

*The current geopolitical situation presents a challenge to EU climate policies and Russia's ambitions of exporting hydrogen, writes Dafydd ab Iago*

*Proving compliance with those criteria may be exceptionally difficult for Russian renewable hydrogen exporters*

## Ukraine crisis complicates EU hydrogen plans

The Ukraine crisis has focused EU policymakers' minds on the long-term need to reduce the bloc's dependence on Russian energy – a policy goal that could take many years if not decades to deliver, and which will necessarily influence and complicate the EU's parallel desire to shift to lower-carbon energy sources.

It could also have big implications for hydrogen – for the role it plays in the EU's future energy mix, and for Russia's ability to advance its plans to become a major hydrogen exporter. At present, it barely merits a footnote in EU-Russia energy relations, which are dominated by the region's dependence on Russian gas.

"We have to reduce our overall reliance on oil and gas and imports, for the Green Deal but also for geopolitics," EU high representative for foreign affairs Josep Borrell said last month. "This means development of renewables at home and greater diversification of routes and sources from abroad."

Hydrogen is already shaping up to be part of these development paths. And it also features prominently in Russia's energy planning – Moscow is eyeing a 20pc share of an eventual global hydrogen market, deputy prime minister Alexander Novak said in June last year, and wants to begin exporting within the next few years, targeting shipments of 2mn-12mn t/yr by 2035.

Europe would be an obvious market, but geopolitics and climate policy will make Russian hydrogen a tough sell. In line with the EU's carbon neutral by 2050 goal, the European Commission is in the final stages of publishing technical legislation defining what constitutes renewable hydrogen, as required by the 2018 Renewable Energy Directive (RED II). Proving compliance with those criteria may be exceptionally difficult for Russian renewable hydrogen exporters.

A further complication is presented by the EU's planned carbon border adjustment mechanism (CBAM), which could include hydrogen [under recent proposals from the parliament](#). As Mauro Petriccione, director general of the European Commission's climate directorate, noted last year, [importing Russian blue hydrogen](#) is not going to be "simple" owing to verifying its carbon footprint.

EU policymakers may also consider whether hydrogen can help them strengthen their sanctions armoury against Moscow. Russia's economy has generally become "[more sanctions-proof](#)" since the country's 2014 annexation of Crimea, Borrell observed last month. But hydrogen may, in the long term, give Brussels some leverage, through banning the export of electrolysis technology. For the moment, however, this is not on the table. Neither electrolysis technology nor hydrogen itself featured among potential financial restrictions and export controls mentioned in February by European Commission president Ursula von der Leyen.

Sanctions require a united EU front, and can be weakened or blocked by a single member country. That creates some scope for Russia to cultivate allies, using the importance of its energy supplies – gas now, perhaps hydrogen in the future – to certain consumer countries. Earlier this month, while other EU leaders were talking about the need to reduce dependence on Russian energy, Hungarian prime minister Viktor Orban was in Moscow with Russian president Vladimir Putin discussing taking an extra 1bn m<sup>3</sup>/yr from Gazprom under its 4.5bn m<sup>3</sup>/yr long-term contract. There is less scope for such tactics when it comes to climate and energy policy, where straightforward majorities are required, including within the European Parliament.

## CONTENTS

UK ATR projects set 2026 start-up	2
Indian steelmakers urge policy aid	3
Washington state eyes incentives	3
EU lawmakers criticise proposals	4
Liquefied H2 on trial in Japan	5
Doubts over German H2 location	6
EU beefs up hydrogen statistics	7
Consortium eyes 500MW plant	8

## MARKET DEVELOPMENTS

*The two blue hydrogen facilities in England are set to be joined by another newly announced plant in Scotland by 2030, writes Aidan Lea*

*The hydrogen will primarily be used to reduce emissions at Essar's refinery and chemicals complex, but will also displace fossil fuels in industry partners*

### Two UK ATR projects eye 2026 start-up

Two UK autothermal reforming (ATR) blue hydrogen projects have announced that they are targeting 2026 start dates, pending government support.

Norway's Equinor has formally submitted a proposal for a 600MW blue hydrogen production facility to phase two of the government's cluster sequencing process.

The UK government's department for business, energy and industrial strategy (Beis) will evaluate submissions until May, when it will open negotiations with shortlisted projects before ultimately deciding which to support in the second quarter of 2023. It has previously said that it intends to support around 1.5GW of hydrogen capacity in this phase. Its goal for 2030 is 5GW, but the [projects already announced far exceed that](#).

