Global Voice of Gas

BY THE INTERNATIONAL GAS UNION

ISSUE 04 | VOL 01

Eliminating methane emissions

Methane emissions and the state of play in the gas industry Top-down versus bottomup approaches India's evolving gas strategy Russia's LNG ambitions



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METHANE SECTION



Why methane emissions



and why now?



Methane emissions and the gas industry: the state of play



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Providing natural gas

Investing in natural gas to reduce the carbon footprint of the global energy mix



<u>Messages</u>

From the President



Dear reader,

Welcome to another issue of the Global Voice of Gas, the digital magazine of the International Gas Union. The three months since our last edition have again evidenced the rapidly evolving environment in which operate.

Within the IGU, we have taken further important steps to establishing our Permanent Secretariat in London, with new staff arriving and a handover underway between our Barcelona and London teams. By August 1 our London headquarters will be fully functional, and Andy Calitz will be installed as our new Secretary General, replacing Luis Bertran, who has so ably led the organisation over the last five years while Barcelona hosted the Secretariat.

As we respond to the ongoing global discussion of climate and energy, an important meeting of the IGU's Executive Committee last month saw the endorsement of an updated IGU position on Climate Change and the Future Role of Gas, which will underline our ongoing advocacy.

The new IGU position makes clear that the Union represents and advocates for natural gas, renewable gases (including hydrogen), decarbonised gases and low carbon gases. It also outlines our support for the Paris Agreement and a commitment to significant decarbonisation of the global energy system – highlighting the vital role that gas will play in meeting those goals.

The position also makes clear that different regions of the world have distinct energy challenges and will have different needs from gas.

The rapidly changing international environment for our advocacy was highlighted by a provocative International Energy Agency report on the pathway to meeting net zero emissions targets by 2050.

The IGU has always respected the balance of IEA's research, its robust analysis, and thought leadership. However, we believe that the pathway described in last month's report is overly reliant on undeveloped technology and more importantly will not lead to a just transition. Under the ambitious pathway, millions of people would be left behind.

We made this position clear in multiple engagements with external stakeholders, and it was published in the Financial Times.

Gas positively contributes to the four core energy dynamics that face global society. Energy must be available to all people on the planet. Energy supplies should be secure and constant. Energy supplies must be affordable. Finally, the energy dynamic should be a catalyst for the just transition. The IGU argues that the prudent use of electrons, natural gas and hydrogen molecules, and the necessary infrastructure can help individual countries meet the UN Sustainable Development and Paris Goals. That's the message policy makers the world over will continue to hear from us.

But as important as these messages are, they mean little if not backed by concrete actions from our industry. A vital area in that regard is delivering on actions to measure and mitigate methane emissions right across the gas value chain. In this edition, we take a closer look at how the role of gas in the transition to a low-carbon future will be influenced by the extent to which the oil and gas industry reduces its methane emissions.

We expect this will be the focus of considerable discussion in the months ahead, as G20 leaders meet and the world prepares for the COP26 summit in November. The IGU is committed to being an important contributor to those discussions.

I hope you find this edition of Global Voice of Gas informative and engaging.

-Professor Joe M Kang President, International Gas Union

Every quarter the Global Voice of gas is sent directly to over 25,000 industry stakeholders around the world and is also available on our website and social media channels. Each edition brings to the global gas community new insights and analysis of key developments impacting global gas markets and the key role our members and industry are playing in a sustainable energy future. elcome to the fourth issue of *Global Voice of Gas* (*GVG*), an International Gas Union publication, produced in collaboration with Natural Gas World (NGW), that sets a new standard in communication for the natural gas community worldwide.

The global gas market has grown increasingly bullish in recent months, as a broad economic recovery has led to strengthening demand. Current and predicted robust demand consequently highlights the need for further investment in gas supply, in order to ensure that energy will be available for the entire population and that it remains secure, affordable and clean in the years to come. Gas will be a vital catalyst and foundation for the world to meet its Paris Agreement and Sustainable Development Goals.

The global climate change debate has chiefly revolved around CO_2 emissions and efforts to abate them. But there is growing awareness that the mitigation of methane emissions also has a vital role to play. This is why we devote some of this edition to shine a light on this topic and the important work underway in the gas sector to minimise these emissions. We also explore the various ways methane emissions can be identified, quantified and eliminated, and look at the various voluntary initiatives that are working to address them.

In addition, we examine what form the European Commission's upcoming legislative proposal on methane emissions in the energy sector is likely to take, and what recommendations the EU gas industry has to make.

We also draw attention to key developments taking place across the world's gas industry, including the unbundling of gas transmission infrastructure underway in China. A new entity, China Oil & Gas Piping Network Corp, was set up in December 2019 and has gradually been accumulating the country's gas midstream assets. These reforms are spurred by a desire to boost domestic production and imports of gas, which is seen as a major component of the country's decarbonisation strategy.

Neighbouring India is meanwhile shifting the focus of its gas policy agenda away from upstream reforms and towards midstream and downstream initiatives. The government of prime minister Narendra Modi has long been pushing for greater consumption of gas in order to establish a gas-based economy. The ultimate goal is to expand gas' share of the country's primary energy mix from around 6% at present to 15% by 2030.

It is a busy year for European climate legislation. Besides its recommendations on methane emissions, the European Commission plans to publish a raft of other legislative proposals this year aimed at aligning the EU's energy and climate policies with its commitment to cut greenhouse gas emissions by 55% by 2030. It is looking to set out rules for how to incorporate renewable, synthetic and decarbonised gases into the gas market, adjust its directive for promoting renewable energy and make changes to the EU emissions trading system.

Finally, Russia wants to leverage its low costs to carve out a 20% share of the global LNG market by 2035, and we look at the various projects it has in the pipeline to achieve this goal. The country is banking on bullish demand for gas in Asian markets, where the fuel has gained ground by displacing coal in power generation, helping to reduce emissions.

— Paddy Blewer Director of Public Affairs, IGU

- Joseph Murphy

Editor of Global Voice of Gas, Natural Gas World



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Events





RODNEY COX Director of Events, IGU

On May 23 2021, delegate registration for the 28th World Gas Conference, WGC2022, opened, marking one year before the conference and exhibition. As an indication of the "whole of country" support for WGC2022 the Korean Prime Minister, Kim Boo-kyum, was the first person to register to attend WGC2022.

The event will embark on a journey to discuss the theme of the triennial conference, 'A Sustainable Future – Powered by Gas'. We have an extensive conference and exhibition lined-up for you over the 4 days. Join WGC2022 to learn and hear the perspectives of the global gas leaders, policymakers, distinguished energy officials and technical experts. You can be a part in this pioneering conversation and shape the energy agenda by submitting your <u>Abstract</u> for <u>Call for Papers</u> and speaking at WGC2022.

Also don't miss the chance to visit the extensive exhibition to network, connect and do business deals with the leading gas stakeholders and buyers. If you are considering exhibiting or sponsoring at WGC2022 check out the 60 second video on the <u>upcoming</u> <u>briefing</u>. Further details at <u>exhibition@wgc2022.org</u>

<u>Register today</u> to be a part of the 28th World Gas Conference, WGC2022, May 23 to 27, at the outstanding EXCO Convention Centre, Daegu, Korea.



LNG2023, St Petersburg

The LNG Events Series is the world's longest running resource for the technical and commercial development of the LNG industry. Now you can access all the papers presented at every event since LNG 1 in 1968, all fully searchable, at Club LNG, which is part of the planning for LNG2023 St Petersburg. Plus, when you join ClubLNG, you have the opportunity to help shape the topics for the programme at LNG2023, so have your say! All this is available for free by joining ClubLNG at www.lng2023. com. For further details contact the team.



IGRC2024, Banff

The Canadian Gas Association (CGA) will host IGRC2024 in May 2024 in Banff, Alberta. While the conference itself is still three years away, CGA is designing a program for IGRC2024, starting in the fourth quarter of 2021, that will include a webinar series and other communications activities that highlight the innovation, research and technology development that is happening in the gas sector around the globe. To stay informed about IGRC2024 developments, please join CGA's mailing list.



5th Latin American Gas Conference & Exhibition

IGU in partnership with ARPEL, EnergyNet and with the collaboration of OLADE, is pleased to announce the 5th Latin American Gas Conference and Exhibition will be preceded in 2021 by a series of digital dialogues, covering key topics on the sector such as country spotlights, investment policies for commercially viable and sustainable development, opportunities for gas in the energy transition strategy, regional integration and global markets. More details at LGC Digital Dialogues.





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Regional Update

North East Asia & Australasia



GRAEME BETHUNE Chairman, Australian Gas Industry Trust, IGU Regional Coordinator, Australia

New Zealand walks away from gas

- ➢ Of all the countries in the IGU's North Asia-Australasia region, New Zealand is the most bullish in pursuing its transition to net zero carbon emissions. The government has legislated a target date of 2050 for this, but the transition is already causing issues for natural gas and the wider energy sector.
- New Zealand is in a unique position in that nearly half of their emissions come from agriculture (with methane emissions not being included in the net zero target) and around 80% of electricity is from renewable sources.
- > However New Zealand's hydro sources are affected by dry years and so require natural gas and/or coal as backup. This is happening now, with temporarily reduced supply from one of the country's main gas fields (Pohokura) combined with a water shortage causing high energy prices and reduced industrial output. This is a clear warning of the challenges ahead in transitioning.

Climate Change Commission

» New Zealand's Climate Change Commission published draft advice to the government on January 31 on how to achieve its emission reduction goals. Following consultation, the Commission plans to provide its final advice at the end of May 2021.

- ➤ The Commission sees natural gas for industrial use being phased out over time but a small role remaining for electricity peaking through until 2050 at least. This is at odds with the Labour government's policy to have 100% renewable electricity by 2030.
- To achieve this the government is investigating a pumped hydro scheme in the South Island. This is controversial given the cost (estimated at \$4bn, almost certainly too low), practicality, and the dampening effect on much needed private sector investment into electricity generation (including renewables).
- The Commission's approach has been criticised as focusing too much on gross emissions rather than net emissions. This has led to a top-down approach with bans and other costly interventions proposed to stop emissions at their source, rather than allowing for offsets (trees) or the use of international carbon units.
- New Zealand prices emissions through an Emissions Trading Scheme (ETS) which has recently introduced a cap on total emissions allowed. This market tool should be sufficient to reach the goal of net zero emissions, but both the government and Commission are increasingly focused on interventions such as subsidies and bans. This could make the transition more difficult and more costly than it needs to be.
- ➤ A good example is the Commission's draft recommendation for no new natural gas connections to the grid or bottled LPG connections from 2025 onwards. However, in April the operator of New Zealand's gas transmission infrastructure First Gas unveiled a plan to decarbonise the gas network through gradually switching to hydrogen from 2030. It remains to be seen if this will lead the Climate Change Commission to amend their proposed connection ban. →

The end of frontier exploration

- In 2018 the New Zealand government announced it would no longer issue permits for offshore oil and gas exploration beyond Taranaki, denting industry confidence in its future. Shell left New Zealand in 2018 after more than 100 years of operation and they have been followed by a number of major explorers such as Equinor and Chevron.
- Earlier this year saw the end of an era when the final offshore exploration permits beyond Taranaki were surrendered. This leaves Taranaki as the only region producing and with active exploration permits.

Supply concerns

- The major drop in exploration acreage raises concerns over future supply, given exploration is essential to replace declining existing fields.
- New Zealand's Gas Industry Company (GIC), established by the government in 2004 as a gas industry body and coregulator with the sector, has begun an investigation into the security of the country's gas supply following a request from the Minister of Energy.
- The GIC has noted the electricity sector and major gas users need certainty and transparency about gas supply as the country moves towards a target of 100% renewable generation and net zero carbon by 2050.
- Their initial report has just been released which warns that while there is enough natural gas in the ground to meet demand until 2035, in a worst-case scenario there may not be enough gas to ensure security of supply for electricity by 2026. The report finds that a lack of predictability in policy settings is hampering investment at every level of the industry.
- ➤ The impacts of this are being felt already. Methanol-producer Methanex, which consumes 40% of the total gas supply, has

announced it will mothball part of its production and the GIC has started to investigate imports of LNG (likely from Australia) to get the country through the transition.

New Zealand's IGU Charter Member Energy Resources Aotearoa has criticised this possibility. CEO John Carnegie said "importing natural gas from Australia in the form of LNG would be crazy when we have our own local resources here. More than likely it would mean higher energy prices for consumers and higher emissions from shipping the LNG here. Our members are continuing to invest in their existing assets to enhance supply in the short and medium term, but beyond that further exploration and development is required."

Change for industry body

- As readers may have noticed above, New Zealand's IGU Charter Member has officially changed its name. This is part of a new strategy to focus on the wider energy sector including users, producers and distributors. The Petroleum Exploration and Production Association of New Zealand (PEPANZ) is now Energy Resources Aotearoa, with 'Aotearoa' being the commonly used indigenous Māori language name for New Zealand.
- ➤ To end on some positive news, it appears an increasing number of New Zealanders understand and value the role of natural gas. A survey of 1,165 New Zealanders conducted in late 2020 found 68% of respondents agreed it would be better to produce gas in New Zealand than import it. There was also a significant decrease in the proportion of New Zealanders with an unfavourable view of the oil and gas industry (down from 32% in 2017 to only 16%).
- In global terms New Zealand is one of the smaller gas users. However, its journey as it attempts to transition to net zero emissions is of global significance and sure to be closely watched.



South & Southeast Asia



HAZLI SHAM KASSIM President, Malaysian Gas Association, IGU Regional Coordinator, Malaysia

Effective government-industry partnership

- At the 52nd GECF Gas Lecture Series held on April 26 2021, Hazli Sham Kassim, President of the Malaysian Gas Association (MGA), highlighted the role of governmentindustry synergy to drive forward the national agenda and shape future opportunities. He showcased the effective role played by the MGA, as the lead advocate of the gas industry in Malaysia, to collaborate with the Malaysian government to position natural gas as the critical fuel for socio-economic growth and in transitioning towards a low carbon economy.
- MGA is credited with realising the gas market liberalisation agenda, and participated in the development of the Natural Gas Roadmap that highlighted and promoted the rising role of natural gas as a source of cleaner energy in the National Energy Policy.

Regional trends on coal

- The latest draft of Vietnam's 8th Power Development Plan has scaled back coal-fired power generation significantly with no new coal generation except those planned for completion by 2025 or sooner.
- The Peninsular Malaysia Generation Development Plan 2020 published in March 2021 also scaled back coal-fired power plants with a net reduction of more than 4 GW of installed capacity by 2039.
- In May 2021, Indonesia's largest utility, Perusahaan Listrik Negara (PLN) pledged to stop building new coal-fired power plants beyond the current pipeline of projects.
- This follows the pledge made earlier by Malaysia's largest utility, Tenaga Nasional Berhad (TNB) on no longer investing in greenfield coal plants.
- Also in May 2021, Malaysia's largest bank and fourthlargest in Southeast Asia, Malayan Banking Berhad (Maybank) committed to stop financing new coal activities as part of its sustainability agenda.
- ➤ This follows the similar commitment made in December 2020 by another Malaysian bank, CIMB Group Holdings, that will also phase out coal from its portfolio by 2040. →

- Earlier in 2019, Singapore major banks, namely, OCBC, UOB and DBS, all pledged to stop financing new coal projects.
- ➢ On May 7 2021, Asian Development Bank issued its Draft Energy Policy for public comments where it committed to withdraw from financing for new coal power generation and support countries to achieve a planned and rapid phase-out of coal.

Regional trends on LNG-to-power projects

- PTT Plc and the Electricity Generating Authority of Thailand (EGAT) signed an agreement on May 12 2021 to jointly conduct a study on potential LNG-to-power projects in the southern part of Thailand. The projects include the construction of floating storage and regasification unit and a gas-fired power plant.
- ➤ Myanmar Investment Commission has approved 15 new investment projects including an LNG-to-power project that will cost \$2.5bn.
- Delta Offshore Energy has selected Stena Power & LNG Solutions to supply a jettyless floating terminal (JFT) and self-installing regasification platform (SRP) to provide energy to the 3,200-MW power plant project to be located at Bac Lieu province in the Mekong Delta, Vietnam. The JFT and SRP will be located approximately 40 km off the Vietnam shoreline.

Malaysia

The Malaysian gas market is expected to be fully liberalised in 2022, when the remaining regulated gas tariff ends on December 31,2021. In an effort to facilitate a smooth transition towards market liberalisation, the Malaysian Gas Association (MGA) organised a series of Roundtables as a platform for both policymakers and industry players to deliberate on topics impacting market liberalisation.

