and $CO_2$ storage, utilizing larger amounts of $CO_2$ in the process).
3. Maximum storage EOR+ (to maximize the long-term storage of $CO_2$ while maintaining the same level of oil production as advanced EOR+).

Table 1 illustrates the reduction in global emissions achieved by capturing and storing a ton of $CO_2$ through these three EOR techniques, based on the well-to-wheel economic perspective. It also provides a breakdown of the reduction across the three effects discussed earlier. Given that the second effect, the increase in emissions due to the EOR oil produced, is accounted for, the resulting reduction implicitly assumes that the EOR oil is fully decarbonized on a well-to-wheel basis.

**Table 1: Changes in global emissions (tons of $CO_2$-equivalent per ton of $CO_2$ stored), well-to-wheel economic perspective**

| | Conventional EOR+ | Advanced EOR+ | Maximum storage EOR+ |
|---|---|---|---|
| Reduction in emissions due to capture and storage | −0.87 | −0.87 | −0.87 |
| Increase in emissions due to EOR oil produced | 1.80 | 0.90 | 0.59 |
| Reduction in emissions due to the oil displaced | −0.97 | −0.49 | −0.32 |
| Total impact | −0.05 | −0.46 | −0.60 |

Source: Almutairi, H. and Pierru, A. (forthcoming), 'Mitigating Climate Change While Producing More Oil: Economic Analysis of Government Support for CCS-EOR', The Energy Journal.

Expressed in tons of $CO_2$-equivalent per ton of $CO_2$ stored, the reduction in global emissions is 0.05 for conventional EOR+, 0.46 for advanced EOR+, and 0.60 for maximum-storage EOR+. In the three cases, CCS-EOR remains a mitigation technology since capturing and storing a ton of $CO_2$ leads to a net reduction in global emissions, even after accounting for the full decarbonization of the additional EOR oil produced. The marginal reduction in global emissions achieved with the conventional EOR+ business model is due to the larger volume of EOR oil that needs to be decarbonized.

For the three $CO_2$-EOR techniques analysed here, CCS-EOR enables producers to sell the EOR oil decarbonized on a well-to-wheel basis while, in addition, generating a reduction in global emissions. If this emission reduction is also used to market fully decarbonized oil, capturing a ton of $CO_2$ and storing it with conventional EOR+ results in the decarbonization of 3.41 barrels of oil. This result captures the effect of the additional oil produced by $CO_2$-EOR on the global oil market (i.e. the displacement effect).

The fiscal incentives provided by governments to support CCS-EOR as a climate-change mitigation technology should be proportional to the impact of CCS-EOR projects on global emissions. After accounting for the decarbonization of the EOR oil, these projects reduce global $CO_2$ emissions by much less than the quantity of $CO_2$ captured. However, given the additional revenue generated by the EOR oil, even limited fiscal incentives may render the projects profitable and thus help to upscale CCS technologies.

[14] International Energy Agency (2015), *Storing $CO_2$ through Enhanced Oil Recovery: Combining-EOR with $CO_2$ Storage (EOR+) for Profit*, https://iea.blob.core.windows.net/assets/bf99f0f1-f4e2-43d8-b123-309c1af66555/Storing_CO2_through_Enhanced_Oil_Recovery.pdf.

The revised Section 45Q of the Inflation Reduction Act, titled Credit for Carbon Oxide Sequestration, provides tax credits for CCS-EOR projects. Capturing a ton of $CO_2$ from industrial facilities or power plants for EOR provides a tax credit of $60, while the credit for storing it in a saline reservoir is $85.[15] The corresponding tax credits for a ton of $CO_2$ captured by direct-air-capture projects are $130 and $180, respectively. Political negotiations have significantly shaped the legislation, and the subsidies might have been tailored to the economics of CCS-EOR projects. However, the ratios 60 over 85 (equivalent to 71 per cent) and 130 over 180 (equivalent to 72 per cent) could be interpreted as an indication that, for the Biden administration, storing a ton of captured $CO_2$ through EOR reduces global emissions by 30 per cent less compared to storing it in a saline reservoir.

When examined in the context of these findings, the tax credit for CCS-EOR in the Inflation Reduction Act is slightly higher than the amount that these calculations would justify.[16]

With many countries committing to net-zero emissions targets by the second half of this century, it is imperative to consider and encourage all technology options. Since CCS-EOR has the potential to reduce global emissions, it must be recognized as part of the solution for achieving a net-zero world.

## THE ESSENTIAL ROLE OF RATINGS IN SCALING THE CARBON DIOXIDE REMOVAL MARKET

***Alex Luke***

It is now clear that carbon dioxide removal (CDR) will be essential to tackling global climate change. The Intergovernmental Panel on Climate Change recently stated that its deployment is unavoidable in every scenario in which the world reaches net zero emissions.[17] This is because global decarbonization cannot be achieved in the necessary time frames through emissions reductions alone. Viable routes to reduce emissions from the so-called hard-to-abate sectors (including aviation, shipping, and agriculture) to zero within the next 30 to 50 years simply do not exist.

To avoid the most catastrophic effects of climate change, we need to limit global warming to well below 2°C at most—and ideally below 1.5°C. This means not only reducing net global emissions to zero rapidly, but eventually removing more carbon from the atmosphere than we emit each year. Removals are the only way to achieve this. To meet climate targets, it is anticipated that around 10 billion tonnes of $CO_2$ will need to be taken out of the atmosphere, and stored, every year by 2050.

CDR refers to any anthropogenic process that removes $CO_2$ from the atmosphere and stores it. This may be achieved through a number of nature-based approaches, such as forestation and soil carbon sequestration. But $CO_2$ can also be removed through a variety of engineered or technological approaches, such as direct air capture (DAC) and ocean alkalinity enhancement (OAE). Engineered removals also include hybrid methods such as biochar and bioenergy with carbon capture and storage (BECCS), in which carbon is initially sequestered by biomass before being converted for long-term stable storage through engineered processes.

Nature-based solutions (NBS) will likely make up a majority of the 10 gigatonnes (Gt) of removals that we need each year by 2050. They are cheap and mature, having already been deployed at commercial scale, in contrast to engineered solutions. But relying on NBS to supply all 10 Gt is unfeasible, in part due to their enormous land requirements. Meeting this target through NBS alone could require dedicating between 3 per cent and 10 per cent of the Earth's total land to the creation of new forests.[18]

As a result, engineered removals will unquestionably need to play a role. Besides reduced land requirements, they typically have other advantages over their nature-based counterparts. Carbon sequestered in biomass and soils, as for NBS, is prone to near-term reversal, for example through drought, fire, pests, or future demands on the land and resources. Engineered removals generally store carbon for much longer periods of time, and with greatly reduced reversal risk. NBS projects are often

[15] Jacobs, J. (20 October 2022), '"Put up or shut up": can Big Oil prove the case for carbon capture?', *Financial Times*, https://www.ft.com/content/b8d6848d-1e8a-4c57-b65b-52105b48b178.
[16] The technical details of this calculation can be found in Almutairi, H. and Pierru, A. (forthcoming), 'Mitigating Climate Change While Producing More Oil: Economic Analysis of Government Support for CCS-EOR', *The Energy Journal*.
[17] IPCC (2022), *Mitigation of Climate Change: Summary for Policymakers*, page 36.
[18] BeZero Carbon analysis.

much quicker to implement at first and require less upfront capital, but biomass takes years to grow and sequester carbon, while some engineered methods can often achieve removals far more quickly.

Ultimately, no single CDR method will be enough on its own. Each method has different advantages and disadvantages across factors such as cost, durability, scalability, energy requirements, public acceptability, and policy support (among many others). As outlined in the *Oxford Principles for Net Zero Aligned Carbon Offsetting*, a wide portfolio of approaches will be required, incorporating both NBS and, increasingly, long-duration engineered removals.[19]

**The current state of the market**

The current market for engineered CDR is very small, but has begun to show signs of growth in the past couple of years. For example, the total number of engineered CDR credits sold has increased sevenfold in the past 12 months, from around 672,000 as of October 2022 to more than 4.8 million as of October 2023.

However, a monumental scale-up is still required over the next three decades if the 10 Gt per year target is to be met. Of the removal credits currently available on the market, 99 per cent are NBS.[20] Most forms of engineered CDR remain at a very nascent stage, with projects no further than the pilot or demonstration phase, such as OAE and DAC. Few technologies have reached delivery at anything approaching commercial scale. On the scale of technology readiness levels, which ranges from 1 (basic research) to 9 (commercialization), most CDR methods are somewhere in the middle at a stage of advanced research or demonstration. As of yet, none have reached commercialization.

Of the credits sold to date, the vast majority are ex-ante, representing a plan or intention to remove a tonne of carbon in the future but the removal has not yet taken place. Just 2.4 per cent of the engineered CDR credits sold to date are ex-post, where the removal has taken place. This is equivalent to just 114,000 tonnes of $CO_2$-equivalent, and almost all of it has come from biochar and bio-oil.[21] Ex-ante credit purchases are also currently dominated by investments in BECCS and DAC credits. For some technologies, the market simply does not exist yet.

As a result, the level of growth required in the engineered CDR markets over the coming decades remains enormous. If all of the annual 10 Gt target for removals by 2050 is supplied by engineered CDR, this translates to a need to increase annual sales of engineered CDR credits by around 2,500 times over the next two and a half decades. But there will also need to be a shift from ex-ante to ex-post credits over this period. This represents an even greater challenge: the total number of tonnes removed each year through engineered CDR methods will need to increase by a factor of 150,000 to achieve 10 Gt of removals annually.

For this scale-up to occur, it is essential that the price of engineered CDR credits comes down significantly. At present, the cost of most engineered CDR credits is in the hundreds or even thousands of dollars. For example, DAC credits range from US$320 to US$2,050 per tonne, while biochar credits are priced between US$100 and US$590 per tonne. While engineered CDR may offer buyers additional benefits, such as increased durability, it is not currently cost-competitive with NBS removals, which generally cost between US$3 and US$50.[22]

**Barriers to scaling**

As with many other technologies before it, such as solar photovoltaic, the price of engineered CDR is expected to fall as the market scales. But there are key barriers to scaling engineered CDR that must be overcome for this to occur.

These barriers are diverse and do not affect each form of engineered CDR equally.[23] For example, some engineered CDR methods are highly resource intensive. DAC is currently a very energy-intensive process, requiring significant amounts of high-grade thermal energy. This is expensive to produce renewably, which may present a significant barrier to DAC deployment in future as the demand for renewable energy becomes increasingly competitive.

Similarly, some methods require large land spaces. This is especially true for BECCS and biochar, which need significant space to intensively grow the feedstock crops they require for their processes. This represents a potential barrier to deployment at

[19] Smith School of Enterprise and the Environment (2020), *Oxford Principles for Net Zero Aligned Carbon Offsetting.*
[20] Climate Focus (2022), *Voluntary Carbon Market Dashboard*.
[21] BeZero Carbon analysis of cdr.fyi data.
[22] BeZero Carbon (2022), *Removal Reconsidered: Carbon Dioxide Removal in the Voluntary Carbon Market*.
[23] BeZero Carbon, 2022, *Scalability Assessment for Carbon Removal.*

scale, given the increasing competition for land from the agricultural sector, urban areas, and even other nature-based removals.

Other methods, such as OAE, will face different barriers to scaling, such as policy and regulatory issues. For example, OAE involves the addition of alkaline materials to the open ocean, reducing ocean acidity and sequestering carbon through a geochemical process. However, it may face significant regulatory challenges, as the internationally recognized London Convention on the Prevention of Marine Pollution heavily regulates ocean additives at present. Similarly, there is great uncertainty regarding the potential impacts of OAE on marine ecosystems, and safeguards protecting biodiversity may restrict OAE deployment down the line.

To scale effectively, it is also critical that engineered CDR methods can back up their removal claims through robust monitoring, reporting, and verification (MRV). Robust MRV is vital to ensuring that the quantity of carbon removed can be accurately determined, the right number of credits are issued, and false claims are not made. However, MRV for some engineered CDR methods remains early-stage, relying on novel methodologies and modelling producing outputs with low confidence and high uncertainty.

Each engineered CDR method is unique in the challenges it faces to scale, but ultimately as new projects and developers come to the market and work to address these barriers, they can each be overcome in turn. For example, proposed new DAC methods are already finding ways to reduce energy requirements.

**Unlocking finance**

Aside from these barriers, fundamental to scaling engineered CDR will be unlocking finance for projects and developers by creating a market for the credits they sell. As the solar industry has shown, significant early-stage investment can help to accelerate progress along the developmental S-curve, bringing down prices. In the same way, CDR could see large cost reductions over a short time period as a result of investment.

Some investment is starting to flow from the public sector, but private-sector investment will be crucial to scaling the industry. As discussed, private-sector investment has also been growing, largely through ex-ante credit purchases. However, levels of investment remain small. Two main issues are preventing investment, and thus the CDR market, from scaling. The first is price. Demand for CDR will not truly take off until the price comes down. Scaling the market will help to achieve reductions in the price of credits and stimulate this demand and investment, but the market will struggle to scale without this investment in the first place.

Investors also want to invest in high-quality credits, which are those with the highest likelihood of actually resulting in a tonne of carbon being removed and stored for a given length of time. There exists the second problem: to unlock finance and grow the market, CDR needs to assure investors of project quality, but quality is difficult to prove until projects reach commercialization and credits are issued at scale.

**The essential role of ratings**

This is where carbon credit ratings can help. Ratings, such as those issued by BeZero Carbon, are independent third-party assessments of the likelihood that a given credit achieves a tonne of carbon avoided or removed. They typically evaluate the quality and efficacy of a given credit against a range of different risk factors. These include the likelihood of a credit not being additional (i.e. not leading to a tonne of $CO_2$ equivalent being avoided or sequestered that would not have otherwise happened) or the risk of a project issuing more credits than tonnes of carbon removed.

Ratings are therefore a crucial tool for credit buyers, investors, and project financiers to evaluate risk. This follows the precedent set within debt markets, where credit ratings issued by the likes of S&P and Moody's provide independent opinions on the risk of debtors failing to service their obligations. Within the CDR sector, ratings will therefore help the market to better understand how risk differs between CDR technologies and across individual projects.

As previously discussed, the bulk of the CDR market at present is made up of ex-ante credit purchases from projects that primarily remain in the development or demonstration stage. This means it is difficult for investors and financiers to accurately determine the cost of capital, and for projects to demonstrate their bankability, thus limiting investment.

Ex-ante credit ratings can help to address this issue by evaluating the 'execution risk' of the project—the likelihood of the project actually reaching the credit issuance stage—alongside the likely quality of these credits once issued. This enables investors and project financiers to better price the cost of capital and can provide them the confidence to invest in more early-stage projects.

By enabling early-stage projects to raise finance in this way, ratings will help to kickstart the growth of the CDR market. Ratings can help investors to direct finance towards high-quality projects with lower execution risk. Over time, increasing numbers of these projects will move through the stages of development and eventually reach issuance.

As the sector scales and more of these projects come online, ratings will also be crucial in helping buyers to compare engineered CDR credits among themselves, and against others available on the market. The price of credits will differ significantly across different technologies and CDR methods. However, the quality of the credits issued by different projects will not be binary.

Within the voluntary carbon market, the price of avoidance and NBS removal credits has begun to align with ratings over time, indicating that buyers are willing to pay more for better-quality credits.[24] As high-quality engineered CDR projects reach issuance, ratings will help to demonstrate the benefits these projects can offer, such as greater additionality and permanence. Although CDR credits are significantly more expensive than NBS removals, ratings can help buyers to justify decisions to pay these premiums in return for higher-quality credits. This will further stimulate demand.

Finally, ratings can help to directly bring down the cost of CDR credits. At present, the vast majority (96 per cent) of CDR credits are purchased bilaterally, through direct agreements between suppliers and consumers with no intermediary involved.[25] This can result in significant extra costs for purchasers who require the internal resources to undertake the necessary due diligence and research process on each project themselves. This cost falls on top of the high prices they then need to pay for the CDR credits. As the current CDR market is demonstrating, this process is currently only possible for a small number of well-resourced buyers. Ratings provide an alternative to this process, by providing buyers with an independent and expertly informed view of projects. This both directly reduces the cost of CDR for buyers and widens the pool of potential buyers, stimulating demand.

Overall, ratings are essential to any future in which the engineered CDR sector scales at the pace required to achieve global climate targets. Ratings will be vital to both de-risking investments in early-stage projects and helping developers secure the necessary finance to build the sector. In addition, ratings will enable CDR buyers to assess the quality of different projects as they develop their portfolios, and reduce their costs.

## THE CHALLENGE OF SCALING DIRECT AIR CAPTURE AND STORAGE (DACS) TECHNOLOGY

***Peter Webb, Mark Fulton, and Nigel Curson***

Climate action seeks to achieve the stretch target of the Paris Agreement to limit global warming to 1.5°C above pre-industrial levels, with little or low overshoot of that temperature.

To achieve this, carbon removal is expected in all scenarios due to the presence of hard-to-abate sectors. Given current economic activity and policy landscape, overshoot beyond 1.5°C also seems to be worth thought and preparation.

Direct air capture (DAC) and direct air capture and storage (DACS) are emerging as carbon removal options alongside others such as bioenergy with carbon capture and storage, promotion of natural carbon sinks such as through afforestation, and other nature-based solutions.

All of these are ‘carbon negative’ technologies, and if deployed at sufficient scale, they would preclude the need for riskier solutions such as geo-engineering. Arguably DACS is a measurable, safe, and secure way to achieve removals. But what might that look like at scale?