The proposed H2H Saltend project would produce hydrogen that could be substituted into the industrial processes of several offtake partners at the Saltend complex, reducing CO<sub>2</sub> emissions by nearly 1mn t/yr, Equinor says.

Offtake partners for the project are gas processor Centrica Storage, chemicals manufacturer Ineos Acetyls, rare earth processor Pensana, gas-fired Triton Power Station, energy provider Vital Energi and bioethanol producer Vivergo Fuels.

Equinor expects to capture 95pc of CO<sub>2</sub> associated with the hydrogen production, with the emissions to be stored under the North Sea. H2H Saltend would sit within the UK's East Coast Cluster project, which was selected by the government in October as one of the [first two carbon capture, usage and storage \(CCUS\) clusters](#) to come on line in the mid-2020s, alongside the Hynet Cluster.

### Essar and Progressive Energy open JV

Meanwhile, refiner Essar and developer Progressive Energy have announced a joint venture that aims to build a £1bn (\$1.35bn) 1GW ATR blue hydrogen facility as part of the Hynet Cluster in northwest England. The venture, called Vertex Hydrogen, is also targeting a 2026 start date.

The hydrogen will primarily be used to reduce emissions at Essar's refinery and chemicals complex at Stanlow, but will also displace fossil fuels in industry partners across the Hynet region, the firms say.

CO<sub>2</sub> emissions from hydrogen production will be stored underground offshore in Liverpool Bay by Hynet partner Eni, in its depleted hydrocarbon reservoirs. The plant's hydrogen technology will be provided by UK chemicals company Johnson Matthey.

### Ineos plans plant for 2030

Petrochemicals producer Ineos recently announced its intention to build a blue hydrogen plant at its Grangemouth chemicals facility in Scotland by 2030, and has invited engineering contractors to bid in a tender process.

Capacity will be determined by the engineering study, but the company expects to capture at least 1mn t/yr of CO<sub>2</sub> emissions from the plant, which will be sent to the Scottish Cluster in the North Sea. The Scottish Cluster missed out on first-phase support, but the UK government has plans to support four CCUS clusters by 2030.

Ineos expects the design to include a network of hydrogen pipelines, and the capability to link hydrogen production to third parties in the area to support the development of a local hydrogen hub.

Ineos has already spent £500mn on decarbonisation projects at the Grangemouth site, including a new and more efficient power plant due to commission in late 2023, which will be converted to run on hydrogen. Hydrogen could be deployed at the site's existing combined heat and power plant, KG ethylene plant and assets in the 210,000 b/d Grangemouth refinery.

## NEWS

## Indian steelmakers call for policy aid for green steel

The Indian Steel Association (ISA) is calling for “policy enablers” from the government to spur the adoption of green steel in the country.

These enablers include the mandating of government-funded construction projects to source a portion of their steel from low-carbon-emitting producers, introducing standards for green steel, having a carbon credit mechanism and taking up the EU’s carbon border adjustment mechanism (CBAM) at various international platforms.

The industry body also called for research and development in the use of hydrogen to transition towards green steel, saying that “if hydrogen prices reduce from the present \$5-10/kg to \$1-2/kg, it can provide a huge push to low-carbon growth. Focus on development of a hydrogen ecosystem is essential”.

The Indian steel sector is required to achieve an emission intensity reduction to 2.4t of CO<sub>2</sub> per tonne of crude steel (tcs) by 2030 so as to align with the already fixed nationally determined contribution, ISA says. The average CO<sub>2</sub> emission intensity of the industry stood at around 2.6t/tcs during 2020.

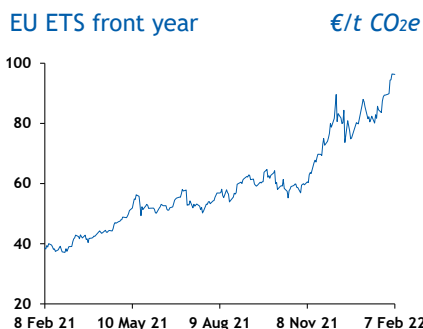
Companies reducing their CO<sub>2</sub> emission intensity below a set sectoral target should be incentivised through subsidies or tax incentives, the ISA says, and the association argues for a carbon credit mechanism.