- The National Energy Policy (NEP) is expected to be announced by the Malaysian government in the second quarter of 2021. The main focus of NEP is to ensure sub-sector energy development is aligned with the global energy transition trend, while also improving Malaysia's energy governance structure and market liberalisation aspects. Together with holistic action plans, the NEP would see a transition towards a lowcarbon future.
- Energy Commission of Malaysia in March 2021 released its report on Peninsular Malaysia Generation Development Plan 2020 forecasting an increase in gas demand from 643mn ft³/day in 2021 to 1.646bn ft³/d in 2039. During the same period, the carbon intensity for that sector is expected to fall by 60%.
- ➤ The Malaysian government on April 27 2021 launched the 10-year National OGSE Industry Blueprint 2021-2030 that will further intensify local development of the oil & gas services and equipment (OGSE) industry into a more robust, resilient and globally competitive sector. The OGSE industry has over 4,000 vendors servicing Malaysia's oil & gas industry that made up 14.5% of GDP and 13.8% of the government's revenue in 2018.
- > Another gas discovery was made in the SK438 block offshore of Sarawak by PTTEP of Thailand. The block adds to its other production assets in Malaysia including in Blocks K, SK309, SK311 and H.

India

- ≫ Natural gas production was up 22.7% in April 2021 from the previous month to 2.65bn m³.
- » Natural gas consumption was up 34.5% year on year in April 2021 at 5.3bn m³. The sharp spike however was due to a lower base in April 2020 when India was under full lockdown due to the COVID-19 pandemic.
- ➤ City gas demand however is expected to drop around 25-30% in Q2 2021 due to the rapid spread of the COVID-19 pandemic across large cities and states.

Europe



ANDREA STEGHER Senior Vice-President, Snam, IGU Regional Coordinator, Italy

Demand on an upward trend

- After an exceptional 2020, 2021 has confirmed gas demand resilience, with final data of the first part to confirm what can be almost 5 year highs, with hub prices again in the €20-25/ MWh range. The upward trend in CO₂ values has continued. They are now in the 50+ €/metric ton range, almost double the 2020 average.
- Energy pricing dynamics are making coal fired CCGTs (lignite and hard coal) less profitable and therefore targets to decommissioning can be substantially accelerated by markets, creating at the same time a stronger focus to security of energy supplies and flexibility, where gas provides substantial support to the electricity market.
- In addition, gas' innate flexibility for heating purposes was also highlighted in early April where a widespread cold snap reversed storages from injecting around 200mn m³/day to withdrawing more than 300mn m³/d in just a couple of days! That's unparalleled flexibility for all consumers.
- In perspective terms, pricing evolution is also creating more immediate appetite for blue hydrogen as it rapidly gains cost competitiveness, within the framework of a strong focus to promote innovation deployment. The gas industry is clearly demonstrating how it can continue to play a substantial role in promoting sustainable innovation and economic recovery in line with Europe's priorities, both in natural gas and in new low-carbon and green markets, with a constant increase of biomethane contribution, and a mounting interest for bio-LNG in heavy duty transport.



The upcoming legislative tsunami

- European gas competitiveness, flexibility, sustainability and innovation will continue being crucial for our industry especially considering the upcoming "legislative tsunami" that will address in the coming months almost every single aspect of the energy space in the region.
- > Together with the "Fit for 55" package (i.e. emission reduction target at 55 % by 2030), a goal of spending 37% of the €750bn NextGenerationEU recovery fund on Green Deal objectives, and the intention to raise 30% of the NextGenerationEU budget through green bonds, have been defined as key priorities for the EU.
- ➤ Alongside specific regional evolution, Europe this year is also key to both the G20 and COP26 initiatives.
- In both circumstances, IGU is working in addition to cooperation with other members of the Gas Naturally platform – to effectively position our industry as one of the key and credible stakeholders to contribute to the discussions.
- As a first step, IGU is currently organising a G20 side event (mid-July) to discuss the "Critical role of molecules in securing energy supplies for sustainable inclusive recovery and energy transition". This will be a clear occasion for the gas industry to showcase both pragmatism in meeting consumers' needs and vision to promote investments and solutions that will support addressing the climate challenge issue and creating a just transition.

Russia, Black Sea and the Caspian Area



MARCEL KRAMER President, Energy Delta Institute, IGU Regional Coordinator, the Netherlands

Russian supply surge

- ➤ Gazprom announced that a total of 68bn m³ was exported to Europe, including Turkey, in the period January-April, a hefty 28% increase over the same period in 2020. This year's much colder weather played a significant role, and there were changes in LNG supply to Europe, in the pandemic's impact on demand, and in prices of gas versus coal. For the year 2020 as a whole, exports to Europe were 175bn m³, a significant drop of 12% from the 2019 volume.
- Infrastructure expansion for gas processing and transport continues at a strong pace. The pipe-laying for the last stretch of the Nord Stream 2 system in German waters has been resumed. Gazprom also started construction of a major new gas processing facility at Ust-Luga south of St Petersburg. This facility will include a 13mn metric ton/year LNG liquefaction plant, named Baltic LNG, whose two trains should be ready in the fourth quarters of 2023 and 2024 respectively. It will also comprise a 3mn mt/yr polymer plant and facilities to process 18bn m³/yr of gas for injection into Gazprom's transmission system. After a start-up period, gas will come from the Tambey field on the Yamal Peninsula.
- Dooking forward, Gazprom expects gas demand in the two major markets of Europe and China combined to grow from the current 865bn m³ to 990bn m³ by 2030. China's gas demand growth will more than compensate for an expected 5-6% demand decline in Europe. Taking into account the projected levels of gas production within Europe and China, the total need for imports from outside Europe and China is set to grow by some 80bn m³ between now and 2030.



Novatek recently announced that the start-up of the third train of the Arctic LNG 2 plant will be brought forward from 2026 to 2025. The three trains have a capacity of 6.6mn mt/yr each, and a 20-year contract for offtake by the partners is in place. Novatek's CEO expressed hope that the Northern Sea Route, allowing for a much shorter route to Asian markets, would be open year-round in 2023-2024. Floating LNG transshipment points are also being built at Kamchatka for the East and at Murmansk for the West. This should enable ice-breaker class LNG tankers to transship to conventional LNG tankers.

TAP market tests

The Trans Adriatic Pipeline (TAP) transports natural gas from the giant Shah Deniz field in the Azeri sector of the Caspian Sea to Europe. The 878-km long pipeline connects with the Trans Anatolian Pipeline (TANAP) at the Turkish-Greek border in Kipoi, crosses Greece and Albania and the Adriatic Sea, before coming ashore in Southern Italy. TAP started flowing gas recently and has now launched the information and binding phase of its market test for various expansion scenarios. Depending on the outcome, we could see a major further increase in pipeline capacity for imports into Turkey and Southeastern Europe with TurkStream (formerly South Stream) and TAP as its largest components. The further decarbonisation of the region through additional gas supplies will result.

The Middle East & Africa



KHALED ABUBAKR Chairman, Egyptian Gas Association. Executive Chairman, TAQA Arabia and IGU Regional Coordinator, Egypt

- Although COVID 19 had its major implications on the gas industry in every corner of the world, it has proven how solid and robust this industry is. Even during the peak of the pandemic and during the second wave, gas in Africa & the Middle East kept sustainably fuelling hospitals, factories, and houses.
- The region is waiting on a significant gas supply boom coming from projects under construction and in the pipeline. However, and for financial issues, many countries are struggling to significantly break into the expanding LNG market besides Angola and Nigeria.
- ➤ Egypt signed nine new agreements worth around \$1bn to drill 18 exploration wells. It is planned to achieve natural gas production rates of 7.2bn ft³/d of gas and 100,000 b/d of condensate.
- 3 13 countries have greenlit a gas pipeline between Morocco and Nigeria. The 5,660-km pipeline, estimated to cost \$25bn, will serve as an extension of the existing West African Gas Pipeline currently serving Benin, Togo and Ghana, as well as connecting with Spain through Cadiz.
- During the last decade, Mozambique has emerged as a leading player in LNG. Although COVID-19 has impacted some projects, the \$20bn Mozambique LNG project achieved \$15bn in debt financing during the crisis, and the country's GDP growth forecast, while significantly reduced, remains positive at 0.7%. In what is distressing news for the African gas industry, France's Total withdrew workers from Mozambique LNG after a nearby attack.



- ➤ Qatar Petroleum took the final investment decision for developing the North Field East Project (NFE), the world's largest LNG project, which will raise Qatar's LNG production capacity from 77mn metric tons/year to 110mn mt/yr. In addition to LNG, the project will produce condensate, LPG, ethane, sulphur and helium. It is expected to start production in the fourth quarter of 2025 and its total production will reach about 1.4mn barrels oil equivalent/day.
- Iraq is exploring the possibility of importing gas from the region through a neighbouring country, as it looks for alternatives to buying expensive fuel.
- The UAE's Mubadala Petroleum, a sovereign wealth fund with \$232bn in assets, signed a memorandum of understanding to buy a 22% stake in Israel's Tamar offshore field. Once completed, this will be the biggest business deal between the two Middle Eastern nations since they normalised their ties in August 2020.



North America



TIM EGAN CEO, Canadian Gas Association, IGU Regional Coordinator, Canada

In North America, there is something of a perfect storm of public and activist policy targeting the gas sector

- ➢ From above (i.e from governments) there is a very strong emission reduction agenda which is invariably manifesting itself as an electrification agenda. Policy and programming from national governments is being aggressively put in place – nominally to meet enhanced Paris targets and ultimately net zero by 2050 targets – that effectively seeks to electrify energy delivery.
- From the ground up (through coordinated but local campaigns) is a push to ban gas delivery. Campaigns at the municipal councils are emerging to phase out gas delivery or, as a step towards that, to ban gas power generation. National governments in North America are coordinating closely, and municipal campaigns are coordinated through a number of strong and well-funded activists groups, many of whom are also pushing additional one-off campaigns such as an internal air quality campaign maintaining that gas is unhealthy in the home.
- In parallel with these public policy actions at national and local levels is a market campaign, driven by activist organisations, pushing for the divestment from hydrocarbons in general. Many in that movement use the current focus on ESG (which often includes legitimate plans to reduce emissions from the hydrocarbon sector) as a rationale for explicit phasing out of hydrocarbons altogether.

And yet, even as all this occurs, natural gas usage continues to grow, building on its core value propositions

- The fuel remains the most affordable delivery option, and its affordability advantage is often growing in the face of ever-rising electricity costs.
- Natural gas' reliability value proposition is also gaining traction – underscored by events like this winter's storm in Texas, where gas delivery continued more or less uninterrupted while electric systems failed on a dramatic scale.
- The innovation agenda is gaining traction quickly, with extensive work being done in many jurisdictions on alternative gases (renewable natural gas, hydrogen), efficiency, carbon capture, use and storage, and more.
- The environmental debate is a particularly animated one at present, and in the extended wake of COVID and massive public spending, significant public dollars are being put on the table to underwrite some of the broader green agenda.
- >> However, there is a sense that the bill on public spending is coming due soon, and inflationary pressure will exacerbate the challenge. The value proposition of gas will only grow in a tougher economic climate. The supply picture remains an extraordinary one, and citizens require affordable, reliable, clean energy.
- These are difficult times for the industry but, if it can remain nimble and get ahead of the discourse rather than just responding to it, if it can continue to show its innovative capacity to manage its environmental impacts, and if it is prepared to defend its interests robustly – and those are not small ifs - it should weather this.

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The closure of the Barcelona Secretariat offices and the departure of Luis Bertrán Rafecas as Secretary General mark the end of an era for the International Gas Union. Here Luis looks back on five fulfilling years for the IGU.

> pain has been the proud host of the IGU Secretariat, and the Union's home and headquarters, since November 2016. This has been a period in which the gas industry has experienced major changes as it faces the tri-fold challenge of meeting increasing demand, fighting climate change and facilitating access to energy worldwide. That made the period of the Spanish secretariat demanding enough, but over the 18 months the unprecedented COVID-19 pandemic has added human, economic and commercial challenges facing the global gas industry.

> IGU has had to respond to these challenges to ensure its relevance to members, increasing the services and benefits it offers and raising its profile as the *Global Voice of Gas*. We have had to update our public positions on key issues of the international energy and climate debate, and expanded our advocacy to highlight the role of renewable gases, low-carbon gases and hydrogen in the energy transition.

This Spanish term has certainly been a transforming period for IGU. This began with very important changes conducted under the *Building for the Future* project. This had three phases with the first two starting during Norway's term as host of the Secretariat. At that time, I was Deputy Secretary General in Oslo and participated from the beginning of the project. We are proud that the project has been brought to a successful conclusion during the term of the Spanish secretariat.

In the first phase of our transformation, membership fees were reviewed to strengthen IGU's finances. A sliding scale of fees was introduced for Charter Members with a supplementary charge aligned with the size of the gas industry in each country being levied on top of the basic fee. A new category of Premium Associate Member was introduced and the eligibility for Associate membership widened.

In the second phase of *Building for the Future* we created and implemented a new model for managing IGU's flagship events to generate stronger royalties to help \rightarrow

fund the Union's activities. The new model included the creation of a formal Steering Committee (SC) for each flagship event working together with the host country and its National Organising Committee (NOC). The SC brought a better leadership of the preparation and execution of each event, and ensured the continuity and legacy from one event to the next, avoiding the new NOC starting from scratching every time.

In the third and final phase, IGU's governance was reviewed and it was decided to move to a permanent headquarters no later than by 2022. This major change required the improvement of the finances, mostly coming from the other two previous phases of *Building for the Future*, and important decisions including the modification of the Articles of Association, on key items regarding the responsibilities of the Secretariat and Secretary General.

The selection of the city to host the permanent headquarters was a long process to which all members were invited to contribute. We received proposals from many members and more than 15 cities were evaluated. In October 2019, the Council was asked to select the host city between two finalists and London was elected. One year later, the incoming Secretary General was selected after a recruitment process conducted by the Implementation Team.

There is still a lot of work to be done, but I am sure that the future development of the Union will be in good hands when the Secretariat becomes operational in London from August 2021. Numerous new initiatives have started to be implemented and many of these now need to be taken from a strategic level to a tactical one. These include the transformation of the gas industry as part of the global response to climate change and meeting the sustainable development goals. Including new renewable gases, low-carbon gases and hydrogen in IGU's remit is an important part of ensuring that the gas industry is part of the sustainable future energy mix.

I wish Andy Calitz and the new team all the best as they prepare to take over for the coming years in London.

The Spanish term as host of the IGU Secretariat would not have been possible without the strong support of Naturgy, and I would like all members to be aware of the significant support they provided. Naturgy has been by far the largest contributor to the IGU in the five years to 2021 through the provision of office facilities, personnel, back office services, telecommunications and IT systems. But also very importantly, in my view, Naturgy has kept a distance to ensure its own and IGU's integrity, and has not at any time tried to influence internal processes in IGU. Having spent most of my career with Naturgy, I am proud of the contribution the company has made to the IGU and the role it enabled me to play personally.

Having weathered the impact of the COVID-19 pandemic and looking to the recovery of economies right around the world, the focus must now shift to meeting the world's energy needs in a safe, sustainable, reliable and affordable manner. The IGU needs to be present in all the relevant arenas where the decisions for the energy future are being made, emphasising the long-term role that natural gas, renewable gases, low-carbon gases and hydrogen will play. Gas is more than a bridging fuel, but an integral part of a long-term sustainable energy mix, where infrastructure, molecules and electrons are needed to ensure a just energy transition.

On behalf on the Barcelona secretariat team, Naturgy and all Spanish members of the IGU, I wish the orgainsation every success in its future development and assure you of our ongoing support.

To use the theme song of the 1992 Barcelona Olympic Games, I am sure we will be Amigos para Siempre!

All the best from Barcelona,

- Luis Bertrán Rafecas Secretary General of IGU

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China seeks to spur gas investment through unbundling

China is in the process of unbundling gas transmission, including thousands of kilometres of pipelines and LNG terminals, in the hope of promoting both upstream investment and downstream gas use

ANNA KACHKOVA

n ambitious oil and gas industry overhaul is underway in China. It is being spurred by a desire to boost both domestic production and imports of natural gas, and the country's adoption last year of a 2060 target for net zero carbon dioxide (CO_2) emissions has added to the momentum.

