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IAEE ENERGY FORUM

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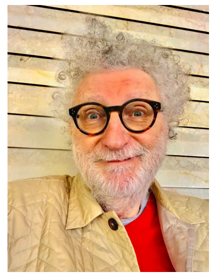
PRESIDENT'S MESSAGE

Acting President IAEE in 2023: an honour and a heavy responsibility



Dear colleagues and dear friends, I am the 2023 IAEE acting President. Of course an honour and, realistically, a heavy responsibility. Both vis-à-vis the energy world and for the community of our members.

1. Analysts at International Energy Agency say that they have never seen a triple energy crisis: oil + coal + gas. To be frank, the gas crisis is not typically worldwide. Regions of the world live in very different "Gas Areas": with different price levels, supply balance, or shortage threat

   While facing these acute energy difficulties, countries and economies still face two former pressures. (a) 800 million humans still have no access to modern energy; (b) the whole 8bn humanity is confronted with an acceleration of global warming. And the COP27 in November 2022 did not find how to reasonably stop that. Meanwhile the geopolitics of energy changed again; and Saudi Arabia, as Qatar, increased their role of non-aligned energy powers between the western world and Asia. Latin America started to organize as a key supplier of "critical materials" for the so-called "Green Supply Chain".
2. Our dear IAEE will have to do a gigantic jump ahead with the end of David William's career as our Executive Director. In a "rotating leaders" worldwide democracy, as our scientific association is, the global relevance, coherence and commitment cannot be guaranteed without a clever, hard-working, altruist and deeply benevolent executive director. We got the best from Dave for years. Living without him will be more than challenging: it will be threatening. All our community, all our members have to be aware, attentive, patient and proactive to make this transition work. We have selected "Talley Management Company", a leader in the world industry of association management, to succeed to Dave. Talley will team with all our central Committees, national chapters, me as acting President and Peter Hartley as executive V.P, to rebuild IAEE on this new basis. Let's do our best for a successful transition.
3. A last word. I am French and European. I don't want westerners like me, my age, my gender, to monopolize IAEE's life, thinking and action. Our IAEE has a special effort to make to give Asia, Eurasia, Middle-East, Africa and Latin America the leading role that they deserve in energy economics. It is what our world conferences are already greatly expressing: 2022 in Japan; 2023 in Saudi Arabia; 2024 in Turkey. We, men of my generation, also have a special effort to make to give women, younger generations and millennials fair opportunities to express their views, to create and undertake in energy economics according to their will and to their skills. After Yukari Yamashita being our President in 2021, IAEE is very proud having elected Anne Neumann as President 2024.

Jean-Michel Glachant
IAEE 2023 Acting President
Professor at Florence School of Regulation
IAEE Career Award 2018
Editor in chief EEEP 2012-16.

Editor's Notes

We thank you for your patience with this delayed 2023 newsletter. Many exciting changes have taken place at IAEE and we are pleased to be returning to regular publication of the IAEE Energy Forum. This issue of the Energy Forum is focused on all things LNG. We will be reaching out soon with a new topic for the next issue and we earnestly solicit your input.

Mamdouh G Salameh argues that the West puts so much importance on the climate change agenda in Africa when what Africa needs immediately isn't green energy transition but the immediate development of its vast oil and gas reserves to overcome its chronic energy poverty.

Kenneth B. Medlock Iii, Anna Mikulska, and **Luke (Leelook) Min** provide an article that initially came with an interactive dashboard that provides tools to assess the potential outcomes for natural gas market balances in Germany. Russia's invasion of Ukraine on February 24, 2022 compromised security of supply for natural gas in Europe. The balance of 2022 was aimed at bracing for a potentially difficult winter marked by high prices and considerable uncertainty. While the winter has not been as bad as it could have been, the situation is far from settled. In order to assess the potential outcomes for natural gas market balances this winter and next in Germany, they constructed three demand-oriented scenarios: (1) cold winter 2022-23, (2) mild winter 2022-23, and (3) an extreme case. Herein, they describe the key takeaways from these scenarios and highlight some critical points.

Franziska Holz, Lukas Barner, Karlo Hainsch, Claudia Kemfert, Konstantin Löffler, Björn Steigerwald, and **Christian Von Hirschhausen** critically assess German LNG terminal plans. FSRUs may provide temporary relief in 2023 and 2024, but they see a risk of asset stranding for onshore import terminals.

John Holding details the circumstances under which LNG was first delivered to the United Kingdom in 1959 and how the trade continued until 1982. The reasons for the interruption are explained which in due course led to the resumption of LNG imports utilizing new terminals from the early 2000s and which are in full use today.

Fredj Jawadi and Philippe Rozin provide a note that recalls the principles and actors of LNG market. It also discusses the potential of LNG market as well as its several challenges.

Michelle Nock writes that Utility Regulators' enabling legislation and processes were designed to address the 'monopoly problem'. They can be great at doing that, but if they ignore the 'decarbonization problem' none of it will matter in the long run. What role could utility regulators play in supporting decarbonization (or at least not undermining it), and do we need a complete overhaul of their enabling legislation to achieve this?

Manuel Frondel, Christoph M. Schmidt, and **Colin Vance** discuss LNG and Germany's fracking ban. Russia's supply stop of natural gas has forced Europe to turn to LNG to meet its energy needs. Rather than locking into a decades-long import dependency on Qatar and the US, it would be more environmentally benign to exploit domestic resources. Germany's substantial reserves of shale gas could make it a major player in Europe's gas market if it were to drop its voluntary ban on shale gas exploitation.

Michael Schach and **Reinhard Madlener** report that the increasingly ice-free Northeast Passage is a game changer for global LNG trading and shipping routes, and especially relevant for the Russian federation with its recently completed Yamal LNG terminal and the upcoming Arctic LNG 2 sister terminal – making Russia the fourth largest LNG producer globally. The ongoing War in Ukraine has also changed the game, with still largely unpredictable consequences depending on its outcome.

Kelly Neill explains that natural gas price caps in Australia are poor policy and may be permanent. Australia exports most of its natural gas, and extremely high international prices caused by the market turmoil in Europe are feeding through to high domestic prices. Contrary to popular thinking, the price cap will reduce investment and production.

Gautam Mukherjee and **Melanie Sawaryn** illustrate a scenario of how Russia's invasion of Ukraine could influence global LNG balances in the medium term to 2030. The reaction to the war reduces Russia's pipeline and LNG exports. However, the overall size of LNG trade in 2030 is broadly unchanged. On demand, higher EU LNG imports offset lower LNG imports into Asia. The US and Middle East share of LNG growth increase to offset the lower Russian LNG exports.

The **Riyadh Conference Secretariat** provides key takeaways from the 44th IAEE International Conference in Riyadh, Kingdom of Saudi Arabia. The Conference, held for the first time in MENA, underscored the critical messages of ensuring stable energy markets, continued investments in fossil fuel sources, and increasing investments in diversified renewable energy sources toward ensuring an orderly energy transition to a sustainable net-zero future.

Carol Dahl contributes a writeup of the Shaybah Wildlife Sanctuary tour sponsored by Saudi Aramco for attendees of the 2023 International Conference in Riyadh.

IAEE MISSION STATEMENT

IAEE's mission is to enhance and disseminate knowledge that furthers understanding of energy economics and informs best policies and practices in the utilization of energy sources.

We facilitate

- **Worldwide information flow and exchange of ideas on energy issues**
- **High quality research**
- **Development and education of students and energy professionals**

We accomplish this through

- **Leading edge publications and electronic media**
- **International and regional conferences**
- **Networking among energy-concerned professionals**

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Executive Director Message

Baptism by fire. That phrase has profound meaning for me as I continue my initial year serving on behalf of professionals concerned with energy and related issues throughout the global community as Executive Director of the International Association for Energy Economics. The common definition for baptism by fire, an employee that learns the craft by being immersed in their field of work, would certainly apply to my first few months on the job. As our members are well aware, IAEE never takes a breather in terms of delivering superior services while also consistently striving to develop innovative programming that will enhance knowledge that furthers the understanding of energy economics to inform best policies and practices in the utilization of energy resources.

By consistently engaging with IAEE's dynamic team of members, volunteers, and professional staff, I'm reminded every day of the purpose of our association: To provide worldwide information flow and exchange of ideas on energy issues, high quality research, as well as the development and education of students and energy professionals. Challenging objectives indeed, particularly when demands on time and resources are at a premium. Fortunately, as an association governed by volunteer leaders, it has become abundantly clear that IAEE has an incredibly robust pool of dedicated individuals from the field of energy economics that are more than willing to share their professional acumen for the betterment of their industry.

Upon arriving to IAEE last fall, I quickly realized that regardless of whether I was learning about our leading-edge publications and electronic media, understanding our international and regional conferences, or networking among energy-concerned professionals, the association's ability to help students and energy professionals succeed is what motivates every decision made by IAEE representatives. To that end, IAEE's seventeen-member council of elected and appointed members in conjunction with staff have been working hard to continue providing multiple forums for professional, multi-national, multi-disciplinary discussion and the means of professional communication and constructive dialog. In addition to publishing The Energy Journal, Economics of Energy & Environmental Policy, as well as the IAEE Energy Forum, our organization recently concluded a very successful International Conference in Riyadh, Saudi Arabia. Please consider joining with industry colleagues for IAEE's 2023 European Conference this July in Milan, Italy and/or our 2024 International Conference in Istanbul, Turkey in June of next year.

I am honored to work within the energy economics industry and will continue to execute comprehensive initiatives to transform the goals of volunteer leaders into organizational benchmarks and sustainable deliverables. In the near term, a blueprint for students and energy professionals to realize significant advancements in the field is in the process of being strategically developed by your IAEE member peers. To achieve long-term benefits, maximizing IAEE member services allows for a competitive edge to be realized, particularly among the global challenges of our industry that lie ahead. Members of IAEE gain a broader understanding of energy economics, policymaking, and theory. Members are kept well informed by IAEE publications and conferences, while also afforded the opportunity to network within the largest Association of energy professionals. Anyone with an active interest in the field of energy economics is eligible for IAEE membership and will benefit from belonging. Thank you for allowing me the opportunity to join this thrilling ride.

Frank Mortl III, CAE
Executive Director
IAEE

Western Green Policies Could Hamper LNG Developments Out of Africa

BY DR MAMDOUH G SALAMEH

Abstract

The West puts so much importance on the climate change agenda in Africa when what Africa needs immediately isn't green energy transition but the immediate development of its vast oil and gas reserves to overcome its chronic energy poverty.

The Making of a Global Energy Crisis

The energy crisis started in January 2021, 14 months before the Ukraine conflict came on the scene. It was sparked by hasty European Union (EU) green policies aimed at accelerating energy transition to renewables at the expense of fossil fuels aided by incessant pressure by environmental activists on the global oil industry to divest of oil and gas assets and calls by the International Energy Agency (IEA) for immediate halt to all new investments in oil and gas. These factors combined have led to a huge underinvestment in the production capacities of oil and gas and plunged EU in a disastrous energy crisis.[1]

The Ukraine conflict and the unprecedented Western sanctions against Russia have exacerbated the crisis transforming it from an EU energy crisis into a global one and causing a polarization of the global energy markets, a re-direction of the global energy flows from west to east.[2]

At the start of the Ukraine conflict the EU depended on Russian gas and oil supplies for 45% and 30% respectively. In order to reduce dependence on Russian energy supplies, the EU has been scouring the globe for alternative sources of energy particularly in Africa.

Todays' energy crisis is unique in that unlike previous crises it involves all fossil fuels (oil, natural gas. LNG and coal). In fact I would hazard a projection that the world is heading towards a permanent energy crisis characterized by shortages. Because leaders of the world won't be able to solve it, they will take the easy option of blaming it on climate change and telling their peoples that by working together, we can move away from fossil fuels. This is the world's biggest lie.[3]

Trying to electrify the global economy including agricultural production with a global transition to renewables won't succeed without major contributions from natural gas and to some extent nuclear power and coal. The reason is the intermittent nature of renewables. Today's technology won't allow us to save solar electricity generated in summer for use in winter. Even if greatly ramped up, wind and solar electricity generation would likely be grossly inadequate by themselves to try to operate any kind of economy.

The intermittent wind and solar energy is neither capable of solving today's energy problems nor is a transition to electric vehicles (EVs) just around the corner.

Dr Mamdouh G. Salameh is an international oil economist. He is one of the world's leading experts on oil and a global energy expert. He can be reached at mgsalameh@btconnect.com

Africa's Fossil Fuels & Climate Agenda

Hydrocarbon-rich African countries are viewing the unfolding energy crisis as an opportunity to monetize their untapped reserves and eliminate the continent's energy poverty.

However, a plethora of western-backed environmentalist groups, the EU parliament and US Presidential Climate Envoy John Kerry were all up in arms against any development of African oil and gas reserves

The EU has advised member states not to assist in the implementation of Uganda's oil and gas projects with 20 western banks and 13 insurers already voicing opposition.

For his part, John Kerry speaking to Reuters on the sidelines of the 18th session of the African Ministerial Conference on the Environment (AMCEN) in Dakar, Senegal warned against investing in long-term gas and oil projects in Africa claiming that these projects will end up as stranded assets by 2030. Instead, he urged African countries to focus on reducing emissions in a continent that has contributed only 3.8% to global emissions in 2021, the least in the world.[4]

On September 15, the Nigerian National Petroleum Company (NNPC) announced plans to build a 7,000-kilometre Nigeria-Morocco offshore gas pipeline (NMGP) running across 13 African countries. According to the Nigerian daily The Nation, the endeavour will be supervised by the Economic Community of West African States (ECOWAS). It is expected that it will improve the living standards of African nations, boost economic integration within the sub-region and tackle desertification through sustainable and reliable gas supply.[5]

Earlier, a number of Central African countries, including Equatorial Guinea, Cameroon, Gabon, Chad, Angola, the Democratic Republic of Congo and Republic of Congo, signed an agreement on September 8 2022 to ensure energy security, tackle energy poverty and boost the internal supply of hydrocarbons. Likewise, Uganda and Tanzania are planning to build the East African Crude Oil Pipeline (EACOP), which will transport crude from Uganda's oil fields to the port of Tanga, Tanzania, on the Indian Ocean.

And yet civil society groups connected with the EU and US environmentalist Funds or Western climate networks argue that Africa's hydrocarbon projects will not benefit African people and that the investment would be better spent on a new green economy.[6]

The West puts so much importance on the climate change agenda in Africa. I would hazard two explanations for the West's attitude. The first is that the West is under the misguided and erroneous view that any future energy assets like investing in oil and gas production and building pipelines will end up after 2030 as stranded assets. The second explanation is a more sinister one with the West wishing to keep African energy resources underground in order to satisfy its own appetite for energy in the future.

West's Climate Change Hypocrisy

In the last two decades, Africa's contribution to the global greenhouse gas emissions fluctuated between 3.4% and 3.8%, the smallest share among all world regions.

Meanwhile, EU countries who promote green policies have abandoned their green credentials to resurrect coal-fired electricity plants because of rising prices of gas and oil. Similarly, Western multinational corporations have never stopped investing in oil and gas and they will be more than happy to twist their green credentials and exploit loose climate regulations in African countries.

While denying Africa's right to push ahead with its own energy endeavours, the West would be eager to offer investments and technological know-how to the continent in exchange for receiving the lion's share of the regional hydrocarbon wealth. The West doesn't care whether African countries are experiencing severe energy poverty or not as long as it gets its hands on these reserves.

A consortium of European investment firms have raised $200 million to fight deforestation in Africa, warning that the increasing consumption of charcoal by the continent's nations is putting pressure on forests. According to Bloomberg, the use of wood-based fuel jumped 90% in Africa to 34.9 million tons in 2020.[7]

With African people suffering immensely from energy poverty, lack of clean drinking water and starvation, the last thing on their minds would be deforestation. African people are being driven by energy poverty to cut trees from the forests to provide themselves with warmth in winter and fuel for cooking.

What Africa needs immediately isn't green energy transition as the World Economic Forum suggested but the immediate development of its vast oil and gas reserves accounting for 12% and 9% of the world's oil and natural gas reserves respectively.

African Gas for the EU

The EU is striving to buy as much natural gas from African producers as possible in order to reduce its dependence on Russian gas supplies. .

For years, the EU neglected if not completely ignored the needs of African countries for investment for the development of their infrastructure and also their energy reserves.

The EU's hypocrisy is exposed by its sudden rush for African LNG while stressing that it doesn't want to fund projects that would allow the world's poorest continent to burn more of the fuel at home.

While Nigeria's Bonny Island produces "enough LNG to heat half the UK for the

Winter, the island's locals are still using black-market kerosene and diesel to light wood stoves and power electricity generators.[8]

Western nations even criticized China when it invested in Africa's infrastructure and energy resources at a time when they were refusing to invest in Africa either because of sanctions they imposed on African countries or because of their old imperialistic streak.

African Gas Infrastructure Needs Investments

The major obstacle in tapping Africa's energy reserves is overcoming underdeveloped infrastructure. The two relatively significant African LNG exporters are Algeria -currently exporting 29.3 million tonnes (mt) and Nigeria with an export capacity of 22.2 mt. The rest of Africa's producers have limited production and export capacities with neither LNG plants nor gas pipelines.[9]

The EU is already importing LNG from both countries. These two countries may be able to raise their LNG exports a bit in the next few years but it will still be a drop in the ocean of the EU's gas needs.

It is highly unlikely that African LNG exporters along with the United States, Qatar and Australia will be capable of replacing Russian gas supplies to the EU now or in the foreseeable future. The reason is that the bulk of US, Qatari and Australian LNG exports is bought years in advance by customers in the Asia-Pacific region and partly because the EU has limited LNG import and storage terminals. Even if the EU pours billions into hydrocarbon extraction and transportation, it would still take considerable time to get these projects up and running.

The EU's efforts to diversify its gas needs away from Russia is a painstaking job that will take years to accomplish if ever. Still, the EU may have no alternative but to invest in Africa if it continues to be hell-bent on reducing its dependence on Russian gas.

Africa will need investments of $190 billion each year between 2026 and 2030 to meet its energy demand.[10] Since the EU is aiming to get a big chunk of its oil and gas needs from Africa, then the onus is on it to contribute the annual $190 bn needed to help African countries meet energy demand and also supply Europe with gas and oil.

Global LNG Shortages

Natural gas and LNG prices are showing no signs of slowing down as a result of rapacious global demand, shortages and shrinking gas production capacity.

Total global LNG exports in 2021 amounted to 381.8 mt the overwhelming bulk of which was locked into long-term contracts with customers in the Asia-Pacific region.[11]

The current global LNG production capacity can't be increased until Qatar raises its capacity to 110 mt/y by 2024/25 and the United States increases also its capacity by 2025. But by then, global LNG demand would have again overtaken the capacity expansion. That is why high LNG prices will be with us well into the future.

Having been the largest LNG importer until the end of 2021 before it was ousted by China, Japan probably has useful insights into how the global LNG market works. So when Japan warns that the global competition for LNG is set to intensify over the next three years due to an underinvestment in supply, the world should heed its warning.[12]

According to Japanese companies, long-term LNG contracts that start before 2026 are already sold out, which is worrying for LNG buyers because these types of contracts offer stable pricing and reliable supply for many years. The report notes that there is little new supply coming online before 2026 even from major exporters like the U.S. and Qatar.

Another indicator of a tight gas market is that 10-year LNG contracts are currently priced at 75% above 2021's rates according to a report by the Oil & Gas Journal. Because of shortages, there is a huge competition for whatever LNG is in the market and a real possibility of LNG prices shooting up further.[13]

The fact that China has rushed to sign a 27-year LNG deal with Qatar is indicative of the competition for the remaining LNG in the market before additional new capacity comes online from 2026 onwards.

