NAVIGATING THE CRISIS
AHEAD OF COP27

The solution to volatility: Chevron interview

Winter is coming: how will Europe’s energy system fare?

Norway braces to ramp up gas supply to Europe: Equinor interview
Sustainability in focus – The NGC Group targets green growth

The National Gas Company of Trinidad and Tobago Limited (NGC) is evolving. The lead architect of the Trinidad Gas Model of Development, the company is today looking to recast the role of energy in the national economy, to make it a driver of more holistic, sustainable development.

NGC and its subsidiaries – together, The NGC Group of Companies – have embarked on a journey to become a more sustainable energy business, through elaboration of a Green Agenda. This refers to a collection of initiatives, strategies and investments all aimed at reducing carbon emissions and supporting climate action – one of the most pressing sustainability goals.

NGC’s Green Agenda includes internal initiatives – targeting a reduction in the carbon footprint of the entire NGC Group of Companies – as well as industry-wide and national projects, which seek to make an impact on a wider scale.

Key on NGC’s Green Agenda are the following:
- Sustained focus on building the natural gas industry of Trinidad and Tobago, to support use of natural gas as a bridge fuel in the global energy transition;
- A methane monitoring and mitigation programme to identify and address leaks along NGC’s pipeline corridor, using satellite data and infrared visualisation;
- Collaborative exploration of opportunities to introduce solar power, green hydrogen and biofuels into the national energy mix, through partnerships with NGC Group subsidiaries and industry stakeholders;
- Support of academic research into clean energy through partnerships with local universities;
- Proactive work with vendors to strengthen supply chains and help vendors integrate ESG considerations into their own businesses;
- Active lobbies across the energy sector to reduce carbon footprint of industries, including a Super ESCO project to help improve energy efficiency among light industrial consumers;
- An expansion of the Company’s 315-hectare reforestation programme to include agroforestry and eco-tourism components;
- A focus on supporting sustainable agriculture to build food and nutrition security;
- Energy education through a free consumer-oriented app Energy SmartTT and a Caribbean clean energy research portal, CarGreen;
- Decarbonisation of the transportation sector through CNG and alternative fuels;
- Support of sustainable energy business development through a Sustainable Investing Initiative.

NGC and its subsidiaries have also articulated the following targets in support of Trinidad and Tobago’s Paris Agreement commitments:
- By 2030, attain 30% of Trinidad and Tobago’s market share for renewable energy and energy efficiency business;
- By 2030, achieve a 75% reduction in venting of methane, and 50% reduction of fugitive methane emissions;
- By 2030, achieve 12% of Trinidad and Tobago’s Nationally Determined Contributions (NDCs) target for greenhouse gas (GHG) reduction;
- By 2040, achieve 50% of Trinidad and Tobago’s NDCs target for GHG reduction;
- By 2050, achieve carbon neutrality across The NGC Group

Through implementation of its Green Agenda, The NGC Group intends to not only grow its business more sustainably, but lead Trinidad and Tobago into an era of clean-powered prosperity.
Message from the President

Dear gas industry colleagues, wider energy sector partners, and valued stakeholders from all corners of the world.

We are moving into the final quarter of this turbulent year, and it is likely to continue challenging us all. The industry, policymakers, and most of all – our consumers. There is a crisis of affordability in many parts of the world; people and businesses are struggling to pay their bills, and the governments are under pressure to help them deal with this difficult reality.

I don’t envy political leaders who are faced with many tough decisions. These decisions will impact how the world will navigate through this crisis now, but they will also necessarily impact the direction of travel for years to come. Decisions made today will determine how global energy systems can rebuild energy security; how they can return to stable and affordable price levels; and how they can get back on a sustainable path, to be sure that generations to come have a good life on a healthy planet.

When I read or hear some of the policy discussions that are ongoing now however, I am concerned. Decisionmakers today are so understandably, but singularly, focused on solving the short-term crisis, that the real planning horizon has been reduced to an unsustainably short period. In some discussions, energy policy is measured in months, not years and decades, as it should. It is absolutely imperative now for governments to show leadership and help their people make it through this difficult period, but in doing so, they must also think about future generations. The long-term implications of the decisions made today must be understood.

The IGU just released its annual survey report on the Global Wholesale Gas Prices. The clear conclusion from its 15-years’ worth of analysis is that despite the immense challenges posed by the abnormally high price levels, a well-functioning market is key to ensuring energy security.

An efficient market has provided the necessary flexibility to reorganise global gas supply flows to where they were required most, in a matter of just a few months – quite incredibly.

The supply-constrained market unfortunately has high prices, reflecting scarcity of the available gas molecules. And so, ongoing efforts to add new sources of gas supply, together with prudent measures to enhance efficiency and conservation are needed to help rebalance global energy markets and make energy access secure and affordable to all.

Ahead of the 27th Conference of Parties, our industry is working relentlessly to bring gas to consumers, to ensure it is done sustainably, to invest in its own progressive decarbonisation, and to support energy security, affordability, and reliability. I hope that governments can truly recognize this, and we can work jointly with the broader energy and climate community toward an achievable, affordable, and sustainable energy future. This future will require gas, electrons, renewable energies, low and zero-carbon gases, hydrogen, and the necessary infrastructure to make all these energy technologies seamlessly deliver energy to societies.

Li Yalan,
IGU President
Editors’ Note

Welcome to the ninth issue of Global Voice of Gas magazine, an International Gas Union publication, produced in collaboration with Natural Gas World (NGW), that started a new standard for the global gas community communication worldwide.

Winter is fast-approaching in the northern hemisphere, and with energy prices in most regions soaring, it will prove to be an extremely testing one for many energy systems. Ongoing fallout from the Russia-Ukraine conflict, high summer energy demand, and years of suppressed investment in natural gas supply risk causing a perfect storm in the months and possibly years ahead. Fortunately, gas supply, albeit very highly priced at present, continues to deliver energy to where the world most needs it, thanks to its inherent reliability and flexibility.

The global energy crisis may have brought energy security and affordability to the forefront this year. But stakeholders in the industry must also not take their eye off the ball regarding energy sustainability, particularly given we are in the run-up to the stage-setting CO27 global climate summit, taking place this November in Egypt.

One of the unfortunate consequences of the energy crisis has been a resurgence of coal, which began even while the previous COP26 summit in Glasgow last year was underway. At that summit, many countries made commitments to phase down their coal use, only to switch coal-burning plants back on this year to keep energy supply stable. It is clear that lessons must be learnt, not only with regards to keeping energy affordable and secure, but also ensuring that we are on the right track to meeting our climate commitments.

In this issue of GVG, one of Europe’s leading gas experts, Anne-Sophie Corbeau, breaks down how Europe’s energy system is likely to fare this winter, as well as how policymakers can best alleviate the hardship. We also include an interview with Helge Haugane, senior vice president for gas and power at Equinor, who discusses how Norway is stepping up as a supplier to ease the energy crunch in Europe. Freeman Shaheen, president for global gas at Chevron, also talks to us about the need for greater and more stable investment in gas supply to ensure that such market volatility is avoided in the future.

Kamila Piotrowska, head of EU policy and advocacy at Baker Hughes, explains why next year will be a critical one in ongoing efforts to reduce methane emissions from the energy sector, while Project Canary CEO Chris Romer makes the case for commercial initiatives supporting the creation of a measurement economy for those methane emissions. Ewan McKenzie, climate director at IPIECA, also discusses pragmatic solutions for future-proofing long-term gas supply investments.

Given the importance of Africa hosting CO27, we also include a feature on the ways in which African suppliers can step up in providing the gas supply that the world needs, and a second one on the extent to which South and Central American nations can also contribute. GVG also interviews leading voices in the Chilean gas industry on the need for government to recognise the value of gas as a fast-working solution for cutting emissions, and Graeme Bettune, CEO of Energyquest, considers how natural gas has been scapegoated for the problems hitting the Australian energy system right now.

We hope that you will find this issue informative, and useful in getting a better view of the topical global gas dynamics.

Tatiana Khanberg, Strategic Communications and Membership Director, IGU

Joseph Murphy, Editor, Natural Gas World

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IGU Upcoming Events Update

Since LNG1 in Chicago in 1968, the International Conference and Exhibition on Liquefied Natural Gas has served as the world’s premier meeting of minds for the LNG industry. The twentieth event in our LNG Series, LNG2023 Vancouver, comes at a time when the challenges, opportunity and responsibility of LNG, and more broadly natural gas, have never been greater. It became abundantly clear from the 28th World Gas Conference in South Korea, which had to be delayed by one year, that face to face events deliver an interaction value and an efficiency dividend that is not achievable any other way. Check out the WGC2022 photo highlights.

So, as we come to the end of another turbulent year and look ahead to what we can collectively achieve in 2023, LNG2023 is the must attend event for those currently and potentially engaged with LNG as part of their ongoing energy solutions, as well as anyone looking to connect with the LNG industry’s representatives in every segment and from every corner of the world. Whether you are in strategic planning, commercial operations, provision of services or technology, we look forward to welcoming you in Vancouver.

RODNEY COX
Director of Events,
International Gas Union

The organising team of LNG2023 is in high gear, preparing for what will inevitably be the most important and timely Global LNG conference in years.

The 20th edition of the LNG series conferences and exhibitions will be held on July 10-13, 2022 at a world leading venue, Vancouver Convention Centre in British Columbia, Canada.

“We are thrilled to have been chosen to host LNG2023 in Vancouver, BC, Canada has a strong and committed natural gas industry and there are vast opportunities for Canada, and Canadian LNG, to play an important role in supporting energy needs around the world. We are looking forward to engaging with the global LNG industry and other stakeholders to collaborate and showcase what LNG can do for the world”, comments Timothy M. Egan, President and CEO, Canadian Gas Association.

The programme committee will meet in the coming weeks to select the Abstracts of the papers that will be presented at the conference. If you are interested in submitting an abstract, please hurry as submissions will close soon!

Finally, we launched Club LNG. The new knowledge exchange platform provides members access to the latest news and a searchable library of papers presented at previous conferences.

IGRC2024 comes at a key time in Canadian and international energy conversations. Natural gas and its world-class infrastructure have supported economic development, affordable energy options, and energy security around the world. Furthermore, the use of gaseous energy and gas infrastructure is forecasted to continue growing in the next several decades.

The energy landscape is highly dynamic at present – leaders around the world are setting bold emissions reduction targets and all are searching for the optimal solutions to environmental challenges. At the same time, the importance of keeping energy affordable has become very clear. The puzzle of how to provide affordable, reliable, secure and sustainable energy must be solved this decade, and that will require above all - research, innovation, and technology.

The International Gas Research Conference (IGRC) has traditionally focused on technology research in the gas sector. The Canadian Gas Association (CGA), as host of IGRC2024, will continue that tradition and further build on it, expanding the focus area to all levels of technology development – from research through to demonstration and ultimately toward deployment. The rationale is tied to the work CGA has undertaken over the last five years including the Natural Gas Innovation Fund (NGIF).

Industry Grants.

Keep up to date on IGRC2024, including with the webinar series at igrc2024.org.

WGC2025
Hold the date: WGC2025 Beijing, May 19-23, 2025.
WGC2025 will take place at the magnificent China National Convention Centre (CNCC) in the heart of Beijing in the Olympic Park precinct. Beijing Gas Group is our host partner in this biggest global gas industry event.

The most anticipated IGU international conference will provide exhibitors and sponsors with opportunities to network with high-level executives, policymakers, industry stakeholders and peer exhibitors. The event provides a perfect platform for industry leaders to meet. The World Gas Conference has been organised by the International Gas Union since 1979, to promote the development of the gas industry and gas-related knowledge, technology, and information.

Inquiries: wgc2025@chinagas.org.cn
Natural gas retains its significant role in Southeast Asia

The Southeast Asia region has developed rapidly over the past decades and is expected to continue its major contribution to global economic growth. Against the backdrop of new uncertainties and net zero ambitions in the gas market globally, the priority to balance the energy trilemma between energy security, energy equity and environmental sustainability remains high for Southeast Asia. As reported in the Southeast Asia Energy Outlook 2022, published by the International Energy Agency (IEA), countries in this region must respond to the current energy crisis in ways that improve its energy security and also advance sustainable efforts to mitigate climate change. For achieving regional energy security and sustainability over the coming decades, pragmatic energy policies are key to map out the future energy mix. According to recent research published by S&P Global, Southeast Asia’s strong power demand growth will require adding more renewable energy, natural gas will continue to play its vital role in fulfilling growing energy demand.

On September 19, 2022, the Malaysian government launched a long-term and comprehensive National Energy Policy (NEP) (2022-2040) to address the energy trilemma and embark on a pragmatic and orderly energy transition toward achieving sustainability and net-zero carbon emissions. For decades, natural gas has played a key role in driving the nation’s socio-economic development, where the rapid rise in GDP was in tandem with the growth of natural gas consumption in Malaysia. The single largest energy source in Malaysia, natural gas accounted for around 42% of total primary energy supply in 2019. It will serve as a key component in driving Malaysia’s sustainable socio-economic growth, with half of the initiatives outlined in the NEP set to have either a high or medium impact to demand for natural gas.

The 40th ASEAN Ministers on Energy Meeting (AMEM), hosted and chaired by Cambodia, was held virtually on September 15, 2022. The 7th ASEAN Energy Outlook (AEO) was launched at the meeting, the flagship ASEAN energy planning document that supports ongoing implementation of the ASEAN Plan of Action for Energy Cooperation (APAEc). It outlines scenarios and potential pathways for achieving long-term energy security and delivering on the energy transition agenda envisioned by last year’s Bandar Seri Begawan Joint Declaration of the 39th AMEM on Energy Security and Energy Transition. APAEC is the regional blueprint for the energy sector in the framework of the ASEAN Economic Community (AEC) implementation plan. Being the blueprint of energy cooperation in the region, APAEC plays a vital role in setting out a sustainable future for the ASEAN energy landscape. Among the other key highlights was the importance of the continuing role of natural gas in a well-balanced and just energy transition. At the meeting, support was also noted for the inclusion of natural gas in the sustainable finance taxonomies developed by governments and transnational bodies, supporting the development of natural gas supply and infrastructure in the ASEAN region.

