



**INNOVATIVE**

**ENERGY SOLUTIONS**

**OFFICIAL PUBLICATION OF THE  
23RD WORLD PETROLEUM  
CONGRESS**



# ADVANCING CLIMATE SOLUTIONS

Every day, more than 23,000 scientists and engineers at ExxonMobil are working to develop solutions for the world's most complex energy challenges. We are committed to reducing our emissions, enabling a lower-carbon future and continuing to contribute to society's net zero goals.

We are the leader in carbon capture and storage solutions around the globe. We're developing lower-carbon hydrogen technologies and advanced biofuels and finding other innovative ways to lower emissions. All with a focus on helping decarbonize the highest-emitting sectors — manufacturing, power generation and transportation.

For nearly 140 years, ExxonMobil has had a history of meeting the world's energy needs with groundbreaking, scalable innovations. We will employ our expertise as we work to help advance climate solutions while continuing to power economies around the world.



*Learn more at [ExxonMobil.com/Solutions](https://www.exxonmobil.com/solutions)*

**ExxonMobil**



## OFFICIAL PUBLICATION OF THE 23RD WORLD PETROLEUM CONGRESS

[www.world-petroleum.org](http://www.world-petroleum.org)

Publisher: Petroleum Economist  
A PE Media Network brand, part of Gulf Energy Information

Managing editor: Dr Pierce Riemer, World Petroleum Council  
Senior project manager: Sarah Ashmore, World Petroleum Council

Publication editor: Peter Ramsay, Editor-in-Chief, PE Media Network  
Section editors: Kurt Abraham, Editor-in-Chief, *World Oil*  
Lee Nichols, Editor-in-Chief, *Hydrocarbon Processing*  
Michael Reed, Editor-in-Chief, *Pipeline & Gas Journal*  
Stuart Penson, Contributing Editor, *Transition Economist*  
Charles Waine, Americas Correspondent, *Petroleum Economist*

Production: Sheryl Stone, Vice President, Production  
Melissa DeLucca, Assistant Production Manager  
Marcia Jones, Designer

**Gulf Energy<sup>i</sup>**

### Gulf Energy Information

John Royall, President & CEO  
Andy McDowell, Vice President, Upstream and Midstream  
Catherine Watkins, Vice President, Downstream

Gulf Energy Information  
2 Greenway Plaza, Suite 1020  
Houston, TX 77046  
Phone: +1 713-520-4498

**Petroleum  
Economist**

### PE Media Network

Owen Raw-Rees, Commercial Manager  
Alastair Noakes, Head of Subscription Sales  
Rachel McGhie, Events Manager

PE Media Network  
27 Furnival Street  
London EC4A 1JQ  
Tel: +44 20 3409 2240

All information in this publication is verified to the best of the author's and publisher's ability, but no responsibility can be accepted for loss arising from decisions based on this material. Where opinion is expressed, it is that of the authors. The views expressed and the data contained in this publication are not necessarily those held or agreed by PE Media Network, Gulf Energy Information, or the World Petroleum Council. All rights reserved. Reproduction in whole or in part without written permission is strictly prohibited. Copyright © 2021 by Gulf Energy Information. Printed in the USA.



# CONTENTS

## INTRODUCTION

- 5 Welcome to the Official 23rd WPC Congress Publication**  
Tor Fjaeran, President, World Petroleum Council
- 7 Cooperation and dialogue hold the key**  
Dr. Pierce Riemer, Director General, World Petroleum Council
- 9 Navigating the rapidly evolving energy journey**  
Peter Ramsay, Editor-in-Chief, PE Media Network



**LEADERSHIP 10**



**UPSTREAM 24**



**DOWNSTREAM 56**



**NATURAL GAS & LNG 76**



**ENERGY TRANSITION  
& SUSTAINABILITY 108**



# Welcome to the Official 23rd WPC Congress Publication

**TOR FJAERAN, PRESIDENT,**  
*WORLD PETROLEUM COUNCIL*



The years leading up to the 23rd World Petroleum Congress have been very different to what we are used to. A commodity price crash at the same time as the Covid-19 pandemic broke out, a dramatic global drop in demand for our products and nations struggling economically across the entire world – all resulting in a substantially different and more virtual life for all of us. In addition to these changes, the energy transition is impacting our industry in a transformative way.

All of this resulted in a one-year delay to the Congress, which now an event representing one of the first times the energy industry can meet face-to-face again in almost 2 years. And it remains an exciting time to be a part of the energy industry, an industry delivering the energy and products the world needs.

The world is experiencing an energy transition towards more decarbonised societies. For the World Petroleum Council, it is important to create arenas for discussion of the issues framing this transition, addressing how to deliver energy and associated products to the world, and to find answers to the question: What will the energy future look like?

- Fundamental to the entire transformation of energy is innovation, and people are fundamental in finding and developing the right solutions
- Climate change is a main global

driver

- Politics drive the process and regulate the steps
- Access to capital is needed to make it happen
- Environmental impact is about not harming the planet earth
- Social impact is vital for companies to earn a licence to operate
- Perception of industry is fundamental to attract and retain the best brains

These are the issues the WPC has identified, through its research with members and stakeholders, as key to framing the global energy agenda of today and tomorrow.

All are interdependent and inter-linked parameters in succeeding with the energy transition – being more energy efficient, decarbonising the production of energy and its products, and reducing the amount of fossil fuels in the energy mix. We have listened to our National Committees, our Young Professionals, and many other key stakeholders for their perspectives of the transformation.

The countries and regions across the world are different and their energy-related challenges and opportunities are unique and country-specific. However, all are fully aligned that these issues are the important ones for us to address going forward.

Climate change is one of the main challenges of our time and a clear

call for action. We acknowledge the scientific consensus on climate change and support the goals of the Paris Agreement.

We recognise that the world's energy systems must be transformed to drive decarbonisation. At the same time universal access to affordable, sustainable and clean energy must be ensured.

In the future energy mix oil and gas will continue to be vital to supply the world with enough energy for decades to come. But an increasing share will come from renewable sources. Our industry must do its utmost to reduce the carbon footprint from our operations and from our products.

Technology and innovation have always been a game changer for our industry. This happens often in cooperation between companies, suppliers, academia, and governments.

Today tech start-ups, attracting many young talents, are becoming important. We also see how digital tools can help us deliver energy in a more efficient way, both when it comes to safety, cost, and emissions.

Decarbonisation technologies have the highest focus. It is likely that hydrogen will be a key contributor to the energy transformation because it is an effective and environmentally friendly energy carrier.

The new challenges we are up against today will require that we invest in new technologies to create and

build new low carbon markets, value chains and industries. The current generation of young professionals will play an important role in meeting and solving these challenges. They should continue to be vocal and active to challenge and push innovation which will be fundamental to success.

Diversity adds value, and we need that more than ever now. Our “Untapped Reserves” study and report is unique and has become a global refer-

ence. The updated Version 2.0 brings this one step further in understanding the value of diversity in our industry.

I am looking forward to a Congress that lives up to this vision and showcases an industry that moves forward together, cooperating in developing and implementing the solutions we all need for a low carbon future.

As I finish my term as President of the WPC, I would like to thank the WPC family of countries for their sup-

port during this time. I wish you a safe, engaging, and enjoyable 23rd World Petroleum Congress addressing the global energy topics of today and tomorrow. ▀



**Tor Fjaeran**  
President, World Petroleum Council



The digital transformation is aiding the energy industry in many different ways, including cybersecurity. Image: Siemens Energy.



# Ensuring our Industry's Stability through Innovation, Collaboration & Dialogue

**DR. PIERCE RIEMER, DIRECTOR GENERAL,**  
*WORLD PETROLEUM COUNCIL*



It is a great pleasure for me to say a few words in this special Congress publication. The WPC is the only neutral, non-profit making and non-political global forum for the promotion and dialogue of the responsible production and use of the world's oil, gas and all energy resources and their products for the benefit of all. Through our National Committees we bring together public and private leaders and experts from producers and consumers to address global energy issues.

Formed in 1933, we are registered as a charity, as unlike many other events or organisations all the profits from our large events go into legacy projects around the world. The WPC is dedicated to the promotion of sustainable management and use of the world's resources for the benefit of all. We want to be recognised as the premier global forum facilitating an open dialogue around oil, gas, energy and their products

We need cooperation and dialogue in order to ensure the stability of the energy sector and to strengthen international co-operation. The World Petroleum Council has always appreciated its National Committees who have always been supportive of our values and goals. More recently, they have fully supported our role, alongside others, in relieving energy poverty, in helping to facilitate the reduction of gas flaring, in, CCUS and, more generally, in helping to promote sustainability throughout the industry as we move towards net zero.

No other industry works on time horizons like we do – most of our projects can last for 20 years or more. Like any industry we like certainty. Unfortunately, on the time scale we work to, that is a rare commodity.

There are some certainties:

- We know population is increasing
- We know energy intensity is increasing
- We are helping to bring vast populations out of poverty
- We know a larger world population needs energy food and water.

But most of the time, as an industry, we manage uncertainty – price, geological, technical and geopolitical. We are as an industry unbelievably good at what we do. We are essential for modern life – there is no escaping it. We are responsible for economic growth, have been for over 150 years! And will be for many years to come.

No energy = no growth = no advancement = no social progress

People, of all genders, are our greatest assets and companies should be encouraged to continue investing in training and working to retain key skills through the up and down-cycles.

By collaborating across the industry, making structural changes, standardising operations, implementing AI and digital solutions to improve productivity and profitability and optimising internal capability to drive higher efficiency and agility, companies can emerge from

uncertain times stronger and more competitive. So, while the business environment may remain difficult and unpredictable, energy companies can take action in numerous areas to reduce the impact to the bottom line and emerge stronger and in a better position to respond to the volatile crude cycle.

Innovation, the theme for this Congress, is a strong driver for the industry. With conventional reserves of oil and gas that are easy to access and inexpensive to produce largely gone, the industry is exploring in ever more challenging new frontiers where large oil and gas discoveries are still being made.

The development of such new discoveries will require deployment of cutting-edge technologies delivered in an environmentally safe manner. Enhanced oil recovery is still one of the more promising areas to increase the production from existing fields, particularly if utilising CCUS. The development of new technologies is significantly increasing recovery factors and prolonging the life of mature oil and gas fields.

Innovation in the oil and gas industry does not only contribute to increasing production. Ensuring safe operations is another top priority. In the oil and gas sector collaboration is especially important due to the high cost and long lead times associated with oil and gas advancements. Producers already partner with oil field service operators and other strategic partners, suppliers or universities around the globe. New technolo-

gies and innovative thinking developed in cooperation with research institutes and the academic community can lead to major advances for the industry.

Strategic alliances enable businesses to gain competitive advantage through access to a partner's resources, including markets, technologies, capital and people. Teaming up with others adds complementary resources and capabilities, enabling participants to grow and expand more quickly and efficiently. Many fast-growth technology companies use strategic alliances to benefit from more-established channels of distribution, marketing, or brand reputation of bigger, better-known players.

With our project cycles lasting sev-

eral decades our industry is a long-term player and we require long term policies for sustainable development. Many companies, associations and countries have created their own definitions, but the real term sustainable development was originally defined by the Brundtland Commission as "development that meets the needs of the present without compromising the ability of future generations to meet their needs".

It describes "a process of change in which the exploitation of resources, the direction of investments, the orientation of technological development and institutional change are all in harmony and enhance both current and future potential to meet human needs and aspirations".

This is what we all adhere to today.

We invite readers to share your outcomes and continue the dialogue with our global membership at the 23rd World Petroleum Congress in Houston and we hope to see you all again in 2023 when we will all meet in Calgary for our 24th Congress where the theme will be 'ENERGY TRANSITION - The Path to Net-Zero'. ▀



**Dr. Pierce Riemer**  
Director General,  
World Petroleum Council



The digital transformation is aiding the energy industry in many different ways, including cybersecurity. Image: Siemens Energy.



# Navigating the rapidly evolving energy journey

**PETER RAMSAY, EDITOR-IN-CHIEF,**  
PE MEDIA NETWORK



We at *Petroleum Economist*, with fitting help from our Houston-based colleagues at our parent company Gulf Energy Information, are delighted to bring you the official publication of this year's World Petroleum Congress (WPC). It is an honour, but it also feels like a great responsibility.

That is because the following pages comprise of some of our industry's foremost voices giving their views on the biggest challenges and opportunities that face them in the coming years. And, given that the industry is facing perhaps its most radical changes since its very early days, probably since before the first ever WPC back in 1933, selecting the topics and the authors that can produce the most useful guide to that evolution seems particularly important.

But we are confident that the lineup of contributors we have brought together have more than fulfilled the brief. From the opening section focused on the leadership challenges facing oil and gas firms to the energy transition and its associated technologies, taking in the full oil value chain and natural gas on the way, the following pages are packed with invaluable insight and analysis.

On the very day I write this letter, Shell CEO Ben van Beurden has faced analyst questions on topics diverging from how it felt to have an environmental activist screaming in his face the previous week to what he thinks

about a letter from a hedge fund that has built a stake in Shell and wants it broken up. On the other side of the Atlantic, the CEOs of ExxonMobil, Chevron and BP America, a Shell president and the head of the American Petroleum Institute are in front of the House of Representative Oversight Committee to face questions about an alleged disinformation campaign to prevent climate action.

Oil and gas firms have never faced challenges like this before. But we should be optimistic that the industry has the calibre of people, the proven track record of innovation and, crucially, the appetite not just to survive but to thrive in the new lower-carbon future.

On winning over public opinion that traditional hydrocarbons firms can maintain a social licence to operate and can play their part in the energy transition, van Beurden was optimistic. "Can we convince a significant part of society? I hope so," he said. We believe that, while the journey will doubtless be a tough one, we should share his optimism.

We thank all of our contributors—every single article that follows has weight and value. But, should anyone question the oil and gas industry's genuine commitment to a lower-carbon future, it is perhaps instructive where the six CEOs that have answered our call have positioned their articles.

All could clearly have answered questions about leadership and bagged a place in the front pages of the publication. But the heads of Baker Hughes, Wentworth Resources, Freeport LNG and LNG Canada all preferred to talk about the role of gas in our future lower-carbon energy mix.

And Bernard Looney, who needs no introduction as CEO of BP, as well as Josu Jon Imaz, his counterpart at Repsol, chose to write in the energy transition and sustainability section that closes the publication. Egos put firmly to one side in a desire to tackle what they see as the biggest challenge facing the industry, that could act as a metaphor for how seriously leaders in the oil and gas sector are taking the pivots they need to make towards serving a net-zero future.

On that note of letting the authors and articles speak for themselves, all of us at *Petroleum Economist* commend them to you and wish you a very informative and enlightening 23rd World Petroleum Congress. We are confident that, like this publication, it will not disappoint expectations. ▀

A handwritten signature in black ink that reads "Peter Ramsay". The signature is fluid and cursive, written over a light blue background.

**Peter Ramsay**  
Editor-in-Chief,  
PE Media Network





# Leadership

**PETER RAMSAY, EDITOR-IN-CHIEF,**  
*PE MEDIA NETWORK*

---

The very definition of leadership in the energy transition has changed dramatically over the past four years. Previous yardsticks for measuring oil and gas firms — reserves, production, capex — have fallen out of favour. Public perception of the industry, its attractiveness and its long-term future have also shifted materially.

So what defines leadership in the new environment in which we find ourselves? To a significant extent, it lies within the, admittedly very broad, area of adaptability. The firms most able to navigate the route to a lower carbon and ultimately net zero future are the new industry leaders. A clear strategy to manage the challenges of an uncertain traditional business while investing in a well-defined pivot to the technologies that will provide the much cleaner energy of the future are what gives certain companies and their executive teams the edge over their peers.

And how those executives lead has also had to evolve. Externally, they have had to justify the economics of their new approaches and their intended speed to the investment community. And they have had like never before to make the case for access to capital, both for ongoing oil and gas activities but also for their new ventures in a range of lower carbon alternatives.

They have also needed to make the case for oil and gas firms having a valid role in the energy transition, as well as maintaining a social licence to operate for the production of the fossil fuels still required to largely power the global economy as it undergoes the tectonic shift towards net zero.

Just as crucially, internally, they have had to reshape their organisations. In part, that is a necessity of moving to a different business paradigm. But it is also a realisation that, particularly for western IOCs, a company of largely white, middleclass, male engineers is not optimised for the nimbleness and capacity for change required to thrive in an uncertain future. More diverse organisations less prone to groupthink will lead in the years to come.

In the following pages, you will read how some of the industry's biggest hitters are thinking about these challenges in leadership, and how they are meeting them. We are sure that you will find value in them. ▀

# CONTENTS

---

- 11 Introduction**  
Peter Ramsay, Editor-in-Chief, PE Media Network
- 13 Leadership in carbon capture and storage**  
Linda Ducharme, President, Upstream Business Development and Upstream Integrated Solutions
- 15 How oil and gas companies can meet society's expectations**  
Wael Sawan, Integrated Gas, Renewables and Energy Solutions Director, Shell
- 17 Leadership toward net-zero: The role of collaboration and partnership**  
Uwem Ukpong, Executive Vice-President of Regions, Alliances, And Enterprise Sales, Baker Hughes
- 19 Betting on women to win on performance**  
Ulrike Von Lonski, COO, WPC, Rebecca Hood, Partner, BCG, Claire Gauthier-Watson, Principal, BCG
- 21 PGPIC takes the lead in sustainable development of Iran's petrochemical industry**  
Dr. Seyed Abdolmajid Khaksar, Deputy Managing Director, Nouri Petrochemical Complex

# Leadership in Carbon Capture and Storage

**LINDA DUCHARME, PRESIDENT,**

*UPSTREAM BUSINESS DEVELOPMENT AND UPSTREAM  
INTEGRATED SOLUTIONS*



Achieving the goals of the Paris Agreement will require not one but many solutions. Industries and government must collaborate, and technology breakthroughs are critical for the world to expand access to reliable, affordable energy that helps create many of the products essential to modern life while reducing emissions of carbon dioxide.

More electrification and greater use of renewables like solar and wind address part of the problem, and electric vehicles will contribute as well as they gain market share. Even as the deployment of those technologies ramps up, projections from the International Energy Agency and the Intergovernmental Panel on Climate Change show that we will need more solutions to reach the goal of net-zero emissions by 2050, especially for the two sectors of the economy that are key to modern life and responsible for significant shares of the world's emissions – heavy industry and power generation. Together they accounted for two-thirds of global energy-related emissions in 2019.

Capturing those emissions could go a long way toward reaching the Paris Agreement commitments, and the ability to do that exists today. Carbon capture and storage, or CCS, describes a collection of technologies that can remove CO<sub>2</sub> emissions before they reach the atmosphere. The captured CO<sub>2</sub> is then safely, se-

curately and permanently stored in depleted oil and natural gas reservoirs or other porous geological formations deep underground. In essence, it returns the carbon to the earth.

ExxonMobil is the world leader in CCS, with more than three decades of experience. Our new Low Carbon Solutions business, led by Joe Blommaert, is advancing plans for multiple new opportunities around the world to enable emissions reductions at a large scale.

Earlier this year, Low Carbon Solutions proposed an idea for a CCS hub in Houston, one of the largest concentrated sources of industrial emissions in the US. With the appropriate support from industry, government and community, we believe our collective efforts could capture and permanently store about 100 million metric tons of CO<sub>2</sub> annually by 2040.

That concept moved forward in September when 11 companies, including ExxonMobil, announced their support for the large-scale deployment of CCS in the Houston industrial area. Discussions with other companies are ongoing.

Our efforts go beyond Houston. In the second quarter, LCS signed two memorandums of understanding to progress large-scale CCS projects in Scotland and France. In the third quarter, we signed an MoU with Rosneft to cooperate to assess the potential of lower-carbon technologies

to reduce greenhouse gas emissions.

Next year we anticipate final investment decisions (FIDs) for a large CCS expansion at our LaBarge facility in Wyoming and a new carbon capture technology pilot associated with the Porthos CCS project in Rotterdam. Porthos, in which ExxonMobil is one of four joint development agreement partners, expects to take an FID in 2022 as well.

Our company can handle every part of the CCS equation, thanks to our experience in establishing and operating partnerships, expertise in building and managing pipelines, and deep understanding of geology and reservoir engineering.

We are also in the early days of researching several promising innovations with partners, including direct-air capture, carbonate fuel cells, and metal-organic frameworks that can trap CO<sub>2</sub> before it ever leaves a power plant.

The CCS opportunities that ExxonMobil is evaluating have the potential to achieve large-scale, game-changing emissions reductions with current technology. What they need now is effective government support – leadership through policy.

ExxonMobil has long believed that the best way to bring down carbon emissions is to establish a market price on them. A market price would provide the clarity and stability required to drive investments, and



it would benefit all the technologies that reduce emissions rather than a few.

The carbon markets operating today are a patchwork, giving some operators the incentive to move their facilities elsewhere. Because much of the world does not have carbon pricing, it is important to ensure that any pricing policy does not encourage emissions leakage across borders. To that end, policy makers should consider coupling carbon pricing with a border adjustment.

Stable, supportive policies and

regulatory frameworks are critical to enable new technology and infrastructure development at the pace and scale needed to help meet the goals of the Paris Agreement. Because many solutions are needed to achieve society's ambition and some have not been invented yet, it is important that policies be agnostic rather than favoring particular technologies. That way, the most effective solutions will win support from investors.

Those policies and frameworks include durable incentives such as

grants and tax credits, as well as support for research and development. Initial policy support for CCS could help develop an effective marketplace that drives down costs and spurs even more investment, both public and private.

ExxonMobil is committed to supporting efforts that address climate change. We are mitigating emissions in our own operations, and we are developing and deploying solutions that can scale up to make up a significant difference in the energy transition. ▀

Petroleum  
Economist

## STAY AHEAD OF THE COMPETITION

*Petroleum Economist* offers the only truly global, full value chain, cross-commodity publication for the hydrocarbons sector

## JOIN TODAY

To arrange a trial or enquire about access please contact::

Alastair Noakes,  
Head of Subscription Sales  
Alastair.Noakes@pemedianetwork.com  
+44 (0) 20 3409 2244

Learn more: [pemedianetwork.com/pages/subscribe](http://pemedianetwork.com/pages/subscribe)



# How oil and gas companies can meet society's expectations

**Wael Sawan, Integrated Gas, Renewables and Energy Solutions Director, Shell**



In July 1933, the first World Petroleum Congress was held in London. Thomas Dewhurst, the president of the congress and James Kewley, the chairman (and at the time Shell's chief chemist), expected two things from attendees: the latest innovations and fierce debates. Both expectations were met.

No fewer than 244 scientific papers offered all the innovation participants could want. And they were debated at length. In fact, a particularly lively discussion about one of these papers overran by hours and only ended because the janitor forced them to go home.

Today, two things are again expected from energy companies. First, to meet energy demand. Society expects energy companies to help power modern life, from fuelling transport and powering industry to heating homes and lighting schools.

At the same time society also, and understandably, expects energy companies to lead in the energy transition to help the world tackle climate change. And just as they did in 1933, energy businesses should meet these expectations with the latest innovations, fierce debates and the tenacity to continue until a janitor forces us to go home.

Leading the transition to a cleaner energy system means the industry will have to change even while delivering the energy needed today.

And each company in our industry is seeking its own pathway through the energy transition.

Some choose to stick exclusively to oil and gas. Some have divested from fossil fuels and are now completely focusing on renewable energy. Others, including Shell, are trying to balance the two expectations from society: to deliver the energy of today – still largely provided by oil and gas – and to help speed the arrival of the energy system of the future.

How this works becomes clear if you look at Powering Progress, Shell's strategy, which shows that we have a target of becoming a net-zero emissions energy business, by 2050, in step with society. This will mean, for example, that the part that wind, solar, hydrogen and biofuels play in our portfolio will grow. These investments in lower-carbon energy, however, will only be possible if cash flow from our activities in oil and gas remain resilient. So oil and gas does not only deliver the energy the world needs today, it can also fund the energy the world needs tomorrow.

This is a huge double challenge. This is why I think oil and gas businesses should become even better than they are today when it comes to capital, carbon and collaboration.

Let me start with capital. If oil and gas businesses are to play their crucial role in funding the transition to a cleaner worldwide energy sys-

tem, they need to become financially even more robust. And in a time of a volatile energy market, this means becoming more resilient to changes in oil and gas prices by improving returns with investments that are easily replicated, lower breakeven prices and faster payback times.

Apart from improving capital resilience by bringing down cost, oil and gas businesses also need to bring down the carbon emissions from their own operations. At Shell, we have been doing that for some time. In fact, we believe that our carbon emissions peaked in 2018.

To give one example of progress: in Nigeria, our joint venture, the Shell Petroleum Development Company (SPDC) has been investing in capturing associated gas for the domestic and export markets. This decreased routine flaring by around 90% between 2002 and 2019 and by 17% in 2020 compared to 2019.

Another crucial part to accelerate the transition to a net-zero energy system is to seek innovation, just like Thomas Dewhurst and James Kewley did when they organised the first WPC all those years ago. I believe innovation, from digitalisation to technologies that capture and reuse or store CO<sub>2</sub>, will not only help cut emissions, they will also fundamentally transform our business.

Take data analytics, for example. Algorithms can process years of his-

torical data and monitor equipment 24 hours a day, seven days a week, to alert engineers to anomalies. This “proactive monitoring” can prevent potential production delays and unplanned maintenance. Drones are another example of a technology that is helping to reduce emissions. In our Shales operations, for example, drones are performing regular methane inspection rounds.

By increasing our capital resilience and reducing our carbon emissions, I am confident we can make progress in navigating our business through the energy transition. But the energy transition is far too big for a company, a country or even a continent to achieve. So even though today’s debates about who should do what may be as fierce as those heard during the World Petroleum Congress in 1933, I think it is clear there is only one way we can succeed... by collaborating.

This collaboration can have many forms. One is between traditional and new parts of the energy sector. While we should continue to develop the oil and gas industry to provide the energy society will still need, oil and gas businesses should also help develop lower-carbon parts of the energy sector, for example by broadening the skills of our people so they can be transferable to new businesses. Maintenance and operations colleagues on offshore oil platforms, for instance, could be a great fit for offshore wind farms, chemists for hydrogen and geologists for carbon capture and storage.

This will take time. Our workforce will transform gradually, but I see great potential. In fact, according to

a study by Robert Gordon University in Aberdeen, over 90% of the oil and gas workforce in the UK have skills that are transferable to other parts of the energy sector.


Our companies need to go much further if they want to help the world tackle climate change. The reason is simple. More than 90% of Shell’s total emissions come from the use of our products by our customers. This means we must also collaborate with our customers and their sectors to help them change the type of energy they use, for example by helping major oil and gas resource holding countries as they try to seek their own pathway through the energy transition.

The energy transition is moving at different rates in different regions in the world and every country needs its own mix of solutions. Internationally operating companies like Shell, with experience and expertise in the entire energy sector, can help countries reduce their emissions. We are doing it already, for instance by helping with coal-to-gas switching in China, growing our biofuels business in Brazil, and capturing natural gas from oil production in Iraq which would otherwise be burned off, or flared.

Another way to collaborate with our customers is by helping sectors that are hard to decarbonise: the production of steel, cement and chemicals and heavy transport such as aviation and shipping. Together with Deloitte, Shell has published reports which examine ways to decarbonise shipping, road freight and aviation. In fact, such collaboration with our customers and their sec-

tors stands at the heart of our Power Progress strategy.

Collaborating as closely as described above will be necessary to keep delivering the energy of today and bring forward urgently the energy system of the future. Just like we need to be resilient when it comes to capital and carbon by using the latest innovations and making the most of the talented people who work for us.

And there is one more thing we need. Something our industry is well-known for, something I luckily see in our staff every day, and something we have often seen at past editions of the World Petroleum Congress: the tenacity to keep working on improving our sector until a janitor forces us to go home. 

#### FOOTNOTES

- 1 The companies in which Royal Dutch Shell plc directly and indirectly owns investments are separate legal entities. In this submission “Shell” is used for convenience where references are made to Royal Dutch Shell plc and its subsidiaries in general.
- 2 For a more detailed description of the first World Petroleum Congress, see Ulrike von Lonksi (Chief Operating Officer at World Petroleum Council), *How it all started ... the story behind the first ever World Petroleum Congress*, published on LinkedIn on July 23, 2020.
- 3 Shell’s operating plan, outlook and budgets are forecasted for a ten-year period and are updated every year. They reflect the current economic environment and what we can reasonably expect to see over the next ten years. Accordingly, Shell’s operating plans, outlooks, budgets and pricing assumptions do not reflect our net-zero emissions target. In the future, as society moves towards net-zero emissions, we expect Shell’s operating plans, outlooks, budgets and pricing assumptions to reflect this movement.
- 4 <http://www.rgueti.com/wp-content/uploads/2021/05/workforce-transferability-report.pdf>



# Leadership toward net-zero: the role of collaboration and partnerships

**UWEM UKPONG, EXECUTIVE VICE-PRESIDENT OF REGIONS, ALLIANCES, AND ENTERPRISE SALES, BAKER HUGHES**



As an industry, we are well versed in tackling impossible feats and managing through repetitious boom/bust cycles, but now we are facing a dual challenge: increasing access to energy so society can advance, while decreasing emissions from energy to protect the planet.

This dual challenge requires a dual approach to achieve a sustainable energy future:

- Solve for the largest sources of emissions in energy operations today by deploying the most efficient and least emissive technologies available, and
- Invest in sustainable energy technology for tomorrow to accelerate the adoption and deployment of new fuel sources and emissions solutions.

Now, more than ever, we must work together. It will take energy producers, technology and service providers, energy buyers, policymakers, and the community at large pulling together to spark the innovation required to reach net-zero.

Leadership and progress toward net-zero requires leading by example. Baker Hughes set an early commitment to reducing its carbon equivalent emissions by 50% by 2030 and to achieving net-zero emissions by 2050 in line with the Paris Climate Agreement. We are helping customers across energy and industrial sectors do the same by applying our technol-

ogies and expertise to enable them to reduce their carbon footprints.

It also requires partnership and collaboration, where we adapt and learn from each other to spur faster innovation and development of low-carbon solutions. Recently, the industry has shown an increased willingness—even a demand—for collaboration through partnerships and alliances. This acknowledges that a variety of specialized technologies and skills is required to reach net-zero carbon emissions.

As the IEA shared, to reach net-zero emissions by 2070:

- 25% of CO<sub>2</sub> emissions reductions will come from currently available technology,
- 35% of technology needed to tackle carbon emissions in the future will come from technologies in the prototype or demonstration phase, and
- 40% will rely on technologies not yet commercially deployed.

This means that without major acceleration in innovation, the industry will not meet its net-zero targets. Collaboration and partnerships are essential to progress, which gives us an opportunity to work together and lead in new ways to maximize shared value.

As a global energy technology company, Baker Hughes is incubating and investing in new technologies for hydrogen, CCUS, energy storage, and geothermal to support energy and industrial sectors. We have cross-

company teams dedicated to accelerating commercial opportunities in these areas to spur both organic and inorganic growth. And collaboration allows us to advance our technologies in these areas.

Meaningful decarbonization is not possible without carbon capture, utilization, and storage (CCUS). Today, Baker Hughes has digital and low-carbon technologies to help customers increase operational efficiencies, minimize project risks, and reduce emissions. Recently, Baker Hughes announced collaborations with Horizon Energy and Borg CO2 focused on carbon capture and storage projects. These collaborations are demonstrating how CCUS technology is accelerating from concept to reality with real-world impact.

Partnerships and collaboration are also critical to delivering the software and technology infrastructure needed to digitally transform operations. In the energy industry, AI and machine learning are critical to reaching the efficiency targets we know are required to meet emissions reductions goals. For instance, the Baker Hughes and C3.ai strategic alliance combines our oil and gas domain expertise with the leading AI technology from C3.ai, allowing deployment of enterprise scale AI applications 40x to 100x faster than alternative approaches. AI-enabled operations support emissions reductions through predictive

asset maintenance, system reliability, and production and inventory optimization – allowing for more efficient and productive outcomes.

Baker Hughes also helps leverage the power of data to reduce non-productive time and energy use, support remote monitoring and diagnostics, and predict system failures for better management of field assets. For example, Baker Hughes's range of digital solutions are supporting Petrobras with expanding its digital capabilities to reduce its risks and emissions, while maintaining safe operations,

by deploying c.20,000 wireless condition monitoring sensors across its critical and essential machinery and to connect upstream, midstream, and downstream processes.

As you can see, optimizing existing energy processes is key to supporting emissions reduction. As we combine expertise and learn together, we can produce better outcomes—reducing emissions from energy operations, decarbonizing industries, and advancing new forms of low-carbon energy.

The increasing call for focused investments and firm commitments to

progress the energy transition means everyone is thinking about how they can reduce emissions to reach their net-zero goals. Making a commitment is the easy part—getting to net-zero carbon emissions as companies, as an industry, and as a society is perhaps the single greatest challenge of our lifetimes.

No one can tackle this challenge alone. Through innovation, partnership, and collaboration, we can all take energy forward, making it safer, cleaner, and more efficient for people and the planet. ▀



# Betting on women to win on performance

ULRIKE VON LONSKI, COO, WPC, REBECCA HOOD, PARTNER, BCG, CLAIRE GAUTHIER-WATSON, PRINCIPAL, BCG

*Our industry is constantly facing new pressures on costs, climate, and now Covid-compliant ways of working. How can we make a difference without diverse backgrounds? How can we ask our teams to go the extra mile if there is no unified spirit?*

Women today are better represented in the oil and gas sector than decades ago. Most companies are deeply invested in making this happen, as illustrated in the latest **Untapped Reserves 2.0** report on gender balance in the global oil and gas industry, a joint effort by the World Petroleum Council (WPC) and Boston Consulting Group (BCG).

But there is still plenty of room for improvement, with a steady -22% share of women in the industry in 2017 and 2020. We are far from reaching “critical mass” as long as even one female colleague feels isolated, especially in operations and at senior levels of the organization.

Many women in the oil and gas sector still face tactical barriers to success, both at entry-level and management-level positions. In some companies there remains a bias (perhaps unconscious) that a woman cannot do a man’s job in field operations. Or even women who lack confidence in their abilities, sometimes reinforced by the perception of team members.

“When I first started in my new management role, I could tell that many of my male team members did not think I was up to the challenge,” explains a

woman in a leadership position during an interview for the Untapped Reserves 2.0 report. “So, I worked harder to get results faster and prove that I was even more credible than anyone else at this job.”

The industry has set out to address these and other barriers, helping women gain confidence in their abilities to work in technical fields and to manage teams. In the study, we found that many firms doubled down on HSE—ensuring that all measures were in place. And top managers made it clear that they will not only encourage but also empower women to take on leadership roles.

## FAST TRACKING WINNING STRATEGIES

A friendly give-and-take has been underway over the past few years

between women and top management. For women, the challenge is to change the industry mindset—not an easy undertaking but doable for those who exhibit first-rate leadership skills. For managers, the focus is integrating diversity and inclusion (D&I) concepts into key performance indicators (KPIs). With CEO leadership, both sides understand the need for powerful initiatives to identify and fast-track winning strategies.

WPC and BCG identified 50+ initiatives across regions in our latest **Untapped Reserves 2.0** Study to meet these industry goals. Three types of initiatives are particularly vital:

- **Leadership.** Leadership from the upper echelons of an organization is critical to creating an inclusive company culture. The research clearly

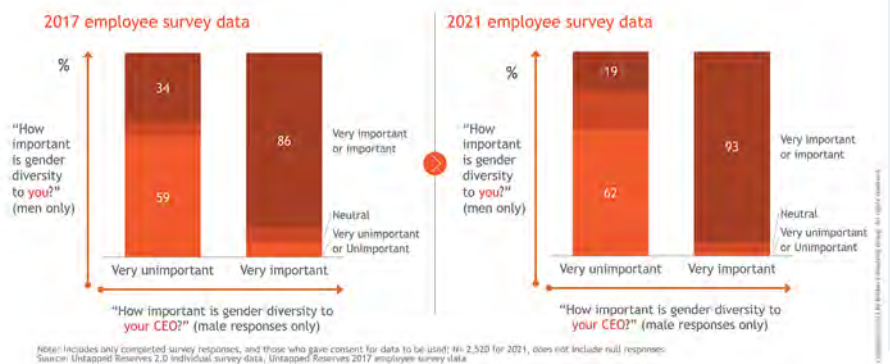


Figure 1. If CEOs commit to gender balance, organisations will follow.





establishes the impact of CEO leadership on changing male attitudes to gender balance.

- **People, policies, and ways of working.** Here the focus is on providing equitable working conditions for all: through equal pay and compensation, flexible work policies, leave options, and reinventing ways of working via the remote model brought on by Covid.
- **Talent management.** Modernizing the oil and gas industry's concept of talent management is critical to winning the talent war. The goal is to attract the world's top graduates. Given that young graduates are less inclined to join what may be perceived as an industry in decline, the

employee value proposition must be even stronger. The industry needs to focus on improving capabilities and developing more dynamic career paths. This includes providing opportunities in new business lines—new energies, new concepts, and digital services—and recognizing the impact that employees can have on the energy transition.


### IT IS ALL ABOUT PERFORMANCE

For companies, it is no longer only about optimizing the asset portfolio, improving commercial competitive advantage, or developing more efficient processes. People and diversity are key differentiators in the 2020s and women are certainly part of the

performance equation.

For individuals, career progression to the upper echelons of the company must be based on performance. It is vital to avoid creating discrepancies between male and female employees. No one ever again wants to hear, “she was promoted because she is a woman.”

It is time to demonstrate that female employees not only have the talent, skills, and ambition for a career in the oil and gas sector, but also have the drive to reach the top on their merits. Now is the time to drive gender balance in oil and gas and proactively make some real changes.

To learn more, read the latest “Untapped Reserves 2.0” report published by the WPC and BCG at [www.untappedreserves.com](http://www.untappedreserves.com) 

## ABOUT THE AUTHORS



Ulrike Von Lonski,  
COO, WPC



Rebecca Hood,  
Partner, BCG



Claire  
Gauthier-Watson,  
Principal, BCG

# PGPIC takes the lead in sustainable development of Iran's petrochemical industry

**DR. SEYED ABDOLMAJID KHAKSAR, DEPUTY MANAGING DIRECTOR, NOURI PETROCHEMICAL COMPLEX**



Iran is one of the largest holders of oil and gas resources in the world. In addition to increasing oil and gas production capacity, one of Iran's strategic goals in the past half century, and especially in the recent three decades, has been the development of the petrochemicals industry as a high value-add.

But one of the more negative results of industrial development has been an increase in greenhouse gas emissions. Thus, Iran, along with Russia, Iraq, the US, China and India, is one of the ten countries with the highest volume of flaring and among the major emitters of CO<sub>2</sub>.

The Persian Gulf Petrochemical Industry Company (PGPIC)—with number of petchems complexes, one large gas refinery and several petchems projects—is the largest specialized petchems holding in Iran. According to the ICIS ranking, PGPIC is the second largest petchems company in the Middle East and is ranked 37th in terms of sales among the top 100 petchems companies in the world.

One of the fundamental values of PGPIC is protection of the environment and adherence to international treaties and standards in the field of HSE. In this regard, PGPIC has implemented several systemic and operational proceedings.

Among the most important milestones for PGPIC are:

- establishment of energy management departments in all subsidiaries

- establishment of an energy management system (ISO50001)
- defining an energy consumption baseline of for various petchems units and
- conducting annual energy audits.

These constructive actions have in recent years improved the pattern of energy consumption and increased energy efficiency through defining and implementing dozens of progressive projects. As a result, they have reduced greenhouse gas emissions in PGPIC's operational units.

In addition, PGPIC has major projects underway that will further reduce greenhouse gas emissions in the near future. The most important environmental projects of this company are:

- the Yadavaran gas refinery (NGL 3200)

This gas refinery is under construction in the oil-rich regions of southwestern Iran with capital of about \$1bn. The mission of the Yadavaran gas refinery is to collect and sweeten 500mn ft<sup>3</sup>/d of associated gas. Important outputs of this project will be the production of 97,000bl/d of C<sub>2</sub>+ and reduction of CO<sub>2</sub> emissions by 13.5mn t/yr.

- Collecting associated gas to feed the Bid-Boland gas refinery

Another major associated gas collection project, which is underway in the oil-rich regions of Iran, is the Bid-Boland gas refinery. In this massive project, in addition to the main flow of incoming gas to Bid-Boland refin-

ery, associated gases are transported to Bid-Boland gas refinery through a 1000km pipeline. After sweetening associated gases, almost 1.5mn t/yr of C<sub>3</sub>+ compounds are produced and sent to downstream petchems facilities to produce various olefins.

With full implementation of this plant, 16mn t/yr of CO<sub>2</sub> emissions will be eliminated. The project will cost \$1.1bn.

- Sweetening and recovery of sour gases sent to flare and production of ammonium sulfate fertilizer in Nouri Petrochemicals

Nouri Petrochemical Company (NOPC) is one of the largest aromatic producers in the world. The nominal capacity of this complex is 4.5mn t/yr of gas condensate. In the process of sweetening the feed of this complex, 10t/hr of sour gases are produced and sent to flare. With implementation of this improvement project, hydrogen sulfide in NOPC's sour gases will be converted to ammonium sulfate. There are several benefits to implementing this project, including production of 60,000t/yr of ammonium sulfate fertilizer instead of sulfur, 65,000t/yr of valuable LPG product and 17.7mn m<sup>3</sup>/yr of fuel gas.

The project will cost c.\$50mn and will prevent the annual emission of 35,000t/yr of CO<sub>2</sub>.

PGPIC is committed to turning its subsidiaries into green industrial plants. ▀



# Empowering Progress









# Upstream

**KURT ABRAHAM, EDITOR-IN-CHIEF,**  
*WORLD OIL*

---


By all measures, the global upstream industry should experience a noticeably better year in 2022 after undergoing a recovery of sorts in 2021. Prices for Brent Blend and WTI have climbed above \$70/bbl and \$80/bbl in recent months; and worldwide oil demand, as of third-quarter 2021, was up roughly 5.0 MMbpd, compared to year-ago levels.

Oil production was up 5.3 MMbpd in the same period; and capital spending still lagged a bit in the U.S., but international capex should be up 8% for 2021. Finally, U.S. rig count was up 84% at the end of October from a year ago, while international drilling outside North America had improved 12% and showed signs of climbing further.

With supply running tight in second-half 2021, an obvious question is whether we need a greater **exploration** effort globally. MOL Group Senior Vice President Allan Scardina asserts that increased exploration offers two advantages. In addition to backfilling world hydrocarbon requirements, he says exploration can be the most cost-efficient way to rebalance upstream portfolios with volumes that are more profitable and have a lower carbon footprint.

Meanwhile, are we on the verge of a rebound in worldwide **offshore** activity? An emphatic “yes” comes from Erik Milito, President of U.S.-based National Ocean Industries Association, and Tim Duncan, Founder, President and CEO of **Gulf of Mexico** player Talos Energy. Globally, says Milito, offshore activity is recovering steadily, poised to increase production at a much-needed time. He adds that a healthy economic recovery should propel offshore drilling activity beyond pre-pandemic levels during the next two years. Duncan points out that the Gulf of Mexico continues to attract capital resources to explore for, and develop, attractive, long-life projects. The basin continues to be a core focus area for numerous Super-Majors and large operators, a testament to its competitiveness.

**Onshore**, Evercore Senior Managing Director James West expects activity to increase in the Middle East, Africa, Western Canada and select portions of the U.S., including the Permian basin. Speaking of the Permian, Scott Sheffield, CEO of leading operator, Pioneer Natural Resources, expects a banner year in 2022, as activity in second-half 2021 has run at twice year-ago levels. Simultaneously, he says the Permian is making great strides to control methane emissions and pioneer technologies that achieve ESG goals. Finally, Toby Rice, President and CEO of leading Marcellus shale operator EQT, says that the region stands ready in this period of higher **natural gas** prices to help satisfy the world’s gas needs while simultaneously reducing emissions from operations.

We invite you to read the analysis and outlooks of these industry leaders, and others, in this upstream section. 

---

The Bakken shale of the U.S. epitomizes the upstream recovery underway, with activity running double the year-ago levels. Image: Hess Corporation.



