# PE Outlook 2024

NEXT DIRECTIONS IN THE EVOLVING ENERGY TRAJECTORY

A PE Media Network Publication

Petroleum Economist

Hydrogen Economist

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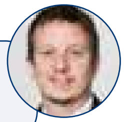
# The new energy order

Geopolitical risks, economic uncertainties and policy commitments leave energy markets open to further radical shifts in the direction of energy flows



By Paul Hickin, editor-in-chief, PE Media Network

The contours of the energy landscape have changed beyond all recognition in the past few years. Much is due to the energy trilemma, a term that for some is a reductive buzzword but unmistakably highlights the trifecta of energy security challenges, energy sustainability drives and economic imperatives that have upended some flows and consolidated others.

The US has become the ultimate hydrocarbon supplier, providing more crude and LNG globally than anyone else. The war between Russia and Ukraine over the past two years further pushed Europe away from Russian Urals and closer to light sweet US grades, so much so that the Platts physical Brent benchmark that is used to price the majority of the world's crude now reflects this historic shift. Mega-mergers between ExxonMobil and Pioneer and between Chevron and Hess also tell their own story as to how the US views oil in the longer term. On one hand these moves are bets that oil demand will more likely plateau than truly peak in the next couple of decades, but they also indicate that big players want to be conservative by spending big on sure things such as US shale and relative newcomer Guyana.

Big players want to be conservative by spending big on sure things

Meanwhile, the US achieved the milestone in 2023 of biggest LNG supplier, overtaking gas heavyweights Qatar and Australia. But it won't stop there: a raft of projects is planned over the next few years so it's a position that it's unlikely to relinquish any time soon. The US is also likely to play a key role as a swing supplier between Asian and European demand and has already carved out a sizeable market share vacated by lost Russian gas supply to the European market.

And it's not just fossil fuels, with the US going big on renewables and clean energy with the Inflation Reduction Act. This all-energy perspective can also be found in the other hydrocarbon hub, the Middle East. Saudi Arabia doesn't do things by halves: its green hydrogen Neom project is backed by the revenue generated from its oil reserves as OPEC+ looks to maintain higher prices to boost economic growth among its members while not killing demand among its consumers. The UAE is following a similar path with huge clean energy projects that accompany a buildout in its crude spare capacity just like neighbouring giant Saudi Aramco.

Buying behaviour is also radically altering. As Europe shifts away from Russia, others step in. India has gone from zero to number one buyer of Russian crude over the past couple of years, while China is hoovering up sanctioned crude from both Russia and Iran. These consumer behemoths are also employing diversification strategies to try to ensure energy security and meet net-zero goals on their own timeline. With upcoming elections in the US and India, geopolitical tensions across the Middle East and Russia and economic threats throughout the globe, energy players must tread carefully. But tread too carefully and investment will grind to a halt; tread too heavily and there is a danger of overcommitting.

However, there is a tentative and growing realisation that oil and gas companies need to be central to the transition rather than harassed on the sidelines—especially with hydrogen's role in oil refining and the potential of CCUS—as well as the irony of longer distances energy must travel to find new destinations that call for new responses and new leadership. The genie is out of the bottle—it can't be put back, but it can tell you to be careful what you wish for. ■

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Editor-in-chief: Paul Hickin
Editors: Simon Ferrie, Stuart Penson
Chief subeditor: Rhys Timson
Digital editor: Caitlin Stevens
Subeditor: Aimee Shields
Project manager: Rachel McGhie
Production: Keith Baldock

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Hamas-Israel violence unsettles energy markets
EU ban on Russian product imports
Indian oil refiners start payments for Russian oil imports in Chinese yuan as an alternative to US dollar
COP28
Nigeria's 650,000 b/d mega-refinery starts operations
Sanctioned Iran adds almost 1m b/d in production
Qatar's North Field gas project awards first contracts
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Saudi Arabia's $8.4b Neom green hydrogen and ammonia project reaches final close
OPEC+ makes series of production cuts, including Saudi Arabia's 1m b/d voluntary additional reductions during H2 2023

# What they said in 2023

APRIL

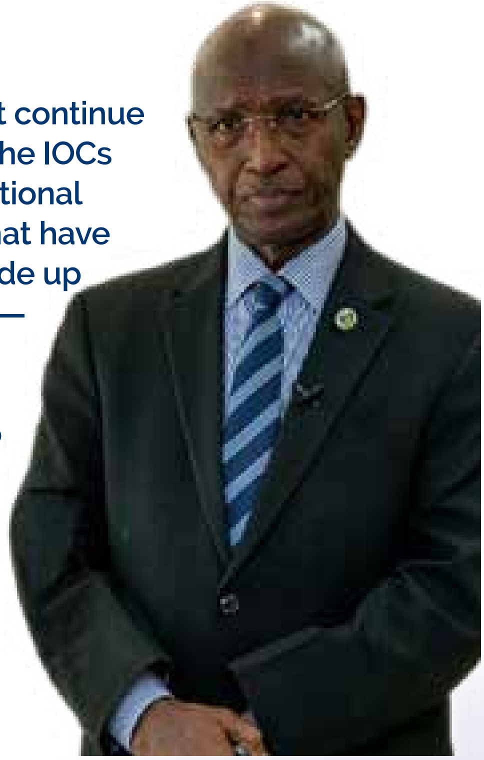
"Argentina is going to be a great supplier of energy to the world"

ENERGY SECRETARY
FLAVIA ROYON

JUNE

"We cannot continue looking to the IOCs and international investors that have already made up their minds—whether voluntarily or forced to do so—to abandon fossil fuels"

DR OMAR FAROUK IBRAHIM, AFRICAN PETROLEUM PRODUCERS' ORGANIZATION



MAY

"Will higher interest rates kill off the capex cycle? No. The higher interest rates are telling you it is time to put money into the real world and take it out of the financial world"

JEFF CURRIE, EX-GOLDMAN SACHS

MAY

"Boosting both the oil and gas sectors is crucial for India's energy security, affordability and investor returns"

GURMEET SINGH, FIPI

JUNE

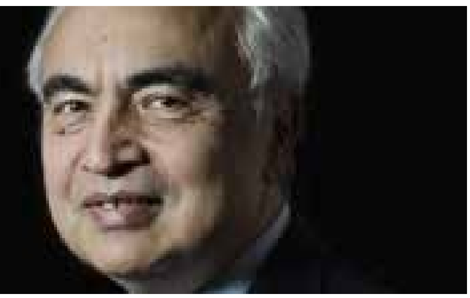
"CCS is a well-known, well-understood technology. The main challenge is that it is expensive"

KENDALL DILLING, PATHWAYS ALLIANCE

JUNE

"I have never seen geopolitics and energy so closely interwoven"

FATIH BIROL, IEA



JULY

"The agricultural sector is now focused on decarbonising and they are moving fast and trying to figure out how can they play a role"

OLIVIER MUSSAT, ATOME ENERGY

JULY

"We think gas is going to be the energy transition fuel for many decades to come"

STUART YOUNG,
ENERGY MINISTER, TRINIDAD & TOBAGO

SEPTEMBER

"Some major players are now admitting that gas will be part of the energy mix post-2050"

MATTHIAS RIGAS,
ENERGEAN

SEPTEMBER

"Ukraine and Russia are bringing energy security back to the spotlight again"

NIKKI MARTIN, ENERGEO ALLIANCE

OCTOBER

"We intend to increase our natural gas production by more than half by 2030 to help the Kingdom achieve a lower carbon energy mix"

AMIN H. NASSER,
SAUDI ARAMCO

OCTOBER

"We need to dramatically lower the cost of capture"

GAVIN RENNICK, SLB

# What they said in 2023

OCTOBER

"We hope to have 1,220MW operational in South Africa in less than one year"

ZEYNEP HAREZI YILMAZ, KARPOWERSHIP

NOVEMBER

"Without that clarity, it makes it challenging for people to invest in long-term projects"

ANDY MARSH, PLUG POWER

NOVEMBER

"We gave up looking at the price as one single target"

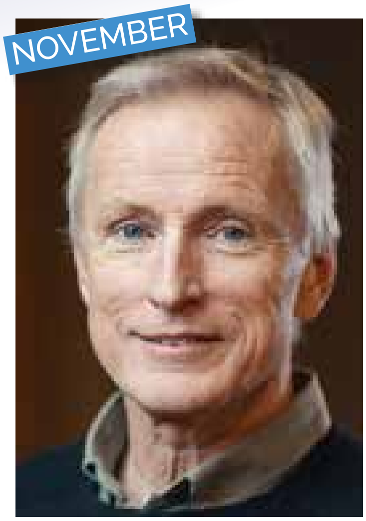
SUHAIL AL-MAZROUEI, UAE ENERGY MINISTER

NOVEMBER

"Balancing global energy markets by ensuring crude prices do not outstrip the paying ability of consuming countries will be of interest to producers"

HARDEEP SINGH PURI, INDIAN OIL MINISTER

NOVEMBER



"Small cap players can find success where the majors are leaving behind opportunities to extract value"

HELGE HAMMER, LONGBOAT ENERGY

NOVEMBER

"We will defend a minimum target of at least 90% net reduction by 2040"

WOPKE HOEKSTRA, EU CLIMATE COMMISSIONER

# Energy flows go in new directions – oil

# OPEC at the wheel

OPEC+ has created a new and higher oil market floor that both sets the scene to revive oil investment and has the begrudging acceptance of consumers

OPEC+ is back in the driving seat. For several years it has felt like huge black swan events have been controlling oil markets and the 23-nation producer alliance has been more in damage control mode than focused on fine-tuning market stability. But that tentatively has all changed. Indeed, oil prices appear to be lacking direction but that is maybe because, for OPEC+, whisper it quietly, they have already reached a destination of sorts.

The oil market's new-found equilibrium of between $80-100/b seems to have the implied support of producers and consumers alike. OPEC has shown it is likely to intervene if either prices drop into the $70s or there are alarming signals around demand. The Gulf-led group has acted swiftly and decisively since November 2022, when it slashed production by 2m b/d, moving again to offset prices falling on banking jitters in April and then with Saudi Arabia offering additional 1m b/d voluntary output cuts through the second half of 2023. The strategy, as the Saudis put it, is to do "whatever is necessary"—whether that is to keep prices stable or elevated is a matter of perspective.

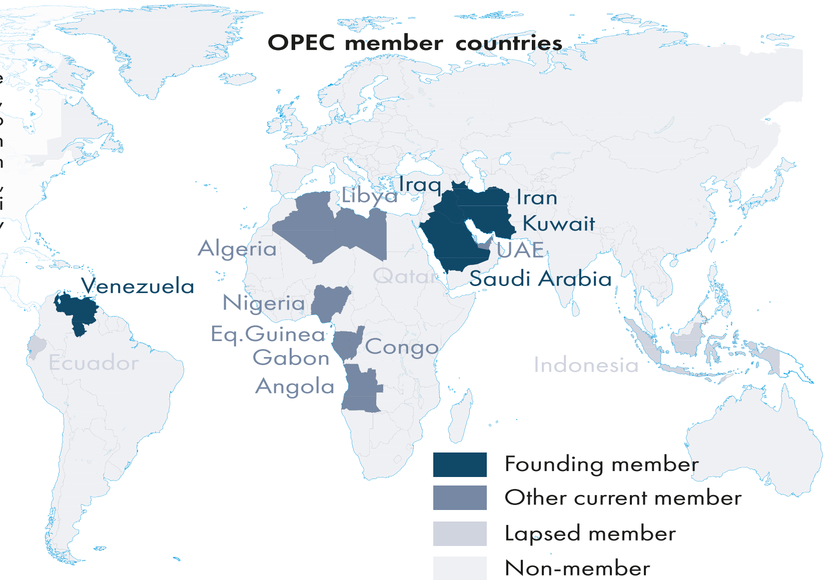

What is clear is that oil prices have a pretty sturdy floor in the event of greater global economic weakness in 2024 and/or higher-for-longer interest rates and inflation

**OPEC Reference Basket (ORB)**

Introduced on 16 June 2005, is currently made up of the following: Saharan Blend (Algeria), Girassol (Angola), Djeno (Congo), Zafiro (Equatorial Guinea), Rabi Light (Gabon), Iran Heavy (Islamic Republic of Iran), Basra Medium (Iraq), Kuwait Export (Kuwait), Es Sider (Libya), Bonny Light (Nigeria), Arab Light (Saudi Arabia), Murban (UAE) and Merey (Venezuela).


Source: OPEC 2023

**OPEC member countries**



By Paul Hickin, editor-in-chief, PE Media Network

given the lack of clarity on the outlook for powerhouses US and China. Whether the line in the sand is driven by budgetary needs of key producers or stated aims to lure oil investment is a moot point since it doesn't make the line any less real.

Less obviously and probably more contentiously, there appears to be a ceiling around the $100/bl mark driven by potential demand destruction at higher prices and OPEC's spare capacity muscle. Demand destruction is a delicate issue. It points as much to the speed of any price rises in triggering further inflation and belt-tightening than absolute crude prices. There is also the more ambiguous link to actual fuel and energy costs—higher diesel and gasoline prices don't always move in tandem with crude.

Meanwhile OPEC spare capacity is now at historically healthy levels, with around 4m b/d held by key swing producers Saudi Arabia and the UAE, which traditionally has been more like half that number. Should prices enter triple digits there is a greater likelihood that Gulf producers will ramp up output. Whether it is explained by the pure profit motive, the geopolitical considerations of not wanting to hurt key consumers such as the US, China or India, or the oft-messaged market stability angle is again another moot point. OPEC+ will act to bring on extra supply.

The question remains as to how long this sweet spot will last before all goes sour or what could throw the oil market off kilter. The Russia-Ukraine war and the atrocities across Israel and Palestine remain known unknowns—with the oil market struggling to attach accurate risk premiums. It's been almost two years since Russia's invasion caused oil prices to spike to $130/bl amid panic over potential supply losses that never materialised and sanctions impacts that were more imagined than real. And now calculations over how Gaza violence will impact wider oil producers across the Middle East remain very difficult to figure out. It may be left to fundamentals to provide the shock treatment to push oil off its plane. A quick change in the global economic outlook—mostly likely to the downside given the double threat of inflation and debt—could test OPEC limits once again, while a slow rise upwards in oil prices on improving demand could see consumers ending up like the boiled frogs from the parable.

**OPEC spare capacity is now at historically healthy levels**

With around 40% of global market share, OPEC+ doesn't have the power to control the oil market but it does have the tools to help keep it on the straight and narrow. In the previous decade, it received support from US shale providing a natural ceiling to prices by bringing on marginal supply, while this decade the cap has to some degree been provided by China as a strategic buyer and hoarder of oil. What is clear is that OPEC+'s market management has become increasingly effective over 2023, and increasingly accepted by consuming nations, which will only embolden the group in 2024 and beyond. Famous last words, but oil prices may be more stable as a result. ■

# Declining Russian oil flows

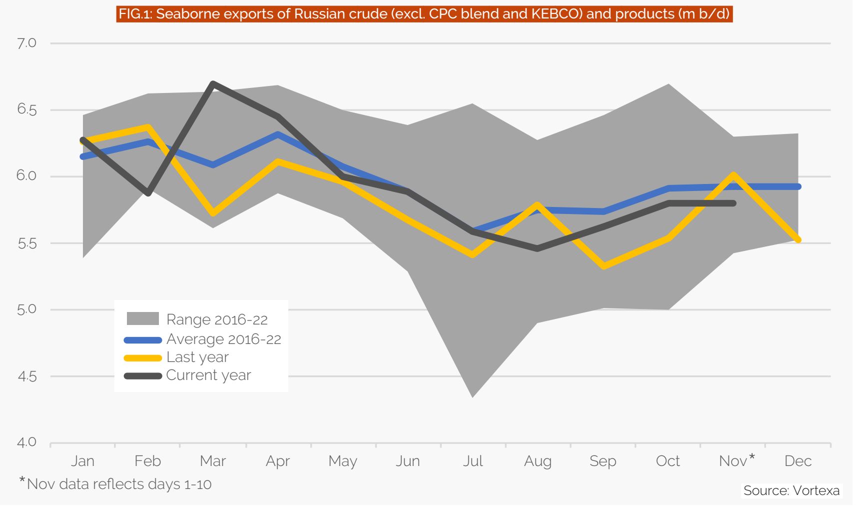
Competition for Russian oil remains strong, but opportunistic buyers will have more challenges in 2024

2023 has been an extraordinary year for Russian oil exports. Driven by Western sanctions, and in particular the phase-out of most European crude and product imports from Russia, the hydrocarbon superpower had to look for alternative outlets.

After all, and against the expectations of many, it was neither particularly difficult for Russia to find new buyers nor for Europe to procure replacement diesel and crude oil. And while the new equilibrium has a higher demand on vessel ton-miles, not even that was sufficient to boost freight rates to a permanently higher level.

> On average Jan-Jul exports of Russian oil were perfectly aligned with the seasonal average

Russian oil flows in the new paradigm can be split into two phases. In the first six months of 2023, Russian arrivals in new destination markets hit steadily new record highs, facilitated by deep discounts. The staged European phase-out (first crude, then diesel) was completed in early February. Some initial hesitation on the buyer side in combination with the seasonal peak in Russian oil exports in March led to a peak in arrivals of Russian oil in new markets in the month of June.




From that point onwards, flows and the stress on the logistical system were easing from various perspectives. As a key factor, seaborne exports of Russian crude (excluding CPC Blend and KEBCO, both transit grades from Kazakhstan) fell from an extraordinarily high 6.7m b/d in March to a low point below 5.5m b/d in August.

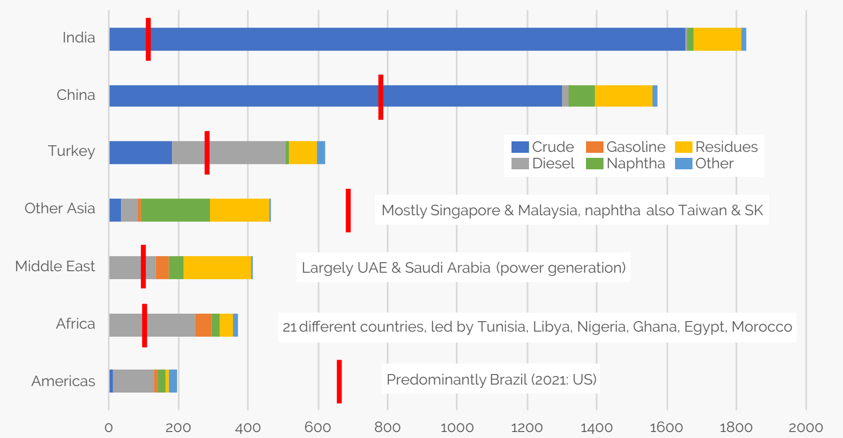
A superficial view on the massive 1.2m b/d gap would suggest that Russia must have curtailed supplies dramatically, having announced combined cuts of 1m b/d in crude exports for the month of August. But the truth is that the average seasonal decline in exports already accounts for more than 0.7m b/d of this. And March figures were just strongly inflated due to substantial delays in exports from February due to winter storms.

On average, January to July exports of Russian oil were perfectly aligned with the seasonal average, while over August to October a shortfall of some 250k b/d can be noted. This may well serve as a good indicator of the combined effects of the announced crude exports cuts in close alignment with OPEC+ and particularly Saudi Arabia, as well as the partial export ban on diesel and gasoline established in the latter part of September.

Slower Russian exports in H2 2023 tightened the market for these semi-sanctioned barrels, leading to higher prices. It is sometimes forgotten that it is entirely legal to import Russian oil for most countries outside the EU/G7 group, as long as no Western shipping, financing and other related services are used. Accordingly, a new fleet established itself over the course of 2023 and logistics became pretty fluent again, curtailing vessel utilisation beyond lower underlying volumes. Furthermore, fresh interest for Russian diesel from markets such as Brazil helped to keep somewhat

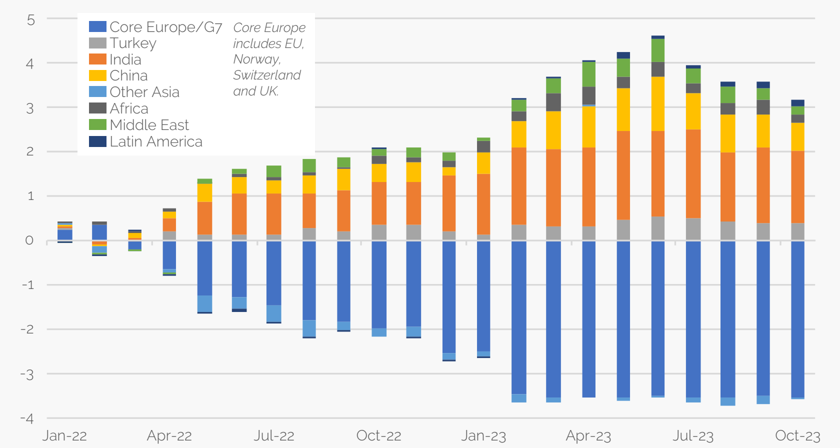
By David Wech,
chief economist,
Vortexa

FIG.2: Main importers of Russian oil Jan-Oct 2023 split by product & 2021 average total import volumes (red lines) ('000 b/d)




Source: Vortexa

FIG.3: Change in imports of Russian crude and products vs 2021 average by main destinations (m b/d)




Source: Vortexa

shorter-haul barrels to the Atlantic Basin more stable, while the declines materialised in particular towards East of Suez markets.

Nevertheless, India is clearly the number one opportunistic buyer of Russian oil. Up from negligible volumes in 2021, Indian imports of predominantly crude oil peaked at 2.1m b/d over May to June, before falling back to 1.7m b/d since then. But Chinese imports of Russian oil declined by 0.7m b/d from a June peak to an October low. Middle Eastern imports fell by about 350,000 b/d from peak to trough, with the end of the power generation season in Saudi Arabia playing a role.

Looking forward to 2024, two things are likely to happen. As domestic Russian oil demand eases over winter months, exports are set to rise by at least 0.5m b/d towards the usual peak in April. But competition for the Russian barrels, which are still offered at some discounts, will remain strong, and the recent marginal transition from East of Suez to West of Suez buyers may well go on.

Opportunistic buyers will have a harder time than in 2023 and logistical costs will play a bigger role. Buyers such as Turkey, North and West African countries and possibly more Latin American players are likely to increase their share in Russian oil further. Meanwhile in particular China may well see a further decline in flows, as it is simply too far away from the key Baltic and Black Sea ports. Only if some hiccups were to materialise in logistics, e.g. due to tightening sanctions, would China become more relevant again as a buyer of last resort.

But such hiccups are unlikely. Ultimately pretty much everybody in the market wants Russian oil to continue flowing, as otherwise massive price rises are unavoidable. Similarly, Russia itself will not deliberately forego crucial income in its war economy. And, as in 2023, any potential shortfall in the fleet transporting Russian oil will be picked up quickly by new players, with procurement prices of old vessels set to fall amid a reasonably long oil tanker market. ■

# Oil pricing in a post-peak-demand world

The carbon intensity of oil may bring a change to pricing long-term


The latest views from the IEA indicate that coal, oil and natural gas demand will peak by 2030, just a handful of years away. Regardless of the date, it is useful to understand how the oil market may change as demand begins to decline. Should demand fall near the natural rate of production decline, as the IEA points out is necessary for the world to reach net zero by 2050, we will see a disruption in the long-term price-setting mechanism for oil. This shift could be as seminal as the switch from posted prices to market prices in the 1970s or the financialisation of oil. The long-term price will fall sharply, placing intense pressure on oil-producing firms seeking to compete to retain a market share foothold. This downward price pressure will cause oil and gas companies to shift their focus away from hydrocarbon production, reduce breakeven costs as well as emissions or otherwise exit the business.

## Peak demand

Whether focused on demand or supply, oil has encountered the belief of a near-term peak since the early days of oil production. While most of the historic focus on peak oil has been on supply, this has shifted to the impending peak in oil demand and when it may occur. Despite some prior views that peak demand occurred in 2019 after Covid-19 brought oil demand down as much as 30%, current data makes it clear it is a date still in the future. Several credible forecasts show a peak in oil demand in the next decade. Many OECD countries have already reached peak oil demand. Weakening gasoline demand in the US is also a harbinger of its approach on a global scale. Aside from the date of the global peak, it is also useful to understand what may happen to the price as well as price-setting for oil.

## The rise of the third number?

When refiners purchase cargoes of oil, outside of relative pricing, they examine two headline numbers, American Petroleum Institute (API) gravity and sulphur, to evaluate how suitable it is for their refining kit. While a global carbon price is unlikely, there is growing regulatory pressure in some localities to consider the carbon footprint of imported goods. Over time, this could cause the rise of a "third number" in oil, namely a focus and pricing related to the carbon intensity of the oil. The spread between the highest and lowest carbon intense oil is as wide as the spread in breakeven production prices across different oil plays. But unlike API and sulphur, this is a number

By Jamie Webster,
partner and associate director at BCG,
non-resident fellow at Columbia's
Center on Global Energy Policy

that can be managed with a wide range of decarbonisation strategies. As end users begin to focus on this new third number, the industry will see sharp declines in carbon intensity at all levels, not unlike what occurred with breakeven prices after the 2008 oil price crash. Over time a market-beating low carbon intensity can be a durable advantage for a company seeking to remain in the oil production business during the industry's decline.

### Capex price setting

Short-term oil price forecasting is the province of traders and analysts that carefully count up barrels of current and expected supply against current and expected demand. Into that quantitative mix are other qualitative factors ranging from OPEC policy, geopolitical risks, short-term economic indicators and other events. But long-term pricing is relatively simple, even if the short-term price can radically depart from it for periods of time. That time horizon is set by the long-term marginal capex cost. That is, the price required to incentivise enough production to offset the estimated 4-7% of natural decline as well as the annual demand growth increment. Depending on your view of the decline rate, oil demand growth and the supply curve, the current number for this is $65-75/bl. For an oil company seeking to set its price decks, this long-term price forecast methodology can serve well—so long as demand continues upward or stays flat.

### The shift to opex price setting

Capex-set pricing will shift as demand begins to recede. Instead, pricing will be set at a partial or full long-term marginal opex cost. Should the decline in oil demand meet or exceed natural production decline rates, the long-term price will be completely set by this mechanism, which at present is $20-25/bl. With little-to-no new oil production needed, the requirement for additional capex investments to drill new wells or offset decline rates falls away. Left in its place is just the remaining operating expenses. The transition to this new longer-term pricing mechanism will be volatile rather than a binary switch. The reason will be the time lag between when oil peak demand is reached and when it is recognised by market players. OPEC member countries may also resist by restraining production, keeping their often but not always low-cost and low-emissions-intensity barrels off the market. And like the current long-term pricing mechanism, price volatility amid ongoing short-term market signal can cause the spot price to veer wide of the new long-term price-setting mechanism. Despite these caveats, downward sloping demand in oil markets will signal the shift to a much lower price deck.

### Implications for oil producers

For oil companies, preparing for this eventuality in price setting is a no-regret move. Future proofing against a new lower oil price regime will provide strategic flexibility, regardless of when peak demand or the implementation of the third number occurs. Companies have already spent more than a decade working to reduce costs and lower their breakevens. And the industry appears to have met a milestone in 2019 when methane emissions peaked. For companies that want the opportunity to be the proverbial "last producer of oil", renewed efforts in these two areas are needed to get low enough in both cost and emissions intensity. This includes root and branch redesigns of every process, fully utilising the still emerging benefits of digital and artificial intelligence. Reducing costs will ensure higher margins in the short term, allowing more to be invested in decarbonisation levers to bring down emissions intensity. A global market driven focus on reducing emissions intensity has not yet occurred. This means when it does occur the average carbon intensity per barrel may drop 30%, further intensifying the competition on this metric.

Reducing costs will ensure higher margins in the short term

Given the sharply lower oil prices post-peak, many companies will likely see that exiting at some point will make more sense than seeking to compete to be the last producer of oil in a rapidly declining market. ■

# Brent's WTI transfusion: A new lease of life or a whole new animal?

With crude production forecast to grow through 2028, what benchmark is going to lead the way?

If there is a second Cold War, then it is in part a struggle between Washington and Moscow for control of Europe's energy supplies. And the US appears to have just won it.

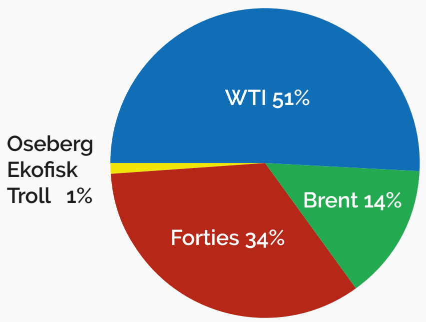
Not only has its crude oil in essence physically replaced all the Urals that Europe stopped buying when Russia invaded Ukraine, but its natural gas—in the form of LNG—has become the replacement of choice for Russian gas.

And now US crude West Texas Intermediate (WTI) has reverse-colonised the price of Brent.

What was unthinkable as little as six years ago has happened. Europe's large oil companies, trading houses and refiners have agreed to allow WTI to be included in the mechanism that determines Dated Brent. WTI joined the pool of crudes that set the Dated Brent price in May 2023. Since then, it has been the major contributor in pricing terms to the mechanism as well as the major source of barrels sold as Brent.

This is quite odd, on the surface of things. Firstly, Brent is quintessentially a European benchmark. Secondly and crucially, it is—or was—a free on board benchmark. And lastly, the determination of its price is quirky, to say the least. In simplest terms the marker is set by the lowest price for a physical cargo of crude from any of the Brent, Forties, Oseberg, Ekofisk or Troll fields, or (now) by a cargo of delivered WTI from the US. None of the five North Sea grades trades as an "outright" price, however.

FIG.1: What has set Dated Brent since May 2023?




Source: Argus data

They trade as differentials to a swaps market, which in turn trades as a differential to ICE Brent futures.

WTI does not do this, of course. The Permian-origin "pure" WTI Houston, which is what European importers are buying, trades relative to NYMEX WTI futures (which represents a less gasoline-rich blend of crudes). And the way that WTI Houston trades raises a major efficiency question for markets. Namely: what is the point of hedging physical exposure in Europe using a futures contract that is at best at one remove from the market actually setting the price? Wouldn't it be better just to hedge the instrument using WTI, since the instrument actually is WTI? Not only has the US grade set the price 50%+ of the time since May, but the actual volume of American crude entering Europe is more than three times that of the five North Sea grades put together.

> **Wouldn't it be better just to hedge the instrument using WTI?**

WTI is the largest crude grade in the world by traded volume. Some 1.5m b/d is exported to Europe. A further 1.2m b/d heads to Asia.

A further philosophical question presents itself: what does it mean to introduce the cost of transatlantic freight into the complexity of the world's most powerful crude benchmark? At first sight, the fact that a delivered crude is a key component of the mechanism would appear to mean that the critical role of arbitrage in determining the destination of US crude is no longer available.

If Brent = WTI + freight, and Asian crude is being priced on a Brent-related basis, how does a US seller determine the best destination for their exports? The tool is lost.


By Neil Fleming,
global head of editorial,
Argus Media

Equally, it remains unclear at this point whether users of the Brent benchmark are prepared to tolerate the potential volatility that a freight component in the price appears to entail. Transatlantic freight is notoriously volatile. As the chart shows, rates for 70,000t dirty tankers across the Atlantic have ranged from just over $1/bl to just over $10/bl in the past five years, with a trend to greatly increased volatility since the Russian invasion of Ukraine in February 2022.

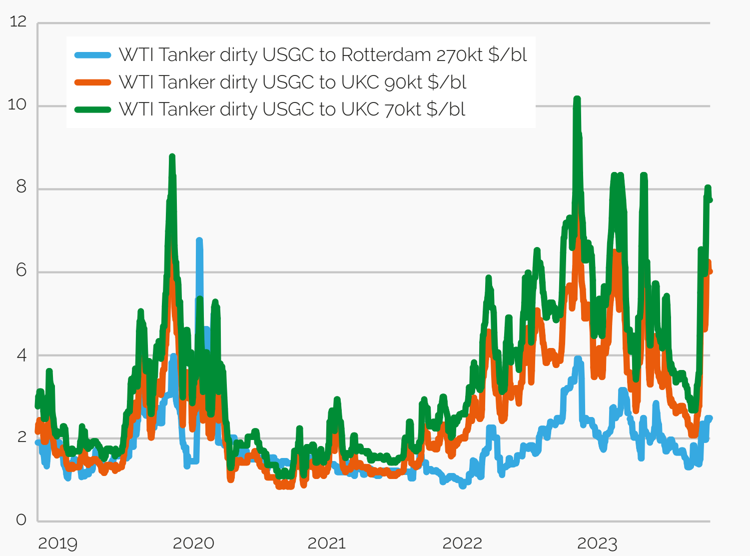
It is therefore perhaps not surprising that some European refiners have begun side-stepping the Brent market leg of this trade flow altogether and are buying WTI Houston at source—physical volume recorded by Argus for its WTI Houston price in July 2023 topped 1m b/d for the first time and continues to climb. And these European firms are not alone. Importers as far afield as India and Taiwan are also buying the grade directly on the Argus WTI Houston number.

Meanwhile, there has been a continuous surge in the volume of derivatives settling against both that WTI Houston price and the Argus WTI Midland price. WTI Houston volume more than doubled in the first ten months of 2023, and open interest in the contract was close to the 300,000 contracts mark as of November 2023.

The use of a non-European benchmark by European buyers is a first since floating price mechanisms first became the market's preferred mechanism in the mid-1980s. How and if this shift will evolve further will depend, however, on multiple factors: whether the market can live with the freight component, how and when the war in Ukraine ultimately is resolved and the future of US oil supply growth. The IEA forecasts US crude production to continue growing through 2028, but at a sharply lower rate from 2024 onwards, and basically flatlining from 2026. As oil demand shifts incrementally to Asia, that may inevitably mean less crude is available for export to Europe. And Brent, first as oil field, then as virtual construct and now as market hybrid, has proved a very resilient animal over the years.

But for now, its transfusion of WTI looks more like changing the beast altogether than reviving it. ■

FIG.2: Transatlantic rollercoaster




Source: Argus Media

# Middle East to continue making headlines in 2024

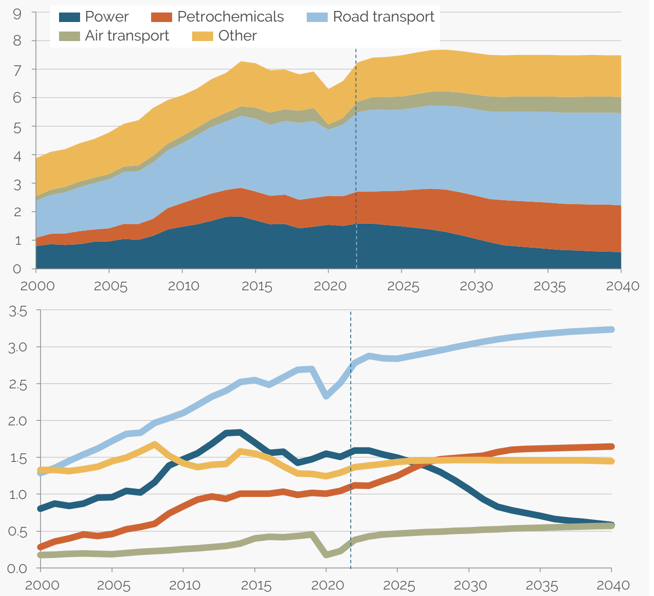
Especially in the products market, the Middle East is set to achieve significant growth

After the oil price crash of late 2014, the Middle East's oil demand growth stalled, with a contraction of approximately 450k b/d between 2014 and 2018. This trend reversed in 2019, but was significantly offset by a 9% year-on-year contraction in 2020 due to the Covid-19 pandemic. By 2022, Middle East oil demand not only recovered to 2019 levels but also exceeded them by over 320k b/d, nearly compensating for the demand loss observed since 2014.