The Natural Gas Development Plan (NGDP) has been completed by the Philippines’ Department of Energy (DOE) and the University of the Philippines Statistical Center Research Foundation, Inc. (UPSCRFI), with the goal of attracting investments in the country’s downstream natural gas industry. Policymakers, regulators, and investors will use the NGDP as guidance in the development of the Philippine Downstream Natural Gas Industry (PDNGI).

Myanmar earned $800mn from the export of 77.89mn kilolitres of gas mainly to China and Thailand between April and July, via pipeline, mainly from four offshore projects: the Yadana, Yedagun, Shwe and Zawtika platforms. Gas export revenue increased by $60.7mn year/year. Malaysia supplies around 14% of Thailand’s gas demand.

Petronas Carigali partnered with Thai counterpart PTTEP in this Malaysia-Thailand joint development area (MTJDA). Petronas Carigali wrapped up negotiations with the Malaysia-Thailand Joint Authority (MTJA) on combining four acreage blocks into one single one, and the company committed to delivering increased gas volumes to ASEAN countries. They have reached an agreement and received the relevant approvals from the Malaysian and Thai governments to annex blocks B-17, C-19 and B-17-02 into the block B-17-01 PSC. Petronas Carigali partnered with Thai counterpart PTTEP in this Malaysia-Thailand joint development area (MTJDA).

PTTEP has restarted gas exports from its Zawtika field offshore Myanmar to neighbouring Thailand. The company is gearing up to develop the country’s first carbon capture and storage (CCS) project at its producing Arthit offshore gas field, supporting Thailand’s net-zero emissions target announced last year. Preliminary front-end engineering and design work has commenced, and the Arthit CCS project is expected to commence operations by 2026.

The Southeast Asia region has developed rapidly over the past decades and is expected to continue its major contribution to global economic growth. Against the backdrop of new uncertainties and net zero ambitions in the gas market globally, the priority to balance the energy trilemma between energy security, energy equitability and environmental sustainability remains high for Southeast Asia.

South & Southeast Asia

ABDUL AZIZ OTHMAN
President, Malaysian Gas Association and IGU Regional Coordinator

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Australia

- Australia’s LNG exports hit a record high of 80.9 MT in 2021. This led to the country regaining its status as the world’s biggest exporter of LNG. On the back of strong international LNG prices, EnergyQuest estimates that Australia’s total 2021 LNG export revenue reached A$48bn ($34.5bn), up 25% from 2020.
- Australia’s east coast gas prices soared to new highs, which resulted in a review by the Australian Competition and Consumer Commission (ACCC). Because of decline at offshore fields that have long supplied gas to Australia’s populous east coast, the commission concluded that there was a shortfall of around 10% of supply. Ultimately, resources minister Madeleine King said at the end of September she was ruling out LNG export restrictions, after reaching an agreement with exporters on diverting more gas to the domestic market.
- Australia’s main LNG customers are China, Japan and South Korea, which imported 85% of the country’s supply in 2021. Japan imported 39.1% of its LNG from Australia in 2020.
- Australia’s west coast gas prices were, in contrast, the lowest in the OECD in September. This is due to high prices, a slowing economy and COVID 19 lockdowns.

China

- China is the world’s largest LNG importer, having overtaken Japan in 2021 with a 19% increase in purchases. LNG imports accounted for approximately two-thirds of China’s total natural gas imports, and this was approximately a third of China’s total natural gas supply. China began importing LNG in 2006 and its imports have grown constantly every year since, as a result of proactive switching from coal to gas as part of government policy introduced in 2017 to to cut emissions and improve air quality.
- But in 2022, LNG imports could decrease as much as 19%, or 15 MT. This is due to high prices, a slowing economy and COVID 19 lockdowns.
- Facing slowing LNG demand, China is reselling some of its LNG surplus to Europe, which is scrambling to avoid a winter crisis caused by reductions in Russian gas flow.
- China’s slowing LNG demand is a relief for other competing LNG spot volume buyers, like Japan, Korea and Chinese Taipei, as the majority of China’s imported LNG will be limited to contracted volumes.
- In October 2021, along with an updated NDC submitted to the UNFCCC, China also officially announced its intention to achieve carbon neutrality “before 2060” and to achieve peak CO2 emissions “before 2030” through its Long-Term Low Greenhouse Gas Emission Development Strategy.
- In March 2022, China announced the country’s first long-term plan for hydrogen, for the 2021–2035 period, in line with its carbon neutrality pledge.
- Now China is the largest producer of hydrogen, supplying 33 MT. Most of this volume comes from fossil fuels and is used as feedstock at refineries and chemical facilities. The China Hydrogen Alliance has said that China’s hydrogen demand would reach 35 MT in 2030 (5% of China’s total energy supply) and 60 MT in 2050 (10%). Meanwhile, according to the latest government plan, China will produce 100,000 to 200,000 TPA of hydrogen from renewable sources by 2025, reducing annual CO2 emissions by 1-2 MT. Hydrogen will be used to fuel HCVs and in various industrial sectors.

Chinese Taipei

- Chinese Taipei imports about 99% of its natural gas, in LNG form. There are two LNG receiving terminals owned by CPC Corp. This number is set to grow to five in the future.
- Natural gas is set to account for half of total power generation by 2025, versus 38% at present, as part of efforts to expand renewables and phase out nuclear power.
- Chinese Taipei imports most of its LNG from Qatar and CPC signed a 15-year LNG sale and purchase agreement in July 2021 for 1.25 MTPA of LNG with QatarEnergy.

Japan

- Japan imports 97.7% of natural gas from overseas and more than 80% of its LNG imports are based on oil-indexed long-term contracts.
- The average price of imported LNG recorded 139,380 yen per T ($20 per mmBtu) this August, up 140% year on year. The average LNG import price is reflected in gas tariffs under the fair adjustment mechanism, which adjusts those tariffs based on the average LNG price in the previous three months.
- Gas utilities set a LNG ceiling price under this mechanism to limit the sharp rise in gas tariffs. But the continuing high LNG price has forced many utilities to lift the thresholds.
- Today, 35% of imported LNG is used to supply 40 bcm of city gas to 27mn gas users.
- In November 2020, the city gas industry announced a target to reach net zero by 2050, by substituting natural gas with low-carbon/decarbonised gases, hydrogen, biogas and e-methane.
- Substituting natural gas with e-methane will make the most of infrastructure already in operation, and could avoid substantial investment needed to transform the gaseous energy value chain. Japan expects to import e-methane from overseas and will be investing in e-methane production facilities preferably built near existing liquefaction facilities. Feasibility studies and pilot projects are already underway with potential supplier countries. The first LNG vessel carrying liquefied e-methane is expected to arrive in Japan around 2030.

New Zealand

- In 2019, the government introduced the Climate
In October 2021, South Korea declared it would become carbon neutral by 2050. South Korea relies on coal for about 40% of its electricity power generation, while renewables make up less than 6%.

KOGAS, sole importer of LNG in Korea, plans to reduce greenhouse gas emissions associated with its use of gaseous energy by blending up to 20% hydrogen with natural gas by 2026. This will require 1.07 MT of hydrogen supply and will reduce CO2 emissions by 7.5 MT. By 2050, 27.9 MT of hydrogen will be needed, of which 22.9 MT, or 80%, will be imported. Out of domestic production, 3 MT is expected to be green hydrogen and 2 MT blue hydrogen.

South Korea is the third largest LNG importer in the world after China and Japan and imports 93% of energy from overseas. Approximately 80% of the LNG that South Korea buys is under long term, oil-index pricing contracts. Therefore, overall, the LNG price is not fully exposed to soaring spot market price.

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From the wellhead to pipelines, from businesses to homes, gas is crucial for fuel, heating, power, chemicals, fibers, consumer goods and more. Shipped, distributed, marketed and stored internationally and domestically, gas fuels the world economy.

S&P Global Commodity Insights provides unparalleled expertise across entire gas value chains. With outlooks, forecasts, supply, demand, technology, capacity, pricing, emissions and more, our end-to-end gas market coverage provides a foundation to confidently invest now for your future.

Learn more about partnering with us: ihsmarkit.com/futureofgas
Argentina

Gas production in Argentina continued to expand during the winter months of 2022. Gross natural gas production peaked at 141.5 mcmd in August 2022, with diverse volumes from different basins. While domestic production in the northwest of Argentina, and the southern Austral basin (shore and offshore) declined, it increased in the Golfo de San Jorge compared to 2021. The Neuquen basin increased significantly, 14% on average, after new shale gas developments continued to surprise with higher productivity ratios.

High domestic demand for natural gas exceeded that of 2021 during the colder than average months of May and June, while milder than average temperatures in July and August softened the residential and commercial demand. However, high demand remained for output from numerous thermal power plants resulting in the unsatisfied demand of natural gas with considerable shortages of transportation capacity from the Neuquen basin.

As the winter gas consumption averaged 180 mcmd during May and June, and 170 mcmd in July, not all demand could be satisfied and power plants burnt large quantities of imported diesel, fuel oil, and coal to a minor extent.

Even though the hydroelectric output has improved since April 2022 compared to record lows during the last two years, it was unable to offset the demand for gas. Therefore, large imports from Bolivia (14 mcmd) and especially LNG (peak rates of 36 mcmd) were required. The record-high average cost of $30 per mmBtu for LNG imports put pressure on foreign exchange rates and reserves, influencing macro-economic problems.

Gas demand may be lower than in 2021 during the rest of this year, as economic activity is slowing down after a strong increase in the first months of 2022.

The Argentinian government finally issued contracts for the supply of a 570-km, 36” new pipeline from the Neuquen basin to the province of Buenos Aires (The Nestor Kirchner Gas Pipeline). The project will transport 11 mcmd by June 20, 2023, while two compression stations, probably due online by the end of 2023, will double its capacity to 22 mcmd. Though ambitious in timing, the construction companies are already working to fulfill the tight schedule.

Gas producers feel confident that an increase in gas supply is achievable for winter 2023, and they will probably continue to export gas to Central Chile during the winter months, like in 2022. Firm export permits have been awarded by the Argentinian government starting in October 2022 and lasting until April 2023, improving the creditworthiness of the granted authorisations and trying to recover Chilean consumer confidence.

Gas imports from Bolivia in 2023 will start to be renegotiated in the coming months, as production in large gas fields continues to decline. The gas volumes imported from Bolivia during winter 2022 were at similar levels compared to the winter months of 2021, as Bolivia reduced deliveries to Brazil due to contractual provisions.

As Brazil’s domestic gas production continued to increase, reaching 134.4 mcmd on average in the first half of 2022, compared to 132.6 mcmd a year earlier. In 2022, approximately 86% of Brazil’s production originated from offshore associated gas, with reinjection volumes reaching record levels in January 2022 168.5 mcmd, and an available supply to the market of 49.3 mcmd in June 2022.

In January–June 2022, gas consumption averaged 69.8 mcmd, down from a peak of 105 mcmd in October 2021, when a severe drought led to the dispatch of gas and oil-fired power plants.

To balance insufficient domestic supply with market demand, Brazil imports gas from Bolivia by pipeline and LNG from international suppliers. The revised contract with Bolivia calls for a maximum volume of 20 mcmd, whereas LNG imports vary due to the intermittent dispatch of gas-fired power plants. In 2021 Brazil imported 13.5 bcm of LNG, mostly from the US, with a total free on board expenditure of $3.5bn. In the first half of this year, LNG imports reached 3.3 bcm, costing $2.5bn. Due to good hydroelectric reservoir levels, following a rainy period, the regasification of LNG hit a new low of 3.2 mcmd in April 2022.

There are currently five LNG terminals in operation (all FSRUs), one in construction (in the southern state of Santa Catarina) and another planned for 2024-2025.

January 1, 2022 marked the effective start of the gas market opening in Brazil. From January to June 2022, eight new supply contracts were executed between suppliers, consumers and local distribution companies (LDCs) accessing Brazil’s transportation grid. A new hybrid contract between a fertiliser plant, LDC and producers allows for excess volumes to be sold back to the market.

In March 2022 the federal government launched its Zero Methane programme, focused on incentivizing the utilisation of agricultural and other organic waste to produce biogas and biomethane.

On April 7, 2022, the federal government issued its CNPE Resolution 3/2022, providing further guidelines on the transition to an open and competitive market.

Brazil’s Regional Integration and Pipeline Expansion plan will see gas transport companies invest 18bn reals ($2bn) in expanding their networks over the next five years.

In May 2022, Bolivia unilaterally cut its export volumes to Brazil by 30%, diverting the volumes to Argentina, which was willing to pay higher prices (up to $20 per mmBtu), during the winter months of May–August.

Petrobras expects to finish the offshore Route 3 pipeline in the first quarter of 2024, allowing for the supply of 18 mcmd of domestic gas.

A number of biomethane and biogas projects are being developed that will together serve as “distributed generation”. Some of these projects require access to natural gas transport networks, thus the need to assure the same quality standards.

Hydrogen projects are emerging that will demand a sharp increase in renewable energy capacity. Green hydrogen and ammonia projects have been announced at Porto de Pecem (Northeast) and Porto do Açu (Southeast).

Colombia

Around 10 bcm of gas is produced at 14 main fields in the Atlantic Coast, Santander, Eastern Plains and Hulla regions with annual supply averaging 10 bcm.

The industry has a transportation infrastructure of more than 7,700 km, with a total of 10,759,513 connected users, 98.1% of which are residential, 1.8% commercial and 0.1% industrial.

The Naturgas 2022 Congress was held in Cartagena on October 5–7, an event that brought together more than 1,000 delegates from different companies, national government entities, academia and experts from the natural gas industry, to analyse the role that gas plays in the transition to renewable energies, carbon neutrality, food security and poverty reduction, and how it serves as the vehicle for social change and economic momentum that the country needs.