Algeria can't fill the gas gap in the EU. It already supplies 10% of the EU gas needs. The maximum amount of gas and LNG that Algeria could supply to the EU is estimated at 40-43 billion cubic metres (bcm). The reason is that out of a production of 100 bcm, domestic consumption takes more than half and this consumption is on the rise.[14]

Who would have thought Germany the EU's largest economy would be stepping up preparations for emergency cash deliveries in case of blackouts as the nation braces for possible power cuts?

And while Germany has managed to fill its gas storage by more than 90% in anticipation of this coming winter, the real crunch will come in March 2023 when gas storage could be down to under 10%. The reason is that if there is a harsh winter, German gas consumption could go up by 800 million cubic metre a day (mcm/d) between now and March next year making it far more difficult to fill its gas storage in both 2023 and 2024.[15]

And with the crisis expected to remain with us for many years to come and with the staggering prices of natural gas and coal and also with the inability of renewables on their own to satisfy a major share of global electricity demand, I can easily project a resurgence of nuclear energy in the years to come. Because of the worsening energy crisis, Germany has decided to extend the life of its three remaining nuclear plants until April 2023a and possibly longer while Japan is expected to extend the lifespan of its plants beyond their 60-year cap. Meanwhile other countries are building new reactors.[16]

Why Capping Russian Gas Price Won't Stop EU's Economic Slide?

Both the G7 oil price cap and the EU's proposed gas cap are doomed to fail miserably.

In a tight global gas and LNG market with shortages, robust demand and shrinking spare production capacity, a price caps can't work. Moreover, Russia will kill it by halting immediately its oil and gas exports to any countries implementing the caps. It will redirect the bulk of its oil and gas exports to China, India and many countries in the Asia-Pacific region.

Qatar, the world's largest exporter of LNG has denounced the price cap for natural gas as "hypocritical." Qatar's Energy Minister Saad al-Kaabi said on 30 October that the EU is seeking to take the measure as soon as this winter in an effort to curb gas prices driven by the energy embargo imposed by the US and its NATO allies on Russia.[17] He added that interfering in markets clearly contradicts the free market rules that Europe has previously applied to producers. "The free market is always the best solution."

The EU is already the largest loser in the energy war with living standards of Europeans already crumpling and the bloc's economy balancing on the verge of a harsh recession.

The fact that Germany Europe's biggest economy was forced to import LNG from faraway Australia despite the huge shipping costs signifies how desperate it is for gas supplies in the absence of cheap Russian piped gas supplies.[18]

Conclusions

The world could be heading towards a permanent energy crisis characterized by shortages.

The West puts so much importance on the climate change agenda in Africa at a time when the EU countries who promote green policies have abandoned their green credentials to resurrect coal-fired electricity plants because of rising prices of gas and oil.

For years, the EU neglected if not completely ignored the needs of African countries for investment in developing their infrastructure and also their energy reserves for the benefit of their people.

The EU's hypocrisy is exposed by its sudden rush for African LNG while stressing that it doesn't want to fund projects that would allow the world's poorest continent to burn more of the fuel at home.

What Africa needs immediately isn't green energy transition as the World Economic Forum suggested but the immediate development of its vast oil and gas reserves to overcome its chronic energy poverty.

Footnotes

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[2] Mamdouh G Salameh, "Has the Ukraine Conflict Changed Global Energy Trends for Good?" an invited talk by the Energy Management Centre (EMC) of the ESCP Europe Business School in London on 11 October 2022.

[3] "Today's Energy Crisis Is Unlike Anything We Have Seen Before" posted by oil price.com on 18 November 2022 and accessed on 1 December 2022.

[4] Ekaterina Blinova, "How West Uses Climate Agenda to Keep Africa's Oil & Gas Underground to Satisfy Own Appetite" Sputnik International News, 18 September 2022.

[5] Ibid.,

[6] Ibid.,

[7] "A consortium of European Investment Firms have Raised $200 million to Fight Deforestation in Africa", Sputnik International News, 21 October 2022.

[8] Eketerina Blinova, "Prof: Russian Gas Is Irreplaceable But If EU Wants More African Fuel, It Should Invest First", Sputnik International News, 11 July 2022.

[9] BP Statistical Review of World Energy, June 2021, p. 36 & 38.

[10] "Africa Will Need $190 bn a year to Meet Energy Demand" posted by oilprice.com on 29 November 2022 and accessed on 29 November 2022.

[11] Mamdouh G Salameh, "Has the Ukraine Conflict Changed Global Energy Trends for Good?"

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[14] "Can North African Gas Fill the Gap in Europe?" Posted by oilprice.com on 22 November 2022 and accessed on 1 December 2022.

[15] "Germany Prepares Billions of Euros in Case of Winter Blackout" posted by oil proc .com on 15 November 2022 and accessed on 15 November 2022.

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Natural Gas Balance in Europe: Germany as a Case Study

BY KENNETH B. MEDLOCK III, ANNA MIKULSKA, LUKE (LEELOOK) MIN

Abstract

Russia's invasion of Ukraine on February 24, 2022 compromised security of supply for natural gas in Europe. The balance of 2022 was aimed at bracing for a potentially difficult winter marked by high prices and considerable uncertainty. While the winter has not been as bad as it could have been, the situation is far from settled. Future natural gas supply faces tremendous precarity due to the substantial reduction in Russian gas imports. Germany, the EU's largest economy, is a microcosm of the European natural gas market and of the current and future issues facing Europe. Natural gas is important for manufacturing, so compromised imports will continue to have an outsized effect on both gas availability and economic performance for the EU as a whole. In order to assess the potential outcomes for natural gas market balances this winter and next in Germany, we constructed three demand-oriented scenarios: (1) cold winter 2022-23, (2) mild winter 2022-23, and (3) an extreme case. Herein, we describe the key takeaways from these scenarios and highlight some critical points.

Framing the Issue

Europe spent the balance of 2022 bracing for a potentially difficult winter. Natural gas supply, in particular, faced, and continues to face, tremendous precarity due to the substantial reduction in Russian gas imports. A combination of new liquefied natural gas (LNG) imports and additional pipeline supplies from other producing regions together are not sufficient to make up for the nearly 40% market share that Russian gas volumes recently occupied (see Figure 1). As such, Europe will need to employ a combination of fuel-switching and demand-rationing to weather the storms of this winter and the balance of 2023 into next winter.

The difficulties do not end with winter 2022-23. The risk of natural gas shortages and high price burdens on European consumers will likely persist, as all signs point to even greater difficulties the following winter. The lingering impacts of reduced Russian gas supplies to Europe will have spillover effects for the world. Already, European demand for LNG imports has forced LNG prices to unprecedented highs, driving a redirection of marketed volumes away from Asia to Europe. This stands in stark contrast to the status quo that generally persisted previously, where Europe was viewed as a "market of last resort" for global LNG volumes.[1] Indeed, European LNG terminals operated at maximum capacity in an effort to fill storage for this winter.[2]

This brief initially came with an interactive dashboard that provides tools to assess the potential outcomes for natural gas market balances in Germany. https://www.bakerinstitute.org/german-natural-gas-market-balance-dashboard

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Germany in Focus

Germany is a microcosm of the European natural gas market and of the current and future issues facing the EU. Figure 2 shows Russian gas supply to Germany. As the EU's largest economy, much of which relies on natural gas for manufacturing, Germany has an outsized effect on both gas availability and economic performance for the EU as a whole. Over the past decade, Germany has accounted for as much as one-quarter of all natural gas imports to the EU in any given year, and for one-third of all imports to the EU from Russia. As such, anything that affects the natural gas market in Germany is likely to have ramifications for the EU as a whole.

Regarding the German gas market, imports of Russian natural gas have accounted for at least 40% of supply since the 1990s. This reliance has been fortified in recent years by two pipeline projects for direct delivery of Russian gas into Germany:

- Nord Stream 1, a pipeline that began operations in 2011 with 55 billion cubic meters per year (bcm/y) capacity, and

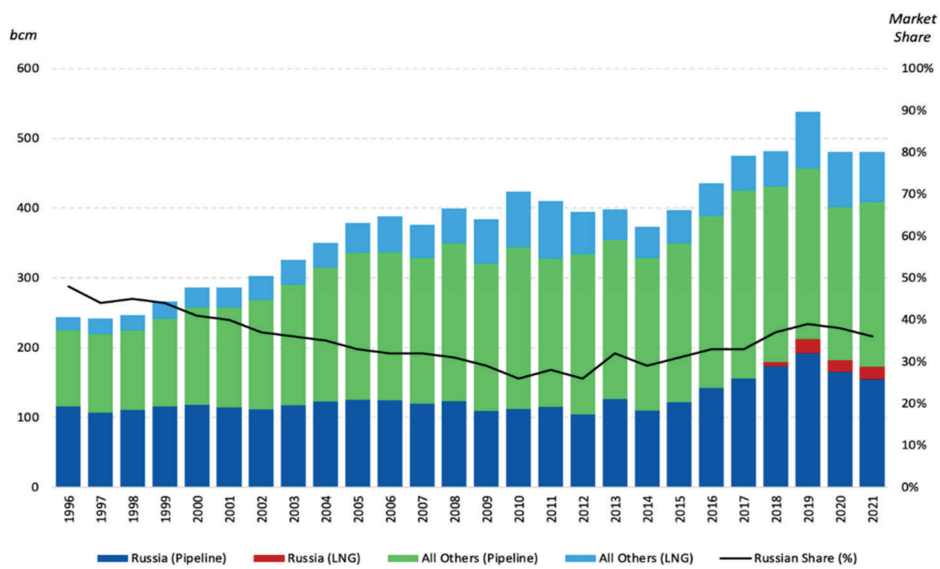

Figure 1. Natural Gas Imports to the European Union and Russian Market Share of Total Supply

Source: Data are taken from CEDIGAZ.
Note: bcm = billion cubic meters.

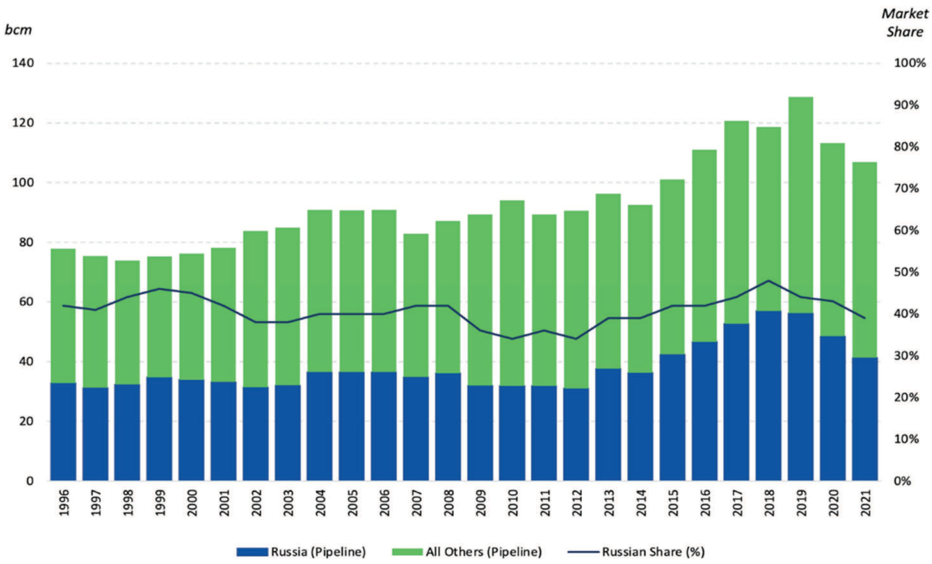

Figure 2. Natural Gas Imports to Germany and Russian Market Share of Total Supply

Source: Data are taken from CEDIGAZ.

Note: Germany re-exports some of its imports to neighboring countries, so not all of the imported volumes are consumed domestically.

- Nord Stream 2, a pipeline completed in 2022 but never commissioned, which would have added another 55 bcm/y of capacity for Russian-sourced imports.

While Nord Stream 2 was not commissioned, its mere existence promised additional volumes, abating investments in other sources of supply into Germany. If Nord Stream 2 had been commissioned and become fully operational, the pipeline together with Nord Stream 1 could have satisfied Germany's entire annual gas demand and provided some gas for re-exports. Both pipelines were portrayed by Germany as a part of the EU's gas market diversification efforts away from transit country risk, i.e., the diversification of gas transit away from Ukraine that both Russia and Germany had considered to be unreliable. At the same time, the need for diversification of suppliers — in particular via LNG imports — was dismissed on the basis of high costs compared to Russian supply.

The notion that Europe would move away from fossil fuels, including natural gas, had also dampened interest from policymakers and corporations in developing long-lived import infrastructures underpinned by long-term supply contracts. Indeed, this perspective was actively reinforced by energy transition policies advanced by most countries in Western Europe. In Germany, the policy of *Energiewende* (energy transformation) was aimed at facilitating the goal of economy-wide decarbonization. Low-cost natural gas from Russia was considered a bridge fuel that would help reach its goal, particularly since the German plans for the energy transition also required phasing out the country's nuclear fleet by the end of 2022. Importantly, while Germany has been the most aggressive of European countries in its effort to eliminate nuclear power, the attitudes of other European countries have been largely ambivalent. Even France, which is very dependent on nuclear power for its energy needs, had not been proactive in maintaining or rebuilding its aging nuclear power fleet until the current energy crisis.

The "wind drought" in the fall of 2021 stoked fears about a lack of sufficient redundancy in the European energy mix.[3] Then, with Russia's invasion of Ukraine, Russian President Vladimir Putin threw a boulder into the proverbial pond of European energy policy. Energy security moved to top-of-mind for most European policymakers and the general public. In March 2022, merely two weeks after the invasion, natural gas and nuclear energy were both somewhat back in favor, and declared "in-line with EU climate and environmental objectives" by the European Commission DirectorateGeneral for Financial Stability, Financial Services and Capital Markets Union.[4] In turn, an accelerated emphasis on bringing more LNG import capacity online emerged.[5]

While floating storage and regasification units (FSRU) have been mobilized as near-term opportunities to bring more LNG into Germany, there is limited capacity along LNG supply chains to do more in the near term. A lack of *spare* LNG liquefaction and tanker capacity drove the LNG market into a very tight situation, so much so that large Asian buyers redirected cargoes to Europe and rationed their own demands. Germany (and Europe more generally) has been faced with the unavoidable outcome of having to use other fuels to sate its energy needs and/or ration its own gas demand, particularly industrial demand.[6] According to Bundesnetzagentur, industrial demand in October 2022 was 27.4% lower than the average from 2018 to 2021, a time period that included the COVID-19 pandemic.[7] High energy prices have many companies, like Germany-based BASF, considering relocation to countries like the U.S. and China. This does not bode well for the future of the German economy, nor, by extension, for Europe as a whole.

Scenario Analysis: Revelations about this Winter and Next

In order to assess the potential outcomes for natural gas market balance in Germany, we constructed three demand-oriented scenarios: (1) cold winter 2022-23, (2) mild winter 2022-23, and (3) an extreme case in which this winter and the next are colder than normal, with a warmer than normal summer. We then evaluated the implications of LNG imports and storage policies in each scenario. The tool for analysis and a technical note to explain the modeling effort can be accessed here.[8]

Herein, we describe the key takeaways from these scenarios and highlight some critical points. Across the three scenarios, imbalance is inevitable — even in a mild winter — and the imbalance can only be rectified through fuel-switching and demand-rationing. In this regard, LNG imports are critical for market balance in every case considered, as two German FSRU terminals in Wilhelmshaven and Brunsbüttel will bring an additional import capacity of 16 bcm/y.

Storage targets that bring inventories to near-full capacity are helpful. They provide a form of insurance that can alleviate shortages during winter periods, but they are not enough by themselves.[9] In fact, the analysis indicates that the combination of new LNG imports and full storage will still require other active margins of response — fuel-switching and/or demand-rationing — even with a mild winter.[10] If the winter is colder than average, the situation tightens significantly.[11] To date, the mild winter scenario has been playing out.

One margin that Germany can consider is its exports to neighboring countries. Specifically, Germany can flex these down to minimum historical levels, which is the assumption in the scenarios we constructed. However, depending on realized demand across all of Europe, this could put pressure on gas market balances in Germany's neighboring regions as well. The political and social fallout that could result might weaken European resolve to completely wean itself from Russian natural gas.[12]

In all of the scenarios we considered, the demand outlook is critical for assessing costs. The 2023 demand forecast is 73.5 bcm for the mild winter 2022-23 scenario, 90.0 bcm for the cold winter 2022-23 scenario, and 95.7 bcm for the extreme scenario. For comparison, demand in Germany was 93.6 bcm in 2021, 89.3 bcm in 2020, 91.8 bcm in 2019 and 85.5 bcm in 2018. Notably, while the mild scenario represents an extremely low-demand case relative to recent history, out analysis indicates that the market will only balance with proactive demand-rationing and/or fuel-switching.

Importantly, our analysis indicates that the gas market balance issues in Germany and throughout Europe will persist. It is likely that the balance of 2023 will be focused on refilling storage for winter 2023-24. In fact, refilling storage will become more difficult if this winter is colder than normal, as inventories will be drawn down more than is typical, and Russian gas will not be available to prepare for next winter. Replenishing depleted inventories in a supply-constrained environment will carry implications for demand-rationing and fuel-switching through the balance of 2023.

Concluding Remarks

The 2022-23 winter heating season is not over. The natural gas market balance remains precarious, particularly if the winter turns colder. Management will require fuel-switching, demand-rationing, and concerted effort to bring new gas supplies to Europe, all while policymakers must thread the needle of keeping energy supplies affordable. This will generally mean that large industrial consumers will be the first to face interruption.

As we move beyond this winter, we already see issues arising for the balance of 2023 and into the next winter heating season. The historical reliance on Russian natural gas for energy balances has set the stage for difficulties to persist, and possibly worsen. This outcome follows from several factors. To begin, global LNG supply cannot be increased quickly enough to offset lost imports of Russian pipeline volumes. It takes years to permit, build and commission new LNG export infrastructure and the associated supply chains to deliver LNG to regasification locations. While FSRUs can serve as a near-term bridge for LNG imports, a casual reliance on FSRUs does not address the lack of sufficient global liquefaction capacity, the time to build new capacity, or constraints on the current availability of FSRU capacity. We already know that only about 6.6 million metric tons per year (mtpa), or 9.1 bcm/y, of baseload LNG capacity will enter global markets in 2023 (with 5.2 mtpa coming from Golden Pass in the U.S. and 1.4 mtpa coming from Congo-Brazzaville).[13] This, however, is nowhere close to the amount of Russian pipeline gas that has been removed from the European market since the invasion of Ukraine. So, the global market will remain stressed, carrying implications for Europe and beyond.

In general, infrastructure and logistical constraints prevent the global market from adjusting rapidly to lost Russian gas volume into Europe. In particular, Russian gas cannot simply be redirected to other markets (e.g., China) due to the lack of alternative infrastructure. As such, there is no displacement opportunity whereby greater Russian pipeline volumes move into Asia and allow more LNG to be redirected from Asia to Europe. Hence, logistics and a lack of excess pipeline capacity prevent rapid, full adjustment.

In addition, by law the EU's natural gas storage must be filled to at least 90% by Nov. 1, 2023. Some countries have set even more aggressive requirements. In Germany, for instance, storage must be filled to 95% by Nov. 1. Such a legal imperative will result in the removal of supplies available to consumers during the non-heating season, since they are instead being injected into storage. This is likely to tighten markets throughout the year.

Finally, significant volumes were still flowing to Europe from Russia for most of 2022, which helped countries to fill storage in anticipation of the coming winter heating season. In 2023, these volumes are very likely to remain unavailable. As such, while the near-term emphasis should be on meeting heating demands for the remainder of winter 2022-23, winter 2023-24 may pose an even more difficult challenge.

