PE Outlook 2025

THE GRAND ALLIANCE: AN ALL-ENERGIES APPROACH TO THE WORLD'S GROWING ENERGY NEEDS

A Gulf Energy Information Publication

In association with

WHITE & CASE

A tale of two energy philosophies

By Paul Hickin, editor-in-chief, *Petroleum Economist*,

The world of energy shows no signs of healing its fractures in 2025 and will not do so until all stakeholders stop the finger-pointing and appreciate that we are all on the same side

The polarisation between climate evangelists and energy pragmatists, between developed economies and the Global South, and between oil and gas producers and hydrocarbon consumers could read like a Dickens novel.

There are certainly all the ingredients of the contradictions in one of the author's famous opening lines: an age of wisdom and an age of foolishness, an epoch of belief and an epoch of incredulity, the spring of hope and winter of despair.

How policymakers and industry leaders approach the energy trilemma—with all its inherent tensions and the various vantage points of those involved—is still very much a work in progress. Sustainability, security and affordability do not have to be at odds, but when there is a cost-of-living crisis, large swathes of the population without access to basic power, significant pockets of regional conflict with rising death tolls and a push to meet moribund net-zero goals, it is clear why priorities end up clashing.

> We should not be complacent about the resources we have and the journey we still need to go on

The ugly state of geopolitical tensions suggests world peace is more fragile than it has been since the Second World War, and there are far-reaching consequences for energy supply.

While the risks are not baked into oil and gas prices, there is an unequivocal message: we should not be complacent about the resources we have and the journey we still need to go on if everyone is to have access to reliable, cheap and abundant energy. Indeed, with the human—and carbon—cost of war, there was a lost irony as policymakers slugged it out in acrimonious fashion at COP29 in Baku in November 2024 to reach a climate finance solution.

But maybe COP is not fit for purpose. After all, dialogue around climate solutions still fails to put energy front and centre of discussions—which is misguided, counter-productive and at odds with the actual energy strategy of individual countries.

It is time to admit that energy security is the number one goal—and, if it is not, it definitely should be—and that we are on the first rung of a coherent sustainability vision. This is the refreshing rhetoric of Donald Trump as US president—a clear return to put the energy needs of his own citizens first.

And while China, for example, is also laser-focused on the same goal, there is often lazy wishful thinking from some climate quarters that the Asian giant's strategy on electric vehicles is all about cleaner energy rather than the fact it does not want to be overly dependent on expensive hydrocarbon imports. Just look at how Chinese refiners snap up cheap Canadian crude and transport it long distances. It is also why 90% of Iranian oil heads to China and why a lot of Russian crude flows to India: economics 101. These flows also highlight the oft-confused Western policy of blocking hydrocarbon projects at home only to end up paying more and doing more environmental damage through bringing in additional cargoes by sea.

Petroleum Economist | Hydrogen Economist | Carbon Economist

Editor-in-chief: Paul Hickin
Editor: Stuart Penson
Digital content manager: Rhys Timson
Project manager: Rachel McGhie
Production: Keith Baldock

Printed by: Stephens & George, Merthyr Tydfil, Wales, United Kingdom

Published: December 2024

Petroleum Economist, Tallis House, 2 Tallis Street, London, EC4Y 0AB, United Kingdom.
Tel +44 (0)20 3409 2240
www.pemedianetwork.com

The Petroleum Economist Ltd is part of Gulf Publishing Holdings LLC. Registered in England. Company number 04531428.

Security of supply underpins the drive for cheap and reliable energy as economies across the world wrestle with inflationary issues and recessionary environments. It is why Europe has been the leading voice on the transition but also why it was entangled in double standards when the Russian crisis hit and coal plants and LNG infrastructure became top of the agenda again. A sensible strategy means both hydrocarbons and renewables, not either/or.

Rules of engagement

There is a lot of merit to the multi-linear—or all-energies—approach and appreciating the different paths different economies are on, and the different resources at their disposal. If solar works in sunnier climes, then great. If wind works off the coast of the North Sea, then let us use it. If hydrogen is a sensible part of the mix, then we should develop the infrastructure. The energy maths is even simpler: it is all about addition.

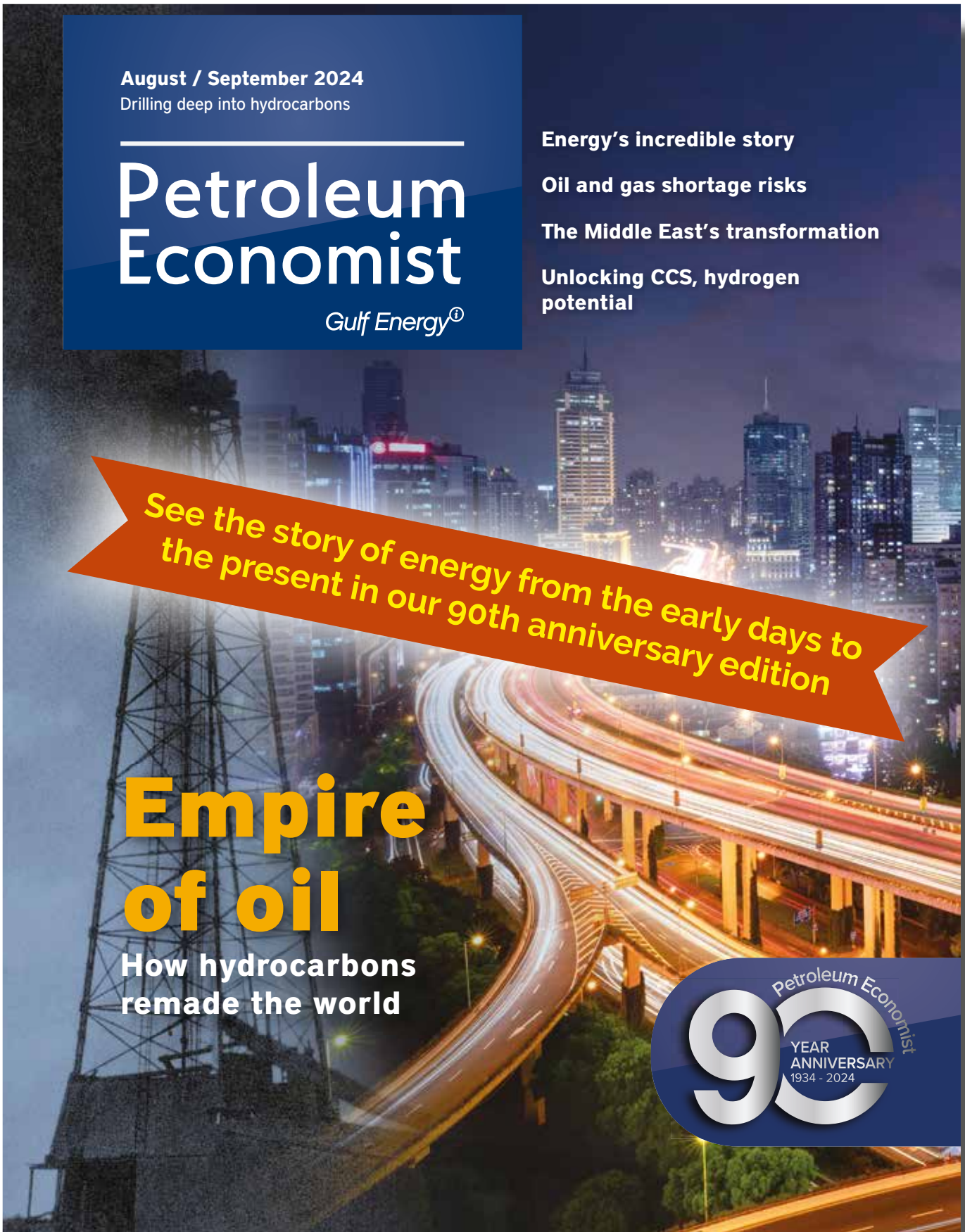
More energy is needed and will continue to be needed for a long time to come if the global economy continues to progress and everyone gets to enjoy the spoils. Greater demand will come from the rise of urbanisation and population growth, as well as newer growth areas such as AI—even if some of its drain on energy resources may be offset by greater productivity. Just let us proceed in a smarter way that embraces carbon capture technologies, creates more energy efficiencies, adds in biofuels and eradicates waste such as methane.

There is also another simple rule of thumb: diversification is crucial. Even great oil powers such as Saudi Arabia and the UAE are following a path of diversifying their energy portfolios. Russia's invasion of Ukraine served as a painful reminder for Europe of the need for diversity of supply, and the principle should serve as a guiding light when building an energy mix. Diversification can still mean the same energy source, but access to that energy should come through different points of entry, being mindful of pipeline options and shipping chokepoints.

The energy mix also has a potentially unsung hero: natural gas. Gas has often found itself awkwardly in the middle: not as cheap as coal for those brazenly focused on cost and not as clean as hydrogen, solar or wind for those targeting clean energy. But things have started to change. Gas is now a huge part of the African economic success story, a growth area in the Middle East—which has generally targeted oil—and is making headway across Asia—including big coal consumers such as China and India.

Gas also works as both an LNG export option for resource-rich nations and as a domestic power driver or a back-up for clean intermittent supply for countries trying to wean themselves off dirtier and cheaper solutions.

Gas should not be lumped with coal on the fossil fuel charts of those with a crass climate agenda and should be effectively used by those still allowing methane leakage and flaring. Finding the path that allows nations to compromise and still pursue self-interested energy goals may not be possible in 2025, but a dose of honesty and self-reflection could be the place to start. Maybe poet William Blake had some sage energy advice for us all: "We are not meant to resolve all contradictions but to live with them and rise above them." Let us make 2025 the best of times rather than worst. It is in all our hands. ■


August / September 2024
Drilling deep into hydrocarbons
Petroleum Economist
Gulf Energy
Energy's incredible story
Oil and gas shortage risks
The Middle East's transformation
Unlocking CCS, hydrogen potential
See the story of energy from the early days to the present in our 90th anniversary edition
Empire of oil
How hydrocarbons remade the world
Petroleum Economist
90
YEAR ANNIVERSARY
1934 - 2024

Contents

New energies & the energy transition

What happened, where

This year's highlights


Last coal-fired power plant closed September 2024
Harbour Energy completes acquisition of Wintershall Dea upstream assets
Key project 8
Highview Power—p15
Key project 9
Sunly—p16
Expiration of Ukraine-Russian gas transit agreement at year's end
Key project 10
Ithaca Energy—p16
COP29 hosted in Baku, Azerbaijan
Key project 3
Government of Azerbaijan—p13
India surpasses 100GW of installed solar capacity in Feb 2024
Key project 7
Balikpapan Refinery—p14
Force majeure declared on El Feel oil field September 2024
TotalEnergies and QatarEnergy sign major agreement to jointly develop North Field East LNG project
Key project 1
NEOM Green Hydrogen—p12
Orange Basin the next big hotspot?
Frelimo's candidate Daniel Chapo (unsurprisingly) declared the winner, although the results are controversial
Federal budget includes AUD 22.7b *Future Made in Australia* package
Key project 11
Golden Plains Wind Farm—p16

What they said in 2024

FEBRUARY

"The global economy is limping along, not sprinting"

PIERRE-OLIVIER GOURINCHAS, CHIEF ECONOMIST, IMF

FEBRUARY

"Now there is a recognition that oil and gas is probably going to have to be around for the next 30 or 40 years as we transition"

GEORGE MAXWELL, CEO, VAALCO

MARCH

"There has been growing recognition across the [UK] political spectrum that gas will play a critical role for decades"

BEN CLUBE, CEO, ENERGYPATHWAYS

APRIL

"We should abandon the fantasy of phasing out oil and gas"

AMIN NASSER, CEO, SAUDI ARAMCO

FEBRUARY

"Wind and solar alone cannot solve emissions in the industrial sectors"

DARREN WOODS, CEO, EXXONMOBIL

FEBRUARY

"Produce green hydrogen and you can rely on us as buyers"

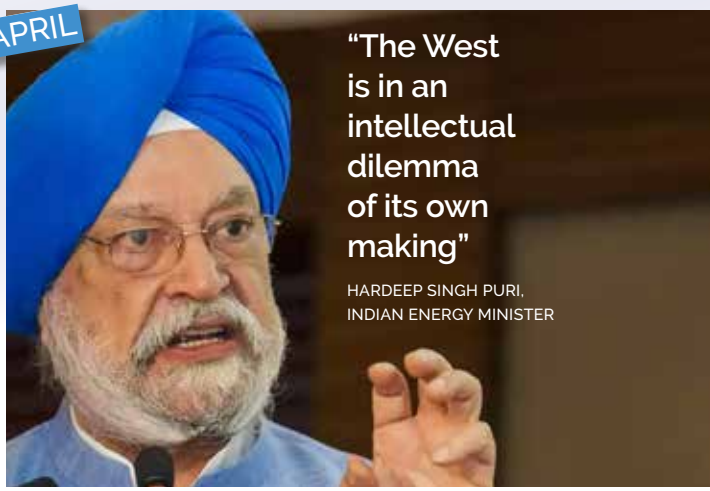
OLAF SCHOLZ, GERMAN CHANCELLOR

MARCH

"We need to move away from the misguided idea of no longer investing in new oil projects. It is not helpful to anyone"

HE HAITHAM AL GHAIS, SECRETARY GENERAL, OPEC

APRIL



"The West is in an intellectual dilemma of its own making"

HARDEEP SINGH PURI, INDIAN ENERGY MINISTER

MAY

"We need certainty in the regulatory arena and transparency"

JACK FUSCO, CEO, CHENIERE ENERGY

"There can be no turning back, no relaxing and no mercy in fighting corruption"

PRESIDENT XI JINPING, CHINESE PRESIDENT

MAY

"The long-term outlook is very bright for LNG"

MEG O'NEILL, CEO, WOODSIDE ENERGY

JUNE

"Africa needs homegrown solutions... and fossil fuels are not going away"

HEINEKEN LOKPOBIRI,
NIGERIAN PETROLEUM MINISTER

JUNE

"We need to be honest and say there is not an economic incentive to move from natural gas to renewable hydrogen"

CAROLINE STANCELL,
EXECUTIVE DIRECTOR OF HYDROGEN, EUROPE & AFRICA, AIR PRODUCTS

JUNE

"The Department of the Interior seems to believe that they care about this land more than we do"

JOSIAH PATKOTAK,
MAYOR,
NORTH SLOPE BOROUGH

JULY

"We think [FLNG] is the right technology to access resources which at the moment are stranded, or might become stranded"

GUIDO BRUSCO,
COO FOR NATURAL RESOURCES, ENI

SEPTEMBER

"We see a significant risk of e-fuels being politically instrumentalised in the debate about the ban on combustion engines in 2035"

OLIVER ZIPSE,
CEO, BMW

OCTOBER

"When I see people talking about green hydrogen, solar energy, wind energy and biomass, I wonder: what country in the world can compete with Brazil?"

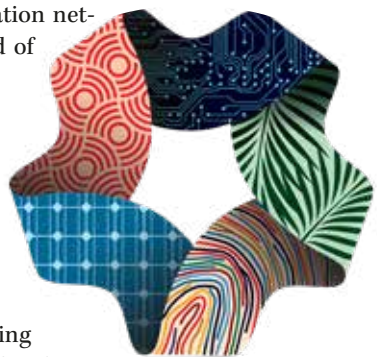
LUIZ INACIO LULA DA SILVA,
BRAZILIAN PRESIDENT

Energy projects reshaping the global landscape

The energy industry is undergoing a profound transformation with international law firm White & Case at the forefront. Here are some of the key projects that will have a lasting impact both for the country and the region in which it being developed, as well as wider implications across the globe and for the type of energy source. Some show breakthroughs in technology to meet climate goals and others how mature industries can find new ways to add value. There is a clear theme: embracing the multi-linear approach to energy.

1 NEOM Green Hydrogen—the world's largest green hydrogen facility

Saudi Arabia is home to the world's most ambitious green hydrogen initiative in the $500b NEOM project. NEOM Green Hydrogen Company (NGHC)—a partnership between ACWA Power, Air Products and NEOM—is developing a world-scale green hydrogen production facility to provide power to parts of the city and transportation network. The $8.4b plant will use power from a nearby 4GW solar farm to produce 600t/d of carbon-free green hydrogen by the end of 2026 in the form of green ammonia.



The produced green hydrogen will not only be used to provide power to the city's industry but will also fuel buses and trucks, offering a cost-effective solution for the transportation and industry sectors both in-country and globally. NGHC has secured an exclusive 30-year off-take agreement with Air Products for all the green ammonia produced at the facility. The project reached financial close in mid-2023 and construction is well underway.

NGHC anticipates the project, powered solely by renewable energy, could save up to 5mt of CO_2 each year. When fully operational, the project will create 300 new jobs, harnessing the most advanced technology to enable the large-scale adoption of green hydrogen as the clean solution to the world's growing energy demands. This project sets the benchmark for major green hydrogen projects globally. ■

2 STRATOS—the world's largest direct air capture plant

STRATOS is a joint venture between BlackRock and Occidental subsidiary 1PointFive, designed to capture up to 500,000t of CO_2 per year. Construction activities for STRATOS, which will be based in Texas, US, are under way and the direct air capture (DAC) plant is expected to be commercially operational in mid-2025. The project is expected to employ more than 1,000 people during the construction phase and up to 75 once operational.

DAC is a technology that captures and removes large volumes of CO_2 directly from the atmosphere, which can be safely and securely stored deep underground in geologic formations. STRATOS is expected to provide cost-effective solutions that companies in hard-to-decarbonise industries—such as steel and cement—can use in conjunction with their own emissions reduction programmes. To date, 1PointFive has signed CO_2 removal credit purchase agreements with customers including Amazon, Airbus, All

3 Azerbaijan's renewable power boost

The Ministry of Energy of the Republic of Azerbaijan, the Azerbaijan Renewable Energy Agency (AREA) and the state electricity utility Azerenerji OJSC have signed agreements with multiple developers on a more than 1.5GW portfolio of renewable energy and battery storage projects. The projects include a 445MW solar plant in Bilasuvar, a 315MW solar plant in Neftchala and a 240MW wind plant in Absheron—Garadagh (Masdar and SOCAR Green), a 240MW solar plant in Jabrayil (Lightsource bp) and a 200MW wind plant and 200MW BESS (ACWA Power). ACWA Power's 240MW wind plant in Khizi—Absheron has also achieved financial close. These landmark projects highlight Azerbaijan's remarkable progress in sustainable development and a strong commitment to investing in renewable and diversified energy sources, which will reduce carbon emissions, bolster the economy through improved employment opportunities and attract investors. ■

Nippon Airways (ANA), TD Bank Group, the Houston Astros and the Houston Texans. 1PointFive has also received backing and funding from the US DOE for its DAC hub.

"We are excited to partner with BlackRock on this transformative facility that will provide a solution to help the world reach net zero," said Vicki Hollub, President and CEO, Occidental. "This joint venture demonstrates that Direct Air Capture is becoming an investable technology and BlackRock's commitment in STRATOS underscores its importance and potential for the world."

1PointFive's DAC facilities, such as the one being built in Ector County, are designed to capture CO_2 directly from the atmosphere, compress it into a liquid and then safely and securely store it deep underground or use it to produce low-carbon products. STRATOS will be able to store CO_2 in saline formations, which creates a carbon removal credit that businesses can buy to address their emissions. ■

4 Restructuring the Atlantic LNG project in Trinidad & Tobago

The Atlantic LNG facility, owned by Shell Trinidad and Tobago Limited, BP Trinidad and Tobago LLC and the National Gas Company of Trinidad and Tobago Limited, is one of the largest LNG export facilities in the western hemisphere and is a critically important component of Trinidad and Tobago's energy industry infrastructure.

The restructuring was announced in December 2023, following years of complex negotiations, with sustained involvement by White & Case as a key legal advisor to the Ministry of Energy and Energy Industries. The arrangement includes agreements executed by the relevant parties including the government's licensing of and support for the restructured project, the revised ownership structure of the project, the corporate governance arrangements among the shareholders of the Atlantic LNG facility and various commercial contracts underpinning the purchase and supply of natural gas, the processing of gas into LNG and the sale of LNG and NGLs.

The new agreement has paved the way for the LNG export facility in Latin America to return to full production. Trinidad and Tobago moved to restructure Atlantic LNG after deciding it was not getting enough revenue from the facility. The restructuring deal also keeps a pricing scheme that was revamped in 2020 to generate more revenue for the government. Atlantic LNG operates four trains, which can produce up to 15mt/yr of the gas that is super chilled into a liquid for transport by tanker, when no trains are idled. The agreement simplifies the project's structure into ownership across all four trains. ■

5 Occidental and BHE Renewables create JV on lithium extraction

Occidental (Oxy) and BHE Renewables formed a joint venture for the demonstration and deployment of TerraLithium's Direct Lithium Extraction (DLE) and associated technologies to extract and commercially produce high-purity lithium compounds from geothermal brine.

TerraLithium, a wholly owned subsidiary of Oxy, has patented DLE technologies that have the potential to process any lithium-containing brine into a responsibly sourced supply of high-purity lithium. BHE Renewables operates 10 geothermal power plants in California's Imperial Valley, which process 50,000 gallons of lithium-rich brine per minute to produce 345MW of clean energy. The JV has begun a project at BHE Renewables' Imperial Valley geothermal facility to demonstrate the feasibility of using the TerraLithium DLE technology to produce lithium in an environmentally safe manner. Upon successful demonstration, BHE Renewables plans to build, own and operate commercial lithium production facilities in California's Imperial Valley.

"By leveraging Occidental's expertise in managing and processing brine in our oil and gas and chemicals businesses, combined with BHE Renewables' deep knowledge in geothermal operations, we are uniquely positioned to advance a more sustainable form of lithium production," said Richard Jackson, president, US onshore resources and carbon management, operations at Oxy. "We look forward to working with BHE Renewables to demonstrate how DLE technology can produce a critical mineral that society needs to further net zero goals."

Lithium is a key component in batteries for electric vehicles, consumer electronics and energy grid storage. It is also used in industrial applications to manufacture glass, ceramics and pharmaceuticals. According to the International Renewable Energy Agency, battery lithium demand is projected to increase tenfold over 2020–30, in line with battery demand growth. ■

6 Calpine's $1b battery storage financing—largest of its kind

Gas and geothermal plant operator Calpine Corporation brought on 510MW of its 680MW capacity battery energy storage system (BESS) project in California online in summer 2024 with BYD battery units. This is thanks to Calpine, the largest generator of electricity from natural gas and geothermal resources in the US, closing on a syndicated project financing transaction in the commercial bank market.

The transaction

7 Financing the Balikpapan Refinery plan in Indonesia

Indonesia is set to have its largest oil refinery with a capacity of 360,000b/d by 2025 as part of the mega Refinery Development Master Plan (RDMP) project in Balikpapan owned by PT Kilang Pertamina Internasional (KPI) as a Subholding Refining & Petrochemical of PT Pertamina.

Currently, PT KPI is pushing for an increase in refinery capacity or revamping the Crude Distillation Unit from 260,000b/d to 360,000b/d. CEO of PT KPI, Taufik Aditiyawarman, said that besides increasing the refinery's capacity, this project aims to improve the quality of fuel to meet Euro 5 standards. The RDMP Balikpapan project is an expansion of the existing Balikpapan oil refinery. Once completed, RDMP Balikpapan will be the largest oil refinery in the country, surpassing the capacity of the Cilacap Refinery, which is currently the largest.

The Cilacap Refinery processes 345,000b/d. With this crude oil processing capacity, the new refinery will produce 319,000 barrels of petroleum products per day, including LPG and petrochemicals such as propylene, which is a raw material for plastics. The $3b financing for the RDMP project plays an important role in supporting

consisted of credit facilities totalling more than $1b to finance the development and construction of a 680MW BESS complex in Menifee, Riverside County, California, which is being constructed in five phases. When completed, the project will be one of the largest battery storage systems in the US. The financing received Climate Bond Certification.

The project could power 680,000 homes for four hours, implying it has a four-hour duration, as the vast majority of Californian projects do. Calpine operates natural gas and geothermal resources across the US with 78 plants. It already has an 80MW BESS in operation in California called Santa Ana and two under construction in addition to Nova: the 25MW West Ford Flat BESS and the 13MW Bear Canyon BESS. The company claims to have 2,000MW of BESS in development in total. ■

Indonesia's energy transition and energy security ambitions by expanding and 'greening' one of Indonesia's largest refineries. It is one of the largest project financings in Indonesia over the past decade. The financing represents an important milestone in geopolitical and cross-continental cooperation, with governments from Korea and Italy investing in the project. ■

8 Highview Power—pioneering commercial-scale liquid air energy storage in the UK

Highview Power has the funding to enable the liquid air energy storage firm to start building its first large-scale project after Centrica and the UK Infrastructure Bank (UKIB) backed the venture with a £300m ($396m) investment. Construction on the 50MW/300MWh long-duration energy storage project started in 2024 and will begin commercial operation in early 2026, the company said.

The project, which will use Highview Power's proprietary liquid air energy storage (LAES) technology, is set to be in Carrington, Manchester, UK. The funding round was led by the state-owned UKIB and utility Centrica, with participation from mining firm Rio Tinto, bank Goldman Sachs, private equity firm Mosaic Capital and and investment management company KIRKBI.

Richard Butland, co-founder and CEO of Highview Power said: "Our first project in Carrington will be the foundation for our full-scale roll-out in the UK and expansion with partners to share this British technology internationally."

The investment will enable construction of one of the world's largest LAES plants and, once complete, the plant will have a storage capacity of 300MWh and an output power of 50MW/hr for six hours. Given the potential of LAES to reduce curtailment costs across the sector, Highview Power intends to accelerate the roll-out of larger scale 2.5GWh facilities, with an anticipated investment of £3b, across the UK. The development could both aid energy sustainability and boost economic growth as the transition will need effective storage to thrive.

The UK already has over 4GW/4GWh of short-duration, one-hour and two-hour lithium ion battery energy storage system projects online, which mainly provide ancillary services and some grid balancing and energy trading activities. Highview Power aims to accelerate the roll-out of its larger facilities across the UK by 2035 in line with one of National Grid's target scenario forecasts of a 2GW requirement from LAES, which would represent nearly 20% of the UK's long duration energy storage needs. ■

9 Sunly looks to accelerate renewables projects across Baltics, Poland

Renewable energy producer Sunly AS secured €300m ($334m) portfolio financing in 2024 to speed up the construction of its 1.3GW pipeline of solar, wind and battery energy storage system facilities across the Baltics and Poland.

Sunly intends to use the €300m portfolio financing in combination with separate project financing packages to develop various integrated hybrid parks that combine wind, solar and energy storage batteries at single connection points, with direct lines to consumers, to improve energy production stability in various weather conditions and optimise cost-efficiency by reducing grid connectivity charges. This investment is provided by Rivage Investment via REDI HR2 and Copenhagen Infrastructure Partners through its Green Credit 1 Fund, with additional financing from Norwegian pension company Kommunal Landspensionskasse.

Priit Lepasepp, co-founder and CEO of Sunly, said: "This investment enables us to improve our infrastructure with new grid connections and solar parks in the Baltics, which will support our onshore wind and storage pipeline expansion. To help reduce energy costs, our focus will be on two key areas: building a hybrid pipeline with storage capabilities and advancing the electrification of heating and mobility systems, thereby diminishing our reliance on imported fossil fuels and optimising the use of local renewable resources."

One of the initial projects to benefit from this financing is the 244MW Risti Solar Park in Estonia, which has the capacity to provide the annual electricity consumption of 55,000 households. It is intended as a hybrid park, but Sunly already has expansion plans that include onshore wind turbines and battery storage in the future. ■

10 Ithaca's Eni asset purchases create large independent operator

Leading UK independent oil and gas producer Ithaca Energy agreed a deal to acquire almost all of Eni's UK oil and gasfields in a transaction worth about $940m. Ithaca is buying the Italian energy company's interests in 11 fields and could boost its production to 150,000boe/d by the early 2030s—more than double its output in 2023. Eni will receive a 38% stake in the enlarged Ithaca group.

North Sea producers are seeking scale to help fund investment and decommissioning costs. Ithaca and others have complained about the impact of UK windfall taxes imposed on the sector. Ithaca has grown exponentially over the past two years, acquiring North Sea competitor Siccar Point in 2022, which gave it stakes in two of the UK's largest producing fields, Schiehallion and Mariner. The deal also gave Ithaca stakes in the undeveloped Cambo and Rosebank fields.

"The agreement affords the opportunity to build scale, realizing efficient upstream growth and maximising value under a dedicated and focused management structure," said Eni CEO Claudio Descalzi. ■

11 Australia's largest wind farm Golden Plains Wind Farm

The Golden Plains Wind Farm is the largest wind farm under construction in the world and will be the largest wind farm in the southern hemisphere. once completed, it will power more than 765,000 homes—the equivalent of every home in regional Victoria. This $3b+ project is a landmark clean energy project for Victoria and Australia.

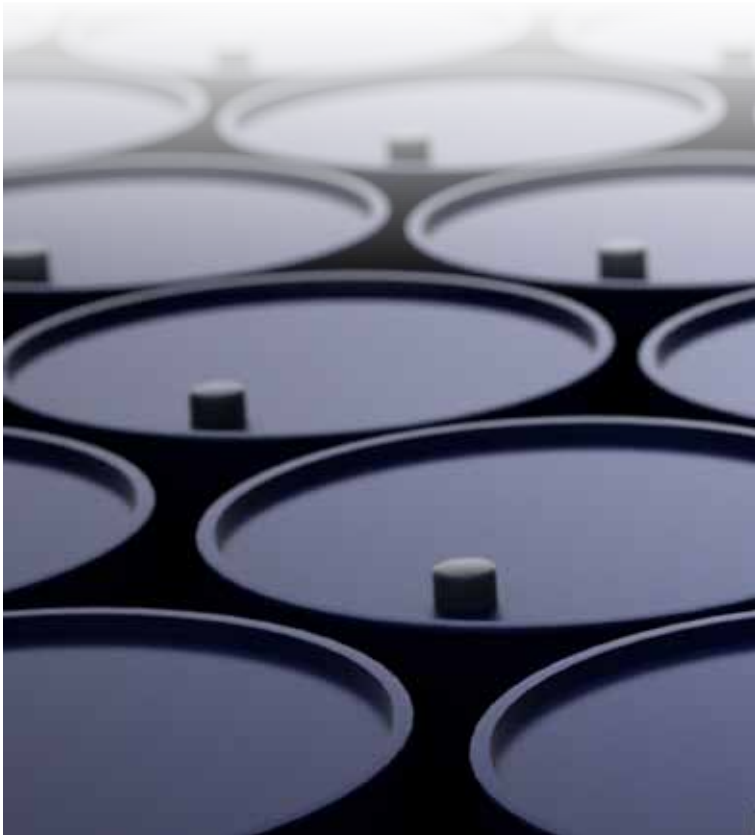
White & Case advised TagEnergy on the acquisition, development and project financing of stages one and two of the 1,300MW project, which was awarded Asia-Pacific Renewables Deal of the Year 2022 by Project Finance International. It was the first such project in Australia to be financed on a purely merchant basis.

The Golden Plains Wind Farm will generate 2% of Australia's electricity demand and will prevent more than 4.5mt of CO_2 from being emitted to the atmosphere annually. The project will also feature a 300MW battery storage facility, adding flexibility and stability to the grid. ■

Crude

Oil is vital to our global energy futures

The world needs to reduce emissions but must do so while providing affordable and reliable energy to meet rising global demand



Realistic, equitable and inclusive are three key words central to evolving future global energy pathways. We need to be realistic about what each form of energy can provide, especially in terms of security, affordability, availability and reducing emissions. We need to provide for equitable outcomes that consider the circumstances of all peoples across the world. And we need to be inclusive, ensuring all voices are heard.

Oil is not only a realistic, equitable and inclusive fuel source, it is also vital to our global energy futures. The term 'futures' is plural, because energy needs and realities vary significantly across the world. Indeed, there is neither a one-size-fits-all solution to meeting future energy demand, nor a singular pathway ahead.

OPEC's most recent *World Oil Outlook*, published in September 2024, takes into account these interlinked issues in its analysis. The *Outlook* is central to OPEC's embrace of data-driven transparency, helping to provide a better understanding of the intertwined issues shaping our energy futures and the energy challenges we face.

> We all want to lower emissions, but we cannot ignore the world's need for ample, reliable and affordable supplies of energy

The *Outlook* sees global primary energy demand increasing by 24% to 2050, with economic, demographic and urbanisation trends demonstrating why.

By 2050, the global economy is set to more than double in size and the global population reach 9.7b. Another 500m people are expected to move into cities across the world by 2030. To put this in context, this urbanisation drive will require the addition of around 56 cities the size of London. We must also keep front and centre the need to bring energy to the billions that still suffer without it.

This is not to mention the burden that emerging technologies are set to place on existing energy infrastructure. The boom in artificial intelligence and corresponding demand for computing data centres, for example, is driving the fastest growth in US power demand since the start of the millennium, outpacing grid expansions.