# CONTENTS

- 25 Introduction**  
Kurt Abraham, Editor-in-Chief, *World Oil*
- 27 Oil Supply & Demand: Oil's bumpy road to recovery**  
Toril Bosoni, Head of Oil Industry and Markets Division, International Energy Agency
- 30 The spending cycle begins anew: 2021 was the beginning**  
James West, Senior Managing Director, Evercore ISI
- 32 Global M&A Activity: Similar to other periods of O&G price volatility, M&A activity is brewing**  
David Levitt, Senior Vice President, LiquidFrameworks
- 34 A brief history of “peak oil”**  
Paul Stevens, Professor Emeritus and Distinguished Fellow, University of Dundee/Chatham House
- 36 Exploration: The role of hydrocarbon exploration in the energy transition**  
Allan Scardina, Senior Vice President, Exploration, MOL Group
- 38 Deepwater Renaissance: The deepwater sector anchors economic and emissions progress**  
Erik Milito, President, National Ocean Industries Association
- 40 Oil Geopolitics: Today vs Tomorrow, as a market transitions**  
Mark Finley, Jim Krane and Kenneth B. Medlock III, Center for Energy Studies, Rice University's Baker Institute
- 44 North Malay Basin Project: Unlocking value and resources in Southeast Asia**  
*World Oil* Staff
- 46 Developing the solutions for the global energy pipeline system**  
Clifford Johnson, President, Pipeline Research Council International (PRCI)
- 48 THE PERMIAN: Still the heartbeat of a global economy**  
Scott Sheffield, CEO, Pioneer Natural Resources
- 50 Unlocking the potential of the Marcellus shale: Marcellus natural gas can support emissions goals while maintaining reliable, affordable power**  
Toby Z. Rice, President and CEO, EQT
- 52 The Gulf of Mexico remains a prime region for technological innovation**  
Timothy S. Duncan, Founder, President and CEO, Talos Energy
- 54 Western Canada: Driving emissions reduction, economics, and indigenous issues**  
TIM MCMILLAN, President and CEO, Canadian Association of Petroleum Producers (CAPP)
- 56 East Coast Canada: Resilient and roaring back**  
Charlene Johnson, CEO, Newfoundland and Labrador Oil & Gas Industries Association
- 58 US shale sees shifting drill mix**  
Alexandre Ramos-Peon, Vice President of Shale Analysis, Rystad Energy

## OIL SUPPLY &amp; DEMAND

# Oil's bumpy road to recovery

**TORIL BOSONI, HEAD OF OIL INDUSTRY AND MARKETS DIVISION,**  
*INTERNATIONAL ENERGY AGENCY*



Two years on from the start of the worldwide Covid-19 pandemic, the global oil market is rebalancing, but the road to recovery has been far from smooth. From the virulent Delta variant unexpectedly sapping oil demand growth, a deep freeze in Texas upending oil flows in early 2021, lingering supply disruptions from Hurricane Ida in the U.S. Gulf of Mexico, and supply chain fuel shortages wreaking havoc on European and Asian economies, the world of oil is struggling to find equilibrium while targeting net-zero emission ambitions down the line.

Fuel prices have soared to multi-year highs at the start of the fourth quarter, this year, after strong compliance with record OPEC+ cuts, a slew of unexpected supply outages, and underperformance from non-OPEC+ producers accelerated stock draws. Those drawdowns largely worked off a massive surplus that built up from the historic collapse in demand last year. Global oil demand, led by Asia and the United States, is picking up from 2020 lows, but it still lags far below pre-Covid levels.

While rising vaccination rates have allowed governments to lift stringent lockdowns and mobility restrictions, the resurgence of more virulent Covid variants, widespread teleworking and lackluster international travel mean that global oil demand is unlikely to return to pre-Covid levels until 2023 on an annual basis. Following an unprec-

edented decline of nearly 9 MMbpd in 2020, world oil demand is expected to rise by 5.2 MMbpd in 2021, recovering around 60% of the volumes lost last year. It is expected to grow another 3.2 MMbpd in 2022 and, in the absence of more rapid policy intervention and behavioral changes, longer-term drivers of growth will continue to push up oil demand over the medium term. Fortifying the outlook, world GDP growth is now expected to average 5.9% in 2021 and 4.9% in 2022 before returning to more normal rates of 3.5% per year through 2026.

## ASIAN DEVELOPING COUNTRIES PROPEL DEMAND GROWTH

Emerging and developing economies, underpinned by rising populations and incomes, will drive all the anticipated demand growth relative to 2019. Asia accounts for most of the higher consumption in the near term, despite being hit hard by the spread of the Delta variant in the second half of 2021. Demand in OECD countries, by contrast, is not ever expected to return to pre-crisis levels, as vehicle efficiency improvements, together with higher penetration of electric cars, significantly reduce transport oil demand.

The speed and depth of demand's recovery is uneven, not only geographically, but also in terms of sectors and products. Gasoline use is unlikely to return to 2019 levels, as efficiency gains

and the shift to electric vehicles eclipse robust mobility growth in the developing world. Aviation fuel demand has been the hardest-hit oil sector during the crisis and is only expected to slowly return to 2019 levels by 2024. The extensive use of online meetings and international conferences could permanently alter business travel trends. The petrochemical industry remains the main pillar of growth in the medium term. Ethane, LPG and naphtha fell only marginally in 2020 and had, by early 2021, already surpassed pre-pandemic levels. The use of these products as feedstock for the petrochemical industry will continue to increase, in line with global economic growth and rising plastic demand.

## GLOBAL OIL SUPPLY PLENTIFUL DESPITE SPENDING CUTS

Meeting expected demand growth is unlikely to be a problem next year, even though weak investment, triggered by the pandemic and uncertain path of future oil demand growth, is impacting global supply. After agreeing to slash oil production by nearly 10 MMbpd in April 2020, in response to the Covid-induced collapse in global oil demand, the 23-member OPEC+ producer alliance has been gradually increasing supplies to the market during 2021. The OPEC+ group is on track to continue ramping up production.

At the start of 2022, OPEC+ will still

**Table 1. Global oil demand and supply, MMbpd.**

	1Q20	2Q20	3Q20	4Q20	1Q21	2Q21	3Q21	4Q21	1Q22	2Q22	3Q22	4Q22
Demand	94.0524	83.0857	92.284	94.1804	93.3881	95.1274	97.2339	98.764	98.1856	98.9368	100.2545	100.1667
Supply	100.3882	91.8292	91.0266	92.2686	92.325	94.2386	96.3145913	98.43200152	99.58753198	101.3205331	102.6555022	103.0062306
Stock Ch. & Misc (RHS)	6.3358	8.7435	-1.2574	-1.9118	-1.0631	-0.8888	-0.919308696	-0.331998475	1.401931975	2.383733054	2.40100215	2.839530596

Source: IEA.

have around 5 MMbpd of spare capacity, excluding crude from Iran that is shut-in by sanctions. The bulk of this is held by Middle Eastern producers—namely Saudi Arabia, the UAE, Iraq and Kuwait. Russia, too, sits on significant spare capacity, but far less than suggested by its new OPEC+ supply baseline of 11.5 MMbpd. By contrast, Nigeria, Angola and Malaysia—struggling with capacity declines, due to lack of investment and technical issues—are all pumping far below their OPEC+ targets. Further supply relief could arrive if sanctions on Iran are lifted, gradually allowing for the release of an additional 1.3 MMbpd to the market.

As for those oil producers outside the OPEC+ alliance, output growth is set to accelerate from 500,000 bpd in 2021 to 1.8 MMbpd next year. The U.S. leads 2022 gains, followed by Canada, Brazil and Norway. U.S. production growth is set to resume, as investment and activity levels pick up in tandem with rising prices.

Oil production in the U.S. fell 600,000 bpd in 2020, as lower prices and unprecedented financial challenges forced massive shut-ins and capital expenditure cuts. In 2021, U.S. producers largely stuck to commitments of maintaining capital discipline, free cash flow generation, deleveraging and cash returns for investors. At current prices of \$80/bbl, there is a strong incentive

for tight oil producers to hike spending while at the same time honoring pledges of disciplined spending. That is why we expect the US to dominate non-OPEC+ oil supply growth next year, adding close to 1 MMbpd, compared to virtually no growth in 2021.

Supply growth from other non-OPEC+ producers is also expected to rebound from the relatively low levels seen in 2021, due to slower rates of investment. New operational regulations and policies introduced to stop the spread of Covid-19 have created staff shortages and increased work-over duration, meaning more production downtime. In some countries, notably the UK, base production is declining rapidly, due to a lack of infill drilling. In Brazil, and also the North Sea, high levels of unplanned outages have been observed, in part because Covid-19 mitigation measures have restricted maintenance.

### ENERGY TRANSITION POSES FORMIDABLE CHALLENGES

Going forward, the oil industry will continue to be tested, as fast-evolving government plans to accelerate the transition toward a more sustainable future create a high degree of uncertainty. In 2020, operators spent one-third less than planned at the start of the year (and 30% less than in 2019) on upstream developments. In 2021, total

upstream capital expenditures rose only marginally, and so far, there are few signs that companies are getting ready to ramp up spending in 2022. It is crucial to invest in the upstream sector, even during a rapid transition, to meet projected global oil demand growth in the medium term. In that case, it would still take years to shift global transport fleets away from internal combustion engines to electric vehicles and other low-carbon alternatives. Some sectors—such as aviation, shipping and petrochemicals—will continue to rely on oil for some time.

Whatever the transition pathway, the oil and gas industry has an important role to play, and no energy company will be unaffected. Minimising emissions from core operations, notably methane, is an urgent priority. In addition, there are technologies vital to the energy transition that can be a match for the industry's capabilities, such as carbon capture, low-carbon hydrogen, biofuels and offshore wind. In many cases, these can help decarbonise sectors where emissions are hardest to tackle. A number of oil and gas companies are already scaling up their commitments in these areas.

An effective and orderly transition will be critical, not only to reach international climate targets but also to prevent serious supply disruptions and destabilising price volatility. ▀

## ABOUT THE AUTHOR

Toril Bosoni is Head of Oil Industry and Markets Division at Paris-based International Energy Agency. She has tracked international oil market developments for the agency IEA's *Oil Market Report* and *Medium Term Oil Market Report* for two decades. Ms. Bosoni's expertise extends to the upstream and downstream sectors, focusing on analysis of non-OPEC supply trends, modelling field declines, charting the impact of investment on supply, and forecasting refinery throughput and crude flows. She contributes regularly to IEA's *World Energy Outlook* and *World Energy Investments* and has a leading role in IEA's energy security work. Ms Bosoni obtained her BA degree in International Economics & Business Administration at the American University of Paris (AUP), and has had extensive training in econometrics and energy economics.





# Innovative Energy Solutions

Halliburton 4.0 is our digital approach to integrate downhole tools with surface equipment, sensors with data science solutions, and office with field locations to reach a new level in collaboration and productivity.

Unlock new potential to shorten time to first oil, lower total cost of ownership, increase production, and optimize value chain performance.

Turn your data into fuel to create new opportunities and put digital transformation into action for a sustainable energy future.

**Learn more at [halliburton.com](https://www.halliburton.com)**

**HALLIBURTON**

## GLOBAL CAPITAL SPENDING OUTLOOK

# The spending cycle begins anew: 2021 was the beginning

**JAMES WEST, SENIOR MANAGING DIRECTOR,**  
*EVERCORE ISI*



The oil and gas industry is poised to experience a significant increase in exploration and production spending, as we enter 2022. Delayed plans from 2020 and 2021, coupled with a goldilocks scenario for commodity prices, are throwing fuel on the fire. The industry is mustering the largest amount of capital investment since the early 2000s, as the investment needs become more and more apparent.

What could become a super cycle is beginning. What will be different this time is the SuperMajors will play a much smaller role, the U.S.-focused independents will likely remain capital-constrained and capital-disciplined, and spending growth will be led by international independents, especially those buying assets from the SuperMajors, and the national oil companies.

This year marked the beginning of the recovery, as oil prices rebounded, pandemic restrictions began to lift, and the global economy slowly re-opened. Spending growth was the strongest in the international markets, which will likely end the year up ~8% (TABLE 1), while North American exploration and production spending continued to decline and should finish 2021, down a little over 6%. This was a much better result than 2020's global decline of 24%, which was led by a 44% drop in North America and a 17% fall abroad.

The largest international declines, unsurprisingly, unfolded in some of the regions hardest hit by the pan-

demic, including Africa and Europe, which is primarily an offshore market. By contrast, in 2021, large percentage gains were witnessed in Europe and Latin America. After a drop of almost 30% in 2020 internationally by the SuperMajors, these companies only increased exploration and production spending by an anemic 3% in 2021. These entities bow to shareholder pressure and are re-focusing their spending on the energy transition and low-carbon strategies.

## 2022 IS THE ACCELERATION

The much-exaggerated end of the fossil fuel era has been on full display, as 2021 moves to a close, with oil prices in the \$70s and \$80s per barrel, and natural gas prices moving above \$5 per Mcf before the winter season starts in earnest. It's going to be cold this winter in Europe.

In North America, we anticipate at least a 20% increase in E&P spending, as oil companies adjust budget expectations in a much-improved oil price environment. As the industry entered 2021, the average E&P company used \$45-to-\$50 WTI for budgeting purposes. While heading into 2022, we anticipate \$55 to \$60 as the minimum levels for budget expectations. If we assume the exploration and production industry remains capital-disciplined, the increase in budget expectations leads us to at least 20% improvement, while there could also be a shift higher (or

lower) of the percentage of cash flow spent on exploration and production activity. We believe there is upside to our initial expectations, with activity increases restricted by inflation (OFS pricing, materials and fuel costs) and labor shortages that are impacting all parts of the global economy.

The international markets, however, are poised for the start of a multi-year upcycle, FIG. 1. For much of the 2010 to 2020 period, the industry focused on North American oil shale. That infatuation is over, as the lack of returns in shale has left investors and industry professionals shocked at the capital destruction. The international markets, especially shorter-cycle barrels in the Middle East and North Africa, are poised to be exploited in a hydrocarbon-short world with longer-cycle barrels likely to begin development in the second half of 2022 and more markedly in 2023. This will include a return to offshore and deepwater activity.

Looking around the world, there is increased activity in the Middle East, as OPEC barrels return and certain countries seek to expand productive capacity; better activity in Africa, as LNG plays in East Africa return and militant activity subsides; plus, the return of West African activity in Sub-Saharan Africa with new oil laws, new incentives, and the ambitions of the majors to put capital into the region. In Asia, we are watching the Chinese majors get aggressive with spending programs while

Table 1. Global upstream capital expenditures

Regions	2021 Mid-Year Survey Data			Y-Y % Change			2021 Survey Data		Initial 2021 Y-Y Change		2021 Delta
	2019A	2020A	2021E	2020E	\$ +/-	2021E	2020E	2021E	\$ +/-	%	bps
U.S. Spending	108,048.60	60,793.2	55,771.9	-43.7%	-5,021	-8.3%	58,284.3	61,436.3	3,152	5.4%	-1367bps
Canada Spending	20,453.20	11,007.4	11,331.7	-46.2%	324	2.9%	9,598.1	9,887.4	289	3.0%	-7bps
<b>NAM Spending</b>	<b>\$128,501.80</b>	<b>\$71,800.6</b>	<b>\$67,103.6</b>	<b>-44.1%</b>	<b>-\$4,697</b>	<b>-6.5%</b>	<b>\$67,882.4</b>	<b>\$71,323.7</b>	<b>\$3,441</b>	<b>5.1%</b>	<b>-1161bps</b>
Middle East	44,524.10	37,268.6	38,991.5	-16.3%	1,723	4.6%	37,242.3	36,938.6	-304	-0.8%	544bps
Latin America	39,148.80	33,861.2	37,316.7	-13.5%	3,455	10.2%	27,068.6	34,334.0	7,265	26.8%	-1664bps
Russia/FSU	59,343.60	52,317.0	51,535.6	-11.8%	-781	-1.5%	48,178.1	50,766.0	2,588	5.4%	-687bps
Europe	28,109.60	21,754.9	28,212.4	-22.6%	6,457	29.7%	22,724.9	25,744.4	3,020	13.3%	1640bps
India, Asia & Australia	84,761.70	78,047.0	88,585.7	-7.9%	10,539	13.5%	78,187.7	85,228.3	7,041	9.0%	450bps
Majors (Int'l Spend)	50,220.00	35,379.8	33,399.0	-29.6%	-1,981	-5.6%	41,773.2	42,885.6	1,112	2.7%	-826bps
Africa	13,276.80	6,945.5	7,806.1	-47.7%	861	12.4%	6,993.6	7,691.4	698	10.0%	241bps
NAM Independents (Int'l Spend)	3,510.00	2,332.2	2,865.0	-33.6%	533	22.8%	2,462.2	3,030.0	568	23.1%	-22bps
Other	19,035.00	17,114.7	18,696.1	-10.1%	1,581	9.2%	17,882.6	16,316.9	-1,566	-8.8%	1800bps
<b>Int'l Spending</b>	<b>\$341,929.60</b>	<b>\$285,020.9</b>	<b>\$307,408.0</b>	<b>-16.6%</b>	<b>\$22,387</b>	<b>7.9%</b>	<b>\$282,513.1</b>	<b>\$302,935.2</b>	<b>\$20,422</b>	<b>7.2%</b>	<b>63bps</b>
<b>Worldwide Spending</b>	<b>\$470,431.40</b>	<b>\$356,821.5</b>	<b>\$374,511.6</b>	<b>-24.2%</b>	<b>\$17,690</b>	<b>5.0%</b>	<b>\$350,395.4</b>	<b>\$374,258.9</b>	<b>\$23,863</b>	<b>6.8%</b>	<b>-185bps</b>

activity offshore Australia, Vietnam, Malaysia and, importantly, India surge.

In Latin America, significant offshore growth will occur in Brazil, as Petrobras and the IOCs ramp drilling activity while exploration will continue offshore Guyana and Suriname, with Mexico somewhat of a wildcard, as AMLO's new proposals backtrack on previous petroleum industry reforms.

The North Sea, which has been strong over the last few years, may be flattish in 2022, as Equinor's plans have shifted to 2023, and the independents are not likely to drive enough growth.

In a world remaining dependent on hydrocarbons to manage energy needs, which will persist for at least another few decades, if not longer, the recent lack of investment has significant consequences. The age

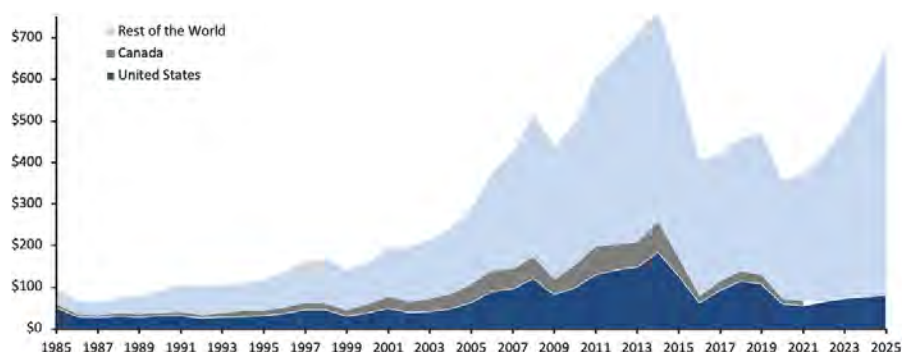


Figure 1. Global E&P Spending, 1985-2025E, \$billions

of cheap hydrocarbons is likely over. The age of expensive oil is beginning, and geopolitical conflicts over oil will likely intensify. The world's move toward renewable energy sources, while admirable, is pushing the planet into a multi-decade period of energy insecurity, which will lead to periods

of conflict. Resource-rich nations will experience prosperity (albeit likely exploitation by wealthy nations), while resource-poor areas will be hurt by global climate policy. A period of unprecedented energy insecurity has arrived. Welcome to the brave new world of the Energy Transition. ▀

## ABOUT THE AUTHOR

James West is a Senior Managing Director at Evercore ISI. He is responsible for research coverage of the Sustainable Technologies & Clean Energy and Oil Service, Equipment & Drilling industries, consisting of detailed fundamental research on companies involved in solar and wind power, battery and power storage technologies, hydrogen, and the drilling and production of oil and natural gas. Prior to joining Evercore ISI, Mr. West was a Managing Director and Senior Research Analyst at Barclays and Lehman Brothers for a combined 15 years. Before that, he worked at Donaldson, Lufkin & Jenrette. Mr. West is consistently top-ranked in *Institutional Investor*. He received his BA degree in Economics and a minor in History from the University of North Carolina at Chapel Hill.



## GLOBAL M&amp;A ACTIVITY

# Similar to other volatile periods, M&A activity is brewing

DAVID LEVITT, SENIOR VICE PRESIDENT,  
LIQUIDFRAMEWORKS



A significant amount of consolidation has marked every oil & gas recovery cycle for the past two decades. As it relates specifically to the oilfield service market (OFS), this recovery cycle isn't any different in that regard. However, while M&A activity historically has mainly been large companies buying smaller companies, this recovery is different.

**Factors in mergers.** Generally, mergers occur for a few specific reasons—fill a product gap, generate increased scale, or create cost synergies. For example, when Schlumberger acquired Smith Industries in 2010, it was clearly to fill a product gap, as was the case when Schlumberger previously acquired Reed Tool in 1998 and, later, Cameron in 2016. When General Electric acquired Baker Hughes in 2017 after the Baker Hughes/Halliburton proposed merger collapsed, it was to achieve increased scale while also filling product gaps. The TechnipFMC merger of 2017 was a combination of complementary product lines, dramatically changing that company's scale. TechnipFMC divided itself into two companies—Technip FMC and Technip Energies—with the former focused on upstream activities.

While scale is important—maybe more now than ever—this recovery is finding mergers occurring between smaller companies to achieve adequate scale, versus merely large com-

panies merging to achieve very large scale or making “tuck-in” acquisitions to fill product or geographic gaps. Private equity funding is focused on these smaller mergers between regional companies for a wide range of reasons, not the least of which appears to be a lack of appetite in the public markets for large-scale consolidation. Tighter-focused private funding is more available, as regional service companies find backing to expand a given service line or more focused vertical integration to provide more services to their customers.

**Covid-19 impacts.** Meanwhile, Covid-19 presented its own set of challenges, dramatically impacting the short-term demand for oil and gas products and services. While businesses across several industries faced a challenging 2020 following the spread of Covid-19 and subsequent decline in economic activity, the oil and gas industry has been one of the most negatively impacted by the pandemic, with energy industry revenues declining 54%, according to Deloitte. There were only 258 deals across the sector in 2020, the lowest number in more than a decade. Deal value fell below \$30 billion the first half of the year, also the lowest in the decade, but rebounded to almost \$170 billion in the second half.

According to industry experts, new sources of capital are needed, or the industry may need to rethink how it

finances both organic and inorganic growth. Since 2016, equity issuance, IPOs, venture capital, and private equity investments have dropped significantly and are often replaced with debt. Oil and gas sector debt issuance has continued to rise, spiking to more than \$240 billion in 2020, \$98 billion of which was in the second quarter alone. Companies will need to boost performance, compared with other sectors, to attract other traditional sources of capital, as well as find other, less traditional sources to support growth, post-2020.

**OFS sector.** Due to the significant differences between the operations of the OFS industry participants, an industry downturn doesn't impact all OFS participants to the same degree. For instance, OFS businesses that disproportionately serve the natural gas side of the industry were not as significantly impacted by the precipitous drop in oil prices during second-quarter 2020. In the same way, OFS participants may be impacted differently, based on the E&P subsector they serve. For example, during the 2020 oil price disruption, new drilling operations were much more adversely affected than were continuing production operations. Following a sharp decline in oil prices, exploration work may be curtailed much more so than production operations.

Of course, there is a direct relation-

ship between dramatic changes in the price of oil and the rise in mergers, acquisitions and divestitures within the oilfield services sector. During periods of downward price pressure, companies merge to gain cost synergies, while during periods of price increases, mergers occur to quickly gain scale and increased market share. The steep drop in oil prices in 2020, from \$60-plus, down to \$20, represented the most significant decline in the shortest time in modern history. Even when the price dropped from \$160/bbl to \$60 in 2008, the price slide took place over a more extended period and found its floor at a level at which profits were still possible. But, in 2020, when prices dropped to \$20 (and below), profits were more difficult to achieve.

The other leading indicator for the need for mergers, acquisitions and divestitures in the oil field is the rig count. With the rig count at all-time lows in the last year, there were too many service companies pursuing the possible business. From a high of nearly 1,600 operating rigs in mid-2015 to a low of approximately 200 in mid-2020, it is obvious why there has been accelerating consolidation within the oilfield service sector.

One of the indications of this repositioning of OFS companies was in the fall of 2020, when Liberty Oilfield Services bought Schlumberger's North American hydraulic fracturing operations for \$430 million. At the same time, Schlumberger invested in Liberty, demonstrating its increased confidence in the North American OFS business. This transaction was an early indication of deals to come, as the recovery in the OFS sector was emerging.

Meanwhile, the emergence of "blank

check" OFS companies has also created a market for OFS mergers. National Energy Services Reunited's (NESR) acquisition of Gulf Energy SAOC and National Petroleum Services (NPS) in the fall of 2017 has also created a category of next-generation, well-financed OFS companies. Former Schlumberger CEO Andrew Gould's Sentinel Energy Services, formed in late 2017, is poised to make a major impact, as well. The first installment of this effort resulted in Sentinel's late 2018 definitive agreement to acquire a majority interest in Strike Capital LLC, which owns Strike LLC, in a deal valued at \$854 million.

**Private equity firms** are also entering the fray, as Argonaut Private Energy acquired BJ Services' cementing business in late 2020 and rebranded it American Cementing. The firm also acquired Pioneer's Well Service business, combining it with Nichols Oil Tools and rebranding it American Well Services in March 2021. Meanwhile, Edge OFS recently acquired Gladiator, Ideal, PCS and Reliance to form a set of complementary services for their customers.

In the public markets, Ranger Energy Services acquired Patriot Well Services in May 2021 to fortify its wireline service business in North America. In addition, Archer acquired Deepwell in May 2021 to strengthen its wireline and downhole services in Norway.

The current environment is ripe for more mergers, acquisitions and divestitures, as rising rig count, and increasing oil and natural gas prices, are creating a situation where demand for OFS services could challenge the supply of those services. OFS companies downsized dramatically in 2020 to re-



**Figure 1.** In 2020, Covid-19 drove OFS M&As to their lowest level in 10 years.

flect the dramatic decline in demand for oil and gas, due to the pandemic. However, with increased demand, mergers and acquisitions are expected to accelerate during the second half of 2021. Essentially, the OFS sector is reformulating itself to reflect the current demand/supply equation, and M&A is often the quickest and most cost-effective way to do so.

**Looking ahead.** Which segments will see the most significant consolidation? Will there be more M&A activity at the high end of the market or within the mid-market? Will E&P companies determine that it is more cost-effective to own a full-service OFS company? Will international companies merge with North American firms to gain global scale? Who will supply the funding for M&A activity, i.e., debt, stock, PE firms? Will M&A activity be basin-specific within the mid-market? Will "blank check" companies continue to enter the market? Which segments/service lines are riper than others for M&A activity? How high will oil and gas prices rise in 2021, and how long before demand reaches and/or exceeds pre-pandemic levels? How high will rig count rise in 2021? The answers to these questions will likely drive the pace of M&A activity within the OFS sector in 2021 and beyond, but every recovery has seen significant M&A activity. ▀

## ABOUT THE AUTHOR

David Levitt is Senior Vice President, Worldwide Sales, at LiquidFrameworks, responsible for all aspects of sales on a worldwide basis. He has spent the past 25 years selling and managing sales into all sectors of the energy industry. Directly before joining LiquidFrameworks, Mr. Levitt created, developed and managed the Energy Region for Salesforce.com, growing his region 20X in total contract value within a four-year period. Previously, he spent six years, each, at SAP, Siebel Systems and Datalogix. Mr. Levitt received a BS degree in Newspaper Journalism from Syracuse University's Newhouse School of Public Communications.

## STATUS OF PEAK OIL DEMAND

# A brief history of “peak oil”

**PAUL STEVENS, PROFESSOR EMERITUS AND DISTINGUISHED FELLOW, UNIVERSITY OF DUNDEE/CHATHAM HOUSE**



The idea of “peak oil” came to popularity in the 1990s. It became commonly translated into the view that “oil is running out!” The original concept was based upon the work of M. King Hubbert, an American geologist, in the mid-1950s. It drew a normal distribution curve, covering historical production and remaining reserves, and (correctly) predicted U.S. crude production would peak around 1965-1970. The fact that this methodology was regarded with such awe and reverence by oil analysts was because it was one of the very few predictions that proved to be true.

**Greater attention.** Its more general popularity in the 1990s came, because it appeared to be based upon very simple, easily understood analysis; namely, there is a fixed amount of physical oil measured by reserves, and at a steady rate of rising output, eventually a peak of production is reached. Thereafter, production will fall, leading to shortages. If an idea is simple and not true, it is simplistic; but if it is simple and right, it is elegant. The supply-side peak oil analysis of the 1990s was far from elegant. Describing it as simplistic is being polite. Indeed, some have suggested the idea, as it emerged in the 1990s, was created by geologists purely to upset economists. In that, it succeeded in bucket loads.

**A basic flaw.** Its fundamental error was the assumption that crude is not being created any more and, therefore, there is only a fixed amount of

crude oil in the world. However, this is only true in some mindless geological sense. What matters for oil supply is the amount of recoverable reserves and their production—a function of the investment needed to translate oil-in-place to recoverable reserves and output. When such investment ceases, and with it oil supply, what is left, in the words of that great oil economist M.A. Adelman, “...is unknown, unknowable and totally uninteresting.” The final nail in the coffin came from the shale technology revolution. This emerged from the U.S. after 2008, when the country’s production increased from 6.78 MMbpd to 17.0 MMbpd (including NGLs) in 2019. Clearly, “recoverable reserves” were not fixed, but rather a moveable feast.

**The term resurfaces.** However, “peak oil” has been resurrected in recent years because of concern that demand for oil has peaked. This demand-side peak oil has been linked into the “energy transition.” An energy transition is when an economy switches from one dominant source of energy to another. Invariably, the transition is triggered by something. Then, reinforcing factors emerge, usually associated with technological changes affecting relative energy prices. There is a long history of such energy transitions.

Until recently, the speed of this transition has been seriously underestimated by the “energy establishment,” including the IEA, OPEC, large

oil companies and many other forecasters. They claim such transitions are “slow.” However, recent transitions, especially when governments have been involved, have been much faster: France’s switch from oil and coal to nuclear took 10 years.

Furthermore, the current Covid pandemic has increased that speed. It has changed politics and the role of government intervention. Voters now expect governments to intervene to manage “crises.” It also has prompted behavioral changes that directly reduce oil demand, such as working practices reducing travel. The result is that demand-side peak oil is probably here now and will prove to have serious consequences, not least for producers. ▀

## ABOUT THE AUTHOR

Paul Stevens was educated as an economist and as a specialist on the Middle East at Cambridge and SOAS; From 1973 to 1979, he worked at the American University of Beirut in Lebanon. Following that period, he spent 14 years (1979-1993) at the University of Surrey; with another 15 years (1993-2008) as a professor at CEPMLP, University of Dundee. Since 2008 he has been working with Chatham House in London. He is now Professor Emeritus at the University of Dundee, and a Distinguished Fellow at the IEEJ in Tokyo. In March 2009, he was given the OPEC Award.





# SPECIAL THANKS TO THE 23RD WPC SPONSORS

## PRESENTING SPONSORS



**HALLIBURTON**

**accenture**



**ExxonMobil**



**Baker Hughes**

**aramco**

**ConocoPhillips**

## PREMIER SPONSORS

**Schlumberger**

**BHP**

**Weatherford**

## ELITE SPONSORS

**Deloitte.**

**CERAWEEK**  
by IHS Market

**BR PETROBRAS**

**Sonangol**

OFFICIAL  
STRATEGIC PARTNER

**BCG**

OFFICIAL  
DESTINATION PARTNER

Houstonfirst.

OFFICIAL  
AIRLINE PARTNER

**UNITED**

## SUPPORTING PARTNERS



## OFFICIAL PUBLISHERS

**PETROLEUM  
ECONOMIST**

**upstream**  
ENERGY EXPLORED

DECEMBER 5-9, 2021 | HOUSTON, USA | 23WPCHOUSTON.COM

## THE EXPLORATION DEFICIT

# The role of hydrocarbon exploration in the energy transition

**ALLAN SCARDINA, SENIOR VICE PRESIDENT, EXPLORATION,**  
MOL GROUP



Paleontologists and evolutionary biologists often speak of the theory of “punctuated equilibrium,” whereby the gradual evolutionary modifications proposed by Charles Darwin are radically interrupted by significant environmental pressures requiring a rapid change to adapt. The Covid-19 pandemic is such an event for the upstream industry. In addition to the tragic human toll, the pandemic has upended many planning assumptions regarding oil and gas supply and demand. Upstream companies and business units have had to adapt to survive.

The energy transition is clearly upon us and, unlike the world’s previous attempts, actionable and accountable progress for a sustainable energy system is underway. Most companies, including the MOL Group, have reformulated their strategies to adapt to this transition.

On the way to a world powered by renewable energy sources, most analyses show that the world will need oil and gas for some time to come:

- World oil consumption has increased to near pre-pandemic levels and is expected to continue to grow through 2022 and possibly beyond. And many of the currently discovered hydrocarbons continue to be uneconomic to develop, and as such will not contribute to the world’s energy demands.
- Most scenarios built to model

a successful green energy transition (e.g., BP’s Net Zero scenario) conclude that the still-required crude oil and natural gas demand cannot be met from currently producing hydrocarbon fields. Thus, significant additional exploration and field development investment is needed.

In addition to backfilling world hydrocarbon requirements, exploration in many cases is the most cost-efficient way to rebalance upstream portfolios with volumes that are both more profitable and have a lower carbon footprint. Older fields with late-life reserves are usually harder to produce, making them more costly and more carbon-intensive than newer discoveries. An ExxonMobil case study has pointed out that new exploration discoveries have, on average, one-third lower CO<sub>2</sub> emissions during production than existing legacy assets. And the emissions difference between better and worse reservoir types can be a factor of three.

Thus, exploration has a future within upstream, but how will it be different from exploration of the past, and on what type of resources should we focus our efforts? The following paragraphs describe some types.

**Low finding, development and production costs** will ensure profitability in what is likely to remain a

volatile price environment, due to local and global supply/demand disruptions and geopolitical challenges. New discoveries will not fully replace existing reserves. However, with the exception of a few national oil companies, the industry focus will shift from volume targets to metrics related to value creation. New discoveries will need to remain profitably resilient to any reasonable price fluctuations.

**Relatively short timelines** from discovery to first production are required. Early production almost always improves a project’s economics. Additionally, with the energy transition, shareholders and other investors must be confident of receiving the full return on their investments before any transition-related changes impact profitability. Projects that require very long lead times to appraise or develop will, with few exceptions, represent a smaller or even non-existent portfolio position for most companies. Conversely, more emphasis will be put on near-infrastructure exploration that can turn discoveries into cash flow quickly.

**Lower carbon footprints** will mean the shift to gas-weighted portfolios will continue. High-quality oil in high-recovery reservoirs also will remain in focus. In addition, full-cycle environmental impact analysis must ensure that all emission abatement opportunities are

maximized at the beginning of project planning, including carbon capture, utilization and storage (CCUS).

**Lower risk profiles** will be needed. While this includes the usual subsurface risks that explorers are used to considering, it also needs to incorporate surface/execution risks, contract and fiscal terms stability, and partner financing capabilities.

**In the future, fundamentals will matter.** Explorers at all levels will need to have an even greater focus on the fundamental technical, economic, commercial and operational aspects of various portfolio positions. And, of course, these positions will need to be executed in a cost-efficient, safe, and environmentally sound manner.

## MOL'S ACTIVITIES

A good example of how the MOL Group is adapting to accommodate exploration's new realities during the energy transition is the ongoing gas exploration program in the Pannonian basin. With acreage positions in Croatia, Hungary, and Romania, MOL is the most significant upstream player in the basin. This region has a long history of oil and gas production and was once considered by many as no longer worthy of future exploration. However, in Hungary, MOL has recently been very successful in exploring gas targets. These results are due to a combination of a) a continuous improvement effort in our subsurface evaluation methodologies; b) a significant and ongoing effort in drilling cost reduction; c) short time to first gas, due to the careful planning that prioritizes prospects to leverage the

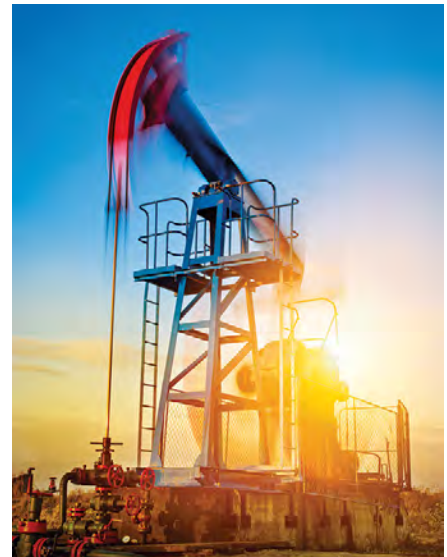
significant local infrastructure; and d) a supportive and stable fiscal regime.

Together, these factors have led to high exploration well success rates, low development costs, first production that usually occurs within six months of discovery, and a resulting portfolio with a progressively lower carbon footprint.

The Pannonian basin is very mature for petroleum exploration, and the resulting prospect inventory consists primarily of small volume targets. By exploiting every possible cost reduction, exploration teams have been able to maximize the value of existing infrastructure and mitigate the production decline while contributing to MOL's overall cash flow targets. Barrels are important, but only if they deliver cash flow required by investors.

Similarly, in MOL's operated positions in northern Pakistan, we have been able to sustain a top-quartile exploration success rate in a very challenging surface and subsurface setting. This success has been achieved by applying cutting-edge 3D seismic acquisition and processing techniques, combined with a unique skillset to interpret that data. However, as prospects have gotten smaller with time, additional contributions to effective exploration have come from best-in-class drilling cost and HSE performance.

"All of the easy oil (and gas) resources have been found" is a comment often made by those working in the upstream part of the business. One of my former colleagues once remarked that none of that "easy oil" was considered easy when it was found! Offshore exploration beyond the shelf edge now rarely draws any attention.



To ensure profitable development of additional production sources in a sustainable manner, exploration will have to be increased, utilizing state-of-the-art methods. Image: MOL Group.

As illustrated by MOL's successful efforts in the Pannonian basin and northern Pakistan, exploration teams have a habit of reinventing themselves to overcome each new challenge. Historically, each price crash has been followed by a phase of significantly better investment returns, as explorers are forced to reconsider how to create value where none was previously thought to exist. I trust that in the future, the same will be valid. ▀

## LITERATURE CITED

1. EIA Short-term Energy Outlook ([https://www.eia.gov/outlooks/steo/report/global\\_oil.php](https://www.eia.gov/outlooks/steo/report/global_oil.php))
2. <https://www.bp.com/en/global/corporate/energy-economics/energy-outlook.html>
3. Wood MacKenzie - Next Generation Energy and Exploration Summit. June 2021
4. <https://www.mckinsey.com/industries/oil-and-gas/our-insights/the-future-is-now-how-oil-and-gas-companies-can-decarbonize>

## ABOUT THE AUTHOR

Allan Scardina has been Senior Vice President for Exploration at the MOL Group since late 2019. Prior to assuming this role, he was General Manager of Exploration Acquisitions for Shell until 2017 and then owner and director of two consulting companies. In addition to Shell, Mr. Scardina has worked at Santa Fe Energy and Devon Energy in a variety of technical, commercial and managerial positions. He earned BS and MS degrees in geology from Louisiana State University, as well as an MBA degree from University of Maryland. Mr. Scardina also has participated in executive training courses at International Institute for Management Development, the University of Cambridge and the INSEAD business school.



## DEEPWATER RENAISSANCE

# The deepwater sector anchors economic, emissions progress

**ERIK MILITO, PRESIDENT,**  
NATIONAL OCEAN INDUSTRIES ASSOCIATION



Energy demand is back on the rise, and oil prices have appeared to steady, well above \$75/bbl. With the world already consuming around 100 MMBopd, and the U.S. accounting for around 20% of that demand (U.S. EIA), the EIA predicts steady growth in global energy demand through 2050. Investments in U.S. oil and gas projects will be key to making sure Americans have affordable, secure supplies for quality of life.

**More demand for hydrocarbons.** A growing global middle class will trigger growing demand, as they will continue to expect safe and reliable oil and gas production. Not only do oil and gas provide a reliable and affordable source of power for modern life and amenities, they are literally the building blocks of many products in modern life.

Fertilizers, irrigation equipment, tires, car seats, asphalt, kitchen appliances, housing insulation and more are built from hydrocarbons. Importantly, the front lines in treating the Covid-19 pandemic are manufactured from the building blocks of petroleum, including rubber gloves, face masks, IV's, MRI scanners, and more.

Furthermore, as the world economy continues to emerge from the Covid-19 pandemic and widespread lockdowns, domestic energy production is positioned well to help avert potential inflationary risks. Greater supplies of oil and gas will proactively ensure affordable energy for all walks

of life, especially low-income communities. In other words, oil and natural gas enables modern society. To truly lift communities out of poverty, the world will need access to safe, affordable and reliable oil and natural gas.

**Greater exploration needed.** According to the energy research firm, Rystad, there needs to be more exploration for oil and gas supplies to be able to supply the volumes needed worldwide by 2050. Massive investments are needed, just to keep pace with growing demand. Rystad suggests capital expenditures of at least \$3 trillion will be required to replenish declining production and meet expected global demand in 2050.

**Global offshore drilling to rise.** Globally, offshore activity appears to be recovering steadily and is poised to increase production at a much-needed time. Rystad expects offshore drilling to increase year-on-year by about 10% in both 2021 and 2022. A healthy economic recovery is expected to help propel offshore drilling activity beyond pre-pandemic levels during the next two years, leading to a transition from economic recovery to additional growth.

**GOM deepwater activity improves.** In the Gulf of Mexico, there has been exciting progress in new deepwater projects. In August, Bea-

con Offshore commissioned Transocean's ultra-deepwater drillship, Deepwater Atlas, to work at Shenandoah field in the Gulf of Mexico. This project is expected to advance the frontier of ultra-deepwater projects. The Shenandoah project is part of the vanguard of new 20,000-psi, ultra-deepwater projects. The first 20,000-psi project in the Gulf of Mexico, the Anchor project, was sanctioned by Chevron just two years ago.

Other projects are moving ahead similarly in the deepwater Gulf of Mexico. In July, Shell and Chevron greenlit their deepwater project, Whale. Scheduled to begin production in 2024, Whale is expected to reach a peak production of 100,000 boed.

In June, BP announced the safe start-up of the Manuel project in the Gulf of Mexico, which includes a subsea production system for two new wells tied into the Na Kikadee platform. BP, with four Gulf of Mexico platforms, expects a fifth deepwater platform—Argos—to come online in 2022.

The continued advancement of deepwater Gulf of Mexico projects is welcome news for the U.S. However, the outlook in the Gulf of Mexico is over-set with political uncertainty. Shortly after taking office, the Biden administration enacted an arbitrary pause on new federal oil and gas lease sales. In June, a federal judge ruled against the pause. The ruling confirmed that the U.S. Department of the Interior is re-

quired by law to expeditiously develop America's energy resources, including the obligation to schedule and hold offshore oil and gas lease sales. After a few months of no action, Interior finally said it would proceed with new leasing, consistent with the injunction, and issued the Record of Decision to restart Gulf of Mexico leasing.

**Regulatory factors.** In Congress, the U.S. House of Representatives continues to consider legislative language that would effectively establish a new regime of punitive measures targeting the offshore oil and gas industry. New taxes and fees, such as a proposed annual pipeline fee, would add millions of dollars in new costs to U.S. energy production. These provisions would fundamentally weaken the ability of American energy producers to compete in the global marketplace.

The U.S. Gulf of Mexico is a region that has historically been characterized by regulatory and fiscal certainty and predictability. Unfortunately, federal government policy out of Washington has disrupted that view.

My organization—the National Ocean Industries Association—commissioned the firm Energy & Industrial Advisory Partners (EIAP) to study the economic and employment footprint of both shallow-water and deepwater project lifecycles.

**Offshore jobs.** Gulf of Mexico projects provide a massive economic boost to the U.S. over their entire project lifecycles. EIAP identified more than 200 types of jobs involved in U.S. Gulf of Mexico oil and gas production. Together, the women and men who fill these positions work in concert to safely produce lower-emission and environmentally responsible barrels of oil and natural gas from the U.S. Gulf of Mexico.

Offshore oil and gas jobs are varied and high-paying, with an average industry wage of \$69,650, or 29% higher than the national average. Every U.S. state has jobs and investments tied to the U.S. Gulf of Mexico oil and

gas industry.

Gulf of Mexico deepwater projects provide a substantial, multi-decade economic footprint. EIAP finds that total lifetime spending on a deepwater Gulf of Mexico project averages \$8.8 billion. Average annual spending is projected at nearly \$295 million, with the highest spending levels taking place during project development, when subsea tieback work is taking place, and during decommissioning.

An average deepwater project sees about \$3 billion in total direct wages. Direct employment at a modern deepwater development project is projected to average over 1,435 jobs across the project's 30-year lifecycle.

During the most active years of deepwater projects, employment impacts peak at nearly 14,400 jobs. During normal operations, total supported employment is projected at around 1,900 jobs. While, these numbers are associated with just one project, the Gulf of Mexico is illustrated by dozens of such projects and an investment horizon that could span several decades.

U.S. policymakers should not discount the widespread economic benefits of continued Gulf of Mexico energy development, nor should they ignore the strong environmental benefits that U.S. offshore oil and gas production provide. Overall, the Gulf of Mexico has a carbon intensity that is about one-half (ChemRxiv) the carbon intensity of other onshore areas. Deepwater, which accounts for 92% of all U.S. Gulf of Mexico (U.S. BOEM and BSEE) production, is the lowest source of GHG emissions (Wood Mackenzie/Pioneer Natural Resources Company) of the oil producing regions, according to recent benchmarking research.

Not to mention, without the Gulf of Mexico and the massive amount of energy provided by the deepwater portion, increased transportation of oil to U.S. consumers would lead to additional emissions.