In 2023, the Middle East is set to achieve over 2% annual growth in total oil demand, reaching a record high of 7.4m b/d.

The primary reason behind the stagnation of oil demand growth in the Middle East has been the power sector, where natural gas has replaced oil, particularly in Saudi Arabia, Iran and Kuwait. Both road and air transport sectors will contribute to rising oil demand, albeit at a slower pace compared to the last two decades. The petrochemical sector in the Middle East continues to expand, driven by local feedstock availability and the integration of petrochemical processes into existing refineries, with significant contributions expected from Saudi Arabia, Iran and the UAE. Bahrain and Oman will also make smaller contributions through standalone petrochemical projects. Notable uncertainties in the petrochemical sector include Kuwait's Al-Zour petrochemical plant and the proposed mega crude oil to chemical projects by Saudi Aramco and SABIC.

FIG.1: Middle East oil demand (m b/d)




Source: FGE

**10.7m b/d**

**Anticipated total regional refinery capacity in 2024**

Although we forecast a moderate growth rate of less than 1% in the region's oil demand for 2024, the products demand is expected to continue growing in all sectors except the power sector in the Middle East until at least 2040. A peak in Middle East oil demand, however, is anticipated between the late 2020s and early 2030s, depending on several factors that will influence the pace of the transition from oil to gas in the next decade, such as the US sanctions on Iran and the timing of gas supply expansion projects in Saudi Arabia, Kuwait and Iraq.

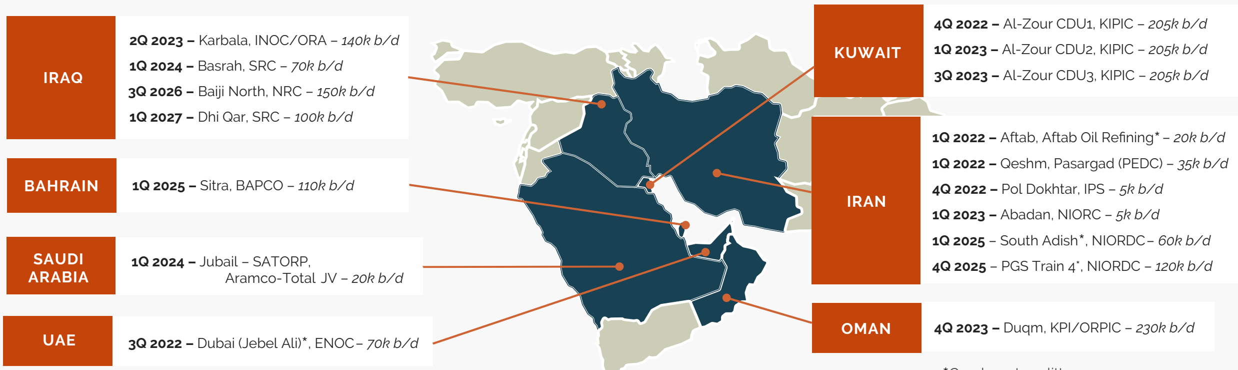
The Middle East ranks as the world's second-largest region for primary refinery capacity additions, following Asia-Pacific, and it continues to witness significant growth in this sector through 2030.

New grassroots refineries and expansion projects between 2023 and 2024 are poised to increase the region's total refinery capacity, including crude distillation units and condensate splitters, from 9.5m b/d in 2022 to over 10.7m b/d in 2024. However, bringing these projects to full operational capacity can be a lengthy process, taking months or even years (as already witnessed in some projects in Asia and the US).

As these projects ramp up to full capacity by the end of 2023 and into 2024, the Middle East is expected to experience a substantial annual growth in products surplus and exports. The region's total products balance is projected to grow by approximately 600k b/d year-on-year in 2024, pushing the annual average surplus to over 5m b/d for

By Dr Iman Nasseri,
managing director, Middle East,
FGE

FIG.2: Middle East refinery additions 2022–27




*Condensate splitter

Source: FGE

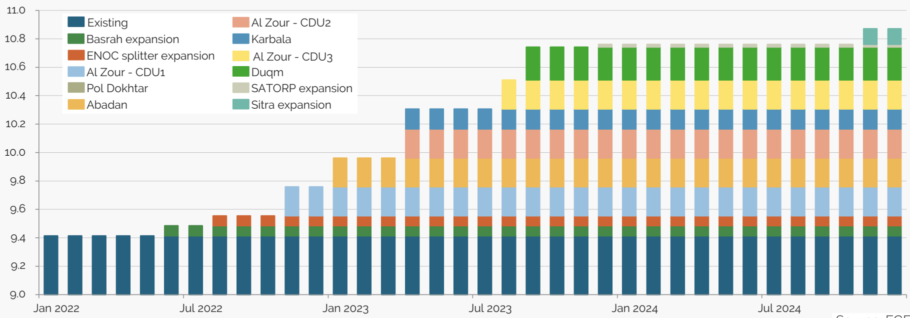
the first time and approaching 6m b/d during Q3 2024, when seasonal demand peaks.

Although the Middle East generally maintains a surplus of products, certain countries consistently or seasonally import specific products, which brings the region's overall product imports to just under 2m b/d. Consequently, the total product exports from Middle Eastern countries, both within the region and externally, are expected to exceed 7m b/d by mid-2024.

While there are no confirmed or likely projects scheduled beyond 2027, numerous proposals across the region may emerge for completion towards 2030. The Middle East seeks to add even more refining capacity, primarily driven by national oil companies and governments.

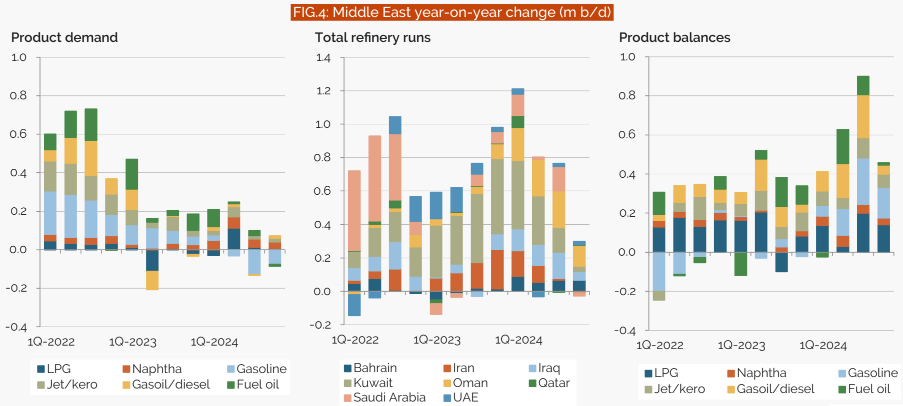
It is estimated that there is approximately 2m b/d of "possible" primary capacity in the region, mainly in Iraq, Saudi Arabia, Iran, Oman and the UAE. These projects are awaiting government funding or hoping to attract local or foreign private investments. ■

FIG.3: Middle East refining capacity (m b/d)




Source: FGE

FIG.4: Middle East year-on-year change (m b/d)




Source: FGE

# Germany rethinks its energy strategy amid European energy crisis

The consequences of Russia's invasion of Ukraine have been particularly significant for Germany

European energy security and energy affordability has been thrust into sharp focus by the Russian invasion of Ukraine and the resulting loss of critical gas supplies that Eastern and Central European countries had come to rely upon. This has also come at a time when Europe was taking steps to respond to the challenges of climate change by making its energy supplies more sustainable by increasing the build-out of renewables, which have not yet been able to replace the need for hydrocarbons.

Since the crisis began, supplies of Russian gas, which made up 45% of all gas imports in Europe, have dwindled by as much as 80% (according to the IMF). This sudden negative shift set off a domino effect, causing wholesale prices of electricity and gas to skyrocket, in some cases surging up to 15 times their early 2021 levels. The repercussions of this energy crisis are widespread throughout the economy, and in particular they are deeply felt in the living rooms and storefronts of households and businesses alike, making this a top priority for policymakers. With all 27 member states of the European Union net energy importers, this posed (and still poses) an existential threat to Europe's economic and social stability.

> This is an opportune moment for independent companies

## Changing strategies

The consequences of Russia's invasion of Ukraine have been particularly significant for Germany. In 2021, Germany was heavily dependent on Russia for its gas supply, importing a substantial 55% of its total gas, equivalent to 53bcm. Cheap Russian gas was to be the bridging fuel to a new energy future, as Germany wound down its nuclear power stations and began reducing its dependency on coal while it invested in renewables. Therefore, Putin's invasion of Ukraine created an acute crisis for Germany as the energy policy and strategy that it had built up under the stewardship of Chancellor Merkel was suddenly no longer workable. The sudden severing of the Nord Stream pipelines, a multi-billion-dollar project that was to have supplied Russian gas directly to Germany, only further underlined that the situation was not temporary and that urgent and radical changes were needed in how Germany sourced its energy.

Through necessity, the response has been fast paced. Germany has rekindled the use of coal, even expanding mining operations at the expense of wind farms, it has begun sourcing nuclear energy from France and has fast tracked the building of LNG import terminals to receive shipped gas from around the world. It has also sought to support its indigenous oil and gas industry.

Remarkedly, this has all happened within months whereas in normal times these changes would have taken years, and it has been driven by a coalition government that includes Alliance 90, the Green party. The discourse in Germany has evolved towards a considerably more practical and realistic approach, as it acknowledges the pivotal role of energy in sustaining both its economy and broader society.

## New opportunities

The oil and gas sector in Germany has historically been the preserve of large IOCs such as ExxonMobil, Wintershall DEA and Neptune Energy, where they have held assets that have generally languished at the bottom of their portfolios in terms of priority for investment.

Beacon Energy plc is observing a seismic shift in how the industry is being perceived and the opportunities that this presents for more agile players like itself. Independents such as Beacon can operate with less overheads and so can leverage their local experience to develop oil and gas resources that might be considered marginal or sub-economic by larger IOCs. Germany's renewed government support, established infrastructure and industry base creates a stable platform for Beacon to contribute to the energy landscape in a responsible and dynamic manner.

New technologies applied to older oil and gas assets means producing them with less emissions and harm to the environment. A renewed focus on oil and gas is hap-

By Larry Bottomley, CEO,
and Stewart MacDonald, CFO,
Beacon Energy plc

Drilling rig on the Schwarzbach-2(2.) well in the German state of Hessen

pening in tandem with an emerging geothermal sector, which is utilising oil and gas techniques and technology to access more substantial heat resources for power generation and heating requirements.

Companies such as Eavor, which is backed by the likes of BP and OMV, are actively progressing the development of enhanced geothermal systems by drilling deep horizontal wells that when paired create giant loops through the subsurface.

Furthermore, indigenous production practices are contributing significantly to the reduction of emissions associated with transport. By producing and processing oil and gas close to the end-user market, these companies are mitigating the environmental impact of long-distance transportation. This approach not only enhances operational efficiency and costs, but also aligns with sustainability goals, ensuring that energy resources are harnessed with minimal ecological disruption and transportation-related emissions. Indigenous production methods are thus playing a pivotal role in the broader transition towards more environmentally friendly energy solutions.

## Outlook

Germany's recent energy policy recalibration underscores the intricate interplay between energy security, affordability and sustainability, and the need to react quickly when all three elements are threatened by sudden and permanent change. To establish a long-term energy strategy, Germany will need to continue to be flexible and open to achieving its energy transition goals with the support of existing hydrocarbon sources. This is an opportune moment for independent companies such as Beacon to play a crucial role in ensuring a reliable indigenous energy supply and a responsible energy transition. ■

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Beacon Energy plc is a newly established, Germany-focused, LSE AIM-listed independent E&P company.

# Freight sector grapples with regulations and geopolitics

EU ETS extension is the latest change for the sector

Freight is a vital but often overlooked component of the oil and product markets. The sector will be subject to additional EU emissions regulation from the start of 2024, while continuing to grapple with the ongoing rerouting of the global energy trade. And with so many significant energy exporting nations under Western sanctions, the shipping industry is central in both the enforcement and attempted evasion of those rules.

In January, the EU will extend its emissions trading system (EU ETS) to cover the $CO_2$ emitted by "all large ships"—specifically vessels with a gross tonnage of 5,000t or more, which includes all classes of tankers—"entering EU ports, regardless of the flag they fly". The system will cover 100% of the carbon emissions from voyages between two EU ports and 100% of the carbon emitted while within EU ports, and 50% from voyages that start or end outside the EU. The maritime sector's emissions will be included in the overall ETS cap, so shipping companies will have to buy allowances as part of the system. But the introduction of the ETS will be phased over the next few years, with shipping companies only having to submit allowances in 2025 for 40% of their reported 2024 emissions, rising to 70% in 2026 for their 2025 output and then to 100% from 2027 onwards. The "administering authorities of EU member states" will "ensure compliance", according to the European Commission. The ETS extension is the latest regulatory change for the freight sector, following various measures imposed in recent years by the International Maritime Organisation (IMO) or EU making stipulations on issues ranging from bunker fuel quality to ballast water discharging.

Critics of the plans suggest that they will do little to curb emissions and might even have the opposite effect. One suggestion is that the ETS plans will render Europe's already relatively green industries less competitive, encouraging activity to shift to other regions—resulting in longer sailing times, say for refined products—or for cargoes to be split up onto smaller vessels for transport to Europe, reducing efficiency in efforts to skirt the new regulations. Other observers believe that the EU's efforts may encourage the IMO to move more quickly to implement a global carbon tax for the wider freight sector, and that those funds could be directed to aid the development and adoption of low-carbon maritime fuels and vessel designs. However, given the phased introduction of the new European emissions regulations, it may be some time before the results and consequences become apparent.

## Rerouting of trade

The ongoing Ukraine war has already resulted in a significant rerouting of oil and product trade, as Europe and its allies have sought alternatives to Russian crude and products such as fuel oil, while Moscow has raised its exports to China and India in particular. But this reordering in global flows means a reduction in overall efficiency and an increase in voyage times, raising ton-mile demand and effectively limiting the availability of tankers, since the ships are occupied by longer journeys. BIMCO—an


By Simon Ferrie,
editor,
*Petroleum Economist*


industry association of shipowners, charterers and brokers—predicts that this freight trend will continue in 2024, albeit for different reasons. "New oil supply is coming mainly from the Americas, while new refinery capacity is added mainly in Asia, causing longer sailing distances for both crude and product tankers," BIMCO states. The association forecasts that "already strong [freight] markets are expected to be stronger in 2024", based on the assumption that "limited supply growth, combined with record oil consumption and longer sailing distances" will boost freight rates. However, the health of the Chinese economy—and in turn, Chinese demand—remains a risk factor for freight demand.

**The health of the Chinese economy remains a risk factor for freight demand**

Another element that is expected to help support the cost of freight is the relative lack of new vessels due to hit the water: BIMCO predicts that the global crude tanker fleet will grow by just 0.4% in 2024.

## Sanctions

Sanctions are another ongoing issue in the freight sector—and particularly with tankers—which has been exacerbated by the Russia-Ukraine conflict. Relations between Russia and the West look unlikely to normalise any time soon. And there were already significant numbers of vessels engaged in deceptive or outright sanctioned activity with Iranian—and to a lesser extent Venezuelan—cargoes. Any hope of deeper rapprochement between Iran and the US seems likely to have been dashed by the conflict in the Middle East, so both Iran and Russia are likely to remain under sanction—both their extensive hydrocarbon resources and their own large fleets. Washington has recently eased its sanctions on Caracas, but both the potential volumes and numbers of tankers are relatively limited, particularly by comparison with Iran and Russia.

According to maritime security firm Windward, only around 185 tankers are explicitly sanctioned, blocking them from access to insurance and Western ports, for example. But thousands more vessels are likely involved in illicit trade in some way, and Western sanctions on Russia have greatly boosted that number. "Only 7.2% of vessels associated with one or more sanctioned regimes are officially sanctioned," Windward notes. Ships engaged in such practices will often disappear from tracking systems as their crews switch off transponders. And ship-to-ship transfers are another commonly employed tactic to help obscure the true origin of a cargo. A number of offshore locations—including the Black Sea, eastern Mediterranean and southern Atlantic—have become known as "hubs" for the transhipment of Russian-origin cargoes. This convoluted activity further reduces the efficiency of tanker transportation, and by occupying multiple vessels limits the availability of ships. That in turn feeds into the rerouting of trade already discussed, and arguably will continue to lend support to overall tanker rates in 2024. ■

# Prime factors around global biofuel growth

Biofuels are addressing the energy trilemma through sustainability and security, but affordability remains a challenge


Global biofuel consumption is expected to rise by 20% from 2022-27, according to the IEA earlier in 2023. Several reasons are expected to be responsible for this increase, including regional demand, climate change and energy security concerns.

The US, Canada, Brazil, Indonesia and India are expected to comprise 80% of the global expansion of biofuel demand. While the US is the clear leader in biofuel facility development, with upcoming projects such as California's 800m gal/y Rodeo Renewed project, the country appears to not be building any new oil refineries domestically for the foreseeable future.

> **Two-thirds of global biofuel demand growth in 2024 anticipated from India, Brazil, Indonesia**

Renewable diesel and sustainable aviation fuel (SAF) are expected to see their growth in advanced economies such as the US and Canada, while ethanol and biodiesel growth is expected to be part of the picture for emerging economies such as Brazil and Indonesia.

Regarding the growth in renewable diesel and SAF, the policies in place that are designed to reduce greenhouse gas (GHG) emissions are primary drivers, since renewable diesel and SAF can have lower GHG emissions, have the ability to be blended and the feedstock can come from basically inexhaustible waste products such as used cooking oil and other residues.

The US is also benefiting from the Inflation Reduction Act, which was designed to make cleaner energy investments more economical while allowing for faster returns on biofuel developments.

Biodiesel growth in emerging economies will also benefit from biofuel-friendly government policies, but what's different there is the advantage of using indigenous resources and plentiful available land to produce the feedstock necessary by way of soybean oil and animal fats. Even as the basic feedstock needs remain similar, the approaches made by these countries vary due to the resources on hand and the support given by the respective governments, such as India's very recent announcement of its global biofuel alliance with Brazil at the G20 Summit to boost cleaner fuels.

Emerging economies are also focused on energy security as a prime driver for biofuel growth. Even before the Russia-Ukraine conflict brought a level of instability to the supply chain, energy security was deemed a goal by

By Thad Pittman,
senior research analyst,
Global Energy Infrastructure

## Future biofuel production facilities

many countries as a means of lower imports and self-reliance while also utilising the resources already on hand. Driven by this need, nearly two-thirds of biofuel demand growth by the end of 2024 is expected to come from India, Brazil and Indonesia.

SAF is approximately 0.1% of the jet fuel being consumed globally, which is somewhat behind the pace of renewable diesel and biodiesel integration into daily consumer use. Although SAF blended with traditional jet fuel can be a drop in fuel, it's the cost of SAF that continues to be a complication. Boeing CEO Dave Calhoun recently said regarding SAF's cost equivalency with traditional kerosene jet fuel that "I do not think that will ever happen." So, although SAF is deemed as an essential way to reduce emissions, high costs remain a barrier for this fuel's growth for now. ■

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# The future is not what it used to be

The appetite for long-term oil investment remains variable


The issue of whether contemporary long-term oil investment appetite is at an optimal level is not a new one, indeed it has been a recurrent feature of both equity and commodity market analysis and discussions since the 1986 oil price crisis. The debate often splits into two broad camps: one view posits that markets are self-correcting and that the amplitude of oil market cycles is usually unproblematic; the other sees corrections as slow with informational failures creating a downward bias in investment leading to overly amplified and damaging cycles.

It is often difficult to separate views about investment appetite from those about prices and long-term demand. For example, the view that the oil industry's investment appetite is too limited is often also expressed as the view that the back of the oil price curve is too low or long-term oil demand is set to exceed consensus expectations. For several decades those assessments have amounted to a similar overall diagnosis because, regardless of its speed or efficiency, there has been a relatively strong link between oil price dynamics and investment. However, as we note below, recent empirical evidence suggests that this link may be weakening, and we believe the widening gulf between the longer-term price and demand views of major energy agencies is also generating an increased potential for informational failure and an associated investment gap.

The self-correcting view of investment gaps is main-


By Paul Horsnell,
head of commodities research,
Standard Chartered

ly based on neoclassical economic theory, and in terms of petroleum economics it tends to be underpinned by the work of Maurice Adelman. The alternative to the neo-classical view is perhaps best described as the structuralist view in which long lags and capital intensity combine with informational failures, as well as the specific institutional features of the oil industry and government policies relating to it, to produce a market with both a weak tendency towards equilibrium and a bias towards underinvestment. The petroleum economics underpinning the structuralist view asserts the primacy of specific oil industry features above general competitive market theory, as is perhaps best represented by the work of Paul Frankel and Robert Mabro.

For most of the past 40 years the two schools of thought have been in a broad holding pattern around each other. The neo-classicists point to the absence of any particularly severe capacity crunches after the 1979 price shock as evidence that by and large the market has, left to its own devices, produced an approximation of an optimal investment path. The structuralists retort that they see the sharp movement up of the entire oil price curve in the early 2000s as the result of a long period of underinvestment, and posit that further severe supply crunches were only avoided by events largely unrelated to the general oil price cycle, such as the loss of four years of demand growth following the coronavirus pandemic and the supply boost gained from technical progress in the exploitation of US tight oil.

The key change from this holding pattern appears to come from a weakening of the relationship between investment decisions and long-term price signals. There is, for example, empirical evidence that the relationship between oil prices and oil investment has changed significantly due to climate policy. In particular, Bogmans et al. (2023) found that, controlling for other factors including prices and market conditions, climate policies reduced oil investment by public companies by 6.5% during their 2015–19 sample. That is a larger effect than might have been expected, the compounded changes leaving investment 25% lower than the base case after 20 years without any change in other determinants. Bogmans et al. note that their results suggest that there is unlikely to be an increase in investment and resultant lower prices as companies seek to accelerate production in advance of an energy transition. Instead, they suggest adjustment is more likely to involve a period of sharp falls in investment and rising prices with high free cash-flow in the short and medium term, giving companies time to adjust and also reducing the weight of stranded asset concerns in investment decisions.

Bogmans et al. note that the presence of informational failures and policy uncertainty have likely both gained in importance. They note “overly optimistic expectations about the pace of the energy transition by fossil-fuel

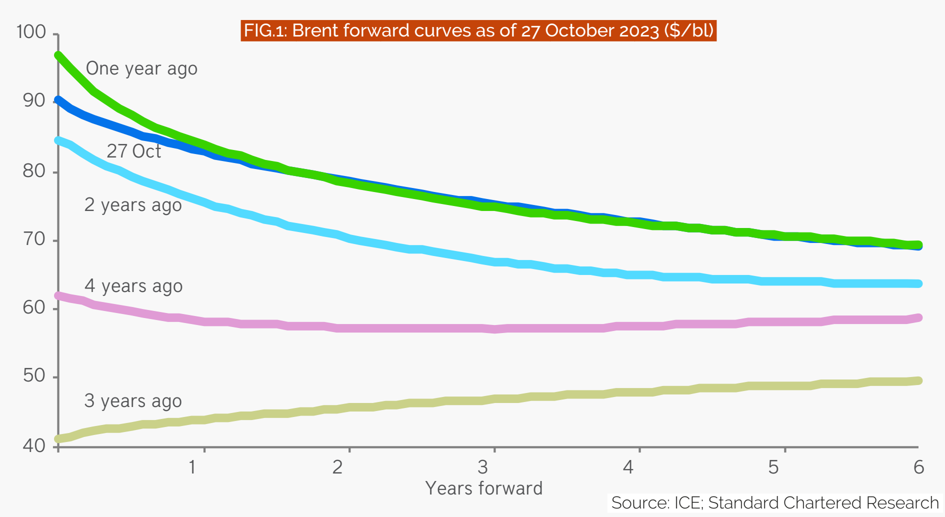



FIG.1: Brent forward curves as of 27 October 2023 ($/bl)

Source: ICE; Standard Chartered Research

firms coupled with a negative effect of climate policy uncertainty (which in theory delays both fossil fuel and renewable investment) may thus result in a shortfall of energy supply, leading to sustained upward pressure on fossil fuel prices and a more volatile energy price environment".

Under current circumstances there is a strong premium for clear and consistent information about long-term conditions, and we think investment appetite is being further dulled by a relative absence of such information. In particular, we think a lack of both consistency and clarity in the presentation of the views of the IEA has played a role in further reducing private sector investment appetite, broadly following the mechanism described by Bogmans et al. above. The IEA view implies that the energy transition involves significant falls in prices as well as falls in demand, offering little prospect for higher free cash flow to help avoid supply shortfalls.

The IEA view has over time moved from warning of a severe investment shortfall onto a view that investment need not be increased and from there onto the current view (as expressed in the 2023 *World Energy Outlook*) that in all scenarios the optimal path involves short-run falls in investment, and in some scenarios it involves very little investment in total. While the IEA's message that consumer governments can simultaneously have energy security, a rapid energy transition and lower prices is likely to be politically popular with those governments, we think this popularity could be eroded swiftly should it emerge that the investment climate created by unnuanced messages can itself become a force behind sharply higher prices.

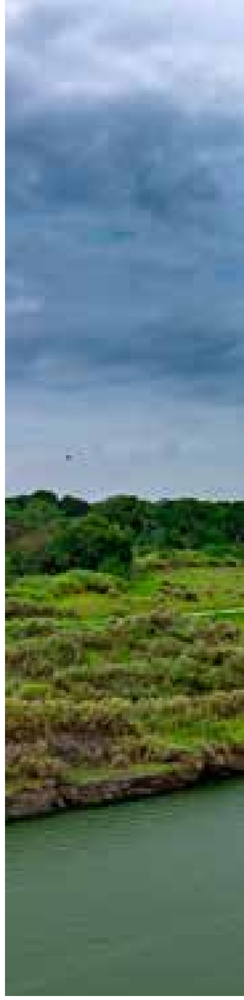
> **The key change [...] appears to come from a weakening of the relationship between investment decisions and long-term price signals**

The market response to the potential for an investment gap has thus far been relatively muted. While the back of the oil price curve has significantly less liquidity and fewer active players than it used to, we think it does still send a partially useful signal, at least over time. The Brent price curve at the time of writing is shown in *Fig.1*, with prices six years along the curve little changed year-on-year at close to $70/bl, having moved higher by about $10/bl since 2019's pre-pandemic conditions despite the hiatus in demand growth caused by the pandemic. The market appears to have moved beyond the idea of $50/bl as a sustainable long-term price, but has yet to naturalise a long-term price above $70/bl let alone one above $100/bl. While investments by national oil companies are likely to prove a stabilising factor, we think that the weakness of investment by public companies in longer-term projects (rather than in short-cycle oil or takeovers of existing projects) argues that the market may be too complacent; we think a six-years-out price of $115/bl would be a closer reflection of the implications of current private sector investment appetite. ■

# Energy flows go in new directions – gas & LNG

# The importance of US LNG in transforming the global market

US LNG has been a key driver in linking Asian, European and Latin American spot cargoes



The re-emergence of the US as an LNG exporter in March 2016 greatly accelerated the linking of global gas markets that had previously priced on their own supply-demand fundamentals. The addition of large volumes of freely divertible LNG supply to the global mix, in contrast to the mostly destination-restricted supply that had gone before, meant that traders could quickly close arbitrage opportunities between the largest global LNG import markets.

A cold winter in Asia (like in 2017–18) or a drought in Brazil (like in 2021) would result in European firms with US offtake diverting their supply to higher-priced markets. And when Russia weaponised its pipeline gas exports to Europe following (arguably also before) its invasion of Ukraine in February 2022, the consequent spike in European hub prices made Europe the most attractive market for US cargoes, rather than Asia or Latin America. The linking of Asian, European and Latin American spot LNG prices has therefore been years in the making and driven by US LNG.

The netback to the US Gulf Coast (USGC) today serves as one of the most important reference points for determining Asian LNG spot prices. The distance from the USGC to import facilities in Japan and China is around 18,000km, while the distance to facilities in Western Europe is around 8,000km. This means that Asian LNG buyers need to pay a premium to European gas hubs to cover the additional shipping costs to attract US spot cargoes.

Factoring in LNG spot charter rates, boil-off and Panama Canal fees, the required freight differential for Asia to outbid Europe for cargoes has averaged $1.12/m Btu over 2017-21. Over that period the JKM M+1 market averaged a premium of $1.20/m Btu to the market for LNG cargoes being delivered to Northwest Europe, as robust growth in Asian demand supported the need for US cargoes at the margin. The freight differential has increased to $1.74/m Btu since January 2022, but the JKM M+1 market has only averaged a $1.00/m Btu premium to the European LNG market, as Covid-19, a weak macro environment and high price pressures have weakened Asian demand, leaving the market often satisfied with just having Qatari supply at the margin.

However, growth in Asian demand over the coming years is unlikely to be fully satisfied by supply within the Pacific Basin, despite Qatar's enormous expansion of its export capacity over 2026-28, resulting in an increasing pull on US supply from Asia. That increased pull puts a strain on the global LNG logistics chain, given the much longer shipping journeys required to deliver US cargoes

FIG.1: JKM-NW Europe DES spreads vs USGC freight arbitrage ($/m BTU)

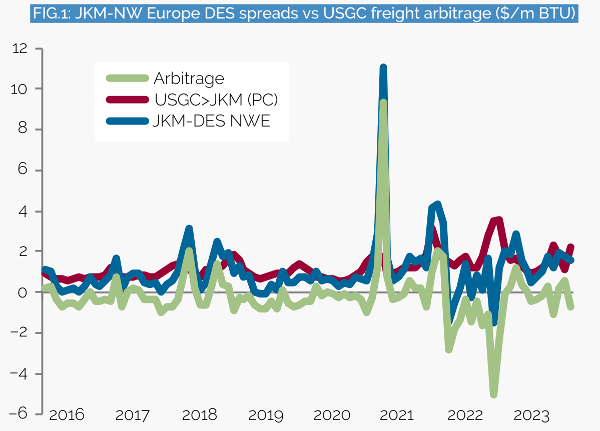
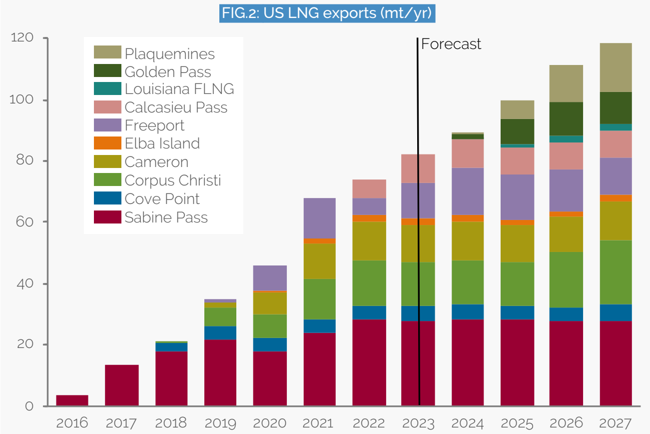



FIG.2: US LNG exports (mt/yr)



By James Waddell,
head of European gas,
Energy Aspects

An LNG tanker navigating the Panama Canal

to Asia and the greater use of the Panama Canal—a choke point for global LNG trade. Record numbers of LNG newbuilds are set to be added to the global fleet over the coming years, putting pressure on spot charter rates.

However, seasonal swings in demand can open and close the arbitrage for US cargoes to go to Asia, creating moments of tightening and loosening of the global shipping market and contributing to large intra-year swings in charter rates.

Tightening of the freight market can be exacerbated when Asia needs so many cargoes from the US that the Panama Canal becomes congested and the marginal US cargo to Asia has to be delivered via the Cape of Good Hope. This adds around 33 shipping days onto a typical round-trip journey to Asia from the USGC relative to using the Panama Canal route and consequently ties up significant additional shipping capacity.

**7.4mt**

**Current US LNG exports/month**

Major congestion around the Panama Canal tends to occur when more than 30 cargoes a month are attempting to make a southbound crossing. Congestion can occur even earlier if a low fill of Panama's Gatun Lake forces the waterway's authority to restrict crossings, as is occurring now.

The US is currently able to export around 105 cargoes (7.4mt) per month. This means that the Panama Canal is prone to congestion with just 29% of US supply going to Asia, and this will only worsen as the US ramps up exports to around 141 cargoes per month by 2027.

The coming years of liquefaction capacity expansion looks set to make the US the largest global LNG exporter over 2024-26, until Qatar reaches the final stages of its own LNG export expansion. Those incremental US volumes, combined with others from North America, and Qatar's contribution form the mainstay of the next big wave of global LNG export growth. Already-sanctioned LNG export capacity is being commissioned over 2025-28 of around 166mt/yr, of which the US accounts for about 77mt/yr. This dwarfs the last wave over 2017-20 of around 10mt/yr, and attention is understandably turning to whether the global market can fully absorb the implied increases in LNG supply suggested by that new capacity or whether, as happened at the outset of Covid in 2020, substantial volumes of US exports will need to be shut in to balance the global market.

It may be possible for all these incremental cargoes to find a home, particularly if China pushes for gas to displace coal in its power sector. However, if global demand falls short, then US shut-ins will again be needed to balance the global market with European gas and Asian LNG prices falling to near parity with the variable cost of US LNG exports, setting a type of floor price for the global market. ■

# Market regime shifts driving LNG portfolio value

Three main characteristics underpin a shift in global pricing dynamics creating a new regime

Russian supply cuts to Europe sent shockwaves through the global gas market across 2021-22. Market stress subsided to some extent in 2023, but the crisis is not over.

The LNG market is set to remain in a tight regime until the next wave of supply ramps up from 2025-26, dominated by North American and Qatari volumes. In the meantime, demand response mechanisms in both Europe and Asia are setting global LNG prices.

In Europe, the primary demand response mechanism is the switching of gas for coal plants in the power sector. In Asia, demand response is a more complex mix of fuel switching and industrial demand response. Asian demand flexibility is becoming increasingly important as European coal plants close, but demand is less responsive and lagged, supporting higher levels of volatility.

*Fig.1* shows our modelling of global supply and demand balance from the latest Timera Energy *Global Gas Report*. The 2024 panel shows why LNG price levels are currently both high and volatile. Relatively inelastic sources of supply and demand are setting prices at the margin. The 2030 panel shows how this is set to change substantially by the second half of this decade as new LNG supply drives a market shift to a new regime.

## Impact of the coming regime shift

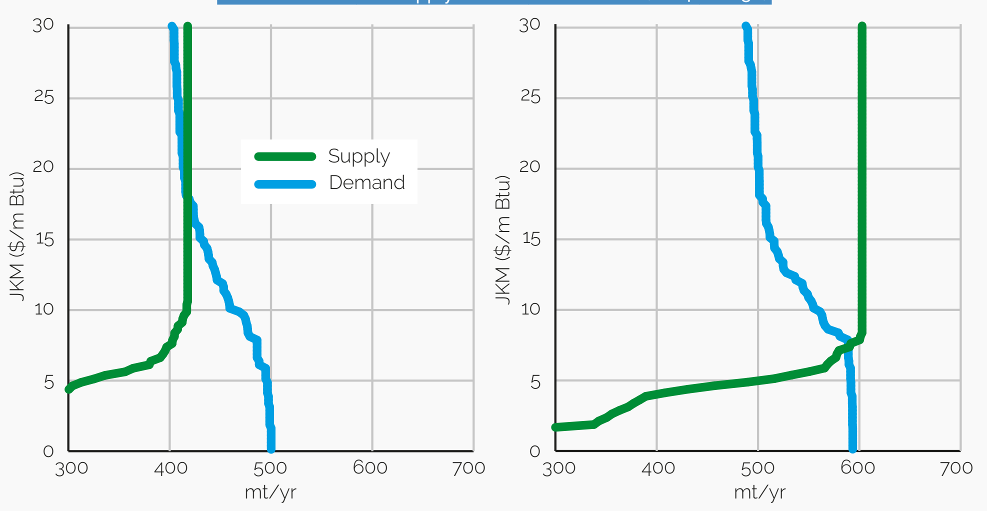
A more than 200mt/yr new wave of LNG supply is set to come online across 2025-29, a compound annual growth rate of almost 7% across this period. Our global gas market model shows there is a high probability that this transitions the global LNG and European gas markets into an oversupplied regime by 2026.