This is because gas is seen as a major component of China's decarbonisation strategy, helping it to shift away from more heavily polluting sources of fuel. And in anticipation of growing gas demand, Beijing had decided even prior to the adoption of the net zero target that reforming the energy industry would make it easier to achieve its aims. →

Plan for PipeChina

Specifically, the reform revolves around the unbundling of midstream infrastructure from China's three national oil companies (NOCs) – China National Petroleum Corp. (CNPC), China National Offshore Oil Corp. (CNOOC) and Sinopec. In December 2019 a new entity, China Oil & Gas Piping Network Corp. (PipeChina), was created to take over the unbundled midstream assets, including pipelines, LNG terminals and storage facilities. The process of transferring these assets kicked off last year.

Beijing hopes that having a single company own and operate midstream infrastructure in a more unified manner will help increase participation in the upstream sector by encouraging third-party access by producers other than the NOCs. Its other aims for the overhaul include improving country-wide distribution of gas, lowering prices for the fuel and ultimately boosting natural gas use.

Previously, third-party access to midstream infrastructure could not be guaranteed, according to Erica Downs, a senior research scholar at the Center on Global Energy Policy, part of Columbia University's School of International & Public Affairs (SIPA). It could be the case that NOCs –particularly PetroChina, CNPC's listed arm, which operated the majority of pipelines – did not have any spare capacity available. Where capacity was available, meanwhile, transmission tariffs could vary widely.

"That was a deterrent for a lot of companies," Downs tells *Global Voice of Gas* (*GVG*). "I think in the government's mind, the way this is supposed to work is that the company [PipeChina] grants and enforces third-party access. And because of that, some of these domestic companies other than the big three NOCs will come in and invest."

In a commentary published by the Center on Global Energy Policy in September 2020 and coauthored by Downs, the importance of enforcing third-party access, penalising non-compliance and resolving any disputes that arise is highlighted. How successfully this will be handled remains to be seen, but there are potential challenges involved, including a risk that NOCs will try to influence PipeChina's operations through their equity stakes in the pipeline company and personnel that were transferred to it.

Obstacles

Given that China's gas pipeline network spans tens of thousands of kilometres, though, the task of managing it in a unified manner is a considerable one. Now, with the company in its second year of existence, there are plenty of obstacles to contend with, including in terms of third-party access and the upstream investment that it is supposed to encourage.

"We believe unbundling of the gas transmission business may encourage upstream investments for non-national oil companies, as a lack of midstream asset ownership is no longer a major barrier to channel the production to the end-market," three Fitch Ratings analysts for Asia-Pacific corporates tell GVG. "However, given the high entry barrier in capital and technology for upstream investments, unbundling the transmission tariff alone will not be enough to drive a substantial investment in this area from non-NOCs," they say.

The Fitch analysts say unbundling is a step towards the deregulation of city gate prices, which have previously been less volatile than global gas prices thanks to the way they were being regulated.

"The unbundling also facilitates direct competition of domestically produced gas and imported gas," the analysts say. "As a result, we expect China's gas price to be more in line with global gas price volatility," they continue. "This factor alone would discourage some smaller players who do not have much experience in managing and forecasting global commodity price trends."

Another issue flagged up by Downs is that of China's geology, which she describes as "quite complex" and not particularly attractive, particularly not to foreign companies. But when it comes to domestic companies, there is some potential for smaller players to become involved.

"There probably are some small blocks in China that may not be attractive to a company as big as →

"We also believe NOCs will maintain their competitiveness in the gas sales market even after they lose their natural monopoly alongside with their midstream ownership"

— Fitch Ratings

PetroChina," Downs said. "But the hope is that there will be smaller domestic companies, especially those that might have gained some experience with upstream assets overseas, that would be willing to invest."

Advantage to NOCs

While developing more of these smaller assets could help boost China's overall production, it appears that the NOCs will continue to enjoy a more advantaged position, even with the unbundling of their midstream assets.

"We also believe NOCs will maintain their competitiveness in the gas sales market even after they lose their natural monopoly alongside with their midstream ownership," say the Fitch analysts. This is attributed in part to the NOCs' success in driving down their lifting costs over the years – which is easier for larger players benefiting from economies of scale to achieve.

"For upstream players, securing an end-user market in China is also a means to stay competitive and to maximise margins," the analysts continue. "Compared to pure play upstream users, integrated NOCs have started to strengthen their presence in the end-market through co-operation with or expanding their own city gas businesses, and also through more direct sales to large industrial users. All the NOCs own both domestic production fields as well as LNG import terminals – they could also have the flexibility of importing more or producing more, depending on the price competitiveness between imported gas and domestically produced gas." Thus, despite the challenges that China faces in encouraging more third-party participation, Fitch expects China's investment in upstream gas operations to stay strong. "The NOCs are keen to increase their gas production, and expect gas to be a key growth driver whereas they expect a flat or declining trend for their crude oil production," the Fitch analysts say.

"The government does want to see more investment in the upstream, but I don't think it wants to see the dominant role of the NOC eroded," says Downs.

The advantages NOCs enjoy can also be seen on the downstream side. The Fitch analysts note that while some Chinese LNG terminals have been transferred from the NOCs to PipeChina, long-term supply deals mean that these terminals will still be predominantly used by those NOCs.

"Only a very limited window period during low season will be available to third parties," the analysts said. "Nevertheless, this is a step forward compared to previous years, and we did see some rated city gas distributors start to import gas through PipeChina's terminals since last year, which helps to drive down their gas procurement cost."

Fitch is also seeing more investment in LNG terminals from city gas distributors such as ENN Group, and provincial state-owned energy companies including Guangdong Energy, Zhejiang Energy and Beijing Gas. "So if the international gas price is more favourable, more and more players will be able to enjoy the cost benefits, while this was exclusively enjoyed by NOCs before," the analysts said.



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India's evolving gas strategy



ANDREW KEMP

ndian prime minister Narendra Modi's government has long been pushing for greater consumption of natural gas as it seeks to transform the country into a gas-based economy.

The government has, since coming to power in 2014, introduced a range of policies pushing upstream reforms, infrastructure development and market deregulation. The ultimate goal is to expand gas' share of the country's primary energy mix from around 6% at present to 15% by 2030.

In his first term in office, Modi sought to achieve this goal by focusing on a number of reforms targeting the exploration and production segment. His administration hoped that an uptick in gas reserves and production would lead to greater economic activity, lower prices and a reduction in the country's growing dependence on imports.

With limited results on this front, however, the Modi administration shifted tack in its second term, focusing more on broadening the country's gas \rightarrow



infrastructure – from adding pipeline connections to gas import terminals and everything in between.

Upstream constraints

India's upstream has long been dominated by state-run Oil and Natural Gas Corp. (ONGC), which currently produces more than 70% of domestic oil and gas production.

While the company has been striving to boost its gas production, and can look forward to a healthy boost from its deepwater KG-D5 field in the near future, India's production has been in decline for a number of years.

India's net gas production shrank from 46.45bn m³ in financial year 2011-12 to 27.79bn m³ in 2020-21, according to Petroleum Planning & Analysis Cell (PPAC) data. The PPAC is a division of the Ministry for Petroleum and Natural Gas.

To counter declines in both oil and gas production, New Delhi launched a wave of upstream reforms in the hopes of reviving investor interest. Foremost among these was the replacement of the New Exploration Licensing Policy (NELP) with the Hydrocarbon Exploration Licensing Policy (HELP) in 2016.

HELP not only introduced major changes to the block tender and award process but also ushered in pricing freedoms for new licences that reached production. HELP's key pillars are the Open Acreage Licensing Policy (OALP) and the National Data Repository (NDR).

OALP was responsible for introducing the more attractive licensing terms, such as reduced royalty rates and year-round bidding, while NDR granted foreign investors access to geoscientific data prior to bidding on blocks.

Progress has been slow, however, and while deepwater projects by both ONGC and the Reliance Industries Ltd (RIL) and BP partnership promise to deliver much needed new supplies to the domestic market, the Indian government has begun looking to midstream and downstream developments to help it achieve its 2030 gas consumption target.

Infrastructure shift

In order for the country to achieve the government's \rightarrow

target of 15% gas share by 2030, Wood Mackenzie predicts that gas demand would have to more than triple to an estimated 170bn m³ from 56bn m³ at present.

With the domestic upstream unlikely to keep pace with such a surge in demand, additional supplies will have to come from the international market. Indeed, the country has already received its first floating storage and regasification unit (FSRU) and, while the coronavirus (COVID-19) pandemic has temporarily derailed demand, the International Energy Agency (IEA) has predicted that India's LNG imports could quadruple to more than 120bn m³ by 2040.

With this in mind, the government's gaze has swung toward infrastructure developments in the hope of preventing supply bottlenecks.

Vidur Singhal, a senior analyst at Wood Mackenzie, tells *Global Voice of Gas* (*GVG*): "The government is making regulatory changes to penetrate gas infrastructure and eradicate gas' last mile connectivity issues, including award of city gas distribution (CGD) network across states, allowing usage of LNG as a fuel in transport sectors, and other small-scale LNG initiatives."

The analyst notes that New Delhi is also providing viability gap funding in order to speed up the laying of gas transmission pipeline in the country's east and northeast.

Modi said in January that his government aimed to see another 16,000 km of gas pipeline added to the national network within the next five to six years. The government announced in September 2020 that an 11th city gas licensing round would be held soon, though this appears to have been delayed owing to COVID-19.

Expanding the country's gas grid is still seen as one of the major challenges to achieving the country's long-term gas consumption targets, however.

Kaushal Ramesh, an analyst at Rystad Energy, tells GVG that the 2030 target is challenging, owing to insufficient pipeline infrastructure, customers' price sensitivity and a continuing emphasis on coal. Wood Mackenzie estimates that without growth in gas-fired power generation, gas demand will only grow by an annual average of 4.5% over the next 10 years. This will result in demand increasing to about 85bn m³ by 2030, or approximately 7% of the projected total primary energy mix.

Power sector rivals

While coal currently accounts for more than 70% of the country's power mix, the right set of policies could still help gas to expand its 4% share and help the country lower its carbon emissions.

Modi recently recommitted to his government's pledge under the 2015 Paris climate change agreement to cut Indian greenhouse gas (GHG) emissions intensity by 33-35% by 2030.

Nevertheless, India has also pledged to increase non-fossil fuel power capacity to 40% by 2030 from 28% in 2015, with every inch of progress on this front represents a challenge to gas' chances of expansion.

Ramesh says: "India has good renewables potential so when it chooses to reduce coal-fired generation, that is going to be the country's likely path forward. Gas is likely to play a complementary role in the power system."

Singhal, meanwhile, argues that without restrictions on the use of coal and/or the introduction of a carbon price then gas would struggle to outcompete cheaper domestic coal. This, too, could undermine the government's 2030 target.

India's vision of becoming a gas-based economy, first unveiled by Modi in 2018, is essential to the government's wider economic and environmental goals.

Key to the country's economic future is its transformation into an advanced manufacturing hub, an evolution that will require plentiful supplies of dispatchable energy. At the same time, India's climate change goals mean the country can ill afford to keep burning coal at its current pace.

This should pave the way forward for greater consumption of gas, but time is running out on the government's energy mix targets.



he European Commission (EC) plans to publish a raft of legislative proposals this year aimed at aligning the EU's energy and climate policies with its commitment to cut greenhouse gas emissions (GHG) by 55% by 2030.

The first measures under the Fit for 55 package are due to be announced as early as mid-July, and will have significant implications for a number of sectors including the natural gas industry. As reported on page 67, the EC will propose measures later this year on reducing methane emissions in the energy sector, but it is also looking to set out rules for how to incorporate renewable, synthetic and decarbonised gases into the gas market, adjust its directive for promoting renewable energy and make changes to the EU emissions trading system (ETS).

Adjustments will be made to the 2009 Gas Directive to cover renewable, synthetic and decarbonised gases under the Hydrogen and Decarbonised Gas Package. Its public consultation on the changes will continue until June 18, but has already generated a number of responses, including from major European oil companies including Shell, Total, Eni and Equinor. →

Hydrogen is a cornerstone in the EU strategy to decarbonise difficult-to-abate industries.

Green gases

At its core, the original Gas Directive set out to break up gas market monopolies, foster competition and ensure energy security, through rules on unbundling and third-party access, and measures to boost liquidity. The EC wants to build the new legislation on the same principles. For instance, it wants to avoid a situation where hydrogen networks are owned and operated by monopolies that also produce the hydrogen and potentially deny access to new entrants.

Hydrogen is a cornerstone in the EU strategy to decarbonise difficult-to-abate industries, with the EC envisaging as much as 40 GW of green hydrogenproducing electrolyser capacity by 2030. Blue hydrogen from natural gas will also play an important role in reducing emissions in the nearer term and developing a well-functioning hydrogen market.

Under debate is whether transmission system operators (TSOs) should be allowed to operate electrolysers. Some raise concerns about competition, while others note that the TSOs prepared to make investments in electrolysers should be allowed to do so to spur the market's development.

Thierry Bros, professor at Sciences Po Paris and an advisory board member at NGW, cautions against the EC getting too bogged down in regulation concerning hydrogen. "Right now we have neither the hydrogen infrastructure or the hydrogen molecules," he tells *Global Voice of Gas* (*GVG*). "Thinking that we are going to achieve something as ambitious as a hydrogen economy with everything fully regulated is not realistic."

Bros notes that the EC does show signs of adopting a more "pragmatic" and "flexible" approach, however.

A number of countries including the UK, the Netherlands and Germany are looking to decarbonise entire clusters of industry including hard-to-abate sectors like steel manufacturing and petrochemicals using hydrogen and carbon capture and storage (CCS). Shell wrote in its response to the public consultation that TSOs ought to be allowed to develop dedicated hydrogen and CCS pipelines, and that doing so would not undermine competition.

"Over time, renewable and low-carbon hydrogen should become a tradeable commodity in a liquid European wide internal market," Shell explained. "To start the hydrogen market and enable commercial players to invest with confidence, the regulatory framework should mirror the main features of the gas regulatory framework: unbundling, third-party access and cost-efficient non-discriminatory tariffs."

However, a risk is that such hydrogen and CCS clusters might be disconnected from the rest of a \Rightarrow

potential hydrogen network. This could mean one hydrogen producer in that cluster having a dominant or even monopolistic position.

The EC has also suggested revisiting the access regime for LNG terminals. The EU's LNG terminals are currently less regulated than its pipelines, with reduced third-party access and less transparency. Making these terminals more accessible and transparent would get them ready for imports of renewable and low-carbon gas, the EC said. Despite its ambitious hydrogen production plans, Brussels has recognised that it will also need considerable imports of the gas.

Other legislative moves

Total recommended in its response that the EC set a binding 2030 target for renewable gas by energy content in the natural gas grid. European gas association Eurogas suggested that this target should be at least 11%.

Natural gas accounts for 95% of gaseous fuels used in the EU, serving not only as an energy carrier but also as a key feedstock in industry processes. Overall gaseous fuels account for roughly 22% of the EU's total energy consumption, and the EC does not expect this share to change much over the next three decades.

TotalEnergies, Engie, Shell and others have also called for an EU-wide guarantees of origin (GOs) market to replace the current fragmented national markets. GOs are documents that prove to energy users that the electricity they consume comes from a specific renewable energy source.

However, both the targets for renewable gases and the GOs should be covered by revisions to the Renewable Energy Directive (RED), also taking place this year. RED II will essentially align EU targets for renewable energy with the 55% goal for reducing emissions by 2030.

Changes to the TEN-E regulations will also set out new rules for eligibility for EU grants. Natural gas pipelines will no longer be eligible for status as Projects of Common Interest (PCI), barring them from grants under the Connecting Europe Facility (CEF) infrastructure fund. But the reasoning here is partly that support so far has established "a well interconnected and shock-resilient gas grid, giving all member states access to at least three gas supply sources or the global LNG market."

The gas industry will still be able to access grants for hydrogen and CO₂ transportation projects, however. The EU Taxonomy Regulation will be key for financing from the private sector, although the EC is yet to decide to what extent gas-fired power plants can be classified as green investments, if for example they replace dirtier coal plants. Modern and efficient combined cycle gas turbine (CCGT) plants can help major European coal users like Germany, Poland and the Czech Republic reduce their power sector emissions significantly while developing reliable baseload capacity that can complement renewables. The EC is expected to decide on gas power plants' inclusion later this year.

Last but not least, the EC is looking to tweak the ETS, which serves as its flagship climate tool that has helped gas win power market share away from coal over the years. Reforms to the system, such as a tightening of the cap on allowances and the inclusion of the shipping tool, are expected to be agreed later this year.