Footnotes

[1] See, for example, Howard Rogers, *Does the Portfolio Business Model Spell the End of Long-Term Oil-Indexed LNG Contracts?*, (Oxford: Oxford Institute for Energy Studies, 2017).

[2] Miles, Steven R., Gabriel Collins, and Anna Mikulska. 2022. *US Needs LNG to Fight a Two-Front Gas War*. Policy report no. 08.18.22. Rice Uni-

versity's Baker Institute for Public Policy, Houston, Texas. https://doi.org/10.25613/GDVP-QN45.

[3] Nora Buli and Stine Jacobsen, "Analysis: Weak winds worsened Europe's power crunch; utilities need better storage," *Reuters*, December 22, 2021.

[4] Directorate-General for Financial Stability, Financial Services and Capital Markets Union, "EU taxonomy: Complementary Climate Delegated Act to accelerate decarbonization," *European Commission*, February 2, 2022.

[5] See Gabriel Collins, Kenneth B. Medlock III, Anna Mikulska, and Steven R. Miles, *Strategic Response Options if Russia Cuts Gas Supplies to Europe*, Research paper 02.11.2022, Rice University's Baker Institute for Public Policy, Houston, Texas.

[6] Tom Käckenhoff, Vera Eckert, and Christoph Steitz, "As German gas rationing looms, industry begs exemptions," *Reuters*, August 9, 2022.

[7] Bundesnetzagentur, "Current Gas Supply Situation," accessed December 1, 2022.

[8] In the appendix of the issue brief in the link, we provide the description of our modeling approach to analyze the German natural gas market. It includes demand, supply, storage, policy, and scenario. Using historical data, we estimate a natural gas demand function by linear regression, and forecast demand for different scenarios. Across the scenarios we make common assumptions regarding natural gas imports via pipelines, and each scenario has different assumptions regarding weather. For policy analysis, we provide two storage paths to meet mandates and include LNG imports via new FSRUs.

[9] German gas storage is 90.4% full as of January 15, 2023, which on its own can provide about one-quarter of annual consumption. Aggregated Gas Storage Inventory.

[10] Demand-rationing for natural gas is already taking place among commercial and industrial users. We, however, define realized rationing as the difference between industrial consumption and its historical minimum. Then, we assume that such demand-rationing will continue throughout the prediction period by applying the share of the rationed volumes to total consumption in Oct. 2022 (18.8%) to quantify demand-rationing that would occur regardless of market balance if such demand-rationing behavior were to persist going forward. Note that this is a somewhat conservative assumption providing a minimum bound in that we ignore the commercial side.

[11] We note that net withdrawals relative to gas in storage in every scenario not only fall within the historical range of net withdrawals, but are also less than the withdrawal capacity limit.

[12] See Perdana et al., "European Economic impacts of cutting energy imports from Russia: A computable general equilibrium analysis," *Energy Strategy Reviews* vol. 44, 2022.

[13] Miles, Steven R., Gabriel Collins, and Anna Mikulska, *US Needs LNG to Fight a Two-Front Gas War*.

LNG Import Capacity Expansion in Germany – Short-term Relief Likely to Turn into Medium-term Stranded Assets

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Abstract

This contribution critically assesses German LNG terminal plans. FSRUs may provide temporary relief in 2023 and 2024, but we see a risk of asset stranding for onshore import terminals.

1. Introduction

After the Russian invasion of Ukraine, security of natural gas supplies has proven to be a controversially debated topic in European and especially in German politics. Part of the debate has been on the necessity of siting new fossil LNG import terminals in Germany. Following February 24th, 2022, supply disruptions by the Russian side and interruption of demand via economic sanctions from the European side appeared equally plausible. Unexpected for decades, this "black swan" event is now reality, and since early September 2022, there have been no more pipeline imports from Russia to Europe via Germany or Poland.[1] The mysterious explosions of the Nord Stream pipelines on September 26th, 2022 have further cemented this state of a "new normal" in European gas markets without imports from Russia.

In this unique situation, the German industry and government has sought to diversify natural gas supplies, including with a large number of new LNG import terminals. These include five floating storage and regasification units (FSRU, total of 40 billion cubic meters per year, bcm/a) that have been or will be installed in 2023, and three fixed LNG terminals (total of 41 bcm) that are still under discussion. All this comes at a time when German energy and climate legislation focusses on the phase-out of fossil fuels, including fossil natural gas consumption, in the run-up of climate and plutonium neutrality by 2045, while the European Union also works towards climate neutrality by 2050.

While being unprecedented in German political debates, interruptions of Russian supplies to Europe have been subject to academic discourse for some time following the repeated conflicts between Ukraine and Russia over the gas transit (Egging et al. 2008; Egging, Holz, and Czempinski 2021). These analyses have shown the importance of access to the global LNG markets to provide an "insurance" option for Europe. Yet, Germany never had a terminal on its own coasts but German importers have booked capacity in terminals in Belgium and the Netherlands, benefitting from the dense European pipeline network to bring their LNG imports to Germany.

This article summarizes recent developments on LNG in Germany and asseses the rationale of the recent boom. We posit that while the short-term construction of a few floating terminals was a reasonable short-term reaction, the construction of fixed onshore terminals will produce stranded assets, given the legally binding objectives of the German energy transformation. The next section summarizes developments prior to 2022, including an overview of the *status quo*. We then discuss the current supply situation without Russian imports which has led to the realization of various LNG import projects in Germany. We then provide some details of the current LNG capacity expansion plans, before critically assessing them in light of the future German and European energy system developments. We conclude that floating terminals (FSRUs) provide flexible short term diversification of supplies while onshore regasification infrastructure is likely to strand in the long term while not being available in the short term.

2. Fossil natural gas supplies to Germany

2.1 Status quo *prior to 2022*

Traditionally, Germany was fully supplied with fossil natural gas by pipelines, the most important source of which was the Soviet Union after the pipeline deal of the 1970s. Supplies from Norway, North Africa, and other European transit countries have also existed. Plans to develop an LNG import terminal in Wilhelmshaven had existed for several decades, but had not materialized due to the unfavorable economics: ample supply capacity in neighboring countries and competition from lower-priced pipeline gas.

In the context of the current crisis, it is important to note that dependence on imports from Russia have been developed to an extent to become politically dependent after 1990. This dependency has been maintained, and even expanded, through the Nord Steam 2 project, even after the 2014 occupation by Russia of the Ukrainian Crimea and East Ukrainian territories (Holz et al. 2014). Many countries in Eastern, Central and Western Europe were supplied from Russia via onshore high-pressure pipelines through Ukraine, mainly via the so-called Brotherhood pipeline system. Already the construction of the connection via Belarus (Yamal-Europe) in the 1990s testified to Russia's will to reduce the importance of the Ukraine transit after independence of the former Soviet republic (von Hirschhausen, Meinhart, and Pavel 2005).

In earlier years, Ukraine transit had a capacity of 140 bcm per year, while the Belarussian route had about 40 bcm/year (ENTSO-G 2021). The two Nord Stream projects directly connecting Germany and Russia with a capacity of 55 bcm/year each can be seen as the logical extension of Russian supply route diversification. Clearly, these projects did not following from techno-economic necessities and rather should serve as expensive double-infrastructure to by-pass Ukraine and (Neumann et al. 2018; Holz and Kemfert 2020).

Germany is well inter-connected in the European gas pipeline system. In addition to connections with Poland (30 bcm/year), Austria (15 bcm/year), and the Czech Republic (40 bcm/year), which were mostly used for the transit of Russian gas via Ukraine and Belarus, Germany has significant pipeline import capacities from Norway and the Netherlands at about 60 bcm/year each, in addition to smaller connections to France (20 bcm/year), to Belgium (10 bcm/year), to Switzerland (10 bcm/year) and to Denmark at about 3 bcm/year (ENTSO-G 2016). The real natural gas flows could be even higher, if an efficient use of the capacities, i.e. bi-directional use, was achieved, instead of the current negotiated bilateral contract volumes.

Figure 1 gives an overview of German natural gas trade flows by country in the recent past. In fact, Russian gas arrived via the Czech Republic (Central corridor) and Poland (Yamal-Europe pipeline). Following the start of direct imports from Russia via Nord Stream 1 in 2011, about one third of total imports had been re-exported, mostly to the Czech Republic.

2.2 The end of Russian natural gas exports in 2022

In June 2022, Russian imports via Nord Stream started to drastically decline, coming to a standstill by September 2022. The same happened with imports via Poland and the Czech Republic, coming from Yamal-Europe and the Ukrainian transit pipeline. Russia stopping deliveries to Germany was a breach of long-term contracts by the Russian side. There have not been any European sanctions on natural gas exports by Russia. Despite worries about supply security, the Russian supply disruptions to Germany could be compensated by increased imports from Belgium, the Netherlands and Norway, as well as cutting back on re-exports to the Czech Republic.

3. Demand and supply of future natural gas in Germany: Short-term and long-term conditions

3.1 Short-term worries about supply security

Supply security in Germany depends on the diversification of supply sources, away from Russian imports, and reduction of demand. In a scenario analysis shortly after the Russian invasion of Ukraine, we have weighted different options and have concluded that no shortage was to be expected for the winter of 2022/23, as long as non–Russian supplies were increased and demand decreased (Holz et al. 2022, Figure 4). As of January 2023, both trends have materialized, such that no shortage has occurred; in fact, prices have come down to a pre-war level.

Pre-war German supply and demand equilibrated between 80 and 100 bcm (2019: 88 bcm, 2021: 100 bcm). Since February 2022, in the wake of the decrease of Russian exports to Europe, consumers have reduced their natural gas use by about 20% compared to the average 2018-2021 under the influence of high prices and public media campaigns that warned about a potential supply shortage in the cold winter months. Demand reduction has been obtained from a mix of measures such as fuel switch, improved energy efficiency, energy savings, and milder weather. Savings in the residential

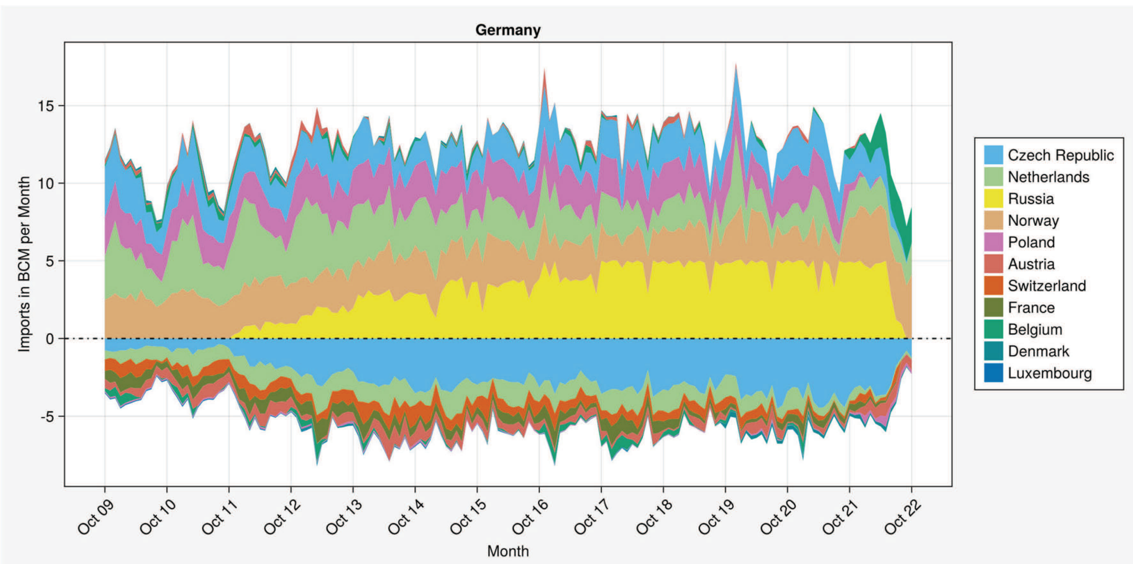

Figure 1: Natural gas trade flows into and out of Germany (2009-2022)
Source: Own calculations based on IEA (2022b).

and commercial sector in Germany – i.e. modified consumption behavior by small consumers independently of weather – were the equivalent of 23 LNG tankers in 2022 (Guéret et al., 2023).

Other suppliers have immediately increased their supplies when tensions with Russia started. In particular Norway has supplied Germany at its maximum capacity of pipelines and production capacity (47.5 bcm net imports in 2022, of which up to a third was re-exported to Austria, Switzerland, Poland, etc.). In parallel, German importers have increased their capacity utilization in LNG regasification terminals in Northwestern neighboring countries, i.e. Belgium and the Netherlands (about ~ 30 bcm of LNG imports in 2022). The capacities in these LNG terminals have been booked for several years. While Russian gas was still imported in Germany until September 2022, it now has to be replaced entirely. Despite the increase from Norway and LNG imports via Belgium and the Netherlands, this leaves a short term supply gap of about 25 bcm per year to be filled from other sources, or compensated by additional demand reductions.

3.2 The long-term role of natural gas in Germany

Overall, European demand for natural gas has been stable or slightly declining since 2000. The declining trend of fossil natural gas will continue in the next decades, even though forecasts vary on the speed of the decline. This is because the long-term use of fossil natural gas is not compatible with the climate targets adopted by Germany and the European Union, namely climate neutrality by 2045 and 2050, respectively. These targets imply a phase out of fossil fuels. In this context, the narrative of natural gas as a bridge technology has lost some of its relevance in recent years (Kemfert et al. 2022; von Hirschhausen, Kemfert, and Praeger 2022). Fossil natural gas faces the same fate as coal, i.e. an exit from the scene, within the next decades.

Therefore, Germany, too, is preparing for a natural gas exit in the next two decades or so, as foreseen by the Federal Government's strategy of decarbonization and de-plutoniazation until 2045. In addition to ending the commercial use of nuclear energy, Germany is targeting the phase out of coal by 2030 while strongly increasing the share of renewables. Overall, a massive expansion of renewables and energy efficiency is required as part of the energy transformation. If energy system developments in the EU respect the political target of 1.5°C global warming, the German energy sector will see a strong decline of primary energy consumption from natural gas, especially after 2030, up to a phase-out in the early 2040s (Figure 2). Between 2018 and 2050, renewables must multiply by three, while primary energy demand decreases due to better conversion efficiency of electric end-uses. In other words, the political targets of Germany and the EU leave no long-term role for natural gas.

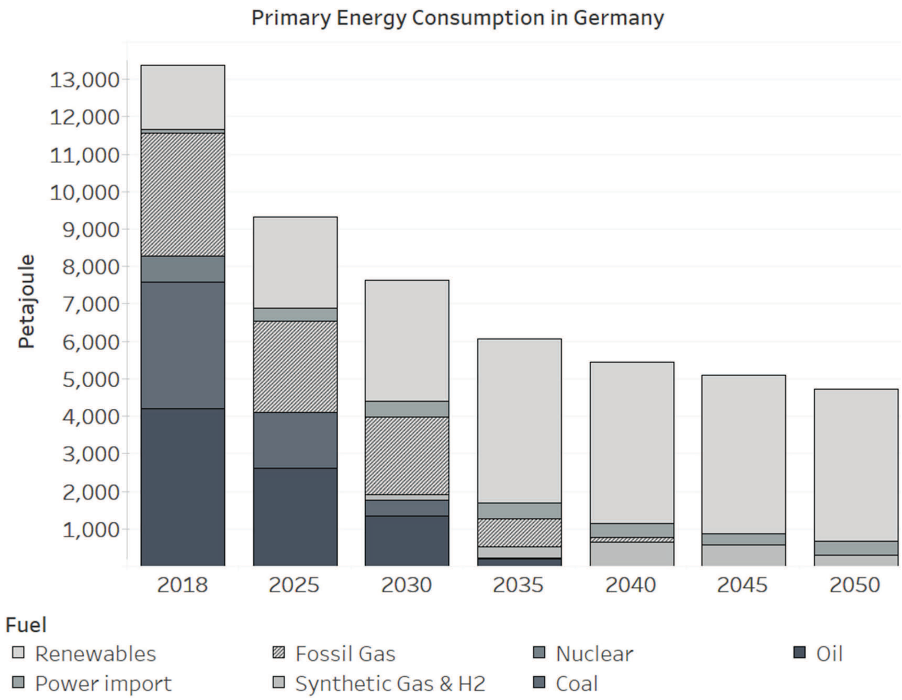

Figure 2: Primary energy consumption in Germany 2018-2050 in a 1.5°C scenario

Source: Updated GENeSYS-MOD results for mid-2022 in the openENTRANCE Societal Commitment Scenario; based on (Auer et al. 2020).

4. Implications for LNG in Germany

Prior to the Russian invasion of Ukraine, Germany did not have any domestic LNG import capacities. Some projects were discussed during the 2010s, but plans were surrounded by high uncertainty and failed to secure investment decisions (GIIGNL 2022). Modelling exercises did not show an economic rationale for new LNG terminals in Europe except in cases of strong subsidization or disruption of Russian supplies (Egging, Holz, and Czempinski 2021).

However, this changed in the aftermath of February 24th, 2022 when Russia invaded Ukraine. As a U-turn to the import policies of the previous decades, the German government and the gas importers quickly decided to start up LNG imports directly into Germany. The focus has been on floating terminals, so-called FSRUs (Floating Storage and Regasification Units) that can be installed rather quickly. The German "LNG acceleration law" (Beschleunigungsgesetz – LNGG") from May 24th, 2022 listed six locations, with a total of 8 FSRUs and 4 onshore regasification sites. However, not all of these projects appear likely, and Table 1 and Figure 3 show an updated overview of recent efforts at four locations for 6 FSRUs and 3 onshore terminals.

4.1 Floating terminals (FSRUs) for the short-term as backup

The German government decided to charter four FSRUs in spring 2022[2] and a fifth one in October 2022. The government-chartered terminals are in Wilhelmshaven, Stade, Brunsbuettel and Lubmin. In addition, one private FSRU terminal has been developed, also located in Lubmin. Lubmin was the landing point of the Nord Stream pipelines where large ongoing pipelines are connected. One of the two FSRUs planned in Wilhelmshaven was inaugurated in December 2022, with operations starting in January 2023. The FSRU in Brunsbuettel as well as the private FSRU in Lubmin are also scheduled to start operations in early 2023 and the remaining three FSRUs later in 2023. This adds up to almost 30 bcm per year of FSRU capacity by winter of 2023/24, of which 23.5 bcm annual capacity are state-chartered. With further planned expansions, more than 40 bcm of yearly floating regasification capacity will be in place in Germany by 2024.

