Citi GPS

NATURAL GAS

Powering up the Energy Transition

Citi GPS: Global Perspectives & Solutions

July 2021

Institute for Energy and Finance Foundation

citi

Citi Commodity Strategy Contributors

Anthony Yuen
Head of Commodities Strategy for Pan-Asia

+852-2501-2731 | anthony.yuen@citi.com

Edward L Morse
Global Head of Commodities Strategy

+1-212-723-3871 | ed.morse@citi.com

Maggie Xueting Lin
U.S. Commodities Strategist

+1-212-723-3873 | maggie.x.lin@citi.com

Eric G Lee
Global Energy Strategist

+1-212-723-1474 | eric.g.lee@citi.com

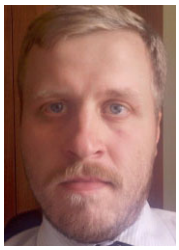
Judy Su
Global Commodities Strategy

+852-2501-2701 | judy.su@citi.com

Institute for Energy and Finance Foundation (FIEF)

Marcel Salikhov
President and Principal Director of Economic Studies
Institute for Energy and Finance (FIEF)

Alexey Gromov
Principal Director of Energy Studies
Institute for Energy and Finance (FIEF)



Alexey Belogoryev
Deputy Principal Director of Energy Studies
Institute for Energy and Finance, (FIEF)

Alexander Titov
Lead Research Fellow
Institute for Energy and Finance (FIEF)

Victor Kurilov
Research Fellow
Institute for Energy and Finance (FIEF)

NATURAL GAS

Powering Up the Energy Transition

Kathleen Boyle, CFA
Managing Editor, Citi GPS

Much of the focus on the Energy Transition has been on how quickly renewables could take over, but reducing emissions from hard-to-abate sectors and places complicates the outlook. In this context, is natural gas a transition fuel, a soon-to-be stranded asset, or is it an energy source that could be part of the Energy Transition?

Natural gas is a topic we have returned to time and time again. In 2013, our Citi GPS Energy 2020 series took a look at the shale revolution and how it would propel the U.S. from being a net energy importer to a net energy exporter. As part of that series, we looked specifically at the transportation industry and the inroads natural gas was making into petroleum's monopoly hold on the transportation fuel market.

Now, as the world comes to terms with the role of greenhouse gas emissions in climate change, consensus has shifted on the role of natural gas as a substitute for petroleum. Instead, renewable energy, "green" energy sources, such as hydrogen and biofuel, and energy storage are being championed as low-carbon alternatives. But these technologies still need time to ramp up in scale and cannot provide the full amount of energy necessary to run the global economy today. While these alternative energy technologies mature, natural gas can be used as a lower-emitting "transition" fuel to bridge to a net-zero world, particularly a substitute fuel or feedstock in hard-to-abate sectors.

As the Energy Transition proceeds, the primary proponents of natural gas as a transition fuel are the six countries making up 84% of all gas exports. The two biggest producers and exporters — the U.S. and Russia — will likely determine how natural gas could fit in to the clean energy future and how the market structure could evolve. Citi's Global Commodities Strategy group has teamed up with Russia's Institute for Energy and Finance Foundation (FIEF) to give their perspectives on the current natural gas market as well as ways the natural gas business can shift away from its incumbent mentality and not only learn to think outside of the box, but perhaps to think more like an upstart industry.

The report identifies five key demand areas where the proposition for natural gas is strong, including: (1) providing reliable electric grid supply; (2) using its smaller footprint to provide power generation in urban areas; (3) as a bunkering fuel to help reduce emissions in shipping; (4) as a lower-emission fuel in road transport; and (5) in the production of blue hydrogen. At the same time, the industry itself needs to work on decarbonizing its processes — from wellhead to generation — including reducing carbon gas emissions and methane leakage in production and transport.

How natural gas producers embrace the future could rest on their approach to the market. Some could manage supply and keep prices high by coordinating the trading of free float gas volume with other producers, thus extracting more export revenue but likely accelerating the Energy Transition. Alternatively, the industry could create an institution similar to a development bank to help finance the upfront liquefied natural gas (LNG) infrastructure that will drive natural gas demand into the future in ways that facilitate the Energy Transition.

Given the size of the industry and its importance to the global economy, a plan to ensure natural gas is part of the Energy Transition is needed now.

REINVENTING THE NATURAL GAS BUSINESS

ASSISTING THE ENERGY TRANSITION IN SEVERAL KEY DEMAND AREAS

Technological advancements in renewables are disrupting the traditional energy market but natural gas can still assist as a 'transition' fuel in reducing emissions in the overall economy. Finding the right product/market fit, innovating industry processes, and reinventing business practices are key for the industry to remain competitive. Provided natural gas can resolve its methane leakage and carbon emission issues, five key areas for natural gas to grow demand include:

Power Generation and Storage
Benefit: With carbon capture utilization & storage, reliable short and long-term storage of energy

Urbanization
Benefit: Compact footprint for lower land-use intensity particularly in emerging markets

Shipping
Benefit: LNG has near zero sulfur and nitrogen and 25% less CO_2 emissions vs. diesel and fuel oil

Freight Transport
Benefit: LNG or CNG vehicles as lower emitting mode of transport

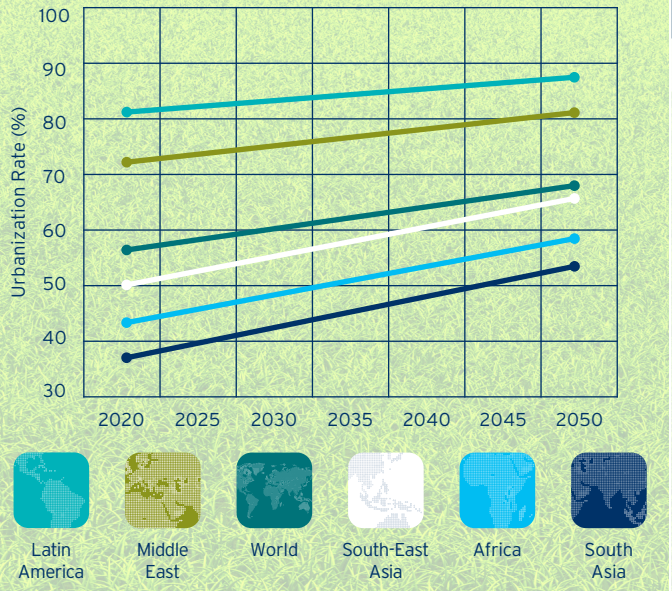
Hydrogen (for hard-to-abate sectors/island nations)
Benefit: Blue hydrogen very competitive as a decarbonized fuel or feesdstock

RISING URBANIZATION GIVES NATURAL GAS A COMPETITIVE ADVANTAGE

The UN expects urbanization rates to rise from a global average of less than 60% today to nearly 70% by 2050, with the biggest gains in emerging markets. High population density in emerging markets also increases power intensity levels and the need for new power generation. Gas-fired generation remains valuable for its compact land-use intensity versus renewable generation.

Urbanization Rates in Key Regions Globally

Source: United Nations



Land Use Intensity of Electricity Generation by Energy Source (M3/MWH)

Source: Trainor et al. (2016)

Primary Energy Source	U.S. Data
Nuclear	**0.1**
Natural Gas	**1.0**
Coal	
Underground	**0.6**
Surface ('open-cast')	**8.2**
Renewables	
Wind	**1.3**
Geothermal	**5.1**
Hydropower (large dams)	**16.9**
Solar Photovoltaic (PV)	**15**
Biomass (from crops)	**19.3**

SUPPLY-SIDE RESPONSE: A TALE OF TWO COUNTRIES

Russia and the U.S., the largest gas producers and both in the top three for natural gas exports, are representative of two different views on how the global natural gas market could evolve amid the Energy Transition. They differ in how they approach pricing, market structure, resource development, and geopolitics.

THE U.S. STRATEGY

- ~20% of U.S. LNG share of global supply capacity and rising
- Remove destination clauses, facilitate spot pricing, and shift pricing to gas-indexed vs. oil-indexed
- Supply allied countries instead of having them rely on Russia or the Middle East
- Lower political risks help develop LNG projects

RUSSIA STRATEGY

- Largest global natural gas exporter, including pipeline gas and LNG
- 'Soft coordination' with other suppliers could be the eventual preferred market structure to maintain export revenue
- Have a long-established reputation as a steady supplier of natural gas

ADOPTING A CONSUMER STRATEGY TO POSITION NATURAL GAS

Co-developing supply, midstream, and demand projects could facilitate the use of gas as a transition fuel on the demand side, build infrastructure that could help with a future hydrogen economy, and make use of the gas resource. Gas producers pooling together via a 'development bank' structure could help solve the 'chicken-and-egg' problem between demand and infrastructure.

Many emerging market countries need funding to electrify, build infrastructure, and reduce existing polluting sources of energy generation

A development bank structure could facilitate infrastructure build-out

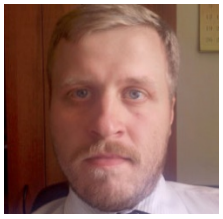
Contents

Institute for Energy and Finance Foundation

The Institute for Energy and Finance Foundation (FIEF or in Russian "ИЭФ") is a Moscow-based independent think-tank working in economic modeling and strategic consulting, with a specialization in global and Russian energy, macroeconomics, and financial analysis. FIEF was founded in 2004 by Gazprombank and Gazpromexport. The primary mission of the FIEF is the formation of a strategic vision for the development of the Russian economy and energy sector.