All-energies approach

We all want to lower emissions, but we cannot ignore the world's need for ample, reliable and affordable supplies of energy, which is only going to intensify. Against this backdrop, the world needs an all-energies approach and not the rigid pathway advocated by some to replace hydrocarbons.

This impractical pathway not only ignores that hydrocarbons today make up more than 80% of the global energy mix—a similar level to 30 years ago—it also flies in the face of the long history of energy supply. The past has always been about adding new energy sources to the mix, not substituting one for another. In a world of rising energy demand, how feasible is it to replace 80% of the energy mix? Simply put: it does not make sense.

OPEC welcomes all progress made in developing renewables and electric vehicles (EVs), with our member countries making significant investments in these sectors.

However, we are also acutely aware that, despite investment of over $9.5t in 'transitioning' over the past two

By HE Haitham Al Ghais,
OPEC secretary general

decades, solar and wind supply only around 4% of global energy today, while EVs have a global penetration rate of between 2% and 3%. It is also worth noting that renewables and EV development also require oil-related products, adding to already rising oil demand.

Pushback on net zero

At OPEC, we see oil demand reaching more than 113m b/d by 2030, before increasing to 120m b/d by 2050. This is driven primarily by non-OECD demand, which is set to expand by 28m b/d to 2050. There is also the potential for this global oil demand level to be even higher.

Today, many parts of the world are witnessing a pushback as populations begin to understand the implications of ambitious and unrealistic net-zero policies. This refocusing, in turn, is prompting policymakers to reevaluate their approaches to future energy pathways, leading to higher oil demand expectations.

At the same time, the world is not only poised to consume more oil, it is set to do so in an increasingly responsible manner. Technological innovation is driving progress in areas such as carbon capture, utilisation and storage; carbon dioxide removal; and direct air capture.

The industry is also working hard to enhance operational efficiencies, as underlined by many oil producers at COP28 pledging to reduce carbon emissions to net zero by 2050 and curb methane emissions to near-zero by 2030.

These improvements come at a time when crude oil and its associated products, such as gasoline, diesel and jet fuel, remain more essential to the global economy than ever.

This is not to mention the necessary products derived from petroleum—such as toothpaste, soap, cameras, computers, upholstery, contact lenses, medicines, wind turbine blades and solar panels.

Against this backdrop, the need for investment in the oil industry has never been greater. To ensure the oil needed today, tomorrow, and many decades into the future remains available, adequately investing in the oil industry is vital. At OPEC, we see cumulative investment needs of $17.4t out to 2050, or around $640b/yr.

> Successfully preparing for the future means focusing on today's realities

Successfully preparing for the future means focusing on today's realities. At OPEC, we believe there is a clear need to prioritise energy security, utilise all available energies, deliver energy affordability, enhance sustainability, reduce emissions and not limit our energy options in the face of expanding demand.

Oil can deliver on all these priorities. It will be vital for our global energy futures. ■

China faces up to slowing clean product demand

Structurally lower GDP growth and the need for a different economic model will contribute to a significant slowdown

In the decade before the Covid-19 pandemic, China was a critical source of clean product demand growth. Over the period between 2011 and 2019, combined Chinese consumption of gasoline, diesel and jet fuel averaged a yearly gain of 335,000b/d, outpacing that of India (+90,000b/d), the US (+110,000b/d) and Europe (+40,000b/d). Nonetheless, over the next decade Chinese clean product demand is set to slow dramatically, driven by structurally lower GDP growth rates and the need to shift away from an investment-led economic model. The rapid adoption of electric vehicles and LNG-fuelled trucks is also limiting the future outlook for Chinese demand, namely for gasoline and diesel.

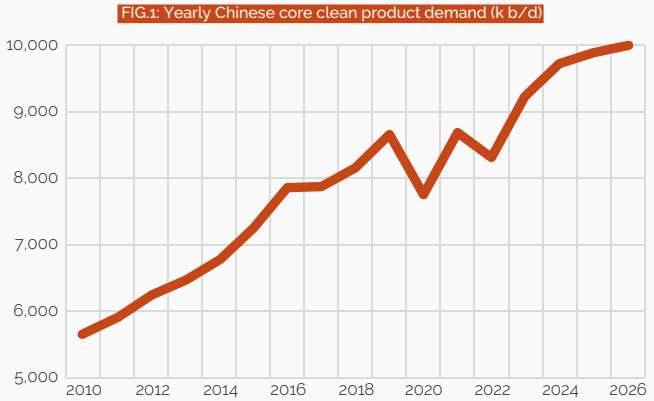
Early in the cycle of an emerging market, heavy amounts of investment make sense. Building new infrastructure, factories and housing typically has a far higher return relative to the cost of investment. The first road built between two cities has enormous economic benefit. However, rely on investment for too long and an economy becomes oversaturated with production relative to domestic consumption and thus must resort to ever higher exports as an offset.

Export reliance can work for a while, but as we are currently witnessing, other countries become worried about their respective domestic industries and implement increasingly aggressive import tariffs. The US, Canada, the EU, Brazil, India, Chile and Mexico have all implemented Chinese import tariffs of some sort. As a result, China's ability to rely on an investment-led growth model is rapidly coming under pressure as its trade surplus pushes to new highs with the rest of the world.

Ultimately, China needs to find a way to shift its economy away from an over-reliance on investment towards household consumption, which includes spending on goods and services. This process of rebalancing is often painful. The US was forced through such a rebalancing during the Great Depression, and Japan stagnated for two decades after relying on investment for too long in the period after the Second World War. At present, over 40% of Chinese GDP goes to investment, while just 39% is a result of household consumption. Long-term sustainable growth will require a significant shift, with consumption in a range between 60–70% of GDP and investment at 20–25%.

As the Chinese economy faces up to serious structural issues, the prospect of slowing oil demand has taken centre stage. While our expectation for 2024 Chinese clean product demand growth is a respectable 485,000b/d year-on-year, much of this strength came in H1 (+660,000b/d year-on-year), before fading considerably into Q3 (+210,000b/d year-on-year). By next year, we anticipate Chinese clean product consumption finishing up just 165,000b/d year-on-year, marking the slowest pace of growth since 2017, excluding the Covid lockdown years of 2020 and 2022. We anticipate this trend of slowing growth will continue into 2026, with demand set to rise just 110,000b/d year-on-year.

FIG.1: Yearly Chinese core clean product demand (k b/d)



Includes gasoline, diesel and jet

Source: Kpler

By Reid I'Anson, senior analyst, macro economy and cross commodity, Kpler

The slowdown in Chinese domestic clean product consumption puts Chinese refiners in a difficult position. At present, we expect Chinese refinery runs to average 15.37m b/d in 2024, a 200,000b/d decline against year-earlier levels. Much of this throughput weakness began to show itself in Q2, as Chinese debt accumulation into the investment side of the economy slowed relative to the start of the year. By Q3, runs were down by nearly 1m b/d. While things are on pace for improvement through Q4, we still expect utilisation to finish lower by nearly 250,000b/d year-on-year.

As mentioned above, the offset to oversupply relative to domestic demand is higher exports. While tariffs on Chinese clean products remain limited, Chinese refiners have still been forced to deal with a relatively weak international environment for gasoline and distillates.

In Q3, middle distillate and light end seaborne exports finished lower by nearly 300,000b/d year-on-year, marking the largest decline since Q4 of the previous year. In effect, Chinese refiners have been unable to export their way out of a weak domestic demand situation. As Chinese core product consumption growth slows in the years ahead, Chinese refiners—which will face a core product supply surplus in excess of 600,000b/d by 2025—will be ever increasingly reliant on the whims of international demand.

> Chinese refiners have been unable to export their way out of a weak domestic demand situation

Despite the doom and gloom, we still see Chinese refinery runs recovering a bit into next year (+270,000b/d year-on-year). Heavy amounts of monetary stimulus should give a short-term boost to investment and economic activity. There are also questions around the extent of fiscal stimulus, which could be used to help boost domestic consumption levels. Exports will likely recover a little from the lows in Q3.

Nonetheless, as we look beyond the short term, it is important to understand that Chinese stimulus is unlikely to usher in another decade like the 2010s. Rapid oil and clean product demand growth will have to come from somewhere else over the next decade, particularly as China grapples with the difficulties of an imbalanced economic growth model. ■

Why oil and gas must play a central role in the transition to a lower carbon economy

The climate narrative has centred on phasing out fossil fuels in favour of renewables and novel solutions, but increasingly, policymakers are realising the importance of hydrocarbons as an enabler of the transition

For over 100 years, oil and gas has been the bedrock of the global economy, enabling immense growth, development and progress across the world. From mobility to materials, healthcare to food, the oil and gas industry has delivered reliable and affordable energy to enable unprecedented prosperity and a doubling of life expectancy.

And yet, in recent years, the climate narrative has centered on phasing out hydrocarbons in favour of intermittent renewables, vilifying oil and gas companies as the central cause of the world's climate problems. Policymakers and activists have sought to hamper energy companies' financing, cut access to markets and even reduce basic access to energy, neglecting the impact these policies have had on large swathes of the world and on human prosperity.

That narrative may now be changing somewhat. As policymakers seek lasting change on carbon emissions and adopt a more inclusive approach, the importance of the oil and gas industry in playing an integral part of the solution is gaining credence as the industry invests heavily to decarbonise its carbon footprint, and as the importance of gas is recognised as a complement to renewables and the gateway to new energy sources such as hydrogen. The necessity of oil in making everything from solar panels to wind turbines to electric cars is also being recognised.

Balancing the energy trilemma

Several important factors brought the industry into the climate fold. Growing pushback from the developing world has demanded greater inclusion in the carbon transition, championing a more tailored approach to each country's needs. This also coincided with the energy crisis in recent years, which highlighted the importance of availability and affordability in addition to sustainability in the energy trilemma.

More than 7b people today are demanding the same right to stable energy and human prosperity that the 1b people in the OECD wealthy nations have enjoyed. Leaders from the developing world are increasingly unwilling to forgo energy security in favour of adopting developed world requirements.

With close to 900m people still without electricity and 2.4b without clean cooking fuel, the developing world is where all the net growth in emissions will come from in coming decades, because it is where the most rapid economic and population growth is taking place. And while the developing world will bear the brunt of climate change impacts, it has contributed minimally to the problem. Bridging the divide between the developed and developing world will be critical for lasting climate progress.

> The world needs the industry to succeed by embracing a pragmatic approach to energy policy that supports economic growth and energy security, as well as environmental responsibility

The energy crisis in 2022 only magnified the developing calls for inclusion by offering a stark reminder of the importance of energy security. As conflict in Ukraine erupted, European countries scrambled for energy supplies and postponed or cancelled long-term emissions measures, resorting to dirtier fuels such as coal.

Despite the trillions invested in intermittent renewables, new energy sources have been unable to meet the growth in global energy demand, let alone replace any current energy sources, leading to more burning of coal in both the developing and the developed world. In fact, while coal use worldwide had flattened over 2012–21, it actually saw a sudden acceleration in 2022; in the starkest case, Germany, a renewables champion, restarted old coal-fired power plants.

It became clear that the West, which decried the role of oil and gas, must embrace the industry as a partner and part of the solution. The most immediate solution the

By Majid Jafar,
CEO,
Crescent Petroleum

industry offers is to enable the switch from high carbon emitting fuels to cleaner ones. Gas, in particular, emits half as much carbon as coal, can be switched off and on affordably, and has an established global production and supply chain.

Enabling developing countries to transition from coal, wood and other dirty fuels to natural gas will enable them to significantly cut their carbon footprints quickly and efficiently, while allowing the addition of intermittent renewable power once a cleaner, more stable baseload has been achieved. Gas turbines can also increase or decrease their power output quickly and handle more frequent starts and stops.

The switch has health implications as well as environmental ones. China's 'Blue Sky' initiative, first launched in 2013 to reduce air pollution, particularly in urban areas, replaced coal with natural gas and virtually eliminated the pollution problem. Now, the discovery of significant gas reserves in Indonesia in 2023 promises to further replace coal burning in Asia and drive meaningful sustainable change while reducing pollution.

The oil and gas industry, for its part, is also redoubling efforts to produce energy more efficiently and cleanly. A range of industry initiatives announced at COP28 in Dubai in 2023 cemented the energy industry's efforts to lower its carbon footprint and deliver energy more cleanly.

For example, the Oil and Gas Decarbonization Charter (OGDC), to which Crescent Petroleum is a proud founding signatory, committed 55 of the world's leading oil and gas companies to reach net-zero emissions by 2050 or earlier, and near-zero upstream methane emissions and zero routine flaring by 2030. OGDC signatories represent 500–550mtCO_2e, of which methane emissions contribute around 45%. Meanwhile, the Aiming for Zero Methane Emissions Initiative of the Oil and Gas Climate Initiative has pushed its members to commit to zero methane emissions and eliminate methane leaks in operations.

Even before these initiatives, Crescent Petroleum reached carbon neutrality across all production operations in 2021 by reducing our energy intensity and offsetting the remaining emissions. We have proudly maintained that status in the years since as our carbon intensity has fallen further to less than a third of the industry average.

For over a century, the oil and gas industry has been proficient at delivering affordable and reliable energy to power the global economy and deliver immense value for humanity. The industry must now direct its scale and ambition to helping decarbonise the energy system. The world needs the industry to succeed by embracing a pragmatic approach to energy policy that supports economic growth and energy security, as well as environmental responsibility. ■

Crude markets look forward to brighter 2025

China drove the market for crude into the doldrums in 2024 with a big drop in demand, but a turnaround looks likely next year

At the time of writing this analysis, the jury is still out on the final oil demand growth figures for 2024. But one thing is for sure: the foremost forecasters and market participants have been deeply disappointed by the oil market's performance.

We at Vortexa track all seaborne oil and gas flows. Unfortunately, the picture looks even bleaker than the demand assessments. Based on data for the first ten months of 2024 vs the same period of 2023, seaborne shipments of all oil were down by 500,000b/d, with 300,000b/d of this accounted for by crude. Only LPG arrivals were up, by about 100,000b/d, thanks to rising US exports, while motor fuels were flat, with the remainder of the decline accounted for by other products, including residuals (fuel oil), naphtha and biofuels.

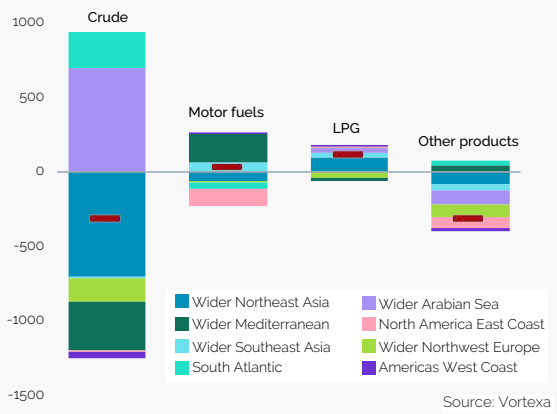
Dissecting crude arrivals by destination market shows the overall relatively marginal decline masks big shifts in regional flows. In fact, the Wider Arabian Sea—spanning from the Middle East to India's west coast and eastern and southern Africa—has seen crude arrivals increase by 700,000b/d. About 400,000b/d of this is backed up by higher consumption at refineries in India, as well as a mix of higher refinery runs in Saudi Arabia (Jizan) and more power generation and desalination in the Kingdom.

The other 300,000b/d is due to shifting oil export logistics rather than actual consumption changes, with Saudi Arabia routing more barrels to Ain Sokhna in Egypt for flows through the Sidi Kerir pipeline and the UAE sending Upper Zakuum to its Ruwais refining complex, freeing up Murban for exports via the Abu Dhabi Crude Oil Pipeline and export terminal in Fujairah. Accounting for these extra arrivals without supply/demand impact, it can be argued that global crude oil import demand declined by 600,000b/d rather than 300,000b/d.

Meanwhile, over in the South Atlantic—made up of West Africa and the east coast of South America—the startup of the Dangote refinery in Nigeria has directed an extra 220,000b/d to the related Lekki port. This pretty much equates to the net increase in the entire region.

From a tanker market perspective, these increases in

FIG.1: Change in seaborne oil arrivals in 2024 1-10 vs 2023 1-10 by product and destination wider shipping region (k b/d)



Source: Vortexa

Wider Arabian Sea and South Atlantic flows are not particular helpful, as they are largely met from local supplies, requiring short-haul, or even shuttle-type, shipments. The only outside supplier to these markets is Russia, but not much changed there from a year-on-year perspective in 2024.

What matters much more from a tanker perspective is the dramatic decline in crude arrivals in the crucial import markets in Northeast Asia and Wider Europe (Wider Mediterranean—all countries and country zones touching the Mediterranean, Black Sea and Caspian, and Wider Northwest Europe, encompassing Northwest Europe, Baltic and the Russian Arctic). Jointly, these markets saw a whopping 1.2m b/d decline in crude inflows, made up by 700,000b/d to Northeast Asia and 500,000b/d to Wider Europe.

Chinese demand

What most would have judged as close to unthinkable is that China alone essentially accounts for the entire 700,000b/d decline in Northeast Asia. A huge shift in trucking from diesel to LNG, as well as the swift electrification of passenger transport are two culprits of this development, joined by various structural problems of the economy in a global challenging environment. At the

Crude oil terminal in Xuwei Port area of Lianyungang Port, Jiangsu

By David Wech, chief economist, Vortexa

same time, refining margins and government policies kept Chinese refiners from exporting their product surplus, resulting in year-on-year declines in refinery operations in nearly every single month in 2024.

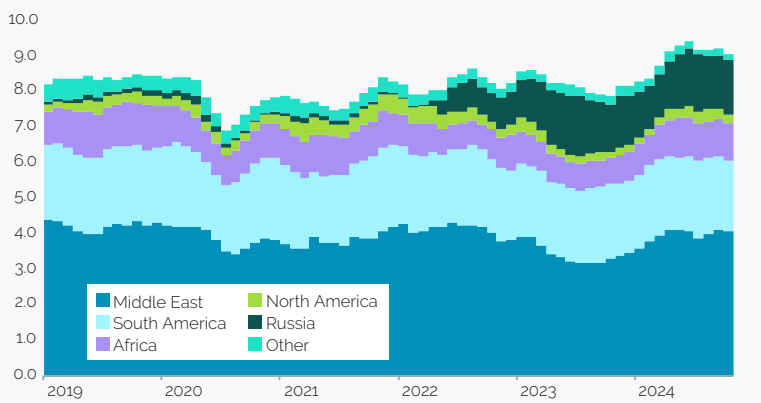
But how likely is it that this extraordinarily poor Chinese performance will be repeated in 2025? While many of the challenges remain, another 700,000b/d decline in imports appears very unlikely, with refinery and petchem expansions, and a likely much slower LNG truck expansion, probably being sufficient to support year-on-year growth in Chinese and potentially overall Northeast Asian crude imports.

At the same time, the Wider European market is likely to see a marked decline in crude imports in 2025. A handful of refinery shutdowns have already been announced. And refinery margins are under pressure from two fronts.

A flood of diesel from the Wider Arabian Sea (in this case also of jet fuel), Russia and the US will continuously hit the area. And outlets for the surplus gasoline will be hard to find after the successful startup of the respective secondary units at the Dangote refinery in Nigeria, while North American export markets shrink as well.

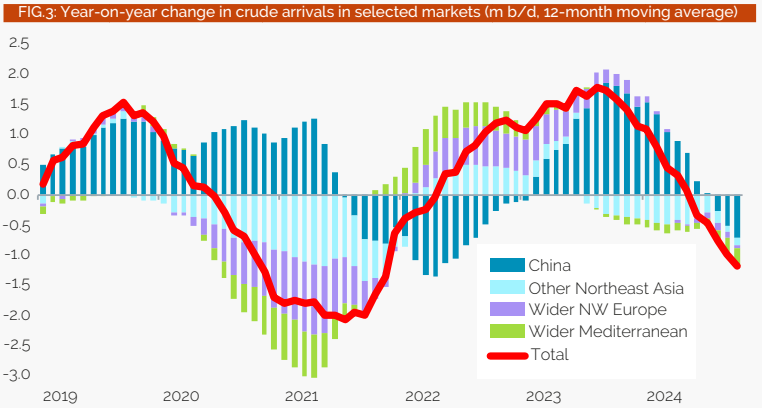
Accordingly, crude flows in 2025 are likely to be driven by stable-to-growing import needs in Northeast Asia and possibly markedly declining arrivals in the Wider European market as well as lower refinery runs in the US. With supply growth dominated by the Atlantic Basin, this will require a re-routing of US and other regional crude grades to Asia, creating substantial additional tonne-miles demand. This in turn, will provide a welcome upside to a recently pressured dirty freight market. ■

FIG.2: Crude arrivals in Wider Arabian Sea and South Atlantic by origin region (m b/d, 3-month moving average)



Source: Vortexa

FIG.3: Year-on-year change in crude arrivals in selected markets (m b/d, 12-month moving average)



Source: Vortexa

IOC investment myths need debunking

With a raft of scare stories around peak demand and climate change, 2025 should be the year smart investors leave the Big Oil bogeyman to the stuff of child's play

IOCs are great assets. But rather than being a statement of the obvious, this is a contested claim due to cynicism over other more potentially lucrative options, questionable risks over stranded assets and slippery arguments over oil ethics. Investors should look again at the world's best-kept secret.

The problem is that IOCs are shrouded in spurious anti-oil hokum, with climate evangelism dressed up as sound energy investment advice.

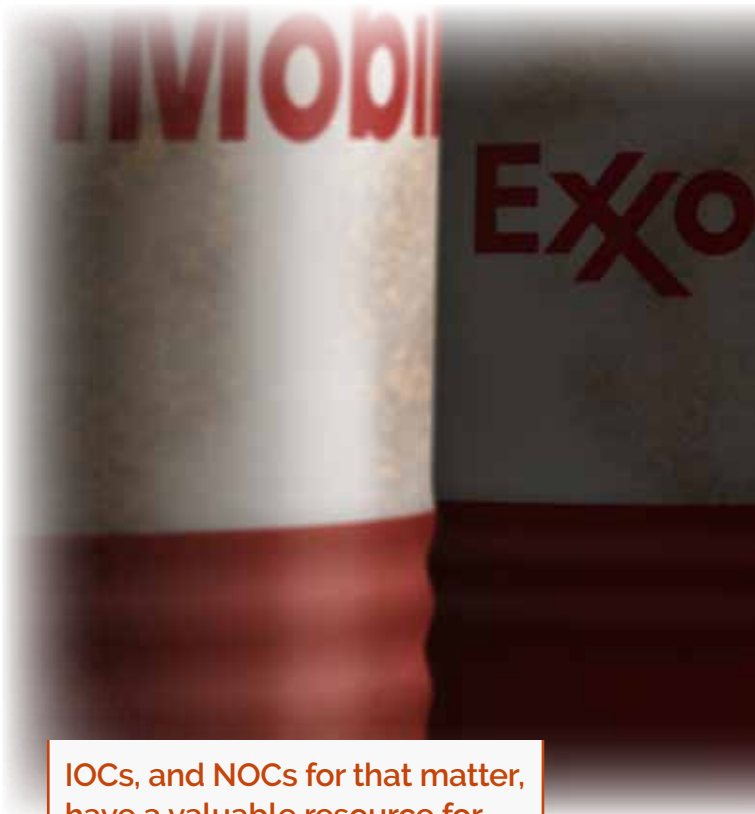
First up: the risk of stranded assets. With the global average timeline from discovery to production averaging around a decade, the line goes that, when institutional investors bankroll hydrocarbons, they are betting that demand for oil will stay high well into the 2030s. That jars against several long-term forecasts, including those of BP and the IEA, suggesting peak demand will be reached by then.

This feeds the narrative that oil prices will be lower for longer, which raises fears that returns will not be realised. The argument goes that, because we could be using less fossil fuels in even a decade's time and that oil use may have dropped off a cliff in several decades' time, then the oil companies' worth is massively reduced. But the logic is flawed. Even in a far-fetched scenario where the world is using much less oil in, say, 30 years' time, the value of the oil companies today would rise. The reason is that there are already sufficient reserves to cover that period. And yet very little value is attached to them.

Large investments

There is the expectation that those same companies will make very large investments, amounting to hundreds of billions of dollars each over the next several decades, in finding more reserves and resources. If global oil use is much less by then, these oil producers will not have to spend.

IOCs, and NOCs for that matter, have a valuable resource for some decades in the future that is not really valued today, and then factored in is the huge capital spend in the pipeline: capex that may not be realised and, therefore, greater profitability. So the claims of stranded assets are back-to-front: companies are worth far more than the current market price even if peak oil demand happens in the shortest of timeframes.



IOCs, and NOCs for that matter, have a valuable resource for some decades in the future that is not really valued today

Then there is the curious case of investment whataboutery, which is akin to faux morality passed off as sound business decisions.

Just look at US heavyweights ExxonMobil and Chevron, which are consolidating through M&A. Both companies are well set to cope with lower oil prices because of their financial discipline over the last few years. They improved their balance sheets by cutting their borrowing. They also have geographically broad upstream assets and significant downstream operations and sustainability arms.

By Paul Hickin,
editor-in-chief,
Petroleum Economist

Integrated business models make these majors less vulnerable to swings in oil and gas prices. ExxonMobil and Chevron are shoo-ins for returns, with both championing around four decades of consecutive dividend increases. Crucial to their success is the maintenance of strong balance sheets to have ample liquidity when there is a downturn and cash in during boom years. These two majors are well-rounded dividend stocks to buy even in a mediocre oil price environment because they have diversified business models and strong balance sheets that can support growing dividends even if profits are falling. They both have business plans based around conservative oil price estimates in the coming years too.

And then there is the ethics argument. But everyone uses oil, everyone needs oil and—whisper it quietly—so many profit from oil. And arguments that oil's competitors—namely electric vehicles—are so much 'better' do not really stand up to scrutiny. The trouble is that the decarbonisation topic trumps every other element of the ethics rainbow, playing down other issues such as the authoritarian control of battery metal supply chains to exploitative child labour.

Carbon footprint

IOCs are decarbonising their businesses, investing in CCS, biofuels and other clean tech, making energy much more efficient—the efficiency gains often exceed the headway made by renewables in terms of carbon footprint—and ensuring a reliable supply of affordable energy. European majors, such as BP and Shell, may have got themselves into a mighty tangle over their energy direction, caught between pressure to clean up their acts and the poor returns from the non-oil and gas parts of their business, but they are now thinking clearly again.

Oil and gas is crucial and the lifeblood of an IOC, a truism as old as oil and gas companies themselves. Maybe it is time to wake up and smell the petrol—it is more investable than some have led you to believe in recent years. ■

US oil production continues slow, steady growth

After hitting a high in 2019, output dropped during the Covid-19 pandemic, only to resume growth in 2021 and reach new highs. The US government expects 2.4% growth in 2025

In the eight years from 2016–24, US oil production (crude oil plus condensate from gas wells) has grown by 49.4%, according to US Energy Information Administration (EIA) data *(see Fig. 1)*. Indeed, the numbers show US output averaged just 8.85m b/d in 2016, grew by 3.5m b/d for three years through 2019, lost 1m b/d during the pandemic of 2020–21 and then topped out at 13.22m b/d in 2024. This remarkable record is spurred by shale activity as well as technological improvements in recovery from conventional wells. Accordingly, the EIA predicts US production will gain another 320,000b/d during 2025.

A closer look at the numbers reveals the bulk of the increase is coming from the Permian Basin of West Texas and southeastern New Mexico. What follows is a look at the five most-prolific regions of the US.

Permian Basin

Since 2016, oil production has more than tripled in the Permian, growing by 205.8%, to 6.27m b/d, in 2024. This was the one region in the country where output continued to grow despite the Covid-19 pandemic.

Improved well productivity contributes to Permian production gains. As noted by the EIA, US oil production has increased steadily despite a decline in the number of active rigs since late 2022. Since early 2023, the Permian region has had more active rigs than the rest of the Lower 48 states.

In the Permian, increased production rates from new completions offset existing wells' output declines, leading to higher oil production. These productivity increases reflect significant efficiency gains and technological advancements. During July 2024, newly completed wells produced an average of 433,000b/d in their first full month.

The EIA forecasts that Permian oil production will increase by 460,000b/d, to 6.27m b/d, in 2024 and then to 6.5m b/d in 2025.

Gulf of Mexico

Production in the federal Gulf of Mexico (GOM) saw a net improvement of 10.6% from 2016 to 2024. After hitting a peak of 1.90m b/d in 2019, output fell during the pandemic but then staged a recovery, reaching a new peak of 1.87m b/d in 2023. However, according to the EIA, production will have fallen by 5.3% this year, to 1.77m b/d. The rate should increase in the next couple of years as new development projects go onstream.

According to the Bureau of Ocean Energy Management (BOEM), about 94% of GOM oil production comes from deepwater wells. BOEM considers water depths greater than or equal to 1,000ft to be deepwater. Deepwater fields have accounted for most GOM oil production since 2000.

The EIA expects 12 new fields to start production in the GOM during 2024 and 2025. Seven fields will be developed with subsea tiebacks to existing floating production units at the surface. The EIA predicts that fields starting production in 2024 or 2025 will contribute 231,000b/d in 2025. Overall, the EIA is calling for a 2.8% increase in GOM output, to 1.82m b/d, in 2025.

Bakken shale

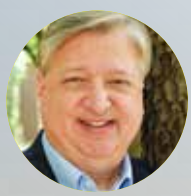
The EIA says Bakken oil production, covering parts of North Dakota and Montana, has had a net gain of

FIG.1: US annual oil production (m b/d)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025-E
Alaska	0.49	0.49	0.48	0.47	0.45	0.44	0.44	0.43	0.42	0.40
Federal Gulf of Mexico	1.60	1.68	1.76	1.90	1.67	1.71	1.73	1.87	1.77	1.82
Lower 48 States (excl. GOM)	6.76	7.18	8.72	9.95	9.21	9.16	9.82	10.64	11.03	11.32
US total crude oil production	8.85	9.36	10.96	12.31	11.32	11.31	11.99	12.93	13.22	13.54

Source: US Energy Information Administration

By Kurt Abraham,
editor-in-chief,
World Oil



13.22m b/d
US oil production in 2024

210,000b/d since 2016, up by 20%. Within North Dakota, Bakken oil output was up about 121,500b/d in 2023 versus 2022. However, the 2023 North Dakota production rate was down compared with 2019's level. The North Dakota production increase in 2023 occurred almost exclusively in the four 'sweet spot' counties of Williams, Dunn, Mountrail and McKenzie.

A small portion of the Bakken shale play is in Montana, but that state's oil production is only about 5% of North Dakota's Bakken figure. The EIA predicts that Bakken output will gain another 80,000b/d during 2025, for a 6.3% increase, to 1.3m b/d.

Eagle Ford shale

Over the last eight years, the Eagle Ford (Texas Railroad Commission Districts 1, 2 and 4) has experienced a small net decline in oil production. Output has dropped by 7.2%, to 1.16m b/d, in 2024.

The region may still produce as much as 300m bl/yr of oil, or about 822,000b/d, by 2035. The extended productivity will come from improved technologies and efficiencies. Nevertheless, the EIA predicts that Eagle Ford oil production will slip by 4.3%, to 1.11m b/d, in 2025.

Alaska

Production in Alaska has declined by 4.3%, to an estimated 420,000b/d, in 2024. Alaska's proved crude oil reserves—which amount to about 3.2b bl—are the fourth-largest in the US.

During 2023, oil production hit its lowest level in 47 years, to 426,000b/d. Most of Alaska's oil production—more than 95%—occurs on the North Slope. For 2025, the EIA predicts that Alaskan oil output will drop further, to just 400,000b/d.

Large areas of the state remain unexplored for oil. Although the Arctic National Wildlife Refuge (ANWR) in northeastern Alaska was opened for exploratory drilling in 2017, the Biden administration cancelled previously issued oil leases for the ANWR's coastal plain in 2023. This is despite the fact that the US Geological Survey estimates the ANWR coastal plain holds 10.4b bl of crude oil. The incoming administration of president-elect Donald Trump may lead to the reopening of parts of the ANWR.

The Department of the Interior in March 2023 approved a reduced version of ConocoPhillips' Willow oil development project that could produce up to 180,000b/d in part of the National Petroleum Reserve. ■

Asia continues to dominate hydrocarbon processing investment

The region accounts for the biggest share in terms of capital investment in the $2t market

The world's population is projected to increase from nearly 8b in 2024 to approximately 9.8b by 2050, according to the UN. This stark rise—combined with an increase in the global urbanisation rate—will significantly boost primary energy consumption.