Gas may stand to benefit from the further phaseout of coal power and the increased use of LNG as a marine fuel. Bunkering association SEA LNG estimates that using LNG in ships can reduce GHG emissions by up to 21% on well-to-wake and 28% on tank-to-wake bases, depending on what engine is used. Meanwhile, CCGTs can continue displacing coal-burning capacity.

Frequent adjustments to the ETS are necessary for the system to continue functioning.

"ETS prices won't keep rising forever. If you take out all the coal-fired power and replace it with gas, you halve the CO_2 emissions and the price could go down," Bros explains. "There need to be tweaks quite often."



FortisBC continues to reduce emissions through renewable gases

n its recent report, Net Zero by 2050, the International Energy Agency emphasized the vital role renewable energies will play in reducing global greenhouse gas (GHG) emissions. The report also acknowledged that renewable gases in particular will be key in achieving a net zero future, and Canadian utility FortisBC Energy Inc. couldn't agree more.

A utility delivering natural gas, electricity and renewable energy to over 1.2 million customers, FortisBC was the first utility in North America to deliver Renewable Natural Gas (RNG) to its customers. RNG is a carbon neutral energy made from the raw methane released from decomposing organic waste. FortisBC and its suppliers capture and purify the methane from sources like landfills and farms, and blend the resultant carbon neutral energy seamlessly into the natural gas infrastructure. Decarbonizing natural gas supply is a game changer in reducing GHG emissions, and FortisBC has big plans for how they will contribute to a lower carbon future.

30BY30 target

In 2019, FortisBC announced its 30BY30 target, a goal to reduce its customers' GHG emissions by 30 per cent from its 2007 levels by 2030. One of cornerstones of achieving the target is aiming to have at least 15 per cent of its natural gas supply be carbon neutral by 2030. But, as there are only so many landfills and farms in British Columbia (B.C.), FortisBC is working to explore new sources of renewable gas.

New sources of renewable gases

FortisBC signed an agreement in the spring of 2020 to purchase RNG from the first commercial wood waste-to-RNG agreement in North America. REN Energy International Corporation is building a facility that will superheat forestry wood waste to produce RNG. Given the size of the province's forestry industry, this new feedstock could unlock significant new volumes of RNG and this facility alone is expected to produce up to a million gigajoules of RNG per year.

This spring, FortisBC hit on another first as it began to receive RNG from the Lulu Island Wastewater Treatment Plant, located in Richmond, B.C. In collaboration with Metro Vancouver, approximately 60,000 gigajoules of RNG annually will be produced reclaiming methane from sewage, with the potential to increase to about 100,000 gigajoules of RNG annually by the end of the 20-year contract. Those 100,000 gigajoules would be enough energy to meet the needs of around 1,100 homes in B.C.

FortisBC also became the first utility in the country to bring RNG in from out of province. With four agreements in Alberta and Ontario so far, FortisBC plans to explore more opportunities outside of its borders while simultaneously increasing its RNG supply from inside B.C.

FortisBC is also exploring other renewable gases, including hydrogen. Late in 2020, FortisBC invested \$500,000 with the University of British Columbia Okanagan to study how to introduce hydrogen safely into its natural gas system. FortisBC is also part of HyDeal Los Angeles, the first regional initiative in the Green Hydrogen Coalition's HyDeal North America platform. FortisBC brings its technical and engineering expertise to the table, along with experience in renewable gas policy, and hopes to learn more about hydrogen from leading companies in the sector.

Strengthening the renewable gas portfolio

At the start of 2020, FortisBC was delivering around one-third of a petajoule of RNG annually from six operations. But by the end of year, FortisBC had secured 13 new supply agreements. Once operational, these developments are anticipated to increase the amount of carbon-neutral RNG in FortisBC's system to five per cent of its total gas supply – a full third of the organization's renewable gas goal outlined in its 30BY30 target, secured all within the first year of announcing the goal.

For more information on FortisBC's RNG efforts, visit fortisbc.com/rng.



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THyGA Burning Bright

NANANA

An EU-backed project is testing hydrogen/ gas blends for use in domestic appliances

DANISH GAS TECHNOLOGY CENTRE

Bending hydrogen into the existing gas grid is a quick win for abating emissions, without expensive additional investments, as most of the existing infrastructure and appliances can continue to be used.

However, the injection of hydrogen in a system designed to operate purely with natural gas requires a comprehensive assessment of the potential impacts. That's the aim of the Testing Hydrogen Admixture for Gas Applications project. The THyGA project, supported by the EU Commission, is investigating the amounts of hydrogen that can be injected ,without compromising on the safety, emissions, and efficiency of existing and new applications. It focuses on the end-user: domestic and commercial gas appliances (space heating, hot water, cooking and catering), which account for more than 40% of the EU gas consumption.

The project is being coordinated by French energy utility company Engie. Eight other partners from six European countries (DGC, Electrolux, BDR, Gas.be, CEA, GWI, DVGW-EBI and GERG) will work together on this project over 36 months. The consortium includes laboratories, gas value chain companies, manufacturers representing different applications (cooking, heating), and an international association. It will be supplemented by an advisory panel of manufacturers and gas companies which will be closely integrated with the main project team. →



Structure of the project

The project is organised in packages each covering a technical aspect. The team will complete an extensive experimental assessment of hydrogen tolerance, based on theoretical background from material science and combustion theory. Outputs include proposed rules and standards regulating H₂NG blends for gas appliances and mitigation strategies for coping with high levels of hydrogen admixture. There is also a strong communication element and the whole industry has been invited to join the project via an advisory panel (still open to worldwide interested experts).

By this approach, the project will determine how different levels of hydrogen blending impact the various appliance technologies, and identify the regime in which safe, efficient, and low-polluting operation is possible. The main goal of the project is to enable the wide adoption of hydrogen in natural gas blends by:

- Closing knowledge gaps regarding technical impacts on residential and commercial gas appliances
- Identifying standards that should be modified or adapted to answer the needs for new appliances and proposals on test gases
- Clarifying the acceptable hydrogen percentages that will not compromise safety and performance.

Focus on combustion theory: impact of natural gas /hydrogen blends

Given that the impact of hydrogen blending on enduse appliances is mainly a question of combustion, the THyGA partners have produced an analysis based on combustion theory and literature reviews. It addresses effects of hydrogen blends on main →


70% H2

▲ Impact of blending on the flame of a cooking hob gas quality properties, combustion temperatures, laminar combustion velocities, pollutant formation (CO, NOx), safety-related aspects, and the impact of combustion control.

One main finding for many common situations found in some of the residential appliances is that different effects of hydrogen may compensate each other to a certain degree. For example, in uncontrolled residential combustion systems (which comprise the large majority of the residential appliance population in Europe), hydrogen blends will result in an increase in the air excess ratio, which will largely counteract the increase of the laminar combustion velocity and combustion temperatures caused by the presence of hydrogen.

Hydrogen embrittlement and tightness issues

When adding a natural gas and hydrogen mixture into a gas distribution network, impacts unrelated to combustion have also to be considered: hydrogen embrittlement of metallic components, chemical compatibility with other materials, and leakage. For hydrogen embrittlement, the main findings indicate that natural gas blended with up to 50% hydrogen should not be problematic for any of the metallic materials employed in the gas distribution system or in buildings.

This theoretical approach will be followed-up by an experimental evaluation of the tightness of existing components.

Experimental Work, Testing Protocol

The test programme of the THyGA project relies on an accurate estimation of the types of appliances used in the European domestic market. This allows the selection of test appliances representative of those installed in European homes and businesses, taking into account new technologies on the way. More than 100 appliances will be tested in a programme up to 2022.

Testing started in mid-2020 (with 10 appliances tested so far). The first results are showing the complex impacts linked to the presence of hydrogen in the gas mixture. One of the expected effects of blending is the increase of sensitivity to flashback. However, flashback may not appear instantaneously and may be the combined effect of flame features changes due to H_2 and e.g. increasing temperatures at the burner surface under certain circumstances.

Next steps

In parallel of the testing, THyGA aims at giving insight to the sector on current standardisation & certification framework and the impact of H_2NG mixtures and the needs for adaptation. Technical solution allowing mitigation will also be explored.

More information on THyGA

Website: <u>thyga-project.eu/</u> Deliverable and workshops: <u>thyga-project.eu/</u> <u>category/news/</u>



This project as recieved funding from the Fuel Cells and Hydrogen 2 Joint Undertaking under grant agreement No 874983. This Joint Undertaking receives support from the European Union's Horizon 2020 research and innovation programme, Hydrogen Europe and Hydrogen Europe research.

Russia's LNG ambitions

Russia wants to leverage its low costs to carve out a 20% share of the global LNG market by 2035, and these supplies will enable Asian economies to decarbonise by switching from coal to gas

JOSEPH MURPHY

ussia is targeting up to a 20% share of the global LNG market by 2035, under a longterm roadmap strategy approved by the government in March. The country is banking on a raft of new liquefaction projects to achieve this goal, as well as bullish demand for gas in Asian markets in the years to come.

КРИСТОФ ДЕ МАРЖЕРИ

The coronavirus (COVID-19) pandemic and the accelerating pace of the energy transition have cast doubt on the long-term outlook for oil demand. But the consensus is that natural gas consumption will -

The consensus is that natural gas consumption will continue seeing robust growth in the decades to come, on the back of increased usage in Asia and other markets.

continue seeing robust growth in the decades to come, on the back of increased usage in Asia and other markets. The International Energy Agency (IEA) predicts in its latest Stated Policies Scenario that global gas consumption will climb from above 4 trillion m³ in 2019 to 4.6 trillion m³ in 2030 and up to 5.2 trillion m³ in 2040. In its *LNG Outlook 2021*, Shell predicts that global LNG trade will nearly double to 700mn metric tons in the next 20 years.

Russia is eager to carve out a significant portion of this market. Despite boasting the largest gas reserves in the world, assessed at 38 trillion m³ proven by BP's *Statistical Review of World Energy* 2020, Russia was relatively slow to join the ranks of global LNG suppliers. It did not launch its first export terminal until 2009, when Gazprom and its partners brought on stream the Sakhalin-2 plant in the Far East, which has a nameplate capacity of 9.6mn metric tons/ year. Novatek finally added a second terminal in 2017, the 16.5mn mt/yr Yamal LNG facility on the Arctic Yamal Peninsula.

Output ambitions

There are now over a dozen more mid- and large-sized liquefaction projects at various stages of planning and development in Russia. In its high-end scenario, the government projects that production could reach 65mn mt/yr by 2024, 102.5mn mt/yr by 2030 and 140mn mt/yr by 2035, while in its low-end scenario, it sees supply increasing to a more modest 46mn mt/yr by 2024, 63mn mt by 2030 and 80mn mt by 2035.

Other suppliers such as Australia, Qatar and the US are also ramping up output. But Russia has several key advantages. \Rightarrow



Russian gas is abundant and cheap to produce, Dmitry Marinchenko, oil and gas analyst at Fitch Ratings, tells *Global Voice of Gas* (*GVG*). And in the Arctic, it is also cheaper to liquefy given the low ambient temperatures. But building infrastructure in such remote regions naturally drives up the investment cost, as does the need for icebreaking vessels to transport the super-chilled gas along the Northern Sea Route (NSR).

Even so, Russia estimates it can supply LNG to the global market at a cost of \$3.7-7.0/mn Btu. While higher than Qatari costs, they are still attractive compared with those of most other suppliers. And the more projects that are advanced in Russia's far north, the more the country will benefit from economies of scale. "The more scale the cheaper the cost," Mitch Jennings, oil and gas analyst at Sova Capital, tells GVG. "Over time it will become even more economically reasonable and efficient to use NSR."

Novatek is expected to launch a 0.9mn mt/ yr fourth train at its Yamal LNG later this year, considered an important project as it will use the company's patented Arctic Cascade technology. Another small-scale project in the pipeline is Gazprom's 1.5mn mt/yr Portovaya LNG plant in northwest Russia, also expected online this year.

Novatek is targeting first gas from its next large project, the 19.8mn mt/yr Arctic LNG-2 facility on the Gydan Peninsula, in 2023. The following year it aims to launch its near 5-6mn mt/yr Obsk LNG project, although it is yet to take a final investment decision (FID).

There are more projects that the government considers as "likely" start-ups before 2030, including →

While Yamal LNG has strong economics, the project was realised both on time and within its \$28bn budget in no small part thanks to supportive government policy.

> Gazprom's 13.3mn mt/yr Ust-Luga plant in northwest Russia, expected online in 2024-2025. There is also Novatek's 19.8mn mt/yr Arctic LNG-1, expected to arrive in 2027, and the 17.7mn mt/yr Yakutsk LNG project in the Russian Far East, led by the privatelyowned Yakutsk Fuel and Energy Co. (Yatek). Rosneft and ExxonMobil's 6.2mn mt/yr Far East LNG plant has an anticipated launch of 2027-2028.

The "possible" projects within the next 10 years are Novatek's 19.8mn mt/yr Arctic LNG-3 and a 5.4mn mt/yr expansion at Sakhalin-2. Gazprom also has preliminary plans for 0.5-1.5mn mt/yr and 1.5mn mt/yr projects on the shores of the Black Sea and the Far East, considered possible before 2025.

Post-2030, there are Gazprom's 20mn mt/yr Tambey LNG and 30mn mt/yr Shtokman LNG and Rosneft's 30mn mt/yr Kara LNG and 30-50mn mt/ yr Taymyr LNG projects to consider, all situated in the Arctic. A 10mn mt/yr expansion at Far East LNG might also be possible after 2035.

Policy

While Yamal LNG has strong economics, the project was realised both on time and within its \$28bn

budget in no small part thanks to supportive government policy.

During its 12 years of operation or until it has produced 250bn m³ of gas, Yamal LNG will be exempt from mineral extraction tax (MET) and property tax and will enjoy a reduced rate of 13.5% profit tax. It will also pay no export duties on its LNG, and receive additional regional tax breaks.

The government will need to continue in this supportive role in order for Russia's LNG ambitions to be realised, the analysts say, especially given the relatively heavy upstream tax burden in Russia. The fiscal regime must remain stable and predictable, Jennings says, to spur investment.

Marinchenko also calls for restrictions to be eased to allow more companies to get involved in LNG development.

"Novatek will not be able to able to reach the government targets alone," Marinchenko says. "Russia definitely needs more companies developing LNG projects."

Russia is also looking to localise more technology and equipment in the LNG sector and reduce reliance on imports. This policy has already yielded results, such as Arctic Cascade and the development of LNG carriers in the Arctic. But cooperation with international companies remains crucial, in terms of both technology and funding, Marinchenko says.

By delivering on its LNG expansion goals, Russia will strengthen its economy and diversify its gas export revenues, which are currently earned mostly in Europe through pipeline sales. In turn, Russia will help Asian economies decarbonise by providing low-cost gas to enable them to switch from polluting coal. Russia will be able to strengthen the environmental case for its gas even further through the use of carbon offsets, as was demonstrated by Gazprom in March, when it delivered Europe's first ever carbon-neutral LNG to Shell. Russian gas companies are also investigating the use of carbon capture and storage (CCS) to make their gas cleaner, as well as the potential export of blue hydrogen derived from gas.

Why methane emissions, and why now?

The scientific basis

DAVID ALLEN,

University of Texas at Austin Gertz Regents Chair in Chemical Engineering, and the Director of the Center for Energy and Environmental Resources

ethane, the major constituent of natural gas, is a greenhouse gas. Methane concentrations in the atmosphere, like the concentrations of other greenhouse gases, have been increasing. The Intergovernmental Panel on Climate Change (IPCC) has estimated that the level of methane in the atmosphere was 722 ± 25 parts per billion (ppb) in 1750, prior to the start of the industrial revolution. Recent measurements from the US National Oceanic and Atmospheric Administration indicate that global average methane concentrations had risen to 1893 ppb in 2021, up from 1873 ppb a year earlier.

Increased concentrations of methane are causing increased warming (radiative forcing) of the atmosphere. The most recent IPCC assessment concluded that additional radiative forcing, due to increases in atmospheric methane concentrations between 1750 and 2011, was about 17% of the warming due to increased concentrations of all greenhouse gases. Not all of the warming due →



to methane emissions is accounted for by the methane that remains in the atmosphere, however. Methane reacts in the atmosphere, producing other compounds that are radiative forcers. The IPCC estimated that the total radiative forcing due to methane emissions was roughly double the radiative forcing due to methane remaining in the atmosphere or about a third of the radiative forcing due all changes in greenhouse gases since 1750.