FIEF combines research, expert, and consulting activities. It has a rich and constantly expanding experience of interaction with leading foreign experts, active participation in Russia's foreign energy policy and energy diplomacy, and in the development of state and corporate strategic planning documents. Since 2015, FIEF also acts as an organizer of energy and risk analysis international seminars and events.

Marcel Salikhov, President and Principal Director on Economic Studies at FIEF. A director of the Institute for Public Administration and Governance at the University Higher School of Economics. PhD in Economics (2008). Dr Salikhov is the coordinator of the FIEF economic modeling projects, including the world economy, global trade and financial markets, as well as problems of the Russian energy sector. In 2005, he graduated from the Moscow Institute of Electronic Technology with a degree in Financial Management. He has been working at FIEF since its foundation.



Alexey Belogoryev, Deputy Principal Director on Energy Studies at FIEF. An expert in economy and history of the Russian and Global Energy markets with a special focus on the long-term Russian Energy strategy and integration and structural reforming of national and regional gas markets. He is one of the main authors of the Concept of the EAEU common gas market formation (2015) and the draft Master plan of Russia's Oil Industry development for the period up to 2035 (2021). In 2005, he graduated from the Faculty of History of Lomonosov Moscow State University. In 2006–2009 worked as an analyst and afterward a head of Gas Research Department in the Institute of Natural Monopolies Research (Moscow). In 2010–2015 he worked in the Institute of Energy Strategy (Moscow) at first as head of Fuel and Energy Complex Department, next as scientific secretary and from April 2013 as Deputy General Director.

Alexey Gromov, Principal Director on Energy Studies at FIEF. Associate Professor of the Gubkin State University of Oil and Gas. PhD in Economic Geography (2004). Dr Gromov heads research and consulting projects for analysis and predictive modeling of Russian and world energy development. Alexey is responsible for the Institute's international projects in the energy sector, including participation in the Energy Dialogue between Russia and the EU, China, BRICS, OPEC, GECF, etc. In 2001, he graduated from the Faculty of Geography, Lomonosov Moscow State University. In 2001-2005 he studied at the University of Paris 1, Pantheon-Sorbonne in the field of "Fuel and energy sector."

Alexander Titov, Leading research fellow at FIEF. An expert in economic modeling of the Oil and Gas markets. In 2011, he graduated from the Gubkin State University of Oil and Gas.

Victor Kurilov, in 2011-2020 research fellow at FIEF. Since January 2021, he has been working at Rystad Energy. Viktor is a developer of the FIEF Model for short-term forecasting of US shale oil production. He graduated from the Faculty of Economics of Lomonosov Moscow State University.

Natural Gas in the Energy Transition

Reducing greenhouse gas (GHG) emissions requires an 'Energy Transition', before full achievement of reduced carbon and methane targets is attained. The role of natural gas in that energy transition has become controversial in the debate about the transition. For some advocates, natural gas is viewed as the ideal transition fuel, given its superior performance compared with coal and oil. For others, this view has become the subject of deep controversy, especially (but not only) in Europe, where proponents of a cleaner planet argue that such a transition is unnecessary and ill-advised. This debate is often very intense, even among those who agree that cutting emissions sufficiently would help to limit the rise of global temperatures and contain the expected severe environmental fallout and negative health, economic, social and geopolitical consequences.

Not surprisingly, vociferous proponents of the long-term role of natural gas as a source of energy are found in the countries of the world's largest natural gas producers — the two super large producers being the United States and the Russian Federation — although critics of this view also reside in both countries. This Citi GPS report is a collaborative effort between analysts from these two countries, through Citi's Commodities Research team in the U.S. and the Moscow-based Institute for Energy and Finance (FIEF), an independent think tank undertaking critical analysis of the interstices of global energy and finance issues.

Citi and FIEF have drawn on their respective expertise, amid differing market and political contexts in the U.S. and Russia, to jointly develop this comprehensive study. First, both organizations jointly derive forecasts on supply and demand, potential growth areas allowing natural gas to make a more meaningful contribution to the Energy Transition, and challenges confronting the sector. Citi and FIEF then separately examine different potential market structure outcomes based on their respective U.S. and Russian market and political contexts. We believe this joint work helps to avoid bias in the analysis as it brings together a collective understanding of market developments, incorporates debates from those who are seeing the market from different perspectives, and tests theories and outlooks that would withstand the scrutiny of experts. We drill down on how demand projections could differ under different market and economic conditions, how feasible demand growth areas are under different settings, and how the market structure might change. On this last point of market structure, we spend time breaking out the analysis, from examining the merits of supply-side management to more innovative demand-side strategies.

In particular, both the Citi and FIEF analyses break ground jointly in looking at ways natural gas can effectively bridge the gap through the Energy Transition by providing a cleaner fuel alternative in power generation and transportation. This is contrary to the riskier approach of eliminating natural gas along with coal and oil. The FIEF analysis in particular provides an innovative approach to fostering natural gas demand, especially in emerging markets. FIEF also suggests ways for surplus gas exporters, like Russia and Qatar, to create pricing hubs by selling surplus gas on a spot basis to encourage flexible pricing for marginal demand and offtake.

There is little doubt the COVID-19 pandemic has accelerated progress on the Energy Transition. Support from the public, government, and corporations has grown significantly, particularly over the past two years. This acceleration has unfolded as climate change is increasingly recognized as an existential issue and despite the COVID-19-related economic damage to countries, companies, and consumers. Massive economic stimulus measures from governments in response to COVID-19 appear to have been a catalyst for change, and governments have been combining climate-abatement measures with stimulus packages.

The costs of solar and wind energy continue to fall and are attracting massive amounts of capital. Today's projects are a more than ten times more efficient use of capital than a decade earlier, and that capital is facilitating a large number of projects globally in a manner similar to how technology start-ups have grown and attracted funding. The large and steady drop of solar and wind installed costs has helped to attract massive capital inflows. In a virtuous cycle, greater investments, in turn, continue to facilitate improvements in economies of scale. Wind, solar, energy storage, and hydrogen could be considered part of the technology sector, on the physical side, as technology enables processes to improve and costs to fall.

Beyond these extraordinary inroads in renewable energy, studies have shown that renewables + battery systems could reach an economic limit of around 70% to 80% in many places. The IPCC (Intergovernmental Panel on Climate Change) also indicates that carbon capture could be a critical part of dealing with climate change.

Natural gas, with its cleaner-burning attributes, can play an integral role in the Energy Transition if the industry finds the right product/market fit, innovates its processes, and reinvents its business practices. The geopolitical consequences of gaining a place in the transition stretch from Russia to the United States. On the one hand, stuck in the old ways of operating, gas could follow coal's demise and oil's expected fall in the future. On the other hand, by breaking out of the box, gas could find new momentum and be useful as the world embraces the Energy Transition.

On the right product/market fit, as oil and coal retreat even as energy demand is still expanding, the energy market is massive for the taking and natural gas excels in several aspects. (1) It is a baseload energy that can be paired with CCUS (carbon capture, utilization and storage) or offsets in powering the massive increase in electrification and the need for grid balancing expected both as market shares of solar and wind rise and as electric vehicle ownership takes off. Natural gas also works as a form of long-term and physically compact energy storage and is easy to transport. (2) It has a vastly smaller physical footprint versus renewables, especially in powering metropolitan areas at a time when urbanization rates continue to rise. (3) It works as a cleaner shipping and transportation fuel. (4) It is highly competitive as a feedstock to make blue, carbon-free hydrogen with the use of CCUS, among other industrial applications.

Despite the usefulness of natural gas, its processes from upstream wellhead production to downstream demand need to change in order to mitigate greenhouse gas (GHG) emissions. Decarbonization measures range from using renewable energy to power its production and capturing methane leakage during its transport, to removing GHGs emitted as gas is consumed by deploying CCUS and applying credible offsets to counterbalance its emissions.

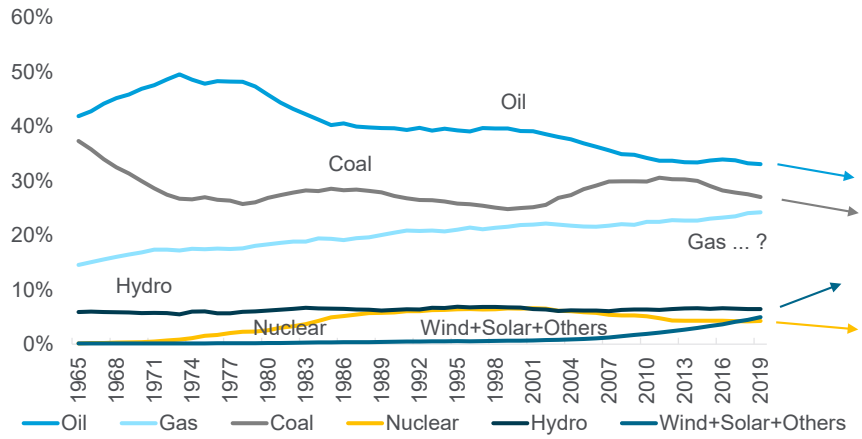
While natural gas is appealing due to its abundance and low cost of production, reinventing the industry's market and business practices is critical to its continued viability and attraction as a transition fuel. Alternatives to natural gas are no longer coal and oil, but solar and wind, and increasingly batteries and hydrogen — all pursuing the market with a tech start-up mindset. The gas industry might have to decide whether to defend its market share through supply-side management, similar to that of OPEC in oil, or join together to collectively facilitate how gas can help with the Energy Transition through project development and financing on the demand side.