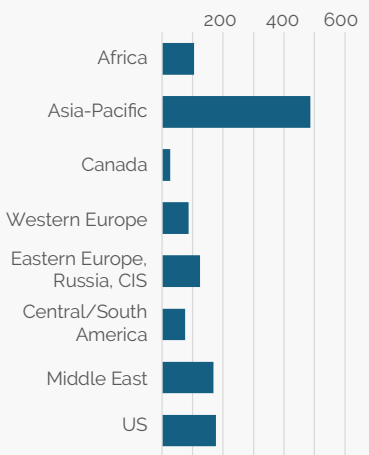
Although renewable energy is forecast to see the highest growth rate in energy consumption to 2050, crude oil is projected to retain the largest market share within the forecast period. For example, according to OPEC's World Oil Outlook 2023, renewable energy consumption is forecast to increase by up to 34% between 2022 and 2045, while oil and natural gas are expected to grow by approximately 15% and 20% respectively. However, renewable energy consumption is forecast to account for nearly 3% of total primary energy demand, while oil and natural gas will account for 31.2% and 23.1% respectively. Coal is expected to make up around 26% of global primary energy demand by 2045, but it is the only form of energy expected to decline in demand during the forecast period.

Depending on what forecast is consulted, global oil demand is forecast to increase from around 102–104m b/d in 2023 to 105–110m b/d by 2030. Much of oil's demand growth will come from its use as a feedstock in the manufacture of petrochemical products. Global petrochemicals demand is forecast to significantly increase to 2050, a direct reflection of urbanisation and a meteoric surge in the global population climbing to a higher socioeconomic status.

For example, around 1b people are forecast to enter the middle class by 2030, reaching up to 5.4b globally by the end of the decade, according to data platform Statista. This rise in the socioeconomic status of the global population will increase demand for products derived from petrochemicals, as well as fuels and natural gas for transportation, power generation, heating, cooking and much more.

With the demand for refined and petrochemical products and natural gas expected to increase in the medium-term, new capacity is being built globally. These investments will help ensure that production capacity is ample to satisfy future demand growth.

FIG.1: Active refining, petchems & gas processing/LNG projects



Source: GEI database

At the time of publication, Gulf Energy Information's Global Energy Infrastructure (GEI) database was tracking around 1,250 active projects in the refining, petrochemicals and gas processing/LNG industries *(see Fig.1)*. This represents an approximately 1% increase in the number of active projects year-on-year.

Most of these projects are within the refining and petrochemicals sectors *(see Fig.2)*—with these two sectors accounting for nearly 75% of the active project market share globally. When broken down by region, Asia continues to lead in total active projects, more than doubling the closest competing regions of the US and the Middle East. In total, these three regions account for nearly 70% of active project market share globally, with Asia representing 40% alone.

When broken down by activity level, 60% of active projects are in preconstruction phases: planning/proposed, feasibility study and pre-FEED.

Global spending

At the time of publication, the GEI database was tracking nearly $2t in active projects in the hydrocarbon processing industry:

- Refining: $620b
- Petrochemicals: $720b
- Gas processing/LNG: $645b

Most of this spending is in the Asia-Pacific region, with investments focused on satisfying increasing demand for

By Lee Nichols, vice president, content/editor-in-chief, Gulf Energy Information

$748b
Capital investment in the Asia-Pacific

refined fuels, petrochemical products and natural gas for power generation. A breakdown of capital investments by sector and region is detailed in *Fig.2*.

At nearly $750b, capital investment in the Asia-Pacific region is more than double that of the next-nearest region, the US. The GEI database is tracking approximately $320b in active capital projects in the US, with nearly 70% of this spending tied to the region's gas processing/LNG sector. The US is followed by the Middle East, at $284b. ■

FIG.2: Total capital investment by region and sector ($b)

Region	Refining	Petrochemicals	Gas processing/ LNG	Total
Africa	95	65	125	285
Asia-Pacific	283	365	100	748
Canada	15	7	26	48
Western Europe	18	9	10	37
Eastern Europe, Russia, CIS	23	90	55	168
Central and South America	36	12	45	93
Middle East	93	126	65	284
US	57	46	219	322
Total	**620**	**720**	**645**	**1,985**

Source: GEI database

Crude oil and changing global energy demand

Oil demand growth may be slowing, but the needs of rising populations and developing economies mean the outlook is still evolving

Global demand for energy is rising steadily due to factors including population growth and economic expansion in developing nations. Crude oil and refined products will continue to be a critical part of the energy landscape for years to come, even as factors such as the energy transition, weakened economics and the potential for oversupply are expected to change the picture.

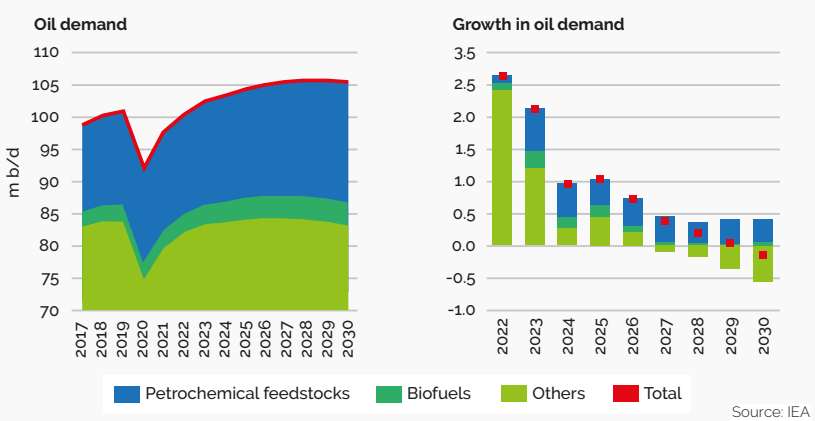
As we move towards the midpoint of this decade, global oil demand will continue to rise, but at a reduced pace, according to some forecasts. In early October 2024, the US Energy Information Administration (EIA) stated that world oil demand is expected to increase by 1.2m b/d, to 104.3m b/d, in 2025. This forecast is about 300,000b/d down from previous statements by the EIA, with sluggish economic activity in both China and North America cited as reasons.

OPEC has also scaled down its global demand growth estimates from 1.74m b/d to 1.64m b/d in 2025 due both to economic struggles and the energy transition. Finally, the IEA stated in mid-October that global oil demand would taper off to approximately 106m b/d by 2030. Additionally, the IEA sees a flattening out of oil demand growth from 2028 to 2030.

Fig.1 shows that the market for petrochemical feedstocks will continue to be a driver for oil demand. Traditional demand for products such as gasoline could arguably reach its peak around 2028, but additional petrochemical implementation could see oil demand continue to rise into 2034–35. This could happen sooner in China, where annual oil demand is expected to increase by 220,000b/d in 2025.

The growth of petrochemical feedstock products would be the primary mover for China, as seen in 2021–24, when 90% of China's oil demand came from petrochemical feedstocks such as LPG, ethane and naphtha.

FIG.1: World oil demand dominated by growth in petrochemical feedstocks



Source: IEA

The Global Energy Instructure (GEI) database continues to track upcoming projects in China such as the Shandong Yulong integrated refining and petrochemical project, which recently started up its first train, and the forthcoming SABIC Fujian petrochemicals complex, which is expected to complete construction in 2026, along with other projects in development.

The energy transition and its effect on crude oil demand will likely be felt towards the end of the decade as electric

By Thad Pittman,
senior research analyst,
Global Energy Infrastructure

vehicle sales continue to rise, led by China with aggressive government support. Refiners will have to consider the onset of reduced demand for road transport fuels, rising biofuel use and geopolitical tensions such as the Russia-Ukraine war. New refining investment plans will have to be developed around these mounting changes.

Significant subsidies

However, it seems India is willing to buck the global trend of reduced traditional fuels. One of the country's goals is cheaper and more reliable transport fuels, and the Indian government continues to provide significant subsidies for diesel, LPG and kerosene. It should also be mentioned that, while India plans to reach net-zero emissions by 2070, fossil fuels are still essential for its rapidly emerging economy.

In August 2024, the EIA stated that it expects the annual growth in liquid fuels consumption to average 4–5% through to 2037 due to emerging elements such as GDP growth and a rising population. The GEI database is tracking nearly a dozen new refineries and refinery expansion projects through 2028, including the 181,000 b/d Barmer integrated refinery, which is due to start up in early 2025.

In North America and Europe, a potential challenge is developing with as much as 1-1.5m b/d of at-risk excess refining capacity by the end of the decade. For example, Germany has been partially addressing this challenge by closing some of its refining capacity due to high energy prices and a weakened economy, partially caused by the Russia-Ukraine conflict, while it continues its push towards the energy transition under an ambitious European net-zero agenda.

> Crude oil and refined products will continue to be a critical part of the energy landscape for years to come

When the pandemic pressed pause on so much refining production in the US at the beginning of the decade, the GEI database tracked several refineries that converted to biofuel production due to the lack of demand and to participate in the energy transition.

What is notable is that many of these conversion plans included backwards compatibility that would allow the option of switching back to crude oil processing. In early October, Vertex Energy announced that its Vertex Mobile refinery in Alabama had converted back to conventional crude oil processing. This is the first US domestic renewable conversion plant to pivot back to petroleum feedstock, and it retains the ability to switch back to renewable feedstock if desired.

It remains to be seen if this is the first sign of new demand domestically, or if it is simply an outlier. The GEI database will continue to track developing crude oil processing refineries and petrochemical facilities, as well as developing biofuel projects around the world as global energy demand keeps evolving. ■

Seize Opportunities Before Your Competitors

Global Energy Infrastructure gives you actionable intelligence to make informed decisions that drive growth and capture new opportunities. Our comprehensive data connects you directly with critical insights across hydrogen, pipelines, refining, CCS, and more, empowering you to lead with confidence.

Why GEI is Essential for Your Business:

Unlock New Opportunities: Identify high-growth regions and emerging trends to act swiftly on new investments.

Strengthen Business Development: Leverage data-driven insights for strategic, long-term growth.

Build Key Relationships: Access decision-makers directly to forge connections that drive new business.

Act with Confidence: Stay updated on project developments to respond quickly and stay competitive.

Experience the ROI of GEI—Book a FREE DEMO Today

Global ENERGY INFRASTRUCTURE

For more information or to get started, please contact Sam Hassaniyeh, *Global Sales Manager,* Sam.Hassaniyeh@GulfEnergyInfo.com.

Gulf Energy

GLOBALENERGYINFRASTRUCTURE.COM

Gas & LNG

Gas cannot secure our future without sufficient investment

The energy transition will not succeed without a reliable baseload, but the world risks a shortfall unless more money goes into gas

Fragility in the global energy markets in recent years has provided ample evidence that the energy transition will be possible only with security of supply and access to affordable energy.

We know these levels of uncertainty are set to continue as we move through the transition, yet current levels of investment in natural gas supply are insufficient to meet the demand trend towards 2030—let alone to 2050. This should be of critical concern to us all, given that natural gas has the greatest potential to complement renewables in the energy transition, providing the reliability needed to balance intermittency and scalability issues.

In addition, 2023 became another record year for emissions from coal use. Shifting from coal to natural gas is the most readily available, cost-effective way to cut emissions in half immediately. However, the investment decisions that will enable provision of the gas supply and infrastructure that will underpin the transition 5–6 years from now risk not being made today.

Investments on the gas supply side, sufficient to deliver the volumes that may be needed in a 5–10-year timeframe, must be made now, given that conventional gas fields can take anywhere from 5–8 years to develop. Living in an era of high energy uncertainty has profound implications for investment decisions, energy infrastructure development and technology planning.

> Investments on the gas supply side, sufficient to deliver the volumes that may be needed in a 5–10-year timeframe, must be made now

Gas demand growth from economic development and improved living standards in the developing world, alongside new consumption trends, is keeping gas demand strong, while producing capacity and infrastructure investment are not keeping pace.

These trends challenge the assumptions of falling energy demand growth that various institutions make in their outlooks. Put bluntly, if energy use continues to evolve as it has in recent years, actual demand will significantly diverge from scenario pathways, potentially leading to a significant gap between demand and available supply of gas and low-CO_2 energy.

Supply shortfall

Between the current projected demand and the volumes from current gas supply, without any further investment there will be a supply gap of around 1,300bcm (29%) by 2030, according to the International Gas Union's (IGU's) 2024 *Global Gas Report*.

New sources of power demand are also emerging. AI-focused datacentres are driving a surge in electricity demand, especially in the US. Extreme weather conditions are significantly increasing global cool-

By Menelaos (Mel) Ydreos,
secretary general,
International Gas Union

ing demand, especially in developing countries with low but growing air conditioner ownership—such as India.

As cooling becomes the fastest-growing energy use in buildings, it puts upward pressure on electricity demand, carving a space for gas to meet these needs. The ability of gas to provide a stable energy supply complements the intermittent nature of renewables such as wind and solar, making it a well-suited source to mitigate these rising energy demand needs.

Investments in gas supply, storage and infrastructure must also happen in parallel with accelerated investment in decarbonising gas technologies, which must be ramped up by orders of magnitude to be consistent with climate targets. Only then can we ensure the priorities of energy security and energy transition do not undermine each other.

Key role

Repurposed gas infrastructure will play a key role in enabling the large-scale rollout of zero- and low-CO_2 hydrogen, thus supporting scalable production and distribution at a much lower cost. Integrating biomethane—chemically identical to natural gas—into the existing energy system and its efficient distribution will require a connection to the gas grid.

Retrofitting existing natural gas infrastructure could also accommodate pure hydrogen delivery and achieve a reduction in hydrogen delivery cost of 20–60% compared with building new hydrogen pipelines. Repurposing gas power plants, pipelines and LNG terminals for zero- and low-CO_2 molecules represents a substantial cost advantage in the path towards a sustainable transition.

As the world has navigated unprecedented energy, financial and political uncertainty, LNG in particular has proved a critical global enabler of resilience in the past two years. The LNG market continues to evolve, with flexible supplies increasing in smaller markets and from smaller market players.

Global supply and demand balances are key indicators for assessing the need for new, multi-billion-dollar investments in LNG projects, with project financing highly dependent on firm offtake deals for future supplies, according to the IGU's 2024 *World LNG Report*.

However, research from the European Economic Review shows that risks related to environmental regulations are increasingly driving up the cost of capital in corporate loan markets through syndicated loans, corporate bonds and higher interest rates charged by banks.

It is critical that such regulations recognise and support regional differences, as gas use varies across countries and global regions. Policies that have cross-border implications, such as sustainable investment criteria or carbon-leakage rules, will need to be recognised and adapted to these differences.

If this does not happen, then policies that raise the cost of capital for gas investments will hurt developing regions the most. They will exacerbate the risk of shortfalls in gas supply and unfairly disadvantage developing regions that are struggling to provide their citizens with access to affordable and reliable energy.

> The global gas industry is essential to building more prosperous, secure, and sustainable societies for everyone

As the world faces growing uncertainty, the global gas industry is essential to building more prosperous, secure, and sustainable societies for everyone. It is doing so through energy diversification, innovation and collaboration.

The required investments not only include natural gas and its infrastructure, but also embrace the potential of low-carbon, decarbonised and renewable gases (including hydrogen, biomethane, synthetic gas and e-methane) to drive an even deeper decarbonisation of the energy system. However, securing this future and balancing the energy trilemma will require continued and sufficient investments across the gas value chain and all the world's regions so that economies can cope with and adapt to a decline in natural supply and growing global energy demand dynamics. ■

Let us not waste time dwelling on diverging gas views

Supporters of the LNG industry need to concentrate on the areas with the most potential before the sector runs out of time to make its mark

LNG terminal in Swinoujscie, Poland

For an industry that takes a long time to get things done, LNG proponents need to shift their focus away from things that may not be worth the effort and dedicate more time to things that will benefit the sector in the long run as well as in the energy transition.

Time is running out for the gas industry to strike and make its mark. The global LNG market is on the brink of a state of oversupply, with BloombergNEF projecting that this is set to emerge in 2027. Prices will fall and so will revenue for LNG producers. What must be done after 2030 will come down to how much demand can be unlocked with low prices.

Time is also running out for gas to figure out its role in the energy transition. The window of opportunity is narrowing for gas to establish itself as the preferred low-carbon option against zero-emissions alternatives across all sectors: power, industry, buildings and transport.

Under time pressure, gas players need to prioritise their efforts and investments in sectors where views on the future role of gas diverge less.

Suppliers of LNG need to extend their reach outside of mainstream gas purchasers and gas demand enablers. Investments beyond import terminals and gas power plants are slow or simply missing. Building an LNG import terminal without connecting it to a wider gas distribution network limits demand upside and value creation from the investment. Not being able to tap non-power sector users could be a real missed opportunity in some markets.

BloombergNEF's Economic Transition Scenario—an economics-led, least-cost modelling scenario—in the 2024 *New Energy Outlook* sees gas consumption in industry rise the most in absolute terms from today to 2050. Finding solutions that play to gas' advantage of being a molecule fuel is worth the time.

What is perhaps a less productive use of time is a single-minded strategy to displace coal-fired baseload generation in the power sector and over-emphasising the role of gas in balancing renewables' intermittency. Coal balances intermittency too, and it is cheaper. It is a hard sell in markets such as China and India where coal reigns supreme in the power system on a bed of cheap domestic supply. Renewables are also growing at an exceptional rate that could, by and large, meet incremental power demand.

To make it worth the time and effort, there needs to be strong indications of coal-to-gas switching potential: low gas prices, the introduction of a carbon price and aggressive coal phaseout plans. But even then, gas power plants will face a tough fight against increasingly cost-competitive renewables.

Opportunities to expand gas-fired capacity are, of course, available. Consider a pecking order of would-be LNG customers for a supplier to target. Customers who already use gas but are running out of domestic supply should be at the top—many of whom are in South and Southeast Asia. These are gas-based economies that have accepted that they will be net importers. They do not, however, necessarily have everything in place to enable the growth of LNG to take off in the power sector. One key enabler is getting power-purchase agreements (PPAs) right, especially addressing the thorny issue of pass-through costs.

It will be worth the investment in time if stakehold-

By Fauziah Marzuki, global head of gas, BloombergNEF

ers can collectively figure out what is the best way to structure PPAs for these developing markets that are becoming newly exposed to international, and potentially volatile, gas prices.

LNG sales and purchase agreements notoriously take a while to close. But they can move faster if both counterparties are aligned and negotiate the best deal for each other. It is not worth the time and effort to play hard ball—from either perspective. There is no 'best price': prices will change and the market will turn. Spending time to ensure price review clauses are nimble enough will ensure both parties see value in the contract. Negotiating for too much or too little flexibility might have unintended consequences further down the line.

> Gas players need to prioritise their efforts and investments in sectors where views on the future role of gas diverge less

All LNG suppliers want the same thing: assurance of demand and getting paid. But buyer wants are varied. Buyers who know they have a need for gas supply to service baseload power should find a supplier that will give them reliability and affordability. Others who have variable demand want diversification, optionality and flexibility—those require very different incentives and concessions in a contract. Spending time to craft an agreement that meets the needs of both parties is worth the time. Being unyielding in pushing one's demands is not.

Come 2030, many things could change for the gas market. Hydrogen as a decarbonisation option for the hard-to-abate sector could turn out to be prohibitively expensive. Gas would be the fallback. Power market reforms may not go far enough to incentivise flexibility and ancillary services, therefore reducing the potential revenue streams for battery and energy storage systems—much to the benefit of gas generators.

The projected LNG supply overhang could spur demand, so much that gas prices end up rising to a level that makes other alternatives attractive again. Strong carbon pricing regimes and policies cracking down on methane emissions are not long shots.

Dwelling on diverging views on the role of gas distracts from taking steps to ensure that, where gas is needed, it will be available. ■

Using gas and LNG to speed up the transition

The role of gas is changing from being a provider of a large volume of energy to peaking supply backing up expanding renewables

Zero-carbon energy continues to increase its share of the energy mix. Gas is seen as a natural partner to back up variable renewable energy, such as wind and solar, because of its firm, fast response and flexible power-generation technologies.

In Australia, the increase in zero-carbon energy has not resulted in an increase in gas-fired power generation (GPG) volumes. Instead, GPG volumes have fallen as more zero-carbon energy supply enters the market. This is primarily due to low—and sometimes negative—operating costs (when subsidies are accounted for) for zero-carbon energy and the low operating costs of incumbent coal-fired power generators. A clear demonstration of this trend can be seen for South Australia, which generates a world-leading 74% of its electricity from wind and solar, and GPG is at new lows *(see Fig.1)*.

In effect, GPG is the electricity generator of last resort, making it a very important part of the generator capacity mix as it ensures peak demand can be serviced and power outages avoided.

The ability of gas supply to meet peak demand is therefore a critical part of the value package of gas. For the east coast of Australia, swing gas supply has been a strength of the large water-drive gas fields in the Gippsland Basin, which met the demand swings of nearby Victoria and New South Wales.

Victoria's gas demand is typically three times greater in winter compared with the summer 'off-season'. Individual days may experience a shift of more than 30% in demand as cold fronts move through. The Gippsland gas fields are in decline, and the total production capacity has already dropped by one-third in the last two years, when the fields provided three-quarters of the gas supply for the southeast of Australia.

Gas reserves on the east coast are 91% unconventional coal-bed methane (also called coal seam gas), which are not well suited to highly variable production. They are also a long distance (more than 2,000km by pipeline) from the major demand centres in Sydney and Melbourne. The long-distance pipelines and gas storage are already operating at capacity in the winter, and it is likely that further expansion will be required in the near future.

LNG plants on Curtis Island, Queensland

It is in this setting that LNG has two potential roles to add to the gas supply and the capacity of the system. The first option is through the diversion of gas feedstock from LNG plants to the domestic market. Each of the three LNG states (Western Australia, the Northern Territory and Queensland) has connections between LNG projects and the domestic gas pipeline system, and most (but not all) LNG projects are active in contributing to domestic supply. Western Australia has a gas reservation policy that aims at securing the equivalent of 15% of

> The reliability of the gas peak energy supply has the added benefit of allowing the transition to go faster and take more risks

By Rick Wilkinson,
CEO,
EnergyQuest

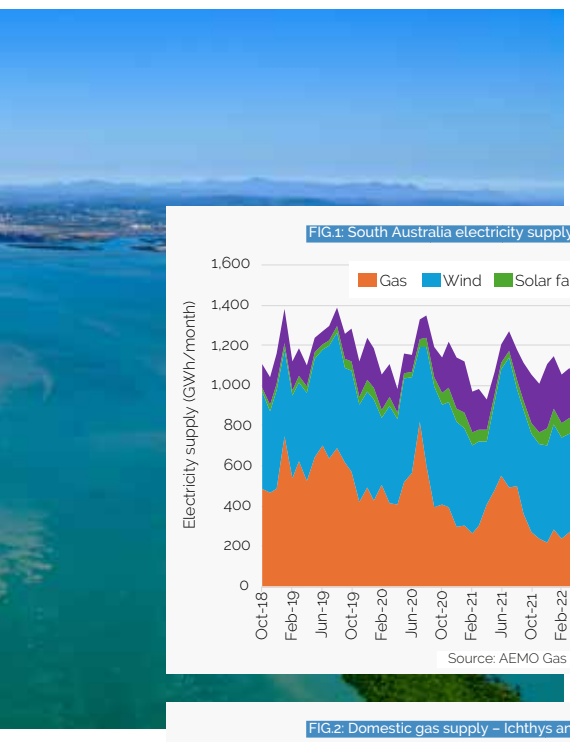
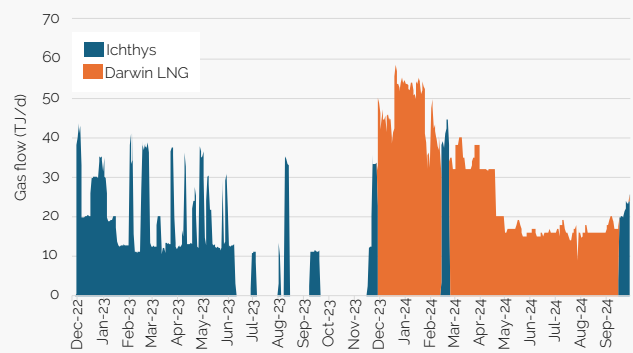


FIG.1: South Australia electricity supply by fuel source

Source: AEMO Gas Bulletin Board; EnergyQuest analysis

FIG.2: Domestic gas supply – Ichthys and Darwin LNG



Source: AEMO Gas Bulletin Board; EnergyQuest analysis

the LNG feedstock volumes for the Western Australia domestic market (which is not physically connected to the rest of Australia).

A typical single LNG train may have a gas feedstock flow of around 250PJ/yr, which is approximately half of the total Australian east coast gas demand. Diverting a small share of the feedstock to meet domestic demand, especially on a peak day or for unexpected supply constraints, should be within the operational parameters of an LNG operation and the domestic market.

LNG project support for a domestic market can be seen in the Northern Territory, where the Darwin LNG and Ichthys LNG projects are providing additional domestic gas supply, after the Blacktip gas field began to shortfall its production requirements *(see Fig.2)*.

The second option for LNG support to domestic markets transitioning to more variable zero-carbon energy is through LNG import terminals. Importing LNG to Australia, which is the world's second-biggest LNG exporter, may seem like a contradiction, if not an outright failure of energy policy. The reality is that the cheapest way to move gas long distances, typically more than 2,000km, is as LNG on a ship. LNG is therefore more like a virtual pipeline and could be used to more cheaply bring gas from the distant Australian LNG projects to the gas demand centres.

LNG regasification terminals add not only gas volume, but also capacity for peaking gas supply. The proposed LNG terminals on the east coast are rated at more than 500TJ/d each, which would compensate for the loss of capacity in the Gippsland Basin.

As we transition to a net-zero-carbon future, the role of gas is moving from supplying large volumes of energy to more firm energy peaking support—a trend already seen in South Australia. The reliability of the gas peak energy supply has the added benefit of allowing the transition to go faster and take more risks, as it provides a backup, or insurance, if the renewables are for some reason not available. Yet having gas available is not holding off the transition to renewables, again as seen in South Australia and more generally on the east coast, as renewables have an operating cost advantage.

LNG is a good fit in this balancing act, as it can readily and quickly add gas supply and capacity either with diverted feedstock or through regasification, in support of the transition to a zero-carbon future. ■

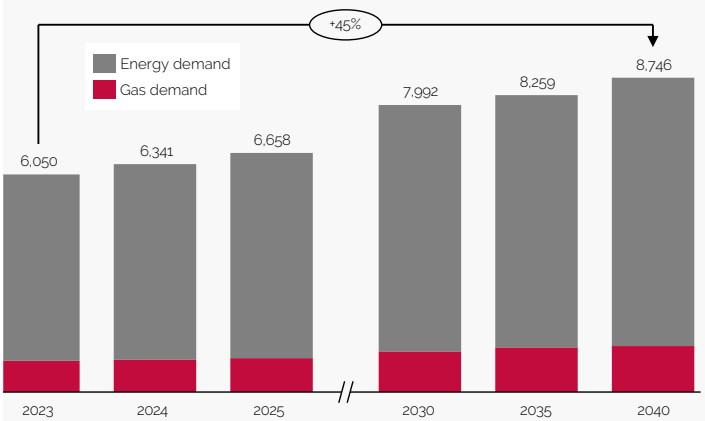
Bridging Southeast Asia's energy gap with gas and carbon capture

Gas with carbon capture can be the solution to the region's rapidly rising energy demand in the age of transition

Asia contains the world's fastest-growing economies and populations. By 2050, the continent is forecast to account for at least half of daily global energy demand. Its economy is driven by rapid urbanisation, industrial growth and rising living standards.

Southeast Asia is ranked second in the world for demand growth. The region is facing significant challenges to meet an expected 45% increase in energy demand by 2040, according to consultancy Wood Mackenzie *(see Fig.1)*. As countries in Southeast Asia strive to meet these growing energy needs, all face the ever-more challenging task of balancing energy security, affordability and environmental impact.

FIG.1: Southeast Asia energy demand (bcm) (excl China mainland)



Source: Wood Mackenzie, May 2024

Energy security and affordability

Historically, countries in Southeast Asia have relied heavily on coal. With its abundance and affordable price, coal consumption today is adversely affected by high environmental costs and significant greenhouse gas emissions. Globally, natural gas has been put forward as an obvious alternative, given it emits only half the CO_2 of coal.

Furthermore, natural gas serves as a more reliable and affordable energy source while renewable technologies continue to advance. Industry leaders recently reached a consensus that natural gas is not only an obvious source of energy but also, with advanced technology, can be produced with lower carbon emissions to qualify as 'cleaner gas'.

Cleaner gas as a transition fuel: a critical bridge

How can Southeast Asia meet the growing demand for baseload energy with cleaner gas? Domestic supply is largely provided through piped gas, while regional distribution and global scale is accomplished via LNG. This demand supports a seamless transition towards cleaner energy by providing lower emissions to allow time for renewable energy to become more economically viable. Thus, it is inevitable that countries will balance effort placed into renewable sources with the production of more cleaner natural gas to meet energy demand.

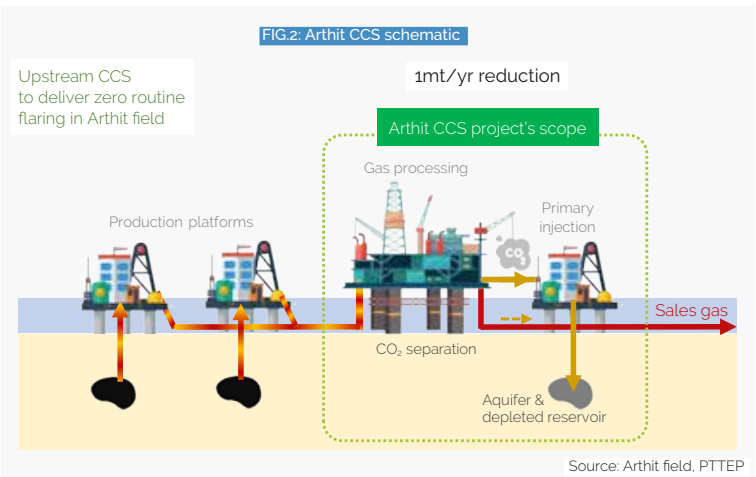
At PTT Exploration and Production (PTTEP), we continue to provide energy security while taking the critical factors of affordability and environmental responsibility into account. We understand why cleaner gas has become more essential than ever. While we are investing in natural gas production projects across Thailand, Malaysia and Indonesia, and developing extensive pipeline networks to deliver gas safely and efficiently, our operations will be carried out with a clear objective to minimise carbon emissions.

Pioneering key technologies for cleaner energy

PTTEP recognises that cleaner gas alone will not be able to combat concern about global climate change. Therefore, we are prepared for the energy transition by investing in advanced renewable energy sources such as hydrogen and offshore wind, while we are increasing gas production and managing emissions through CCS technologies. We will make a significant impact by transforming ourselves into a low-carbon organisation.

One of PTTEP's flagship developments is the CCS project in the Arthit gas field, located in the Gulf of Thailand. This project predominantly reflects our broader strategy to reduce our carbon footprint while continuing to produce natural gas to meet energy demand.

By Montri Rawanchaikul,
CEO,
PTTEP



The Arthit pilot project has been our focus since 2021, with an aim to implement CCS technology by 2027 to reduce CO_2 emissions by up to 1mt/yr *(see Fig.2)*. The project also supports PTTEP's goal of reaching net zero by 2050 and is part of Thailand's target to do so by 2065. A similar initiative is underway at the Lang Lebah gas field development in Malaysia.

Our vision for CCS extends beyond our gas producing fields. PTTEP has introduced the concept of a CCS hub on Thailand's eastern seaboard, offering a CCS service platform for other companies across various industries to store CO_2. Such a service would allow companies to reduce their carbon emissions and enable them to meet their sustainable business goals. The CCS hub will contribute to the region's low-carbon transition. PTTEP sees this as an opportunity to foster innovation and, most importantly, to reduce carbon emissions on a broader scale.

With more companies in the petroleum industry pledging to reach net zero, PTTEP believes that natural gas with CCS is an obvious approach to achieving regional energy security and meeting global sustainability targets. Cleaner gas with CCS fully implemented is the most efficient way to achieve these environmental goals.

> PTTEP believes that natural gas with CCS is an obvious approach to achieving regional energy security and meeting global sustainability targets

Driving regional collaboration

We believe that balancing Southeast Asia's energy security with a climate control target cannot be achieved by one country alone. The effort requires collaboration across borders and industries. This is why PTTEP is committed to fostering regional cooperation by working with other key regional energy companies such as Malaysian NOC Petronas and Indonesian NOC Pertamina, as well as governments and international partners such as Japanese energy companies JOGMEC and INPEX in the region to explore joint ventures. We firmly believe that public-private partnerships and cross-regional collaboration will enable us to scale up CCS. Southeast Asian countries can develop a shared infrastructure for CCS that would not only reduce carbon emissions across the region but also create new economic opportunities.

Despite the tough challenges we are facing, we strongly believe we can all work collaboratively to meet our region's energy needs and create a better future for the next generation.

2025 perspective onwards

When it comes to the challenge of the energy trilemma, the road ahead is not only demanding but also full of opportunities. Natural gas will continue to play a vital role in Southeast Asia's energy mix. It ensures reliable energy supplies as an essential transition fuel to a cleaner future.