The U.S. cannot afford to be left behind as the world resumes offshore oil and gas projects. The U.S. federal



Exemplified by Transocean's *Deepwater Asgard* drillship, deepwater projects continue to progress in the Gulf of Mexico. Image: NOIA/Transocean.

government should always strive to prevent the substitution of American offshore production with barrels from high-emitting foreign sources with weak environmental oversight.

Trying to limit responsible federal oil and gas leasing is an unforced error that undercuts American jobs, businesses, national security, and emissions and environmental performance. It also would cut off the main source of funding for the Land & Water Conservation Fund, for maintenance for our national parks, and for constructing and restoring parks and recreational centers in urban, underprivileged communities.

The best policy solutions for Americans are here in the Gulf of Mexico. The U.S. Gulf of Mexico is an incredible American energy, economic and environmental success story, one that policymakers would be wise to embrace. ▀

## ABOUT THE AUTHOR

Erik Milito is President of NOIA since November 2019, having come from API, where he served for 17 years, most recently as Vice President, Upstream and Industry Operations. From 2000 to 2002, Mr. Milito served as a career attorney in the Solicitor's Office of the U.S. Department of the Interior. He holds a Juris Doctor from Marquette University Law School, and a Bachelor of Business Administration from the University of Notre Dame.

## OIL GEOPOLITICS

# Today vs Tomorrow, as a market transitions

MARK FINLEY, JIM KRANE AND KENNETH B. MEDLOCK III, CENTER FOR ENERGY STUDIES,  
RICE UNIVERSITY'S BAKER INSTITUTE

An emerging narrative posits that oil is a fuel of the past. Shifting investor preferences and consumer behaviors, along with national climate policies, are pushing disruptive technologies like electric vehicles, signaling the inexorable decline of oil demand. Indeed, slogans referring to the recovery from the Covid-19 pandemic often speak of “accelerating energy transitions” as “we build back better,” thus conveying an expected decline in the use of oil and all hydrocarbons.

In this narrative, oil-producing countries are losing their strategic importance. Instead, we see geopoliti-

cal leverage moving to countries like China that dominate the associated supply chains for rare earths, non-fuel metals and minerals, and processing capabilities.

**Realities differ.** However, this “structural decline” narrative is confounded. World crude oil prices have moved higher than they were pre-pandemic. In the face of rising prices at the pump, the Biden administration asked Saudi Arabia, Russia, and other OPEC+ countries to increase production, and directed a release of oil from the U.S. Strategic Petroleum Reserve. World

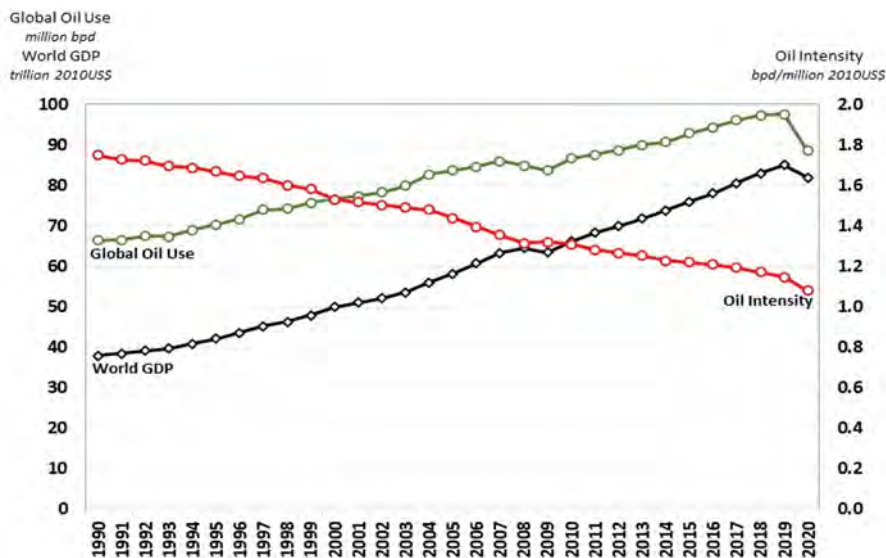
oil demand this year is likely to see the largest absolute increase ever, as economies emerge from the pandemic, and many forecasters project oil demand will increase, despite a growing number of scenarios indicating a long-term, structural decline. Of course, the dissent from some corners is notable.

How can we square the emerging narrative of structural decline with what is happening today?

## LET'S START WITH TODAY

Oil remains the world's dominant energy source, as it has been since the 1960s. BP's *Statistical Review of World Energy* shows oil accounting for 31.2% of the world's energy consumption in 2020, followed by coal at 27.2%, and natural gas at 24.7%. Even though oil's share in the energy mix has declined from 39.6% in 1990, demand increased by over 30 MMbpd through 2019, over 20 MMbpd of which were in developing Asia. In 2020, we saw a pandemic-driven decline in global demand of almost 10 MMbpd, but the rebound to date in 2021 indicates a robust return to pre-pandemic levels.

In general, oil demand and economic activity (measured as gross domestic product, or GDP) are positively related. The only time global oil demand fell over the last 30 years—2009 and 2020—coincided with declines in world GDP. So, absent structural changes to global energy markets, oil demand will increase as the world's economies grow.



Global Oil Demand, World GDP and Global Oil Intensity, 1990-2020.



**Oil intensity** (defined as oil demand per \$ of GDP) generally declines as economies grow, driven by changes in economic structure, improvements in efficiency, and fuel switching, as new sources of energy become competitive, **FIG. 1**. But that simply means GDP grows faster than demand. So, given that the correlation between oil demand and economic growth has persisted for over 60 years, a structural shift is necessary to alter course.

**Transportation usage.** Oil is the dominant fuel in the transport sector and is likely to remain so for the near term. The IEA reports that, in 2020, EVs accounted for just 1% of the global car stock, even with impressive growth in global sales over the last several years. So, while new technologies are emerging, they are not yet sufficiently deployed to shield consumers, and hence politics, from higher oil prices. Thus, promoting a transition away from oil requires navigation that avoids sustained increases in oil prices, and hence prices at the pump. Based on U.S. weekly motor fuel use in 2020 versus 2021, the increase in gasoline prices during the first nine months of 2021, alone, cost American drivers at least an extra \$115 billion, relative to the first nine months of 2020. Energy costs still resonate with voters.

As we have seen with President Biden's request for OPEC+ members to increase oil output, geopolitical leverage derives from response capability. The U.S. remains the world's largest oil producer, but it does not hold spare production capacity, which places the OPEC+ group of countries in an advantaged position. Following last year's large production cuts, OPEC+ holds more than 5 MMbpd of spare capacity, with Saudi Arabia holding the largest increment.

In sum, certain key oil players still command significant geopolitical leverage.

## WHAT ABOUT THE FUTURE?

Despite current market consider-

ations, the coalescence of several factors may reduce oil's future geopolitical importance.

**Climate change impact.** At the top of the list is the collective response of consumers, investors and governments to climate change, which is a problem of the global commons, and countries are approaching it with varying intensity. Going forward, the pace of decarbonization remains highly uncertain, and some experts are flagging a "radical uncertainty" around the future of oil demand. Indeed, the future of oil may be less certain than it's been since Edison invented the electric light. This uncertainty is laid bare in scenarios produced by the IEA, which projects world oil demand in 2040 could range anywhere from 44 MMbpd (Net Zero Scenario) to 104 MMbpd (Stated Policies Scenario).

**Decreasing demand.** Further uncertainty arises around the unevenness of energy transitions. Without substantial external finance for different energy sources, fossil fuels are likely to expand in developing nations, particularly where they represent the least-cost development option. Nevertheless, concerted action to reduce greenhouse gas emissions renders little upside for future oil demand, and even optimistic forecasts like OPEC's point to sluggish long-term growth. Slowing growth of oil demand, coupled with world economic growth, means oil intensity will continue to decline. If competition from new energy sources accelerates, not only will the trend in oil intensity continue—as it has for several decades—it will accelerate. All else equal, oil supply disruption risks will drop, as energy security takes on increasingly different dimensions.

Another factor to consider is the threat that EVs exert on oil's dominance in transportation. EVs only comprise 1% of the global fleet today, but sales are rising dramatically. Thus, while the oil market grew by an

average of just under 1.1 MMbpd annually from 1990 to 2019, alternative technologies may bring a different future. If so, a future crisis in oil markets may not spill into the transportation sector with the same intensity, and be less politically charged than previous crises. However, oil's continued importance in other sectors, such as petrochemicals, will still bear some importance.

**On the supply side,** new sources, such as shale, have broadened the geographic distribution of oil producers while shortening timelines for getting oil to market. The dramatic increase of U.S. oil production in just over a decade increased the diversity of global supply, thereby reducing the strategic importance of any single oil producer. Past and ongoing developments in countries, such as Brazil, Argentina and Guyana, have similar implications. Growing diversity of supply contributed to OPEC expanding its sphere to the OPEC+ group, but the larger this cohort of producing nations becomes, the more difficult it gets to coordinate—witness early 2020, when some countries could not agree on output targets, which coupled with the pandemic to crash oil prices.

Interestingly, climate change may ultimately lead to greater market concentration, despite the recent emergence of new supplies. In the long run, low-cost suppliers with low-carbon footprints will be better able to hold market position. Recognizing that higher-cost supply with higher carbon emissions will face headwinds, Aramco is highlighting the low cost and low carbon intensity of its oil production, while also pushing to expand production capacity. Hence, in the face of declining demand, efforts to reduce carbon content may lead to greater market concentration, albeit in a world with lower oil dependence.

Overall, oil-related geopolitical risks should decline, as alternatives gain ground. Oil and oil product delivery depends on highly-coordinat-

ed, complex supply chains that must operate consistently to avoid price spikes. Alternatives, such as renewables and batteries, depend on imported materials during construction and installation—not during operation—which alters the energy security paradigm. Of course, renewables can't yet deliver energy at the scale of oil, especially in transport. But, once

installed, supply security from renewables is dictated by nature, sufficiency of capacity and redundancy of infrastructure, not foreign actors.

### IN SHORT, THE OIL MARKET IS TRANSITIONING

Oil remains vital and will continue to be so for years to come. Thus, rising oil prices will continue still draw

political attention. But these disruptions may grow less painful over time, which will dictate that the strategic importance of oil, and the countries that produce it, will decline. As this transition occurs, petrostates will shift ties toward large developing countries, like China and India, leaving other open questions regarding the future security of oil supply. ▀

## ABOUT THE AUTHORS



Ken Medlock is the James A. Baker III and Susan G. Baker Fellow in Energy and Resource Economics at Rice University's Baker Institute for Public Policy and senior director of the institute's Center for Energy Studies. Medlock has published numerous scholarly articles in his primary areas of interest, which include: natural gas markets, electricity markets, energy commodity price relationships, transportation, national oil company behavior, economic development and energy demand, energy use and the environment, and various energy transitions topics ranging from engineered and nature-based carbon capture to hydrogen to the economic drivers of technology adoption.



Jim Krane is the Wallace S. Wilson Fellow for Energy Studies at Rice University's Baker Institute for Public Policy. He specializes in energy geopolitics, with a focus on oil-exporting countries and the challenges they face from energy subsidies, internal demand and climate change. He teaches classes on energy policy and geopolitics at Rice.



Mark Finley is the fellow in energy and global oil at Rice University's Baker Institute for Public Policy. He has over 35 years of experience working at the intersections of energy, economics and public policy. Before joining the Baker Institute, Finley was the senior U.S. economist at BP. For 12 years, he led the production of the BP *Statistical Review of World Energy*, the world's longest-running compilation of objective global energy data. He also was responsible for the company's long- and short-term oil market analysis, and he led the global oil market and transportation sector analyses for the long-term BP Energy Outlook.

**WHAT IF THE  
ENERGY INDUSTRY  
COULD ELIMINATE  
ITS CARBON  
EMISSIONS?**

**LOOK TO US**



Copyright 2021 Baker Hughes Company. All rights reserved.

**Baker Hughes** 

**An energy technology company**

[bakerhughes.com/energyforward](https://bakerhughes.com/energyforward)



## NORTH MALAY BASIN PROJECT

# Unlocking value and resources in Southeast Asia

## WORLD OIL STAFF

About a decade ago, Malaysia faced growing concerns about natural gas shortages on Peninsular Malay, where about 80% of the population lives. One way for the country to address this supply challenge was to develop a group of large natural gas fields in the Gulf of Thailand, which had been considered stranded resources. The ten fields, estimated to contain approximately 1.7 Tcf of gas resources, lay approximately 300 km offshore Peninsular Malay, across three blocks.

In 2012, U.S. independent energy company, Hess Corporation, was selected by Malaysia's national oil company, PETRONAS, to help develop these fields in what would become

known as the North Malay Basin (NMB) Integrated Gas Project.

## A LONG, STRONG PARTNERSHIP AND PRESENCE IN S.E. ASIA

Prior to its entry into the NMB Project, Hess had enjoyed a long presence in Southeast Asia, and was not a newcomer to Malaysia. The firm had acquired an interest about two decades earlier in the prodigious Block A-18 production asset in the Malaysia/Thailand joint development area.

Hess President and COO Greg Hill noted that Block A-18, operated by Carigali Hess, had provided the company with deep experience in the Gulf of Thailand and the North Malay basin.

"We knew that our long history in the basin, along with the knowledge and technical expertise we had obtained, would position us well for success," said Hill.

Hill also noted that the North Malay area was immediately south of Block A-18. There, he says Hess learned how to "optimize gas production from these types of reservoirs, where there are multiple gas-bearing zones at depths between 1,000 m and 3,000 m."

## EARLY PRODUCTION SYSTEM/FULL FIELD DEVELOPMENT

The initial NMB development concept targeted nine stranded gas fields—Bergading, Bunga Dahlia, Tera-

tai, Gajah, Melati, Kamelia, Zetung, Anggerik and Kesumba—through the deployment of an FPSO. Later in 2018, a tenth field was identified, Bunga Kangsar.

Hess began work with the Kamelia project, for which it already had a field development plan. Kamelia became the initial phase, or what would be known as the early production system (EPS).

The concept for Kamelia was a wellhead platform that was based on a design similar to those platforms in Block A-18, and the leased FPSO vessel, Perisai Kamelia. Early production was brought onstream in October 2013.

Subsequently in 2014, Hess and PETRONAS submitted a plan for Phase 1 of the full field development that included the Bergading central processing platform (CPP, Fig. 1) that bridge-linked to Bergading A wellhead platform, and three additional wellhead platforms—Bergading C, Bergading D and Kesumba.

In 2017, PETRONAS completed the Terengganu Gas Terminal plant, which was designed to receive the gas extracted offshore. The Gas Terminal would be connected to a 300-km offshore pipeline.

"The gas is sent from the CPP to the onshore, where NMB gas helps to blend down other higher CO<sub>2</sub> gas feeders," explained Gerbert Schoonman, Senior Vice President of Global Production for Hess. "The CO<sub>2</sub> is then further removed onshore and sent to PETRO-



**Figure 1.** The Central Processing Platform takes production from four wellhead platforms and routes it to the Terengganu Gas Terminal plant onshore. Image: Hess Corporation.

NAS, which typically sends the gas on to its gas processing plants. From there, the gas is sent through the Peninsular grid to power plants for power generation throughout Malaysia.”

With the completion and installation of the CPP and the many significant inter-related pieces of this complex development, first gas was achieved for the full field development in July 2017. This was only three years after project sanction with a nameplate capacity of 400 MMcfd.

### NMB EXPANSION: GROWTH AND INNOVATION

While 2017 saw start-up of the full field development, it also saw sanction for Phase 2 of the project, which would leverage the Bergading CPP. In Phase 2, Zetung and Anggerik fields would be developed with nine production wells and the construction, transport and installation of two three-legged remote wellhead platforms, as well as the pipelines that serve them, with gas flowing to the CPP.

The wells were completed between July 2019 and July 2020. Phase 2 achieved first gas from the Zetung wells in December 2019, and the Anggerik wells followed. Then, the Covid-19 pandemic struck.

Despite workforce restrictions required by Covid-19 safety protocols, the Hess-Petronas partnership achieved several important innovations:

- Installing gas tracer technology in six wells to verify the effectiveness of well cleanup for each reservoir section;
- Applying geosteering and LWD technology to map reservoir and fluid boundaries;
- Introducing offline well test operations.

Phase 3 fabrication started in 2020, in the midst of the Covid-19 pandemic. The fabrication entailed construction of a new wellhead platform to develop Bergading deep high-pressure, high-temperature resources between 80 Bcf and 100 Bcf, gross sales gas. First gas for Phase 3 is expected in 2022.



**Figure 2.** The Mercury Removal Unit enables the NMB asset to achieve full potential by allowing production of gas with higher mercury levels to be processed offshore to required specifications. Image: Hess Corporation.

For Phase 4a, Hess has been awarded the contract for engineering, procurement, construction and commissioning of three wellhead platforms. The work will accommodate Dahlia, Kangsar and Teratai fields in the eastern part of NMB. It will include the fabrication and installation of one remote and two minimal wellhead platforms to develop more than 500 Bcf, gross sales gas, starting the last quarter of 2022. A network of sub-sea pipelines will be installed to tie the wellhead platforms to the central processing hub.

Phases 3 and 4a of the project will extend the NMB production plateau past 2025.

### ON TO DEEPER WELLS

While each phase of the North Malay Basin development advanced the project, the completion of the Mercury Removal Unit (MRU, **Fig. 2**) in late 2020 was also a major milestone that is helping unlock the full potential of the asset.

Hess discovered high levels of mercury in some of its deep wells in 2018. While the presence of mercury in gas wells is not unusual, the company blended the gas produced with low mercury gas from shallow wells to ensure that health and safety standards

were maintained.

“The MRU enables production of gas with higher mercury levels to be processed offshore to required specifications,” said Ziyang Zhao, Hess Asia Vice President. “It will enable Hess to deliver full value from the potential of Phases 3 and 4a safely, and responsibly, while ensuring we meet our gas sales agreement obligations.”

At full capacity, the MRU will be capable of processing more than 400 MMcfd of high-mercury hydrocarbon gas with 100% redundancy.

### A PARTNERSHIP DELIVERING FOR MALAYSIA

Fast forward to today, and it is clear that the combined technical expertise of Hess and PETRONAS, along with a multi-billion-dollar capital investment by the partners, has turned the potential of NMB into a reality. The project is delivering new gas supply to peninsular Malay from what were previously considered stranded resources.

“Thanks to our great partnership with PETRONAS, we have achieved a number of important production milestones since we were first selected to develop and operate NMB,” said Greg Hill. “Hess remains committed to developing future phases of NMB to the same exacting standards....”

# Developing the solutions for the global energy pipeline system

**CLIFFORD JOHNSON, PRESIDENT,**  
*PIPELINE RESEARCH COUNCIL INTERNATIONAL (PRCI)*



The rapid pace of change facing the pipeline industry today makes it a unique time to be involved. To outsiders, it appears to be a very mature industry with little technical change. From machine learning to drones, the evolution in technology to ensure pipeline safety and integrity is not always visible or easily understood.

Additionally, we are now shifting to the next generation of fuels. The pace of these changes is rapidly increasing, and the industry needs the ability to make the right decisions and advances in a timely fashion.

To prepare for energy transition, there are technical challenges that must be addressed for safe transportation and storage. To meet the energy demands of today and the future, we must also acknowledge the need to advance our current pipeline infrastructure to enable the continued safe and efficient movement of our current products.

Pipeline Research Council International (PRCI) is uniquely positioned to deliver research solutions needed to provide for the current assets and prepare members and the industry to lead in the energy transition. Founded

in 1952, the primary focus was to address a single challenge. Today, our community has become the leading collaborative research body with over 75 members from around the globe, a diversified research portfolio addressing a wide range of challenges, and an opportunity to enable to the next generation of fuels. The not-for-profit corporation works to collaboratively deliver relevant and innovative applied research to continually improve the global energy pipeline systems.

PRCI identifies key issues facing our members and the industry, ranging from enhancing in-line inspection (ILI) and nondestructive evaluation (NDE) tools, to eliminating emissions and enhancing leak detection capabilities, to preventing and mitigating the impact of geohazards. Enhancing ILI and NDE tools begins with developing an industry guide on performance.

Research done at the PRCI Technology Development Center (TDC) in Houston, Texas, uses a diverse set of real-world pipe samples with defects including corrosion, hook cracks, and mechanical damage. The TDC enables us to enhance the tools, processes, and personnel associated with ILI and NDE, and advance these key resources. Following this baseline, we work closely with solution providers to enhance these tools.

The reduction and elimination of emission from pipeline systems has been a key part of the research program. However, we acknowledge that more needs to be done in this space to further eliminate leaks and greenhouse gas emissions. PRCI has defined a research priority to target a 25% reduction in emissions.

Recently, we hosted a forum for industry and the US and Canadian governments to clearly define targets needed in the next steps of leak detection. This work leverages ground-based, aerial, and space technologies to find and mitigate leaks as soon as possible and are part of research focus on addressing the challenges of climate change.

In December 2020, PRCI completed two state-of-the-



A length of pipeline used for testing by PRCI.



art reports addressing needs for the transportation and storage of hydrogen and renewable natural gas (RNG), leading to a research roadmap for each fuel. To include these roadmaps in our research program, we created the Emerging Fuels Institute (EFI). Members of the EFI will define the research program to produce a guide for the transition to moving, maintaining and operating hydrogen blends and RNG systems.

The EFI collaborates with other research organizations to share learnings and accelerate this shift. Partnerships include the Australian Pipeline Gas Association, Future Fuels CRC (Australia), the European Pipeline Research Group, and the European Gas Research Group. Another key collaboration is working with the Canadian Energy Regulator, US Department of Energy, National Resources Canada, and the US Department of Transportation Pipeline & Hazardous Materials Safety Administration to develop a research overview across North America. These efforts go a long way in advancing the needed research for operators globally.

The energy pipeline industry is at an inflection point. It is imperative that we deliver the research needed to



The Technology Development Center (TDC), located in Houston, Texas.

enhance the safety and integrity of the vital global pipeline systems and enable the industry to transition to the next generation of fuels. These actions play a key role in reducing the environmental impact of the energy pipeline industry. ▀

# Answers for an evolving industry

Start your *World Oil* premium subscription and access thousands of operator-oriented case studies.

Premium plans include:

- Your choice of Print & Online or Online Only subscriptions
- Unlimited access to thousands of technical case studies
- Exclusive access to detailed E&P forecast data
- Expert presentations from *World Oil* conferences
- Extensive resources including webcasts, white papers and videos
- **And more!**

**Subscribe Today!**  
WorldOil.com/Subscribe



## PERMIAN BASIN

# The Permian: Still the heartbeat of a global economy

**SCOTT SHEFFIELD, CEO,**  
PIONEER NATURAL RESOURCES



For more than 40 years, my career and the prosperity of Pioneer Natural Resources have been intertwined with the Permian basin. Through the ups and downs of commodity price cycles, technical and operational challenges, and now a global pandemic, the Permian has been the foundation of our company. Put simply, the Permian is Pioneer's home.

**Economic trends.** As countries, industries and employees emerged faster from the pandemic than many economists expected, demand for oil ticked up at a rapid clip, as global energy consumption steadily returned to pre-coronavirus levels. We've witnessed, time and again, generation after generation, the abundant resources in the 75,000-mi<sup>2</sup> Permian basin of West Texas and New Mexico—the world's largest shale oil and gas field—help fuel much of that demand.

Pioneer's strong balance sheet allowed the company to quickly adjust to the free cash flow model that investors demand today. In addition, this shift from production growth to returning capital to investors would not have been possible without the subsurface, technical and operational expertise we have developed over our decades in the Permian. Pioneer continues to drill the best wells in the basin at the lowest cost.

But the Permian means so much more, and perhaps many outside our

industry are only now beginning to understand and appreciate its value, which is not solely based on the barrels of oil we extract from it. The Permian basin symbolizes a greater quest for American energy independence—in 2020, the U.S. became a net oil exporter for the first time in 70 years, per the U.S. Energy Department—and our ability to offer emerging nations around the world access to affordable, reliable energy, as we make the transition to a lower-carbon future. Perhaps once unthinkable, the International Energy Agency estimates U.S. oil production will equal Saudi Arabia and Russia *combined* by 2025. Permian basin resources factor into that estimate in a significant way.

It's impossible to put a price tag on possibility, and that's what this basin offers.

As we emerged from 2020, Permian-supplied energy meant large and small businesses could open again and put employees back to work. The sharp uptick also meant that the more-than-11.3 million jobs supported directly or indirectly by the oil and natural gas industry—accounting for nearly 6% of total U.S. employment, per a July analysis released by the American Petroleum Institute—means Texans and Americans can continue to earn a living, support their families and enrich their local communities.

**Permian analysis.** Indeed, as the

Permian goes, so goes our industry for more than the next half-century. But it wasn't always like that. To borrow a quip from Mark Twain, "*Reports of the Permian's death have been greatly exaggerated.*" Humor aside, many industry "experts" and oil exploration companies have made a bad habit of writing off the Permian basin, and countless articles—some dating back more than 70 years—from national media outlets, industry trades, and even some members of the geological community, dismissed it as a used-up patch depleted of resources.

An October 1951 dispatch in *Time* characterized the 1 million-acre Spraberry Trend as the most uneconomical field in the world with "low production" wells. Outlets from *The Wall Street Journal to Oil & Gas Journal* also took turns—the latter publication summing up the Permian as "a mature crude oil province by any measure."

I'm also reminded of the *Texas Monthly* cover from 1983, featuring an illustration of actor James Dean—the elaborate mansion from the classic film *Giant* and rusted derricks sketched in the background—sticking his thumb out to hitchhike anywhere but the oil patch. The title of the story was, "*So Long, It Was Fun While It Lasted.*" I take a good deal of pride in the fact that we never relinquished our holdings in the Permian basin, or abandoned it outright, as so many independents and majors did at the time.

Even when Pioneer—along with many in the industry—decided to explore for oil beyond West Texas in the late 1990s, entering Argentina, Canada, Tunisia and South Africa, to name a few countries, we still knew our crown jewel properties remained primarily in the Permian basin of Texas, with proved reserves of more than 400 MM-boe in 2000.

Around 2009, with the U.S. re-emerging from the great recession, there again was a huge global demand for oil. Our petroleum geologists and engineers started experimenting with equipment that could penetrate the Permian's multiple layers of shale to unlock and extract those hydrocarbon reserves. We perfected our methods of basic hydraulic fracturing and horizontal drilling, then innovated and developed unconventional drilling and completion techniques that streamlined the intricate extraction process and made it more cost-effective—all while taking the utmost pride and care in preserving our valuable environmental resources.

Much like the Permian has always been Pioneer's touchstone, so is our mission of becoming America's leading independent energy company. And we do that by remaining a low-cost, environmentally responsible producer.

We believe in the still-unlocked potential of the Permian basin. Accordingly, in the past year, we've acquired two additional top-tier Permian-based companies: Parsley Energy and DoublePoint Energy. The acquisitions not only strengthen our best-in-class Permian asset, but they have made Pioneer the largest oil and gas producer in the Permian basin, and the largest

oil producer in Texas, with over 10 Bbbl of recoverable oil and gas.

**ESG angles.** But if you truly know Pioneer, we're about more than the bottom line: We put a premium on our most valuable asset, our people, and we conduct business with respect.

Environmentally, we recognize that our steadfast commitment to sustainability is paramount to the future of the company, the oil and gas industry, and the world. We have set new, more ambitious targets to reduce our GHG emissions intensity 50%, and our methane emissions intensity 75%, by 2030 from our 2019 baseline. This puts Pioneer on a path to net zero carbon emissions by 2050, including the combined assets of Pioneer, Parsley and DoublePoint. Pioneer has also led efforts in the Permian to reduce flaring and venting through the use of low-altitude flyovers and the latest surface methane detection technology, to identify leaks and promptly make repairs. We also recently endorsed The World Bank's Zero Routine Flaring Initiative, bringing together governments, oil companies and partners agreeing to eliminate routine flaring by 2030.

We publicly document to numerous stakeholders our progress toward accomplishing these benchmarks and how we measure up among industry peers. We recently published our fifth annual Sustainability Report and our inaugural Climate Risk Report.

Socially, Pioneer is proud to be a force for good in our local communities. In 2020, Pioneer and our employees donated \$4.1 million to hundreds of charitable organizations, and we remain focused on positively impact-



In March 2021, a Pioneer-operated rig targets the Wolfcamp formation at a well pad in Midland County, Texas, south of the city of Midland. The current activity level in the Permian basin is such that rig spacing like this is not uncommon. Image: Pioneer Natural Resources.

ing the communities where we live and work. We remain a leader in the Permian Strategic Partnership.

We're bullish about the belief that a diverse workforce is essential to achieving our goals, and we've made good on that mission, increasing our minority representation to 40% and our female representation to 26% percent from 2017-2019, and we're far from finished.

From a governance standpoint, our previously mentioned Climate Risk Report follows the Task Force on Climate-related Financial Disclosures (TCFD) guidelines. In 2020, we formally adopted a companywide Human Rights Policy and Human Rights Commitment, and we signed the Business Coalition for the Equality Act. Today, our Pioneer Supply Chain team actively works to ensure we source products from vendors who respect their workers and meet our standards of responsibility. ▀

## ABOUT THE AUTHOR

Scott D. Sheffield is an energy industry leader, who played significant roles in the American shale revolution and in lifting the U.S. crude oil export ban. He currently serves as CEO of Pioneer Natural Resources, now the largest crude producer in Texas. A graduate of The University of Texas at Austin (BS degree, petroleum engineering), Mr. Sheffield began his career as a reservoir engineer with Amoco Production. In 1979, he joined Parker & Parsley Petroleum, ascended to CEO in 1985, and became its chairman in 1991. When Parker & Parsley merged with MESA, Inc., in 1997 to form Pioneer Natural Resources, Sheffield became its CEO, later becoming Chairman of the Board in 1999. He retired from Pioneer in 2016 but returned as President and CEO in 2019, continuing to serve on the Board.



## MARCELLUS SHALE POTENTIAL

# Marcellus gas can support emissions goals and maintain reliable power

TOBY Z. RICE, PRESIDENT AND CEO, *EQT*



As the U.S. implements strategies and policies to accelerate the development of renewable energy resources, the country and the world still must meet critical energy demand. It is increasingly apparent that the Marcellus shale has the potential to serve as a key strategic catalyst in the efforts of our nation to accelerate a sustainable path to a low-carbon future. However, it is also becoming increasingly apparent that the private sector must fulfill an outsized role to ensure this opportunity becomes a reality.

**Keeping reliable supply accessible.** We believe we are approaching an inflection point in our collective journey toward a low-carbon future. The actions that have been proposed by advocates who suggest achieving this goal through *elimination* of fossil fuels and associated infrastructure are beginning to bear fruit, highlighting the impact of moving from an abundance of accessible energy to a deficit of accessible energy.

The shale gas boom of the early 2000s resulted in a unique combination of environmental improvement and a strong supply of reliable, affordable power. Energy-related domestic CO<sub>2</sub> emissions declined 1.3% per year, on average, since 2007, while power prices remained relatively flat. Despite this, advocates for elimination gained headway, successfully targeting pipeline and LNG infrastructure

projects to curtail the growth of accessible natural gas. As a result, the very thing that the energy abundance of recent years has conditioned us to undervalue—reliable, affordable power—is eroding.

It should come as no surprise that effectively addressing the risks posed by climate change, while also fundamentally reshaping the existing energy ecosystem, is no simple task. The solution of *elimination* does not address the ramifications of the U.S. no longer having ample, accessible energy, be it the economic equality and upward mobility for millions of low- and middle-income citizens, or the geopolitical ramifications of climate-conscious energy security. Instead of *elimination*, we must advocate for policies that support an *optimization* of resources to meet demand in the most prudent, environmentally responsible manner possible.

In this scenario, the Marcellus shale should shine.

**Abundant natural gas resources.** The U.S. is among the fortunate minority of countries with an abundance of energy resources, which gives us the opportunity to optimize these resources to solve our climate needs. Recent data show that natural gas produced in Appalachia is produced with the lowest carbon- and methane-intensity in the nation, meaningfully lower than those from foreign

suppliers and significantly lower than coal production and use.

EQT is the largest producer of domestic natural gas in the U.S., representing approximately 6% of the country's output. Our recently announced 2025 Scope 1 and 2 net-zero emissions (NZE) target puts us over a decade ahead of most energy providers. If EQT were a country, it would be the 12th largest natural gas producer in the world. Among this group, EQT would have the lowest emissions intensity—an emissions intensity less than half that of Russia—even before giving effect to our plan to reduce greenhouse gas and methane emissions intensities by 70% and 65%, respectively, versus 2018 levels.

Our leading emissions profile is both a strategic opportunity and a key differentiator in a global market that increasingly values high-quality assets and operations that limit carbon and methane emissions across the supply chain. This strategic opportunity applies to producers operating across the Appalachian basin.

**Greater infrastructure needed.** What limits this opportunity is a lack of infrastructure. As a result of activist-driven cancellations of natural gas infrastructure, the ability to meaningfully increase production volumes to support domestic and global markets has been effectively capped as a result of delayed LNG terminal approv-

als. While we can produce more, we cannot deliver more.

The repercussions of the delay and destruction of energy infrastructure have become readily apparent in recent months, with the rapid acceleration of natural gas prices domestically and abroad, as we are left unable to remedy systemic shortfalls. As natural gas supply is unable to reach points of demand, the demand turns elsewhere, namely to less-environmentally friendly coal. In summary, the advocates of “keeping it in the ground” have succeeded, but their actions have resulted in less reliable, less affordable power, and likely increased emissions.

It is undeniable that a transition to increased renewable market share is needed over the long-term to meet our climate goals. However, this is not as easy as flipping a switch, and renewable power generation is only a subset of the solution to meet these challenges. Ramping up renewables too fast will add massive cost burdens for families and businesses, and ultimately could hinder environmental progress.

In order to pave the way for a clean, low-carbon future, we need policies that support the energy resources that are right for where we are now, not just where we hope to be some day. Whether policies support emissions reductions or bolster investment in infrastructure, agendas can be appeased on both sides of the aisle, and clean, low-cost and reliable natural gas can play a crucial role in the energy transition.

And while the opportunity for increased utilization of Marcellus shale gas is meaningful, that opportunity

will not fall into the lap of a passive industry. What has put the Marcellus in a position of strength today—the high productivity of its assets, the relatively stringent state regulatory regimes, and the enhanced public scrutiny in the region—is not going away.

**Maintaining emissions reductions.** However, for many in the region, the concept of natural gas being a tool to achieving our emissions reduction goals is counter to the narrative that has been pushed in recent decades. Therefore, it is the responsibility of operators in the Marcellus shale to enhance our operations and positioning to attain a more sustainable future. By actively curbing our methane emissions while implementing new technologies and strategies to further decrease our carbon emissions over the long-term, we will shift the misinformed narrative and further situate operators in the region for success.

Part of this involves setting aggressive emissions reduction goals and establishing methods to exchange best practices. Through digitization and other innovative technologies, EQT has transitioned to a more modern well-development strategy, making significant progress in reducing its combustion emissions, while also significantly reducing flaring, venting and fugitive emissions. Pairing EQT’s emissions reduction programs with those of peers will further reduce the methane intensity of the Marcellus shale, which is already one of, if not the least intensive in the country. Combining these emissions reductions with a commitment to deploying new tech-



The Marcellus shale is one of the top natural gas-producing regions in the U.S., and EQT is the largest gas producer in the country. Image: EQT.

nologies in a modern emissions monitoring and management framework, the Marcellus shale will be sufficiently justified in deserving supportive policies and infrastructure.

Unlocking the use of natural gas not only domestically, but globally, will allow the Marcellus shale, and the U.S., to play an outsized role in the global energy market. Not only would incremental LNG infrastructure allow the U.S. to remedy the global supply issues driving the crises in Europe and Asia, it also would allow the country to replace higher emissions sources in times of supply abundance.

In short, we propose a total reset to what’s achievable, affordable and forward-moving. Our opportunity to change the conversation has a lingering shelf life, and by implementing forward-thinking climate strategies and recognizing the value of clean, low-cost and reliable natural gas, we can help pave the way for a clean, low-carbon future. ▀

## ABOUT THE AUTHOR

Toby Rice was named President and Chief Executive Officer and joined EQT’s Board of Directors in July 2019. He has served as a Partner at Rice Investment Group, a multi-strategy fund investing in all verticals of the oil and gas sector since May 2018. Prior to that, Toby was President, Chief Operating Officer and a member of the Board of Directors of Rice Energy from October 2013 until its acquisition by EQT in November 2017. He served in a number of positions with Rice Energy, its affiliates and predecessor entities since February 2007, including President and Chief Executive Officer of a predecessor entity from February 2008 through September 2013.

## GULF OF MEXICO OUTLOOK

# Gulf of Mexico remains a prime region for technological innovation

**TIMOTHY S. DUNCAN, FOUNDER, PRESIDENT AND CEO,**  
*TALOS ENERGY*



In the roughly four years since the last World Petroleum Congress in Istanbul, the world and our industry have evolved in many ways, with new opportunities, new threats, emerging players, an evolving geopolitical landscape and continued growth in global energy demand. This evolution has played out in global physical and financial energy markets, and undoubtedly will continue to shape the world of tomorrow.

The Gulf of Mexico, where Talos Energy is one of the leading independents, has been front and center for the evolution of our industry, not just over the past four years, but for many decades. The area remains today, as it

has since the middle of last century, one of the most prolific hydrocarbon provinces on the planet, providing approximately 15% to 20% of the United States' total production. The basin is a significant national resource that provides secure, affordable hydrocarbon supply directly into one of the country's most important industrial corridors, located along the coast of Texas, Louisiana, Mississippi and Alabama.

**Continued GOM investment.** In an era of highly selective capital investment in the energy complex, the Gulf of Mexico continues to attract capital resources to explore for, and develop, attractive, long-life projects.

The basin continues to be identified as a core focus area for the numerous Super-Majors and large operators in it, a testament to its global competitiveness. Additionally, an array of smaller independents, as well as infrastructure, midstream and service providers, continues to play an active role in the basin and contribute to its rich ecosystem of industry participants and stakeholders.

The region is also a leader in safety and environmental responsibility. Gulf of Mexico operators have safety track records that are among the best across an array of industrial categories, not just oil and gas. Additionally, numerous research institutions have reported that Gulf of Mexico deepwater production has among the lowest greenhouse gas emission intensities, relative to other global and domestic oil producing regions. This reinforces the basin's ability to continue to attract capital in the future, as the world focuses on reducing emissions intensity and decarbonization.

We expect a prosperous future for the Gulf of Mexico, as we move forward. In oil and gas, the Gulf of Mexico has long been at the forefront of engineering and technological achievement, boasting many of the world's biggest, deepest and most challenging energy projects. This trend continues today and into the future. Continued improvements in seismic data acquisition and reprocessing technology,



One of the few floating production facilities operating in the Gulf of Mexico, the Helix Producer I receives oil and gas production from subsea wells at Talos' Phoenix complex in the Green Canyon area. Image: Talos Energy.



coupled with advances in subsea engineering technology, allow operators to unlock new resources in existing operating areas as well as new exploration regions, all with less uncertainty and at a faster rate than ever before.

**Safety and ESG.** There is good reason to believe that Gulf of Mexico operators will remain at the cutting edge of environmental and safety matters as well, ensuring responsible production of ESG-advantaged hydrocarbons for decades to come. Finally, decades of operating history in the basin provide the foundation for the addition of new forms of energy and carbon solutions. With an extensive supply chain and logistics network, hundreds of thousands of highly skilled workers, and an existing operating and regulatory platform, the basin is a logical place for new technologies, such as Carbon Capture, Utilization and Storage (“CCUS”), offshore wind, wave, hydrogen, and other investments to experiment and succeed, diversifying the country’s energy supply mix while leveraging the basin’s energy hub legacy in the process.

**Growth at Talos.** As the founder and chief executive officer of Talos Energy, I’m also excited for our company, as we lead many of these trends in the Gulf of Mexico. Since our founding in 2012 with just five employees, we’ve grown to over 400 professionals in less than a decade and are one of the leading independent operators in the basin, as well as the largest publicly-traded Gulf of Mexico pure-play company. We play a major role in providing secure, affordable energy supply to global markets, as well as exert leadership in environmental performance, safety and community involvement. We have been ranked as one of the Top Workplaces in Houston every year since inception, and we strive to be a positive force in our local community through volunteerism and charitable support for numerous organizations.

**Balancing record output with ESG performance.** Our business is strong, achieving record production in two consecutive quarters this year while maintaining a solid balance sheet despite the volatility of the past 18 months. We are actively investing in the Gulf of Mexico across a diverse size and risk spectrum, ranging from our in-field development activities at the company’s Pompano project to high-impact exploration in our Puma West asset alongside BP and Chevron. We expect to continue to deliver strong organic results through our internal growth efforts while also looking for avenues to increase the scale of our business through attractive inorganic growth via acquisitions.

Talos has worked to be a leader in environmental responsibility and sustainability. We’ve set a target to reduce emissions from our operations 30% by 2025, and we continue to operate with minimal flaring while utilizing pipelines to transport 100% of our production to markets, compared to trucking and rail alternatives onshore. We maintain a diverse, independent board of directors and have strongly aligned management incentives to both underlying business performance as well as ESG performance. We’re shown leadership in these important areas for not just our shareholders, but for all of our stakeholders.

**Implementing technology for ESG gains.** Lastly, Talos is leading the basin’s evolution as a hub for new energy technologies and applications. Our company is actively exploring CCUS opportunities across the basin, which is strategically advantaged near a major industrial corridor while also offering some of the most attractive geology for carbon storage in the country. These factors, combined with Talos’s operational expertise and offshore experience, make the company a logical leader in advancing offshore CCUS along the Gulf Coast.

Earlier this year, we did just that,



Talos operates the Pompano oil production platform in 1,290 ft of water, in the Mississippi Canyon portion of the Gulf of Mexico, offshore Louisiana. Image: Talos Energy.

winning a competitive state process to be named operator for the first major U.S. offshore carbon storage hub, located in Jefferson County, Texas. Additionally, through our venture with UK-based Storegga Geotechnologies, we’re actively advancing numerous other CCUS project opportunities in key strategic areas. We expect the CCUS business will ultimately evolve through multiple projects with the potential to capture significant carbon emissions, many multiples of what we produce in our own operations. ▀

## ABOUT THE AUTHOR

Tim Duncan is a Founder, President and Chief Executive Officer of Talos Energy. Prior to Talos Energy, Mr. Duncan was the Senior Vice President of Business Development and a founder of Phoenix Exploration Company LP, where he was responsible for the firm’s business development evaluations and negotiations, including the sale of the company to a group of buyers led by Apache Corporation. Prior to Phoenix, he was Manager of Reservoir Engineering and Evaluations for Gryphon Exploration Company. Mr. Duncan also worked in various reservoir engineering and portfolio evaluation functions for Amerada Hess Corporation, Zilkha Energy Company, and Pennzoil E&P Company.

## WESTERN CANADA

# Driving emissions reduction, economics, and indigenous issues

**TIM MCMILLAN, PRESIDENT AND CEO,**  
CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS (CAPP)



As global economies recover, demand for all forms of energy is expected to continue growing. At the same time, the focus on a sustainable future has never been greater. With strong environmental standards and a focus on continuous improvement, Canada's upstream natural gas and oil industry can help meet the energy needs of the world with affordable, reliable, responsibly produced products, while building recovery and sustained prosperity at home.

## CANADA'S UPSTREAM INDUSTRY AT A GLANCE

Canada has the third-largest oil reserves in the world; some 168 Bbbl are recoverable with today's technology. Conventional and tight-formation deposits are located in Western Canada, notably in the liquids-rich Montney and Duvernay plays of British Columbia and Alberta. In addition, Canada's East Coast has oil production offshore from the easternmost province of Newfoundland and Labrador.

By far, this country's biggest asset lies in the oil sands: more than 162 Bbbl, the largest single deposit of crude oil on the planet. Canada's oil sands are found in three regions within the provinces of Alberta and Saskatchewan, with a combined area of more than 142,000 km<sup>2</sup>. Only about 3% of that land area will ever be impacted by surface mining—most oil sands deposits are too deep to be mined and are produced, using in situ

technologies, notably steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS).

Current production also places Canada among the world's energy leaders. At an average daily output of 4.5 MMbbl of oil and 15.4 Bcf of natural gas, Canada is the fifth-largest global producer of both these resources. More than 90% of that production is concentrated in the western provinces of British Columbia, Alberta and Saskatchewan.

Currently, nearly all of Canada's exported oil and natural gas goes to markets in the U.S., particularly the Midwest and Gulf Coast. Enbridge's Line 3 pipeline project provides enhanced capacity to serve these markets, while completion of the Trans Mountain Expansion pipeline project will provide improved capacity for oil export to global markets, especially India and China. Similarly, completion of the LNG Canada liquefied natural gas facility near Kitimat on Canada's West Coast will open new global market access for natural gas production from Western Canada.

For further detail on Canada's upstream industry, I invite you to visit our main website ([capp.ca](http://capp.ca)) and our online newsmagazine, Context: Energy Examined ([context.capp.ca](http://context.capp.ca)).

## FOCUS AREAS: WHAT'S DRIVING US FORWARD?

The industry is focused on three overarching areas: reducing green-

house gas (GHG) emissions; continuing to be a major economic driver contributing to Canada's economic recovery; and supporting the growth of sustainable, economically prosperous Indigenous communities.

