European and Asian Energy Security in the Context of LNG

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Abstract

In this paper, the future of LNG trade is examined, recognizing that the market is at a critical juncture following Russia's invasion of Ukraine on February 24, 2022. The war has led to a sharp increase in European LNG demand to compensate for the disruption in Russian pipeline flows, resulting in extreme gas and LNG price volatility, and has reduced LNG supply available to other markets. Energy security now sits more prominently alongside decarbonization as key imperatives for global energy markets. These are considered in relation to short-, medium-, and longer-term LNG supply/demand dynamics. The analysis shows that current market tightness is unlikely to subside until the second half of this decade when more LNG supply capacity becomes available led by the United States and Qatar. The longer-term outlook is less certain. Emerging markets in Asia that were encouraged to switch to gas (via LNG) when it was relatively cheap and plentiful throughout the 2015-2020 period may no longer see gas as the ideal transition fuel. For Europe, the move away from gas is now as much an issue of energy security as it is one of decarbonization. As a result, investors now face more uncertainty regarding long-term demand. Combined with the risks inherent to the LNG industry (on account of the cost, size, and complexity of projects often in unstable regions), investment in new capacity could slowdown despite the current supply shortages.

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Introduction

In a context of rising geopolitical risks and energy security concerns, and record international gas and liquefied natural gas (LNG) prices, the longer-term outlook for gas demand has turned negative. LNG has been Europe's savior in response to the rapid curtailment of Russian supplies of pipeline gas, but only as a short-term fix on what Europe hopes will be a faster transition to non-fossil energy. In Asia, dependence on LNG has proven more of a liability, with Europe's grab for spot volumes leaving other markets short, impacting timelines for investment in gas infrastructure, such as import terminals, grid infrastructure and gas-fired power plants.

Whether natural gas can rebuild its reputation as a reliable transition fuel again is unclear. This will depend on governments' policies and priorities (whether in the interests of decarbonization or energy security) as well as the affordability and availability of supply. A wave of new LNG supply capacity will enter the market later this decade, and the market will move from 'famine to feast'. But the rise in prices has done little so far to incentivize investments in new capacity. No new large-scale LNG projects were formally sanctioned outside of the US in 2022 and except for Qatar's North Field South, none are immediately on the horizon. The prospect of either Russia or Mozambique becoming major engines of LNG supply growth have been thrown into doubt. Commercial momentum is almost entirely with developments planned in the US Gulf Coast, which continue to face significant challenges raising the capital needed for construction.

1. Managing Global Supply Chains

1.1 Evolution of LNG Supply Chains

LNG supply chains historically, and still today, have centered more on how trade is structured rather than a straightforward function of supply meeting demand.

From the LNG industry's beginnings in the 1960s and throughout much of its history, LNG projects were developed to operate on a point-to-point basis, between dedicated markets, dedicated infrastructures (terminals) and dedicated buyers and sellers.

Market participants comprised a relatively small 'club', dominated by a handful of international and national oil and gas companies (producers/sellers) and large Asian (predominantly Japanese) utilities (buyers). Trade was carried out under long-term 20-to-25-year contracts at an agreed contract price, indexed to the price of crude oil.

The trade has continued between countries that generally only export or only import natural gas, and as a means of connecting natural gas production in areas with limited local demand with distant demand centers. Today, the global LNG market is comprised of more than 40 importing countries and about 20 exporting countries. Total LNG supply has grown to about 400 million tonnes per annum. In 2022, Asia imported about 60% and Europe (EU + UK) almost 30%, and smaller markets across the Americas and Middle East account for the remainder.[1]

Patterns of exploration, development, production, and resource depletion are always evolving and can lead to the reversal of supply chains. Some markets have gone from being primarily importing to exporting countries (e.g., the United States), while some exporting countries are now also importers (e.g., Indonesia, the United Arab Emirates), and the importer/exporter status of others (such as Egypt) have changed several times due to the dynamics of their gas supply and demand.

As the overall size of the market has grown, the commercial structures and characteristics of the global supply chain have also changed in several ways. Key among them include:

[1] The EU as a bloc was the largest importer of LNG in 2022, importing more than Japan and China. https://www.ft.com/content/3b48c327-978d-4a82-9349-c4228fdf99bd

- Increasing amounts of LNG are traded on the spot market or on short-term contracts.
- Increasing amount of flexible supply, primarily driven by US LNG.
- The diversity of market participants has expanded in tandem with the market's size.
- Increasing proportions of longer-term sale and purchase contracts involve portfolio sales without a fixed origin.

1.2 Spot Markets

Spot sales of LNG have grown as a proportion of total global LNG trade and now amount to more than a third of all traded LNG (more than 130 Mtpa). Spot trade has grown as a function of the growth of physical and financial market liquidity, especially through the development of gas hubs in North America and Europe. The growing liquidity of international gas hubs occurred in parallel with new capacity built during the 2000s to supply these liquid gas markets.

Following the US shale revolution, which ended the need for LNG imports into most parts of the US (outside of the northeast), LNG supply intended for the US was remarketed and contracted to buyers in other markets, as well traded on a spot and short-term basis, either in Europe or Asia, helping to propel spot trading.

Pacific Basin markets are generally more ‘managed’, lacking the structural characteristics that give rise to liquid trading hubs, which would include competition between LNG and alternative sources of supply, including domestic gas production and other non-LNG imports, as is the case in Europe and North America.

But spot trading specifically of LNG in the Pacific basin (as opposed to gas trading hubs) has become well established; and the Platts Japan Korea Marker (JKM) has emerged as the benchmark price for LNG delivered into Northeast Asia.

Spot LNG trade is now structured primarily around European and Asian pricing dynamics, between the Dutch Title Transfer Facility (TTF) in Europe and JKM in Asia, with differentials providing market signals to direct spot LNG trade and flexible supply between these regions. (Spot LNG can be thought of as LNG procured from the market as opposed to purchases made under longer term contract arrangements; and flexible supply are contracted volumes, the supply of which is not restricted to a specific destination market or end-user).

Prior to the events leading to and following from Russia's invasion of Ukraine on 24 February 2022, the JKM market tended to be the premium market to attract flexible volumes from the Atlantic into the Pacific Basin. This reversed in 2022, as Europe has balanced the loss of Russian piped volumes with higher LNG imports, with TTF trading at a premium to JKM to attract volumes.

LNG spot price volatility over the last two years (from the record low prices in 2020, when global gas prices fell to below $2.00/mmbtu, to the record highs of last year, when European gas prices almost reached $100/mmbtu) has shown the advantages from a pricing perspective for both buyers and sellers of not being totally reliant on either the spot market or contracted volumes.