4.2 Fixed onshore terminals potential stranded assets

In addition to flexible floating capacities, three onshore regasification terminals are currently discussed, totalling over 40 bcm per year of onshore regasification capacity. Some are located in the same ports as the floating installations. It is unclear whether the floating terminals will cease operations when the onshore terminals become operational. Given the charter contract durations, this seems unlikely, however, and there will potentially be parallel operations for some years of a total of 81.5 bcm yearly LNG import capacity.[3]

While FSRUs are relatively flexible by nature and can, hence, have a limited lifespan in Europe, the opposite holds for investments into fixed onshore import infrastructure. Considering an average lifetime of onshore LNG terminals of several decades, we see two problematic consequences. First, investments are likely to turn stranded even in scenarios not compatible with achieving the climate targets by 2045. In case of pure private-sector investments, it would in principle be pos-

Table 1: Current LNG plans in Germany

Location	Type of terminal	Operational when	Capacity (bcm/year)	Public / private	Contract Duration	Operator
Wilhelmshaven I	FSRU	January 2023	5	State-chartered	10 years	Uniper
Lubmin I	FSRU	Early 2023	Starting capacity: 5.2, Final capacity: 13.2	Private	5 - 10 years	Deutsche ReGas GmbH
Brunsbuettel	FSRU	Early 2023	Starting capacity: 3.5, Final capacity: 7.5	State-chartered	Until 2026	RWE
Wilhelmshaven II	FSRU	2023	5	State-chartered	5 years, or until the H_2 onshore terminal planned by TES is in operation	E.ON, Tree Energy Solutions (TES), Engie
Stade	FSRU	2023	5	State-chartered	Until 2026	Hanseatic Energy Hub
Lubmin II	FSRU	2023	5	State-chartered	15 years	RWE, Stena-Power
Total	**FSRU**		**40.2**			
Wilhelmshaven	Onshore	Late 2025	20		Following the LNGG, until end 2043	Tree Energy Solutions (TES)
Brunsbuettel	Onshore	2026	8	50% funding via government investment bank KfW	Following the LNGG, until end 2043	KfW, Gasunie, RWE
Stade	Onshore	2026	13.3		Following the LNGG, until end 2043	Hanseatic Energy Hub
Total	**Onshore**		**41.3**			
Total	**All**		**81.5**			

Source: Own compilation based on various public sources (available upon request).

sible to argue that asset stranding is part of the entrepreneurial risk. However, sunk costs appear particularly problematic due to the involvement of public money in some proposed terminals. Second, in addition to traditional carbon lock-in effects, stranding public investments into long-lived fossil natural gas infrastructure induces a conflict of interest on the regulatory side, creating further barriers to the phase-out of fossil fuels and, hence, hindering the energy transformation in a potentially drastic manner (Kemfert et al. 2022).

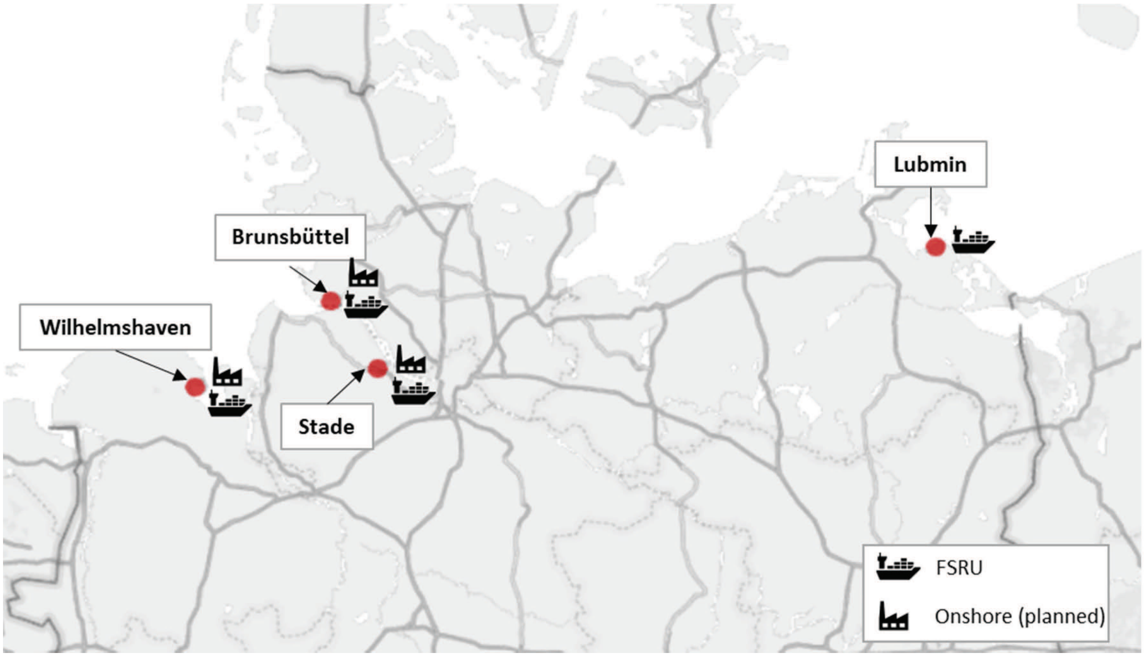

Figure 3: LNG terminal projects in Germany (floating and fixed), as of January 2023

Source: Own depiction based on (Table 1) and geographical data from TomTom

While not being compatible with long term demand projections, onshore regasification terminals also fail to address import needs in the short term. Due to long construction time, terminals are scheduled to come online in 2026 at the earliest. Given experience from other capital-intensive infrastructure investments in Germany, considerable delays are likely.

Even though onshore terminals are planned in an "H_2-ready" format, and operations of fossil LNG are only permitted until end of 2043 under the German LNG acceleration law, the actual degree of "H_2-readiness" remains highly questionable (Riemer, Schreiner, and Wachsmuth 2022). With the current state of technology, it is still unclear which part of the LNG equipment can be used for the imports of hydrogen or its derivates, so that "re-conversion" is likely to turn out a very expensive strategy with large sunk costs.

Conclusions

Following the invasion of Ukraine, Russian supply interruptions of natural gas have put considerable, but manageable stress on the German market. Supplies were never interrupted and ample storage capacities could be filled during the summer 2022, albeit at very high spot prices. The access to diversified imports from other sources than Russia ensured continued gas supplies, in particular from Norway and as LNG via terminals in neighboring countries.

Facing the end of imports from Russia, the federal German government has decided to charter five floating regasification terminals, with one additional private project underway. Total floating regasification capacities under development are over 40 bcm per year with an additional 40 bcm per year of onshore terminals scheduled to come online by 2026. These terminals are to fill a supply gap left by disrupted imports from Russia that we estimate at about 25 bcm per year. In other words, there would be an excess capacity of about 15 bcm per year of the floating terminals and up to 55 bcm per year of total planned regasification terminals.

FSRUs are relatively flexible by nature and can be chartered by other importers around the world. The opposite holds for investments in onshore infrastructure. While not being compatible with long term demand projections, the onshore regasification projects also fail to contribute to the import needs in the short term. We see a considerable risk of asset stranding. In the unlikely case of a natural gas shortage in the late 2020s, prolonging the use of FSRUs has a much lower risk of stranding investments and creates less barriers for the energy transformation.

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Footnotes

[1] See also https://www.bruegel.org/publications/datasets/european-natural-gas-imports/ .

[2] Detailed references on the terminal plans are available on request.

[3] All onshore terminals and some of the FSRU terminals have plans for a later conversion to other gases, be it hydrogen (H_2) or its derivatives such as ammonia (NH_3). In other words, "H_2 readiness" is part of the terminals' applications, but the plans are not concrete. We argue that a conceptual design to import 100% renewable energy carriers from the start of operations should be considered for onshore energy import infrastructures instead of an "H_2-ready" design.

The United Kingdom's 60-year engagement with LNG

BY JOHN HOLDING

Abstract

This article details the circumstances under which LNG was first delivered to the United Kingdom in 1959 and how the trade continued until 1982. The reasons for the interruption are explained which in due course led to the resumption of LNG imports utilizing new terminals from the early 2000s and which are in full use today.

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Introduction: 1959 – the first UK LNG imports

The United Kingdom's LNG history dates back to February 1959 when an innovative terminal located on the north bank of the River Thames estuary at Canvey Island in Essex received the world's first ocean cargo of LNG. The carrier was the British-flagged MV Methane Pioneer, a converted US Liberty ship, which arrived with 32,000 bbls (ca. 1,700 tonnes) of LNG[1]. The vessel had been refitted with two aluminum tanks insulated with balsa wood in a shipyard in Mobile, Alabama and was funded by the UK's Gas Council. The vessel was operated by a joint venture between Conoco and Union Stock Yards of Chicago; Constock International Methane. The LNG was loaded at Lake Charles, Louisiana and the voyage took 27 days to cross the Atlantic to the United Kingdom.

The motivation for the project from the British side was that during the 1950's it became apparent that there was a need to find new energy sources. The ever-increasing demand from industry and the domestic market for both gas and electricity required larger more efficient plants to be built which used coal and oil products to produce gas and generate electricity. The feedstocks were becoming more expensive and the supplies less reliable. Consequently, in 1959-1960 a total of seven such cargoes of LNG were transported to the UK and the regasified product was sent by pipeline to a local gas works. The natural gas was reformed into town gas (a carbon monoxide and hydrogen mixture) which was of low calorific value but was the standard at the time[2].

The success of this endeavor led to the first carrier specifically designed for LNG, the Methane Princess[3], which entered service from Algeria to the UK and France in 1964. The vessel took on the first load of LNG (12,000 tonnes) at Arzew where the liquefaction plant was located being sourced from new gas fields at Hassi R'Mel in the Sahara Desert. Delivery arrived at Canvey Island in October 1964 – the first of 50 shipments of LNG each year continuing until 1982 after which the owner British Gas closed the site in 1994.

The LNG hiatus lasted for 20 years until new terminals were constructed and deliveries commenced from the international market. Today (year-end 2022) the United Kingdom is expected to have received record quantities of LNG[4]. The country is now well-equipped having three LNG receiving terminals including the largest one in Europe, South Hook LNG, situated at Milford Haven in southwest Wales.

UK gas in context: manufacture of town gas – the original driver for LNG

The beginnings of gas use in the UK stem back to the early 19th century when town gas was manufactured from coal and used for public lighting, industrial and commercial processes and for heating. Coal had been in use since the 14th century in domestic hearths (fireplaces) but it expanded rapidly with the Industrial Revolution from the late 18th century when it was used to raise steam for power purposes. The world's first coal-fired power station, the Edison Electric Light Station, was built in London in 1882 with the promise of supplying light and warmth to London homes.

Coal was also converted (chemically 'reformed') to make manufactured gas, or town gas, but this peaked in the 1960s when it was quickly displaced by natural gas from the North Sea. UK coal production had reached its high point in 1900 at over 250 million tonnes per year but then declined steeply to below 50 million tonnes by in 1990 and today is barely 1 million tonnes alongside imports of approximately 5 million tonnes[5].

Town gas became 'new technology' when the first piped gas supply was used for street lighting in Pall Mall London (1807) and was followed by similar application in provincial towns across the country as well as in commercial and industrial activities. However, it wasn't until the development of the Bunsen Burner in 1855 that gas was used for a range of direct and indirect heating purposes in domestic settings for heating and cooking. The rapid establishment of private or municipal-owned town gas plants, or gas works, became the norm along with the huge gas holders that are even still to be seen today.

The opportunity to switch to gas from coal was seen as an obvious choice given the air pollution (evident at ground level with the choking smogs of the Victorian and early 20th centuries). Gas was seen as clean, safe and controllable.

The ascent of natural gas production and utilization: North Sea developments and the demand shift to gas use for power generation (the 'Dash for Gas' -1990s)

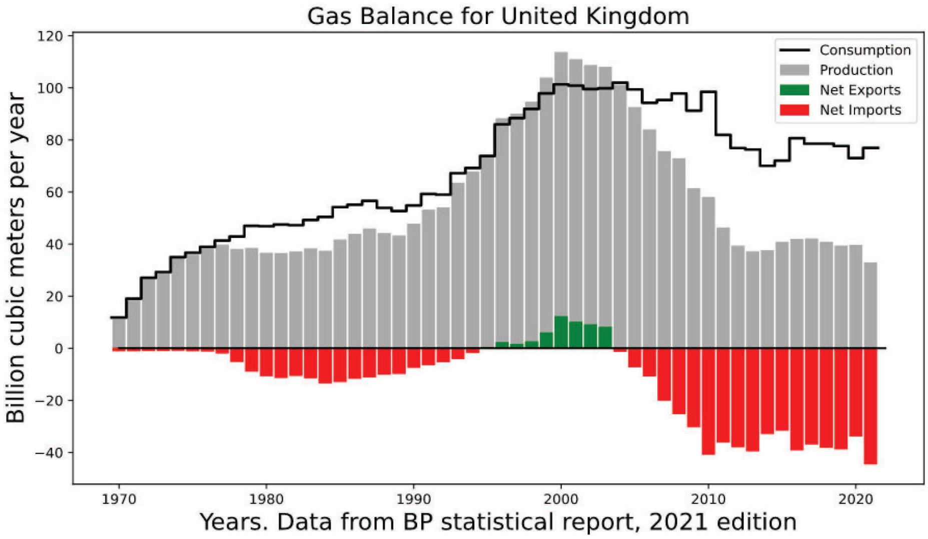
Whilst Algerian LNG supply was initiated in 1964, the following year witnessed the first discovery of offshore natural gas by BP in the West Sole field off the coast of East Anglia. This was developed commercially in 1967 and the field started to transmit gas by a pipeline to Easington on the northeast coast of England. This event triggered a huge exploration and development of the UK North Sea, firstly in the shallower waters of the southern sector to be followed from 1975 by oil and gas discoveries and field development in the much deeper and remoter central and northern areas between the UK and Norway. Astonishingly, by the mid-1990s Britain had become a net exporter of gas. However, this major supply expansion peaked in 2000 and started a decline thereafter.

The era of the 1960's are regarded as the start of the UK's total commitment to natural gas, whether sourced domestically from the North Sea or by import from overseas as LNG or by pipelines from Norway and the near continent. From 1967 until 1972 manufactured town gas was replaced across the whole of the UK by natural gas under a major conversion project affecting all homes, institutions and commercial and industrial premises. Basically, the gas burners had to be modified for the different composition and combustion properties of natural gas versus town gas.

Gas demand grew further as a result of government policy during Margaret Thatcher's three tenures as Prime Minister (1979-1990). Thatcher initiated a far-reaching and aggressive privatization of state entities which notably included that of the National Coal Board resulting in the coal miners' strike of 1984-1985 against the large-scale closure of collieries. British Gas was privatized in 1986 and the National Coal Board a year later followed by the regional electricity companies in 1990. These actions resulted in the so-called 'Dash for Gas' when the newly privatized electricity generating companies shifted towards using natural gas when regulatory changes allowed gas to be used as a fuel for power generation. Moreover, high interest rates at the time favored gas turbine power stations which were quick to build and the use of new technology, specifically combined cycle gas turbine generators (CCGT) offered higher relative efficiencies. North Sea gas production was rising at the time – the future for gas looked attractive and by 2002 the new CCGT power stations made up 28% of UK electricity generating capacity. Separately, domestic gas boilers and home central heating had expanded in the Thatcher years alongside the original use of gas - that is, town gas used for cooking and water heaters/geysers. A secure supply of natural gas was needed for the long term.

2000 and beyond: a new era for LNG in the UK

The chart shows the widening gap between UK gas production and consumption from 2004 which had to be filled by imports (shown in the red bars) coming either from gas pipelines or LNG deliveries. A new era for LNG in the UK had dawned.



Firstly, in the case of gas by pipeline, four terminals already serve the UK with natural gas from abroad;

- Norwegian North Sea gas imports arrive at (1) St Fergus in Scotland (from 2001, after the 1978 Frigg gas line was expanded) and (2) at Easington in northeast England (from 2006). Combined delivery capacity of 37.5 BCM/annum represents approximately 45% of UK's current gas demand making Norway the UK's top supplier.
- The Interconnector (1998), a bi-directional gas pipeline connects Zeebrugge (Belgium) to Bacton in eastern England with an import capacity of 25.5 BCM/annum
- The BBL line (Balgzand Bacton Line), a bi-directional gas pipeline (2006) connects North Holland also with Bacton allowing 15 BCM/annum to be imported.

The implication of the total gas capacity of these four pipelines is that the UK could in theory be supplied with 78 BCM/annum – virtually its total current demand (see the Consumption line on the chart). Clearly, given the two-way flows permitted in the lines from Belgium and Holland these particularly represent options to satisfy UK demand and surplus supply whilst the two Norwegian lines are more 'base load' supplies subject to volume nominations under the respective contracts.

Secondly, with respect to LNG receiving terminals the UK currently has three in operation (a fourth one utilizing FSRU technology at Teesside GasPort – north of the Easington gas pipeline terminal – was operational from 2007 but suspended in 2015[6]). With respect to the UK's fully operational terminals, two are located on the north bank of Milford Haven in southwest Wales and one is on the south bank of the River Thames estuary in Kent (downstream from the original Canvey Island terminal mentioned at the outset herein).

- South Hook LNG in Milford Haven southwest Wales is the largest LNG terminal in Europe providing approximately 25% of the UK's current gas requirements (ca. 19 billion cubic metres per annum). The terminal was established in 2004 and is operated by QatarEnergy (with a 67.5% stake), Total Energies (8.35%) and ExxonMobil (24.15%). The first delivery of LNG was in 2009 from Qatar and the 500th cargo from Qatar was delivered to South Hook on 24 March 2016.
- Grain LNG located on the Isle of Grain in the Thames estuary was commissioned in 2005 and has 1 million cubic metres of storage (to become 1.2 million cubic metres by 2025) with the capacity to process approximately 15 million tonnes of LNG per annum and deliver 25% of UK gas demand. In 2020 the terminal welcomed its 500th LNG carrier. Terminal capacity is currently allocated to BP/Sonatrach, Centrica and Total through term contracts along with other supplies coming from the spot market. The terminal is owned by National Grid, the UK's electricity and gas system networks operator and is a public company.
- Dragon LNG Terminal is the smallest of Britain's three LNG terminals. It can handle approximately 7.6 billion cubic metres, around 10% of UK needs. It's located upriver from the larger South Hook terminal. The Dragon LNG terminal is under shared ownership between Shell (a 50% share) and Ancala LNG Ltd (50%). Petronas shares capacity rights with Shell (50% each).

Longer term outlook for UK LNG

Not just for the UK, but globally and not just for LNG, the longer term use of natural gas is problematic given that it is a fossil fuel albeit the least harmful to the climate compared with coal and oil. Continued use of natural gas implies that its emissions are abated or mitigated and whilst several options are already available widescale take-up appears sluggish such that Net Zero by 2050 is surely in question; the IEA considers it a *formidable goal* in their June 2021 'Roadmap for the Global Energy Sector'[7]. The next UNFCC COP (COP28 to be held in December in 2023 in the United Arab Emirates) may or may not address the issue of fossil fuel emissions[8] and it is unclear if any consensus for global action will be agreed - given COP27's outcomes.

Reverting specifically to LNG use in the UK, the energy source is in direct competition with imported pipeline gas; this state of affairs certainly assists security of supply and might have an impact on prices depending on demand-side trends and on the depletion of North Sea gas reserves. At the end of the day LNG has to be competitive in the UK gas market.

Yet, a backward glance to the mid-20th century recalls that LNG was imported for the purpose of reforming it into town gas to produce a mixture of Carbon Monoxide and Hydrogen. This is interesting in that Hydrogen is a current contender to replace the direct use of natural gas because there are no greenhouse gas emissions from burning hydrogen – only water vapor. Meanwhile carbon monoxide has uses as a chemical feedstock in the manufacture of methanol and phosgene – an intermediary in the manufacture of dyes, pesticides, plastics, polyurethanes, isocyanates, and pharmaceuticals.