CCS technologies—through collaboration, innovation and a shared commitment to progress—will lead to lower carbon emissions in the era of energy transition. As the region continues to grow, PTTEP's approach will serve as a model for balancing energy security, affordability and climate action. ■

Datacentres, AI and the increasing need for power

With electricity consumption continuing to grow and set to surge further with the rise of digital technologies, natural gas remains critical to meeting demand

The insatiable demand for power and electrification continues to be a theme that is dominating the energy, technology and industrial complexes. We have been vocal about the 'age of natural gas' and the notion of natural gas as the most viable transitory fuel source throughout the energy transition in the US to address heightened power demand. And while there has been a tremendous number of regulatory initiatives aimed at accelerating the deployment of renewable energy resources globally, the world—and the US in particular—is quickly realising the intersection of electric load growth and the transition of energy generation resources will not be as cut and dry as originally contemplated.

In our view, there is a multitude of factors at play that jeopardise the ability to achieve the energy transition goals laid out within the US, from intermittency to regulatory, but the most prevalent and likely most important remains the speed at which alternative energy assets will need to be deployed to address the combination of scheduled fossil fuel retirements and load growth.

In addition, the surge in digital transformation and AI has dramatically increased the demand for datacentres, making them pivotal components in the modern energy landscape. As datacentres proliferate, their energy consumption is expected to rise significantly, creating a critical intersection between electrification, AI and natural gas.

The growing demand for datacentres

Datacentres are the backbone of the digital age, supporting everything from cloud computing to AI-driven applications. According to recent analyses, the power requirements for datacentres in the US are projected to more than double, rising from 3–4% of total US power consumption today to approximately 11–12% by 2030. This surge is driven by the increasing volumes of data, computing power and connectivity demanded by digital transformation and cloud adoption. A McKinsey analysis predicts a rise in power demand from 25GW in 2024 to more than 80GW by 2030, requiring an investment exceeding $500b in datacentre infrastructure.

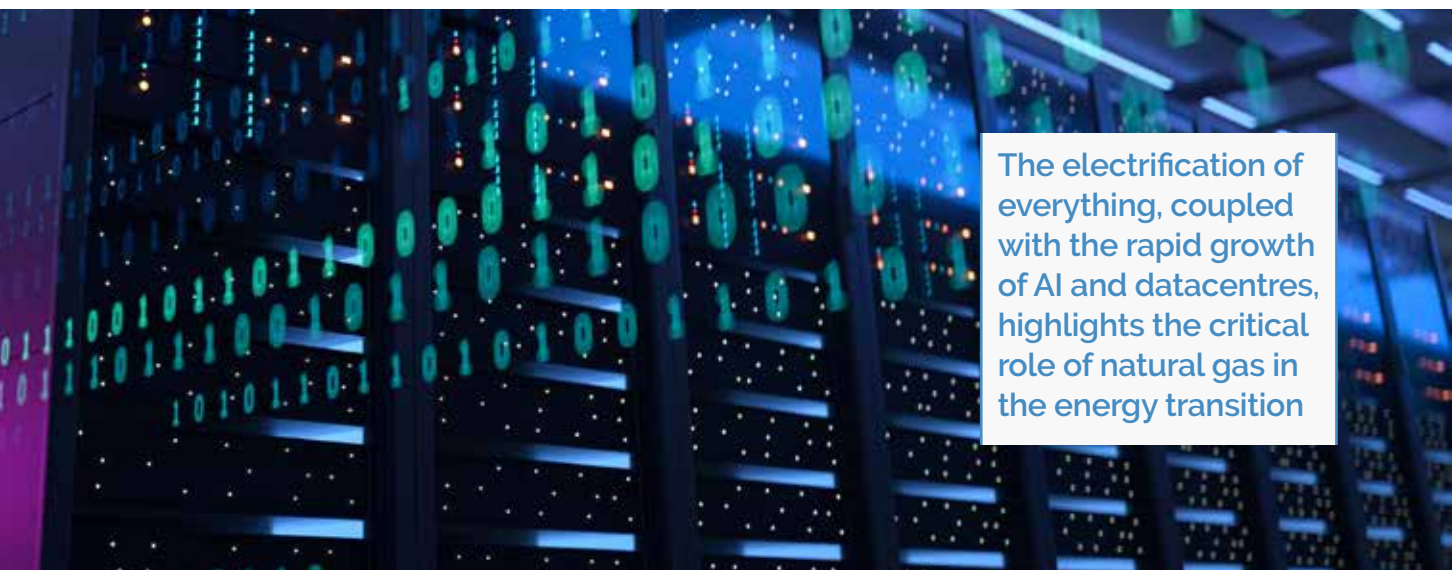
The rapid growth in datacentre demand poses significant challenges to the power sector. Key issues include limited reliable power sources, sustainability concerns, infrastructure for power access and a shortage of skilled electrical trade workers. Moreover, connecting new datacentres to the grid is hampered by long wait times and high costs, with 70% of queued projects typically withdrawn. These challenges highlight the need for strategic investments and regulatory reforms to ensure a robust and sustainable power supply.

Natural gas: A critical component

Natural gas emerges as a critical component in addressing the energy needs of datacentres. Its role is emphasised by its reliability, lower emissions compared with other fossil fuels and its ability to provide dispatchable power. The energy-intensive nature of datacentres and AI operations significantly drives up natural gas demand. Datacentres alone are estimated to consume 10–20% more energy annually, with a substantial portion sourced from natural gas.

The expansion of LNG export facilities and the increas-

By James West,
senior managing director and partner,
Evercore ISI



The electrification of everything, coupled with the rapid growth of AI and datacentres, highlights the critical role of natural gas in the energy transition

ing global demand for natural gas further highlight its importance in the energy mix. Industry leaders such as Baker Hughes and TC Energy are investing heavily in expanding pipeline networks and storage facilities to meet this growing demand. However, these projects often face regulatory hurdles and community opposition, demanding careful navigation of associated risks and challenges.

Electrification and the energy transition

The broader theme of electrification is also reshaping the energy landscape. As society moves towards greater electricity consumption driven by onshoring, reindustrialisation and transportation electrification, the demand for reliable power sources grows. The current deviation between the generation required and new additions being brought online continues to expand due to interconnection delays. This has led to the emergence of onsite or islanded power solutions, with natural gas playing a pivotal role as a transitional fuel source.

The US electricity generation landscape is evolving, with net generation from utility-scale generators reaching approximately 4.2TWh in 2023. Of this, around 60% was produced from fossil fuels, with natural gas accounting for more than two-thirds. This proportion is expected to increase as power demand grows—given its reliable, dispatchable and sustainable characteristics.

Strategic considerations for the future

To sustain its leadership in AI infrastructure, the US must address these energy challenges through strategic investments and regulatory reforms. Ensuring a robust and sustainable power supply is crucial for future AI developments. The intersection of electric load growth and the transition of energy generation resources presents a complex landscape that requires careful management. The lag in the deployment of generating assets supports a bullish stance on natural gas and the 'bring your own power' thematic.

In conclusion, the electrification of everything, coupled with the rapid growth of AI and datacentres, highlights the critical role of natural gas in the energy transition. While challenges persist, the opportunities for growth and innovation in the energy sector are significant. As we navigate this transformative era, natural gas remains a vital component in meeting the growing power demands of the future. ■

Trump to unleash new wave of US LNG projects

The incoming administration is expected to quickly change-up the LNG approvals process and boost several major projects to FID. But market fundamentals still matter

The election of Donald Trump to the presidency of the US has raised hopes among LNG developers, who see an opportunity for significant regulatory reform. But while many promises of sweeping changes will face bureaucratic and legislative limitations once in office, the LNG sector stands out as an area where the president could easily institute immediate and far-reaching reforms.

Within its first few days in office, the new administration is expected to revoke a Biden-era directive to the Department of Energy (DOE) asking it to pause the issuing of LNG export permits while it developed a process for considering their climate impacts. This regulatory shift—moving away from what had been an almost automatic approval—halted a parade of FIDs while project sponsors waited on regulatory certainty. Before the directive, terminals with a total capex of $64b reached financial close over 2022 and 2023. These under-construction terminals, already issued with permits and unaffected by the pause, will almost double the pre-2022 US export capacity of 90mt/yr.

The lifting of the pause on US LNG export permits will unleash another wave of export terminal FIDs. Projects with a combined capacity of more than 45mt/yr are waiting for a DOE export permit and little else. This includes Venture Global's 10mt/yr Calcasieu Pass 2 Phase 1, Kimmeridge's recently acquired 9.3mt/yr Commonwealth LNG project and Cheniere's expansion projects at Corpus Christi and Sabine Pass—together adding as much as 23mt/yr. Currently, 24 US LNG export projects, with a total capacity of 203mt/yr, are in a pre-construction stage of development.

203mt/yr
US LNG projects in pre-construction stage of development

46mt/yr
US FLNG capacity at some stage of development

Floating points

Unblocking the fraught Maritime Administration (MARAD) regulatory process FLNG projects are subjected to represents another significant opportunity for the Trump administration to make its mark. Around 46mt/yr of FLNG capacity is at some stage of development in the US.

These projects do not need Federal Energy Regulatory Commission (FERC) approval (except for associated onshore facilities), dodging a major regulatory hurdle. But those sited in federal waters swap FERC's oversight for that of MARAD, which issues deepwater port licences. In theory, the MARAD approvals process works broadly similarly to that of FERC, with the agency evaluating the ability of applicants to safely build a project and overseeing an environmental review process. But in almost ten years, no US FLNG project has ever received MARAD approval.

MARAD is required by the Deepwater Ports Act to issue a decision within 330 days of the date of publishing a notice of a completed project application in the public register. However, the agency has made more than liberal use of the 'stop clock' mechanism available to federal agencies, pausing the counting of days towards the deadline. In the case of New Fortress Energy's (NFE's) 2.4mt/yr Louisiana FLNG project, an application was submitted to MARAD in April 2022. In August 2022, the agency stopped the clock, citing insufficient information in the application. The clock has remained stopped, despite supplemental submissions from NFE, and the company has since moved the project to the backburner.

Another project, Delfin Midstream's four-vessel, 13.4mt/yr Delfin FLNG facility, received an initial favourable record of decision (ROD) in March 2017, with conditions, after submitting an application to MARAD in May 2015. But no final decision was issued until April 2024, when MARAD denied the application, citing extensive changes to the project since the favourable ROD and requesting Delfin submit a new application that would require a "thorough, statutorily required, interagency, and public review".

By Seth Haskell,
research analyst,
Global Energy Infrastructure

US President Donald Trump on a visit to Cameron LNG in 2019

Delfin argues the changes in its project are the predictable result of a long approvals process. Since the initial application, there have been major improvements in FLNG technology: In 2015, only one commercial FLNG project was operating anywhere in the world. The denial of Delfin's application followed a two-year period in which Delfin had worked to obtain a final approval, including the completion of two supplemental environmental assessments.

MARAD has reviewed several FLNG projects over a period of nearly ten years, and it is unclear if it will ever approve one under the current regulatory regime. While untangling the MARAD process will not be as easy as renewing the issuing of DOE export permits, it should be within Trump's ability to at least make obtaining a project approval possible. Changes at the top—former congressman Sean Duffy has been nominated to lead the Department of Transportation, of which MARAD is a part—may help make the organisation friendlier to FLNG projects. The president also has the power to order a review of the use of the stop-clock mechanism at MARAD.

But it should be noted that issues with MARAD approval were clear as early as 2018 or 2019 during the first Trump administration. FLNG projects should beware, as regardless of Trump's commitment to supporting the industry, government inertia is a powerful force. The returning president failed to effect huge changes in the bureaucracy during his previous term.

International competition

While the US LNG industry is celebrating regulatory reform under Trump, it still faces significant challenges. In parallel to the explosive US LNG build-up, Qatar is adding 66mt/yr of new capacity and there are several large projects in development in Mozambique, Indonesia and Argentina. This surge in global supply will require substantial growth in LNG demand to avoid a buyer's market. If the new administration implements promised tariffs on China—the US LNG's largest customer—retaliatory tariffs could make the hunt for buyers even more difficult. Easier permitting is a boon, but US LNG still needs to find customers. ■

The LNG market: Stuck in the middle

With substantial volumes of liquefaction capacity on the horizon and buyers holding more of the cards, the LNG market is evolving in unpredictable ways

The LNG market is undergoing radical change. At the highest level, the risk has gone from buyers trying to secure accessible supply at a low enough price to sellers finding accessible demand at a high enough price to justify the trade.

Gone are the days when a limited number of LNG producers held most of the cards in a game with potential buyers facing limited alternatives. Not only are more LNG suppliers entering the market each year, options such as renewable energy or even coal also offer viable alternatives depending on the priorities—ranging from pollution control to bearable price—of the buyer.

As a result, the underlying structure of the LNG market will be changing drastically by the end of the decade to what could best be described, albeit somewhat anticlimactically, as the middle. While equity producer Qatar remains a central force in the quest to sign end-use buyers to long-term contracts, it is increasingly the case that equity sellers and portfolio re-sellers of LNG, such as energy majors or trading companies, are taking on extraordinary amounts of length out of both necessity and choice and will emerge as the primary setters of price in the spot market.

The reasons for this shift to the middle are wide-ranging: from believing that LNG demand growth is going to provide high prices and a strong market for this during a lengthy period of energy transition, to simply needing to find a suitable outlet for stranded gas that is holding back stronger development of crude oil and condensate production.

> The amount of investment pouring into creating new supply is outpacing investment in creating new demand by a significant margin

Meanwhile, what end-use buyers are seeing is plenty of LNG supply being built up without the need to sign long-term contracts, putting them in an increasingly advantageous position to sit on the sidelines waiting for multiple offers to emerge.

While buyers will continue to sign some long-term deals to address issues such as security of supply or geopolitical risk, the level of risk associated with buying incremental volumes is not what it once was. In the past, buyers would lock up 90–100% of projected demand under contract. In the future, assuming half this amount would be fair. Even the Russian invasion of Ukraine and subsequent loss of most Russian gas supply to Europe has not been enough to send end-use buyers running to LNG producers for long-term deals.

Rising supply

A 50% increase in LNG supply by 2030 will undermine many of the traditional aspects of how LNG is traded. This supply is under construction and coming to the market whether buyers want to contract it or not. Whether on time or delayed, under long-term contract or on the short-term spot market, this incremental LNG will be entering the market in a manner that promises to be disruptive, and the key question is where prices will need to go for demand growth to keep up.

The amount of investment pouring into creating new supply is outpacing investment in creating new demand by a significant margin, which suggests the price of LNG and gas is going to have to drop to attract buyers. Apart from a sudden belief that LNG demand associated with AI is going to support significantly higher gas use, the presumption is that prices will need to drop for more demand to emerge.

As spot prices drop, these buyers are typically found in the power generation sector, where LNG will be competing with a rapid influx of renewables and battery storage as well as a growing fleet of plants burning low-priced coal. Pricing LNG at a netback that is high enough to make money for sellers but low enough to displace renewables, battery storage or coal will be a tough needle to thread, particularly for the energy majors and portfolios buyers who have already lifted the LNG covering a fixed cost and need to re-sell.

A world is emerging where a significant increase in the volume of LNG spot trading will occur and daily prices will be set at the margin. How these spot prices will

By Ira Joseph,
senior research associate,
Centre on Global Energy Policy at Columbia

interact with long-term contract prices, which in many cases will be tied to oil prices, is unclear. What is clear is that long-term LNG contracts are still being signed; the difference is that they are being signed by buyers that will need to re-sell the volumes to which they are committing. Energy majors such as Shell, TotalEnergies and ExxonMobil—and portfolio players such as Vitol, Trafigura and Gunvor—have taken on this role. Through 5–20-year contracts, these companies have essentially taken a long position on LNG supply, which has allowed many LNG projects in the US, Africa and Asia to be built.

Meanwhile, the Qataris are forging ahead with their own vision of how the market will trade, holding on to the idea that oil-indexed, long-term contracts with end-users will be in demand and that they will remain in a position to provide the LNG. For now, Qatar is not budging and still holds more than 50mt/yr of unsold LNG in equity production that is scheduled to start over the next 36 months.

What exactly they will do with this supply if they cannot find long-term buyers is unclear. In addition, legacy contracts covering the existing 78mt/yr of production capacity will begin to expire at the end of the decade. Significant amounts of this LNG are contracted to Japanese buyers which are either re-signing contracts at lower volumes or dropping them altogether due to declining demand associated with the energy transition, the return of nuclear capacity or a falling population.

It would be a bridge too far to suggest that the LNG market is broken; it is just evolving in a manner that is becoming increasingly difficult to predict. All this new LNG supply will create its own demand; the question is for how long and how low the price will have to go initially for it to happen. ■

Timing is everything

The disconnect between export terminals coming online and vessels being available to transport cargoes means shipping rates are not looking so good, at least in the short term

At this point, all reservations about the medium-to-long-term outlook for growth in the LNG industry seem to be put to rest. New export terminals are ramping up operations in the US, Canada and Africa, with more not far behind in Qatar, Mexico and a smattering of other locations.

With just the projects under construction, we expect the industry to grow by almost 50% by the end of the decade relative to 2023 levels. If that were not enough, the pipeline of new projects likely to make FIDs in the next 24 months should keep the cargo count growth at a frothy pace well into the next decade. All the pricing thus far remains strong given the solid elasticity of demand, particularly in Asia.

Of course, the process of chilling gas molecules to -162C is incredibly complex and outrageously expensive, but it is necessary to move them without pipelines. As a result, there needs to be LNG carriers to transport the ever-growing number of cargoes. There are two compounding effects on the additional shipping needs: Firstly, new voyages will have longer average journeys—roughly two ships per mt/yr are required from North America versus one ship per mt/yr from Australia or the Middle East; and, secondly, of the 675 large LNG ships in the market (excluding FSRUs), 216 are steam turbine vessels, many of which are more than 20 years old and are meaningfully less efficient relative to modern two-stroke engine vessels. As a consequence, while the cargo count is set to rise by 40–50% from 2023 to 2030—depending on Russia and the timing of other projects—we estimate the need for ships could be closer to 65–75% higher.

Currently, the orderbook is 341 vessels, or 384 including those delivered since the beginning of 2024, which represents just over 50% of the size of the existing fleet. On that basis, more ships still need to be ordered to cover the growth in cargo count by the end of the decade. The maths behind solid fundamentals seems straightforward, yet LNG shipping rates are currently at multi-year lows and the forward curve for shipping rates is not much better into 2026.

Ships before terminals

Shipping is the relatively low cost and 'easy' portion of the LNG supply chain. Given that developers may be spending $20b to build an export terminal, they expect to be able to fully utilise the facility by making sure there are ships to move the LNG. Fortunately for those developers, the Korean, Chinese and Japanese shipbuilders are extremely efficient and timely in building new ships, while the timing of new LNG projects is (being kind) hit

By Ben Nolan,
managing director,
Stifel

65–75%

Stifel estimate of rise in need for LNG carriers, 2023–30

and miss. As a consequence, in most large LNG-capacity building cycles, the ships tend to arrive before the cargoes, leaving those shiny new vessels to compete in the spot market until the export projects are up and running.

This disconnect in timing leads us to where the market stands today, which is to say not great for short-term shipping rates, but not bad for the longer-term outlook. The delayed startup of the Golden Pass export terminal means that about 30 ships that should have been dedicated to that facility are poaching cargoes elsewhere. Delays on other projects appear less significant to shipping, but even a few months can be a drag on the supply/demand balance. While several years out, should the regulatory challenges of NextDecade's Rio Grande project lead to construction being stopped and ultimately a delay to startup, there would be approximately 36 too many associated ships in the market until LNG production begins.

The current malaise in LNG shipping rates is particularly disconcerting given that the ships are not transiting the Red Sea. All else being equal, going around Africa significantly lengthens average voyage durations, particularly for cargoes originating in the Arabian/Persian Gulf destined for Europe. Other markets, such as crude and refined product tanker markets, have realised much better than average results as a consequence of the longer ton-miles, but not so much for LNG.

In our view, the teething issues of a growing market are likely to continue to impact LNG shipping for at least the next several years. That is not to suggest there could not be periods of seasonal strength, such as October and November, when over the past few years, Europe has utilised as many as several dozen ships for floating storage in advance of colder months and inventory drawdowns. However, that seasonal godsend for shipping has not materialised in 2024, so there are no guarantees.

Between 2014 and 2018, total LNG production grew by 31%, but shipping rates were stubbornly low, averaging 52% below normal levels during the period, including quite a bit of time below cashflow breakeven levels. So, while LNG is structurally a growing industry, shipping is still a cyclical business, and history has shown the two can coexist with limited correlation. That is not to suggest there will not be opportunities and that the future is written in stone, but for now, it may be prudent to hope for the best but prepare for the worst—at least for the next several years. ■

LNG outlook: 2025 and beyond

Significant expansions are underway in both liquefaction and regasification capacity as LNG firms up its position as a long-term solution for the world's energy needs

LNG has emerged as a crucial player in the global energy mix, serving as a bridge between the carbon-intensive present and a cleaner, more sustainable future.

LNG has witnessed a surge in demand over the past decade. Its role as a transitional fuel is particularly pronounced in regions that are heavily reliant on coal-fired power plants. Countries such as China and India, with their growing economies and energy demands, have turned to LNG to reduce their carbon emissions while ensuring energy security.

The competition for LNG resources is intensifying as countries vie to secure their positions in the global energy market. The US, Australia and Qatar have emerged as the leading LNG exporters, with substantial capacity expansions planned for 2025 and beyond.

In the US, ExxonMobil's Golden Pass project is set to commence operations with two LNG trains, each capable of producing 6mt/yr. Additionally, Corpus Christi Liquefaction Stage III will increase that plant's capacity by a further 9.52mt/yr, bringing the total to 24.52mt/yr. By the end of 2025, the US is expected to surpass 125mt/yr of LNG capacity and could reach more than 300mt/yr by 2028, solidifying its position as the world's largest producer of the fuel.

While Australia does not have any projects under construction for 2025, plans are in place to expand the Pluto LNG project in 2026. Australia's total LNG capacity remains slightly above 83mt/yr and is set to rise to nearly 90mt/yr in 2028.

Qatar, already a major LNG exporter with 77mt/yr of operational capacity, is undertaking significant expansion projects. The North Field East development will add an additional 32mt/yr in 2025, followed by North Field South, which will contribute another 16mt/yr by 2027. Qatar's ambitious plans also include a further expansion of 16mt/yr by 2030.

In Canada, Shell's long-awaited LNG Canada project is poised to enter full commercial operations in 2025. This two-train project, with a capacity of 14mt/yr, is strategically located to supply LNG to Asian markets. Two other large projects—Ksi Lisims LNG (12mt/yr) and Kitsault LNG (20mt/yr)—could, if approved and built, make Canada the fifth-largest producer by 2028.

Fig.1: Top five LNG producing nations by 2028

	Country	Export capacity 2024 (mt/yr)	Export capacity 2028 (mt/yr)*	Growth rate
1	US	92.55	312.06	237.2%
2	Qatar	77.00	125.00	62.3%
3	Australia	83.50	89.90	7.7%
4	Indonesia	35.99	35.99	-
5	Canada	0.69	34.99	4,971.0%

*Assuming all current projects under construction, planned and proposed reach operational status.

Source: GEI database

LNG-importing countries are rapidly increasing their regasification capacities to meet growing energy needs, particularly in Asia and Europe. The Asian LNG consumption market is dominated by Japan, South Korea and China. China in particular has ambitious expansion plans, with more than 50mt/yr of LNG projects either under construction or planned to commence in 2025. This significant increase will add to China's existing capacity of 123.75mt/yr. Such is the demand in China that data projections suggest capacity could double from 2024 figures to nearly 250mt/yr.

India is also set to almost double its import capacity in the next three years. The majority of this growth will be through expansions to existing projects.

Korea Gas Corporation is constructing an additional 11.6mt/yr of capacity at the Dangjin LNG terminal in northwestern South Korea, with further expansions planned. In Japan, the second phase of the Naoetsu LNG project will add a modest 1.2mt/yr of capacity to its operational terminal. Japan currently boasts more than 200mt/yr of available capacity, while South Korea has 114mt/yr.

300mt/yr

Potential US liquefaction capacity by 2028

By Peregrine Bush,
senior director, data and technology,
Global Energy Infrastructure

Europe is witnessing a noteworthy push to expand LNG import capacity, driven primarily by the desire to keep diversifying gas supply sources away from Russian pipeline volumes. Between 2025 and 2028, an additional 138.13mt/yr of regasification capacity is expected to come online.

Global Energy Infrastructure data shows that the German LNG capacity growth rate will be over 400% by 2028. Seven projects are either under construction or planned across Germany, utilising a mixture of FSRU vessels and land-based plants. Other Baltic Sea nations looking to diversify gas supply away from Russia include Estonia, Latvia, Lithuania and Poland—with import capacity adding up to more than 18mt/yr.

These projects, among others, are contributing to Europe's efforts to enhance energy security and reduce reliance on a single gas supplier.

Fig.2: Top five LNG receiving nations by 2028

	Country	Import capacity 2024 (mt/yr)	Import capacity 2028 (mt/yr)*	Growth rate
1	China	123.75	249.23	101.4%
2	Japan	202.82	203.02	0.1%
3	South Korea	114.10	129.20	13.2%
4	India	47.50	94.70	99.4%
5	Germany	11.00	55.48	404.4%

*Assuming all current projects under construction, planned and proposed reach operational status.

Source: GEI database

LNG is poised to continue to play a vital role in the global energy transition. As renewable energy sources become more competitive, LNG can be used to provide baseload power and support the integration of intermittent renewable energy sources such as solar and wind.

As the world continues to grapple with the challenges of energy security and geopolitical issues, LNG has emerged as a vital transition fuel. Its role as a bridge between the carbon-intensive present and a more sustainable future is becoming increasingly evident. While the industry faces challenges related to geopolitical competition, environmental concerns and technological advancements, the potential benefits of LNG are undeniable. As the global shift to a low-carbon economy progresses, LNG is likely to remain a significant player for the long term. ■

Trusted. Partners.

Advising clients across the full life cycle of the energy industry for more than 70 years

Energy Legal Services Provider of the Year

Gulf Energy Information Excellence Awards 2024

WHITE & CASE

Bridging climate action and sustainable development with natural gas

Global population growth is leading to ever-rising demand for reliable and affordable energy, a need gas is perfectly placed to meet

Energy poverty is one of the most pressing challenges globally, disproportionately affecting low-income regions where billions lack access to electricity and clean cooking fuels.

As the global population is expected to increase by more than 1.7b by 2050—mainly in Africa and Asia—the demand for affordable and reliable energy will grow, despite energy efficiency improvements. For many, energy access is not just a utility, but a fundamental need tied to poverty alleviation, healthcare improvement and socioeconomic development. However, expanding energy access while limiting greenhouse gas emissions presents a dilemma: how can we meet these pressing development and social needs and still address the challenge of climate change?

> Investing in natural gas as part of a diverse energy mix can foster a more equitable world

Natural gas, as the least carbon-intensive hydrocarbon, offers a viable bridge between these seemingly conflicting objectives; it provides cleaner, affordable, reliable, versatile and flexible energy that supports socioeconomic development while mitigating environmental impacts. Its lower carbon footprint and extensive applications make it essential for tackling the global 'energy trilemma': balancing energy security, economic growth and environmental sustainability.

Rising energy demand and sustainable development

Global primary energy demand is expected to increase by 20% by 2050, with more than 80% of this rise concentrated in low- and middle-income countries across Africa and developing Asia, according to the Gas Exporting Countries Forum's eighth *Global Gas Outlook (GGO)*. In these regions, the drive for improved living standards and economic growth increases energy demand, which is essential for meeting basic needs and advancing UN Sustainable Development Goals. For many of these economies, natural gas provides a cleaner alternative, supporting a transition to modern, sustainable energy sources.

In power generation, for instance, switching from coal to natural gas can reduce CO_2 emissions by nearly half and enhance urban air quality. This shift has proven effective in reducing greenhouse gas emissions and providing a stable power supply, improving environmental and public health outcomes. Moreover, in residential settings, LPG offers a safe and clean alternative to traditional biomass, which is used for cooking in many low-income regions. This transition curtails indoor air pollution, preserves forests (a vital carbon sink), helps alleviate energy poverty and empowers women and children.

Enhancing renewable energy integration

Natural gas also provides backup and stability for renewable energy, addressing one of the primary challenges of solar and wind power: variability and intermittency. As renewable energy use grows, so does the need for reliable flexibility and backup that can stabilise electricity grids, especially during periods of low wind or sunlight.

This is also the case for hydropower in droughts. This reliability is particularly valuable in areas prone to cli-

By Dr Mohammad Amin Naderian,
head, energy economics and forecasting department
and Dr Abubakar Jibrin Abbas,
senior energy forecast analyst, GECF

mate variability, such as Latin America, where droughts can limit hydropower generation, as observed in the last four years. By supplementing renewable sources, natural gas enables a smoother, more resilient shift towards clean energy without sacrificing reliability.

It is also likely that natural gas will be the main fuel to support the increased demand for dispatchable electricity created by power-hungry artificial intelligence datacentres.

Supporting industrial growth and food security

Beyond power generation, natural gas has vital applications across industries, notably as the primary feedstock for ammonia production in fertilisers. Fertilisers are essential for boosting crop yields and supporting food security, particularly in developing regions, where agriculture remains a dominant form of livelihood. As food demand rises along with populations, access to affordable fertilisers directly impacts global food security. Additionally, natural gas is foundational to producing materials such as plastics, synthetic fibres and pharmaceuticals, underpinning industrial development, healthcare and economic progress.

This versatility across sectors highlights natural gas' multi-dimensional role in sustainable development—fuelling industrialisation, supporting public health and enabling countries to build self-sufficient economies. These benefits are essential for emerging economies striving to lift millions out of poverty and improve quality of life, aligning natural gas use with several core Sustainable Development Goals.

According to the *GGO*, global natural gas demand is projected to increase by 34% from 2023–50. By 2050, natural gas is expected to become the leading energy source, accounting for 26% of the global energy mix—up from its current 23%.

Environmental sustainability via technology

While natural gas is inherently cleaner than other hydrocarbons, recent technological advancements are further reducing its environmental impact. CCUS and methane abatement technologies are helping to minimise emis-

sions across the natural gas lifecycle, from extraction to end-use. CCUS allows industries to capture CO_2 emissions, preventing them from entering the atmosphere, while methane abatement tackles leaks that would otherwise contribute to climate change.

In addition, blue hydrogen—hydrogen produced from natural gas with captured CO_2—emerges as an effective tool for decarbonising sectors that rely on high-temperature processes, such as cement and steel manufacturing. Together, these technologies enhance the role of natural gas as a cleaner energy source, facilitating its integration into the low-carbon economy. For many countries, natural gas, backed by these technologies, serves not just as a bridge but as a sustainable energy source that meets both present and future needs.

Contextualising gas: Transitional versus destination fuel

The role of natural gas varies by region, reflecting different socioeconomic priorities and environmental goals. In developed economies such as Europe, where rapid decarbonisation is a primary objective, natural gas functions as a transitional fuel supporting a structured shift towards renewables by providing backup for intermittent sources. Here, the emphasis is on using natural gas to ensure energy security while meeting ambitious emissions targets, making it a bridge in the journey towards a fully decarbonised energy system.

In contrast, in low-income regions where energy needs are immediate and centred around affordability and reliability, natural gas is seen as a 'destination fuel'. For these countries, natural gas is foundational to achieving long-term development goals, fostering industrialisation, enhancing food security and alleviating energy poverty. It supports economic growth by providing stable energy for businesses and cleaner options for households, positioning it as an enduring energy source rather than a transitional one.

1.7b

Global population increase by 2050

The ethical case for gas investment

The call to halt fossil fuel investments, including in natural gas, raises ethical concerns, especially for developing regions with low historical emissions and high development needs. Africa, for example, holds approximately 8% of the world's natural gas reserves but has contributed only 3% of global historical emissions.

For African countries, denying access to natural gas undermines their opportunity for socioeconomic progress and energy independence, potentially deepening global inequality. By providing these regions with a sustainable development tool, natural gas investments align with global equity and fairness principles, offering an ethical pathway for low-income countries to build robust economies and improve living standards.

Conclusion

Natural gas holds a pivotal role in bridging the need for climate action and sustainable development, especially in regions facing severe energy poverty. Its versatility, relatively low emissions and ability to support both renewable integration and industrial growth position it as an invaluable asset in the global energy landscape. By advancing technologies such as CCUS and blue hydrogen, we can further minimise natural gas's environmental impact, aligning it with long-term climate goals.

As countries pursue energy transitions based on their national circumstances and capabilities, natural gas offers a balanced approach to meeting diverse energy needs while supporting the goals of energy security, socioeconomic equity and environmental sustainability. For many countries, it is more than a bridge, it is a vital foundation for a resilient, just and inclusive energy future. Investing in natural gas as part of a diverse energy mix can foster a more equitable world, addressing immediate development needs while laying the groundwork for a sustainable, low-emissions economy. ■

PE Outlook 2025

Geopolitics and markets

A new era in energy: How the UK offshore sector can lead in a competitive market

The government must take the opportunity to harness the sector's immense potential to support the long-term development of the UK's low-carbon sector

In today's rapidly changing world, we face a unique set of challenges. The cost-of-living crisis, rising geopolitical tensions and the urgent need to address climate change create a landscape where collaboration between governments, industry and the public is essential.