It may be that the LNG market continues to be split between trade carried out under a mix of medium to longer term contracts and the balance traded on spot. For market participants to be completely dependent on the spot market or to be fully contracted on all their expected supply and demand carries obvious risks. The spot market is less predictable than contractual arrangements, but to be completely contracted on the other hand would leave buyers and sellers vulnerable to unexpected changes in supply and demand. Ultimately it is for market participants to determine their own LNG sales or procurement strategies, which will inevitably be shaped by their specific needs and wider market fundamentals.

1.3 Contract Flexibility

Until the last ten years or so, LNG trade was carried out almost entirely under inflexible long-term contractual arrangements between project developers and end-user buyers, under which buyers accepted stringent terms on volume (annual contract quantities) and strict destination clauses (with no flexibility to re-route cargoes to other markets/buyers) in exchange for security of supply.

This is changing due to the growth of US LNG and as more capacity is developed globally on an equity offtake basis and via sales into company portfolios rather than to serve specific end-users, each of which allows for greater destination flexibility. Traditional end users, such as Japanese and other utilities are also demanding that sale and purchase agreements include more flexibility with respect to destination clauses and volume.

US LNG has been developed through commercial frameworks that provide a significant degree of commercial flexibility, including destination and volume. In combination with US LNG's scale, this has added a significant amount of supply flexibility into the global LNG market.

- **Destination flexibility:** All the onstream US projects have contracted capacity on either a tolling basis or via sale and purchase agreements with no destination restrictions, and mainly on a free on board (FOB) basis (i.e., at the point of loading). Capacity holders are free to market their volumes wherever they want.
- **Volume flexibility:** US LNG has relatively low take-or-pay costs. Capacity holders pay a fixed charge (this generally varies by contract from less than $2.00/mmbtu up to $3.50/mmbtu on the volume that has been contracted with some exceptions) but have no obligations to lift the volumes that have been contracted. This differs to most LNG SPAs that allow for some downward quantity tolerance (DQT) but otherwise the take-or-pay obligations are quite close (i.e., 85% or more) to the annual contracted volume.

The last two years strikingly demonstrate US LNG's flexibility in both areas. The commercial rationale of US LNG is predicated on the arbitrage between the US and international gas markets. During the market collapse in 2020, when cash margins on exports of US LNG turned negative, offtakers of US LNG exercised their right to cancel cargoes (volume flexibility), helping rebalance the global market. In 2022, the destination flexibility of US LNG has been evident. In response to high prices, US LNG exports to Europe more than doubled in 2022, compared to 2021, helping Europe replace the loss of Russian piped volumes.[2]

1.4 Growing Diversity of Market Participants

The LNG market is no longer a small club of buyers and sellers. Key trends in the industry's growth include:

- Growth of a more diverse group of international buyers, driven by the growth in LNG demand in emerging markets, especially in Asia, but also Europe, central and Latin America.

[2] In January-November 2022, EU imports of US LNG more than doubled, to 52 bcm, compared to 22 bcm in 2021 as whole. https://energy.ec.europa.eu/system/files/2023-01/Quarterly%20report%20on%20European%20gas%20markets%20Q3%202022.pdf

- Increasingly prominent role of infrastructure players – companies that invest in specific parts of the value chain (e.g., liquefaction, shipping, and regasification terminals).
- The rise of LNG trading companies that operate primarily as intermediaries between producers and end-users, and which now account for a sizeable portion of world LNG trade.

The major international oil and gas companies still predominate within the industry, but their roles have evolved from project developers to traders, whereby part of their supply portfolio is via contracted purchases on a third-party basis.

A similar trend has occurred among traditional LNG buyers (Asian and European utilities), which have developed trading capabilities and have moved further upstream (i.e., investing through the value chain in liquefaction facilities and upstream supply).

The historic distinction between buyers and sellers is less apparent today and market participants occupy positions across the value chain and in multiple markets. The drivers are often commercial and economic but can also be to ensure greater security of demand and supply. Japan has supported new LNG supply entrants, for example, to increase security of supply through more diversity of supply. Other market participants such as IOCs and trading companies can act as a 'bridge' between suppliers and customers in emerging markets, where sellers may have concerns about security of demand.[3]

1.5 Portfolio Sales

LNG projects are among the most capital-intensive energy projects in the world, with long payback horizons. Long-term contracts are needed to manage the investment risk and buyers will also continue to value long-term contracts for the security of supply. Long-term contracting has been, and will remain, a key pillar of the global LNG market.

But long-term contracting has evolved beyond traditional point-to-point supply chain models to include a much higher proportion of portfolio sales, of which there are generally two categories:

[3] An example would be the sales agreement between QatarEnergy and Vitol for delivery to Bangladesh. http://country.eiu.com/article.aspx?articleid=1320744315&Country=Qatar&topic=Economy&subtopic=Forecast&subsubtopic=External+sector

- **Sales into portfolio:** these are sales with no firm destination; usually from a project developer to an international oil company/trader buyer. The buyer in this case is a company that does not have its own end use demand but is managing a portfolio of supply and demand. With increasing frequency, integrated oil and gas companies (IOCs) are sourcing LNG on a third-party basis.
- **Sales out of portfolio:** these are sales with no firm source; usually involving sales to an end user from the portfolio of an international oil company seller. This may suit many buyers that value the role played by the seller which can source volumes from within its portfolio and on the global market, rather than the buyer taking on the project/country risk of contracting with a specific project.

Discussion questions:

- How are the interests of buyers and sellers aligned / misaligned in the current market?
- How will the market continue to evolve from where things are today?
- Could LNG become fully commoditized where long-term contracts become a thing of the past? What are the factors that work against this?

2. Future LNG Supply Chains

LNG is inherently cyclical, and supply chains have grown through a series of major investment cycles over the last few decades. LNG projects take years to build and, once completed, have tended to increase supply in large tranches simply because of the scale at which they have been built (to achieve scale economies). LNG demand on the other hand tends to grow incrementally. The cycle has therefore tended to move through periods of market tightness signaling the need for investment in new capacity, which then enters the market in large tranches, satiating demand growth for a period, until the market tightens once again, and the cycle repeats itself.

The demand ‘shock’ resulting from the Fukushima nuclear disaster in Japan in March 2011 combined with China’s rapid LNG demand growth at around this time were key drivers of the investment booms in new capacity in Australia and the United States over the last decade.

The major investment cycles in Australia and the United States followed the earlier boom in Qatar (starting around 2005), leading to the emergence of ‘the big three’: Qatar, Australia, and the US. These account for roughly 20% each of current global LNG supply (equal to some 240 Mtpa). Additional capacity is currently under construction in each country totaling some 85 Mtpa coming onstream in the second half of the decade.