**Reducing emissions.** *Invest in innovation to decarbonize while becoming a global supplier of choice for lower-carbon natural gas and oil.*

Canada's upstream industry already has a broad portfolio of innovative solutions to deliver ongoing emissions reductions. These technological advances are not aspirational, they are actual: the industry is taking serious, substantial steps to reduce emissions intensity. As a result, per-barrel oil sands GHG emissions decreased 20% between 2009 and 2018.

Current technologies that are driving down upstream GHG emissions include: lowering methane emissions; carbon capture, utilization and storage (CCUS); cogeneration; and process efficiency improvements.

Canada has mandated a reduction in methane emissions of 45% below 2012 levels by 2025. In addition to reducing or eliminating flaring and venting, the upstream oil and natural gas industry is actively working to reduce fugitive emissions sources, such as tank vents, pneumatics and pumps, in order to meet this reduction target.

Carbon capture is also having a tremendous impact. The Quest facility at the Shell-operated Scotford Upgrader

near Fort Saskatchewan, Alberta, began operation in 2015 and has captured more than 6 million tonnes of CO<sub>2</sub>, approximately equal to the annual emissions from 1.5 million cars. And the Alberta Carbon Trunk Line (ACTL) system, which started operation in 2020, captures about 1.3 million tonnes of CO<sub>2</sub> annually from industrial sources near Edmonton for transport and injection into mature reservoirs in central Alberta for enhanced oil recovery and permanent storage. With a large inventory of suitable reservoirs, Alberta is a strategic location for CCUS developments.

A number of emerging technologies, such as solvent injection at in situ developments, and partial upgrading at oil sands mining operations, hold significant promise to further reduce the industry's GHG footprint—making Canadian oil sands emissions comparable to other North American production. CAPP's publication, *Canada's Natural Gas and Oil Emissions: Ongoing Reductions, Demonstrable Improvements*, available on our website, contains additional details about the industry's dynamic and effective efforts to reduce emissions.

**Economic recovery.** *Creating jobs and pan-Canadian benefits.*

The natural gas and oil sector is among Canada's largest industries, generating more than \$100 billion in annual GDP. Natural gas, oil and refined products are Canada's number one export, accounting for 19% of the value of all Canadian exports—outpacing agriculture, automobiles and manufacturing. Through an average \$10 billion a year in taxes and royalties, the industry generates critical

revenues for municipal, provincial and federal governments.

Canadians from coast to coast are involved in oil and natural gas development and production. In 2019, the industry supported more than 522,000 direct and indirect jobs across the country, and the industry's multi-billion-dollar supply chain includes some 10,000 businesses.

Canada's energy industry has the nation-wide reach to stimulate broad, large-scale economic recovery and to sustain Canada's financial future.

**Indigenous reconciliation.** *Support shared economic opportunities arising from resource development.*

Views and perspectives regarding resource development are as diverse among Indigenous peoples as they are among Canadians as a whole. Many Indigenous communities see resource development as a pathway to economic reconciliation and opportunity, and a means to end poverty in their communities.

With some 13,900 Indigenous workers across the industry, oil and natural gas development is one of the largest employers of Indigenous peoples in Canada. The energy sector presents a significant opportunity for inclusive and sustainable economic growth, prosperity, and self-determination for Indigenous communities. In 2018, the oil sands industry procured \$2.4 billion in goods and services from 275 Indigenous-led companies.

### A FORWARD PATH: INVESTMENT IS CRITICAL

Oil and natural gas will be a significant part of the world's energy mix for the foreseeable future. At



Surmont is a SAGD bitumen recovery facility that is operated by ConocoPhillips under a 50/50 joint venture agreement with Total E&P Canada. Current gross production capacity is 140,000 boed. Image: CAPP.

the same time, climate change is a global challenge that requires global perspectives and solutions. Ongoing GHG emissions reduction is critical to realizing the vision for Canada to be a global natural gas and oil supplier of choice. And the key to meaningful emissions reduction is technology.

When it comes to innovation and technology aimed squarely at reducing emissions, Canada is a world leader. However, capital investment is crucial to advancing development and deployment of new technologies. Investment in this industry presents an opportunity to achieve critical goals at a pivotal time for Canada—and the world. ▀

## ABOUT THE AUTHOR

Tim McMillan was appointed president of CAPP on Oct. 1, 2014. In this role, he is responsible for leading activities in education and communications, as well as policy and regulatory advocacy on behalf of CAPP member companies, which represent over 80% of Canada's upstream oil and natural gas production. Born in Saskatchewan, Mr. McMillan grew up on his family's century-old farm. After earning an economics degree from the University of Victoria, he traveled and worked overseas, later returning to Western Canada to found and operate an oilfield services company. He sought a seat within the Saskatchewan Legislature in 2007. From 2010 until his appointment as president of CAPP, Mr. McMillan held several strategic cabinet portfolios in the Government of Saskatchewan, including Minister of Energy and Resources.



## EAST COAST CANADA

# Resilient and roaring back

**CHARLENE JOHNSON, CEO,**

*NEWFOUNDLAND AND LABRADOR OIL & GAS INDUSTRIES ASSOCIATION*



Just like the international oil and gas industry, the Newfoundland and Labrador offshore oil and gas industry—eastern Canada’s oil and gas hub—was dramatically impacted by the large price fluctuations, followed by the emergence of Covid-19 and the subsequent drop in demand.

While the industry was known for its ability to operate in extremely harsh conditions and adapt to difficult circumstances, this scenario challenged its most experienced members. And while much work remains, the story of the Newfoundland and Labrador offshore oil and gas industry during this time is similar to the history of the province; it is a story of resiliency and a desire to keep going in the face of challenging headwinds to achieve its potential.

## CHALLENGES KEPT COMING

This difficult period began in early March 2020, with the announcement from Equinor that it had delayed any further progress on the anticipated Bay du Nord project, due to low oil prices. The Bay du Nord field is the next potential project to receive sanction in Newfoundland and Labrador, and if it does, it has the potential to produce upwards of one billion barrels of oil and would be the farthest offshore field in the world. Over the spring and summer, Equinor proceeded with an exploration program with the Transocean Barents rig drilling

exploration wells Cappahayden and Cambriol. Equinor later announced that hydrocarbons had been found during the program.

That same month, Husky Energy announced a “systematic and orderly suspension of major construction activities” related to the West White Rose (WWR) project, leaving the fixed drilling platform—a Concrete Gravity Structure (CGS)—being constructed in Argentia, Newfoundland and Labrador, about 60% complete. Husky subsequently confirmed the 2021 construction season for the WWR project was cancelled, and first oil was delayed to 2023.

CNOOC International delayed its 2020 Flemish Pass exploration drilling campaign in response to the pandemic but did conduct an exploration program in 2021 with the Stena Fourth drillship.

The Terra Nova FPSO was taken off-field and moored while its turret cover plate was installed. Later, the FPSO moved to the Bull Arm Fabrication facility to be docked quayside for at least six months while Suncor determined next steps. The future of the proposed Asset Life Extension (ALE) project of the FPSO was in doubt, putting at risk an additional 10 years of production.

Newfoundland and Labrador’s first offshore installation at Hibernia ceased drilling operations in May. A positive factor within the industry during this period was that Hebron field achieved a significant milestone, when Exxon-

Mobil announced the platform had produced its 100 millionth barrel of oil.

## INDUSTRY ADVOCACY

For most of the last 22 months or so, Noia worked diligently, advocating to the federal and provincial governments for support for the offshore industry in the form of incentives for offshore exploration, as well as incentives to encourage approval of development projects.

Noia hosted two virtual town halls in 2020 to discuss concerns about the future of Newfoundland and Labrador’s offshore oil & gas industry, and led an industry news conference that included Dwight Ball, then premier of Newfoundland and Labrador; Siobhan Coady, then natural resources minister; along with industry leaders and the president of Memorial University. The association actively pursued and participated in local, national, and international media opportunities, along with virtual events, podcasts and a nationally published op-ed. Noia’s efforts culminated in a rally led by the offshore union, Unifor Local 2121, held at the provincial legislature, where members demonstrated their support for the industry.

## ASSISTANCE ARRIVES

An Emission Reduction Fund of \$750 million was announced by the federal government, with \$75 million allocated to Newfoundland and Labrador’s offshore sector. In September

2020, the provincial government announced a new offshore exploration initiative to provide leaseholders with financial incentives to drill more wells.

The Government of Canada also announced C\$320 million for Newfoundland and Labrador to “support jobs and ensure the sustainable, long-term, lower-emitting future for our offshore,” with C\$32 million set aside for the supply and service sector. A volunteer task force established to help determine criteria to allocate the funds produced an exceptional report, including 52 recommendations to move the industry forward in a progressive and expedient manner.

Husky Energy received C\$41.5 million of the fund to maintain jobs and move toward restarting the West White Rose project. For the Hibernia platform, C\$38 million was provided to restart well work, perform drilling rig upgrades, and invest in new digital technology.

After much negotiation, an agreement was reached in the summer of 2021 to continue the Terra Nova FPSO ALE project. As stated by Suncor, ALE is expected to produce an additional 70 MMbbl of oil. This was made possible by a significant financial contribution of up to C\$205 million (on a matching contribution basis) by the provincial government and reinvestment by partners Cenovus and Murphy Oil Corporation. It also included investment by Suncor in the WWR project where, should a restart of that project occur, Suncor will increase its interest in the White Rose offshore field by 12.5% and Cenovus is to complete a restart evaluation of WWR by mid-2022.

## THE FUTURE

The Government of Newfoundland and Labrador has committed to achieving net zero emissions by 2050, and the clean energy space is one that Noia has been working in as part of a collaborative effort with econext—formerly known as the Newfoundland and Labrador Environmental Industries Association (NEIA)—and other industry stakeholders.



The new agreement to move the Terra Nova FPSO ALE project forward has been a significant reinforcement to the East Canada offshore industry. Image: Suncor.

At the September Noia Oil & Gas Conference 2021, Minister Andrew Parsons announced approval of our application to commence a net zero project with econext and OilCo to collaborate on finding solutions to achieving net zero within our industry.

Also, at the Noia conference, several operators in our offshore provided updates on their activities. Cenovus Energy had positive things to say about the West White Rose project and the CGS. While there was no commitment to restart, a decision could come next year.

Equinor indicated it will be drilling two exploration wells in 2022 at Bay du Nord field, and industry confidence is growing that development project sanction will occur. Next year, ExxonMobil also plans to drill, using the Provincial Exploration Initiative. BHP (Woodside) has indicated it plans a 2023 campaign, and we are hopeful that BP, CNOOC and Chevron will do the same in the next couple of years.

At the end of September, PGS and TGS completed a seismic campaign of over 9,900 km<sup>2</sup> offshore Newfoundland and Labrador that included 3D data to compliment existing 2D data. This was the 11th consecutive acquisition season, and the new datasets expand 3D multi-client coverage to 80,000 km<sup>2</sup>.

The Canada-Newfoundland and Labrador Petroleum Board (C-NLOPB)

issued a Call for Nominations (Parcels) in three land tenure regions this fall. These calls will assist the C-NLOPB in selecting parcels to be included in subsequent 2022 Calls for Bids, with successful bidders to be awarded licences early 2023. A C-NLOPB Call for Bids in the Labrador South Region was scheduled to close in December 2021.

Newfoundland and Labrador has world-leading prospectivity that includes a resource potential of 63.3 Bbbl of oil and 224.1 Tcf of gas, in just 10% of the offshore area assessed. When you combine that with our resource that is 30% below the global average for carbon emissions at extraction, we have a bright future ahead. ▀

## ABOUT THE AUTHOR

Charlene Johnson has been CEO of Noia since January 2018. Previously, she had been a Member of the House of Assembly, Government of Newfoundland and Labrador, from 2003 to 2014. As a senior cabinet minister, Ms. Johnson led a number of high-profile departments, Prior to that, she worked as a policy analyst for the Nova Scotia Utility and Review Board. She holds a BS degree in forest engineering, a Master of Applied Science in environmental engineering, and an MBA (with Distinction) from Heriot Watt University, Edinburgh, Scotland (2017).

# US shale sees shifting drill mix

**ALEXANDRE RAMOS-PEON, VICE PRESIDENT OF SHALE ANALYSIS,**  
 RYSTAD ENERGY



The rapid expansion in the pace of US onshore drilling and completions raises the question of how much of the activity is infill drilling or new developments in fresh, unexplored acreage positions. And whether performance degradation can be observed in empiric production data.

As activity matured over the past decade, the industry saw a rapid increase in the share of wells drilled as 'child', or infill, wells from 'parents' on a previously existing pad or spacing unit.

Such infill activity represented about 15% of all horizontal completions in the US back in 2010, increasing to about 50% by the middle of that decade. Back then, much of the project developments focused on new single

wells being drilled on their own. Then over the next five years, the share of child wells remained relatively stable.

Indeed, during 2014-21, as the industry entered full-scale development mode, the trend was of executing projects with simultaneous completions of several wells in a new acreage position.

In mature onshore plays such as the Niobrara, the Bakken and south Texas' Eagle Ford, the drop from 70-90% to 5-10% of single-well parents took place between 2011-15. In the Permian, the trend was much more gradual, as delineation activity expanded to unproven areas, while the more consolidated basins quickly ran out of new areas or single-well developments could not be commercially justified.

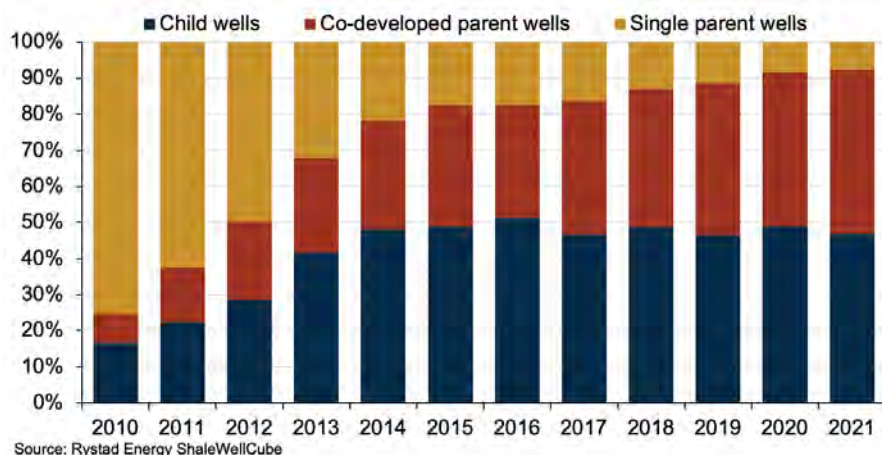
Nowadays, nearly nine out of 10 new completions in the Bakken are classified as child wells, meaning the wells were completed in 'spacing units' where previously some wells would have been completed within one quarter of a mile. At the other end of the range is the Anadarko basin, where essentially no infill activity has taken place over the last couple of years.

When it comes to performance, there are important pitfalls to sidestep when attempting to assess parent-child interactions or productivity degradations. Foremost are the changes in completion techniques used in the same spacing unit, even when operators return several years after the initial pilots.

In North Dakota, for example, two-mile lateral design with low completion intensities were not unusual 10 years ago, and modern wells drilled next to the parents, unsurprisingly, outperform them in all metrics, despite the steeper initial declines.

Hence simple comparisons, of initial production rates or estimated ultimate recoveries (EURs) for example, for parent vs child wells might lead to counterintuitive conclusions. With all things equal—and this is the challenging part—the understanding is that child wells are typically expected to underperform.

A complete, robust assessment of whether child wells drilled in an exist-



**Figure 1.** Share of parent wells vs child wells in major US shale plays\* % of horizontal wells completed each year



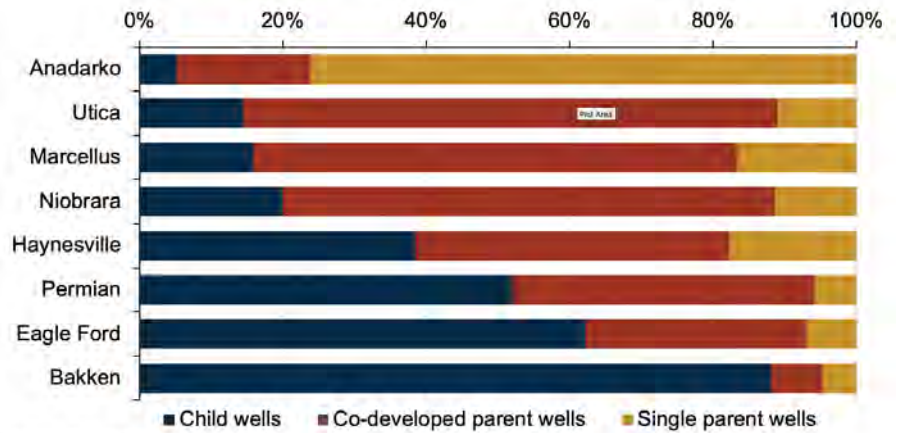
**Table 1.**

	Pads with co-developed parents	Pads with 2012-2013 parents only
1-2	0.996838697	0.936
3-4	0.975989109	0.967
5-6	1.808359676	1.277
7-8	1.806885706	1.845
9-10	1.851181435	1.676

ing spacing unit, with a comparable design to the parent, would underperform, would require a very careful control for several factors. Yet we can illustrate with a simple analysis the conclusion that consultancy Rystad Energy has exposed through several research studies: a slight degradation in child well productivity, while keeping in mind the above caveats of simplistic comparisons.

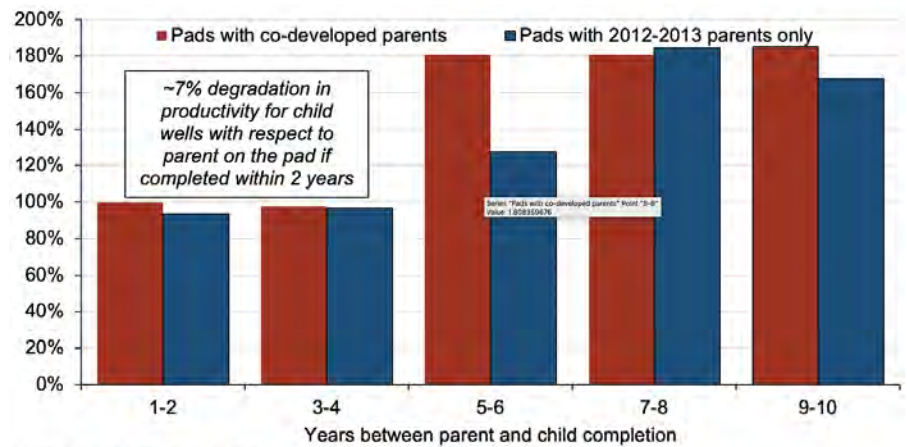
We can for example select all spacing units in the Bakken, with parent wells with laterals the range of 8,500-11,500ft and infill activity after year 2012. For each unit, we calculate the average performance—one-year cumulative recovery per foot—of the parent and compare it to the average of the child wells. If the child well is completed within two years of the parent, then the typical recovery rate of the child is about 7% below that of the parent.

However, as the gap between the two completions increases, very clear signs of overperformance of the infill wells emerge, for reasons outlined



Source: Rystad Energy ShaleWellCube

**Figure 2.** Share of recent parent-child completions by region % of horizontal wells completed in 2020-2021



Source: Rystad Energy ShaleWellCube

**Figure 3.** Changes in productivity for child wells in the Bakken Child-to-parent ratio of 1-year cum two-stream per foot

above. In fact, if one only looks at units with 2012-13 parents, then the typical

overperformance of infill wells exceeds 60% for completions in 2018-21. ▀

## ABOUT THE AUTHOR

Alexandre Ramos-Peon is vice president of shale analysis at Rystad Energy





# Downstream

**LEE NICHOLS, EDITOR-IN-CHIEF**


*HYDROCARBON PROCESSING*

---

Change is inevitable. Regardless of the industry, companies, processes and people must continue to adapt and evolve in an ever-changing market. The same is true of the hydrocarbon processing industry (HPI). The HPI is witnessing several changes and owner-operators, engineering, procurement and construction (EPC) companies, technology licensors, vendors and suppliers are adjusting to the future of processing hydrocarbons.

The HPI is accelerating several aspects of the energy transition. Strict regulations and government initiatives are pushing refiners to produce low-sulfur and ultra-low-sulfur fuels, as well as mandating higher blending quotas of biofeedstocks within fuels production. These trends are moving the HPI into increased production of renewable fuels, biofuels/alternative fuels, etc.

The petrochemicals industry continues to make significant investments in chemical recycling technologies, utilizing biofeedstocks to produce “green” petrochemicals and incorporating new techniques to mitigate carbon emissions during production.

Lastly, refiners and petrochemical producers and HPI companies are utilizing digital technologies to increase plant reliability, safety, productivity, profitability and sustainability. The following articles provide an analysis of the several technologies and trends that are affecting the HPI and are helping it shape the production of fuels and petrochemicals in the future. 

---

Refinery at sunrise. Photo courtesy of Phattana Stock.



# CONTENTS

---

- 61 Introduction**  
Lee Nichols, Editor-in-Chief, *Hydrocarbon Processing*
- 63 What is the future for the hydrocarbon processing industry?**  
Helion Sardina, Chief Commercial Officer, Lummus Technology
- 65 Where next for global refining? Are we there yet?**  
Alan Gelder, Vice President Refining, Chemicals and Oil Markets, Commodities Research, Wood Mackenzie
- 67 Innovative advanced recycling, driving circularity while decarbonizing petrochemical industry**  
N. Menet, Plastic Recycling Business Development Manager, Axens
- 69 Why EPC firms are accelerating digitalization**  
P. Donnelly, Industry Marketing Director, Engineering and Construction, AspenTech
- 71 Enterprise-wide energy efficiency fleet monitoring tool**  
K. Trivedi, Project, Development Manager, ExxonMobil Global Projects; S. Nehete, Technology Improve Lead, ExxonMobil Chemical Operations Pvt. Ltd.; and J. Gunter, Element Venture Lead, ExxonMobil Fuels & Lubricants Co., EXXONMOBIL
- 74 Green, faster, together**  
C. de Regt, Senior Principal Consultant, Safety and Risk Management, Energy Systems, DNV
- 76 Decarbonizing Shell PernisX**  
A. Gosse, President Shell Catalysts & Technologies
- 78 Illuminating the future of chemical manufacturing**  
M. Acharya, Vice President, Commercialization, and M. Marfani, Director of Corporate Development, Syzygy Plasmonics

# What is the future for the hydrocarbon processing industry?

**HELION SARDINA, CHIEF COMMERCIAL OFFICER,**  
LUMMUS TECHNOLOGY



What does the hydrocarbon processing industry look like in the future? That was the topic *Hydrocarbon Processing* discussed with Helion Sardina (HS), Chief Commercial Officer, Lummus Technology. In this interview, Mr. Sardina offered his market insight on the COVID-19 pandemic, the process technology industry now and in the future, and its role in the energy transition.

## How has COVID-19 affected the hydrocarbon processing industry in 2021?

HS: When COVID hit in 2020, it plunged the refining and petrochemicals industries into a deep downturn, except for products such as polymers that are tied to the medical sector. Fortunately, 2021 has not been as severe as 2020, and the industry is close to a full, worldwide recovery, with China leading the way.

The pandemic resulted in lower plant utilization rates and caused some construction projects to be delayed—forecasts still show that new projects are necessary to satisfy growing customer demands globally. Due to our company's diversification and longer-term planning and execution windows for customers, we fared much better than most other players in our industry. We did, however, experience challenges and delays in being able to deliver proprietary equipment for ongoing projects and reloading catalysts for our licensees.

## Do you foresee similar impacts in 2022?

HS: Based on our current pipeline, we anticipate growth in many areas this year. We are seeing previously delayed projects now getting awarded and moving forward. If efforts to curb the pandemic are successful, it will bring our global markets back into balance. As a result, we anticipate increased consumer activity, which fuels growth in our business and industry.

## What are some of the key drivers and technology developments shaping the market today? In the next 5 years?

HS: As an industry, we need to transform current technologies and develop new ones that minimize our environmental impact and contribute to the circular economy. It is also important that we provide refiners solutions that help them pivot away from declining transportation fuels by repurposing existing assets to meet the growing demand for petrochemicals.

Lummus is hard at work around this vision. Our efforts include developing and administering licenses focusing on world-scale crude-to-chemicals projects. We have added energy conservation components to our portfolio, such as gas turbines in our ethylene crackers. We have teamed up with New Hope Technologies that has a leading plastic waste conversion technology that produces pyoil that

can be co-fed into a refinery or petrochemical plant with fossil fuel-derived feedstocks. With this partnership, we have applied our expertise to scale up the plant design to ensure it can have a significant impact on the end-of-life plastics challenge.

We are keenly aware that we need to proactively manage future trends by developing technologies to meet customers' needs.

## What role will process technologies and companies like Lummus play in the energy transition?

HS: Customers across all regions are requiring more environmental, social and governance (ESG) compliance, and a lower carbon footprint at their existing facilities.

Last year, Lummus established Green Circle to focus on the circular economy and provide energy transition solutions. We have developed new technologies related to the energy transition, while simultaneously continuing to enhance existing technologies that produce renewable and cleaner fuels, lower the carbon footprint of our customers' downstream investments and help facilities co-process circular products.

Our industry's products are vital in supporting and improving global living standards, so the technology licensor's job is to continue delivering them at the lowest impact to the environment per ton of product produced.

Our industry has a long and lasting legacy of making things work. We know how to convert hydrocarbons into fuels and consumer products. This is one thing that has not changed. Therefore, process technologies and the companies that license them, can build on this legacy in the energy transition.

### How does the process technology industry need to evolve going forward?

HS: One way the industry needs to evolve is by accepting its role in the energy transition. Our licensees are under pressure to reduce emissions and become more environmentally friendly, and we can help them lower the carbon intensity of their plants.

We must provide every one of our

licensees the most efficient plant design, which translates to the lowest impact to the environment. This holistic approach can reduce the overall carbon footprint, while also improving plant operating expenses. We need to continue minimizing feedstock consumption, optimizing energy use, extending the use of catalysts and reducing emissions.

On the surface, those do not typically sound like they go together—plant operations and environmental cleanliness. However, process technology licensors have historically produced technologies that have helped customers increase efficiency, emission and waste reductions and savings in their operations. These have made positive impacts to the environment.

Our industry can also evolve by

accelerating digitalization, an area where we have been slower than some other industries in adopting. At Lummus, we formed a joint venture with TCG Digital—called Lummus Digital—to combine our leading process licensing portfolio with TCG Digital's proven big data and artificial intelligence platform. The JV works with our existing customers and prospects to implement digital solutions for their refining, petrochemical and gas processing assets, as well as across the hydrocarbon processing value chain.

We see opportunities to further the digitization of our industry—from performance monitoring, system optimization and remote management of facilities, among others—to empower industry leaders with smarter ways to do business. ▀

## ABOUT THE AUTHOR

Helion Sardina has spent his entire career with Lummus Technology, serving in different management roles of increasing responsibility. At present, Mr. Sardina is Lummus' Chief Commercial Officer, where he is responsible for overseeing all aspects of sales and business development for the company.





# Where next for global refining? Are we there yet?

ALAN GELDER, VICE PRESIDENT REFINING, CHEMICALS AND OIL MARKETS,  
COMMODITIES RESEARCH, WOOD MACKENZIE

After well over 1 yr, Wood Mackenzie's global composite gross refining margin recovered to exceed the historical 5-yr average in August 2021 (FIG. 1). However, global refinery profitability is not back to pre-pandemic levels, as global crude runs are still depressed and product stocks still high.

There are, of course, differences in this “new normal.” These include:

- The composition of global oil demand has changed, with light distillates (such as naphtha and gasoline) setting global crude runs as petrochemical demand has remained strong and LPG supplies are tight. Aviation demand remains depressed due to ongoing mobility restrictions.
- Crude differentials remain relatively tight, particularly for North America, limiting support to margins. China's high transport fuel exports have limited the recovery of Asian refining margins and kept European utilization low, while U.S. utilization is back to historical norms.

**What is next?** The refining sector has proven its adaptability over many years as it has addressed:

- Significant product quality specification changes, ranging from the elimination of lead in gasoline, sulfur reduction in road and marine fuels, and liquid biofuels blending.
- Structural shifts in product demand, with the rise of Asian demand and middle distillates from European passenger cars, along with the elimination of fuel oil for power generation.
- A rapidly evolving crude slate, as growth in heavy oil was put into reverse by the emergence of U.S. tight oil.

This adaption has often been achieved without due consideration to the overall profitability of the sector. The sector has often suffered from over-investment, followed by prolonged periods of weak financial performance, leading

to capacity rationalization.

The sector will certainly need to be agile to thrive in the energy transition, which is driving the electrification of the vehicle fleet. In Wood Mackenzie's base case outlook, we consider that the global sales of internal combustion engine (ICE) passenger cars have already peaked, with the sales of battery electric and plug-in hybrid vehicles to increase from under 5% in 2020 to over 50% in 2025. Electrification has a profound effect on refined product demand, with gasoline declining faster than middle distillates, as commercial freight and aviation sectors are harder to decarbonize. Meanwhile, increasing global population and urbanization results in sustained petrochemical demand growth, despite rapid

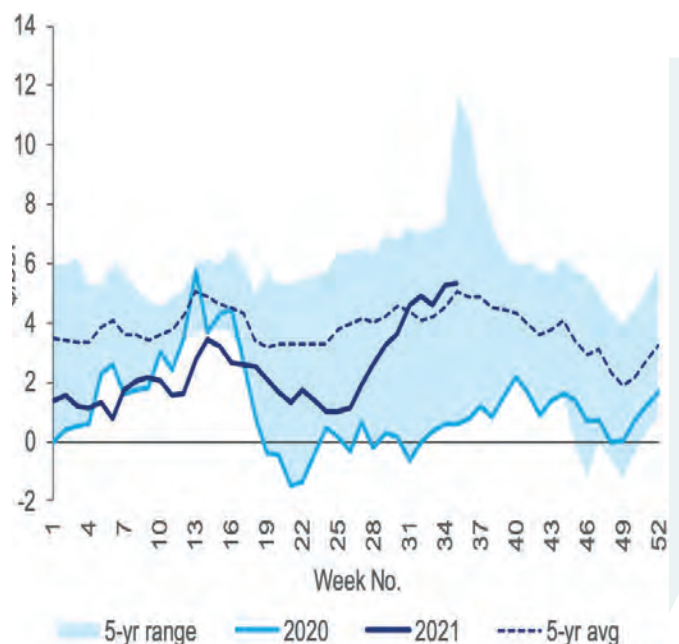


Figure 1. Weekly 5-yr range for gross refining margin.

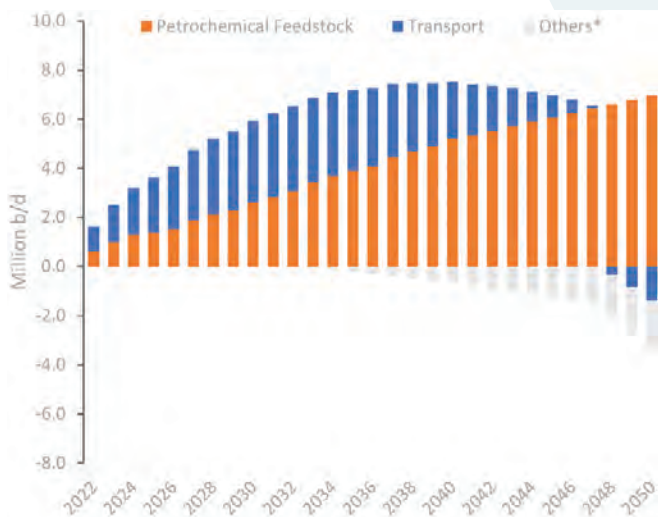


Figure 2. Change in Asian oil demand (MMbpd), 2022–2050.

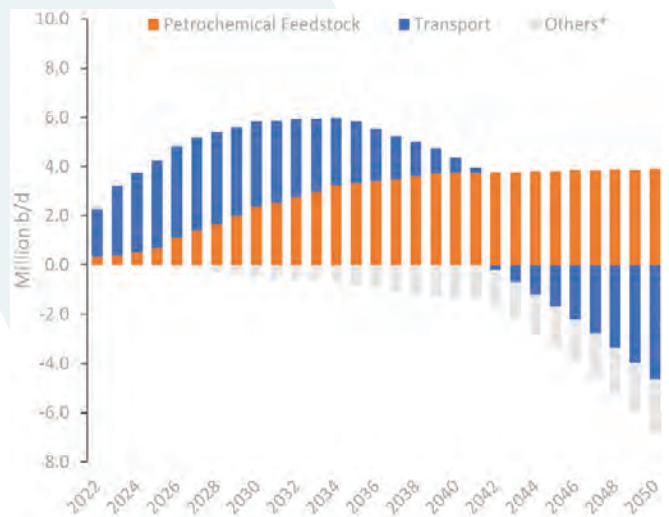


Figure 3. Change in rest of world oil demand (MMbpd), 2022–2050.

growth in the recycling of waste plastics.

The key global themes that the refining industry needs to address are:

1. Refining as a business is challenged by the shift in demand away from refined products. The sector needs to establish where to allocate its future capital and how best to monetize its current capital base.
2. Oil demand is shifting both geographically and in terms of end-use (FIGS. 1 and 2). Integrated refinery-petrochemical sites in Asia and the Middle East are advantaged in capturing East of Suez demand growth as transport fuel demand peaks.
3. Refiners in the Atlantic Basin need to shift their business models, as small petrochemical demand growth is outweighed by a large fall in transport fuel demand:
  - o Refiners in the European Union (EU) could lead the decarbonization of the refining sector, as the EU Emissions Trading Scheme means they incur carbon emissions costs of over USD \$70/t without any protection from a carbon border adjustment mechanism. Despite some free allowances, these costs spur fuel efficiency projects and decarbonization activities, such as carbon capture and storage projects and the adoption of green hydrogen, both of which can provide a platform

to synthetic liquids made from carbon dioxide and hydrogen (i.e., E-fuels). Participation in the circular economy will become critical to retain the social licence to operate.

- o U.S. refiners face a less aggressive fall in demand and have opportunities to reduce the carbon intensity of liquid fuels by supplying renewable diesel and sustainable aviation fuel. As U.S. demand starts to decline, securing a home for U.S. exports in deficit Atlantic Basin markets in Latin America and Africa will sustain strong cash generation from their existing sites.

**Key risks and opportunities.** The key risk to refiners is to do nothing, as this will lead to rationalization as others adapt to the evolving downstream landscape. Cost reduction, asset optimization and site decarbonization are essential to stay in business. Refiners need to utilize their core competencies as a “large-scale chemical conversion” business to become a partner in the circular economy (via biofuels, hydrotreated vegetable oil, recycling of plastic wastes, etc.) and a key future supplier of E-fuels.

Refining is, after all, a conversion business, which needs to pivot away from crude oil/high carbon feedstocks to provide low-carbon energy and feedstocks for the wider economy that aspires to achieve net-zero emissions. ▀

# Innovative recycling, driving circularity while decarbonizing the petrochemical industry

**N. MENET, PLASTIC RECYCLING BUSINESS DEVELOPMENT MANAGER, AXENS**



Plastic pollution's environmental challenges, as well as new government legislation, are having a significant impact on the plastics industry. Polymer manufacturers are being urged to experiment and implement alternative production processes—such as bio-based plastics and recycling—to decarbonize their products.

The complexity associated with the development of alternative production processes is amplified by the fact that they are a variety of polymers, and the formulations generated by adding additives differ depending on how they are used.

Let us first focus on recycling of thermoplastics. Thermoplastic waste can be either mechanically or chemically recycled. At present, chemical recycling only accounts for about 1% of recycled plastics. However, that proportion is expected to rise sharply, especially given that this approach enables the production of polymers that can be reused in a true circular “closed loop,” even for the most demanding applications such as food or pharmaceutical plastic grades.

Chemical recycling opens new opportunities to bridge the gap in the need for additional plastics recycling capacity and the need for high-quality recycled plastics products. For example, chemical recycling addresses more difficult waste plastic feedstock that cannot be valorized through mechanical recycling, while fully meet-

ing quality requirements and regulatory objectives. Chemical recycling particularly addresses the following limitations, preventing routing all plastics waste to a mechanical recycling process:

- Being able to valorize in closed-loop complex mix plastics streams (where sorting and separation stages, as well as the regeneration processes required for recycling are too complex). It also enables valorization of plastics polluted during the various stages of its life, from its manufacture to its arrival at the recycling plant (contamination from the different sorting steps or simply contaminant from contact with other materials during its use)
- Being able to remove all the intentionally added contaminants to permit a true close loop recycling of plastic waste
- Enabling an infinite closed loop recycling of plastics vs. mechanical recycling, where recycling may be limited to a certain number of cycles due to the temperature effects associated with the various stages of the recycling process, ultimately causes degradation of the recycled raw material
- Enabling upcycling (e.g., recycling of waste textile into

food grade packaging such as bottles).

Chemical recycling (also referred to as advanced recycling) encompasses different processing technologies. Depolymerization and conversion processes can be used to modify the chemical structure of the polymer and purify the resulting product to enable production of new raw polymers. Dissolution processes are also being developed to recover additive-free polymer chains. Some argue that dissolution is an extension of mechanical recycling, as the chemical structure of the polymer remains unchanged. However, that process relies heavily on chemical stages and is often grouped in with chemical recycling. Depending on the type of polymer waste, some chemical recycling routes are more appropriate than others. For example, waste polyethylene terephthalate that cannot be mechanically recycled will be recycled through a depolymerization process and is not suitable to conversion or dissolution process.

**Pyrolysis.** The following will focus on the conversion process, especially with a special focus on mixed plastic pyrolysis and its associated purification and decontamination step. This is a key building block to a sustainable polyolefin chemical recycling value chain.

Pyrolysis of mixed plastic waste is considered the novel route to accomplish a true closed loop recycling



process of polyolefins, adhering to quality requirements and regulatory objectives. However, this route relies on the ability to properly purify the pyrolysis oil (pyoil) for reprocessing in an existing petrochemical plant. That purification step is not a trivial refining processing, as pyrolysis oil usually combines multiple contaminants and unstable molecules that if not removed and stabilized would jeopardize the operation of a petrochemical plant's steam cracker.

Repsol, Axens and IFPEN have joined their efforts to unlock the recovery of plastic waste that would otherwise remain in landfills or be incinerated. The consortium has developed and commercialized Rewind™ Mix technology to solve the challenges of purification and decontamination of pyrolysis oils.

The Rewind™ Mix process removes impurities such as silicon, chlorine, diolefins and other metals from the produced plastics pyrolysis oils, allowing the direct and undiluted feed to the steam cracker. Proper purification is key, as not only contaminants could jeopardize operation of petrochemical steam crackers but can also flow to downstream units and ultimately end up in produced polymers products.

The successful commercialization of the purification technology would not have been possible without the development of new analysis methods by IFPEN to properly assess the different qualities of pyoil. Pyoil products concentrate a large proportion of multiple contaminants, making it difficult to analyze through conventional analysis methods.

As pyrolysis oil qualities vary sub-

stantially, the Rewind™ Mix process has a unique flexibility (vs. conventional hydroprocessing refining units) to cope with quality changes and be able to continually guarantee production of on-specification products suitable for direct undiluted processing in a naphtha steam cracker. In addition to the capacity to process the full range of pyrolysis oil to maximize closed loop production of polyolefin circular polymer, Rewind™ Mix can embed a hydrocracking function that will convert heavier product back into virgin-equivalent recycled naphtha.

With Rewind™ Mix, the pyrolysis pathway for plastics recycling can play an important role in mitigating the environmental impact of plastic waste. It also unleashes the full potential of converting any polyolefin plastic waste into food-grade quality. ▀

## ABOUT THE AUTHOR

Nicolas Menet earned an engineering degree from Ecole Des Mines de Nantes in France. He is also a functional safety certified engineer and holds lean and six sigma qualifications. Mr. Menet has 20 yr of experience in the energy sector and has focused on performance improvements in assets through innovative processing technologies and digital solutions. He is currently the Development Manager for two plastics chemical recycling technologies launched by Axens.



# Why EPC firms are accelerating digitalization

**P. DONNELLY, INDUSTRY MARKETING DIRECTOR, ENGINEERING AND CONSTRUCTION,**  
*ASPENTECH*

Even before the challenges of the COVID-19 pandemic emerged, engineering, procurement and construction (EPC) firms were already under considerable stress. Combining low net margins with the burden of carrying much of the project risk was resulting in general underperformance by the sector. When plant owner-operators announced capital spending cuts in the range of 20%–50%, it looked like engineering firms were about to enter another cyclical downturn. Interestingly, the management of these firms did not act as one might have predicted. Instead of immediate deep cuts to personnel, engineering firms looked for alternative ways to pare costs, such as cutting dividends, reducing bonuses and eliminating certain non-employee contractors.

While layoffs have not been completely avoided, these actions have mitigated the deeper reductions in the workforce that were seen in 2014–2015 and have also better positioned these firms to capitalize as a recovery slowly emerges. It is also worthy to note that, in addition to carefully managing cost reductions, certain investments have continued and even accelerated—most notably in digitalization. According to McKinsey & Company's 2020 report *The Next Normal in Construction*, two-thirds of the 400 surveyed EPC executives were accelerating their investments in digitalization. These managers and executives understand

that smart investments in digitalization will help preserve core competencies and personnel, and, over the long term, protect their ability to compete as business conditions improve.

Often, the objectives of digitalization investments include streamlining software and technology portfolios, along with automating the flow of project data. This enhances collaboration internally and externally, while making data available for reuse across disciplines and project phases. In addition, many firms are now seeking to continue leveraging project engineering data to provide value-adding services in operations and maintenance. This can increase customer intimacy, while adding necessary and more stable revenues based on operating budgets. The digitalization of project data is a key enabler of these digital-twin-based services, which will be enhanced through a digital handover.

**Four key challenge areas for EPC firms.** Many EPC firms are well underway on their digital journey, while others are still in the planning phase. Common digital initiatives can be categorized into four key areas. These include:

1. **Data management:** Digital technologies can play a hugely important role in helping EPC firms manage and move massive amounts of data more efficiently. This means a reduced

reliance on physical documents to store and share information and making that information more available for review and use by others, as well as making it faster and easier to hand off to other disciplines, partners, vendors, owner-operators, regulators and other parties in the project ecosystem.

2. **Technology consolidation:** Many EPC firms have dozens (if not hundreds) of unique software solutions in the engineering department. Comprised of Tier 1 providers, niche commercial applications and engineers' homegrown applications, these types of solutions create a bird's nest of technology that prevents any real progress toward digitalization. By standardizing and reducing the overall number of software providers, eliminating redundancies, and using stricter criteria for the support of smaller niche apps, chief information officers (CIOs) and heads of engineering departments can simplify the landscape of the software that they rely on, while creating the conditions required for automating the flow of data.
3. **Apps and data integration:** Once the software portfolio is rationalized and consolidated, the work of integrating

the remaining applications should start. Connecting the remaining apps with the intent of automating flow and reusing data should be the priority.

4. **Expansion of digital-twin-based services:** The engineering data used to design and build the plant can also be used to enhance startup, training and operations, while providing additional and diverse revenues for EPC firms. Examples might include the use of engineering tools to ensure that the models used for running the plant are accurate and up to date; that dynamic models and operator training tools ensure safe, profitable operations; and that predictive maintenance services maximize asset uptime.

Digital twins of the physical asset and its operating conditions are a marriage of the digital representation of the physical plant and the information about the process occurring within that physical equipment.

A digital twin can be viewed in three ways. The first is the plant digital twin, which provides equipment and process models of the plant, along with relevant cost data. These types of digital twins are typically used for plant design, debottlenecking and revamping, as well as for tuning of the asset during operations and maintenance. Plant digital twins can be deployed offline and online and can be calibrated to plant operating conditions through autonomous model tuning. Used for equipment monitoring, operator open-loop advice or autonomous optimization, their scope may range from a single piece of equipment to an entire unit's operations, and to plant-wide or enterprise-wide. They can be simulated dynam-

cally to provide operator training.

The second type is the operational digital twin. This provides plant operations—from a business level all the way to the control level—that are modeled and virtually viewed as planning, scheduling, control and utility models. These twins inform business decisions such as crude selections and products trading. They also inform technical decision making, like optimizing quality, throughput, energy use, emissions compliance and safety.

The third type is the operational-integrity digital twin. This twin provides guidance on both tactical and strategic decisions around prescriptive maintenance, offering real-time recommendations to maximize uptime, adjust production to deal with failing equipment, minimize environmental impacts, mitigate production losses and prioritize safety. EPC firms can also assist the owner-operator in obtaining a future view of equipment and asset health, as well as risk profiles and root causes of failures, to improve overall uptime and operational integrity.

Increasingly, EPC firms are seeking to deliver digital twin-based services to their clients. Creating, delivering and maintaining these three types of twins make good use of engineering talent and resources, while adding considerable value to plant owners.

**Digitalization successes.** While some may be just beginning their digital journey, many firms have already seen notable successes with leveraging this digital engineering data.

Worley's digital platform initiative is designed for speed without compromising the quality of the engineering work. It relies on digital information from concept and front-end engineering design to inform a digital estimating platform that helps clients

reach a final investment decision up to 50% faster. Benefits include expedited evaluation of concepts through process simulation software, automated artificial intelligence-driven 3D plant layout and piping designs, and coordinated estimates tied to the engineering information.