Focusing on overshoot of the 1.5°C target, there are several scenarios in which an overshoot of around 350 gigatonnes (Gt) develops—including the International Energy Agency’s Announced Policies Scenario, Inevitable Policy Response Forecast Policy Scenario, and Shell Sky 2050.

With this as the yardstick and given current announced DAC and storage capacity and projects, it is not impossible that current

[24] BeZero Carbon, 2023, *Five New Ways to Look at the Voluntary Carbon Market*.
[25] BeZero Carbon, 2022, *Removal Reconsidered: Carbon Dioxide Removal in the Voluntary Carbon Market*.

and imminent plans deliver 10 megatonnes (Mt) of capture capacity by 2030. If this were to scale up to 1 Gt of DACS by 2050 and 5 Gt by 2070, then by 2130 approximately 350 Gt of $CO_2$ would be removed, corresponding over time to about half a degree of warming and bringing warming back down towards 1.5°C.

To assess this in engineering and infrastructure terms, it helps to break the challenge into three areas—capture, power, and storage—and to describe what each implies for infrastructure on the ground. Then to address scaling, and describe a path to scale from 1 Mt to 1 Gt by 2050, consistent with tackling hard-to-abate sectors and beyond into overshoot. This can inform a more coherent discussion on costs, financing, and policy design.

**Capture**

There are currently two ways to capture $CO_2$ from the air which are at the point of commercialization: liquid and solid DAC. Commercialization corresponds to technical readiness level 7 or 8, the latter being 'first of a kind' commercial. Other pre-commercial DAC technologies include electro-swing adsorption and membrane-based DAC.

Liquid DAC (L-DAC) is based on two closed chemical loops.[26] The first loop takes place in a unit called the air contactor, with an aqueous basic solution (such as potassium hydroxide) that captures $CO_2$. The second chemical loop releases the captured $CO_2$ from the solution in a series of units operating at high temperatures (between 300°C and 900°C). Around 5 tonnes of water per tonne of $CO_2$ is required in moderate atmospheric conditions (ambient conditions of 64 per cent relative humidity and 20°C). More water is required in dry air.

The first example of L-DAC under construction at scale is the Stratos project in Texas, owned by Oxy, 1PointFive, with the technology developed by Carbon Engineering. Construction on this 0.5 Mt/year facility started in 2023,[27] and at the time, initial start-up was expected mid-2025. This liquid process requires higher temperatures, which has implications for the net-zero power source. Chemical sorbents are simple and available. However, very dry or very cold ambient conditions can be a challenge for the liquid loop. The current development trajectory indicates L-DAC is suited to major industrial installations.

Solid DAC (S-DAC) is based on solid adsorbents operating through an adsorption/desorption cycling process. While the adsorption takes place at ambient temperature and pressure, the desorption happens through a temperature-vacuum swing process, where $CO_2$ is released at low pressure and medium temperature (80–120°C). A single adsorption/desorption unit has a capture capacity of several tens of tonnes of $CO_2$ per year, and there are several units in a capture container (of approximately shipping container size).

Climeworks' Orca plant in Iceland deploys the S-DAC process at small scale. But though its modular design, it can be scaled by adding more modules. In theory, scaling could occur up to a 1 Mt/year supersite—though at current levels of capture capacity (500 tonnes of $CO_2$ per year per capture container) this would require 2,000 capture containers, compared to eight at Orca today.

Compared to L-DAC, the S-DAC process requires a lower-temperature heat cycle, so it can use low grade heat which reduces its electrical power requirement. It uses less water than L-DAC and can be designed to operate across a range of different humidities. On the other hand, the vacuum regeneration process and amine chemical reactants it requires both bring complexity and challenge. Table 1 summarizes the requirements of the two approaches.

[26] IEA (2022). *Direct Air Capture A Key Technology for Net Zero*, page21, https://iea.blob.core.windows.net/assets/78633715-15c0-44e1-81df-41123c556d57/DirectAirCapture_Akeytechnologyfornetzero.pdf
[27] 1PointFive announcement, April 2023, https://www.1pointfive.com/1pointfive-holds-groundbreaking.

**Table 1: Comparison between requirements of L-DAC and S-DAC to capture 1 Mt of $CO_2$/year**

| | **Liquid direct air capture** | **Solid direct air capture** |
|---|---|---|
| **Construction** | | |
| Land area | 100 acres, 40 hectares, or 0.4 $km^2$ | 220 acres, 90 hectares, or 0.9 $km^2$ |
| Location | Not super dry/cold, water, lower altitude preferred | Lower altitude preferred |
| Materials | 50 kt steel, 20 kt cement | 40 kt steel, 20 kt cement |
| Chemical reactants | 10 kt KOH and 20 kt $CaCO_3$ | 12 kt Amine sorbent |
| Technical units | Various including high-temperature calciner-slaker | Up to 2,000 container units; expensive adsorbent |
| Staffing | Estimated 1500 full-time equivalents | Estimated 2000 full-time equivalents |
| Build time (excluding permits) | 2 years | 2 years |
| **Operation** | | |
| Water | 5 Mt/year, potentially more | 0.1 Mt/year, with some potential variability |
| Heat cycle | 900°C, at atmospheric pressure | 80-120 degrees Celsius; in a vacuum |
| Power cycle | Some flexibility; high-temp calciner remains on | Demand response flexibility is possible |
| Material supplies | Likely not critical | Likely not critical |
| Chemical reactants | 1 kt KOH and 1 kt $CaCO_3$ per year | At least 3 kt amine adsorbent (potential challenge) |
| Maintenance | Like large industrial site with high-temp process | Similar to large industrial site |
| Staffing | Estimated 100 full-time equivalents | Estimated 100 full-time equivalents |
| Risk management | Similar to a simple chemical plant | Similar to a large, simple industrial process |

Note: these requirements assume that a net-zero 2 terawatt-hour power source is available, as discussed in the next section. Where numbers are point estimates, there is a range of uncertainty around each.

Sources: International Energy Agency[28] with literature review (Nature, Rhodium, others); interviews based on public information with technology providers and subject matter experts.

### Power and storage

As above, one of the challenges of scaling up DAC is simply to produce sufficient net-zero power. There are several ways of doing this to deliver the approximately 2 terawatt hours required to capture and store 1 Mt of $CO_2$. Options include solar, wind, hydro, geothermal, industrial waste heat, nuclear, and natural gas with carbon capture and sequestration, each with different levels of inherent intermittency. In this last option (which has been chosen for the Stratos project), the storage capacity exceeds the atmospheric $CO_2$ capture capacity by around 30 per cent.

Each power source has a different characteristic load factor, which means that equivalent nameplate capacities do vary depending on the level of intermittency. Another consideration is that capture plants cannot switch all units on and off instantaneously. For example, the L-DAC process would need to keep the high-temperature calciner hot, while the existing S-DAC process, with its periodic and lower-temperature heat cycle, would seem to be more suited to responding to cyclical power.

The best commercially viable way to permanently store $CO_2$ is to pump it at high pressure into an underground reservoir where

[28] IEA (2022). *Direct Air Capture A Key Technology for Net Zero*, https://iea.blob.core.windows.net/assets/78633715-15c0-44e1-81df-41123c556d57/DirectAirCapture_Akeytechnologyfornetzero.pdf

it stays in supercritical phase (supercritical fluids have gas-like surface tensions and viscosities and liquid-like densities) or as the solute in the formation fluid. With time it can become a solid through mineralization. Exactly what happens in the reservoir depends on pressure, temperature, and other minerals present. Some standards to ensure permanent storage already exist, developed by the US Environmental Protection Agency.

**Scaling**

To scale up, from a few multiples of 1 Mt/year of capture capacity in 2030 to 1 Gt in 2050, early indications from interviews with experts and a review of published studies are that no showstoppers exist. Where there are constraints, there is every chance that mining, commodity, and technology markets could find solutions. The liquid process, with its high requirement for water, may have trouble deploying in arid locations at scale if treated seawater or subsurface water is not available.

With respect to future scale of capture, comparison can be made between 1 Mt of DAC capacity and a medium-sized, relatively simple refinery. There are currently 825 active oil refineries[29] in the world, so from the capture perspective it may be helpful to think of 1 Gt as similar in scale to today's refining industry. Power requirement to capture 1 Gt/year in 2050 would be comparable to less than a tenth of current global electricity supply,[30] or 2–4 per cent of 2050 electricity generation capacity, assuming both power production and capture plant process efficiencies improve by a factor of up to 50 per cent.

Storage infrastructure could be compared to existing natural gas production infrastructure, which had a total annual capacity of 4,037 billion cubic metres in 2022,[31] equivalent to 3 Gt of LNG. So the scale of future storage infrastructure to pump 1 Gt of $CO_2$ downhole might be in the same ballpark as one-third of today's gas extraction infrastructure, if the difference in density between natural gas and $CO_2$ is ignored.

The International Energy Agency[32] makes the point that power and DAC plant capture and storage capabilities need to be co-located or at least close enough to transmit power or transport $CO_2$ between dispersed assets. Studies exist on locations that favour renewables. These need to be compared with storage locations, which are often sedimentary or basaltic formations.

**Costs**

Current unit costs have for a while been estimated in a range around \$1,000 per tonne of $CO_2$ ($tCO_2$). By one measure the weighted average cost of all DAC removals announced publicly over the last three years is \$718/$tCO_2$.[33] This includes \$800/$tCO_2$ paid by JP Morgan Chase to Climeworks earlier in 2023 (Chase paid \$20 million for 25 kilotonnes of removals over nine years).[34] If this benefits from the \$180/$tCO_2$ support in the US Inflation Reduction Act, then it implies that the pre-subsidy removal cost is close to \$1,000/$tCO_2$. There are lower unit price ranges (\$400–630/$tCO_2$),[35] where cost ranges are highly dependent on the power source.

Looking ahead, Climeworks estimates costs could move to \$400–700/$tCO_2$ by 2030 and \$100–300/$tCO_2$ by 2050. This fall in cost is predicated on deployment-led innovation and iterative learning, in particular to improve the chemical process and to realize both heat-cycle and mechanical efficiencies.

**Policy**

From a policy design perspective, DAC and DACS can be deployed in two ways—first to remove $CO_2$ from the atmosphere and store it in a permanent way (in other words, to deploy it as a removal solution), and second to produce $CO_2$ feedstock for use. The risk with deploying DACS to address existing emissions is that like any negative-emissions technology, apart from helping

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[29] Offshore Technologies (2023). *Global top ten active oil refineries*, https://www.offshore-technology.com/data-insights/global-top-ten-active-oil-refineries/

[30] Statista puts 2022 world electricity consumption at 25,500 terawatt-hours (https://www.statista.com/statistics/280704/world-power-consumption/#:~:text=The%20world's%20electricity%20consumption%20has,25%2C500%20terawatt%2Dhours%20in%202022.); the International Energy Agency's Announced Policies Scenario projects 2050 world electricity consumption at 61,300 terawatt-hours (https://iea.blob.core.windows.net/assets/830fe099-5530-48f2-a7c1-11f35d510983/WorldEnergyOutlook2022.pdf).

[31] *BP Statistical Review of World Energy*, https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2022-full-report.pdf.

[32] IEA (2022). *Direct Air Capture A Key Technology for Net Zero*, https://iea.blob.core.windows.net/assets/78633715-15c0-44e1-81df-41123c556d57/DirectAirCapture_Akeytechnologyfornetzero.pdf

[33] https://www.cdr.fyi/.

[34] https://www.wsj.com/articles/jpmorgan-makes-one-of-the-biggest-bets-ever-on-carbon-removal-c7d5fe63?st=3kcjrkkl7aei6xf&reflink=desktopwebshare_permalink.

[35] Oxy/Carbon Engineering, *Second Quarter Earnings Conference Call*, https://www.oxy.com/siteassets/documents/investors/quarterly-earnings/oxy2q23conferencecallslides.pdf, slide 38.

to address hard-to-abate emissions, it can be used to offset any existing emissions, and therefore can distract from addressing the underlying need to decarbonize. This points to the need for policy and technology to address core decarbonization as its primary focus, at least for the time being.

The challenge with DAC is that currently the cost of its various applications seems set in a broad range around $800t $CO_2$. Significant policy incentives will be crucial to enable innovation, and scale up, in order to bring costs down.

Direct policy tools are fairly straightforward and can be taken from the current climate playbook; for instance, direct funding for R&D and for constructing large-scale first-of-its-kind plants in DAC hubs, as in the US Inflation Reduction Act, or direct incentives through tax credits or for production such as in the Inflation Reduction Act at $180/t $CO_2$. Carbon pricing (e.g. in Europe) could also be adopted, or contracts for difference (such as in the UK). Public procurement of DAC credits and through reverse auctions could be used for price discovery and to launch major programmes.

There is also a need for consensus on life cycle analysis methodologies of the various types of DAC, and accounting frameworks to assure carbon offsets that are sold either bilaterally or through the Voluntary Carbon Markets. In the future, standards aligning with UN Article 6 will further be required.

Today, the demand for DACS comes predominately from the Voluntary Carbon Markets and the need for high-quality credits. JP Morgan Chase paid $800/t $CO_2$ earlier in 2023 for DACS credits, but demand is likely to be constrained at these prices. Thus, incentives will have to rise substantially to start the level of scale-up that could lead to a virtuous circle of cost reductions. Governments may see decarbonization of hard-to-abate sectors as reason enough to do this. However, it is in the context of addressing any overshoot of the 1.5°C target that policy design could expand to be far more comprehensive, because if that scenario prevails, then removals including DACS will be required.

Overshoot with multiple significant climate events would usher in a new world, which would need to be addressed at the global level. Deciding when overshoot of the key 1.5°C level occurs will be contentious but, by the early 2030s, the Inevitable Policy Response Forecast Policy Scenario sees this as confirmed, and average annual temperature will be overshooting the 1.5°C level in particular years ahead of that. Any associated severe climate events or mass migration will bring into question who is responsible for the overshoot, and that will reach back into the history of emissions since the late 18th century. These will not be easy discussions.

It is most likely discussions to resolve overshoot will start in the context of the Intergovernmental Panel on Climate Change as the apex climate body (which could begin to address the issue in the context of carbon markets and Article 6). It seems likely that as overshoot happens and climate impacts gather pace, then social tipping points will also be reached, leading to collective recognition that action will be required to stabilize the climate. In other words, recognition of the need to address overshoot may simply become inevitable. As in the case of the Green Climate Fund, *who* pays for action to address the $CO_2$ overshoot will hold the key.

With respect to coordinating and setting the direction for collective global initiatives, the G20 has proven to be an effective apex international organization. It brings together the wealthier nations, bridges the global North and South, and includes both hydrocarbon-producing and net-consuming nations. Furthermore, it has successfully addressed global issues in the past.

An agreement sponsored and paid for by the G20 may pave the way for historic emissions to be removed. The G20 includes China and India and cumulatively accounts for 80 per cent of historic emissions, and in effect creates a greater share in the remaining carbon budget for the smaller emerging and developing countries. How these countries finance these costs—through carbon taxes, which would make sense economically, or directly from the budget—will be a huge debate.

**Conclusion**

It makes sense that policy further encourages the development of DAC within the overall context of pushing as hard as possible for low overshoot of the 1.5° target, while in effect preparing a ‘plan B’ to tackle overshoot if and when that may be required. DAC coordination, accounting, and definitions for use in different contexts are all in the short-term focus. Governments should be bold in shouldering the costs to get the learning curve of reducing costs in motion, as they were once with renewable energy. Planning for the longer term should not wait long.

# CHALLENGES AND OPPORTUNITIES FOR GROWTH IN THE VOLUNTARY CARBON MARKET: AN OVERVIEW

***Andrea Bonzanni and Antoine Diemert***

The voluntary carbon market (VCM) is no ordinary market. Its emergence in the late 1990s and its growth over the last two decades defied expectations and challenged some of the basic tenets of economic theory. It is now a complex ecosystem of project developers, accreditation bodies, advisors, marketplaces, and intermediaries that generate independently verified carbon credits for public use. A carbon credit is an instrument representing the reduction, avoidance, or sequestration (biological or technological) of one tonne of $CO_2$ equivalent. Since its inception, the VCM has allowed corporates and other non-state actors to achieve climate goals through the purchase of carbon credits, usually as a complement to internal decarbonization measures. It is estimated that over 1.5 billion tonnes of $CO_2$ equivalent have been abated by the VCM.

The key difference between the VCM and other carbon markets is the apparent lack of incentives for market participants. As the name suggests, participation in this market is purely voluntary. Rather than being driven by regulations or global agreements, the VCM has been a bottom-up movement led by corporations that wanted to demonstrate leadership in climate action by neutralizing their greenhouse gas emissions alongside direct reductions in their value chain.

Since its inception in the late 1990s, the VCM built its success on a clear value proposition, as it provides:

- a robust mechanism for corporates to reduce or remove emissions beyond their value chains and take responsible action as part of their science-aligned net-zero pathways;
- a credible tool to channel finance where it is most needed, including developing and least developed countries, forest conservation and restoration, removal technologies, and the implementation of the UN Sustainable Development Goals; and
- a potential pathway to compliance markets in jurisdictions where mandatory emissions trading systems remain nascent.

While the adoption of the Paris Agreement in 2015 and the acceleration of global efforts to reduce emissions has radically transformed the politics of climate change in recent years, the value proposition above remains valid and has contributed to a dramatic growth in the VCM. Its market size went from approximately $300 million in 2019 to $2 billion in 2021.[36] These figures pale in comparison to the aggregate size of compliance carbon markets, which is around $850 billion (albeit 90 per cent of this number is made up of the EU emission trading system).[37] To put things into perspective, the cryptocurrency market at its peak in November 2021 was worth $3 trillion.