But whereas in Australia, new supply capacity will maintain production at plateau (i.e., counteracting production declines on older projects), the United States and Qatar will increase their total supply and overall global market share.

- **Qatar:** Production capacity is expected to grow from 78 Mtpa currently to 126 Mtpa through two further phases of North Field expansion – North Field East and North Field South. North Field East is under construction and will add 32 Mtpa and is expected to start by 2026, while North Field South is at an earlier stage of development and will add a further 16 Mtpa potentially by the end of this decade. Further phases of development have yet to be defined and will depend on QatarEnergy’s strategic planning. The 126 Mtpa of Qatari capacity in addition to QatarEnergy’s 12 Mtpa equity offtake at Golden Pass means that it will have an enormous (and by far the world’s largest) LNG supply portfolio to manage.
- **United States:** Three projects are currently under construction, Golden Pass LNG, Plaquemines LNG, and Corpus Christi Stage 3, which will increase US LNG export capacity by 50% later this decade (between 2025 and 2027), adding 44 Mtpa to the roughly 88 Mtpa which is already under construction, increasing total US LNG capacity to 132 Mtpa. Several other planned developments are at an advanced stage and are widely expected to move forward to construction within the next year or two, contingent on finalizing the necessary financing. This in turn may depend on further progress with respect to marketing, permitting, and engineering, procurement, and construction (EPC) contracts. The US is the most active market for the development of new capacity globally. Marketing activities have accelerated following the war in Ukraine and the volatility in European and global gas prices, leading to a boom in contracting of US LNG

capacity at planned projects. Leading players include Cheniere, Sempra and Venture Global.

- **Australia:** Australia's LNG production profile is expected to remain roughly flat this decade at between 80 and 85 Mtpa. Only the 8 Mtpa Pluto expansion project is currently under construction (and due to start in 2026). Australia's first LNG project, North West Shelf, has been producing since the late 1980s and is entering decline as feedgas to the plant decreases due to reserves depletion. Australia still has huge reserves of undeveloped gas, but high development costs are a major barrier to their development. The gas quality can be quite poor, with high levels of CO_2. The environmental abatement and regulatory compliance costs in addition to the generally high-cost environment in Australia (for labor and due to the fields' remote offshore location off northern and western Australia) make these projects uncompetitive compared with other development opportunities globally.

In addition to the 'big three', Russia and Mozambique were on course to be part of the next growth cycle (and become the 'big five'), until geopolitical events derailed things.

- **Russia:** Several planned and under-construction projects including Novatek's Arctic LNG-2 and Arctic LNG-1 projects, as well as Gazprom's Baltic LNG and Rosneft's Far East LNG projects have been thrown into doubt due to Russia's invasion of Ukraine, and the exit from Russia by Western oil and gas companies and services companies crucial to their development (e.g., Baker Hughes, Siemens, and Linde). Russia's two large-scale operational plants at Sakhalin-2 (Gazprom) and Yamal (Novatek) continue to operate at full capacity, with about 30 Mtpa of capacity combined. Were the projects that have stalled as a result of the Ukraine conflict to still go ahead, Russia's LNG capacity would be tripled to some 90 Mtpa.
- **Mozambique:** Uncertainty hangs over the future of Mozambique LNG developments due to conflict in the Cabo Delgado region. The facilities under construction linked to the Area 1 development (Mozambique LNG) are in an area that came under direct attack from insurgents. TotalEnergies declared force majeure in April 2021 and has yet to restart work on the project.[4] The Eni and ExxonMobil-led Rovuma LNG project involving

[4] Force majeure issued at Mozambique LNG: https://totalenergies.com/media/news/press-releases/total-declares-force-majeure-mozambique-lng-project

development of the Area 4 gas reserves and construction of facilities adjacent to Mozambique LNG have been put on hold. The conflict has not impacted development of the Area 4 joint venture's floating LNG project, Coral FLNG, which is supplied completely offshore and may be a more viable development solution going forward. Coral FLNG shipped its first cargo in November 2022 and is relatively small at 3.4 Mtpa capacity. The planned land-based terminals for Area 1 and Area 4 would add some 28 Mtpa in the first phase, with potential to add more trains.

Iran is also in the category of countries whose LNG potential has been thwarted due to economic sanctions and geopolitical factors. Iran shares the world's largest non-associated gas field with Qatar. The field straddles the maritime jurisdictions of both countries (and named the North Field in Qatar and South Pars in Iran). Whereas Qatar's section has been developed for LNG exports through partnerships with IOCs (ExxonMobil, TotalEnergies, Shell and ConocoPhillips), Iran does not have the technological capabilities to develop LNG, and due to sanctions and investment risks preventing IOCs doing business in Iran, has been unable to develop an LNG industry with supply from South Pars or from any other of its giant natural gas discoveries.

Additional LNG capacity is currently under construction in several other regions globally including west Canada (LNG Canada), Nigeria (NLNG 7), Indonesia (Tangguh Phase 2), Mauritania/Senegal (Tortue) and west Mexico (Costa Azul Phase 1). Collectively these projects will add some 32 Mtpa of capacity over the next few years. The smaller projects at Tangguh and Tortue will start in 2023 but it will likely be another two-to-three years until the larger Canadian and Nigerian projects come onstream.

The combination of these volumes in addition to those under construction in Qatar, the US and Australia means the onset of a huge wave of LNG supply growth from the middle of this decade, of more than 100 Mtpa, from capacity that is already under construction, even without contributions from Russia and Mozambique. But beyond this wave the sources of future supply are more difficult to identify and the lack of commercial and project momentum outside of the US and Qatar save for a few small projects globally points to future supply challenges over the longer term.

2.1 Key Issues for the Growth of Global LNG Supply

LNG projects have been proposed in a variety of other locations where natural gas fields could be developed for LNG exports. Examples include onshore gas in Papua New Guinea, offshore Tanzania, shale gas in Argentina, and gas reserves growth in United Arab Emirates.

Some, but perhaps few, of these projects will be developed. While some have good prospects for development (e.g., the medium-sized Papua LNG project), there are others that have been in the planning stages for several decades, and may never be developed (e.g., Abadi in Indonesia, Greater Sunrise in Australia/East Timor, and Alaska LNG).

The issue for all proposed LNG developments firstly is whether the framework conditions (policy, regulatory and fiscal) exist for the project's development, and then whether it is economically attractive, and the benefits for the project participants outweigh the risks.

The commercial risks associated with large-scale LNG projects loom large; and increasingly for the world's integrated oil and gas companies, potential LNG investments are being deprioritized in favor of other investment opportunities and other commercial strategies (with a preference for procurement and trading, rather than investment).