The Story of Natural Gas: Great Expectations

A decade ago there was near universal agreement that the prospect of natural gas was bright. **The thesis sounded compelling and simple: even with wind, solar, and other renewables gaining share within total energy demand, gas should capture market share from coal and oil.** Oil's share has been falling, as power generation, heating, and some industrial processes have largely switched their feedstock or fuel away from oil and the electrification of the transport sector should erode oil's share further. Coal's decline looks inevitable due to environmental factors. The costs and safety concerns of nuclear limit its potential in the years ahead, unless and until a true breakthrough in fusion, as discussed in the Citi GPS report, Disruptive Innovation VII, would completely upend the world of energy. Hydro's future is limited by geography, since many sites suitable for hydro development have already been tapped. Shares of wind and solar should continue to surge due to falling costs and favorable policies. Gas's share has been expected to grow, given its cleaner-burning properties in replacing "dirtier" fuels such as oil and coal, and its ability to back up wind and solar. But that expectation is now being challenged.

Natural gas is supposed to be a winner in the energy space, with an enviable track record. Natural gas is a resource with a 25% market share in the energy space — a dominant size — out of five other competitors including oil, coal, nuclear, hydro, and other renewables (as a way to group solar, wind and other renewables together due to their small individual market shares historically). It has nearly 55 years of uninterrupted annual demand growth (outside of only two years), while almost all others have more years of negative growth (from 7 to 12 years). Natural gas has better environmental properties than two larger competing fuels — oil and gas — that are certain to lose market shares in the years ahead and that gas could grow into. Finally, it can both compete against and complement solar and wind, even as their combined market share only rose from 2% to 5% in the last 10 years.

Figure 1. Market Share of Each of the Major Energy Sources Globally: Oil, Coal, Natural Gas, Hydro, Nuclear, and Other Renewables (including Wind and Solar), 1965-2020



Source: BP, Citi Research

In this report, while we refer in general to the current state and future of the natural gas market worldwide, much of the investments are focused on liquefied natural gas (LNG). That's because regions with strong demand growth often have insufficient or no domestically-produced natural gas to satisfy local demand. Thus, a lot of the large-scale investment in natural gas happens in the LNG space, while LNG supply-demand fundamentals strongly affect the broader natural gas space that includes various pipeline natural gas markets.

In fact, just before the COVID-19 pandemic hit in 2020, the industry was still buoyant about the future of gas, backed by hundreds of billions of investments in new LNG export liquefaction facilities and cross-border pipeline infrastructure over the last few years. The industry was so optimistic that, in 2019, it celebrated reaching a record amount of Final Investment Decisions (FIDs) in LNG export terminals.

However, after enjoying years of uninterrupted demand growth and expectations for a bright future, natural gas is confronting a potential existential crisis with far-reaching economic and geopolitical implications.

Becoming Existential

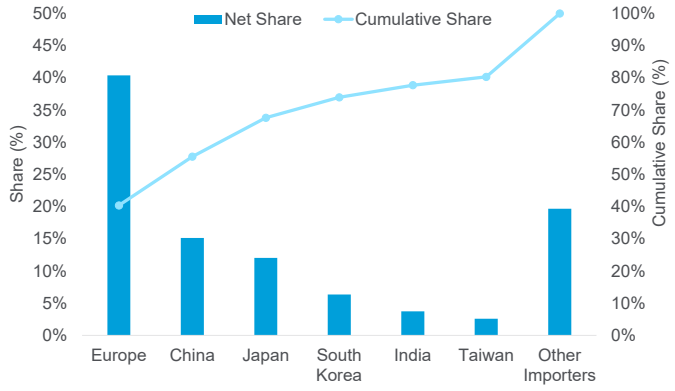
The future is becoming cloudy. Peak coal demand might have been reached in 2013 and peak oil demand might be within sight this decade or next. However, more robust growth in renewables, due to favorable developments in technology, economics, and politics, could now threaten to arrest the growth of natural gas. On the surface, the thinking of the industry was that gas still has a role. Even if gas consumers are not signing decades-long offtake contracts, as was the custom in the past, just build LNG export terminals and customers will come, even if those terminals cost tens of billions each. However, deep down, perhaps the industry has long recognized the difficulty in growing gas demand. For years, the industry, while sponsoring supply projects with high capital costs, kept talking about how to grow demand and touted the strong growth prospect of small nations.

Now, gas is at a potential existential juncture. The once bright, then later decent, demand growth prospect might end up being a mirage, as, one by one, major countries and regions announce full decarbonization goals as part of the Energy Transition. The top four import markets — Europe, China, Japan, and South Korea — together make up around 83% of traded global gas demand. These same markets have also adopted aggressive net-zero emissions goals. Politically, the European Union has been steadfast in its decarbonization drive. China's Premier, Xi Jinping, promises a net-zero future by 2060. Japan and South Korea, among others, have made net-zero pledges. Further, in the U.S., President Biden's net-zero goal by 2050 is a top policy priority.

Economically, the COVID-19 pandemic plunged oil and natural gas demand and prices so much that oil and gas producers and petrostates sharply cut back investments. Some supermajors announced delays to their gas projects, some aim to turn themselves into power companies, and only one LNG export terminal reached FID this past year — in Mexico at a brownfield site called Costa Azul. Over the next few years, it might turn out that no companies will sanction new LNG export projects, other than the long-anticipated expansions in Qatar (which reached FID in the first quarter of 2021) and Russian projects backed by the Kremlin.

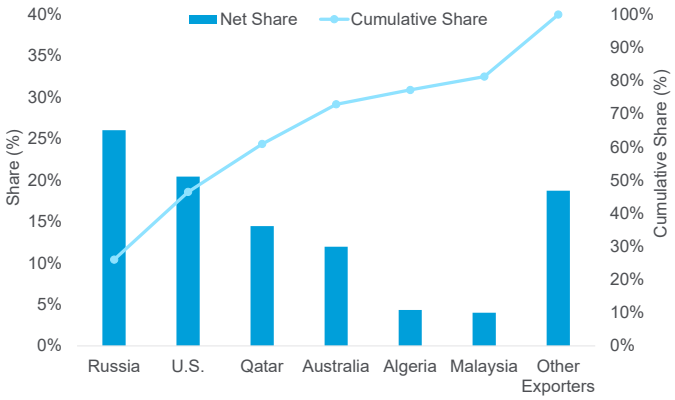
Economically, trillions of dollars are at stake. With asset lives of new gas projects easily reaching 30, 40, or 50 years, the prospect of countries and regions aiming to achieve net-zero greenhouse gas emissions by 2050 or 2060 means that billions in long-term investment decisions on gas have to be made now. Yet those decisions are cast under the foreboding shadow that gas resources left behind might become stranded assets. Thus, the question becomes whether to invest or to not invest. The highly concentrated nature of gas demand and supply, where a few countries make up 80% to 90% on both the supply and demand sides, also means that losing market shares to other energy sources in large consuming countries could be detrimental to gas producers and exporting countries.

Figure 2. Demand Is Highly Concentrated: Share of Demand by Major Region or Country in the "Globally Traded Gas Market"[1] — 90% of Total Demand Comes from the Top 6 Markets



Source: Citi Research

Figure 3. Similarly, Supply Is Also Highly Concentrated: Share of Exports by Major Countries in the "Globally Traded Gas Market" — ~84% of Gas Exports in this Context Come from the Top 6 Countries



Source: Citi Research

[1] We define the 'globally traded gas market' as the combined global LNG and European gas markets, since Europe has a large, competitive and flexible power and gas markets that absorb excess LNG. Although the U.S. has a large, integrated market, this market only imports a very small amount of LNG into New England. Thus, we treat the U.S. as an LNG exporter instead.

Geopolitically, Russia and the U.S., the two largest gas producing countries in the world and two of the three largest exporters, approach the market very differently and have generally different geopolitical stances. Russia is the largest global gas exporter, with dominant control over Europe's energy supply and increasing effective influence over global LNG prices. The U.S. went from being a net gas importer less than a decade ago to potentially becoming the second-largest global gas exporter over the next few couple of years**.** The rise of U.S. LNG has already upended the traditional market structure, from one based on long-term contracts linked to oil prices and restricted supply destinations, to one based on spot prices, the freedom of movement (for LNG cargoes) and choice (for gas consumers). How these two countries confront or embrace the Energy Transition will likely determine whether natural gas and its associated infrastructure becomes stranded or an integral part of the "clean energy future". And, whether their own gas production and exporting industries survive or fade.

This report examines key drivers and potential outcomes of the natural gas market:

(A) The competitive landscape of natural gas: supply-demand projections over the coming years.