Despite its relatively small size, the VCM has been under the spotlight. As voluntary purchases of carbon credits started to become the norm among large corporates, it captured the attention of the media and regulators who focused on failures and shortcomings, often ignoring the impact this market had in abating emissions and channelling finance where it is most needed. The VCM is now at a crossroads; it needs to evolve and mature to keep growing and win public confidence.

### The VCM ecosystem

Various stakeholders are involved in the lifecycle of a carbon credit. Typically, the first link along the chain is the project developer, who designs and implements the activity. Over the project's lifetime, the activity is validated, monitored, and verified by third-party auditors (also called validation and verification bodies) before carbon credits can be issued and transacted.

Project activities that may qualify are diverse. Historically, renewable energy and natural climate solutions (e.g. avoided deforestation, improved forest management, afforestation and reforestation, soil management, and regenerative agriculture) have been prominent, but the list is much longer, with energy efficiency, waste management, clean cooking, biogas, and carbon capture and storage, to mention a few examples. A lot of attention is currently placed on new methodologies in the technology-based $CO_2$ removal space, even though emission reductions still represent over 80 per cent of all carbon credits issued.

[36] https://www.ecosystemmarketplace.com/articles/the-art-of-integrity-state-of-the-voluntary-carbon-markets-q3-2022/, Ecosystem Marketplace, 2022, VCM Reaches Towards $2 Billion in 2021: New Market Analysis Published from Ecosystem Marketplace.
[37] https://www.refinitiv.com/perspectives/market-insights/global-carbon-market-value-hits-new-record/, Refinitiv, 2023, Global carbon market value hits new record.

What all projects have in common is that their activity is based on a specific methodology, developed by an independent carbon crediting programme, usually referred to as a standard. These programmes ultimately decide on the issuance of carbon credits in a public registry they manage, where each transaction is visible until the credit is finally retired by an end user, typically a corporate. Standards are central in ensuring the quality of carbon credits.

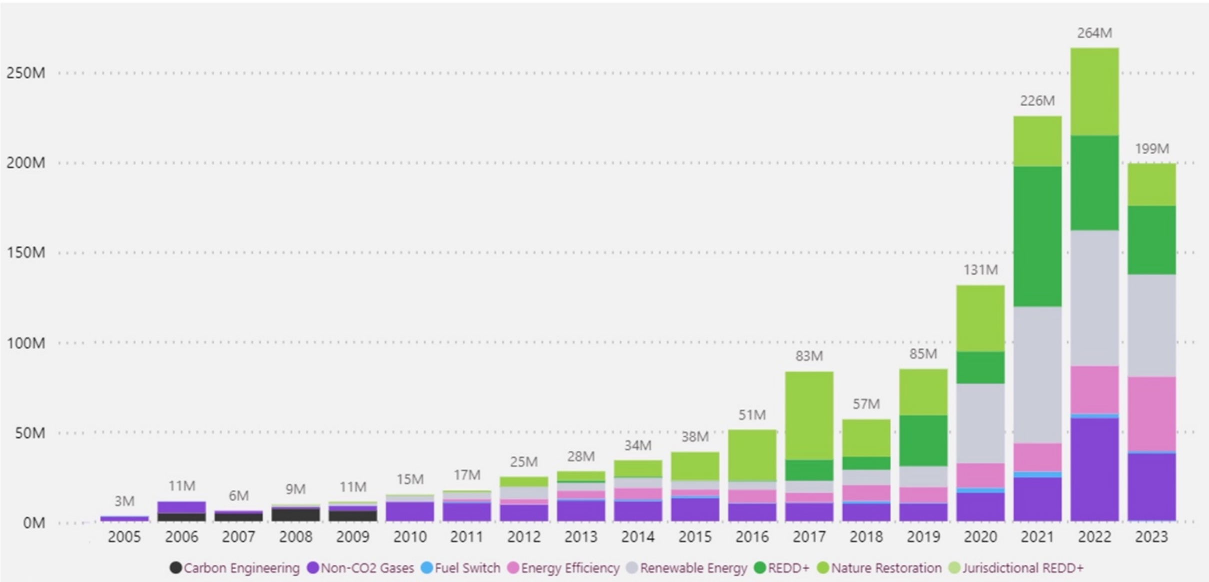
The Verified Carbon Standard, run by the Washington, DC-based nonprofit Verra, is the most commonly used standard globally, holding a market share of over two-thirds of all credits issued and retired worldwide, mainly from renewable energy and avoided deforestation projects. Other significant players are the Gold Standard (based in Switzerland), the American Carbon Registry and the Climate Action Reserve (both US-based), and the Global Carbon Council (based in Qatar). As the market grows, new standards have emerged, often focused on specific solutions (e.g. removals or natural climate solutions) or specific jurisdictions. The International Carbon Reduction and Offsetting Alliance (ICROA), an industry accreditation body, endorses standards that meet a certain quality threshold.

The universe of buyers is vast, and includes small and global corporates in all sectors of the global economy, e.g. energy, mining, transport, technology, and consumer goods. Other stakeholders in between act as intermediaries, like in many other markets. They are brokers, traders, consultants, and other service providers working with clients to design and implement carbon management strategies that include market-based solutions. Recent newcomers in this space are rating agencies. Similar to their counterparts in the credit market, they assign scores to individual carbon credits in an attempt to guide buyers and differentiate between available instruments.

**VCM achievements**

Over the last 20 years, 1.5 billion carbon credits have been issued, from over 4,300 projects globally (Figures 1 and 2). The trend goes towards an increase in the number of carbon crediting standards, both as a reaction to bottlenecks due to the limited capacity of established players and in response to specific local needs. Issuances come from projects around the globe, quite evenly distributed across continents over the last couple of years. Since 2020, more than 1,500 new carbon credit projects have been developed and registered. This represents an increase of about 160 per cent in the rate of registration compared to the 2012–2020 period.[38]

**Figure 1: Global carbon credit issuances by project type**

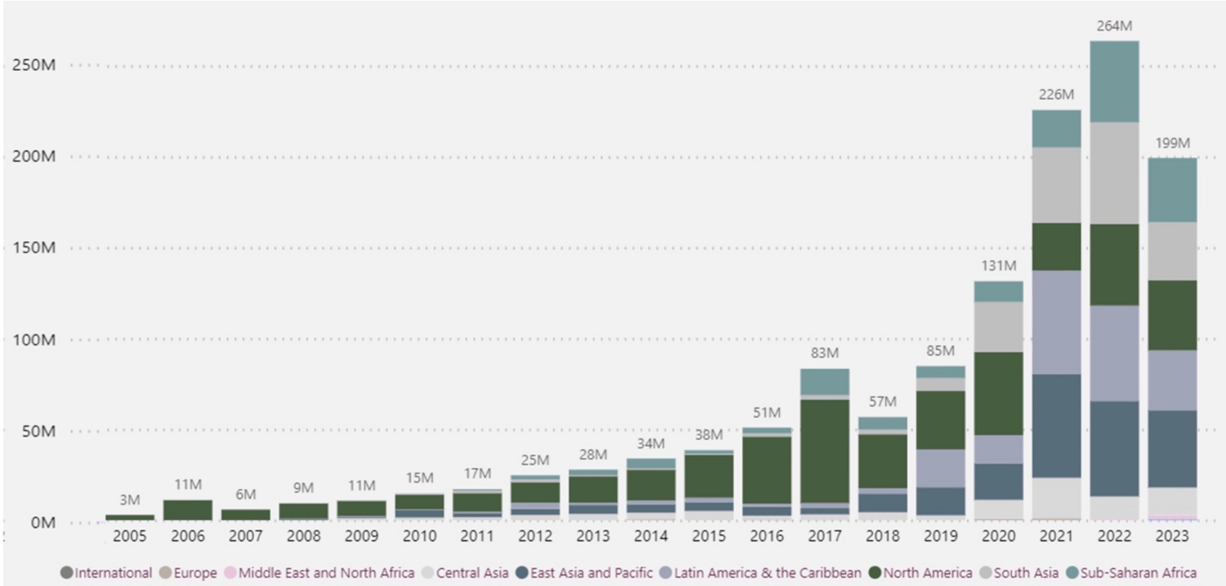



Note: 2023 includes Q1 to Q3 data.

Source: MSCI Carbon Markets.

[38] https://trove-research.com/report/global-carbon-credit-investment-report, Trove Research, 2023, Global Carbon Credit Investment Report.

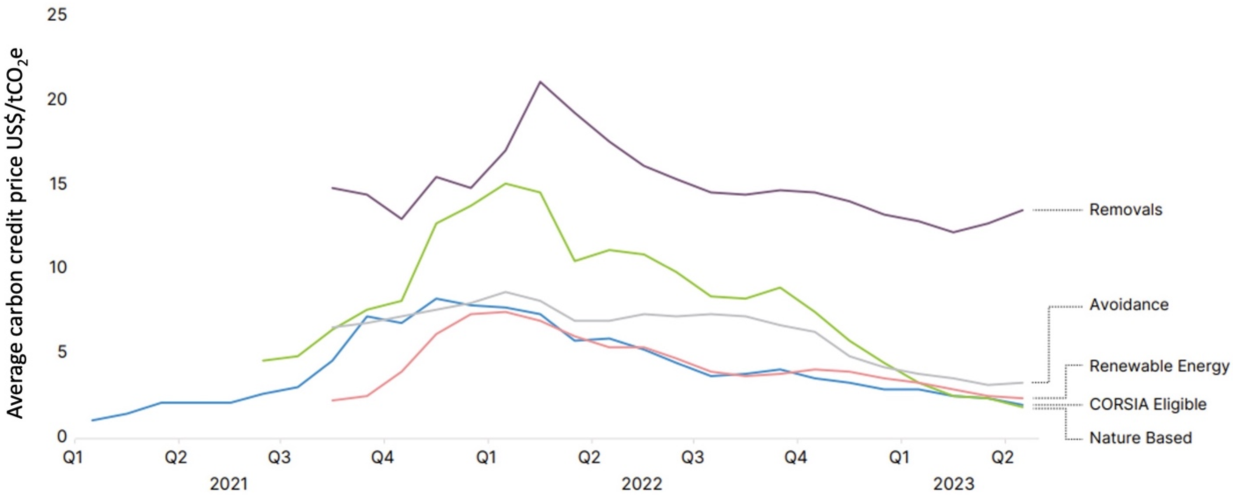
**Figure 2: Global carbon credit issuances by region**




Source: MSCI Carbon Markets.

Price levels also went through a phase of rapid growth in the same period and peaked in the first half of 2022 (Figure 3). Then they entered a slump that continues to this day, due to various factors covered in the following section. However, publicly available data from exchanges and price reporting agencies reflect prices of standardized benchmark contracts. Prices for high-quality projects traded bilaterally have always traded at a premium, and the spread between the two has widened in the current market environment.

**Figure 3: Prices of standardized carbon credit contracts**




Source: S&P Global Platts.

Some observers consider the current slowdown temporary when surveying investment levels in the sector. A recent study by Trove Research (now MSCI Carbon Markets),[39] an organization that specializes in carbon market data, found that investments into carbon projects between 2012 and 2022 totalled $36 billion, with half of this amount occurring in the last three years, and more than $3 billion in future investments is already committed. Investment levels over the past three years are running at several times the value of the VCM, indicative of an industry planning for significant future growth.

[39] https://trove-research.com/report/global-carbon-credit-investment-report, Trove Research, 2023, Global Carbon Credit Investment Report.

**Current challenges**

After operating under the radar for many years, the VCM has received a lot of attention lately. Media reports have investigated some shortcomings in how the market operates, exposing flaws in both methodologies and specific projects that led to over-crediting or double counting of emission reductions. These concerns have been aired by major outlets such as Bloomberg in the United States, The Guardian in the United Kingdom, and Nikkei in Japan, contributing to a significant echo and shaking the credibility in the market.

Regulators have not been idle either. In the EU, the European Commission has put forward legislative proposals on ‘green claims’ and on ‘empowering consumers in the green transition’, with strict rules governing the claims associated with the use of carbon credits. In the US, the Commodity Futures Trading Commission has been convening stakeholder meetings with the aim to eventually bring in more regulation in the VCM. The International Organization of Securities Commissions may follow suit.

The common undertone in these reports and initiatives is that the VCM is being used by corporates as a permission to keep polluting and greenwash their operations. A common perception is that money spent by corporations in the VCM is money diverted away from more meaningful action within their operations and supply chains. This claim is resolutely disputed by industry. An analysis of 100 companies performed by the carbon ratings agency Sylvera showed that those who purchase carbon credits are decarbonizing at a rate almost twice as fast as those who do not purchase carbon credits.[40]

A negative perception of carbon credits and the VCM has also informed the work of the Science-Based Targets initiative (SBTi)—an initiative of CDP, the World Resources Institute, the World Wildlife Fund, and the UN Global Compact which has established a framework for corporate decarbonization in line with science and the goals of the Paris Agreement. Over 6,000 companies worldwide have committed to a science-based target; by the end of 2022, these companies represented 34 per cent of the global economy by market capitalization. Current sectoral guidelines put forward by SBTi do not consider the use of carbon credits as a tool to meet interim targets, seriously limiting the ability of the VCM to help companies achieve their targets. SBTi is currently developing guidance on ‘beyond value chain mitigation’ in the context of net-zero goals. A recognition of the role the VCM could play has the potential to unlock greater action and impact. This would require new incentives, clear use cases and guardrails for a scale-up, and credible use of carbon credits.

The need to improve market integrity and credit quality in the VCM had been identified by industry long before it attracted the attention of external stakeholders. In particular, two major international multi-stakeholder initiatives are underway: the Integrity Council for the Voluntary Carbon Market (IC-VCM) and the Voluntary Carbon Market Integrity Initiative (VCMI). IC-VCM was launched in 2020, under the name Task Force for Scaling the VCM, by former governor of the Bank of England Mark Carney. Its work focuses on setting a benchmark for credit quality. In June 2023, it published the final version of its Core Carbon Principles Assessment Framework. It defines how carbon crediting standards and their methodologies will be assessed for high quality, as a way of building integrity and scaling the VCM. It is a daunting but welcome endeavour, especially as many new carbon crediting standards are emerging, leading to confusion over the quality and attributes of the units they issue. VCMI is attempting to set a similar quality benchmark on corporate claims. It published a code of practice that constitutes useful guidance for buyers on how to use carbon credits as part of their climate strategy and what claims to make to the public. A key question that needs to be addressed is whether and under what circumstances carbon credits can legitimately give rise to a compensation (or offsetting) claim. Otherwise, corporates will have to reorient towards different models, such as ‘climate contribution’ or ‘funding climate action’ claims.

IC-VCM and VCMI are complementary initiatives in nature—one is addressing the supply side and the other the demand side of the VCM. If successful, they will represent a significant achievement in industry self-regulation and discipline. However, the list of governance initiatives does not stop here. The International Organization for Standardization is currently finalizing a new global standard for organizations to achieve carbon neutrality. In the UK, the Treasury launched a Transition Plan Taskforce to develop best practices for the private sector. The United Nations has also sought to play a role in this space by convening a High-Level Expert Group on the Net-Zero Emissions Commitments of Non-State Entities, which delivered its recommendations at COP27 in November 2022.

[40] https://www.sylvera.com/resources/carbon-credits-and-decarbonization, Sylvera, 2023, Carbon Credits: Permission to Pollute, or Pivotal for Progress?

Another challenge the VCM has been facing is related to government intervention in countries where the projects generating carbon credits are located (called host countries in industry parlance). Throughout 2022, the market was taken by surprise when the governments of Indonesia, Papua New Guinea, and Honduras announced moratoria on all or some VCM projects within their jurisdictions. In May 2023, Zimbabwe declared all VCM contracts in the country null and void and announced a new framework allocating 50 per cent of total revenue to the government, 20 per cent to local communities, and only 30 per cent to investors. Several African countries signalled their intention to follow suit. While not all announcements were followed by concrete measures, and most countries maintain an investor-friendly stance, some saw in these developments the ushering in of a new era of carbon nationalism pitting host country governments against foreign investors, similar to what has happened with oil and other extractive industries.

**The future of the VCM**

With such a level of uncertainty around market integrity, governance, policy, and reputational risk, it is not surprising that the VCM has taken a hit and potential buyers of carbon credits have been deterred. While as recently as January 2023, BloombergNEF forecasted that the VCM could reach a market size of $1 trillion by the end of the next decade,[41] such optimism now appears misplaced. The difficulties have been compounded by an unfavourable macroeconomic and geopolitical backdrop, characterized by rising interest rates, a slowing global economy, the war in Ukraine, and heightened US-China tensions. However, there are many signs of resilience. While some companies openly terminated or scaled back their investment and purchase plans, others are taking a cautious approach to avert criticism and backlash—to avoid being blamed of greenwashing, some are *greenhushing* (not taking credit for their undertakings). Many are simply holding tight and waiting for greater clarity on market governance and government policy.

In addition to an increase in corporate purchases, the blurring of boundaries between the voluntary and compliance markets represents a significant opportunity for the VCM. As all countries now have nationally determined contributions to achieve, some of them are likely to look to the VCM and its infrastructure. Domestic carbon credits generated in the VCM can already be used to partially offset compliance obligations under an emissions trading system (in California) or a carbon tax (in Colombia and South Africa). The adoption of guidance on Article 6.2 of the Paris Agreement at COP26 in November 2021 opens the door for the use of international carbon credits. In 2022, Singapore established a carbon tax that can be partially compensated by using eligible carbon credits from participating countries. More broadly, emission reductions achieved by VCM projects, if not claimed by the country in which the corporate buyer is incorporated, can be counted towards the host country's climate targets, creating obvious synergies between VCM players and host country governments.