- **Multi-billion-dollar LNG investments carry big risks:** LNG projects are complex and expensive and face myriad risks for the investor throughout the project's life cycle. Cost and schedule overruns are not unusual. Examples include the massive cost overruns at Australian LNG projects last decade. Once the capital is sunk, market conditions and other circumstances can change, impacting project returns. Technical issues and equipment failures or fires can severely impact project economics such as at the Angola LNG plant, Prelude LNG's continuing operational challenges in Australia, and the fires at Snohvit in Norway and Freeport LNG in the US over the last couple of years, which resulted in both plants being offline for extended periods. Sovereign risk includes politically driven risks that include everything from changes to fiscal and regulatory terms to war. Examples include Yemen LNG which was shut down shortly after it was built due to conflict, or impairments taken on Russian LNG projects in the wake of company exits (such as TotalEnergies at Yamal and Arctic LNG-2).

- **Cost competitiveness is key:** IOCs will consider the cost competitiveness of potential projects in several ways: (1) whether the project is competitive with other planned projects globally; (2) whether it is competitive under various long-term pricing scenarios; and (3) whether it is competitive with other investment opportunities in companies' portfolios. The economics of any development are a function of costs, production, and the fiscal terms under which the project operates. The attractiveness of provinces such as Qatar, Russia and Mozambique for LNG development stems from the scale and quality of their natural gas resources. In the case of Qatar, and to a lesser extent Russia, development economics are enhanced by natural gas liquids (condensate and LPGs) that can be produced with the gas stream. Typically, the issue in these low-cost provinces concerns restricted market access (e.g., Qatar/Russia) and/or fiscal terms.
- **LNG has an emissions problem.** Emissions are produced throughout the LNG value chain from upstream, to liquefaction, to shipping, regasification, and eventual combustion of the gas in end use applications. The liquefaction process itself is energy intensive, generating emissions from the running of gas-fired turbines to power refrigerant compressors. Some 8% to 12% of the inlet gas will be combusted during liquefaction, although this can be reduced through use of electric-drive systems depending on the electricity source. The LNG industry has been under pressure particularly in the last few years to reduce emissions, and IOCs themselves seeking to decarbonize their global operations are giving greater consideration to the long-term emissions profiles of LNG investments. IOCs are now only likely to invest in LNG projects if it has an emissions management plan in place, which adds to project costs and complexity.

IOCs continue to predominate in the LNG industry but are showing increasing reluctance to move forwards with investments in new LNG projects due to the high capital expenditure and risks involved and/or lack of access to the best quality gas reserves. Rather, they are increasingly prone to high grade investment opportunities within their portfolios with shorter payback horizons, as well as those more in line with corporate decarbonization objectives. Large-scale greenfield LNG projects tend to score poorly on both.

It is notable that during a year of global LNG shortages and record LNG and international gas prices, when plans for LNG investments might have accelerated, IOCs have not taken a final investment decision on any new large-scale LNG projects. Instead, it is US project developers and infrastructure players which have benefited from the diminished opportunities available to international buyers to secure term LNG. Notably it is the IOCs, as a group, that have signed most of capacity contracted by US LNG projects over the last 12 months, but as buyers not sellers, showing their greater willingness to take on the price rather than the investment risk.[5]

Discussion questions:

- What are the challenges for growing global LNG supply and how much of this is commercial (investment hurdles/investment theme), geopolitical, policy related, ESG pressures, etc?
- How have the LNG strategies of the Majors evolved, do they reflect more permanent changes or response to current market dynamics?

3. Ensuring Supply and Security of Export Contracts

Long-term sales contracts play a fundamental role underpinning investment in new capacity, especially in the US, where many developers are looking to fund investment through bank debt. US LNG is fundamentally an infrastructure business, unlike globally where LNG is more about upstream resource developments.

Thus far, US LNG projects have succeeded in getting financed based on demonstrating that the infrastructure investment can pay back debt with interest and provide equity investors with a satisfactory rate of return. This has been possible mainly through contracts that guarantee the project's costs (via fixed fee construction contracts) and revenues (via fixed-fee sale and purchase agreements (SPAs) or tolling agreements (LTAs) with investment grade counterparties). In each case, the risk is borne by a third party, not the developer.

[5] Chevron, ExxonMobil, Shell, ConocoPhillips have been active in signing US LNG offtake agreements with various developers at projects that are planned or under construction. https://www.energyintel.com/00000182-81d9-d4e0-abc6-d1f9f3700000

Banks and a certain type of equity investor (infrastructure funds) have generally been keen to lend/invest on this basis.

In the current market the risks are having to be distributed more equally. Engineering, procurement, and construction (EPC) services companies are less willing to sign 'fully wrapped' lump sum turnkey (LSTK) EPC contracts, which force the EPC contractor to carry the cost risk. This follows losses made by several EPC LNG contractors in the US working under the fixed price model, including McDermott's bankruptcy in 2020 mainly due to LNG cost overruns at the Freeport and Cameron LNG projects.[6]

A relatively small number of EPC companies worldwide have the capabilities to build large-scale LNG projects, and some (such as KBR) have opted out completely from the LNG LSTK contract market and will only build facilities on a cost reimbursable basis (pushing the cost risk back onto the developer and by extension its lenders/investors).

Others, such as Bechtel, remain willing to sign lump sum turnkey contracts, but will incorporate greater contingency into the fixed price (thereby increasing project costs) or insist on more cost elements being open to upward revision, such that 'true' fixed price contracts may be a thing of the past. Industry cost inflationary pressures add further cost risk for the developer and its financiers.

Working against this trend (of higher costs and more cost risk borne by the developer) is the fact that competition between US project developers to secure customers has driven down the sales price. While contract prices are not being publicly disclosed, secondary sources (e.g., market research firms and ratings agencies) point to deals being signed at prices well below the first wave of deals, many of which were publicly disclosed (and generally with liquefaction fees in the $3.00 - $3.50/mmbtu range). Current price volatility and record high international gas prices would seem to make the price of US LNG attractive at almost any price, but market conditions today may not be all that relevant given that it will be at least four or five years from construction to production and contracts will run for 10, 15 or 20 years.