A key and transcendent topic has been hydrogen, as it is emerging as a flagship green gas for the energy transition due to its high efficiency and the fact that it does not generate greenhouse gas (GHG) emissions. The ANDI-NATURGAS Hydrogen Chamber was created, formed by companies from different sectors. The objective of this group will be to convert hydrogen into an energy vector, fuel, input, and raw material in applications in the industrial, commercial, residential and transportation segments. Demand for
Chile

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European gas industry takes hits from Russian cuts

1. 2021 was a challenging year for the gas industry worldwide. Demand has soared amid a post-COVID-19 recovery, and there has been drought and an absence of wind in many countries, forcing them to resort to more gas-fired power generation to replace lost hydroelectric and wind power. The substitution of coal with gas, combined with a relatively low supply due to incidents at LNG terminals and pipelines, led to rapidly increasing prices.

2. In Europe, the effect was compounded by some players (EU competition rules), leading to high prices, some gas demand destruction, and an acceleration of the move towards renewable energies (including biogas).

3. Starting in February 2022, the Russia-Ukraine war completely changed the landscape. After initially claiming it would respect its long-term contracts, Gazprom started to arbitrarily reduce or cut off supplies to certain countries.

4. The impact was dramatic: the price of gas at the leading point of exchange (TTF) rose to €100, €200 and then €300 per MWh. Due to the power market design in Europe, the price of power also skyrocketed to €1,000 per MWh.

5. LNG importing countries have seen all their capacity slots used for additional imports as these prices were well above what any other destination could offer. The Iberian peninsula was an exception as the existing connection capacity from Spain to the rest of Europe is limited; but this connection capacity, previously used to send gas from the north to the south, is now mostly working in reverse. All countries with access to the sea accelerated or revived plans for additional LNG facilities (FSRU or land-based). The Netherlands started up a new FSRU on September 8, 2022, a mere six and a half months after the start of the war, but many other countries are following the same path at a slower pace.

6. Demand destruction happened rapidly. Even if most EU countries tried to protect domestic gas customers from the worst of the price increase, the effect on industry was dramatic, and industrial demand reductions of between 20% and 40% have been reported in most countries. This means forced demand cuts coming mostly from economic activity curtailment and closing businesses.

7. The EU reacted by coordinating and accelerating the filling up of gas storage facilities, while also presenting its RePowerEU plan, outlining how the bloc could do without Russian gas at all. These measures are being implemented rapidly: storage facilities are almost 100% full, the

8. The situation will most likely remain very difficult. Current trends include a situation in the EU countries which has been described as “supplier overhang”. This is due to the fact that the EU is dependent on its gas supplies and that the gas market (and possibly the power market) design is such that it “remembers” the past. This “memory” is currently being blown out of all proportion, leading to a situation where the EU is in a position where it has no other option than to buy the gas they are committed to deliver to customers at very high prices on the spot market. Some gas companies were in such trouble that governments had to step in with support to prevent them defaulting and creating a domino effect.

9. These are just some of the known effects of the current crisis. It is far too early to say how this situation will develop but there are some predictions we can make about trends going forward:

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exploit the growing international momentum in directing global efforts to confront climate change. Also, to move from pledges to actual implementation on the ground, whether in terms of reducing emissions, or adapting to the negative effects of climate change or climate financing for developing countries, especially African countries, as they are disproportionately affected by the consequences of climate change.

African gas as the alternative to Russian energy
Most of the African exported gas is mainly sent to Europe, which now wants to import even more to make up for supplies lost due to the the conflict in Ukraine. Italy struck deals to buy gas from Angola and the Republic of Congo, while Germany has been looking to secure supplies from Senegal. That is despite discouragement of the use of gas and other fossil fuels around the world in pursuit of global climate goals, a case some European leaders made at the United Nations’ COP26 conference in Glasgow. While African countries are eager for the revenue that the gas deals are likely to bring in, they are also calling out the sudden interest in their resources as a double standard that perpetuates the West’s exploitation of the region. They question why Africa be preventing from using its own gas resources — thereby delaying energy access for hundreds of millions of people — while its gas is used to keep the lights on in Europe.

Rich countries have been reluctant to fund pipelines and power plants that would facilitate the use of gas in Africa and have not yet delivered on promises to help finance green projects that could be an alternative source of energy. Many African governments support boosting exports to help their cash-strapped governments, but they also want access to financing that would allow them to harness the fuel’s potential to create domestic gas markets.

The pathway being pushed by European leaders — that Africa moves straight to clean energy sources — is not viable unless rich countries, private investors and development banks help with funding. There’s ample sunshine and wind in sub-Saharan Africa, which collectively uses less energy than Spain, but little infrastructure to harness it. Developing countries also face much higher financing costs for green projects because they are seen as riskier investments. Adding to Africa’s frustration is that rich nations have failed to deliver on a target to provide $100bn a year in climate finance that was supposed to have been met in 2020.

COP 27 taking place this year in Africa
Egypt is to become Africa’s voice during the United Nations’ Conference of Parties on Climate Change COP27 taking place in the Egyptian coastal city of Sharm El Sheikh. Africa faces many challenges in the climate change file, and Egypt is willing to share its experiences with the continent and cooperate with the World Bank to prepare a guideline in this regard as part of the Egyptian government’s preparations for the summit.

African countries are keen to deliver their main message, which is that poorer countries bear the consequences of climate change despite their limited contribution to global emissions. Moreover, African countries need more serious assistance to mitigate risks and damages in order to achieve zero emissions targets. Egypt is also keen that the upcoming climate summit reflects the positions of African and developing countries and turns promises and commitments into actions.

During the conference, Egypt is expected to be presenting to the world the great progress Africa and the country are witnessing in the field of the environment and transitioning to clean energy. This comes within the framework of the state’s persistent efforts to fulfil its humanitarian obligations to protect the environment as well as presenting the image of the modern state in Egypt and its efforts to implement the Sustainable Development Strategy of Egypt’s 2033 Vision. The Egyptian president also addressed national and African concerns on climate change issues and provided an opportunity to conclude partnerships with various international institutions to finance projects related to addressing climate change in Egypt.

Egypt intends to build on what was achieved during the last session of the conference in Glasgow and to work to

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KHALED ABUBAKR
Chairman, Egyptian Gas Association.
Executive Chairman, TAQA Arabia and
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The Middle East & Africa

REGIONAL UPDATE
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In the midst of the global energy security crisis the North American industry is in overdrive.

- US production has reached all-time highs as the market endeavours to serve the bounce back in the global market post-COVID, and the particular demands of Europe triggered in part by the Russia-Ukraine war. North American prices, while still far below those of other markets, have increased significantly over those of the last several years, adding to cost pressures for end-users of natural gas, and for electricity users as more and more electricity is gas-fired.

- In the US, while the administration continues with its aggressive emissions reduction agenda embodied in the recently-passed Inflation Reduction Act, and while that policy framework could be argued to be counter to the long-term interests of the sector, the fact remains that the industry is building out to meet growing demand. New infrastructure for gas transportation and LNG production are being developed at a fast pace, and while policy makers continue to talk of getting off of gas, the market is doing anything but.

- In Mexico, the AMLO government is signalling its strong support for rapid development fuelled by gas.

  - The recently announced Southeast Gateway project marks a significant milestone in private-public sector cooperation in the country, and is seen as a signal that private sector gas investment is considered core to the government’s prosperity agenda. Gas is seen as delivering economic well-being, addressing social concerns by bringing people out of poverty, and cleaning up the environment. With the project’s core investor being Canada-based infrastructure company TC Energy, the project moves Canada to 2nd spot after the US as the largest investors in Mexico.

- While Canada’s gas end-use continues to grow, the policy framework continues to stifle investment in infrastructure.

  - This is preventing Canada from capitalising on the significant LNG opportunities across the globe. This has resulted in a lower market price for gas in Canada than in the US, as producers are not able to move their abundant product to market.

- European buyers continue to seek more Canadian infrastructure development – with the German Chancellor making a personal visit to Canada to appeal for LNG this past August. The visit ended up focusing on hydrogen project development – a long-term interest of the whole Canadian gas value chain, but not something that facilitates more gas infrastructure / production needs in the near or medium term.

Industry opponents double down across North America

- On the public acceptance front across North America, opponents of the industry have been doubling down with new anti-gas campaigns at the municipal level, and more recently with campaigns targeting the domestic end-user by arguing that indoor air quality is severely threatened by gas use. The industry has been responding with government and independent laboratory data demonstrating how exaggerated the health danger claims are. Nonetheless the ability of activists to create a scare remains very real.

- North Americans are not sheltered from the current inflationary pressures hitting global markets, but by comparison to several other parts of the world, customers in the region are in much better shape from both a supply and price perspective for this winter. The global crisis has contributed to a higher appreciation of the value of gas in the market, but the industry still has many challenges in the public square to ensure North Americans truly understand the assets that gaseous energy and gas infrastructure represent for society.
Winter is coming: how will Europe’s energy system fare?

Natural gas expert Anne-Sophie Corbeau discusses how Europe’s energy system will manage this winter and beyond, and what steps governments should take to ease the crisis.

Global Voice of Gas: There is great uncertainty about how the European energy system will fare this winter. But what are the main factors that will determine the outcome? Put bluntly, how bad could things get?

Anne-Sophie Corbeau: There are two different ways to look at this. The demand side and the supply side. We need to get the demand to drop, while getting as much non-Russian gas supply as possible.

First, on the demand side, let me note that natural gas and power demand are linked. To reduce total natural gas demand, one also needs to act on the power side. I have the impression that both are treated separately, while the efforts should be joint (the EC proposed to reduce 15% of gas demand over the August-March period in the Save gas for a safe winter plan in July 2022, but only proposed the reduction of 10% of gross electricity consumption and a mandatory reduction target of 5% of the electricity consumption in peak hours in the most recent discussions in September 2022). In 2021, gas-fired generation represented about one-fifth of total EU power resource mix.

Second, there is a need to focus on energy efficiency, conservation and switching to alternative products/energy – when available – in all sectors: in buildings (residential & commercial), industry and power generation. Energy efficiency aims to get the same output (comfort in terms of heating temperature or industrial output) with lower energy consumption, conservation will reduce the energy consumption and the service as well (lowering the thermostat, reducing lighting for example for public buildings, potentially shutting down some non-essential infrastructure such as swimming pools etc).

Conservation behaviour could be induced by higher energy prices as this impacts households’ budgets – forced by the need to manage costs. Energy efficiency (better insulation, optimised industrial processes) will not be readily available for all, as it takes time to be deployed. Switching is also not possible for all users – some industries have already switched to oil products; it’s doubtful that more can do so now as they would already have done so given the past year of high gas prices. Some households are planning to use more wood pellets or have bought electric heaters as they fear gas shortages – in my opinion, using an electric heater makes things even worse as it is far less efficient to use gas for power generation than to use gas directly in an efficient boiler.

In practice, we have seen industrial output being curtailed as industries are no longer able to keep up with increased energy costs: fertiliser producer Yara has implemented curtailments taking its total ammonia capacity utilisation to around 35%. Other industries have also reduced output or shut down factories due to high electricity and gas prices. Gas demand has therefore been reduced (with an estimated 30% year/ year reduction in major European economies in August according to the IEA). Demand in buildings has dropped as well, partially due to milder weather in early 2022, but recently due to conservation triggered by higher prices. The IEA estimates that the drop was 15% in Q3 in distribution networks. But the power sector has been surprisingly resilient, with an 8% yr/yr increase in gas-fired generation over the first 8 months of 2022, due to lower nuclear (-15% yr/yr over the first 8 months compared to 2021) and hydro generation (-25% yr/yr), which have not been compensated by higher renewables and coal-fired generation output.

On the supply side, it is fair to say that there is now very little upside on the Russian supply – if anybody had counted on that possibility. With the sabotage of Nord Stream 1 and 2, at least three of the four pipeline strings are out of service for months, if not years to come. Russian pipeline gas supplies as of late September 2022 are at less than 20% of their 2021 levels. It seems unlikely that Russian gas supplies will increase, and they might very well drop further if transit through Ukraine is interrupted. There has been no upside so far on North African pipeline gas supplies, only a few additional billion cubic metres from Azerbaijan and Norway (on top of Snohvit coming back online) and no reversal in terms of domestic gas production (besides Norway and the UK). Groningen will not come back to higher production volumes and biomethane will add a maximum of a few bcm.

All hopes are on LNG – how much global supply will increase and how much can be further diverted away from Asia. We have been lucky so far that Chinese LNG demand has been muted (it actually dropped...
significantly and neither Japan nor Korea needed to compete for LNG (for example: if the weather had been cold). So far, we have been able to balance the EU market and reflation storage to comfortable levels thanks to additional supplies (mostly LNG) and lower industrial and building demand. Going through this winter assumes that demand is further reduced, notably in the power sector, and Europe continues to attract significant LNG flows and expand its LNG import infrastructure.

There are some factors on the demand side that we will not be able to influence: the weather, the renewables production, including hydro-generation, and to some extent nuclear generation. My opinion is that weather is by far the biggest uncertainty. A winter similar to 2010 would create a major challenge. LNG demand outside of Europe is also a major source of uncertainty. The muted demand from Asia so far has provided for a lucky coincidence, but a revival in Chinese LNG demand in a country which has signed no less than 29 LNG contracts since early 2021 could change the global balance (unless Chinese players find it more profitable to sell their contracted LNG to European players!). We also need to have as few LNG supply disruptions as possible – the recent accident at Freeport LNG has deprived the world of the equivalent of 20 bcm of gas for the duration of several months.

**Russian supply volumes are already at an all-time low. How great a risk does a complete shutdown in Russian supply pose to Europe?**

Daily Russian gas volumes as of late September are at less than 20% of the average of 2021. Now that Nord Stream 1 and 2 have been sabotaged, the likelihood of Russian gas supplies coming back to higher levels is reduced, although Gazprom suggested on October 3 that it could maybe use the last undamaged 27.6 bcm of Nord Stream 2 string if the inspection confirms it is operational and “if a decision is made to start supplies.” Given the opposition to Nord Stream 2, it does not sound that likely. Based on Gazprom’s Twitter announcement on September 28, it seems that the supplies through Ukraine could be at risk due to a disagreement with Naftogaz. I do not think that the remaining supplies through TurkStream, which supply among others Hungary, will be stopped.