LNG portfolio value creation and risk management in this new regime is set to be very different from the current tight market regime. This is underpinned by a shift in global pricing dynamics, with three key characteristics as set out in *Fig.2*.

The other important factor that may impact LNG portfolios is a structural shift in gas versus crude price levels. Crude market fundamentals are tight, with limited investment in new supply and a rapid increase in the cost of upstream capital. This is set to support crude prices relative to gas, as the LNG market transitions to an oversupplied regime mid-decade.

The regime-driven shift in LNG pricing dynamics has important implications for price volatility and price correlations, as shown in *Fig.3*. Recent very high levels of volatility are set

FIG.1: Global market supply and demand balance (2024 vs 2030)




Source: Timera Global Gas Model

By David Stokes managing director,
Olly Spinks managing director, and
David Duncan director of LNG and gas, Timera Energy

to ease. Inter-regional LNG price correlations are set to strengthen, anchored by Henry Hub. Correlation with crude is likely to remain weak.

## LNG portfolio value and risk implications

The next five years represent an unprecedented opportunity to build LNG portfolio value as demand grows, new supply and regas capacity comes online and pricing dynamics shift. LNG portfolios face the following five challenges in developing a competitive advantage to capture value:

1 **Henry Hub** – It will be important to be able to effectively quantify and manage Henry Hub exposures within LNG portfolios and how these interact with other exposures, e.g., Brent, JKM.

FIG 2. Changing pricing dynamics as market regime shifts

| Price driver | Characteristics |
|---|---|
| 1 Henry Hub | Strong increase in the influence of Henry Hub on global prices, as new supply expands the global supply curve, pushing LNG prices down to converge with the variable cost of US export volumes *(see 2030 panel in Fig.1).* |
| 2 Demand response | Asian demand (e.g., fuel switching and industrial flex) playing an increasingly important role setting LNG global prices, but via mechanisms that are lagged and less responsive, supporting higher price volatility. |
| 3 Supply flexibility | A large increase in flexible US supply (more than 100mt/yr by 2030) causing more dynamic cargo diversion flexibility between Europe and Asia, with net Pacific Basin demand growth supporting JKM versus TTF price spreads. |

2 **Supply** – There is strong innovation taking place in the contracting of "new wave" supply; the negotiation of price index and flexibility terms in the context of broader portfolio impact is key.

3 **Flexibility** – LNG portfolio flexibility is becoming more important for value capture and risk management, both contractual and physical supply chain flexibility.

4 **Regas** – Over 80mt/yr of new regas capacity is coming online across the EU, with portfolio regas strategy and the effective sizing of regas capacity key for accessing physical hub price liquidity.

5 **Gas versus crude** – It is important to understand the value and risk implications of major shifts in gas versus crude prices on LNG portfolio exposures.

These challenges are also driving an increased focus on investment in trading and risk management capabilities within LNG companies. An effective trading function acts as the commercial hub of an LNG business model, managing and optimising portfolio exposures and driving value creation. ■

FIG.3: Regime shift impact of price volatility and correlation

| | | Volatility | | | Correlation | | |
|---|---|---|---|---|---|---|---|
| | | JKM | TTF | HH | TTF/ JKM vs HH | JKM vs TTF | TTF/ JKM vs oil |
| 'Supply constrained' tight regime | 2024-26 | High | High | Medium | Low | Medium | Low |
| 'New wave' oversupplied regime | 2026-31 | Medium | Medium | High/Medium | High/Medium | High/Medium | Low |

High Medium Low

Source: Timera Global Gas Model

# Building LNG's resilience through turbulent times

## Larger and more diversified portfolios are best placed to navigate through volatility

The global LNG industry is thriving. A record 200mt/yr of new supply is under construction as players bet big on Asia's push to reduce its dependence on coal and Europe's need to replace Russian gas.

Given the urgency of the energy transition, an increasingly fractious geopolitical system and concerns over global economic growth, could the LNG industry have bitten off more than it can chew?

In this article, we explore some of the market and external risks that players need to grapple with and consider how they can prosper through turbulent times.

**Is there too much LNG under construction?** In short, no. Increased supply availability will bring prices down and boost demand growth. In our latest *Investment Horizon Outlook*, we anticipate the market will need another 60mt/yr of new LNG by 2033. Much will hinge on sustained economic growth driving increased demand across emerging markets in Asia. China's LNG demand will increase by 12% in 2023, and with 50mt/yr of LNG contracted over the past two years, imports will double by 2030. LNG demand in South and Southeast Asia will also grow twofold by this time.

But economic growth won't be enough. Domestic policies across Asia must increase their focus on decarbonisation and ensure appropriate pricing and infrastructure developments. LNG developers must also play their part, ensuring affordable LNG supply if Asia's full potential is to be unlocked.

Europe will also need more LNG. While overall gas demand continues to fall, pipeline imports from Norway and Algeria will decline beyond 2025, meaning LNG imports will not peak until around 2030. They will remain relatively resilient thereafter as decarbonisation of the residential and industrial sectors slowly gathers pace. The recent signing of 8mt/yr of LNG contracts from Qatar and its partners Shell, TotalEnergies and Eni to Europe through 2053 underpins supplier confidence in the longevity of European demand.

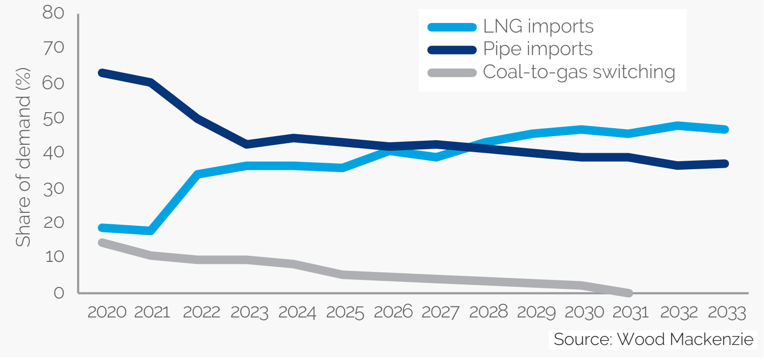
**How long will price volatility persist?** There is no immediate cure as most supply under construction will not be available until at least 2026. As a result, buyers face several years of high—and volatile—prices before the next wave of LNG supply rebalances the market and improves affordability.

But the arrival of more LNG isn't the end of the story. Investment in new LNG supply will slow beyond 2025, setting the scene for potential renewed market tightness around 2030.

Ultimately, the market has structurally changed. In the past, Europe provided flexibility for the global LNG market. At times of excess supply, Europe could reduce discretionary pipeline imports to use more LNG, limiting the downside on prices. And when less LNG was available, Europe leveraged more pipeline imports and coal, preventing price spikes.

Those days are over. With Europe increasingly dependent on LNG, and with limited flexibility from pipeline imports and coal, Europe and Asia will both rely on global LNG availability. At times of excess LNG supply, prices could be extremely low as the market tries to absorb more LNG than required, possibly testing the economics of US LNG. But as markets tighten, prices could be extremely high as both Europe and Asia scramble to secure marginal cargoes. Volatility is now a constant.

FIG.1: European LNG imports, pipe imports and coal-to-gas switching as % of gas demand




Source: Wood Mackenzie

By Gavin Thompson, vice chair EMEA,
and Massimo Di Odoardo, vice president
and head of gas & LNG analysis,
Wood Mackenzie

**Could external shocks upend the outlook for LNG?** Recent dynamics are a stark reminder of how susceptible energy markets are to external shocks, including conflict, geopolitical tensions and supply disruption. The global gas market has staged a remarkable recovery since Russia's invasion of Ukraine in early 2022 but remains easily spooked: the conflict in Israel/Gaza, possible pipeline sabotage in the Baltics and the threat of fresh strike action at Australian LNG facilities all pushed spot prices up 35% through October.

The risk of further external shocks to the LNG market looks almost inevitable. Accurately forecasting these is an impossible task, but in an already tight market, their impact will only amplify volatility.

> China's LNG demand will increase by 12% in 2023

**How are companies positioning for market turbulence?** The risks highlighted underline the importance of building low-cost, low-carbon portfolios supported through deeper trading and optimisation capabilities. Several IOCs and traders are doubling down on LNG, leveraging their role as aggregators to develop ever larger and diversified portfolios. This will best position them to capture market opportunities and secure buyers through suitable pricing and volume optionality.

Key buyers are also embracing this approach. PetroChina is building a global portfolio way beyond its legacy footprint. Some European (RWE, SEFE Energy) and Japanese (Tokyo Gas, JERA) companies are positioning to become bigger local players and expand trading into other regions. Joint ventures may come back in vogue. Smaller players that lack optionality will inevitably be exposed to market volatility. Securing some long-term supply remains their best bet to navigate through turbulent times. ■

# LNG investment: Hydrocarbon challenges or green opportunity?

## Many LNG projects already incorporate emissions mitigation methods, hastening adoption for future projects

This decade's unprecedented LNG supply investment is strongly focused on managing emissions intensity. Wide-ranging measures, particularly CCS, renewable-energy-powered liquefaction trains, carbon offsets and FLNG conversions, are being aggressively rolled out globally. While previous cycles of LNG production growth focused on the environmental benefits of offsetting buyers' coal demand and shippers' liquid fuel usage, supply projects are now under the greenhouse gas (GHG) microscope.

Geopolitics and supply under-investment combined to push LNG spot prices to record highs in 2022 and c.$20/m Btu this winter. While LNG cargos will remain scarce until 2026, new trains, mainly in the US and Qatar, then ramp up aggressively.

Since 2000, LNG supply projects have adopted various GHG mitigating measures, with mixed success:

**CCS:** The world's largest CCS project started up in 2019 at Chevron's Gorgon LNG in Australia. The objective is to mitigate over 100mt of $CO_2$ over Gorgon's life. Following a three-year startup delay, challenges with pressure management, lower-than-expected connected reservoir volume and water handling have reduced the project's $CO_2$ injection rates.

**Electrifying liquefaction trains:** Commissioned in 2007, Equinor's Snohvit LNG project was the first to be powered by electric liquefaction trains. The Freeport LNG plant in the US then began production in 2019 and is the world's largest all-electric plant. The project's electric power is drawn from the local grid, instead of adopting the conventional steam or gas turbines for liquefaction, reducing site combustion emissions by c.90%.

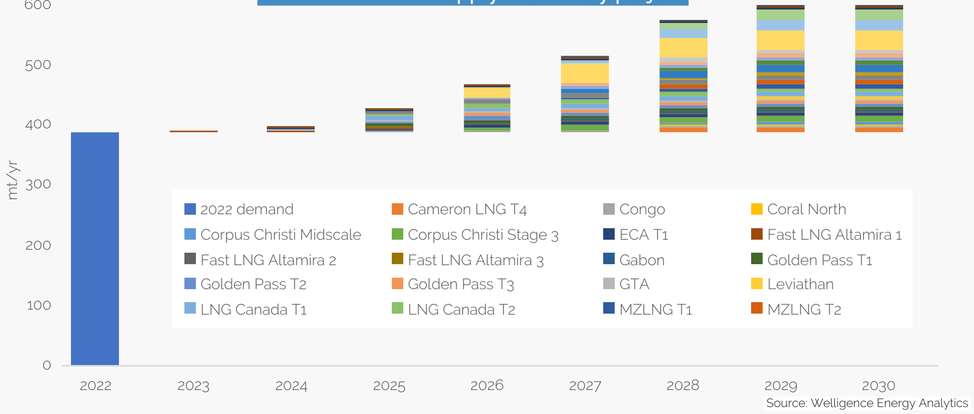
**Gas-flaring reductions:** In 2000, most of Nigeria's associated gas output, over 20bcm/yr, was flared. By 2020, the country had reduced gas flaring by 70%, as the Nigeria LNG project ramped up gas monetisation from 1999, exporting LNG and supplying LPG to the domestic market.

Lessons learnt from LNG suppliers' early harnessing of innovative emission management measures, particularly CCS and electric liquefaction trains, combined with net-zero targets, are supporting their widespread adoption by the next wave of projects. The aggressive global ramp-up in LNG output by 2030 is therefore accompanied by highly proactive GHG control measures, increasingly essential requirements for LNG-related supply developments to progress:

**Southeast Asia:** The race is on to develop the region's first operational CCS project, with several startups planned in the coming years, mainly to provide feedgas for liquefaction projects. Petronas' Kasawari CCS project in Malaysia (FID in 2022) and BP's Vorwata CCUS in Indonesia, which was approved by SKK Migas in 2021, are the frontrunners. Also in Indonesia, the INPEX-operated Abadi LNG project, incorporating CCS, will take FID post-2025.

**Australasia:** In Australia, Woodside Energy will supply the Pluto 2 LNG project with the negligible $CO_2$ Scarborough gasfield and the company has committed to purchase carbon offsets to support its climate ambitions. Meanwhile, INPEX

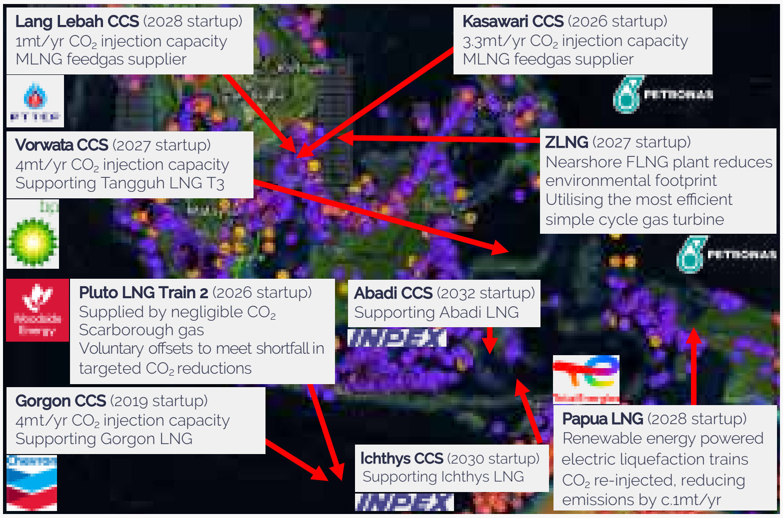
FIG.1: Global LNG supply outlook by project




Source: Welligence Energy Analytics

By Marc Howson,
head of Asia-Pacific and global LNG,
Welligence Energy Analytics

FIG.2: Southeast Asian and Australasian LNG-related emissions management measures




Source: Welligence Energy Analytics

plans to add CCS to its operational Ichthys LNG project by 2030. In Papua New Guinea, TotalEnergies' Papua LNG project, targeting FID in 2024, will harness renewable-energy-powered electric liquefaction trains and also re-inject $CO_2$, for emissions reductions.

**North America:** By harnessing hydroelectric-powered electric compressors, re-liquefying boil-off gas and other measures, Canada's Woodfibre LNG is aiming to be the world's least carbon-intensive LNG plant with net-zero emissions upon startup in 2027. Meanwhile, several US liquefaction projects also have CCS plans, including the Venture Global-operated Calcasieu Pass and Plaquemines projects and the NextDecade-operated Rio Grande LNG project.

**Europe:** In 2023, the Norwegian government approved Equinor's development plan to install electric compressors on the Snohvit gasfield and also electrify the liquefaction plant's gas turbines. The improvements will allow the Snohvit LNG project to produce beyond 2030 and facilitate an estimated 850,000t/yr $CO_2$ reduction.

FIG.3: Select global FLNG projects


Source: Welligence Energy Analytics

**West Africa:** The region is the global hub for adopting FLNG conversions and redeployments. FLNG vessel repurposing brings lower environmental footprints over onshore plants and new-build FLNG vessels. In 2020, Keppel converted a conventional LNG carrier into Golar LNG's Hilli Episeyo FLNG vessel, now producing in Cameroon, saving c.33% of the GHG compared with a new-build. In the coming months, the Gimi FLNG conversion vessel will start up in Senegal-Mauritania, for the BP-operated GTA LNG project, and the Tango FLNG redeployment will begin production for Eni in the Republic of the Congo.

**Middle East**: Qatargas awarded the FEED contract for QatarEnergy LNG's CCS projects, to capture over 4mt/yr of $CO_2$ across Qatar's expansion liquefaction trains. Meanwhile, Adnoc is planning for its Ruwais LNG plant in the UAE, expected to start up in the late-2020s, to be powered by both nuclear and renewable energy. ■

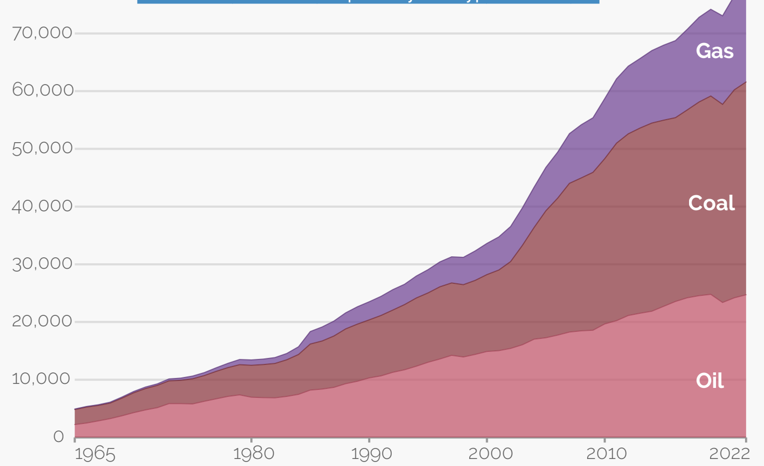
# Replacing coal with gas is more important than ever for Asia

More gas is needed across Asia—at affordable prices—to encourage the move away from coal

The past 12 months have seen positive developments in Asia's use of natural gas to underpin energy security and energy transition. The Philippines, Vietnam and Hong Kong have taken delivery of first LNG shipments, with Vietnam charting an ambitious pathway to emissions reductions through gas use. India and China continue to grow the use of gas in their energy systems, and Indonesia and Malaysia have identified gas as pivotal to decarbonisation. Meanwhile, traditional consumers of gas—Japan, South Korea, Singapore, Thailand and Taiwan—continue to benefit from its reliability as they map out low-emissions futures.

However, if you look beyond the past year back to Russia's invasion of Ukraine in 2022, challenges in global markets become more apparent. When Europe rushed to replace Russian gas supply, it started importing significant quantities of LNG. Supply limitations saw prices rise sharply and emerging nations, including in Asia, could not afford gas. Prices have since declined but spot prices remain elevated relative to historic levels and further shocks—industrial action, significant technical supply issues or a cold European winter—could send short-term market prices climbing again.

FIG.1: Fossil fuel consumption by fuel type, Asia (TWh)




Source: Energy Institute Statistical Review of World Energy 2023

The unfortunate reality is that when emerging economies can't afford gas they go back to coal as a cheap and available fuel. Global coal consumption reached all-time highs in the past two years.

If the world is to achieve the climate targets of the Paris Agreement, this cannot continue. Let's keep in mind that gas produces up to 60% less emissions than coal in electricity generation. In an Asian context, it's estimated that if just 20% of the region's coal-fired power stations switched to gas, $CO_2$ emissions reductions would be 680mt/yr.

It's an equation the Asia Natural Gas and Energy Association (ANGEA) and its members are working to address. The world needs enough gas that all countries in Asia—developed and emerging—can access sufficient supply at affordable prices to meet needs during energy transition.

The next five years offer cause for optimism. New export facilities in the US and Canada and Qatar's North Field Expansion Project will alleviate some tightness in global supply. Australia, with the right policies, could maintain its role as a reliable supplier of LNG, helping bring energy security while leading Asia-Pacific decarbonisation efforts through scale-up of CCS.

However, we must acknowledge the immense volumes of coal that need to be displaced in decades to come. Between now and 2050, Asia's gross domestic product is expected to quadruple and energy demand more than double. Much of the demand will come from countries currently reliant on coal: Indonesia, the Philippines, Vietnam and India.

By Paul Everingham, CEO,
Asia Natural Gas & Energy Association

The Rystad Energy study into energy security in Southeast Asia, commissioned by ANGEA and the American Petroleum Institute, identified gas as the energy source best suited to support credible energy transition in terms of acceptability, availability and affordability. Switching out coal-fired power for gas can strike a balance between providing energy for growth and progress on emission reductions, while ensuring baseload power that counters the intermittency of renewables.

However, the study also highlighted potential barriers to achieving necessary supply, including policy settings in gas-producing nations not supporting future projects and the reticence of some financial institutions to fund any kind of hydrocarbon activity, despite the clear advantages of gas. Commitments to flexible and long-term contracts are other challenges to progressing LNG-to-power projects in emerging Asia.

> **Global coal consumption reached all-time highs in the past two years**

A key aspect of the work ANGEA undertakes around the world is raising awareness at the highest level about the positive impact global LNG production currently has and will continue to have in Asia. We're also collaborating closely with countries in Asia as they seek to grow the role of gas in energy systems. LNG import and storage facilities take years to plan and build and countries must make decisions now rather than waiting until they are needed.

There are no perfect energy solutions and we recognise the emissions profile of gas also requires management. Gas production and use is becoming more sustainable, with a strong focus on identifying and addressing methane emissions and producing LNG with the smallest possible carbon footprint. In the future that footprint will become much smaller still, through at-scale implementation of transboundary CCS via a regional carbon economy. It's likely we'll see CCS employed to reduce emissions right along the gas value chain, in production, liquefication, transport and consumption.

ANGEA and its members are committed to partnering with governments and industries throughout Asia to ensure CCS realises its undoubted potential, including creating new economic opportunities. CCS technology has been effectively employed in oil and gas operations for decades but there is work to be done to ensure it is cost-effective at the required scale and to establish regulatory and policy environments to support region-wide rollout.

ANGEA is excited to be leading a ground-breaking, multi-year programme to build understanding and consensus in the Asia-Pacific region for a cross-border carbon-reduction accreditation system. The programme will seek to harmonise standards, policies and regulation covering the accreditation or certification of $CO_2$ emission reductions, with a strong focus on the requirement for cross-border carbon trade. We hope our study will facilitate significant future investment in CCS and be another milestone towards Asian nations unlocking the full benefits of natural gas and avoiding increased use of coal. ■

Paul Everingham is the inaugural CEO of the Asia Natural Gas and Energy Association (ANGEA), which works with governments, society and industry throughout Asia to build effective and integrated energy policies that meet each country's climate objectives.

# Asia's appetite for LNG in an age of uncertainty

Asia remains primed for long-term LNG growth, despite the commitment by countries to meet their net-zero emissions targets

The main driver for Japan is replacement demand for its long-term contracts as they expire over 2024-26, while in China new terminals coming on stream over the next two years are fuelling LNG demand. Southeast Asia remains a key driver for long-term demand growth although questions remain over the affordability of gas in the near term. Here we explore the region in more detail.

**Japan:** Japan remains committed to long-term LNG buying as current long-term contracts expire from 2024 to 2026. However, they are looking for up to ten years' supply as they are unable to forecast their downstream demand in the longer term.

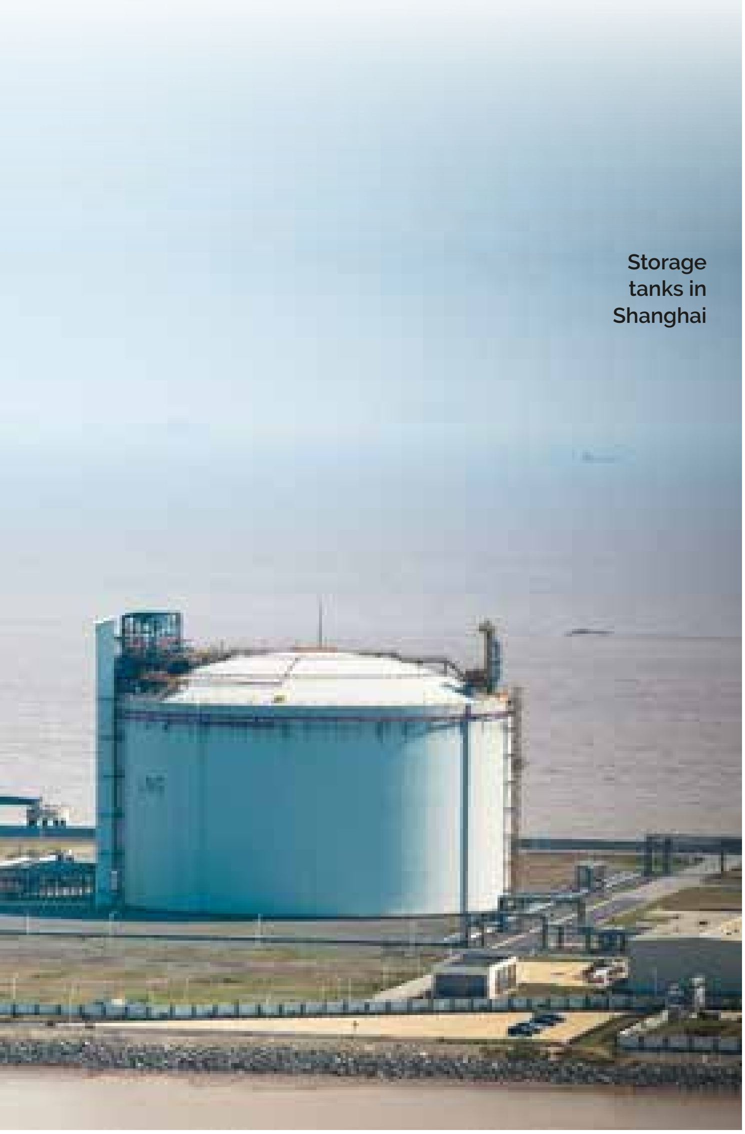
Expectations of 12 nuclear reactors to come online by 2024 means that Japanese LNG importers are looking for more flexible long-term contracts with optionality to divert outside of the country. A handful of second-tier Japanese buyers have bought strips or mid-term supply in 2023 tied to Brent amid demand uncertainty.

**China:** Chinese buyers remain heavily wooed by sellers. They are mulling a proliferation of long-term LNG supply offers from Qatar and others ahead of the start up of several new regasification terminals between 2024 and 2026. While state-owned Chinese NOCs CNOOC, Sinopec and PetroChina are considering long-term supply, second-tier Chinese firms remain price sensitive and will take a longer time to commit to long-term contracts.

Traditionally, these NOCs used to hold access to terminal capacity, but this changed with the creation of PipeChina in 2019. Chinese firms also used to sign LNG supply deals prior to building new import terminals. However, second-tier Chinese companies are now building them before committing to long-term supply. Purchasing supply long term is still widely seen to be a risk for second-tier Chinese companies given the amount of credit support they need. By comparison, building a regasification facility is low in cost.

Several new terminals are expected to start up in 2024 and 2025. China Urban Rural Energy (Cure) is considering buying long-term supply for its two regasification terminals. Cure is building a 5.9mt/yr import facility at Yantai, northern Shandong province, with five storage tanks of 200,000cm each. The terminal is expected to start up in 2025 while the second terminal with a capacity of 6.2mt/yr at Yingkou, eastern Liaoning province is scheduled to start up in May 2026. The Yingkou facility

By Kit Ling Wong,
head of Asia-Pacific,
Poten & Partners



Storage tanks in Shanghai

will have four 200,000cm storage tanks and can take vessels with a maximum size of 267,000cm.

Cure wants to reserve approximately 40% of the regasification capacity to meet its own downstream requirements and provide the remainder for third-party regasification leasing. Cure's downstream markets are in northeast China and its core businesses are city gas distribution and winter heating.

> Chinese buyers remain heavily wooed by sellers

Zhenhua Oil is seeking Brent-linked supply contracts and has a 34% stake in the Rudong terminal in eastern Jiangsu province. The terminal is jointly owned with Jiangsu Guoxin and Jiangsu port, which hold 61% and 5%, respectively. The terminal is planned for startup in H2 2025.

There are three proposed import facilities in Rudong alone, raising concerns of stiff competition in the eastern region. PetroChina currently operates one terminal in Rudong with Pacific Energy, while China Resources is also planning an import facility there that will come online in 2027.

Huaying Natural Gas will bring its import terminal online in Raoping county, which is in the eastern Guangdong province, in December 2023. The terminal is 50% co-owned with Sinopec. The commissioning cargo will be supplied by PetroChina.

Also in south China, Guangdong Energy plans to bring onstream its 4mt/yr Huizhou terminal in Guangdong province. Two other import terminals are planned for startup in 2024, including Pacific Energy and Guangdong Energy's Yangjiang terminal in 2024 and a PipeChina terminal in Shenzhen.

**South Korea:** In South Korea, state-owned Kogas will lead the country's LNG demand although a handful of state-owned generating companies have bought long-term supply for their new gas-fired power plants as part of the country's coal-to-gas switching policy. South Korean state generation companies are also looking to co-fire hydrogen and ammonia in their gas-fired power plants post-2030 as part of a wider government initiative to move to clean fuels.

**Southeast Asia:** Southeast Asia saw two new LNG importers—Vietnam and the Philippines—in 2023 but securing stable supply will be challenging. The countries are grappling with elevated global LNG prices that their respective downstream markets find hard to absorb. The Philippines has had some success in raising power tariffs to allow partial cost passthroughs, but the issue remains politically and economically fraught in Vietnam. For industries, LNG prices have overall been less competitive compared with alternative fuels such as LPG. The importing firms—PV Gas in Vietnam and First Gen and SMC Global Power in the Philippines—have also yet to secure or commence long-term supply. Supply remains fundamentally limited in the near to medium term, so sellers are keeping Brent slopes propped up and targeting buyers with better credit.

In Thailand, declining gas production in Myanmar and the Gulf of Thailand is keeping LNG imports propped up, particularly amid a post-pandemic demand rebound. Tier-two buyers have also secured mid-term supply as the Thai gas market nudges ahead with market liberalisation. ■

# The evolution of gas infrastructure: From short-term resilience to long-term sustainability

In the ever-changing landscape of global energy, the European gas infrastructure is undergoing a remarkable transformation, poised to play a pivotal role in shaping Europe's energy future

Recent global events have underscored how geopolitical challenges can disrupt gas supply chains, reinforcing Europe's need to enhance its energy independence. The keys to overcoming such crises are diversification and adaptability. EU member states have taken strategic steps to diversify their gas supply sources and routes. Recognising the critical role of gas infrastructure operators in preserving energy security during challenging times, the European Commission initiated REPowerEU.

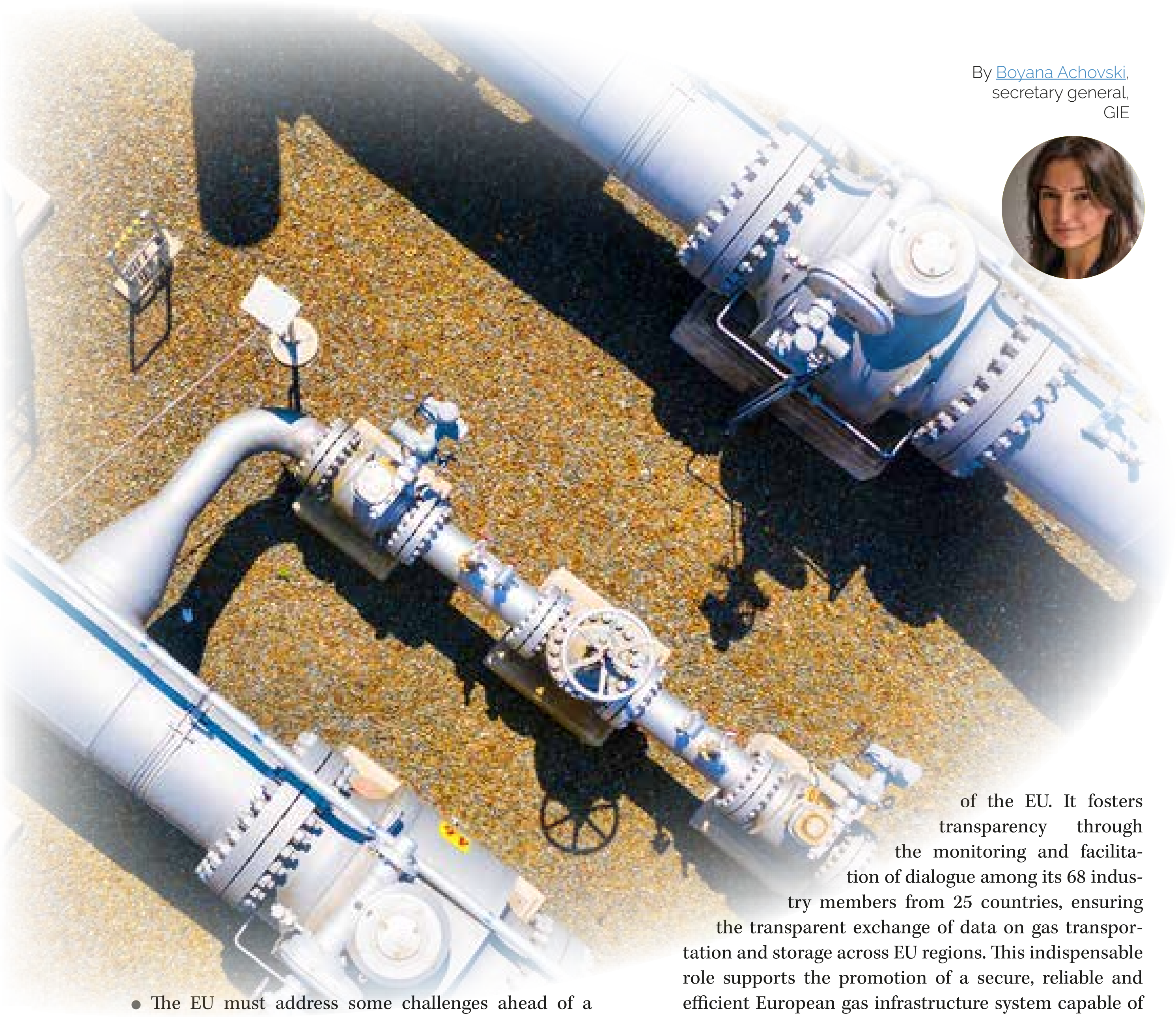
This initiative aimed to meet storage filling targets and streamline permitting processes for LNG terminals and FSRUs, enabling rapid responses to evolving energy supply needs. This includes expanding import capacities through the construction of new LNG terminals—for 2023, 56.54bcm/yr of new capacity was announced, out of which almost 80% is already operational (44.6bcm/yr). Setting ambitious targets for domestic production of biomethane were also part of the plan.

In the mid-term, gas infrastructure is set to transform in response to several key factors. These include the transition to renewable gases such as hydrogen and biomethane, leading to the development of new pipelines and storage facilities. Decentralisation may reduce the need for large centralised pipelines, with smaller-scale production systems, especially for locally produced renewable gases.