The fact that a US LNG project may have signed contracts for a significant amount of planned capacity does not in itself guarantee the project's development. The developer's

[6] McDermott in bankruptcy talks with lenders: https://www.wsj.com/articles/engineering-company-mcdermott-in-bankruptcy-talks-with-lenders-11577736205?page=1

ability to raise finance will depend on the terms of the deals it has signed (and counterparty risks) in relation to the project's costs and overall risk profile. Project developers such as Tellurian have tested banks' willingness to lend against contracts that incur greater market risk, and the result was that lenders were ultimately not supportive. Its strategy to sell LNG from its proposed Driftwood LNG project in Louisiana at international LNG market prices (JKM and TTF) was unsuccessful, forcing the company to adopt a different marketing strategy.[7]

Given current US LNG market trends (towards more cost risk and low fixed-fee prices) it is unclear whether banks will be as keen on lending to proposed projects seeking financing today than they might have been previously. In the context also of ESG pressures on banks to stop financing of fossil fuel projects, financing of new LNG developments has become harder than it was several years ago.[8]

For LNG buyers, one of the attractions of the US market is that it offers some unique advantages over alternative LNG suppliers. Flexibility is one (see Section 1.3) and liquidity is another. A US LNG contract is supplied by natural gas sourced from the US market rather than from a specific gas field or group of fields whose production declines over time through reservoir depletion. The NYMEX Henry Hub contract is the most traded gas contract in the world, and buyers and sellers of US LNG can manage the commodity risk with various financial trading and hedging tools such as futures and options.

It is a testament to the deep liquidity of the US market that the largest US LNG producer, Cheniere, on a daily basis buys more than 6 billion cubic feet of natural gas to meet its LNG sales commitments, through transactions with hundreds of producers in multiple gas producing basins across the country, to meet its LNG sales commitments. It is the US gas market which ensures the availability of gas, in combination with the world's most extensive natural gas grid, rather than a single producer or even single resource play.

Discussion questions:

- What are the issues and risks that buyers need to consider in terms of LNG pricing and indexation e.g., oil vs gas (HH, JKM, TTF)?

[7] https://www.tellurianinc.com/news-and-presentations/press-release-tellurian-updates-financing-process-for-driftwood-lng/
[8] A recent example is HSBC which has decided to no longer provide financing for new oil and gas field developments. https://www.bbc.com/news/science-environment-63975173

- What are some of the strategic considerations (e.g., energy security) that have underpinned the procurement strategies of buyers in the past, and which may still need to be considered for the future?

4. Effects of Europe's Decarbonization Timeline

Post Russia's invasion of Ukraine, the European gas market is in a state of revolutionary change, where the result could be that within a decade or so, the continent's gas demand and need for LNG imports is greatly diminished. This is what the RepowerEU plan seeks to achieve.[9] The plan is not so much a war on Russian gas imports as it is a war on natural gas in the energy mix in toto. If it were to be implemented in full, by 2030 the EU would be able to meet its gas demand primarily from non-Russia regional pipeline supplies, in addition to a small amount of LNG that would be less than the amount of LNG Europe imported pre-war in Ukraine.

Targets are one thing while reality is a different matter, however. But the experience of 2022 has shown the effect that a crisis can have in changing behavior and focusing resources (political and financial) on a specific goal. When the RepowerEU plan was launched, its ~60% gas demand reduction target (from 400 bcm to 150 bcm) by 2030 seemed unrealistic. Yet Europe has reduced gas demand by more than 10% in 2022 alone. It's possible that given the lead time on building the infrastructure and facilities to switch from gas in the power sector (to renewable electricity) and in the heat sector (to green hydrogen and electricity/heat pumps) that natural gas demand reduction could accelerate over time. While the plan may ultimately fall short of the target, it is now not unreasonable, in the context of demand reductions already achieved, to expect the EU's gas market to be 40%-50% smaller in 2030 compared to 2021.

[9] REPowerEU: Joint European action for more affordable, secure and sustainable energy. https://ec.europa.eu/commission/presscorner/detail/en/ip_22_1511

RepowerEU proposes several legislative/regulatory reforms in four different areas: energy savings, supply diversification, accelerated renewable energy penetration, and reductions in industrial and transportation fossil fuel consumption. It increases the EU's 2030 gas reduction targets from 2021's FF55 proposal, which itself was forecast to reduce gas demand by 30% mainly through renewables and energy efficiency. The gas reduction target has more than doubled from a decrease of 116 bcm under FF55 to 250 bcm under RepowerEU. If achieved, this would reduce total EU gas demand to some 150 bcm per annum, an amount that could be supplied relatively easily without Russian gas and with a relatively small amount of LNG to plug the gap between available pipeline supplies from Norway, North Africa and the Southern Corridor (Azerbaijan).

The EU has historically found its energy efficiency targets difficult to meet. Energy consumption largely increased year-on-year from 2015-2019, and the European Environment Agency in those years assumed the prior 2030 mandated efficiency targets would not be met. However, both industrial energy demand and total electricity demand fell in 2022 and the longer the shortage of gas and high energy prices persist, the greater will be the incentive to implement measures and change behavior to bring down overall energy consumption.

Building on the EU's RepowerEU and Save Gas for a Safe Winter plans, the IEA has recommended a suite of additional short-term measures that are estimated to cost around €100 billion (and which they believe have the potential to reduce gas demand by a further 8% in 2023).[10] These include efforts to improve energy efficiency (building retrofits), faster deployment of renewables (more wind and solar), changes in consumer behavior (lowering thermostats) and electrifying heat (installing more heat pumps). The aim of this strategy is to find ways of living within the constraints of the European Union's available supply, which, without Russian gas, the agency estimates could drop to 340 bcm in 2023.

4.1 Europe's 2022 Gas Balance

Europe's market balanced in 2022 through significantly increased LNG imports (up 60% compared to 2021) to compensate for reduced Russian pipeline flows (down by 55% compared to 2021). Europe paid a premium to attract flexible LNG primarily from the US,

[10] How to Avoid Gas Shortages in the European Union in 2023. https://www.iea.org/reports/how-to-avoid-gas-shortages-in-the-european-union-in-2023

Qatar and Russia (account for about three quarters of all European LNG imports) as well as smaller increases from Egypt as well as more distant suppliers including Australia.

TTF prices averaged $45/mmbtu from April through October 2022 as Europe replenished gas storages in its largest ever annual storage refill. Gas power demand was notably resilient, even at record high gas prices, marking a slight increase on 2021. This was mainly due to reduced French nuclear generation (due to maintenance and corrosion repair works) and low hydro power generation across the continent propping up demand for gas-fired generation but notably it was renewable electricity generation (from solar PV and wind) that thrived the most in 2022, growing more than 10% combined.