The European Commission proposed a carbon border tax on imports of steel, fertilisers, ammonia and several other energy-sensitive commodities last year, and lawmakers are considering adding hydrogen imports. Under the CBAM, non-EU companies exporting to Europe need to pay the same price for their carbon footprint in Europe as European companies. Importers must purchase a certificate for the difference between the carbon content of the imported product and the same product produced in the EU as an adjustment amount.

India’s finished steel exports stood at 10.33mn t in April-December 2021, up by 24.2pc on the year, on strong international prices.

Hydrogen’s role in steelmaking is widely seen as a metallurgical coke replacement, by developing the use of the gas to reduce iron oxides into purer iron.

*By Sumita Layek*



## Washington state eyes new hydrogen incentives

A bipartisan contingent of Washington state lawmakers is pushing a bill that would apply existing tax credits to hydrogen produced from electrolysis.

House Bill 1792 would add the production of green electrolytic hydrogen to existing retail sales, use, and leasehold excise tax incentives that already apply to hydrogen projects that use renewable feedstocks. It would also create a new tax exemption for public utilities on the sale of electricity for the purposes of clean hydrogen production. The legislation would make explicit that public utilities can produce, use and sell hydrogen produced from electrolysis.

The bill recently passed the House Environment and Energy Committee on a unanimous vote. It now heads to the House Finance Committee, where a hearing is expected to be scheduled “fairly quickly”, according to state representative Ed Orcutt, a co-sponsor of the bill and the ranking member on the committee. The state legislative session is scheduled to end on 10 March.

In 2019, Washington passed legislation that allowed public utility districts to generate hydrogen produced from renewable feedstocks.

But representative Alex Ramel, who introduced the bill, says existing standards “set a very high bar”, only offering incentives for the production of hydrogen from renewable feedstocks and not for hydrogen produced directly from an

NEWS

electric grid “that is clean and getting cleaner”. The new legislation would make explicit that electrolytic hydrogen qualifies for existing state incentives and would make it easier for utilities to benefit from clean hydrogen production.

While hydrogen could eventually be used across various sectors, bill supporters have pointed to hydrogen fuel cell vehicles as a likely near-term use in the state.

Blue hydrogen would not qualify for state incentives. Ramel says that Washington’s progress towards a carbon-neutral grid by 2030 means the state is well positioned to become a hub for clean hydrogen produced through electrolysis, but he thinks too much uncertainty exists about the effectiveness of carbon capture to justify incentives for blue hydrogen.

Lawmakers across the US have shown increasing interest in encouraging low-carbon hydrogen production. The bipartisan infrastructure law passed last November tasks the US Energy Department with releasing a “clean hydrogen strategy and roadmap” by May and spending \$1.9bn/yr over the next five years to kick-start clean hydrogen production. The Build Back Better Act would create new tax credits for hydrogen, although that legislation remains stalled in Congress.

In New Mexico, governor Michelle Lujan Grisham is pushing a bill that would provide tax incentives for new low-carbon hydrogen facilities in the state.

*By Cole Martin*

**EU lawmakers criticise draft hydrogen legislation**

Draft EU legislation defining renewable hydrogen would overburden the emerging sector, say key lawmakers. The technical legislation will be proposed “very shortly”, according to an EU official.

“A delegated act with requirements for the production of renewable energy must be an accelerator and not a fence standing in the way of the hydrogen economy,” German centre-right MEP Markus Pieper says.

The European Parliament has charged Pieper with drawing up a legal report on the European Commission’s proposal to amend the EU’s 2018 Renewable Energy Directive. That directive also tasks the commission with proposing a legal definition of renewable hydrogen, key for the sector to benefit from state financial incentives and to implement the EU’s hydrogen strategy, presented by the commission in July 2020.

Pieper questions why the commission is proposing a requirement for renewable hydrogen to be linked to solar or wind power plants built in the same year or within two years of when the electrolyser starts producing hydrogen. Pieper also wants annual balance sheets rather than a requirement for hourly or two-hourly simultaneous supply of power and hydrogen production. And he questions why older wind turbines are not allowed to serve hydrogen production.

“We also need very flexible requirements for power purchase agreement contracts for electrolysers that have to get some of their electricity from the grid,” Pieper says. So-called additionality restrictions not only make hydrogen production in Europe less attractive, but also restrict future imports, he adds.

Centre-left German socialist Jens Geier characterises the additionality requirement for renewable hydrogen as discrimination. “The commission is building obstacles rather than opening up perspectives. Additionality seems to be one of these problems,” says Geier, who drew up a parliamentary report on the EU’s hydrogen strategy. “It looks like discrimination [against other energy carriers] instead of opening avenues for immediate production of green hydrogen.”