At the heart of these discussions is the need for economic growth driven by our offshore energy sector. For the past 50 years, this sector has been the backbone of the UK's energy supply, meeting approximately 50% of our oil and gas needs. It supports more than 200,000 skilled jobs and contributes £30b ($39b) to the economy, providing a solid foundation for our energy future.

The UK is home to a world-class energy supply chain composed of hundreds of companies that, while not household names, are the lifeblood of the offshore energy sector. These firms employ tens of thousands of people, using revenue from oil and gas activities to invest in wind, hydrogen, carbon capture and the broader energy transition. However, unlocking the potential for significant investment in homegrown energy production will require supportive government policies, including a predictable and competitive tax regime.

UK offshore energy companies could invest up to £200b this decade in carbon storage, hydrogen and renewable energy projects alongside producing the oil and gas the country needs. This investment will help the UK meet its net-zero commitment by 2050—or sooner—by decarbonising offshore energy production to power homes and businesses. By leveraging our extensive North Sea experience and innovative technologies, we can ensure our energy needs are met sustainably, securing a brighter future for communities across the UK.

> If Labour intends to make the UK a global superpower in clean energy, it must collaborate with the existing offshore sector and foster an environment that encourages private investment

If Labour intends to make the UK a global superpower in clean energy, it must collaborate with the existing offshore sector and foster an environment that encourages private investment. Chancellor Rachel Reeves must implement a clear industrial strategy that builds on our strengths.

By David Whitehouse,
CEO,
Offshore Energies UK

Accelerating renewable energy is crucial for achieving net zero, but it is important to remember that 24m homes in the UK still rely on gas for heating. Ignoring the need for domestic production would be a serious mistake. We cannot protect consumers or tackle climate change by relying solely on imported energy. Balancing the rapid expansion of renewables with domestic production is essential for energy security.

Window of opportunity

We have a narrow window to get this right. The US and China are already engaged in a competitive subsidy race to advance clean energy technologies, and global competition for renewable energy investment is fierce. A volatile fiscal environment could drive investment elsewhere, to countries with more favourable policies.

Public investment plays a vital role in our energy transition. Price support mechanisms have gone some way to unlocking the UK's offshore wind potential and can do the same for floating wind, carbon storage, hydrogen and necessary infrastructure investment.

However, the bulk of the £1.4t needed to achieve net zero must come from private companies.

We need a fiscal regime that offers a fair return and prioritises the UK supply chain. Windfall taxes and negative rhetoric about our energy companies can deter the private investment we urgently need. The demands on the UK Treasury are significant as we manage historic debt, high inflation and challenging borrowing environments.

Success and growth will rely on collaboration between private and public capital.

Our long-term goal should be to grow low-carbon sectors rapidly in a way that is revenue-neutral for the Treasury, with subsidies diminishing over time as enduring economic value is created.

Ultimately, this is about people and communities. We must avoid further de-industrialisation and ensure a just transition that includes everyone. Prime Minister Keir Starmer's commitment to managing the North Sea responsibly and safeguarding jobs is a step in the right direction, but words must translate into action. Recent government approvals for Track 1 carbon storage projects mark a significant milestone, positioning the UK as a leader in this emerging market, with the potential to offer storage solutions to European neighbours.

Similarly, the UK is making huge strides in offshore wind. The first commercial-scale floating offshore windfarm in Europe, developed by Flotation Energy, will soon be operational off the coast of Aberdeenshire, Scotland, powering both offshore oil platforms and the national grid. This is just one example of how our sector is already contributing to the energy transition.

We are also encouraged by the decision to locate the government's new GB Energy headquarters in Aberdeen, with satellite offices in Edinburgh and Glasgow. This reinforces what we have long argued: the path to a successful energy transition lies in leveraging our existing industrial strengths. Listening to industry experts and building partnerships will be key to the success of Energy Secretary Ed Miliband's new agency, as we navigate the challenges and opportunities of the energy transition.

The potential for growth and leadership in the net-zero economy is within our grasp. Let us choose the path that makes the most of existing resources and builds on our industrial strengths and our skilled people. ■

Navigating the windfall tax and the future of UK energy

Policymakers and stakeholders must work together to develop a stable and predictable fiscal regime that prioritises the country's energy security and economy

The UK government recently announced an increase in the windfall tax on oil and gas companies from 35% to 38%, a move aimed at capturing a share of the "extraordinary profits" generated during soaring energy prices. While the additional 3% will undoubtedly inject a significant sum into the budget, concerns are mounting about the potential long-term consequences for the UK's energy security and economy.

The windfall tax, designed as a temporary measure, is intended to fund support packages for households struggling with rising energy bills. This short-term gain, however, will likely come at a steep price.

The tax directly impacts the profitability of oil and gas companies operating in the UK, significantly discouraging investment in new projects and exploration.

> We must be wary of unintended consequences that could jeopardise the nation's energy security and economic stability

As the situation on the ground has demonstrated over the past few months, the Energy Profits Levy (EPL) risks undermining the very industry that is crucial to meeting the UK's energy needs, and we must be wary of unintended consequences that could jeopardise the nation's energy security and economic stability.

Ambitious target of net-zero emissions by 2050

The UK still relies heavily on fossil fuels, which made up 78.4% of its energy sources in 2022. While this shows a decrease from 87.2% in 2012—mainly due to less coal use—the transition away from fossil fuels remains a challenge.

The UK has pledged to reduce its greenhouse gas emissions to net zero by 2050, but this goal is ambitious. The current pace of reduction is slow, making it difficult to achieve net zero within the proposed timeframe.

It is clear that completely shutting down oil and gas production too quickly could have negative consequences, disrupting energy supply and potentially causing economic instability. A gradual transition is crucial to ensure a stable and secure energy future.

But high taxes discourage investment in new oil and gas exploration. This is particularly concerning as the UK already relies heavily on imports to meet its energy demands. By stifling domestic production, the windfall tax could worsen this dependence, leaving the nation vulnerable to global price shocks and supply disruptions.

Additionally, renewables are not yet capable of consistently delivering the baseload power required to keep the lights on. Placing unrealistic expectations on green energy while simultaneously discouraging fossil fuel investment is a recipe for energy insecurity.

Scrapping investment allowances: a double blow

Adding to the concerns, the latest change in the tax will also eliminate within a year the levy's 29% investment allowance, which allows companies to offset tax from capital that is reinvested. Needless to say, this move further discourages investment in the sector, as companies now have even less incentive to reinvest their profits in the UK.

This has already created a negative cycle of reduced investment, job losses and further decline in domestic energy production.

However, considering that the announcements leading up to the final budget indicated that the current government would remove the investment allowance for the sector entirely, it could be interpreted as a first step by them to being open to finding more constructive solutions for these issues and an effective energy transition as a whole.

Economic repercussions and a ripple effect

Unfortunately, the impact of the windfall tax will quickly extend beyond the oil and gas companies. A diminished profit landscape leads to cost-cutting measures. This immediately translates into reduced contracts for supply chain companies, many of which are local businesses

By Francesco Mazzagatti,
CEO,
Viaro Energy

supporting the offshore sector.

These SMEs, often based in regions such as the east of England or in Scotland, are vital employers and contributors to local economies. A slowdown in their activity due to reduced contracts could lead to job losses, impacting workers and potentially triggering a talent migration from the region.

The impact on our operations

The EPL creates a substantial financial burden, primarily impacting our ability to invest in new projects. The North Sea holds significant remaining potential, but developing these resources requires capital investment. The windfall tax reduces our capacity to fund these vital projects.

Funds are diverted into maintaining existing infrastructure. Safe and efficient operation of our existing assets requires ongoing maintenance and upgrades, and we prioritise spending money on these aspects of running a business.

In addition, we are committed to playing our part in the transition to a lower-carbon future. But, the windfall tax, to a degree, limits our ability to invest in renewable energy technologies and carbon-capture initiatives.

In the face of these challenges, we are taking proactive steps to mitigate the negative impact of the EPL:

- Engaging with policymakers: We are committed to constructive dialogue with the government, highlighting the long-term consequences of the windfall tax and advocating for policies that support sustainable energy production.
- Optimising operational efficiency: We are constantly striving to improve efficiency across our operations, reducing costs and maximising production from existing fields.
- Exploring new technologies: We are actively seeking and implementing innovative technologies that can enhance production and reduce our environmental footprint.

While the windfall tax presents significant challenges, we remain committed to our role in the UK energy sector. We believe that a stable and predictable fiscal regime is essential to encourage investment and ensure the long-term security of energy supply. By working together with policymakers and stakeholders, we can navigate these challenges and build a sustainable energy future for the UK. ■

UK offers upstream opportunity as transition and policy evolve

The importance of the oil and gas sector to the UK and the value of its assets mean 2025 could offer new opportunities and a recovery in activity

The UK upstream continues to be under pressure as the basin ages and successive governments have leaned on the sector for increased tax revenues. The country, on the other hand, maintains a significant reliance on oil and gas for its energy requirements, and the extent to which a material pivot to renewable sources will be achieved in the coming years remains a subject of debate.

As such, not only is UK oil and gas well positioned to continue making a meaningful contribution to the country's energy use, the underlying value of the assets, infrastructure and services remains, and ongoing policy clarity during 2025 could—in our view—drive renewed opportunities for operators and a recovery in sector activity.

Domestic oil and gas still attractive for UK

In 2023, more than 72% of UK primary energy demand was met by oil and gas. This contribution has been largely consistent for the last two decades, with the growth in UK renewables mainly displacing coal. Despite this significant and sustained demand for oil and gas, the UK's domestic contribution to supply has reduced markedly. In 2000, the UK consumed 1.7m b/d of oil and 9.8bcf/d of gas and was a net exporter of both. In 2023, domestic oil consumption was 1.3m b/d with imports of 46%, while gas consumption was 6.1bcf/d with imports also at 46%. There is hence significant scope for increased domestic production for to help meet domestic demand overall.

Producing its own oil and gas has numerous advantages for the UK. Apart from the tax revenues generated, it supports significant employment—trade association Offshore Energies UK estimates the UK industry supports 200,000 full-time jobs—increases security of supply, can help put downward pressure on regional gas prices and reduces emissions versus imports. Indeed, the UK government has estimated supply via LNG imports is over 2.5 times more carbon-intensive than domestic volumes.

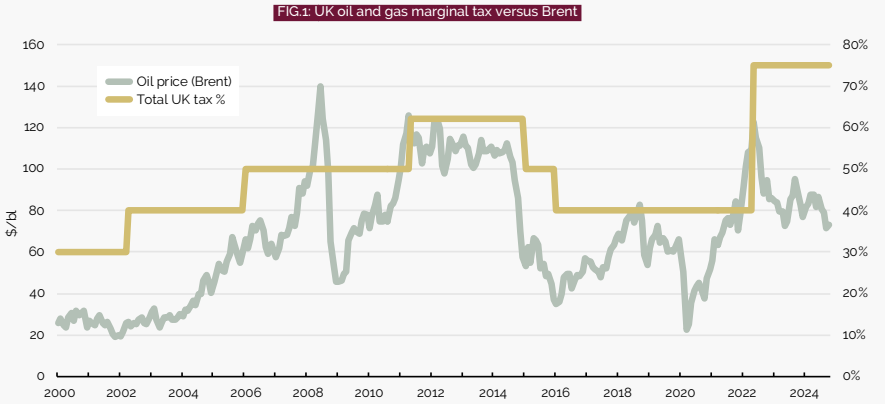
Given the obvious and consistent domestic demand and the advantages to be had from domestic production, UK oil and gas production has clear value to the country. While the UK government has ambitious plans to remove hydrocarbons from the UK power grid and reduce internal combustion engine vehicle use over the coming years, it is hard to imagine a scenario where UK domestic oil and gas demand falls to anywhere near the level of domestic production any time soon, whatever the government's aspiration.

Policy continues to evolve

The UK has a track record of adjusting its oil and gas tax regime on an ad hoc basis, often in response to oil prices. The most recent, and most enthusiastic, example of this was the introduction of the Energy Profits Levy (EPL) in 2022 by the Conservative government, in response to higher oil and gas prices driven by a combination of the Ukraine war and underinvestment during the Covid pandemic.

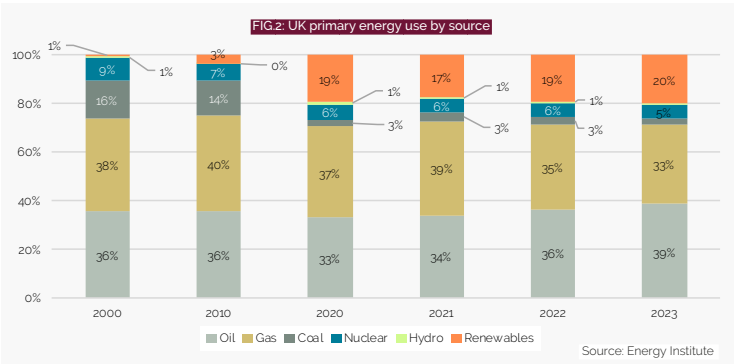
The Conservatives raised and extended the EPL on several occasions, and it was then recently continued

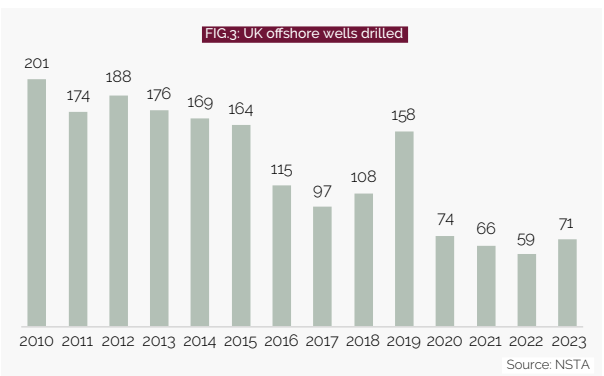
FIG.1: UK oil and gas marginal tax versus Brent



Source: UK government; Bloomberg

By Daniel Slater,
director, research,
Zeus Capital





by the new Labour government, which topped the total UK oil and gas tax burden out at 78%, while also removing a helpful 29% investment allowance available against the EPL.

This has had a painful effect on the UK sector, both in terms of mood and actual activity. Over 2010–19, the average number of wells drilled offshore UK was 155. This unsurprisingly dipped in the pandemic years of 2020 and 2021 but has since failed to recover, with 59 wells drilled in 2022 and 71 in 2023—the years in which the EPL has been in effect. This is despite a healthy oil price environment otherwise conducive to increased investment.

There is now a chink of light, however. At the recent UK budget, the government chose to maintain all capital allowances for oil and gas, despite having guided to a review of these as they apply to the EPL. This gives a degree of confidence that, despite more than two years of negative changes, fiscal terms may not now get any worse.

The government is also progressing two important industry consultations. First, there is an ongoing consultation as to how development licence applications should deal with scope three emissions, in light of the UK supreme court Finch vs Surrey County Council ruling. This consultation is due to report by spring 2025 and should provide helpful regulatory clarity for what should be a straightforward and largely academic piece of work. Second, in early 2025 there will be a consultation on the UK fiscal terms to apply post the end of the EPL in 2030, targeting a long-term regime giving clarity on tax rates when prices rise.

In our view, it is good to see the government getting on with both of these processes.

What are the opportunities for UK operators?

We firmly believe in the attractions for the UK of a vibrant domestic oil and gas sector over the coming decades, and while we believe a 78% tax rate is inappropriately high to encourage this, the recent maintenance of capital allowances and upcoming clarity on scope three emissions and long-term tax does create an environment with opportunities for operators. The scope remains large: the UK currently produces 715m b/d of oil and 3.3bcf/d of gas, with 2P oil reserves of 2.3b bl and gas of 6.6tcf.

First, the clearest opportunity is acquisitions. The current tax regime, alongside the maturity of the basin, is likely to lead to some—particularly larger—operators to look for an exit. Concurrently, increasing clarity on tax and regulations should create a stable enough environment for buyers to construct bids and make them with a degree of confidence. This is all the more the case for those with existing tax losses.

Second, there remain numerous attractive producing assets offshore UK, and for those already holding them, clarity on tax and scope three will allow them to calibrate their work programmes, reinvesting where attractive and maximising cash flow otherwise.

Third, it remains hard to believe UK domestic oil and gas demand will disappear any time soon, particularly given how much higher than domestic production it already is. This makes space for progression of new investment and new developments, and creates an incentive for the country to facilitate these, both from a regulatory and tax point of view.

Overall, we believe there remain significant opportunities for operators in the UK, with ongoing regulatory and tax clarity to further encourage activity. UK-listed companies that are well positioned here include Serica Energy, Enquest, Kistos, Ithaca Energy, Harbour Energy, Jersey Oil and Gas and Orcadian Energy. ■

The global energy transition: Complex and urgent

Uruguay has made significant progress in decarbonising its electricity generation, with state-owned ANCAP now leading the second phase of the country's energy transition

There is widespread consensus on the immense challenge posed by the global energy transition. But what makes this shift so complex? The urgency to decarbonise, in alignment with international climate goals, demands a profound transformation of the global energy system within a few short decades. This transformation requires not just the introduction of new technologies, but the replacement of existing primary energy sources.

Today, fossil fuels account for more than 80% of the world's energy mix. To achieve sustainability objectives, we must transition to a low-carbon system—one that is not yet fully developed or scaled. Meanwhile, global population growth and rising living standards will continue to drive energy demand, with energy security emerging once again as a critical priority. Consequently, for the foreseeable future, the world will rely on a dual energy model in which traditional fossil fuels and renewable technologies complement and coexist. This is not a question of choosing between one or the other; it is a matter of 'and', not 'or'.

Given these realities, analysts and energy companies alike emphasise the need for a balanced, orderly and realistic transition. Acknowledging that the shift from oil and gas will not happen overnight is crucial. In sectors such as heavy industry, aviation and maritime transport, where electrification is particularly challenging due to the need for high energy density, liquid fuels will remain indispensable. Decarbonisation in these sectors will likely come from the adoption of sustainable fuels, such as biofuels produced from bio-based feedstocks and e-fuels derived from low-carbon hydrogen.

> Uruguay has already made remarkable progress in decarbonising its electricity generation

Leading the way

Uruguay has already made remarkable progress in decarbonising its electricity generation, often referred to as the first phase of the country's energy transition. Renewable sources—including wind, hydroelectric, biomass and solar—now account for more than 90% of electricity production, although this share varies with climatic conditions. However, electricity represents less than 20% of Uruguay's total energy consumption. Thus, the development of a green hydrogen economy and its derivatives is a natural and necessary next step in the country's decarbonisation efforts.

ANCAP, Uruguay's state-owned energy company, has embraced the motto "responsible transition". This means ensuring the continued supply of reliable, affordable and high-quality fuels to meet domestic needs while also leading Uruguay's second phase of energy transition by developing sustainable molecules that will become critical to the global energy mix in the coming decades.

Key ANCAP projects driving the transition

1 Hydrocarbon exploration and production: While Uruguay's basins remain underexplored and present high geological risk, they offer significant opportunities, highlighted by recent discoveries across the Atlantic. Major oil finds in Namibia's Orange Basin have revealed hidden potential in Uruguay's offshore basins, which represent Orange's conjugate margin. These basins share strong analogies in petroleum systems and play types.

Over the past 17 years, ANCAP has actively attracted investment through bidding rounds, resulting in more than $1.4b invested in hydrocarbon exploration, primarily by IOCs. Despite this investment, Uruguay's offshore basins remain largely underexplored, with only three exploratory wells drilled in an area larger than 120,000km^2. However, renewed interest in 2022 and 2023 has led to new bids for the offshore blocks.

This marks a historic moment for Uruguay, as all offshore blocks now have contracts in force for the first time. The success of these rounds is due to recent discoveries in Namibia, but also undoubtedly due to Uruguay's strong reputation for democratic, economic and legal stability—as well as its adherence to contractual commitments.

By Santiago Ferro,
energy transition manager,
ANCAP

In the coming four years, committed exploratory work will include 3D seismic acquisition and reprocessing, with a deep exploratory well to be drilled in Area OFF-6 by US explorer APA.

2 Green hydrogen production: In 2024, Uruguay published its Green Hydrogen Roadmap, outlining the key elements needed to support the development of green hydrogen in the country. This includes fostering innovation, regulation, investment, capacity-building, international cooperation, infrastructure and logistics. ANCAP plays a pivotal role in implementing this roadmap.

- **E-fuels:** ALUR, ANCAP's biofuels subsidiary, has launched a project to capture and use the biogenic CO_2 from its bioethanol plant. The project, awarded to US e-fuels company HIF Global, aims to combine this CO_2 with green hydrogen to produce 250,000t/yr of e-fuels. ALUR holds an option to acquire up to a 30% stake in the project once FID is made.
- **H_2U Offshore:** ANCAP is preparing to launch the H_2U Offshore Round, offering offshore areas for energy companies to conduct feasibility studies and potentially develop infrastructure for producing green hydrogen and its derivatives. This round mirrors the successful structure of ANCAP's hydrocarbon bidding rounds, ensuring transparency and a predictable schedule for participants.

3 Biorefinery transformation: ANCAP is also advancing plans to transform its La Teja refinery into a biorefinery. A techno-economic feasibility study is underway for the production of sustainable fuels such as hydrotreated vegetable oil and sustainable aviation fuel, targeting export markets.

This project will leverage ALUR's expertise in feedstock contracts and supply and ANCAP's refining and processing capabilities to produce advanced biofuels from oilseeds, tallow and used cooking oil. ■

Southeast Asia: Defining a new narrative for net zero

The region's fast-growing economies stand at a pivotal juncture, with the opportunity to drive a sustainable growth strategy that will keep the world's net-zero ambitions alive

The new energy order is set to be shaped by the rapidly developing economies of Southeast Asia—particularly Indonesia, Malaysia, the Philippines, Thailand and Vietnam. Once dubbed 'tiger cubs' for their vast economic promise, these nations are now maturing into significant players in the global economy. Southeast Asia is expected to experience one of the largest growths in energy demand over the coming decade. How this region powers its growth will be crucial in determining the world's ability to respond to climate change and achieve net-zero emissions.

Economic growth and energy demand

Southeast Asia's population is expected to grow from more than 670m today to become the world's third-largest workforce—digitally enabled and young, ranking as a leading economic force behind the US, China and the EU by 2030.

The region's GDP has more than doubled since the year 2000, lifting millions out of poverty. During 2025, the International Monetary Fund predicts most Southeast Asian countries will continue to exceed global economic growth rates.

Energy demand continues to grow at around 3% annually, with carbon emissions rising in parallel, indicating carbon-intensive development. The IEA predicts Southeast Asia will become the largest net importer of energy, accounting for 25% of global energy demand growth by 2035, with fossil fuels dominating the energy mix until 2050.

How the region powers its growth will significantly impact international trade flows and climate outcomes.

Commitment to the global climate agenda

Southeast Asian countries, driven by young demographics aspiring for inclusive growth and greater environmental stewardship, are committed to addressing climate change. Rising awareness about climate adaptation is evident as typhoons, floods and droughts impact food crops and infrastructure.

Indonesia, Malaysia, Myanmar, Thailand and Vietnam rank among the 20 most vulnerable countries to climate change globally. While many citizens focus on daily needs, climate change remains a regional priority, high on the political agenda.

The energy mix is heavily reliant on fossil fuels, with 83% of the region's energy coming from coal, oil and natural gas. This dependency raises concerns regarding energy security, affordability and sustainability. If not properly managed, it could impede growth trajectories. In response, commitments to addressing climate change are well-articulated in both national and regional policy. These policies also highlight the potential for green growth and drive the energy transition forward through initiatives such as regional power grid integration and enabling new cross-border value chains for carbon capture and storage.

> Southeast Asian decarbonisation pathways have the unique potential of combining energy, industrial and trade policy with climate policy

Energy transition trends

To diversify the energy mix and reduce carbon emissions, significant renewable energy and new technology initiatives are underway, although they currently account for only 2% of global clean energy investments. By 2050, Southeast Asia is expected to require $7t—or $220b annually—to reach net-zero carbon emissions.

As clean energy equipment costs decrease, more solar, wind and hydroelectric projects are being developed.

Following the Association of Southeast Asian Nations' power grid electricity import pilot in 2022, which connected hydropower in Laos to Singapore via Thailand and Malaysia, further regional power integration is being considered. According to a presentation from the National Renewable Energy Laboratory, this integration would ease energy security concerns, increase the share of renewables and add 0.8–4.6% to GDP growth.

By Charlotte Wolff-Bye, vice president and group chief sustainability officer, Petronas

Capturing the opportunity in the energy transition

To attract inward investment, the region is repositioning itself as an enabler of the global energy transition, ready to support decarbonisation efforts.

The energy transition presents an opportunity to move up the value chain from manufacturing to a knowledge-based society, driving the greening of global value chains.

Analysis by strategic management consultants Boston Consulting Group shows that net-zero policies could add $3–5.3t to GDP by 2050, attract $3.7–6.7t in inward investment, and create 49–66m additional jobs for the region.

The manufacturing base is already benefiting, with Vietnam and Malaysia emerging as leading solar photovoltaic module manufacturers, and electric vehicle (EV) production is growing rapidly in Thailand and Vietnam. EV sales are also seeing double-digit growth across the region, potentially reducing the need for oil imports over time.

To earn a prominent role as a global partner, national and regional energy transition efforts must be comprehensive and sincere, aligning with the decarbonisation trajectories of the markets they serve.

Defining a new pathway

In much of the Western world and mature economies, climate change is driving regulatory actions such as carbon pricing and low-carbon technology incentives, while much existing infrastructure needs to be retrofitted, repurposed or even abandoned. Concurrently, post-COVID, uneven economic growth and development are reshaping politics, favouring onshoring and trade barriers. While this is the reality for many countries, emerging economies face different circumstances. Therefore, their pathway must be distinctly forward-looking, engage citizens and resonate locally.

Southeast Asian decarbonisation pathways have the unique potential of combining energy, industrial and trade policy with climate policy, and working with trading partners to drive cooperative models for decarbonising global value chains.

Malaysia's National Energy Transition Plan (NETR) is an example of a policy aiming for a systems-wide approach. The NETR promotes ten catalyst flagship projects—including renewable energy, hydrogen, biomass and CCS—that could generate an estimated $5.7b in investments. These projects aim to combine criteria for emission reductions, social inclusiveness and economic opportunity, solidifying a development trajectory that benefits both industrial and sustainable development. The projects are attracting significant interest and could foster novel collaborations.

A new narrative for the journey ahead

Southeast Asia stands at a pivotal moment, with the opportunity and need to adopt a path that serves equitable growth and enables a sustainable energy transition.

Its role in global trade offers the chance to lead in redefining the decarbonisation of value chains.

With the region's tremendous growth trajectory ahead, the world depends on Southeast Asia to define a new sustainable growth narrative and keep the global net-zero ambition alive. ■

The thoughts expressed reflect the views of the author and do not represent those of the organisation

Energy access, military considerations and regional security

The traditional concept of the energy trilemma is insufficient to understand how energy and politics really work

Economic theorists would contend that any energy supply strategy comprises considerations that make up the well espoused energy trilemma. In this well-publicised trilemma, energy security, affordability and sustainability are the considerations that must be cautiously balanced to achieve social and economic stability while concurrently pursuing a cleaner environment. The level of focus on each element of the trilemma shifts as global macro conditions change from time to time.

> It is only a simple interpretation that projects the energy trilemma as being about energy security, affordability and sustainability

But is this the trilemma that really underpins how our world works? Perhaps, there are other tangential forces at play that impact decision-making at the control centres of global geopolitics?

Oil and military security

In 1911, on becoming the First Lord of the Admiralty, Winston Churchill oversaw the modernisation of the coal-powered British naval fleet, converting its vessels to run on oil. It was an expensive effort, but it was vital to preserve British naval dominance. Coal had many advantages, but oil provided more firepower and speed for reduced size and cost.

Together with the expensive technical conversion of naval vessels, a secure source of oil was also required. Thus, on 14 June 1914, Churchill introduced an Oil Bill in Westminster. This called for investing £2.2m ($2.86m) of British government funds in the Anglo-Persian Company. The bill passed by 254 to 18 votes in favour, giving the British government a 51% ownership of a company that assured its navy of fuel oil for at least 20 years.

Decades later, the Anglo-Persian Oil Company was renamed British Petroleum, one of the antecedents of the modern BP, a corporation that would extend its original purpose of ensuring the British Navy had access to oil to become one of the largest global oil and gas companies.

In this arrangement, the British government prioritised controlling ownership of energy resources to ensure military dominance, but it was not the only government to undertake such an activity in the interest of energy security.

On Valentine's Day 1945, US President Franklin D. Roosevelt and the reigning Saudi monarch, Abdulaziz bin Abdul Rahman Al Saud, struck a multi-faceted arrangement that would last nearly three decades. The crux of this arrangement was this: the US, close to being the only nuclear power at that time, would guarantee the security of the House of Saud and Saudi Arabia for as long as the US was given access to all the oil it needed, for as long as Saudi Arabia had oil in place.

This meant that the US and its Western allies, through their IOCs, were able to secure oil—the key resource they required to drive an imminent post-Second World War economic expansion effort, at a very low cost. This arrangement also provided the foundation of growth for many of the enterprises that became collectively known as the Seven Sisters. In this US-Saudi pact, energy security was being traded for political security and stability.

By Kenneth Pereira,
managing director,
Hibiscus Petroleum Berhad

EU gas supply and the Russia/Ukraine conflict

The importance to the EU of assured access to natural gas was demonstrated in 2022 after the level of Russian-Ukrainian hostilities, which had commenced in 2014, escalated. In February 2022, with a war at their doorstep, EU nations collectively agreed to increase sanctions on Russia-related individuals and entities.

Before the extent of the sanctions was fully developed and understood, European economies aggressively competed for whatever energy resources that were available, causing inflation in global energy prices and a great deal of economic uncertainty. This sudden spike in energy prices, in particular that of LNG, directed how the EU subsequently cautiously imposed its Russian sanctions, the objective being to reduce financial resources afforded to Russia to use for military purposes while minimally impacting energy security considerations in the EU.

It should be noted that, while the EU was forced to be cautious on how it imposed sanctions on Russia, the energy independent US was able to freely wield its military and political might in support of Ukraine.

There are other lessons to be learned from the Russia-Ukraine conflict. It is estimated that, in 2021, the EU imported 155bcm of gas from Russia, which accounted for about 45% of its total gas imports. As a result of EU sanctions, and the sabotage of the Nord Stream pipelines, Russia delivered only about 60bcm of gas to the EU in 2022. Interestingly, Russian gas continued to transit Ukraine via pipelines in 2023, flowing to Austria (6bcm/yr), Slovakia (6.5bcm/yr) and Hungary (1bcm/yr). All three countries compensate Russia for this gas supply in its own currency to avoid the effects of other sanctions.

This scenario raises the question of why Ukraine allows this supply, amounting to 25% of Russian gas currently used in Europe, to transit across its territory? Is this action not assisting the funding of a war being carried out against it?

These questions can be answered only by the relevant Ukrainian leaders, but over the past century, what has been identified through several prominent examples is that there is a strong linkage between energy access, military considerations and regional security. It is only a simple interpretation that projects the energy trilemma as being about energy security, affordability and sustainability. The considerations go far deeper. In a volatile world, nations that have the capacity to be energy independent, particularly in the areas of oil and gas—as these are the fuels that enable military dominance—should value these resources lest they wish to reduce their degree of influence in the global forums. Simply put, energy independence is a hedge: valuable in peace, invaluable in strife.

As Churchill was reported to have said: "Those that fail to learn from history are doomed to repeat it." ■

Nationally Determined Contributions: Critical roadmaps for climate investment

If they are ambitious enough, NDCs can provide investable pathways to deliver each country's energy transition and keep the world on track to limit global warming

Nationally Determined Contributions (NDCs) are powerful tools in the global effort to combat climate change. NDCs are the crucial mechanism, established by the Paris Conference, through which countries commit to voluntary national actions to reduce emissions in line with the global objective of limiting global warming to well below 2C and as close as possible to 1.5C. Countries are required to submit ratcheted NDCs every five years, and the next submissions are due in early 2025. These new NDCs must do more to unlock large-scale investments in the clean technologies needed for the future.

In 2024, the IEA estimates that approximately $2t will be spent on the clean energy transition. However, investment levels need to scale up rapidly. The Energy Transitions Commission (ETC) estimates that $3.5t of capital investment is required annually from now until 2050 to achieve the energy transition and limit global warming to 1.5C above pre-industrial levels. This increase will be partially offset by gradual reductions in fossil fuel investments, which currently average $500b/yr. A net annual investment of $3t is needed to build the clean energy system of the future, including solar, wind, batteries and transmission infrastructure. While this figure is substantial, it is manageable on a global scale, equating to only 1.3% of global GDP between now and 2050.

Ambitious NDCs that provide clear pathways for countries and sectors to reduce emissions can unlock this large-scale investment. The current NDCs, submitted in 2020, put the world on track to overshoot 2C warming by 2050 even if implemented. And despite global guidance on NDC-setting, the nationally determined nature of NDCs has led to inconsistencies, with uneven coverage, granularity and specificity across submissions. For instance, NDCs may or may not cover methane emissions or include clear decarbonisation targets for all sectors of the economy.