Most of the downward flexibility in gas demand was in the industrial sector in response to high prices. This was achieved through several means, including operating industrial facilities at lower capacities; import substitution (buying rather than producing industrial chemicals and materials, e.g., ammonia); and switching to oil (from gas) for heat and power. Based on preliminary data, Rapidan Energy estimates that European industrial gas demand was some 15-20% lower in 2022 compared to previous years. Notably, European industrial production increased about 2% in 2022 (May-October) compared to the previous year.[11]

4.2 Gas Diversification

Most of the actions to diversify away from Russian gas have centered on infrastructure rather than LNG supply agreements. More than a dozen floating storage and regasification units (FSRUs) have been chartered for the European market.[12] Several started up in the second half of 2022 including two in the Netherlands, one in Finland and two in Germany that are likely to be fully operational in 1Q23. The remainder will come online in 2023 and 2024. Germany has contracted the most (five) and is also moving forward with construction of large-scale land-based import terminals.

[11] Germany has the largest industrial gas consumption in Europe and its industrial gas demand in 2022 was 15% less than the 2018-2021 average. https://www.bundesnetzagentur.de/DE/Gasversorgung/aktuelle_gasversorgung/Rueckblick/start.html;jsessionid=621874742738411DDBC77A44162533B9
Data on European industrial gas production available at: https://ec.europa.eu/eurostat/documents/2995521/15585043/4-14122022-AP-EN.pdf/ce49c92a-e109-96b6-6a89-16a7ca39650c?version=1.0&t=1670944989773

[12] FSRU availability is discussed in the IEA's Gas Market Report Q4 2022: https://www.iea.org/reports/gas-market-report-q4-2022

Other aspects of Europe’s gas infrastructure strategy involve improving pipeline interconnections between different EU markets. Numerous choke points have persisted for decades while the alternative has been to import cheaper Russian gas, and the building of new interconnecting pipelines is now underway. New transmission links completed in 2022 included interconnects between Poland and Lithuania, the Poland-Slovakia interconnector, the Baltic Pipe from Norway to Poland via Denmark, and the Greece-Bulgaria pipeline.

4.3 Assessing Europe’s Need for Long-term Contracted LNG Supply

Amid the boom in long-term contracting of new US LNG capacity in 2022, only a handful of deals have been signed by European end-user buyers (e.g., RWE, ENbW, Ineos, Galp). Market intermediaries (or portfolio players), mainly international oil companies and some trading houses, have signed the bulk of the deals. Chinese buyers have also been prominent in signing US LNG deals.

For European buyers, the question of whether to sign long term contracts with pre-FID LNG projects (planned either in the US or elsewhere) raises several challenges. Firstly, it doesn’t solve the problem of there not being enough supply in the short term. Projects that have yet to start construction won’t be producing for at least another four years or so. Secondly, it goes against the grain of national and EU policy making and gives rise to criticism that long-term contracts will ‘lock in’ future emissions. But the biggest impediment is simply the risk of being locked into payments for LNG given the uncertainty of long-term European gas demand. As an example, a 20-year US LNG contract for 1 Mtpa paying a fixed liquefaction fee of $2.50/mmtbu would amount to $2.5 billion in fixed fees over the life of the contract.

Furthermore, some two thirds of the 44 Mtpa of new capacity that is currently under construction in the US Gulf Coast does not have a firm destination. QatarEnergy and ExxonMobil, which will have 18 Mtpa available to market through their equity shares at Golden Pass LNG in Texas, have access to European regas capacity and do not need LNG sales agreements to enter the European market. They are also investing in an expansion of South Hook regas terminal in the UK (already one of Europe’s largest LNG import terminals) to provide a bigger outlet for their flexible US volumes.

Other regas capacity being built in Europe (both the fast track FSRUs and the larger land-based terminals) is being contracted by international companies, signaling to potential European buyers that new supply capacity being developed either in the US or Qatar will be marketed in Europe irrespective of contracts being signed. An example of this is the deal between QatarEnergy and ConocoPhillips, whereby Qatar will be able to access the German gas market via regas capacity held by ConocoPhillips at the Brunsbuttel regas terminal currently under-construction.

Arguably the loss of Russian supply creates the need for Europe to contract LNG in very large volumes (the roughly 150 bcma Russia has historically supplied Europe would be equal to more than 100 Mtpa if it was to be replaced with LNG).

However, several trends and factors work against the rationale for European buyers to sign long term contracts with pre-FID LNG projects in very large volumes (from either the US or elsewhere):

- A long-term contract for delivery starting later this decade (which would be the case if contracted with any supply project that has not yet started construction) doesn't help with Europe's current supply deficit.
- A long-term contract priced on anything other than a European price index (such as Henry Hub or Brent) carries price risks. (And planned US projects cannot get financed by contracting on a European price index).
- European policy is firmly in the direction of reducing gas demand to achieve 'net zero' emissions targets, in which context committing to the purchase of LNG for supply well past 2030 carries commercial and financial risks given the uncertainty of long-term demand.
- A substantial amount of new LNG capacity is under construction globally, which will grow in volume through the second half of this decade.
- Much of the capacity under construction in the US and Qatar is inherently flexible and will flow to the highest priced market.
- Despite extreme levels of price volatility in 2022, European security of gas supply was achieved largely through the price mechanism, with high prices incentivizing more LNG supply and lower gas demand.

- Much of the capacity that has been contracted at planned (i.e., pre-FID) projects in the US (equal to some 50 Mtpa in binding SPAs) has been contracted by LNG marketers (international oil companies and traders) that will need to remarket their volumes. Europe is the largest proximate market for US LNG.
- Construction of additional import infrastructure (such as regas terminals and pipeline interconnections) facilitates access to the European market without the need for LNG sale and purchase agreements.

Counter to this view is that Europe could fail to meet its demand reduction targets, which could leave it dangerously exposed to spot market price volatility and structurally high gas prices, which could further undermine competitiveness of European industry.

Europe's response, in general, however has been to advocate an accelerated energy transition to avoid this outcome, while working at the intergovernmental level with regional gas exporting countries to enhance gas supply.

Decisions relating to the long-term sale and purchase of natural gas are essentially commercial ones and companies will ultimately determine the best course of action for themselves, and the most suitable procurement strategy, and the balance between spot and contracted supply.

Discussion questions:

In western Europe, (much like OECD economies in Asia), gas is neither a transition nor a destination fuel, and demand is set to decline through time. Key questions include:

- How quickly can European and Asian OECD economies transition from gas? What is a realistic pace of structural decline?
- What are the roadblocks in this transition – to replace gas in power, industry, and heating?
- How should market participants be thinking about long-term commercial risks associated with gas and LNG investments, and how can these be adequately managed?
- What are the pros and cons for buyers of contracting LNG long-term, from a price or security of supply standpoint?

- What are the risks that future supply will fall short of demand again in the future, and therefore what might prompt European companies and governments to focus more on supporting additional investment in gas and LNG supply?