So, the worst case scenario would be that in 2023, we are left with only Turkstream, which would be the equivalent of roughly 13 bcm to the EU based on current flows.

That is compared with 140 bcm of Russian pipeline gas delivered to the EU in 2021. This is not something that only additional supplies of LNG or alternative sources of pipeline gas will be able to replace – there is no 130 bcm of spare capacity in the global gas system. In January-August 2022, LNG imports to the EU increased by around 30 bcm. Even taking into account higher Norwegian, Azeri gas flows in 2022, and potentially higher gas pipeline flows from Algeria in 2023, an increase in UK gas production and the ability of the country to serve as a bridge to get more LNG towards Europe through the Interconnector and BBL pipelines, it is obvious that EU gas demand will have to adjust downward.

**What about the following winter?**

One of the key issues will be not only to meet next year’s demand, but also to reflation storage. It is quite likely that we will emerge from this winter with depleted storage levels. EU gas storage capacity is about 100 bcm, so the reflation needed to get us back to 91% filling rates by the start of the winter could stand at 70 bcm assuming that storage levels are at 20% in April. Storage is an essential element of the European gas balance – without it, we cannot meet peak gas demand in the residential sector. Storage also serves to provide gas supplies to gas-fired power plants, which can be used at peak times in the power sector where there is not enough solar and wind.

Another issue is that going forward, there is relatively little LNG supply coming to the market: most of the plants coming online over 2023-2024 are relatively small, with the exception of Arctic LNG 2, the outlook of which is unclear due to sanctions. It was expected to come online in 2023. The largest LNG plants are expected to come online in 2025 or later: North Field East Qatar, Golden Pass, Plaquemines and Corpus Christi Stage 3 in the US, Canada LNG, and any yet to be sanctioned projects.

**What about the outlook for prices over the next year?**

There are two issues with prices: they are high and also volatile. Regarding their levels, Europe has to continue to come up with measures to reduce the impact of high energy prices on consumers. One of the measures announced by European Commission President Ursula von der Leyen in her State of the Union speech was a change in the electricity price mechanism, whereby there will be a cap on the revenues of companies that produce electricity at a low cost (wind, solar, hydro, nuclear). These benefits would be redistributed to consumers. But the most complicated issue seems to be introducing a cap on gas prices. Several suggestions have been made – capping the price of Russian gas, capping the price of all imports, or changing TTF to another benchmark as the price “has not adapted.” All these solutions could create unintended consequences and may in fact worsen the situation. But I am also equally worried about the rest of the world – inflation is hitting developing countries hard. The impossibility to access affordable gas is also a concern for many countries (land could jeopardise the long-term outlook for gas and LNG demand). It is also a concern due to the impact of high gas prices on fertiliser prices. Not only do we have an issue with energy, but we may have an issue with food as well in the coming years.

**How effectively has the EU handled the crisis?**

Not so well, in my opinion.

First, the EU thought it was in the driving seat when it came to reducing imports of Russian gas. Actually, Russian President Vladimir Putin was in the driving seat, exploiting what was already a tight market. When he
decided to cut supplies to selected countries, then to reduce supplies through Nord Stream (but always saying that they were complying with long-term contracts or as a prudent operator), European leaders were caught off guard. Russian pipeline gas supplies were being reduced faster than they wanted, and the two-thirds reduction was being achieved without them having any say in the matter. It is very interesting how Putin has tried to rule and divide Europe by testing how compliant European leaders and companies would be, first by deciding that all unfriendly countries would have to pay in rubles. It turned out that most countries complied with the Kremlin decree.

My second criticism of the European leadership is their disproportionate focus on supply, forgetting about demand from early on. Demand reduction was part of the measures initially proposed in the March REPowerEU plan, but few focused on it. In my home country, all French presidential candidates promised to protect consumers. Nobody had the political will to say in a true “Churchill moment”: “this is going to be tough, so we all need to be doing our part.” That would mean protecting the poorest and the most vulnerable, but reducing everyone’s consumption (of gas and electricity). The mere fact that there is disagreement over simple and effective measures, such as closing the doors of an air-conditioned shop during summer, shows that there has not been enough effective communication from the start. Energy efficiency is boring for all policy makers and conservation is viewed as difficult because it means asking people to change their behaviour; they all preferred a brand-new LNG terminal. However, energy efficiency and conservation are key to reach a true net-zero future.

Additionally, on the supply side, our policymakers have not been very successful when it comes to securing additional LNG supplies. Only a few deals have been signed – and definitely not that many by Germany. The first issue is that suppliers want long-term commitments, but European players would prefer shorter ones, since they are told that gas demand (and therefore LNG demand) is going to decline. No supplier would want to sign a five-year commitment at a low price, given where spot prices are right now (unless you want a TTF indexation). Given that so much LNG has come to Europe in the first months of 2022, maybe policymakers thought it was easy to procure. The reality is that it is not. I am quite curious to see how the so-called LNG procurement platform will play out – we have been hearing about it since March, and there is very little detail to be seen, despite a call to form an advisory committee for its development. For sure, I would be worried to see LNG supply sourcing in the hands of public servants, if they have not negotiated a contract in their lives.

Looking forward, what can Europe do to better ensure energy affordability and security, without jeopardising climate commitments?

We need to be less ideologic and more pragmatic. One example of ideology is the planned decommissioning of German (or Belgian) nuclear power plants. Removing them, while we need every single kilowatt hour of power and asking people to reduce their heating in winter makes little sense to me.

Unfortunately, because energy security and affordability have taken the front seat, it is unavoidable that our emissions – notably from coal – will increase. We need to minimise this, but with nuclear, hydro and renewable power supply not growing fast enough, it seems that we will again need to be pragmatic, or decrease our energy demand even further – potentially with a lot of economic damage.

I think there is a need to really ask whether European companies are ready to support LNG export plants or are just happy to pay spot prices with Europe playing the role of the global trade balancing market. I hear a lot of people wondering whether, because of the call towards sustainability, there is not enough push towards supply investments. There is a need for more supply, not only for Europe but also for other countries, particularly in the developing world. Will it be better if Southeast Asia stays with coal?

One of the most secure gas supply sources is domestic gas. Europe has declining gas production, but still some resources: maybe fast-tracking Black Sea developments, having a serious discussion with Norway, finding a pragmatic solution for East Mediterranean gas, are to be more actively considered.

We also need to future-proof new investments. That means that even if there are investments in natural gas supply, they need to be as low-carbon as possible.

Finally, we need a better understanding of our progress in reaching targets. Therefore, the European Commission should be tracking progress in terms of energy efficiency, wind and solar deployment, biomethane production, gas demand reduction and other areas on a yearly basis.
The solution to volatility

LNG will remain a key part of the energy mix in the long term, Shaheen argues. Greater and more stable investment is needed to ensure the supply is as affordable, secure and clean as possible.

JOSEPH MURPHY

Unprecedented volatility in the natural gas market today has vindicated the need for greater and more stable investment in supply, and added attention to energy security and affordability, Freeman Shaheen, president of Chevron Global Gas, tells Global Voice of Gas.

LNG spot prices in Asia slumped to an all-time low of $1.85 per mmBtu at the height of the coronavirus pandemic in May 2020, prompting many suppliers to make steep cuts in investment. With the oil market undergoing similar turmoil, Chevron reduced its capital spending by 37% that year, to $8.9bn.

“When the pandemic hit, everybody was in survival mode and demand was destroyed,” Shaheen says. “Capital was pulled out of the market – people weren’t investing, and it takes time to develop new supply assets.”

In contrast, prices in Asia and Europe spiked to over $70 per mmBtu in late August. While the global energy crisis has been exacerbated by geopolitics – namely Russian cuts to gas supply to Ukraine – it was these cuts in supply investment, even if necessary at the time, combined with a swift recovery in demand, that caused the market to grow increasingly tight last year.

Neither the high prices today or the low prices like those seen in the pandemic are sustainable, Shaheen says. The answer, he says, is a renewed focus on energy security and affordability.

“At Chevron we believe in making energy more affordable, reliable and clean, but I think the world was more focused on making energy cleaner than on making it affordable and reliable,” he says. “Affordable and secure energy takes capital investments, supported by partnerships – long-term agreements. Partnerships make sure that we’re optimising. There’s an abundance of gas worldwide, it just needs to get monetised with the right partnerships in place.”

Betting on LNG

Chevron is bullish on the long-term prospects for LNG demand. The company has several of its own liquefaction projects around the world, including Gorgon in Australia, and has additional trading operations. It is eager to grow its LNG business further, having signed two major US LNG deals in June, to take 4 MTPA of US Gulf Coast LNG from terminals operated by Cheniere Energy and Venture Global.

The company also has gas production assets in the US Permian Basin, and is looking at LNG exports as an option to better monetise them.

While Asia is the main driver of LNG growth, Europe is now scrambling for extra volumes to replace lost Russian supply, and Chevron is eager to find ways of bolstering deliveries to the continent, Shaheen says.

“We haven’t been a large LNG player into Europe, but we think there’s more opportunity to be part of the solution. … Asia continues to be a very important market and they’ve contracted on a long-term basis. But the Europeans are seeing the value and the need for LNG in the longer-term mix as well,” he says.

However, ramping up shipments to Europe will take time, he warns. While a focus on debottlenecking and efficiency can help free up volumes at existing assets, it will take time for investment in new assets now to translate into extra supply. The agreed deliveries from Cheniere and Venture Global, for example, will only start in 2026 and 2027 respectively.

Chevron’s assets in the East Mediterranean also offer a new source of supply for Europe. The US major entered the region through the $13bn takeover of Noble Energy in 2020, which Shaheen describes as “a bold move to make” in the middle of a downturn. The assets it assumed control of include the producing Leviathan gas field off Israel and the undeveloped Aphrodite field off Cyprus.

Both are considered potential suppliers to Europe, whether through the development of a pipeline or LNG facilities.

The current volatility creates a challenge to taking decisions on new investment, Shaheen says, and Chevron’s approach has been to focus on the needs of customers and balancing its risk exposure.

While energy security and affordability have been brought to the forefront amid the current crisis, making gas supply as clean as possible remains important, according to Shaheen. An example of the company’s commitment here has been its elimination of routine methane flaring in the Permian. This summer, it also had 85 wells in the Permian certified as producing responsibly sourced gas (RSG) by Colorado-based assessor Project Canary, as part of a pilot project.

“We believe LNG and other gas will remain a key part of the mix in the long term. It is going to lead us to a lower carbon world,” Shaheen says, stressing the fuel’s role as a supporter of intermittent renewables. “Our strategy as a company is achieving higher returns and lower carbon from that supply.”

Affordable and secure energy takes capital investments, supported by partnerships – long-term agreements.

- FREEMAN SHAHEEN, Chevron Global Gas President
Ewan McKenzie, Climate Director at Ipieca, a global oil and gas association dedicated to advancing environmental and social performance across the energy transition, discusses with Global Voice of Gas the challenges to investing in natural gas supply, and how those investments can be future-proofed.

Global Voice of Gas: What are the main hurdles to adequately investing in long-term natural gas supply? How can governments and financiers support this investment?

Ewan McKenzie: In a world aspiring to net-zero emissions there exists a dual challenge: transforming the energy system to meet the increasing energy demand of a growing global population – set to reach 10bn by 2035 – while also lowering global emissions in line with the Paris Agreement goals. As an industry we are also faced with the challenge of ensuring a sustainable return on capital to investors. This triple bottom line, covering people, planet and financial performance, will require a broad energy mix with oil and gas being part of the energy transition to net-zero emissions.

Recognising the role of gas in the global energy mix, Ipieca, IOGP and GGFR, in 2022 published the Flaring transition programme detailing how to reduce methane emissions from operations through energy efficiency, flare reduction and managing methane emissions, as well as increasingly powering operations with low carbon or renewable energy sources.

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How can investments in natural gas assets that are built today be “future-proofed” to stay compatible with Paris targets?

The industry is contributing to a net-zero future in a number of ways. For example, in reducing greenhouse gas (GHG) emissions from operations through energy efficiency, flare reduction and managing methane emissions, as well as increasingly powering operations with low carbon or renewable energy sources.

Understanding GHG abatement opportunities for assets is critical to reducing GHG emissions. Ipieca and IOGP have published the Compendium of energy and GHG efficient technologies and practices which showcases a vast range of technology solutions, readily available on the market, to drive GHG efficiency across the industry. Operators can maximise future proofing by adopting technologies when designing new facilities and by considering design requirements for future installation of GHG abatement technologies, e.g. CCUS.

Methane management is a key issue. Natural gas has a significant part to play in the energy transition, however, methane emissions have to be controlled across the entire value chain to ensure its place in the future energy mix. Dealing with methane emissions is technically and economically feasible. Supporting the industry to adopt good practices and current and emerging technology to reduce methane emissions is a big part of Ipieca’s work. We’re currently working with OGCI and IOGP on a framework for improved methane quantification. We’ve also partnered with them on a series of webinars and knowledge sharing sessions on innovation in this area, including the use of sensors, drones and satellites. We make the most of our industry reach, encouraging alignment with global initiatives such as the Methane Guiding Principles, UNEP’s OGP 2.0, IOGP’s Aiming for Zero Methane Emissions Initiative (Ipieca was the first global oil and gas association to become a supporter of this initiative), and World Bank’s Zero Routine Flaring initiative to name a few.

Ipieca is proud to play our role in sharing best practices globally to advance our members and the industry’s progress in reducing GHG emissions.

What role does innovation play in driving the economic and environmental case for natural gas?

Innovation plays a huge role in advancing the world towards net zero. Many companies are also helping their consumers reduce their emissions through the increased use of natural gas, enhanced efficiencies in engine-fuel systems, and developing low-carbon mobility technologies such as electric vehicles, biofuels, LNG, ammonia and hydrogen fuel-cells. Ipieca has published a series of papers detailing low-emissions pathways for transport and the role of hydrogen in enabling the energy transition and achievement of net zero.
African LNG: incremental gains add up

Increased use of existing LNG facilities, with new FLNGs under development and others in the pipeline could boost African LNG volumes significantly. But larger-scale onshore, greenfield projects are unlikely to start flowing much before 2030.