The UK's engagement with LNG has surpassed 60 years - - - and still counting

Footnotes

[1] Refer to "A Short History of LNG Shipping 1959-2009" by Peter G. Noble - available at https://higherlogicdownload.s3.amazonaws.com/SNAME/1dcdb863-8881-4263-af8d-530101f64412/UploadedFiles/c3352777fcaa4c4daa8f125c0a7c03e9.pdf

[2] Town Gas was produced by Steam Methane Reforming which converts natural gas (methane) to carbon monoxide and hydrogen in a reversible reaction: $CH_4 + H_2O \leftrightarrows CO + 3H_2$

[3] Methane Princess plus its sister ship Methane Progress, purpose-built LNG carriers, were constructed in the UK and commissioned in 1964 to carry LNG from Arzew (Algeria) to Canvey Island on the River Thames. Each had a carrying capacity of 27,000 cubic metres (ca. 12,000 tonnes)

[4] Author's assessment (January 2023) based on UK Government's *National statistics Energy Trends: UK Gas* (Last updated 3 January 2023) available at Energy Trends: UK gas - GOV.UK (www.gov.uk)

[5] The death of UK coal in five charts - Our World in Data. Available at The death of UK coal in five charts - Our World in Data

[6] FSRU (Floating Storage and Regasification Units) act in all aspects similar to a land-based terminal and, in addition to transporting LNG, purpose-built FSRUs have the onboard capability to vaporize LNG and deliver the natural gas through specially designed offshore and near-shore receiving facilities. Teesside GasPort was the world's first dockside floating regasification facility located near Middlesbrough in the United Kingdom and it operated from 2007 to 2015 for its customer Excelerate Energy of Texas, USA

[7] Net zero by 2050: a roadmap for the global energy sector - A special report by the International Energy Agency for UNFCCC

[8] The Daily Telegraph (London, 13 January 2023, p.12) reported that the UAE had appointed Sultan Ahmed Al-Jaber – CEO of ADNOC and Minister for Industry – as the President of COP28.

On the LNG Market: Actors, Development, Potential and Challenges

BY FREDJ JAWADI AND PHILIPPE ROZIN

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Capsule

This note recalls the principles and actors of LNG market. It also discusses the potential of LNG market as well as its several challenges.

Abstract

This note analyses the LNG Market while recalling its actors, rules and the main steps related to its development. We also discuss the main perspectives of LNG market in terms of ecological transition and therefore a more clean energy environment; even it is still an on-going project that requires more attention given the heterogeneous positions of governments and policymakers. Finally, we discuss the challenges with LNG Market and its development in the future.

1. The development of LNG Market

What does Liquefied Natural Gas (LNG) Market refer to and what are its main principles, actors and rules?

LNG is a natural gas that has been transformed into a liquid form, which requires a heavy industrial process to transform it from a gaseous state (its initial state when extracted) to a liquid state. To this end, the gas should be heated to a temperature of between -161°C and -163°C. Once in this liquid state, LNG is 600 times less voluminous than when it is in its gaseous state, which is an important natural advantage in particular to facilitate its transport by ship to consuming countries.

In 2021, the global LNG market size was estimated at USD 109.48 billion, but this market is expected to grew up at an annual rate of 8.1% from 2022 to 2030. This dynamics of LNG market is explained by the fact that LNG Global demand has doubled over the past decade. LNG is hence expected to play an increasing role in meeting global natural gas demand. Accordingly, the long-term outlook for natural gas is the most favorable among fossil fuels. As for the supply side, Qatar, the United States of America, Russia, Australia, and Malaysia are the main producers as they provide around three quarters of global supply in 2021.

As for the actors of this market, it is important to recall that after oil and coal, natural gas is the third largest source of primary energy in the world, accounting for 24.7% of primary energy consumption. The consumption of this commodity is often of domestic origin. Indeed, in 2021, 69.8% of global natural gas demand came from domestic production and the remaining 30.2% was supplied by cross-border pipelines (in gaseous form) or by seaborne trade (as liquefied natural gas, LNG).

The gas economy is a pipeline economy and less global than oil market. Pipeline flows accounted for 57.7% of international trade, and the remaining 42.3% was supplied in the form of LNG (BP, 2022). Even, a new trend is emerging. In fact, since the 1990s, global LNG trade has grown faster than domestic gas production and pipeline supply. Accordingly, internationally traded LNG now accounts for 12.8% of global natural gas supply (BP, 2022). This growth of LNG market was supported by Global demand for LNG that has doubled over the past decade. Interestingly, this growth has been driven by significant cost reductions along the supply chain. The most decisive factor is probably the increase in LNG tanker capacity. In addition, the strong demand for natural gas due to the arrival of new players on the market has played a decisive role. Finally, it is worth noting that LNG has proven surprisingly resilient. Indeed, while global primary energy demand fell by 4.5% in 2020, the largest decline since 1945, LNG demand increased by 0.6% in the same year (BP, 2021). In 2021, global LNG trade grew by 5.6% (BP, 2022).

2. The perspective of LNG market in term of ecological transition

Obviously, the expectations from LNG markets are being high in particular in terms of dealing with more clean energy, which gives more credit to the growth prospects for petroleum liquefied gas that are very promising. Indeed, according to the latest IEA report, almost one hundred billion cubic meters of new LNG supply capacity will come on stream between 2018 and 2023. Both mature and fast-growing emerging markets have contributed strongly to this growth. In particular, China is expected to be the main driver of natural gas demand growth in the near future. This is due in part to the continued growth in energy consumption coupled with strong political support to reduce the pervasive air pollution in China's major cities. As the second largest importer of LNG, China's LNG supply structure remains a complement to domestic production and pipeline imports of conventional hydrocarbons. That is, the objectives of the 13th Five-Year Plan (2016-20) aim to adjust the country's energy mix. The desire to decarbonize its economy has increased the demand for natural gas and accelerated infrastructure development.

However, in relation to LNG, policies and rules vary from one country to another in Asia. The Japanese market, for example, is particularly liberalized. It comprises more than 200 players operating in different market segments. Trade is very intense, despite the serious dependence on LNG imports and limited domestic pipeline interconnections. Korea has a lower share of natural gas in the energy mix and a fairly early market opening. The incumbent KOGAS imports nearly 90% of LNG demand in the wholesale sector and is the only wholesale supplier of gas to large consumers and city gas companies.

3. The challenges with LNG Market

Despite this bright outlook, the LNG market faces challenges in the face of price volatility and uncertainty. First, at the capacity level, it is clear that commercially viable liquefaction projects with a proven impact on carbon emissions are still limited. Underinvestment is indeed a major challenge for this energy source. There is also price volatility in a context of massive supply uncertainty, even if demand remains strong. Accordingly, the market is facing challenges actually: it is experiencing bear months when LNG demand is generally low; most Russian gas is still in circulation and LNG demand in China is down significantly. This can yield more uncertainty about what will happen next.

Second, noteworthy is the geopolitical concentration of producers. North America is the big source of new LNG production and there are not many others. The concentration of LNG production areas is an inherent constraint to its production. In the short and probably medium term, the United States will easily consolidate its position as the largest LNG exporter, as the trend of increasing domestic supply and rising prices in Europe and Asia will encourage operators to seek outlets for their gas abroad. For example, the $10 billion Golden Pass LNG project in Texas, with export capacity of approximately 18 million tons per year, and the Plaquemines LNG project, which could produce approximately 24 Mtpa, will start up in 2025. At the other end of the geographic spectrum, Qatar intends to increase its LNG export capacity to 126 million tons per year by 2027, up from 77 million tons currently. Russian volumes, meanwhile, depend mainly on the success of the Arctic LNG 2 project, the on-going war in Ukraine and the series of sanctions against Russia that have caused delays in the commissioning of trains 2 and 3. In Africa, Mozambique will see its first LNG production at the end of 2022 thanks to the Coral South LNG project, currently under development. The project is expected to supply about 150 million cubic feet per day (MMcfd) of gas.

Third, Russia, the United States and Qatar hold about 70% of the world's approved and as yet unproduced LNG resources. LNG is on a roll. The deepening global energy crisis is fueling the need for investment in new LNG infrastructure. This is estimated to be $42 billion per year by 2024, according to a study by Rystad Energy.

That is, it should be noted that several governments are moving quickly to make a major energy transition away from fossil fuels. This is resulting in accelerated investment in low-carbon energy infrastructure. Thus, this upward effect on investment could be misleading. Russia's war in Ukraine is stimulating new LNG projects, but these would be mainly driven by a short-term increase in natural gas demand in Europe and Asia. So, while global gas demand is expected to increase by 12.5% by 2030, from about 4 trillion cubic meters (Tcm) to about 4.5 Tcm, gas demand in the US is expected to remain relatively flat through 2030. This demand would be offset, thanks to strong economic growth and pro-gas policies, by demand from Asia and the Pacific will increase (by 30%, from about 900 billion cubic meters (Bcm) to about 1.16 Tcm by 2030). The US will account for 30% of cumulative gas demand in 2030, while Asia-Pacific will account for 25%. So, different challenges do exist for LNG market.

Stuck in the 1950's: Updating Regulatory Mandates for the 21st Century

BY MICHELLE NOCK

Abstract

Utility Regulators' enabling legislation and processes were designed to address the 'monopoly problem'. They can be great at doing that, but if they ignore the 'decarbonization problem' none of it will matter in the long run. What role could utility regulators play in supporting decarbonization (or at least not undermining it), and do we need a complete overhaul of their enabling legislation to achieve this?

Introduction

Professor Malcolm Sparrow states that regulatory agencies exist primarily to control risks to society. Utility regulation dates back to before the 1950s and was put in place to address the risk to society arising from natural monopolies.

While there can be differences between jurisdictions in market design and the type of regulation, the basic nuts and bolts of how utility regulators address monopoly risks are fairly similar worldwide. These include allowing the utility to earn an adequate return on its invested capital, regulatory review of capital and operational expenditures, and setting rates such that the costs of the utility are fairly recovered from all its customers and properly apportioned between customer classes.

However, Professor Sparrow also states that major programs, once created, tend to ossify over time and lack the flexibility to cover the shifting landscape of risks.

What are the new risks to society that have arisen since the 1950s that traditional regulatory processes do not address? What new processes or market design changes would be needed to address these risks, and is the regulator constrained by an outdated regulatory mandate to achieve them?

Where do we start?

This article suggests a roadmap to address these questions. The following steps are recommended and described in more detail in the following sections:

1. Identify the risks to society that an economic regulator could mitigate
2. Understand how these risks affect the utilities and their stakeholders
3. Develop new regulatory processes to address these risks
4. Update the regulator's mandate (if required)

A key item to note is that the update of the regulatory mandate is the last, and not the first, step in the process. Starting with identification of the risks to society instead (as shown in Figure 1 below) will allow for the development of regulatory processes and mandates that are not unnecessarily constrained by the status quo, and so support regulatory innovation.

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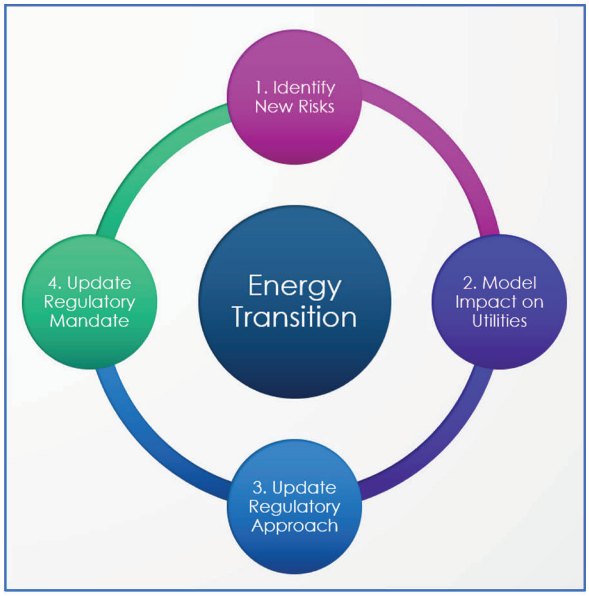

Figure 1: Updating the Regulatory Framework for the Energy Transition

Step 1: Identify risks to society

The first step is to identify the risks to society that an economic regulator could be well placed to mitigate. Professor Sparrow states that risks not addressed by existing programs generally fall into the following categories:

- *Emerging risks* that did not exist or were not understood at the time when the major programs were designed. These could include government decarbonization targets, technology changes and increasing investor and consumer expectations around energy affordability, diversity and indigenous reconciliation
- *Catastrophic risks* related to disasters that do not normally happen (or maybe have never happened yet), and which therefore are not represented in the normal workload. These could include the increased risk of extreme weather events as a result of climate change

- *Invisible risks* related to issues that have sufficiently low discovery or reporting rates such that we do not know the true scope, scale or concentrations of the problem
- *Risk involving conscious adversaries* or adaptive opponents who deliberately circumnavigate controls (such as cyber criminals and geopolitical risks resulting from the Russia-Ukraine war)
- *Boundary-spanning risks* where responsibility for controlling a risk sits awkwardly across the missions of several major public agencies. This could include broader regional integrated planning
- *Persistent risks* where cases of one type keep on surfacing at high volumes so treating these cases one by one is not controlling the underlying problem. This could include existing processes designed for large utilities which may be unnecessarily burdensome for the growing number of small utilities

Economic regulators are not responsible for determining environmental policy or driving social policy. However, these new or emerging risks are those that a utility will face whether they chose to proactively address them or not. An economic regulator could play a role in ensuring that these risks are well managed by utilities

The starting point is therefore a stock-taking of the new risks facing utilities. For example, to better understand decarbonization risks the regulator could identify government 2030 and 2050 targets for decarbonized energy supply (electricity and natural gas) and energy end-uses (buildings, transportation, industrial processes).

Step 2: Understand how these risks affect utilities and their stakeholders

The next step is to understand how these new risks could affect regulated utilities. For example, government decarbonization targets could result in the following risks to utilities and their customers:

- *Natural gas utilities* could face a risk of stranded infrastructure investments if they are unable to deliver decarbonized energy (renewable natural gas and hydrogen) to customers at a comparable cost to electric utilities
- *Natural gas customers* may find that they have to prematurely replace natural gas equipment as it becomes uneconomic to operate. Customers who may have less ability to switch away from natural gas (low-income customers, renters, 'hard to decarbonize' industrial processes) could find themselves shouldering a disproportionate share of the costs
- *Electric utilities* could face a dilemma of building out their network in advance of expected load (and risk not being able to recover all these costs if the load does not materialize) or waiting until the load does appear and then risk not being able to reliably serve it. Electric utilities could also risk over-investing in supply side assets if they do not give enough attention to the increased ability of distributed energy resources to supply this new load
- *Electric customers* - electrification could increase customers' need for a reliable and resilient electric service. However, at the same time increased integration of renewables to meet decarbonization targets may decrease reliability from current levels if not proactively managed

How could a utility regulator obtain this insight? Professor Sparrow recommends that a project is set up for new problems the regulator has identified as important:

> The work is conducted by temporary project-based teams, usually cross functional in nature, organized around a specific problem. These teams are expected to gather the data, study the problem, consult with others as necessary, and then generate a plan or set of plans suitable for tackling the problem.

For the 'decarbonization problem', to allow for better targeted outreach it is recommended that utility regulators launch three separate inquiries into the future of:

- Buildings – how will they be heated/cooled in 2030/2050
- Transportation – how will it be fueled in 2030/2050
- Industrial processes – how will their energy needs be met in 2030/2050

For example, a building inquiry could allow for public debate over renewable natural gas (cost and availability assumptions), electricity renewable integration (alternative approaches and costs) and the role that distributed energy resources could play in meeting future energy needs.

While numerous decarbonization models have already been developed to estimate how 2030/2050 climate targets could be met, they may be of little use if they do not recognize the local context, are undertaken by entities with a vested interest in the outcome, and where key input assumptions have not been tested in a public process.

By contrast, utility regulators are policy and technology agnostic and so regulator led inquiries can be trusted to look at the decarbonization risk from an impartial perspective. Energy regulators are also experts in their local context, which is important as decarbonization pathways could vary significantly between regions.

While it is not expected that we can predict how, for example, buildings will be heated and cooled in 2030 and 2050, it should be possible to at least develop a range of reasonableness, discard unrealistic assumptions and get visibility into the role electric and natural gas infrastructure will likely play in a fully decarbonized world.

Regulators may already have the ability to hold inquiries on their own motion. However, they could lack the resources to undertake one and traditional regulatory proceedings (with rules of evidence) can be complex and difficult for customers to participate in.

It may therefore be more efficient for the government to direct and fund the regulator to undertake these inquiries, and support a less formal process to ensure wider participation.

Similar inquiries could be held to get visibility into other problems identified by the regulator as important (such as extreme weather events and cybersecurity), although Professor Sparrow recommends that the regulator should not attempt to launch more than a small number of projects at a time.

Step 3: Develop new regulatory processes to address these risks

The third step is to develop new regulatory processes and approaches to address these risks. This is not an easy task – it probably took a talented team of people coming from diverse backgrounds to develop the regulatory processes we have today to address monopoly risk. However, once this process has been done, it could then be rolled out to utility regulators worldwide.

Regulators can look to the finance industry for inspiration, as they have already started on this path in updating their processes to address the decarbonization risk. Mark Carney in his book 'Values' sates:

> When I was named the Special Envoy of the UN Secretary General for Climate Action and UK Prime Minister's advisor for Climate Finance, we formed a small team of experts seconded from the Bank of England and Whitehall and set ourselves a simple but vital task: to have in place by COP 26 in Glasgow all the necessary foundations so that every financial decision takes climate change into an account.
>
> This requires a fundamental reordering of the financial system so that all aspects of finance - investments, loans, derivatives, insurance products, whole markets – systematically take the impact of their actions on the race to net zero. ...
>
> To ensure that every financial decision takes climate change into an account, the COP process has drawn on experts across the private sector, in central banks and regulators and at not-for-profit organizations which had been among the first to identify and advocate some of the necessary changes.

Two previous International Association for Energy Economics (IAEE) articles provide some insight into what these changes could look like for energy regulators' processes:

- *Rate Setting for an Electrified World:* This article proposes rate setting changes if electrification was found to be most likely pathway for buildings, including reviewing residential gas and electric rates and energy efficiency programs together to determine if they encourage (or at least do not discourage) electrification of homes.
- *Hackers and Extreme Weather:* This article suggests that existing regulatory approaches (such as planning reserve margin and reliability metrics) may no longer be sufficient to ensure utilities are adequately addressing cybersecurity and extreme weather risk and proposes the addition of a risk-based framework.

Potential changes arising from decarbonization risk were also identified in *The Challenge of Retail Gas in California's Low-Carbon Future* report prepared for the California Energy Commission by Energy and Environmental Economics (E3).

E3 used a model to evaluate building scenarios that would achieve an 80 percent reduction in California's greenhouse gas emissions by 2050 from 1990 levels. Based on these scenarios, E3 concluded that building electrification is likely to be a lower-cost, lower-risk long-term strategy.

E3 then recommended the development of a natural gas transition strategy which could include: accelerated depreciation of natural gas assets, changes to natural gas cost allocation between customer classes, avoiding future gas system expansion, shut-down of uneconomic gas infrastructure, reducing barriers to electrification, and developing pathways to pay for early retirement of gas assets (such as from electric bills, taxpayers and cap-and-trade revenues).

Redesigning regulatory processes and approaches to address monopoly risk *and* new risks that have arisen since the 1950s will be both difficult and intellectually challenging. However, by working together - and with sufficient resources - utility regulators should be able to effectively build on the legacy of those that have come before us.

Step 4: Update the regulator's mandate

The last step in the process is to determine if the utility regulator has the mandate to put in place the new processes or initiatives it has identified.

Utility regulators are 'creatures of legislation' and their enabling legislation is often designed to mitigate the risk posed by customers from monopoly utilities. For example, it allows regulators to review and accept/reject long-term resource plans, capital and operating budgets, and rate designs.

However, it may not allow a regulator to, for example:

- Initiate strategic targeting of electrification and develop pathways to pay for early retirement of natural gas assets
- Direct gas and electric utilities to file their residential rate design and energy efficiency programs together, or
- Put in place a risk-based framework to address resiliency risk for gas utilities and the electric distribution grid

For example, in a recent Quebec decision (D-2022-061) the utility regulator approved a generic principle whereby the electric utility will compensate the gas utility for 80% of its lost revenues related to the conversion of natural gas clients to a dual (natural gas/electricity) energy system where natural gas is used only for building heating during peak periods. However, one commissioner issued a dissenting decision, saying the deal's costs "can't be considered a necessary expense in the service of distribution of electricity."