(B) The right product/market fit including five key demand growth areas for natural gas: (1) gas-fired power generation could help ensure grid supply and reliability; (2) a gas power plant's smaller footprint could be an effective source of generation versus renewables, especially amid rising urbanization rates in many emerging markets; (3) LNG bunkering could be a viable way to help cut emissions in the still-polluting shipping sector; (4) LNG could be a fuel for long-haul trucking, while compressed natural gas (CNG) could emerge as a viable alternative to diesel for deliveries "in the last kilometer (or mile)"; and (5) gas could sustain and grow its position in hydrogen production.

(C) Decarbonizing the process and movement of gas from wellhead to generation to reduce, if not remove, the main stigma from the fuel: If the stigma over natural gas is its GHG emissions, then we highlight ways to solve this, including CCUS, offsets and dealing with methane leakages.

(D) How should the industry respond? Options for the gas industry — band together to manage supply or expand demand? Should industry participants simply compete against each other constantly for market share? Should the industry band together to manage supply, like OPEC does in oil, and keep prices at a higher price floor than otherwise might be? Or, should the industry finally proactively embrace the Energy Transition, focus on growing demand by delivering on the value proposition of gas, and facilitate it, potentially, by turning the global organization Gas Exporting Countries Forum (GECF) into a development bank?

(E) A view from Russia: How the gas market structure could evolve and how the main players would respond: The Institute for Energy & Finance Foundation (FIEF), a Russian think tank, discusses how the gas market structure could evolve; analyzes the effectiveness of various supply-side management strategies (including coordinated supply cuts); and examines electronic sales platforms as well as potential reactions from major Russian gas companies.

(F) A view from the U.S.: How its market-based reaction and ample shale resources should keep supply adequate at the right price: Citi's Energy research team examines the technical and economic fundamentals of shale, which constitutes the driving force of U.S. natural gas exports that led to the transformation of the global natural gas sector and beyond.

(A) The Competitive Landscape of Natural Gas: Supply-Demand Outlooks

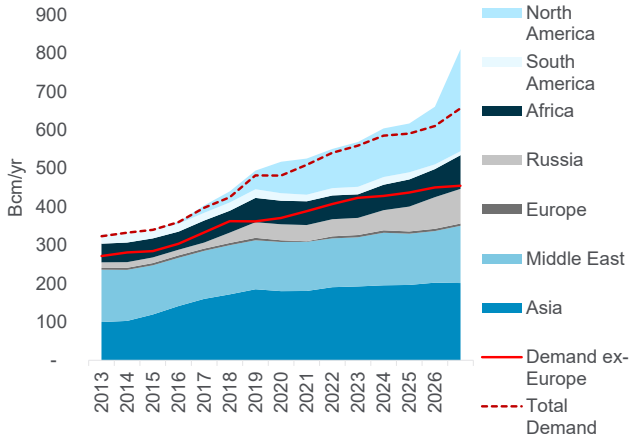
Natural Gas Demand Growth Looks to be Moderating: An Analysis of Regional and Major Consuming Markets

Citi's Analysis

Environmental, Social & Governance (ESG) concerns, energy security issues, and falling costs of renewables and energy storage are all competitive challenges for gas in the traditional energy market. This past year, despite the industry resetting its optimistic LNG demand growth outlook, evidenced by the dearth of LNG supply projects reaching final investment decisions (FIDs) following the euphoria in 2018-19, LNG's fight for market share in the energy space has not gotten any easier.

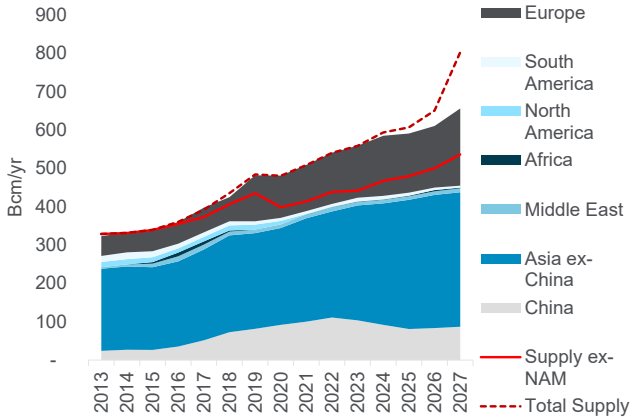
To understand the future of natural gas, we first need to estimate a baseline forecast of supply and demand, in particular looking at major importers and major demand growth regions. Doing so highlights the challenges confronting this energy resource, since just six markets make up ~90% of demand in a globalized gas market. Although a generic forward-looking analysis could focus squarely on new and exciting growth drivers and areas, this implicitly assumes that incumbents would not be a drag on the entire market. To illustrate, Asia is the largest LNG importing region, consuming ~70% of global LNG supply. Just five markets in Asia — Japan, China, South Korea, India, and Taiwan — absorb more than 60% of global LNG. With more than 20% of all LNG supplies going to Europe as a "single" competitive market, where the European Commission is an umbrella entity driving policies, this means 85% of all LNG goes to just six markets — a highly concentrated set of consumers. Thus, a 5% change in their total demand over time is more than the combined imports of the Middle East and South America — both thought to be potentially major future growth areas. In addition, the largest gas exporter, including both LNG and pipe, is Russia, which principally supplies both Europe and China – two of the six big consuming markets. Thus, it is crucial to assess demand trajectories of these large markets first and to not miss the forest for the trees.

Figure 4. Global LNG Supply to Surge Starting in Mid-2020, but Slower Demand Growth Outside of Europe Could Leave the Market Oversupplied …



Source: Citi Research

Figure 5. …If True, Europe Theoretically Has to Absorb Much More Excess LNG Supply…



Source: Citi Research

Overall, LNG demand growth in four regions — Asia, Europe, the Middle East, and Latin America — looks to be slowing. While Asia is the largest LNG importing region, and should remain so in the future, demand in mature markets there looks stagnant collectively. There is considerable risk of a much weaker-than-expected appetite for LNG from China. Europe's decarbonization goal should lead to more moderate — or even lower — domestic gas demand over time. The Middle East and South America, once touted as new key demand growth drivers, have sought to increase their own local production, while renewable energy challenges the growth outlook for gas. Note that North America is self-sufficient and is a gas exporter.

Figure 6. Global LNG Balance

Annual (Bcm/y)												
Supply	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Asia	**185**	**180**	**181**	**190**	**192**	**195**	**196**	**202**	**201**	**205**	**206**	**207**
Australia	107	107	106	111	109	108	111	115	113	111	113	117
Malaysia	36	33	34	36	37	40	40	40	40	40	40	39
Indonesia	22	20	20	23	25	26	25	26	27	27	26	25
Papua New Guinea	11	12	12	12	12	12	12	12	13	18	19	19
Middle East	**128**	**128**	**128**	**127**	**128**	**137**	**133**	**134**	**149**	**167**	**173**	**183**
Qatar	106	107	106	106	106	106	106	109	126	147	154	167
Oman	14	13	14	14	16	16	11	9	6	4	3	-
United Arab Emirates	8	7	7	7	7	6	7	7	7	7	7	7
Europe	**6**	**4**	**1**	**5**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**
Russia	**41**	**42**	**43**	**44**	**45**	**53**	**65**	**82**	**91**	**105**	**106**	**106**
Africa	**63**	**61**	**62**	**62**	**61**	**66**	**71**	**73**	**87**	**99**	**107**	**105**
Algeria	17	15	15	13	11	11	11	10	10	10	10	8
Nigeria	29	29	28	27	27	27	27	28	36	38	37	37
Egypt	5	5	8	10	10	10	10	5	8	8	8	8
Mozambique	-	-	-	-	2	4	9	17	22	33	43	43
North America	**49**	**82**	**94**	**102**	**117**	**126**	**127**	**150**	**266**	**349**	**363**	**398**
US	49	82	94	102	117	126	127	143	233	297	303	323
Canada	-	-	-	-	-	-	-	5	16	25	27	27
South America	**22**	**19**	**17**	**19**	**20**	**20**	**18**	**12**	**11**	**10**	**12**	**12**
Trinidad and Tobago	17	14	12	14	14	15	13	7	5	-	-	-
Peru	6	5	5	6	5	5	5	5	5	5	5	5
Total Supply	**484**	**481**	**508**	**540**	**558**	**593**	**607**	**650**	**802**	**933**	**966**	**1,010**
Demand												
Asia	**331**	**344**	**370**	**388**	**403**	**408**	**418**	**431**	**438**	**453**	**460**	**471**
Japan	111	107	113	110	108	106	105	103	102	100	96	95
China	82	92	100	111	104	92	81	84	87	90	93	97
South Korea	54	54	58	54	51	52	53	55	55	57	58	57
Taiwan	22	24	26	27	29	30	31	32	32	32	31	31
India	26	32	31	32	34	35	38	39	40	42	42	45
Other	36	35	42	54	78	93	110	118	122	131	139	146
Middle East	**9**	**10**	**9**	**11**	**10**	**10**	**9**	**9**	**10**	**11**	**14**	**17**
Europe	**120**	**110**	**120**	**134**	**136**	**157**	**154**	**160**	**201**	**212**	**204**	**183**
Africa	**0**	**0**	**0**	**0**	**1**	**1**	**2**	**4**	**2**	**2**	**2**	**2**
North America	**12**	**9**	**2**	**2**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
South America	**9**	**8**	**7**	**7**	**10**	**9**	**8**	**6**	**5**	**5**	**5**	**6**
Total Demand	**482**	**481**	**509**	**541**	**559**	**585**	**591**	**610**	**656**	**683**	**684**	**678**