In early 2025, countries are expected to update their NDCs as part of the process established by the 2015 Paris Agreement to "pledge, review and ratchet" country contributions. Improvements in the next round can help unlock the scale of financial investments needed for a sustainable future.

Four priorities for investable NDCs

The ETC set out four clear priorities for the next round

By Ita Kettleborough,
director,
Energy Transitions Commission

of NDCs in our *NDCs, NCQG and Financing the Transition* briefing note, suggesting improvements to the scope and format of NDCs to make them investable pathways to deliver each country's energy transition.

Firstly, the next round of NDCs can feasibly triple in ambition compared with current NDCs by reflecting existing technological progress and policy commitments. Clean solar, wind and battery technologies have boomed as a result of innovation and cost declines, enabling countries to rapidly reduce emissions while continuing to meet growing demands for affordable energy access and use. For instance, electric vehicle (EV) adoption continues to exceed expectations, with 42m passenger EVs on the road by 2023, two years ahead of forecasts.

Solar generation costs have plummeted by more than 90% since 2010, making solar power the cheapest form of power in many regions. Current NDCs from G20 countries aim to install 4.6TW of renewable energy capacity by 2030, but current trends suggest this figure could reach 6.4TW: 40% more. And to achieve the COP28 target of tripling global renewables capacity by 2030, G20 countries must collectively deploy 9.4TW, according to the International Renewable Energy Agency. Priorities within countries will differ, but the ETC's analysis indicates that all countries can reasonably aim for a significant increase in ambition since the last NDCs were set.

Secondly, the next round of NDCs should include comprehensive economy-wide targets, such as absolute or equivalent emissions targets, sector-specific targets and targets for specific greenhouse gases. These detailed targets will help companies and investors understand each country's decarbonisation plans and the necessary technologies, investments and policies to deliver them. New NDCs should specify absolute emissions reduction targets covering all sectors and greenhouse gases, avoiding relative targets that introduce uncertainty. Where relative targets are used, they should include clear assumptions, such as GDP growth, to allow for conversion into absolute emissions reductions.

Thirdly, NDCs should outline clear policy frameworks essential for achieving stated emissions targets. Sector-specific policies, such as installed renewables capacity targets or internal combustion engine phase-out dates, will drive the delivery of sector-specific targets. For countries whose NDC targets are conditional on international support, it is crucial to clearly define the required technical or financial assistance. Recent analysis suggests that, of the $4.5t needed to meet current NDC targets, $1.6t is required to unlock conditional targets. Investment figures are cumulative over the implementation period of NDC targets, presently up until 2030 (see the World Resources Institute's 2023 report, 9 things to know about NDCs).

$3t
Amount needed to build clean energy system of the future

Finally, NDCs should outline financial needs in detail, along with proposed funding sources. Most capital investment for emissions reduction will come from private institutions or state-owned companies operating competitively. Governments must incentivise this investment through well-designed policies. In middle and lower-income countries, a mix of funding sources will be necessary, with multilateral development banks catalysing private finance flows, domestic savings and concessional finance playing important roles.

With these improvements, the next generation of NDCs can feasibly close the investment gap for the energy transition and unlock the finance needed to deliver the emissions reductions that can limit global warming. NDCs can guide the investment decisions required for the decade ahead, setting out a clear vision, demonstrating strong leadership and driving collaboration between policymakers, industry stakeholders and financial institutions to accelerate the flow of finance into the clean economy. ■

Geopolitics and gas: Volatility and the potential for energy security and peace

Regional cooperation over the development of gas resources has the potential to bring peace and prosperity to the East Mediterranean

Take a look at a number of major reports from some of the most high-profile and respected global energy stakeholders: Shell, ExxonMobil, IEA and the EU. What do they have in common?

- Natural gas remains a vital energy source, both now and in the future, on every continent due to its ability to provide energy security and support the transition.
- The global market remains tight and needs new supply, with major LNG projects again delayed and the fabled 'gas glut' moved back again.
- Geopolitics and gas remain inseparable.
- Majors that made big commitments to reduce oil and gas production are reversing under pressure to provide affordable energy security and returns to shareholders.
- Sanctions on Russia have not managed to cripple the Russian economy, as oil and gas produced in country has been diverted east.

The tight energy markets we are experiencing are primarily driven by geopolitics and a significant reduction in upstream investments, while global demand for energy keeps rising.

This is why Energean remains focused on natural gas. We see sustained demand for gas reaching beyond 2050. Gas remains a vital positive component of the energy trilemma.

We see sustained demand for gas reaching beyond 2050. Gas remains a vital positive component of the energy trilemma

The energy security and energy transition that gas can provide have recently been challenged by geopolitics. However, one could argue gas has and can again be a partial solution to geopolitical friction in an area we know better than anyone: the East Mediterranean.

I am not making this argument for today, or even tomorrow, but for the near future, once the ongoing conflict has ended. One only has to look at the recent past to understand the potential of gas to connect countries that have previously had challenging relationships.

A key example is the supply of gas from Israel to Egypt. Energean played a crucial role by developing the Karish offshore gas field in Israel. Our efforts have helped Israel's energy transition through coal to gas replacement and enhanced Israel's energy security. Just as importantly, this has permitted Leviathan and Tamar to increase their exports to Egypt.

Growth and stability

The consequent sovereign interdependence not only strengthens the economies of Israel and Egypt but contributes to a more stable geopolitical environment in the region—something that could be a model for the future. Both countries are encouraging investment in their upstream value chain, which could well strengthen a regional partnership.

Natural gas could be a major driver for post-war socio-economic reconstruction. Whether that is through royalty payments or by securing domestic supplies of energy, both Lebanon and Gaza Marine have significant potential that could bring existential value to their countries and people.

We have mentioned Egypt, Israel, Lebanon and Gaza. We should look at the broader region and consider the concept of an Eastern Mediterranean gas network. Cyprus and Greece, both strategically positioned and politically aligned, are key players in this emerging network. Cyprus with its Aphrodite gas field and Greece as a potential transit hub for gas pipelines to Europe, and possibly the last unexplored country in the region, are integral to the vision of an interconnected Eastern Mediterranean energy market. One should also not forget Turkey, with its own significant liquidity platform and recent Black Sea discoveries. All this combined could support regional energy security and beyond, making up for the lack of global LNG liquidity.

The establishment of an East Med gas network, through fixed or virtual (LNG) pipelines would serve not only as an economic powerhouse but also as a symbol of regional cooperation.

By Mathios Rigas, CEO, Energean

Enhanced liquidity and inter-sovereign cooperation could significantly support regional energy security, reduce costs and provide a platform for deeper economic integration. Sovereign states that are mutually bound together by trade are less likely to engage in conflict. Mutual need can create lasting peace.

Unique commitment

For this vision to materialise, the region needs committed operators. We need more delivery. Energean has demonstrated a unique commitment to this region by investing more than $2b and successfully operating through geopolitical instability, including a recent complex project execution amid very challenging operational and security uncertainties. This dedication contrasts with others in the Eastern Mediterranean leaving critical resources undeveloped for over a decade, or halting operations and postponing projects due to regional tension.

Energean's success with the Karish field, which supports Israel's coal-to-gas transition and energy security, has allowed Israel to increase exports to Egypt, fostering economic interdependence and reducing regional tensions. This framework could be expanded into a more integrated Eastern Mediterranean energy network—connecting Israel, Egypt, Lebanon, Gaza, Cyprus and Greece. Such a network would enhance liquidity, stabilise the market and help build sustainable peace by binding these countries together through mutual economic interests.

To make this vision a reality, the region requires committed operators willing to execute in volatile environments. Energean's track record proves that, with dedicated action, the Eastern Mediterranean's energy resources can provide not only energy security but also a foundation for long-term regional cooperation and peace.

In a post-war scenario, natural gas could prove to be more than just an energy resource. Natural gas has proven to be a powerful tool for socioeconomic and industrial development and for a dampening of regional geopolitical tension. We need committed operators who can turn visions into reality, and we need politicians brave enough to reach out to their neighbours, no matter what the history. ■

How all energies must work together to meet increasing global demand

Whether it is hydrogen, LNG, carbon capture or water treatment, collaboration is key to meeting the world's growing energy demand while meeting decarbonisation goals

Chart Industries operates at the intersection of multiple energy sectors, each playing a critical role in the transition towards a cleaner, more sustainable future. Chart is a unique player in the energy landscape, thanks to our molecule-agnostic approach.

This means that we do not prioritise one energy source over another; rather, we design and manufacture equipment that supports a range of energy solutions, from LNG and hydrogen to carbon-capture technologies and water treatment. Chart's mission is to provide solutions across what the company calls the Nexus of Clean™: clean power, clean water, clean food and clean industrials. This strategic business model positions the company well in a world where energy demand is growing rapidly and solutions are evolving at an unprecedented pace.

> Collaboration is key to meeting the world's energy challenges

The need for an integrated approach

Today, global energy demand is on the rise due to population growth, increasing urbanisation and industrial expansion. According to the IEA, energy demand is expected to grow by about 30% by 2040. At the same time, the world faces the urgent need to reduce carbon emissions to mitigate climate change. These two challenges—rising demand and the need for decarbonisation—seem contradictory on the surface, but they are not insurmountable.

At Chart, we believe the solution lies in a diversified energy portfolio, where no single technology or energy source can meet all the world's needs. Hydrogen, natural gas, carbon capture, renewable energy and even nuclear energy each have a role to play. As a molecule-agnostic company, we are not tied to one energy pathway; instead, we are focused on developing the technologies that make all these pathways more efficient, scalable and sustainable.

Hydrogen: A key solution in the energy transition

One of the most exciting developments in the energy world today is the rise of hydrogen as a clean fuel. While Chart has experience designing, engineering and manufacturing hydrogen-related equipment for nearly 160 years, hydrogen is now being recognised as a versatile, zero-emission fuel for industries ranging from transportation to heavy industry.

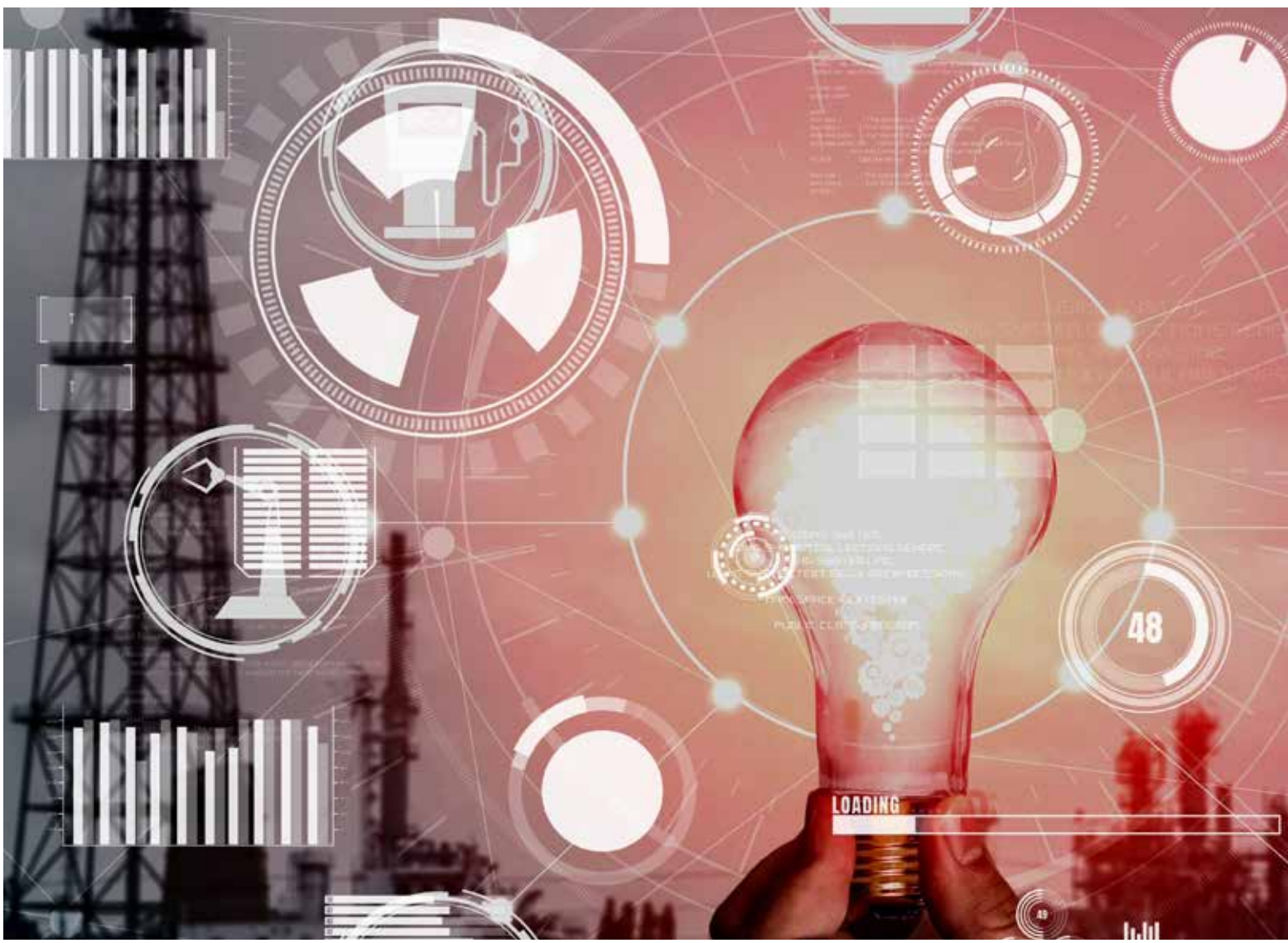
Our hydrogen solutions span the entire value chain, from production and storage to transportation and end-use. Chart is involved in global hydrogen developments such as the world's first green steel project in Sweden, the world's largest hydrogen refuelling station in China and the world's largest hydrogen compression solution in Kuwait, among others. We continue to partner with other industry leaders on large-scale hydrogen deployment projects and are also involved in exploring liquid hydrogen in new markets and applications, such as aviation. The versatility of hydrogen makes it a powerful tool in decarbonising sectors that are traditionally hard to electrify, such as shipping and heavy manufacturing. However, for hydrogen to reach its full potential, we need to build out the infrastructure that will allow it to scale, a challenge that will require cooperation between public and private sectors globally.

LNG: A bridge to a lower-carbon future

While hydrogen and renewable energies hold significant promise for the future, the reality is that we still rely on fossil fuels to meet the bulk of our energy needs today. LNG plays a critical role in this transitional phase. As a cleaner alternative to coal and oil, LNG is helping to reduce emissions while providing the reliable, affordable energy that is necessary to power industries and economies.

Chart is a leader in LNG infrastructure, supplying the liquefaction, storage and transport equipment that underpins this sector. We have worked on major projects around the world, from ExxonMobil's liquefaction technology in Mozambique to LNG facilities that provide energy security in times of geopolitical instability. LNG is not the end goal, but it is an essential step in the journey towards a more sustainable energy future.

By Jillian Evanko,
president & CEO,
Chart Industries Inc



Carbon capture and water treatment

At Chart, we also focus on technologies that address two critical elements of sustainability: carbon and water. Our small and industrial scale carbon-capture solutions are designed to help industries capture and store CO_2 emissions before they enter the atmosphere. These systems can be deployed across various sectors, from breweries and wineries to industrial manufacturing and cement plants, making them a vital tool in reducing global carbon emissions.

Water is another area that we believe will be a key priority as we move towards a clean energy future. The nexus between energy and water is well-known: energy production requires water, and water treatment requires energy. Our water treatment technologies help reduce water consumption and improve water quality in industrial processes, which is especially important as water scarcity becomes an increasing concern in many parts of the world.

The role of marine and mining

Other sectors where Chart is making a difference include marine and mining applications, to name but two. For mining, we support the electrification of mines and improve overall sustainability through our equipment and digital monitoring solutions, such as Ventsim™. Our solutions help reduce energy consumption, enhance operational efficiency and promote safer working conditions with real-time monitoring. Similarly, in the marine industry, we offer cleaner solutions such as hydrogen and LNG, helping to reduce emissions and promote a low-carbon future for maritime operations.

Collaboration is key

One of the most important lessons we have learned as a molecule-agnostic company is that collaboration is key to meeting the world's energy challenges. No one company, technology or government can solve these issues alone. It will take partnerships across industries, regions and sectors to develop the infrastructure, policies and innovations needed to transition to a low-carbon economy.

Chart continues to partner with global industry leaders to prioritise technological breakthroughs and innovation, while also participating in initiatives such as the UN Global Compact. These collaborations allow us to apply our expertise to a wide range of industries, each with its own unique challenges and opportunities.

> Our molecule-agnostic approach allows us to stay flexible, providing solutions that work across the entire energy spectrum

Conclusion

The world's energy landscape is changing rapidly, and we are proud to be at the forefront of that transformation. Our molecule-agnostic approach allows us to stay flexible, providing solutions that work across the entire energy spectrum. Whether it is hydrogen, LNG, carbon capture or water treatment, we believe all forms of energy must work together to meet the growing global demand while addressing the urgent need for decarbonisation.

As a company, we are committed to providing the innovative technologies that will make this future a reality, helping the world transition to cleaner, more sustainable energy sources without compromising reliability or affordability. The energy future is not about choosing one path—it is about embracing them all. ■

PE Outlook 2025

New energies and the energy transition

US hydrogen's next inflection point

With a new president and new Congress imminent, attention must turn to the next stage of hydrogen development

After the passage of the Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022 by the 117th Congress, the US rapidly advanced the development of its domestic clean hydrogen industry and is aiming to become a global leader for this emerging sector. However, progress in putting steel in the ground has slowed.

The supportive programmes and incentives within the laws—the Regional Clean Hydrogen Hub Program (H2Hub) and the Credit for Production of Clean Hydrogen (45V) being the cornerstones—were meant to provide much-needed certainty for project developers and investors to spur the scale-up of the nascent industry.

Despite support from the Biden administration and Congress, agencies charged with issuing the rules and regulations for these programmes and incentives have moved at a slower pace than anticipated. This puts the US' ambition to be a global leader into question.

The Department of Energy (DOE) continues to advance H2Hub selectees to the first phase of its detailed project planning process. Meanwhile, the Department of the Treasury plans to release its final regulations for 45V before the end of 2024. The 45V rules sparked an intense debate around the methodology used to calculate clean hydrogen carbon intensity.

Though the final regulations are still pending, both policymakers and industry must turn the page and look ahead to future challenges facing US projects that will enable achievement of decarbonisation imperatives.

The last few years have been very focused on developing the supply side for our sector. Now, more attention needs to be given to deploying hydrogen-using technologies and supporting adoption. The DOE set aside $1b of its H2Hub appropriations to implement demand-side support mechanisms to de-risk investments and lower costs for early adopters. However, this funding will be used to support only H2Hub-sponsored projects.

The next Congress can hone in on demand-side support to boost adoption across several hard-to-abate sectors by reintroducing the bipartisan package of hydrogen legislation developed by senators Chris Coons (Democratic senator for Delaware) and John Cornyn (Republican senator for Texas), which includes the Hydrogen for Ports Act, the Hydrogen for Industry Act, the Hydrogen for Trucks Act and the Hydrogen Infrastructure Finance and Innovation Act. Together, these bills will enhance the development of a sustainable hydrogen supply chain and lower costs for applications that have limited decarbonisation pathways.

Policymakers and industry must turn the page and look ahead to future challenges facing US projects that will enable achievement of decarbonisation imperatives

Permitting questions

In addition to growing clean hydrogen demand and adoption, US policymakers in Congress and the White House are grappling with the longstanding questions around the permitting process for energy infrastructure.

The federal permitting process under the National Environmental Policy Act (NEPA) has hamstrung projects development for decades. No technology, from renewables to oil and natural gas, is immune to the broken NEPA process that is being used to stop all projects across the US. Anti-development forces have used litigation to delay projects, raise costs for developers and, in many cases, cause projects to be cancelled altogether.

Over the past two years, the current Congress has made incremental progress in addressing permitting reform through changes passed under the Fiscal Responsibility Act (FRA) of 2023. However, most of the new changes that amended the NEPA process deal with how an administration structures its review process and not the underlying issues with litigation and extended timelines.

Since the FRA amendments were passed, Congress

By Frank Wolak,
president and CEO,
Fuel Cell and Hydrogen Energy Association

has introduced the bipartisan Energy Permitting Reform Act of 2024. While the bill has received mixed reviews, it establishes a postmark for an 'all of the above' approach for the next Congress to build upon and create a process that all energy infrastructure developers can rely upon.

Other major opportunities will arise in the next session to enhance federal support for clean hydrogen development, including reauthorisation for surface transportation programmes and tax legislation. Industry and the bipartisan champions in Congress will need to continue the decades of steadfast support for clean hydrogen development policies, which will provide domestic clean energy job gains.

Both the US and the hydrogen industry are nearing their next inflection. We will soon have a new administration and Congress that have an opportunity to provide more certainty by addressing demand side and permitting challenges for clean hydrogen stakeholders. Attention and resources need to be refocused on the next stage of clean hydrogen development. While programmes and incentives like H2Hub and 45V are important to spurring development, the full potential of those programmes will not be realised without meeting tomorrow's challenges. ■

The energy transition and the Southern Cone

The region has ample resources of both gas and renewable energy and developing both will be vital to the global effort to reduce emissions

The world needs to reduce global warming by lowering greenhouse gas (GHG) emissions. Considering that almost 73% of GHG emissions are generated by energy use, achieving this goal is extremely challenging, especially if we aim to provide energy to all people around the world. Rapidly transitioning the current energy sector to one with low emissions is an enormous task and requires the collaboration of all global players.

It is also essential to achieve sustainable socioeconomic development for a growing world population. It is fair to recognise that the efforts required for a successful transition should not be uniform across all countries or regions. We must consider multiple transitions rather than a single, universal transition for everyone.

Not much progress has been made since the signing of the Kyoto Protocol in the 1990s. Furthermore, the economic development of some countries seeking low energy costs has increased the use of coal.

This increased demand for coal was (and still is) driven by 12 countries that together consume 90% of it and represent nearly 70% of today's global CO_2 emissions. Developed nations are also responsible for most of the current concentration of CO_2 in the atmosphere.

Developed economies are pressuring the developing world to adopt their energy transition policies to reduce emissions, without considering that these nations are striving for prosperity and poverty reduction.

Latin America cannot be compared to wealthy economies with homogeneous socioeconomic development and well-developed infrastructure. It is a heterogeneous region where one of the most critical challenges is poverty, a condition in which one-third of the population live.

Although Latin America has 8.3% of the global population, it contributes only 4.5% of total CO_2 emissions and 8.3% of GHG emissions—mainly from land use, agriculture and forestry. Energy use accounts for only

FIG.1: CO_2 emissions and coal consumption from 1970 (mt)

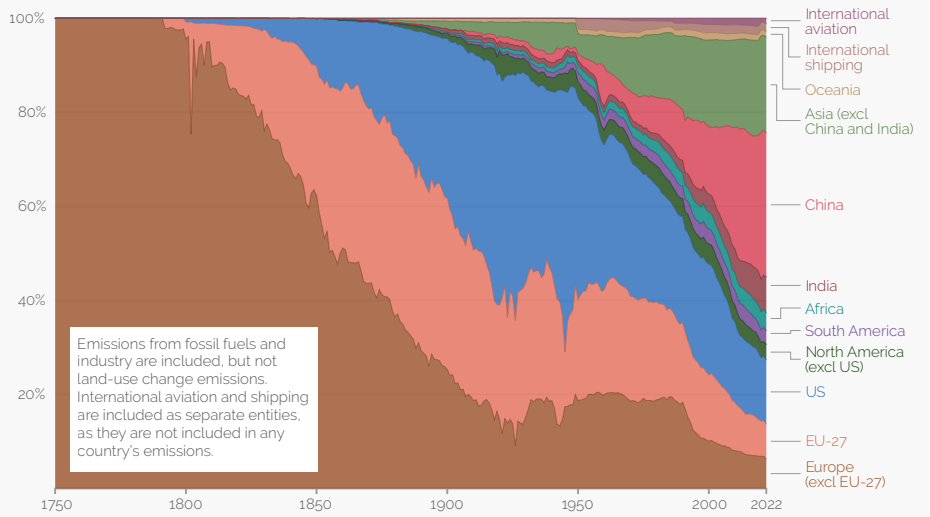
CO_2 emissions	1970	1980	1990	2000	2010	2020	2021	2022	2023
12 countries	7,744	9,594	13,755	15,804	21,797	22,969	23,480	23,934	24,521
Total world	14,313	18,434	21,331	23,676	31,086	31,983	33,884	34,580	35,130

Coal consumption	1970	1980	1990	2000	2010	2020	2021	2022	2023
12 countries	7,574	10,100	16,118	18,614	30,596	29,375	34,191	34,605	35,373
Total world	14,678	17,946	22,281	23,590	36,135	36,145	38,273	38,623	39,204

Source: BP Statistical Review of World Energy 2022; EI Statistical Review of World Energy 2024

By Ernesto A. Lopez Anadon, president, IAPG

FIG.2: Annual CO_2 emissions by world region



Source: Global Carbon Budget (2023); Our World in Data

43% of these emissions, compared with the global average of 75%.

Latin America possesses a more sustainable primary energy mix, with coal accounting for only 5%, versus the global average of 27%, and nuclear and renewables 35%, compared with the global average of 18%. Almost 61% of electricity generation comes from renewable sources, compared with the global average of 30%. In addition, the region contains nearly half of the world's remaining tropical forests.

Southern Cone

I would now like to focus on the subregion known as the Southern Cone, which includes Chile, Argentina, Bolivia, Paraguay, Uruguay and Brazil.

The countries of the Southern Cone have varying levels of development, energy sources and oil and gas resources, and different levels of exposure to the potential effects of climate change.

Most of these countries possess significant hydrocarbon resources, which are vital for their economic prosperity—affecting tax revenue, investment, exports and GDP.

The Southern Cone enjoys physical integration through natural gas pipelines and electrical grids that connect its countries.

The unconventional Vaca Muerta play in the Neuquen Basin in Argentina, with more than 300tcf of natural gas resources, will make Argentina a key exporter of natural gas and LNG. Brazil also presents vast opportunities in the pre-salt region.

There will be new opportunities to supply gas from Argentina to Chile, Brazil, Paraguay and Uruguay and via LNG to the rest of the world. This will help reduce emissions and make the electrical infrastructure more flexible, allowing for greater integration of renewables.

This presents an excellent opportunity to further develop these resources in a sustainable manner, helping to reduce poverty and bring energy to the entire population. At the same time, natural gas can help phase out coal in global power generation and support the growth of renewables in the region.

The development of the Vaca Muerta in Argentina, the pre-salt fields in Brazil and the broad natural gas market in the region will reshape the integration map.

The oil and gas sector is a mature industry in our countries, with both domestic and international operators and service companies employing cutting-edge technologies to ensure the sustainable development of these resources. These companies are also committed to reducing the intensity of production emissions and achieving net-zero methane emissions by 2030 and 2040.

In addition to the oil and gas resources in Brazil and Argentina, there are excellent conditions for deploying wind and solar power generation.

The increased use of renewables, combined with natural solutions widely available in the region, can help offset the rise in emissions that will inevitably occur as countries continue to develop.

The major challenge facing the region is securing access to low-cost financing, not only for the oil and gas sector but also for the deployment of renewables.

Despite the targets set at successive COP meetings, developing countries are frustrated because they have yet to see the promised support materialise.

As mentioned earlier, the region needs to address poverty. If this goal is not achieved, the poorest countries and populations will suffer the most from the consequences of climate change.

What they have at their disposal is the development of their natural resources. ■

Uruguay's approach to the 'all energies' future

The country's technology-neutral position and competitive business environment mean it is looking to be surfing the second wave of the energy transition while others are still grappling with the first

The small South American nation of Uruguay applies two basic—and quite differentiated—philosophies as it approaches the energy future.

First, Uruguay takes the view that development of the nation's energy resources should be technology neutral. That is, no specific energy source is seen as being 'better', with energy development thus driven by local applicability, economics and market dynamics. As compared to countries where, in pursuit of the energy transition, a technology preference often comes first and development choices then flow from the (sometimes non-commercial) biases the stated preference creates.

Second, Uruguay's various potential energy resources are considered to be additive, rather than substitutive. That is, energy policy is seen less as a way to arbitrate the 'fight' between alternative energy sources of different merit, and more about promoting fair competition between alternatives that are all prima facie regarded as equal. This is a quite different approach to one where the phrase 'energy transition' often becomes shorthand for the drive to replace one source of energy (whichever is considered the 'bad one') with another (whichever is considered the 'good one').

A practical outcome of Uruguay's approach is the degree to which it is open to foreign participation in its energy industries. Of course, most emerging countries allow foreign investment in their energy sectors, but that openness is frequently distorted when various local use and local involvement requirements are superimposed—even more if foreign investors are effectively made to subsidise local investors as the 'price of access'. Whereas Uruguay's regulators, informed by the abovementioned philosophies, have always had to take a more holistic, commercial view.

Thus, Uruguay has invested in thoroughly defining the whole of its energy potential, regardless of source and its perceived position in the energy transition and then matching that to a realistic assessment of strengths ('what can we offer?') and weaknesses ('where is it not worth even trying to compete?').

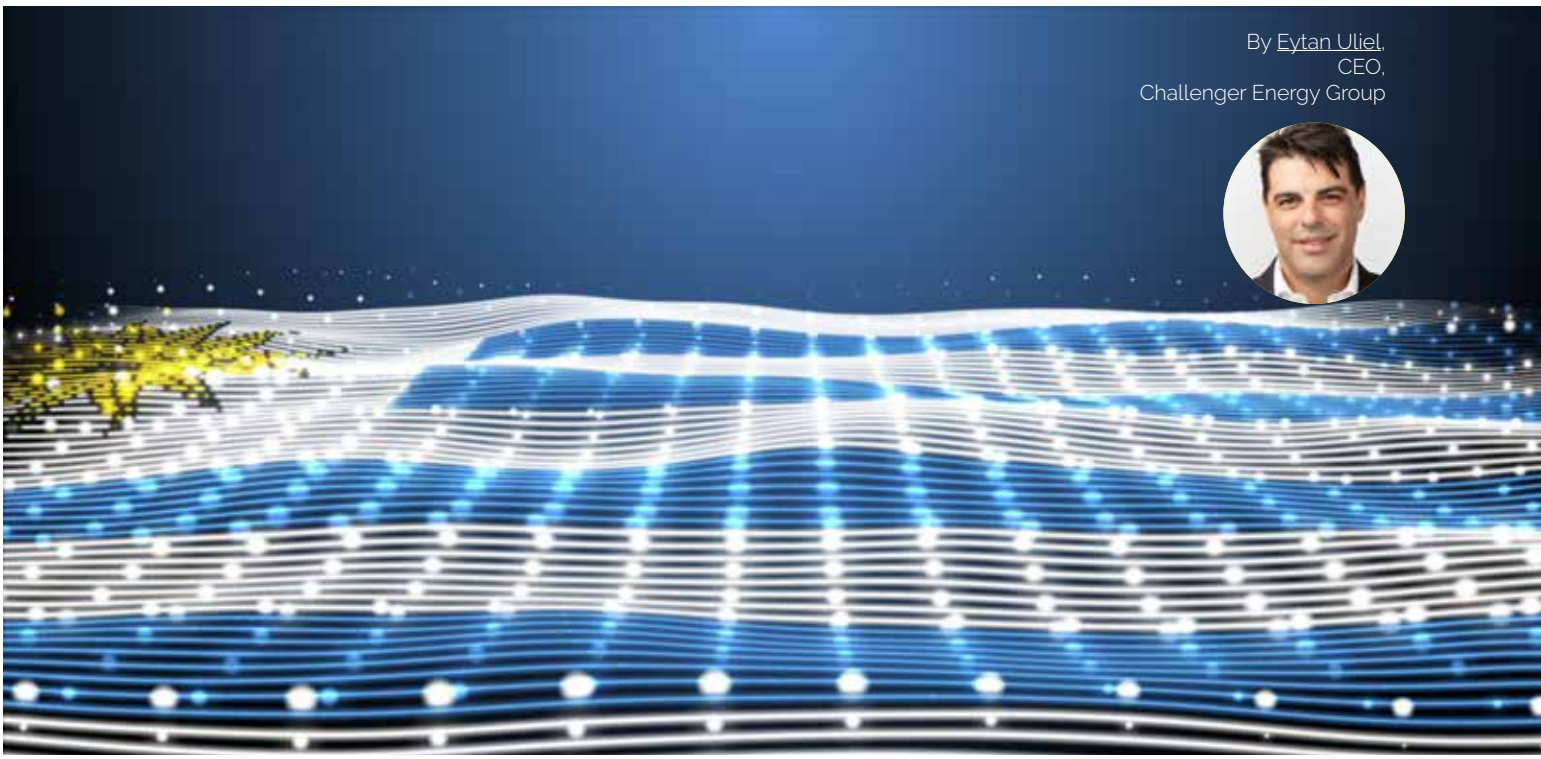
> When many other nations are only at the start of their energy transition, Uruguay is already at work on what regulators there refer to as 'the second energy transition'

In parallel, Uruguay has committed itself to creating a globally competitive, albeit technology-agnostic, playing field, such that on virtually every metric—including rule of law, political stability, ease of doing business, transparency and absence of corruption, etc.—the country consistently ranks as the number one location in South America. There are moderate taxes, minimal capital controls, no onerous local participation or local use requirements and no requirement to fund the state's participation in energy projects—a position distinct from almost every other frontier energy province.