Concentrations of methane in the atmosphere have increased by more than 150% since 1750; methane contributes a significant fraction of the warming due to greenhouse gases

Global emissions of methane are estimated to be approximately 576 megatons/yr. The most precise estimates of global emissions are obtained by balancing the emission rate, the rate at which methane is removed from the atmosphere (sinks) and rate of accumulation of methane (emissions = sinks + accumulation). While significant uncertainty remains about specific sources of emissions of methane, the sinks for methane and the rate of accumulation of methane, based on global observations, are reasonably well known and therefore total global emissions of methane can be reliably estimated.

Methane sinks total approximately 556 (range of 501-574) megatons/yr. The annual rate of increase of methane in the atmosphere adds another 13 (range of 0-49) megatons/yr to the atmosphere, leading to an estimated total global emission estimate of 576 (range of 550-594) megatons/yr. These methane emissions come from a variety of natural and man-made sources, and the contributions of these individual sources have more uncertainty than the global total. Among the natural sources, which are estimated to account for approximately 40% of global emissions, are wetlands, termites, and hydrates. Man-made sources include energy systems, rice and other agriculture, livestock →

operations, landfills, waste treatment, and biomass burning. These sources are estimated to account for approximately 60% of global emissions.

The global energy sector is estimated to emit 120 megatons/yr (with an uncertainty of ~30%), or about 20% of global emissions. The most extensive work on understanding energy sector methane emissions has been done in the United States, and in the US, the Environmental Protection Agency (EPA) estimates that natural gas systems are the dominant source of energy sector emissions.

The energy sector is estimated to account for about 20% of global methane emissions

Emissions from individual source categories, like the energy sector, are generally based on measurements of methane emissions made at a small number of representative sources. Results from the measurements at a small number of sites are then extrapolated to estimate national or global emissions. For example, emissions from a few hundred natural gas wells in the US have been used to estimate the emissions from the national population of more than a half million natural gas wells. This approach is generally referred to as a "bottom up" analysis.

The difficulty with "bottom-up" approaches is obtaining a representative sample for large, diverse populations. "Bottom-up" emission estimates have been compared to "top-down" measurements, which quantify total emissions in oil and gas production basins or similar groups of sources. Many "top-down" measurements have been made using aircraft, but satellites are becoming a more common source of data. In the US, synthesis of bottom-up and top-down data has led to the conclusion that approximately 1.7-2.3% of the methane leaving wells is emitted before the gas is combusted by the end user. The International Energy Agency (IEA) has estimated similar percentages for methane emissions from global oil and gas production. Performance by country and production region can vary widely from these averages, however, and it is generally accepted that a small fraction of sources contribute a majority of emissions.

Many studies have found that approximately 5% of sources contribute on the order of 50% of emissions. For example, a small percentage of sites in a production basin may contribute the majority of the emissions, and these are not necessarily the sites with the largest production or throughput. A small percentage of certain types of equipment (e.g., pneumatic controllers or compressors) may contribute the majority of the emissions from these pieces of equipment. Since high emitting sources can account for a large fraction of emissions, rapidly finding and repairing or replacing these high emitters can be an effective approach to reducing emissions.

Emissions of methane from oil and gas supply chains are ~2% of production; a small fraction of sources account for a large fraction of emissions.

Reducing emissions of methane from natural gas systems can result in significant climate benefits, but to put these benefits into context, it is necessary to compare the radiative forcing of methane to the radiative forcing of carbon dioxide, and to report emissions of methane as carbon dioxide equivalents (CO_2e) . A kilogram of methane in the atmosphere today has a radiative forcing (warming) equivalent to ~120 kg of CO_2 (a Global Warming Potential (GWP) of 120). However, because methane does not persist in the environment for as long as carbon dioxide, if the radiative forcing of methane emitted today is evaluated over an extended time period, its radiative forcing, compared to carbon dioxide, will decrease.

Over a 20 year period, a kilogram of methane emitted today has a radiative forcing equivalent to ~84-87 kg of CO_2 . Over a 100-year period, a kilogram of methane emitted today has a radiative forcing equivalent to ~28-36 kg of CO_2 . These GWPs \rightarrow are periodically updated by organisations such as the IPCC, but the important conclusion to draw is that the immediate warming effect due to methane emissions is about 4 times the warming integrated over a 100 year period. The importance of reducing methane emissions therefore depends on whether the focus is on near term or long term reductions in warming. For example, in the US, emissions of methane, expressed as carbon dioxide equivalents using a 100 year GWP, account for about 10% of national anthropogenic greenhouse gas emissions. Using a GWP of 120 would increase that percentage to ~40%.

The significance of methane emissions on global warming depends on whether the focus is on reducing warming in the near term or long term. Immediate warming impacts of methane are estimated to be ~4 times the impacts when warming effects are integrated over a 100 year period.

Keeping in mind that any assessment of the warming effect of methane emissions needs to be clear about the GWP used in the analysis, several examples illustrate the significance of methane emissions from natural gas systems. If emissions of methane from natural gas systems are 1.7%, consistent with the IEA's estimate of global average emissions, the immediate warming due to methane emissions (GWP=120) is equivalent to 2.0 kg CO₂e per kilogram of natural gas. Combustion of natural gas releases 2.75 CO_2 per kilogram of natural gas, so methane emissions, evaluated using a GWP of 120, adds 75% to the warming associated with using natural gas. In contrast, if a GWP of 30 is used, the methane emissions add 19% to the warming associated with natural gas use.

As policy actions increasingly focus on near-term reductions in global warming, methane emissions will assume increased importance. Emissions from energy systems will be relatively large targets for emission reductions on an absolute basis, if there is a focus on near term reductions. The 120 megatons/ yr of methane emissions from the global energy sector have a warming potential equivalent to the annual carbon dioxide emissions from approximately 3 billion passenger cars (at 4.6 tons CO₂ per car per year) if a GWP of 120 is assumed.

Low methane emissions are critical if natural gas is to be successful as a transition fuel to low carbon energy systems

Natural gas generates lower emissions of carbon dioxide per energy provided, compared to other fossil fuels, making natural gas a potential transition fuel to low carbon energy systems. Emission rates of methane, however, amounting to only a few percent of the rate of natural gas production, have the potential to erode the climate benefits of natural gas.

Recent measurements suggest that methane emissions from natural gas systems could be reduced significantly if high emitting sources can be found, and quickly reduced. This makes mitigating methane emissions a strategic opportunity for the natural gas sector.

ANGIF EMISSIONS TESTING CENTRE

NGIF breaks new ground in emissions testing

Created in 2017, NGIF supports the funding of cleantech innovation in the natural gas value chain, filling a technology development gap and encouraging natural gas solutions to a lower-emissions future.

Earlier this year, the company announced its expansion under NGIF Capital Corporation (NGIF), a Canadian venture capital firm offering grant and equity financing for start-ups that deliver solutions to the environmental and other challenges facing the natural gas sector.

Now, NGIF is taking the disruptor label to another level with the NGIF Emissions Testing Centre (ETC), a groundbreaking C\$35mn industry-led emissions testing platform.

With C\$8.25mn in funding from Natural Resources Canada provided by the Canadian Emissions Reduction Innovation Network (CERIN) initiative and more than C\$26mn of in-kind investor support, the ETC represents a "plug and play platform" for innovators with pre-commercial technologies to validate their emissions detection, quantification, and reductions.

"Emissions measurement and reduction technologies face several challenges to widespread adoption in the Canadian gas sector," says Scott Volk, Technology and Innovation Lead at Tourmaline Oil and host site of ETC.

One challenge is common across many emerging technologies: customers aren't interested in buying until the technology is proven, but innovators need real-world data to prove their technologies. It's the classic "chicken-andegg" conundrum, Volk says. The second major challenge – and it's related to the first – is that field trials are often carried out in "siloes" and communication of the results is often very limited. With only a few people knowing the positive results, innovators remain challenged to advance to other trials and move their technology to a commercial stage.

The ETC tackles both challenges, Volk says. Technology developers with field-ready but pre-commercial products can have their systems tested in a realworld system that provides results in a live operating environment. Emissions reduction technologies will be tested at the West Wolf Lake natural gas processing plant near Edson, owned by Tourmaline Oil and Perpetual Energy and operated by Tourmaline on their network of upstream wells and drilling rigs.

The summary results of those tests are developed into an external facing report shared with all stakeholders, making the results of field trials much more accessible – and valuable.

"These two key factors, both present in the ETC, allow for an acceleration of emissions reduction technology testing and adoption in upstream gas operations," Volk says.

But the model isn't available only to field-ready technologies: innovators who are at a lower Technology Readiness Level (TRL), or those who might benefit from testing in a more controlled environment, can bring their products to the ETC laboratory at the University of Calgary (UCalgary) Research Centre. There, scientists can help innovators obtain data critical to further refine their technologies or prove that their systems are ready for real-world testing.

And while the ETC is focused on making technology ready for commercial deployment, it will also help train and develop high qualified personnel (HQP) through UCalgary and its other partner research facilities.

"This will provide Canada with an emerging workforce that is trained in emissions management and testing, and in turn the HQP can provide testing and data analytics support to technology providers or site end users," says lan Gates, Professor, Chemical and Petroleum Engineering, University of Calgary and Director of the Global Research Initiative in Sustainable Low Carbon Unconventional Resources.

John Adams, NGIF Capital's CEO, says there are several pathways into the ETC. The first is through NGIF itself – companies which have already been approved for testing through NGIF or its partner companies. A second is through NGIF's trusted partners – innovators who have accessed funding from NRCan and Alberta Innovates.

But ultimately, Adams says, the idea behind the ETC is to make it available to as many innovators as possible. "We do have a formal intake process through which any innovator on the gas value chain, can contact us directly and apply for access."

NGIF is committed to accelerating cleantech innovation in natural gas, cutting new ground in Canada's energy marketplace. "The natural gas sector has long been at the forefront of the effort to reduce emissions. NGIF's ETC will further advance the kinds of technology and solutions needed to move the industry towards an even lower emission future."

Methane emissions and the gas industry:

Gas companies are already undertaking significant efforts through individual and group initiatives, motivated by pressure not only by governments but also investors and customers

JOSEPH MURPHY

he conversation about climate change has chiefly focused on reducing carbon dioxide emissions as a means of capping global temperature growth at under 2°C above pre-industrial levels, the central goal of the Paris Agreement. But increasingly, methane is gaining attention as a key contributor to global warming.

Methane's importance was highlighted in UNEP's recent *Global Methane Assessment*, which called for urgent action across multiple sectors to reduce methane emissions, arguing that this effort could have a much more rapid impact in preventing temperature growth than the ongoing focus on CO_2 emissions. While identifying the agricultural sector as the biggest contributor to methane emissions, the report stressed the critical role that the oil, gas and coal sector also had to play.

Group initiatives

Gas companies are already undertaking work through individual and group initiatives, motivated by pressure →

not only from governments but also investors and customers. On the group level, there are initiatives like the Oil and Gas Methane Partnership (OGMP) 2.0 (see page 62), Its members are targeting a 45% reduction in methane emissions from infrastructure by 2025. OGMP 2.0 now counts 67 companies among its participants.

Other initiatives include the Methane Guiding Principles (MGP) (see page 54), which is striving to reduce methane emissions across the value chain, partly through improving the accuracy of data and advocating for sound policy and regulations. Another is the Oil & Gas Climate Initiative (OGCI), whose participants pledged in 2018 to reduce their methane intensity to 0.25% by 2025 – a target they say they reached last year. They subsequently raised their ambition to 0.2% by mid-decade.

Many leading international oil and gas companies have also joined the World Bank's Global Gas Flaring Reduction Partnership (GGFR), which strives to end routine flaring by 2030, in turn reducing the amount of methane that escapes from flaring systems unburnt. The Global Methane Initiative is a broader organisation aimed at identifying and deploying practical and cost-effective methane mitigation technologies and methods across various sectors.

Cheniere Energy points to the US as a leader in driving improvements in methane emissions monitoring and control through voluntary initiatives.

"The US already has had voluntary methane abatement programmes for over two decades," Cheniere's senior director for climate and sustainability, Fiji George, tells *Global Voice of Gas* (*GVG*). "Much of the science and emissions data employed globally are due to these initiatives."

Individual targets

Most major oil and gas operators are striving to reduce their methane emissions intensity by 25-50% by 2025 and have already made significant progress towards this end.

BP, for example, reduced its methane emissions intensity to 0.12% in 2020 from 0.14% in 2019 and 0.16% in 2018. Methane emissions from its upstream operations alone fell 22% to 71.6kt last year. BP's aim "is to install methane measurement at all our existing major oil and gas processing sites by 2023, publish the data, and then drive a 50% reduction in methane intensity of our operations," the company says in its latest sustainability report.

Shell meanwhile achieved a methane intensity of 0.06% in 2020 for assets with marketed gas, down from 0.08% in the previous year. At its ONEgas facility in the North Sea, it has managed to lower its methane emissions by 55% since 2017, having made improvements to reduce venting and avoid valve leakages. Another key focus for the company is in the Permian basin, where it has deployed drones with cameras and laser detection technology to detect and reduce leaks.

Norway's Equinor is already working from a very low base, estimating its methane emissions intensity at only 10% of the industry average, at 0.03%. Last year it launched a joint project with the Norwegian Oil and Gas Association (NOROG) and other operators offshore Norway to assess potential methane leaks from abandoned wells.

Over in the US, Chevron managed to lower its upstream methane intensity to 2 kg of CO_2 equivalent/barrel of oil equivalent in 2020, down from 2.4 kg in 2019 and 4.5 kg in 2016. In volume terms, it has reduced its methane emissions by almost 50% in the past five years.

"We are actively addressing the reduction of methane emissions by using data, technology, and innovation to prioritise opportunities and execute the most efficient detection and reduction strategies," Chevron says. "As a part of our update to the methane metric, we are deploying a global methane detection campaign that will utilise proven and emerging detection technologies at assets representing 80% of our equity methane emissions."

Fellow US producer ExxonMobil is meanwhile targeting a 40-50% reduction in methane intensity by 2025. The company estimates it fulfilled its goal of achieving a 15% cut in methane emissions by the end of last year versus the level in 2016.

The push to eliminate methane emissions from the energy sector is very much a global effort. Saudi →

Along a gas value chain, however, the company that bears the cost of eliminating methane emissions is not necessarily the one that benefits from the resulting gas sale.

> Aramco, the world's biggest oil producer, has achieved an upstream methane intensity of just 0.06%. It has done this through the use of LDAR and gas recovery across all its facilities. Using the same methods, China's CNPC lowered its methane intensity by 12% between 2017 and 2019. It aims to halve its intensity between 2019 and 2025. Brazil's Petrobras is similarly targeting a 30-50% reduction in intensity by 2025. Russia's Gazprom, the world's largest gas producer, describes its methane intensity as one of the lowest in the industry, estimating it at 0.02% for production, 0.29% for transport and 0.03% for underground storage.

> "The company carries out regular in-line inspections of gas pipelines, examines their technical condition, and monitors methane emissions by means of helicopters and drones with laser scanners," the company says.

Innovation

There have been significant developments in methane detection, quantification and mitigation in recent years.

Satellites have been used to view greenhouse gases for almost two decades but only recently have technological innovations made methane tracking a profit-generating business. Other so-called top-down approaches such as aircrafts and the use of drones have also become easier and cheaper to use.

There have also been innovations in bottom-up approaches. One recent example is a new sensor developed by QLM Technology that combines optical imaging with laser-based sensing to measure methane and enables 24/7 monitoring without requiring an operator. It is designed for long-range, high-sensitivity and high-speed quantitative imaging of gas plumes, to help operators find and fix leaks.

Companies have also taken steps to reduce their expected emissions, particularly from valves and gas-powered pneumatic devices. Common options are installing new emissions control devices like vapor recovery units (VRUs) and replacing pneumatic devices with instrument air systems. VRUs capture the gas that accumulates in oil storage tanks that would otherwise be vented into the atmosphere. EcoVapour, for example, has designed a technology to capture 100% of vapour gas from tanks, and this was used by Shell to cut its emissions in the Permian basin.

Older equipment can also be replaced with new, lower-emitting versions. ClarkeValve, for instance, has created a steel composite valve that can replace legacy valves, nearly eliminating emissions.

Costs

The cost of reducing methane emissions varies significantly across different regions and over time, as market conditions change. The International Energy Agency (IEA) estimated that 40% of leaks in 2019 could have been avoided at no net cost, thanks to the resulting sale of the methane, only to lower this to just 10% for 2020, reflecting the drop in gas prices. The UNEP's *Global Methane Assessment* estimates as much as 60-80% of methane emissions from oil and gas could be abated at a low or even negative cost.