For the last four to five years, the VCM has been on a roller coaster. A new phase of consolidation and steady expansion is what it needs to mature and contribute to global efforts to reduce emissions and meet the Sustainable Development Goals. Depending on how things unfold, in a decade's time we may regard the present day in very different ways. We could see either an exciting time where industry and governments strived to improve the VCM and deliver greater climate impact, or a forgone opportunity to rapidly channel corporate money into climate action.

[41] https://about.bnef.com/blog/carbon-offset-market-could-reach-1-trillion-with-right-rules/, Bloomberg NEF, 2023, Carbon Offset Market Could Reach $1 Trillion With Right Rules

# THE ROLE OF HYDROGEN IN ENERGY TRANSITION, BEYOND THE BATTLES: HOW TO LEAD THE WORLD INTO A HYDROGEN FUTURE—A GUIDE FOR OFFTAKERS

***Erik Rakhou***

How will a zero-carbon future look? Many offtakers ask this as they face a pressured choice on how to decarbonize. Will it be based on electrification, biofuels, or hydrogen? In the EU and well beyond, various strategies and initiatives are driving both of these options with a view to achieving decarbonization by 2050 in line with the Paris Agreement. This article sets the scene on how to think of factors affecting decarbonization choices, including use of hydrogen. It takes a look into the future—where the ideological discussion over what works best, electrons or molecules, may continue—based on the book *Touching Hydrogen Future*[42] and the author's work as consultant. It then takes a step back into the present, examining which factors will be crucial for consumers and businesses in the choices they make as they move towards a zero-emissions society where hydrogen will play a role. Surprisingly (or not?), it's a brighter world if we collaborate and find platforms where we can do so.

### Hydrogen in the limelight

Hydrogen has been the focus of global attention for a while, as a molecule that is abundant and is vital to fuel the world without carbon emissions, if only it could be produced and transported at scale economically in comparison to decarbonized alternatives. As an example of hydrogen's importance, a big part of our global food value chain already depends on it. Hydrogen is used to produce ammonia, which is a key ingredient in fertilizers. Any country or alliance that masters hydrogen will be a world leader in energy and in the food value chain and will have the economic independence for which so many strive.

This article does not aim to present a defence of hydrogen technologies or summarize their pros and cons. It simply showcases two highly critical issues—battles, if you like—that may drive the uptake or downfall of hydrogen as an 'important' energy carrier in Europe and perhaps globally. ('Important' would mean that it made up at least 10 per cent of the primary energy mix by 2050, as some of the leading global energy agencies, like the International Energy Agency and the International Renewable Energy Agency, have professed on occasion in the past.)

Before we dive into the battles, we first give a quick guide to where hydrogen can play a role, viewed from an offtaker perspective.

### Choosing where and when to use hydrogen

Hydrogen is competing for its place in energy transition in traditional strongholds of fossil fuels (coal, natural gas, and oil) in power generation, industry, and domestic heat. The key drivers of decisions on where and how to use hydrogen to replace fossil fuel applications include at least the following factors, presented in random order.

- **Cost:** Producing, storing, and transporting hydrogen, when unsubsidized, is at present more expensive than other energy sources, such as unabated natural gas and electricity. However, the cost of hydrogen is expected to come down in the future, as the technology improves and economies of scale are achieved, helped by initial projects being derisked for first-mover disadvantages.
- **Efficiency:** Hydrogen is a very energy-dense fuel (by mass), as known from its use for sending rockets to space, but it is so far inefficient to produce and use. For example, if a hydrogen-based fuel cell powers a truck, a much smaller portion of the solar energy that was originally put in is used for propulsion than with a battery. The ratio is about 30 percent vs 70 percent. The so-called well-to-wheel efficiency of fuel cells is therefore lower than that of batteries by a factor of two to two and a half. The reason for this is that a significant portion of the usable energy is lost when hydrogen is generated in the electrolyser and later converted into electricity in the fuel cell. However, there are some applications where the benefits of using hydrogen outweigh the inefficiencies, such as hard-to-abate industries, long-term energy storage, and transportation.
- **Safety:** Hydrogen is a flammable gas, so it needs to be handled with care. However, it is also a very safe fuel when handled properly. Similar to natural gas, its safety can be enhanced by odorization.
- **Availability:** Hydrogen is not currently widely available, but there are plans to build new hydrogen production and infrastructure in many parts of the world. As the availability of hydrogen, and its supporting infrastructure, increases, for example driven by policies, it will make it more feasible to access and use in a wider range of applications.

[42] https://europeangasmarket.eu/.

- **Alternatives:** The key alternatives to hydrogen depend on the specific application and a number of factors, including cost, efficiency, safety, and availability. However, some general alternatives include the following:
    - Electricity reinforced with batteries—electricity is a very versatile energy source that can be used for a wide range of applications, including transportation, heating, and industrial processes. In addition, batteries are becoming increasingly efficient and affordable, making electricity a more efficient alternative to hydrogen for many applications, such as electric vehicles and short-term energy storage.
    - Biofuels—these are liquid fuels that are produced from organic matter, such as plants and algae. Biofuels can be used to power vehicles, generate electricity, and produce heat. Such alternatives can be limited, for example by availability of power grids or sufficient biomass feedstock.

Based on the above factors, one can see offtakers across the globe prioritizing the following applications for hydrogen:

- **Replacing fossil-based hydrogen in existing use cases:** Hydrogen is currently used in a number of industrial processes, such as ammonia production and oil refining. This hydrogen is produced from fossil fuels, so it is important to replace it with low-carbon hydrogen produced from renewable energy sources, nuclear energy, and/or abated natural gas.
- **Supporting electrification for new use cases:**
    - Long-term energy storage—hydrogen can be stored for long periods of time, making it ideal for balancing the intermittency of renewable energy sources. Particularly in power generation, in peak support, one can see such use cases considered.
    - Mobility—hydrogen can be used to power mobility, including cars, trucks, buses, trains, airplanes, and ships. However, hydrogen fuel cell vehicles are currently more expensive and less efficient than electric. In some use cases, for example in shipping, there has been progress on this (synthetic fuels).
- **Other potential applications for hydrogen due to policy preferences:** Heating and baseload electricity generation are not globally considered because there are other, more cost-effective and efficient solutions available. Some countries, due to policy concerns—for example energy security and traditional assets being left stranded—still prioritize such solutions for heating and baseload.

**Tales of consumer choice**

And so back to battles. Two key issues driving hydrogen market uptake at present are ‘electrons versus molecules’ and ‘green jobs and competition’ (also known as the regulatory incentives and subsidies battle). Two stories may contribute to insight and debate on what it may take for Europe to co-lead the hydrogen market rise. The thinking can also be applied to more geographies globally wishing to lead in shaping hydrogen markets.

One story is from Touching Hydrogen Future,[43] a book, downloaded in over 130 countries, that explores hydrogen futures in Jules Verne style, travelling the world in the 2030s and 2040s, of which this author is initiator, co-editor and one of 38 co-authors.

The other story is on the importance of policy context and reviews the ongoing debate on Europe’s response to global green competition through the hydrogen market prism. The first story is fictional and futuristic, while the second story is playing out now. The common thread between the two battles is hydrogen leadership on a global scale being driven by policy competitiveness, in turn driving consumer and business preferences.

After presenting these two stories, the article will offer conclusions on what may be the next step for Europe and others wishing to lead hydrogen market evolution, inviting debate. This battle is likely to be won through policy, not by pitting electrons against molecules.

[43] https://europeangasmarket.eu/.

***Electrons versus molecules***

'We need to be at consumer's future car dashboard' said the former CEO of a global energy company, speaking on a recent podcast of his firm's energy transition pathway.[44] Now, there are many ways in which you can read such a thought. This author's reading, as a hydrogen advisor and someone who has worked with over 50 firms and governments in the last year on energy transition and hydrogen, is that the pathway of change and the future of energy transition both depend on the technological choices consumers make. The only way to experience what such choices entail is to live through them as a business or consumer.

The story below illustrates one such choice. It is an extract from the chapter 'The Netherlands 2029' in *Touching Hydrogen Future*.[45]

> His watch bleeped again—his hydrogen-fuelled next-generation Toyota taxi, called the Dutch HYPE after a few successful Paris projects—was reporting to wait for him at the airport. How things had moved on since his debate with a Tesla taxi driver in Amsterdam in the early 2020s, who happened to be an expert on the pros and cons of electric vehicles versus hydrogen cars and trucks.
>
> Me: So what do you think about the use of hydrogen in cars and trucks?
>
> Tesla taxi driver: It's feasible but not sensible. It can't compete with battery electric and uses too much energy. The distribution of hydrogen is almost prohibitively expensive, and they're struggling to get rid of grey hydrogen in sectors like fertilisers and refining. Hydrogen is not a solution that justifies expanding the market for it. We're better off putting the effort into finding ways to make it competitive in sectors where hydrogen is already used. I'm all for green hydrogen for ammonia in the fertiliser industry, and methanol production. That's about it.
>
> Me: Hmmm … but I do see some industrial scale-ups for hydrogen trucks—Hyzon, Nikola, Daimler, Quantron, Hyundai, Tevva, Gaussin & Plug Power…
>
> Taxi driver: It does not make it right, just because strong and innovative players are doing it. Most of the world's hydrogen is made from methane and coal in a dirty energy consuming process. Any expansion of that market shouldn't be allowed today. I can put it into perspective. Do you like maths? Here are some quick numbers for you. The current wind generation in this country is, let's say, 1x. Converting the trucks and car fleets from diesel to green hydrogen would require another 1.5x in comparison with 0.5x for the fully electric conversion of fleets. There are ball park figures based on Volkswagen research, which show huge conversion losses from renewable energy down to using hydrogen in fuel cells in comparison to the direct use of renewable power. It would be insanely expensive.
>
> Me: If we were only looking at building 100 percent renewable energy just here in Europe, I would agree. But there are global trade value chains emerging where hydrogen helps to bring stranded renewable power to end-users on different continents. And what about other factors in the decision? In your experience, are your solutions for cars and trucks able to cover, say the 800 km between Rotterdam and Munich?
>
> Taxi driver: I don't drive trucks, so it's a mental exercise. But if you are suggesting that hydrogen is superior to battery electric in terms of range, you're wrong. Range is similar in my view. The limitation for hydrogen is weight and volume, with emphasis on volume. The limitation for battery electric is also weight and volume with emphasis on weight. In reality there is no real difference at present. The only benefit for hydrogen trucks over battery is filling time, which is a perceived benefit rather than a real one. There is no problem charging a 44-tonne truck with 400 km of range in well under an hour. 400 km is roughly what's required to cover the allowed time for driving intervals under European rules for taking breaks. That's more or less all you need to know to realise that hydrogen for cars and trucks is a dead end.
>
> Me: If range is indeed manageable at 400 km, in Europe hydrogen in trucks will face strong electric competition. It

[44] See *In good company with Bernard Looney*, at https://youtu.be/xdFD6dJVj_A?si=pcdHCJ6bUmrHdvr5
[45] See *Touching Hydrogen Future*, www.europeangasmarket.eu.

> will come down to who manages the supply and storage better. Nikola's and the Shell-Daimler concept, which appear to copy Tesla's approach of fuel-plus-vehicle, is a good one. If the same is offered in electric, hydrogen trucks will face competition indeed. The electric storage is not trivial—battery solutions don't yet match the required duration, so one needs grid power. Grids may be slow to ramp up. But as the hydrogen value chain gets developed for other industries, then its supply chain could be reused for cars and trucks with hydrogen fuel cells, just in time to compete with electric cars and trucks …?
>
> Taxi driver: All those things matter, but in the end three main arguments should put a stop to any tax money being poured into subsidising hydrogen for vehicle use. First, it's still a monumental task to get rid of the existing grey hydrogen. Second, hydrogen trucks and cars need two to three times more energy as input due to energy conversion losses versus electric solutions. Third, we are talking about the fruits hanging highest in the tree for $CO_2$ reduction in transport. All efforts of transport decarbonization should be focused on the lowest hanging fruits where electrification is another no-brainer. I'm sure there will be shipping industry or aviation industry firms that struggle for alternatives to decarbonize and will be more than happy to pay top dollar for fuels derived from green hydrogen, and pay for their special properties as molecules—hence there's no reason to waste green hydrogen in trucks or cars, just yet.
>
> At that point we arrived and the conversation ended. My mind circled back to today —in 2029: That taxi driver was quite right, aviation and shipping came first. But the use of hydrogen in cars and trucks came second.

The above story illustrates, through a fictional dialogue, how consumers can deeply disagree on the role that electrons and molecules play. Historically such 'technology choice' battles are often won due to nontechnological reasons, with policy support being a big driver of the outcome.[46] We are seeing the making of this in the green jobs battle, which may decide hydrogen and electron technological preferences, as illustrated in the second story.[47]

***Green competition and the fight for green jobs***

This story that follows is an amended version of 'A rising tide lifts all boats—Europe and US are both working to develop green technologies—Hydrogen as example'[48].

The world was woken up in January 2023 by the developing global debate on green competition. At the World Economic Forum meeting in Davos, Ursula von der Leyen, President of the European Commission, announced a new Net Zero Industry Act as part of the Green Deal Industrial Plan, widely seen as Europe's response to the US Inflation Reduction Act (IRA).[49] She said: 'We need to create a regulatory environment that allows us to scale up fast and to create conducive conditions for sectors crucial to reaching net zero.' This includes wind, heat pumps, solar, clean hydrogen, and a continued response by the EU for access to critical raw materials needed for energy transition.[50]

The pressures for and value from decarbonization (the rising tide of green competition) are creating new sources of competition between global governments. This includes competition for capital, market share, raw materials, and labour/capabilities. In turn, these new competitive dimensions are shaping the US and EU responses on policy formulation in the context of green competition. The next section offers an example of what this means for hydrogen in particular.

*EU responding to the US IRA approach on hydrogen*

The EU has its own ambitions to develop a green hydrogen sector and is concerned that this might be undermined by highly subsidized imports from the US. It is responding by stepping up its own hydrogen strategy, including the following:

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[46] For an illustrative discussion on the battle of electrons versus molecules, see https://www.linkedin.com/posts/erik-rakhou_electrons-hydrogen-eu-activity-7027934076720291841-fCBj?utm_source=share&utm_medium=member_desktop.

[47] For an illustrative sentiment on the matter, see Breton, T., 'No Green Deal without strong European clean tech manufacturing', *LinkedIn*, https://www.linkedin.com/pulse/green-deal-without-strong-european-clean-tech-thierry-breton/?trackingId=AbJQXxkcQumBN4jrRvk3Dw%3D%3D.

[48] See LinkedIn, https://www.linkedin.com/pulse/rising-tide-lifts-all-boats-europe-us-both-working-develop-rakhou/?trackingId=hie3UbHKSBCgV%2FCIyhJv3w%3D%3D.

[49] https://ec.europa.eu/commission/presscorner/detail/en/SPEECH_23_232.

[50] https://www.euractiv.com/section/energy-environment/news/eu-to-introduce-targets-for-raw-materials-self-sufficiency/.

- **Access to funding:** Theoretically this should ultimately provide access to overall EU climate spending of at least €600 billion in the 2021–2027 Multiannual Financial Framework. (The 2021–2027 EU budget is the largest stimulus package ever financed in Europe, totalling €2.018 trillion. It comprises the budget for the next seven years, the Multiannual Financial Framework (totalling €1.211 trillion), and a temporary recovery instrument, NextGenerationEU (NGEU, totalling €806.9 billion). A large part of each is directed to climate change, and together these EU funds represent a target of at least €600 billion in climate funding, or €86 billion in public funding per year over seven years. [51]
- **Relaxation of state aid:** There is strong pressure from member states with more limited national resources for more EU-level funding to help them introduce IRA-similar measures. The EU Sovereignty Fund—more EU funding for member states with less strong balance sheets—could be a way forward for such assistance).
- **Investments in green upskilling:** This includes initiatives like the EU-funded Clean Hydrogen Partnership,[52] to benefit with an additional focus on education and upskilling.
- **A fair trade focus:** The EU will take a carrot and stick approach to the international trade in hydrogen. CBAM, Carbon Border Adjustment Mechanism, is an example of such regulation, providing a stick to keep 'bad' hydrogen out. As a carrot, the EU wants to extend its free trade agreements with key partners to include products such as hydrogen.

*Trade conflict and the rise of hydrogen technology*

In her speech in Davos in January 2023, Ursula von der Leyen mentioned the US IRA, to which these measures appear designed to be part of the EU response. Does this mean that the EU and the US are set for a trade conflict over decarbonization? No. In reality, the rising tide of climate action will lift both the European and American boats, just through different regulatory models. And in particular hydrogen markets may be the area where this will play out.

The green competition of incentives in Europe and the US to promote (among other things) the use of clean hydrogen will have a significant impact on the global hydrogen market. It will accelerate the cost curves for both supply and demand, driving investments in larger assets and increasing the efficiency of electrolysers. This will establish both the US and Europe as leading hydrogen players, which could potentially stimulate a further subsidy race globally and reorient and strengthen equipment suppliers in their manufacturing build-up.