Hargrove Engineers + Constructors provides digital twin-based services that improve plant operations, profitability and reliability. The company provides digital twins that represent a virtualized copy of the historical, current and future behavior of the physical plant asset, so their customers can improve throughput and quality, lower operating costs and increase equipment uptime.

Leveraging digital design and engineering tools, Burns & McDonnell created a digital representation of a conceptual plant design to quickly redesign a column from traditional design specifications to a more efficient divided wall column. The redesign was accomplished in a matter of hours instead of the normal weeks-long effort. This was only possible because the multidisciplinary team could collaborate around digital project information.

**Takeaway.** Prior to 2020, the majority of EPC firms were already embracing initiatives to digitalize areas of their businesses. With uncertain market conditions likely to continue into the foreseeable future, digitalization is accelerating and will fundamentally change the way EPC firms bid and execute project work, hand over projects to customers, and support projects throughout their operating lifespan. Digitalization also enables closer collaboration with owner-operators, which can drive significant new value for the entire ecosystem. 

## ABOUT THE AUTHOR

Paul Donnelly is the Industry Marketing Director for Engineering and Construction at AspenTech. Mr. Donnelly has more than 25 yr of experience in engineering, construction and supply chain management positions with global business responsibilities. He earned an undergraduate degree in geology and has an MBA from the University of Massachusetts.



# Enterprise-wide energy efficiency fleet monitoring tool

**K. TRIVEDI, PROJECT, DEVELOPMENT MANAGER, EXXONMOBIL GLOBAL PROJECTS; S. NEHETE, TECHNOLOGY IMPROVE LEAD, EXXONMOBIL CHEMICAL OPERATIONS PVT. LTD.; AND J. GUNTER, ELEMENT VENTURE LEAD, EXXONMOBIL FUELS & LUBRICANTS CO.**

EXXONMOBIL

In response to challenges related to global warming, climate change and greenhouse gas emissions, numerous countries are adopting regulatory measures requiring industry to further improve energy efficiency. ExxonMobil has a long tradition of effectively improving energy efficiency and mitigating emissions, both for internal operational efficiency and to support external drivers within the industry—such as the API Compendium challenge—as well as managing the risk of climate change through emissions reduction goals for 2025, which are projected to be consistent with the goals of the Paris Agreement. The company continues to invest in lower-emissions technologies, such as carbon capture and advanced biofuels, which are necessary for society to achieve its ambition for net zero emissions by 2050.<sup>1,2</sup>

Energy management improvements over several decades, has enabled ExxonMobil to become the most energy efficient international refining company in the world. The company has achieved a 10% improvement in energy efficiency across its global refining and chemicals operations following an effort launched in 2000<sup>3</sup>, showcasing a robust set of processes to improve energy efficiency and mitigate emissions, including programs focused on reduc-

ing methane emissions, flaring and venting. This rigorous approach is effective to promote efficiencies and reduce greenhouse gas emissions in operations, while striving to achieve industry-leading performance.<sup>4</sup>

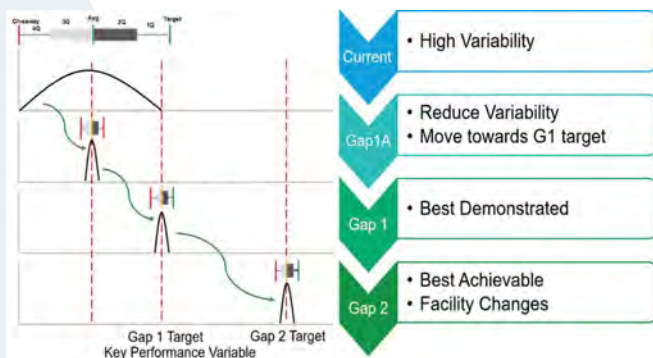
However, with regulations to manage climate change risk emerging around the world, it is becoming increasingly important to develop smart ways to identify further energy efficiency improvement opportunities in existing facilities. Such initiatives support the company's aim for industry-leading greenhouse gas performance across its businesses by 2030.<sup>1</sup>

**Need for enterprise-wide monitoring tools.** For an organization like ExxonMobil, plant performance monitoring activities consume significant resources. For example, the global fleet of fired heaters within ExxonMobil exceeds 700. Adding other equipment that impact the energy footprint to the fleet will result in thousands of pieces of equipment that must be monitored. It is important to deploy smart and efficient digital solutions to minimize resource requirements without affecting the quality of the monitoring.

Fleet performance presented on one visualization platform also acts as a “social proof” and psychologically motivates people to match the best demonstrated behavior. The concept of social proof is widely discussed in psychology. Cialdini<sup>5</sup> coined the term to represent a phenomenon wherein people copy the actions of others to undertake behavior in a given situation.

## TOOL DEVELOPMENT

The entire fleet development work process can be broken down into eight major steps. The entire work process begins with the identification of the critical energy fleet population, followed by the development of a technical functional specification that acts as a backbone for the entire tool development process. This considers defining key energy performance indicators, establishing calculation methodologies, target setting and energy gap calcu-



**Figure 1.** Typical variability of performance parameters and how improvement is made.



Figure 2. Example dashboard.

lations. Once tool mechanics are developed, it is important to arrange the millions of data points generated by the tool into visuals for easier interpretation. The last and most critical step in achieving success is to gain the trust of business partners and embed the tool into normal work processes. This sets up the tool for long-term success. Some of the key steps are discussed in the following sections.

**Identification.** Configuring thousands of pieces of

equipment into the fleet tool is resource intensive. So, for every fleet family, it is important to identify the critical fleet population based on the Pareto Principal.<sup>6</sup>

**Define key performance indicators (KPIs).** This step includes the development of the technical approach defining KPIs, universally consistent estimation methodologies and target setting. It is often important to have a balance between accuracy vs. complexity of the techniques to quantify KPIs. For example, furnace efficiency for gas-fired furnaces can be estimated based on stack conditions, such as oxygen concentration and temperature.<sup>7</sup>

**Target setting.** The historical performance of the fleet in terms of KPI is valuable information in defining targets. Normally, KPI variability follows the normal variation with the fleet being operated at its best performance at least 10% of the time. A typical variability is shown on the upper left hand of FIG. 1. Minimizing the variation is the first step in improving performance, followed by pushing the mean value closer to a constraint. The energy penalty caused due to a large variability is defined as an operational gap (GAP 1A)



# INSIDE INTELLIGENCE

for the Downstream Industry

**Includes:**

- \* Unlimited access to *Hydrocarbon Processing's* online technical archives
- \* Access to the latest version of *Hydrocarbon Processing's*:
  - HPI Market Data book
  - Gas Processes Handbook
  - Petrochemical Processes Handbook
  - Refining Processes Handbook
- \* Print or digital subscription to *Hydrocarbon Processing*

**SUBSCRIBE TODAY**  
[HydrocarbonProcessing.com/Subscribe](http://HydrocarbonProcessing.com/Subscribe)

**HYDROCARBON PROCESSING®**

Published By: *Gulf Energy®*

that can be closed through operational excellence; whereas GAP 1 is the energy penalty due to the difference between the current and the best demonstrated performance. This can be closed via engineering and maintenance excellence. Finally, GAP 2 represents the gap between the best demonstrated and the best-available technology. This gap closure often involves capital investment.

**Data collection.** This is the most challenging aspect of the entire process. A robust tool requires information, including instrumentation tags, equipment design information and piping and instrumentation diagrams (P&IDs). Developing a pictorial list of required instrumentations facilitates the data collection request.

**Data analysis and visualization.** As a part of tool development, it is important to sanitize the process information using data analytics tools. Data sanitization includes, but is not limited to, screening poor measurements, identifying the equipment running status, etc. To turn data points into actionable information, it is important to arrange these millions of data points using an adequate visualization platform. A “visual story” based on plant information can be developed that will support improvement opportunities.

A dashboard displaying information for all sites, such as the one shown in Fig. 2, promotes the social proof principle, initiating dialogue between various sites for expertise and knowledge transfer.

**Applications in ExxonMobil.** The authors’ company widely employs the fleet monitoring tool for a variety of energy fleets, including furnaces, boilers, gas turbines, waste heat recovery steam generators, steam systems and heat exchangers. The prime advantage of such a tool for ExxonMobil is to drive transparency and impel action to steadily improve energy efficiency. For example, with the furnace fleet tool rollout, ExxonMobil has realized improved operational and maintenance discipline at sites by repairs of dampers, seal air leaks and identifying capital projects, such as air-preheat replacement with improved technology. ▀

#### LITERATURE CITED

- 1 ExxonMobil, “ExxonMobil sustainability report,” 2020, online: <https://corporate.exxonmobil.com/-/media/Global/Files/sustainability-report/publication/Sustainability-Report.pdf>.
- 2 ExxonMobil, “ExxonMobil announces emission reduction plans; expects to meet 2020 goals,” 2020, online: [https://corporate.exxonmobil.com/News/Newsroom/News-releases/2020/1214\\_ExxonMobil-announces-2025-emissions-reductions\\_expects-to-meet-2020-plan](https://corporate.exxonmobil.com/News/Newsroom/News-releases/2020/1214_ExxonMobil-announces-2025-emissions-reductions_expects-to-meet-2020-plan)
- 3 ExxonMobil, “ExxonMobil announces greenhouse gas reduction measures,” 2019, online: <https://news.exxonmobil.com/press-release/exxonmobil-announces-greenhouse-gas-reduction-measures;>
- 4 ExxonMobil, “Energy and carbon summary,” 2021, online: <https://corporate.exxonmobil.com/-/media/Global/Files/energy-and-carbon-summary/Energy-and-Carbon-Summary.pdf>.
- 5 Cialdini, R., Influence: How and why people agree to things, Morrow, 1984.
- 6 Kiran, D. R., Total quality management: Key concepts and case studies, Elsevier, 2017.
- 7 Ganapathy, online: <http://vganapathy.tripod.com/efficy.html>

## ABOUT THE AUTHORS



Kirtan Trivedi has more than 35 yr of experience, and worked for Brown & Root Braun and Parsons before joining ExxonMobil 23 yr ago. His expertise is in process integration and energy efficiency, project planning, design and development, process simulation and reliability modeling. He has worked in technologies related to refining, ethylene, upstream gas processing, aromatics, renewable diesel, sustainable aviation fuel and methanol-to-gasoline. He earned a B.E. degree from M. S. University of Baroda, India, an M.Tech degree from the Indian Institute of Technology Bombay, India, and a PhD from the University of Adelaide, Australia, all in chemical engineering. Dr. Trivedi did his post-doctoral research at ETH Zurich, Switzerland, and is a registered Professional Engineer in California. He volunteers in organizing and chairing sessions for the AIChE Spring National Meeting and was the Chairman of Process Integration Research Consortium at the University of Manchester.



Suhas Nehete has 15 yr of industry experience, and worked for Reliance Industries and Shell before joining ExxonMobil 6 yr ago. His expertise is in process intensification, energy optimization and monitoring, energy and CO<sub>2</sub> management, and process automation. He has worked in technologies related to refining, olefins and aromatics. Mr. Nehete earned a B.E. degree in chemical engineering from the Institute of Chemical Technology, Mumbai, India. He is also registered as a Chartered Engineer by IChemE, UK.



John Gunter has worked for ExxonMobil for 31 yr, specializing in advanced process control with recent contributions to the deployment of operator guidance tools, such as abnormal event detection and procedural operations technologies. He has worked in technologies related to fuel and lubricant additives, neo acids, oxygenated fluids, polypropylene, metallocene linear low-density polyethylene films, and refining. He now works in a business planning role where new energy efficiency improvements and emissions mitigation opportunities are evaluated to support the company’s goals. Mr. Gunter earned an MS degree in chemical engineering from the University of Maryland, A. James Clark School of Engineering, where he conducted pioneering research in the application of partial least squares to compositional analysis for biosensors.



# Green, faster, together



**C. DE REGT, SENIOR PRINCIPAL CONSULTANT, SAFETY AND RISK MANAGEMENT, ENERGY SYSTEMS, DNV**

A new forecast of the energy transition has warned that even if all electricity was ‘green’ from this day forward, the world will still fall far short of net-zero emissions stipulated by the COP21 Paris Agreement.

In keeping with the previous Energy Transition Outlooks, DNV has consistently stated that the most likely future for the world’s energy system is one that will result in global warming exceeding 2°C by 2100.

The 2021 report cites the global pandemic as a “lost opportunity” for speeding up the energy transition, as COVID-19 recovery packages have largely focused on protecting rather than transforming existing industries.

In the report, Remi Eriksen, Group President and CEO, DNV, stated, “I am deeply concerned about what it will take for governments to apply the resolution and urgency they have shown in the face of the pandemic to our climate. We must now see the same sense of urgency to avoid a climate catastrophe. It is not the last opportunity we have for transitioning faster to a deeply decarbonized energy system.”

**A future for fossil fuels?** Efforts to decarbonize the oil and gas industry are increasing, as many supermajors strive to achieve their own stringent net-zero targets. However, fossil fuels usage—which have held an 80% market share of the global energy mix for decades—are forecasted to decrease, they will still account for approximately 50% of global energy mix, testament to the apparent inflexibility of fossil energy in an era of carbon purging (FIG. 1).

In 2014, demand for coal peaked at 7.9 Bt. It will be the fastest of the fossil fuels to decline in demand, decreasing 62% by 2050. Though global oil demand may have peaked in 2019, the post-pandemic recovery could witness a new all-time high; forecasted demand between 2019–2025 differs by only 1%. Oil demand then slides slowly downwards to 2030, followed by a steeper average decline of 2.8%/yr to 2050. This decline is much faster than the average growth of 1%/yr seen in the past. The sharpest decrease in oil demand is in the transport sector, halving over the next

30 yr due to electrification of road transport and the rising use of low- and zero-emission fuels in the aviation and maritime industries after 2030. Cutbacks in petrochemicals will begin to nip oil demand after 2035 due to recycling and bio-derived feedstocks. Globally, oil demand will decline by 45% to 2050 vs. 2019 demand, with production concentrated ever more strongly in the Middle East and North Africa.

In contrast, the use of natural gas will increase over the coming decade, then level off for a 15-yr period before subsiding in the 2040s. It will surpass oil as the largest energy source in 2032 and will represent 24% of global energy supply by mid-century.

Natural gas demand changes will differ regionally. These include:

- In Organization for Economic Co-operation and Development (OECD) countries, natural gas consumption will gradually decline
- In Greater China, natural gas demand will peak in the early 2030s
- In the Indian Subcontinent, demand will almost triple by mid-century.

Nearly half the demand for natural gas derives from its final use in buildings, transport and manufacturing. The other half involves transformation into other uses: electricity, petrochemicals and hydrogen production. The LNG share of total gas export will increase throughout the forecast period.

By 2050, only 15% of natural gas will be carbon free, led by regions with higher decarbonization ambitions and higher carbon prices (e.g., Europe, Greater China, North America and OECD Pacific). Decarbonized fossil energy is an important aspect of reaching the goals set out in the Paris Agreement; however, the adoption of carbon capture and storage (CCS) is forecast to be woefully slow, primarily due to cost, with just 3.6% of fossil CO<sub>2</sub> emissions abated in 2050. Hydrogen will grow to supply 3.5% of natural gas demand, with CCS in power and industry and biomethane making up the balance of ‘carbon free’ gas.

**Flattening energy demand.** Energy efficiency is the unsung hero of the energy transition and should be the utmost priority for companies and governments. Many efficiency measures have marginal or even negative costs, but due to split incentives and/or a lack of long-term thinking, industry standards and regulations are needed to ensure implementation.

Energy intensity (unit of energy per dollar of gross domestic product) improvements predicted by the independent energy expert and assurance provider, will average 2.4%/yr over the next 30 yr, against the 1.7%/yr average over the past 20 yr.

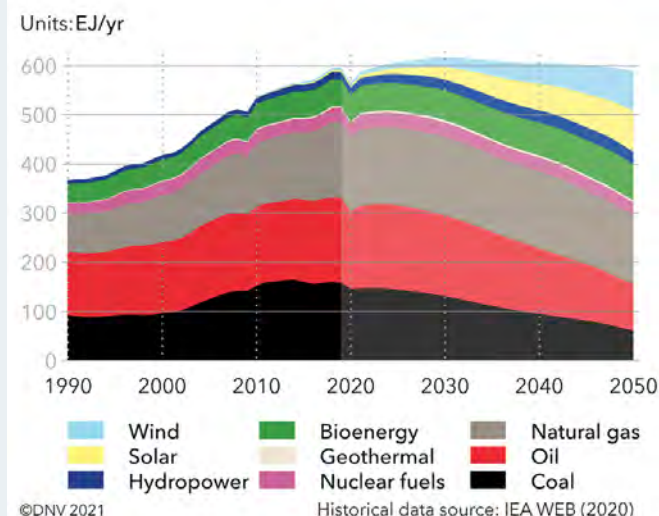
Most of the accelerated efficiencies are linked to electrification, with the remainder coming largely from efficiency improvements in end uses, such as better insulation. The largest efficiency gains happen in the transportation sector, but there are significant gains also in manufacturing and buildings.

Overall, efficiency gains will result in a levelling off in global energy demand despite a population increase of 22% and the global economy growing 111% by 2050. Global energy demand will grow only 8% from 2019–2035, thereafter, remain essentially flat over the following 15 yr.

Securing significant improvement in this vital area is viewed as the most significant lever for the transition—achieving greater efficiency is the reason why global energy demand will level off, even as the global population and economy grows.

**Extraordinary action required.** The COP21 Paris Agreement was intended to keep global warming to below 2°C and strive to limit its increase to 1.5°C.

If we are to reach this target, we need to achieve net-zero emissions by mid-century. While electrification is on



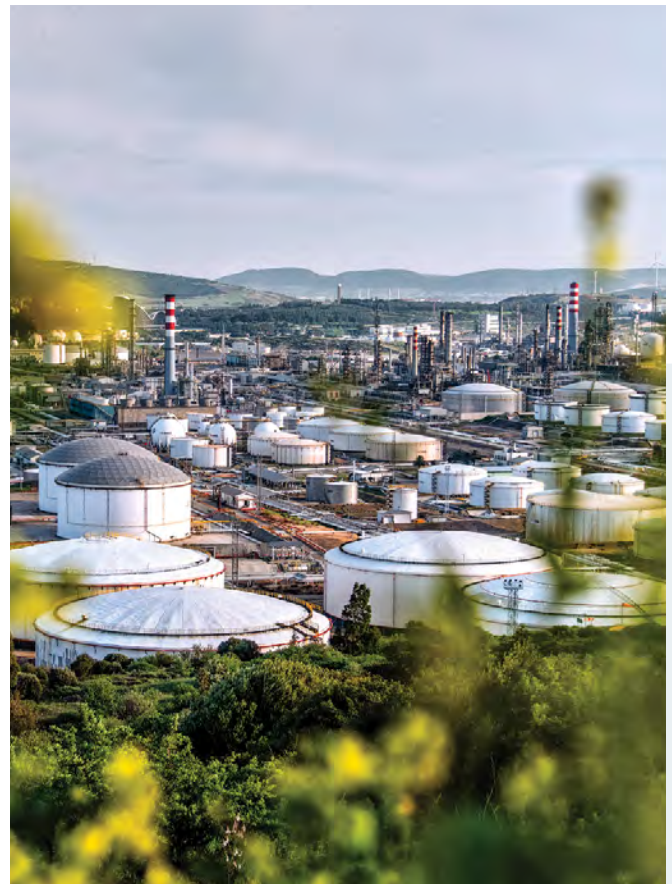
**Figure 1.** World primary energy demand by source. Sources: DNV and the International Energy Agency.

course to double in size within a generation and renewables are already the most competitive source of new power, global emissions will only reduce 9% by 2030. Therefore, the pace of the energy transition has not outstripped DNV's initial forecast dating back four years, where a global temperature increase of 2.3oC is still expected by 2100—a level considered dangerous by the scientific community.

Large-scale action is vital for vastly more green electricity (both direct and indirect), more biofuels and more CCS on a dramatically accelerated timescale. ▀

## ABOUT THE AUTHOR

Cees de Regt is a Senior Principal Consultant, Safety and Risk Management, Energy Systems at DNV. He has 35 yr of consulting and engineering experience in oil and gas, with roots in risk management, reliability engineering and process safety management. His previous roles include Global Director of Technical and Process Safety for Amec FosterWheeler and Vice President of Safety Engineering at Samsung Heavy Industries.



Tüpraş integrates sustainability into all of its processes, from its supply chain to its after-sales operations. Photo courtesy of Tüpraş.

# Decarbonizing Shell Pernis

**A. GOSSE, PRESIDENT**

*SHELL CATALYSTS & TECHNOLOGIES*

Refining has never been easy. However, the sector has a remarkable track record of overcoming challenges. No challenge is bigger than the one we all face today: reducing the carbon footprint of our refineries and the products that we sell to market.

Our organization is supporting the transition to a net-zero energy business by 2050. We also help other companies achieve their own net-zero goals. This support is founded on three complementary mitigation strategies:

1. Maximizing the energy efficiency of facilities
2. Producing lower-carbon and more sustainable energy products

### 3. Carbon capture and storage (CCS)

This article details how Shell is deploying all three strategies to reduce carbon emissions at its Pernis refinery in Rotterdam, the largest such facility in Europe, and to provide lower-carbon products to consumers. The Pernis refinery is set to become Shell Energy and Chemicals Park Rotterdam (FIG. 1) as part of a plan by Shell to convert five refineries into energy and chemicals parks that will increasingly focus on chemicals and lower-carbon energy products such as biofuels and hydrogen.

### Maximizing energy efficiency.

An important part of any net-zero strategy is to maximize the energy

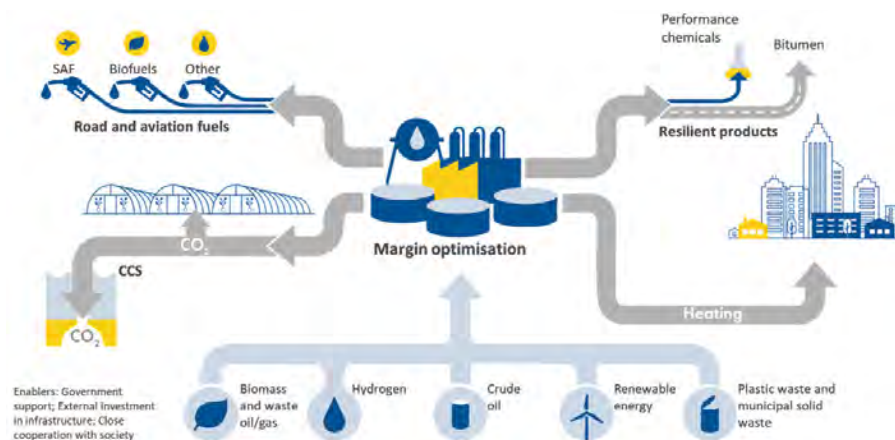
efficiency of existing assets. Across all of Shell's downstream assets, our teams are working purposefully to reduce the carbon intensity of refinery operations. For example, at the Pernis refinery, a recent energy-efficiency program led to a reduction in annual carbon dioxide (CO<sub>2</sub>) emissions equivalent to those from 50,000 cars.

Furthermore, an innovative project at the Pernis refinery has deployed specialized technology to capture and store enough residual heat to warm up 16,000 Rotterdam households.

### Lower-carbon energy products.

Mitigating greenhouse gas (GHG) emissions goes far beyond maximizing the energy efficiency of facilities. Up to 85% of all GHG emissions associated with energy products result from their end uses (e.g., people driving their cars or heating their homes). Therefore, as a sector, we need to provide fuels with as low a carbon footprint as possible.

For Shell, developing lower-carbon fuels is at the heart of our decarbonization strategy. Soon, the Pernis refinery will receive up to 60,000 kg/d of green hydrogen produced at the Rotterdam Clean Energy Hub. The hub—an industry collaboration scheduled for completion in 2023—will produce green hydrogen by electrolysis using renewable energy from the Hollandse Kust Zuid wind farm.



**Figure 1.** Pernis will be transformed into Shell Energy and Chemicals Park Rotterdam.



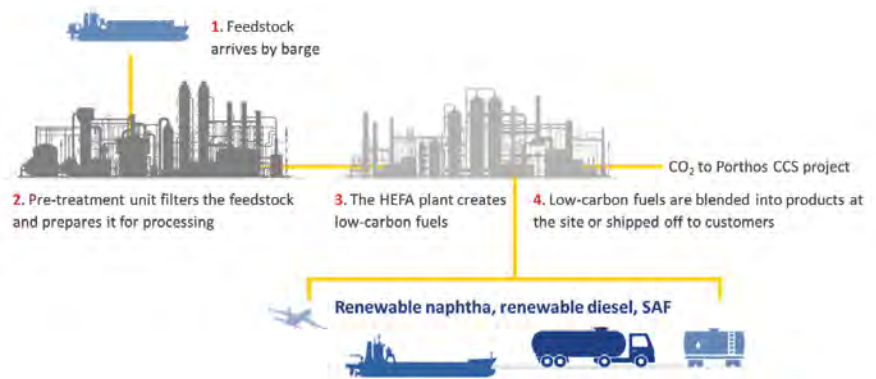
Green hydrogen will serve two purposes. First, the Pernis refinery will use the fuel to lower its facility emissions. Secondly, the hydrogen will be an important driver in encouraging heavy-duty transport customers to invest in hydrogen-fuelled trucks. Therefore, the Rotterdam Clean Energy Hub will play a crucial role in decreasing Pernis' emissions (Scope 1) and reducing its end-use fuel emissions (Scope 3).

Pernis refinery is also pursuing an ambitious biofuels strategy. Shell has recently announced a final investment decision (FID) to build an 820,000-tpy biofuels facility at the site (FIG. 2). To begin operations in 2024, it will be one of the largest biofuels production facilities in Europe.

The facility will use the Shell Renewable Refining process to convert low-carbon oils and fats (e.g., used cooking oil, waste animal fat and other industrial and agricultural residual products) into sustainable aviation fuel and renewable diesel. Shell's new biofuels facility will produce enough renewable diesel to avoid 2.8 MMtpy of CO<sub>2</sub> emissions—equivalent to taking more than 1 MM European cars off the road.

The Shell Renewable Refining Process is a hydroprocessing or hydrotreated vegetable oil technology licensed by Shell Catalysts & Technologies that will enable Pernis and other refineries to process 100% bio-feedstocks.

**CCS.** The Pernis refinery has traditionally routed 40% of the CO<sub>2</sub> produced from its Shell gasification hydrogen unit to local greenhouses, where it is used to accelerate crop growth and



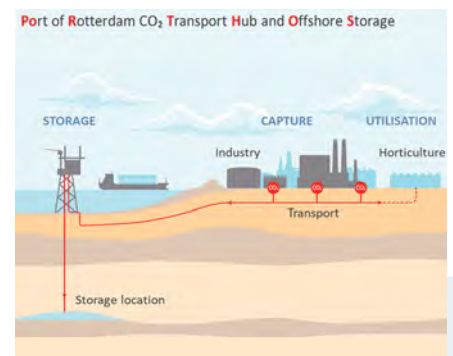
**Figure 2.** Shell's planned biofuel facility will produce low-carbon energy products from 100% bio-feedstocks, using the Shell Renewable Refining process.

reduce the need for horticulturalists to generate their own CO<sub>2</sub>.

The high purity of this CO<sub>2</sub> also makes it ideal for CCS. By the end of 2023, the planned Porthos CCS project will route the remaining CO<sub>2</sub> to the North Sea for storage in depleted gas reservoirs. This project also involves three neighboring plants: the ExxonMobil refinery and the Air Products and Air Liquide hydrogen plants (FIG. 3). The Pernis refinery will use Shell Catalysts & Technologies' solvent technology (ADIP ULTRA) to capture the CO<sub>2</sub> from high-pressure process streams, as is already done at Shell's Quest CCS project in Canada.

A second CCS project, Aramis, a collaboration between Shell, TotalEnergies, Energie Beheer Nederland (EBN) and Gasunie, will provide additional CO<sub>2</sub> transport and storage capacity for local industrial clusters. An FID is expected in 2023, followed by operational start-up in 2026.

**Key learnings.** A key takeaway is that there exist a wide range of decarbonization solutions that can be



**Figure 3.** Capturing and storing emissions with Porthos, the Netherlands' first CCS project.

applied today or in the future. The right solution will depend on the individual scenario but having multiple strategies will provide the necessary options. I think that the Pernis plans demonstrate the power and necessity of collaboration. As an industry, we are all facing the same challenges. Working together to develop solutions will build sectorial resilience and an environment in which we can all prosper in a low-carbon and more sustainable world. ▀

# Illuminating the future of chemical manufacturing

**M. ACHARYA, VICE PRESIDENT, COMMERCIALIZATION, AND M. MARFANI, DIRECTOR OF CORPORATE DEVELOPMENT, SYZYGY PLASMONICS**

Modern society is built on a foundation of petroleum and petrochemical products. It is hard to conceive of a world where these are not used in some form every hour of every day. From transportation fuels to toothbrushes, cell phones to cosmetics, molecules derived from hydrocarbons are ubiquitous and very often invisible to the consumer.

Thermocatalysis—an industrial process that reacts feedstocks under high temperature provided by fossil fuel combustion to produce high-value products—is the foundation upon which these products, and nearly one-third of the global economy, are built.<sup>1</sup>

The dominant paradigm for producing most of these products are high temperature processes that depend on fossil fuel combustion, a reality that stands at odds with the threat of climate change. In its recently released assessment report, the International Panel on Climate Change unequivocally stated that human activity is the primary driver of observed global warming effects over the past 150 yr. Broad alignment by the public and private sectors with this assertion has been the driving force behind decarbonization efforts and various net-zero emissions goals. To date, decarbonization has focused on increasing renewable power capacity and electrification of mobility, with few solutions provided for “hard-to-abate” sectors (i.e., transport, shipping, aviation and heavy industries such as

cement, steel and chemicals) that rely on inexpensive petrochemicals as fuels/feedstocks and contribute nearly 30% of global greenhouse gas (GHG) emissions.<sup>2</sup> In addition to supporting 30% of emissions, 5.8% of global carbon dioxide (CO<sub>2</sub>) emissions are directly attributed to refining and petrochemical processes.<sup>3</sup> Assets with lifetimes measured in decades and reliant on high throughput/utilization to succeed have made it challenging for the industry to keep pace with the power sector.

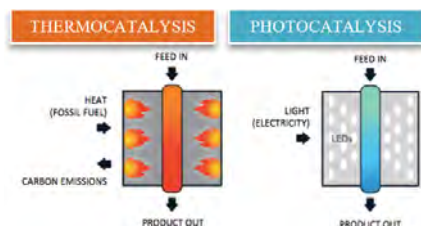
While there is some momentum to decarbonize the feedstocks that form the input for chemical processes (recycled materials and bio-based inputs), replacing the combustion fuels is proving to be more difficult to achieve. Industrial electric heating technology is costly, inefficient and not mature enough to provide sufficient temperatures to power production at scale. Simply put, it is cheaper to combust fossil fuels for heat instead of relying on electricity. To successfully electrify chemical manufacturing, a completely novel solution is required.

Consider a reaction like steam methane reforming (SMR), which is responsible for producing more than 70 MMtpy of hydrogen<sup>4</sup> that is used in refining, steel making, glass making, etc. A typical SMR unit generates 9 kg CO<sub>2</sub>/kg H<sub>2</sub>–11 CO<sub>2</sub>/kg H<sub>2</sub>, of which approximately half of the emissions are the result of the high temperatures (more than 1000°C) needed to

drive the reaction. Most SMR units are extremely large (about 1 MMtpy) and optimized with heat integration. The likelihood of further efficiency improvements in a mature technology are low. Given the importance of hydrogen as an energy vector (the International Energy Agency estimates that approximately six times current hydrogen production is required to achieve net-zero ambitions by 2050<sup>5</sup>), there is an urgent need to find lower emissions alternatives for production.

Electrolysis has emerged as the front-runner in low-carbon hydrogen production. Branded as “green hydrogen,” electrolytic hydrogen can be generated from water and renewable electricity, resulting in zero emissions from the process. However, the energy consumption is steep. The most efficient electrolyzers consume 50 kWh of energy for every kg of hydrogen, and long-term projections have that number decreasing to 40 kWh by 2050. Shifting all hydrogen production over to electrolysis will require exponential growth in renewable electricity, well beyond what is needed for the grid alone.

Houston-based Syzygy Plasmonics is developing an alternate solution centered around cutting-edge photocatalytic technology and proprietary light-driven reactors (FIG. 1). Together, these technologies enable low-cost reactions at a fraction of the temperature and pressure required by traditional thermal catalysis. Milder operating conditions

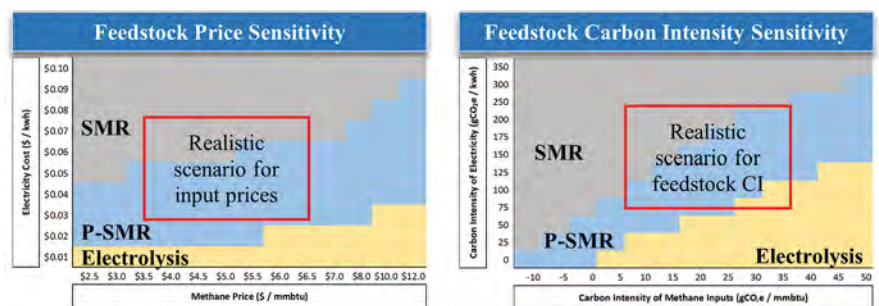


**Figure 1.** Thermocatalysis vs. photocatalysis.

mean reactors no longer must be fabricated from high-cost alloys nor require fossil fuel combustion, reducing both capital and operating costs and emissions. This technology is not limited to one or two production pathways. By adjusting its proprietary catalyst, Syzygy can utilize the same reactor design for many different chemical reactions.

One reaction Syzygy is commercializing is photocatalytic steam methane reforming (P-SMR). P-SMR eliminates emissions from combustion and lowers the electricity required to make 1 kg of hydrogen, resulting in a viable low-carbon and cost-effective alternative. Along with high feedstock conversion and energy efficiencies, the P-SMR reactor also produces an ultra-concentrated stream of CO<sub>2</sub>, allowing for easy capture and utilization.

P-SMR is a low-cost and low-carbon option under most price and feedstock carbon intensity scenarios. FIG. 2 is a sensitivity analysis of the P-SMR process, with process CO<sub>2</sub> emissions captured and reformed into methanol (CO<sub>2</sub>-to-methanol is another reaction



**Figure 2.** Sensitivity analysis of the P-SMR process.

Syzygy is developing under a National Science Foundation grant), SMR with amine-based CO<sub>2</sub> capture and electrolysis where the low-cost/carbon intensity option is identified under a range of feedstock prices and carbon intensity scenarios.

P-SMR is a lower cost choice compared with electrolysis, except when electricity prices are (unrealistically) low and methane prices are high. P-SMR is also less carbon intensive than electrolysis when considering typical well-to-plant emissions for methane and typical values for carbon intensity of electricity production.

This technology can be applied in the same way and achieve similar advantages vs. other foundational chemical reactions, such as ammonia (synthesis and cracking) and methanol. Broad adoption will enable an orderly and smooth energy transition. As the need for immediate action to ward of the worst effects of climate

change grows, novel technologies, such as Syzygy's photocatalytic platform, stand ready to scale and be deployed globally to start reducing emissions and realize the long-term goals of preventing gigatons of CO<sub>2</sub> from entering the atmosphere. ▀

#### LITERATURE CITED

- 1 Armor, J., "What is catalysis or catalysts, so what?" North American Catalysis Society, February 2008, online: <http://nacatsoc.org/above/what-is-catalysis/>
- 2 Strategic Sustainability Consulting, "Getting to net-zero for hard-to-abate sectors," June 2021, online: <http://www.sustainabilityconsulting.com/blog/2021/6/1/getting-to-net-zero-for-hard-to-abate-sectors>
- 3 Ritchie, H., "Sector by sector: Where do global greenhouse gas emissions come from?" Our World in Data, September 2020, online: <https://ourworldindata.org/ghg-emissions-by-sector>
- 4 Chen, L., Z. Qi, S. Zhang, J. Su and GA Somorjai, "Catalytic hydrogen production from methane: A review on recent progress and prospect," Catalysts, August 2020
- 5 International Energy Agency, "Net Zero by 2050," May 2021, online: <https://www.iea.org/reports/net-zero-by-2050>

## ABOUT THE AUTHORS



Madhav Acharya earned his PhD in chemical engineering from the University of Delaware before joining ExxonMobil, where he spent 17 yr in a variety of technical and managerial roles focused on technology development and commercialization, operations support, and research and development strategy. He then joined ARPA-E as a Technology-to-Market Advisor, where he supported the commercialization plans for transformative technologies in carbon neutral fuels, novel cementitious materials and methane conversion. Dr. Acharya has also played a leading role in the first SCALEUP program. He has more than a dozen patents and publications to his name.



Murtuza Marfani has an extensive background in finance and economics, with a passion for identifying and understanding the opportunities for novel technologies participating in the energy transition. He earned a Bch degree in economics and an MBA from Rice University. Prior to joining Syzygy Plasmonics, Mr. Marfani worked at Goldman Sachs' Oil and Gas advisory group, where he advised global energy companies on capital markets and M&A execution, strategic finance and options for participation in the energy transition.







# Natural Gas/LNG

**MICHAEL REED, EDITOR-IN-CHIEF**

*PIPELINE & GAS JOURNAL*

---

As the industry faces the two-pronged challenge of meeting the energy needs of the world's growing population and reducing greenhouse gas emissions in order to improve our quality of life, it would be short-sighted of us to overlook the continuing major contributions of natural gas on both of these fronts.


As the cleanest-burning fossil fuel, natural gas has many advantages, not the least of which are that it can be stored seasonally and that gas-generation plants have the ability to start up quickly, making them invaluable backups whenever energy demand spikes or renewables slump.

Beyond that, the ongoing availability of natural gas remains undeniably linked to economic growth, both among residential and agricultural properties. Put simply, many people prefer the low cost and comparative cleanliness of natural gas.

With global gas prices at extreme levels due to low inventories and strong demand in Europe and China, the sector appears headed for a reasonably strong period over the next few years. For much of this year, spot LNG cargos have been going to Asia rather than Europe due to more attractive prices.

OPEC recently projected natural gas demand will increase from 64.2 MMboe/d in 2020 to 85.7 MMboe/d in 2045, with almost 95% of this growth expected in developing countries, driven by the power generation and industrial sectors.

In the United States, the Energy Information Administration (EIA) recently presented data that supported expansion efforts when it bumped up its forecasts for the remainder of 2021.

With that in mind it is important to remember that when creating and adapting energy system solutions, it is best to be flexible and keep in mind that no one approach will work in every situation nor in every corner of the world. To that end, however, natural gas and LNG will certainly remain part of that solution for years to come. 

# CONTENTS

- 81 Introduction**  
Michael Reed, Editor-in-Chief, *Pipeline & Gas Journal*
- 83 Gas as a transition and destination fuel: reducing emissions, not fuel sources**  
Lorenzo Simonelli, Chairman and CEO, Baker Hughes
- 85 Natural gas in the energy transition**  
Mike Fulwood, Senior Research Fellow, Oxford Institute for Energy Studies and Fellow, Center on Global Energy Policy
- 87 The gas future—more challenged than we think: Natural gas: Navigating to a lower-carbon future**  
Kate Hardin, Bernadette Cullinane and Aijaz Hussain, Deloitte
- 89 Natural gas: Navigating to a lower-carbon future**  
Alessandro Agosta, Dumitru Dediu, and Marijn van Diessen, McKinsey & Company
- 91 Rebalancing the LNG Market**  
Fauziah Marzuki, Head of Global LNG & APAC Gas BloombergNEF
- 94 Innovation in floating LNG—liquefaction: Innovation in second-generation floating LNG**  
Young-gyu Kang, Executive Vice President of Offshore Project Development and Execution, Samsung Heavy Industries
- 96 China's natural gas market offers resilience**  
Dr. Qing Wu, Chief, Engineer, China National Offshore Oil Corp., (CNOOC)
- 98 European gas in a more import-dependent future**  
GPA Europe Management Committee, GPA Association Europe
- 100 Driving the just transition: The role of gas in Tanzania's green transformation**  
Katharine Roe, CEO, Wentworth Resources
- 102 Henry Hub and changes in the global gas markets**  
Ajey Chandra, Ken Chow and Jeremy Goh, Muse, Stancil & Co.
- 106 Freeport LNG: Serving the world's current and future LNG demand**  
Michael Smith, Chairman and CEO, Freeport LNG
- 108 LNG Canada to usher in new era for Canadian gas**  
Peter Zebedee, CEO, LNG Canada
- 110 Great exaggerations—The demise of U.S. LNG**  
John Baguley, Chief Operating Officer, Magnolia LNG LLC



# Gas as a transition and destination fuel: reducing emissions, not fuel sources

**LORENZO SIMONELLI, CHAIRMAN AND CEO,**  
*BAKER HUGHES*



As the CEO of global energy technology Baker Hughes, I am often asked about my outlook on hydrocarbons and natural gas. Are hydrocarbons here to stay? Do I see hydrocarbons playing a role in the energy mix in 2050? How are hydrocarbons compatible with net-zero goals? Is natural gas a destination fuel?

My answers: Yes, hydrocarbons are a key part of our future. Yes, they are compatible with net-zero goals. Yes, natural gas (and, within it, LNG) is a transition and destination fuel.

How can we achieve net-zero whilst still utilizing hydrocarbons, and why is gas such a key part of our future?

## THE NEED FOR HYDROCARBONS

At Baker Hughes, we believe that the world is facing a dual energy challenge; not only do we need to increase access to energy, but we also need to decrease emissions from energy.

Energy is an enabler of societal progress. Whether it is medical innovations that need to be powered, or someone using online payments for their new business via their smart phone, or someone taking a plane to see their family; energy is in high demand.

As we switch the heating on in our homes or walk around a well-lit conference hall at the World Petroleum Congress, it is easy to take energy for granted. However, there are al-

most one billion people in the world with no access to electricity. Everyone deserves the opportunities that a consistent and reliable energy source provides to them.

Hydrocarbons are vital to deliver energy security and reliability for many parts of the world. We know that renewables are also important and will continue increase. We should embrace wind, solar, hydropower, geothermal and biomass.

Companies including Baker Hughes are supporting the growth of renewables, too, by developing technology solutions and innovations across the renewables supply chain. However, a balanced and diverse energy mix is essential to overcoming the dual energy challenge. We support pairing renewables with natural gas as a baseload fuel source to provide grid stability while lowering the overall carbon footprint versus baseload coal in use today.

I know that there are many who push back on this argument. They might argue that renewables are the only solution to achieving net-zero and limiting global warming. I respectfully disagree.

The primary challenge with hydrocarbons is not the fuel source; it is the associated emissions. We need to re-frame the discussion around solving for climate change when we talk about achieving net-zero. The discussion should not be 'how do we replace

one energy source with another?'

Instead, the discussion should be 'how do we make all our energy sources, including hydrocarbons, compatible with net-zero?' If a certain fuel can be used to generate electricity with no emissions we should consider it as a key driver of a net-zero future, whether it comes from renewables or hydrocarbons.

Utilizing hydrocarbons in a responsible manner will enable us to overcome the dual energy challenge: to ensure greater access to energy, including for developing countries, whilst also reaching net-zero targets.

## GAS IS CRITICAL

We see natural gas, and LNG, as key to supporting a shift away from coal over the next 10-15 years. Natural gas will continue to grow as a transition and destination fuel, especially as we aim to move further from coal in places like India and Southeast Asia.

Coal makes up around 30% of the global energy mix today. If we were to try to completely replace coal with renewables and other non-fossil fuels, even at high adoption rates, it would most likely not be feasible.

LNG's primary use is as a replacement for coal in power generation and industrial segments. It represents a significantly lower carbon alternative than coal in these applications with up to a 50% reduction in CO<sub>2</sub> emissions in some cases.

Even so, we must continue to improve the carbon footprint of natural gas and LNG. Technology is key to this – in particular, technologies which increase efficiencies, reduce emissions, and leverage CCUS and hydrogen solutions.

### 1) Efficiency

Energy efficient solutions are critical to reducing emissions, and, according to the IEA, represent more than 40% of the total emissions reductions needed to meet Paris Climate Agreement goals of net-zero carbon emissions by 2050.

Baker Hughes has developed higher efficiency turbomachinery to support in the decarbonization on LNG. Our LM9000 aeroderivative turbine was recently validated as the world's most efficient simple cycle gas turbine in its class after its First Engine to Test (FETT) for Novatek' Arctic LNG 2 project. We have also paired our LNG technology with leading execution, testing, sensing and monitoring capabilities to increase project efficiency and productivity while reducing risks, total costs and carbon footprint.

### 2) Emissions management and reduction

If today's oil and gas operations were 10% more efficient, we would save c.500,000 tons of CO<sub>2</sub> per year. That represents a contribution of 5% per year of the emissions reduction target of the Paris Agreement climate goals.

Luckily, there are mature and effective technologies available today to support our customers to reduce their emissions.