ROSS MCCracken

Africa has multiple prospects for new LNG supply, but many of the quickest options lie with existing producers and under-utilised capacity. Africa has a total 77.8 MTPA (105.8 bcm) of liquefaction capacity, but its utilisation rate across all producers was just 54.4% last year, primarily reflecting upstream constraints.

Algeria exported 11.78 MT of LNG in 2021, despite Algeria opposes. However, gas exports to Spain are not expected to be affected beyond the closure of the Maghreb-Europe pipeline, which also supplies Morocco.

Algeria’s upstream prospects brighten

Italy’s ENI and Algerian state oil and gas company Sonatrach struck a deal to increase pipeline supplies in April, one which is expected to utilise almost all the spare capacity on the TransMed pipeline. Increased flows by pipeline to Italy are likely to be offset by a small reduction in exports to Spain. The ability to increase LNG output thus depends on further rises in gas production beyond that which will be directed to export pipelines.

Algeria faces major upstream challenges largely as a result of production declines from old fields and the need to meet growing domestic demand. The giant Hassi R’Mel field, which still accounts for about 50% of national production, is well past its peak and expected to enter end-of-life decline from around 2025.

However, the recent government changes and high oil and gas prices have prompted a significant improvement in the country’s investment environment. In addition, record oil and gas revenues have improved the capital available to Sonatrach. Indeed, the Algerian upstream appears to be on something of a roll. Sonatrach announced a major gas condensate discovery at Hassi R’Mel in June, which is expected to result in an additional 3.65 bcm of gas from November. The company has announced a number of new oil and gas discoveries this year across various oil and gas basins.

Feedstock problems limit NLNG

According to local reports, Nigeria’s NLNG’s Train 7 is about 30% complete. It has a targeted start-up date of 2024, but company officials have said 2025 is more realistic in light of construction and engineering delays, which occurred as a result of the COVID-19 pandemic.

T7 will have a capacity of 8 MTPA and would increase NLNG’s total capacity to 38.8 MTPA. However, Nigeria’s LNG production has suffered from upstream problems which have limited the amount of gas reaching the facility. Nigerian LNG exports last year were 16.42 MT, or 74% of capacity. NLNG receives gas from joint ventures covering various concession areas, both on and offshore. The company said in August that it had lost $7bn in revenue this year alone as a result of gas shortages. NLNG officials put utilisation this year at 68%.

The problem - a persistent one - is outages on the

Source: BP
plant’s feeder pipelines, often the result of sabotage. The Trans-Niger pipeline, for example, has not operated since March. The pipelines are not controlled by LNG and the company can do little to ensure their security amid oil thefts which have reached unprecedented levels, afflicting associated gas supply, according to the authorities. Any increase in Nigeria’s LNG exports is largely dependent on improved security for its onshore feeder pipelines, but a lack of security has plagued the Nigerian oil and gas sector for decades and it is not clear that action adequate to address the problem will be taken.

**Egypt and Libya**

Upstream issues are also central to the fortunes of North Africa’s other two LNG producers. Libya’s 3.2-MTPA Marsa El Brega LNG plant has not operated since 2011 and continued instability and conflict in the country suggest its prospects for rejuvenation look limited. Available gas will almost certainly be used to boost pipeline exports to Italy via the currently under-used Greenstream pipeline. Libyan gas exports to Italy last year amounted to 3.1 bcm versus transmission capacity of 8 bcm.

Greenstream is fed from the country’s western oil and gas system, including the Bahr Essalam offshore field and the Bouri and Wafa fields. Marsa El Brega is supplied from oil and gas fields in the east, although a gas pipeline linking the western and eastern systems runs along Libya’s Mediterranean coast. However, the Marsa El Brega terminal, built in 1970, was already in need of major renovation prior to the onset of conflict in the country in 2011.

Egypt offers more promise, particularly given imports of Israeli gas to boost domestic supply. Egyptian gas output, like Algeria, last year saw a jump from 58.5 bcm in 2020 to 67.8 bcm. Gas consumption also increased last year by 3.6 bcm, but the surplus for export increased substantially.

Egypt exported 6.56 MT LNG last year, a significant increase on the 1.34 MT exported in 2020, but has a total liquefaction capacity of 12.2 MT, leaving plenty of room for further increases, if the feedstock gas is available. However, shortfalls in supply continue to hamper operations. The Idku plant was reported to be idle in July and working at only very low capacity in June, while Damietta was reported to be working at about two-thirds capacity.

Domestic gas supply and, more recently, regional exports have been prioritised over LNG exports, but bumper prices on the European gas market appear to be changing Cairo’s focus. According to consultants Rystad Energy, a government plan to reduce electricity demand could result in gas savings of 16 mcmd, freeing up gas for export as LNG. Reports suggest that the country is switching some power plants to burn fuel oil in the effort to support LNG exports.

**East Africa gains momentum**

The prospects for new LNG from Sub-Saharan Africa vary considerably in terms of both timing and scale. Plans for two large onshore LNG facilities in Mozambique continue to be frustrated by the security situation in the north of the country. The TotalEnergies-led 12.88-MTPA Mozambique LNG project was forced to suspend construction in March last year, following an attack by militants on the town of Palma in Cabo Delgado province, where the project is located.

According to a statement made in August by one of the minority stakeholders, India’s BPCL, building activities could restart in the first half of next year. All going well, which recent history suggests is not given, the plant could be up and running in the late 2020s.

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However, Eni’s plans for a second FLNG vessel to complement its Coral Sul project suggest that Mozambique’s LNG development may be taking a new course. The Area 2 partners invested in the Eni-led 3.4-MTPA Coral Sul project as a means of fast-track development, recognising the length of time it would take to build the country’s first LNG plants onshore. Coral Sul is expected to be on-stream by the end of this year.

The hold-ups onshore have vindicated the strategy and moving ahead with another floater could signal a shift to modular offshore development of the Area 4 resources, insulated from the onshore security problems. Indeed, this model could be replicated by the Mozambique LNG partners, if the onshore situation fails to improve. Eni is expected to make a decision on a second FLNG vessel early next year, which could be onstream in as little as four years, according to the company. No final investment decision (FID) was ever taken on the second proposed major onshore LNG development, Rovuma LNG, which was supposed to be the means by which most of Area 4’s gas resources were monetised. How a second FLNG project would affect its prospects remains uncertain.

Eni holds a 40% share in the Mozambique Rovuma Venture (MRV), along with ExxonMobil (40%) and China’s CNPC (20%). MRV owns a 70% interest in the Area 4 exploration and production concession while Portugal’s Galp, South Korea’s KOGAS and Mozambique’s Empresa Nacional de Hidrocarbonetos each hold 10%.

Meanwhile, to the north, Tanzania continues to move forward with its LNG plans, which have progressed more slowly than those in its southern neighbour. As in Algeria, a change of government has resulted in a more accommodative approach to foreign investment. The government has still to formulate a Host Government Agreement (HGA), which is expected later this year, but it signed an LNG framework agreement with major concession holders Shell and Equinor in June. Front-end engineering and design work is to be completed within three years of the HGA and the companies are targeting an FID in 2025, suggesting that the proposed major onshore facility could start producing in 2028.
around 2030. Equinor estimates reserves on its Block 2 acreage at around 566bn m^3, while Shell has discovered 453bn m^3 on Blocks 1 and 3.

West Africa
A decision by Eni and BP to merge their Angolan businesses into the Azule Energy joint venture should prove positive for Angola LNG. BP joins Eni in the New Gas Consortium, which took an FID on the development of Angola’s first non-associated gas development, Quiluma and Maboqueiro, in July. First gas from the project is expected in 2026 and will feed into the existing 5.2-MTPA Angola LNG facility, which last year operated at about 70% of capacity and currently depends solely on associated gas for its feedstock.

However, NLNG’s T7 aside, it is FLNG, as in East Africa, that looks the most likely source of new LNG on the West African Coast. The BP-led Greater Tortue Ahmeyim LNG project is close to completion and could start up this year. The first phase is relatively small with a capacity of 2.5 MTPA, but the project is designed to be modular and up to four FLNG vessels are possible, raising capacity to 10 MTPA.

As the project moves to operational status, the key question is whether a second vessel receives sanction in what is a very different gas market to only two years ago, when the project partners scaled down their initial ambitions in the face of the COVID-19 pandemic. With much of the necessary infrastructure for expansion already in place, the lead time for subsequent phases should be substantially shorter than for Phase 1. Market conditions arguably support a full steam ahead approach to maximise production from the project as early as possible.

Meanwhile, incremental gains are expected from Africa’s only producing FLNG vessel off Cameroon. So far, the Hilli Episeyo has been operating at 50% of its capacity of 2.4 MTPA, but this is expected to rise by 200,000 T this year and a further 400,000 T in 2023 as development drilling increases gas supply.

Another potentially fast-track development is Eni’s plans for FLNG off Congo-Brazzaville, although again the scale is relatively modest. Nonetheless, initial plans for 1.5 MTPA have been doubled to 3.0 MTPA, possibly in two phases. Although a more marginal source of gas supply in terms of proved reserves than the large resources off East Africa, Congo appears to have sufficient gas to support a facility of the size envisaged by Eni.

The possibility of quick development is certainly attractive as Italy attempts to make do without Russian gas imports. Eni signed a head of agreement in February with New Fortress Energy (NFE) to deploy its first ‘Fast LNG’ unit off Congo-Brazzaville.

The Fast LNG concept uses jack-up rigs or other floating infrastructure to house midsize liquefaction trains. NFE estimates it will be able to produce LNG for between $3-4 per mmBtu and, more importantly, have the FLNG facility in place 20 months from FID. NFE also reached a memorandum of agreement in December last year with the government of Mauritania for an energy hub, which would incorporate a Fast LNG unit.

Africa’s existing LNG producers and FLNG look the most promising points of delivery for new LNG supply in the short term, but the construction of large-scale onshore facilities will be slower to arrive. Nonetheless, incremental gains and new projects in Africa should still provide a much-needed boost to global LNG supply.

### UNDER CONSTRUCTION

- **Morrocoy**
  - Court RFS/GMS: 2022
  - Floating
- **Mauritania**
  - Técnica/Enagas: 2023
  - Floating
- **Nigeria**
  - NLNG T7: 2024
  - Onshore
- **Morrocoy (Colón B) (TGT)**: 2025
  - Floating

### African LNG capacity (MTPA)

<table>
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<tr>
<th>Country</th>
<th>Project</th>
<th>Capacity (MTPA)</th>
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### NEXT BIDDING ROUND

Perupetro S.A. is promoting 02 blocks of the Talara Basin which contain areas with contracts to expire in the upcoming years. The purpose is to increase their production through secondary recovery and the implementation of new technology.

**Next bidding round for producing contracts will include blocks 1, II, V, VII, XV, and X.**

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Global energy crunch revives South and Central American LNG prospects

High levels of political risk and unwelcoming investment environments continue to hamper gas development in Central and South America. However, there are bright spots on the horizon in Suriname and Trinidad and Tobago, while Argentina’s Vaca Muerta holds a longer-term promise of a more fundamental impact on global LNG supply.

ROSS MCCRACKEN

“South America has never been short of gas from a geological point of view, but there are many other factors which have frustrated upstream development”

Europe’s thirst for LNG in the wake of Russia’s war with Ukraine and its quest to replace Russian gas supply, which has dramatically shrunk, has been driving European gas prices to unprecedented levels. Countries across the region are pulling out all the stops to install new regasification capacity, a process likely to increase demand quicker than the global LNG market can respond in terms of new supply.

But whether it arrives tomorrow or in a few years, there is little doubt that new LNG supply capacity is needed, not least to prevent a long-term backslide into coal use, which would reverse the substantial environmental gains made from coal-to-gas switching. It is no surprise that upstream producers are thus scouring the world for potential sources of new supply and that South and Central America’s substantial and varied gas resources should be of interest.

Reserve base

The region has very significant proven gas reserves of 7.9 trillion cubic metres (tcm), according to BP’s Statistical Review of World Energy 2022. South America has never been short of gas from a geological point of view, but there are many other factors which have frustrated upstream development, not least, as elsewhere in the world, a focus on oil rather than gas as a quicker means to earn export revenue.

Even more frustrating, however, have been unstable economies and policy gyrations from open markets to often aggressive resource nationalism, which have deterred long-term foreign investment. Yet there are multiple countries in South and Central America which, given the right conditions, could sustain LNG export sectors.

Venezuela

The vast majority of Latin America’s proved gas reserves lie in Venezuela, which is credited with 6.3 tcm, a vast resource by any standard. The country’s gas production last year stood at a meagre 24 bcm, implying a reserve-to-production ratio of 262.5 years and massive potential for LNG exports, in theory at least.

However, Venezuela’s oil and gas industry is moribund, a result of government mismanagement, not helped by US sanctions, which has seen oil production fall from over 3mn bpd in the late 2000s to just 654,000 bpd last year. Gas production has also suffered and is now well below its 2017 peak of 38.6 bcm.

Overt resource nationalism has left the oil sector dominated by state company Petróleos de Venezuela, S.A (PDVSA), the revenues of which prop up an economy seemingly in perpetual crisis. A lack of investment capital, a long-standing drain of personnel abroad and the politicisation of appointments has made PDVSA increasingly incapable and inefficient.

Much of Venezuela’s current gas production is used for LNG exports, in theory at least. Plans for both pipeline and LNG exports have been on the drawing board for years, but currently the country has no LNG capacity and a brief period of pipeline exports to Colombia could not be sustained. Given
LNG development in the country, despite its vast gas resources, is unlikely until there is a fundamental change of political direction.

**South and Central America proved gas resources end-2021 (tcM)**

- Argentina
- Colombia
- Other S & Cent. America
- Venezuela
- Brazil
- Bolivia
- Trinidad & Tobago

**Existing producers offer real but limited opportunities**

Peru is the only country in South America to export LNG, having started in 2010 with the single-train, 4.45 MTPA 6.05 bcm/s Peru LNG, which derives its feedstock from the Block 56 Camisea gas field.