Along a gas value chain, however, the company that bears the cost of eliminating methane emissions is not necessarily the one that benefits from the \rightarrow

resulting gas sale. For example, midstream operators in the US do not own the gas that runs through their pipelines. Roy Hartstein, founder and managing director at Responsible Energy Solutions, notes that this and some other "problematic" assumptions leave questions about some past marginal cost studies. His company helps oil and gas firms find economic solutions to methane emissions and other concerns.

"One of the assumptions, that every 1,000 ft³ of gas that is "saved" as the result of a company taking action to prevent that gas going into the atmosphere will result in \$3 of revenue, if that is the market rate, and that amount will be available to pay the cost of mitigation," Hartstein tells *GVG*. "If an upstream operator prevents emissions at the wellhead before it goes through a metre, it may be able to sell that gas for \$3 downstream. However, the \$3 sales price of the gas is not the value available to the company. After considering operating costs to deliver that gas to the customer, the value is actually lower. This can significantly affect evaluations of the "net costs" to control emissions. Costs including processing, transport and other marginal costs should be considered for the additional gas."

"So the operator isn't actually getting \$3, it is just getting a small portion of that," Hartstein continues. "The studies of marginal abatement costs only minimally account for that. We believe significantly reducing methane emissions is the right thing to do, but the solutions are not as "free" as is often characterised."

The net cost of eliminating methane emissions is naturally higher in regions where gas prices are lower. In Texas, for example, operators can find it difficult to commercialise the associated gas they produce at their oilfields. Prices at Texas' Waha gas hub even swung negative two times last year owing to weak demand.



Quantifying methane: **Top-down versus bottom-up approaches**

There are advantages and disadvantages to both approaches, and they need to be reconciled to create data that can most effectively be acted upon JOSEPH MURPHY overnments and energy companies alike are setting targets for reducing their methane emissions in the years and decades to come. But quantifying how much methane is escaping into the atmosphere from a given company or sector is no easy task. There are a range of different methods available that can produce widely different results. And the technologies that are employed are constantly evolving.

Broadly, these methods can be split into two categories: bottom-up and top-down approaches.

Top-down methods include the use of aircrafts and increasingly satellites to quantify methane in the atmosphere and larger emissions sources on a very broad scale. Bottom-up methods for methane detection involve techniques such as handheld LDAR cameras, fixed-location detectors and surveys by wheeled vehicles, as well as drones, and are primarily used to detect and eliminate smaller emissions at the source including unplanned ones. But they can also be used to quantify emissions at an individual facility or device. A representative sample of such units can then be used to quantify emissions across entire supply chains.

Pros and cons

There are advantages and disadvantages to both approaches, and they must be reconciled to create data that can most effectively be acted upon.

As the Methane Guiding Principles' (MGP) Secretariat explains in its *Best Practice Guide*, "top-down assessments generally lack detail about individual sources but can provide comprehensive information about emissions at a site or in a region."

> The top-down approach can flag up major, unexpected emitting sources that might otherwise have been missed. But it has limitations. Firstly, it does not →

work offshore or in equatorial regions due to sensor reflectivity. When attempting to quantify emissions from an individual sector, for example the natural gas supply chain, it can also include emissions from other sources, potentially skewing the data.

In the oil and gas sector, top-down methods generally result in higher assessment of methane emissions than bottom-up methods. This can be connected, for example, with the time of day at which top-down aircraft surveys typically take place, which can coincide with a peak in emissions from field activity.

A 2018 research article by the Energy Institute of Colorado State University explored this issue by carefully studying an area of the eastern Fayetteville shale play in the US. It found an explanation for the temporal variability between top-down and bottomup difference in methane emission estimates, as summarized below.

"Episodic venting from manual liquid unloadings, which occur at a small fraction of natural gas well pads, drive a factor-of-two temporal variation in the basin-scale emission rate of a US dry shale gas play," the article states. "The mid-afternoon peak emission rate aligns with the sampling time of all regional aircraft emissions studies, which target well-mixed boundary layer conditions present in the afternoon."

The article concludes that this can lead to very misleading estimates for emissions, when such high, episotic levels of emissions are assumed to be the norm.

"Some top-down studies have taken that snapshot information and then applied it over a 24-hour seven day a week period, assuming that it was representative of the average," Roy Hartstein, founder and managing director at Responsible Energy Solutions, tells *Global Voice of Gas* (*GVG*). "When in fact it may have been measuring a peak rather than an average. The absence of detailed information on the source and reason for emissions at that given moment may lead to error when extrapolated to an annual basis."

Collaboration with industry

Hartstein notes that one of the strengths of the study undertaken at Fayetteville was that it had the

participation of the major operators in the basin, including ExxonMobil and Southwestern Energy. Prior top-down studies of the area did not have the benefit of knowing what was happening on the ground.

"Having detailed information about operations on the ground enabled understanding of the differences seen between top-down and bottom-up information," Hartstein explains. "This might suggest that having operators participate in the design of studies and in providing information may generate more useful results."

A notable example of operator participation in the study of methane in the US is Collaboratory to Advance Methane Science (CAMS), whose members include Cheniere, Chevron, Equinor, ExxonMobil, Pioneer Natural Resources, Sempra LNG and Shell. The group is funding research into methane emissions including the development of basin level modelling. They are also developing what is known as Project Astra in the Permian basin (*see GVG Volume 1 Issue 1*), aimed at creating an innovative sensor network to continuously monitor methane emissions across large areas to enable quick and efficient detection and repair of leaks.

CAMS also teamed up with the Queen Mary University London and Spain's Enagas recently to conduct a first-of-its kind study to directly measure methane emissions of an operating LNG vessel. Researchers collected comprehensive direct measurements aboard the Cheniere Energy-chartered newbuild *GasLog Galveston* during a round-trip voyage from the Corpus Christi liquefaction facility in Texas to a discharge port in Europe. This represents another example of successful industry collaboration in methane research.

"LNG shipping is an area where Cheniere and fellow CAMS co-founders believe there is potential for real progress on measuring and reducing methane emissions," Anatol Feygin, Cheniere's chief commercial officer, commented on the study. "This important work is consistent with our commitment to enhance the transparency around the emissions profile of the LNG value chain and robust scientific results are important data points to guide future mitigation strategies."

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Plumes do not correspond with sites shown.

The Methane Guiding Principles: taking action to support the transition

The MGP's goal is to reduce methane emissions along the entire natural gas value chain, with action centred around five guiding principles

REBECCA MIDDLETON,

Programme Manager, Secretariat, Methane Guiding Principles









roviding access to energy, while addressing global climate change, is one of the greatest challenges of the 21st century. Since natural gas consists mostly of methane, a potent greenhouse gas, its part in the transition to a low-carbon future will be influenced by the extent to which the oil and gas industry reduces its methane emissions.

Founded in 2017, the Methane Guiding Principles (MGP) is a voluntary, multi-stakeholder partnership seeking to address this challenge through collaborative and ambitious action. The MGP's goal is to reduce methane emissions along the entire natural gas value chain, with action centred around five guiding principles:

- 1. Continually reduce methane emissions
- 2. Advance strong performance across the gas supply chain
- 3. Improve accuracy of methane emissions data
- 4. Advocate sound policy and regulations on methane emissions
- 5. Increase transparency

The MGP has three main differentiators: it covers the full supply chain; it has full and equal collaboration between companies and civil society; and it adopts an agile approach, which doesn't rely on consensus. These three elements make it complementary to the other important coalitions that deal with methane emissions. \Rightarrow



The following examples provide a flavour of current areas of work:

- International Oil Companies have on average 50% of their production generated from Non-Operated Joint Ventures (NOJVs) and with this in mind, an MGP working group is seeking to reduce methane emissions at NOJV assets. During 2020 the member organisations consulted to devise six initiatives that aim to drive meaningful reductions in emissions, better reporting, and increased transparency from NOJVs. These initiatives were kicked off at the beginning of 2021 and some initial outputs are expected later in the year.
- Established in 2019, the MGP EU Policy Working Group (EPWG) brings together the different segments of the natural gas supply chain to contribute to EU policy discussions. In 2020, the EPWG focused on developing policy recommendations and engaging with the European Commission as it developed the EU Methane Strategy. In 2021, the EPWG delivered a set of robust policy recommendations covering the full scope of EU legislative activity.
- Flaring is a major methane source for many companies. Balancing practical considerations

with the need for improved confidence in the data, this initiative is aimed at developing material that will support companies in understanding and improving flare methane performance. The focus will be reporting, identifying suitable improvement pathways as well as highlighting and detailing available flare burn assessment technologies.

Any relevant outputs from these and other completed projects are made public where appropriate.

Improving understanding of methane and its management is core to MGP's mission to reduce methane emissions. A Dallas Fed Energy survey (December 2020) flagged that, for the onshore US, only 50% of larger firms have plans in place to address methane emissions, and for small firms the percentage drops to 30%.

MGP has worked with leading academics and NGOs to develop a suite of materials, freely available to download from the MGP <u>website</u>, to help organisations develop their own methane action plan.

 Ten Best Practice Guides providing a summary of current known mitigations, costs, and available technologies. These guides were developed →



On November 22 2017, eight international oil and gas companies signed a set of Methane Guiding Principles. Since the inauguration of the Methane Guiding Principles, the number of signatories and supporting organisations has steadily expanded.

by leading academics with input from a team of representatives from the MGP partnership. They include illustrative case studies and can be downloaded in English, Russian, French, Spanish, Arabic and Mandarin.

- The Methane Cost Model provides the user with an interactive screening tool to identify and evaluate potential methane reduction projects across the natural gas supply chain. The model can be used for both the early design phase of a project as well modifications to existing operations.
- The Gap Assessment Tool enables organisations to carry out a self-assessment of the completeness and maturity of their existing methane management arrangements based on a simple scoring system. Gaps in current arrangements can be identified, so that improvement measures can be developed.
- The MGP Global Outreach Programme comprises of two courses taught by experienced instructors from the Sustainable Gas Institute of Imperial College London. The first of these is a three hour Executive Course which highlights the importance of methane management to the future of the gas industry. The second is a Masterclass designed to improve awareness and know-how on managing methane emissions. The Masterclass has recently been made available as an e-learning, to supplement face-toface or virtual delivery mechanisms.

MGP members commit to support at least one

project annually, in -kind and/or financially. Those interested can find out more about the work being undertaken by MGP members by accessing their MGP reports via the website. These reports provide details on company methane emissions and targets (where relevant), and on current and future planned methane action.

Going forward, the MGP is looking to further its influence throughout the supply chain and gain wide uptake of the MGP Best Practice Guides. To achieve this the MGP will leverage its network and contacts to run a global, ambitious programme of stakeholder engagement and advocacy.

Manfredi Caltagirone, Program Manager in UNEP's Energy and Climate Branch, observes "The results of the Climate and Clean Air Coalition / UNEP Global Methane Assessment clearly show that without deep reductions in methane emissions, the international community won't be able to reach the objectives of the Paris Agreement. As a significant contributor of methane emissions, and as the sector with the highest potential for cost-effective reductions, the oil and gas industry has a climate and business imperative to be part to the solution to global warming. UNEP is glad to work with stakeholders under the Methane Guiding Principles and looks forward to mitigation announcements being followed by credible, ambitious, mitigation actions".

For more information on the MGP click here.

EXPLORE

MADRE DE DIOS BASIN

THE MOST PROSPECTIVE AREA FOR NATURAL GAS IN PERU 73<u>°</u> O 72° 0 70° O 69° O F42-19 F26-17 E25-17

Perú () petro

1°S F27-17 F28-17 LEAD PLAYS PROSPECTS Blocks under Promotion **Blocks under** National National Contract Parks Reserves 71 0 73° O 72° 0

Main exploratory areas

Camisea Area:

- The most successful area for hydrocarbons production and future exploration of resources to increase gas reserves in the Sub Andean Folded and Thrusted Belt with a 77% Success Factor is Camisea Area.
- There exists at least 6 prospects and 8 leads located in the Fold Thrust Belt. The leads can be upgraded through acquisition of additional detailed seismic and non-seismic methods to confirm closures.
- The higher estimated volume for prospective resources is of 6,495 BCF in Camisea Area.

Madre de Dios Basin:

- Madre de Dios Basin has proven hydrocarbons discovered in 1999 (Candamo Well-78-53-1X/ST).
- There exist at least 5 prospects and 17 leads located in the Fold Thrust Belt and in the Foreland Area. The leads can be upgraded through acquisition of additional detailed seismic and non-seismic methods to confirm closures.
- The estimated volume for prospective resources is of 18,915 BCF.

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MiQ: the market-based approach to methane

MiQ grades producers based on their methane intensity, with the expectation that cleaner operators will be able to fetch a premium for their gas

JOSEPH MURPHY

S authorities are looking to tighten methane regulations in the oil and gas sector, as part of efforts to halve the country's greenhouse gas emissions over the next decade. But there has also been a push to introduce market-based solutions that could produce results faster.

The US RMI and Systemiq launched their MiQ not-for-profit initiative in December last year, to offer companies an incentive to address the methane intensity of their natural gas. The initiative is still in the pilot phase, but the ultimate goal is creating a global standard for differentiating the natural gas market based on its methane intensity.

MiQ will use as granular data as possible to quantify emissions, requiring producers to deploy top-down monitoring – satellites, airplanes, drones, towers and continuous monitoring – with bottomup ground-level monitoring on a semi-annual or quarterly basis to detect and fix any emitting sources. A qualified independent third-party assessor will audit and certify that the producer's operations in a certain basin or sub-basin comply with the standard and monitoring requirements.

"We're heavily focused on the 1.5 degree Paris Agreement target goal. We want to create marketbased and technology-led solutions," Lara Owens, MiQ project manager, tells *Global Voice of Gas* (*GVG*). "We want to work with industry and not simply put up more roadblocks."

Producers' gas will be graded on a A to F basis, depending on its methane intensity. A requires an intensity of no greater than 0.05%, B 0.10%, C 0.20%, D 0.50%, E 1.00% and F 2.00%. The intention is that cleaner operators will then be able to fetch a premium for their gas, while lower-grade producers, as MiQ grows in popularity, may even have to sell theirs at a discount.

"The idea is that we get mass participation in this market that really drives towards making the cleanest production as possible, while the production which can't be cleaned up ultimately leaves the market," Owens says.

"This market-based approach, which encourages companies to do the right thing, with independent validation, to get a differentiated commodity \rightarrow

MiQ methane emissions intensity grading chart



premium, delivers better results than the threat of non-compliance penalties from regulators," Roy Hartstein, founder and managing director at Responsible Energy Solutions and an advisor in crafting the MiQ standard, adds.

How high companies can rank in the MiQ standard will also depend on how effectively they can monitor their emissions. To rate as A or B, for example, companies need to undertake methane leak detection and repair (LDAR) work on a quarterly and semi-annually basis respectively. In order to achieve C or higher, they need to reconcile their findings with top-down data. LDAR inspections over the entire facility are needed at least once a year for a company to score an F.

The standard will later be expanded to the full natural gas value chain, using the relevant methane intensity metrics set out by the voluntary Natural Gas Sustainability Initiative (NGSI). And the ultimate goal is for MiQ to serve as a global standard for rating natural gas based on how clean it is.

"There are so many fantastic voluntary initiatives out there, a lot of producers are doing the right thing. But it's all disaggregated, things are being done differently in the US compared with Europe or in Russia or Algeria," Owens explains. "We want to create a global mechanism that is fully transparent, fully visible and open source. There should be a clear level playing field for companies to differentiate themselves, instead of black box solutions separate groups are working on."

MiQ has also added an LNG component to its standard.

"So if you're an LNG producer, you can track your methane emissions from all your upstream sources, and therefore a cargo that arrives in Europe can be compared at the burner tip level with other sources of supply," Owens says. "This means you can be an informed consumer of your natural gas in terms of methane emissions."

MiQ is looking to take the standard fully public in the third quarter of this year.

"We're in serious talks with at least a couple of dozen groups and we hope many will be signing up as pilot participants in the next quarter," Owens says. "We're road testing this to get good global distribution to test that component of the standard and various gas types such as dry gas, unconventional production and associated gas. We need to test these different types of operations."

The standard needs to be calibrated to be impactful all across a "heterogenous market," Owen says. She does not see larger market players having an advantaged position over smaller ones in achieving grades under the standard. "A larger company may have 40 facilities in a country, but they treat each one as almost an individual facility," she says. "There's a little bit of economies of scale when it comes to implementing these practices, but our research suggests it's not significant."