Geier also questions the “huge” amount of information required from producers of renewable hydrogen under the draft legislation.

*By Dafydd ab Iago*

EU hydrogen targets		
	2024	2030
Electrolyser capacity GW	6	40
Green H2 production mn t/yr	1	10
– European Commission		

ANALYSIS

**Additional, much larger carriers are planned, but the segment faces significant barriers, writes Aidan Lea**

**‘The cost of shipping hydrogen is significantly higher due to the technology costs and [lower] volumes you will carry’**

**Liquefied hydrogen on trial in Japan**

The world’s first liquefied hydrogen carrier – Kawasaki Heavy Industries’ 1,250m<sup>3</sup> *Suiso Frontier* – is en route to Japan with the first seagoing hydrogen cargo of 75t, having left Australia on 28 January. The voyage undertaken by the \$385mn joint venture Hydrogen Energy Supply Chain (HESC) proves that moving hydrogen by ship is possible. But high costs and inefficiencies limit the segment’s prospects.

Shipbuilders are developing designs for far larger hydrogen carriers. Kawasaki Heavy Industries and South Korean shipbuilder Samsung Heavy Industries are both developing 160,000m<sup>3</sup> vessels. The findings from the *Suiso Frontier* pilot may determine whether these designs are ever realised.

Major barriers for transporting hydrogen are its extremely low boiling point of minus 253°C, compared with 33°C for ammonia, and an energy density of just 2kWh per litre, below ammonia’s 3.75 kWh/l. And liquefaction consumes the equivalent in energy of one-third of the original hydrogen.

Ammonia already has a fleet transporting around 20mn t/yr. “Ammonia seaborne trade is expected to grow 50pc over the next five years and about a third of our fleet is already able to load and carry ammonia,” shipowner BW Epic Kosan’s CEO Charles Maltby says. “The cost of shipping hydrogen is significantly higher due to the technology costs and [lower] volumes you will carry.”

German engine maker Man Energy Solutions, which has developed a fuel-gas-supply system for hydrogen, found cryogenic equipment was even more expensive to build than the costly LNG equivalent, because of the thick tanks required. “Transporting of ammonia, methanol or methane is more likely, either to be used directly or reconverted to hydrogen at the destination,” a source at the firm says.

Fertiliser company Yara, which has several projects to make ammonia from green hydrogen, has no immediate plans to enter the market for hydrogen shipping, which is “moving slowly”, its clean ammonia president Magnus Krogh Ankarstrand says, noting higher equipment costs and significant product losses during transport. The company sees pipeline networks as a source of hydrogen, which “large players in energy are looking at”, but accepts that this also faces significant challenges.

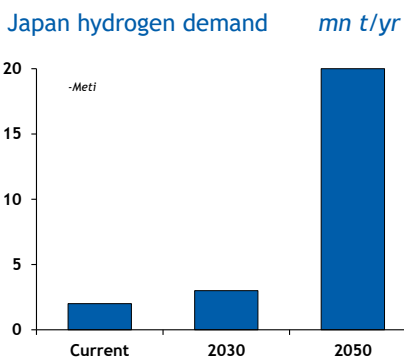
HESC says that liquid hydrogen has no reconversion costs, unlike ammonia, and argues that the toluene needed to convert hydrogen to the liquid organic hydrogen carrier methylcyclohexane, an alternative to ammonia, is very expensive. But it did not respond to the suggestion that liquid hydrogen is likely to be most expensive overall, when accounting for all the stages of the supply chain.

**Find your niche**

HESC maintains that “liquid hydrogen would be more easily handled and ideal for mass transportation”. The company says that most hydrogen fuelling stations in the US and China, where “a number of liquefaction plants have been planned and constructed”, plan to use liquid hydrogen. And it has observed a trend for switching from compressed gaseous hydrogen to liquid hydrogen for transport in Japan.

But while Japan’s lack of domestic resources and its enthusiasm for hydrogen have led it to push the boundaries of hydrogen transportation, the prospects for a carrier fleet may be limited to supplying niche applications. Ankarstrand says that “for some short sea routes like coastal ferries or service vessels, batteries and/or hydrogen can be a better solution than ammonia if the infrastructure is in place”.