Digitalisation and automation will improve efficiency and safety. Hybrid systems that integrate gas infrastructure with other energy sources will promote energy storage and balance. Energy efficiency upgrades and carbon capture and utilisation are expected, alongside regulatory changes promoting green gases. Resilience and international cooperation will play vital roles in ensuring reliable gas supplies and a transition to cleaner energy sources, all driven by the need to address climate change and increased demand for sustainability. In our journey to achieve mid-term energy transition goals, a comprehensive action plan has been developed to bring decarbonisation. Among the levers available:

> In the long term, gas infrastructure stands as the linchpin of an innovative energy system

- Legislation should respect different pathways and national starting points, which means that some transitional solutions in some member states must be enabled.
- To facilitate cross-border activities, we should apply an EU-wide approach to certification in the transport sector.
- Reducing permitting time is a challenge for all infrastructure developments.
- Synergies between existing gas infrastructure and future hydrogen infrastructure must be exploited as much as possible—the regulatory framework must facilitate this transition.



By Boyana Achovski,
secretary general,
GIE

- The EU must address some challenges ahead of a pan-European hydrogen infrastructure before it becomes a reality. In parallel, it's essential to have the right mindset and remember that security of supply and decarbonisation are two sides of the same coin.

In the long term, gas infrastructure stands as the linchpin of an innovative energy system. This visionary perspective, expected to materialise by 2050, underscores the central role of gas infrastructure in delivering clean, secure, efficient and sustainable energy supplies. At the forefront of this vision stands Gas Infrastructure Europe (GIE), the voice of gas infrastructure operators in Europe. As the representative of these operators across the continent, GIE plays a pivotal role in bridging the practical realities of the energy sector with the broader ambitions of the EU. It fosters transparency through the monitoring and facilitation of dialogue among its 68 industry members from 25 countries, ensuring the transparent exchange of data on gas transportation and storage across EU regions. This indispensable role supports the promotion of a secure, reliable and efficient European gas infrastructure system capable of meeting both current and future energy requirements.

The evolution of gas infrastructure embarks on a dynamic journey spanning short-term resilience, mid-term adaptation and long-term sustainability. It constitutes a journey that responds to geopolitical challenges, embraces the energy transition and envisions gas infrastructure as the bedrock of an innovative energy system.

As the global energy landscape shifts towards cleaner and more sustainable sources, gas infrastructure remains a steadfast vector of supply security today and a pivotal driver in the reduction of emissions. Cooperation between industries, policymakers, generations and genders across regions remain at the core of this transformation: story to be continued. ■

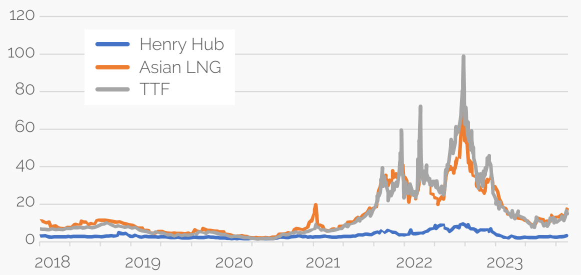
# Europe's pivot from Russian gas

## Energy crisis leads to supply diversification

Russia's invasion of Ukraine triggered an era of energy insecurity that has been felt acutely in the EU and rippled across the globe. Long the dominant supplier of natural gas to the 27 countries in the EU, Russia's gas is closer and cheaper than many other options for Europe, despite some geopolitical trade-offs. While some called for diversification from Russian gas long before the invasion, geopolitical turmoil accelerated that movement and sparked deep uncertainty around the continent's gas supply amid a transition to new sources that could see Russia's role forever altered.

Over decades, Russia built sprawling infrastructure to transport its gas from often-remote gas fields to population centres in Europe. Pipelines spanning from the Siberian tundra reach Europe through numerous entry points in Belarus, Germany, Poland, Turkey, Ukraine and beyond. Russian gas also reaches European ports via ships as supercooled LNG. In 2021, Russian gas covered roughly 40% of the EU's consumption, with about 140bcm imported by pipeline and 15bcm (or 15mt) as LNG, according to the IEA.

FIG.1: Global gas prices ($/m Btu)




Source: Chicago Mercantile Exchange

The invasion of Ukraine in February 2022 was a major turning point, both geopolitically and for the European gas market. EU leaders called for a swift pivot away from Russian gas as prices spiralled to new highs, rocketing up 50% on news of the invasion and tipping higher to $70/m Btu in March 2022. Dutch TTF prices surged to an apex of $99/m Btu in August that year, setting a historic high for wholesale gas prices. EU member states scrambled for alternative sources of gas supply as demand-reduction schemes aimed to ease consumption. High prices also sharply cut into industrial consumption as dramatically increased costs forced factories and businesses to close—possibly permanently.

Russian pipeline gas to the EU fell by more than 50% in 2022 to about 60bcm and continued decreasing in 2023. Virtually every pipeline route, except for the TurkStream pipeline from Russia to Bulgaria via Turkey, showed sharp declines in flows year-on-year. For the Nord Stream pipeline, a 55bcm line that runs under the Baltic Sea, an explosion in September 2022 rendered the route to Germany unusable for an indefinite period.

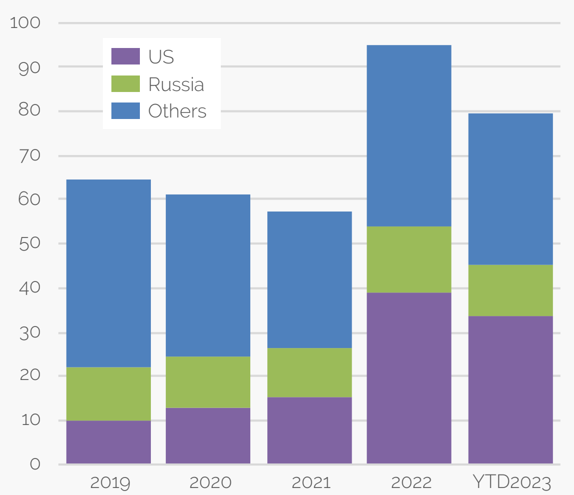
Amid the energy crisis that ensued, new supplies—particularly from LNG—flowed to the EU. From 2021 to 2022, EU LNG imports jumped 65% to 95mt and will likely increase further in 2023, albeit at a lower rate. LNG from the US has been one of the largest sources of increased inflows to the EU, jumping more than 150% in 2022 and likely to increase further in 2023. At the same time, Russian LNG to the EU also increased, up nearly 40% year-on-year in 2022, primarily under existing long-term contracts.

Market conditions calmed considerably in 2023. Mild winter, demand destruction and strong LNG flows that pumped up storage levels kept TTF prices subdued at

By Adam Bennett,
US natural gas analyst,
Kpler

an average $13/m Btu. However, an abundance of uncertainty remains and as a result volatility is high. In the second half of 2023, European prices swung sharply on supply threats, from potential Australian LNG plant strikes to conflict-led reductions in regional flows in Israel to an unforeseen multi-month closure of the Balticconnector pipeline connecting Estonia and Finland.

FIG.2: EU-27 LNG imports by source (mt)




Source: Kpler

This volatility comes despite nearly full EU underground storages, with most reporting countries reaching the mandated 90% target months before the November deadline, underscoring the depth of uncertainty and that ample storage is no guarantee against tight market conditions during the winter. And with questions about how tight the market may get, a major determinant for market conditions in the winter of 2024–25 is where storages will exit the season in 2023.

Russian gas will likely continue to play a role in Europe's supply mix for some time. Existing long-term LNG and pipeline contracts are binding arrangements that are difficult and costly to break. While some of these pipeline contracts span as far as 2040, many are set to expire before the end of this decade, opening a potential window of opportunity for gas supply diversification.

While Norway continues to be a major gas supplier to Europe, LNG will likely take a more prominent role in Europe's gas mix. Since 2021, import capacity has increased by more than a third, with new receiving terminals and FSRUs in the Netherlands, Finland, France, Germany, Italy and Turkey.

While operators will have to compete on the global market for LNG cargoes, the new infrastructure ensures the technical capacity is available to receive gas from a wide variety of suppliers. Long-term contracts—such as the one recently signed between US LNG exporter Cheniere and German chemical giant BASF—signal durable linkages between global LNG suppliers and European industries and gas consumers.

However, long-term questions remain for Europe's gas markets. Economic contraction and the energy crisis may have permanently crippled some of Europe's industrial base, paring sectoral gas demand. Factories and businesses closed during the energy crisis may never reopen. Additionally, the installation of renewables may mean that gas takes a smaller piece of the power mix going forward. With net-zero targets aiming to sharply reduce carbon emissions, new investments in gas-related projects have been losing out to battery storage, hydrogen, solar, wind and other renewables technologies. ■

# Is blue the new green?

## The role of gas in the energy transition


A biogas plant and farm

The natural gas sector has undergone many changes in the last few decades. Back in the 1980s gas was still considered a "noble fuel" destined only for home heating and other limited markets. By the 1990s, natural gas was being produced in quantities that made it a fuel of choice for power generation and other large-scale industrial uses, aided by exponential growth in the LNG sector. During the 2000s, gas took on the moniker of the "transition fuel", a cleaner, lower-carbon form of energy that advocates saw as a foundation for many decades of continued development and growth.

Arguably the development that started to "rain on the parade" was in fact one of the most positive—the shale gas revolution. That marked a tipping point, where first the risks of fracking and water source pollution were seized upon and then climate concerns raised new hurdles to be overcome. The clean and climate-friendly image of gas and LNG is now in doubt.

So, as we start another year, almost halfway through the 2020s, gas seems to have an uphill struggle in the competition with renewables, green hydrogen, battery storage and other zero-carbon technologies that have so much potential, at least in the long term. But is gas and the global trade in LNG really on the way out? Many would have you believe otherwise. Let's look at some of the reasons why.

Let's start with some of the hard and fast data around gas and LNG. Each 1m Btu of natural gas creates around 55kg of $CO_2$. Depending on the source, development plan and delivery chain, as much as another 30kg of $CO_2$ can be produced producing, processing, liquefying and shipping the gas before it reaches the end user. That's 30kg of emissions that can be addressed in some form or another. Electrification of pumps and compressors, controlling fugitive methane emissions and other mitigation technologies are already starting to make inroads, with more to come.

> Each 1m Btu of natural gas creates around 55kg of $CO_2$

Next, technologies such as CCUS are evolving at a rapid pace. This can include relatively low-hanging fruit such as capturing and storing $CO_2$ from an acid gas removal plant, an essential step prior to liquefaction. Not only does this mitigate the carbon intensity of LNG production, but under current US tax credit mechanisms it is also profitable!

CCUS also has the potential for a game-changing transformation of the gas industry by incorporating gas-reforming technology within the value chain and removing the carbon before the gas is sent on to the consumer, in the form of hydrogen or, more practically speaking, ammonia.

By Nick Fulford,
senior director, gas/LNG-carbon management-energy transition – Americas,
GaffneyCline

Let's go back to that 55kg of $CO_2$ again and work through the economics. Right now, US tax credits and European emissions trading system credit prices are in the range of $85 to $100/t of $CO_2$. That means the costs of addressing emissions are in the range of $4 to $6/m Btu in addition to the cost of the fuel. In round terms, that's not so different from the cost of constructing and operating a gas-reforming plant and permanently sequestering the $CO_2$, although combustion gases are more costly to deal with than the process $CO_2$ that is produced. It's not a perfect solution, but it can mitigate $CO_2$ emissions up to about 90%. The higher the price put on carbon, the more feasible hydrogen or ammonia produced from gas becomes.

Moving on from the conventional fossil fuel sources of gas, how about biogenic gas? Although small-scale natural gas production from biomass has been a feature of the developing world for many years, "biogas" is rapidly being transformed into an industrial-scale, global industry. Biogas is a mixture of methane and $CO_2$, but it's $CO_2$ that's been captured from the atmosphere and re-released, as the gas is purified into conventional natural gas quality. That makes it carbon neutral.

Biogas as a renewable LNG feedstock, or "RNG", is therefore another promising avenue for the industry. RNG also has the potential to be blended with hydrogen to continue to utilise the billions of dollars of natural gas and LNG infrastructure that exists today, with a lifespan of multiple decades.

Better still, why not combine biogas with CCUS technologies to create "carbon-negative gas", effectively removing $CO_2$ from the ecosystem, going from "net zero" to "net negative". As the world places a higher value on carbon, whether it's through credits, subsidies, carbon taxes or cap and trade systems, more and more of these low-carbon solutions for natural gas start to become a reality based on commercial rates of return, and on an ever-increasing scale.

Finally, although not yet firmly established as a full climate solution, carbon offsets are emerging onto the market, and have already been used to create "carbon-neutral" LNG cargoes. Since 2018, industry estimates suggest that over 60 offset cargoes of LNG have been delivered, approximating to about 4mt of LNG, with most deliveries being made to China, Taiwan and Japan. There is now a standard for offsetting LNG cargoes, which is helping to standardise what has been an ill-defined practice and establish carbon-neutral LNG as a verified source of carbon reduction.

So is gas and LNG destined to be cast aside to make way for greener solutions? Far from it. Those blue flames are burning with a growing shade of green these days. ■

Any views expressed in this article are strictly those of the author and should not be attributed in any way to GaffneyCline

# US LNG: The next wave?

The LNG build-out gaining momentum in the US since 2022 is unprecedented in its size, but as risks grow it will reach its peak in 2024

The European energy crisis in 2022 reshaped global LNG flows, with higher prices drawing cargoes from around the globe to the now gas-starved continent. US LNG has played a particularly important role in filling the gap. In 2021, 34% of US LNG exports went to Europe. In 2022, nearly 70% did, meeting 15% of total European gas demand.

The past two years have seen many LNG projects advance as US companies rush to take advantage of European demand. Since the beginning of 2022, five projects in the US representing 66mt/yr of capacity have taken FID. In combination with the Golden Pass LNG project, which has been under construction since 2019, a 91% increase in US LNG capacity over present levels is now baked in. The US is already set to edge out Qatar as the world's largest LNG producer in 2023. By 2030, that gap will widen significantly even as Qatar completes its own massive LNG expansion projects.

> 2024 could see upwards of 25mt/yr of US LNG capacity reach FID

This US build-out will shape gas markets across the world. But there are uncertainties concerning both when projects already under construction come online and how many of the approximately 120mt/y US projects eyeing FID eventually move forward.

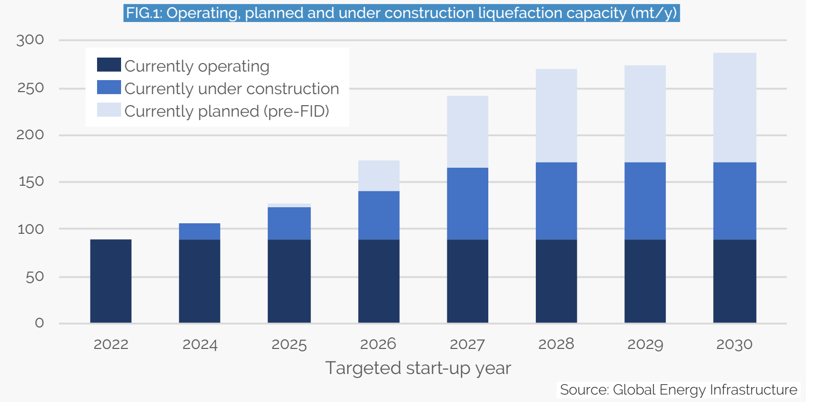
One source of risk is the very size of the US build-out. Between 2000 and 2020, the largest five-year build-out of US liquefaction capacity occurred from 2015-19, when 75mt/yr of additional capacity was added. As of now, 82mt/yr of liquefaction capacity is already under construction, with another wave of projects on the way. Projects outside the US (c.120mt/yr of new capacity is currently under construction) will further strain the global LNG supply chain.

As more projects try to begin construction at once, labour supply and the LNG construction supply chain risk being overstretched. Even projects where construction is currently underway risk seeing their start dates slip six months to a year. Projects now attempting to start construction are unlikely to meet aggressive timelines for project start up and should expect to pay higher prices compared to earlier projects.

Those US projects that are yet to take FID also face regulatory risks. The past year has seen the Department of Energy (DOE) change its approach to US LNG projects. Traditionally, the agency has wielded its oversight power with a light hand. But in May 2023, the DOE announced a new policy requiring projects to have both "physically commenced construction" on a project and demonstrated that the project delay is due to "extenuating circumstances outside of [the project's] control" to extend their export commencement deadlines.

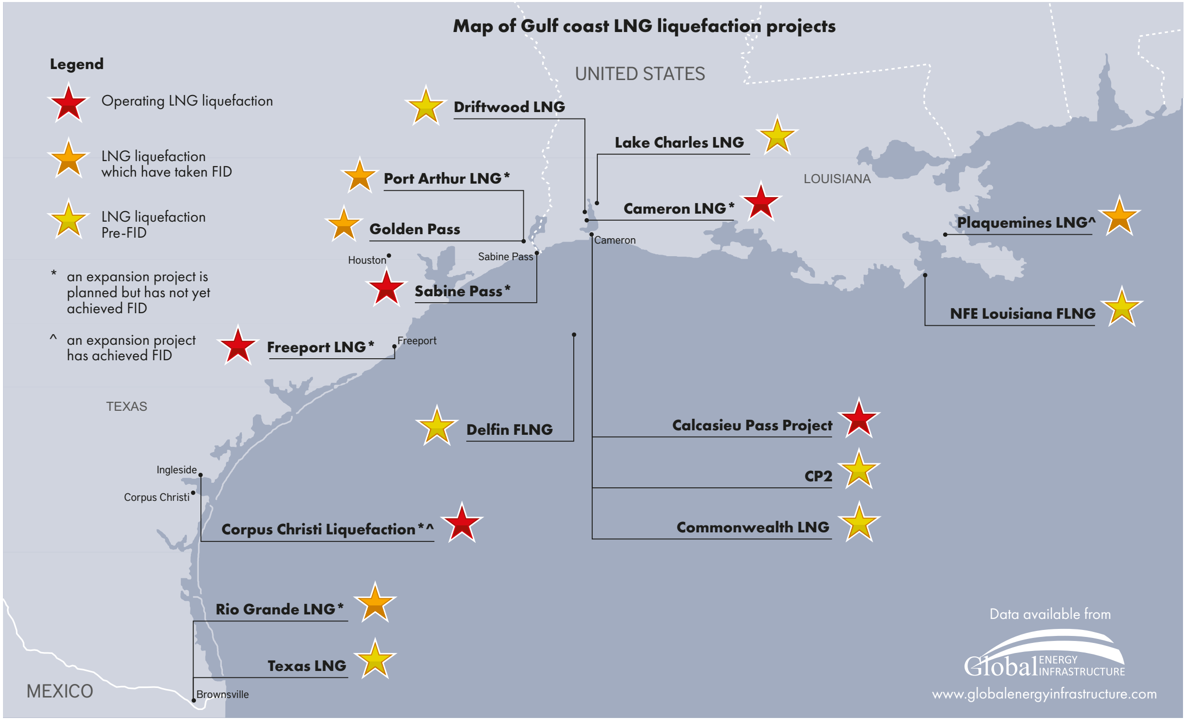
The agency is also yet to approve Commonwealth LNG's export licence almost a year after the project received FERC approval. Past projects have seen DOE export licences granted within only a few months of obtaining FERC approval. If this is indicative of the DOE adopting an aggressive stance on regulating LNG terminals, projects that are otherwise well placed to take FID may face significant delays or be stopped altogether. The DOE itself has not formally announced a substantial policy change beyond its new approach to commencement deadline extensions, requiring projects to have begun substantial construction to obtain one.

FIG.1: Operating, planned and under construction liquefaction capacity (mt/y)




Source: Global Energy Infrastructure

By Seth Haskell,
research analyst,
Global Energy Infrastructure




Three US projects look to be approaching FID as part of a next wave of projects: Venture Global's Calcasieu Pass 2 (CP2) facility, Delfin Midstream's first FLNG vessel and the independent Commonwealth LNG terminal. Together, the projects represent 23mt/yr of LNG capacity. All three projects have obtained FERC approval (in the case of Delfin FLNG, MARAD approval) and have either secured or are close to securing the offtake and tolling agreements needed to support FID. The projects have also seen a burst of momentum in the past several months, with Commonwealth LNG and Delfin FLNG signing financing and offtake agreements as well as heads of agreements that may be firmed up soon, and CP2 securing FERC environmental approval.

CP2 and Commonwealth LNG will want to secure DOE approval before taking FID. Delfin LNG will need to decide if it wants to take FID in the hope that physically commencing construction will enable it to secure a necessary extension to its current commencement deadline or if it will simply apply for a new export licence, heavily delaying the project. The fate of these projects will do a great deal to help clarify the DOE's position going forward.

Even if projects are only delayed, that may be enough to kill them due to the uncertain trajectory of global gas demand. As the energy transition continues, gas demand in mature markets is at constant risk of entering terminal decline. At the same time, growing global LNG liquefaction capacity means that the end of the decade will see a softer market. Big terminals take more than a decade to pay off, and late arrivals risk beginning production too late.

2024 could see another 25-35mt/yr of US LNG capacity reach FID, but as risks stack up, it may be the last wave to move forward. ■

Global Energy Infrastructure provides exclusive global project data across LNG, hydrogen, CCS, oil & gas pipelines and refining & petrochemicals. For more, visit www.globalenergyinfrastructure.com

# Geopolitics & global markets

# The evolving role of OPEC and OPEC+

The organisation remains vital to ensuring future energy demand is met

Founded in September 1960 at what has become known as the Baghdad Conference, OPEC began life as five oil-producing member countries: Iran, Iraq, Kuwait, Saudi Arabia and Venezuela.

Previously, powerful outside interests in the shape of the leading international oil companies of the day dominated almost all aspects of the development, production and sale of crude oil, while the countries from whose lands the crude oil was extracted received only minimal returns, hindering their national development.

Over the ensuing decades, however, OPEC's member countries—today numbering 13—have evolved to run their own domestic oil sectors, and the organisation has become a respected member of the international energy community and multilateral system, guided—remarkably—by essentially the same binding objectives agreed at the Baghdad Conference.

OPEC's mission remains to help ensure sustainable stability for oil markets in order to secure an efficient, economic and regular supply of petroleum to consumers; a steady income to producers; and a fair return on capital for investors in the petroleum industry.

OPEC's very first resolution, adopted at the Baghdad Conference, also put dialogue and cooperation at the forefront of the organisation's *modus operandi*. This was clearly underscored in December 2016 with the signing of the Declaration of Cooperation (DoC) between OPEC and 11 non-OPEC oil-producing countries—often referred to as OPEC+.

> OPEC is proud of its role in helping to foster market stability and deliver energy security

The DoC's success stems in large part from proactive and pre-emptive decision-making, and participants' flexibility to support a balanced and stable global oil market at critical junctures, most recently to counter the hugely destabilising effects of the Covid-19 pandemic.

OPEC is proud of its role in helping to foster market stability and deliver energy security, and at the same time its member countries are focusing fully on the need to reduce emissions continually, with 2019 seeing OPEC+ endorse a permanent platform to examine longer-term industry challenges and opportunities, known as the Charter of Cooperation (CoC).

Given the oil industry has an important role to play in addressing climate change, it was fitting that OPEC hosted a pavilion and organised a programme of events at COP28 in the UAE that outlined, among other topics, its contributions to global energy security and key industry technologies and best practices to reduce emissions.

On the latter, OPEC member countries are investing in upstream and downstream operational efficiencies; deploying vast expertise to decarbonise the oil industry; mobilising cleaner, innovative technologies, such as CCUS, direct air capture and carbon dioxide removal; making major investments in renewables and hydrogen; and promoting the circular carbon economy.

With all of this in mind, and to avoid future instability, it is imperative that the entire world focuses on ensuring just, orderly and stable energy transitions that have both energy security and reducing emissions at their heart.

Against this backdrop, calls to stop investing in oil are not conducive to maintaining energy security or market stability, particularly given the huge importance of oil- and petroleum-derived products to our daily lives and with the global population set to expand by 1.5b people and the world economy to almost double in size by 2045.

Furthermore, they become even more unrealistic when considering that the world is set to see energy demand increase by 23% between now and 2045, according to OPEC's *World Oil Outlook (WOO) 2023*. Indeed, all energies—with the exception of coal—are set to grow, with other renewables, notably wind and solar, expanding at the fastest rate, albeit from a low base, and oil retaining the largest share at close to 30% in 2045.

Global oil demand is set to expand to 116m b/d in 2045, with the potential to move even higher, necessitating oil sector investment requirements over the period totalling $14trillion, or around $610billion/yr.

By HE Haitham Al Ghais,
OPEC secretary general

Overall, the *WOO 2023* emphasises that if the world is to achieve a sustainable, orderly and just energy future, policymakers need to adopt an "all-peoples, all-fuels and all- technologies" approach and plan for the world's energy future based on facts and realities on the ground.

When it comes to fuel sources to meet future energy demand, it is not a question of choosing one over another, it is a question of how best to utilise every single fuel source at the world's disposal while simultaneously developing innovative technologies and best practices.

Over the course of their respective histories to date, OPEC and OPEC+ have demonstrated what can be achieved when working together and adhering to collective, transparent and realistic objectives.

Sixty-three years on from the Baghdad Conference, seven years on from the signing of the DoC and four years on from endorsing the CoC, OPEC and OPEC+ continue to evolve in order to deliver the sustainable market stability that is vital for producers and consumers, especially as constant investments in energy capacity and technologies are more vital than ever. Addressing the world's looming energy and climate challenges must put this kind of pragmatism and fairness front and centre, making sure that all stakeholders help deliver reliable and sustainable energy for all, alongside reductions in emissions. We owe this to future generations. ■

# The IEA 50 years on: Ensuring a secure transition to clean energy

We have the tools to transition but we must make sure we take advantage of them

History doesn't always repeat itself, but it often rhymes. Half a century has passed since the 1973 oil crisis began, but today's global energy landscape is echoing with familiar concerns. Energy security concerns are looming large for world leaders in a system that is still largely dominated by fossil fuels and especially oil. But unlike in the early 1970s, the world now has many other proven energy technologies at its disposal, such as renewables, electric vehicles and heat pumps, which are already driving rapid changes.

Born out of the 1973 crisis, the IEA was initially dedicated to oil. By establishing emergency stocks, sharing data and coordinating policies among its member countries, the IEA was designed to help stabilise oil markets in turbulent times. As recently as 2022, during the global energy crisis, the agency undertook the two largest ever coordinated emergency oil stock releases in its history, demonstrating that oil security remains at the core of its mission.

But the IEA, its expertise and its mission have broadened significantly to adapt to the changing energy world, taking in natural gas, electricity and many aspects of clean energy technologies such as renewables, energy efficiency and critical minerals. The IEA family has grown well beyond the agency's original group of member countries to include many major emerging economies, and today it represents close to 80% of global energy use. This global reach has underscored the agency's reputation as the world's leading energy authority.

For natural gas, we have been publishing a *Global Gas Security Review* every year since 2016 and demonstrated our focus by raising the alarm early on that Russia was distorting gas markets in 2021 by reducing its deliveries to Europe, driving up prices at exactly the same time as geopolitical tensions were rising over Ukraine. When Russia's invasion began and sent energy markets into turmoil, the IEA responded quickly and effectively. Only one week after the invasion, we released a ten-point plan showing how the EU could rapidly reduce its reliance on Russian gas supplies through a combination of measures

that would support energy security and affordability while keeping Europe on track for its climate goals.

As the energy crisis unfolded, we continued to provide support and advice to governments, businesses and citizens. This includes the establishment of the IEA Task Force on Gas and Clean Fuels Market Monitoring and Supply Security, which has provided key market updates and a platform for the effective exchange of data and information as well as policy responses.

While energy security challenges in areas such as oil and gas remain a key focus for the IEA, we are also expanding our work to cover emerging risks in newer parts

By Keisuke Sadamori,
director of energy markets
and security, IEA

of the global energy system. In particular, this involves supply chains for clean energy technologies and the critical minerals that go into many of them. Following our landmark 2021 report *The Role of Critical Minerals in Clean Energy Transitions*, the agency has been asked by governments around the world, including the G7, to make recommendations on options to diversify supplies of critical minerals and clean energy technology manufacturing. We are also providing regular market updates on critical minerals and recently held the first ever Critical Minerals and Clean Energy Summit, which brought together almost 50 countries from across the globe as well as leaders from industry, investment and civil society.

As clean energy transitions progress, the role of electricity is increasing strongly across our economies. This makes ensuring security of electricity supply paramount. Higher investment in robust and digitalised grids needs to be accompanied by roles for batteries and demand response measures for short-term flexibility and lower-emissions technologies for seasonal variations. This has become a major area of work for the IEA, including for our Renewables Integration and Secure Electricity team, which recently produced, in cooperation with colleagues across the agency, an important study showing the urgent need to expand and replace a vast amount of electricity grids worldwide.

**The echoes of past energy crises remind us of the need to adapt**

The IEA's work also addresses the environmental aspects of energy, notably the tight interlinkages with climate change. Over the past two decades, the IEA has been publishing scenarios that provide pathways to reduce the energy sector's emissions in line with international climate targets. The deepening climate crisis makes clear the necessity of transforming the energy system while maintaining the affordable and secure provision of energy services. As global warming intensifies, an increasing amount of energy infrastructure that was built for a cooler, calmer climate is no longer reliable or resilient enough as temperatures rise and weather events become more extreme.

The echoes of past energy crises remind us of the need to adapt. We have the technologies, the manufacturing capacity and the knowledge base to fully address the problems we face today. Fifty years ago, we were also not fully aware of the urgency of tackling the herculean challenge of global warming. But times have changed, the tools to act swiftly are there to guarantee the intertwined goals of energy and climate security. We have to work much harder to take advantage of these tools. ■

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# Libya ready for investment

New strategic plan includes significant investment in oil and gas

By Mohamed Oun,
minister of oil and gas,
Government of National Unity,
Libya

Libya's oil and gas sector is open for business. With a clear and diverse plan in place to attract investment and boost output this decade, the OPEC member is hopeful of tapping dormant and unexplored resources in 2024 and beyond. The Libyan government, through the Ministry of Oil and Gas, considers energy to be crucial to the three interconnected and mutually reinforcing pillars of sustainable development: economic growth, social progress and environmental protection. Energy is crucial for driving progress across all sectors of society, from generating power for industry to supplying essential services such as healthcare, education and clean water. Reliable energy sources are of the utmost importance.

To meet this diverse energy demand, a short-term strategic plan (2023-26) has been developed that includes huge investment in the petroleum sector covering all aspects of the oil industry, with expectations for output to reach 2m b/d by 2026, an increase of 0.8m b/d from current levels.

The strategic plan includes developing newly discovered fields and raising the production capacity of existing fields, in addition to developing the infrastructure that was damaged due to the geopolitical and environmental events that Libya has experienced. Work is in progress to announce a call for international oil companies to bid on new concession licences for oil and gas during 2024. A large portion of the onshore and offshore areas (>50%) are currently unexplored.

Oil and gas account for almost all of Libya's export revenues and are therefore the main economic drivers for the country. Greater effort is being made to enhance oil and gas recovery, maintain high output levels and find more hydrocarbon sources such as shale oil and gas reservoirs to add to reserves.

According to an assessment report prepared by the US Energy Information Administration (EIA), Libya has the fifth-largest proven shale oil reserves in the world. This assessment addresses three out of the six of Libya's major hydrocarbon basins: the Ghadames Basin in the west, the Sirte Basin in the centre and the Murzuq Basin in the southwest of the country.

The EIA estimates that these three basins in Libya contain 942tcf of risked shale gas in place, with 122tcf as the risked, technically recoverable shale gas resource and 613b bl of risked shale oil and condensate in place, with 26.1b bl as the risked, technically recoverable shale oil resource.

The Ministry of Oil and Gas has tasked a team of experts from the oil sector to evaluate these shale oil and shale gas resources, of which the Government of National Unity has issued a resolution on this regard, with the aim to determine the reserves in all six basins and the respective development options available, including bringing in international companies with expertise in unconventional resource exploration and development.

## Six strategies

In the pursuit of such a strategy, navigating the complex landscape of the energy transition, Libya must adopt a multifaceted approach that encompasses six crucial strategies: adopting enhanced operational methods; optimising the effective monetisation of methane; transitioning towards low-carbon energy sources; implementing corporate-wide strategies; investing in CCUS technologies; and facilitating the production, transportation and utilisation of hydrogen in both blue and green forms, the latter by leveraging the country's solar resources. Among these, CCUS and methane emissions reduction emerge as the standout strategies. The strategic deployment of CCUS technologies can significantly reduce emissions associated with traditional energy production.

Additionally, the General Electricity Company of Libya, under a framework of co-operation with the Renewable Energy Authority of Libya, has signed a contract with French company TotalEnergies to implement a 50MW solar energy project in the city of Bani Walid at Sadada town. The project is expected to enter into commercial operation in 2026 and is set to become the largest solar project in the country. This is a key step in unlocking Libya's potential for a diversified energy portfolio, taking advantage of the average 3,200 hours of sunshine each year and working to stimulate economic growth as well as create job opportunities. ■


Source: Petroleum Economist, Global Energy Infrastructure

# Welcome to the geopolitical rollercoaster

Oil and gas are once again being weaponised

The geopolitics of energy are not what they used to be: they're getting much "worse". And also much "better". Worse, because the risks are getting more heated than they have in decades. But also better, because the markets' resilience and ability to weather geopolitical turmoil have never been greater.

The reasons for the risk proliferation are many. Let me point out three.

First, the rise of what Ian Bremmer calls the "G-Zero" world: the decreasing ability and/or willingness of the US to serve as the world's policeman, the Sino-American rivalry and the mounting tensions between the West and the Rest.

After the 1973 Arab oil embargo, of which we just marked the 50th anniversary, the world seemed immunised against the use of oil as a political weapon. The industrialised countries' strategic oil reserves provided a safety cushion against disruption, and in so doing deterred exporters from using oil as a weapon again.

More recently, though, the oil weapon has made a comeback. In 2019, a drone attack hit Saudi Arabia's Abqaiq crude oil processing plant, responsible for 10% of global crude supply. In my days as head of oil at the IEA, this was the worst-case scenario we could dream up for our annual energy security war games.

Russia has been breaking ground by using gas, not oil, as a weapon, notably by restricting spot exports to Europe in the run up to the invasion of Ukraine (in an apparent bid to make it more vulnerable and less willing to object) and then by reducing pipeline exports even further.

Meanwhile, oil consuming countries have been using their oil buying power as a weapon too, through sanctions and import bans against Iran, Venezuela and Russia.

A second reason for the rise in geopolitical risk is the energy transition. The shift from fossil fuels to renewables is upending the geopolitics of energy as we know it. It is both threatening the future economic lifeline of oil exporters and creating new forms of dependence around critical mineral and battery supply chains. New fault lines are also emerging around loss and damage issues, and in due course the race to net zero will cause large wealth transfers to countries in the Amazon and Congo Basins and elsewhere in the global south whose forestry endowments will be crucial to meeting our climate goals.

> The good news is we are getting better at managing these risks

The staggered, lumpy and somewhat unpredictable pace of renewable energy deployment adds to the risks, as does the variability of wind, solar and hydro energy and resulting volatility in demand for incumbent fossil fuels.

Last but not least, global warming is contributing to the rise in geopolitical risk by threatening to make part of the world uninhabitable, thus causing large shifts in energy supply and demand.

As large and unpredictable as these risks may appear,

By Antoine Halff,
chief analyst and co-founder,
Kayrros

the good news is we are getting better at managing them.

Two major causes for this improvement stand out. The first one is to a large extent the flip side of some of the very factors that have been driving risk in the first place, i.e. the growth in renewable energy, supply diversification and accelerating inter-fuel competition.

These factors have dramatically increased the flexibility of energy markets in the face of supply/demand disruptions. Likewise, the rise of LNG in the gas market has helped Europe cope with the loss of Russian piped exports and blunted the edge of Moscow's gas weapon—even as growth in heat pumps and wind and solar have reduced European dependence on gas altogether.