Peru LNG, which is owned by US company Hunt Oil, UK-based Shell, Japan’s Marubeni and South Korea’s SK Energy, has successfully managed to increase its domestic gas use for power generation and other purposes, as well as provide sufficient feedstock for enlarged LNG exports.

In January, an official commission called for work to restart the project in the second half of next year. In April, the government announced plans to form a working group to reactivate the project, which would depend on increased gas production from Blocks 56 and 57, as well potentially Block 56, which is controlled by China’s CNPC.

However, the government, led by Pedro Castillo, has yet to issue new contracts and seems to favour state-led development of the country’s gas transmission infrastructure.

There are thus a lot of moving parts and different interests – up, mid and downstream – which need to be tied together amid an unstable political environment to make an expansion of Peru’s LNG capacity viable.

Trinidad and Tobago is Central America’s only LNG producer from the four-train Atlantic LNG complex. The country’s gas production has been in decline, dropping to 15.6 bcm in 2021 from just over 20 bcm from 2010-2015. A lack of feedstock gas saw the closure of Atlantic LNG’s T1 last year, reducing liquefaction capacity from 14.8 to 11.8 MTPA.

LNG exports amounted to only 6.19 MT last year, down from 10.08 MT in 2020, according to IGU data. Atlantic LNG is also undergoing ownership restructuring to bring the diverse ownership shares of each train into a unified single entity.

However, the start-up in April this year of the Shell-operated Colibri field has provided a much-needed boost to gas output. The field is expected to deliver 1.8 bcm in the near term, rising to 2.6 bcm at peak production. Shell is the majority partner in Atlantic LNG.

The government is pushing upstream producers to bring more production online by the end of the year, having started in April this year of the Shell-operated Colibri field has provided a much-needed boost to gas output. The field is expected to deliver 1.8 bcm in the near term, rising to 2.6 bcm at peak production. Shell is the majority partner in Atlantic LNG.

The government is pushing upstream producers to bring more production online by the end of the year, but no decision has yet been made on whether to bring Atlantic LNG’s Train 1 back into service, given spare capacity in the three operating trains. Other upstream projects underway include Woodside’s Ruby project, BIP’s Matapai and Cassia compression projects and Shell’s Barracuda area development. Shell’s Manatee field, which involves gas production from an oil field extending into Venezuelan waters, could add further to output, potentially from 2026.

With spare liquefaction capacity in place, accelerated development of Trinidad and Tobago’s offshore resources looks a likely source for a near-term recovery in the country’s LNG exports.

**Suriname**

The Firebird LNG project off Suriname, which would be the country’s first LNG project, also looks promising. Unlike Atlantic LNG, there is no liquefaction capacity in place, but upstream gas is readily available. The joint-venture project between US companies Phoenix Development and Make a Difference Ventures seeks to piggyback on the ExxonMobil-led fast-track development of Suriname’s oil resources.

Feedstock would be sourced via an open access pipeline bringing onshore associated gas currently flared from oilfields off Suriname and Guyana for use either as LNG or gas-to-power. Associated gas resources in the Suriname-Guyana basin have been estimated at almost 1 tcm, far in excess of Firebird LNG’s requirements, suggesting potential for future expansion, and the upstream producers have every interest in seeing flared gas put to good use.

Phoenix last year partnered with port management company N.V. Havenbeheer Suriname to develop a deep water port and special economic zone in Suriname. The company in February this year awarded a Phase-1 FEED contract for the proposed LNG plant to Dallas-based Schwab Energy Services. Firebird CEO Walter Teter said in August that the 4 MTPA onshore facility is fully funded through to the final investment decision.

Phoenix has suggested an in-operation date of end-2024. This is a highly ambitious timescale for an onshore LNG plant, but the project otherwise looks sound.

**“There are a lot of moving parts and different interests -- up, mid and downstream -- which need to be tied together to make an expansion of Peru’s LNG capacity viable.”**

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**South and Central America LNG net imports (-ve) and Exports (+ve) (MTPA)**

- Argentina
- Columbia
- Panama
- Jamaica
- Dominican Republic
- Argentina
- Chile
- Brazil

**2021 vs. 2020**

- Argentina
- Colombia
- Other S & Cent. America
- Venezuela
- Brazil
- Bolivia
- Trinidad & Tobago

The political stance of the Maduro administration, US sanctions and the non-recognition by western powers of the results of the 2020 National Assembly elections, Venezuela remains a no-go area for foreign investors with the capability to deliver LNG projects.

LNG development in the country, despite its vast gas resources, is unlikely until there is a fundamental change of political direction.

**Global Voice of Gas**

October 2022

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Argentina Peru Colombia Other S & Cent. America Venezuela Brazil Bolivia Trinidad & Tobago

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Argentina

Given Venezuela’s chaotic state and Brazil’s growing LNG imports, Argentina arguably holds the greatest promise in South and Central America for large-scale LNG exports, but when and if remain open questions.

The giant Vaca Muerta shale play has been under development for the last decade and is estimated to hold resources of 2.6 tcm of gas and 14.3bn barrels of oil. Last year, oil production from the play exceeded 160,000 bpd for the first time and gross gas production leapt to 45 mcm/d per day in August up from below 28 mcm/d in April, signalling the results of expanded drilling activity. Vaca Muerta was identified by consultants Rystad Energy last year as the world’s fastest growing shale play, with well costs now on a par with the US’s Permian basin. The problem, however, is getting gas to market and the first hurdle is expanding takeaway capacity from the Neuquén basin, in which the majority of Vaca Muerta is located. The government is actively supporting construction of the 44 mcm/d President Nestor Kirchner gas pipeline, which would connect Vaca Muerta with the Buenos Aires area, raising regional takeaway capacity by about 25%. The pipeline is slated for completion in mid-to-late 2023, although the project has already attracted some controversy, suggesting the timetable could slip. Increased supply in the first instance is likely to displace Argentina’s own LNG imports, which are mainly used to balance winter and summer demand. These amounted to 3.7 bcm last year amid low hydropower output. Increased supply could also be funnelled to neighbouring markets such as Chile and Brazil, but even so, in both cases increased Argentinean output would serve to reduce LNG imports into South America’s major economies thereby improving supply on the global market.

A step further would be to build liquefaction capacity, a feat achieved briefly on a small-scale in 2019 via a floating liquefaction vessel chartered from Belgium’s Exmar. The prospect of much increased gas supplies from Vaca Muerta has prompted both the government and state oil and gas company YPF to actively look at the opportunities for LNG exports. YPF chairman Pablo Gonzalez, for example, has said the company is looking at three to four potential sites for an $11.5bn project, including upstream drilling and a feeder pipeline. A start up date of 2026 has been floated, but it would take a concerted effort to achieve such a timeline for a full-scale LNG export supply chain. Argentina’s swings in energy policy, as well as recurrent financial crises, and an often unwelcoming investment environment, have hampered more active development of Vaca Muerta in the past, as well as deterring major foreign investors from making large-scale, long-term investments. Nonetheless, the growing maturity of the Vaca Muerta shale, if coupled with a more accommodative and stable investment environment, could eventually see it have a major impact on the global LNG market.”
Chile needs action on emissions today

Gas can decarbonise Chilean energy in the short term, but authorities are waiting for cleaner options such as green hydrogen to be available in the future, even though the timeframe for their deployment is uncertain.

JOSEPH MURPHY

Key stakeholders should consider whether it makes sense not to take any steps today to cut emissions in order to wait for cleaner options in the future. Do we have time for paralysis?

- CARLOS CORTES-SIMON
Executive Chairman of the Chilean Natural Gas Association and IGU Regional Coordinator

In the power generation market, LNG not only serves as a relevant baseload source, but it is also a key stabiliser for the Chilean energy system. It helps to offset fluctuations in output from hydroelectric and other renewable power sources, as well as fluctuating pipeline supply from Argentina, while also providing an emissions-reducing replacement for coal – currently the South American nation’s main source of power generation.

However, the government has not been sufficiently recognising this clean energy source’s value and risks the country increasing its use of coal, while it waits for greater deployment of renewables and green hydrogen, Carlos Cortes-Simon, Executive Chairman of the Chilean Natural Gas Association and IGU Regional Coordinator, tells Global Voice of Gas.

“Today, Chile’s main source of power is generated from coal – 31% of the total according to International Energy Agency data from 2020. In second place is hydroelectricity, with a share of 25%, and in third place natural gas with 18%. The remainder of the mix consists of solar (9.3%), wind (6.7%), biorefineries (0.5%), oil (3.7%) and geothermal (0.3%). Gas is also used in industry, household and commercial heating and cooking, and in transportation. Participation in power generation and in final consumption are well below OECD and global averages. We only produces 15% of its gas needs itself, with 70% brought ashore at two regasification terminals located in the northern and central zones of the country. The remainder is delivered via pipelines from Argentina, but this gas flow has been fluctuating, making LNG supply key to stabilising Chile’s energy system.

According to market sources, “the gas supply from Argentina has been very uncertain. Production has been rising and falling and there have been some issues”. However, in the last year Argentina has managed to increase its natural gas production. It provided a continuous supply to Chile during the last summer season (October 2021–April 2022), and is projected to continue doing so for the next summer season (October 2022–April 2023).

With a capacity of about 5.5 bcm, the GNL Quintero terminal accounts for three quarters of Chile’s overall regasification capacity. The terminal sources its gas primarily from the US, Trinidad & Tobago and Equatorial Guinea. Most of this supply is provided by Shell under a long-term contract that expires in 2030. This has helped shield Chile from soaring spot gas prices over the last year. In fact, the Quintero LNG terminal did not receive any volumes from the spot market this year, according to the same source.

Likewise, Chile’s other terminal in Mejillones, which is used to power mining operations in the north of the country, relies primarily on volume supplied under a long-term contract by France’s TotalEnergies.

Green plans

Last year Chile pledged to expand renewable power generation to 80% by the end of the decade, whilst also covering 70% of non-power energy needs with zero emission fuels by 2050 – first and foremost green hydrogen. It also targeted ending the use of coal by 2030. The current Chilean government, led by president Gabriel Boric, who took office in March 2022, has yet to update the country’s climate objectives, but once it does so, those deadlines could well change.

In a positive development, the Chilean energy ministry launched its 2022–2026 Energy Agenda in August, which highlighted gas as a transitional energy source that could support the phasing out of coal-fired power. However, the industry believes that the level of support for gas needs to be higher.

“If the country is a net importer of oil and gas as it doesn’t produce much itself, its government often does not have a positive view of those fuels,” Cortes-Simon tells GVG. “This is the case with Chile – neither the past government nor the present one have been supportive of gas. They only see gas as a bridge towards a completely green energy mix.”

This contrasts with the positions of authorities in Argentina, Brazil, Colombia and Peru, endowed with much greater oil and gas reserves than Chile, Cortes-Simon says. “In the long term we do not see any significant growth in the natural gas electrical power market,” sources say. “There is no new infrastructure or new combined cycle power plants being planned right now.”

For new major energy-intensive projects to go ahead in Chile, either more LNG import capacity needs to be developed, or the supply issues with Argentinian gas need to be resolved, Cortes-Simon says.

“We strongly believe that gas is going to play a key role in the coming 15–20 years, providing not only a baseload, but also a flexible source of energy that can substitute in power generation, and that green hydrogen will be there in time to replace it. Those signals are well perceived by investors.”

Gas can help reduce emissions today by phasing out dirtier fuels such as coal and diesel, and furthermore, start material and cultural changes towards the use of green gases in the future (including blends and hydrogen). However, some decision makers prefer to wait for completely green alternatives, even though the timeframe for their widespread feasibility is still uncertain, Cortes-Simon says.

“Key stakeholders should consider whether it makes sense not to take any steps today to cut emissions, in order to wait for cleaner options in the future. Do we have time for paralysis?” he says.
Norway braces to ramp up gas supply to Europe

Natural gas will be important in easing energy market volatility in Europe as the deployment of renewables is accelerated in the years to come.

JOSEPH MURPHY

Norway and its national energy company Equinor are working to supply additional natural gas to Europe, helping to ease the continent’s unprecedented energy crunch. But there are limits to how much can be done in the short term, as new projects will take time to reach production, and greater policy certainty is needed in Europe to facilitate investment by suppliers, Equinor’s senior vice president for gas and power, Helge Haugane, tells Global Voice of Gas.

Short-term measures

Following steep reductions in Russian flow, Norway is now Europe’s largest gas supplier, having produced 79 bcm for export in the year up to the end of August. The country is targeting an output of 122 bcm in 2022, up from 113 bcm last year.

Norway has resorted to three key measures to bolster short-term energy supply, according to Haugane. Firstly, its government has amended field permits to allow producers to pump more gas in the short term. In July, for instance, the country’s energy minister approved permit adjustments at six fields – Troll, Gina Krog, Duva, Oseberg, Asgard and Mikkel. Secondly, Equinor and other producers have been exporting more gas that would otherwise have been injected back into field reservoirs to boost oil recovery. Thirdly, Equinor has been adding butane, ethane and propane into the grid, adding volume and giving the gas a greater calorific value, which means it creates more energy when combusted.

However, there are limits to how much extra supply Norway can bring into the mix in the short term, given project lead times. “In the short term you cannot bring new wells, new exploration fields into play,” Haugane says. “What we are doing right now is optimising our existing production mix.”

Equinor also entered a new long-term 1.75-MTPA LNG supply contract with US exporter Cheniere in June, to provide additional volumes for Europe in the medium term, from 2026.

Government support

Norway would be in less of a position to help ease Europe’s energy crunch had its government not stepped in to support the industry at the height of the coronavirus pandemic, when oil and gas prices crashed.

The pandemic triggered significant cuts in upstream investment in 2020 across much of the world, as producers were left struggling with constraints on capital and a very uncertain market outlook. In Norway, though, parliament agreed in June that year to provide a 100bn kroner ($10.6bn) support package to oil and gas companies, enabling them to deduct investments made in 2020 and 2021 from their tax bill, and secure additional relief for projects they approve before the end of 2022.