Passenger ships such as ferries and cruises may be averse to carrying ammonia because of its toxicity, and certain locations, such as Norway’s fjords, require zero-emission fuels, which leaves only hydrogen or battery propulsion. But batteries have a significant head start, with 533 ships in operation and on order, 234 of these in the ferry segment, data from ship classification society DNV show.



## ANALYSIS

*Electrolysers could help ease north-south bottlenecks in Germany's power system, but industry in the south and west is unimpressed, writes Chloe Jardine*

*Most of the hydrogen used in Germany will come from imports, the majority of which will initially land at the northern seaports*

## Hydrogen could shift German industry northward

Germany's four power transmission system operators (TSOs) have warned of "great uncertainty" over where the country's electrolysers will be installed, as they face the task of planning the development of their network in the decades to come.

Grid regulator Bnetza says that it is not yet clear where the bulk of Germany's electrolysers will be located. One option is the less industrialised north or east of the country, to relieve the north-south power grid bottlenecks, caused by excess wind energy in the north and the closure of conventional stations in the south.

These bottlenecks have led to ballooning redispatch costs – where a TSO pays cheaper units in the north to switch off and more expensive units in the south to ramp up – and contributed to the breaking up of Germany's joint power market with Austria in 2018. And Germany's politicians have been fearing for years that the EU may force them to split their country's power market in two.

Existing legislation sets no restrictions on location. Politicians in Germany's new federal government have championed the construction of large-scale electrolysis in the north as the most efficient and obvious solution. But politicians have, so far, not held out the prospect of dealing with the issue with legislation.

TSOs Tennet and 50Hertz, which run the offshore grid connections in the North and Baltic Seas, respectively, have repeatedly called for electrolysers to be predominantly built in the north, particularly along the coast to harness offshore wind power. These demands are echoed by the country's renewables sector.

Bnetza provides some limited guidance. The regulator asked TSOs, in making the power network development plan for 2021-35, to assume around one-third of anticipated electrolysis capacity in the south. The TSOs had initially adopted an almost exclusively northern focus, which was rejected by Bnetza.

Germany's gas TSOs have also been under fire over their plans for a 1,200km hydrogen "starter grid" plan, which has a strong northern focus.

Faced with accusations of "sidelining the south" at an industry event last month, dominant gas system operator Open Grid Europe's chairman of the board Jorg Bergmann stressed that gas system operators have since "moved on". Their latest take on a hydrogen grid for 2030, presented in December 2021, suggests a 5,000km grid, of which 3,700km would be converted gas pipelines. And in this scenario, south Germany is no longer bypassed, Bergmann says. Rather, the south is expected to import hydrogen from Ukraine via the Czech Republic or Austria.

Bergmann pointed out that most of the hydrogen used in Germany will come from imports, the majority of which will initially land at the northern seaports – including Amsterdam-Rotterdam-Antwerp – far from the landlocked south, but relatively close to the industry-heavy west of the country.

Some hydrogen supply gaps will be unavoidable in the south in 2030, a manager from southern system operator Terranets says. In some areas around Stuttgart for instance, gas system operators still expect strong methane demand in 2030, leaving no capacity for hydrogen.

### The off-site trap

Part of the north-south hydrogen debate is mirrored in the debate on the merits of installing electrolysers on industrial sites. Medium-sized companies cannot be expected to build their own combinations of wind farms and electrolysers, utility Eon's chief executive Leonhard Birnbaum said at an industry event last month.

The TSOs' draft scenario framework for 2023-37 expects the share of on-site electrolysis to dominate versus off-site electrolysis until 2037, before the proportion then starts to reverse. By 2045, the TSOs expect around two-thirds of electrolysis capacity to be off-site.

## IN BRIEF

**High met coal prices could hasten greener steelmaking**

Reduced investment in coking coal mines and coke batteries could push up prices, hastening the transition to greener steel production, according to consultancy McKinsey. Banks and governments continue to move away from coal mine investments and investors are also wary of the long campaign life of a coke battery, given the shift away from blast furnaces to gas-based reduction of iron ore. This could lead to a capacity squeeze, pushing prices up as mills compete for a shrinking pool of material. The cost and availability of hydrogen, which the main gas producers are looking at to feed their direct reduced iron units, will be key in determining steelmakers' reliance on coke-fed blast furnaces. The transition away from blast furnaces will diverge depending on regional dynamics "relating to differing decarbonisation pressures and local coal and coke availability", McKinsey says.