Post-1973, gas and nuclear energy helped Western economies reduce their power sector's addiction to oil. Electric vehicles and biofuels are now doing the same for transportation.

Equally important in the world's growing resilience, however, are recent breakthroughs in data science and earth observation, and the unprecedented level of transparency thus provided on energy markets.

New data technologies powered by AI and satellites now let energy market participants monitor energy supply, demand, storage and transportation as well as greenhouse gas emissions and climate risks in near realtime, from crude stocks to lithium supply to solar farms and battery storage to floods and wildfires and all forms of energy consumption, anywhere.

Increased transparency means an unprecedented ability to arbitrage, and even prevent, disruptions.

Thanks to this transparency, the 2019 Abqaiq attack, far from a devastating blow, barely caused a blip. Saudi Aramco and the Saudi energy ministry did a great job managing the crisis but wouldn't have been as effective if satellite imaging had not let market participants independently verify the damage to the spheroids, monitor the repairs, find alternative supplies, reroute tankers and track global oilfield and refining activity.

Abqaiq was the first oil crisis of the satellite age. It turned out to be a non-event.

Looking forward, realtime actionable data from satellites will play an ever-growing role in helping manage geopolitical risk and smoothing our bumpy path to net zero. Most energy and trading companies are increasingly relying on it not only for their day-to-day trading needs but for their own transformation to sustainability.

The world is getting both more unpredictable and more transparent. So critical will satellites be in providing this needed transparency that they may themselves become a focus of geopolitical tension. Today, more and more countries are rushing to launch their own earth-observation satellites. Some may object on sovereignty grounds to having others independently monitor their emissions and economic activity.

Our efforts to deal with geopolitical risk through earth observation may cause geopolitical risk to spread to space itself. This too can be managed. For the time being, just as climate change and the energy transition are upending the nature of geopolitical risk, so too is earth observation transforming our ability to ride it out. ■

# Regulatory convergence of the Inflation Reduction Act and international subsidiary models

The EU and Japan are developing regulations to counterbalance the US' perceived protectionist strategies

In the US, the Inflation Reduction Act (IRA) of 2022 has thus far been a clear market signal to incentivise private capital flows into the energy transition. The IRA allocated $369b of federal funding toward energy security and climate change programmes, with a major emphasis on renewable energy development. Further, the IRA established a number of new tax credits aimed at increasing adoption of clean energy technologies in pursuit of ambitious targets to lower greenhouse gas emissions.

However, the law stipulated that new investments comply with a domestic content requirement, known as "Buy America". In order to be eligible for the electric vehicle (EV) tax credit of $7,500, for instance, the critical minerals and battery components of the EV must be sourced and manufactured either in North America or by a country with an existing free trade agreement (FTA). Ostensibly, the intent was to reduce US reliance on products originating from China—ranging from the aforementioned EV batteries to renewable energy components such as solar photovoltaic panels. As is not uncommon in transformative national policy, though, Buy America may have led to unintended consequences.

**The overarching approach in Japan deviates from the US and EU**

Given the robust supply chains abroad needed to support the burgeoning EV segment and related emerging clean energy technologies, the domestic content mandate initially struck the wrong chord. Both the EU and Japan stated that the requirement was discriminatory and not in the spirit of like-minded economies to build out the energy transition. Neither the EU nor Japan hold FTAs with the US, although there has been an established record of mutually beneficial trade flows.

Accordingly, the EU and Japan set out to counterbalance the perceived protectionist effects of the IRA, particularly due to the sheer magnitude of funds to be spent by the US in the coming years.

The EU had already passed the European Green Deal in 2020, which provided €503b ($538b) through the end of the decade. Responsive to the scope and scale of the IRA, the EU introduced a revised version entitled the Green Deal Industrial Plan (GDIP) in the spring of 2023. The GDIP compels the EU to fulfil its goal of net-zero emissions by 2050. Notably, the new plan proposes to streamline the permitting process for new renewable energy generation, create a new agency (the European Critical Raw Materials Board) to oversee and expedite rare earth mineral projects, and bolster the prospects for clean hydrogen development through relaxing EU subsidies rules and financial incentives, among other provisions.


In this context, the EU has already relaxed its EU state aid rules to respond to the IRA, which further simplify

By Serena A. Rwejuna, partner,
Aaron Bryant, energy analyst,
and Irina Trichkovska, counsel,
White & Case


the grant of (highest amount of) subsidies to energy transition projects. In response to the IRA, the EU also exceptionally allowed its EU member states to offer "matching aid" to companies wanting to relocate from the EU to the US—or elsewhere—because of foreign subsidies.

In addition to the GDIP, the European Commission proposed the Net-Zero Industry Act (NZIA) as a complementary piece that would formalise specific targets for decarbonisation and related sourcing. In particular, the proposal would require at least 40% of clean technology be derived from EU countries by 2030. The NZIA would also purport to streamline—or eliminate entirely—certain bureaucratic and regulatory bottlenecks for the most impactful "strategic" technologies, including but not limited to solar photovoltaic, onshore and offshore wind, batteries, heat pumps, clean hydrogen, nuclear fission and carbon capture.

Finally, at the beginning of 2023, the EU also adopted the EU Foreign Subsidies Regulation (FSR), which gives new powers to the European Commission to investigate subsidies provided by non-EU countries that may distort the EU internal market. Applicable as of 12 July 2023, the FSR establishes a new system of foreign subsidies control, under which the IRA may be subject to the European Commission's review.

Meanwhile, Japan responded in kind to the IRA by enacting the Green Transformation Basic Policy, more commonly known as GX, in May 2023. The primary goal of GX is to meet domestic carbon reduction targets of 50% by 2035 and net-zero by 2050. Japan authorised $14b into GX to eventually support its public-private investment goal of a $1t decarbonisation market focused on the domestic industrial, transportation and energy sectors.

However, the overarching approach in Japan deviates from the US and EU. A substantial amount of funding in GX will go toward existing fossil fuel facilities, through technology such as "zero-emission thermal power" achieved by the use of hydrogen, ammonia or biomass in natural gas and coal power plants.

It is worth pointing out that the geographic limitations of Japan yield fewer opportunities to deploy large-scale renewable generation projects with large footprints. With that consideration in mind, it may be prudent for Japan to build facilities beyond its borders—such as in Australia or the Middle East—to produce hydrogen for import. As such, GX appears to double down on hydrogen fuel-cell technology in vehicles rather than pivoting to EVs, where its market share is minimal and is likely to only diminish in light of the massive investments detailed earlier by the US and EU, as well as existing power players such as South Korea. ■

# Toward a realistic US energy and climate strategy

A realistic, yet forward-looking, energy and climate strategy is possible if US policymakers can eschew ideological divides in favour of a durable political compromise


It is inarguable that the US has emerged as a global energy superpower over the last decade. Even so, partisan disunity has left the US without a coherent energy and climate strategy suitable for the world's largest economy and, presumably, dedicated leader in the still elusive global energy transition. Faced with this internal division, the US's vast potential as a dominant producer for both conventional and emerging fuels brings as many challenges (and contradictions) as it does opportunities.

The Biden administration has walked a delicate tightrope with respect to the US's energy superpower status. Certainly, the administration has reinvigorated US climate leadership in the form of executive actions (particularly rejoining the Paris Agreement with an ambitious net-zero commitment) and transformative legislation (notably the Inflation Reduction Act (IRA) with its $370b in dedicated funding prioritising clean energy incentives). At the same time, the administration has adopted a nuanced approach to the fossil fuels industry—simultaneously touting the value of American natural gas as a resource for US allies, overseeing the continuation of the federal on- and offshore leasing programs it once vowed to end and approving new fossil projects (such as the Alaska Willow Project) and infrastructure (such as LNG export facilities and interstate pipelines) where political and geopolitical considerations are at play.

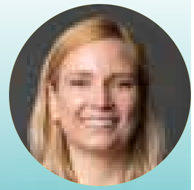
> Shared alignment around the imperative of reaching the US's Paris Agreement targets should be the cornerstone

The mantra for the next decade seems to be "all of the above—and much more." In 2024, US oil production may break 13m b/d as the US appears set to retain its mantle of the world's largest producer. The same is true of natural gas, which the US produced more of in 2022 (94.7b cf/d) than the entire Middle East, and which enabled over 104bcm of US natural gas exports in the last year—increasingly to European shores as those countries disavow piped Russian gas supplies. But conventional fuels are only a part of the story. In the wake of the IRA, new estimates project that American annual renewable energy capacity could triple in the next decade to 110GW. This is to say nothing of substantial federal investments in a series of hydrogen hubs and a wave of newly announced carbon capture projects as potentially lynchpin technologies for the post-2030 push toward deep decarbonisation.

In this complex situation, many US policymakers have struggled to reconcile the US's role as a conventional fossil fuels producer with its emerging role as a clean energy heavyweight. Conservative Republicans have attempted to undercut the IRA's clean energy incentives and framed them as a waste of taxpayer funds, if not a giveaway to China. On the opposite side, some progressive Democrats are disillusioned over new federal approvals for oil and gas development and are reportedly working to remove industry-friendly mandates within the IRA itself.

Clarification and unity are possible, but will require both conservatives and progressives to eschew ideological approaches and prioritise what can—and should—be achieved in a US energy and climate strategy. A viable grand bargain would recognise that the US must aggressively pursue opportunities to deeply decarbonise its energy system, but with a clearly defined role for its oil and gas industry to provide the fuels needed now and evolve its businesses toward future needs simultaneously.

By David Goldwyn, president,
and Andrea Clabough, associate,
Goldwyn Global Strategies




Shared alignment around the imperative of reaching the US's Paris Agreement targets should be the cornerstone of a bargain; such alignment means setting aside ideologically driven efforts to repeal the IRA in whole or in part, and instead monitoring its incentives and costs to determine how it should be extended (or re-evaluated) in the post-2032 period. It should also include comprehensive, bipartisan permitting reform that enables rapid, nationwide transmission buildout necessary to maximise the potential for clean energy expansion in the US.

The other crucial piece is a sincere conversation around the role of US oil and gas, throughout its value chains, amid the marathon that will be deep decarbonisation. Even if the US's domestic needs for fossil fuels decline with the expansion of clean electricity capacity and a transition to electrified or otherwise non-fossil transportation, oil and natural gas demand growth is already shifting to the world's industrialising economies.

The IEA's controversial Net-Zero Roadmap acknowledges that a world with fast-growing clean energy capacity is still vulnerable to price shocks and misalignments of supply and demand. Such worrisome possibilities have been dramatically reconfirmed by the war in Ukraine and now the renewed violence in Israel and Gaza.

Rather than a barrier to the US's achievement of its Paris Agreement targets, the US oil and gas industry should be incentivised and managed in such a way that it is fully integrated into the wider strategy. In such a scenario, the US industry would operate within a predictable, consistent regulatory and permitting environment, free of the risk of whiplash in the wake of a given election. By the same token, industry would work to meet the challenge of rapidly reducing methane and fugitive emissions and cooperate with federal initiatives toward this goal.

Maintenance of conventional business lines should also be paired with genuine efforts toward acceleration of energy transition sectors where the oil and gas industry has useful expertise—particularly around carbon capture sequestration, geothermal energy, mining, infrastructure and export of renewable/low-carbon gases.

A predictable and stable US energy and climate strategy, which enjoys widespread buy-in from policymakers across parties, would strengthen the US and reassure its allies of both its intention and the pathways to achieve it. Amid an ever-worsening climate crisis and intractable energy security challenges from all sides, such a conversation cannot come soon enough. ■

David Goldwyn is president of Goldwyn Global Strategies, LLC, an international energy consultancy, and served as special envoy for international energy at the US Department of State. Andrea Clabough is an associate at Goldwyn Global Strategies, LLC and a nonresident fellow at the Atlantic Council Global Energy Center.

# Competing priorities for green industrial policy

Three overarching policy goals can be seen to achieve decarbonisation

International governments are adopting more interventionist economic policies, particularly concerning the energy transition and associated clean technologies. Since the early 2000s, industrial policy has been a key feature of the drive for decarbonisation, but recently the priorities have shifted. While earlier efforts were concerned with reducing greenhouse gas emissions, a newfound enthusiasm focuses on reducing dependence on global value chains, which are increasingly perceived as threatening. Growing acceptance of the inevitability of energy transition also sees countries keen to gain domestic market share of rapidly growing green industries.

With the Inflation Reduction Act, the US has placed industrial policy as the centrepiece of its efforts to reach 2030 climate targets. More than $300b of public money is being made available for often quite specific sectoral interventions. The EU has published its own Net-Zero Industry Act, setting targets for domestic manufacturing to meet 40% of domestic demand for a range of clean technologies. India is using subsidies to boost domestic manufacturing of specific clean technologies, while China has been prioritising the domestic production of certain strategic goods for the past two decades under the framework of its five-year plans.

We can consider three contemporary goals of such green industrial policy. The first is reducing greenhouse gas emissions. Early-stage research and development are typically underfunded by the private sector and governments play a fundamental role. In the early 2000s, government subsidies (particularly German) for the deployment of solar PV kickstarted rapid growth and enabled huge cost reductions. The collapse in the price of renewables led to mass global deployment and was a key factor in facilitating the 2015 international Paris climate agreement.

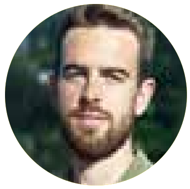
A second goal of green industrial policy is stimulating economic growth and creating jobs. While economists debate the potential for industrial policy to create growth—it depends on the ability of governments to allocate resources better than markets—politicians are vocal proponents. The president of the European Commission, Ursula von der Leyen, has described the European Green Deal as "our new growth strategy", while officials in President Biden's administration frequently cite the creation of well-paying jobs as rationale for the Inflation Reduction Act.


**The pandemic starkly illustrated tensions associated with dependence on foreign suppliers**

When governments intervene in an economy with the idea of stimulating growth, they would typically focus on highly competitive domestic sectors. This gives the greatest chance of support being transformed into export revenues. However, an ongoing trend is to support industries with a relative absence of domestic players, a prime example being Indian and US support for scaling domestic solar manufacturing bases, currently dominated by China. The aim is to break import dependencies—the third goal of contemporary green industrial policy.

Growing policy concern about exposure to global value

By Ben McWilliams,
affiliate fellow,
Bruegel



chains has been driven by the Covid-19 pandemic and recent energy crisis. The pandemic starkly illustrated tensions associated with dependence on foreign suppliers for medical goods, which were urgently required in vast quantities. During the energy crisis, the role of Russia as the EU's primary natural gas provider created huge challenges when exports were dramatically cut. The consequence is an increased policy discussion about reducing dependence on foreign countries for strategic goods.

While this position is understandable and indeed desirable to a degree, it is vital that governments do not take it too far. Any moves toward protectionism, trade wars and slowing of the global exchange of clean technologies will increase costs of decarbonisation. It is not efficient for all developed countries to produce each and every necessary clean technology. A more nuanced approach should retain a primary focus on reducing greenhouse gas emissions.

Domestic manufacturing is not the only tool for addressing excessive import dependences. Most developed countries are dependent on fossil fuel imports, a risk far more serious to economic health than clean technology products. Two approaches to mitigate this risk have been importing from a diversified group of suppliers and stockpiling. Governments might consider maximum import shares from any one country for key goods such as solar panels and batteries. At the same time, they might stockpile key goods and inputs along the value chain such as forms of polysilicon, lithium or final products such as solar panels.

Sectors should be evaluated on a case-by-case basis for the threat of trade disruptions. Key metrics include substitutability and the lead time for new manufacturing facilities to be built. While the EU response to the cut-off of Russian natural gas led to limited economic pain, it also highlighted the ability of modern economies to rapidly adjust to supply shocks.

Green industrial policy has a pivotal role to play in achieving decarbonisation. It can broadly be considered to target three policy goals: the reduction of greenhouse gas emissions, domestic economic growth and reducing strategic import dependencies. In many cases, these goals will be complementary. In cases where policy design involves a trade-off, governments must be sure to keep the reduction of greenhouse gas emissions as the primary purpose. ■

# Negative energy pricing strategies to capitalise on flexibility assets

Negative pricing has become more frequent in European energy markets, and GB markets are now experiencing a similar increase. Increased volumes of variable renewable energy, combined with favourable weather conditions and decreased demand, are driving much of this increase

Negative energy pricing occurs when electricity supply outstrips demand in such a way that grid system operators are forced to choose between paying renewable generators to turn down or paying customers to use more. As solar and wind farms generally have agreed prices for their output, paying customers to consume is often significantly cheaper than paying generators not to produce, even when that price becomes negative.

Several factors create the conditions that cause negative pricing, including generation and demand being driven by weather conditions and the seasons. Nuclear operators have strong economic and technical reasons to remain inflexible with production, meaning they're not suited to respond to increases in renewable production. Storage is a partial solution to the problem, but many countries don't have enough to meet the demand. National transmission networks and cross-border interconnectors can help curb variations across wider regions, but they have capacity limits.

Driven by these forces, negative pricing has become more common in the GB energy market. In July 2023 there were several negative pricing events clustering around weekends. The EPEX hourly day-ahead market reached a record low of –£70/MWh (–$90/MWh) and at one stage the intraday price dropped to –£120/MWh (–$150/MWh).

## Benefits and strategies

There is a lot to gain from negative pricing for organisations that can store energy or adjust consumption. By using their flexibility, they can generate revenue by accessing the shorter time-scale electricity markets and the balancing mechanism. Alternatively, they can use pass-through supply agreements to access cash-out prices too.

While there are regulatory changes concentrated on widening access to these markets, organisations must focus on determining the assets they can use to create the required flexibility, along with the best strategies for capitalising on negative prices.

Dedicated, always available battery energy storage systems are a clear candidate and can deliver the highest revenues. They can effectively generate revenue twice

By Dr Alastair Martin,
founder and chief strategy officer,
Flexitricity

from a single negative pricing event. For example, during the negative pricing events of July 2023, battery owners were able to charge batteries while day-ahead prices were negative, discharging them once they had returned to positive pricing. Batteries also have the response-time capabilities to operate in faster markets like frequency response, which generates more value than just tracking negative prices.

The one-hour, 50MW West Gourdie battery, operated by Flexitricity and owned by Foresight Group, was one of the highest earners during the 2 July 2023 negative pricing event.  Over four-fifths of West Gourdie's revenues came from Dynamic Containment—mostly the low-frequency service, where prices averaged £13/MWh. It was able to stack trading actions to take advantage of negative prices; charging and subsequently discharging once they were positive, accounting for 17% of revenues. The system cycled approximately 0.9 times on the day.

Electric vehicle fleets can exploit negative pricing events in a similar way by choosing when to recharge. Industrial and commercial energy users that can modulate processes such as cooling, heating and pumping can

**–$90/MWh**

**Record low July 2023**

get the same results and revenue streams. These assets have to perform their "day job", so organisations must create a strategy around their functions while deploying their flexibility in an ad hoc manner. It is important to set operational parameters for these assets and give the business dynamic control over the parameters.

Aggregation and automation are also key. A primary goal of a flexibility provider like Flexitricity is to remove size-based restrictions from the market opportunities. This is done by aggregating many assets into virtual power plants with a large enough capacity to make a difference to the grid or to a distribution network operator. Securing value from negative prices and other fast-moving events is not a manual task and working through an experienced flexibility partner with sound relationships across a wide range of different asset classes will be vital. While the approach will likely vary depending on the specific site and assets, operational access to all appropriate markets alongside all other assets should be the goal.

## The longer-term outlook

Negative pricing has a role to play in helping the UK transition to net zero as it provides financial incentives for organisations to support a net-zero grid by encouraging the use of batteries and other flexible energy assets.

The continued growth in variable renewable energy generation plus production and demand inflexibility across the grid make it likely that negative pricing events will be more frequent, with their depth and duration continuing to change as the grid transforms further.

Such events are a market signal calling on us to invest more in flexibility that optimises the energy resources helping us to achieve net zero. As the National Grid ESO has highlighted, all credible future energy scenarios will depend on market participants being able to gain revenue and savings from flexible operation. ■

# Uncertain outlook for East Med

The geopolitical risks of the East Med could affect regional energy integration and global markets

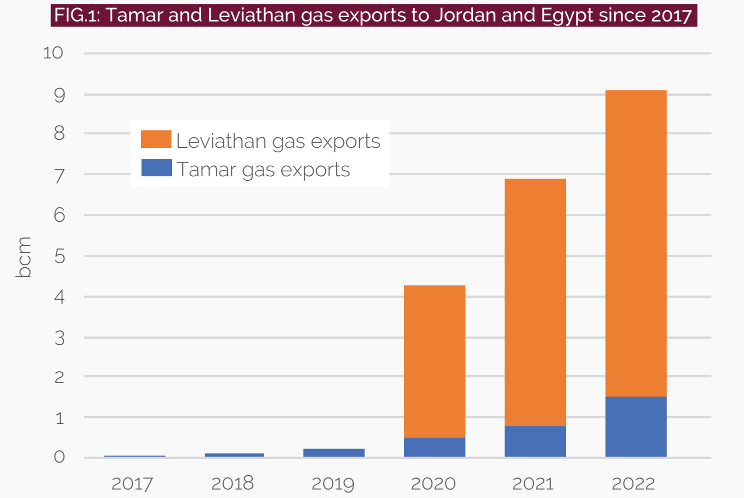
Zohr gas field in Egypt

The ongoing conflict in Gaza had an immediate impact on East Mediterranean gas supply and, if prolonged, could lead to a future of uncertainty around gas development plans and energy integration among regional players.

Over the past few years, East Med gas has gained increasing momentum from the international community, following the discovery of the giant Zohr gas field offshore Egypt in 2015 and its fast-track development in less than 30 months. Zohr was a game-changer for Egypt as it helped the North African nation to stop importing LNG and turned it into a net gas exporter. Zohr was not the first gas discovery in this region, with the Tamar and Leviathan fields offshore Israel discovered earlier in 2009 and 2010, respectively, while the Aphrodite field was discovered offshore Cyprus in 2011. These discoveries highlighted the great potential of gas resources in the East Med region and paved the way for potential regional cooperation and integration among its countries in the field of natural gas.

The regional cooperation was first materialised by the establishment of the East Mediterranean Gas Forum (EMGF) in Cairo in 2019, with a unified vision among its seven founding members on developing a regional gas market and setting up a base for a gas trading hub. Before the EMGF's official establishment, a number of binding agreements had been signed to allow the export of gas from Tamar and Leviathan to Jordan and Egypt. Chevron-operated Tamar commenced gas exports to Jordan in 2017, while Egypt received its first gas from Tamar in 2020. Chevron commenced exporting gas from Leviathan to Jordan and Egypt in January and July 2020, respectively. Gas exports from both fields have been growing since 2017 and reached a new record high of 9.1bcm in 2022, as shown in *Fig.1*. Egypt, the most populous country in the MENA region, marked itself as the key destination for Tamar and Leviathan gas, with a share of 67% of their total exports.

FIG.1: Tamar and Leviathan gas exports to Jordan and Egypt since 2017




Source: Author estimates based on data from different sources

## East Med as a gas supplier to the EU

Following the start of the Russia-Ukraine conflict in late February 2022, the East Med emerged as one of the key gas-rich regions that Europe

By Wael Abdel Moati,
gas/hydrogen expert,
Organisation of Arab Petroleum
Exporting Countries (OAPEC)

considered in its endeavour to shift away from Russian gas, thanks to its proximity and good ties with its countries, in particular Egypt and Israel. Consequently, the EU energy commissioner Kadri Simson and Egyptian and Israeli energy ministers signed an MOU in June 2022, by which Israel would send more gas to Egypt, before liquifying it and exporting it to Europe via Egypt's LNG plants. The trilateral agreement would last for nine years and would take immediate effect upon signing. Although the agreement didn't specify any quantities, the regional players took it as a signal to act quickly to maximise the benefit of their natural gas resources and the infrastructure in place.

The revival of Egyptian LNG exports in 2022 to their highest level in a decade indicated the opening of a new chapter in the regional integration between East Med countries, marking the region's role as a hub for gas trading and supplier to Europe. Egypt's LNG exports increased by 3.6% in 2022 from 2021, reaching 6.8mt, with more than two-thirds of its LNG exports heading to Europe. Egypt was on track to boost further LNG exports upon receiving more gas from the Leviathan gas field in 2023, and hence increasing LNG deliveries to gas-hungry Europe.

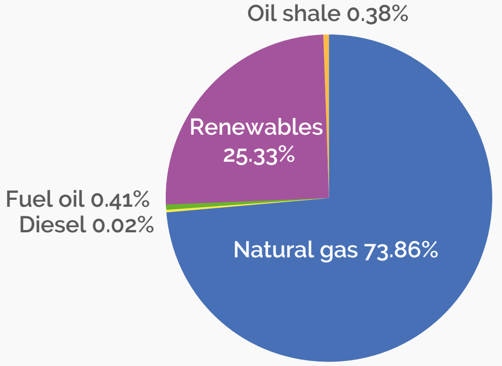
Jordan has nearly eliminated its need to import LNG

## Gas supply risks

However, the scene in the East Med has changed dramatically upon the escalating conflict in Gaza since early October 2023. This situation will impact East Med gas supply and could potentially lead to a future of uncertainty around gas development plans and energy integration among the regional players. Prior to the conflict, Israel was planning to proceed with gas development plans in its offshore fields to increase gas flows to Egypt and build its first floating LNG export platform. The first immediate impact of the conflict was when oil major Chevron shut in production at the Tamar gas field on the instructions of the Israeli Ministry of Energy and Infrastructure. The ministry took the decision as a security measure and put a plan in place to compensate for the lost Tamar gas in the local energy mix by using alternative fuels such as coal or fuel oil in power stations and other economic sectors. It is worth mentioning that Tamar is the main gas supply source for the local market as it alone meets more than two-thirds of the market's needs. The closure of Tamar also impacted gas flows to regional consumers in Jordan and Egypt, where 15% of Tamar production is dedicated for exports.

Shutting in Tamar was not the only impact of the war in Gaza as Israel halted gas exports from Leviathan, the largest gas producing field offshore Israel, to Egypt following the Egyptian cabinet's announcement. As a consequence, deliveries to Egypt dropped to zero for some days, from its normal figure of 22.4mcm/d, before partially increasing to 10mcm/d. Before Leviathan's gas cut, Egypt was already struggling to meet its local needs amid growing demand and lower gas output. For the first nine months of 2023, Egypt LNG exports dropped to 2.9mt, from 4.9mt over the same period in 2022. With intermittent gas supplies from Tamar and Leviathan, there would not be enough gas for liquefaction and exports. Indeed, the outlook for Egypt's local gas supply as well as LNG exports in 2024 will be affected by future gas deliveries from Tamar and Leviathan.

FIG.2: Power generation mix in Jordan 2022




Source: NEPCO 2023

## Supply risk in Jordan

Jordan has two binding agreements to import gas from Tamar and Leviathan. The impact of potential gas cuts from Israel is even more severe for Jordan as the kingdom is highly dependent on Israeli gas to meet its local market needs, particularly in the power sector. The Jordanian National Power Company (NEPCO) started importing gas from Leviathan in 2020 and its annual imports increased gradually from 1.9bcm in 2020 to 2.7bcm in 2022. The imported gas from Israel as well as small gas volumes from the local Richa gas field are used to generate over 72% of the electricity production in Jordan, while the remaining share is generated by renewable energy sources, diesel, fuel oil and oil shale, as shown in *Fig.2*.

Halting gas exports from Tamar and Leviathan would severely impact the Jordanian power sector, which has to choose one of two bitter options: either importing more diesel/fuel oil quantities or importing spot LNG at a high cost using the chartered FSRU in Aqaba. Over the past few years, Jordan has nearly eliminated its need to import LNG and completely turned its dependence on Israeli gas. In 2022, Jordan imported only one LNG cargo, interestingly from Egypt, while it has imported two further LNG cargoes since the beginning of 2023. In 2024, Jordan may have to import more LNG cargoes depending on future gas deliveries from Tamar and Leviathan. This will cause a further increase in the state's energy bill.

If the current conflict in Gaza is prolonged, it will lead to a future of uncertainty around gas development plans offshore Israel. Furthermore, escalation could threaten the energy security in the region and energy integration among East Med countries. Jordan, for instance, could face gas supply risks as it is highly dependent on Israeli gas in the power sector. While for Egypt, the outlook for gas supply in 2024 will be impacted by future deliveries from the East Med gas fields offshore Israel that account for roughly 10% of Egyptian gas supply.

Europe is not so far removed from the regional implications of this conflict because East Med gas, in the form of LNG from Egypt, was among its alternatives to shift away from Russian gas. With intermittent or no gas flows from Tamar and Leviathan for export to Egypt, lower gas quantities will be available for liquefaction and export from Egypt's LNG facilities to Europe. ■

# The energy transition

# The energy trilemma: Addressing sustainability, security and affordability

Key trends identified as drivers of the trilemma

Nine of the ten hottest years on record have occurred in the last decade. In the face of such an unequivocal and worrying trend, governments worldwide must balance competing energy goals. These are embodied in the energy trilemma, a concept that illustrates the enormity of the task at hand facing the nations as the world grapples with rising temperatures and their impact. From industrialised economies aiming to reduce greenhouse gas (GHG) emission footprints while balancing geopolitical challenges and energy security, to developing economies combatting poverty while also pursuing climate goals, the energy trilemma creates varying and specific challenges for each country.

The overall push-and-pull is succinctly summarised in *Fig.1*, which draws on Verisk Maplecroft's global risk indices.

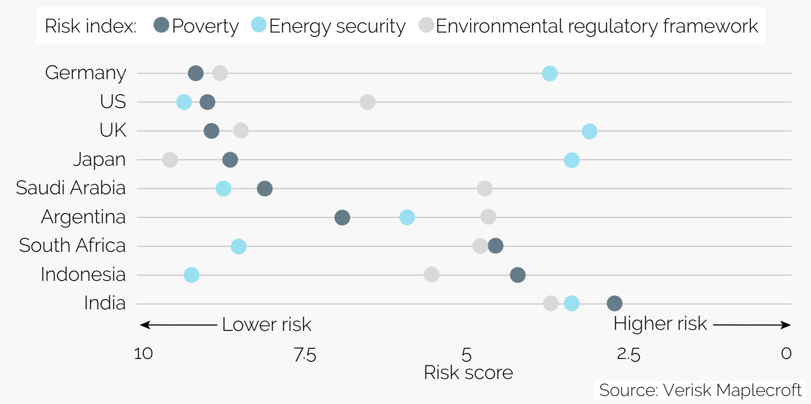
The interplay between these issues is complex and hard to navigate, but four clear trends are emerging.

**1: Affordability and security will determine approaches to energy transition**

While industrialised economies can afford to pursue higher-cost decarbonisation efforts, for developing economies affordability drives energy mix choices. Wind and solar costs have fallen and are poised to continue to fall significantly, but there remains a premium compared to power generated by fossil fuels in much of the developing world.

Some coal-dependent economies are pursuing natural gas as an alternative, though this too may prove too costly for lower-income countries, extending reliance on coal in many cases. Natural gas is also an important energy source for developing and developed countries in Europe, though securing of natural gas supplies is impacted by geopolitical factors such as Russia's war in Ukraine (illustrating the pull of the security side of the energy trilemma). Such security considerations may push countries to develop more renewable energy as a form of energy independence. Of course, countries are also considering nuclear energy, geothermal and other zero-emissions sources as options, but affordability remains a challenge in the near term.

FIG.1: Energy trilemma: competing drives for affordability, security and sustainability shown for a selection of G20 countries




**2: More countries to tackle emissions from existing assets with CCUS and carbon markets**

Energy transition policies of developing countries, particularly those reliant on fossil fuels, will increasingly focus on incorporating technologies such as CCUS and carbon market mechanisms to achieve net-zero targets. The basic energy security of these countries still relies heavily on fossil fuels because renewable is not yet a ready option due to financing, technical and other challenges.

CCUS has become an important tool to tackle emissions from existing fossil fuel assets. Similarly, carbon markets serve as a platform for companies to offset unavoidable emissions by purchasing carbon credits from projects that remove or

By Dr Kaho Yu, head of energy and resources research, and Laura Schwartz, senior analyst, Verisk Maplecroft

reduce GHG emissions. An effective carbon market creates a financial mechanism to incentivise companies to use market-based solutions to meet their climate pledges. Some countries such as Singapore even incorporate the carbon market with carbon tax rebates to further incentivise companies to meet their climate pledges.

**3: More grid investment is needed to enable an effective renewables power market**

Enhanced investment in smart grid and regional transmission infrastructure is essential to maximise the deployment and effectiveness of the renewable power market, particularly in bridging the supply-demand divide in the Asia-Pacific region. This approach is vital for connecting distant renewable sources with consumption centres, with some connections crossing national borders.

Despite the swift expansion of renewable capacity and falling costs in recent years, the lack of sufficient grid integration impedes the practical utilisation of these energy resources. This shortfall helps explain why renewables have not yet become a ready alternative to fossil fuels in times of energy crises. Strategic policies and investments aimed at bolstering smart grid and power grid infrastructure are critical to achieving energy security while also facilitating a shift toward cleaner energy alternatives.

**4: Developing countries will team up to demand more financial assistance to achieve climate goals**

We must recognise that in most countries energy transition will be expensive and politically challenging. For developing countries, without financial support, a full-fledged energy transition is impractical and is increasingly seen as unjust, as most countries currently seeking to climb up the income status ladder are not responsible for the historical GHG emissions causing climate change today.

Developing countries will continue to argue for climate financing support from developed countries—many of which are notably not meeting their own emissions reduction targets. While country-specific examples such as the Just Energy Transition Partnerships in South Africa, Indonesia and Vietnam show promise, significantly more is needed, and developing countries will continue to band together to call for energy transition finance, loss and damage support and broader reform of international financial institutions to better address global public goods.

> Affordability remains a challenge in the near term

As 2023 marks another year of extreme temperatures, the energy trilemma remains at the forefront of the global agenda. Addressing the intersecting challenges of sustainability, security and affordability requires a multifaceted approach. The path forward involves rationalising energy mixes, leveraging industrial innovations such as CCUS, navigating carbon market mechanisms to offset emissions and investing in grid infrastructure to unlock the full potential of renewables. Critical to this journey is the support for developing countries, ensuring equitable access to the means and finance for a just transition. ■

# Long-term innovation and cost declines will overcome short-term volatility

Supply chains face short-term challenges but not fundamental barriers as clean energy technologies scale

"High prices are the solution to high prices". 2023 has borne out this adage when it comes to key energy transition materials. Just over a year ago, analysts and commentators were in shock as prices for lithium carbonate (the high-purity chemical version of lithium used to make electric vehicle batteries) soared like a helium balloon, rising sevenfold throughout 2022 to over $80,000/t. Come November 2023, prices have fallen by 75% from their peak, returning to something resembling normality. Prices for nickel and cobalt, too, have come tumbling down in the last year.

Such short-term volatility is a feature, not a bug, of clean energy supply chains as they scale up. Over months, or even years, prices oscillate wildly, companies go under and panicked headlines are written. Yet, once we get a better vantage point, over three, five, ten years and beyond, long-term trends and cost declines take hold of clean energy technologies.

We have seen something similar already with the polysilicon price cycles of the late 2000s and the post-covid experience of 2021–22. A supply shortage emerges—due to surging demand, a pandemic or an unexpected outage at a key factory (or all three, as happened with polysilicon production in 2020–22)—prices skyrocket, and analysts and investors grimace. Then prices and markets reassert themselves and do what they do best.

Higher prices incentivise increased production—sometimes far too much, as too many players rush back in. Supply booms and prices come tumbling back down. It is no coincidence that, according to BloombergNEF, solar modules saw their lowest-ever prices in August 2023, well below the trend expected from long-term cost declines.