What have been the results?

Around a decade ago, Uruguay reached a point where more than 90% of the country's domestic electricity need was met from renewables, which has continued to this day. This did not happen because of a 'roadmap' mandating an increase of renewables or because of generous incentives. Rather, Uruguay's high contribution from renewables was born of an honest assessment at the time of different energy development options matched to the nation's needs, resources and competitive position. In this context, regulators came to the view that early development of renewables, even if more costly in the short term, made longer term sense in the specific Uruguayan context.

This in turn means that, today, when many other nations are only at the start of their energy transition, Uruguay is already at work on what regulators there refer to as 'the second energy transition'. This is a multifaceted programme seeking to access the wider potential of all of Uruguay's possible energy resources—conventional, emerging and new.



By Eytan Uliel,
CEO,
Challenger Energy Group

This means Uruguay is at the forefront of promoting environmentally friendly hydrogen—both via a process to tender offshore blocks for green hydrogen production and also preparing to offer onshore exploration licences for naturally occurring hydrogen.

At the same time, even exploitation of offshore conventional oil and gas is on Uruguay's agenda, with oil majors having taken up every available licence in just the last two years. Partially, this reflects recent exploration successes in Namibia, the geological conjugate margin to Uruguay. But at a more fundamental level, this also reflects how the global E&P industry sees Uruguay's present-day 'edge' in the broader context of transition.

That is, Uruguay has fostered the ability to attract the capital needed for energy developments, on attractive terms, without the need for incentives or subsidies. At the same time, Uruguay's regulatory regime has been set up to ensure that any conventional molecules produced will be of comparatively low carbon intensity. And in a world where the focus on carbon footprint is ever more intense—but also where the need for conventional energy sources will continue for decades to come—Uruguay's ability to offer exports of not just low-cost, but also low-carbon, barrels creates a competitive advantage.

Uruguay's ability to offer exports of not just low-cost, but also low-carbon, barrels creates a competitive advantage

And, rounding it all off, a slate of new projects has recently been kickstarted, aimed at establishing Uruguay as a future producer of e-fuels (e-methanol, e-SAF, e-gasoline) and modern biofuels (SAF or HVO), for both export and local markets. This means that over the next 20 years, when other nations may be seeing only the first wave of their own energy transitions coming to fruition, Uruguay hopes it will be leading the pack on energy diversification and whatever comes next.

Two decades of well-administered policies mean Uruguay has positioned itself well, so that today it has the opportunity to deliver—in a balanced and responsible way—what both domestic and global markets may need during the energy transition. Driven by the underlying philosophies that no technology in and of itself is superior, all potential energy resources should be considered additive, and all options should be assessed based on unbiased competitiveness. ■

Challenger Energy Group is an Atlantic-margin focused energy company. Within its portfolio, Challenger Energy holds interests in two offshore hydrocarbon exploration blocks in Uruguay and has recently introduced Chevron as a partner in one of these blocks. The company is working closely with Uruguay's Ministry of Industry, Energy & Mining, the Uruguayan regulatory authority, ANCAP and Chevron to unlock the potential of these blocks, an integral part of Uruguay's balanced approach to navigating the energy transition.

Europe must take new approach to transition

The EU should turn the page on its prescriptive approach and encourage innovation and competition, with biofuels and biogas being an essential part of the conversation

Energy has been an agent of prosperity and growth for society since time immemorial. It has fuelled every societal revolution, and its history is that of the advancement of civilisation. Yet today in Europe we find ourselves in the sobering situation where energy has become a barrier to prosperity and wellbeing.

In 2025, a new European Commission will kick off its legislative cycle, an opportunity that we should not squander if we want Europe to remain a leading economic player. Europe must be smarter about its energy transformation and recalibrate some of the complexities of the previous legislature, whose unprecedented lawmaking spree was rushed through with more ambition than realism, more dogmatism than logic.

High prices, dependence on imports, regulatory barriers and one-sided technological bets have all been cited by as major problems by many, not least by former European Central Bank President Mario Draghi in his much-commented report *The Future of European Competitiveness*.

Legislative choices

Certainly, the war in Ukraine and other armed and commercial conflicts have affected supply chains and energy prices, but we would be wrong to ignore that many of our problems are the consequences of our own legislative choices, and that structural changes need to be made in Europe to attack our current alarming lack of competitiveness.

Europe's effort to lead the world in the drive for decarbonisation is laudable. But policy has neglected price and availability of energy by abandoning the principle of technological neutrality in favour of a narrow view of the energy transition based on the single principle of electrification at all costs.

The transport sector is a case in point: billions spent on subsidies for electric vehicles have so far not stopped the growth of emissions from the sector. Legislators have shunned existing, cheaper alternatives such as biofuels, which are also faster to roll out at scale. The current narrow focus on nascent e-fuels and on using biofuels for just a part of the transport sector ignores the economic realities and the conditions necessary for investment to build up this type of industrial production.

> Europe must abandon an approach to the energy transition that has mandated solutions and technologies instead of encouraging experimentation, innovation and competition of ideas

Biofuels should be an essential part of the conversation, not least because they are compatible with the existing energy infrastructure and vehicles that will continue to form the backbone of transport for decades to come. Draghi sees European companies' existing leadership in advanced biofuels as a clear area where the EU can compete technologically, and he calls for a rapid upscaling of capacity and for R&D and public support to help reduce related market and technology risks.

The progress in waste-to-fuel technology, for example, is an avenue that merits serious investigation and re-

By Luis Cabra, executive managing director for energy transition, technology, and institutional relations and deputy CEO, Repsol

sourcing because it has the potential to not only provide relevant quantities of homegrown liquid and gaseous fuels but also meaningfully impact the growing problem of waste that is generated by our advanced consumer society.

Similarly, the continent's biogas potential has been unevenly developed, with German and French efforts unmatched elsewhere, depriving large industrial users of a gas that is currently seeping into the atmosphere from the decay of agricultural waste. Instead, the ballooning price of its conventional alternative has damaged industrial consumers throughout the EU.

Protecting European industry is an end in itself. Industry has traditionally been a source of quality jobs that pay better and are more stable than those of the services economy, especially in southern Europe. Innovation and development and a strong manufacturing base are also products of industry and an advantage we are rapidly losing. The EU's goal of achieving 20% of GDP in 2020 is long gone and missed, and Europe's weight in the global economy has fallen almost 5 percentage points, to 17.5%, in the last two EU legislative cycles. Almost a million industrial jobs have been lost in the last five years, according to trade unions.

Industry in Europe needs regulations that do not just prohibit or mandate but rather provide incentives to attract private capital to finance the major investments needed. Europe needs an Industrial Deal to complement the Green Deal, a gameplan plan that is based on technology rather than ideology, to recover European competitiveness on a global level.

Scientific approach

Europe must abandon an approach to the energy transition that has mandated solutions and technologies instead of encouraging experimentation, innovation and competition of ideas that, as any engineer will tell you is the bedrock of a solid scientific approach to problems.

At Repsol, we are putting our money where our mouth is. We are committed to the decarbonisation of our energy mix. To that end, we are making big investments at our industrial facilities. Our strategic planning contemplates an increased production of HVO and SAF and development of biogas in Spain, as well as renewable hydrogen and waste-to-gas technology. One in every three euros the company is spending will be directed to low-carbon businesses, including—but not limited to—renewable power generation.

Private capital can be mobilised quickly and effectively by the right regulatory signals, by predictable and easy-to-navigate legislation. Europe's proud tradition of innovation and leadership is something to cherish and nourish, and lawmakers would do well to give industry the tools to recover the ground lost to competitors who in the last decade have been more focused, more pragmatic, and, ultimately, more effective than the EU. ■

The importance of ensuring a just transition for developing nations

While the global energy transition is essential for reaching net zero, it is equally important that less-developed countries are allowed to realise the benefits of their hydrocarbon resources

There is a need for nations to transition their energy sources from hydrocarbon-intensive ones to 'greener' varieties. However, how to do this is widely debated among politicians and business leaders.

Eco Atlantic believes that a successful global energy transition is important to achieve a 'net zero' result, yet it is equally important not to penalise nations with unrealised hydrocarbon reserves.

According to the UN Development Programme, 1.18b people, or 13% of the global population, live in energy poverty—mostly in Africa and South Asia. All nations must determine their own energy policies and carefully consider their energy mixes to ensure energy poverty is overcome. This is especially important in economically developing nations to ensure a balance between decarbonisation and growth is established.

Eco Atlantic is proud to have assembled a portfolio of exploration licences in some of the most exciting energy jurisdictions in the world. Namibia, South Africa and Guyana are all nations that possess considerable untapped hydrocarbon resources, which have the potential to help generate economic growth and a sustainable low-cost power source for generations to come.

2.73%

Proportion of global CO_2 emissions from African countries from 1751 to 2017

However, global political leaders often suggest that developing nations should elect to not develop these energy sources and instead focus on renewable energy projects. These projects require significant infrastructure development and technological advancements and are unlikely to have the same positive economic and social impacts. Our view is that these nations should be able to develop their hydrocarbon resources.

Energy self-determination

South Africa produced 83% of Africa's coal generation in 2023, and in turn 83% of South Africa's energy generation came from fossil fuels, according to thinktank Ember. This reliance on coal has created a large domestic industry, which as of 2019 employed c.108,000 workers, according to national data service Statistics South Africa. It is important that in transitioning away from coal, these skilled workers are not left behind. Their skills should be looked to be repurposed to serve the country's energy transition.

The untapped hydrocarbon resources of South Africa's 160,000km^2 Orange Basin present such an opportunity. The basin has the potential to transform the country's energy sector, boost development and employment opportunities, and provide a solution for the country to wean itself off coal and move towards domestically produced transitional sources of energy.

Ever-growing interest in the basin and upcoming drilling activity, evidenced by TotalEnergies and QatarEnergy's recent farm-in to Block 3B/4B, in which Eco holds a 6.25% working interest, has the potential to create an offshore energy sector that meets both South Africa's economic needs and environmental requirements as well as addressing sub-Saharan Africa's growing energy demands.

Since ExxonMobil's discovery of oil in Guyana in 2015, the country's energy sector and its economy have grown exponentially, with GDP rising by 33% in 2023 and forecast to increase by a further 34% in 2024. Guyana's oil developments have presented the country with a unique opportunity to embark on its own journey to net zero. With around 82% of the country covered by humid forest, Guyana has a unique perspective on the impact of climate change and should be entrusted to determine its own energy policies.

The country has shown exemplary leadership in setting responsible frameworks for its hydrocarbon sector, having some of the best-performing upstream assets in the world in terms of emissions intensity, according to consultancy Rystad Energy. Moreover, using domestically produced natural gas as a source of energy can enable Guyana to create jobs and further boost its economy while lessening its reliance on dirtier energy sources.

Namibia is another example of the importance of allowing nations to enact their sovereign energy policies.

By Gil Holzman,
CEO,
Eco Atlantic

The country's vast oil and gas resources have attracted the likes of TotalEnergies, Shell, Chevron and ExxonMobil, and have the potential to transform Namibia's economy, with its GDP expected to double by 2040 once the discoveries are proven to be commercially viable, according to the US Department of Commerce's International Trade Administration. With development plans continuing to be announced, such as TotalEnergies' probe in the Venus discovery targeting a billion-barrel resource, Namibia is getting closer to realising its potential as a global hydrocarbons player.

Namibia has an opportunity to stake its place on the global stage, while also improving the lives of Namibians as well as localising its energy production to produce cleaner energy needed to drive its economy forward. Attempts to curtail Namibia's ability to maximise its resources would, therefore, limit the benefit these resources provide to its economy and its citizens.

> **Eco sees how the energy resources of Namibia, South Africa and Guyana could transform the economic and social landscapes of these countries**

This is symptomatic of the hypocrisy within global decarbonisation policies. From 1751 to 2017, only 2.73% of global CO_2 emissions were produced by African nations, according to research group Zero Carbon Analytics, despite the continent now contributing to around 18% of the global population. Yet many of these countries and their citizens are now being told by wealthier nations that have emitted far more that they are not allowed to reap the rewards of their resources. Striking a balance between growth and environmental responsibility is, therefore, key to a just energy transition.

In summary, Eco sees how the energy resources of Namibia, South Africa and Guyana could transform the economic and social landscapes of these countries, while also enabling them to transition away from more carbon-intensive energy sources and explore renewables. We believe it is imperative that these countries are allowed to do this in a just and sustainable manner, to enable fair economic development and to end energy poverty in Africa and South America. ■

The role of biofuels in global renewable energy investments

Bioenergy will be a key part of the energy transition as the world decarbonises, and Brazil is set to be a major player in the sector

The world is facing climate change driven by global warming, primarily caused by greenhouse gas (GHG) emissions. In response, decarbonisation goals have been established to mitigate the impact on society and the economy, leading to structural changes in energy generation and production methods.

The Paris Agreement, signed during the 21st Conference of the Parties (COP21), created a framework for this transformation. The agreement sets out measures to reduce carbon dioxide emissions, aiming to strengthen global responses to climate change and enhance nations' capacities to manage environmental impacts. Governments committed to keeping global temperature increases well below 2C above pre-industrial levels, with efforts to limit the rise to 1.5C. To achieve this, countries submitted Nationally Determined Contributions outlining their plans to reduce emissions.

A key element of this transformation is the energy transition, which involves gradually shifting towards renewable and low-carbon energy sources, as well as pursuing greater efficiency and low emissions from traditional sources of energy in a just, orderly and equitable manner. This shift must be managed methodically to ensure energy security throughout the process.

Decarbonisation targets affect various economic sectors, including the oil and gas industry, which is crucial in maintaining energy supply and supporting socioeconomic development. In Brazil, the oil sector has a competitive advantage due to its lower GHG emission intensity—17kg CO_2/boe, below the global average of 20kg CO_2/boe. In the pre-salt area, some fields emit as low as 10kg CO_2/boe.

Despite the need for decarbonisation, oil remains a dominant energy source, accounting for around 80% of the global energy mix. Maintaining oil production during the energy transition ensures energy security and prevents cost increases that could hinder economic development. Moreover, revenues from oil exploration and production can be reinvested in low-carbon technologies, including renewable energy projects such as solar, wind and biofuels.

Brazil's commitment to renewable energy is evident. Between 2018 and 2023, expenditure on renewable energy projects increased from $9.2m to $156.4m. In 2023, biofuels received 35% of the total investment, followed by wind energy (28%), hydrogen (13%), CCS (9%), hybrid systems (9%), solar energy (6%) and ocean energy (1%), according to Brazilian regulator the ANP.

Global policies supporting the energy transition have also spurred renewable energy capacity growth. By 2030, renewable energy is expected to account for 20% of global energy consumption, up from 13% in 2023, with wind and solar energy's share of electricity generation doubling to 30%, according to the IEA.

Harvesting sugar cane in Brazil

In mobility, biofuel production plays a significant role, especially in countries such as Brazil, the US and India, where biofuels are produced from various feedstocks, such as sugarcane and corn. Although biofuel production is increasing, there is still a significant space for market growth, particularly in hard-to-abate sectors such as air and maritime transport.

> Biofuels' share in liquid fuel transport demand is projected to increase from 5.6% in 2023 to 6.4% in 2030, potentially reaching 215b litres annually

The biofuels market faces challenges in reducing production costs and improving efficiency. However, technological advancements are expected to lower costs and enhance biofuels' applicability across different transportation and industrial sectors. By 2030, bioenergy—including liquid, gaseous and solid fuels—is expected to account for 95% of renewable fuel growth, driven by rising demand from industry, transpor-

By Roberto Ardenghy,
president, Brazilian Petroleum
and Gas Institute – IBP

tation and buildings, according to the IEA.

Biofuels' share in liquid fuel transport demand is projected to increase from 5.6% in 2023 to 6.4% in 2030, potentially reaching 215b litres annually. The US, Europe, Brazil, Indonesia and India will drive this growth, accounting for 85% of the market, the IEA says,. These regions are enhancing biofuel policies, setting decarbonisation targets and offering financial incentives to integrate biofuels into their energy mixes.

Hurdles to clear

Globally, biofuel demand for road transport is expected to grow by 27b litres, while demand for aviation and maritime fuels will rise by nearly 9b litres by 2030. This indicates progress in integrating biofuels into sectors where electrification is challenging.

Brazil is a pioneer in encouraging biofuels. In 2017, it created the RenovaBio policy to reduce the carbon intensity of the transport matrix with the use of biofuels and generate energy efficiency gains. The programme's main instrument is the annual decarbonisation target for fuel distributors, determining percentages of ethanol and biodiesel blends.

In 2024, Brazil enacted a new law entitled 'Fuel of the Future'. The standard creates national programmes for green diesel, sustainable aviation fuel and biomethane, in addition to increasing the mixture from ethanol and biodiesel to gasoline and diesel. The objective is to avoid the emission of 705mt of CO_2 by 2037, according to the Ministry of Mines and Energy.

Liquid biofuels, which can be used with minimal modifications to the existing vehicle fleet, are expected to see the most significant growth in the transport sector. New policies for aviation biofuels and maritime transport could stimulate about 30% of the new demand in the transport sector overall, according to the IEA.

The oil and gas industry is also contributing to decarbonisation by blending biofuels into conventional fuels used for mobility, such as adding ethanol to gasoline and biodiesel to diesel. This integration supports a smoother and more equitable energy transition, particularly for sectors that are difficult to decarbonise, such as transportation.

The energy transition requires a balanced approach that ensures energy security while gradually reducing carbon emissions, and Brazil is playing a key role in this area. With investments in low-carbon technologies and the integration of biofuels, the oil and sector plays a pivotal role in ensuring a smooth transition to a more sustainable and equitable energy future. ■

IBP contributors to this article: Isabella Costa, oil and gas technical analysis manager; Aldren Vernersbach, economist; Leonardo Lima, senior analyst; Vinicius Daudt, analyst

Financing cutting-edge transition tech: Paving the way to a net-zero future

Governments, developers, investors and lenders are keen to support and scale up cutting-edge energy transition projects, but funding such projects will require innovative financing and strategic collaboration

It remains to be seen how the recent US presidential election result will impact US policy towards the energy transition, but much of the world is racing towards a net-zero future.

Cutting-edge energy transition technologies are evolving, with first-of-a-kind projects coming to market that are pushing the boundaries of what is possible. Milestones include the first sustainable aviation fuel project financing in Southeast Asia, the world's largest green hydrogen project financing in the Middle East and the financing of a liquid air energy storage project in the UK—the first of its kind globally. These projects are not just technological achievements; some represent financial innovation in bringing cutting-edge technologies to fruition.

At the forefront of these developments is White & Case, leveraging our experience and expertise across the globe to navigate the successful financing of such projects.

An evolving landscape of transition technologies

The energy transition encompasses a vast array of technologies at different stages of development. The focus here is on the cutting-edge innovations that, after years of research and development, are beginning to mature. These technologies have the potential to redefine how we generate, store and use energy

1. Renewable energy

- **Solar power:** Innovations such as solar thermal and floating solar farms promise to unlock new potential in harnessing the sun's energy.
- **Wind power:** Larger, more efficient turbines and floating windfarms capable of being deployed offshore in deeper waters signal a new phase of growth in the wind sector.
- **Hydropower:** Small-scale, advanced hydropower systems, high-density hydro, tidal and wave energy technologies offer new options for water-based energy generation.
- **Geothermal energy:** Enhanced geothermal systems are unlocking untapped reserves of geothermal energy.

2. Energy storage

- **Energy storage:** Advances in lithium-ion technologies and solid-state batteries are improving storage efficiency, while long-duration energy storage solutions such as flow batteries and liquid air energy storage are making it easier to store renewable energy, thereby increasing grid efficiency.
- **Thermal storage:** By storing energy in the form of heat—such as molten salt—these systems can store excess energy generated during peak periods for later use, providing stability and reliability to the grid.

3. Carbon capture, utilisation and storage

- **Direct air capture:** Technologies that remove CO_2 directly from the atmosphere are poised to become critical tools in the fight against climate change.
- **Point source emissions capture:** These are CCUS projects that involve capturing CO_2 from industrial plants (i.e., point source emitters) rather than directly from the atmosphere.

By Kamran Ahmad,
partner,
White & Case LLP

> Cutting-edge energy transition technologies are evolving, with first-of-a-kind projects coming to market that are pushing the boundaries of what is possible

- **Carbon utilisation:** Beyond capturing CO_2, there is interest in technologies that convert captured carbon into valuable products, such as synthetic fuel or building materials.

4. Grid modernisation & smart grids

- **Smart grids:** Digital technologies are transforming how we manage energy distribution, allowing for better integration of renewable energy, improved demand management and grid efficiency.

5. Electrified mobility

- **Electric transport:** The electrification of transport—from electric buses and trucks to planes, ships and trains—is revolutionising mass transport across industries.

Lessons from cutting-edge transition finance

Cutting-edge energy transition projects that have reached financial close require capital structures put together with considerable care. This involves a coalition of capital, with each lender or investor contributing to the overall capital structure based on its own risk and reward expectation.

An understanding of project finance techniques is, in our view, critical. Project financing seeks to deploy capital against a project's cash flow, rather than relying on the balance sheet of the project developer. This is clearly attractive to project developers grappling with limited balance sheets and technology risk.

The project finance discipline is used to test the project's risk allocation, even if it is recognised that the project may depart from 'project finance 101'. For example, a turnkey wrapped construction solution, robust take-or-pay offtake, comprehensive insurance or hedging strategy may simply not be available in the market for a nascent technology project or product. Nonetheless, ensuring transaction advisers have a sound understanding of project finance techniques and when and how to negotiate flexibility is critical.

A challenge here is the cost in time and money involved in negotiating and implementing the project development and funding plan. Perseverance, patience and persistence is critical. It helps, of course, for the project to have a robust business case and technology that has been proven at pilot stage..

Conclusion: A multifaceted approach

The financing of cutting-edge transition technologies demands coordination and collaboration across public, private and multilateral sources of finance. While the challenges of financing early-stage technologies are considerable, well-conceived projects targeting profitable segments of the energy ecosystem are reaching financial close. Building a coalition of diverse financing sources plays a central role in enabling rapid scale-up of nascent but transformative technologies. ■

Digital in the grand alliance: Driving energy technology beyond the energy transition

Global energy demand keeps rising, and digital technology will play a crucial role in both meeting that demand and doing so in a sustainable way

A few years into the energy transition, meant to be a shift away from oil and gas as the world's primary energy source, it is clear that we are really experiencing an energy expansion, in which every source of energy will be necessary to meet the world's growing energy demands.

This situation presents a set of interesting challenges that we must address simultaneously. First and foremost, we need to keep our focus on sustainable energy development—making sure that energy is affordable, secure and sustainable for people, for the planet and for the long term. But within that context, we must:

- Develop and integrate renewables into the mix at a much faster pace
- Find and champion new sources of energy
- Ensure that traditional energy sources can still meet the world's demands while becoming cleaner and more efficient; for example, in order to reduce the percentages of coal and 'dirtier' fuels in the mix, we must make gas globally available at affordable prices.

If the past is any indication, technology will play a critical role in meeting these challenges—but what excites me most about this technology is that it is being developed through a digital lens.

Energy operations, no matter the source, produce an abundance of data that can guide how we make decisions, how we prioritise activities and how we create efficiencies. The digital mindset of measuring, analysing and actioning drives continuous improvement in all areas, but it is especially pronounced in helping us understand what data are telling us.

Digital gives us the tools—secure IoTs, data analytics, cloud computing, machine learning, generative AI and large language models, for example—to put that data to use. To be clear, digital provides the toolbox, not the solutions. Collaborative, problem-solving engagements with customers and communities define the solutions. But when we can do that, we can connect with customers and communities in faster, more precise and more transparent ways. It helps us see what is possible today and forecast what comes next.

Does the injection of a digital lens mean that 'energy technology' is shifting to 'digital energy technology'? Absolutely—because digital is now a required element in technology development; for example, in my company, a key priority for all technology projects and field execution is to view those projects with a digital mindset. The language we speak with our customers—and internally—is digital. We infuse digital into everything we do, without constructing a digital unit or standalone business divi-

By Maria Claudia Borras,
chief growth & experience officer,
Baker Hughes

sion. This mindset extends to AI—it's simply part of what we do and how we design.

The surest proof of this shift is to cite a few of the technologies, underpinned by digital, that are making huge differences in how we think about energy technology and its role in sustainable energy development.

- **Renewables integration:** Geothermal has a long history of providing heat and power to communities and businesses close to the energy source. Digital will change the game for geothermal, enabling us to build automated ecosystems in which optimisation occurs from subsurface to surface. With this advancement, we can minimise project uncertainty and risk, construct geothermal plants that operate at peak efficiency throughout their lifetimes and bring this important renewable into the mainstream.
- **Emissions abatement:** In CCUS, managing risk is paramount, and it is crucial to monitor, measure and report carbon throughout the process. Digital enables us to track subsurface and surface activities, delivering real-time data and alerts on CO_2 flows across the CCUS value chain—from carbon capture and compression to pipeline transportation to subsurface storage. This connectivity across the project lifecycle enables operators to identify and manage risk, improve decision-making, enhance operational efficiency and simplify regulatory reporting.
- **Business performance:** In industrial applications, disconnected systems and unstructured asset data in functional silos result in value loss and unrealised opportunity. Digital provides a thread connecting hardware, software and services to deliver actionable insights that improve asset, process and sustainability performance. These insights enable organisations to view operations holistically, anticipate outcomes and evaluate scenarios and take strategic actions that drive success.
- **Operational efficiency:** In oilfield operations, an automated field production solution enables operators to improve efficiency by optimising production rates in fields in which grid power is limited. This solution monitors power consumption, recommends optimum voltage and sets power consumption limits. It can also automatically identify and recommend reallocating power to the wells that produce the most hydrocarbons and the least water.

> It is clear that digital is a game-changer in taking energy forward

Finally, I suppose that any discussion on digital energy technology must include a few words about AI. Our industry is still on a learning curve for AI, and I know that its successful application in the energy industry will depend on how we establish the partnership between the AI tool and the people who can apply its results to deliver a meaningful outcome. Recently, we have seen some great results in applying AI to transform the way oil and gas assets are managed, and I am excited and encouraged by them.

Across the energy expansion, it is clear that digital is a game-changer in taking energy forward. The infusion of digital—including AI methods—allows us to drive our own efficiencies forward, and also the efficiencies of our customers. In the end, that means supplying the affordable, secure and sustainable energy that the 7b people on our planet deserve. ■

The cost of incohesive policies: why supply chain energy transition remains challenging

Policymakers need to step up with a long-term, global strategy if the energy transition is ever to be a success

Why are net-zero investments stagnating and failing to live up to the hype? Many say it is due to failing markets or supply chain constraints. Doubtless, we are bound by market forces, and with weak, lumpy and poorly funded demand for net zero, this means success stories in the supply chain struggle to emerge. But is it all about supply and demand, vision and investment? Or, as our members suggest, are the rules and policies set against us from the start?

FID rates remain stubbornly low

EIC data red-flags chronically low FID rates for fixed offshore wind projects, which are showboated by governments of countries with windy shorelines as the linchpins of their net-zero commitments, including by the UK's new Labour government. There is therefore no shortage of demand, with nearly $2t of projects announced globally. And yet, outside of China only 7% of these are at FID, as projects flounder with negative margins when today's higher capital costs are priced in, requiring reluctant governments to reintroduce subsidies to try to attract investors again. This 7% compares with around 40% FID rates for large nuclear and upstream oil and gas.

> It is time to do what is needed to confront the pressing challenges facing our global energy landscape to build the sustainable future we all want

Longer term, hydrogen and carbon-capture are painted as solutions to the harder-to-abate sectors, but FID stats are even lower. The reason here is a lack of demand, with projects requiring eye-watering levels of financial stimuli and complex new regulations to get them off the ground. Outside the US, with its innovative Inflation Reduction Act, governments are fearful of lame-duck projects and rising national debt, so are dragging their feet.

The consequences of mismatched high policy net-zero ambition against low industry reality, which ultimately result in lack of opportunities for companies across the energy value chain to get involved in net-zero projects, are far-reaching. Large corporations are beginning to withdraw from their net-zero pledges. Our members in the supply chain report many of the renewable contracts they have been able to secure have come with low or negative margins. They are now also tired of hearing yet another net-zero pledge that fails to accept the inevitable—what everyone seems to know except policymakers—that absolute net-zero deadline dates, especially interim target dates, are not going to be met. But publicly declaring this still feels too risky, so we battle on.

Lack of global governance and consensus

Shared global urgency about COVID and the climate in 2020 is behind us, with vaccines delivered, net-zero not. The UK has flip-flopped on its oil and gas policy, from anti to pro and back again. The London mayor has announced that electric vehicles (EVs) will pay the congestion charge in 2025, surely sending already wavering EV sales into sharp reverse. Globally, the world is using more hydrocarbons in 2024 than ever before.

Nowhere is the absence of cohesive and realistic global governance for the energy transition more apparent than at COP meetings. At COP28, countries were unable to agree on measures for Global Stocktake dashboards, an essential tool for tracking each country's progress towards their own publicly declared national decarbonisation commitments—a league table of those performing best to worst, if you like. They could only agree to declare a global 43% shortfall in emissions reduction to 2030. This absence of transparency not only stalls progress and raises doubts about equity and investment risk, but also reveals deep-rooted challenges in establishing a unified approach to a global net-zero policy.

As populist and far-right political movements gain traction, the political landscape becomes increasingly polarised, further undermining collaborative efforts essential for a successful energy transition. The short-termism of political cycles overshadows the long-term investment decisions crucial to energy infrastructure. Projects with high upfront costs and extended develop-

By Stuart Broadley,
CEO,
The Energy Industries Council

ment timelines, such as nuclear energy, suffer as a result despite growing recognition that nuclear power serves as the answer for many countries as a reliable low-carbon baseload power source.

Is meeting in the middle feasible?

Supply chain companies and policymakers are at odds, separated by developers and operators. Global political discourse is growing, conflicted by global north-south tensions and wars in Europe and the Middle East that send worrying undercurrents of fuel insecurity. Can we bridge the divide?

Talking about net-zero while engaging in virtue-signalling achieves worse than nothing: it degrades trust in policymaking and exhausts investors who look elsewhere for surety of returns.

The argument for a long-term, global industrial strategy is compelling. EIC's annual 'Survive and Thrive' research and our new 'Net Zero Jeopardy' research reveal a common view from the supply chain: nations lack a long-term strategy that extends beyond the political horizon and election cycles.

We need certainty, and to achieve this we must look ahead to where we need to be, then work backwards to develop a structured pathway that leads sustainably to our net-zero goals. This includes aligning national grids, enhancing shared capacity and embracing cross-border collaboration and trade to unlock cost-competitive net-zero technologies.

We must recognise that the issue is not market failure but erratic energy policies, lacking coherence and foresight. A sustainable energy future demands robust, global governance frameworks, offering the clarity needed to drive investment and innovation. Once such structures are established, governments can develop national energy policies to support meaningful global commitments. This will be true global cooperation.

Ultimately, the blame game about market forces must yield to assuming responsibilities for systemic obstacles in policymaking. It might feel risky for policymakers to say it, but it is time to do what is needed to confront the pressing challenges facing our global energy landscape to build the sustainable future we all want. Those are the policymakers of the future. ■

Greener use of fossil fuels is an essential part of the energy transition

The hurdles standing in the way of rapid move away from fossil fuels are proving harder to clear than first thought

In the early days of the energy transition, there were widely held views that, in order to achieve new net-zero and other climate-related commitments set by many companies—objectives that derive from ambitious Nationally Determined Contributions of countries in support of the Paris Agreement's goals for reducing greenhouse gas (GHG) emissions and adapting to climate impacts—it would be necessary to rapidly and precipitously transition away from reliance on fossil fuels. Several factors have demonstrated that a hasty shift away from fossil fuels towards renewable energy sources will be far more challenging than initially anticipated.

Firstly, many countries are realising that reducing reliance on fossil fuels has to be balanced against ensuring the security and reliability of energy supplies, which many believe to be of paramount significance. Political events, such as the disruption of Russian gas supplies to Europe, dramatically illustrate the risks associated with energy security and the benefits of a multi-faceted approach.

Secondly, the cost, reliability, technical and regulatory issues associated with switching to renewable energy and alternative fuel sources, compared with continued use of conventional energy, create obstacles to a quick transition to these new energy sources. In many cases, these alternatives are economically viable only with substantial governmental incentives, and there is a growing realisation that the pace of the energy transition will differ by region.