Source: EIA, IEA, Wood Mackenzie, Company Reports, Citi Research

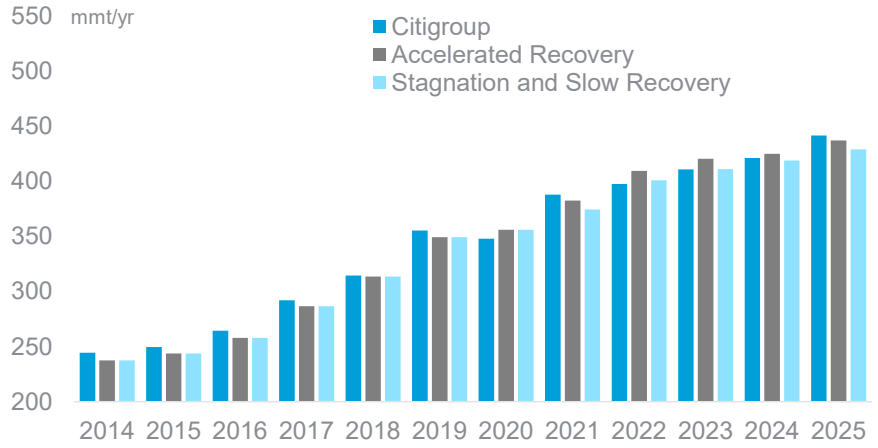
FIEF's Analysis

FIEF has also conducted forecasts of future supply and demand. Its analysis considers two scenarios for the development of the global LNG market, depending on various options for the post-COVID-19 world:

1. **Accelerated recovery or V-shaped scenario:** The scenario assumes the end of the COVID-19 pandemic no later than autumn 2021 and the cancellation of all "hard" quarantine measures in the second quarter of 2021. All "soft" quarantine measures will be canceled by early 2022. This scenario assumes a rapid return to the pre-crisis trajectory for the global gas market;

2. **Stagnation and slow recovery or U-shaped scenario:** The scenario assumes a slow and unstable response to the COVID-19 pandemic during the second half of 2021 and first half of 2022, with a local resumption of "hard" measures and a widespread continuation of "soft" measures. Mutation of the virus potentially may lead to a new wave of the pandemic in late 2021.

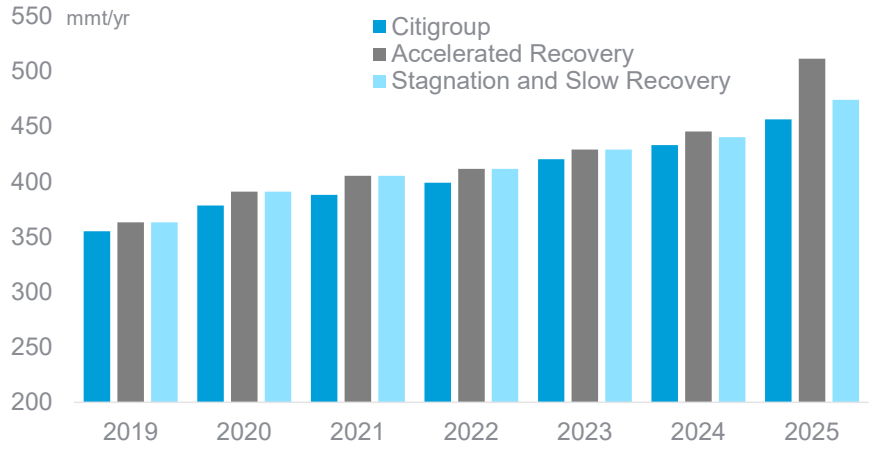
Figure 7. Global LNG Consumption



Source: FIEF and Citigroup estimates, Refinitiv, EIA

The supply and demand balance of the global LNG market during 2021-25 looks likely to be unstable and volatile. Both Citi and FIEF analysts expect a sharp increase in the supply surplus in 2020-21 and 2025 and a significant reduction in 2022-24.

Figure 8. Global LNG Supply



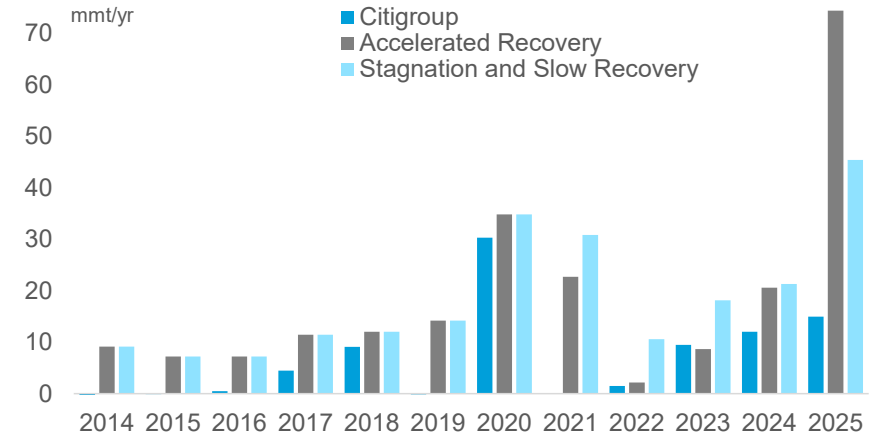
Source: FIEF and Citigroup estimates, Refinitiv, EIA

In the both scenarios, market balance might be achieved as soon as 2022. In the scenario of accelerated recovery, even the formation of a slight supply deficit cannot be excluded in 2022.

One of the features of this joint analysis between Citi and FIEF is in presenting similarities and differences in views that mimic ones that are hotly debated in the market. This includes slight differences in supply and demand outlooks. The strength of this approach helps to preserve the independence of our respective analyses and free us from the interference of perceptions of the other partner of this joint report. Instead, such differences help to enrich our respective understanding of the market through shared knowledge and allow us to appreciate different points of views, including approaches to market structure. In particular, Citi comes at this analysis from the perspective of the U.S., which historically embraces market-driven policies, but is a relatively new entrant in the global natural gas space through its massive LNG export volume.

FIEF comes at this analysis from the perspective of Russia, an incumbent in the global natural gas space which historically has been much more of an oligopolistic supplier.

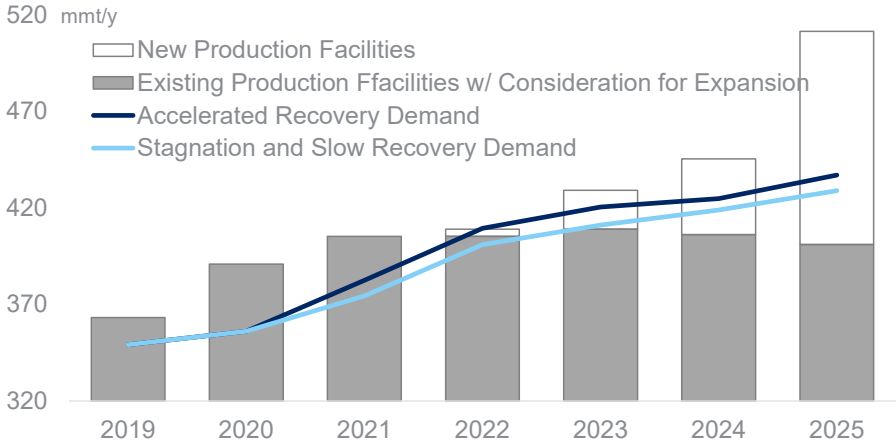
Figure 9. Global LNG Surplus



Source: FIEF and Citigroup estimates, Thomson Reuters, EIA

The growth rate of global LNG demand should slow significantly in the first half of the 2020s compared to 2016-19. That's due to a higher base, saturation of several markets, intense competition with pipeline gas in Europe and North America, and the start of additional pipeline gas supplies to China (the "Power of Siberia" Russian pipeline and domestic gas). Due to a sharp decline in growth rates in 2020, supply dynamics in 2021-22 should remain relatively high.

Figure 10. Global LNG Demand and Supply Projections for 2019 to 2025



Source: FIEF and Citigroup estimates, Thomson Reuters, EIA

(B) The Right Product/Market Fit: Five Key Demand Growth Areas for Natural Gas

Natural gas is under threat from the very "creative destruction" process that once helped it to displace oil and coal in power generation, space heating, and industrial processes. The natural gas sector, despite its useful properties and incumbency in the energy space, needs to find its right product/market fit. Incumbency by itself is not bad. However, complacency often precedes the demise of an industry, regardless of how strong its value proposition once might have been. For example, Sears pioneered the use of catalogs for at-home shopping; Xerox used to be a verb. While the market segments of these businesses used to dominate still exist (i.e., online shopping is the modern version of the catalog business and document services remain a sizable segment), firms that fail to innovate enough get displaced.