5. Effects of Asia's Decarbonization Timeline

While Asia will continue to be the largest market for LNG imports over the long-term due to population size and energy demand, and relative lack of domestic gas supply, individual markets are at various stages of growth, which has implications for the future role of gas and LNG in countries' decarbonization strategies. This is true of the top five markets – Japan, China, South Korea, India and Taiwan – which together account for about two thirds of the global LNG market.

Japan, Korea, Taiwan (JKT): The JKT markets have the longest history of LNG imports in Asia and collectively account for more than one third of global LNG demand at around 130 Mtpa. Japan regained its status as the world's number one LNG importer in 2022 (China overtook it in 2021 but imported less than Japan in 2022). Korea is the third largest importer and Taiwan the fifth largest after India in fourth place.

For the JKT markets, where LNG is already a core part of the energy mix, the emphasis from a policy standpoint is not about replacing coal with more gas in the energy system. Their paths to decarbonization vary and entail more nuclear (particularly in Japan and Korea), renewables and low-carbon gases (hydrogen, ammonia, syngas/biogas). LNG imports will remain a large part of the energy mix over the long term, but the trajectory is one of gradual decline not growth.

These markets are highly contracted. Japan's JERA and Korea's KOGAS hold the world's largest portfolios of contracted LNG. The key issue for these and other buyers in these markets will be whether to continue to remain as contracted as they currently are, or to become gradually more reliant on spot purchases as existing long-term contracts expire.

Prior to events in 2022, JERA's aim had been to move to a more flexible supply portfolio, with the eventual aim of 50% of its demand met through long term contracted supply and 50% a mix of spot and shorter-term contracts. This could change based on a reappraisal of market risks including: (1) security of supply concerns (risk of reduced Russian LNG exports to Japan, potentially from a disruption of Sakhalin LNG); (2) spot market volatility; (3) growing competition with China for long-term contract supply; and (4) limited new LNG supply options in the Asia Pacific region.

Uncertainty over Japan's nuclear reactor restart, however, complicates the outlook for Japan's gas and LNG demand and commercial negotiations. Eleven years after the Fukushima disaster, many of Japan's nuclear plants remain offline. Last year, Japan progressed plans to accelerate the timeline for nuclear restarts and extend the lifespan of nuclear reactors beyond 60 years, as well as develop a new generation of advanced reactors.[13] However, decisions on nuclear starts are undertaken by an independent body and remain highly contentious as an issue of public policy. But from a gas and LNG demand standpoint, growth in nuclear generation will cause a decrease in natural gas demand for power generation.

China: 2022 saw Chinese LNG demand contract by around 20%, bringing an abrupt halt to six consecutive years of growth. Weak economic growth and increased non-fossil electricity generation were the key factors in LNG's decline in 2022. Higher pipeline gas imports from Russia and growing domestic gas production, coupled with weak spot LNG demand in the face of extreme prices also acted to squeeze LNG demand. This contrasted with the previous year when China ordered its energy companies to secure energy "at all costs" as the country struggled with numerous blackouts increasing concerns of energy shortages ahead of the Beijing winter Olympics.

The end to the strict lockdowns in 2023 could lead to an uptick in LNG demand. This would be expected anyway as China's contracted supply will increase in 2023 due to new supply contracts starting up. China remains the biggest market for signing new, long-term LNG contracts as it seeks to reduce reliance on spot purchases. An increase in contracted supply does not necessarily translate into higher overall demand as 2022 has shown. And the longer-term trajectory for China's gas and LNG demand is hard to call.

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[13] Japan approves nuclear energy U-turn to avert crisis: https://www.ft.com/content/721b66c6-fd73-432f-aef9-fe59befba2cf

Import dependence with respect to natural gas has become a problem. Chinese NOCs committed heavily to new LNG projects in Russia (with equity and offtake at Arctic LNG-2) and Mozambique (with offtake from the Area 1 project and equity and offtake at Area 4 project) all of which have stalled due to political and security issues. Chinese companies have signed deals with various US project developers with no guarantees that these projects will be developed. Dependence on the US for energy security is fraught with geopolitical risk, as is the case to some degree with Canada and Australia (neither of which offer scope for significant supply growth anyway).

This mainly leaves Qatar, with whom China's LNG relations have already deepened considerably (China is now the largest contracted buyer of Qatari LNG following a string of recent deals QatarEnergy, the largest deals are with Sinopec and CNOOC), and portfolio supply deals with international oil companies.

It is not realistic to expect China to make a transition through large-scale substitution of gas for coal, as has been the pathway for North America and Europe: China doesn't have the gas reserves itself to be able to make that kind of a transition and import dependence without a wide diversity of suppliers runs counter to China's aims for greater energy security.

China's decarbonization policy is to achieve peak emissions by 2030 and carbon neutrality by 2060, but the policy sees a continuing marginal role for natural gas. All the projected growth in the power sector is in renewables and nuclear. Coal will continue to be the foundational fuel to provide energy security for the country, but the aim is to develop larger more efficient coal plants that over the longer term will be used more to balance intermittent wind and solar output rather than as baseload supply.[14]

India: As with China, India's decarbonization plans see a minor role for natural gas over the long-term. India has pledged to reach net zero by 2070 but its energy policy priority is on security of supply and economic development, rather than emissions reduction. Coal will continue to be the major source of power generation with the potential for renewables growth over time. Gas' prospects for growth are better in the industrial sector, but this will depend on affordability and availability.

[14] See policy statement by China's NDRC "Ensure the security of food, energy resources, and supply chains of important industrial chains", 15 November 2022: https://www.ndrc.gov.cn/fzggw/wld/hlf/lddt/202211/t20221115_1341266.html; and, China's fast-growing renewables limit coal generation https://www.reuters.com/business/energy/chinas-fast-growing-renewables-limit-coal-generation-kemp-2022-11-17/#:~:text=LONDON%2C%20Nov%2017%20(Reuters),overall%20emissions%20peaking%20before%202030

The difficulties for LNG demand growth in India relate to its high cost relative to competing fuels (mainly coal in the power sector as well as with other petroleum products such as naphtha in the industry).[15] The country sources most of its LNG under long term contracts with Qatar at a price indexed to oil and the US indexed to Henry Hub. Another of its large supply contracts with Gazprom was disrupted by Germany's expropriation of Gazprom's Germany-based trading business, with whom the contract had been signed.

India hasn't signed a new long-term purchase agreement for several years. Indian companies have been totally absent from the boom US and Qatari sales activity over the last two years. LNG demand above contracted levels is met through spot purchases and is highly price sensitive. India's LNG imports in the first eight months of 2022 were 14% lower than the previous year and the country's total gas demand was around 2% lower. About a third of India's LNG imports supply the fertilizer industry. Indian state-owned enterprises purchase the LNG and sell it at subsidized prices.