So, price volatility should be baked in for anyone looking at clean energy manufacturing and supply chains as the energy transition unfolds. But what does this mean going forward?

The Energy Transitions Commission estimates that the shift to a clean energy system will need 6.5bt of materials to build all of the wind turbines, solar panels, batteries, power grids and more in coming decades. Wind and solar installed capacity will need to grow three- and five-fold, respectively, by 2030. We expect to see up to 300m electric cars on the road by then.

Achieving this transition and scaling up the clean energy technology supply chains and manufacturing will not be simple. Some challenges have emerged in the past few years, from lack of supply of materials or complex components, to worries around the environmental and social impacts of supply, or the ever-present threat of trade tensions and geopolitics on free-flowing and fair trade.

Still, just as certainly as prices go up and down, so the engineers and companies behind clean energy technologies find ways to innovate through and around these challenges. In the last few years we have seen a drastic shift towards cobalt-lite or even cobalt-free electric vehicle batteries, driven by a mixture of high cobalt prices and concerns around the social impacts of the material's supply in the Democratic Republic of the Congo. We could see a similar rapid shift away from nickel in coming years. Likewise, grid operators are making their systems smarter: requiring fewer high-power transformers, kilometres of cabling or kilogrammes of copper in their wires—in some cases even swapping it out entirely for aluminium.

> Human ingenuity drives long-term technology and innovation trends

However, not everyone will have plain sailing. Complex or highly customised technologies that have intricate and extended supply chains could experience slower long-term price declines. For example, some nuclear projects in developed countries over the last decade have struggled with costs and timescales, and Europe and the US are facing concerns around offshore wind prices. In the case of copper mining, a new mine might take 15-20 years to go from discovery to production so a short-term price spike won't be enough on its own to expand supply quickly over the short term. In such cases, help is needed, whether through strategic


By Dr Leonardo Buizza,
lead supply chains & materials analyst,
Energy Transitions Commission

government support, smarter company procurement or innovative solutions to expand mined or recycled supply of key materials.

Still, in many cases human ingenuity drives long-term technology and innovation trends: it is why we have seen solar and battery costs plummet year after year in the last decade, and why we should have confidence in such trends continuing. For these clean technologies that are simple and can be mass-manufactured, exponential deployment in the next decade and beyond is near inevitable.

So, where challenges do lie, what needs to happen to keep energy transition materials and supply chains on track for the coming years?

Expanding supply, from the mine site to manufacturing plant, must be the priority. Governments and companies should be carrying out strategic assessments and setting clear targets for demand over the medium to long term, and plan and invest in the required supply. Some reasonable amount of de-risking and diversification, to help mitigate risks from the current over-concentration of supply, is also warranted—but not at any cost. And, although clean energy technologies are always cleaner than their fossil fuel-based alternatives, addressing environmental and social impacts throughout supply chains will help give communities confidence in a transition to a better, more responsible clean energy system.

Finally, as we have seen and will continue to see, investing in research and innovation to help push the boundaries of materials and technology efficiency, recycling and circularity can help make all of these challenges easier to confront.

The transition is already happening. Let's make it go even faster. ■

# The need for ambition and more action on the energy transition in tougher times

Progress in decarbonisation but significant challenges lie ahead

2023 saw the imperative to address climate change become more urgent. More frequent and extreme weather events around the world dominated the news. The world's September 2023 temperatures were the warmest on record, shocking climate scientists. Yet, even as climate change accelerates, significant progress is being made in decarbonisation.

Global spend in clean energy technology reached $1.7t in 2023, up more than 40% on 2019 and outpacing investment in fossil fuels by a factor of nearly two *(see Fig.1)*. The G20 countries committed to tripling renewables output by 2030. Electric vehicles are proliferating, accounting for 18% of all new car sales globally in 2023 versus less than 5% in 2020. Political consensus across party divides in many regions will advance policy and funding to support clean energy technologies and the energy transition. The US's Inflation Reduction Act is a case in point, where it has attracted over $200b of clean energy technology investment, tripling in total since 2018.

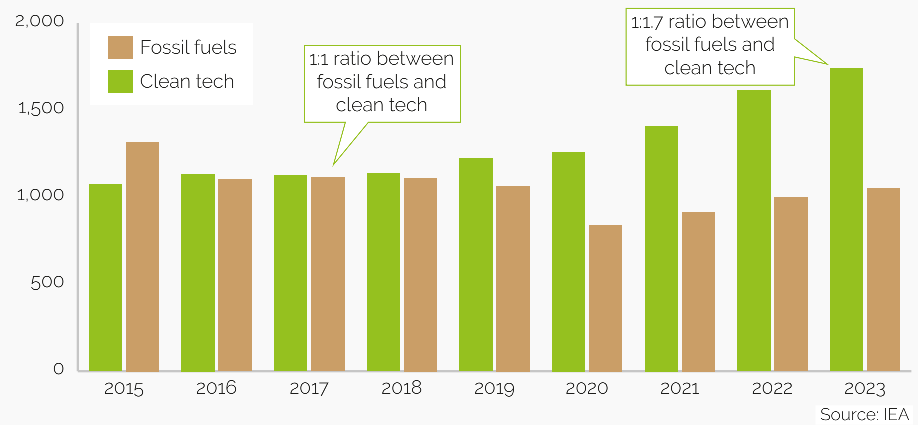
Despite this progress, significant challenges lie ahead. The business environment is getting tougher to navigate, with cost inflation, high interest rates and supply chain challenges. This will have an adverse impact on the pipeline of low-carbon projects, where upfront capital expenditure is high. Some of this distress is already manifesting itself in the offshore wind sector, which is seen as the backbone of future power generation.

There is also an emerging narrative around the affordability of the transition. The UK government's decision to defer the internal combustion engine ban to 2035, as well as soften ambitions in decarbonising heat, reflect the political sensitivity of asking consumers to incur more costs during a cost-of-living crisis. We may see other governments reacting in a similar way.

As for decarbonisation across the business sector, there is a sense that the easier initiatives are already being tackled and the harder challenges remain. Addressing supply chain emissions is a good example of more complex decarbonising efforts. Other companies in heavy industry also acknowledge that carbon abatement technology is simply not available to help them meet their interim emissions targets.

So, looking ahead to 2024, what should governments and business do?

FIG.1: Global energy investment in clean tech and fossil fuels 2015–23 ($b)



By Jennifer Obertino, senior vice president,
global energy practice leader, AECOM
Adrian Del Maestro, vice president,
global energy advisory, AECOM

Governments need to sustain their decarbonisation ambitions. Rowing back on commitments will send the wrong message to consumers and business. Inevitably it will get harder for governments to juggle affordability with political support from voters, especially when tackling more complex decarbonisation themes such as heating. Softening net-zero policies now to avoid short-term costs will only increase long-term costs to consumers and ultimately the planet. Governments will also need to ensure regulatory continuity and avoid diluting their net-zero pledges and maintain commitments to develop technology. Businesses need long-term stability to deploy significant capital and the regulatory environment must facilitate that spend by instilling confidence that there is predictability.

> **Governments need to ensure regulatory continuity and avoid diluting their net-zero pledges**

As for businesses, they will need to be more selective and focused with regards to decarbonisation initiatives. Companies with a large pipeline of low-carbon projects will need to focus on those projects where the economics and returns make most sense. For example, hydrogen production projects that have integrated value chain plays, such as providing a feedstock for "green steel", will help de-risk projects and improve project feasibility.

Delivering these projects will also require an enhanced focus on the workforce capable of doing so and the communities that will be impacted by these initiatives. A people-centric energy transition is imperative. It is worth noting that the bottleneck in capabilities to deliver the transition is not widely recognised and will need to be a focal point going forward.

With regards to decarbonising supply chains, this will remain a major focus for business. Achieving this will require close collaboration between companies and their respective supply chains. Businesses will need to figure out where to target their efforts for the best possible returns. For example, where there are strong regulatory forces already shaping aspects of the supply chain, such as transportation decarbonisation, this may require less attention. Instead, companies may be better advised to focus efforts on elements of the supply chain where there is currently no major regulatory driver to decarbonise. Think for example of a train operator looking at heat decarbonisation opportunities in its network, or a food producer sourcing raw materials from agricultural suppliers, where sustainability measures are not yet embedded in the industry.

More broadly, partnerships are and will be critical to accelerating the energy transition. These may be public-private, such as the US government using tax credits and loans to attract private capital, as illustrated by the Inflation Reduction Act. More saliently, consider how since COP26, business is taking a leadership role alongside governments to accelerate decarbonisation. Then there are the partnerships evolving between companies that will be essential to decarbonise their respective supply chains.

With cost inflation and high interest rates likely to shape 2024 and make it a challenging operating environment, net zero must remain the North Star of government and industry alike. There is a real sense in many regions that the partnership between the public and private sector is accelerating the transformation of our energy system. That momentum must be maintained. ■

For more on how to navigate the energy transition with practical, profitable, predictable and people-centric strategies to achieve net zero, please see AECOM's latest global research report *Lost in transition?* available at: https://infrastructure.aecom.com/

# Latin America will continue to be a place of innovation

The region is well placed to lead on the energy transition, embracing oil and gas as a transition fuel

As the world begins to grapple with the energy transition and what it will mean to move away from fossil fuels, there is one place that is already ahead of the game. Latin America has historically been an area that has relied on many resources aside from hydrocarbons for things such as power generation and mobility.

Due to its enormous size, relatively low and concentrated population and geographic features, the region has been a net exporter of hydrocarbons, and raw commodities in general, from the start. There is no doubt that fossil fuels will still be important for Latin America, particularly natural gas as a flex fuel of sorts, but no region has a longer history with, or is better prepared to embrace, renewable energy.

The definition of the term "energy transition" is still evolving and from a semantics standpoint is probably somewhat misleading. Humans have been transitioning through different sources of energy since the advent of fire and will always continue to do so. What is generally meant by the term is a pivot away from using hydrocarbons.

But much like humans still use wood to produce energy even today, hydrocarbons will, in some form or fashion, likely remain in use for the foreseeable future. What is forecasted is that their importance, both in terms of oil and natural gas, will lessen as the supply of wind, solar and other forms of renewable resources is able to erode the demand for hydrocarbons.

It's important to note that this displacement of oil and natural gas isn't something that will occur overnight or in a vacuum. As it stands today, the world needs around 100m b/d of crude oil to sustain the modern version of life. Fast forward to 2050 and the forecast is still robust with regards to demand for oil—the mean case lands at 66m b/d.

So, while peak demand for oil may occur in this decade, the demand tail will be long, and even longer for natural gas. In the period of 2020-22 it was observed that of all the investment in energy globally, 55% went to fossil fuel projects. Until renewable energy projects can become more competitive from an investment standpoint, without having to depend on government subsidisation, hydrocarbons will continue to receive a similar percentage of capital outlay going forward.

With all of that said, when thinking about oil and gas as a transition fuel in Latin America, it's much more about being a producer and exporter of this resource than it is about being an end user. As mentioned previously, Latin America is a net exporter of oil and is well placed to continue to be so in the medium to long term. In fact, Latin America may have an edge on other oil producing regions going into the 2030s and 2040s because of the unique characteristics of its production.

In the offshore regions of both Brazil and Guyana, oil can be produced at an extremely low breakeven cost. The pre-salt projects and Liza 1 and 2 are below $30/bl in most cases. That same production also has an exceptionally low emissions intensity per barrel produced, in the range of 8-9kg of carbon dioxide per barrel. To put it into context, that's about half the global average of 18kg of carbon dioxide per barrel. These are both the necessary and sufficient conditions to be a part of the future global supply mix.

> Latin America may have an edge on other oil producing regions

From an end-user perspective oil and gas are maybe less important as a transition fuel in Latin America. Power generation has traditionally been dominated by hydro in a region that has been blessed with an incredible fluvial system. The foresight to install generators into massive public works projects dates back decades and created several "green" grids throughout the region. Latin America also benefits from having a low population density, with around 600m people who live between the Rio Bravo in Mexico and the Straits of Magellan in Argentina.

That small population is, however, highly urbanised, in fact more so than any other region on earth. This unique fact means that power generation can be dispatched in a more concentrated manner. It also means that mobility can be tackled in more creative and innovative ways.

By Schreiner Parker,
managing director Latin America,
Rystad Energy

The Itaipu Hydroelectric Dam on the Parana River, Brazil

Already in Brazil almost all vehicles can run exclusively on ethanol produced from sugarcane. Mass transit systems are turning to other sources of fuel as well. The city of Bogota has rolled out hydrogen-powered buses as part of its efforts to decarbonise. Although mass adoption of electric vehicles may seem a distant prospect, the region has many other routes to a non-fossil fuel future.

Latin America will continue to be a place of innovation, mostly by way of necessity, when it comes to the energy transition. All of the building blocks for a green future can be found there. Lithium deposits are plentiful and there is no lack of wind or sun across the vast expanses of both South and Central America including Mexico.

Green hydrogen and biofuels production are already gaining strong footholds across several different countries and these sectors can only be expected to grow. While it's true that diesel and gasoline still play a big role in agriculture, which is arguably the lifeblood of the region, the trend is already moving in the right direction. Hydrocarbons will have their role to play in Latin America as a transition fuel, but more likely as commodities to be sold abroad rather than consumed domestically. ■

# Changes and trends in the offshore energy sector

Wind among emerging technologies developing offshore

**47GW**

**Total global offshore wind capacity by 2032**

Taking a snapshot of the global offshore energy sector presents a complex picture where oil and gas continues to be an important component of the energy mix, while the contribution from renewable energy sources, predominantly from wind, is becoming more established in certain locations such as the UK. The energy transition is visibly playing out on the UK's continental shelf as the offshore oil and gas industry continues to operate while its well-established supply chain is actively engaged in supporting the installation of new renewable offshore energy capacity.

## Global trends

Globally, oil and gas production rates are declining in mature offshore basins, while additional reserves are being sought in other provinces through exploration and reinvestment. Some areas such as Guyana and Namibia are at the outset of establishing an oil and gas industry with rapid growth, whereas mature basins such as offshore UK are in decline. Norway, the Middle East, Africa and the Asia-Pacific region all remain active with continued oil and gas exploration and production-enhancement activities. Continued investment in the sector is being driven by robust global demand for oil (the IEA estimates 101.9m b/d), which is expected to remain resilient for the foreseeable future.

Meanwhile, there is an emerging new offshore energy sector centred on renewable energy generation through wind, and for now to a lesser extent wave and tidal. This is in addition to potential growth in other decarbonisation solutions that will utilise offshore infrastructure such as CCS and hydrogen (storage and transportation). Offshore wind is set for significant growth, with the Global Wind Energy Council expecting that over 380GW of new offshore wind capacity will be added over the next decade (2023-32), bringing total global offshore wind capacity to 447GW by the end of 2032.

## Utilising an established supply chain

There is a determination and optimism within the oil and gas supply chain about a pivot toward new energy projects. This industrial shift is happening now and is set to continue in-step with declining hydrocarbon demand over the next couple of decades as energy consumption needs are increasingly met by low- and zero-carbon solutions. The oil and gas industry has delivered decades of economic prosperity and energy security and, of critical importance looking forward, it has equipped the UK with a legacy skill base of people experienced in operating offshore energy assets in some of the most hazardous environments. This depth of experience is now supporting the UK as it develops a leading position in offshore wind and clean ocean energy, second only to China in built-out capacity.

The oil and gas supply chain and the skills, capabili-

By John Heiton,
CEO,
OEG


Offshore wind turbine installation on the UKCS

ties and technologies are actively being leveraged and are an integral part of the success of new low-carbon energy projects. In offshore wind, the UK has the second largest capacity globally, with almost 14GW coming from complex projects such as Hornsea, Dogger Bank and Seagreen. In addition to the UK securing a leading position in the rollout of offshore wind projects, it has also been able to create a supply chain that is largely British, which has not been the case with onshore wind.

## UK businesses taking the lead

Aberdeen-headquartered OEG, the global leader in the provision of specialised container units to the oil and gas industry, is an example of an established supplier proactively responding to the energy transition with new ambitious growth strategies to expand into the growing offshore energy sector. OEG is growing a renewables business providing high-value services to offshore wind farm developments and other offshore energy projects in the UK and internationally. OEG's robust revenues are underpinned by stable cashflow from oil and gas activities and growing levels of activity in the offshore wind sector, coupled by a bullish long-term outlook for the offshore renewables sector in the UK and globally.

The UK oil and gas industry, which today consists of 220,000 jobs and in 2022 generated, according to the latest OEUK economic report, around £30b ($36b) in gross value added (c1.5% of the UK economy), is a strategic asset for the UK that must be utilised for the energy transition. To ensure a successful and timely transition, a robust and capable supply chain is essential to support the meaningful growth of new offshore energy technologies into the 2030s, 2040s and beyond. That means finding a balance in supporting the oil and gas industry and its suppliers so that they can power the energy transition.

## Challenges

Policymakers need to ensure that the oil and gas industry remains sufficiently buoyant to continue supporting the emerging offshore wind and other new clean-energy sectors. This means retaining the physical assets that are both required for a functioning oil and gas industry and employed in the development of windfarms such as lift barges and support vessels. It also means retaining the skilled workforce and businesses that want to support and drive the transition.

## 2024 and beyond

The existential threat of climate change will continue to drive significant changes across the global energy market, which means continued growth in the contribution of renewable energy into the energy mix around the world. An agile, collaborative and innovative approach from all stakeholders will be necessary given the need to develop new supply chains, technologies and business models to successfully bridge to a net-zero future, coupled with a need for long-term strategic planning to reduce investment risk. ■

# An equitable and just energy transition should balance sustainability with social cost

## Many African nations rely on oil and gas revenues, but a just transition will need a careful balance

The global energy transition is underway, with policymakers seeking to decarbonise the energy mix to secure a sustainable future for the planet. This, of course, is in everyone's interest and it's a common goal that humanity should rightly focus on. However, the pace and shape of this energy transition is markedly different between the developed and developing world. There are diverse views on how an equitable and just global transition can be delivered to meet climate goals, while allowing developing nations to grow their economies to the benefit of their populations, as well as ensuring there is sufficient energy supply to meet growing global demand.

Despite trillions of dollars' worth of investment into renewables and associated infrastructure in recent years, mostly in developed countries, according to the IEA oil and gas comprise around 60% of the global energy mix. It is expected that, despite the contribution from renewables increasing, there will continue to be a significant demand for hydrocarbons, with consultancy Wood Mackenzie predicting an oil demand increase from current levels of c.103m b/d to c.108m b/d by 2030. This continued demand for hydrocarbons contrasts with decades of underinvestment in the oil and gas industry, which is likely to result in a significant supply gap of c.22m b/d in the coming years.

### The need for an equitable and just transition

The need to tackle climate change and expedite a responsible transition are beyond debate. However, there is a growing argument that less developed nations, especially those whose economies are so reliant on hydrocarbon revenues, should be able to benefit from the exploitation of their resources in the same way that Western developed nations have. Not only is this critical for these developing economies, it is also needed to fund their transition to a cleaner energy mix. Africa has become the centre of this debate given its slower socioeconomic development, its vast untapped discovered resources and its relatively low contribution to global emissions relative to its population.

Many African nations with mature oil and gas industries rely heavily on the revenue they generate from hydrocarbons to fund social development. As such, the suggestion that African countries should cease to benefit from that vital income is rightly met with an argument that there is a need for a more equitable approach, whereby the importance of tackling climate change is balanced with the "social cost" of the energy transition. Those championing a just transition for Africa argue that the drivers for an accelerated transition cannot proceed at any social cost and we need to find the right balance between climate and social impact.

### African energy transition

Within the African energy transition there is another industrial transition underway within the oil and gas industry. This transition involves mature oil and gas assets changing hands from IOCs to smaller independents capable of breathing fresh life into these assets through a focused approach. This is a similar transition to that which happened in mature basins like the North Sea in the 1990s, resulting in greater operating efficiency and performance of aged assets. This transition in Africa is gathering pace, although the industry backdrop is far less favourable than it was in the North Sea, with envi-

By Paul McDade,
CEO, Afentra plc

ronmental headwinds making access to capital more challenging, especially for smaller independent players on which this fine balance relies.

### Creating an attractive investment climate

African governments are responding accordingly as they seek to encourage foreign investment and welcome ambitious independents by improving fiscal terms and extending licences to create stable operating environments. Credibility is key, and divesting companies recognise that these divestments are not just about "price", it is equally about making sure these assets will be managed responsibly with a focus on optimising production and reducing environmental impacts through employing the latest techniques and technologies from other regions.

Afentra plc was established in 2021 with the purpose of supporting a responsible energy transition in Africa. The company has since entered Angola through the acquisition of assets from Sonangol, the national oil company, and Azule, the JV between BP and Eni. Angola's GDP has relied heavily on oil and gas revenues for decades, with its industry being dominated by IOCs. Afentra, as an early mover, has witnessed firsthand how the Angolan government has welcomed the company's entry and recognised the important role it will be able to play, bringing its technical knowledge and experience gained through previous industry transitions. Further demonstrating Angola's commitment to creating a stable investment climate, Afentra's core producing asset, Block 3/05, has recently been granted a licence extension out to 2040 with improved fiscal terms. This extension, coming well in advance of the licence lapsing, critically reduces investment risk, supporting better access to capital to fund the industry transition.

> Many African nations with mature oil and gas industries rely heavily on the revenue they generate from hydrocarbons to fund social development

### Different lenses

This collaborative and forward-looking approach between government and industry is in stark contrast to the approach adopted in the UK's North Sea, where windfall taxes and negative political sentiment are reducing investment. This creates incentive for operators to look at more welcoming jurisdictions, even as the UK faces energy security and affordability challenges. It highlights the different lens through which developed nations and developing nations view the energy transition.

A successful global energy transition is essential. However, if it is to be achieved then all global stakeholders must adopt a pragmatic and agile approach. Developed nations have built their economies and wealth on the back of hydrocarbon revenues. As developed nations progress the roll-out of new energy solutions such as renewables, developing nations should be allowed to continue to exploit their hydrocarbon resources efficiently while utilising the latest techniques and technologies. This will allow their economies to grow and societies to develop so that they are ready to tackle the transition at a pace that is fair. ■

# Oman: Taking a leading role in the global energy transition

Oman offers an attractive destination for investment in the energy transition

The Omani energy sector, which has long been synonymous with oil and gas production, is set to take on a leading role in addressing the energy transition, with positive domestic, regional and international implications. According to the IEA, Oman has set out an ambitious strategy to derive 30% of electricity from renewable sources and to be producing 1mt of hydrogen by 2030. In following this ambitious strategy, Oman is embarking on a transformative journey given that it continues to rely on oil and gas for around 30% of its GDP. Its goal is to emerge as a leader in the global energy transition, diversifying the country's exports while reducing its own reliance on fossil fuels and lowering its own emissions.

In a global economy shaken by the aftermath of the pandemic and a surge in inflation on the back of Russia's invasion of Ukraine, the energy trilemma looms large for policymakers trying to address rising energy costs, energy security and climate change. Navigating this complicated economic landscape has posed a complex challenge for industry and policymakers around the world. The Omani government has recognised that the country is well positioned to pivot from a reliance on oil and gas to two other plentiful resources in this region: solar energy and wind energy.

## Abundance of clean energy potential

Oman's abundant renewable energy resources provide an exciting opportunity. The intensity of solar radiation is among the highest in the world, with on average 360 days of sunshine per year. This, coupled with vast amounts of available land, offers an excellent opportunity for large-scale solar exploitation. Oman also has significant wind energy potential along its southern coast, upon the coastal highlands facing the Arabian Sea and in the mountains in the north of Salalah. In these locations, the average wind speeds consistently exceed 8 metres per second, similar to the wind conditions at successful established European projects. Oman has the potential to position itself as an attractive destination for foreign direct investment into the renewables market.

The Sultanate of Oman proudly stands as a nation known for its political stability and promising economic growth prospects. Similar to other Gulf region countries, Oman has undergone a comprehensive overhaul of its commercial laws, regulations and policies, with the goal of establishing a more open and flexible environment to foster economic growth and attract foreign investment.

## Targets and drivers

Currently, oil and gas constitute roughly 60% of Oman's export revenues, while domestic natural gas powers over 95% of the nation's electricity production.

To facilitate a successful transition, in what is clearly a fossil fuel dominated economy, Oman has set ambitious goals for its renewable energy sector. In 2022, in line with the Paris Agreement, Oman set a key target of reaching net-zero emissions by 2050, increasing the renewables share of the energy mix to 20% by 2030 and 39% by 2040.

Hydrogen is set to play a vital role in meeting these targets. Aiming to become a major player in the global hydrogen market, Oman plans to produce more than 1mt of renewable hydrogen annually by 2030, with targets escalating to 3.75mt by 2040 and a staggering 8.5mt by 2050. These long-term objectives would not only meet Oman's domestic energy needs but also surpass the current total hydrogen demand in Europe.

This planned transition will transform Oman's ener-

By Majid Qamardeen,
director, Euphrates Energy

industrial aspirations could put a strain on domestic resources, increasing the importance of utilising renewable energy sources. As well as this, the uncertainty over future fossil fuel export revenues in favour of clean alternative energies adds to the necessity for producer economies like Oman to get ahead of the curve in their transition efforts.

There is already a pipeline of renewable projects under development set to boost electricity generation to meet the decarbonisation targets, such as the Dhofar Wind Project. This will be the first large-scale wind farm in the GCC, comprising 50MW. The wind farm's aim is to reduce domestic reliance on gas for electricity generation, which can be redirected towards more valuable industrial uses and preserve natural gas resources. In solar, the Ibri-2 Independent Power Producer will be Oman's largest utility-scale solar PV independent power project and will generate 500MW of renewable power.

gy mix and is a testament to the country's commitment to sustainable energy development and its determination to be a prominent figure in the global renewable energy space.

In addition to the need to meet decarbonisation targets and reduce greenhouse gas emissions, the strategy also recognises the positive economic solutions that the transition will offer. Although natural gas has long been a key part of Oman's economic growth, resources are slowly dwindling. So, while in the short and medium term gas reserves are expected to be enough to fulfil current levels of consumption, in the long term growing population and

## Independents supporting strategy

Euphrates Energy, a recently established independent, is leveraging the favourable operating environment to capitalise on opportunities arising from prevailing industry trends while actively supporting Oman's energy objectives. Its strategic approach involves the acquisition of interests in mature oil and gas assets, contributing to energy security, all the while channelling its resources and expertise towards the financing of solar power projects in Oman. This dual-focused strategy underscores Euphrates Energy's alignment with the global and Omani transition goal to develop cleaner and more sustainable energy sources. As an early mover in this space, Euphrates Energy mirrors Oman's ambition to establish itself as a pivotal provider of energy security solutions in the short term and for the future. ■

# Focused financing: Will it unlock capital for the transition?

In a transformative shift, the consumer's role in meeting net-zero challenges and reducing reliance on fossil fuels is crucial

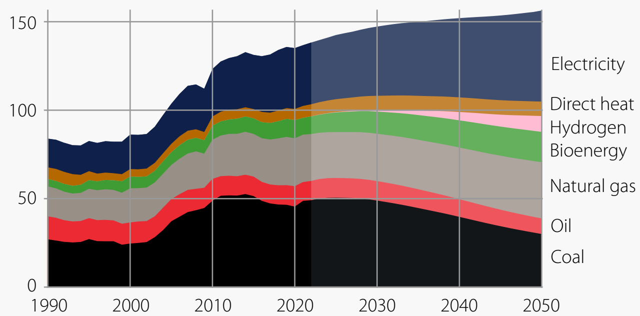
High-intensity energy users, largely within the manufacturing sector, are steadily decarbonising their operations, transitioning towards sustainable and proven renewable energy technologies such as solar and wind, and employing battery energy storage systems (BESS).

In DNV's latest annual *Energy Transition Outlook (ETO)*, we found that manufacturing is currently the largest energy consumer at 138EJ (30%) of final energy demand in 2022. Despite substantial energy efficiency gains and increased recycling and reuse of materials and goods, the sector's energy demand will keep growing. It will increase an average of 0.5% every year, reaching 156EJ by 2050. The success of these decarbonisation endeavours relies largely on robust financial backing.

But is there enough capital to finance this transition? The financial sector's role in supporting the transition is pivotal, with investors having to redirect more capital to facilitate this shift. By adopting a consumer-centric approach, this process could be accelerated to foster a more energy-efficient future and propel us towards net-zero targets.

The manufacturing and heavy industry sectors—notably steel, cement and chemical production—are often considered the most challenging to decarbonise. All are high-intensity energy users, heavily reliant on fossil fuels for their energy-intensive processes. Traditional renewable energy sources, such as wind and solar, are often unable to meet energy demands when deployed in the traditional sense, necessitating the need for innovative solutions. The use of BESS is one such promising development as it offers the potential to store surplus renewable energy for use during periods of high demand or low supply.

FIG.1: Manufacturing energy demand by carrier (EJ/yr)




Source: IEA

The exact energy demands of these industries vary significantly based on sector and region. However, it is universally recognised that their energy consumption is enormous.

Grid constraints pose a notable challenge to the decarbonisation efforts of these industries, which often operate in locations with limited grid infrastructure, hindering the integration of renewable energy systems.

Furthermore, the fluctuating nature of wind and solar energy can strain existing grid networks, creating the potential for instability between supply and demand. Overcoming these constraints will require substantial investment in grid reinforcement and expansion, as well as the development of flexible demand-response strategies and advanced energy-storage solutions.

But is the money there? We believe the answer is yes, with caveats.

## The pathway for the financial sector

Investors are increasingly recognising the potential returns from investing in renewable energy and decarbonisation initiatives, and this diversion away from other asset classes is leading to a growing pool of capital for such investments. However, we have also found that the allocation of this cash must be carefully managed to ensure it is directed towards the most effective and efficient solutions. As well as providing the necessary funding, the financial sector must also work closely with industry to


By Nicholas Cole, director, financial markets, energy systems, DNV

ensure that investments are well-targeted and yield the greatest impact in terms of decarbonisation.

**In 2020, nearly 70% of global energy investments were in renewables**

Estimating the exact quantum of global capital available to support the energy transition can be challenging due to the dynamic nature of financial markets. According to the IEA, nearly \$1t/yr will be needed to achieve net-zero emissions by 2050 but current investment levels in clean energy and energy efficiency stand at around \$300b/yr.

In recent years, green bonds and sustainable finance have emerged as significant sources of capital for the energy transition. However, these tools are not mainstream or readily available and often have strict requirements that create barriers to those looking to access capital. More readily available and far larger pools of capital exist, seeking a home in well-structured assets.

Institutional capital and commercial banks are more accessible. They also have an increasing responsibility to their shareholders and partners to direct their capital away from fossil fuel investments and towards more socially and environmentally responsible sectors. These financial resources, if properly leveraged, can substantially support the energy transition. Nonetheless, we are aware of the necessity of strategic capital management to ensure that these funds are effectively allocated towards the most impactful decarbonisation initiatives.

Investors are progressively moving away from fossil fuel industries and redirecting their capital towards renewable energy. This evolution is driven by the increasing urgency of climate change, as well as the improving economics of green energy. Solar, wind and other renewable technologies have advanced significantly, reducing costs and improving performance, making them a viable and economically competitive alternative. This shift is evidenced by the growing proportion of renewable energy in global investment portfolios.

In 2020, nearly 70% of global energy investments were in renewables, compared to just over 50% a decade earlier. This trend is expected to continue, with our *ETO* forecasting a considerable increase in the share of renewables in the global energy mix. However, for the energy transition to be successful, it is essential that the financial sector continues to scale up its support for renewables, ensuring that sufficient capital is available to finance the decarbonisation of high-intensity energy industries such as manufacturing.

While the voluntary redirection of investments from fossil fuels to renewable energy is a positive trend, it is imperative that mechanisms designed to discourage investment in fossil fuels are introduced.

Policymakers play a critical role in this aspect. By enforcing stricter environmental regulations, implementing carbon pricing and ending subsidies for fossil fuel industries, governments can make investments in these sectors less attractive. ■

Nicholas Cole has been investing, managing and structuring financing for infrastructure and renewable energy projects for over 20 years in roles he has held at commercial banks, asset management firms and boutique investment platforms. Combined with his passion for the energy transition, Nick brings his experience to support DNV's financial sector clients across energy systems business and provides financial market insight and sector knowledge.

# Can carbon credits help you decarbonise faster?

VCM to help scale climate finance

REDD: reducing emissions from deforestation and forest degradation.

REDD+ refers further to the role of conservation, sustainable management of forests and enhancement of forest carbon stocks in developing countries.

"Do you not think I could be accused of greenwashing?" asked the oil major, with regards to my suggestion that they invest today in nature-based removals (tree planting, for the rest of us). Followed by: "What do oil companies know about planting trees?" A surprising amount.

Launching a carbon project requires origination skills, operating in high-risk countries, financing it, securing and negotiating long-term offtake agreements, liaising with multiple, sometimes thousands, of stakeholders and doing so in a changing regional, domestic and global regulatory and political environment. Starting to sound familiar? How about if I tell you the Democratic Republic of Congo, Cameroon, Papua New Guinea, Cote D'Ivoire, Kazakhstan, Brazil, Tanzania, Mozambique… are all host countries seeking international finance and partners to support the export of carbon to developed countries.

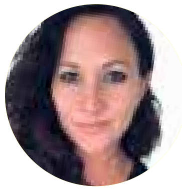
Energy companies also have the balance sheets required, risk appetite, hard-to-abate emissions to compensate and abilities to warehouse or hedge price exposure. However, for many we speak to, investing in renewables, decarbonisation technology and carbon capture on facilities is proving a more comfortable first foray into carbon credits than investing in nature.

Investment in nature-based solutions—such as afforestation, improved forestry management, mangrove restoration and preserving our remaining rainforests—might not feel relevant but protecting and growing biodiversity is critical to climate stability. Prices of REDD+ projects in particular have been hit in 2023 by hyperbolic media articles homing in on the worst projects. And by worst we don't mean spewing trillions of barrels of oil into the sea, we mean overestimating the baseline assumptions of deforestation rates should the project have not happened. The way to think of the early carbon projects though is the way you think of the first Nokia: it's incomparable to an iPhone but at the time it was revolutionary.

Carbon markets are critical for not just scaling climate finance, but sending the price signals we need to decarbonise faster. In a 2023 report by Ecosystem Marketplace, the following conclusions were reached: "Companies engaging in the voluntary carbon market are reducing their own emissions more quickly than their peers. They are 1.8 times more likely to be decarbonising year-over-year; 1.3 times more likely to have supplier engagement strategies; and the median voluntary credit buyer is investing 3 times more in emission reduction efforts within their value chain."

Voluntary carbon buyers were also found to be more likely than non-buyers to have more ambitious sci-

By Melissa Lindsay,
founder and CEO,
Emsurge and Emstream

ence-based targets to address climate change. They were also 1.2 times more likely to have board oversight of their climate transition plans.

The takeaway being that quality is important, but action is more so. Nonetheless, a huge amount of work is underway to ensure the next generation of credits are maximising climate impact. Key examples include the Integrity Council for the Voluntary Carbon Market, which is launching the Core Carbon Principles in 2024 to provide a quality assurance label for buyers. Digital measurement, reporting and verification is being adopted by project developers and carbon standards. There has also been an emergence of rating agencies to centralise the task of stringent due diligence on projects and simplify the outputs. These initiatives have brought some inertia and led demand to feel lacklustre throughout the year, but the impact on growth should be short term and pave the way for a more effective and robust carbon market in the future.

As well as a shift towards higher quality, future buyers are searching for removals, both nature-based and engineered. If procuring in size, you have the option to invest in projects at an equity level or through a pre-payment structure, where your investment amount is drawn down on as credits are issued and transferred to you. You will often find project developers open to option structures and upside-sharing models with the communities the projects serve once the initial investment has been recovered. It's worth noting, a good deal in carbon is one where everyone benefits; if the deal is too in the favour of the offtaker, the resale value of the credits is reduced.