This decision illustrates the difficultly of regulators being asked to address decarbonization risks without having a clear visibility into the nature of the risk and their jurisdiction in addressing it.

This fourth step may also identify regulatory gaps. For example, under Canada's constitution, each province controls the electricity market structure within its borders. Federal government authority is limited to certain aspects of the nuclear generation sector, electricity exports, and inter-provincial transmission. There may therefore be no regulatory body with the authority to ensure broader regional market planning is undertaken in response to the decarbonization risk.

The purpose of this step is therefore to identify any barriers or gaps in the regulator's enabling legislation to implement regulatory processes and initiatives that effectively address new and emerging risks.

It is recommended that this is the last step in the process as it will not be clear what changes to the regulator's mandate will be needed until the regulator has a clear handle on what the new risks are, how they could affect regulated utilities, and how they are best addressed.

There is a risk that, if the regulator's mandate is the starting – and not the ending – point, it will just result in minor tweaks to the mandate to, for example, 'consider GHG emissions' or 'consider affordability' in regulatory decisions. Instead, the proposed approach allows for increased flexibility and innovation to design a solution that maximizes the value regulators can provide to society.

Whose job is it anyway?

Not all regulators have the 'mandate to question their own mandate' or they may lack the funding to do so. In those cases, the ball is in the government's court to initiate this regulatory mandate review process, although the regulator can certainly play a central role in this review.

It is therefore recommended that the government empowers and funds the regulator to get visibility into these new and emerging risks. For the decarbonization risk, tasking the regulator with holding open and transparent inquiries into the future of buildings, transportation and industrial process could be a good place to start.

This approach also has broader benefits of raising public awareness around what the decarbonization pathways are, what they are going to cost and the trade-offs. Trusted regulators could help to both inform energy policy and educate the public.

Conclusion

Professor Malcolm Sparrow describes the purpose of regulation as 'Pick important problems; fix them'. Regulators have been tasked by the government to address the 'monopoly problem' but can be constrained by their regulatory mandate to address new emerging problems such as decarbonization.

To ensure that utility regulators identify and fix important problems of today (rather than just those of the 1950s) requires an understanding of what these new risks are, how they affect utilities they regulate, which problems should be addressed though regulatory processes and how these should be designed. The last step is an update of the regulatory mandate, if required, to allow regulators to effectively manage the new risks.

This is not a herculean task. For example, to better understand the effect of the decarbonization risk on utilities and their customers the regulator could hold time limited inquiries into the future (2030/2050) of buildings, transportation and industrial processes. A cross sector-team could then be created to update regulatory processes (and suggest mandate changes if required) to address this new risk, similar to the work being done by the finance industry.

We don't need a plan, we just need to start planning.

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Germany's Self-restriction in Shale Gas Exploitation: A Missed Opportunity?

BY MANUEL FRONDEL, CHRISTOPH M. SCHMIDT, AND COLIN VANCE

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Abstract

Russia's supply stop of natural gas has forced Europe to turn to LNG to meet its energy needs. Rather than locking into a decades-long import dependency on Qatar and the US, it would be more environmentally benign to exploit domestic resources. Germany's substantial reserves of shale gas could make it a major player in Europe's gas market if it were to drop its voluntary ban on shale gas exploitation.

Russia's nearly complete stop of natural gas supplies has revealed the precariousness of Europe's dependence on natural gas imports. Prior to its attack on Ukraine, Russia covered almost 40 percent of Europe's gas consumption. Germany alone lost more than half of the amount that is needed to cover its annual gas demand of about 95 billion cubic meters, almost a quarter of Europe's total consumption. In the short term, these dramatic supply shortages cannot be compensated without large amounts of LNG, as the construction of new pipelines to increase the gas supply from other sources requires many years.

Natural gas scarcity may become even more acute if the prognosis of the International Energy Agency (IEA 2022) concerning winter 2023/2024 proves true, especially if China's energy demand were to increase substantially in the wake of revitalized economic growth. As recently as 2022, Europe could rely, at least in part, on Russian supplies via the Nord Stream pipeline through the Baltic Sea to fill its gas storage facilities. This option is highly unlikely for 2023 and the upcoming years. Hence, according to the IEA, the EU member states could be short of around 27 billion cubic meters of gas, a gap of about 7 percent if total EU consumption of just under 400 billion cubic meters were to be sustained in 2023.

Against this background, and without having any LNG terminals until recently, Germany's government decided to spend billions of euros for the installation of five floating storage and regasification units, the first of which went into operation in December 2022 with an annual capacity of about 5 billion cubic meters. In addition, while private investors have chartered two other floating units, two stationary terminals are foreseen to start operating in 2026. These efforts document how desperately Germany needs LNG in the foreseeable future.

But as important as establishing the recipient infrastructure is at home, it is also vital that sufficient LNG can be procured on the world market and channeled to the EU. The agreement reached with Qatar in December 2022 to supply up to 2.8 billion cubic meters annually for at least 15 years from 2026 is a valuable step, but relatively insignificant in magnitude. LNG imports from other countries, such as the US, appear to be indispensable.

This increased dependence on LNG will come at high costs for consumers: Prices for natural gas are likely to be higher for the foreseeable future than before Russia's invasion of Ukraine, as the liquefaction of natural gas at temperatures below -160 degrees Celsius and the transport of LNG are very energy-intensive and thus cost-intensive (acatech / Leopoldina / Akademienunion 2022). Estimates by Prognos (2022) assume that natural gas in Europe could be about twice as expensive in the long term as it was before the crisis if deliveries of the previously low-cost pipeline gas from Russia continued to fall. EWI (2022) also expects high prices for natural gas in the foreseeable future and assumes that these will be three times the US prices in 2030 if gas deliveries from Russia are not resumed and natural gas demand does not fall by a third. By contrast, European prices before the energy crisis were "merely" twice the US prices.

In addition to the economic cost, Germany will incur environmental costs from its dependency on imported LNG. LNG imported from the US, for example, is transported to Europe by tanker, resulting in high energy costs both for gas liquefaction and for transportation. Thus, it would be more environmentally benign if Germany were to exploit its own substantial gas reserves through hydraulic fracturing methods (fracking) that extract natural gas from shale rock, as is done in the US. So far, resting on the narrative of a virtually endless supply of Russian pipeline gas, it had been easy to dismiss this idea on the vague notion of residual environmental risks. Now, with Russian pipeline gas being a highly unlikely option for the future, the possibility of domestic production needs to be discussed in earnest.

The Expert Commission on Fracking (2021) established by the German government recently assessed one of the commonly cited risks – that of triggering a damaging earthquake through fracking – as extremely low. Likewise, the Commission assessed the risk to groundwater pollution as low. According to these experts, fracking would pose an acceptable risk if current standards were adhered to. Extracting domestic gas reserves could also contribute substantially to reducing import dependency: According to a study by the Federal Institute for Geosciences and Natural Resources (BGR 2016: 13), Germany's shale gas resources may cover about ten times of Germany's annual gas consumption. This decision would require, however, that Germany abolishes its fracking ban of 2017.

Next to unfounded environmental concerns, critics also fear a lock-in effect: It is true that building up the infrastructure for shale gas exploitation will take several years, and that once this machinery is set in motion, domestic shale gas will be extracted for a protracted period. But the tremendous energy requirements that will characterize the transition towards climate neutrality will inevitably require the utilization of fossil resources. And among these, natural gas is relatively clean: burning gas comes along with only about half the carbon emissions of burning lignite. To refrain from using this available and comparatively benign energy source is clearly not a viable option for the European economy, as natural gas will either have to be imported or produced domestically. Exploiting its substantial reserves of shale gas could make Germany a significant player in Europe's gas market.

The only serious obstacle preventing lifting the fracking ban thus seems to be politicians' fear that a vociferous minority of the German population would demonstrate against shale gas exploitation via fracking for ideological reasons. This is not sufficient basis for eschewing a rational decision. The exploitation of shale gas in Germany could increase both domestic value added and security of supply, while at the same time reducing the environmental impact, especially greenhouse gas emissions.

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LNG Shipping via the Northeast Passage

BY MICHAEL SCHACH AND REINHARD MADLENER

Abstract

The increasingly ice-free Northeast Passage is a game changer for global LNG trading and shipping routes, and especially relevant for the Russian federation with its recently completed Yamal LNG terminal and the upcoming Arctic LNG 2 sister terminal – making Russia the fourth-largest LNG producer globally. The ongoing War in Ukraine has also changed the game, with still largely unpredictable consequences depending on its outcome.

Introduction

In our research, undertaken before the outbreak of the War in Ukraine and the Covid-19 pandemic, we examine the economic and geopolitical relevance of an ice-free Northeast Passage (NEP) as a shipping route, with a particular view on the major LNG-supplying and LNG-consuming countries, and expected changes in LNG trade flows. Several key aspects are considered in-depth, such as the developments in natural gas production in the Russian Arctic, important trends and strategies of major Asian LNG-consuming countries, and the geographical and climatic particularities of the Arctic.

In our study we also aim at examining the significance and the impacts of the NEP on LNG shipping. First, the major trends in LNG supply and demand and the specific role of the NEP are analyzed. Next, a hybrid algorithmic model is applied, considering these insights to optimize the global LNG flows and capacities with regard to an ice-free NEP. In addition to the model, the effects on spatial price arbitrage are investigated. The three research questions raised are: (1) What are the impacts of an ice-free Northeast Passage on LNG transport routes and transport capacities? (2) To which extent is an ice-free NEP a competitive advantage for Russian LNG producers? (3) How does the emergence of additional LNG capacities originating in Russia impact the global pricing of LNG?

Methods Used

The impacts of a second wave of LNG supplies on the market balance are demonstrated in four distinct scenarios: Scenario 1 "The second wave fails to materialize and no new capacities are constructed"; Scenario 2 "A moderate expansion of supplies occurs by 2025"; Scenario 3 "A moderate expansion of supplies occurs by 2025, but faces heightened natural gas demand in Asia"; and Scenario 4 "A massive expansion of supplies occurs by 2025". The constituents of the 'moderate' and 'massive' expansion of supplies directly result from the prior analysis of pre-FID (projects before the final investment decision) LNG projects in the US and Russia. The assessment of these liquefaction terminals, considering stakeholders such as government and competitors, forms the very basis for reasonable assumptions needed for the modeling. Also the segments of the LNG value chain, as well as corresponding costs, are examined. As an outcome of the LNG routing optimization research, recommendations for action are formulated concerning the optimal extent and pace of the next LNG supply expansion.

In order to find the optimal solution for a specific LNG shipping problem, various algorithms can be applied. However, before such an application a definition of 'optimal' is needed: What is the shortest or fastest path between multiple locations? Which bottlenecks have what impacts on the capacity planning? What is the most cost-effective route? In our research, several algorithms are applied for evaluating the relevance of the NEP for LNG shipping. Specifically, the applicability of the interpretation of the LNG transport routes network as (1) a Shortest Path Problem, (2) a Max-Flow Problem, and (3) a Min-Cost Flow Problem is evaluated. More specifically, the Dijkstra Algorithm, the Ford-Fulkerson Algorithm, and the Cycle-Cancelling Algorithm were used and the results obtained compared with each other. The analysis of various scenarios reveals the relative competitive-

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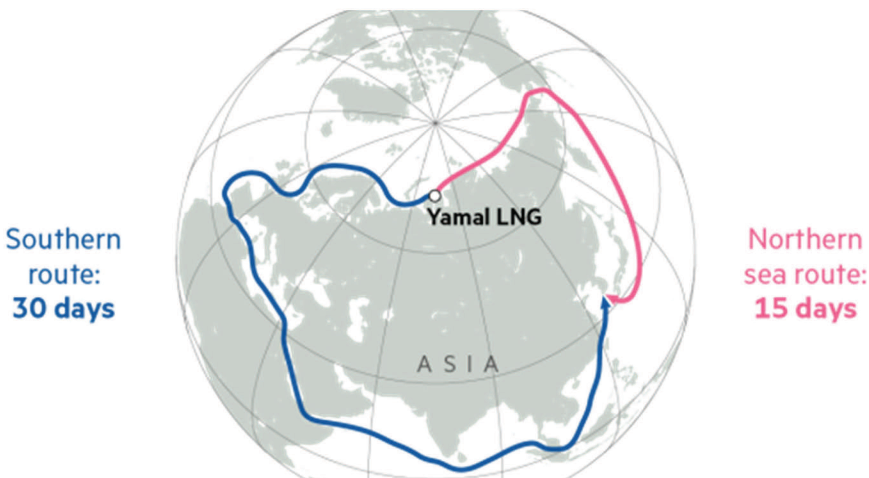

Fig. 1: Shipping scenarios of the Yamal LNG project
Source: Foy (2017)

ness of different LNG producers. Furthermore, the impacts of a sudden shutdown of one of the depicted chokepoints, in the case of a terrorist attack, a natural catastrophe, or regarding the NEP of an extensive freeze, are analyzed.

Results

The analysis reveals the competitiveness of Russian LNG exports along the Northeast Passage due to Yamal LNG and Arctic LNG 2, with the NEP as a potential game-changer for global LNG supplies. We further find that an ice-free NEP is primarily relevant for maritime bulk (and particularly LNG) shipping, and thus of great geopolitical importance and strategic interest, especially for Russia and the US on the supply side, and China, Japan, and South Korea on the demand side.

Three major insights are found with the algorithmic model. First, the Suez Canal Route (SCR) is not used at all in the regular scenario with all chokepoints intact. While the US LNG is transported through the Panama Canal Route (PCR), the Russian exports take place along the NEP, and Qatari tankers pass through the Strait of Hormuz (SOH), the other considered producers can ship their cargo directly to Asia. However, it should be kept in mind that the model used is simplistic, taking into account only the Asian consumer market and only the major LNG producers. Second, the demand variation scenarios depict a supply-side competition, considering the costs of transportation and production. The results show that the Australian und US LNG exports are the least competitive, primarily due to the high production costs. Again, the model is highly simplified and, for instance, does not fully consider the sunk costs of the producers. Third, a shutdown of the NEP, as it occurs during the winter months, shifts all Russian exports through the SCR and almost triples the transportation costs. Nonetheless, the Russian exports remain competitive, if compared to the US or Australia. A shutdown of the SOH, resulting in a cut-off of Qatari supplies, benefits the other market participants who occupy Qatar's market share. There is no imminent threat to the LNG supply security. If the PCR closes down, the US exports would be rerouted trough the NEP and SCR with only a slight cost increase.

The dynamics in the global LNG market are likely to evolve in the next decade, due to significant developments both on the supply and demand side: The wave of new upstream investments in the early 2010s generated abundant LNG volumes on the market upon completion of the projects. On the contrary, the demand of the mostly Asian LNG consumers is expected to increase insufficiently in order to absorb the oversupply. As a result, the Japanese and Chinese consumers will increasingly find themselves in an advantageous position to enforce their requirements concerning short-term contracts or the abolishment of destination clauses. The greater availability of LNG volumes and the liberalization of regulations on gas infrastructure can facilitate an integrated, possibly virtual trading hub in Asia and progressively integrated prices in the region. Considerations about energy supply security and the diversification of supply sources strengthen the position of LNG in the energy mix of most Asian countries. In order to pursue these considerations, numerous investments in hydrocarbon production, amongst others in assets in the Russian Arctic, have been made. Therefore, it can be concluded that the LNG-consuming states have economic, political and strategic interests in the Arctic as a prospective hydrocarbon province and the NEP as a prospectively crucial future shipping route.

Conclusions

The political relevance of the Arctic is becoming more lucid, because the retreating ice creates possibilities for the development of hydrocarbons and new shipping routes, but also fosters strategic and military considerations of the litoral countries.

In this research, it turned out to be very difficult to determine whether the NEP impacts the LNG market or vice versa. Undoubtedly, the ice-free NEP will impact the Asian markets to some extent by facilitating Russian LNG exports from the vast gas fields in North-Western Siberia within the Arctic Circle. The completion of the Yamal LNG project increased the Russian LNG export capacity by 165%. Russian LNG exports to Europe increased by 13.5% in 2022 (compared to 2021), totaling to 14.65 million tons. This represents almost the full annual capacity of Yamal LNG, amounting to 16.5 million tons (Staalesen, 2023). On the one hand, any further large-scale LNG export aspirations in Russia are ultimately correlated with the usage of the NEP as a uniquely competitive shipping route to the Asian markets. On the other hand, all further aspirations will primarily be driven by the LNG market conditions and prices. In the end, aside from strategic political interventions, the demand and corresponding investments will determine the prospects for any Arctic hydrocarbon developments, and therefore for any extensive Arctic shipping activities.

The geographical location of the leading LNG producers and consumers makes the NEP mainly relevant for Russian LNG suppliers, if all other global chokepoints remain intact. However, for Russia's ambitions as a major LNG supplier, the NEP is of ultimate significance. Still, no significant LNG shipping between Europe and Asia has taken place yet, since both regions are primarily consumers. The scale of the exports of Russian hydrocarbons from Arctic regions will determine the scale of any Arctic shipping activity along the NEP in the near future. However, the prospects for destinational bulk shipping remain significant in the long term. Until then, the use of the NEP will remain a crucial competitive advantage for the producers and exporters of Arctic natural resources. Naturally, future shipping along the NEP will be of national significance for the Russian federation. Firstly, the development of infrastructure along the NEP can be a substantial factor of growth for the country's most remote regions, and will thus also be relevant from a regional development policy perspective. Secondly, an ice-free Arctic ocean creates multiple perspectives not only for E&P activities and trade, but also for politico-military applications. Again, a common policy approach by the Arctic Council, involving both the US, Russia and the other members is necessary, in order to limit the conflict potential and to create statutory foundation for future commercial and governmental activities. Obviously, in light of the waging War in Ukraine, this is all questionable now.

Nevertheless, Russia's entry in the LNG supply competition will probably exacerbate the political tensions between Russia and the US. Since the shale gas revolution, the US has permanently challenged the dominant Russian market position in Europe. Now, it will find itself competing against considerable volumes of highly competitive Russian LNG in the mid-term future. A comparative economic analysis of Russian and US LNG supplies and a systematic analysis of the political risks and opportunities that examines these considerations in a broader manner, would provide useful but had to be left for future research.

The developments in the Asian LNG market and the facilitation of a trading hub are of great interest from both a scientific and corporate perspective. Especially the interdependencies between the currently advantaged LNG consumers and the producers with regard to, e.g., contract conditions and market power could be examined in more detail. Another truly absorbing thought is a joint global reduction of LNG exports. The Gas Exporting Countries Forum (GECF) was established as an effigy of OPEC but for natural gas production (exports). But unlike OPEC, which mainly consists of Arab states, the members of the gas cartel are very heterogeneous and pursue different political agendas. In addition, the significantly varying costs of the leading LNG producers enhance the potential gains from finding a Pareto-efficient joint solution. In this respect, and in light of the forecasted oversupply in the next decade, a study that examines possible reduction measures and the corresponding effects appears very useful.

The NEP is a crucial element in the supply chain of Russian LNG producers. It opens up a shorter and less expensive alternative to the SCR for Russian LNG producers. Because most of the Russian gas fields are located in North-West Siberia, such a sea route is a necessity for any large-scale LNG export aspirations. A shutdown of the NEP nearly triples the transportation costs to the Asian markets when using the SCR instead. However, the NEP is hardly relevant for other LNG-producing countries for exports to Asia. Since the expansion of the Panama Canal in 2016, all North- and South-American producers will prefer the usage of the PCR as the shortest and most cost-efficient route to Asia. Nevertheless, the crucial element for the competitiveness of various worldwide projects remains the projects' break-even costs. Further, a more detailed assessment of the parameters might facilitate a more accurate forecast on achievable cost savings with regard to the NEP. However, the objective of the modeling in this study was to initially demonstrate the usefulness of applying various methods to LNG shipping routes with regard to a temporally ice-free NEP, and to pave the way for further research. Finally, it can be stated that, although there are other factors to consider, Russia's market entry, largely enabled through ice-free shipping along the NEP, does affect both global LNG pricesas well as competition and geopolitics.