We use the term Product/Market Fit (PMF)[2] — common in the technology sector — to define what natural gas has to do. The traditional energy market, where natural gas is an incumbent, is being disrupted by solar, wind, batteries, and hydrogen — all of which are products propelled by technological advances and driven mostly by entrepreneurial investors. To compete, natural gas has to shed the incumbent mentality and find the right fit. Successful technology companies become successful because they are able to find big markets with the right products. Don Valentine, founder of Sequoia Capital, asserted: "Give us a technical problem, give us a big market when that technical problem is solved so we can sell lots and lots and lots of stuff." Clearly, the energy market, with the fall of coal and eventual decline of oil, is massive. Technological advances allow solar, wind, batteries, and hydrogen to capture greater market shares. Marc Andreessen, founder of Andreessen Horowitz, also observes that: "You can always feel when product/market fit isn't happening. The customers aren't quite getting value out of the product, word of mouth isn't spreading, usage isn't growing that fast, press reviews are kind of 'blah', the sales cycle takes too long, and lots of deals never close." In the natural gas world, this equates to LNG supply projects are not being sponsored, long-term contracts are not being signed, and investor capital is not as available. Thus, natural gas needs to finds the right product/market fit.

In fact, the value proposition of gas is strong, with five key demand growth areas, including: (1) natural gas could ensure energy and power grid supply reliability, through gas-fired power generation to shore up grid stability and through gas storage to provide long-term, seasonal storage to offset renewable weather issues beyond what typical batteries could do; (2) a gas power plant's smaller footprint could be an effective source of generation versus renewables whenever land use becomes a concern, such as amid rising urbanization in many emerging market countries; (3) LNG bunkering (providing LNG fuel to a ship for its own consumption), dependent on gas's continued vigor, could be a viable way to help reduce emissions in the still-polluting shipping sector; (4) road transportation vehicles could also increasingly turn to natural gas to replace gasoline or diesel, especially where electric vehicles or hydrogen fuel cell vehicles are yet to catch up, for example passenger vehicles in countries like Iran or India and heavy-duty trucks, as well as in delivery over the "last kilometer/mile"; and (5) gas could sustain and grow its position in hydrogen production, as we show via a Levelized Cost of

[2] Andreessen Horowitz, 12 Things About Product-Market Fit.

Hydrogen (LCOH) comparison between "blue hydrogen" from gas + CCUS and "green hydrogen" from renewables.

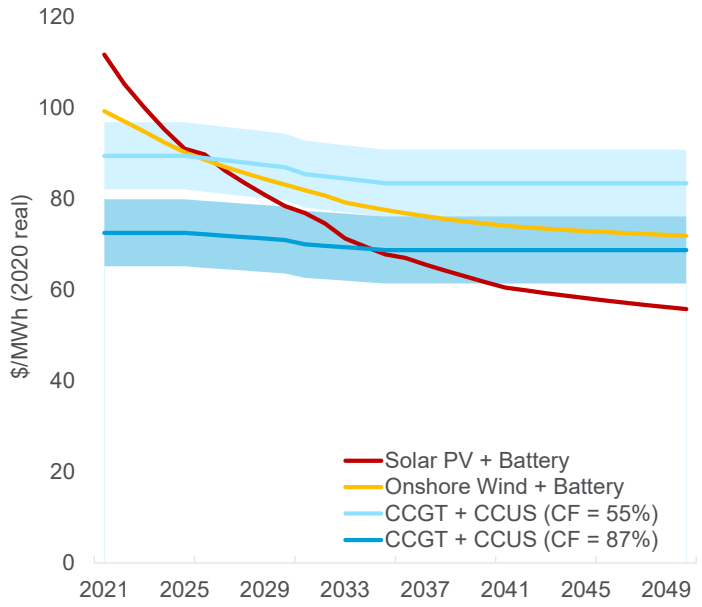
(1) Ensuring Energy and Power Grid Supply and Reliability

On the power side, the need to ensure the reliability and stability of power systems of the future is critical to the ambitious expansions of new energy. Age-old issues of renewables' intermittency, extreme weather, and rising penetration of electric vehicles (EVs) would all test the reliability of power grids in the future. A broad spectrum of "energy storage" technologies is integral to this development, from batteries (electrochemical) to compressed air and pumped storage (mechanical), as well as hydrogen (chemical).

Natural gas — itself a form of energy carrier — used as dispatchable generation equipped with carbon capture, utilization and storage (CCUS) could be one of the most reliable solutions. In this context, natural gas should remain key in supporting the Energy Transition, even against the global policy push for renewables. However, public support is key. Economics for current CCUS projects are challenging and the perception exists that natural gas is still a fossil fuel and fossil fuels should be avoided. But, in this context, natural gas could still serve as the bridge fuel in the Energy Transition.

Instead of outlining a misleading standalone comparison on an LCOE (levelized cost of energy) basis between renewables and gas, we compare the enhanced LCOE of gas with CCUS against a renewables + battery system for an apples-to-apples comparison. Electricity demand is often smooth, or smoother than what intermittent solar or wind could immediately provide. Thus, while a gas-fired or hydro-powered plant could supply electricity smoothly, solar and wind would need their intermittencies smoothed, such as by integrating with batteries or even hydrogen. However, since there are no emissions associated with renewable generation, making this LCOE analysis comparable requires a gas-fired power plant to pair with CCUS.

Figure 11. Comparing the LCOE of a Gas-Fired Power Plant + CCUS at Different Capacity Factors and Gas Prices with a Solar or Wind + Battery System



Source: Citi Research

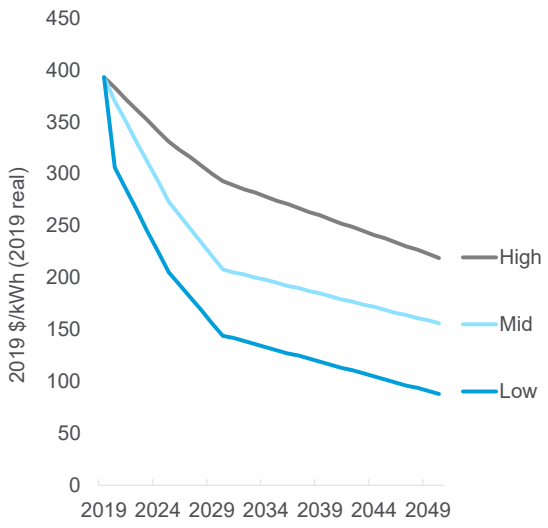
For now, gas is often more economic than renewables + storage systems when smooth power supply is needed. Bloomberg NEF (BNEF) estimates there could also be an economic limit of ~70-80% penetration by renewables + battery systems in most markets. A 4 megawatt (MW) solar photovoltaic cell (PV) + battery (1 MW/4 megawatt-hour (MWh)) system still produces highly intermittent power, unless a costlier 7 MW PV + battery (6 MW/24 MWh) system is in place. However, clean energy costs are falling.

At the low end of the gas price range of $4/million British thermal unit (MMBtu), constructing a gas power plant with CCUS running as a baseload resource (at a capacity factor of ~87%) could be more economic than constructing a solar PV + battery system until around 2040. It could be more economic until around 2035 if gas prices were $5/MMBtu, and until around 2030 if gas prices were $6/MMBtu.

Thus, this is a way that gas could preserve its competitive position against solar or wind in the power sector, or could become even more competitive.

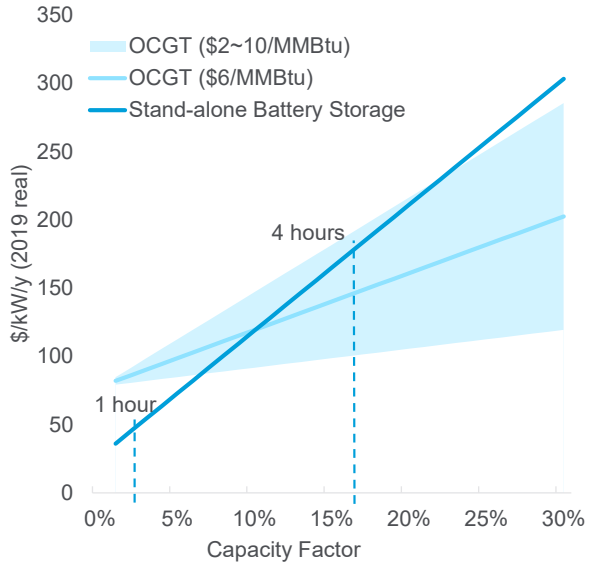
On overall energy supply stability, energy storage with batteries has made considerable headway globally, especially as pairing renewables like solar and wind with batteries is increasingly common. But providing power for a full week, let alone for weeks at a time, remains a challenge. Natural gas, after operating for years as a form of seasonal storage, could help. Costs of utility-scale battery systems have plunged over the past decade. Lithium-ion (Li-ion) batteries are preferred for their high-cycle efficiency, fast response times, and high energy density. U.S. National Renewable Energy Laboratory's (NREL's) base case projects a 47% and 60% decline, respectively, in the overnight capital costs of total battery systems by 2030 and 2050 compared to 2019 levels for a typical 4-hour output duration system. Nonetheless, a 4-hour standalone battery is currently not competitive with gas peakers (i.e., gas plants that turn on when energy demand is peaking), except when natural gas prices hit almost $10/MMBtu. There is also the possibility that the ability of batteries to charge and discharge could degrade at extreme temperatures, particularly at low temperatures. Natural gas could provide the kind of longer-term, seasonal storage needed. The U.S. and Europe operate continental-scale gas storage systems for years that supply gas to homes, power plants, and industrial facilities during winter or when extreme temperatures hit.