We have technology to detect, monitor and reduce emissions, including utilizing associated gas otherwise flared as a fuel source; detecting and repairing leaks; improving flare combustion efficiency; and upgrading equipment to reduce venting during ordinary operations.

Flare.IQ, our flare monitoring and management technology, can have

a huge impact on downstream and upstream operations. If deployed on every downstream flare globally, flare.IQ could save more than 80 million tons of CO<sub>2</sub> equivalent emissions. This is a similar impact to taking 18 million cars off the road. By using flare.IQ and its advanced analytics platform, downstream operators can ensure 98%+ high-efficiency flare combustion (versus typical operation of 85% flare combustion efficiency for downstream facilities).

Hydrogen is also a huge opportunity for reducing emissions in natural gas. One of the benefits of hydrogen as a fuel source is that it emits near-zero greenhouse gas emissions. We can integrate hydrogen blends into existing natural gas pipelines to reduce the emissions intensity.

With our gas turbine technology, we have significant experience in burning a variety of fuel mixtures, with hydrogen content from 5% up to 100%. We have also extended the capabilities of our new NovaLT gas turbine generator technology to start and operate on 100% hydrogen fuel. Hydrogen fueled turbines can be a key enabler of zero carbon energy systems and the opportunity to use hydrogen as a zero-emissions fuel source has significant growth potential. It is no, surprise, then, that we view hydrogen as a fuel of the future, with a potential addressable market of up to \$30 billion by 2030.

### 3) Carbon Capture Utilization and Storage (CCUS)

CCUS is critical to reducing emissions from the oil and gas sector and meeting the Paris Climate Agreement goals, and to decarbonizing LNG. In the past, many critics discussed solar and wind power with the same skepticism that they now speak about CCUS. The reality is that today if you look at the maturity of wind and solar over the past 2+ decades, the costs have been reduced dramatically, and CCUS could follow a similar path at scale.


Baker Hughes has been involved in CCUS projects for more than a decade. Our product development focus is on improving the economic viability of CCUS projects at scale and applying our core technologies across industrial sectors.

CCUS technology can be applied to reduce emissions from natural gas. In pre-combustion, CCUS could be deployed when producing hydrogen by reforming natural gas and storing the CO<sub>2</sub>. In post-combustion, CCUS could be deployed by capturing and storing the CO<sub>2</sub> emitted by gas processing or power plants.

Baker Hughes recently announced several additions to our carbon capture portfolio to enhance our ability to support customers in advancing industrial decarbonization. For example, we have acquired Compact Carbon Capture with carbon capture tech that has a 75% smaller footprint and lower capital expenditures than traditional solvent-based solutions. We have also taken a financial stake in Electrochaea's bio-methanation process for carbon utilization in synthetic natural gas (SNG) production.

Overall, gas presents a huge opportunity for the energy transition; it is truly a transition and destination fuel. Each region will have its own roadmap, yet natural gas and LNG are key to shifting away from coal on a global level and accelerating towards net zero.

At Baker Hughes, our purpose is to take energy forward – making it safer, cleaner, and more efficient for people and the planet. We see natural gas as a key enabler of the future of energy, and a key enabler to more sustainable planet.

If we accept that fuels are not the problem, emissions are, and if we accept that technologies exist today to increase efficiencies, reduce emissions and capture carbon, we can see the clear path forward for gas. Natural gas can, and should be, part of a world dedicated to safer, cleaner, and more efficient energy. 

# Natural gas in the energy transition

**MIKE FULWOOD, SENIOR RESEARCH FELLOW,**  
*OXFORD INSTITUTE FOR ENERGY STUDIES*  
**AND FELLOW, CENTER ON GLOBAL ENERGY POLICY**



The International Energy Agency (IEA) published a pathway to net zero (NZE) earlier this year. A statement in the report—that there is no need for investment in new fossil fuel supply—generated many headlines. The conclusion on fossil fuel investment was logical and consistent in that peak oil and coal demand have already been reached. Peak natural gas demand is expected in the mid-2020s at some 4,300 Bcm, declining to around 3,700 Bcm in 2030 and continuing to fall thereafter. To reach the 4,300-Bcm peak, there are already enough LNG projects and pipelines coming on-stream in the next few years.

Yet, the IEA pathway is only one of many pathways to limit the global temperature rise to 1.5°C. The Intergovernmental Panel on Climate Change (IPCC) in 2018 gathered together information on over 400 scenarios considering climate change. Some 85 or so of these scenarios were consistent with 1.5°C global warming. The implications of these 85 scenarios for global gas demand are shown in the chart below in addition to two Oxford Institute for Energy Studies (OIES) scenarios, as well as the IEA's NZE pathway.

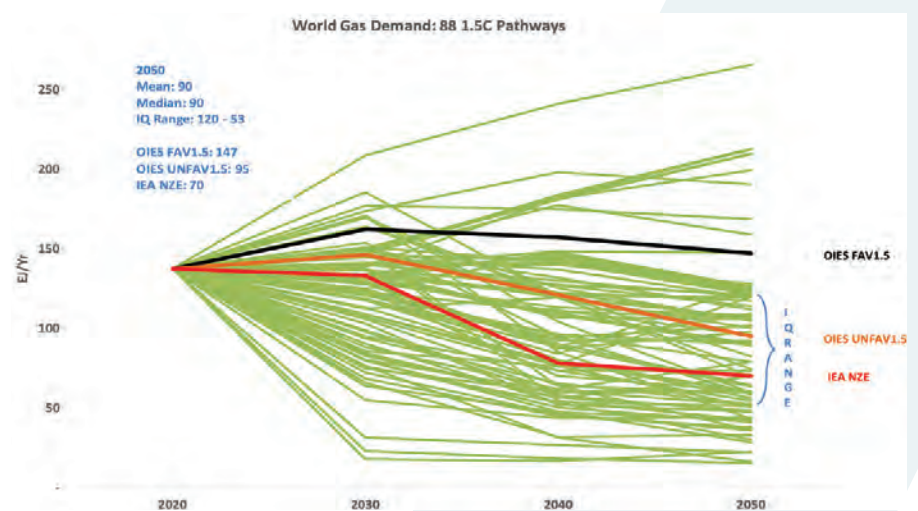
This illustrates the wide range of uncertainty about the role of natural gas in the energy transition. The OIES has developed alternative scenarios, FAV1.5 and UNFAV1.5, with a wide range of global gas demand by 2050, with some 4,200 Bcm in FAV1.5 and

2,550 Bcm in UNFAV1.5. In the OIES scenario that sees a greater role for gas in the transition (FAV1.5), natural gas gains significantly relative to coal and oil, especially in the 2020s, given the slower pace of rollout of renewables, than in the IEA's NZE.

FAV1.5 is significantly higher than the IEA's NZE, which is below 2,000 Bcm. On closer inspection, the main differences lie in nuclear, hydro-power, bioenergy, geothermal and marine relative to gas, rather than in differences in solar and wind development. The UNFAV1.5 scenario, meanwhile, incorporates a much slower switch from coal and a more rapid rollout of renewables.

Gas demand declines the most in

North America and Europe in both OIES scenarios, but also falls sharply in the Middle East in UNFAV1.5 as renewables grow more rapidly than in FAV1.5, where abated gas is much stronger. In Asian markets, however, gas demand generally continues to grow, reflecting the need to switch from coal to gas, mainly in power but also in industry and, in China, in buildings, as well. The growth in Asian gas demand is particularly evident in the period to 2030, even in Japan, South Korea and Taiwan, with an accelerated move away from coal to reduce emissions. The most rapid growth, however, is in India, given the switch-out of coal to other fuels. However, as in other Asian countries, there is a need



**Figure 1.** IPCC gas demand scenarios.



for significant infrastructure buildout, which may be challenging.

The growth in Asian demand has significant implications for gas trade and LNG trade, in particular. In FAV1.5, LNG exports in the 2020s will need to rise substantially, requiring significant additional final investment decisions (FIDs) on top of those already taken, along with a rapid infrastructure build-out. However, in UNFAV1.5, the prospects in the 2030s and beyond look less rosy. By 2050, LNG trade is well under half the level in FAV1.5 at around 350 Bcm—lower than the current level of trade. Such a scenario would raise concerns over the prospect of stranded assets, the potential for early contract termination from the buyer side and a

free-for-all in a plummeting market.

For natural gas to remain relevant under any energy transition scenario that meets either the Paris agreement and/or net zero by 2050, significant abatement is required. In both OIES scenarios, around 60% of natural gas is abated by 2050, whether through direct abatement at the burner tip, conversion into blue hydrogen or via biomethane. In the IEA NZE scenario, where gas demand and trade are much lower, the level of abatement is 75%. Any abatement of natural gas will need the development of carbon capture and storage (CCS) on a large scale. Although there do not appear to be any technical obstacles to the rollout of CCS on an extensive scale

worldwide, costs and, in some regions, policies could prohibit the on-shore construction of CCS facilities.

Just as the IEA NZE scenario depicted a pathway to limiting temperature increases in line with COP21, the OIES has painted two different possible pathways for an energy transition that could achieve the Paris COP21 emissions targets, while involving gas to a much greater degree, especially in FAV1.5. We do not suggest that this is *the* answer, but it does offer an alternative view of the future that may be considered more achievable given the existing infrastructure and the important role that gas can play in many regions as an agent of decarbonization. ▀

## ABOUT THE AUTHOR

Mike Fulwood is a Senior Research Fellow at the Oxford Institute for Energy Studies and a Fellow at the Center on Global Energy Policy, focusing on global gas modeling and LNG markets. He has over 40 years of experience in the gas industry. Mr. Fulwood worked as a Consultant with Energy Markets between 1997 and 2008, and then with Nexant as Director, Global Gas & LNG, until August 2017. Before working as a consultant, he worked for British Gas from 1979, latterly as a Director at British Gas Transco, in charge of price control review. Prior to that, Mr. Fulwood served as President of British Gas Americas, during which time he oversaw many successful acquisitions and projects including the acquisitions of Metrogas (Argentina), NGC (now Dynegy), the Bolivia–Brazil pipeline and the Trinidad LNG project. While working as a consultant, Mr. Fulwood undertook a wide range of projects in all areas of the gas chain, covering regulatory matters, gas pricing and tariffs, gas sales and transportation contracts, market studies and price forecasting, as well as helping develop NexantECA's World Gas Model. He is a past Chairman of the International Gas Union's Gas Pricing Group, which undertakes the Wholesale Gas Price Survey. He also speaks widely at gas conferences around the world, particularly on gas markets, gas trading matters and gas pricing.



Image: Wojciech Wrzesien / Shutterstock.com.

## THE GAS FUTURE—MORE CHALLENGED THAN WE THINK

# Natural gas: Navigating to a lower-carbon future

KATE HARDIN, BERNADETTE CULLINANE AND AIJAZ HUSSAIN,  
DELOITTE

Over the past decade, natural gas has accounted for nearly one-third of global energy demand growth, making it the fastest-growing hydrocarbon fuel. The energy transition will likely continue to reshape natural gas demand, particularly as net-zero target dates draw near and policy attention and investment capital focus on the low carbon future. For example, renewables are expected to account for 95% of the net increase in global power capacity between now and 2025, potentially slowing power sector demand growth for natural gas in some regions. As electric vehicle sales share increases, doubling to 10% in Europe in 2020, followed by China at 5.7%, demand for natural gas in transportation will likely decline. And the chemical industry, among others, is expected to continue to experiment with alternative feedstocks and alternative fuels (such as low- or no-carbon hydrogen).

How might these trends shape natural gas demand? The answer may lie in the ability of natural gas to become a lower-carbon alternative while remaining cost-competitive with alternative fuels. This is likely a patchwork picture, regionally differentiated and characterized by disparate policy and regulatory approaches. For example, although emissions trading mechanisms are in effect in various countries, no single comprehensive system yet exists to create a

common value for avoided emissions. In addition, increasingly frequent severe weather events can continue to create market volatility. In Q1 2020, before the pandemic lockdowns, unusually mild weather in Europe, North America and Asia led to a 2.6% overall decline in gas demand year on year. But in 2021, cold weather in Northern Asia created LNG price spikes. Five months later, due to extreme heat and drought, the Henry Hub spot price averaged its highest level during any summer month since 2014.

Amid these uncertainties, the following factors may help natural gas remain a critical part of the energy mix for the longer term:

- **Coal-to-gas switching in the power sector:** In the U.S. alone, carbon emissions fell nearly 3% in 2019, due largely to the replacement of coal plants with gas. In China, as well, coal to gas switching has been underway, with natural gas generation increasing by 2% in 2020 at the expense of coal. The next phase of decarbonization will include switching from gas to renewables, as the levelized cost of energy (LCOE) of renewable generation is, in some cases, already less than that of new gas peaking plants.
- **Leveraging existing infrastructure:** There is a growing focus on using the

existing natural gas pipeline infrastructure to transport a natural gas/hydrogen blend. The acceptable blend depends on at least two factors: the age and condition of the current pipeline network; and the ability of end-use equipment to accept a blended stream, usually up to 15% hydrogen. Projects in Europe are already leveraging the existing infrastructure for a lower-carbon blend.

- **Carbon capture:** Carbon-capture technologies could be a partial solution as industrial users abate emissions even before retrofitting facilities for lower-carbon feedstocks and fuels. Moreover, carbon capture as part of blue hydrogen production from steam methane reforming could also maintain industrial natural gas demand. The costs of carbon-capture technologies are still high, and concerns about storage persist. However, projects like the Porthos project in the Netherlands may help make CCS more viable and economically competitive. Also, Qatar is expanding its LNG production with the North Field East project and is continuing its focus on decarbonizing LNG through the increased use of CCS.

For natural gas to contribute fully to the energy transition, two conditions should be met. First, producers should continue to decarbonize by further reducing flaring and curtailing operational carbon emissions.

Second, natural gas should remain cost-competitive with alternative fuels. Currently, green hydrogen can be more than five times as costly to produce as natural gas, and the important calculus is the point where those

cost curves cross when emissions abatement is priced in. If natural gas can become greener and remain cost-competitive, then the gas industry could continue to be a critical partner in the energy transition. ▀

### ABOUT THE AUTHORS



As executive director for the Deloitte Research Center for Energy & Industrials, Deloitte Services LP, Kate Hardin works closely with Deloitte's Energy, Resources & Industrials (ER&I) leadership to drive energy research initiatives. In tandem with Deloitte's ER&I partners, Kate manages the execution of the Center's strategy, as well as eminence and thought leadership. During her more than 20-year career as an energy and mobility leader, Kate has occupied senior roles in energy research and consulting/advisory firms. She has led global research teams based in North America, Europe, and Asia, and she has worked with energy and automotive companies, institutional investors and startups. She is also a member of the Council on Foreign Relations.



Bernadette Cullinane is the Deloitte Australia Oil, Gas & Chemicals Leader and Global LNG Leader. She has worked with companies in the upstream, downstream, midstream, LNG and trading segments, conventional and unconventional resources and across the end-to-end project-to-operations lifecycle. Bernadette supports Australian and international companies to improve business performance, implement growth strategies, and transition to a decarbonizing economy where LNG and electricity play increasing roles. Bernadette is an active speaker in oil and gas industry conferences and frequently writes about the competitiveness of the Australian oil and gas/LNG industry.



Aijaz Hussain is a research and insights leader at Deloitte U.S. serving the manufacturing and energy industries. He leads the chemicals and specialty materials, aerospace and defense, and engineering and construction research for the firm. He has over 20 years of experience in research, thoughtware development and business strategy. Aijaz has authored numerous compelling, high-impact thought leadership studies in the areas of business strategy, advanced technologies, digital transformation, innovation, sustainability, the future of mobility and the future of work.



Image: muratart / Shutterstock.com.



# Natural gas: Navigating to a lower-carbon future

ALESSANDRO AGOSTA, DUMITRU DEDIU, AND MARIJN VAN DIESEN,  
MCKINSEY & COMPANY

Over the past decade, several traditional producers of LNG have started to transform their portfolios. In doing so, they are becoming bigger, more diversified and more dependent on third-party volumes. They are also developing greater flexibility and are investing in building stronger commercial capabilities, such as origination, trading, optimization and marketing. Many aspire to capture incremental margins from global arbitrage opportunities and better manage the risks of market disruptions.

The first three quarters of 2020 were a perfect storm of market disruption, with both supply overcapacity and COVID-related reduced demand. To compare the performance over this period of traditional integrated producers, such as marketers, with portfolio optimizers, McKinsey & Company conducted two analyses—a financial reporting analysis and a bottom-up, outside-in modeling exercise to compare the performance of traditional integrated producers with portfolio optimizers (those that focus on optimizing flows across the overall asset portfolio, including managing both equity production and third-party volumes

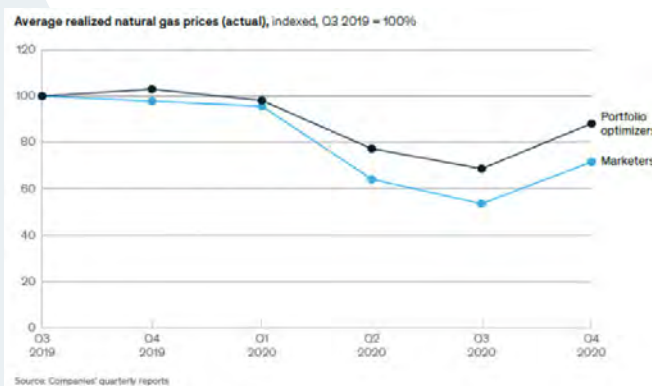
through advanced trading). We looked specifically at LNG producers, but believe the results are relevant across the LNG value chain. The findings were unambiguous: Portfolio optimizers generally outperformed those with traditional business models.

For example, in the third quarter of 2020, traditional marketers saw a 47% decline in realized prices compared with the same period in 2019; for optimizers, the figure was 31%. Earnings fell for both, but the optimizers suffered less and recovered faster.

To better understand how significantly operating models affect earnings before interest, taxes, depreciation and amortization (EBITDA), we modeled the performance of two LNG players with the same assets but different operating models. We used actual prices between Q3 2019 and Q3 2020, taking into account a time lag on long-term contracts. Player A is an illustrative example of a marketer with a liquefaction portfolio that sells the volumes from each liquefaction position through a flexible, long-term contract that goes directly to a fixed set of buyers. Player B is a real-life portfolio optimizer with the same liquefaction assets, but with an additional portfolio of mostly free-on-board, third-party offtake contracts and access to global LNG spot markets.

Both players took an earnings hit—especially on upstream margins, due to absolute-price decreases and on portfolio value—because of different prices narrowing. However, because the value of Player B's short-term optimization activities increased, its overall decline in EBITDA was less (54%) compared with Player A (61%).

Company A's optimization activities included practicing price and time arbitrage across regional gas markets; revising strategies for where to reposition ships after spot commitments were met; and extracting value from medium-term commitment options by, for instance, offering call options (for 2–5 years) on cargoes going to clients that paid a premium. All of these capabilities bolstered its resiliency and resulted in better performance.



**Figure 1.** Portfolio optimizers have seen a slower decline in realized prices and volumes compared with marketers since third quarter 2019.

That is the case for portfolio optimization. But how can it be done? Traditional LNG players who want to go in this direction should focus their efforts in four areas.

First, understand the strengths and weaknesses of your portfolio. This is the essential starting point, and it requires evaluating scale, risk and composition. For smaller operators—less than 5 million tons per year—optimization may be too expensive and complicated to pursue. In terms of risk, LNG players need a clear understanding of what can happen to the profitability of their portfolios in different market scenarios. Depending on their composition, portfolios will have different risk profiles. Having the right combination of assets, such as equity and third-party offtake volumes, access to spot LNG markets, regasification capacity and hub access, and positions in multiple basins, can reduce those risks.

Second, explore how to expand and strengthen the portfolio. With a better understanding of the portfolio in hand, the next step is to fill gaps. One way to do this is through mergers and acquisitions, such as Pavilion’s purchase of Iberdrola’s LNG assets in 2019; this enabled the Singapore company to expand into Europe and the Atlantic basin. Another option is third-party offtake agreements, such as European producers booking regasification capacity or U.S. independents providing flexible volumes at a Henry Hub price indexation. Finally, there is alliance-building and joint ventures, which can provide many of the same benefits without the need to invest large amounts of capital in resources or midstream assets. Examples include the partnerships between Commonwealth LNG and Gunvor in the U.S. or ENH and Vitol in Mozambique.

Third, develop optimization and risk-management capabilities. Having the right assets will not translate into performance without the right talent and technologies ready to go. Traditional companies will need to cultivate advanced trading, optimization and risk-management capabilities if they are to successfully change their business model. Advanced analytics, including the use of machine learning, satellite imaging and vessel tracking, are critical to making the right decisions, day in and day out. For example, these tools can help make the best scheduling and dispatching decisions to capture time-arbitrage opportunities or redirect cargoes to monetize geographic-arbitrage opportunities.

Fourth, manage your greenhouse gas (GHG) emissions footprint. In a world where emissions are increasingly regulated, the GHG profile of different assets could become an important commercial differentiator, as well. For example, lower-emissions LNG cargoes with certified carbon tags are likely to become the preferred choice for buyers. Creating transparency on GHG emissions and managing them—for example, by reducing emissions from venting and flaring—will enhance the flexibility and value of the portfolio.

There have been market disruptions in the past, and there will be more in the future: that is why portfolio optimization matters. It can help LNG players react swiftly to such disruptions; from a broader perspective, it can also improve the global energy market by reducing inefficiencies and making it more resistant to shocks. That would mean a more affordable and reliable energy system, providing the power the world needs to prosper. ▀

## ABOUT THE AUTHORS



Alessandro Agosta is a partner in McKinsey & Company’s Milan, Italy office. He leads the development of McKinsey & Company’s natural gas knowledge, helping build a distinctive perspective on gas market discontinuities, natural gas and LNG. He serves clients globally, working across all the functions from operations, marketing, and sales to corporate finance and organization.



Dumitru Dediu is a partner in McKinsey & Company’s Boston, Massachusetts, U.S. office. He helps leading energy and capital-intensive companies with shaping their strategies and work in M&A, commercialization, negotiations, and transformations (including digital), bringing particular expertise in the gas and broader energy sector.



Marijn van Diessen is an associate partner in McKinsey & Company’s Amsterdam, the Netherlands office. He holds a bachelor’s degree in econometrics and a master’s degree in quantitative finance from Tilburg University in the Netherlands.

# Rebalancing the LNG Market

**FAUZIAH MARZUKI, HEAD OF GLOBAL LNG & APAC GAS**  
*BLOOMBERGNEF*



LNG is the reason that once-isolated, regional markets are now in competition. New supply capacity coming online in the next 5 years will cause trade flows to reset. Once these investments materialize, demand creation will also prompt a rebalancing of the market. Net-zero targets and the energy transition could lead to yet another reset around 2030 during this rebalancing.

**The balance.** The energy crunch ahead of the northern hemisphere's 2021 winter was a culmination of many little things adding up, rather than a structural change in the market.

Competition between Europe and Asia for LNG cargoes intensified so much that it highlighted a vulnerability that comes when there is limited spot LNG supply to help balance the market. After a harsh winter, both Europe and Asia started the year with low gas storage levels. Trimmed output across various production facilities during the summer and smaller markets hogging U.S. LNG output meant there was not enough spot supply to go around. Asia ensured that it got the supply it needed to face a normal winter, but Europe was starved of supply from its usual sources.

When Japan-Korea Marker prices rose to unprecedented levels in December 2020-January 2021, big LNG buyers got spooked. "Take no chances," the buyers probably told them-

selves. Asian importers increased the number of cargoes they wanted delivered under their oil-linked contracts, pushing the upper bounds of their annual contract quantity tolerances. When this happens, LNG plants have less spot supply to spare.

The pandemic first struck at a time when many LNG production facilities were going into maintenance season. With health and safety concerns around the spread of the virus, many facilities deferred big maintenance plans to the summer of 2021—skimming any extra supply in the Pacific Basin.

The extent of China's coal-to-gas switching initiatives through 2018–2020 are being felt now. China took in very high volumes of LNG in the second quarter, supported also by smaller players buying cargoes through LNG import terminal third-party access. Asian spot prices climbed, and supply options tightened.

Brazilian hydropower levels were unseasonably low, especially in the key southeast region. The country increased its LNG purchases for power generation to offset reduced hydropower production, leading to record LNG imports. Argentina needed to bring back a second floating regasification unit to meet peak gas demand. Both countries guzzled U.S. LNG that would have otherwise been offloaded in Northwest Europe. And they made sure it flowed their way by paying a premium to the Dutch gas

benchmark.

For a multitude of reasons, Europe was starved of LNG from its usual suppliers in the run-up to winter. LNG exports from Qatar in June and July were at a 4-year low, at a time when Northwest Europe usually receives large amounts of Qatari supply. The shift in output pattern may have been to accommodate for higher contract deliveries in the run-up to winter. Falling production from the Atlantic LNG project in Trinidad and Tobago impacted supply to import markets in the Americas. Portfolio players made up for this with U.S. LNG supply, so less went to Europe to fill gas storage over the summer. Nigerian LNG production, a key source of supply into France and Spain, was also down this year. Just before Europe was hoping to fill inventories, Russian Arctic LNG went to Asia. As soon as the Northern Sea Route opened, Europe became the secondary market for Yamal LNG supply.

Playing the role of global LNG balancer is not always in Europe's favor. Northwest Europe can get very cheap LNG when there is excess in the market, but it is vulnerable when there is limited spot supply. In Asia, the trade is dominated by long-term contracts, and those customers take priority from a seller's perspective. European gas prices react in a way to pull back supply to the Atlantic, but these high prices are translated to consumers



across power, industry and into heating bills for homes. In contrast, only a limited number of customers feel the pain of high Japan–Korea Marker prices in Asia. If it is a cold winter in Europe and Asia, the LNG market may start 2022 on a low note again. Next year will bring some new supply capacity to look forward to, however.

**The reset.** New LNG supply capacity over the last 3 years has been concentrated in the Atlantic Basin, mostly the U.S. Gulf Coast. Projects under construction that announced final investment decisions in the last 3 years are expected to be online between 2023 and 2026. A fair number of these projects were approved on an equity-lifting basis, not sales-and-purchase agreements. Mozambique LNG was one exception. These new projects will reset LNG trade dynamics, because a big chunk of capacity is currently unaccounted for in terms of where it is going.

Supply from LNG Canada and Russia’s Arctic LNG 2 will be weighted toward the Pacific, given the buyers backing the projects. Others, like Golden Pass LNG in Texas and the Qatar mega-expansion announced earlier this year, do not have firm end markets yet. European terminal capacity bookings are lined up by sellers, but they would not be enough for all Golden Pass volume plus Qatari expansion supply. Marketers are jet setting everywhere to secure customers. Many recent contract signings with existing customers are, however, assumed to be for renewal volume from existing Qatargas projects and not yet for the expansion volume.

Golden Pass volume, in particular, could cause a shift. Existing U.S. LNG projects have a different balance of destination market shares. They emulate the tolling agreement holders’ domicile or the project’s primary buyers. For example, 40%–50% of Cameron and Freeport LNG supply in the last 2 years went to Japan, Korea, China and Taiwan. Sabine Pass

and Corpus Christi supply have largely (50%–60%) shares staying in the Atlantic Basin—Europe and South America.

To optimize shipping, it makes sense for Golden Pass volume to stay in the Atlantic and for Qatari supply to be funneled toward Asia. This avoids canal transits for both. Golden Pass cargoes would not need to take the Panama Canal, and Qatari supply would not need to transit the Suez Canal. Previous instances have shown that these shipping passages risk being choke points that lead to longer shipping times and translate into higher delivered LNG prices.

In the meantime, portfolio players signed up to these projects will use their supply options to service new LNG import markets coming up. These include the likes of Ghana, El Salvador and others in sub-Saharan Africa and Central America looking to start LNG imports.

**The rebalance.** By 2030, the full potential of all new announced LNG supply project investments will materialize, around the time BloombergNEF last projected that a supply–demand gap would emerge in the market. Demand growth after 2030 is expected to come from emerging Asian markets. Since gas demand growth will slow in the traditional Asian markets of Japan and Korea, as well as Europe (amid strong decarbonization efforts), the LNG market will recalibrate and rebalance toward these markets with big gas growth potential.

Coal retirements, investment in distribution networks and policy support will enable gas to grow in both South and Southeast Asia. South Asian economies continue to push for natural gas use, with really only LNG import infrastructure holding back growth potential. In Southeast Asia, LNG features prominently in power development plans to support a transition from coal and to supplement falling domestic gas production.

It will be a tussle for market share

among suppliers. Contracts from Malaysia, Russia’s Sakhalin and Papua New Guinea, for example, will begin to expire in the late-2020s and early 2030s. By that time, backfills will need to be lined up, or they will risk losing their customers to newer projects looking for buyers. Purchase agreements from the newer projects in Australia, U.S. and Arctic Russia expire just before 2040.

The two big projects announcing construction this year—the Qatar expansion and Russia’s Baltic LNG project—may end up channeling a big portion of their supply to the spot market. This would capture potential latent demand creation post-2030, as well. A lot more free-flowing LNG supply means that Europe might still be playing that LNG balancer role, even if it is trying to curb gas use.

**The reset within the rebalance.** Tempting as it may be to dust off LNG supply project proposals when seeing prices of \$20/MMBtu, there are bigger questions surrounding the future of gas in a net-zero world. Natural gas is a lower-emissions fuel, but not a zero-emissions one. As such, the gas industry is potentially headed for another reset—an existential one—within this rebalance period.

It is around 2030 when BloombergNEF’s net-zero pathway scenarios in the “New Energy Outlook 2021” report see the role of natural gas tapering. By that time, carbon capture and storage and hydrogen technologies need to be deployed on a mass scale to get the world on track for a net-zero scenario by mid-century. As policymakers increasingly pledge net-zero emissions targets in big gas-consuming markets, there is uncertainty in the role of gas in the future energy economy.

The use of gas in the energy economy will need to be focused on where it adds the most value in terms of the energy transition. Renewable electricity can substantially help reduce emissions, but many ap-

plications in today's economy require the physical properties of a molecule—namely, high energy density, the capacity to be stored and the ability to perform chemical reactions. That is why gas has a role to play in a lower-carbon world.

The development of decarbonized gas technologies, such as biomethane, hydrogen and natural gas

with carbon capture, is expected to be a crucial next step to enable long-term climate goals to be reached. These technologies could decarbonize the key hard-to-abate applications, such as heavy transport, heavy industry and dispatchable power. They also represent a means for the natural gas industry to maintain and even expand its role in the global

energy mix.

From now until then, however, LNG suppliers will be focusing on Scope 1 and 2 emissions reductions along the value chain. With two-thirds of emissions coming from the combustion of natural gas, adoption of carbon capture, utilization and storage technologies on the end-use side is critical. ▀

## ABOUT THE AUTHOR

Fauziah Marzuki is Head of BloombergNEF's Global LNG and Asia-Pacific Gas research and analysis. She joined Bloomberg in 2018 and was previously with Petronas, Malaysia's national oil and gas company. She has held various roles across the oil and gas sector spanning corporate strategy, LNG trading and business development in Asia, upstream oil commercial planning and operations in the Middle East, and lecturing and training. Ms. Marzuki shapes the BNEF Global Gas & LNG service, which includes market outlooks, short-term analytics and strategic insights. She holds a master's degree in energy, trade and finance from Cass Business School in London, and a BSc degree in business management from King's College in London.

# Pipeline & Gas Journal

**Largest worldwide pipeline publication**

- 30,000 pipeline industry subscribers
- print and digital editions
- eNewsletters
- webcasts/whitepapers
- events

**Subscribe Now: [www.pgjonline.com](http://www.pgjonline.com)**

**Gulf Energy<sup>®</sup>**

## INNOVATION IN FLOATING LNG—LIQUEFACTION

# Innovation in second-generation floating LNG

**YOUNG-GYU KANG, EXECUTIVE VICE PRESIDENT OF OFFSHORE PROJECT DEVELOPMENT AND EXECUTION,**  
SAMSUNG HEAVY INDUSTRIES



Many countries around the world are committing to net zero in an effort to alleviate global climate change. Natural gas will play a critical role as a transition fuel during next two to three decades of the energy transition to help maintain energy security. Gas produces roughly half of the CO<sub>2</sub> emissions of coal, while still being affordable. Although “greener” alternative energies, such as wind, hydrogen and ammonia, are emerging as game-changers, they require further technological innovation, economic viability and establishment of infrastructure. Gas remains an important part of the energy mix.

According to McKinsey & Co.’s “Global gas outlook 2050,” demand for natural gas will reach its peak in 2037 with a 0.9% growth rate, and then slowly decrease in demand to 2050. However, the market share of LNG will rise from 13% of the entire natural gas supply to 18% in 2035 and to 23% in 2050.

The “second-generation floating LNG (FLNG)” solution is an interesting, flexible and affordable solution for LNG producers and buyers considering the characteristics of LNG as transition fuel. FLNG solutions will continue to draw significant interest from LNG producers, as they do not require significant CAPEX investment (compared to mega-scale onshore LNG plants), and local populations often do not want to build mega-scale onshore plants on their land due to

environmental and security reasons.

Considering the current market situation, Samsung Heavy Industries introduces its technically and commercially viable second-generation FLNG solutions.

**Advantages of second-generation FLNG.** The “first generation” of FLNG, such as Shell’s *Prelude*, Petronas’ *FLNG Satu* and *FLNG Dua*, and ENI’s *Coral South*, was intended for deep waters offshore, serving as literally “floating offshore LNG FPSO” including LNG liquefaction, full inlet and pre-treatment facilities to process heavy liquids and impurities. These facilities considered the bespoke compositions of the gas fields with the necessary mooring facilities, such as the external and internal turret systems due to their deep-water locations.

An advantage for such facilities is that they allow direct access to their final destination via ship-to-ship transfer without the hassle of subsea pipeline, but this is characterized by relatively higher CAPEX and a longer construction schedule due to remote offshore locations and extensive operating expenses.

Second-generation FLNG with a nearshore FLNG solution addresses the concerns of first-generation FLNG. It focuses on already treated feed gas coming from existing onshore gas processing facilities (or from another offshore production/processing facility,

such as subsea or gas FPSO), freeing itself from the additional equipment and processes that are necessary to address impurities and heavy liquids. The second-generation FLNG solution requires minimal inlet and pre-treatment facilities and focuses more on the liquefaction function, allowing for a simplified and lightweight topside process with a strong possibility for standardization.

Second-generation FLNG can offer substantially better economics (lower \$/tons per year) compared to first-generation well stream FLNG, and it can be built within a relatively shorter period of construction, based on a simplified construction approach. Proven offshore liquefaction technology from first-generation FLNG is applicable to second-generation production schemes, alleviating concerns about technology novelty.

Samsung Heavy Industries believes that second-generation FLNG can be a game-changing supply option in the LNG industry, as it allows for a standardized solution as a hybrid application sourcing feed gas from an onshore facility. As the industry has witnessed with the introduction of a drillship and an FSRU, the successful launch of second-generation FLNG can breathe new life into the global LNG market. The second-generation solution also offers commercial flexibility. Relatively small LNG offtake is required to make an investment decision—compared to



mega-scale onshore LNG with its substantial required land space, authority approval and pipeline investments—allowing for tailored capacity and trade timing for both sellers and buyers.

**Technical characteristics of second-generation FLNG.** Second-generation FLNG possesses many advantageous technical characteristics (FIG. 1):

1. No need for a complicated inlet and heavy liquids separation, as it directly receives the pre-treated gas
2. Simplified pre-treatment and a small equipment count (low level of CO<sub>2</sub> and H<sub>2</sub>O from pipeline-quality gas)
3. No need for subsea control (MEG, pigs, etc.)
4. No need for extensive mooring (can be installed/moored to a simple jetty structure or soft yoke system).

As the liquefaction itself is the core of the FLNG technology, additional emphasis has been placed on simpler, more economical liquefaction technology application to be utilized for second-generation FLNG. SHI has been cooperating with various liquefaction licensors during the successful EPC execution of its first-generation FLNG projects.

In addition, SHI has successfully developed efficient, safe and construction-friendly in-house liquefaction technology (SENSE-IV) and established its own pilot plant for testing within SHI's Geoje Shipyard. The plant has been drawing market attention as a successful "one-stop shop" for SHI's FLNG solution from EPC to com-

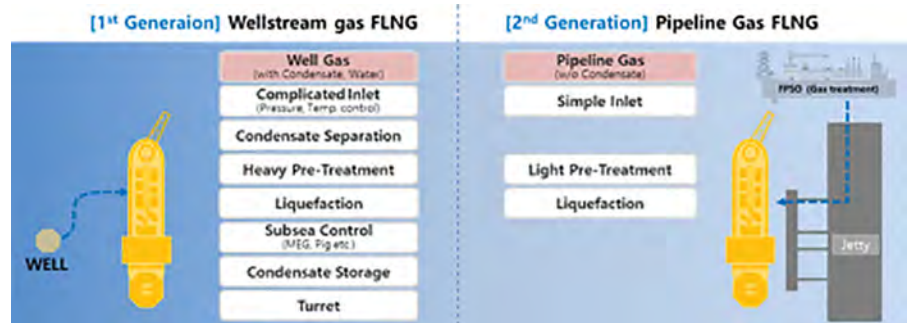


Figure 1. IPCC gas demand scenarios.

missioning and production, based on knowledgeable understanding of liquefaction and associated technologies.

**SHI's FLNG expertise and experience.** SHI has been working to realize its second-generation FLNG concept via pre-FEED and FEED studies over the past few years and is making good progress to capitalize on various FLNG prospects. As SHI has been developing an FLNG project portfolio ranging from 2.5–6 million metric tons per year, the company is ready to provide optimized and tailored FLNG solutions based on global clients' commercial and technical requirements, such as production capacity, met-ocean data, feed gas composition, cooling method, offloading profile, etc.

Recently, an increasing number of global LNG producers—including IOCs, NOCs and independent developers—have expressed keen interest in the feasibility of second-generation FLNG solutions to their natural gas portfolio. Some of these projects are already at a matured development phase, such as FEED and pre-FID preparation. With lessons learned and

design improvements gained from previous experiences, SHI is ready to successfully execute and deliver second-generation FLNG projects with high technical confidence.

**Closing remarks.** The price of LNG and natural gas hit rock bottom during the COVID-19 outbreak in early 2020. However, it has since surged beyond market forecasts, breaking its record with the assistance of seasonal demand and raising concerns about gas and LNG supply shortages.

In addition to the paramount importance of gas as a transition fuel during the energy transition, many LNG buyers are again seeking long-term LNG supply contracts to ensure stable energy supplies through a balance between spot purchase and long-term supply. New LNG project developments adopting second-generation FLNG provide the advantages of a low-cost, fast-track schedule; a low FID threshold (1–3 million metric tons per year to take FID) and commercial flexibility (redeployable). Second-generation FLNG is an efficient and economical solution to deliver LNG on the journey to a net-zero world. ▀

## ABOUT THE AUTHOR

Young-gyu Kang is Executive Vice President of Offshore Projects Development and Execution for Samsung Heavy Industries Co. Ltd. (SHI). He holds a MS degree in mechanical engineering from Busan National University and a BS degree in mechanical engineering from Pusan National University. Prior to becoming EVP of Offshore Projects Development and Execution, Mr. Kang served as Vice President, Senior Manager, Project Director and Project Manager of the Offshore PM Team at SHI. He joined SHI's Offshore Proposal department in 2003. Prior to his work at SHI, Mr. Kang worked as Proposal Manager for Hyundai Heavy Industries, as well as on Hyundai's structural engineering team. Earlier in his career, he worked as Lead Structural Engineer at LG Electronics' R&D Center.

# China's natural gas market offers resilience

**DR. QING WU, CHIEF ENGINEER,**  
CHINA NATIONAL OFFSHORE OIL CORP. (CNOOC)



In recent years, China's natural gas market has generally remained stable, under challenges such as the stagnation of economic growth and energy security issues. China's natural gas demand has gradually become more balanced after rapid growth was seen in 2017–2018, and the natural gas consumption structure has been optimized and adjusted. The scale of utilization in fields such as coal replacement, power generation and transportation has continued to increase, leading to a multifaceted demand market development.

In 2020, China's natural gas consumption growth rate was slowed by the impact of the COVID-19 pandemic, but the development of the gas market still exceeded expectations, and supply and demand remain relatively balanced. In 2020, China's natural gas consumption was 325.37 billion cubic meters (Bcm), with a year-on-year increase of 6.1%, showing the resilience in growth and huge development potential of China's natural gas market.

From the supply side, China's natural gas production has continued to rise steadily, resulting in growing reserves and production. Domestic natural gas production reached 188.85 Bcm in 2020, with an increase of 43% in the past five years. At the same time, natural gas imports increased rapidly, reaching 140.5 Bcm in 2020. Of this amount, 92.9 Bcm were in the form of LNG, representing an increase of 244%

over 2015. At present, 22 LNG terminals are in operation in China, with a receiving capacity of 90.35 million tons per year. After China announced its carbon peak and neutrality goals in 2020, the Chinese gas market is preparing to step into a new period of development and accelerate the green and low-carbon transformation of Chinese energy.

Over the near and medium terms, natural gas will play an important role in achieving China's carbon peak and neutrality goals, and China's natural gas consumption market will still have a period of steady growth for 10–15 years. With the increasing resilience of industrial economic growth, the steady growth of power consumption, the continuous advancement of urbanization, and the gradual improvement of natural gas supply capacity, China's natural gas consumption will continue to maintain steady growth. Under the country's carbon peak and neutrality goals, the combination of gas power can be deeply integrated with renewable energy, further promoting the increase in natural gas consumption. It is estimated that by 2025, the scale of China's natural gas consumption will reach 430–450 Bcm, and 550–600 Bcm in 2030. After that, natural gas consumption will grow steadily and sustainably, and it will plateau around 2040.

CNOOC is China's second-largest natural gas supplier at present. The company has formed a stable, clean

energy supply model by exploring and developing offshore natural gas resources and importing LNG. In recent years, the development of China's LNG market has become prominent, and the country's share of total natural gas imports has gradually increased. As the world's third-largest LNG importer and China's largest LNG importer, CNOOC is far ahead in total imports. In 2020, LNG imports accounted for an estimated 44% of China's natural gas imports.

In the context of China's carbon neutrality goals, CNOOC has achieved net zero carbon emissions in the entire industry chain of a single ship of LNG resources by purchasing carbon credits, thereby creating a precedent for carbon neutrality practices in China's natural gas industry. In the future, CNOOC will continue to provide stable, reliable, safe, green and low-carbon energy products to Chinese consumers; promote green and low-carbon development through the innovation of technology, management and business models; build a diversified clean energy supply system; vigorously develop its natural gas business; expand the scope of natural gas applications; develop distributed energy in accordance with local requirements; focus on integrated and coordinated development of new energies; explore new integrated development models such as "wind + solar power + oil and gas," "wind + solar power + natural

gas power,” “offshore wind power + ocean pasture”; and implement new constructions and renovations for oil, gas, electricity, hydrogen and solar integrated energy stations.

CNOOC will strive to reduce its car-

bon emissions intensity by 10%-18% from 2020-2025 and achieve more than 50% of its energy supply with clean energies in 2025, making positive contributions to the realization of China’s carbon peak and neutrality

goals. At the same time, CNOOC will continue to expand its involvement in international LNG trade and contribute to the prosperity of the global LNG market, thereby pushing global energy transformation. ▀

## ABOUT THE AUTHOR

Dr. Qing Wu is Chief Engineer at the Science and Technology Development Department of China National Offshore Oil Corp. (CNOOC). He has extensive experience in engineering, research, processing and operations management for refining and chemicals in China’s petroleum and petrochemicals industry. His research areas include CO<sub>2</sub>-rich natural gas direct conversion, heavy oil conversion, petroleum molecular engineering, hybrid energy and chemical systems, and intelligent optimization of green manufacturing in refining and chemical enterprises. He has published more than 160 technical papers and several academic books, and was named by SINOPEC and CNOOC as a refining and chemicals specialist. He holds more than 60 authorized patents and many national awards.



Nanshan LNG terminal in Hainan. Image: Muyu Xu / Reuters.



# European gas in a more import-dependent future

## GPA EUROPE MANAGEMENT COMMITTEE

GPA ASSOCIATION EUROPE

To support the Paris Climate agreement and to decarbonize the energy mix, natural gas demand will continue to grow within Europe in the next few decades, even with the rapid increase in renewable energy use. With gas production within Europe in decline, there will be a need for greater imports—this is likely to be a combination of LNG cargoes and natural gas from Russia and the CIS region.

Today, society faces its biggest and most urgent challenge: How to meet the increasing energy needs of a growing global population, while reducing greenhouse gas emissions and improving air quality. While renewable energy from sources such as wind and solar will continue to grow, in the next few decades, natural gas (the cleanest-burning hydrocarbon) will remain a dominant element in the global energy mix, as gas is expected to meet 43% of additional energy demand up to 2040. The community is working in decarbonizing, along with efficiency improvements in natural gas processing. A few factors allow this:

- Gas has advantages when used to produce electricity alongside renewable sources of energy, such as wind and solar. Gas plants can start up and shut down quickly, which makes them ideal to quickly respond to dips in solar or wind and demand surges. Over the coming years, in a move to decarbonize energy

supply, an increasing share of electricity generated from renewables will drive greater use of electricity across industry, in cities and in transport. As this share continues to grow, the flexibility of gas will make it more competitive against other thermal power sources, such as coal. Within Europe, the growth in renewables and a well-developed electrical infrastructure may mean that the gas contribution to the energy mix could be lower than in other regions; however, considering in parallel the decline, or removal, of nuclear-based power production in many European countries, gas will still be a significant portion of the energy mix.