Owens is hopeful that by monitoring and reducing their emissions, the natural gas industry "has an opportunity to take a leadership role in the Paris commitments." \rightarrow

Responsibly-sourced gas

M iQ has also partnered with non-profit organisation Equitable Origin (EO) to provide joint certification for responsibly-sourced gas (RSG). EO's EO100[™] Standard for Responsible Energy Development assesses gas producers based on principles of corporate governance, transparency and business ethics; human rights, social impacts and community development; Indigenous Peoples' rights; occupational health & safety and fair labour; and climate change, biodiversity and environment. Each principle carries a number of objectives and three levels of performance targets.

"The vision was to create a mechanism that would allow downstream users, buyers and distributors of energy, to have a way to recognize and reward responsible upstream practices," EO CEO Soledad Mills tells *GVG*.

EO draws from successful certification systems used in the forestry and agricultural sectors that enable producers to fetch a premium price for their products on the market.

"We spent the first three years coming up with what the best practice standards are, through unprecedented collaboration with industry, communities, NGOs, academics, government agencies and indigenous organisations," Mills says. "At the same time we didn't want to reinvent the wheel so we made sure to align the standard with other international standards and initiatives that already exist, bringing them all under one roof."

The first transaction to use EO100 was signed in February 2020 between Calgary-based Seven Generations Energy and gas distributor Énergir. Both EO100 and MiQ have been gaining momentum in recent months. EQT, North America's largest natural gas producer, said April 15 it would commit to have the majority of its production in the Marcellus shale basin certified under the MiQ and EO100 standards by the end of the year. US producer Northeast Natural Energy (NNE) then said on April 29 it would seek EO100 and MiQ certification for its facilities.

EO plans to upgrade the natural gas supplement of EO100 to cover methane intensity, aligning it with MiQ.

"We're aligning with their scoring system so it will be easier for producers to have a joint certification. We consider MiQ to be the de-facto international standard on methane," Mills tells *GVG*. "Addressing methane is incredibly important for climate change, for the US to meet its commitments, but there are other ESG issues that are



also of concern. It will definitely be important for the US to reinstate regulations around methane, but I think voluntary standards still have a role to play in helping companies demonstrate where they are going above and beyond minimum compliance."

The first trade of RSG took place in 2018, when Southwestern Energy agreed on the sale of gas from selected wells in its Marcellus play certified by IES' TrustWell[™] as complying with best practices for reducing methane emissions as well as some other environmental parameters. IES went on to merge with monitoring technology firm Project Canary last year.

EQT launched a pilot project on producing TrustWellcertified RSG in the Marcellus play. UP Energy said it too would get its gas certified by TrustWell in early March. That month, Project Canary announced a pilot project to deliver gas certified as RSG by TrustWell across the value chain from wellhead to burner tip. The gas in question will be gathered by processed by Rimrock Energy Partners in the Denver-Jules Basin, transported by Colorado Interstate Gas Co and delivered by Colorado Springs Utilities to residential and commercial distribution customers. In May, Xcel Energy said it would purchase Trustwell-certified RNG produced by Crestone Peak Resources for its Colorado operations.

"Our members are utilising an array of multi-faceted options to reduce the carbon intensity of the energy they deliver to customers while achieving climate goals without jeopardising affordability, reliability and resilience," Lori Traweek, CTO of the American Gas Association (AGA), tells GVG. "This includes the possibility of purchasing certified lower methane gas as well as incorporating renewable natural gas and hydrogen, modernizing infrastructure and investing in innovation."





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Oil and Gas Methane Partnership 2.0

OGMP 2.0 is the gold standard solution for methane emissions measurement, reporting and verification capability in the energy sector

GIULIA FERRINI

OGMP Programme Manager, UNEP

flagship multi-stakeholder initiative helping the industry to better understand and manage methane emissions is the Oil & Gas Methane Partnership (OGMP), which was launched by the UN Environment Programme and the CCAC at the United Nations Secretary General's Climate Summit in 2014. It is a comprehensive measurementbased methane reporting framework that standardises rigorous and transparent emissions accounting practices. In practice, the OGMP provides a protocol to help companies systematically manage their methane emissions from upstream oil and gas operations, as well as a platform to help them demonstrate this systematic approach to stakeholders. To date, the OGMP is the only broad multi-stakeholder partnership working on methane emissions reporting on an international level.

With its ten original member companies representing many of the world's largest oil and gas operators, the OGMP has been successfully raising awareness on methane emissions from the oil and gas sector. Its partners have also been working to encourage methane mitigation by other actors in the industry. For instance, the OGMP designed a series of Technical Guidance Documents (TGDs) presenting suggested methodologies for quantifying methane emissions from nine core emission sources in collaboration with member companies. These TGDs are considered best practices in the field and are widely used by practitioners beyond OGMP members for guidance on methane emissions.

Given the growing awareness of methane emissions being both a major climate issue and a significant mitigation opportunity, the OGMP members responded by adjusting the ambition of the Partnership. When it was launched in 2014, many companies had limited knowledge about managing methane emissions from oil and gas production. Currently, several companies have committed to methane reduction targets, such as the Oil and Gas Climate Initiative collective target of 0.25% methane intensity target by 2025 and the BP target of 0.2% by 2025. Many have also implemented comprehensive methane reduction programmes. Simultaneously, a negative public view has shaken the oil and gas industry in an EY survey, only 37% of the public said it trusted the industry to do the right thing. Faced with this perception and increasing pressure from investors, governments and civil society, the OGMP member companies decided to re-imagine the framework to make it more ambitious, impactful and comprehensive. →



Data flow of the IMEO



The gold standard

In 2020, UNEP, the European Commission, the Environmental Defense Fund, the CCAC and 64 companies (this number has now grown to 67) with assets on five continents representing 30% of the world's oil and gas production adopted a new reporting framework: OGMP 2.0. is the most ambitious and comprehensive measurement-based reporting framework for methane emissions from the oil and gas sector that will improve the accuracy and transparency of methane emissions reporting.

The new reporting framework will provide industry, civil society and government with more detailed and transparent information about methane emissions levels, sources and mitigation opportunities. Under the OGMP 2.0, companies commit to report actual methane emissions figures from both operated and non-operated assets in line with their reporting boundaries. Reporting covers all segments of the oil and gas sector where material quantities of methane can be emitted. Companies also commit to their own individual reduction targets and periodically report on progress towards these targets.

The OGMP 2.0 establishes five reporting levels, with the highest level requiring that emissions include source-level (level 4) and site-level measurements (level 5). Companies have 3 years to achieve compliance for operated assets and 5 years for non-operated assets. The gold standard is achieved when all assets with material emissions are measured and reported, with no demonstrable impediments at level 4 and notable efforts by companies to move to level 5.

This improved methane reporting will help the oil and gas industry realise the deep reductions in methane emissions that are badly needed over the next decade, and do so in a way that is transparent to civil society and governments, and can therefore inform policy making. The European Commission's 2020 methane strategy referenced the OGMP as "the best existing vehicle for improving measurement, reporting and verification capability in the energy →

OGMP 2.0 will improve methane reporting around the world



sector". It will serve as a basis for the EU's binding legislation to be tabled later this year.

New global methane observatory

To further catalyse methane mitigation at the scale and speed needed to limit the worst effects of climate change, UNEP, in collaboration with the European Commission, officially announced the creation of the International Methane Emissions Observatory (IMEO) on March 2 2021. IMEO is a data-driven activist entity with the goal of fostering an ecosystem of methane action from industry, governments, scientists, and other key stakeholders.

IMEO will create a public dataset of empirically verified methane emissions, with an initial focus on fossil fuel sources. Despite the technical feasibility and the cost-effectiveness of methane reduction measures, the current methane emissions data landscape is not enough to address emissions on the scale and in the timeframe necessary to meet the 1.5°C target. Methane data available today is largely based on engineering factors that have been repeatedly shown to be inaccurate – in most cases dramatically underestimating true levels of methane emissions. A deeper understanding of methane emissions is urgently needed.

IMEO fills the gap in the current data landscape by collecting and synthesising data from various sources and using the results to generate the most comprehensive picture to-date of the scale and sources of fossil methane emissions. Key to this approach is the company reporting via the OGMP 2.0. The Observatory will aggregate and analyse company reports and compare these with multiple methane emissions data streams (national inventories, direct measurement studies, satellite observations) to reconcile inconsistencies between reported and observed emissions levels.

By combining all those sources of data, IMEO will provide a comprehensive understanding of where and how much methane is being emitted and will work with governments and companies around the world to connect these data to effective mitigation actions. By interconnecting research, data, reporting and policy-relevant science to deliver the necessary reductions, IMEO will be a powerful agent for change in the ecosystem of partners and institutions engaged on the methane challenge.

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T.EN

Brussels takes aim at methane emissions

Methane emissions in the European energy sector have fallen significantly over recent decades, and the EC's legislative proposal aims to reduce them further

ANDREAS WALSTAD, JOSEPH MURPHY

he European Commission (EC) is preparing a new legislative proposal to further curb methane emissions in the energy sector, after publishing its landmark methane strategy last year.

The EU currently has no dedicated policy framework for addressing these emissions, despite recognising methane as second only to carbon dioxide in its contribution to climate change. That is soon set to change, however. The EC aims to present its proposal by the end of the year, likely before the UN climate summit in Glasgow in November. The final details are being drafted, after closing a public consultation on May 1 that generated responses from many of the leading players in Europe's gas industry. Final adoption by the European Parliament and the Council of Europe is expected to take place next year. →



Source: European Environment Agency

The EC intends to propose "compulsory measurement, reporting and verification (MRV) at a company level for all energy-related methane emissions," it says in its consultation document. The measures will build on the methodology of the updated Oil and Gas Methane Partnership (OGMP 2.0), a voluntary initiative to monitor, report and reduce anthropogenic emissions from the energy sector (see page 62). The commission will also oblige companies to improve leak detection and repair (LDAR) at hydrocarbon infrastructure, and consider rules to eliminate routine venting of methane and flaring across the full supply chain.

The EC foresees an important role for the UNEP's International Methane Emission Observatory (IMEO), which it helped launch in March, as well as the EU-led Earth observation programme, Copernicus, to help quantify methane emissions.

The import question

A key concern is the extent that the EC will apply its methane rules to oil and gas suppliers beyond the EU. Europe is already the world's biggest oil and gas importer, with the EU importing an estimated 80% of its gas needs in 2020, according to EC data. And its dependence on imports is only growing as indigenous production declines.

"The EU ultimately wants to regulate methane emissions on a global level," Thierry Bros, professor at Sciences Po Paris, tells *Global Voice of Gas (GVG)*. "It wants to push its suppliers like Russia and the US to follow suit in addressing their emissions."

The EC could propose emissions performance standards for imported oil and gas. More radical measures would be to include methane emissions under the EU emissions trading system (ETS) or restrict gas imports from countries with relatively high →



methane emissions. But such measures would likely struggle to gain support and could be problematic.

"Most methane emissions are from gas production outside the EU. The EU could restrict gas imports from those countries, but that would mean a big fight with the World Trade Organisation. Another option is to oblige importers of gas from these regions to buy twice as many EU carbon allowances," Walter Boltz, an independent senior energy advisor, tells *GVG*. "But for now I think the EU will focus on improving monitoring and reporting at home and negotiate with third countries on emissions standards."

The commission has also flagged the idea of a methane-supply index (MSI) at an EU and international level to increase transparency and help fuel buyers make more informed decisions. Over time, it would be supplied by data from IMEO.

Industry efforts

Europe's oil and gas industry has already made substantial progress in addressing its methane emissions. The sector's fugitive methane emissions dropped 59% between 1990 and 2018, according to the European Environment Agency (*see graph on page 68*), while fugitive greenhouse gas emissions as a whole fell 44%.

European oil and gas companies have taken part in a number of voluntary initiatives to reduce their emissions. OGMP 2.0 now comprises 67 companies representing more than 30% of the world's oil and gas production and includes European majors BP, TotalEnergies, Eni, Shell and Repsol. The group aims to deliver a 45 % reduction in the industry's methane emissions by 2025 compared with estimated 2015 levels, and a 60-75 % reduction by 2030. Some 22 oil and gas companies, mostly operating in Europe, have also aligned with the *Methane Guiding Principles Best Practice Guides* (see page 54).

"Methane emissions are an important focus area when it comes to overall emissions reduction and our industry has already undertaken a number of steps to minimise them. Voluntary efforts by individual companies are important, but they do not drive industrywide change on their own," Francois-Regis Mouton, the regional director for Europe at the International Association of Oil & Gas Producers, tells *GVG*. "The recent creation of the IMEO for example is a positive step. In addition to standards and guidelines, we support cost-effective and efficient regulation to drive change across the full energy value chain where appropriate."

The EC argues gas companies can benefit from LDAR initiatives thanks to the resulting revenues from the methane that is saved and subsequently sold. But the size of this benefit fluctuates greatly. In 2020, the International Energy Agency (IEA) estimated that 40% of methane emissions from the energy sector could be abated at zero cost worldwide, only to lower it to 10% the following year because of weaker gas prices. It estimates only a 5% reduction is possible in Europe.

"The European Commission should therefore take into account any fluctuations in the economic benefit associated with emission abatement actions," Italy's Eni said in its consultation response.

In any case, the commission concedes that "there is a distinct possibility that the costs associated with such measures could in some instances lead to higher operating costs for energy companies that could be passed on as higher energy prices for consumers."

In their responses, the European gas association Marcogaz and others call for investments in MRV, LDAR and mitigation measures to be recognised as regulated activities by national regulatory authorities.

"In the case of non-regulated operators, authorities should also ensure the investments and efforts through European and national incentives," Marcogaz says in its response.

Market input

The industry has offered various other suggestions for what shape the legislation should take. Many have warned against the EC pursuing too prescriptive an approach to monitoring and abatement.

"MRV and LDAR can't be seen independently and legislation should be more goal oriented → than prescriptive and allow flexibility to focus resources on activities that ensure the highest methane emissions reductions," France's Engie wrote in its response.

Marcogaz adds that "the previous long term efforts of the gas companies who took early action in measurement and mitigation should be recognised and fairly accounted for."

James Watson, secretary general of Eurogas, wants to see precise definitions for terminology covering equipment and assets.

"To address the issue properly, we would need to see accommodations for variations along the value chain, like characteristics of assets and equipment," he tells GVG. "Blanket obligations in leak detection and reporting will not work."

Others like Gazprom stress that "an objective system of verification and control is needed that ensures equal treatment of all gas suppliers in a transparent manner. Its sole goal must be to objectively measure and then reduce emissions."

"It will be important to avoid measures that may lead to artificial market distortions with respect to natural gas as an energy source," the Russian supplier continues. "Imposing quotas or charges on methane emissions that are not supported by objective data can lead to an unjustified increase in the price of gas and an unjustified restriction on the development of low carbon hydrogen from natural gas."

Gazprom and others including the US LNG Allies trade association, have called for the EC to take into account legislation and regulation in supplier countries. A number of companies also stress the need for legislation to tackle other methane-emitting sectors like agriculture and waste. Both are bigger contributors to anthropological methane emissions than the oil and gas industry.





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The upcoming EU methane legislation:

A chance to accelerate methane mitigation policies

Upcoming EU legislation could provide a modern dynamic approach to methane regulation





ANDRIS PIEBALGS AND **MARIA OLCZAK** Florence School of Regulation Gobal methane policies could considerably strengthen the path to limiting global warming to 1.5 degrees Celsius. The recently published Global Methane Assessment by the CCAC and the UNEP concludes that just by reducing methane emissions the world could avoid nearly 0.3 degrees Celsius warming by the 2040s. In order to get there, a decrease in anthropogenic methane emissions of 45% by 2030 is necessary. Fossil fuel value chains are responsible for 35% of global methane emissions. In this sector, existing technologies →
The remaining question under consideration is whether the EU should flank its climate diplomacy by using its market power to support a global reduction in anthropogenic methane emissions.

> and knowledge could be used to produce a fast reduction in emissions. Therefore, it is important to use this potential to put the world on the least costly path to limiting global warming.

Upcoming EU legislation could provide a modern dynamic approach to methane regulation. Methane is the second largest GHG in the EU. In 2018, 3800 kt of CO₂ equivalent were emitted, which constituted 10% of the overall GHG emissions. Agriculture is the main source, accounting for over half of all anthropogenic emissions in the EU. Energy is responsible for 13.5% of EU methane emissions. The European Green Deal called for a reduction in energy-related methane emissions. The EU Methane Strategy specifies an intention to table EU legislation on energy-related methane emissions with the aim of improving measurement and reporting combined with mitigation measures. The following public consultation did not identify major obstacles to a legislative proposal by the end of 2021.