**Weaving the two stories together—the common thread**

Europeans tend to like ideological debate (as in first story), but for once we should be, and indeed are, paying attention to competitiveness on a global scale driving consumer and business preferences (as in the second story).[53]

Companies must consider their exposure to the US and European market, portfolio shape, supply chain position, regulatory approach, and funding opportunities. Similarly, country agendas must consider their competitiveness, their role, and localizing supply chains to stay competitive amidst a global green jobs race.

As an example, Europe may need to take a pragmatic approach for the transition period and use well-designed, easy-access IRA-type subsidies to steer consumer choices towards energy transition. This may mean facilitating multiple winners, both electrons and molecules. In hydrogen we are now enabling fuel cell vehicles to finish parallel to battery electric vehicles by mandating refuelling stations every 200 km across Europe under the Alternative Fuels Infrastructure Regulation, part of the Fitfor55 framework.[54] This, paired with an EU blueprint for easy-to-access subsidies at EU level for switching industrial and mobility demand to hydrogen, may further unleash the hydrogen future and bring a tide of energy transition lifting all boats, including European co-leadership of the hydrogen landscape.

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[51] *Recovery Plan for Europe*, https://commission.europa.eu/strategy-and-policy/recovery-plan-europe_en#:~:text=The%20EU%E2%80%99s%20long-term%20budget%2C%20coupled%20with%20NextGenerationEU%20%28NGEU%29%2C,a%20greener%2C%20more%20digital%20and%20more%20resilient%20Europe.
[52] https://www.linkedin.com/company/clean-hydrogen-partnership/.
[53] For an illustrative debate on the need for pragmatism, see https://www.linkedin.com/posts/erik-rakhou_what-should-be-the-price-of-green-hydrogen-activity-7032295620581183488-N1Rn?utm_source=share&utm_medium=member_desktop.
[54] See *Fit for 55: Towards More Sustainable Transport*, https://www.consilium.europa.eu/en/press/press-releases/2023/07/25/alternative-fuels-infrastructure-council-adopts-new-law-for-more-recharging-and-refuelling-stations-across-europe/

Finally, there is still enough time to achieve strategic innovation leadership in climate and energy security for all those able to look beyond the battles and form alliances. Collaboration, and platforms for collaboration, is the key topic going forward for hydrogen, not the battles, or else offtakers—key in choosing hydrogen as one of the options alongside electrification and/or biofuels—will not even consider hydrogen as option to decarbonize.

## CARBON MANAGEMENT AND HYDROGEN: AN INTERNATIONAL SHIPPING PERSPECTIVE

***James Dallimore***

International shipping is a notoriously difficult sector to decarbonize due to its global nature and reliance on 'dirty' fuels, contributing approximately 3 per cent of total global greenhouse gas (GHG) emissions.[55] At present, approximately 80 per cent of global merchandise is transported by sea. And as populations increase and develop, global dependence on maritime transportation of commodities and goods is likely to grow. This presents a challenge and great opportunity for change within such a key sector of the global supply chain, where decarbonization is now gaining positive momentum. However, the question is, how best to achieve this?

Over recent years key players such as MOL (Mitsui O.S.K. Lines), Maersk, COSCO, and CMA CGM have taken the initiative to mark their positions with ambitious goals to decarbonize and lead the global movement through technology development, alternative fuel utilization, and significant investments within innovation and research and development projects.

In combination with industry ambition, regulation is working to align efforts, which can be seen from the Marine Environment Protection Committee (MEPC) 80 meeting held in July 2023. MEPC 80 resulted in adoption of a revised strategy to reduce GHG emissions to net zero by or around 2050, which is considered a great improvement over the initial target of 50 per cent reduction of 2008 emissions levels by 2050. This has sent a clear message to the industry and to the wider global audience of shipping's decarbonization intentions and closer alignment to the 2015 Paris Climate Agreement target.

### Barriers to shipping's transition to net zero

Decarbonization of the maritime sector is complex and will not be immediate. One important aspect of this is that the technical lifetime of an oceangoing vessel is 25–30 years. Therefore, within the shipbuilding sector the development of zero-emission vessel design and associated engines must happen by 2030 to achieve 2050 decarbonization targets. This highlights the urgency of the situation and need for rapid advancements which will define the long-term outlook of the maritime industry.

Equally, the existing global fleet and vessels under construction at present form a critical element of the decarbonization pathway of the industry. Lloyd's Register estimates that without decarbonization of the existing fleet some 20,000 vessels of a potential 270,000-vessel global fleet may still be using fossil fuels in 2050.[56] Engine retrofitting to alternative fuels is a potential solution to this but brings several challenges. These can be summarized as follows.

- **Technology readiness:** Alternative fuel engines remain in the development phase and have yet to reach commercialization at scale.
- **System integration:** This includes modifying existing vessel arrangements to accommodate larger fuel tanks, new piping routes, fuel equipment, and safety arrangements.
- **Human factors:** Alternative fuels will require additional safety and operation training for crew members.
- **Shipyard capability and capacity:** Shipyards are at near capacity for the foreseeable future with the current drive for LNG carrier procurement specifically. Conversion capability will require in-depth knowledge and experience with new technology, which will require time to develop.
- **Economics**: The conversion process will be costly, which is coupled with the higher expenditure on fuel once in operation. Depending on the age of the vessel and trade pattern, retrofit simply may not be viable.

[55] United Nations Conference of Trade and Development (2023), *Review of Maritime Transport, https://unctad.org/publication/review-maritime-transport-2023*

[56] Lloyd's Register (2023), *Engine Retrofit Report 2023: Applying Alternative Fuels to Existing Ships*, https://www.lr.org/en/knowledge/research-reports/applying-alternative-fuels-to-existing-ships/

Although there has been significant progress from regulatory bodies on the above challenges, highlighted by the recent ambition of MEPC 80, the International Maritime Organization requirements for the use of alternative fuels remain under development, with interim guidelines given for the use of methanol (Maritime Safety Circular MSC.1/Circ.1621) and a risk-based approval process for ammonia and hydrogen. Risk-based approval is an effective method and framework to progress alternative fuel use; however, it requires a far greater amount of work in comparison to prescriptive requirements, adding to stakeholders' points to address.

**Pathway to decarbonization**

The pathway to decarbonization can be achieved through immediate, short- to mid-term, and long-term methods and strategies.

***Immediate actions—operational optimization***

This can be summarized as improvement of operational efficiencies whereby operators optimize their voyage performance management. This includes ship speed optimization to conserve fuel and align with port berthing time frames to minimize idling and wasted energy; weather routing to improve safe, accurate, and efficient voyages; bespoke software-based trim, draft, and ballast optimization to maximize speed with constant shaft power to reduce energy and fuel usage; and management of hull and appendage roughness to reduce resistance and subsequently fuel use. These methods are relatively simple to implement and can be done without conversion or large expenditure.

***Short- to mid-term actions—energy-saving devices***

Energy-saving devices are becoming more standard components within new build specifications and retrofit of existing vessels. This has been driven by industry and regulation, specifically the adoption of the Energy Efficiency Design Index, Energy Efficiency Existing Ship Index, Energy Efficiency Operational Indicator, Carbon Intensity Indicator, and Ship Energy Efficiency Management Plan. From implementation, these regulations progressively become more stringent year on year, which has encouraged shipowners to make larger investments such as in energy-saving devices. Examples include (but are not limited to) the following.

- **Air lubrication systems:** Air is supplied to the vessel hull bottom to create a thin layer which reduces frictional resistance, reducing emissions and saving fuel.
- **Wind propulsion:** This includes Flettner rotors, rigid wing sails, and kite sails. Wind propulsion is a highly promising technology which can provide good return on investment through fuel saving and ensure vessels maintain regulatory compliance.
- **Propeller optimization:** This focuses on improving and manipulating the water flow through the propeller via structural ducting or propeller-mounted boss fin caps to increase propulsion efficiency.
- **Hull coatings**: High-performance silicone-based coatings can reduce vessel friction and extend hull cleaning periods, therefore reducing emissions with a cost advantage.

***Mid- to long-term actions—alternative fuels, port infrastructure, and onboard carbon capture***

*Alternative marine fuels*

The maritime sector has identified the need for utilization of clean fuels such as ammonia, methanol, and hydrogen. However, the technology and commercialization are not sufficiently developed at present, nor is a global bunker supply chain in place. MOL and other key players are accelerating this through collaborations and investments for procurement of alternative-fuel-powered vessels, alternative fuels, and associated infrastructure.

In parallel to this, it is of clear importance that there is a need to reduce GHG emissions as technology and infrastructure materialize. Liquefied natural gas (LNG) as a fuel is seen as a realistic, viable solution to navigate this transition period. For this reason, various shipowners have taken the position of proactively procuring LNG-fuelled vessels with ambitious targets to transition their fleets away from traditional 'dirty fuels'. For example, MOL plans to be operating 90 LNG-fuelled ocean-going vessels by 2030,[57] with the aim of transitioning the vessels to synthetic methane use in the future. LNG as fuel is well documented as reducing nitrogen oxide emissions by approximately 80 per cent, while sulphur oxide and particulate emissions are negligible, with a 23 per cent carbon dioxide ($CO_2$) reduction in comparison to diesel or heavy fuel oil powered vessels.[58]

[57] MOL Group (2023), *Environmental Vision 2.2*, https://www.mol.co.jp/en/sustainability/environment/vision/
[58] '*LNG as marine fuel*', https://www.dnv.com/maritime/insights/topics/lng-as-marine-fuel/environmental-performance.html.

However, it is also well documented that engines burning LNG as fuel encounter ‘methane slip’, whereby not all the LNG (predominantly methane) combusts and unburnt methane escapes to the atmosphere. This is problematic as methane has warming potency more than 28 times that of $CO_2$, albeit with a far shorter life span in the atmosphere.[59] There has been considerable progress by maritime engine manufacturers in the reduction of methane slip since the 1990s to ensure LNG’s potential as a fuel is achieved, with even greater focus by stakeholders following MEPC 80. To address this, MOL and other key players are part of the Methane Abatement in Maritime Innovation Initiative, led by the Lloyd’s Register Safety Tech Accelerator, which promotes the development of methane slip reduction technology in collaboration with global shipping companies. On reflection, LNG is seen as a key fuel, but a temporary solution as the maritime industry transitions to zero-emission fuels.

Looking ahead, it is apparent that the optimal alternative fuel will be largely dependent on factors including the type of vessel, shipping route, and cargo carried. Therefore, the industry players who own/operate diverse fleets are investing across the board in developing the optimum fuel case by case. Adopting this method not only benefits the individual company, but also accelerates the wider use and commercialization of alternative fuels.

However, it is clear the use of hydrogen will have a role to play within the maritime sector energy mix where green methanol and green ammonia should be the focus of decarbonization of ocean-going vessels. Pure hydrogen as an oceangoing vessel marine fuel is not seen to be a viable option at present, mainly due to high capital and operational expenditures, low volumetric energy density, complex storage and distribution, and safety issues yet to be fully regulated.

The spotlight must first focus on technological readiness to allow industry to invest confidently when procuring new vessels or retrofitting existing ones. The first commercially operated vessel to be retrofitted with a methanol-capable engine was the *Stena Germanica* in 2015, and this vessel has since successfully been using methanol as fuel.[60] Shortly following this, in 2016, methanol-fuelled engines became commercially available for new builds and were first installed on MOL’s world-first dual-fuelled methanol carrier *Taranaki Sun*.[61] Methanol dual-fuelled vessels have since seen steady continued growth and now occupy 30 per cent of newbuilding orders, with particular momentum from the container ship segment driven by players such as Maersk and Evergreen. The technology is available, and increasing newbuild orders make demand for green methanol clear, but supply is lagging and will need fast acceleration of production to meet market demand and align with decarbonization targets.

Throughout 2023, major green methanol suppliers such as OCI and Methanex have looked to address this and have grown key partnerships with shipping stakeholders to accommodate bunkering methanol-fuelled vessels and develop the green methanol supply chain. With the combination of these initial programmes and the firm new building orders, it is expected that green methanol supply and demand will continue to grow, which in turn will reduce associated costs and allow further investment decisions to be made with exponential growth and global bunkering infrastructure. Until then, defined routes must be applied, limiting vessel type and uptake.

Ammonia is tipped to be the predominant alternative fuel for the maritime industry, due to its expected cost advantage per unit volume and means of eliminating the use and emission of $CO_2$. This is driven by the use of cheaper nitrogen in comparison with biogenic $CO_2$ required for carbon-based e-fuels. However, the technology readiness of ammonia dual-fuelled engines is relatively low, with testing ongoing as of 2023. Engine manufacturers foresee the first ammonia engine to be available for installation in 2024 ,[62] with subsequent sea-going testing before full-scale commercial availability. Equally as with green methanol, the supply chain will have to be developed as industry gains confidence with the technology and demand grows. Demand for both alternative fuels will grow outside the shipping sector, which can only bring positive development and potentially drive the costs down and accelerate adoption within the shipping sector.

*Port infrastructure*

Leading ports can contribute and are contributing significantly to decarbonization as the industry transitions, due to the nature of trade routes and regular calling ports, namely Rotterdam, Singapore, and Shanghai. Key opportunities for these ports are primarily to develop cold-ironing shore-power facilities, allowing vessels to shut off auxiliary engines whilst in port, which drastically reduces emissions. The investment should be made in utilizing renewable sources of electricity to ensure tangible overall emission reduction is achieved. Also, research and development should focus on creating bunkering infrastructure for

[59] ‘*Methane emissions’*, https://energy.ec.europa.eu/topics/oil-gas-and-coal/methane-emissions_en.
[60] ‘Industry celebrates five-year anniversary of world’s first methanol-powered commercial vessel’, https://www.methanex.com/news/release/industry-celebrates-five-year-anniversary-of-worlds-first-methanol-powered-commercial-vessel/.
[61] Mitsui O.S.K. Lines, ‘MOL signs long-term charter contract for methanol carriers with waterfront shipping and construction of newbuilding vessel’.
[62] MAN Energy Solutions (2023), ‘MAN B&W two-stroke engine operating on ammonia’, https://www.man-es.com/marine/strategic-expertise/future-fuels/ammonia

alternative fuels in advance of the demand. This can be initially developed for port vehicles and equipment and port vessels such as tugboats and dredgers, to prove the concept before scaling for the wider transiting commercial fleet.

*Onboard carbon capture and storage*
There is increasing interest in the potential of shipboard carbon capture and storage units as an interim solution whilst alternative fuels become commercialized. This involves installation of post-combustion equipment to 'clean' the exhaust gases and capture the $CO_2$ to then be discharged ashore for alternative uses or sequestration. This is an energy-intensive process with large equipment, reducing the cargo carrying capacity and thus the vessel efficiency, and therefore should not be the key focus of maritime decarbonization. In addition, the utilization of onboard carbon capture and storage will prolong the use of fossil fuels and distract shipowners from investing in alternative fuels. Ultimately the choice will boil down to economics and whether alternative fuels are competitive as and when regulations come into force.

**Final remarks**
There are clear challenges to the pathway to decarbonization and adoption of hydrogen-derived alternative fuels. Due to the 25- to 30-year technical lifespan of vessels, urgent action is required for the development of new vessels and for as many emission-reducing, efficiency-improving methods to be implemented in the existing fleet as possible. Through partnerships and collaboration throughout the value chain, net-zero ambitions can be achieved. Momentum is increasingly building from shipping players, governments, shipyards, ports, and fuel suppliers to work together for this common goal and drive the costs down to accelerate decarbonization of the maritime sector.

## HYDROGEN'S ROLE IN DECARBONIZATION OF AVIATION

***Abdurahman Alsulaiman***

Today's aviation sector predominantly relies on conventional aviation fuels, with the majority being Jet A and Jet A-1 fuels, derived from crude oil.[63] These fuels have long held sway as the industry's go-to choice due to their well-established compatibility with existing aircraft engines and their consistent performance in a wide array of conditions. Nevertheless, amid global endeavours to combat anthropogenic emissions and address the urgent challenge of climate change, the aviation industry faces formidable hurdles on the path to decarbonization. Encouragingly, a spectrum of potential technologies are poised to usher in a transformative era of sustainable aviation practices, and hydrogen, as it may seem, holds a focal point.

The current and recent literature seems to converge towards one of three measures to achieve aviation decarbonization: efficiency improvements,[64] sufficiency measures (i.e. demand reduction),[65] and fuel-and-propulsion technology innovation.[66] The compensation of residual $CO_2$ emissions would be done through carbon credits, which play a more significant role for efficiency and sufficiency measures than for technology innovation.