“That support package turned out to be very sensible. If we hadn’t had it, a lot of projects wouldn’t have happened and we would have less gas in the short term,” Haugane says. “Without it, we would have probably also seen the supply chain scaled down. By making sure the supply chain still had activity, we are now better prepared to implement new projects into the future.”

Price volatility

The soaring cost of gas on the European spot market this year has benefited Equinor financially in the short term, as the company sells most of its supplies based on short-term hub pricing.

“From a producer’s standpoint, it is good in terms of short-term profit,” Haugane says. “But costs this high are not good for the trust in energy markets. It is very negative for Europe and the globe. It will affect all sorts of industries, global GDP, and the welfare of many people.”

There is also uncertainty about how quickly demand destruction will be reversed when prices fall, and concern that some of that demand destruction will be permanent, he says.

While the accelerated deployment of renewables should continue, Haugane stresses that this needs to be accompanied by sufficient dispatchable energy supply to avoid price volatility.

“We need to have enough backup for that intermittency,” he says. “Without that, even if it’s unclear whether prices will be high or low looking ahead, I can say with mathematical certainty that those prices will be more volatile. We need gas to serve as a bridge until we have enough hydrogen to provide that backup, but that’s quite far out in time.”
The outlook ahead

Still, current high prices are temporary and have had little impact on Equinor’s long-term price assumptions. New global supply will build up, particularly in the US, where a wave of new LNG export projects are making progress, Haugane says. But this will take time, and there is significant uncertainty going into this winter, regarding the level of demand, which will depend greatly on temperatures, as well as the level of Russian supply.

To attract extra LNG supply, Europe needs to provide suppliers with greater policy certainty about how much gas it will need in the years to come, to support the necessary investment, Haugane says. Asian LNG buyers particularly in China have clinched a number of new long-term gas supply agreements over the past year, whereas Europe has been less inclined to commit to taking volumes for long periods, amid concerns about how much supply will be necessary, and for how long, as the continent embarks towards net zero.

As for hydrogen, while Haugane believes that green hydrogen is rightfully considered the end goal, blue hydrogen is starting to gain more attention from policymakers in Europe, given its potential to be scaled up quickly. But regardless of whether the hydrogen is green or blue, first Europe will need to return to having an energy surplus to support the development of these fuels.

While the accelerated deployment of renewables should continue, Haugane stresses that this needs to be accompanied by sufficient dispatchable energy supply to avoid price volatility.
Creating a measurement economy for methane

A rigorous certification system for methane emissions will help support the natural gas industry’s social licence to operate and strengthen the case for gas globally as a tool to tackle climate change, Project Canary CEO Chris Romer believes.

JOSEPH MURPHY

Having a rigorous certification system for how responsibly natural gas has been sourced is vital for LNG producers in the US to gain the necessary social licence to build out their facilities and expand supply to the global market. Project Canary CEO Chris Romer tells Global Voice of Gas. And this is particularly true when concerning the methane emissions intensity of that gas.

Established in 2019, Project Canary offers natural gas producers a means of certifying their production based on methane emissions intensity and many other environmental criteria, from water management to well integrity. That certified gas is referred to as responsibly-sourced gas (RSG) - a term the company coined three years ago. Project Canary has already certified close to 11bn ft3/yr of gas supply, with more coming as certifications are completed and its sensor arrays are installed in the US, Canada and abroad.

“Climate is a maths problem,” Romer explains. “And we need to have a rigorous measurement standard to solve that problem.”

This means the natural gas industry moving to a “measurement economy,” he says, where the methane intensity and other environmental impacts of the entire supply chain are measured to meet the increasingly strict criteria of customers, such as utilities and LNG buyers.

To get their natural gas certified as RSG, producers have the environmental impact of their assets assessed using 62 key measurement criteria and more than 600 data points under Project Canary’s TrustWell programme. Their methane intensity is also measured using continuous emissions monitoring, and their gas is certified either as silver, gold or platinum RSG.

“Everyone would love to get a gold star for not doing anything different, but what we’re all about is continuous improvement, and giving operators a path to becoming part of the climate change solution,” Romer says. “It’s very important to give companies the standardised incentive to change their behaviour.”

Romer stresses the need for the natural gas industry to move further away from emission factors – representative values that attempt to estimate the quantity of emissions from a given asset or activity. Given their estimated nature, the market simply does not trust them, and this is why finding ways to integrate these with continuous monitoring of individual assets is key, he says.

There are other initiatives underway in North America to certify gas based on its methane intensity and other environmental and social criteria – notably Equitable Origins’ EO100 standard and the MiQ standard. But while both are not-for-profit, Project Canary is commercial in nature. Project Canary believes its own model can best build the scale of certification, though “our competition isn’t the other certification programmes, it is the status quo,” Romer says.

In time, Romer says that certified gas will sell at varying premiums depending on its rating, while uncertified gas will sell at a discount.

Certification standards for gas will be increasingly important as the US gears to greatly expand its LNG exports over the coming years, in part to displace Europe’s lost Russian supply. They can help strengthen the case for gas globally as a tool for reducing emissions, in tandem with renewables, helping to drive out coal from the energy mix. Having a social licence will not only be important for buyers of that gas, but also for building the necessary infrastructure in the US to support increased exports.

“People are not going to give us the social licence to build more pipelines and LNG facilities unless we go to a measurement economy that is highly accurate,” Romer explains. “And that measurement has to be incredibly rigorous to get bipartisan support.”

There are further implications for blue hydrogen, the environmental value of which depends on the methane intensity of the feedstock gas that is used, as well as the effectiveness of carbon capture and storage.

“Without the measurement economy, blue hydrogen is a dead molecule,” Romer claims. “It will have no social licence without rigorously measuring the gas that is used.”

Everyone would love to get a gold star for not doing anything different, but what we’re all about is continuous improvement, and giving operators a path to becoming part of the climate change solution.
2023 is the year of methane policies

Kamila Piotrowska, Head of the EU Policy and Advocacy at Baker Hughes, tells Global Voice of Gas why next year will be a critical one in ongoing efforts to reduce methane emissions from the energy sector.

Global Voice of Gas: Why do you believe that 2023 will be the year of methane policies?  
Kamila Piotrowska: There are several reasons why regulators and policymakers around the world are taking steps to significantly reduce methane emissions: methane is the second most abundant anthropogenic greenhouse gas (GHG) after CO2, and its GHG effect is significantly stronger in the short term, making it more potent than CO2. Also, according to the IPCC findings, methane alone would need to decline by almost a third to limit global warming 1.5°C. Hence, reducing methane emissions is a low-hanging fruit to achieve net-zero emissions.

In 2021, the European Commission and the United States Environmental Protection Agency (US EPA) released proposals to tackle methane emissions from the energy sector—both of which should be finalised in 2023. The US also recently proposed a methane “fee” as part of the Oil and Gas Methane Partnership (OGMP) Reporting Framework, while the US developed its reporting system prior to creation of the OGMP 2.0 standard.

Additionally, the EU proposed law covers— to some degree—imported natural gas. The EU imports over 80% of its natural gas and 90% of its oil. Therefore, the European Commission’s proposal includes measures on transparency and visibility on methane emissions from imports and leaves open the possibility for future action to cut methane from imports.

Global Voice of Gas: What are your views on the EU’s proposed law to tackle methane emissions from the energy sector?  
KP: Overall, Baker Hughes supports the European Commission’s proposed regulation to address methane emissions from the energy sector, but we recommend several critical changes.

Our top recommendation is to set limits not based on concentration—expressed in “parts-per-million (ppm)”—but rather mass flow rate as a function of kg/hr. The proposed concentration standard of 500 ppm would bind operators to use a specific method and technology that precludes more effective alternatives. Specifically, the proposal would require measuring at the point of leakage by a technician using Method 21 (i.e., “sniffing”). The inspector must be in close proximity—often less than 2 m to the leak source—which means many potential sources of leaks at a site are inaccessible. Any valve or other potential source of leaks, that are beyond the reach of a human, will not be detected. Flow rates are also more indicative of the size of a leak which helps in prioritising which ones to fix.

Global Voice of Gas: Do you think the governments are well-equipped to start their journey to tackle methane emissions?  
KP: The EU and US regulations could be used as a reference for governments looking for a framework. In addition, supporters of the Methane Guiding Principles have developed the Oil and Gas Sector Toolkit to support policymakers in their effort to drive down oil and gas methane emissions. The Toolkit was launched in July and provides a variety of resources and case studies to reduce methane emissions. Governments can design policies based on the demonstrated results of actions undertaken around the world.

Global Voice of Gas: What are your recommendations for policymakers in terms of regulating methane emissions?  
KP: First, there must be a credible baseline upon which to manage emissions. This requires a robust system for monitoring, measuring, quantifying and reporting methane emissions.

Second, the technology to understand methane emissions is developing rapidly, and therefore, it is essential to avoid prescriptive requirements as they may harm innovation. A technology-inclusive approach will, over time, enable a greater reduction of emissions at a lower cost.

Third, funding is needed to further develop innovative technologies. R&D and demonstration programmes should support technologies for quantification, detection, mitigation, and prediction of methane emissions.

Global Voice of Gas: What are your views on the EU’s proposed law to tackle methane emissions from the energy sector?  
KP: The European Commission’s proposed regulation to address methane emissions from the energy sector is a significant step forward. The proposed concentration standard of 500 ppm would bind operators to use a specific method and technology that precludes more effective alternatives. Specifically, the proposal would require measuring at the point of leakage by a technician using Method 21 (i.e., “sniffing”). The inspector must be in close proximity—often less than 2 m to the leak source—which means many potential sources of leaks at a site are inaccessible. Any valve or other potential source of leaks, that are beyond the reach of a human, will not be detected. Flow rates are also more indicative of the size of a leak which helps in prioritising which ones to fix.

Global Voice of Gas: How does the EU proposed law on methane emissions compare to the one in the US?  
KP: The EU law is the first EU-wide proposal on tackling methane from the energy sector. The EU has not had any harmonised law on methane before. Whereas the US has always been ahead of the EU in terms of legislations around methane emissions for obvious reasons—the production of oil and gas is larger in the US than in Europe.

The EU has also built its methane provisions on measurement, reporting and verification (MRV) on the Oil and Gas Methane Partnership (OGMP) Reporting Framework, while the US developed its reporting system prior to creation of the OGMP 2.0 standard.

Third, funding is needed to further develop innovative technologies. R&D and demonstration programmes should support technologies for quantification, detection, mitigation, and prediction of methane emissions.
GVG: Prediction? That sounds exciting. Would you be able to elaborate on this?

KP: Improved detection and quantification will help us understand where the biggest problems consistently occur, so we can prevent these issues before they happen instead of simply trying to abate the resulting emissions after the fact. For example, by knowing a pipeline’s corrosion rate, we will be able to repair it before it begins leaking. This automation and anticipation make emissions management even more cost-effective. Understanding how operational processes affect emissions and efficiency based on real-time and historical data can also enable decisions to optimise various parameters.

GVG: What trends do you see emerging with policies to reduce methane emissions?

KP: We have been actively involved in policy discussions around methane emissions globally, including in the US. One concept which is gaining attention is around “differentiated natural gas”, “responsibly sourced gas” or “certified gas.” This means that a natural gas producer can receive a label recognising that it has minimised methane leakage and therefore, the natural gas has a lower methane intensity than what is available on the market.

The expectation is that buyers of natural gas will pay a premium for natural gas with lower emissions. Several oil and gas producers have sought to certify their natural gas as having lower emissions intensity, and there has been a proliferation of third-party certifiers such as MiQ, and Equitable Origin to name a few.

The demand for certified natural gas is expected to increase, but the market must be credible. Therefore, government policies could potentially play an important role by establishing a set of principles to disclose emissions.

GVG: What role can technology play to address methane emissions?

KP: We believe that technology is at the centre of tackling methane emissions. Additionally, emissions management software will be critical to managing all the data and provide more intelligent insights for process optimization and abatement.

Baker Hughes has a growing portfolio of over 40 solutions that can help abate methane emissions for our customers including associated gas recovery, improving flare combustion efficiency, waste heat recovery, upgrade of equipment such as valves, seals. Many of these solutions can be deployed with a positive business case.

For example, our technology supports customers by utilising associated gas as a fuel source that is otherwise flared and improving flare combustion efficiency. This technology is already being deployed, and we are seeing growing interest from customers. During this summer, we kicked off the cooperation with the Egyptian General Petroleum Corporation, for the first deployment of our flare.IQ technology to reduce emissions in refining operations in the country.

GVG: If 2023 is the year of methane policies, what happens after that?

KP: Recent trends to reduce the environmental footprint of natural gas will continue. Initiatives like OGMP 2.0, Methane Guiding Principles and OGCI will drive efforts related to reducing methane emissions intensity and credible quantification. We will see more focus on the reduction of emissions from the LNG value chain.

There will be an increasing number of stakeholders — especially from the industry — to work together to set goals and establish roadmaps for emissions reductions to ensure both competitiveness and progress in lowering specific emissions. This will lead to increased transparency about actual emissions rather than just estimates. Governments will also require companies to provide more details on their Scope 1, 2 and 3 emissions.

Meanwhile, technology to identify and quantify emissions will continue to improve and become more accessible. Emissions management tech will also become more automated, shifting from widget-driven to data and analytics-driven via the increasing application of AI and machine learning.

Finally, as we gain learnings from detecting and reducing methane emissions in the oil and gas operations, this knowledge and even technologies will expand to other sectors such as agriculture. We also expect to see more actions in the coal, biogas, and waste industries.

From awareness to action: A five step approach to reducing emissions

Start at the beginning
Assess your baseline and identify emissions sources. This provides a starting point to measure improvement against desired target.

Create a roadmap
Set reduction targets and determine how to achieve them. Consider basing your roadmap on industry best practices or standards.

Mitigation options
When it comes to mitigating emissions, one size doesn’t fit all. Explore every option to determine which works best in a particular situation.

Communicate and report
Communicate progress made to stakeholders, industry commitments, and society using reliable, transparent, and verified data.
Engineering a sustainable world for a better tomorrow

Technip Energies brings our clients' ground-breaking LNG projects to life, integrating technology and expertise. We are committed to enhancing their performance and accelerating the energy transition by offering solutions to reduce CO₂ emissions from liquefaction and export terminals.