**Gas blending risks 'wasting' green hydrogen: Fraunhofer**

Blending hydrogen into natural gas networks would be "wasting" a scarce resource and would significantly raise costs for customers, a study by Germany-based applied science research body Fraunhofer has found. The report says blending green hydrogen into gas networks at 20pc of the total would cut emissions by just 7pc. This compares with a 30pc reduction if the hydrogen were to be used directly in priority areas such as shipping, aviation fuels and the replacement of grey hydrogen. A 5pc blend in the gas grid would use almost 40pc of the green hydrogen likely to be available in 2030, even as overall demand from priority sectors is expected to exceed the total supply available. Costs increase at higher blends, as it requires more investment in infrastructure, the report finds (*see table*).

Hydrogen blend impact on gas costs %		
	5% blend	20% blend
Residential consumers	+0.6	+11.0
Industrial consumers	+1.3	+24.0

– Fraunhofer

**Dutch 250MW hydrogen project progresses**

BP has signed an agreement with hydrogen firm HyCC for the joint development of the H2-Fifty green hydrogen plant in the port of Rotterdam. The 250MW facility is expected to produce 45,000 t/yr of green hydrogen, which will be used in BP's largest European refinery for desulphurisation, replacing grey hydrogen made from fossil fuels. The final investment decision is planned for this year and the facility is due to start operations in 2025.

**EU beefs up hydrogen statistics**

The European Commission will require EU member states to give more detailed energy statistics from next month, including about the types of hydrogen used. The commission says the data will be essential in implementing the bloc's hydrogen strategy. Whether used as a feedstock, fuel or energy carrier and storage, all hydrogen use must now be reported. But when in a mixture, hydrogen only has to be reported when it is the "main component with a high degree of purity". The commission says improved data will differentiate green hydrogen from hydrogen that is produced from oil or gas. It hopes to gain data on how hydrogen is used in the economy, particularly in sectors that are difficult to decarbonise, such as maritime and air transport. The commission views the new statistics as an essential tool in monitoring the implementation of the EU's hydrogen strategy.

**Indian refiner HPCL aims for net zero emissions by 2040**

Indian state-controlled refiner HPCL wants to achieve net zero carbon emissions by 2040, and plans to have a green hydrogen production capacity of 24,000 t/yr in the coming years. The company is in the process of developing a roadmap to achieve net zero Scope 1 and 2 carbon emissions by 2040, details of which will be released this year, chairman MK Surana says. HPCL's ambition to set a net zero

## IN BRIEF

target follows fellow [state-run refiner BPCL](#) and private-sector [RIL](#), which target 2040 and 2035, respectively. India is looking to reduce the carbon intensity of its economy by 45pc and to reduce projected carbon emissions by 1bn t by 2030 from 2005 levels, and to achieve a net zero target by 2070.

### Consortium eyes 500MW green H2, ammonia plant in Spain

Danish fund Copenhagen Investment Partners is leading a consortium that plans to develop a 500MW hydrogen and ammonia plant in Aragon, northeast Spain, alongside wind turbine manufacturer Vestas, Spanish utility companies Enagas and Naturgy, and fertiliser producer Fertiberia (*see table*). The project will involve transporting green hydrogen from Aragon to a newly built 200,000 t/yr green ammonia plant in Valencia. Fertiberia will use the ammonia to manufacture fertilisers at its existing assets at Sagunto. The hydrogen will also be used to decarbonise other industrial processes and blended into the natural gas grid, the companies say. The project is applying for grid connection in Aragon.

### Green ammonia plant in Norway set to supply maritime sector

Green hydrogen company Hy2gen, trading firm Trafigura and Danish fund management company Copenhagen Infrastructure Partners will build a 240MW electrolyser and a 600 t/d green ammonia facility to supply the maritime sector in Sauda, Norway. Production will ramp up significantly thereafter. The facility, named Iverson eFuels, will provide ammonia exclusively for carbon-free marine fuel. Investment will be made in production, storage and shipping facilities, allowing the consortium to export product too. A full plan for construction should be completed by 2023, with construction to begin in the first quarter of 2024. The facility will be fully operational at the beginning of 2027. The carbon-free marine fuel will help Trafigura meet its goal of [reducing its shipping emissions by 25pc by 2030](#).

Aragon project details		
	Phase 1	Phase 2
Wind + solar capacity MW	1,700	5,000
Electrolyser capacity MW	500	2,000
Hydrogen production t/yr	40,000	na
CO2 reductions mn t/yr	1	2
Construction start	2023	na

– CIP



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