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Natural Gas Price Caps in Australia are Poor Policy and may be Permanent

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The Australian government has imposed a price cap on natural gas, which may become permanent. Australia exports most of its natural gas, and extremely high international prices caused by the market turmoil in Europe are feeding through to high domestic prices. Contrary to popular thinking, the price cap will reduce investment and production.

Australians expect to share in their resources wealth, but price caps are not a good way to achieve that. Forcing companies to sell on the domestic market at a lower price reduces the value of Australia's gas resources – an opportunity cost. It would be better to maximise the value of the resource and then to choose a tax policy that does not affect investment. A prototype for this already exists.

Australian price cap might become permanent

The price of natural gas sold in Australia has been capped at AUD $12 per gigajoule (GJ) for 2023. At current exchange rates, that is equivalent to USD $7.90 per mmbtu[1], which is much lower than the Asian price of around USD $30 per mmbtu late last year.[2] The domestic price cap has a relatively narrow scope – it applies to gas supplied by producers in eastern Australia during 2023, under agreements signed after 23 December 2022.

More importantly, the government has proposed permanent price controls in the form of a 'reasonable pricing provision'. The aim is for domestic gas prices to match production costs, where costs include exploration costs and a return to capital.[3] So far, we know that the government currently considers AUD $12 per GJ to be a reasonable price.

To ensure that producers do not avoid the price cap by simply re-directing gas to the export market, producers would be required to make offers broadly available to the domestic market. The timing for issuing expressions of interest would be regulated, and binding arbitration would be available to parties that cannot form an agreement. However, the government cannot force producers to explore for, or produce, more gas.

How did we get here?

A quick overview of recent market history. During 2015 and 2016, three Liquefied Natural Gas (LNG) export terminals commenced operation on the east coast of Australia. Since then, domestic gas prices have risen, together with Australia's collective eyebrows. Real gas prices averaged AUD $4.21 per GJ between 2010 and 2015 and then doubled to AUD $8.55 per GJ between 2016 and 2021.[4]

The LNG projects produce large amounts of gas in Queensland, some of which is sold on the domestic market. The LNG projects have substantial bargaining power because they have an outside option to export at the Asian price. As such, they offer prices to the domestic market that are linked to the Japan Korea Marker (JKM).

Some large industrial gas users have struggled to cope with the higher gas prices, with many closing up shop. Following the turmoil in Europe, contract prices as high as AUD $30 per GJ have been offered for domestic supply in 2023.

The influence of the export price in the domestic market has increased over time as gas supply in southern states has declined. State governments in NSW, Victoria and SA share responsibility for this, with bans on new developments contributing to the decline in gas production. If produced, southern gas could be sold at a discount to the LNG price, because it is further from the export plants and closer to demand centres. Indeed, if gas supply was large enough that LNG export plants were at capacity, the domestic price would again de-couple from the export price.

Price caps will discourage investment

Some have argued that the LNG industry never expected prices to be as high as current levels, so imposing price caps would not affect investment incentives. I disagree.

Although a war in Europe was unexpected, high LNG price events are not. Global LNG supply is inherently inflexible, because increasing liquefaction capacity is costly and slow, and the market remains illiquid, particularly in Asia. Investors know that small increases in demand can create large increases in price. (The converse is also true, small declines in demand create large price falls.)

Figure 1 shows the Australian netback price, from before the turmoil in Europe. This is the Australian domestic gas price that is equivalent to the prevailing export price (calculated as the spot JKM price, converted to Australian dollars and units, subtracting liquefaction and shipping costs).[5] During the time that the Queensland LNG projects made their investment decisions, the LNG price was well above $12 per GJ for a sustained period. That high price event was due to the tsunami that hit Fukushima in 2011.

Investors in eastern Australia surely recognised the potential for high LNG prices, certainly above $12 per GJ. They deliberately left some room to participate in the spot market, rather than selling their full capacity to Asian buyers under long term contracts. That is, the decision to invest in Queensland gas fields was made on the basis that that large volumes would be sold under long term contracts to Asian byers, with some upside opportunity from the spot market.

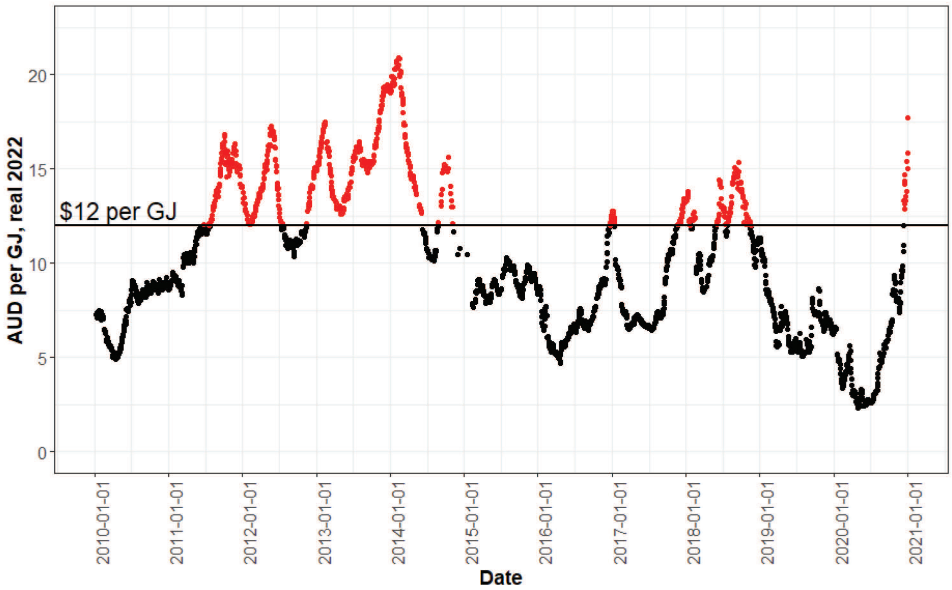

Figure 1: JKM - Australian netback price

If the Australian government limits LNG profits in the good times, but does not help out during the bad times, companies are left with all of the downside risks, and reduced upside risks. They will be less willing to invest in natural gas exploration and development, reducing longer term production levels.

In the short to medium term, LNG projects can respond to reduced profitability by producing less from their existing fields. The government argues that the price cap covers the lifecycle costs of gas and would not affect production. While the cap may be higher than average gas costs, within any field there are always wells that are low productivity and too expensive to drill. The lower the price cap, the more of these wells that will not be drilled.

Production is flexible enough to respond in the short term – production volumes in Australia already respond to seasonal fluctuations in demand. In Queensland, gas is produced from coal seams, which require more frequent investment in drilling activities, and will therefore be more responsive to prices.

A price cap diminishes Australia's resource wealth

Most importantly, Australia now has the option to export gas at prices much higher than AUD $12 per GJ. By forcing gas companies to sell to the domestic market at lower prices, the gas industry foregoes revenue. The value that domestic users get out of this gas is not high enough to make up for this. We know that domestic users value the gas less than the export market, because otherwise they would be willing to pay the higher price.

Fundamentally, this policy will reduce the value of Australia's natural gas, at the same time as reducing investment in exploration, development and production.

A tax whereby Australians share resource profits and losses would be better

Policy makers wish to ensure that the "domestic wholesale gas market delivers for Australians". Australians own the country's natural resources (through their governments), and as such are entitled to benefit from their extraction.

To maximise their benefits from natural gas, Australians should first seek to maximize the resource's value, by exporting it. Then, they can share in this value using a tax similar to the existing Petroleum Resource Rent Tax (PRRT).

The PRRT currently applies to offshore oil and gas projects, and attempts to replicate a situation where the Australian government is a silent shareholder in each resources company. Under a well-designed version of this tax, the government shares in resources profits when prices are high. Importantly, it also shares in the investment costs and any losses when prices are low. In theory, the tax does not change the risk profile of the project, it only reduces the company's share of the project. As a result, investment incentives are not reduced. A project that is marginally profitable without the tax is still marginally profitable with it. It does not become unprofitable.

The current design of this tax is not perfect, as highlighted by the Callaghan Review in 2017. However, it is far better than the ad-hoc interventions in the market currently being considered.

To tax gas extracted by LNG exporters, the Rudd and Gillard governments extended the PRRT to onshore gas projects in 2012. However, significant grandfathering concessions were made, and at the time no revenue was expected to be earned from the LNG export projects. In 2019, onshore projects were exempted from the tax, by the Morrison government.

Australian voters currently feel that they deserve a greater share of their resources wealth, particularly from the gas industry. This momentum should be channelled into designing a better longer-term mechanism for Australians to share in their resource wealth. It should not be wasted on counter-productive price caps.

Footnotes

[1] On January 17, 2023, the exchange rate was 0.6973 and an MMBtu is 0.947817 of a GJ.

[2] Japan Korea Marker, JKM

[3] This will be implemented via a mandatory code of conduct, which requires producers to offer their gas domestically at 'reasonable' prices, and binding arbitration for pricing disputes.

[4] Spot prices in the Victorian 'Declared Wholesale Gas Market', adjusted to real terms (2022) using the producer price index.

[5] The netback method follows the ACCC, but extends it backward to include a longer history.

The Impact of Russia's Invasion of Ukraine on Global LNG Balances in 2030: A Scenario from the bp Energy Outlook 2023

BY GAUTAM MUKHERJEE AND MELANIE SAWARYN

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Abstract

This paper illustrates a scenario of how Russia's invasion of Ukraine could influence global LNG balances in the medium term to 2030. The reaction to the war reduces Russia's pipeline and LNG exports. However, the overall size of LNG trade in 2030 is broadly unchanged. On demand, higher EU LNG imports offset lower LNG imports into Asia. The US and Middle East share of LNG growth increase to offset the lower Russian LNG exports.

1. Introduction

The Russian invasion of Ukraine in February, 2022 has upended global gas markets and has had major implications for energy affordability globally. In 2021, EU imports of pipeline gas from Russia made up about a third of its demand and this declined by more than 50% in 2022. Due to its fungibility, LNG has been the main source of supply that has helped to balance the EU gas deficit. The magnitude of the loss of Russian pipeline volumes in 2022 was almost 15% of the global LNG market and a third of the spot LNG market, resulting in a drastic tightening of global LNG balances and more than doubling of global natural gas prices. These dramatic changes raise the question of how long global LNG markets may remain disrupted and what the medium-term impact might be on natural gas markets. In this paper, we use a scenario from bp's Energy Outlook 2023 (EO23) to inform this question.

bp's EO23[1], released in January 2023, updates bp's Energy Outlook 2022 (EO22) to take account of changes to the evolution of the global energy system out to 2050 because of Russia's war and the passing of the Inflation Reduction Act in the USA. As in EO22, the EO23 focuses on three main scenarios - Accelerated, Net Zero and New Momentum - to capture a wide range of uncertainty underlying this evolution. Accelerated and Net Zero explore how different elements of the energy system might change to obtain a substantial reduction in carbon emissions consistent with keeping global temperature rises to well below 2° C and 1.5° C respectively, while New Momentum is designed to capture the broad trajectory along which the energy system is currently progressing. These scenarios vary substantially in terms of the outlook for demand for natural gas and fossil fuels more generally, with different implications for how long markets could remain disrupted because of the war. Below, we summarize the most relevant outcomes from the New Momentum scenario (NMS) in EO23 and how it differs from the outcomes in the same scenario in EO22 due to the Russian war.

The main impacts of the war on global LNG markets out to 2030 in EO23 NMS (relative to EO22 NMS) would be:

- An increased focus on energy security resulting in a preference for domestic sources of energy. In addition, there is also a move away from globalization which negatively impacts economic growth and consequently, energy demand growth.
- Russian gas exports remain disrupted due to the EU's determination to increase energy security by phasing out dependence on Russian pipeline imports, and the introduction of EU and US (see below) sanctions on exports of LNG liquefaction technology to Russia, substantially denting Russia's ambition to become a major LNG exporter.
- This reduction in Russian pipeline imports into the EU results in higher EU LNG imports. However, concerns over energy security and lower economic growth result in lower LNG demand growth in Asia, offsetting growth in the EU. Thus, the overall size of LNG market in EO23 in 2030 is similar to our outlook in EO22, c. 770 bcm, a c.50% increase from 2021.
- Loss of Russian LNG exports is made up for by higher exports from the US and Middle East. Together, these two regions account for 70% of the supply growth to 2030. Many projects have already begun construction in both these regions and there remains a substantial pipeline of projects, especially in the US, that will add to this total.

2. The outlook for LNG Demand

The EU is the epicenter of the current disruptions to energy flows emanating from Russia's invasion of Ukraine. This is particularly true for natural gas. In 2021 the EU imported via pipeline c. 132 bcm - around one third of its gas demand - from Russia[2]. In 2022, these pipeline imports from Russia declined to c. 63 bcm[3], requiring a combination of demand reduction and increased alternative supply mainly in the form of higher LNG imports.

In EO22 NMS, EU reliance on Russian pipeline imports out to 2030 was similar to levels in 2021. Thus EU LNG imports grew only modestly. In contrast, almost all of the growth in global LNG demand was in Asia. This growth was driven by coal to gas switching in China, continued industrial growth and limited pipeline supply alternatives outside of China. The overall size of LNG trade grew by more than 50% to 790 bcm in 2030.

In EO23 NMS, due to the Russian invasion of Ukraine, Russian pipeline imports into the EU are largely phased out by 2030. To make up for the shortfall, natural gas demand declines by 20% between 2021 and 2030, driven by an increase in the share of renewables in the power sector and an increase in the electrification of heating in the residential, commercial and light industrial sectors. Despite this decline in demand, LNG imports increase by c. 50% relative to 2021 highlighting limited alternative pipeline supply options given the decline in domestic production in Europe.

By contrast, Asian LNG demand growth slows in EO23 NMS compared to EO22 NMS. The Russian invasion triggers a move towards deglobalization, reducing economic growth especially in Asia which has benefited substantially from globalization. The weaker macroeconomic outlook reduces energy demand and, in particular, gas demand. In addition, the energy security concerns engendered by the war also result in a preference for lower energy imports in favor of domestic resources. For example, both South Korea and Japan increase reliance on nuclear power generation compared to EO22, negatively impacting gas demand. Finally, the loss of the EU as an export market makes China the largest market for Russian pipeline gas by 2030. Given the lack of many alternative export markets, Russian pipeline exports to China increase relative to EO22 NMS, reducing the need for China to import LNG. The decline in Asian LNG demand growth offsets the growth from Europe, resulting in the overall size of LNG trade growing to 770bcm by 2030, similar to EO22 NMS.

3. Outlook for LNG Supply

In EO22 NMS, the US, Middle East and Russia contributed to almost 75% of the growth in LNG supply between 2021 and 2030. Russian LNG exports more than doubled to almost 110 bcm by 2030 and included continued exports from existing projects such as Yamal LNG and Sakhalin-2 LNG, new supply from projects under construction such as Arctic LNG-2 (which took Final Investment Decision [FID] in 2019) and other projects that were still under development. The scale of the increase in Russian exports was supported by the existence of abundant upstream resources, as well as the ambition of both Gazprom and Novatek to increase their share of exports in the global LNG market.

However, Russian LNG has so far continued to be dependent on support from western partners for technology and finance. Since the invasion of Ukraine, the US and EU have imposed sanctions on the export of LNG and other technology to Russia. These sanctions have been imposed on all potential projects including those already under construction and those still under development. In EO23 NMS, Russia is unable to overcome the sanctions in time and LNG exports increase more modestly, to 50 bcm by 2030. The shortfall in supply is made up for mainly by higher exports from the US and Middle East.

US LNG exports more than double relative to levels in 2021, to 200 bcm by 2030, and make up the greatest share of the loss of Russian LNG exports. Progress towards reaching this level of growth is well underway. Several LNG liquefaction facilities are already under construction in the US as of early 2023, including two major projects which reached FID in 2022 (the first phase of Plaquemines LNG and Corpus Christi LNG Stage 3). Moreover, there are several other projects at various stages of development aiming to make positive FID in the near future.

The Middle East is the second largest source of additional non-Russian LNG supply by 2030 in EO23 NMS compared to EO22. LNG exports from the Middle East grow by around 75 bcm between 2021 and 2030. Of this growth, nearly 45 Bcm is already under construction at Qatar's North Field East expansion project. Among other Middle Eastern new LNG export projects aiming towards FID in the short term are Qatar's North Field South expansion project (22 Bcm) and the UAE's Fujairah LNG (13 Bcm).

4. Conclusion

This paper looks at how the current disruptions to global gas markets may evolve out to 2030, based on one scenario alone. There is clearly substantial uncertainty to the view expressed above not least related to the length of the conflict and any resolution thereof. At this time, the EU remains quite determined to permanently reduce its reliance on Russian pipeline imports and it is certainly difficult to envisage pipeline imports getting back to 2021 levels in the medium term. However, the prospects for Russian LNG exports are more uncertain. Countries in the EU and elsewhere continue to import Russian LNG and there is currently no talk of that changing. Russia's ability to continue to develop projects and export more LNG is therefore dependent on its ability to develop technology either on its own or with non-western help. In a situation where Russian teams were able to make technological advancements we would likely see an increase in global LNG supply and a boost to LNG demand sooner than expected. However, Russia remains reliant on foreign spare parts to service its current LNG liquefaction facilities and sanctions on these could keep Russia out of LNG for longer.

Footnotes

[1] Please see Energy Outlook | Energy economics | Home (bp.com) for a more comprehensive description of the scenarios.

[2] bp Statistical Review 2022

[3] Based on various European Transmission System Operator data.

[4] References to 2021 volumes in charts are data from bp Statistical Review 2022.