Figure 12. Overnight Capital Cost Projections for a 4-hour Battery System (2019-2050)



Source: NREL, Citi Research

Figure 13. Levelized Cost of Capacity* for New-Build Peaking Technologies, Comparing OCGT with Batteries, U.S. (2020)



Note: * including charging cost for batteries; prices for natural gas input to open cycle gas-turbine (OCGT) range from $2 to $10/MMBtu; assumed a daily cycle for batteries
Source: BNEF, Citi Research

Some might argue that the February 2021 Texas power outage could also be blamed on a natural gas supply shortage, making reliance on natural gas not dependable. However, better winterization and additional gas storage capacity would help. Natural gas power and heating systems work fine in colder climates, as these places are better prepared for winter than Texas, which does not often experience extremely cold weather. If there were also a gas shortage to supply dispatchable power generation, the argument would revert to having more natural gas storage or very large-scale energy storage. However, the natural gas infrastructure would need to have back-up power.

Options to Account for Carbon Emissions from Natural Gas Facilities:

Carbon capture, utilization & storage (CCUS) constitute mechanisms whereby greenhouse gases emitted during combustion can be captured and used in processes that require carbon dioxide, such as enhanced oil recovery (EOR), and/or stored. Economies of scale and technological improvements could help deliver significant cost reductions at future CCUS facilities. According to a study by the International CCS Knowledge Center,[3] a second-generation capture facility could be built with 67% lower capital costs, at $45/t$CO_2$ captured. Ultimately, the U.S. Department of Energy (DOE) is seeking to bring the cost of carbon capturing down to $30/t$CO_2$ in order to promote greater use of this technology. Independent of technological gains in efficiency, the right price for carbon offsets would also help.

Emitters could also reduce their net GHG emissions by acquiring credible carbon credits, or offsets, produced from qualified sustainable projects. These qualified projects could include reforestation since forests act as GHG sinks. Genetically modified crops with higher yields and bigger root systems can act in the same way. Revenues from GHG credits help support the development of GHG-reducing projects.

[3] The cost reduction potential for CCUS at coal-fired power plants, IEA (Nov 2019).

Examples of older offset markets include ones developed under the UN Clean Development Mechanism (CDM) and Joint Implementation (JI) out of the Kyoto Protocol. CDM/JI market grant certified emissions reductions (CERs) and emissions reduction units (ERUs) to companies involved in the realization of sustainable projects. Each CER or ERU is equivalent to a credit of 1 metric tonne of CO_2 equivalent ($MtCO_2e$). However, older offset programs often lack or do not strictly enforce the "additionality" requirement. Offsets are supposed to be useful in reducing GHG emissions if revenue from selling offsets is required for these carbon-reducing projects to develop. Thus, gas power plants with qualified offsets could end up with a net-zero emission profile.

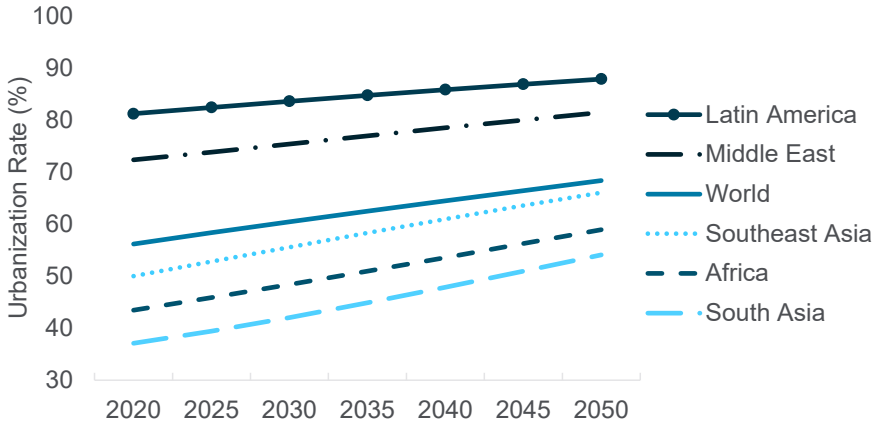
(2) Smaller Footprints of Gas Power Plants a Competitive Advantage When Land Use Becomes a Concern

Gas-fired generation could see strong demand from metropolitan areas, which have high energy densities. Although renewable energy, paired with long-haul transmission lines and energy storage, increasingly supplies urban areas, the land-use issues that make gas-fired generation more appealing still persist in the area of renewable generation.

The UN expects the amount of people who live in urban areas (urbanization rates), to rise over time, from a global average of less than 60% today to nearly 70% by 2050. Urbanization rates should rise the fastest in South Asia, from the high-30% range currently to potentially the mid-50% range by 2050. Importantly, urbanization rates in Southeast Asia and Africa would also climb at close to this rate.

While urbanization rates in some developed countries have largely flattened out and could even regress due to the ability to work remotely, the rise in urbanization rates in emerging markets should continue, as populations seek higher-paying jobs in urban centers and as economies industrialize.

Figure 14. Urbanization Rates in Key Regions Globally (Projected from 2020 to 2050)



Source: UN, Citi Research

The generally larger footprint of renewable energy means it is not necessarily the most convenient power-generating source for serving urban centers. Gas-fired generation remains valuable when looking at the amount of land (in square meters, m^2) needed to generate one unit of power (in megawatt-hour, MWh), using a "land use intensity" metric. While different power supply sources have different land-use intensities, depending on location and how land use is assessed, gas-fired generation generally comes out the most compact. Separating out the upstream drilling and, in the case of LNG, the liquefaction aspects, the land use of a gas-fired power plant would be even smaller. Many emerging market countries are already densely populated. Rising urbanization levels should also increase power intensity levels, even if the per-capita use of power were to be lower in urban areas versus more rural areas due to smaller per-capita space heating and light demand. Although nuclear generation has the lowest land-use intensity, the very high total cost of nuclear, as well as lingering safety concerns or perceptions, make it less likely to be used.

Figure 15. Overview of Land-Use Intensity Relating to a Range of Energy Systems or Electricity Generation and Transport Fuels

			LAND USE INTENSITY (M^3/MWH)				
PRODUCT	Primary Energy Source		U.S. data[a)]	U.S. data[b)]	EU data[c)]	UNEP[d)]	Typical[e)]
ELECTRICITY	Nuclear		0.1	0.1	1.0		0.1
	Natural Gas		1.0	0.3	0.1	0.2	0.2
	Coal	Underground	0.6	0.2	0.2		0.2
		Surface ("open-cast")	8.2	0.2	0.4	15	5.0
	Renewables	Wind	1.3	1.0	0.7	0.3	1.0
		Geothermal	5.1		2.5	0.3	2.5
		Hydropower (large dams)	16.9	4.1	3.5	3.3	10
		Solar Photovoltaic (PV)	15	0.3	8.7	13	10
		Biomass (from crops)	19.3		7.8	14	15
LIQUID FUEL	Fossil Oil		0.6		0.1		0.4
	Biofuels	Corn (maize)	237		220		230
		Sugarcane (from juice)	274		239		250
		Sugarcane (residue)					0.1
		Soybean	296		479		400
		Cellulose, short rotation coppice	565		410		500
		Cellulose, residue			0.1		0.1

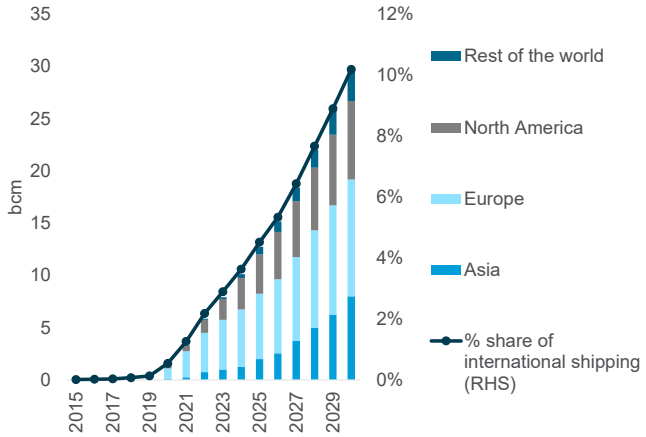
Source: UNCCD, UNEP, Citi Research (a)Trainor et al. (2016); (b) Fthenakis and Kim (2009); (c) IINAS (2017); (d) UNEP (2016); (e) own estimate for unspecified region (i.e., generic)

(3) LNG Bunkering Should Provide a (Modest) Boost to Natural Gas Demand to 2040

Continuing efforts to reduce sulfur and carbon emissions in shipping should see LNG's role as a bunker fuel continue to increase over the next two decades. Forecasts from the IEA in 2017 pointed to a more than 600% increase in the use of LNG by 2030, rising to ~18.8 million tonnes per year (annum) (mtpa) (~2.5-bcf/d) under its Sustainable Development scenarios and to ~29.7-mtpa (~3.9-bcf/d) under its New Policies Scenario. Depending on the source of the forecast, the base case would amount to 8-12% of the total marine use by 2030, and to about half that level (~10-mtpa or ~1.3-bcf/d) This is a level similar to forecasts by ENGIE/RWE, Lloyds, and Energy Intelligence (EIG's) Research and Advisory group, which point to the advantages of LNG, including emitting basically 0% sulfur or nitrogen and around 25% less CO_2 and 20% less GHGs than very-low-sulfur fuel oil (VLSFO). However, as 2020 ended, LNG fueled less than 0.5% of the 80,000 registered ships then in use.