- Natural gas systems are also designed to store energy over time—for example, between winters and summers. The International Gas Union estimates that over 4,700 TWh of gas can be stored seasonally, which is the energy equivalent of the total U.S. electricity demand, or seven times annual generation from solar (or double the total generation from wind and solar).
- Gas can also be vital in parts of the economy that are hard to electrify, such as

industrial processes and freight transport. One example is the consortium BioLNG EuroNet, which announced in 2018 the commitment to build 39 LNG fueling stations for trucks across Belgium, France, Germany, the Netherlands, Poland and Spain. The first LNG stations in Herstal, Belgium and Hamburg, Germany were opened in 2018.

- The quick decline of coal is mandatory to accelerate the reduction of emissions, although its share in power production and heavy industries (e.g., steel) in Europe is still high in 2021. Despite the impressive growth of renewable power production in Europe, gas can substitute coal when infrastructure must be decarbonized swiftly. For steel, the DRI-EAF (Direct Reduced Iron-Electrical Arc Furnace) production route, using natural gas, already halves the carbon footprint of blast furnace operated with coal. It can be considered as a step to a carbon-free DRI route based on green hydrogen, pending green hydrogen production becoming available at the scale awaited by the industrial emitters of CO<sub>2</sub>.

While gas demand remains high in Europe and the rest of the world, many of the existing European natural gas reserves are in decline, and only a few

new developments are expected due to high costs, government policies and society pressure to meet a net-zero ambition. Domestic production of bio-methane is expected to grow in many countries, such as France, but the net result is that Europe will continue to be a net importer of natural gas, whether via pipeline from Russia/CIS or through increased global LNG imports.

What is clear is that while the region continues to require gas to sustain the quality of life, we have come to expect that much of the gas will need to be used in processes supporting the net-zero ambitions of the EU and other European nations. This will require a wide range of solutions including not only the expansion of renewable electricity, but also blue

hydrogen, CCS, biogas, bio-LNG, etc.

Within GPA Europe, we have recognized the need for our industry to be ready for the future and aim to support the European gas industry through the transition toward a decarbonized energy economy by promoting technical and operational excellence. ▀

## ABOUT THE AUTHOR



Gas Processors  
Association Europe

Gas Processors Association (GPA) Europe Ltd. is a not-for-profit industry group whose mission is to promote technical and operational excellence and to service as a forum for the exchange of ideas and information for all participants in the European gas processing industry. We create value for our members by improving knowledge-sharing, technology, people development and public acceptance of our industry. GPA Europe has helped with the implementation and spread of modern gas processing technologies and equipment through our ability to share knowledge across the industry. The gas processing knowledge we have gained, and the best practices for sharing this knowledge, are transferable to other energy markets that will need production, processing, transmission and use of a gaseous energy source. The GPA Europe Management Committee consists of volunteers who are representatives of our corporate members. They meet at least four times per year to ensure the excellent corporate governance of the association for the benefit of its members.



Croatia's first LNG terminal is located in Omišalj, on the island of Krk in Croatia. Photo courtesy of LNG Croatia LLC.

# Driving the just transition: The role of gas in Tanzania's green transformation

**KATHARINE ROE, CEO,**  
*WENTWORTH RESOURCES*



Tanzania remains one of the fastest-growing economies on the African continent, with aims to transition to a middle-income nation by the end of this decade. Yet, as sustainable development remains at the top of the political agenda globally, Tanzania is confronted with the task of rapidly decarbonizing its growing energy sector, while striving to lift the nation's poorest out of energy poverty. Tanzania faces obstacles in reaching its net-zero future, but natural gas can play a role in facilitating a just and equitable transition for all.

In July 2021, and ahead of COP26 later this year, the Tanzanian government announced ambitious plans to reduce domestic emissions levels by 30%–35% by 2030—the equivalent of removing potentially more than 150 million tons per year of CO<sub>2</sub>. Decarbonization of the nation's energy sector is set to be a key focal point in achieving this goal.

Meanwhile, in the context of Tanzania's broader sustainable development goals, the government has also pledged to achieve universal energy access for the country's rapidly growing population within the same time frame, with a clear aim of mitigating energy poverty and spurring Tanzanian industrialization.

Yet, as a nation that is already among the world's most vulnerable to intensifying climate impacts, and with still over a quarter of its population liv-

ing below the poverty line, such ambitions remain no small feat. As of now, only 36% of Tanzanians have access to electricity, and as the population is set to grow threefold by mid-century, action to address this challenge is becoming more and more urgent.

How, then, does Tanzania expand its energy infrastructure in a clean and equitable way, ensuring that the burden of achieving this expansion does not fall upon those most vulnerable in society?

**The need for a just transition.** To meet this task, Tanzania must pursue a just transition, emphasizing the importance of justice and equity as central components to the country's vision of a net-zero future. The key aim of this just transition is ensuring that no one is left behind, through facilitating an open dialogue between policymakers, citizens and workers, while the economy is transformed into one fit for a sustainable future.

Firstly, ensuring that this transition is a just transition requires the provision of valuable opportunities for communities to thrive, ensuring that local employment is not impacted as industry moves away from heavily polluting sectors. At Wentworth Resources, this stands at the core of our business—we prioritize the creation of local opportunities, with our supply chain largely located in Tanzania, the vast majority of our

workforce being from Tanzania and our staff remuneration and employee conditions ranking among the best in Tanzania's energy sector.

Working alongside the principle that this transition is just, is a point of practicality that the transition actually *happens* in the first place. On this, we believe natural gas has a key role to play in providing a reliable and affordable baseload power supply. Through the provision of natural gas, Wentworth now accounts for over 30% of the electricity supplied by Tanzania's grid, helping expand energy access throughout the country's population, particularly across isolated, rural locations.

Natural gas is facilitating Tanzania's decarbonization efforts while also setting the country on a pathway to universal energy access—one of the most important factors to unlocking wider socioeconomic goals for Tanzania, according to the World Bank. The displacement of diesel and heavy fuel oils with natural gas alone is contributing an annual CO<sub>2</sub> emissions avoidance of approximately 328,000 metric tons across the Tanzanian economy.

Tanzania provides a brilliant example of the delicate balancing act many nations must manage as they move toward a cleaner and more sustainable future. Natural gas, as a low-carbon alternative to crude oil, can play a key role in Tanzania's energy transition, bolstering low-carbon en-



ergy expansion while supporting local communities.

When looking to the future and picturing the energy system we want to create globally, we must remember that when prescribing clean energy solutions, maintaining a flexible

approach is key. There can be no one-size-fits-all solution for nations with complex inequalities to consider, as it is these supposed solutions that prove far less fitting when they result in those most vulnerable footing the bill.

While more progress is needed, the positive steps being taken to unlock the potential of natural gas in Tanzania can hopefully serve as a blueprint for other nations to follow in securing a just energy transition globally. ▀

## ABOUT THE AUTHOR

Katherine Roe has over 20 years of senior corporate and capital markets experience. Having worked as Chief Financial Officer (CFO) for Wentworth Resources following her role as Vice President of Corporate Development & Investor Relations in 2014, Ms. Roe was appointed as CEO in January 2020. Prior to Wentworth, Katherine spent 11 years at Panmure Gordon & Co., having moved from Morgan Stanley's investment banking division. As well as Wentworth's CEO, Katherine is independent Non-Executive Director of ITM Power PLC and Longboat Energy PLC.



Image: JEGAS RA / Adobe Stock.

# Henry Hub and changes in the global gas markets

AJEY CHANDRA, KEN CHOW AND JEREMY GOH,  
MUSE, STANCIL & CO.

The primary trading location and benchmark for U.S. gas pricing is Henry Hub, and this benchmark is the most liquid gas hub in the world. While Henry Hub had always been an important trading hub for U.S. gas pricing, it increased in prominence from April 1990, when it was chosen as the trading point and physical delivery point for the NYMEX natural gas futures contract. While other trading hubs exist in North America, Henry Hub has greater liquidity; therefore, the price transparency is greater here than at any other location. Other regional hubs are often strongly linked to Hen-

ry Hub prices based on transportation differentials. For example, the Waha hub, which serves as the primary trading point for Permian Basin gas, closely follows Henry Hub, except for periods of market dislocations based on transportation constraints, as illustrated later in this article.

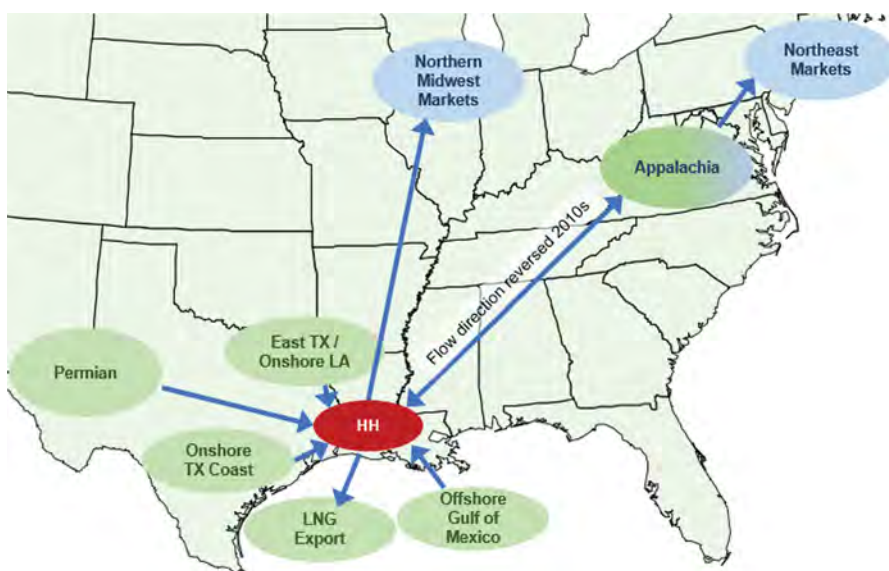
It is important to understand why Henry Hub was chosen as the location for settlement of NYMEX traded contracts. While Henry Hub is a physical location, it should be viewed as a notional point that encompasses the surrounding area. Henry Hub, located just outside the small town of Erath,

Louisiana, is strategically located at the nexus of pipelines bringing gas from the key supply basins, including onshore Texas and Louisiana, the Permian basin and offshore production from the Gulf of Mexico. Additionally, the takeaway pipeline capacity in the area connects the gas supply to the demand centers. Thus, the notional “Henry Hub” serves as this interconnection between supply sources and demand centers, making it a logical point for both physical trading of natural gas and a major point for price discovery.

Henry Hub is at the heart of the key gas demand centers along the U.S. Gulf Coast and is the starting point for the large-capacity interstate pipelines that take gas to key markets in the Midwest and Northeast. Today, eight interstate and three intrastate pipelines connect at Henry Hub, and regional gas storage provides needed services to help balance seasonal supply and demand.

The map in **Figure 1** shows how the supply regions, demand centers and regional storage connect to make Henry Hub the nexus that connects the natural gas industry.

**The rise of shale.** In the 2010s, two key developments dramatically changed the structure of the U.S. gas industry. These increased the importance of Henry Hub as the most important gas trading point in North America.



**Figure 1.** Henry Hub connects supply basins to major markets

The first was the massive growth in shale gas production. In particular, the Marcellus and Utica shales in the Appalachian region provided gas production in an area that had traditionally been a demand center. This production caused a reversal of the traditional flow patterns of gas between the Gulf Coast and the Northeast. Pennsylvania became the second-largest gas producing state in the U.S., and West Virginia and Ohio have risen to be the sixth- and seventh-largest gas producing states in the country in 2020. These states together produced 12.3 Bcf of gas in 2020, or around 30% of the national total. As Appalachian production exceeded regional demand, pipelines that historically took gas from the producing regions to the demand centers in the Northeast reversed direction. Consequently, Northeast hubs that traditionally traded at a premium to Henry Hub now trade at a discount.

By 2015, the U.S. was virtually balanced in terms of production and consumption, and natural gas production had the potential to continue to increase dramatically. To keep supply and demand balanced, some changes would become necessary in the North American gas industry.

**The U.S. becomes an exporter of gas.** This need led to the second development that changed the structure of the industry. Infrastructure to export the excess gas production was developed, including pipelines and facilities to liquify the natural gas into LNG for export to world markets.

In a few short years, total U.S. LNG export capacity has risen to over 72 MMtpy (9.5 Bcfd). Of this total, approximately 65 MMtpy (8.5 Bcfd) is located along the U.S. Gulf Coast, within reasonable proximity to Henry Hub. With these facilities coming online, the U.S. has become a major global LNG exporter for the first time in its history.

**LNG connects Henry Hub to global gas prices.** The ability to export natural gas as LNG has tied Henry

Hub gas prices to other world markets for the first time. U.S.-produced natural gas has gone from a regional commodity to one traded around the world, and Henry Hub gas prices have started to connect with other world prices.

At the end of 2020, the U.S. accounted for about 15% of global LNG capacity. Since U.S. gas prices are generally linked to Henry Hub, this has caused some other world regional gas prices to be influenced by U.S. prices. In fact, Henry Hub has taken on a strong role in affecting global gas prices.

**LNG demand to grow throughout the decade.** Currently, the existing and under-construction LNG export facilities in North America have a total capacity of 47 MMtpy (6.2 Bcfd). The majority of these are price-linked to Henry Hub, with the AECO hub in Alberta being an alternative pricing point for Canadian projects. By 2025, North America is expected to have nearly 120 MMtpy of LNG export capacity.

Muse, Stancil & Co. expects that global LNG demand will continue to grow strongly, led by additional de-

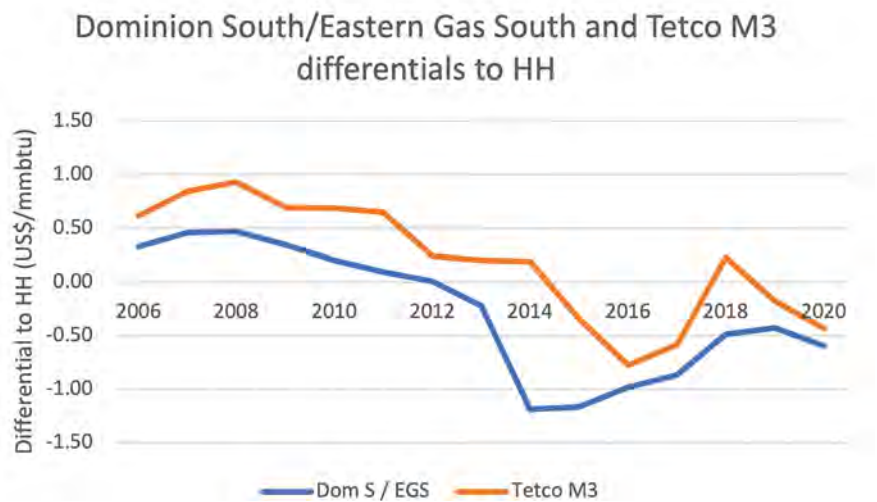


Figure 2. Northeast hubs now trade at a discount to Henry Hub

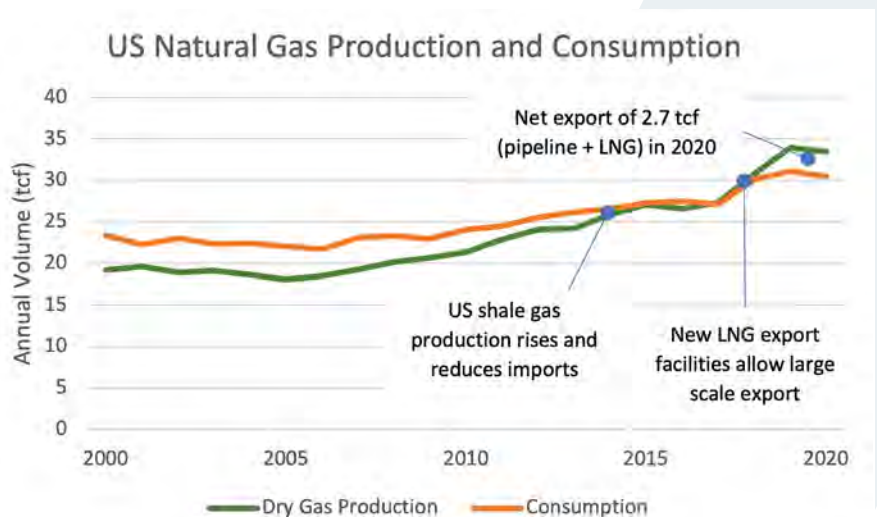


Figure 3. The U.S. has recently become a net exporter of gas



mand from Asia. In 2020, 356 MMtpy (47 Bcfd) of LNG was traded worldwide, and Muse expects that this will grow to 450 MMtpy (59 Bcfd) by 2025, for a 27% increase. Muse expects the growth will continue beyond 2025, but there are multiple alternative scenarios that will produce different rates of growth.

Gas has a key role to play in decarbonization. While growth projects have traditionally focused on the larger economies of China and India, other Asian countries will also influence the overall demand trends by increasing their gas use. For example, Vietnam announced a national power development plan that envisages less coal and more gas in the power mix, with gas-fired power projected to quadruple over the next decade. A majority of this additional gas will need to be supplied by LNG imports. This story of switching from coal to natural gas is expected to be replicated across other countries in

Asia, adding to the need for additional LNG imports into the region.

**Global gas prices.** Historically, LNG sales prices were tied to crude oil. This was the underlying major LNG pricing mechanism for much of the world prior to 2008.

Between 2008 and 2015, the natural gas price “decoupled” from crude oil. Due to significant increases in U.S. production from shale fields, Henry Hub natural gas prices dropped, while prices in Asia (as shown by the Japan–Korea Marker, or JKM index) and the UK (as shown by the National Balancing Point, or NBP) increased significantly.

Figure 4 illustrates how gas prices in the various world regions have begun to equilibrate, and the gaps have narrowed because of the various pricing mechanisms moving closer together. In the U.S., many of the new LNG facilities offered different pricing mechanisms. The U.S. LNG facilities

provided tolling agreements for gas owners based on Henry Hub gas prices. This has driven Henry Hub prices to become an important marker for world LNG prices, as much of the U.S.-based LNG is now exported to Asian markets. Therefore, the Henry Hub gas price has a much stronger influence on worldwide natural gas and LNG prices.

**Additional U.S. LNG export projects needed, but face more challenges.**

The increase in worldwide demand for LNG will necessitate additional LNG capacity in the U.S. The EIA forecasts U.S. LNG exports to more than double by 2029, with the caveat that demand forecasts will depend primarily on how competitively U.S. gas is priced in the global market. To incentivize LNG projects to be developed, the long-term expected differential between Henry Hub and global gas markers must cover the cost of liquefaction, shipping and regasification.

Table 1 shows additional LNG capacity expansions that are currently under construction, along with potential start dates for these projects.

Beyond 2025, there are about 52 MMtpy (4.84 Bcfd) of planned and proposed LNG export projects in the U.S. alone. Muse does not expect that all of these projects will be sanctioned and built, as there are uncertainties associated with the building of the additional facilities, including financing, permitting and concerns over future CO<sub>2</sub> emissions. Hydrocarbon pro-

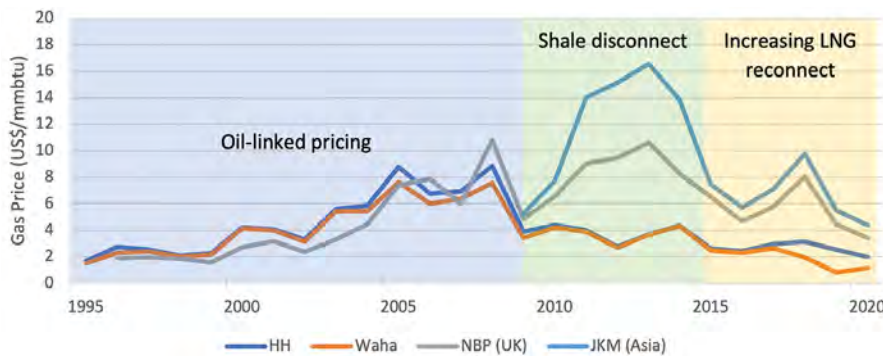


Figure 4. Global gas benchmark prices

Table 1: US LNG export projects under construction

Project	Train	Location	Expansion capacity, Bcfd	Expansion capacity, MMtpy	Total capacity (including expansion), MMtpy	Start date
Sabine Pass	6	LA	0.59	4.5	27	2022
Calcasieu Pass	1-5	LA	0.66	5	5	2022
Calcasieu Pass	6-10	LA	0.66	5	10	2023
LNG Canada	1-2	British Columbia, Canada	1.84	14	14	2023
Energia Costa Azul	1	Baja, Mexico	0.43	3.25	3.25	2024
Golden Pass	1	TX	0.68	5.2	5.2	2024
Golden Pass	2	TX	0.68	5.2	10.4	2025
Golden Pass	3	TX	0.68	5.2	15.6	2025

duction and use around the world is increasingly being challenged as governments attempt to decrease overall CO<sub>2</sub> emissions to meet climate goals.

**Takeaway.** Henry Hub has long

served as the key trading hub for North American natural gas, and has recently become a key price marker for worldwide gas prices due to the addition of significant liquefaction capacity along the U.S. Gulf Coast.

With additional growth expected in both U.S. LNG export capacity and demand for LNG in the developing world, the influence of Henry Hub on world prices is expected to expand further. ▀

## ABOUT THE AUTHORS



Ajey Chandra is a Director of Muse, Stancil & Co. in the Houston, Texas office. Mr. Chandra joined Muse in 2014 after 28 years of experience in various facets of the midstream industry, including operations, engineering, business development, management and consulting. He has had a wide variety of assignments covering all aspects of the energy industry during his career. Mr. Chandra's operating, consulting and management experience includes working at Amoco, Purvin & Gertz, Hess and NextEra Energy Resources prior to joining Muse, Stancil & Co. Mr. Chandra has a BS degree in chemical engineering from Texas A&M University and an MBA degree from the University of Houston.



Ken Chow is a Senior Principal in the midstream practice of global energy consultancy Muse, Stancil & Co., with over 20 years of experience developing and operating assets in the midstream, NGL and natural gas sectors. In addition to his consulting experience at Muse and at Purvin & Gertz, he has worked for NextEra Energy, Williams and Enron in various managerial, technical and commercial capacities. He holds a BS degree in mechanical engineering from McGill University in Montréal, Canada and formerly served on the GPA NGL Market Information Committee.



Jeremy Goh is a Consultant in the Houston office of Muse, Stancil & Co. He has over 20 years of experience in natural gas, LNG and chemicals, with global experience in Asia and Europe. He previously held roles in global gas and LNG strategy, along with the techno-economic aspects of the gas-to-liquids business. More recently, he has worked on business development of large capital projects in the U.S., guiding the economics, risk and strategy assessment of chemicals and LNG plants. His operating company experience includes working at Shell and Cheniere. Mr. Goh holds an M.Eng degree in Engineering from the University of Oxford.

# Freeport LNG: Serving the world's current and future LNG demand

**MICHAEL SMITH, CHAIRMAN AND CEO,**  
*FREEPORT LNG*



At the time of the last World Petroleum Congress in July of 2017, the United States was the 17th-largest LNG exporting country, with only 3 million tons of exports during the prior calendar year. Today, the U.S. plays a critical role as the world's third-largest exporting nation, with 78 million tons per year (MMtpy) of production. Moreover, an additional 30 MMtpy is under construction, which will make the U.S. the largest exporting country in just a few years—at least, until Qatar's expansion trains are completed late in this decade.

This massive and speedy growth came from five regasification facilities that were redeveloped into liquefaction facilities, including Freeport LNG's 15-MMtpy facility, plus one greenfield liquefaction facility. With all of these new facilities under construction in July of 2017, the consensus prediction envisioned the output from these plants leading to a multi-year oversupply of LNG. And yet, today, despite the temporary demand destruction that took place due to COVID-19 shutdowns, we find ourselves in a tight market with record LNG prices throughout the world, proving once again that the only certainty about the future is that what we think is going to happen rarely does.

What changed between then and now was the accelerated adoption of international energy transition goals, which has seen an increasing sum of

capital invested in renewable and natural gas power generation. The Asia-Pacific region, which represents 60% of the world's population and 75% of the world's demand for coal, is also the epicenter of solar panel manufacturing. These developing nations are in a delicate situation that requires public policy to balance between socioeconomic growth and clean energy programs. To do this, gas-fired power generation, including LNG-to-power projects, will play a key part in decarbonizing these countries, not only because these projects provide affordable energy, but also because natural gas-fired plants ensure stability within the grid.

Nowhere is this more evident than in China. In the 5-year period from 2011–2016 before the last Congress, China increased its consumption from 12 MMtpy to 26 MMtpy, a very impressive 116% increase. Assuming that China continues its current rate of demand for the last months of this year, it will surpass 80 MMtpy of demand in 2021, which is a 200% increase from the prior 5-year period! This will likely mean that China surpasses Japan as the largest importing country in the world. While it is very unlikely that China's demand will continue to grow at its current 5-year CAGR of approximately 25%, there is no evidence that it will slow to the mid-single-digit growth rates that many are forecasting. China has announced plans to

double its regasification capacity in the next 4 to 5 years, with 68 MMtpy already under construction. This level of development, especially in the context of the energy transition and increased electrical vehicle usage, etc., means it should be quite clear that LNG demand will be very robust for the foreseeable future.

The bigger question, then, is where will all of the supply come from? We already know that there were only a few FIDs for new projects totaling more than 100 MMtpy over the last 3 years, and a few of those are experiencing significant delays due to quarantine measures, terrorism and cost disputes. We cannot expect a new wave of supply to alleviate an increasingly tight market until at least 2026, when the Qatar expansion trains start coming online. Last year, before the market tightened up due to increasing demand and some lost production, the market was afraid of another glut of LNG developing in the second half of this decade when the Qatari expansion comes online. Whether the Qatari expansion is the current 32 MMtpy or the rumored larger expansion of 42 MMtpy—which would not be fully online until the end of this decade—demand growth has outstripped supply growth handily, meaning a lot more than just Qatari LNG is needed!

A significant portion of this much-needed LNG will come from the U.S.,



which has some of the lowest-priced gas and most-flexible terms in the world. With an ability to consistently deliver sub-\$10/MMBtu LNG into Asia, the U.S. provides an affordable energy solution that benefits the import bills of our trade partners by putting downward pressure on global gas prices—something they definitely appreciate today, even as prices for LNG into Asia punch above \$20/MMBtu and will likely stay in the double digits for the next several years. More U.S. LNG is obviously necessary given these prices—and more we can provide. The shale gas revolution created so much cheap natural gas that it is propelling the U.S. to become the largest exporter in the world—and there is plenty more gas for additional terminals or expansion trains like Freeport LNG’s Train 4. Our 15-MMtpy-plus plant on Quintana Island in Texas, which would become a 20-MMtpy-plus plant with our fourth train, is currently the second-largest in the U.S. and the seventh-largest LNG-producing facility in the world.

Given that so much of the demand growth is and will continue to be energy transition-driven, the Freeport LNG plant was strategically designed to be one of the most cost-effective suppliers of low-carbon-intensity LNG cargoes in the market. Our best-in-class electric motor technology reduces greenhouse gas emissions by

90% versus traditional gas turbine-driven liquefaction. No other large-scale electric liquefaction plant is operating in the U.S. and, moreover, our electricity is sourced from the Texas ERCOT electricity system, which is ahead of the national curve when it comes to adopting renewable sources of power generation. Wind and solar power comprise roughly 30% of the electricity generated in Texas—more than twice the U.S. national average—and that percentage continues to grow. Our fourth train expansion will also be electric motor-driven, and thus presents a unique opportunity for a buyer to not only support the energy transition through an LNG purchase, but also for that LNG to be meaningfully less carbon-intensive than the other potential sources.

Since Freeport LNG started liquefaction operations in July 2019, we have successfully exported over 300 cargoes to customers in over 30 countries. This is no easy accomplishment. We have experienced once-in-a-lifetime events—knock on wood—that have forced us to change the way we live and work. Initially, the pandemic that ensued in early 2020 suppressed demand for all energy types on a global scale, forcing liquefaction operators across the U.S. to reduce plant run rates. Then, almost 1 year after the start of the pandemic, when we were running at full capac-

ity, Winter Storm Uri brought below-freezing temperatures to half of the U.S., blanketed 73% of the Lower 48 states with snow, taxed the power grid in Texas to never-before-seen extremes, and forced Freeport LNG to balance our operations with the safety of our local community.

Despite all of these black swan events, we have been able to keep our plant running at a high rate of 20 cargo loadings per month for the better part of a year. Freeport LNG has also managed to remain injury-free going all the way back to our original import and regasification operations. Freeport LNG’s comprehensive safety risk management protocol has enabled a strong track record of safety management, with zero employee recordable incidents in 13 years of operations and top-quartile safety performance over the course of construction.

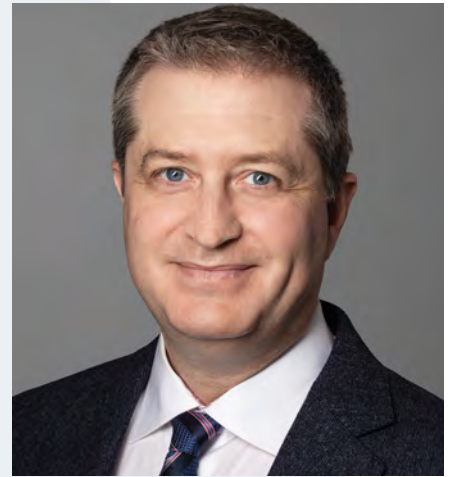
The US liquefaction industry will continue to grow to meet the needs of an ever-greening world. Natural gas continues to be the cleanest way to power the world’s growing energy needs while nonetheless remediating carbon emissions. We are proud that Freeport LNG stands ready as a proven, efficient, safe, reliable and eco-friendly operator to serve the world’s LNG demands both through our current production and our planned expansion. ▀

## ABOUT THE AUTHOR

Michael Smith founded Freeport LNG Development LP in 2002 and is the company’s Chairman and Chief Executive Officer and majority shareholder. Freeport LNG Development L.P. owns and operates an LNG terminal on Quintana Island near Freeport, Texas. The terminal began LNG import operations in June 2008. In May 2020, Freeport LNG began full, commercial LNG export operations of its three natural gas liquefaction trains. In excess of 15 million metric tons per year of LNG is produced from Freeport’s trains. A fourth liquefaction train is under development with an expected start date of 2026. Of the 15 MMtpy of Freeport LNG’s export capacity, 13.4 MMtpy has been sold to Osaka Gas Co. Ltd., JERA Co. Inc., BP Energy Co., Total Energies and SK E&S LNG LLC. Mr. Smith previously founded Basin Exploration Inc. in 1981 and served as its Chairman, Chief Executive Officer and President. Basin Exploration was a publicly traded oil and gas company active in the Gulf of Mexico and the Rocky Mountain Region. Mr. Smith successfully negotiated the sale of the company to Stone Energy in February 2001 in a \$410-million stock-for-stock merger. Mr. Smith was past President of the Colorado Oil & Gas Association and was previously a Member of the State of Colorado Governor’s Minerals, Energy & Geology Policy Advisory Board.

# LNG Canada to usher in new era for Canadian gas

**PETER ZEBEDEE, CEO,**  
LNG CANADA



This is an exciting time for Canada's LNG industry, which has advanced considerably since the World Petroleum Congress was last held 4 years ago. The project I lead, LNG Canada, reached a final investment decision in October 2018. With support from our five joint venture participants—Shell, Petronas, PetroChina, Mitsubishi, and Korea Gas—and working collaboratively with indigenous peoples and local communities, non-government organizations and all levels of government, we have made significant progress and are now entering our fourth year of construction in Kitimat, British Columbia, Canada in the traditional territory of the Haisla Nation.

As Canada's first major LNG project and the largest private investment in the country's history, we are setting the benchmark for economically, environmentally and socially responsible LNG development. We are also demonstrating how LNG development benefits individual Canadians and their families. To date, the value of awarded contracts and procurement in British Columbia alone is well over C\$3 billion.

At each stage in our journey, with every critical construction milestone we reach, every contract we award and every social investment we make, the public's interest in our project increases; so, too, does the understanding of LNG's role in the global energy transition. We know that future

population growth and development around the world will require more affordable energy, with fewer CO<sub>2</sub> emissions. Indeed, natural gas is already displacing higher-emitting sources of energy, such as coal, for power production in cities with air quality concerns and where renewable resources are limited.

LNG provides 50% lower CO<sub>2</sub> emissions than coal. That is a big reason why it is replacing coal in so many places, and why it represents an important opportunity for Canada, which has an abundance of lower-carbon natural gas; and for countries such as China, where the use of natural gas is expected to almost triple by 2040.

LNG Canada will provide security of supply for global LNG markets that rely on Canada's natural gas reserves to advance their economies and reduce global greenhouse gas emissions. This is important in the context of commitments that Canada has made to reducing greenhouse gases, while helping our international partners meet their own climate change initiatives.

LNG Canada is a long-life asset with a 40-year export license that will initially export 14 million metric tons per year of low-carbon LNG from two processing units, or trains, with the potential to expand in the future.

While we will be the first major LNG company in Canada to export in-

ternationally, we are entering a highly competitive global market that is looking for lower-carbon energy. We are advantaged by access to abundant Canadian natural gas, a location in an ice-free harbor, and our shipping distance to North Asia, which is about 50% shorter than from the U.S. Gulf of Mexico and avoids the Panama Canal.

Adding to that, we have designed a project to have the lowest carbon intensity of any large-scale LNG export facility in the world. GHG emissions from LNG Canada's Kitimat operation will be lower than any facility operating today: 35% lower than the world's best-performing facilities and 60% lower than the global average.

Energy-efficient gas turbines and the latest methane mitigation technologies will help us reach our low-emissions standards. LNG Canada will use British Columbia natural gas that is produced with the highest standards, and for additional power requirements we will rely on renewable electricity from BC Hydro, a provincial Crown Corporation that provides 95% of British Columbia's electricity—most of it from hydroelectric facilities.

As we continue our journey to first cargo, we are helping create lane-ways for additional LNG development in Canada, with strong indigenous participation. In just the past year, a number of new LNG project proposals have been advanced near our facility on British Columbia's northwest

coast. These include Cedar LNG, co-led by the Haisla Nation, and the Ksi Lisims LNG project, a partnership that includes the Nisga'a Nation.

This is very encouraging. LNG Canada would not be where it is today

without the knowledge, support and participation of indigenous peoples, and we welcome more indigenous involvement in Canada's growing LNG industry. By working together with our joint venture participants

and leveraging our combined skills, experiences and emerging technologies, we can help create a sustainable and prosperous low-carbon future for everyone's benefit, in Canada and around the world. ▀

## ABOUT THE AUTHOR

Peter Zebedee is the CEO of LNG Canada, a Shell–Petronas–PetroChina–Mitsubishi Corp.–Korea Gas joint venture. Under Mr. Zebedee's leadership, LNG Canada is building the country's first large-scale LNG export facility in Kitimat, British Columbia, on the traditional territory of the Haisla Nation. With its first LNG cargo expected by the middle of this decade, the project represents the largest energy investment in Canadian history and will deliver substantial economic benefits to indigenous communities, businesses, the province and the country. Once complete, the facility will deliver the lowest-carbon-intensive LNG in the world, helping address global climate change. Mr. Zebedee is passionate about safety and protecting the LNG Canada workforce, site and adjacent communities. It is his ambition to build the safest project on earth. He brings more than 22 years of industry experience to his role at LNG Canada. Prior to joining the joint venture, he was Vice President of Canada Manufacturing and GM Scotford at Shell. A geological engineer and graduate of the University of British Columbia, Mr. Zebedee has held roles in engineering, operations and numerous corporate assignments throughout his professional career. In 2009, he joined Shell, where he held senior leadership roles with the Athabasca Oilsands Project (AOSP) joint venture as General Manager of Shell Albian Sands and the Scotford Upgrader. He led the successful integration of Scotford into a single, combined site in 2017 and 2018, and was a driving force in Scotford's improvements in personal and process safety, the delivery of exceptional business results and enhanced competitiveness. In 2018, he became Vice President for Shell's Downstream Manufacturing portfolio in Canada and the General Manager for Shell Scotford Manufacturing Complex (Upgrading, Refining & Chemicals). Mr. Zebedee is on the Board of Directors for Energy Safety Canada and is a member of the Association of Professional Engineers and Geoscientists of Alberta.



LNG tank pad at the LNG Canada site in Kitimat, British Columbia, Canada. Photo courtesy of LNG Canada.



# Great exaggerations— The demise of U.S. LNG

**JOHN BAGULEY, CHIEF OPERATING OFFICER,**  
*MAGNOLIA LNG LLC*



To paraphrase Mark Twain, we have heard on good authority that U.S. Gulf Coast LNG is dead. And as Mr. Twain said when he received the news of his death, “The report is indeed an exaggeration.”

The rate of growth of the U.S. LNG export business over the past 5 years has been nothing short of phenomenal. By comparison, Indonesia as an early global leader in LNG production took 23 years to develop a peak production capacity of 34 million metric tons per year (MMtpy). Australia installed 84 MMtpy over 30 years. Small volumes from Kenai aside, the U.S. exported no LNG coming into 2016, but over the following 5 years, nameplate capacity has grown to nearly 70 MMtpy.

Some recent news reports would indicate this is the end of the road, particularly with the energy market softness through the onset of the pandemic in 2020. This is far from reality, however; the world is moving to reduce greenhouse gas emissions and decarbonize, and U.S. LNG will play an increasingly important role in this transition while also underpinning energy security, energy stability and the ever-growing demand for access to clean, affordable energy in developing economies.

Through the downturn in global LNG demand in 2020, U.S. facilities demonstrated their value as swing producers to stabilize the balance between supply and demand. Most of the world’s LNG is produced from dedicated gas

fields with no local or regional capacity to use or store short-term excess feed gas. This scenario, coupled with the nature of take-or-pay contracts plus a lack of destination optionality from traditional LNG suppliers, renders the cancellation of traditional cargoes impractical and expensive.

For U.S. cargoes, the structure of the contracts allows buyers to cancel cargoes in a timely manner, for only a fraction of the total cost, by paying only the liquefaction fees and avoiding the gas supply, gas transportation and shipping costs. The impact of this variable liquefaction demand on the upstream gas producers is dampened by a combination of extensive gas storage capacity coupled with the overall size of the U.S. gas market, compared to the gas consumed by the LNG production trains, thereby eliminating major impacts on any segment of the supply system.

Traditional LNG sales-and-purchase agreements have been linked to the price of oil due to the early use of LNG to displace oil in power stations. Over time, the rationale for this link to oil pricing has faded as LNG now competes more directly with pipeline gas, coal, and the growing use of renewables. Since the onset of U.S. LNG exports transparently linked to Henry Hub (HH) natural gas prices, buyers of U.S. LNG have gained access to a much more stable pricing basis that can support long-term economic

planning. While oil-linked spot LNG pricing can be very attractive at times, it is also highly mercurial. U.S. LNG supplies may not always represent the least expensive gas molecules available, but under long-term contracts they will always represent a reliable, low-cost base far from the peaks of spot prices, the Japan-Korea Marker and oil-linked pricing.

The U.S. remains the world’s largest producer of natural gas, accounting for almost 25% of global production. This is 36% higher production than number-two producer Russia, and nearly six times the production of global number-one LNG producer Qatar. The U.S. gas grid is also highly interconnected with Canada, the world’s number-five producer. Available upstream natural gas supply to feed a growing U.S. liquefaction industry is functionally unlimited for the foreseeable future. While some traditional stranded gas LNG producers have seen the decline of feed gas assets (Arun and Bontang in Indonesia, Trinidad and Egypt—at least temporarily), the U.S. is able to grow production to meet future needs for both domestic consumption and exports.

The U.S. is also well positioned to produce some of the greenest LNG globally, as access to abundant and growing renewable energy along the U.S. Gulf coast increases. With ready access to gas supply and renewable electricity, future planned LNG export plants are increasingly turning to com-

bined-cycle and electric motor compressor drives as ways to minimize and eliminate onsite CO<sub>2</sub> emissions and to benefit from the continued decarbonization of regional power grids.

Stable and transparent pricing,

production and delivery flexibility; a virtually limitless supply base; an early leader in the transition to reduced-carbon LNG production; and relentless growth in global energy demand—U.S. LNG production is indeed

far from decline and demise. Rather, U.S. production can be expected to continue to grow and underpin a secure, reliable and reduced-carbon energy source for a bright future. ▀

## ABOUT THE AUTHOR

John G. Baguley is Chief Operating Officer for Magnolia LNG LLC, a Glenfarne Group/Alder Midstream company. His involvement in international LNG project development and delivery spans 40 years and includes project management, engineering, construction and commissioning roles. He holds a BS degree in chemical engineering from Michigan State University in East Lansing, Michigan and is a registered Professional Engineer in Texas.



Image: Edgar Lee Espe / Shutterstock.com.









# Energy Transition and Sustainability

**STUART PENSON, CONTRIBUTING EDITOR,**  
*TRANSITION ECONOMIST*

---

The energy industry is never far from the spotlight and it now finds itself at the centre of a rapid global industrial revolution - the transition to low-carbon.

The energy transition has gained momentum in the last twelve months and now enters a critical phase. Strategic decisions and investments made over the next twelve months by producers, infrastructure operators and consumers will be critical to achieving targeted emissions cuts by 2030, and setting the trajectory to net-zero by 2050.

Recent energy price volatility has highlighted the scale of the challenge. Demand has returned more rapidly than some expected in the wake of the global pandemic, stretching natural gas supplies and exposing the scale of spending needed on renewables and storage capacity to stabilise energy systems as they pivot away from fossil-fuels. The International Energy Agency says global investment in clean energy must more than triple from current levels to \$4tn by 2030 to achieve net-zero emissions in 2050.

The burden falling on oil and gas operators is immense. They must weigh increasingly aggressive calls from investors and wider society to divest fossil fuel assets against the need to maintain upstream supply to prevent extreme price swings and keep energy affordable. And business models which have delivered impressive returns for decades must be redesigned for a world of lower returns from renewables, hydrogen and electrification.

At the same time, the largest energy companies will probably determine the fate of many emerging low-carbon technologies. It is only with the full force of big oil's balance sheets behind them that technologies such as clean hydrogen and carbon capture and storage will reach the scale needed to make meaningful contributions to the emissions reductions demanded by the Paris Agreement on climate change.

Collaboration between companies which have historically competed for dollars will be crucial. The number of strategic alliances emerging across the industry in recent months has shown the industry's genuine readiness to work together to a common goal.

Governments also have a role in creating the incentives and investment frameworks to help deliver change across the value chain, from production to distribution infrastructure and, crucially, consumption. ▀

# CONTENTS

---

- 113 Introduction**  
Stuart Penson, Contributing Editor, Transition Economist
  
- 115 From IOC to IEC—how BP approaches the energy transition**  
Bernard Looney, Chief Executive Officer, BP
  
- 117 Driving industrial business transformation through the energy transition**  
Josu Jon Imaz, CEO, Repsol
  
- 119 Clean hydrogen primed for key role in US**  
Dan Feldman, Omar Samji, Paul Epstein, Gabriel Salinas, Shearman & Sterling
  
- 121 The great global switch on: Electrifying the transition**  
Jason Goodhand, Global Leader—Energy Storage, Energy Systems, DNV
  
- 124 Taking a stance on portfolio decarbonization**  
Katharina Beumelburg, Chief Strategy and Sustainability Officer, Schlumberger
  
- 127 Oilfield services rebound back smarter**  
James West, Senior Managing Director, Evercore ISI
  
- 129 Digital twin technology will help green the oil and gas sector**  
Vanessa Erickson, Engineering and Execution Portfolio Marketing Manager, AVEVA

# From IOC to IEC – how BP approaches the energy transition

**BERNARD LOONEY, CHIEF EXECUTIVE OFFICER**

*BP*



For more than 90 years, the World Petroleum Congress has wrestled with some of the most pressing energy issues of the day. In the past—even the very recent past—the main challenge up for discussion was how to produce more reliable and more affordable energy. But as the WPC gathers in Houston this year, the challenge we all face is bigger, messier and more complex than ever before. And we don't have a lot of time to solve it.

The world still needs reliable, affordable energy, of course. Fast-growing economies and rapid urbanization will drive energy demand—which could rise by 25pc by 2050. As that demand is met, millions of people around the world will gain access to the things many of us already take for granted—electric lighting, clean cooking, heating, perhaps a car or an aeroplane-ride. At the same time, customers—more than ever before—are being increasingly concerned and selective about the kind of energy they want to consume and how they want to consume it.

The world wants and needs energy that is affordable and reliable—and now it wants energy that is also low carbon. The world's carbon budget is finite and running out and we need a rapid transition to net zero. That means emissions have to fall dramatically and at scale.

We all have a role to play in this:

governments, NGOs, citizens—and, of course, companies. For our part, BP has set an ambition to be net zero by 2050 and to help the world get there. And we have a strategy to deliver on that—with concrete aims to guide us and show the world our progress. Even in these early days, we're making headway, but we know there is much more to do.