Thirdly, and directly related to the first two points, the top priority of many emerging market countries is to improve the economic conditions of their citizens. Consumers in developing countries may be less willing to adjust their energy use or volunteer to pay a 'green premium' for renewable energy. It seems highly unlikely that, given this goal, many of these countries, particularly those with substantial fossil fuel reserves (such as Bangladesh or Indonesia), can be convinced to forgo readily accessible and relatively inexpensive fossil fuel sources of energy in favour of more expensive and less reliable alternative fuel sources.

> A hasty shift away from fossil fuels towards renewable energy sources will be far more challenging than initially anticipated

Finally, in addition to producing energy, fossil fuels are critical for the production of other essential products such as plastics, fertilisers, personal care products, pharmaceuticals and medical devices. Demand for these essential products will remain high until affordable and reliable alternatives are developed to facilitate an orderly product transition.

Future fuels

In light of all of the considerations above, it seems clear that some significant degree of continued fossil fuel use is inevitable for many years to come. Based on this analysis, and given the net-zero goals that have been widely accepted, there needs to be a higher degree of focus on methods of using fossil fuels in a more environmentally friendly manner. These measures broadly fall into three categories:

1. Transition to cleaner forms of fossil fuels. Global demand for electricity is rising. A key to reducing GHG emissions is the development of cleaner methods of electricity production, particularly through the shift from coal to natural gas, including through expanded use of LNG to transport gas from countries with excess gas supplies to countries with vast energy needs but relatively small amounts of indigenous gas reserves. This is particularly important in the context of countries such as China, which continue to use coal as a major source of energy generation.
2. Promotion of CCS. Many companies have made substantial investments in CCS projects to achieve net-zero goals and to reduce the environmental effects of the production and use of fossil fuels. Even with the support of significant government incentives, CCS projects face certain technical and economic challenges for scalable development. The emergence of vol-

By Jay Cuclis, partner,
and Taylor Pullins, partner,
White & Case LLP

untary carbon markets, which provide an additional means for monetising carbon removal and emissions reduction projects such as CCS, is viewed as an important component of the global effort to mitigate climate change.

3 Improved energy regulatory regimes. Governments in some of the world's largest economies have introduced programmes that offer a range of incentives—including tax credits, federal grant programmes and government-backed loans—to promote the 'greening' of fossil fuels and accelerate the energy transition. CCS projects qualify for many of these incentives, yet the permitting timelines for CO_2 injection wells remain a challenge for project developers and a burden to industry efforts to lower the emissions profile of fossil fuels. The streamlining of permitting programmes by governments has the potential to unlock investment in CCS and other energy transition technologies. In addition, regulations addressing such areas as energy efficiency, environmental protection and community engagement promote a focus by industry to continuously improve on the production of energy from fossil fuels in cleaner and safer ways. Federal regulations in the US apply a particular focus on the management and reduction of methane emissions in oil and gas development.

In some quarters, there has been an effort to demonise the use of fossil fuels, given their impact on climate, biodiversity and the environment. These efforts ignore the undeniable benefits that fossil fuels have and continue to provide in terms of providing readily accessible, secure and relatively inexpensive sources of energy to power homes and communities, fuel economic growth, and produce essential products. To achieve net-zero goals, the reality is we will need an 'all of the above' strategy that includes increased transition to non-fossil fuels, as well as greener use of fossil fuels. All of these energy sources should be viewed as essential components of a successful energy transition. ■

Green shoots ahead for VCMs in 2025 and beyond

Tightened standards have helped improve the outlook for the voluntary carbon market, which is set for a record year and poised for long-term growth

In 2024, the voluntary carbon market (VCM) underwent emergency surgery following heightened scrutiny of market mechanisms and allegations of corporate greenwashing. Swift action taken by carbon credit registries and framework setters has overhauled categories such as clean cooking and renewables and removed many low-quality carbon credits from the market. And a tightening of standards has significantly increased the hurdle for the issuance of new carbon credits.

This renewed VCM is more resilient and poised for long-term growth. While carbon credit sales contracted by 56% in 2023, 2024 is likely to be a record year, with direct investments into 'upstream' carbon projects already reaching $62b by the end of Q3.

Going forward, we must continue to embrace additional calls for transparency, governance and due diligence as these will build trust, integrity and stability in the market as a vehicle for climate action through more rigorous verification processes and credit methodologies.

As we navigate the path ahead, we will continue to see market forces eliminate low-impact projects, increase carbon prices and drive up demand for high-quality supply into 2025 and beyond. Already, we are seeing green shoots in the market.

Green shoots in the VCMs

Around the world, market infrastructure is being established across the public and private sector to enable carbon trading; enhance clarity around methodologies, credit quality and end-use claims; and increase the availability and transparency of data. The VCM has become a pre-compliance market, which is stimulating demand today, and bilateral agreements between countries will determine which credits can be traded across borders.

Meanwhile, governments are establishing greater incentives and compliance measures, which are expected to be a significant source of demand. In Singapore, organisations operating within the country are incentivised to purchase carbon credits in exchange for a tax break. Similarly, as of 2024, 126 countries have signed up to join the Carbon Offsetting and Reduction Scheme for International Aviation to reduce the environmental footprint of long-haul flights through carbon offsets.

New frameworks are building trust and oversight in the market. The US Commodity Futures Trading Commission has approved guidance on the use of voluntary carbon credit derivative contracts and initiated its first enforcement actions. And in October 2024, a UN expert group agreed a deal on key elements of a global carbon trading system. This framework will allow governments to trade carbon credits towards their own climate goals, unlocking significant opportunities to fund climate adaptation in developing countries.

These developments—though many are still being operationalised—pave the way for mainstream credibility and longevity of the VCMs. Private investors are increasingly seeing the VCM as an asset class in its own right. In the last six months, Key Carbon, one of the largest investors in carbon offset projects, announced $33m in new investment and carbon financing deals from private equity firm Cartesian Sustainable Finance and global financial platform Marex Group. These deals are a powerful endorsement of continued demand for high-quality, high-integrity credits and a validation of the need for robust governance, monitoring and due diligence by those across the sector.

Impact of VCMs

As the market continues to grow stronger, we cannot lose sight of the tangible impact that high-integrity carbon offset projects have on combatting global emissions, improving biodiversity and elevating the standard

By Luke Leslie,
CEO and co-founder,
Key Carbon

of living for some of our most vulnerable communities around the world.

For instance, a lack of clean cooking affects more than 2b people around the globe, including over 1b in Africa. Displacing inefficient and carbon-intensive cooking methods can improve air quality, reduce respiratory illnesses and help avoid the estimated 3.7m premature deaths per year associated with poor indoor air quality. Roughly 150m people across Africa need to gain access to clean cooking methods to achieve universal access by 2030. However, less than one-third of clean cooking plans in Africa are funded.

Clean cookstove credits provide an opportunity to help plug this gap. To date, Key Carbon has provided $45m in funding to expand the rollout of clean cookstoves in eight African countries, which will improve the lives of an estimated 7.5m people and help avoid or remove more than 45mt of carbon emissions.

VCMs also provide a pathway towards positive nature outcomes. In 2022, a monumental agreement was achieved during COP15, including targets to halt and reverse biodiversity loss, protect 30% of land and sea areas and restore 30% of degraded ecosystems—all by 2030. But despite this global agreement to protect nature, the rate of biodiversity loss and habitat destruction is accelerating.

High-quality carbon offsets help improve local biodiversity and reverse nature loss. For example, mangrove restoration projects have the highest impact on mitigating the effects of climate change since mangrove swamps are up to four times more effective at absorbing carbon dioxide emissions than terrestrial forest.

> We cannot lose sight of the tangible impact that high-integrity carbon offset projects have on combatting global emissions, improving biodiversity and elevating the standard of living for some of our most vulnerable communities

They also help to maintain biodiversity by providing a rich habitat for marine and bird nurseries while improving fish stocks and water quality. To date, Key Carbon has financed the planting of 3.75m trees since its incorporation alongside other projects that support biodiversity action.

2025 and beyond

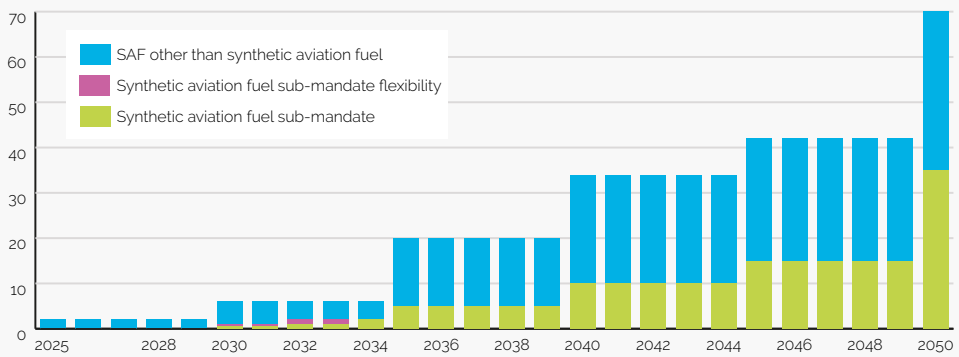
Next year will be a critical juncture for voluntary carbon markets as new regulations are passed around the world and integrity standards are operationalised. As we race ahead to 2030, we expect this surging demand to drive tremendous benefits to local communities, nature and the planet. ■

eSAF: Overcoming financial, technical and market challenges

Sustainable aviation fuel from electrolysis has great potential for reducing aviation sector emissions, but cost, energy requirements and the need for substantial investment stand in the way of take-off

Sustainable aviation fuel (SAF) has emerged as a crucial option for reducing emissions in a sector that is challenging to electrify. Electrolysis-derived SAF, or eSAF, holds particular promise as it uses power-to-liquid (PtL) technology to convert renewable electricity, water and captured CO_2 into synthetic jet fuel. This alternative differs from bio-based SAF, which depends on agricultural feedstocks and has inherent scalability limits. eSAF, by contrast, can theoretically be produced at larger volumes due to its reliance on renewable electricity and CO_2. However, eSAF production faces significant barriers, such as high costs, large energy requirements and the need for substantial investment in renewable infrastructure and carbon-capture technology.

FIG.1: SAF and eSAF mandates, EU (% total jet consumption)



Source: EU Commission, etasca interpretation

The adoption of SAF is being supported by policies such as the EU's ReFuelEU Aviation regulation, which establishes blending mandates for airlines and includes specific blending targets for PtL fuels such as eSAF. These mandates are geared towards bio-based SAF production, starting in 2025, but by 2030 incorporate a proportion of eSAF. The mandates themselves are placed on the aviation fuel suppliers, which will face penalties for non-compliance of at least twice the price difference between traditional jet fuel and SAF. This penalty encourages uptake even with a SAF price significantly higher than that of fossil-derived jet fuel.

There are two main pathways to eSAF being explored, both of which use captured CO_2 and electrolytic (green) hydrogen as feedstocks. One pathway includes the production of e-methanol as an intermediary before being converted into olefins then oligermerised into eSAF. Another pathway uses Fischer-Tropsch (FT) and reverse water gas shift reactions to combine the feedstocks, via synthesis gas, into a synthetic jet fuel. Each of these reactions are used in commercial production of a range of fuels and chemicals.

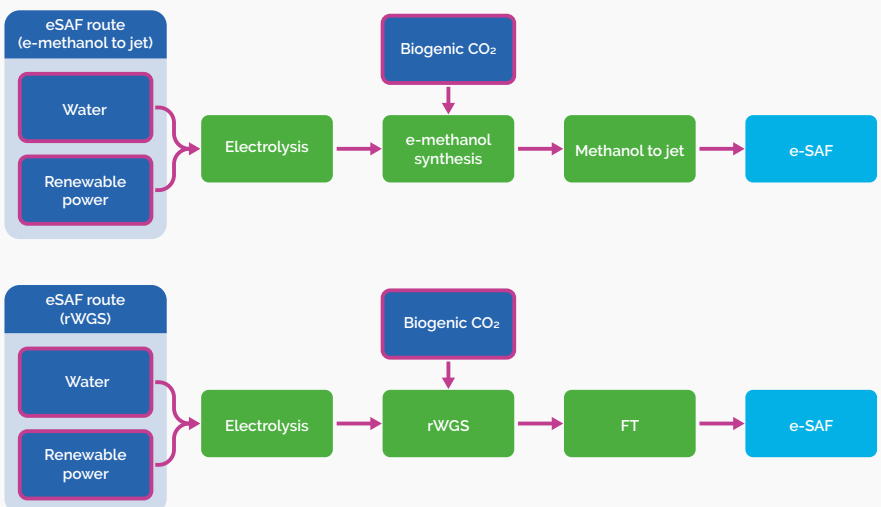
> While bio-based SAF may meet short-term needs, eSAF offers a longer-term solution with fewer limitations related to feedstock availability

While the aforementioned policies mandate consumption of eSAF, there remain several hurdles for widespread implementation of commercial production facilities. Firstly, eSAF production costs are estimated at 3–4 times higher than those of fossil-derived jet fuel, mainly due to the large amount of renewable energy required to produce the green hydrogen, but also to the capital costs of electrolysers and downstream processing equipment. These high theoretical costs can be mitigated by developers via locking in power costs—by establishing a power purchase agreement—and ensuring a long-term offtake is secured.

A second hurdle to overcome is the large amount of CO_2 required. Most eSAF mandates, especially in Europe,

By Andy Ballard,
director,
etasca

FIG.2: eSAF production pathways



Source: etasca

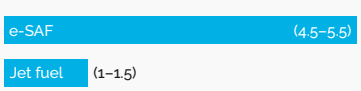
will require the CO_2 to be from biogenic sources, which are currently limited in scale. As an example, one of the obvious biogenic sources of CO_2 is biogas, but a typical biogas plant produces only 30,000t CO_2/yr, less than 20% of the approximate 160,000t/yr that etasca estimates is required for a commercial-scale eSAF plant. As such, there may be a need to aggregate CO_2 from a variety of sources, which will further add to the costs. Innovative methods of utilising CO_2 sources will be one of the key challenges to be addressed by individual project developers. In the longer term, CO_2 could be used from direct air capture, but this technology is still prohibitively expensive (currently 5–6 times as costly as biogenic CO_2 from biogas facilities).

A further hurdle to establishing commercial plants is the demonstrated scale of the technology. As yet, the individual elements of the eSAF process have been demonstrated in other applications, but the integration into eSAF production at scale has yet to be commercialised. The variability in renewable power leads to challenges related to intermediate storage of both energy (in a battery energy storage system) and hydrogen. In addition, economies of scale dictate that large eSAF plants will be required, but this then requires a significant scaleup of most of the technology elements. The technology risk as a barrier to investment can be mitigated to an extent by technology suppliers providing equity in the project, or through providing robust guarantees on performance.

Lastly, the market is driven by the need for offtake. While the mandates are geared towards the fuel suppliers themselves, many have been reluctant to investment in production or enter into long-term offtake agreements. To combat the high upfront costs mixed with uncertain revenue streams as a barrier to investment, support mechanisms such as contracts for difference—whereby producers are guaranteed a price for eSAF and receive payments to compensate for any shortfall in market prices—may be necessary to reduce investment risk and attract private capital for scaling eSAF production.

As the aviation sector pursues net-zero emissions by 2050, eSAF has the potential to support decarbonisation efforts alongside bio-based SAF. While bio-based SAF may meet short-term needs, eSAF offers a longer-term solution with fewer limitations related to feedstock availability. However, achieving eSAF's potential requires coordinated support from policymakers, investors and technology developers to address cost, infrastructure and technical barriers. ■

FIG.3: eSAF cost of production versus the current price of fossil-derived jet fuel ($/kg)



Source: eSAF – Average cost of production from etasca estimates from both FT and MtJ pathways, jet fuel – public domain

How the UK can be a world leader in decarbonising aviation

The aviation industry needs government action and policy support to realise the potential of hydrogen as part of SAF, and the UK has the potential to lead the way

Aviation is a highly energy-intensive sector, accounting for around 2% of the world's CO_2 emissions and up to 4% of the EU's. It is also the second-biggest source of emissions in the transport sector, after road transport, generating 13.9% of emissions, according to the European Commission. To give context to the intensive nature of its energy use, a person flying from Lisbon to New York and back generates roughly the same level of emissions as an average person in Europe does heating their home for a year.

This is a stark reminder to all of us on a personal level of the responsibility we have as consumers. Government, industry and financiers are working hard to make adoption easier and cheaper for consumers, but if we are to accelerate towards a net-zero future, it is imperative we do all we can to reduce our own individual carbon footprints. Fighting climate change needs a change of behaviour, and we are clearly not doing enough, as highlighted by the International Civil Aviation Organisation's forecast that, by 2050, global aviation emissions could triple compared with 2015. And while new generations of aircraft will improve efficiency and smaller aircrafts will be electrified or use hydrogen with jet turbines or fuel cells, new fuels including sustainable aviation fuel (SAF) are required to substantially reduce carbon emissions in aviation.

How SAF works

SAF is chemically similar to conventional jet fuel, which means it can work with existing plane and engine design and refuelling structures. SAF is, unfortunately, not a decarbonising magic wand since greenhouse gases are emitted in its refining processes and when it is used to power the planes, but it can significantly reduce greenhouse emissions over its lifecycle through reusing harvested CO_2 in its production. Therefore, SAF is part of the solution between short-term, low-impact efficiency improvements and longer-term complete redesign of the aviation system.

There are several synthesis routes to produce SAF, broadly based on biomass or electrical energy 'e-fuels'. While SAF produced by biomass such as vegetable oils, animal fats and greases is the most established method and will play a key role, its use is ultimately restricted by the limited supply of feedstocks available, and so alternative methods for SAF such as power-to-liquid (eSAF), which combines green hydrogen and harvested CO_2 as feedstocks, need to be used to meet demand for aviation fuel, which is currently in the billions of tonnes per year.

This is highlighted in the IEA's Net Zero roadmap, where it is projected that hydrogen-based fuels and biomass will increase to 37% and 33% respectively of final energy consumption by 2050. The number for both currently stands at below 1%, according to the IEA.

There are certainly supportive signs coming from the industry. For example, One World Group—a body that includes airlines such as American, Qantas and Cathay Pacific—has targeted using SAF for 10% of combined fuel volumes by 2030. Yet there remains a long way to go in supplying the required amount of SAF to achieve these targets, and it will take a holistic approach to achieve it.

UK government leads the way

If we are to realise the potential of hydrogen as part of SAF, the industry cannot do it alone. Government action and policy support will go a long way to facilitating the momentum across the market that the industry can subsequently capitalise on.

To that end, it is encouraging to see the UK government mandate for change. Its target of SAF making up 10% of total UK jet fuel demand by 2030, and then up

By Caroline Hargrove, CTO, Ceres

to 22% in 2040, positions it as one of the more ambitious globally.

Policies and mandates such as these are a clear signal to the market and are crucial in stimulating the industry to decarbonise. They provide the market with much-needed confidence to make the change at a time when the industry needs support to contribute to the capex investments that are often seen as a barrier. This is the case in aviation, where an obstacle to demand growth for SAF produced via green hydrogen remains the cost. However, the appropriate incentives will act as a catalyst for investment, which will accelerate the development, maturation and related cost-down of the technologies we need to drive industrial decarbonisation more generally.

22%

UK mandate for proportion of SAF in jet fuel demand by 2040

Time for industry to deliver on the mandate

The UK is widely considered Europe's leading tech hub, with world-leading R&D infrastructure positioning it strongly on a global scale too.

Specific to the energy transition, the UK is a leader in innovative and proven technologies across the entire value chain. Moreover, any innovation technologies that are being developed today will inherently identify new applications and innovations that will further contribute to net-zero targets. For SAF, this technology leadership is complemented by the level of existing chemical engineering expertise and existing infrastructure in place in key locations in the UK, including increasingly good access to renewable energy as well as existing gas storage and refining.

The potential for the UK to be a global trailblazer in aviation has already been demonstrated, achieving a number of world-first advances in hydrogen-powered aircraft technology from hydrogen engine testing to the first flights of hydrogen-fuelled planes. However, to capitalise on this opportunity we need to act now. Industry, government and academia all need to come together to realise this opportunity for the UK, pull through and further mature some of these technologies, which will also accelerate the wider industrial decarbonisation. ■

The future of the utility-scale BESS market

The utility-scale battery energy storage system market is evolving rapidly, with diverse offtake models emerging to offer bespoke, flexible contracting solutions

The rapid evolution of the utility-scale battery energy storage systems (BESS) market in Australia, Europe and the US has seen the emergence of a wide range of offtake products. These arrangements offer opportunities for more bespoke contracting solutions compared with traditional power purchase agreements (PPAs) for renewable energy projects. The options can largely be grouped into three categories: physical tolls, swaps and revenue floors.

These options vary significantly in terms of complexity and level of physical performance risk assumed by the parties. Whether one or more of these models is suitable for a particular BESS project will depend on various factors, including the parties' operational capability, financial goals and risk appetite.

Physical toll agreements

One of the most prevalent structures for BESS offtake agreements is the 'physical toll' agreement, also known as a BESS licence or capacity services agreement. Under a physical toll agreement, the offtaker pays a fixed fee for the right to control the trading strategy and dispatch of the BESS. The offtaker is entitled to the market revenues and responsible for all market costs associated with trading the BESS capacity.

In Australia, the offtaker is typically appointed as the market-facing participant under the National Electricity Rules. The BESS owner retains responsibility for the operation and maintenance of the BESS, passing through the availability and performance guarantees obtained from its suppliers.

In Europe, physical toll agreements are also common. Currently, innovation in offtake contracts is being driven by investor demand for more sophisticated structures, as well as growing competition and sophistication across optimisers, especially utilities or energy traders, leading to other forms of BESS optimisation contracts. There are also growing differences in performance to reflect a wide range of optimisation methodologies, from more traditional trader-driven models to fully automated algorithms. The importance of intraday and balancing revenue requires more sophisticated optimisation capabilities, including AI technology and the availability of solid balance sheets to back floors.

In the US, physical toll agreements are the largest category for utility-scale BESS projects, particularly in states with renewable portfolio minimums such as California and New York. These agreements are often awarded to cost-effective projects under competitive RFP solicitation processes. These agreements may allow the offtaker to purchase the entire capacity of the BESS units and implement a bidding and dispatch strategy and share in the market revenues.

In states such as California, where utilities are required to purchase power from renewable sources, the offtaker is appointed as the 'scheduling coordinator' under grid operator rules. The BESS owner retains responsibility for the operation and maintenance of the BESS and is often exposed to significant operational risk.

A key negotiating point for physical tolls is the pass-through of availability and performance guarantees and any shortfall damages for failing to satisfy minimum guarantees or round-trip efficiency requirements.

Swap arrangements and 'virtual' toll agreements

Swap arrangements are increasingly being pursued in all markets. A swap involves exchanging a fixed price (paid by the offtaker) for a floating price (paid by the owner,

By Ged Cochrane, partner,
Florian Degenhardt, partner,
Raymond Azar, partner,
White & Case LLP

based on the market proceeds generated by the BESS). Swaps may be confined to specific periods and calculated based on the financial performance of the BESS as dispatched per the offtaker's instructions. Alternatively, a swap may resemble a physical toll, where the offtaker pays an annual fee for a share of the net market revenue.

Virtual toll agreements, also known as 'swaps', are prevalent in the Australian and US energy markets, particularly in Texas. These purely financial contracts involve no or minimal physical performance obligations, making them simpler to execute and administer than physical tolls. Virtual agreements are favoured by large corporate purchasers with renewable credit carbon offset portfolios or by energy trading houses.

These agreements do not need to relate to 100% of a project's capacity, providing a more flexible offtake structure. They can attract a wider range of potential offtakers, including financial or energy market participants seeking to maximise arbitrage opportunities.

In the European market, virtual toll agreements are expected to gain a bigger market share, similar to the emergence of virtual PPAs for renewable energy projects. These agreements can satisfy the demand of different offtaker types, from utilities and energy companies to industry and manufacturers.

Revenue floor agreements

Revenue floor arrangements guarantee the owner will receive at least a minimum amount of revenue over a specified period. If market revenue falls below the floor, the offtaker compensates the owner for the shortfall. In return, the offtaker is entitled to a share of market revenue exceeding a pre-agreed ceiling. Revenue floor arrangements can be implemented alongside swap arrangements to count towards the revenue floor.

In Australia, revenue floor structures are increasingly popular among government and government-owned entities supporting BESS projects. The federal government's Capacity Investment Scheme, for example, is essentially a revenue floor arrangement. In commercial settings, revenue floor agreements are often linked to the actual availability of the BESS, limiting the offtaker's risk exposure to market price fluctuations.

In European markets, revenue share arrangements both with and without a floor are regularly transacted, with tenors typically ranging between two and ten years. While a revenue floor can mitigate merchant risk, revenue share agreements without a floor price expose the owner to full market risk. Conversely, this allows the owner to capitalise on high market prices since there is no ceiling on its potential revenue.

As the full risk profile makes it more difficult to attract lenders, the unfloored revenue share model has been chosen for equity-funded projects, portfolios and co-located BESS. Revenue floor agreements are generally preferred where debt financing for a standalone BESS project is sought. European BESS projects can also benefit from capacity market mechanisms that certain countries (such as the UK, Belgium, Italy and Poland) have introduced, ensuring a reliable revenue stream for BESS projects.

Conclusion

The utility-scale BESS market in Australia, Europe and the US is rapidly evolving, driven by the need for more flexible and reliable energy storage solutions. The emergence of various offtake products—physical tolls, swaps and revenue floors—offers bespoke contracting solutions that can be tailored to meet the specific needs of different projects whether on a standalone basis or co-located with renewable energy projects (as is increasingly the case in the US and Europe).

Whether in the form of a physical toll agreement, a swap, or a revenue floor arrangement, these contracts provide the flexibility needed to integrate BESS into the grid, complement renewable energy sources and meet regulatory requirements. ■

Mobilising capital for green hydrogen: The commercial and financial realities

More must be done to lower the cost of green hydrogen and its derivatives

Hydrogen is viewed as a critical component in achieving net-zero emissions. The versatile element can be used to decarbonise a diverse set of sectors—from the traditional use cases in industry and refining to novel ones in transportation and electricity generation. However, 99% of hydrogen is currently produced using grey or carbon-intensive methods and leads to more than 900mt/yr of CO_2 emissions, according to the IEA. For context, that is nearly three times the emissions of all of France. For hydrogen to play an effective role in decarbonisation, low-carbon production methods need to be scaled up.

With the recent advances in solar and wind energy, using renewable electricity to electrolyse water has gained immense popularity as a way of producing 'green' hydrogen with minimal emissions. Nevertheless, transforming this momentum into actual deployment of green hydrogen facilities continues to be a challenge.

While many countries have announced ambitious green hydrogen targets and conducive policies, the underlying economics still fail to align. In most scenarios, green hydrogen and its derivatives, such as green ammonia and SAF, are prohibitively expensive, costing nearly 2–3 times that of grey alternatives. This article explores what could be done to reduce this 'green premium', and address the challenges faced in commercialising green hydrogen facilities.

Despite the promise of green hydrogen, mobilising capital to build gigawatt-scale facilities remains a distant goal in most scenarios

Expensive energy

Despite the promise of green hydrogen, mobilising capital to build gigawatt-scale facilities remains a distant goal in most scenarios. Producing green hydrogen (which costs $4.5–12/kg, according to BloombergNEF) is much more expensive than producing grey hydrogen (costing $1–3/kg) for three reasons.

Firstly, building an electrolyser train can be exceedingly expensive. The US Department of Energy (DOE) recently published a study suggesting the total capital cost to install electrolysers has increased from the previously estimated range of $1,000–1,600/kW to $2,000–$2,500/kW. A large part of the cost increase is due to a significant rise in installation costs, which forms 50–60% of the total electrolyser costs. The increase in installation costs has been driven by the uncertainty in executing first-of-a-kind projects. Capital costs, labour requirements, supply chain risks and cost schedules for constructing such facilities are challenging to predict accurately. Moreover, novel technologies may not perform as well at large scale

By Rishabh Agarwal, energy transition development manager, and Robert Clews, head of UK & Western Europe, Bechtel Enterprises

compared to pilot and laboratory tests. As a result, EPC contractors may be reluctant to assume completion and performance risks for unproven technologies, leading to an increased overall risk premium and capex.

Secondly, the substantial capital investment in electrolysers is compounded by operational costs, as renewable energy sources exhibit low-capacity factors. Depending on the renewable energy source and the location of the plant, the cost of the electricity alone could surpass the total cost of all other components in a green hydrogen facility, according to consultancy GEP.

Thirdly, the need for robust infrastructure to support the storage, transportation and distribution of hydrogen adds another layer of complexity. Massive investments are required to develop infrastructure, which is crucial for lowering overall costs and transitioning to a more extensive hydrogen economy.

Limited demand and ineffective policy

The high price of green hydrogen has made it difficult to find buyers willing to pay the green premium. Overall, many businesses tend to prioritise immediate cost-effectiveness over long-term sustainability, making them cautious about committing to a fuel that is significantly more expensive than traditional sources.

The unavailability of long-term offtake agreements impacts these projects' financeability as banks and equity funds require predictable cash flows to commit capital. Additionally, international energy companies that could potentially finance these projects on their balance sheets also seem to be moving away from renewable power due to lower operational synergies and financial returns, according to BloombergNEF. Consequently, green hydrogen projects end up not getting built, and the price of hydrogen stays high.

To foster a positive change and develop a market, many governments have introduced policies aimed at decarbonising the economy, with a particular focus on supporting renewables and green hydrogen. The Inflation Reduction Act in the US has implemented a production tax credit of up to $3/kg to incentivise green hydrogen. The UK has proposed a hydrogen business model based on contracts-for-difference (CfD), which aims to provide revenue support to overcome the operating cost gap between low-carbon hydrogen and high-carbon fuels. Similar CfD-based subsidies have also been announced through Japan's Hydrogen Act and Germany's H2 Global initiative. The EU has also

introduced a host of programmes and policies, such as the Hydrogen Innovation Fund and Fuel EU, which promote low-carbon hydrogen and penalise high-carbon incumbents.

However, these policy initiatives have achieved only limited on-the-ground impact. A case in point is the US Treasury Department's proposal for additional guidelines for green hydrogen credits, which require projects to adhere to stringent additionality, deliverability and time-matching standards. While these rules ensure the electricity supply remains truly green, they increase capital cost, lower operational efficiency and move production away from demand centres. As a result, US green hydrogen projects may still not be realised, despite the tax credit being in place. Without effective policy adjustments, which can incentivise both demand and supply while striking the right balance, the green hydrogen sector risks stagnating instead of growing.

> Economic incentives need to be aligned with environmental goals to achieve a net-zero world

Navigating major hurdles

While there are major commercial and regulatory challenges in unlocking large-scale capital deployment, some creative approaches could enable green hydrogen projects to cross the finish line. To begin, developers can pursue applications with a relatively low 'green' premium, such as green steel, which is estimated to cost only 40% more than conventional steel, according to BloombergNEF, rather than green shipping and aviation fuels, which could cost 3–5 times more than carbon-intensive options. One of the forerunners, the H2 Green Steel project in Sweden, has secured $6.9b in funding and long-term offtake from Mercedes Benz.

In addition to pursuing low premium use cases, developers could reduce peripheral infrastructure costs by collocating facilities with a renewable source and a customer to develop a 'hub'. For example, Hy Stor's project in the US state of Mississippi is co-located with steelmaker SSAB. Hy Stor plans to produce hydrogen using onsite wind and geothermal energy and use an underground salt dome to store it. Additionally, brownfield developments could also lower additional capital costs by reusing existing infrastructure. Fertiglobe, a collaboration between ADNOC and OCI, plans on repurposing an existing ammonia facility in Egypt to supply green ammonia to Europe. This strategy contributed to reducing the overall capex and helped Fertiglobe win the H2 Global auction bid, according to the Ammonia Energy Association.

Developers could also lower the cost of capital by tapping into state-sponsored programmes for grants, subsidies and low-cost financing. For example, a significant part of the debt for the NEOM green ammonia project was covered by the Saudi Arabian state lenders and the German ECA Euler Hermes. In the US, the DOE's Loan Programs Office has awarded federal loan guarantees of over $2b to foster the development of green hydrogen ecosystems.

Ultimately, partnering with a trusted EPC provider could be an advantage for developers. The comprehensive solutions offered by an integrated EPC—ranging from early-stage permitting and financing assistance to design optimisation and construction—could be invaluable in ensuring a project's successful completion.

With an endless pipeline of green hydroge n projects and ever-increasing national production targets, it seems expectations have raced far ahead of reality. The high cost of production, coupled with limited demand, has created a complex landscape for developers and investors. More pronounced support from the government bolstered by agile design approaches could help bridge the cost gap between low-carbon hydrogen and conventional fuels. Furthermore, forging key partnerships with end-customers, EPC contractors and long-term investors could help overcome the technical and commercial barriers in deploying capital at scale. Ultimately, economic incentives need to be aligned with environmental goals to achieve a net-zero world. ■

A Gulf Energy Information publication