Other emerging Asia markets

All other Asia LNG markets combined (Pakistan, Bangladesh, Thailand, Singapore, Indonesia, Malaysia, and Myanmar) imported less than 30 Mt in 2021, just 15% of what was imported by the big five (China, Japan, South Korea, India, and Taiwan) but along with other potential new LNG markets (such as Vietnam and Philippines) could potentially contribute greater levels of LNG demand growth as a group than the region's larger and more established markets. This is particularly the case for markets such as Malaysia, Indonesia and Pakistan which all have relatively well-developed gas infrastructure and industries and will steadily become more dependent on LNG imports as their domestic gas production declines.

However, present market conditions including global LNG supply shortages, limited availability of FSRU vessels and lack of infrastructure investment, coupled with efforts being made in some markets to decarbonize by means of transitioning more directly from coal to renewable, make the outlook for LNG demand in emerging Asian markets more uncertain. The longer the supply crunch lasts, the more incentive these markets have to diversify from gas.

[15] India Energy Outlook 2021, IEA: https://www.iea.org/reports/india-energy-outlook-2021

- **LNG procurement**: lack of affordable/available LNG supply in the near-term have pushed back project timelines and gas infrastructure investments such as import terminals and gas-fired power plants.
- **FSRU availability**: Europe has chartered most of the world's available FSRUs, which were to play a critical role in growth of LNG demand in emerging LNG markets in Asia. Shipyards in South Korea have limited capacity to build more FSRUs in the short term.
- **Coal to clean energy transitions**: Just Energy Transition Partnerships have been agreed for coal-intensive economies in Asia including Indonesia and Vietnam to make the transition to clean energy. Indonesia will receive an initial $20 billion and Vietnam $15.5 billion over the next three to five years to help phase out coal and invest in renewable energy infrastructure.[16]

5.1. Summary of Effect of Decarbonization Timelines on Long-Term Contracts for Terminal Investments

For gas to act as a transition fuel in Asian markets where gas penetration is low and coal consumption is high (especially China and India), gas and LNG needs to be affordable and accessible in ways that do not increase energy insecurity. Reliance on a volatile spot market and/or relatively expensive oil-indexed or Henry Hub-indexed contracts is proving too much of a barrier for governments to commit to LNG as a core part of their energy transition and decarbonization strategies. Coal will remain the foundation fuel for energy security for the long term, with most new investment focused on renewable electricity generation, such as solar PVs and wind.

[16] US government announcement on Just Energy Transition Partnership with Indonesia: https://www.whitehouse.gov/briefing-room/statements-releases/2022/11/15/indonesia-and-international-partners-secure-groundbreaking-climate-targets-and-associated-financing/; UK government announcement on Just Energy Transition Partnership with Vietnam https://www.gov.uk/government/publications/vietnams-just-energy-transition-partnership-political-declaration

- China has been notably active in signing long-term contracts with US developers to support terminal investments, but this burst of activity may already have come to an end, with conflict risks now at the forefront of US-China relations. With few other supply options available, China is deepening relations with Qatar and could potentially also do so with Russia with respect to increased pipeline imports.
- India's inertia with respect to signing long-term contracts to support terminal investments has less to do with decarbonization strategies than it is an issue of cost competitiveness. LNG (as well as domestically produced natural gas) cannot compete with coal in the power sector, and India has decided that decarbonization will not be done at the expense of economic development and security of supply. To avoid reliance on volatile spot LNG, the choice for Indian companies would be to contract on an oil index or Henry Hub index for which the risks of being locked into an expensive contract long term are too great. India wants cheap LNG. There's no-one able to provide it.
- The premium LNG markets in Japan and South Korea may decide to alter their LNG procurement strategies, with a greater focus on recontracting volumes to ensure security of supply, as opposed to relying more on the spot market. But they are less likely to be signing contracts with developers of new capacity that will be looking to sign long-term contracts extending towards the middle of the century, when LNG demand in these markets will be significantly lower than it is today due to the focus of decarbonization strategies being more on nuclear and renewables.

Unlike Europe, where the transition from gas has been more about decarbonization now given a huge boost due to energy security concerns, in Asia it is more about LNG's competitiveness and general availability.

5.2. The Future Role of Russia in Asian Energy

The potential role for Russian gas in Asia is constrained by infrastructure. Potential new large-scale pipelines such as Power of Siberia 2 could take a decade or more to come to fruition, requiring negotiations with China on gas sales and project financing prior to the start of construction.

Power of Siberia 2 is a 1,600-mile pipeline that would cost tens of billions of dollars and 5-10 years to build. Power of Siberia 1, which is similar in size (capacity / diameter / length), started construction in 2012 and began gas deliveries to China in 2019 and is expected to reach its full 38 bcm capacity in 2023.

Commercial discussions on Power of Siberia 2 as well as other proposed pipelines from Russia to China (e.g., from Sakhalin oil and gas fields) will be complex and time consuming. China would seem to hold an advantage in those negotiations, as it is now Russia's only real alternative to Europe as a gas market. The prospects of these pipelines being built may rest on Russia's willingness to make concessions on price and financing arrangements.

With respect to LNG, Russia also faces challenges in growing market share in Asia. Russian industry does not currently have the capabilities to build large-scale LNG. Several LNG projects that Russian companies planned to move forward with, including those that had already started construction, will struggle to be completed due to the exit of western technology companies and service providers. These projects include Novatek's Arctic LNG-2 and Arctic LNG-1 projects, Gazprom's Baltic LNG, and Rosneft's Far East LNG.

Completing these projects will depend on the return of western companies or on Russian industry developing LNG capabilities, which could take 5-10 years to develop.

Discussion questions:

In developing economies of Asia, gas' role in the energy transition is up for debate. Countries that had bought into the idea of the 'golden age of gas' predicated on it being abundant, cheap, and widely available have been left brutally exposed to new geopolitical realities. Key questions include:

- What is the longer-term impact of the energy crisis on Asian energy transition policies? Have things been permanently altered?
- How are these countries managing the tradeoffs between energy security, climate goals and economic development?
- Where does natural gas and LNG offer strategic and economic benefits relative to other fuels? How much of this depends on LNG price and what are the risk factors for buyers?

- Where should Asian markets be looking to source imported gas? Where does it make sense to do so, and where might there be challenges?
- What can be done to facilitate infrastructure investment and supply arrangements in low-income economies and those with higher sovereign and credit risk?
- What is the potential role for international financial institutions in supporting such infrastructure investments?
- What lending guarantees can be given to banks and investors insuring against the risks of buyers defaulting on their contract payments?
- How might counterparty agreements between LNG suppliers and buyers in emerging markets be protected from broader geopolitical and sovereign risks?

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