As the aviation industry grapples with the urgent need to reduce its carbon footprint, these three approaches have gained significant attention. Efficiency improvements, such as aerodynamic design enhancements and the use of advanced materials,

[63] Hemighaus, G. et al. (2007), Aviation technical aviation fuels, Chevron, https://www.chevron.com/-/media/chevron/operations/documents/aviation-tech-review.pdf; Davidson, C., Newes, E., Schwab, A., and Vimmerstedt, L. (2014), An Overview of Aviation Fuel Markets for Biofuels Stakeholders, NREL, https://www.nrel.gov/docs/fy14osti/60254.pdf.
[64] Lee, J. and Mo, J. (2011), 'Analysis of technological innovation and environmental performance improvement in aviation sector', *International Journal of Environmental Research and Public Health*, 8(9), 3777–3795, https://doi.org/10.3390/ijerph8093777; Singh, J., Sharma, S. K., and Srivastava, R. (2018), 'Managing fuel efficiency in the aviation sector: challenges, accomplishments and opportunities', *FIIB Business Review*, 7(4), 244–251, https://doi.org/10.1177/2319714518814073; Borer, N. K. (2018), 'Catalyzing disruptive mobility opportunities through transformational aviation power', 2018 Aviation Technology, Integration, and Operations Conference, https://doi.org/10.2514/6.2018-3356.
[65] Katz-Rosene, R., and Ambe-Uva, T. (2023), 'Degrowth, air travel, and global environmental governance: scaffolding a multilateral agreement for a smaller and more sustainable aviation sector', *Global Environmental Politics*, 1–22, https://doi.org/10.1162/glep_a_00714; Ertör, I., and Hadjimichael, M. (2019), 'Editorial: blue degrowth and the politics of the sea: rethinking the blue economy', *Sustainability Science*, 15(1), 1–10, https://doi.org/10.1007/s11625-019-00772-y; Nick, S., and Thalmann, P. (2022), 'Towards true climate neutrality for global aviation: a negative emissions fund for airlines', *Journal of Risk and Financial Management*, 15(11), 505, https://doi.org/10.3390/jrfm15110505.
[66] Airport Council International and Aerospace Technology Institute (2022), Integration of Sustainable Aviation Fuels into the Air Transport System, ACI, https://www.ati.org.uk/wp-content/uploads/2022/06/saf-integration.pdf; Zhang, J., Roumeliotis, I., and Zolotas, A. (2022), 'Sustainable aviation electrification: a comprehensive review of electric propulsion system architectures, energy management, and control', *Sustainability*, 14(10), 5880, https://doi.org/10.3390/su14105880; Dinçer, İ., and Acar, C. (2016), 'A review on potential use of hydrogen in aviation applications', *International Journal of Sustainable Aviation*, 2(1), 74, https://doi.org/10.1504/ijsa.2016.076077.

have the potential to reduce emissions from existing aircraft. Sufficiency measures, on the other hand, involve strategies such as optimizing flight routes and decreasing the demand for air travel. These approaches can complement the efforts to reduce emissions but may not be sufficient on their own. However, it is worth speculating that the aviation industry seems to favour efficiency improvements and technology innovations over sufficiency measures. The former align with the industry's growth goals and technological advancement. Sufficiency measures, which involve potentially reducing the number of flights or optimizing operations to lower emissions, could be seen as counterproductive to the industry's growth aspirations.

In the context of rising aviation emissions and a slowdown in efficiency-related carbon reduction,[67] the development of novel fuel and propulsion technologies emerges as a promising avenue for achieving substantial decarbonization in the aviation sector. Among these innovative solutions, hydrogen has emerged as a frontrunner, offering a unique set of capabilities. It plays a central role in the production of sustainable aviation fuels (SAFs) and can be directly employed as a fuel for both hydrogen combustion and fuel cell propulsion systems. This innovation not only holds the promise of improved efficiency but also offers the potential for significant reductions in tailpipe emissions, which currently represent the largest source of aviation emissions.[68]

**Hydrogen-powered flight: combustion and fuel-cell propulsion**

Hydrogen can be utilized as a direct fuel source for aircraft propulsion through two primary methods. The first method involves using it much like traditional jet fuel in hydrogen-compatible jet engines, offering the advantage of completely eliminating carbon emissions. In this case, the primary tailpipe emissions from these jet engines would consist of water vapor, nitrous oxides, and waste heat.

The second method represents a novel approach in aviation, as it achieves lift-off by harnessing electricity generated from hydrogen-fed fuel cells, rather than through combustion. This method, along with battery-powered flight, represents a significant shift in the way we've taken to the skies over the past century. In a fuel-cell-powered aircraft, hydrogen is converted into electricity, which then drives an electric motor and a fan or propeller to produce the necessary thrust. The principal tailpipe emissions from fuel cells in this case are water vapor and waste heat.[69]

Before 2020, there were only nine publicly available projects focused on aircraft powered by hydrogen. Eight of these projects used fuel cells, while one aimed to use hydrogen combustion.[70] Only one of these projects, known as the HY4 project, took flight in September 2016. It was a four-seat aircraft powered by hydrogen fuel cells, using gaseous hydrogen as its fuel source.[71] However, starting in 2020 and continuing thereafter, there has been a noticeable increase in the number of projects involving hydrogen-powered aircraft. One of the most significant and ambitious projects is Airbus's ZEROe initiative, which intends to introduce the world's first commercial aircraft powered by hydrogen by 2035.[72] Additionally, the team behind the HY4 project achieved another milestone in September 2023 by conducting the first flight using liquid hydrogen and fuel cells. This change from gaseous to liquid hydrogen doubled the aircraft's range, from 750 kilometres to 1500 kilometres, according to the company.[73]

Starting in 2022, major jet engine manufacturers have made important developments in hydrogen-powered technology for commercial aviation. On 21 February 2022, Pratt & Whitney announced that it was chosen by the US Department of Energy to create an innovative and highly efficient hydrogen-based engine called the Hydrogen Steam Injected, Inter-Cooled Turbine Engine. This engine will use liquid hydrogen for combustion and recover water vapor as part of the Department of Energy's

[67] Lee, D. S., Fahey, D. W., Skowron, A., Allen, M. R., Burkhardt, U., Chen, Q., et al. (2020), 'The contribution of global aviation to anthropogenic climate forcing for 2000 to 2018', *Atmospheric Environment*, 244: 117834, https://www.sciencedirect.com/science/article/pii/S1352231020305689?ref=pdf_download&fr=RR-2&rr=812f2d52899b4be2; Kramer, S., Andac, G., Heyne, J. S., Ellsworth, J., Herzig, P., and Lewis, K. C. (2022), 'Perspectives on fully synthesized sustainable aviation fuels: direction and opportunities', *Frontiers in Energy Research*, 9, https://doi.org/10.3389/fenrg.2021.782823.
[68] Jing, L., El-Houjeiri, H. M., Monfort, J.-C., Littlefield, J., Al-Qahtani, A., Dixit, Y., et al. (2022), 'Understanding variability in petroleum jet fuel life cycle greenhouse gas emissions to inform aviation decarbonisation', *Nature Communications*, 13, 7853 (2022), https://www.nature.com/articles/s41467-022-35392-1.
[69] Thomson, R., Weichenhain, U., and Sachdeva, N. (2020), Hydrogen: A future fuel for aviation?, Roland Berger, https://www.rolandberger.com/en/Insights/Publications/Hydrogen-A-future-fuel-for-aviation.html.
[70] Thomson, R., Weichenhain, U., and Sachdeva, N. (2020), Hydrogen: A future fuel for aviation?, Roland Berger, https://www.rolandberger.com/en/Insights/Publications/Hydrogen-A-future-fuel-for-aviation.html.
[71] German Aerospace Center (2016), Zero-emission air transport – first flight of four-seat passenger aircraft Hy4, DLR, https://www.dlr.de/en/latest/news/2016/20160929_zero-emission-air-transport-first-flight-of-four-seat-passenger-aircraft-hy4_19469.
[72] Airbus (2020), ZEROe, https://www.airbus.com/en/innovation/low-carbon-aviation/hydrogen/zeroe.
[73] H2FLY (2023), H2FLY and partners complete world's first piloted flight of liquid hydrogen powered electric aircraft, https://www.h2fly.de/2023/09/07/h2fly-and-partners-complete-worlds-first-piloted-flight-of-liquid-hydrogen-powered-electric-aircraft/.

Advanced Research Projects Agency-Energy programme.[74] The very next day, on 22 February 2022, CFM, a collaboration between GE and Safran Aircraft Engines, disclosed their partnership with Airbus to conduct tests on an aircraft engine powered by hydrogen.[75] Additionally, in November 2022, Rolls-Royce, in conjunction with easyJet, achieved the successful conversion of a Rolls-Royce AE 2100-A regional aircraft engine to run entirely on renewable hydrogen.[76]

To summarize the differences and similarities between the two hydrogen propulsion methods, Figure 1 provides a comparative overview of hydrogen-powered fuel cells and combustion.

**Figure 1: Aviation value-chain components in hydrogen-powered fuel cells and combustion**

<table>
<tr><th></th><th></th><th>Hydrogen fuel cells</th><th>Hydrogen combustion</th></tr>
<tr><td>Climate impact</td><td>Direct $CO_2$</td><td>-100%</td><td>-100%</td></tr>
<tr><td></td><td>Nitrogen Oxides ($NO_x$)</td><td>-100%</td><td>-50% to -80%</td></tr>
<tr><td></td><td>Water vapour</td><td colspan="2">+150%</td></tr>
<tr><td></td><td>Contrails cirrus</td><td>-60% to -80%</td><td>-30% to -50%</td></tr>
<tr><td>Aircraft design</td><td>Compatibility with conventional engines</td><td>No compatibility</td><td>Some compatibility</td></tr>
<tr><td></td><td>Engine architecture</td><td>New propulsion concept</td><td>Same propulsion concept</td></tr>
<tr><td></td><td>Aircraft architecture</td><td colspan="2">New fuselage required</td></tr>
<tr><td></td><td>Electrical systems</td><td>New system requirements</td><td>Traditional system requirements</td></tr>
<tr><td></td><td>Increased fuel volume compared to kerosene</td><td colspan="2">High for gaseous $H_2$<br>Medium for liquid $H_2$</td></tr>
<tr><td></td><td>Increased fuel and propulsion system mass</td><td>High for gaseous $H_2$<br>Medium for liquid $H_2$</td><td>High for gaseous $H_2$<br>Low for liquid $H_2$</td></tr>
<tr><td>Aviation supply chain</td><td>Complexity</td><td>High complexity</td><td>Medium complexity</td></tr>
<tr><td></td><td>Infrastructure</td><td colspan="2">High for gaseous $H_2$<br>Medium for liquid $H_2$</td></tr>
<tr><td>Hydrogen source</td><td>Fossil-based</td><td colspan="2">Requires carbon capture and storage for $H_2$ production</td></tr>
<tr><td></td><td>Renewable-based</td><td colspan="2">No requirements</td></tr>
</table>

Sources: Author's analysis of data from Thomson, R., Weichenhain, U., and Sachdeva, N. (2020), Hydrogen: A future fuel for aviation?, Roland Berger, https://www.rolandberger.com/en/Insights/Publications/Hydrogen-A-future-fuel-for-aviation.html; European Union Aviation Safety Agency (2022), Hydrogen and its potential in aviation, https://www.easa.europa.eu/en/light/topics/hydrogen-and-its-potential-aviation; and the European Union Fuel Cells and Hydrogen Joint Undertaking (2020), Hydrogen-powered aviation: A fact-based study of hydrogen technology, economics, and climate impact by 2050, https://www.euractiv.com/wp-content/uploads/sites/2/2020/06/20200507_Hydrogen-Powered-Aviation-report_FINAL-web-ID-8706035.pdf.

As shown in the previous figure and to summarize current publicly available industry knowledge, in a world that strictly controls carbon emissions, hydrogen-powered aviation must play a significant role in achieving carbon neutrality. However, it's crucial to highlight two important points.

Firstly, in an industry that's highly regulated and driven by efficiency, it's challenging to imagine a future where both hydrogen-powered and conventional aircraft coexist equally. Airlines, aiming for increased profitability through streamlined operations, may find it impractical to manage two entirely different types of aircraft with distinct propulsion systems. The history of the Aérospatiale/BAC Concorde serves as a pertinent example where innovation was constrained within the aviation industry.

Secondly, a consensus has emerged among major aviation stakeholders, indicating that hydrogen-powered flight is unlikely to be the primary means of achieving carbon neutrality by the mid-21st century. This achievement is more likely to be attributed to SAFs and efficiency improvements. This perspective is notably presented in all three scenarios detailed in the reports of the International Civil Aviation Organization (ICAO) Long-Term Aviation Goals.[77]

[74] Pratt & Whitney (2022), Pratt & Whitney awarded department of energy project to develop hydrogen propulsion technology, https://www.prattwhitney.com/en/newsroom/news/2022/02/21/pw-awarded-department-of-energy-project-to-develop-hydrogen-propulsion-technology.

[75] GE (2022), Hydrogen takes flight: Airbus and CFM international to partner on hydrogen-fueled demonstration, https://www.ge.com/news/reports/hydrogen-takes-flight-airbus-and-cfm-international-to-partner-on-hydrogen-fueled.

[76] Rolls-Royce (2022), Rolls-Royce and easyJet set new world first, https://www.rolls-royce.com/media/press-releases/2022/28-11-2022-rr-and-easyjet-set-new-aviation-world-first-with-successful-hydrogen-engine-run.aspx?sc_lang=en.

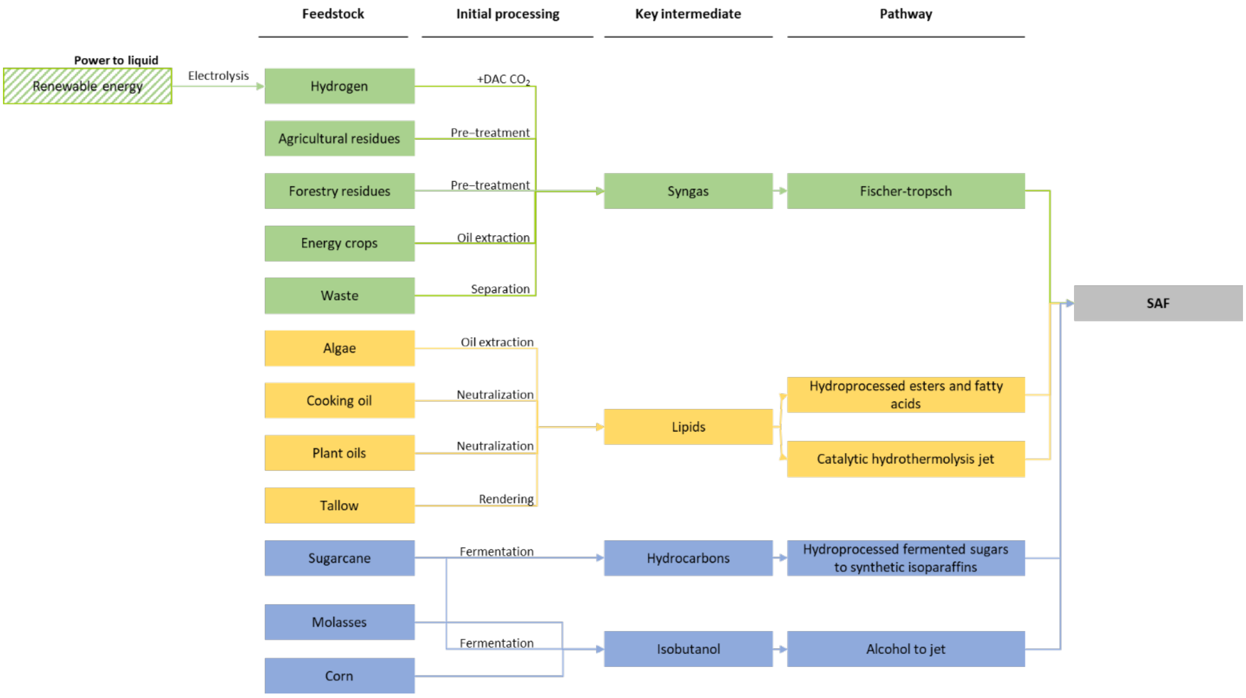
[77] ICAO (2022), Long term global aspirational goal, https://www.icao.int/environmental-protection/LTAG/Pages/LTAGreport.aspx.

### Hydrogen's role: from feedstock to SAF

Before delving into the discussion of hydrogen's role in SAF production, it's crucial to grasp that SAF, as per ICAO, refers to aviation fuel derived from renewable or waste sources and is subject to specific sustainability criteria detailed in Annex 16 Volume IV of CORSIA[78]. Presently, SAF is certified in accordance with the ASTM D7566 standard (ASTM International is a globally respected organization for developing and publishing technical standards). However, the definition of SAF could evolve over time, depending on the consensus among ICAO member countries participating in CORSIA. Additionally, the approved methods for SAF production may broaden as the aviation industry evolves.

Currently, there are eleven approved methods for producing SAFs, as recognized by CORSIA, falling under the ASTM D7566 Annex 1 to 8 and D1655 Annex A1[79], most of which can be seen in Figure 2. These ASTM-approved pathways include Hydroprocessed Esters and Fatty Acids (HEFA), Gasification and Fischer-Tropsch (FT), Alcohol to Jet (AtJ), Hydroprocessed Fermented Sugars to Synthetic Isoparaffins (HFS-SIP), and Catalyzed Hydrothermolysis Jet (CHJ). The importance of these ASTM standards lies in their role as a reference point for the aviation industry and regulatory bodies. ASTM standards ensure the quality, consistency, and safety of SAFs, allowing for their widespread adoption in the aviation sector. Indeed, these standards help in making sure that SAFs meet specific criteria, such as composition, performance, and emissions reductions.

**Figure 2: Methods for SAF production**




Source: Adapted from Thomson, R., Sachdeva, N., Healy, A., Bailly, N., and Stern, C. (2020), Sustainable aviation fuels, Roland Berger, https://www.rolandberger.com/publications/publication_pdf/roland_berger_sustainable_aviation_fuels.pdf.

The importance of these ASTM standards lies in their role as a reference point for the aviation industry and regulatory bodies. ASTM standards ensure the quality, consistency, and safety of SAFs, allowing for their widespread adoption in the aviation sector. These standards help in making sure that SAFs meet specific criteria, such as composition, performance, and emissions reductions.