When buying credits, our Emsurge platform sets out to make it easy and maps out all the considerations that should factor into your decision and price paid—whether spot or forward, the carbon standard, the additional attributes (things like the sustainable development goals), the programme eligibility, the fungibility of the credit, the vintage, the project specification, the quality, the size and the location. For assistance, please reach out to our team of specialists at Emstream. ■

# Quality concerns and geopolitics to dominate carbon markets

Carbon pricing is inevitable, but the mechanism is still to be determined

High integrity rather than rapid growth will be the focus for carbon markets in 2024 after months of turbulence. The sector is also likely to become more politically charged with the proliferation of carbon pricing mechanisms potentially impacting global trade.

The voluntary carbon market (VCM) has been gripped by a credibility crisis as the efficacy of many projects and carbon credits have come under fire by the media and academia. This has led to a steep fall in liquidity and confidence in the VCM, with many buyers reducing their activity.

A host of quality and market initiatives aimed at boosting transparency and trust in carbon offsets are set to be embedded in the market, creating a new framework of standards to support the credibility of existing and future projects.

Meanwhile, the compliance carbon market has proven more resilient despite the geopolitical instability and recent economic turmoil. More and more, governments are looking towards carbon pricing to drive their climate policies and also earn much-needed revenues.

Putting a price on carbon is now an essential part of energy transition, giving a financial incentive to a country, company or any entity to reduce its emissions. But like many a new market, the road to expansion has been riddled with potholes.

## VCM trials and tribulations

The $2b VCM has had its annus horribilis as the growing and intense scrutiny has caused many of its key players to reflect on its behaviour.

Verra, which is the world's largest carbon registry, making it the largest issuer of carbon credits, has had to overhaul its methodology in a bid to improve the process and quality of its forest carbon offsets.

Similarly, South Pole, the largest trader of carbon credits, has recently ended its involvement in the Kariba REDD+ project in Zimbabwe, amid reports alleging the emissions avoided were vastly overestimated. This controversy led to the resignation of South Pole's celebrated CEO Renat Heuberger, as the Switzerland-headquartered company looks to move forward.

A series of articles and studies in 2023 questioning the integrity of the VCM has seen the prices of carbon offsets crash, particularly those belonging to the nature-based categories.

The Platts Nature-Based Avoidance 2023 credit price was assessed at $4.50/mt of $CO_2$ on 9 November, according to information provider S&P Global Commodity Insights data, the lowest since the assessment began in August 2021. Prices in January were as high as $11.60/mt of $CO_2$.

## Higher-quality offsets

The industry is to some extent banking on initiatives led by the Integrity Council for Voluntary Carbon Markets (ICVCM) and the Voluntary Carbon Markets Integrity Initiative to help define higher-quality offsets.

The steps do not represent a silver bullet for the sector, however, with participants seeing any upswing in liquidity or price as unlikely in the short term.

The situation is not helped by a small delay, with carbon offsets eligible under the Core Carbon Principles (CCP) standards from the ICVCM not expected to be available until early 2024.

The CCP includes ten codes that are broadly based under three groups: governance, emissions impact and sustainable development.

"Given timelines, we do not expect prices to experience significant changes until early 2024," analysts at S&P Global said in a recent note. "If the market is able to respond quickly to these developments, 2024 could be a pivotal year for the VCM, with more demand, lower supply in the short term and consequently higher prices."

The compliance markets, which include cap-and-trade schemes such as the EU's emissions trading system (EU ETS), have had more to cheer.

Government revenues from carbon pricing mechanisms such as carbon taxes and emission trading schemes have been estimated to be as high as $100b in 2023, according to industry estimates.

These markets, however, have a long way to go to

By Eklavya Gupte,
editorial lead, EMEA energy news,
S&P Global Commodity Insights

# Putting a price on carbon is now an essential part of energy transition

achieve majority coverage. The share of global emissions covered by carbon taxes and emissions trading systems (ETSs) was around 23% in 2022, according to the World Bank, with as many as 73 carbon taxes or ETSs in operation globally.

Meanwhile the launch of the EU's new carbon border tax, the Carbon Border Adjustment Mechanism (CBAM), is likely to have a material impact on international trade in the coming decades.

The key objective of CBAM, whose transitional phase started on 1 October 2023, is to accelerate the energy transition and to push peers to decarbonise and adopt carbon prices. It essentially levies a tax on imports of selected carbon intensive materials and products (including aluminium, cement, electricity, fertilisers, hydrogen, iron and steel) into the EU, removing the gap between the EU ETS price and the export country of origin's carbon price.

Coralie Laurencin, a senior director at S&P Global, said the main objective of the tax was "to level the playing field". "Europe is serious about net zero and its energy intensive industry is under growing pressure to decarbonise in the carbon market. The CBAM should be seen in that context," Laurencin said.

This move has heightened political and trade tensions, especially between the developed and developing world.

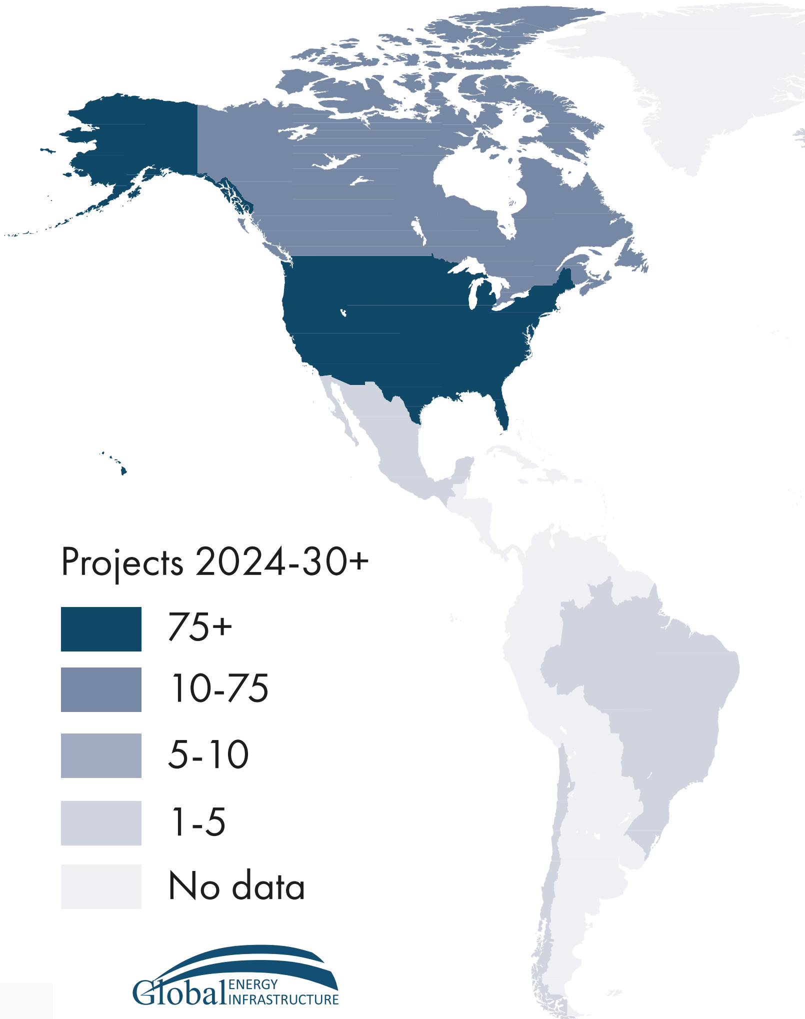
China and India have been leading the pushback against the EU's CBAM, having proposed multilateral talks through the route of the World Trade Organization, looking to garner support from impacted countries.

The main purpose of the tax is to reduce the risk of carbon leakage—EU industries relocating abroad—and encourage importer nations to introduce their own carbon markets and, in doing so, limit CBAM impacts on their traded goods.

Only time will tell if this move will work, but many in the industry believe that the adoption of such carbon pricing globally is inevitable. ■

# CCS projects outlook in 2024

## An ambitious pipeline of CCS projects through 2030 shows optimism for the sector




CCS is one of the most promising technologies for mitigating climate change, as it has the potential to reduce $CO_2$ emissions from a wide range of sources. The Global Energy Infrastructure (GEI) global CCS database shows a vast number of projects being proposed and planned for 2024 and beyond.

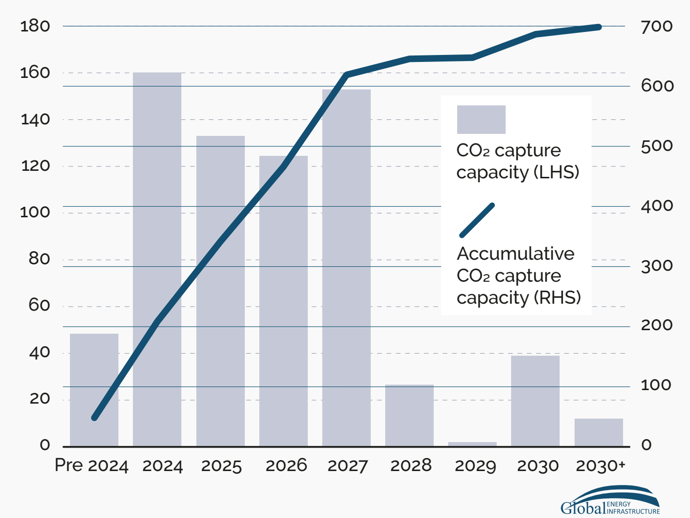
In 2024 an estimated 160mt of new $CO_2$ capture capacity is expected to be developed, with similar levels year to year through to 2027. The GEI data shows a slowdown from 2028, but by 2030 accumulated $CO_2$ capture capacity will exceed 680mt—that's an increase of 1,319% from 2023 levels (assuming that all projects become operational by 2030).

### Emerging technologies in the CCS sector in 2024

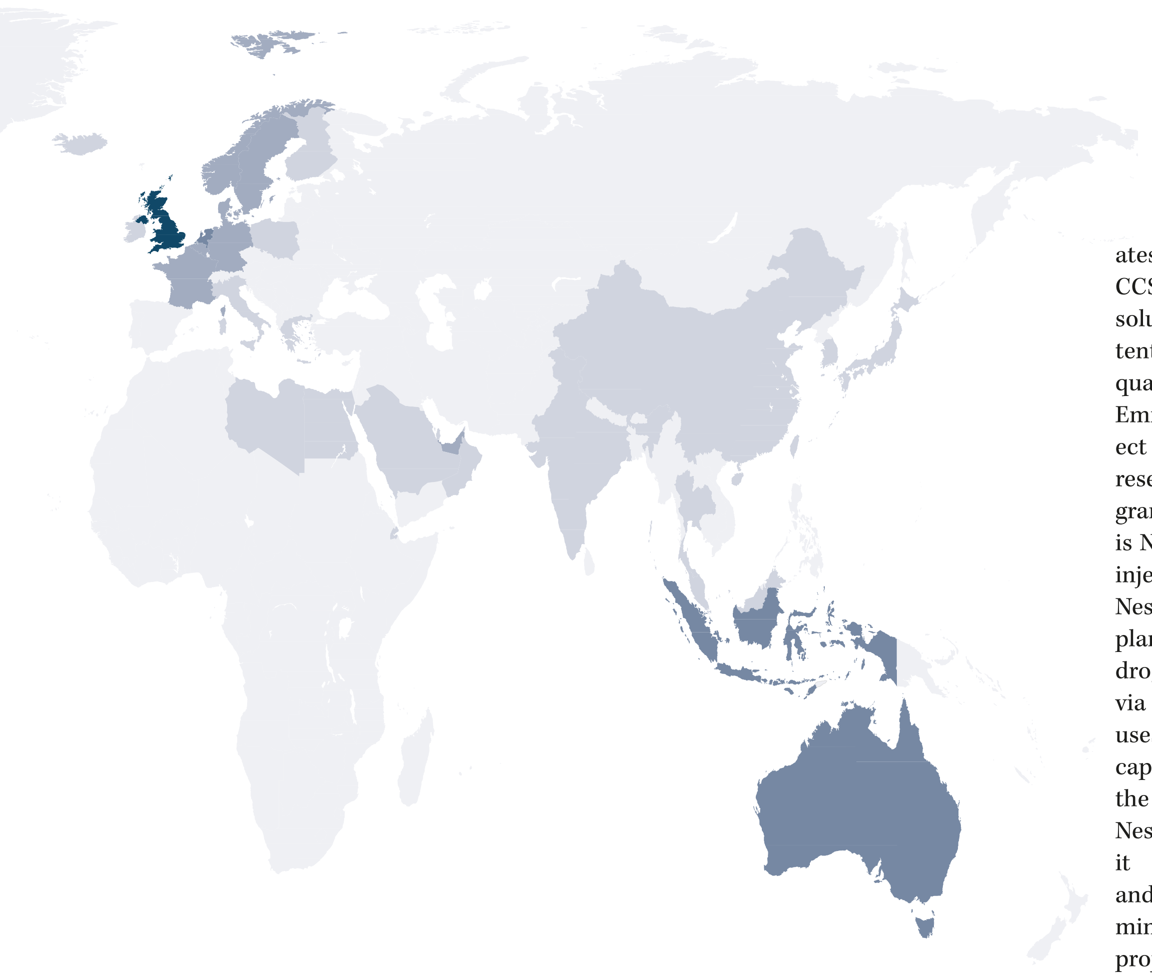
We can see several trends emerging across the CCS sector, with new technologies gaining momentum—as tracked in the GEI database. These three in particular are attracting significant interest:

Direct air capture (DAC) captures $CO_2$ directly from the atmosphere. DAC is still in its early stages of development, but it has the potential to play an important role in reducing global $CO_2$ emissions in the future. One of the most advanced is the Permian DAC 1 project. Occidental (Oxy) and its subsidiary 1PointFive are constructing their first large-scale DAC plant in Ector County, Texas, near Oxy's portfolio of acreage and infrastructure, which is conducive to safe and secure storage of carbon dioxide. This project intends to capture and store 500,000t/yr. In October 2023, 1PointFive also launched a jointly funded preliminary engineering study in partnership with Emirati state energy company Adnoc for what will be the first megaton-scale DAC facility outside the US, using the same technology as the Ector County project—so already this technology is showing its ability to scale up quickly.

FIG.1: CCS capture capacity by year (mt/yr)



By Peregrine Bush,
senior director,
Global Energy Infrastructure



## Future CCS engagement by number of projects

Carbon capture and utilisation (CCU) is a technology that captures $CO_2$ and uses it to produce products such as fuels, chemicals and building materials. CCU is another relatively new technology, but it has the potential to reduce global $CO_2$ emissions and create new economic opportunities. UK $CO_2$ capture specialist Carbon Clean has joined the FlagshipONE project seeking to develop a green methanol bunker production facility. Carbon Clean will capture 70,000t of $CO_2$ per year from the facility. The captured $CO_2$ will be combined with hydrogen to produce 50,000t of eMethanol per year. eMethanol will be used for the shipping industry. The facility is due to come online in 2024.

Carbon capture and mineralisation (CCM) captures $CO_2$ and reacts it with minerals to form stable carbonates. CCM is an alternative to CCS and is a permanent storage solution for $CO_2$, with the potential to be used to store large quantities of $CO_2$. A Geothermal Emission Control (GECO) project under the EU Horizon 2020 research and innovation programme of particular interest is Nesjavellir. This is a pilot $CO_2$ injection project at the Icelandic Nesjavellir geothermal power plant. Capture of $CO_2$ and hydrogen sulphide is carried out via a scrubbing unit that only uses water and electricity. The captured $CO_2$ is injected into the basaltic subsurface at the Nesjavellir injection site where it reacts with the bedrock and forms stable carbonate minerals. Following the pilot project, GECO is planning to operate a full-scale CCS plant at the site by 2030.

These emerging technologies have the potential to transform the CCS sector in the coming years and the outlook for this sector is positive. The technology is becoming more mature and cost-effective, and there is increasing government and industry support for CCS projects across the globe. CCS is expected to play an increasingly important role alongside other technologies in the energy transition mix so that global $CO_2$ emissions are reduced in the coming years, and will contribute significantly to achieving the ambitious net-zero goals required by global governments. ■

Global Energy Infrastructure provides exclusive global project data across LNG, hydrogen, CCS, oil & gas pipelines and refining & petrochemicals. For more, visit www.globalenergyinfrastructure.com

# Geothermal energy sector set for growth

Geothermal energy provides reliable baseload power and heat supply

Geothermal energy is experiencing a renewed resurgence of interest and investment as governments at a national and local level work to decarbonise their energy mix away from an overreliance on hydrocarbons. The geothermal industry last saw significant investment following the oil supply shocks of the 1970s but has until now largely remained confined to regions with particularly high geothermal gradients, marked by high volcanic activity such as countries around the Pacific.

With the energy transition a key focus for policymakers, geothermal has returned as an attractive clean and renewable energy source. A key advantage of geothermal over other renewable solutions lies in its reliability, as it can produce a constant supply of energy 24/7, in contrast to the intermittent nature of wind and solar. The capability to provide a reliable baseload of power and heat supply ensures geothermal will be a critical element of future energy systems.

For power generation, as well as increased drilling in conventional hydrothermal reservoirs there is an active programme of exploratory drilling to access so-called enhanced geothermal systems (EGS) through deep drilling with hydraulic fracturing to enhance the resource potential. This has the potential to open up new regions to geothermal. Geothermal can also be an attractive energy source for domestic and industrial heating, which represents a significant source of hard to abate $CO_2$ emissions (in the UK heating accounts for about 37% of total UK carbon emissions (Climate Change Committee 2022)).

## Key growth drivers

The recent energy crisis has brought energy security and energy affordability into sharp focus for governments and consumers across the world. Government incentives have played a pivotal role in fast tracking the move to clean energy production. In the US, the Inflation Reduction Act (IRA), in addition to curbing inflation, has provided significant stimulus through tax credits to promote investment in clean energy. In turn, the EU has outlined its Green Deal Industrial Plan, which similarly aims to incentivise the adoption of clean energy. As the energy transition has gathered pace there has been a notable trend of oil and gas suppliers looking to reposition themselves and diversify toward supporting more sustainable energy sources. In geothermal they have seen an opportunity to leverage their experience and skills in terms of sub-surface formation evaluation, drilling and more efficient use of the technology necessary for cost-effective injection and production of fluids to surface.

Even before the IRA, the US was the global leader in geothermal energy, with California and Nevada, both endowed with high geothermal gradients, producing around 6% and 10% respectively of their electricity from geothermal. Other global "hotspots" are to be found in Iceland, Kenya, Turkey and some Asia-Pacific countries including the Philippines, Indonesia and New Zealand. These countries are ideally located close to geological zones of relatively shallow high heat flow. In Europe, development of geothermal district heating networks is making great strides, most notably in countries such as Denmark, the Netherlands, France and Germany. Development of exciting next-generation geothermal extraction technologies strives to attain the possibility of geothermal everywhere.

## Supported by leaders in oil and gas

Hunting plc, a global leader in the provision of services to the energy sector, with an established history supplying oil country tubular goods (OCTG), downhole perforating


Geothermal power plant

By Sean O'Shea,
director of energy transition and
OCTG business development,
Hunting plc

systems and other specialist equipment to the oil and gas industry, forecasts significant growth in geothermal activity. In fact, Hunting has been supporting geothermal projects for decades, but it has now observed a significant uptick in business activity across the key geothermal market areas in the US, Asia-Pacific and Europe.

The endorsement of major oil and gas operators, such as in the case of Eavor, backed by the likes of BP and OMV, Fervo Energy's collaboration with Devon Energy and Chevron's JV with Baseload Capital, signifies a step-change in the capabilities and ambitions to make geothermal a bigger part of the energy mix.

> Ambitious targets … have bolstered investor confidence in the geothermal energy sector

## Ambitious targets

In 2023 in California, the California Public Utilities Commission approved an ambitious plan that aims to add 2GW of geothermal power plants, representing over double the state's current geothermal power production of c.1,900MW. Ambitious targets set in California and other regions have bolstered investor confidence in the geothermal energy sector.

This growing confidence has inspired companies such as Eavor and Fervo Energy to push the boundaries of traditional geothermal drilling techniques in pursuit of advanced geothermal systems and EGS respectively. In their endeavours, they draw upon techniques and technology derived from the oil and gas industry to achieve their goals.

Temperatures downhole in some of the hottest geothermal wells can reach over 620°F, with fluids often being highly corrosive under these superheated steam conditions. This environment requires exotic corrosion-resistant materials that can withstand these extremely challenging conditions, providing a safe and reliable well infrastructure for production of superheated steam up to surface power plants and reinjection of cooler fluid back down to superhot rock formations, thus resuming the cycle.

## Leveraging oil and gas HPHT

Hunting is leveraging its significant experience in OCTG and metal-to-metal sealing premium connections that maintain well integrity and extend the lifespan of these wells, alongside the use of advanced materials with its experience in subsea technology and precision manufacturing of critical components used in aerospace and space industries.

The oil and gas industry has overcome numerous technical challenges to reach deeper and deeper depths to produce high-pressure, high-temperature (HPHT) hydrocarbons and has pioneered critical directional drilling and completion technologies. These advancements in HPHT and unconventional oil and gas technologies can now help drive geothermal to the next level, increasing the geothermal potential that can be harnessed.

## Significant growth potential

The geothermal sector is primed for growth, with strong market drivers supporting its development as a key component of strategies to achieve net-zero targets. Increased investment and leveraging of the oil and gas industry's experience and technology means new techniques can propagate into areas where previously geothermal was deemed unworkable. This opens up the opportunity to develop a reliable clean energy source and help to reduce carbon emissions from hard to abate energy sectors. ■

# Crunch time for hydrogen

## The nascent low-carbon hydrogen sector needs 2024 to be a breakthrough year if it is to get within striking distance of the production targets set by policymakers

Hydrogen policymakers around the world are pinning their hopes for 2024 on a sharp rise in the number of proposed production projects reaching FID, as 2030 supply targets start to look increasingly challenging.

Only about 4% of announced projects have so far entered construction or hit FID as lenders and investors hold back because of uncertainty around long-term demand, production costs, availability of state subsidies and the lack of a transportation and storage infrastructure.

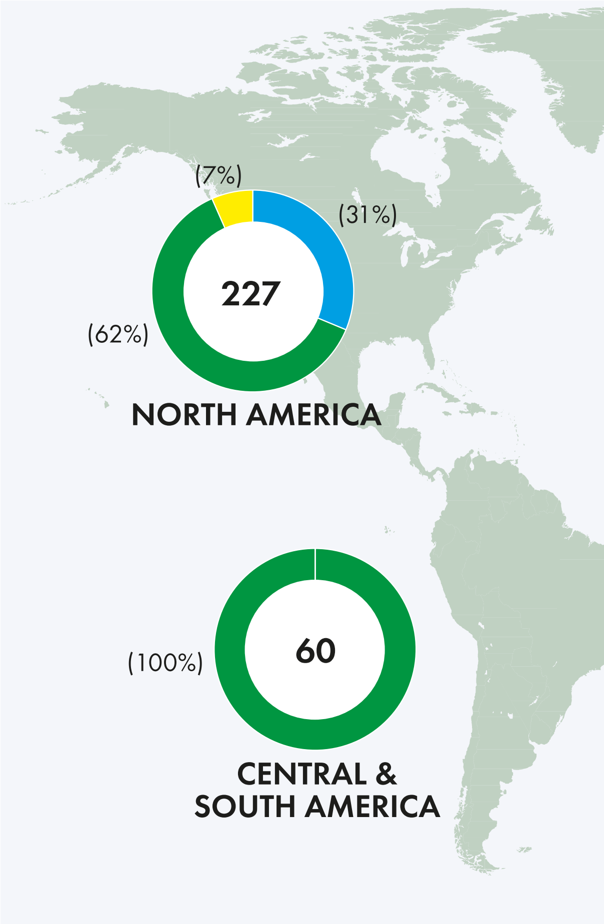
This reluctance to finance projects has left a “funding gap” of about $380b through 2030, according to some estimates.

Much faster progress is needed in 2024 to mature hundreds of proposals into bankable projects and to get the industry on track to meet governments’ targets, which in total call for production of 27–35mt/yr by 2030. The ultimate goal is to grow hydrogen’s share of the global energy mix to 12-15% by 2050 as part of the push for net zero.

Assuming all announced projects are realised, low-carbon production of more than 20mt/yr could be online by 2030, the IEA says.

Some argue the industry is at a tipping point and that the next 12-18 months will see a surge of projects advancing to FID. However, the headwinds that hampered projects in 2023 are expected to spill over into 2024 against a backdrop of fragile economies and geopolitical tensions. Higher costs of capital, elevated energy and capital equipment costs, and supply chain bottlenecks are all expected to weigh on the sector in the months ahead.

**4%**
Share of announced projects reaching FID or construction




### Offtake challenge

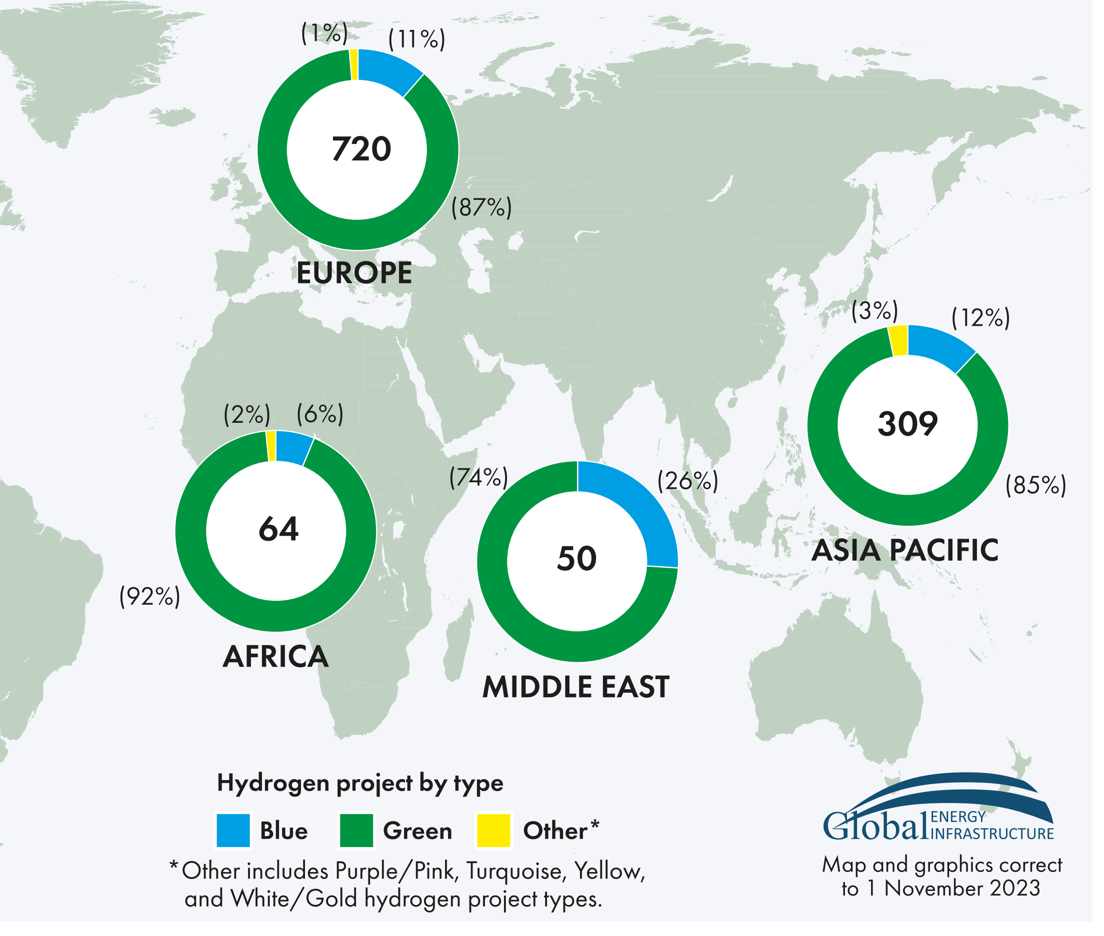
Aside from the immediate cost pressures, one of the sector’s biggest long-term challenges is persuading industrial consumers to sign up to long-term offtake agreements at prices that reflect a “green premium”. Price is not the only concern for consumers—many also worry about the reliability of supply from new production facilities without a long track record of operation.

Projects without the security of a contracted buyer for their output are seen as too risky for many, if not most, lenders. Given the risks involved, projects may be more likely to secure equity finance than debt in the near term.

One very large project has solved the offtake conundrum: the 2.2GW NEOM project, which reached financial close in 2023, will produce both green hydrogen and ammonia in the planned Saudi city of Neom from 2026. The project is backed by a 30-year offtake agreement with one of its three shareholders, US industrial gases company Air Products.

The success of Neom has lifted sentiment across the industry, but it remains to be seen if its unique offtake

By Stuart Penson,
editor,
*Hydrogen Economist*




and financing structure offers a repeatable template for other projects.

Policymakers have woken up to the offtake issue amid growing criticism that their support for the hydrogen sector has been too heavily focused on the supply side. Uptake of low-emission hydrogen remains "very limited", accounting for only 0.6% of total hydrogen demand, the IEA warned in its 2023 review of the sector. It urged governments to clarify their targets for demand and to increase them in line with production targets.

In July, the US Department of Energy (DOE) announced plans for a $1b funding programme aimed at "jumpstarting" the hydrogen economy by stimulating demand, as it acknowledged a lack of offtake deals was hampering the progress of production projects.

## America beckons

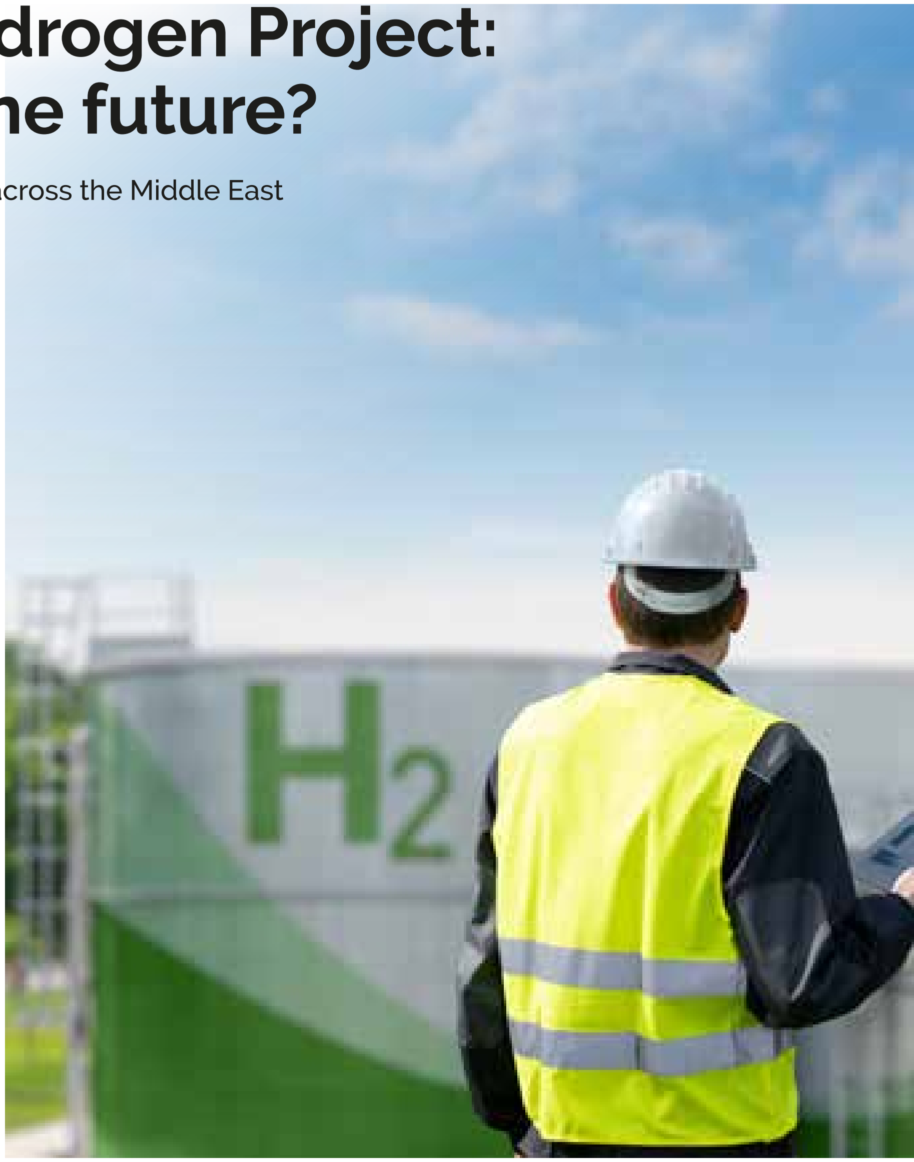
Despite concerns over the demand side, and some policy uncertainty ahead of presidential elections, the US is expected to remain a big draw for hydrogen project developers in 2024. It is expected to build on the momentum gained in 2023 on the back of highly competitive tax credits offered under the Inflation Reduction Act (IRA) and will continue to erode Europe's early lead in terms of project numbers.

Many details around the implementation of the IRA have still to be clarified but developers are impressed by features including direct payments of tax credits and the ten-year duration of support for projects starting construction before 2033. Bloomberg New Energy Finance reckons $137b is expected to flow to eligible projects over the next ten years, mainly via tax credits offered by the IRA.

The Biden administration further demonstrated its commitment to driving forward the hydrogen economy in October when the DOE allocated $7b to support the launch of seven multi-state regional clean hydrogen hubs across the country. The progress of the hubs, which have the combined potential to meet 30% of the government's 2030 target, will be watched closely in 2024. ■

# NEOM Green Hydrogen Project: A blueprint for the future?

Significant potential for green hydrogen across the Middle East




Much has been written about the NEOM Green Hydrogen Project since the landmark project reached financial close earlier in 2023. Amid tighter credit lines, increasing construction costs and challenges to supply chains resulting from the exponential demand for key technologies used in hydrogen projects, such as electrolysers, the media and the market have been particularly alive to the replicability of the project, which is the first mega-scale green hydrogen project to be successfully project financed.

Yet the success of the project is a clear indicator of the trajectory of travel and the market's willingness to invest in a sector that will form the bedrock of the energy transition. And as a first-mover in the sector, the NEOM Green Hydrogen Project faced certain challenges that will be less relevant for other projects that follow suit. One of the key factors behind the project's bankability was the strength of its sponsors, and the exclusive offtake agreement with Air Products was necessary to give lenders comfort on future revenue streams in an otherwise nascent market.

Going forward, it is arguable whether such a high degree of comfort on the offtake will be necessary. Merchant grey hydrogen is commonly used in refineries, and demand curves continue to show some element of a merchant market for clean hydrogen in the future. This suggests a real possibility for future projects to be banked with a proportion of fixed offtakes and outstanding merchant capacity, shifting some of the risk away from developers.

One thing is clear: the Middle East is poised to continue to lead the way in these mega-scale green hydrogen projects. The region is in prime position to take advantage of the growing clamour among developers to get clean hydrogen projects off the ground, and indeed is forecast to be the world's largest producer of clean hydrogen by 2030. Clearly one of the key components of a successful green hydrogen project is access to renewable energy in amounts sufficient to power the electrolysis process, which is significant in a mega-scale hydrogen project.

Renewable energy sources are, by their nature, dynamic and one of the bankability issues that developers have faced globally is ensuring the proposed project site has long-term measurement campaigns behind it showing sufficient wind and/or solar resources to ensure load stability of the electrolysers.