In Qatar, we are delivering the world’s largest Liquefied Natural Gas project including a large CO₂ Carbon Capture and Sequestration facility that reduces CO₂ emissions by around 25% when compared to similar LNG facilities.
What’s going on with gas in Australia

Although natural gas has been scapegoated for energy problems in Australia’s east coast, the federal government and producers have been able reach an agreement that avoids curtailing LNG exports.

It must be confusing for anyone outside Australia to understand what is happening when one of the world’s largest LNG exporters has been talking about possibly restricting LNG exports. In this article, I will try to clarify matters.

It is best to start with the geography of Australian gas. Figure 1 shows the gas consumption and production centres in the June quarter of 2022, together with major gas pipelines. Most of Australia’s gas lies on the west coast and most of the population lives on the east coast, which also has the largest domestic gas market. There have been a number of attempts to justify a west-east gas pipeline, but the distances are too great and east coast gas demand is too scattered for a pipeline to be commercially viable.

Australian gas is dominated by LNG. The country has ten LNG projects, with five projects in Western Australia, two in Darwin in the Northern Territory and three at Gladstone in Queensland. LNG exports are almost five times the size of domestic gas demand.

Australian LNG has been performing well. In FY 2022 Australia was the world’s largest LNG exporter, shipping 81.5 MT, mostly to Japan, China, South Korea and Chinese Taipei. The strong performance in terms of volume allowed the Australian LNG industry to leverage the opportunity of the current high price environment for both oil-linked contract sales and spot market sales. This was reflected in a surge in exports to a record US$51bn in FY 2022, up by 130% on the previous year.

The bulk of Australian LNG is produced from Western Australia and the Northern Territory, 71% overall in FY 2022. In both jurisdictions, the domestic gas market is effectively quarantined from the international LNG market. Indeed, Western Australia has a long-standing domestic gas reservation policy requiring LNG projects to reserve 15% of their production for the domestic market. Contrary to industry fears, this has not impeded LNG development or even onshore gas exploration.

Following the surge in international gas prices, Western Australia now has some of the lowest wholesale domestic gas prices in the OECD. Contract gas prices are currently around US$3.90 per mmBtu. Electricity prices are also low, averaging US$39 per MWh in FY 2022, reflecting the state’s low-cost fuel mix: 28% gas, 32% intermittent wind and solar, and 39% low-cost coal. (WA coal is not exported.)

It is a different story on the east coast where, similar to the US, the LNG projects are integrated with the domestic gas market. The LNG projects can both draw on and contribute to domestic gas. The east coast is also one of the world’s major coal exporters, and it generates 59% of its electricity from coal.

In the June quarter (the beginning of winter in the southern hemisphere), east coast electricity prices spiked to over US$200 per MWh, spot gas prices to over US$30 per mmBtu and coal prices to over US$400/T. This was due to both international and domestic developments.

Higher international prices had a flow-on effect domestically, including to electricity prices. In addition, there were disruptions to coal-fired power generation. Flooding caused delays in delivery of coal to some New South Wales (NSW) power stations. The east coast

Senex ... is investing more than US$650mn to expand its natural gas developments in Queensland’s Surat basin. Industry initiatives like this will obviate the need for government action.
Gas was the immediate target of blame for the east coast energy security. The Australian Energy Market Operator was forced to close the electricity and gas markets and direct markets. The increase in international energy prices together with generation, which was up by 29% from a year earlier.

Two-thirds of the gap was met by wind, solar and hydro, while total electricity demand was up by 1%. Around half of first quarter coal-fired generation was down by 7% compared with a year earlier, as the long-planned closure of one unit at Liddell, a major power station in NSW. Total second quarter coal-fired generation was down by 7% compared with a year earlier, but that left 1,000 GWh to be supplied by gas-fired power. As the southern winter approached this year, there were disruptions to several coal generators as well as the ageing coal-generating fleet is becoming increasingly unreliable. Some of the plants were built as long ago as the 1970s. The coal plants, which were intended to provide steady baseload generation, have had increasing difficulty competing in a market with intermittent renewables.

Electricity market is an energy-only market rather than a capacity market, which values availability, while the ageing coal-generating fleet is becoming increasingly unreliable. Problems, particularly the Queensland LNG producers, even though there was no sudden increase in LNG exports and, as happens every winter, gas from Queensland was flowing south into the colder southern states. The Australian competition regulator was quick to throw fuel on the fire with claims that the LNG producers were profiteering by selling spot LNG rather than supplying gas domestically. The regulator called on the Australian competition regulator to consider possible measures to restrict Queensland LNG exports.

This is the preferred option for the Victorian and NSW energy ministers. Speaking after a meeting of federal and state energy ministers on August 12, they were particularly critical of Queensland LNG exports.

“We produce more than sufficient gas to meet our needs, but the problem is too much of it has been allowed to be exported at our own cost, and that’s got to change,” Victoria state energy minister Lily O’Ambrosio said at a televised media conference on August 12, according to Reuters.

NSW energy minister Matt Kean said, “And what we need to do is prioritise Australian gas for Australian gas users ahead of companies making super profits and exporting that gas offshore,” according to Reuters. NSW is of course one of the world’s major coal exporters. Having the federal government restrict Queensland exports to divert gas south would be an easy option for the federal government, with most LNG exports from Queensland shipped under long-term contracts. Twenty percent of China’s LNG imports were sourced from Queensland in 2021-22. Australia’s relations with China remain difficult, with Australia complaining about Chinese restrictions on some imports from Australia, including coal, and concerns that China may ban Australian beef.

In these circumstances, it would be bizarre for Australia to deliberately restrict exports to China. Japan, Korea, Malaysia, Singapore and Thailand also rely on LNG from Queensland.

At the August 12 meeting, all ministers also agreed to the principle that any actions to restrict exports should respect existing foundation contracts for export supply and international partners, but it was only as a throwaway line at the end of a long communiqué.

Following extensive consultations with gas producers and buyers, the federal government announced on 29 September that it would not place restrictions on LNG exports. Rather, the government has signed a Heads of Agreement with east coast LNG exporters to prevent a gas supply shortfall and secure competitively priced gas for the domestic market. The federal resources minister Madeleine King said the negotiations ensure additional gas supply, improving security and affordability of domestic gas supplies in future years, while also introducing transparency measures to improve the information available to customers.

In July, the Australian competition regulator forecast a gas shortfall of 56 petajoules (PJ) for the domestic market in 2023. The new commitments from LNG exporters will lead to an extra 157 PJ for the domestic market in 2023, with the gas to be supplied in line with seasonal demand.

Meanwhile, the best long-term solution is to find and develop more gas. Australian company Senex has been quick to take up the challenge, announcing it is investing more than US$650mn to expand its natural gas developments in Queensland’s Surat basin. Industry initiatives like this will obviate the need for any future government action.

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Blame on Gas?
Gas was the immediate target of blame for the east coast

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IGU gas price report highlights value of market-based trade

Clear gas market price signals have been critical in redirecting trade flows to address major energy market stresses. They are also guiding upstream investment to deliver the capacity increases sorely needed to bring prices back to more normal levels.

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Market-based LNG trade has been at the heart of international gas market flexibility amid a series of tumultuous supply and demand-side shocks over the last two and a half years. The ability to respond actively has even more critical since Russia’s invasion of Ukraine, but was already evident from the rising share of LNG traded on a market basis in 2021.

While respecting the difficulties created by high prices, President of the International Gas Union (IGU), Li Yalan, makes a pertinent point: “A well-functioning gas market was able to reorganise global supply flows to where they were required most in just a few months.”

Market-based pricing in the LNG market played a key role in this redirection of trade. The share of gas-on-gas (GOG) pricing reached 46% of total LNG imports last year, up 2% on 2020, according to the IGU’s 2022 Global Wholesale Gas Price Survey Report.

GOG pricing for LNG includes LNG volumes traded on a spot basis and those with prices linked to gas hubs. 2021 saw more contracted LNG volumes tied to hub prices, notably the US’ Henry Hub as US liquefaction capacity continued to expand, providing relief to constrained European markets.

The move toward market-based pricing, allowing the efficient allocation of traded cargoes, is all the more evident over the longer term; in 2016, the share of GOG pricing in LNG imports was only 25%. The growth of LNG trade has been fundamental to the creation of a responsive global gas market, one which ties together formerly disparate and disconnected regional pipeline networks.

No flex without market-based trade

Although the volume of spot cargoes as a share of total imports fell for the first time since 2016 to 34% from 35%, the combined increase in spot and hub-linked volumes sold into traded markets (mainly Europe) resulted in the higher share of GOG pricing in total LNG imports.

In terms of total gas consumption, bucking the long-term trend towards more market-based trade, GOG pricing reflects the interplay between real gas supply and demand, as opposed to OPE, which sets gas prices in response to changes in the oil market.

GOG trading typically takes place at gas hubs, for example the Dutch TTF, UK NBP or the US’s Henry Hub. Gas is bought and sold on a fixed price short-term basis, but also on longer-term contracts, using gas price indices to determine a monthly price. Spot LNG sales are also included in this category, as are bilateral agreements in markets where there are multiple buyers and sellers.

Worldwide GOG has the largest share in domestic gas production at 46%, totalling some 1,372 bcm of gas. Of this, 935 bcm, or 68%, is accounted for by the well-developed North American gas market, where prices have risen, but not to the high levels experienced by Europe.

The next largest share in terms of volume is Russia, followed by Europe and then Asia. OPE’s share of domestic production is relatively small at 11%, with most of the remainder sold under a variety of regulated pricing mechanisms.

Although there was little change in 2021 from 2020, GOG in domestic production has steadily gained market share since 2005, largely owing to market deregulation, which has increased competition.

GOG’s share of the market is higher when it comes to pipeline imports at 63%. OPE’s share is also larger at 28%. Much of the GOG element is in Europe’s competitive gas markets, particularly in northwest Europe.
Europe, although Turkey continues to source a large proportion of its gas imports on an OPE basis. Pricing for the remaining 9% of pipeline imports falls under Bilateral Monopolies (BIM), where a price is generally set for a fixed period and then renegotiated at the end of that period. These agreements usually feature a single buyer or seller.

The LNG market is split 54% OPE and 46% GOG, according to the IGU report. However, there are large regional variations. 67% of LNG imports into Europe are now GOG, according to the IGU.

At the same time, markets where OPE predominates, for example, Japan, Korea and China, also have significant volumes of spot LNG imports. China has become the largest importer of spot LNG cargoes, closely followed by Japan.

In 2021, the two-point rise in GOG LNG trade reflected a large increase in spot LNG cargoes heading to Latin America, a large increase in spot LNG cargoes into Asia Pacific and China, and a switch away from OPE cargoes to GOG in Europe. Brazil’s ability to import LNG on a spot basis, and the LNG market’s ability to provide it, was essential for power supply as the country faced an intense drought which reduced the amount of hydro power available.

The volume of LNG going into traded markets in northwest Europe rose significantly in 2019 and declined only slightly in 2020. Last year, there was also an increase in US LNG cargoes going to Asia, according to the IGU. The volume of spot LNG shipments has risen two and a half times in five years, from 62bn m³ in 2016 to 170bn m³ in 2021.

Overall, the share of GOG pricing in imports – both pipeline and LNG – was 56% in 2021, while OPE accounted for 39% and BIM 5%. This stands in marked contrast to the shares in 2005, when GOG accounted for just over 21% and OPE dominated with 63%. Since 2009, OPE has lost around 27 percentage points to GOG in terms of market share, while from 2005 to 2021, GOG pricing in volume terms rose by over 300%, in comparison with a 7% decline for OPE, the IGU says.

Gas prices rise from record lows to new highs

There is no question that the imbalance caused in the gas market by supply and demand shocks has resulted in price volatility, but the gas market’s response is more than just short-term. According to Li, “ongoing efforts to add new sources of gas supply, together with prudent measures to enhance efficiency and conservation on the energy demand side are needed to help rebalance energy markets and make energy access secure and affordable to all.”

Last year saw rises in wholesale gas prices in almost every region of the world, the exception being the Middle East. In fact, prices swung from record lows in 2020 -- induced by the economic dislocation of the Covid-19 pandemic – of $3.22 per mmBtu to $5.54 per mmBtu, just below the highest ever level of $5.58 per mmBtu recorded in 2013.

Regions’ exposure to market pricing has a significant impact on the prices they experience. The IGU report shows Europe receiving very low-priced gas in 2019 as spot prices collapsed and then again in 2020, when spot prices fell sharply a second time. Then, in 2021, European prices rose as a result of the global post-pandemic recovery to over $13 per mmBtu. In contrast, Asian prices barely changed in 2019 from 2018 and rose only slightly in 2021 to $8 per mmBtu.

The variation in price response to a rapidly changing market effectively decoupled Asian and European prices, which had broadly tracked each other in the period 2015-2018, the IGU says.

The factors forcing prices higher in 2021 reached a crescendo in the latter part of the year – cold winter weather across the northern hemisphere, COVID-related supply chain issues, reductions in Russian pipeline exports and strong post-pandemic economic growth.

These strains have become even more intense in 2022, owing to the substantial reduction in pipeline gas flows from Russia to Europe.

Nonetheless, while hitting record lows and then, more recently, new highs, the signals provided by market pricing are vitally important. They have been critical to the huge redirection of LNG flows into Europe this year and are fundamental to attracting new investment into upstream pipeline gas and LNG supply, which is badly needed to return gas prices to more normal levels.

Overall, the long-term trend towards market pricing in its broadest sense is substantial, rising from 62% in 2005 to 72% in 2021, mirroring the decline in regulated pricing from 38% to 28% over the same period. This has helped to increase the gas market’s short-term flexibility and short-to-medium-term investment responsiveness.

As Catelin points out, governments do need to respond, but not in ways that obscure market signals thus threaten investment. He says: “What is needed is a rebalancing of supply and demand, combined with some carefully-targeted social relief measures for the most vulnerable groups, and well-planned energy efficiency and conservation measures.”