Among these pathways, the most commonly used method for commercial SAF production is the HEFA pathway, although some FT-based SAFs are also available, albeit in smaller quantities. Each of these pathways, except for HFS-SIP, results in the production of a synthetic paraffinic kerosene (SPK), which can be readily blended with conventional jet fuels. Most of these pathways allow for blending of up to 50 per cent SAF (subject to current regulatory limits), while HFS-SIP and Hydrocarbon-Hydroprocessed Esters and Fatty Acids (HC-HEFA)are approved for up to 10 per cent blends. More details can be found in the

[78] ICAO. (2023a), Sustainable aviation fuel, https://www.icao.int/environmental-protection/pages/SAF.aspx
[79] ICAO. (2023b), Conversion processes, https://www.icao.int/environmental-protection/GFAAF/Pages/Conversion-processes.aspx

ASTM D7566 standard. In the FT pathways (FT-SPK and FT-SKA), the feedstock is thermally converted into syngas, which is a mixture of hydrogen and carbon monoxide. The syngas then undergoes a series of iron/cobalt-catalysed reactions to synthesize kerosene. In HEFA pathways (HEFA and HC-HEFA), oils are treated with hydrogen to reduce and isomerize them into suitable hydrocarbons, which are subsequently cracked and fractionated to create an appropriate blend of paraffins for jet fuel.

The CHJ pathway follows a similar process using lipid intermediates to HEFA. It reacts lipids with water under extreme temperatures and pressures to produce a mixture of hydrocarbons. Alcohol to jet and HFS-SIP both involve fermenting carbohydrate feedstocks with additional secondary reactions and purification steps, resulting in different intermediates and products. Notably, HFS-SIP does not directly produce SPKs[80]. Interestingly, the widespread misconception about the role of hydrogen in SAF production being confined to the FT-based pathway is incorrect. In reality, in almost all SAF production routes, the incorporation of external hydrogen sources is essential to enable diverse chemical processes leading to SAF production. It's crucial to acknowledge that, although the amounts of required hydrogen may differ among these pathways, its involvement is indispensable in SAF production.

Once SAF is produced, blended with regular jet fuel, and certified under the ASTM D7566 standard, users become eligible for carbon offset credits through CORSIA. Notably, SAF can be handled just like traditional aviation fuel and can be easily mixed in the existing infrastructure. The rationale behind the current blending limits is to ensure compatibility with the majority of airworthy commercial aircraft. The standard establishes limitations on specific compounds (e.g. aromatics, cycloparaffins, and trace compounds) that a fuel must adhere to in order to gain certification as aviation fuel, meeting its secondary functions of lubrication and sealing.[81] Nonetheless, this is anticipated to become less of a concern as older aircraft fleets retire and the engines of new fleet aircraft do not impose the same constraints.[82]

In the realm of policy announcements, there has been a notable upswing in support for SAF over the last five years, with approximately 96 per cent of all SAF policies having been adopted or declared to be in the developmental stage.[83] Positively, there is a substantial commitment to the utilization of SAF, exemplified by the ReFuelEU proposal.

According to the EU proposal, by 2025, a minimum of 2 per cent of aviation fuel supplied should be derived from sustainable sources. By 2030, this minimum share of SAF is to increase to 5 per cent, and by 2050, it should reach an impressive 63 per cent. Within this SAF requirement, there is a sub-obligation pertaining to synthetic aviation fuels, which are produced using hydrogen. This sub-obligation is set to increase from 0.7 per cent in 2030 to 28 per cent by 2050.[84]

Shifting focus from policy to recent and current SAF production, it’s worth noting that in 2022, SAF made up only 0.1 per cent of the total aviation fuel demand, as reported by the International Air Transport Association (IATA).[85] However, in 2023, analysis of ICAO data indicates that more than 5.5 billion litres of SAF are projected to be delivered.[78] If the total fuel demand increases as estimated by IATA, which is a 15 per cent growth,[86] this would amount to more than 1.5 per cent of the total aviation fuel demand.

Looking ahead, there are various estimates regarding the potential market share SAF could attain in the next decade and by 2050. ICAO and IATA, prominent entities in the aviation sector, suggest that SAF could play a substantial role. According to ICAO’s Long-Term Aviation Goals report scenarios, SAF could represent a significant portion, ranging from 27 per cent to 98 per cent, of total international aviation energy use by 2050.[87] In line with IATA’s strategy to achieve net zero emissions, 65 per cent of emissions reductions are expected to be achieved through the deployment of SAF.[88]

[80] Thomson, R., Sachdeva, N., Healy, A., Bailly, N., and Stern, C. (2020), Sustainable aviation fuels, Roland Berger, https://www.rolandberger.com/publications/publication_pdf/roland_berger_sustainable_aviation_fuels.pdf.
[81] Airport Council International and Aerospace Technology Institute (2022), Integration of Sustainable Aviation Fuels into the Air Transport System, ACI, https://www.ati.org.uk/wp-content/uploads/2022/06/saf-integration.pdf.
[82] Hailey, R. (2022), First A380 powered by 100% SAF takes to the skies, Rogistics, https://rogistics.net/first-a380-powered-by-100-saf-takes-to-the-skies/.
[83] ICAO. (2023a), Sustainable Aviation Fuels, https://www.icao.int/environmental-protection/pages/SAF.aspx.
[84] European Parliament (2023), ReFuelEU aviation - sustainable aviation fuels, https://www.europarl.europa.eu/legislative-train/package-fit-for-55/file-refueleu-aviation.
[85] IATA (2023), Sustainable aviation fuel output increases, but volumes still low, https://www.iata.org/en/iata-repository/publications/economic-reports/sustainable-aviation-fuel-output-increases-but-volumes-still-low/.
[86] Lagerquist, J. (2023), Jet fuel to dominate oil demand growth in 2023, https://ca.finance.yahoo.com/news/jet-fuel-dominate-oil-demand-growth-2023-capital-economics-161347301.html.
[87] ICAO. (2023a), Sustainable Aviation Fuels, https://www.icao.int/environmental-protection/pages/SAF.aspx.
[88] IATA. (2021), Sustainable aviation fuels, https://www.iata.org/en/programs/environment/sustainable-aviation-fuels/.

When exclusively considering hydrogen-based SAF, which is not yet produced, projections indicate that by 2030, its annual production could reach up to 8 per cent, as suggested by SkyNRG, an SAF distributor.[89] Looking further into the future, a report from the Air Transport Action Group forecasts that power-to-liquid SAF could account for 42–57 per cent of SAF production in 2050.[90]

### Conclusion

Hydrogen is poised to play a pivotal role in the aviation industry's journey towards sustainability. It holds a promising position in both novel propulsion technologies and the production of SAFs. Post-2050, hydrogen-powered propulsion technologies are expected to gain substantial market share, while the creation of synthetic SAF using hydrogen appears to be the leading candidate to drive the aviation sector toward carbon neutrality by 2050. This dual role of hydrogen underscores its significance as a key enabler of a greener and more sustainable future for aviation.

## THE ROLE OF CLEAN HYDROGEN/AMMONIA IN JAPAN'S ENERGY TRANSITION

***Hendrik Gordenker****

Japan is a significant emitter of greenhouse gas (GHG). It is the fifth largest GHG-emitting country, on an absolute and per capita basis, just ahead of Germany.[91] Japan also has ambitious emission reduction goals. It has announced that it seeks to reduce GHG emissions by 46 per cent compared to 2013 levels by 2030 and achieve net zero emissions by 2050. Hydrogen and its derivatives are poised to have a significant role in Japan's decarbonization, but context is needed to consider that role.

The energy sector will play a key part in Japan's net-zero transition. Japan's primary energy demand includes a relatively high proportion of fossil fuels, at 88 per cent, compared to, say, Germany, at 77 per cent. Fossil fuel accounts for a large share of Japan's power generation, at 72 per cent—compared to 46 per cent for Germany.[92] [93] Consequently, energy conversion, mainly electricity production, accounts for the largest share of Japan's direct GHG emissions, at about 40 per cent,[94] a larger share than in many other developed nations. To reduce GHG emissions, Japan will need to electrify its mobility, industrial, commercial, and residential sectors. Consequently, decarbonizing electric power generation is essential to Japan's net-zero ambitions. In addition, Japan must tackle sectors with significant GHG emissions for which electrification may not provide a solution, such as iron and steel, chemicals, and potentially long-distance large-load transportation.

How can Japan decarbonize its electric power sector? Hydro has limited opportunity to increase its current 7 per cent share. Nuclear provided about 5 per cent of Japan's power in 2022; it peaked at about 30 per cent before the 2011 Fukushima nuclear disaster. Restarting existing facilities has proven politically difficult, and new construction is even more difficult. The Japanese government's 6th Basic Energy Policy, published in 2021, retains a target share for nuclear in 2030 of 20–22 per cent, but many regard this target as difficult to achieve.

Given the limited potential of hydro and nuclear, renewable power sources will play an important role in Japan's decarbonization. Japan has made significant headway in installing renewable power sources, especially solar photovoltaic (PV) capacity, supported by government policy such as feed-in tariffs. Together, in 2022, renewables (other than hydro) accounted for about 15 per cent of Japan's power generation. Power generated from solar increased from less than 1 per cent in 2012 to almost 9.9 per cent in 2022. Wind, biomass, and geothermal each continue to make a small contribution, with wind near 1 per cent, biomass at 4.6 per cent, and geothermal at substantially less than 1 per cent in 2022.[95]

Japan aims to increase the share of renewables in power generation from 18 per cent in 2021 to 36–38 per cent in 2030 and

[89] SkyNRG (2023), Sustainable aviation fuel market outlook, https://skynrg.com/safmo2023/.
[90] ATAG (2021), Waypoint 2050, https://aviationbenefits.org/W2050.
[91] 'Greenhouse Gas Emissions by Country 2023', World Population Review (2019) <https://worldpopulationreview.com/country-rankings/greenhouse-gas-emissions-by-country>, Retrieved October 2023.
[92] 'Japan data explorer: Electricity generation by source', IEA, < https://www.iea.org/countries/japan>, Retrieved October 2023
[93] 'Germany data explorer: Electricity generation by source', IEA, < https://www.iea.org/countries/germany>, Retrieved October 2023.
[94] 'GHG Emissions in Japan' Annual Report on the Environment in Japan 2022, Japan Ministry of the Environment (2022), page27.
[95] 2022 Share of Electricity from Renewable Energy Sources in Japan (Preliminary), Institute for Sustainable Energy Policies (2022) ＜ https://www.isep.or.jp/en/1436/＞, Retrieved October 2023.

50–60 per cent in 2050.[96] Achieving these targets will be challenging. Limited land is available for additional solar or wind power. Development of offshore wind has just started; but shallow, nearshore, windy areas are few, impeding bottom-fixed wind power development. Floating offshore wind technology is not yet mature. Local resistance and a lack of leadership from the central government have slowed offshore wind development. Also, Japan's power grid was developed in a regional fashion, so nationwide interconnections are limited, and the mountainous and populous geography makes construction of long-distance transmission difficult and costly. This limits renewable power source connections.

The Japanese government recognizes these constraints and has expressed determination to tackle them in its GX (Green Transformation) Roadmap, published in draft form in December 2022. The GX Roadmap would make renewable power a mainstay. It prioritizes further development of solar PV (for example on rooftops), accelerating auctions for conventional offshore wind and promoting floating offshore wind, and developing a nationwide grid. However, even if these efforts succeed, Japan's renewable resources are limited: the Japanese government aims for renewables to account for not more than 50–60 per cent of the nation's power supplies by 2050.

Moreover, Japan has a highly seasonal climate, with periods of cold under overcast skies and snow in winter, a cloudy rainy season in early summer, intervals of low wind, as well as powerful typhoons and intense heat in summer. Japan needs considerable long-term storage of energy to manage stable electricity supplies, as well as dispatchable reserve power to manage daily demand fluctuations.

Japan's Basic Energy Strategy sees a role for hydrogen and derivatives such as ammonia (as well as fossil fuel power generation with carbon capture, utilization, and storage) in providing a backup to variable renewable power. Currently, Japan uses essentially no hydrogen for power generation. The target is for hydrogen/ammonia to generate 1 per cent of Japan's power by 2030 and 10 per cent by 2050. However, Japan will need to import much of this hydrogen/ammonia. Some hydrogen could be produced from renewable power that would otherwise be curtailed, but since Japan's renewable power resources are constrained, domestic hydrogen likely will be marginal.

A threshold question is, does it even make sense to use hydrogen/ammonia for power generation? Some commentators have noted that producing clean hydrogen, transporting it, and then using it for power generation has low end-to-end efficiency and should be a low-priority use of hydrogen.[97] However, even critics such as Michael Liebreich admit that in Japan hydrogen and its derivatives may have a role in power generation—although he suggests that such use of hydrogen should focus on backup for variable renewables.[98] For Japan, barring an unforeseen technological breakthrough on dispatchable clean power, hydrogen has an essential role.

Scaling up the import and use of hydrogen in Japan raises challenging questions:

- **What is low-carbon hydrogen?** Japan can decarbonize its power system using hydrogen only if that use entails low carbon emissions. Over time, Japan may employ 'green hydrogen', produced from renewable power. However, sufficient quantities of green hydrogen are not available in the short or even medium term, so Japan initially will import fuel based on 'blue hydrogen', produced from natural gas with process carbon dioxide emissions captured and sequestered (carbon capture and storage). Japan's Basic Hydrogen Strategy, announced in June 2023, does not prioritize green, blue, or other 'colours' of hydrogen—Japan takes a technology-neutral approach and seeks to define clean hydrogen in terms of carbon intensity, in line with international standards.
- **How best to transport clean hydrogen?** Japan is considering options for transporting imported hydrogen. It is testing a demonstration liquefied hydrogen ship. However, the energy losses of liquefying hydrogen and boiloff losses during transportation may make this pathway unviable. Methods of transporting hydrogen in liquid organic carriers (such as toluene/methylcyclohexane) are under consideration, but these so far exhibit limited energy density and therefore would require very large-scale shipping, logistics, and processing infrastructure. Perhaps the most advanced pathway is ammonia, which is already in oceanic trade—although the safe use of ammonia, which is poisonous, would require attention.

[96] 6th Basic Energy Policy, Agency for Natural Resources and Energy (2021) < https://www.enecho.meti.go.jp/category/others/basic_plan/pdf/strategic_energy_plan.pdf >, Retrieved October 2023.
[97] 'Power System' The Clean Hydrogen Ladder [Now updated to V4.1], Liebreich Associates (August 15, 2021), <https://www.liebreich.com/the-clean-hydrogen-ladder-now-updated-to-v4-1/>, Retrieved October 2023.
[98] M. Liebreich, 'Japan's big bet', The unbearable lightness of hydrogen, (Bloomberg, December 12, 2022) <https://about.bnef.com/blog/liebreich-the-unbearable-lightness-of-hydrogen/>, Retrieved October 2023.

- **How best to use clean hydrogen?** If Japan imports clean hydrogen in the form of ammonia, one option is to crack the ammonia back into hydrogen. It is already feasible to use hydrogen efficiently in a combined cycle gas turbine power plant. However, with currently available technology, cracking results in substantial energy losses. Japan is preparing a demonstration test of burning ammonia directly in a coal-fired power plant, in an 80/20 coal/ammonia mix, with ambitions to increase the share of ammonia. This project has attracted criticism—with a co-firing mix of 80/20, even if green ammonia is used, total emissions are probably greater than from a conventional gas-fired power plant. Japan for now probably needs its coal power plants to maintain a stable power supply, so in the interim it can reduce consumption of coal in these plants by substituting low-carbon ammonia. This interim use of ammonia also creates an opportunity to develop clean ammonia infrastructure. However, using coal, even co-fired with clean ammonia, is not consistent with zero emissions and must taper. Moreover, a modern coal-fired power plant can achieve thermal efficiency of at most around 47 per cent. Given that low-carbon ammonia is likely to remain a relatively expensive fuel, it does not make sense to continue using this valuable fuel at such low efficiency. Developing more efficient uses of ammonia is key, for example through better ammonia cracking, or burning ammonia directly in combined cycle gas turbine facilities, where thermal efficiency can exceed 65 per cent.
- **How to meet the infrastructure scaling challenge?** Building the infrastructure for the targeted supply and use of clean hydrogen is a colossal undertaking. To illustrate this issue, consider that Japan seeks to derive about 10 per cent of its power from clean hydrogen/ammonia by 2050. Japan's current and projected demand for power in 2050 is around 1,000 TWh annually. If 10 per cent of this power comes from clean ammonia replacing coal in existing power plants, Japan would need to import roughly 34 million tons of ammonia each year (calculated using the higher heating value of ammonia of 22.5 GJ/ton). If this is green ammonia, on the order of 136 GW of solar power would be needed. (It is assumed that 1 GW of solar power generation capacity can produce 250,000 tons of ammonia annually.[99]) This is almost double the total solar capacity installed in Japan as of 2022. In addition to this new power source, large-scale hydrogen electrolysers, ammonia synthesis facilities, and logistics infrastructure to store and transport the ammonia would be needed. Japan's GX Roadmap lays out a menu of policy supports for the intensive investment required, including financing supported by GX transition bonds funded by a carbon tax, but Japan has so far taken only the first few steps along the GX Roadmap.
- **Will the cost of clean hydrogen be acceptable?** The size and cost of the clean hydrogen infrastructure will inevitably make this new fuel expensive, at least in early years. However, to the extent that renewable energy sources are used, the operating cost of the assets once built should be low. Also, as the supply chain gains experience, unit equipment costs should fall. Japan aspires to substantial reductions in the cost of clean hydrogen. Japan's 2023 Hydrogen Strategy recognizes that clean hydrogen is expensive now, at about JPY 100 per normal cubic meter (equivalent to roughly US$72/MMBTU). This compares to the average cost of LNG imported into Japan in the past four years of about US$13/MMBTU. Japan targets reducing the cost of imported hydrogen and ammonia to levels comparable to recent LNG import costs. In the near term, Japan intends to provide imported hydrogen and ammonia policy support—perhaps a subsidy—to kickstart adoption, but that policy support is still under discussion. Nevertheless, given the scale of investment required, hydrogen and ammonia seem likely to be relatively expensive for some time. However, Japan has long borne energy costs higher than in regions with greater indigenous energy resources, so the incremental cost may be manageable for Japan.
- **How to store clean hydrogen?** The challenge of storing hydrogen is underappreciated. Hydrogen in gaseous form has low density and escapes containment easily. It can be stored in salt caverns, but there are few in Japan. Storing it in liquefied form has prohibitive energy costs. Storage in the form of ammonia seems more feasible, but given ammonia's toxicity, the location and safe operation of that storage will be a concern. Japan now uses LNG to manage seasonal demand fluctuations. (Coal also plays a role, but this role should diminish.) More than 50 years after the introduction of LNG, Japan currently has 33 LNG import terminals. Despite this build-out, Japan now struggles to maintain a stable supply of LNG during peak demand periods and when facing supply disruptions. Ammonia has lower volumetric energy density than LNG; it occupies about 1.8 times the volume of LNG. To gain the same amount of

[99] Z. Cesaro et al., 'Ammonia to power: forecasting the levelised cost of electricity from green ammonia in large-scale power plants', Applied Energy (January 15, 2021), <https://doi.org/10.1016/j.apenergy.2020.116009>

energy storage for ammonia that Japan currently has for LNG, substantially more tank capacity is needed. If the use of hydrogen/ammonia focuses on backing up other sources of power, then demand will become more variable, and even more storage will be needed. How will Japan address this challenge? Overseas or floating storage? Perhaps new technology?