The EU legislative proposal

There is good reason to expect that the EU MRV system will be anchored to the principles of the

OGMP 2.0 reporting standard, which requires direct measurements at the source and site levels, reporting from all assets (operated and nonoperated) and individual dynamic reduction targets. National regulatory authorities will be involved in this process, providing incentives for regulated network companies to make the necessary investments. There will be requirements for ambitious leak detection and repair (LDAR) programmes with well-defined leak detection criteria, on-site surveys, leak repair and monitoring, reporting and data analysis. We can also expect measures for the elimination of routine methane flaring and venting. All these measures will provide a mandatory robust transparent scientifically-rigorous fossil methane mitigation framework in the EU.

Establishing a robust MRV framework at home will give the EU more weight in pursuing international initiatives to reduce methane emissions. The EU Member States have acknowledged this as a priority in their climate and energy diplomacy. They will be focusing on establishing international partnerships and encouraging participation in the recently established International Methane Emissions Observatory (IMEO) to strengthen global methane measurement, reporting and verification.

The IMEO will publish anthropogenic methane emission data coming from various verified sources, providing the necessary transparency for policymaking and accountability. The IMEO was established by the UNEP with significant support from the EU in March 2021. Additional opportunities for methane diplomacy nowadays result from high-frequency monitoring satellites, e.g. via the EU Copernicus programme. Methane monitoring technology provides a global tool to check methane inventories and provide incentives for operators with high emissions to improve to best-in-class levels.

An open question: imported emissions

The remaining question under consideration is whether the EU should flank its climate diplomacy →

by using its market power to support a global reduction in anthropogenic methane emissions. The EU is a major importer of fossil fuels. Threequarters of the fossil fuels consumed in the EU are imported and in the case of natural gas the import dependency is almost 90%. This means that the majority of methane emissions are emitted in value chains outside the EU's borders. In the case of natural gas value chains, the estimated methane emissions from imported natural gas and LNG are up to eight times those produced within the EU's borders.



There is also a call to establish a path towards the implementation of a mandatory methane performance standard for all gas sold in the EU. In 2019 the EU imported a third of all internationally traded natural gas and therefore has significant leverage in the global gas market. A relevant reference for a benchmark value that could serve as a methane performance standard in the EU is the Oil and Gas Climate Initiative's (OGCI) 2025 methane intensity target. The target is 0.2-0.25% by 2025, and it covers all emission sources from operated assets in the upstream sector, including fugitive emissions and emissions from venting and incomplete combustion. The 0.2% target could be used as the emission intensity level initially required for complying with an EU methane performance standard for the oil and gas industry. The target should be dynamic over time to incentivise the industry to apply the newest technological solutions to limit methane emissions.

To achieve the performance standard, a procurement standard should be applied. It should guarantee that all the gas sold in the EU gas market meets the performance standard. There should be consequences for procuring gas that does not meet the performance standard. Establishing methane regulatory equivalence between the EU and gasexporting countries is potentially the most effective path to delivering the performance standard. This creates a win-win situation. The producing countries can put more emphasis on methane mitigation in their nationally determined contributions (NDCs) and buyer countries can procure gas at a credible performance standard.

Achieving regulatory equivalence could be a long and complicated process. In parallel with these diplomatic efforts, a certification scheme should be established. This should be based on reliable and transparent MRV criteria. It would provide fair access to the EU market. Establishing a methane performance standard for all gas sold in the EU is not yet universally supported and it is also not clear if this approach will find its way into the legislative proposal. It is important to note, however, that this approach is being supported by some large international oil and gas producers. Not using the performance standard instrument would be a missed opportunity to mitigate methane emissions.

It is also important to note that methane policies should also put a spotlight on methane emissions from the agriculture and waste sectors. Capturing these emissions, even at greater cost, could provide a double benefit: reducing climate warming and advancing the circular economy.





NGC Joins The Fight Against Methane

Alarms around atmospheric methane levels were raised only fairly recently, but the world is now attentive to the major threat posed by this potent greenhouse gas (GHG). As an energy company with over 45 years in the business, The National Gas Company of Trinidad and Tobago Limited (NGC) acknowledges its contribution to global methane output and is pursuing an operational target of near-zero methane emissions.

NGC operates a 1000km natural gas pipeline network in Trinidad and Tobago, which comprises both onshore and offshore segments, almost thirty (30) above-ground installations, and connections to over 120 consumers. Through its subsidiaries, the Company also manages industrial site, port and marine infrastructure, a natural gas processing plant and an extensive CNG distribution network.

Given the national footprint of these assets, routine asset integrity management (AIM) and leak detection have always been a top priority from the perspective of safety, which is a pillar of the Company's operations. With methane now in focus, locating and repairing leaks has assumed a new dimension of importance, so NGC is strengthening its arsenal of leak detection tools.

NGC has joined the ranks of global energy players leveraging satellite data to visualise

leaks and reduce their methane footprint. In 2021, NGC announced a pioneering partnership with Netherlands-based provider Orbital Eye, which monitors energy infrastructure and measures associated GHG output using satellite data. This partnership will allow NGC to access critical research and emissions information about Trinidad and Tobago's industrial assets over the next three (3) years, which will be used to inform mitigation and AIM plans.

As a complement to this technology, NGC has also acquired the most sensitive Forward-Looking Infrared (FLIR) optical imaging camera on the global market, which is capable of detecting much smaller leaks from infrastructure than other models. This handheld camera is being used for annual leak surveys and is supporting routine maintenance and inspections across the Company's network. Of course, methane emissions are a systemic issue, and mitigation requires collaboration and commitment at a broader level. NGC has therefore taken a seat at the global table by joining the Oil and Gas Methane Partnership (OGMP), led by the United Nations Environment Programme (UNEP). This Partnership is a voluntary association of governments, international organisations, NGOs and energy stakeholders working together to reduce methane emissions.

NGC's membership signals its intent to not just lead national efforts in methane mitigation, but help shape the global offensive. The Company intends to leverage knowledge-sharing platforms to spread the word, and help equip companies along the entire local energy value chain to tackle emissions in their own operations.

Indeed, education is one of the most powerful tools being used by NGC to bring emissions down, not just of methane but also carbon dioxide. The Company has partnered on several external initiatives, and spearheaded some of its own, to raise consumer awareness around this pressing global concern. These have included the launch of an energy efficiency mobile app, a school-based education campaign, and an industry-oriented Super ESCO project.

In the background of all these efforts, NGC is working to upskill its human resource base, through training and new hires, to outfit for the new energy future and lead innovation in the sector.

Bringing emissions in check requires collective and concerted effort. NGC has demonstrated its deep commitment to that fight, as a leading gas company at the forefront of energy.

www.ngc.co.tt





Europeangas industry is committed to curbing methane emissions

Gas operators remain more than ever committed to delivering on the EU Green Deal's objectives

FRANCISCO P. DE LA FLOR GARCÍA,

Lead, IGU Policy Task Force

TANIA MEIXÚS FERNÁNDEZ,

GIE Chairwoman Methane Emissions group

ethane emissions management and reduction has become a top priority for the European gas operators. For many years, gas operators have successfully been working to reduce methane emissions through mandatory and voluntary initiatives, not only as a safety requirement but also for environmental reasons.

According to the European Environment Agency published in May of 2021, between 1990 and 2018, methane emissions from the natural gas chain have been reduced by -58 % and they account for 0.5 % of total GHG emissions in the EU.

The gas industry considers minimisation of methane emissions as an opportunity to actively contribute to short-term mitigation of climate change, accelerate environmental commitments and further enhance the environmental value of natural >



gas. Gas operators remain more than ever committed to deliver the EU Green Deal's objectives.

In October of 2018, the Directorate General for Energy of the European Commission at the 31st European Gas Regulatory Forum (Madrid Forum), invited GIE and MARCOGAZ to investigate the potential ways that the gas industry can contribute to the reduction of methane emissions. Responding to the request, GIE and MARCOGAZ conducted an industry-wide study, with contributions from IGU and other representatives of the entire gas value chain, from production to utilisation, including biomethane production, and covering all types of methane emissions.

This study was published in June of 2019 and provides an overview of the current status of methane emissions in the EU gas sector and the actions undertaken by the gas industry until now. The report contains also information on ongoing initiatives and a number of proposed commitments for future actions for the industry.

Following the excellent reception of this study and the consequent recommendations of the European Commission to disseminate the content and the conclusions of the report, GIE and MARCOGAZ organised a series of dissemination activities and training sessions to share knowledge and raise awareness.

In addition, to tackle the identified challenges and gaps in the report, European representatives from the entire gas value chain have developed collaboratively an action plan, which is updated on frequent basis. It is worth to highlight some of the latest deliverables achieved thanks to the leadership of GIE and MARCOGAZ:

- Guidelines for methane emissions target setting
- Methane emissions glossary
- Technical recommendation to reduce venting and flaring
- Technical recommendation on LDAR campaigns
- Assessment of methane emissions for gas transmission and distribution systems - This document is the basis for a future European CEN technical standard to quantify methane emissions in transmission and distribution networks, LNG regasification terminals and underground gas storages (currently under development) →



Also, in 2020, GIE and MARCOGAZ brought together with the UNEP and the European Commission, an important number of European mid and downstream operators to collaborate on the extension of the OGMP methane emissions reporting framework to these segments of the gas chain. A proposal on the reporting template was developed based on the MARCOGAZ reporting methodology. The OGMP 2.0 is one of the key initiatives, as it will allow improvements to the reporting accuracy as well as to the credibility of the data reported by the gas industry. Currently the vast majority of the industry partners are European companies. The data reported by the companies will be included in the future International Methane Emissions Observatory (IMEO).

To get the OGMP 2.0 gold standard, companies need to demonstrate efforts to quantify their methane emissions with top-down/site-level technologies. For this reason, the GERG (European Gas Research Group) has recently launched a firstof-its-kind project to measure methane emissions with top-down/site-level technologies in midstream gas installations. This project comes at a critical time and will set recommendations on the best available technologies to be used for these kind of assets.

In October of 2020, the European Commission published its strategy to reduce methane emissions in the European Union. In this Strategy, the Commission announced that they will publish a legislative proposal on methane emissions for the energy sector before the end of 2021. One of the aims of this forthcoming legislation is to improve the accuracy of the methane emissions data, while further emissions reductions are achieved. For this reason the EC will establish rules on monitoring, reporting and verification building on the OGMP 2.0 reporting framework, LDAR campaigns and reduction of venting and flaring.

After the publication of the Strategy, the European gas industry collectively expressed their support to the European Commission's Strategy on methane emissions via a joint declaration. It is worth mentioning that the industry welcomes the holistic approach of the Strategy to better exploit the synergies between sectors thereby helping to avoid emissions (e.g. injection of biomethane – produced from manure and waste - into the European gas grids).

In addition, the industry highlighted in its Declaration that to achieve a sustainable and \rightarrow cost-effective



The presentation in Madrid in June 2019 of GIE and MARCOGAZ's study providing an overview of the current status of the methane emissions in the EU gas sector and the actions undertaken by the gas industry until now.

From left to right: Andris Piebalgs - former European Commissioner and part time professor in the Florence School of Regulation; Ricardo Bolado Lavin - Scientific research officer in the Joint Research Centre of the European Commission; Francisco de la Flor García, Lead, IGU Policy Task Force; Tania Meixús Fernández, GIE Chairwoman Methane Emissions group; Klaus-Dieter Borchardt – European Commission Deputy Director General for Energy; Jos Dehaeseleer - MARCOGAZ Secretary General.

> reduction of methane emissions, a series of principles and elements should be taken in consideration while designing and deploying methane mitigation tools:

- Flexibility is needed for industry to implement the tools and available technologies enabling the highest emissions reduction at the lowest cost and in the shortest time.
- A well-structured, fit for purpose MRV system is crucial for a better evaluation of the data and the results of mitigation measures in place, as well as to improve the transparency of the emissions data.
- Investments on MRV, LDAR and mitigation measures undertaken by infrastructure operators should be allowed and accordingly incentivised by the Regulatory Authorities.

- We are ready to support the European Commission in exploring the feasibility and added value of other incentivises and tools for methane emission reduction in the EU.
- Companies along the gas value chain should account for the methane emissions from the assets under their control.
- The previous long-term efforts of the gas companies who took early action in measurement and mitigation should be recognised.
- The innovation, development and implementation of fit-for-purpose technologies and practices are at the centre of effective reductions and they should be further supported.
- The global dimension should be taken into account by establishing an international methane emissions observatory aimed at improving credibility and transparency.
- Cooperation with non-EU countries should be fostered as it is key to address methane emission reductions along the chain of gas imported into the EU.

When we speak about methane emissions in the European gas sector, the key words are collaboration, commitment and minimisation. According to the quote "if you want to go fast, go alone. If you want to go far, go together", it is clear that the gas industry wants to remain a key part of the European energy mix in the future. For this reason, there is a full commitment to continue minimising the methane emissions based on a close collaboration among all the actors.

Getting a measure of flares

If we can get better at identifying and quantifying emissions, then we can get much better at reducing them, hence the focus on trialling and deploying new technologies

GORDON BIRRELL,

Executive Vice President, Production & Operations, bp

laring is, for many oil and gas facilities, the single biggest potential source of methane emissions. As the industry moves towards better transparency and accuracy of its reported emissions, improved data on flaring will be a key criterion for success. And if better data is to translate into reduced emissions then this data needs to be available quickly and reliably to front line operations.

Operating companies would rather not flare gas at all – gas is a valuable product – and significant progress has been made in recent years, with companies such as bp aiming to eradicate the last vestiges of routine flaring by 2030. But simply turning flares off is not an option. They provide an essential safety feature to many facilities and so it is incumbent upon operators to reduce flaring as much as possible and to try to optimise their efficiency at the same time.

Measuring flare efficiency in live operations is notoriously difficult. By design, they are the highest, hottest and least accessible piece of equipment on a facility. That is why, for decades, reported emissions have assumed that 98% of the gas combusts with the remaining 2% going to the atmosphere – a figure derived from empirical studies of flares going back to the 1980s. Since then, progress in the way that flares \Rightarrow

Thanks to technology advances such as these, the pathway to reducing methane emissions from flaring looks clearer than ever

> operate mean that newer facilities are designed to operate far more efficiently, but academic research has also found some flares operating well below this value.

> The desire to replace calculated averages with actual measurements forms the basis of the commitment to measure methane seen in emerging agreements – such as the Oil and Gas Methane Partnership which was relaunched by the UN Environment Programme in 2020 and signed by companies that represent around 30% of global oil and gas production, including bp. The value in accurate measurements is that they allow operators to target emissions reductions in a focused way – intervening where the greatest impact can be achieved and provide stakeholders with confidence in our performance.

Thankfully, recent development in digital technologies are paving the way for better measurements of flares. For example, advances in computational fluid dynamics are allowing us to model how a flare behaves under the varied and often extreme conditions experienced in the field. The technique, first developed for industries such as the automobile sector, is providing assurance that modern flares have the capability to exceed the 98% expectation – even when low flaring rates encounter strong cross-winds. And as flaring rates drop, it helps to ensure that the primary role of the flare, as a safety device, is never compromised. At bp we have also turned to advances in spectrometry and image processing to peer deep into the flame itself – to measure the light emitted by the gases to measure efficiency.

However, to provide real-time operational data we need to go further. By combining the accurate-to-the-second measurements of the rate of gas sent to flare, process conditions and gas composition we can predict efficiency and provide continuous live feeds to the facility on how the flare is performing. These techniques were first developed by Baker Hughes for use in refineries, but using the power of cloud computing they were able to take much of the 'heavy-lifting' of data processing out of the facility and only feed back the essential output figures – making it accessible to a wider range of assets including ones offshore. The whole process takes a matter of seconds, allowing the facility to see how the flare is performing and make adjustments as required.

The technique was first tested on a bp operated vessel in the North Sea and now forms part of bp's methane measurement approach being rolled out under our Aim 4 – to install methane measurement on all major oil and gas processing facilities by 2023.

Thanks to technology advances such as these, the pathway to reducing methane emissions from flaring looks clearer than ever. A Publication of the International Gas Union (IGU) in conjunction with Minoils Media Ltd.

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Publisher Minoils Media Ltd.

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Global Voice of Gas

BY THE INTERNATIONAL GAS UNION

ISSUE 04 | VOL 01

International Gas Union

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