And while not everyone can move at the same speed, the direction of travel is clear. China has set a net zero target, the EU is working on a Green Deal, the UK is planning a green industrial revolution, while the US has re-joined the Paris Agreement and has an ambitious climate agenda.

As I write this, the world's eyes are turning to the latest major UN climate conference, COP26 in Glasgow, where countries are hoping to take the next big step towards a lower carbon future. Unsurprisingly, it's also top of the agenda at the WPC in Houston, where we'll be discussing the energy solutions the world needs. What will those look like?

Some people say green companies are the answer. They're right—yes, more green companies are needed. But the reality is we can't possibly grow or create enough new green companies fast enough for them to solve the problem on their own.

## JUST TRANSITION

To meet the Paris goals, we need

to go where the emissions are. That means transforming energy, transport and industry—the sectors accounting for 70pc of global emissions. So, to deliver a just transition and avoid massive disruption to people's lives, we also need to support greening companies—companies that are not low carbon today but are serious about lowering emissions, now and into the future.

The more that process of greening is supported—by policymakers, investors, customers and the world's best talent—the faster greening companies can move and the greater chance the world has of meeting the Paris climate goals.

As the world makes the multi-trillion-dollar transition to a cleaner, greener energy system, we see huge potential for BP and greening companies like us with reach and scale, with expertise and capabilities, and with a clear and credible plan to deliver on our net zero ambition.

To do that, we have to reinvent the company. It's why BP is undergoing the biggest transformation of our 112-year history—pivoting from an international oil company to an integrated energy company, or from IOC to IEC.

We will continue developing the oil and gas the world needs—producing the best barrels as safely and efficiently as possible. But from a smaller, more focused and more valuable portfolio.



We will build scale in renewables and low carbon. Since we began this transformation, we've moved into offshore wind in some of the best markets on the planet; we're growing fast in solar through our Lightsource BP partnership; we've seen BP Bunge become a leading producer of bio-ethanol in South America; and we're fast developing a great hydrogen business, most recently agreeing to work on plans to develop hubs in the UAE and UK.

And we're aiming to double the number of customer touchpoints by 2030 as we expand our global retail network—doubling our earnings from that business as we make life easier for our customers and help advance

the mobility revolution. We'll do this by putting customers at the heart of our offer—advancing in new markets, providing the fuels and EV chargers they need to get around, and offering them coffee and convenience.

The reinvented BP will be leaner, faster-moving, lower carbon, and more valuable. We'll deliver the energy society demands, we'll generate more value for our shareholders, and we'll create a more energizing and exciting place to work for our people.

Of course, we can't do this alone. As much as any of us brings to the table, we don't have all the answers. And as tomorrow's problems get harder, we'll need each other even more. That's why BP places so much

emphasis on strong relationships with others—including companies, like Microsoft, Uber, Equinor, Amazon and Reliance Industries—and with cities, such as Aberdeen and Houston.

When we support each other, we all benefit. That mutual support is going to be crucial for the world reaching net zero. And one of the biggest, most urgent things the world could do to address global warming is to back companies of all kinds that are not green now but are committed to getting greener—and are in action. Set policies that help advance our transition, partner with us, invest in us and come work for us. Because together, we can make a real difference. ▀

## ABOUT THE AUTHOR

Bernard Looney is the Chief Executive Officer of BP.



# Driving industrial business transformation through the energy transition

**JOSU JON IMAZ, CEO,**  
REPSOL



The energy transition is gathering momentum, and so more and more possibilities to decarbonise are being explored, implemented, and scaled up. Electrification is a significant lever, but by no means the only one. Much more needs to happen to succeed in reducing emissions, and industry has a key role to play in finding solutions that can accelerate and expand decarbonisation.

At Repsol, we have embarked on a wholesale transformation of our industrial complexes into multi-energy hubs based on the circular economy, where municipal and industrial waste, residues from agriculture and forestry, as well as recycled raw materials are used as feedstock. The results are exciting since the products produced are a cost-efficient way of reducing CO<sub>2</sub>.

And this has not happened by coincidence. This transformation is the result of a company mindset that made us an early mover in sustainability. We were the first company in our sector to commit to a net zero emissions target. Our ambition is quite simply to be a leading player in the energy transition, supplying our clients and society with all the energy products they need in an efficient, affordable, and sustainable way. And so, we are re-examining everything that we do in our industrial complexes with a clear goal that has already borne fruit at scale.

Repsol is leading the production of biofuels in the Iberian Peninsula, and we are currently producing around

700,000t/yr of sustainable biofuels. Our objective is to reach 2mn t/yr of low carbon fuels by 2030. This year we produced Spain's first aviation biofuel from waste, and we plan an advanced fuels plant in Cartagena with the capacity to produce 250,000t of hydro-biodiesel, biojet, bionaphtha, and bio-propane from waste every year.

Liquid fuels with a zero or even a negative net emissions profile are not only desirable but essential to serve key transport sectors where electrification is not yet a solution, but where we must make progress because the world needs both the transport logistics and lower emissions.

In addition to producing products with a low, neutral, or even a negative carbon footprint, our industrial complexes are also maximising the value of efficiency. Since 2010, Repsol has avoided 2.5mn t/yr of direct CO<sub>2</sub> emissions through our energy efficiency programme. These and other initiatives are allowing us to accelerate and deepen our intensity emissions reduction targets, which we have recently upped to 15% by 2025, 28% by 2030, and 55% by 2040.

This progress is not only about reducing emissions, though. It also aims to preserve efficient, competitive, and innovative industrial activity. Industry is key to getting society back on the path to prosperity after the pandemic and achieving a lower emissions future. Covid lockdowns have shown

that industry is crucial in times of crisis. It supplies society with essential goods and creates stable, high-quality jobs, generating wealth in the area where it is based.

And to biofuels and synthetic fuels, we must also add the possibilities offered by renewable hydrogen and carbon capture and storage, which will also be essential levers. We are taking steps to be a leader in the development of all these solutions.

## TAKING THE LEAD

Hydrogen is a strategic pillar for Repsol's net zero emissions target by 2050. Our company currently operates the largest hydrogen plant in Europe. It has the expertise, experience, and technological projects to play a leading role in renewable hydrogen in Europe and stand at the forefront of the growing market in the Iberian Peninsula.

Hydrogen can serve current industrial needs as well as new uses in mobility, heating, and energy storage. We have the capacities and the ambition, and we are targeting 552MW equivalent of installed capacity by 2025. We are working with different technologies to reach this goal, including electrolyzers and the use of biogas from organic waste instead of natural gas. We are also developing a proprietary technology—photoelectrocatalysis—that will use solar energy to turn water directly into hydrogen without the intermediate step

of electrolysis. This project recently received EU funding, and a pilot plant at our Puertollano industrial complex will launch in 2025. We expect this technology to be commercially viable by 2030. Open innovation and close collaboration can help speed up this process, and we are doing so in different industrial clusters around our industrial complexes.

The role of our petrochemical capabilities in the energy transition also deserves close attention, since the materials we produce have countless applications in enabling, accelerating, and increasing energy transition ambitions. These range from packaging applications that lower food waste to insulating materials that increase buildings' energy efficiency or sturdy, flexible, and light materials that lower the weight of vehicles—the manufacture of electric vehicles (EVs) would be impossible without hydrocarbons. Therefore, in 2021, Repsol announced two new polymer materials plants for highly specialized applications at its Sines Industrial Complex, representing the largest industrial investment in Portugal over the last ten years.

Our chemicals transformation is led by innovation and circularity, and we have a target to recycle the equivalent of 20% of our polyolefins production by 2030. We are one of the first European chemical producers to feed pyrolysis oil into our system and market circular polyolefins. And in addition to the current mechanical and chemical recycling polyolefins in place, in 2021, we announced plans to build Spain's first chemical polyurethane foam recycling plant at our Puertollano Industrial Complex, and we joined the project to build a plant with the capacity to convert around 400,000t of non-recyclable municipal solid waste into an annual production of 220,000t of methanol for renewable plastics or advanced biofuels.

## HELPING HAND

The industrial activity of energy companies is becoming a powerful

lever that is driving progress in many technologies that can complement and enhance the benefits of electrification. Companies and technologies must compete to make the energy transition efficient and profitable, but the regulators must set the playing field for 'fair play' competition. The efforts of companies must be matched by regulation that drives down emissions effectively rather than simply outsourcing them elsewhere.

It is vital that the EU and member states create balanced decarbonisation frameworks that promote reindustrialisation, ensuring a level playing field for companies and different technologies to participate in the recovery and the road to zero net emissions.

Supporting industry in countries with responsible environmental policy means supporting an environmentally responsible industry. The high standards set in Europe are not met in other regions of the world so producing one tonne of steel, cement, or liquid fuels in European countries generates less greenhouse gas (GHG) emissions than the same ton produced outside the EU.

Strategic thought must be given to the role of industry in the future within the global framework. Recently, CO<sub>2</sub> prices in Europe surpassed €60/t (\$69.3/t), causing enormous strain to the industry's competitiveness. In addition, we have seen electricity prices soar in an unjustified manner, with a significant impact on inflation and vulnerable sectors of the economy and society.

The European Commission must act to prevent speculation on allowances and, therefore, on the price of CO<sub>2</sub>. Europe needs an open and transparent reflection of the costs of the energy transition to ensure that it can be done not only as fast but also as fairly and cheaply as possible, without penalising the consumer or European industrial jobs.

In the same vein, policy must acknowledge that emissions matter

globally regardless of where they are produced. When we import batteries for EVs produced with high carbon emissions in China, we cannot just start measuring emissions within our borders and only look at what comes out of the tailpipe. It is cheating at solitaire, emissions are global, the CO<sub>2</sub> molecules in our atmosphere are the same whether emitted in Asia, Europe, or America, so we must consider the life-cycle emissions of our products. We, therefore, believe that a carbon price must be set worldwide as a key element in policies to fight climate change, but, in the absence of it, a border adjustment mechanism is needed to avoid speculative movements.

Keeping in mind that much of this regulation will only apply to European players and European markets, to produce an efficient response, European external action should also start calling for a more ambitious international pivot in the fight against climate change, matching its own efforts.

All technological solutions for decarbonisation are valid and complementary, and incentivising them all will accelerate the energy transition. The challenge is to commit to those that contribute to reaching our goals in the most cost-effective way, generating opportunities for us to move forward.

Hydrocarbons have been the backbone of social welfare gains, progress, and the development of societies, and they remain of capital importance especially in the developing world, to build back better after Covid 19 in a more sustainable and inclusive way, without leaving anyone behind. We are pursuing a clear goal to be enablers of progress by continually refining and improving existing solutions as well as by exploring and developing new ones that maximise the reduction of emissions while minimising costs and disruption. Progress never rests, and neither will we. ▀



# Clean hydrogen primed for key role in US

DAN FELDMAN, OMAR SAMJI, PAUL EPSTEIN, GABRIEL SALINAS,  
SHEARMAN & STERLING

The U.S. is currently at an inflection point in the decarbonization of its economy and hydrogen is expected to play a crucial role as an essential clean fuel for the future of major U.S. industrial sectors.

Earlier this year, the Biden administration issued executive orders<sup>[2]</sup> committing to the following carbon reduction targets: (i) a 50 percent reduction from 2005 levels of economy-wide net greenhouse gas pollution by 2030; (ii) a 100 percent carbon pollution-free electricity sector no later than 2035; and (iii) net-zero carbon emissions by no later than 2050. These targets are generally consistent with the Paris Agreement, which was signed and ratified by almost all of world's developed nations.

These are ambitious goals that will require the U.S. to scale up a range of new clean energy technologies—in addition to expanding renewable generation and transmission and distribution infrastructure. Regulators and industry participants will need to come together within a framework that will incentivize the development of large scale, clean hydrogen projects.

Challenges ahead are significant but less so than the consequences of staying the course, and potential market participants are encouraged to consider the opportunities of first-mover advantage before the rush starts.

## GOVERNMENT SUPPORT FOR PRIVATE INVESTMENT

Hydrogen is widely recognized as a critical technology for the decarbonization of the U.S. economy, especially “hard-to-decarbonize” sectors such as steel, cement and fertilizer production, transportation, off-grid power generation and building heating. The U.S. Department of Energy (“DOE”) takes the view that “[c]lean hydrogen is a form of renewable energy that—if made cheaper and easier to produce—can have a major role in supporting President Biden’s commitment to tackling the climate crisis.”<sup>[3]</sup> Accordingly, this summer DOE announced the “Hydrogen Shot,” a “1-1-1” goal to cut the cost of clean hydrogen to \$1 per 1 kilogram in 1 decade, an 80 percent reduction from its current estimated average cost of \$5 per kilogram.<sup>[4]</sup>

Consistent with this goal, the Infrastructure Investment and Jobs Act, currently being discussed in the U.S. Congress,<sup>[5]</sup> would provide \$8 billion to establish at least four regional clean hydrogen hubs for the production, processing, delivery, storage and end-use of clean hydrogen. The bill would also provide \$1 billion for hydrogen research and development focused on the commercialization of green hydrogen and \$500 million for the advancement of clean hydrogen production, processing, delivery,

storage and use. A U.S. \$3-per-ton subsidy for low carbon hydrogen production, proposed in the bill, could significantly incentivize production by bringing down the price of green, pink, blue and turquoise hydrogen relative to grey hydrogen and even natural gas itself.

Both public officials and industry recognize the important role hydrogen could play in the decarbonization of the U.S. economy. Yet, as the world’s largest economy, the U.S. is still far from the investment levels required to achieve its net zero goals. In its 2021 Global Hydrogen Review, the International Energy Agency (the “IEA”) estimated that a \$1.2 trillion investment in hydrogen is needed globally if the world stands a chance of reaching net-zero emissions by 2050. According to the IEA, the U.S. and other major countries need to move faster and more decisively on policy measures and incentives to enable hydrogen and other clean energy technologies to truly emerge.

## PRODUCTION COST

Per the IEA, “the main obstacle to the extensive use of low-carbon hydrogen is the cost of producing it.”<sup>[6]</sup> Currently, hydrogen from renewable sources costs about \$5 per kilogram to produce in the U.S., with the cost heavily driven by the cost required to acquire and install renewable power equipment, electrolyzers and hydro-

gen compressors. As noted above, the DOE has a goal to unlock new markets for hydrogen, including steel manufacturing, clean ammonia, energy storage and heavy-duty trucks, to achieve an 80 percent cost reduction to bring the cost to \$1 per kilogram<sup>[7]</sup>.

With technological advances and economies of scale, the cost of making hydrogen with solar photovoltaic (“PV”) electricity can become competitive with hydrogen made with natural gas, according to the IEA’s Roadmap to Net Zero by 2050<sup>[8]</sup>. The Roadmap<sup>[9]</sup> provides a scenario in which hydrogen from renewables falls to as low as \$1.30 per kilogram by 2030 in regions with excellent renewable resources and to \$1 per kilogram in the longer term. This scenario makes clean hydrogen from solar PV cost-competitive with hydrogen from natural gas, even without carbon capture, usage and sequestration (CCUS).

The cost of automotive fuel cells and electrolyzer units is also expected to come down significantly thanks to technological advances and economies of scale, though we may ironically see cost increases in the short term due to demand for equipment significantly outstripping supply.

## INFRASTRUCTURE

The next biggest obstacle to widespread adoption of green (and blue) hydrogen in the U.S. is the slow pace of development of low carbon hydrogen infrastructure. Whereas large megaprojects are already beginning to be developed in Australia, the Middle East, the UK, Europe and Af-

rica, the U.S. is regarded by many as a sleeping giant, with world-leading production potential and consumption demand waiting to be unlocked.

Achieving the Biden administration targets using green hydrogen, the cleanest hydrogen, would require massive investment in renewable sources and related power grid infrastructure to connect renewable power to green hydrogen producing hubs or plants.

On the consumption side, hydrogen prices for consumers are highly dependent on how many refueling stations there are, how often they are used and how much hydrogen is delivered per day—as well as the cost of competitor fuels and, of course, the market share increasingly occupied by battery electrification which is very well suited to personal vehicles. Tackling this will require planning and coordination that brings together federal, state and local governments, industry and investors.

## OFFTAKE

There is currently no merchant market for green hydrogen in the U.S. (or indeed elsewhere) and developers and lenders are grappling with how to manage the associated market risk exposure. To be considered bankable, green hydrogen projects will generally require long-term, fixed price offtake contracts with creditworthy offtakers, structured on a take-or-pay basis, similar to early LNG projects.

However, there is a limited pool of creditworthy offtakers with the risk appetite and downstream distribution

network to offtake green hydrogen at utility scale. It is difficult for producers to commit to steady and predictable production profiles because of the reliance on renewable power sources, making volume commitment arrangements complex.

## REGULATORY

The lack of regulation and proper incentives currently limit the development of a clean hydrogen industry. The U.S. government and industry would also need to work together to ensure the regulatory environment does not pose an unnecessary barrier to investment.

U.S. regulations setting criteria for description of hydrogen as green, and acceptable carbon limits for describing hydrogen as blue or “low carbon,” do not yet exist. Therefore, first mover developers must be conservative so as to not inadvertently exclude themselves from a particular market. This drives up the time and cost of engineering and potentially reduces the operating efficiency of the projects, making hydrogen unnecessarily more expensive for consumers. It is important for the U.S. to define green criteria for hydrogen projects that are consistent with global standards and provide certainty for project developers and lenders. All aspects of the supply chain should be considered in determining the carbon content. Ideally, the U.S. would work with the European Union and Asian countries to set global standards allowing for a traded market similar to crude oil and LNG. ▀

## ABOUT THE AUTHORS

Dan Feldman—Partner and Leader of the Global Hydrogen Industry Team  
 Omar Samji—Partner and Co-Lead of Energy Innovation  
 Paul Epstein—Partner  
 Gabriel Salinas—Counsel

# The great global switch on: Electrifying the transition

**JASON GOODHAND, GLOBAL LEADER—ENERGY STORAGE, ENERGY SYSTEMS, DNV**



Switching to green electricity today will not be enough to reach 2050 climate change targets. That's the stark warning by DNV in its latest forecast on the energy transition.

Despite industry initiatives and stringent efficiencies globally, the Energy Transition Outlook predicts that energy-related CO<sub>2</sub> emissions are likely to be only 9% lower than 2019 by 2030, and by mid-century, only 45% lower. This falls far short of the 1.5°C carbon budget agreed by global economies in the COP21 Paris Agreement.

The report, now in its fifth year, has consistently called for a rapid transition to a decarbonized energy system within three decades but concedes the planet will most likely reach global warming of 2.3°C by

end of the century.

Electrification is being hailed as the light at the end of the tunnel. In 2019, only a quarter (26pc) of electricity was supplied from renewable sources. By 2050 that share will have risen to 82%, along with major changes in flexibility and storage. But despite an insatiable appetite to advance its use, the pace to upscale has been slow, impacting its sway on averting a climate crisis.

## EVOLVING ENERGY SUPPLY

Primary energy, the total amount of energy behind delivering energy services, was 594EJ before the pandemic. This is expected to return to 2019 levels next year but will then only rise by a further 4%, reaching its peak by 2030 at 617EJ before slowly

reducing by 4% to around 590EJ in 2050.

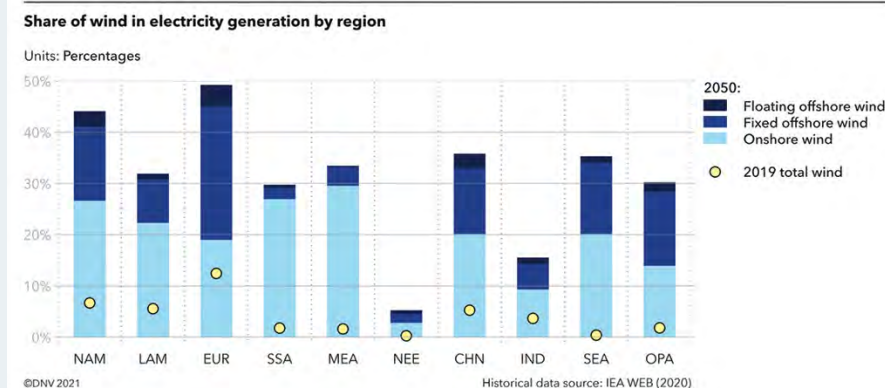
Over the next three decades, renewables will accelerate, tripling from 15% today to 45% by 2050, while fossil fuels, in particular coal and oil, will decline. Natural gas, on the other hand, will grow over the coming decade, then level off for a 15-year period before starting to reduce in the 2040s. It will surpass oil as the largest energy source and will represent nearly a quarter (24%) of global energy supply in 2050. While the overall share of fossil fuels will fall from 80% today, it will still retain half the energy mix by mid-century. Nuclear will be stable at 5% over the entire period.

As CO<sub>2</sub> emissions continue to accumulate, the window of opportunity to act narrows every year. Relying on large-scale, net-negative emissions technologies and carbon removal in the latter half of the century is a dangerous, high-risk approach. With global warming, every fraction of a degree is important, and all options to reduce emissions need urgent realization.

## POWER SURGE

Electrification is by far the most dynamic element of the energy transition. The share of electricity in final global energy demand is set to double from 19% to 38% within a generation.

Wind and solar PV energy are al-



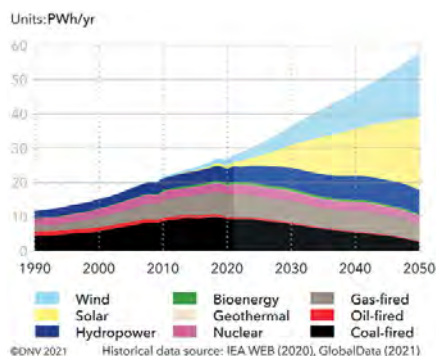
**Figure 1.** Share of wind in electricity generation by region.



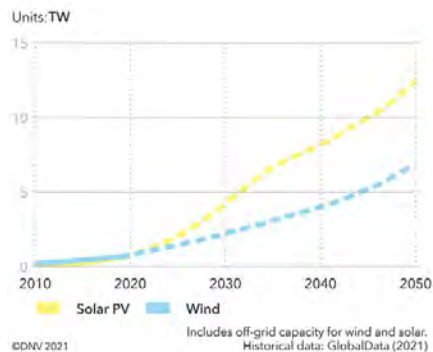
ready the most competitive sources of new power. Within a decade, it is expected they will also be cheaper than operating existing thermal power, in most places.

Wind power provided 5% of the world's electricity output in 2019, almost exclusively in the form of onshore wind. By mid-century that share will rise to 33% as electricity generation from wind increases from 1,420TWh/yr in 2019 to 19,000TWh/yr in 2050. Global wind capacity additions will increase from 60GW/yr in 2019 towards 340GW/yr by 2050, with marked differences in regional developments as illustrated in **FIGURE 1**.

Grid-connected solar PV electricity will rise from 3.2% in 2019 to 36% by 2050, while installed capacity grows 20-fold over the next 30



**Figure 2.** World grid-connected electricity generation by power station type.



**Figure 3.** Build-up of solar and wind—global installed capacity

years to reach 11.5TW in just 30 years. Greater China will hold a 35% share of this capacity, followed by the Indian Subcontinent at 20%.

In 2020, despite the supply-chain disruptions caused by the COVID-19 pandemic, new solar PV installations again set a record at 129GW. From 2030 onwards, we expect annual additions of between 300 and 500GW.

The share of variable renewable energy sources (VRES) in the energy mix will mushroom towards 2050 from 8% to 69% of grid-connected power generation, compared to just 13% for fossil fuels (**FIGURE 2**). Connectivity, storage, and demand-response will therefore be critical assets in the decarbonized power system of the future.

On the demand side, passenger and commercial electric vehicle (EV) uptake is rising quickly in Europe, China and to some extent the US Government. Incentives, cost reductions and technology improvements in both batteries and charging infrastructure will drive a rapid expansion. By 2032, half of all new passenger vehicles sold globally will be electric, with some regions lagging owing to infrastructure challenges. In buildings, the use of heat pumps will triple, providing 42% of space heat in 2050 while consuming only 15% of energy.

## ROADBLOCK REMOVAL

Variability and low power prices should not be viewed as barriers to a renewable-based, electrified power system. In fact, plunging costs, government support for renewable power build-out, and carbon pricing will ensure that renewables will eventually dominate power generation.

Over the coming 30 years, USD12 trillion will be invested in both building a larger grid and adapting it to the variability of solar and wind through technical solutions such as connectivity, storage, and demand response.

The cost of power from solar and wind will continue to reduce but price

cannibalization threatens the investment case for renewable capacity if cheap power is unused at times of ample supply. However, indirect electrification through power-to-X will require massive renewable electricity production, and along with various storage solutions, will ensure that surplus power will be used, and capture prices maintained at a satisfactory level.

Solar PV + storage will make solar more directly competitive with thermal generation, nuclear, and hydropower. One-third of all solar production will be built with direct storage, and by 2050, solar PV + storage is predicted to produce 12% of all grid-connected electricity (**FIGURE 3**).

## THE GREAT GLOBAL SWITCH ON

Electrification is pivotal to the ongoing energy transition. Demand will more than double between now and 2050. Growing at almost 3% per year to reach some 60,000GWh in 2050, it will outpace economic growth despite continuous efficiency improvements. This is due to vast new categories of demand totalling 35,400TWh/yr by 2050. Of this new demand:

- The electrification of road transport—with around 2.8 billion EVs forecasted to be on the road by 2050—is responsible for one fifth
- Electrolysers producing green hydrogen will take a 23% share
- 11% to new space cooling requirements
- A similar share is for the growing manufacturing subcategory of machines, motors, and appliances.

Historically, prices have been set by the variable cost of the most expensive generation technology, providing revenue for all generators. With the growing dominance of new technologies, including solar, wind, storage, and power-to-X, new rules will emerge. For example, in the 2050 power system, the maximum

price arises when wind and solar supply are at their lowest, unlike the current power system where peak price would typically be at the time of maximum load.

Towards 2030, demand growth and an expansion of VRES will see a steady increase in grid investments, rising by between USD150-200bn/yr from pre-pandemic levels. In terms of circuit length, transmission lines will double and distribution lines more than double by 2050. Some 15% of grid investments will be steered towards digital infrastructure, to address the complexity of a more decentralized power system.

Not everything can be electrified. This is what makes tackling the hard-to-abate sectors of high heat, aviation, shipping, and trucking so very urgent. Hydrogen is a major contender where electrification is either infeasible due to the low energy density of batteries or very costly. Its production, however, is expensive and involves significant energy losses. Absent some extraordinary policy shift to subvert its production and

use, hydrogen is expected to supply no more than 5% of global energy demand by 2050.

### FLEXIBILITY AND STORAGE

As we move towards a decarbonized electricity system, there is both opportunity and need for flexibility. With high shares of solar and wind, traditional sources of flexibility will need to be accompanied by a large amount of storage. Over the next 30 years, utility-scale storage capacity will grow 160% to reach 7.3TWh.

There will be a growing emphasis on shifting electricity usage from peak periods to times of lower demand. Better prediction of renewable-power generation and consumption levels will evolve. New technologies and market mechanisms will also allow more consumers to provide flexibility in the form of demand response.

Storage technologies will increasingly allow power generation to be decoupled timewise from power demand. High penetration of wind and solar raises price variability and

strengthens the business case for storage, as does the plunging cost of battery technology.

### NARROWING WINDOW OF OPPORTUNITY

Energy efficiency remains the biggest opportunity to tackle climate change as the world absorbs the warnings and addresses the urgent actions needed from COP26. Securing significant improvement in this vital area is viewed as the most significant lever for the transition—achieving greater efficiency is the reason why global energy demand will level off, even as the global population and economy grow. Extraordinary action will be needed but these are extraordinary times. The window to avoid catastrophic climate change is closing soon, and the cost of not doing so is unimaginable.

*All the forecast data in DNV's suite of Energy Transition Outlook reports, and further detail from our model is accessible on Veracity – DNV's secure industry data platform. [eto.dnv.com/forecast-data](https://eto.dnv.com/forecast-data)*

## ABOUT THE AUTHOR

Jason Goodhand joined DNV in 2019 as the global business leader for energy storage. Jason has pursued a career focused on new energy technologies. With over 15 years of experience in the cleantech energy sector, Jason has developed and managed businesses and projects involving grid-scale renewable energy, hydrogen fuel cells, and energy storage in Canada and the United States.

Jason's role at DNV comes after 10 years with international energy giant ENGIE in various roles and locations, most recently its North American Storage group. Jason holds a Master of Business Administration degree from the Richard Ivey School of Business and a Mechanical Engineering degree from the University of Western Ontario.

# Taking a stance on portfolio decarbonization

**KATHARINA BEUMELBURG, CHIEF STRATEGY AND SUSTAINABILITY OFFICER, SCHLUMBERGER**



Rising global populations and increasing energy demand in both developed and developing countries leave the oil and gas industry facing a new imperative—actively and directly addressing climate change while also meeting global demand for energy today and into the future, sustainably. To tackle this imperative, the industry must act with purpose and intent, focusing on driving change today, while simultaneously transforming for a more sustainable tomorrow.

While an upcycle is on the horizon—most indicators are pointing towards a demand-led recovery toward the end of 2022—the oil and gas industry must work collectively across the value chain to decarbonize operations. Significant emphasis must be placed on ensuring the industry can meet the near- and mid-term demand, sustainably, while also playing a role in progressing toward developing the solutions required for energy transition.

The upstream oilfield services sector is uniquely placed to meet these challenges and play a key role in the world's energy transition. By leveraging its extensive domain expertise and more than a century of technological innovation, combined with world-class manufacturing capabilities and a global footprint that reaches into the most remote parts of the world, the oilfield services sector will be integral to decarbonizing

the oil and gas industry and driving the energy transition.

## GETTING TO NET ZERO

In June 2021, oilfield services firm Schlumberger announced its commitment to achieve net-zero greenhouse gas (GHG) emissions by 2050. With minimal reliance on offsets, the plan is focused on reducing Scope 1, 2 and 3 emissions across the oil and gas value chain. The inclusion of Scope 3 emissions is a first from an energy services provider. Schlumberger's net-zero commitment is aligned with the 1.5 degree Celsius target of the Paris Agreement.

Leveraging its history and culture rooted in science, the company is taking a science-based approach to climate change, and views technology as a key enabler to create change. To ensure transparency along its net-zero journey, Schlumberger has aligned with the Task Force on Climate-related Financial Disclosures (TCFD) and Sustainability Accounting Boards (SASB).

The company is focusing its net-zero commitment on three key elements: operational emissions, technology-use emissions, and carbon-negative actions. Operational emissions constitute 25% of the company's baseline footprint, whereas technology use comprises 75% of the baseline footprint. The third component, carbon-negative actions such as bioenergy with carbon capture and storage, will help to ensure minimal reliance on offsets.

## REDUCING OPERATIONAL EMISSIONS

The first component of Schlumberger's decarbonization plan is reducing operational emissions. Schlumberger is addressing its own operations and footprint to directly eliminate its Scope 1 and 2 emissions. Core to this effort is leveraging digital innovation to enable remote work, automation and now autonomous operations. These capabilities help to reduce the number of people at field operations sites, which translates to reduced transportation costs and waste production.

The company is also utilizing low-carbon and electrification solutions that help to reduce operational energy consumption and emissions, while ongoing facility rationalization—including retrofitting buildings to be more energy efficient and converting to green energy utilization where possible—is providing significant opportunities to reduce waste and power consumption. The company is also addressing its heavy and light vehicle fleet by converting to low-carbon fuels, and shifting to electric over time, further contributing to a decrease in overall emissions and energy use.

## TRANSITION TECHNOLOGIES

Reducing emissions associated with technology use is the second component of Schlumberger's decarbonization plan. Schlumberger is looking to its own supply chain and working with



its customers to help achieve their decarbonization targets. Customer use of technology accounts for 75% of Schlumberger's baseline GHG footprint.

The company has introduced its Transition Technologies portfolio that is specifically aimed at helping customers reduce their emissions, which in turn enables Schlumberger to meet its Scope 3 emissions target. The Transition Technologies portfolio is comprised of solutions designed to help customers minimize emissions and reduce energy consumption, as well as address other key sustainability attributes, while simultaneously driving efficiency, reliability and performance.

With both sustainability and performance in mind, the Transition Technologies portfolio is divided into specific themes that target a wide range of sustainability challenges and opportunities across exploration through to production. These themes include:

- Addressing fugitive emissions (measuring, monitoring and assessing operations to minimize impact)
- Minimizing drilling carbon footprint (reducing emissions per foot drilled)
- Reducing or eliminating flaring (predicting and adjusting emissions)
- Full-field development solutions (collaborating to drive high performance, sustainably, for low-carbon impacts)
- Electrification of infrastructure (accessing renewable power, digitizing customer infrastructure and reducing environmental impact).

## QUALIFYING AND QUANTIFYING

To qualify and quantify the Transition Technologies portfolio, the company developed a basic framework, which is specifically aligned to six of the United Nations Sustainable Development Goals (SDGs) that are most applicable to its technologies. Schlumberger then defined eight sustain-

ability attributes that more easily enable direct impact comparisons:

- Emissions reduction
- Reduction in energy consumption
- Electrification of infrastructure
- Measurement, monitoring, and assessment
- Less hazardous material and cleaner chemistry
- Water stewardship
- Waste reduction
- Physical size and impact reduction.

The framework was initially used to identify more than 100 products and services for potential inclusion in the Transition Technologies portfolio. The technologies were then prioritized for impact quantification. At this early stage, a fundamental consideration was developing a consistent identification and qualification approach applicable to different types of operations.

Today, the methodology has evolved to be able to facilitate detailed and quantified comparisons, using the framework's attributes, between the environmental impact of the technology being qualified and a similar reference technology, established industry standards, or a before-and-after scenario. This process ensures a consistent and accurate quantifiable comparative analysis.

There are three critical factors that must support a credible methodology: transparency of scope, validity of scope, and robust data to inform the comparative calculations. To ensure that the technologies and scenarios involved in the comparison are valid and realistic options, all phases of the technology life cycle must be considered. Ensuring that the data used for comparison is accurate and consistent is also imperative.

A robust technical review process involving domain and engineering experts ensures all aspects are thoroughly covered when quantifying the impact of a given technology. The next step is to then document the review findings and the data, methods and reference so that it can be repeated. Multiple review iterations are typically required before a sufficiently accurate quantification is achieved. As the process matures, the company is improving its understanding of how technologies rank in terms of sustainability impact.

## NEW ENERGY

The third component of Schlumberger's decarbonization plan is carbon-negative actions. Integral to this effort was the introduction of Schlumberger New Energy, which explores new avenues of growth by leveraging



**Figure 1.** Schlumberger's decarbonization plans are based on climate science and focused on three key areas: operational emissions, customer emissions and carbon-negative actions.

Schlumberger's intellectual and business capital in emerging new energy markets, with a focus on low-carbon and carbon-neutral energy technologies. Its activities include ventures in the domains of hydrogen, lithium, energy storage, carbon capture and sequestration, geothermal power and geoenergy for heating and cooling buildings.

Since its inception in 2020, Schlumberger New Energy has announced initiatives exploring new energy verticals. For example, in March 2021, Schlumberger New Energy, Chevron, tech giant Microsoft and US renewables firm Clean Energy Systems announced

plans to develop ground-breaking bioenergy with carbon capture and sequestration project designed to produce carbon-negative power.

Another example is Celsius Energy, which is a Schlumberger New Energy business venture, focused on heating and cooling solutions for buildings. Essentially, the solution aims to plug buildings into the Earth's continuous and resilient energy resources to deliver heating and cooling, while reducing CO<sub>2</sub> emissions by as much as 90%. Celsius Energy completed the first installation in December 2020 at the Schlumberger Riboud Product

Center in Clamart, France.

### LEADING ENERGY TRANSITION

The oil and gas industry—with the expected increase in energy demand, both in the short- and mid-term—must address the challenge of climate change while also meeting global energy demand today and into the future. By working collaboratively across the value chain, the industry can collectively help drive the change to decarbonize, while also playing a significant role in the world's overall energy transition. ▀

## ABOUT THE AUTHOR

Katharina Beumelburg is chief strategy and sustainability officer at Schlumberger



# Oilfield services rebound back smarter

**JAMES WEST, SENIOR MANAGING DIRECTOR,**  
*EVERCORE ISI*



A strong, globally coordinated recovery has begun. 2021 marked the first year of a multi-year global recovery in E&P capex spending that we expect will accelerate in 2022 and into 2023.

Oil prices are firmly in the \$70's/bl range, oil market tightness is expected to continue as economies re-open, and Opec is likely to gradually return barrels to the market. We expect North American E&P spending to rise ~20% in 2022, and international spending to also be up in the mid-double digits range.

Including the sharp downturn in 2020, global capex spending has only declined nine times in the past 35 years, with the 24% contraction in 2020 ranking third (behind a 31% decline in 1986 and a 33% decline in 2016). Looking ahead, the under-investment in global oil production and the impairment of North American shale will drive the need to produce more hydrocarbons to ensure a smooth energy transition.

## A NEW OIL SERVICE INDUSTRY EMERGES

The oilfield services sector went through a great reset in 2020, a period which was painful for the entire industry and all stakeholders involved. However, it served as a major catalyst to propel the industry towards re-invention, necessary for the sector to stay competitive and

ensure a healthy future.

Today, companies are focused on generating returns rather than just growth and market share. The steps they have taken to dramatically reduce their cost structures, exit certain basins and countries, and close low return product lines drove strong incremental margins off the trough.

We expect advances in digital technologies and company adoption. The sector will be driven by activity increases in international markets and the rebirth of offshore development, more resilient production-oriented businesses, and rich opportunities created by the energy transition to drive further margin improvement. The real operating leverage for oilfield services companies will surprise the market!

## ENABLING THE ENERGY TRANSITION

The oilfield services sector is actually well positioned to steer the energy transition and bring greater decarbonization to oil and gas, despite the surprise of some. The industry can help operators lower emissions during well construction operations. High quality, modern equipment has lower emissions profiles and uses lower emissions fuels, such as dual fuel pressure pumping spreads.

The industry can also provide technology that reduces the carbon footprint of oil and gas operations,

such as technology that reduces sand or water usage, thereby lowering truck trips and diesel emissions.

Emerging technologies will be another important factor in decarbonising operations. Digital tools and renewable tech could include emissions and leak detection, carbon capture and storage, clean energy sources like geothermal and hydrogen. The industry will also support the continued build out of LNG liquefaction facilities, as natural gas will be a key transition fuel. And importantly, the industry's technological expertise will be used to support growth and investment in emerging clean energy sources, such as geothermal, hydrogen, and even lithium.

## REBIRTH OF OFFSHORE DEVELOPMENT

Offshore drilling is experiencing a marked recovery. The offshore rig count bottomed out toward the end of last year and has trended higher ever since. Ultra-deepwater market-ed utilization is up 764 basis points (bps) from the trough of November 2020, and is 670bps higher than a year ago.

Strong Brent oil prices, aggressive rig retirements, and higher demand have all combined to drive utilization higher. The year-to-date average of 12 co $\Omega$ ntracts per month in ultra-deepwater and average day rates of \$235,000/d is tracking ahead of the



2020 average of 7 and \$228,000/d respectively.

Offshore activity levels are also improving in key regions including Mexico, Guyana, Brazil, Suriname, Norway, and Southeast Asia. In ad-

dition, the industry is well placed to play a key role in the success of floating wind installations. These installations utilize similar mooring systems and subsea cables as well as expertise in risk reduction and proj-

ect execution. From a novel concept with only 200MW installed globally, floating wind is expected to gain commercial scale with more than 500MW in capacity wind parks within a decade. ▀

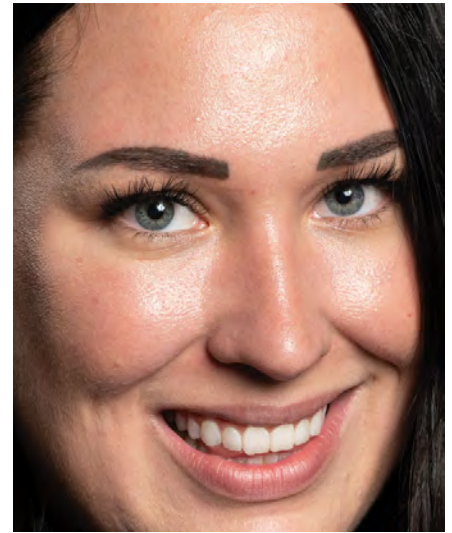
## ABOUT THE AUTHOR

James West is senior managing director at Evercore ISI.



# Digital twin technology will help green the oil and gas sector

**VANESSA ERICKSON**  
AVEVA



The oil and gas industry, in the face of the global climate emergency, has been left with little option but to change its ways and dramatically reduce greenhouse gas emissions. Under ever-increasing regulatory and public pressure, NOCs and IOCs—together with their Engineering, Procurement, Construction (EPC) counterparts—have set ambitious net-zero targets to prevent global temperatures rising more than 1.5 degrees Celsius.

This, coupled with economic, market and political pressures has the energy industry in a race to find new and better ways of working that reduce emissions and maintain shareholder interests. The industry must deliver on its energy reduction commitments while simultaneously optimizing the performance of existing assets to reduce their environmental impact.

The energy facility of tomorrow has a big job to do—improve emission performance of existing operations and transition new investment to deliver greener outputs (such as blue and green hydrogen, or carbon capture), all while optimizing efficiencies holistically to remain competitive. Finding smart solutions that empower workers and help them identify ways to minimise resources, environmental impact and costs are critical in meeting these imperatives.

## ALL CHANGE AT THE TOP

When BP's CEO, Bernard Looney,

stepped into the role in 2020 he announced plans to make the supermajor a net zero emitter by 2050 but admitted that it would not take place overnight. Commenting earlier this year, he said: "This will certainly be a challenge, but also a tremendous opportunity. It is clear to me, and to our stakeholders, that for BP to play our part and serve our purpose, we have to change. And we want to change—this is the right thing for the world and for BP."

And although BP is one of the highest-profile oil companies in the world, it is certainly not alone in its drive to reposition towards greener and leaner. Most recently, French energy giant Total rebranded as TotalEnergies to reflect its broader energy focus, following in the footsteps of other players such as Norwegian firm Statoil, which became Equinor in 2018. Even the UK's Oil and Gas Technology Centre, which has played such a central role in facilitating the development of new technologies has recently renamed itself the Net Zero Technology Centre. More than just brand facelifts, these name changes represent significant commitments to reposition towards a more climate-friendly future.

Going greener also needs to make financial sense. Shareholders are increasing pressure on companies to become more sustainable, but the shift cannot come at the cost of re-

turns. That is why finding smart ways to reduce environmental impact, while improving production performance from the existing hydrocarbon business, is so critical.

According to the ratings organization Better Business Bureau, there is growing evidence that higher sustainability performance delivers better financial performance, and this is gaining traction with investors. The agency says that 90% of studies in this area show that high environmental, social and governance (ESG) standards reduced companies' cost of capital, and that 80% show a positive correlation between stock price performance and good sustainability practices.

## DIGITAL FOCUS

There is a clear remit not only for the energy industry to transition to greener energy technologies, including renewables and hydrogen, but major steps must also be taken to reduce the environmental impact of hydrocarbon production, while continuing to deliver value for shareholders.

And this is where digital twin technology can make the difference. Deeper data-driven insights enable operations to become leaner and reduce capital investment risk by delivering projects more economically. Research executed by technology firm AVEVA found that 85% of industrial organizations plan to increase their

investment in digital transformation over the next three years to tackle climate change, embrace automation and unlock the performance benefits of advanced technologies.

Digitally connected capital projects foster a culture of collaboration—whether greenfield or brownfield—to break down siloes, improve information sharing and reduce project risk. Projects can be delivered on time and within budget, with full visibility and control at all phases. Wasted time and

material are eliminated.

By transitioning organizations to a data-centric approach—where all verified engineering data and tools are stored in a secure, cloud-hosted hub—handover is seamless and plant operations teams are empowered to make better, faster decisions and identify new and better ways of working. And, with a complete digital twin, workers can benefit from training on a replica of the as-built facility before they ever step foot onsite.

From the Feed phases of a capital project through to long-term operational and maintenance excellence of an asset, connecting people with data and processes enhance decision making and optimizes performance. Digital Twins, which aggregate physical, behavioural and process data in context, will create the sea change that the industry needs by connecting people to the right data, processes and tools to make informed decisions faster. ▮

## ABOUT THE AUTHOR

Vanessa Erickson is Engineering and Execution Portfolio Marketing Manager at AVEVA.







BE PART OF THE ENERGY

24TH WORLD  
**PETROLEUM  
CONGRESS**  
**2023**  
CALGARY | CANADA

**17 - 21 SEPTEMBER**

24<sup>th</sup> World Petroleum Congress  
**ENERGY TRANSITION:  
THE PATH TO NET ZERO**

**SAVE THE DATE**

**17-21 September 2023**

Calgary, Canada

[www.24wpc.com](http://www.24wpc.com)

Join us in Calgary as we discuss paths to a net zero energy industry through which governments, organizations and individuals unify as agents of change.





American  
Petroleum  
Institute

# API'S GLOBAL INDUSTRY SERVICES

Learn more:  
[www.api.org/GIS](http://www.api.org/GIS)

API drives safety, environmental protection and sustainability across the natural gas and oil industry by setting world-class standards and best practices, and by administering certification, training and safety programs for global operations.

Visit us at booth **#3201**