- **How to coordinate the introduction of hydrogen/ammonia across sectors?** While decarbonizing Japan's power sector is a priority, other difficult-to-abate sectors can use low-carbon hydrogen to reduce GHG emissions. Ideally, Japan will coordinate the introduction of clean hydrogen imports for use in multiple sectors. Perhaps Japan's initial imports of ammonia for co-firing with coal can trigger this process. However, such coordination remains a challenge.
- **How to handle fugitive emissions?** Atmospheric emissions of hydrogen and ammonia have global warming effects an order of magnitude greater than carbon dioxide, although with shorter duration. Fugitive emissions of hydrogen or ammonia can undercut the GHG emission reduction effects of introducing these clean fuels. The pathways for fugitive emissions are many: hydrogen escapes containment easily but is difficult to detect, and incomplete combustion of hydrogen or ammonia can result in slippage. Deeper understanding, and appropriate standards, are required in this area.

Japan not only seeks to establish itself as a leader in clean hydrogen, but also has ambitions to extend the model it develops, especially in Asia. It would make sense to develop common standards, co-invest in the large-scale infrastructure required, and seek complementarities on a regional and global basis. Such coordinated development will, however, require a daunting level of cooperation. A question not yet fully answered is whether clean hydrogen is the best choice in different Asian regions. The circumstances across Asia vary, and other alternatives may emerge. Also, even though the Japanese government proposes to offer financial support, affordability will be a hurdle in much of Asia.

Japan faces enormous challenges in adopting clean hydrogen to decarbonize its economy. But as of now, this difficult road seems to be Japan's best alternative.

** The author is senior advisor to JERA Co., Inc. This paper reflects the personal views of the author, which may differ from the views of JERA. The author is grateful for the invaluable assistance of Takato Shiozaki, staff member of Business Research Unit, Research Group, Planning Division of JERA.*

## THE IMPORTANCE AND CHALLENGE OF ALIGNMENT ON EMISSIONS MEASUREMENT AND CERTIFICATION OF HYDROGEN

***Alex Barnes***

The last couple of years have seen enthusiasm grow for hydrogen as a means to decarbonize hard-to-abate sectors. The US has announced large tax breaks for clean hydrogen under the Inflation Reduction Act; the EU has recently agreed on challenging targets for renewable hydrogen consumption in industry and transport as part of the revised Renewable Energy Directive; and the UK is pressing ahead with support for low carbon hydrogen production using its Hydrogen Production Business Model. At the same time there is growing interest in international trade in hydrogen or its derivatives, with the EU in particular keen to import up to 10 megatonnes (Mt) per year of renewable hydrogen by 2030.

However, whilst hydrogen molecules are identical irrespective of the method of production, the carbon footprint of these molecules certainly is not. Amid all the enthusiasm for hydrogen as part of the energy transition, it is sometimes forgotten that current hydrogen production emits up to 1,300 Mt of $CO_2$ equivalent emissions each year for 95 Mt/year of hydrogen.[100] Hydrogen has sometimes been criticized as being 'the fuel of tomorrow, and it always will be'. This is because, absent concerns about greenhouse gas (GHG) emissions, fossil fuels are much better in terms of cost, energy density, and ease of handling. The only reason there is so much excitement about hydrogen is that it offers solutions for sectors that cannot electrify as part of the energy transition—for example, high temperature heat in industry, virgin steel production, and some forms of transport such as aviation, shipping, and heavy goods vehicles. But this means the real value of hydrogen is based on its carbon footprint.

[100] International Energy Agency, *Hydrogen*, https://www.iea.org/energy-system/low-emission-fuels/hydrogen.

Hydrogen with low $CO_2$ emissions is currently more expensive to produce and use than fossil fuels. If hydrogen was an easy decarbonization solution, we would be using it already. Hence the proliferation of subsidy schemes and targets and strategies aimed at kick-starting a hydrogen economy. But governments need to be assured that they are getting value for money for their support and that support for hydrogen will result in a net reduction in emissions compared to existing energy use. The only way to do this is to have proper and robust carbon accounting. The old business school adage 'if you can't measure it, you can't manage it' holds especially true in a situation where the market cannot value hydrogen with low emissions without clear government regulation. GHG emissions are a classic externality—their cost is not borne by those who produce them. It would clearly be absurd for a brick kiln to replace its natural gas use with hydrogen produced using gas-fired electricity or steam methane reforming without carbon capture and storage (CCS), as this would result in much higher $CO_2$ emissions overall even when the kiln's direct emissions were zero.

If international trade in hydrogen is to take off, with production based in those areas with lowest costs, importing countries need to be sure that the hydrogen they buy has the same or lower carbon footprint as hydrogen produced domestically. Otherwise exporting countries have an unfair advantage, and the importing country is simply exporting its emissions. This highlights another key requirement, in addition to robust carbon accounting—namely, reliable certification so that buyers know the GHG footprint of the hydrogen they are buying.

So far, so blindingly obvious. But applying robust carbon accounting and creating reliable certification are a bit more complicated in practice. Recent developments, such as the arguments over the definition of renewable electricity in recent EU legislation, illustrate some of the pitfalls.

The first step is to avoid use of non-precise terms such as 'clean', 'green', 'blue', 'renewable', or 'low carbon' other than as very generic descriptive terms. Using current definitions, EU renewable hydrogen, UK low carbon hydrogen, and US clean hydrogen could all include electrolytic hydrogen using grid-based electricity including fossil fuels or nuclear electricity. A much better approach would be to classify hydrogen based on its carbon footprint, similar to the way that fuel oil is defined as high or low sulphur. Then everyone would be able to compare hydrogen on a level playing field.

Secondly, there needs to be a common approach to how the carbon footprint is measured. This includes which emissions along the value chain are included, and a common methodology for measuring those emissions. Which emissions to count will be determined by the system boundary chosen(for example, well-to-wheel or well-to-production-gate), and which emissions scopes are included, based on the GHG Protocol. Scope 1 emissions are those directly caused by the hydrogen production process, and Scope 2 emissions are those relating to the production of electricity or steam or heat bought in by the hydrogen producer, whilst Scope 3 covers all other emissions.

To ensure a fair comparison between hydrogen produced by different technologies and in different locations, it makes sense to apply a well-to-wheel approach. This would encapsulate emissions associated with the upstream production and transportation of feedstocks used in hydrogen production, such as coal or natural gas. Including transportation, storage, and conversion of hydrogen in the system boundary would include emissions associated with shipping of hydrogen over long distances, as well as any conversion of the hydrogen required for transport, for example liquefaction or into ammonia, and its reconversion into hydrogen. If hydrogen derivatives, such as synthetic aviation fuel or methanol, are used, it is necessary to include emissions associated with that usage, since it results in emissions, and the source of the carbon also needs to be sustainable.

Using this approach would mean that Scope 1 and Scope 2 emissions would automatically be included. Some Scope 3 emissions would be included—for example, those associated with the upstream production of feedstocks such as natural gas, and those associated with transportation and storage. However, emissions associated with the manufacture of equipment used to produce hydrogen do not need to be included.

Thirdly, there needs to be a common approach to measuring emissions within the system boundary. This can include standard values for feedstocks such as natural gas, or agreed methodology for assigning emissions where hydrogen is a co-product (such as in the chlor alkali process), or an agreed methodology for measuring the GHG intensity of electricity used in electrolysis. Again, simple in theory but a bit more complicated in practice.

With natural gas the key challenge is fugitive methane emissions in the production and transportation of the gas to the point of hydrogen production. Monitoring, verification and reporting of methane emissions varies significantly between individual companies and across jurisdictions. $CO_2$ emissions will depend on the energy used in production and transportation of the gas.

Gas transported over long distances as LNG will have higher emissions compared to that produced near to the hydrogen production.

When assigning emissions where hydrogen is a by-product there are different approaches (by value, by input, etc.) which can lead to different results. There is clearly scope for temptation to assign as many of the emissions as possible to other products to keep the carbon footprint of the hydrogen as low as possible.

The carbon footprint of electricity is one of the thornier issues. Electricity produced using renewable energy sources has zero emissions, but renewable electricity such as solar or wind is intermittent. If an electrolyser only operates when renewable electricity is generating, it reduces the electrolyser load factor and increases the cost of the hydrogen. As electricity cannot be easily stored, it is not possible to save electricity when renewable generation is plentiful and then use it when there is less renewable generation. Instead, electricity can be taken from the grid. However, this will impact the carbon footprint of the hydrogen produced, depending on the carbon footprint of the electricity fed into the grid.

Electricity fed into the grid varies throughout the day depending on the level of demand and what is available. The key driver of this is again the relative inability to store electricity, combined with the intermittency of renewables. If demand is high and renewable availability low, grid operators call on dispatchable (i.e. controllable) electricity generated by fossil fuels, hydro, or nuclear. The carbon footprint of the electricity available from the grid is therefore determined by the generation mix at that point in time. This can vary significantly between countries. For example, the annual average carbon footprint of the German grid (99.3 $gCO_2e$/MJ) is about 25 times that of Sweden (4.1 $gCO_2e$/MJ) and five times that of France (19.6 $gCO_2e$/MJ).[101] Sweden uses mainly nuclear and hydro, whilst the majority of French electricity is nuclear. Germany has a lot of renewables but also a lot of coal and lignite. At times when the sun is not shining and the wind is not blowing, German electricity will be even more carbon intensive because of its reliance on fossil fuels for dispatchable power.

The simplest approach is to measure the carbon footprint of hydrogen produced based on the electricity used during a given period. The carbon footprint is based on the weighted average carbon footprint of the electricity used during the hydrogen production period. This is the approach taken by the UK in its Low Carbon Hydrogen Standard,[102] which companies have to meet in order to qualify for government subsidy. It enables hydrogen producers to keep the electrolyser running even if renewable electricity is not available. The measurement period is 30 minutes, which corresponds to the UK electricity system balancing period, which enables identification of electricity supplied to the grid during that period. If the carbon footprint of electricity results in hydrogen produced in excess of the UK's Low Carbon Hydrogen Standard of 20$gCO_2e$/MJ (well to production gate), that consignment of hydrogen is not eligible for subsidy, but the carbon footprint of the hydrogen is known.

The EU has taken a different approach, driven by its preference for hydrogen based on renewable electricity over other forms of low-carbon hydrogen based on nuclear electricity or fossil fuels with CCS. The new targets in the revised Renewable Energy Directive are for renewable fuels of non-biological origin (RFNBOs), which means electrolytic hydrogen based on renewable electricity or its derivatives. Earlier this year the EU published two regulations which determine what counts as renewable electricity when producing RFNBOs and the carbon footprint threshold for RFNBOs. The latter is set at 28.2 $gCO_2e$/MJ (well to wheel) based on a 70 per cent saving compared to a fossil fuel comparator.[103] Electricity which meets the renewable electricity standard is deemed as having zero emissions when calculating the GHG footprint of hydrogen, irrespective of its actual carbon footprint.

The rules determining what counts as renewable electricity are complex but allow electrolysers to take electricity from the grid and count it as renewable whatever its actual source. For example, if an electrolyser has a power purchase agreement with a renewable generator, it can take electricity from the grid so long as over a month the total amount of electricity used by the electrolyser is no more than the total electricity produced by the renewable generator. This enables the electrolyser to run at a

[101] EU Commission Delegated Regulation (EU) 2023/1185, Annex C, Table A, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2023.157.01.0020.01.ENG&toc=OJ%3AL%3A2023%3A157%3ATOC.
[102] UK Low Carbon Hydrogen Standard, Version 2, April 2023, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1151288/uk-low-carbon-hydrogen-standard-v2-guidance.pdf.
[103] EU Commission Delegated Regulation (EU) 2023/1185, Article 3 and Annex A (2), https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2023.157.01.0020.01.ENG&toc=OJ%3AL%3A2023%3A157%3ATOC.

high load factor all the time based on its expectation of the renewable generation.

To illustrate the effect this has, imagine a case where the renewable generation is a solar farm with capacity of 2 MW and the sun shines reliably for 12 hours a day. Based on a 31-day month this would produce 744 MWh of electricity. This would allow an electrolyser to run 24 hours a day for 31 days so long as it was using only 1 MW of electricity per hour. However, for 12 hours a day the electrolyser would be using electricity from the grid when the sun was not shining. Of the 744 MWh consumed by the electrolyser, 372 MWh would be grid electricity and 372 renewable. If the grid electricity has the same carbon footprint as Germany, the weighted average calculation of the carbon footprint would be half that of the German grid, i.e. 49.7 $gCO_2e/MJ$. After allowing for a 70 per cent efficiency rate of the electrolyser, this would imply a carbon footprint for the hydrogen at the production gate of 70.9 $gCO_2e/MJ$, considerably above the EU threshold, and also more than the well-to-wheel carbon footprint of natural gas of 66.0 $gCO_2e/MJ$.[104] Under EU rules, however, the carbon footprint of the electricity would be deemed as zero for the purposes of calculating the hydrogen's carbon footprint. This would imply the brick kiln was reducing its emissions by 66.0 $gCO_2e/MJ$ of energy used, but in reality it would be increasing them by 4.9 $gCO_2e/MJ$.

The EU decision to put these rules in place until 2030 was based on, first, its insistence on prioritizing hydrogen produced using renewable electricity, and second, the lack of renewable electricity capacity within the EU. The first factor precluded an approach which was agnostic about the production method for hydrogen but focused on the carbon footprint. The lack of renewable electricity within the EU, and the inability to easily store renewable electricity, meant that hydrogen projects would have to either significantly overbuild renewable generation or curtail utilization of the electrolyser in order to ensure that it was using renewable electricity. This, of course, would increase costs and delay the ramp-out of hydrogen production. The compromise was the looser rules described above. This was justified on the grounds that it was important to ramp up hydrogen production as quickly as possible to enable the decarbonization of the hard-to-abate sectors.

The EU approach underrepresents both the emissions and the costs associated with hydrogen production by making it easier to meet the carbon footprint threshold. This makes it more difficult for companies and governments to choose projects which lead to the biggest reduction in emissions for the least cost. At the margin, it may lead to companies choosing hydrogen as a decarbonization route even though other routes would be more cost effective in terms of euros per $CO_2$ saved in reality. The approach may also make it more difficult to limit global warming, which is based on the total amount of GHG in the atmosphere, not the annual emissions rate. Faster ramp-up of hydrogen production in future years cannot remove higher emissions made today, because $CO_2$ stays in the atmosphere for hundreds of years.

The constraint on renewable hydrogen is the availability of renewable electricity. Thus, it makes more sense to prioritize the ramp-up of renewable electricity production, which can also decarbonize both existing electricity demand and all those sectors which will not be relying on hydrogen, as well as supplying electrolysers.

The advantage of robust carbon accounting and using standard accepted methodologies for calculating emissions is that this ensures that governments, investors, and hydrogen consumers can properly compare the costs of hydrogen and its carbon footprint. This enables them to value them properly and in turn allows efficient investment decisions. Projects which are genuinely low cost and low carbon, wherever they are based and using whatever technology they prefer, will be able to thrive. Deeming the carbon footprint of electricity to be zero because it meets an arcane definition of renewability merely muddies the waters, and makes efficient economic decisions and comparison between different legal frameworks more difficult. A better approach would be to allow for a higher GHG intensity in early years and then tighten the standards later. This would enable projects to go ahead whilst still making recognizable and properly accounted GHG savings.

[104] EU Commission Delegated Regulation (EU) 2023/1185, Annex B, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2023.157.01.0020.01.ENG&toc=OJ%3AL%3A2023%3A157%3ATOC.

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