The Middle East is one of the few regions in the world with an abundance of complementary solar and wind energy, thus helping to ensure a steady supply state at both day and night and consequently maximising output (and revenue)

> The Middle East is poised to continue to lead the way


By Alec Johnson, partner,
and Jake Seal, associate,
White & Case

and these resources are a key factor as to why the Middle East has fared so well in projects announced to date, with planned clean hydrogen capacity more than doubling year-on-year since 2022.

There are other geographical factors that make the region attractive to green hydrogen developers. Firstly, many of the countries enjoying the largest capital inflows, such as the Kingdom of Saudi Arabia, are relatively sparsely populated and have ample land for greenfield construction. This is particularly important for projects featuring captive renewable power generation, which is land intensive.

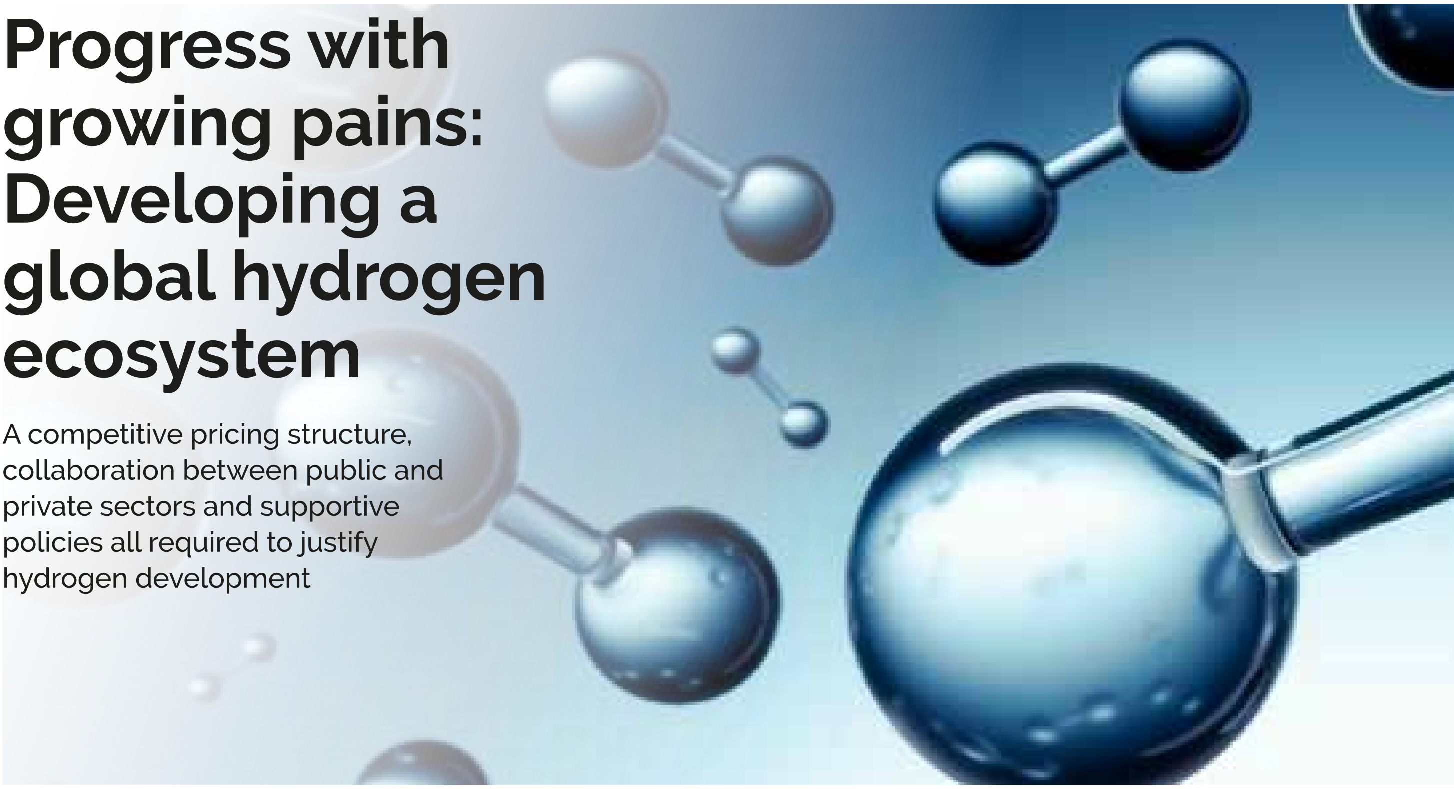
Secondly, a key focus for the coming years will be to ensure that transportation infrastructure keeps pace with the demand curve for green hydrogen given that cost-competitive green hydrogen hubs will often be located far from demand centres. The Gulf, traditionally a key supply hub for oil and gas, is well-placed in its proximity to the Suez Canal and existing shipping lanes to Europe and Asia to both produce clean hydrogen and ship it to key export markets around the world.

Coupled with this, there is a growing political desire among GCC states to diversify their economies away from their traditional dependence on oil and gas revenues and focus on new engines for growth, such as the energy transition. This is particularly notable in the Kingdom, where the Vision 2030 strategy has transformed all aspects of the economy since its launch in 2016. These states are deploying funds strategically through sovereign wealth funds and state-owned development funds, and green hydrogen is likely to be a big beneficiary moving forward.

Against this backdrop, the NEOM Green Hydrogen Project has led the way as the first large-scale green hydrogen project to achieve financial close. It has established itself as the benchmark for other similar projects moving forward, both in the region and globally, for the foreseeable future. Yet the project's enduring legacy will perhaps be as a catalyst in unlocking the flood of investment in the green hydrogen sector that is sure to come.

The sponsors' confidence in the long-term growth of the green hydrogen market was visionary and the project has paved the way for other developers to reach their own final investment decisions. Green hydrogen production at this scale is a landmark moment in the energy transition but no doubt we will see announcements of larger projects in the future. ■

Alec Johnson and Jake Seal of White & Case LLP were part of the multi-disciplinary team advising NEOM Green Hydrogen Company. Any views expressed in this publication are strictly those of the authors and should not be attributed in any way to White & Case LLP.



# Progress with growing pains: Developing a global hydrogen ecosystem

A competitive pricing structure, collaboration between public and private sectors and supportive policies all required to justify hydrogen development

Hydrogen is a key tool in decarbonising the world's energy sector. It's a fuel for the 'hard-to-abate' industrial sectors and for activities that cannot be readily electrified such as aviation, long-haul freight and international shipping.

However, as we're all aware, the cost of using it as an energy source is high—and in Europe, particularly, this is one of the main impediments to large-scale deployment. Since European electricity prices are driven by the cost of gas, the cost of carbon-free hydrogen produced by electrolysis has risen over the past two years. Fossil fuels are relatively cheap compared to hydrogen, but we pay the costs of their carbon emissions and subsequent effects on the planet.

**95mt**
**Global hydrogen use in 2022**

With the right policies, and appetite from the private sector, we can provide the right incentives and infrastructure for hydrogen. Between the public and private sectors, we need to create an industry with a competitive pricing structure for renewable electricity to justify reasonable production costs versus the alternative, and a reasonable business case on the demand side, due to the carbon pricing and the energy pricing that would justify end users to do the switch.

I'm calling for 2024 to be a year of collaboration in our industry, to drive change and make hydrogen an affordable energy source. We need to get out of our silos and have conversations that deliver solutions to the barriers we face to create a global hydrogen ecosystem.

The signs of progress are there: the IEA's 2023 *Hydrogen Review* notes how global hydrogen use reached 95mt in 2022, a nearly 3% increase year-on-year, with strong growth in all major consuming regions except for Europe.

## Why is Europe the outlier?

Governments are starting to create a suitable environment for the hydrogen industry.

The European Commission has utilised the benefits of being a large trade bloc in its hydrogen strategy, which highlights the importance of integrating the EU's entire energy system, overcoming national and sectoral silos, as well as advocating an international harmonisation of standards. Meanwhile, REPowerEU aims to attract clean energy investment to accelerate decarbonisation across multiple sectors.

However, when we dive into the details of these policies, we see that more needs to be done. For example, on one hand, the European Commission is promoting green hydrogen by adopting proper definitions and labelling for green hydrogen derivates such as e-fuels, helping to create certainty for investors and industry and encourage them to build value chains in Europe. On the other hand, the labelling of downstream products produced by green hydrogen, such as green steel, is lacking and isn't adequately supporting customers.

By Professor Dr Emmanouil Kakaras,
executive vice president,
NEXT Energy Business,
Mitsubishi Heavy Industries EMEA

While it's easy to look at legislators and call on them to do more, the energy sector has the power to drive change by continuing to innovate and develop technologies. We have the resources and the knowledge to address the increasing capital and financing costs highlighted in the IEA's 2023 report. Here are some of the partnerships that are revolutionising the hydrogen industry.

## Partnership in action

In Utah, US, the Department of Energy's Loan Programs Office is supporting Mitsubishi Power Americas and Magnum Development in developing the Advanced Clean Energy Storage hub, which will be the world's largest industrial green hydrogen facility and the world's single largest hydrogen storage site. The hub is supporting the Intermountain Power Agency's IPP Renewed project—upgrading to an 840MW hydrogen-capable gas turbine combined cycle power plant, which will be operating on 100% green hydrogen by 2045. It will produce up to 100t/d of green hydrogen from renewable energy using electrolysis. The green hydrogen produced at this facility can then be stored in two massive salt caverns, each capable of storing 150GWh of energy.

In Austria, the hydrogen-based fine-ore reduction (HYFOR) pilot plant developed by Primetals Technologies on the Voestalpine Donawitz site has demonstrated hydrogen's potential to reduce the carbon footprint of the ironmaking process to close to zero. This is thanks to the 100% hydrogen fuel used in the reduction of iron ore. This programme is supported by the Austrian Government via funding from its Climate and Energy Fund.

## Where next?

I appreciate these examples I shared haven't solved the problem of high energy prices in Europe dampening the uptake of hydrogen. But I think the solution is the next frontier for us: what I call 'hydrogen islands'—clusters of wind and solar farms making green hydrogen and shipping it straight to offtakers, via pipelines or ships. These can then set an independent hydrogen price since there is no connection to the electricity system.

I also think the European policy environment is shifting in a promising direction with the Hydrogen Bank, which will lend crucial support to the supply side by offering a subsidy of up to €4.5/kg ($4.8/kg) of clean hydrogen produced. A total of €800m ($852m) will go toward projects in the EU on this route after a first pilot auction in November 2023.

It's an exciting time to be working on hydrogen technology. I'm energised by the conversations we're having and the direction of travel for the decarbonisation of the energy sector. Looking back, the progress we've made is substantial. However, as always, there's more to do. The foundation for the global hydrogen ecosystem is being laid. We must continue to be solutions focused and assess all available options. Let us start with playing to our strengths and working together in 2024. ■

# How digitalisation can help enable the hydrogen economy

The time for us to act on hydrogen technology is now, and if we hope to achieve success, digitalisation will play a critical role in those efforts

It's long been used in industry for everything from refining petroleum to treating metals to processing foods, but in recent years hydrogen has been hailed as a key fuel source that could reduce—or even end—the world's dependence on fossil fuels.

For all its promise, though, the reality is that hydrogen is not a silver bullet when it comes to climate change.

While there is little doubt that hydrogen will play a key role in global decarbonisation efforts, to understand how and why, it's important to first start with what's been called the "long tail" model of climate change solutions.

According to that model, renewable energy sources such as wind, solar, geothermal and even nuclear power, in the form of small modular reactors, can generate enough power to satisfy most of the demand for green energy.

Where hydrogen will be most critical is in reducing or eliminating emissions from some of the hardest-to-abate industries, such as steel production, long-distance transportation and shipping and aviation.

## Decarbonising industry

For an example of how hydrogen can help decarbonise industry, take steel production. Today, steel production generates significant carbon emissions due to the use of coke—typically derived from coal—to both create high heat and to chemically reduce iron ore into raw iron, which is later used to make steel.

By replacing coke with hydrogen, producers can achieve the same result. Using arc furnaces—which can be powered with renewable electricity—hydrogen both provides the heat needed for the process and chemically reduces ore to create iron. The result is steel produced without the need for carbon-based feedstocks or the emissions that come with them.

By Rasha Hasaneen,
chief sustainability officer,
AspenTech

In recent years, hydrogen's potential role in decarbonisation has driven a worldwide explosion in projects, with nearly 1,500—representing more than $2t in investment—proposed in just the last two-and-a-half years, according to Global Energy Infrastructure.

Demand for hydrogen is expected to see similar increases. According to the International Renewable Energy Agency, demand could increase six-fold, to as much as 650mt/yr, by 2050, while other studies suggest the value of the hydrogen market could increase from about $160b today to $640b by 2030 and more than $1.4t in 2050.

During a recent panel discussion on the hydrogen economy at key industry event ADIPEC, the agreement among government and business leaders was clear: scaling the hydrogen economy to meet those demands will require effort and focus on many levels, as well as unprecedented global cooperation.

> Demand for hydrogen could increase six-fold, to as much as 650mt/yr, by 2050

The time for us to act on hydrogen technology is now, and if we hope to achieve success, digitalisation will play a critical role in those efforts.

Modelling and simulation tools, optimisation software, reliability analyses—all will be critical to de-risking hydrogen projects, ensuring that projects that go forward are based on the best possible plans in terms of safety, sustainability and profitability.

## Technology innovations

Technology will also be a critical factor in the economics of hydrogen. By enabling efficient hydrogen production, advanced process controls and optimisation will help reduce the green premium for industry and drive increased adoption of hydrogen-based technologies and processes.

Digitalisation will also allow companies to improve the safety and reliability of hydrogen systems through the use of asset performance management tools and other maintenance solutions. By monitoring for potential leaks in both above- and below-ground hydrogen storage facilities, digital tools can make such systems significantly safer, resulting in better outcomes in general.

Hydrogen, however, does not come without challenges, one of which is related to cost. The electrolysers used to produce green hydrogen depend on extremely rare and precious metals, such as iridium, ruthenium and platinum, making them expensive to build, particularly at scale.

Beyond cost, though, there are significant safety issues associated with hydrogen, which—unlike gasoline—is explosive when ignited. Those risks must be considered at all stages of the hydrogen value chain, from production to storage to transport and distribution.

Beyond helping to decarbonise some of the hardest-to-abate parts of the economy, hydrogen may also be key in helping unlock the success of other technologies, particularly renewable energy generation.

While wind and solar today make up nearly a third of all electricity generation around the world, their intermittent nature represents a challenge. When the sun shines or the wind blows, renewable systems can often generate enough power to push the grid over capacity. Today, the solution is to redirect some of that energy into batteries, which are later discharged back into the grid.

Though effective for short-term power storage, such battery systems aren't particularly efficient when it comes to longer-term storage. If utility companies instead used that excess electricity to power electrolysers, the hydrogen they produce could be stored almost indefinitely, and be used to generate power as needed.

It's clear today that there is no singular solution, no one technology or approach that can solve the challenge of climate change on its own. There are many pathways the world can take as we work to meet sustainability targets, and those will likely be different in different parts of the world and in different industries. But what's also clear is that hydrogen will be an indispensable part of that future, and we must begin working today to help make it a reality. ■

# EU hydrogen and sustainable fuel policies

## Shaping the framework of a key market

The EU has identified in particular renewable (green) hydrogen and other sustainable fuels as key components to achieve its goal of climate neutrality by 2050. In 2020, the European Commission published its EU Hydrogen Strategy with the goal to initiate a market ramp-up of hydrogen, in particular by increasing electrolyser capacities in Europe. These goals were expanded in 2022 by the REPowerEU Plan as a reaction to the war in Ukraine. Under the REPowerEU Plan, domestic (European) production of renewable hydrogen will be expanded to 10mt/yr by 2030 and renewable hydrogen imports to 10mt. Renewable hydrogen and other sustainable fuels will therefore replace natural gas and fossil fuels by creating wholly new supply and value chains.

The last few years have shown the challenges of creating entirely new value chains and promoting a market ramp-up for products as yet unavailable at a universal scale. Thus far, marginal supply, comparably low demand, the absence of infrastructure and technical uncertainties constituted a risk for emerging business models. Another challenge is that the legal framework for the production, transport, usage and import of renewable hydrogen and sustainable fuels is still very dynamic.

However, the European legislator has recently shown considerable diligence with respect to the energy transition and enacted several laws that had previously been subject to a lot of controversy among the stakeholders. Although there is not yet a coherent legal framework for the market of hydrogen and other sustainable fuels, the enacted material rules do provide at least some guidance for stakeholders to become involved in this emerging sector.

The most relevant rules can be summarised as follows: stakeholders in the energy, transport and industrial sector must comply with specific requirements for carbon emissions savings and respective quotas for renewables under the Renewable Energy Directives Legislation (RED II & RED III). Specific rules apply for the use of sustainable fuel for the maritime and the aviation sector (FuelEU Maritime and ReFuelEU Aviation). This concept of setting renewable quotas in specific sectors is accompanied by rules mandating investments in fuelling infrastructure (Alternative Fuels Infrastructure Regulation), regulating the pipeline infrastructure (Draft Hydrogen & Decarbonised Gas market package) and funding programmes, e.g. for the import of hydrogen (the European Hydrogen Bank). Also, the European legislator finally approved the long-awaited requirements that renewable hydrogen has to fulfil to be eligible under the Renewable Energy Directive Legislation (Delegated Act Art. 27 (3) RED II). Nevertheless, there is still no general definition on what qualifies as renewable hydrogen (outside of the Renewable Energy Directives Legislation).

While the REPowerEU Plan also acknowledged that low-carbon and alternative products, such as grey and blue hydrogen, must be permissible at least temporar-

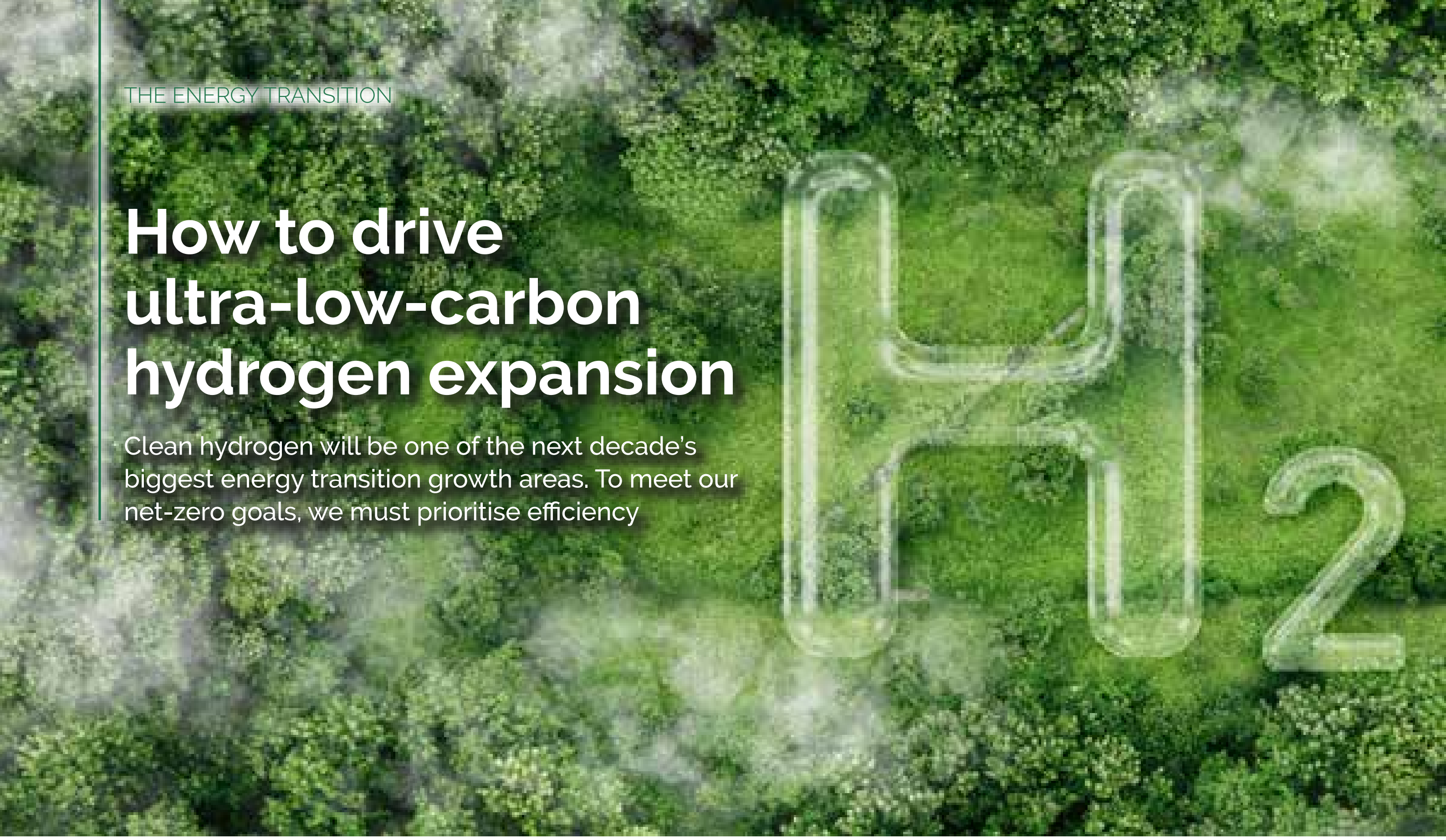
By Dr Petra Kistner, associate,
and Thomas Burmeister, partner,
White & Case

ily during the transitional phase to ensure a continued function of the economy, there is also no respective definition yet.

However, despite all political and legislative efforts, the goal of achieving climate neutrality by 2050 relies heavily on private enterprises' own initiative to decarbonise their products and processes. As the EU is a net importer of energy, the emerging framework also opens up new business opportunities for stakeholders not only within the EU but also in non-EU countries. In fact, the EU seeks to actively encourage international trade in the field of renewable hydrogen and sustainable fuels in order to secure the energy supply in the long term. For this purpose, the EU is working on establishing an auction process based on competitive bidding for the import of hydrogen as it already exists in some member states (e.g. European Hydrogen Bank and H2 Global in Germany). However, potential enterprises from non-EU countries considering to undertake the export of raw materials, sustainable fuels or hydrogen and its derivates to the EU are to be aware that their goods must comply with EU requirements and standards such as the means of transport, namely in the maritime and aviation sector, and the need to be fitted for the mandated target shares of renewable energy in order to enter EU territory. During the transitional phase, the recently established Carbon Border Adjustment Mechanism (CBAM) additionally applies to emissive imports, such as blue and grey hydrogen (CBAM Regulation). The CBAM intends to prevent so-called "carbon leakage" and effectively puts a price tag on emissions embodied in the imported goods. Importers need to register if they want to be permitted to purchase CBAM certificates.

**The EU has the potential to become the biggest and leading market for hydrogen and sustainable fuels**

The EU certainly holds the potential to become the biggest and leading market for hydrogen and sustainable fuels. It is already working on establishing a global network for hydrogen collaboration with partners around the world. It remains to be seen whether the elaborate and strict requirements for emissions savings and renewable energies factually result in the intended energy transition within Europe and whether they will last against the growing international competition for energy markets. Establishing a coherent legal framework for important energy carriers such as hydrogen and other sustainable fuels remains imminently desirable in order to provide a sufficient legal backbone for the markets to properly unfold. Nevertheless, there is still a long way to go to reach net zero. ■



# How to drive ultra-low-carbon hydrogen expansion

Clean hydrogen will be one of the next decade's biggest energy transition growth areas. To meet our net-zero goals, we must prioritise efficiency

If the "road to net zero" consisted of physical paths, renewable generation would be a straight road. Steep, yes. Stony, occasionally. After all, arrays must connect with project finance; onshore wind must win over NIMBYs; battery makers must secure critical minerals to build the requisite energy storage to make solar and wind dispatchable. The route poses challenges—but the road is clear.

If renewables are akin to driving along Highway 46 (supposedly the US's longest, straightest stretch of highway), hydrogen is more like parachuting into a forest with a flashlight and compass. The IEA projects that hydrogen will contribute to roughly 6% of global emissions reductions by 2050, especially those in sectors difficult to electrify directly. But what makes hydrogen such a fascinating (and, occasionally, frustrating) growth area is how much debate exists on how best to scale clean hydrogen effectively.

As my colleagues at 8 Rivers and I have found ourselves in those woods, we've made efficiency our compass. Here's how energy efficiency, cost efficiency and time efficiency indicate how best to scale ultra-low-carbon hydrogen.

## Clear need for clean hydrogen

According to the IEA's net-zero scenario, the world will need more than 150mt of hydrogen annually by 2030, and even more by 2050.

While energy experts debate the fringes of hydrogen's use cases, the general consensus is that hydrogen is the energy transition's leading "green molecule".

Chief among its potential applications is decarbonising existing supply: in 2022, the world used 95mt of hydrogen across industry, agriculture and defence, a 3% increase over 2021. That production is currently 99% unabated, with 2022 outputs stemming c.70% from natural gas and c.30% (mostly in China) from coal.

Additionally, hydrogen offers potential to decarbonise industries that can't feasibly be electrified directly. Here, long-haul transportation and heavy industry are particularly pertinent, with maritime shipping, long-haul trucking and aviation top candidates for decarbonisation in the former category and cement, steel and high-grade heat production top candidates in the latter.

According to the IEA's net-zero scenario, these "novel" applications—only 0.1% of the global hydrogen demand today—account for 30% of global demand by 2030.

To meet this growing clean hydrogen demand and our broader net-zero goals, we'll need to scale ultra-low-carbon hydrogen rapidly—and with efficiency top of mind.

## Efficiency: a map and compass

The US Department of Energy's first-round Hydrogen Hub selections, which were announced in October 2023, varied across use cases, geographies and technologies. As the clean hydrogen industry looks to identify best-practice business strategies, it should set aside industry preconceptions and prioritise technologies that deliver the best carbon intensity, economic viability and speed to commercialisation.


By Steve Milward,
chief operating officer,
8 Rivers

In other words, clean hydrogen buildout should seek to maximise energy, cost and time efficiency.

### 8RH2: Delivering ultra-high-efficiency, ultra-low-carbon hydrogen production

At 8 Rivers, our 8RH2 clean hydrogen technology includes a game-changing innovation: the CO2 Convective Reformer. It achieves ultra-low carbon intensity via an economical, easily scalable process that overcomes the limitations of conventional fossil-fuel based and electric technologies. We believe this system's best-in-class energy, cost and time efficiencies can provide an industry model for the carbon intensity, economic viability and speed to commercialisation the clean hydrogen economy needs.

### Inherent carbon capture competes for best-in-class carbon intensity

By combining the pressurisation of reforming with the gas separation of steam methane reforming, 8RH2 keeps process and flue gasses both separate and pure, uncontaminated by nitrogen, oxygen and other elements in the outside air. This $CO_2$ separation enables carbon capture of above 99%, a rate significantly above the 90% and 95% maximum capture rates of small modular reactors and autothermal reforming, respectively.

8RH2's 99%+ carbon capture competes on carbon intensity with electric hydrogen pathways. Additionally, by decarbonising widely available fuel sources, it enables the electrons generated by renewables to "focus" on where they can deliver their biggest impact: greening the electric grid.

### Economic viability

By capturing carbon inherently, 8RH2 eliminates the need for more expensive, less effective back-end carbon capture systems. Consequently, this innovation lowers carbon intensity while increasing economic viability. Welded ducts, bayonet construction and in-shop fabrication further enhance system efficiency, all together yielding 5-10% cost savings compared to conventional hydrogen production systems.

This ability to compete on cost with conventional, "grey" hydrogen technologies without government subsidies insulates it from potential uncertainties about how clean energy incentives might be executed and whether they might be affected by future elections.

### Speed to commercialisation

8RH2's straightforward adjustment of conventional technologies makes the system easily approachable for industry stakeholders, facilitating a scalability that enables the speedy commercialisation that our energy transition goals require. While electric hydrogen faces challenges with electrolyser bottlenecks, policy uncertainties and renewable access, an approach to ultra-low-carbon hydrogen that focuses on carbon intensity over energy source can (with sufficient attention to eliminating upstream methane leakage) make the most of existing fossil fuel infrastructure to get a clean hydrogen supply chain scaled up and commercialised quickly.

### Efficiency is paramount to speed

To meet our mid-century emissions-reduction goals, the world must scale hydrogen production cleanly, affordably and cost effectively. As the industry accelerates this key energy transition growth area, it must navigate how best to achieve that trifecta. The path is clear: groups looking to scale clean hydrogen must adopt a fuel-agnostic, results-first approach that prioritises carbon intensity, economic viability and speed to commercialisation. ■

# A hydrogen benchmark: developing a price for hydrogen

Transparent pricing will be key to developing the hydrogen economy

The hydrogen market today has annual demand of around 95mt, equivalent to the combined gas demand of Germany, the Netherlands, the UK, Italy and France in 2022. However, there is little-to-no understanding of hydrogen's fair market value in the sense of a transparent, established price reference. Today, the majority of hydrogen is traded under bilateral offtake agreements, meaning its price is known only to the counterparties on each side of the deal.

The lack of a price for hydrogen is important, as it risks hindering the energy transition. In standard commoditisation of energy products, price differentials indicate what balancing actions should be taken. If there is too much of a commodity, the price eases, deterring sellers and incentivising buyers. Similarly, if there is a shortfall, the price should rise, reversing the dynamic.

Without a transparent price, buyers and sellers act with less certainty, and new entrants struggle to consider cost-benefit analysis, prolonging the time to take FID.

Lastly, in a traded market with price transparency, it is possible to take multiple positions to balance and optimise portfolios, such as through a primary offtake agreement while holding positions for overlapping delivery periods.

There are arguably three potential pathways towards the emergence of a market price reference. For the purposes of this article, these shall be listed as the conventional approach, the policy-driven approach and the accelerated approach.

## The conventional approach

History is important in commodity markets when identifying structural consistency. The conventional approach is exemplified through the evolution of European gas hubs, tracking them to becoming liquid, signalling ideal market conditions.

In the 1960s, following discoveries of natural gas in the Netherlands and the British section of the North Sea, market participants faced a challenge. A new source of energy supply meant no historical reference for value, meaning it was hard to sell and harder still to gain financing.

To overcome this, participants used long-term contracts (LTCs) lasting 20–25 years, referenced to oil, a related and more established commodity. Oil was indexed in LTCs as it was a competing fuel, so if the price of oil changed, the drivers of that price change should also impact gas.

Over the first LTCs, infrastructure developed to connect market parties, driving price evolution as parties could buy spot volumes to balance unexpected outages or changes to demand. The spot price could have been based on contract prices but represented a shorter deal.

Starting with the UK, Heren Energy, now known as ICIS, became the first market information source to price the spot activity of the UK gas market in the mid-1990s. These assessments were generated using submissions from market parties that wished to understand fair market value for their spot transactions.

At the same time, gas transmission system operators (TSOs) developed a high level of data transparency, reporting on changes to supply and demand in near-to-real time, meaning participants could review this data with market prices to hand and negotiate trades in response.

As more parties entered European markets, information transparency elevated and trade increased into the 2000s, and to this day there are core gas markets in Europe where liquidity continues to grow.

The conventional approach predicates established supply and demand, as well as infrastructure and information transparency. Although there is demand for some

By Jake Stones,
hydrogen editor,
ICIS

first publicly accessible hydrogen grids may develop over the 2020s, depending on the country, with some regions more towards post-2030. The Netherlands could offer the first public hydrogen grid by 2025 in Rotterdam, before expanding nationally. Germany's revised hydrogen strategy also outlined 1,800km of hydrogen network by 2028.

A hydrogen price could emerge through the conventional approach from 2025. However, storage capacity may prove critical. Further, although a price could be developed, market parties may not accept it at a national level if based on localised information, pushing the development of a price towards the end of the decade, as national hydrogen grids and storage capacity come online.

95mt of hydrogen globally today, in 2022, 0.7% of global hydrogen production came from low-carbon sources, according to the IEA's *Global Hydrogen Review*. This means interactions between current buyers and sellers of hydrogen are not reflective of a future hydrogen market, and therefore initial projects need to be established, likely underpinned by LTCs.

However, sellers may not enter an LTC for all their capacity. As hydrogen is produced from power and gas, producers may spare capacity for when power and gas prices are low, optimising output. Further, as the capacity is spare, volumes can be used for spot deals, meaning some spot activity could emerge from the middle of the 2020s when the first hydrogen projects commence operation.

Infrastructure will be critical for spot trade and the emergence of a price. Today there are very few hydrogen networks in operation, and those operational tend to be privately owned. European TSOs indicate that the

## Policy approach

Although lessons from history are important, they are not binding. The policy approach explores how hydrogen is different, and how this difference is being supported by governments. To bring the hydrogen market to reality, governments are developing policies to financially incentivise its use. It is through production support that the market's development of a price could be drawn out, as subsidy models so far have aimed to enhance transparency.

Chief among these is the European Hydrogen Bank, a scheme brought forward by the European Commission in 2022 that offers hydrogen producers a fixed subsidy per kilo of hydrogen produced over a ten-year period. The subsidy is awarded via competitive auction, with the first held in November 2023.

The European Hydrogen Bank intends to publish initial results of the auction in the first quarter of 2024, including anonymised offtake prices. This means European and global market participants can see raw offtake agreement information at which market parties aim to transact.

It is no small thing to say that such an abundance of information at such an early phase in the market will categorically move Europe closer towards a realisable price reference.

**95mt/yr**

**Global hydrogen demand today**

However, one difficulty is that these prices will be infrequent, so as energy markets move, which can happen by the hour, the information from auctions could quickly be less relevant—at least until later auctions are held.

Nonetheless, the emergence of this information will be highly useful in moving deals forward, likely supporting project negotiation and therefore bringing volumes to the market.

Other policy support mechanisms encourage price transparency, and therefore parties involved in such schemes are likely to be initial drivers of information to develop a price reference. However, like the conventional approach, it will be a case of seeing these projects enter operation over the late 2020s.

## Accelerated approach

The accelerated approach considers what information is available today, ahead of projects coming online.

Price information is present in the market at the negotiation phase between buyer and seller, ahead of taking FID. Under the accelerated approach, rather than await specific trades, a methodology could be developed that captures today's price information based on these negotiations.

By developing a potential price assessment methodology to acknowledge usable bids and offers from the negotiation phase of a project's development, participants could offer the hydrogen market substantial price transparency that could be used to develop an assessment.

Similar to the policy approach, this assessment would hold limitations due to the nascency of the market, but its frequency would track market progress.

The methodology would need to be adaptable, prioritising trades and deals, progressing down to LTC information. So long as a methodology ordered source type appropriately, there could be a lasting price history.

Standards such as project size would need to be developed to ensure the assessment is representative of the market. Or, in the case of sub-size project information submission, this detail would need to be reflected in the assessment's notation for the week.

This is the task of price reporting agencies today, to assess what has worked in the past but to be open to the information of the present. With a robust pricing methodology, an assessment could be published towards the middle of the decade or sooner.

## Which approach for hydrogen?

A hydrogen price is on the horizon provided market participants present information in a transparent manner. However, it is likely that the development of hydrogen may well balance components of all approaches. An assessment could be developed through the accelerated approach, but the strength of this assessment may struggle ahead of characteristics seen in the conventional approach. Policy will be critical to revealing price information and creating an environment where participants feel comfortable with price transparency—likely an outcome from the European Hydrogen Bank.

Nonetheless, fully liquid trade requires certain market characteristics seen in the conventional approach. Projects need to be built, LTCs and subsidies phased out, and additional components such as the use of carbon pricing need to come to play. As fossil fuels become more costly through carbon pricing, hydrogen projects will be able to stand without support, driving further FIDs and adding molecules to the value chain, ready to be transacted. ■

Petroleum Economist

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Carbon Economist

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