Appendix – Charts[4]

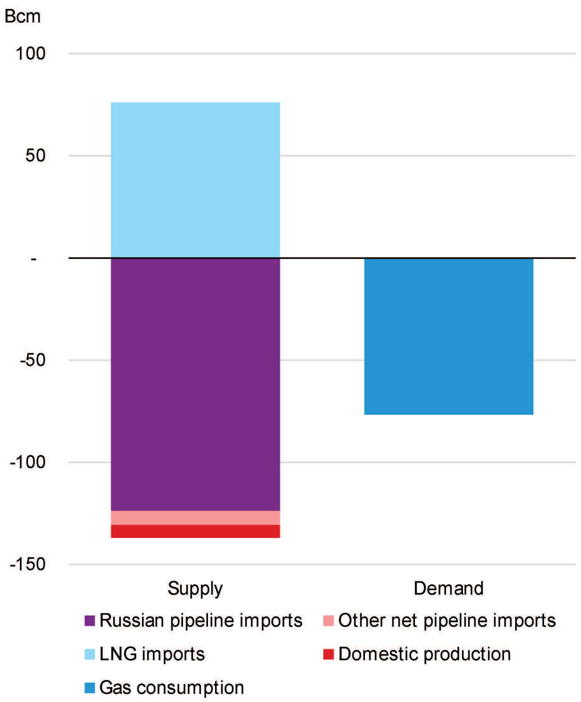


Figure 1: Change in EU natural gas balance 2021-30 in bp's EO23 NMS

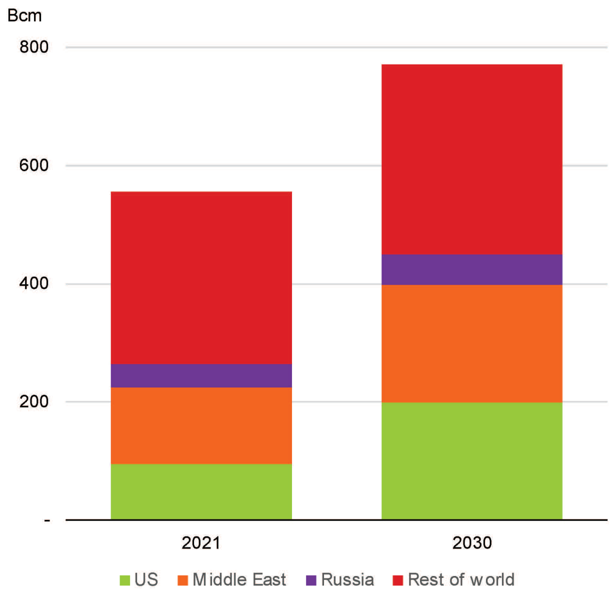


Figure 3: LNG supply in bp's EO23 NMS

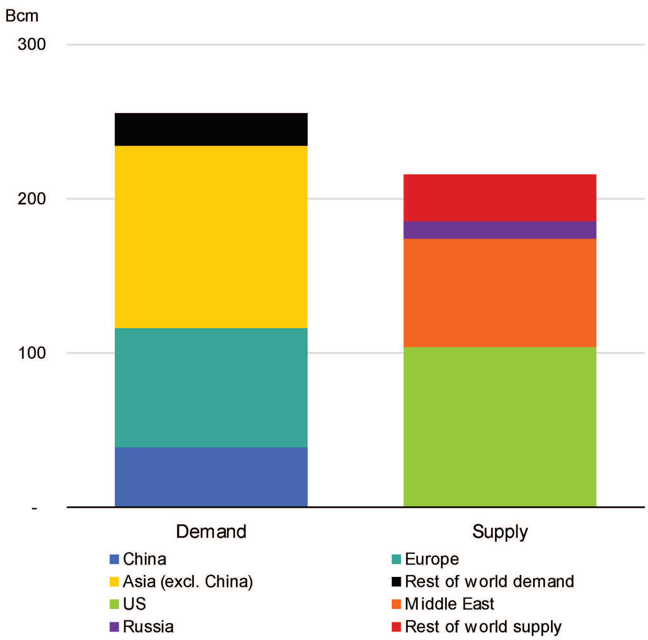


Figure 2: Change in global LNG demand and supply, 2021-2030 in bp's EO23 NMS

44th IAEE International Conference, Riyadh, Saudi Arabia 04-09 February 2023 "Pathways To a Clean, Stable and Sustainable Energy Future"

BY RIYADH CONFERENCE SECRETARIAT

The recently concluded 44th IAEE International Conference in Riyadh, Kingdom of Saudi Arabia, discussed multiple avenues toward exploring the most efficient pathways to a clean, stable, and sustainable energy future. The Conference, held for the first time in MENA, underscored the critical messages of ensuring stable energy markets, continued investments in fossil fuel sources, and increasing investments in diversified renewable energy sources toward ensuring an orderly energy transition to a sustainable net-zero future.

Although renewables accounted for over 80% of all *new* power-generating capacity in 2021, they still comprise only about 4% of today's energy mix.[1] Despite the significant advances in alternative energy sources like renewables, fossil fuels, including oil, coal, and natural gas, continue to supply around 80% of the world's energy.[2] The decarbonization of existing fuel will be key to achieving the goals of the Paris Agreement, to reach net-zero greenhouse gas emissions and deliver on governments' commitments, as those sources will be part of the global energy in 2050 and beyond. Therefore, it is critical that investment in hydrocarbons continues to ensure energy security and energy access to a vast majority on the planet who struggle with energy poverty, and helps propel the engine of global economic growth while mitigating emissions from those sources. However, energy markets are being impacted by policy uncertainty, leading to policy risk feeding into price volatility. These risks are exacerbated by political moves toward resource nationalism and reduced access to global markets, reversing the previous globalization policy. To achieve an orderly global energy transition, we need to ensure that there are no disruptions in the energy supply and address these challenges.

Therefore, it is essential to take a sensible macro view of the challenges that we are facing. The projections show that global energy demand will increase by 30% by 2050 due to the expanding global population, estimated to grow from 8 billion to 9.8 billion people. This surge in demand will have far-reaching implications for the world's energy infrastructure as governments and businesses strive to meet the needs of a rapidly increasing population. The population in the MENA region alone will almost double in the next 50 years, according to the Population Reference Bureau, and 90% of the GCC's residents will live in cities by 2050. We are responsible to billions of people worldwide to ensure they have access to the energy they need.

Given that there are forecasts that an additional 400 million people globally will gain access to electricity in the next 15 years, feeding into an increased need for a stable, ongoing, and reliable supply of energy, the recent and growing polarization of the climate debate is not helpful because this is not a binary issue; it's taking place in an increasingly interconnected world with multiple aspects globally. As we address this issue, we must balance industry, government, and academic approaches, ensuring that the broadest possible range of views and reliable data is incorporated in policy, discussion, and action. Conventional energy must be utilized with alternative energy sources while prioritizing reduced emissions to meet the growing global energy demand and achieve net-zero emissions goals.

Policymakers recognize that the energy transition will take time as well as substantial financial and technological investments. They are engaging in a pragmatic conversation on a natural energy transition: ambitious but also practical, with a long-term goal to restrict emissions but not progress. The economic and environmental development security of the world must be balanced. The adoption of renewable energy and other low-carbon sources has the potential to provide long-lasting energy security, but we are not there yet. There has been a significant drop in the cost of renewables, now cheaper than coal, for decades considered the cheapest source of electricity. While solar became 89% cheaper and wind 70%, coal's electricity price declined by only 2%.[3]

The impact of the Covid-19 global pandemic persists in upended demand for energy. Central banks, which were earlier profligate during the pandemic with financial stimulus packages to boost consumption and spending to stabilize demand-hit pandemic economies, are now coming face to face with increased inflation and are seeking to shrink their balance sheets and raise interest rates. These moves will have repercussions on project financing and costs across the board, further fuelling inflationary trends globally. Mobilizing the finance and resources needed to enable a sustainable, reliable, and stable energy transition and accelerating the deployment of modern renewable energy and battery storage, CCUS, clean hydrogen, energy efficiency, and even electric vehicles have become increasingly important. For developing countries, the increasing role of financing in the energy transition is critical, primarily as they often do not have access to developed markets domestically. Increasingly complex and structured green finance products often inhibit their ability to finance energy transition projects, making them lag in deploying energy transition technologies. This increases pressures on these countries to develop low-cost adaptation pathways which are accessible, equitable, and have a focus on generating profits to increase investor attractiveness.

We cannot, however, talk about energy without talking about trade. The effects of the Covid-19 pandemic and the ongoing conflict between Russia and Ukraine have entirely changed the energy landscape. It raises the critical issue of how trade and global energy requirements are intrinsically linked. The world was already facing a profound energy-supply crunch as economies began to bounce back from the Covid-19 pandemic. The Russia-Ukraine conflict made a tight market even tighter and forced countries to reassess their urgent near-term strategic energy needs. By banning Russian oil and gas, we have raised the cost of doing business for the simple reason that trade is about cost efficiency. Trade is vital to ensuring energy security and the foundation of initiatives and plans to utilize low emissions. The undeniable reality is that energy security and climate action are inextricably linked, and one cannot exist without the other. It is a simple fact that if people's essential energy needs are not met, economic growth will be hindered, thus stifling meaningful climate action. Trade also profoundly affects any initiatives seen as part of the journey toward meeting net-zero goals. For example, sales of electric vehicles (EVs) globally doubled in 2021 from the previous year to a new record of 6.9 million. This is good news, but as the electrification of various modes of transportation becomes more widespread, the limitations of this approach will become increasingly apparent.

With this rising demand for electric vehicles comes a growing need for raw materials, manufactured materials, and energy sources. This mainly includes battery metals such as lithium, manganese, nickel, and cobalt. The Democratic Republic of the Congo has nearly half of the world's cobalt reserves needed to achieve economic goals, including EV usage, so a new trade structure is required to facilitate the movement of these critical minerals. Likewise, global lithium production surpassed 100,000 tonnes for the first time in 2021, quadrupling from 2010. Roughly 90% of lithium came from just three countries – Australia, Chile, and China – and we now see a supply gap with a limited production and refining capacity. Meanwhile, 39% of manganese comes from South Africa, so again, there is a precarious supply and demand issue surrounding trade and the availability of components required for EVs.

To overcome this, we need to improve the resilience of supply chains for different minerals and an overarching international framework for dialogue and policy coordination among producers and consumers. The case of EVs is one example, but it applies to everything, making it incredibly difficult to transition from fossil fuels to renewables. In contrast, investments in renewable deployment could become expensive due to trade and supply issues. The criticality of these aspects will increasingly impact investments in the decarbonization of sectors such as transport. Policymakers are increasingly focusing on growing the penetration of electric vehicles in public transport and providing sustainable transport options to consumers. A crucial part of the transportation paradigm is the increasing focus on sustainable and resilient cities becoming more relevant as the pressures of urbanization increase exponentially. We need a pragmatic, inclusive, holistic approach to the energy transition and security. We should be realistic, pursue this vital challenge, and avoid a crowd-out effect. This, however, is easier said than done. Especially as countries seek to focus on energy transition as a commercial opportunity rather than to collaborate, and collaborate equitably, a framework approach that helps governments work together to tackle such global problems could help ensure that the gains of such cooperation are available to a broader population.

A circular carbon economy with a robust framework for managing and reducing emissions is an excellent place to start – a closed-loop system involving the 4Rs: reduce, reuse, recycle, and remove. The Kingdom of Saudi Arabia, including Aramco, are among those who have adopted the circular carbon economy framework to reduce their carbon footprints. The industry can also embrace technology, including artificial intelligence and big data, to minimize emissions by monitoring company energy consumption and to optimize operations, improving seismic processing and analysis, optimizing crude oil recovery methods, and enhancing oil well productivity. Many of the innovations and technology we see as part of that transition process already come from the major oil and gas producers. The world's legacy energy companies are not only a key part of the energy transition but will also lead it. Through this holistic and multi-faceted approach, the immediate and long-term impacts will be transformative, given that oil will remain vital for global sustainability for decades. Not only because it's the primary source of global energy and many thousands of daily items we rely upon.

Petrochemicals derived from oil and natural gas make manufacturing over 6,000 everyday products and high-tech devices possible. Primary petrochemicals — including ethylene, propylene, acetylene, benzene, toluene, and natural gas constituents like methane, propane, and ethane — are the feedstock chemicals needed to produce many items we use and depend upon every day.[4] Products that rely on the oil and gas industry range from mobile phones, laptops, detergents, refrigerants, and asphalt to contact lenses, insect repellents, toothbrushes, and shampoo. Polyester is a synthetic petroleum fiber incorporated into 60% of clothing worldwide. It has played a key part in clothing since the early 1950s, making a rapid transition back to cotton and wool clothing impossible. The oil and gas industry continues to shoulder a huge responsibility. The key to its future is to ensure that we control emissions rather than divestments and ensure continued investments in traditional energy sources. The expectation is that as renewables and low-carbon options become increasingly available, they will replace conventional energy sources and, in some cases, provide energy to those who have never had it. But even in a future net-zero emissions world, energy security and everyday life require that oil and gas be part of the mix. The energy mix also has to diversify to meet the increasing demands of a growing population. These include solutions like nuclear energy, with the potential development of Small Modular Reactors (SMRs).

The energy industry continues to innovate and develop solutions as we transition from fossil fuel as quickly as possible, with multiple projects and initiatives financed by companies that previously only supplied oil and gas. Conventional fossil fuel energy – supported by lower emissions and mitigation and adaptation strategies – still has an essential role to play and needs to work alongside alternative energy to meet the rising global energy demand while continuing to work on delivering on net-zero ambitions. The world must not undermine energy security, erode economic stability, and slow down critical investments in the energy transition. The global energy transition is perhaps the most important project that humanity has ever undertaken. However, while alternative energy sources are developed, implemented, and expanded, we cannot relinquish our responsibility to secure affordable, essential oil and gas. We'll need it for decades, so we must ensure we obtain it sustainably.

Footnotes

[1] https://www.project-syndicate.org/commentary/realistic-energy-transition-oil-gas-renewables-by-sultan-al-jaber-2022-08

[2] https://ourworldindata.org/energy-mix

[3] https://www.arabnews.com/node/1826641/world

[4] https://www.energy.gov/sites/prod/files/2019/11/f68/Products%20Made%20From%20Oil%20and%20Natural%20Gas%20Infographic.pdf

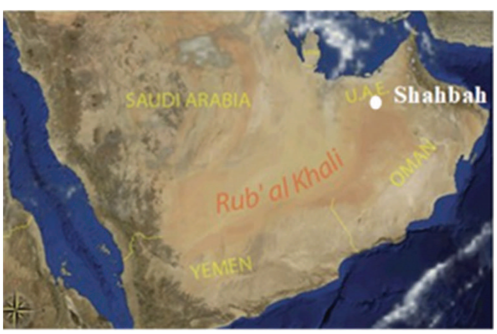
Shaybah Technical Tour February 9, 2023

BY CAROL A. DAHL

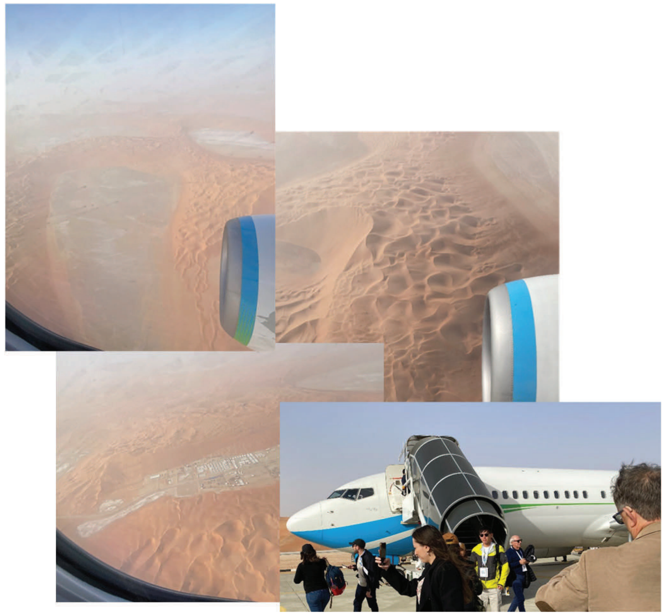
The International Association for Energy Economics' annual conference took place for the first time in the Middle East in Riyadh, Saudi Arabia in February, 2023. With over 1700 attendees representing 98 nationalities, much information and comradery were shared. We were also treated to Arab hospitality and culture especially at the gala cultural dinner including an Arab men's dance and lamb roasted over an open fire. With the conference over, Saudi Aramco sponsored a special technical tour to Shaybah oil field. The field was discovered in 1968 but not developed for decades until technological advances made it possible to unlock the black gold that had been hidden under the sands for millions of years. This super giant field was estimated to have more than 14 billion barrels (2.2 billion cubic meters) of extra light sweet crude (42° API) and 25 trillion cubic feet (710 billion cubic meters) of natural gas. The first production commenced in 1998 with production reaching a million barrels a day by 2016. The field is connected to Abqaiq with a 400 mile (640 kilometer) crude oil pipeline, from where the oil can be transported to Saudi refineries and export terminals. A 2.4 billion cubic feet/day (68 million cubic meters/day) natural gas processing plant has been extracting natural gas liquids from natural gas production for the petrochemical industry since 2015 and is currently being expanded. This separation leaves the methane for reinjection or use to generate electricity for the operations and supports Saudi goals of reducing natural gas flaring and replacing the use of liquid fuel for power generation with lower CO_2 emitting natural gas.

We boarded the plane provided from a private airport in Riyadh. On take-off, we were given the usual cautions about seat belts and oxygen masks with no mention of life vests in case of a water landing. That is because the Shaybah field is in the Rub' al Khali desert, whose name means empty quarter in Arabic. Just south of Abu Dhabi, UAE, it is justly named. With less than 2 inches (5 centimeters) of rain a year and temperatures ranging from 32 ° - 124 ° F (0 -50 °C), it is rather empty but with no shortage of sand.

We flew over miles and miles of orange red sand dunes deriving their color from feldspar. The dunes up to 820 feet (250 meters high) are broken with gravel and gypsum plains and occasional salt flats with green circles signifying irrigated crops.



Source Underlying Map: NASA posted at media.org/wiki/File:Empty_quarter_Arabia.PNG.



We landed at the Shaybah airport right by the camp. A large tank wagon labeled jet fuel stood nearby as we deplaned and boarded nearby waiting buses. We passed by the camp, and some large storage tanks on our way to the Shaybah Wildlife Sanctuary sponsored by Saudi Aramco. As the road wound and twisted upward, we were able to see up close the impressive dunes and look down on gravel plains below.

At the sanctuary visitor's center, we were greeted with traditional tokens of desert hospitality: Arabic coffee and dried dates. We were given a short briefing and tour of the exhibits. The 246 square mile (637 square kilometer) fenced sanctuary was developed to

reintroduce and protect native species of plants and animal to the Rub' al-Khali. A top priority was given to three species of animal: the Arabian sand gazelle, the Arabian oryx, and the ostrich. Food, watering holes, shaded areas, and veterinary care are provided across the sanctuary to ensure their survival.

In our continuing tour, we were able to see the results of their efforts and view all three of these special species and even have a group picture with oryx and huge sand dunes in the background.

No trip to so much sand would be complete without the opportunity to play on the dunes. The culmination of the sanctuary tour allowed us this opportunity. We watched the sun set over the Rub' al-Khali from the dunes before we headed back to Riyadh.

The attendees extend their thanks to Saudi Aramco for the rare opportunity to experience this unique ecosystem. Alas, there was not much technical in our technical tour as a reported sand storm prevented our visit to any of the oil or gas operations.

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IAEE
International Association for
ENERGY ECONOMICS

IAEE/Affiliate Master Calendar of Events

(Note: IAEE Cornerstone Conferences are in boxes)

Date	Event and Event Title	Location	Supporting Organizations(s)	Contact
2023				
July 24-27	18th IAEE European Conference *The Global Energy Transition: Toward Decarbonization*	Milan, Italy	AIEE/IAEE	G. Battista Zorzoli https://www.aiee.it/
Nov 5-Nov 8	40th USAEE/IAEE North American Conference *Theme TBD*	Chicago, Illinois	USAEE/IAEE	Doug Conrad usaee@usaee.org
2024				
June 23-26	45th IAEE International Conference *Overcoming the Energy Challenge*	Istanbul, Turkey	TRAEE/IAEE	Gurkan Kumbaroglu http://www.traee.org/
2025				
June 22-26	46th IAEE International Conference *Energy Solutions for a Sustainable and Inclusive Future*	Paris, France	FAEE/IAEE	Christophe Bonnery https://www.faee.fr
2026				
May-June	47th IAEE International Conference *Forces of Change in Energy: Evolution, Disruption or Stability*	New Orleans	USAEE	Peter Balash www.usaee.org
Sept 6-9	19th IAEE European Conference *Energy Security, Sustainability and Affordability: Does Regulation or Liberalization Pave the Way?*	Munich, Germany	GEE	Aaron Praktiknjo apraktiknjo@eonerc.rwth-aachen.de
2027				
August 15-18	48th IAEE International Conference *Reshaping Energy for the Future*	Hong Kong	City Univ. of HK	Lin Zhang l.zhang@cityu.edu.hk
2028				
March 12-15	49th IAEE International Conference *Energy Security and the Energy Transition*	Abu Dhabi	UAEE	Steve Griffiths steven.griffiths@ku.ac.ae

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The following individuals joined IAEE from 10/20/2022 to 5/12/2023.

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