Preparations to deliver LNG as a bunker fuel escalated through 2020 at a near frenetic pace, just as new cruise and container ships and dry bulk carriers fueled by LNG saw orders at shipyards increase. BHP and Shell inked an agreement to fuel five iron ore bulk carriers in Singapore starting in 2022 and, by 2023, could reach 10% or so of expected total Asian LNG bunker demand. This followed BHP securing 2022 delivery in mid-2019, eight years before the International Maritime Organization's (IMO's) new 2030 low-sulfur fuel requirements kick in. IMO's current plans point to reducing 2008 carbon emissions levels in shipping by another 40% by 2030 and 70% by 2050. Europe remains the leader in moving toward LNG for shipping. Equinor and other LNG producers are supplying to a variety of European ports, including Emden in Germany. It is also expanding fueling out of the NW Europe Amsterdam-Rotterdam-Antwerp (ARA) fueling and storage center. Demand for LNG shipping in Asia is also taking off, with ship-to-ship bunkering in Japan, Malaysia and soon in Singapore (2021).

Figure 16. Annual Actual and Projected Marine LNG Demand for International Shipping, in BCM, by Region (2015 - 2030)



Source: Wood Mackenzie, Citi Research

Figure 17. Global Marine Fuels Projected Demand Growth Over Five-Year Periods (5-yr periods from 2025 to 2040), by Fuel Source

Source: Wood Mackenzie, Citi Research (*LNG: volume of oil displaced by LNG)

The fastest strides seem to be underway in inter- and intra-coastal carriers of people and materials — ferries, cruise lines and barges. While Europe appears to be ahead in this area, as well as in bunkering barges and other barges, strides are being made elsewhere in the world, including along the U.S. East Coast and the Caribbean. However, Europe has consolidated its early lead in this business with LNG available near all major regasification terminals and critical bunkering sites, including Gibraltar. Carnival Corporation's Costa Cruises subsidiary started LNG fueled carriers in the Mediterranean this year following Carnival Cruise Line's Mardi Gras 10-day trial in the Baltic. This mega ship is scheduled to operate from Florida, once leisure travel resumes following the pandemic. Its fuel supply will come from the Elba Island LNG terminal in Georgia. Additional cruise liner LNG use is coming from the U.K., where P&O Cruises accepted its first LNG-powered carrier in the fourth quarter of 2020 and anticipates starting operations in 2021. Disney Cruises is also following suit in ordering new carriers for post-pandemic use.

The total scale of LNG in shipping needs to be put in context. If the global shipping industry, which currently uses ~4.6 thousand barrels/day (k b/d) of oil products moved entirely to LNG, it would require more than 200 million tonnes per year (mtpa), or ~27.5 billion cubic feet/day (bcf/d) of LNG — more than half of today's global LNG market. However, nothing of that scale looks likely. Even an aggressive build out of LNG for use in the bunker market would see only some 300 to 350-k b/d of oil displacement by 2025, or ~13.5 to 16-mtpa, 1.8 to 2.1-bcf/d in gas-equivalent terms, according to Wood Mackenzie. The consulting/analytics firm also sees that level just about doubling to some 650-k b/d of oil displacement by 2030, just over 1-m b/d by 2035 and potentially just under 1.5-m b/d by 2040, when it would be shy of 9% of the total LNG market, far less aggressive than the EIG estimates.

LNG use in bunkering is undoubtedly positive for LNG demand, though there remain obstacles to its use. Wood Mackenzie calculates that, as LNG grows to above 10% of global marine fuel demand in 2030, the largest share of demand would still come from Europe at ~200-k b/d, or 1.1-bcf/d. Yet the politics of natural gas in Europe have become more negative amid concerns raised about use of LNG as a shipping fuel due to methane leakage. Some European governments have started opposing the use of gas, for which production is accompanied by flaring at the wellhead or just with significant methane leakage. Opposition to LNG is generally based on analyses showing that LNG might be a worse emitter of GHGs than clean distillate fuels. Sometime in the near future, more accurate information will become available globally on methane emissions, including how much of it stems from natural conditions and how much stems from production. Data on the more precise amount and source of these emissions by well and by company would be made available to the public. The French government is one of many in Europe that has become publicly sensitive to the origins of imported gas and the amount of emissions associated with the entire supply chain, from wellhead to pipelines, liquefaction, transportation, regasification, and delivery. The EU Commission is currently trying to standardize these supply chain calculations.

Dealing with methane leakage is critical to addressing growing concerns on the use of natural gas as a significant part of the Energy Transition. On the one hand, the transportation leg of the LNG supply chain is often questioned as an especially high source of methane emissions, with some indicating the industry cannot be trusted and others claiming that as much as 10% of LNG is lost via boil-off during transportation. On the other hand, the industry is answering and addressing these issues, though the ultimate level of reduction and whether authorities will accept the results of the industry's efforts, are uncertain.

Shell indicates its newest LNG vessels can reduce carbon emissions versus 2004 steam turbine LNG carriers by 60% with a large cut in "boil-off" from natural evaporation (vaporization). Many LNG carriers now use boil-off gas as a fuel instead of high sulfur fuel oil (HSFO). While vaporization cannot be prevented, the use of vapor return lines enables vented gas to return to both liquefaction and regasification facilities at both ends of the supply chain. Some LNG carriers have built-in liquefaction units to deal with boil-off. LNG carriers had an average boil-off rate (BOR) of ~0.15% a decade ago, falling down to ~0.125% half a decade ago with some shipyards recently guaranteeing rates of around 0.075%. The level of boil-off is affected by many conditions that are still changing, and forced boil-off is often necessary if natural boil-off is inadequate to fuel the vessel.

Ultimately, whether incremental natural gas will be accepted for use as a bunker fuel in shipping and the suitability of LNG in the Energy Transition will depend on where regulators' views come down on the leakage from LNG vessels in comparison to the "fuel oil equivalent" leakage. Similar issues will affect LNG demand in trucking and other forms of transportation.

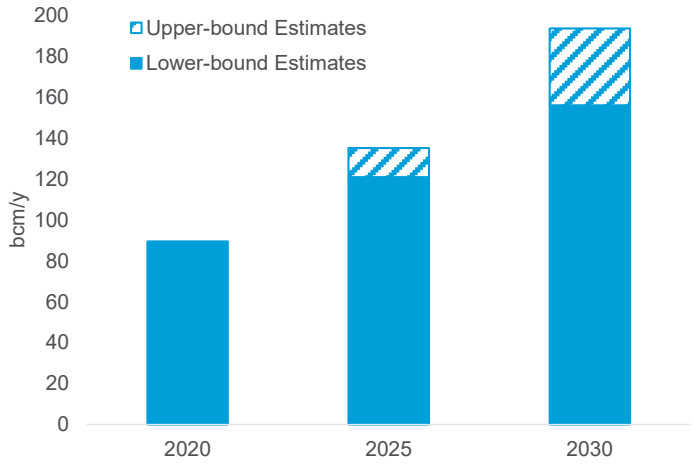
(4) Road Transportation

Transportation accounts for 24% of global direct CO_2 emissions from fuel combustion,[4] and nearly 75% of these transportation CO_2 emissions come from road vehicles, i.e., cars and trucks. Therefore, there is a pressing need to turn to low- and zero-emission vehicles in place of gasoline and diesel-powered vehicles. Battery electric vehicles (BEVs) and natural gas vehicles (NGVs) are two promising candidates. While BEVs are leading in the small-size passenger car segment, NGVs are going head-to-head with BEVs in the bus and truck segments. Please see the appendix II on NGV adoption in different countries and regions.

(a) Robust Potential Over the Upcoming Decade

The next 10 years could potentially see natural gas demand for road transportation in major NGV markets[5] grow by 70% or even double, driven by demand from heavy-duty vehicles (HDVs). In 2020, total natural gas consumption for road transportation in these markets likely reached nearly 90 billion cubic meters (bcm). This number could range between 120 and 135-bcm/y by 2025, and 150 to 190-bcm/y by 2030. China is the elephant in the room, with over 60-bcm of demand in 2020. With more stringent truck emission standards taking effect this year, together with policy support, the number of gas-powered HDVs in China could double by 2025. Other countries like India, Iran, Russia, and Argentina have also taken measures to expand domestic gas refilling networks and boost NGV sales by slashing taxes and offering subsidies. Note there is great uncertainty over longer-term forecasts as we await how technological developments play out in BEVs and hydrogen-fueled vehicles. For large on land vehicles, hydrogen fuel cell vehicles might well turn out to be a longer-term winner.

Figure 18. Natural Gas Demand for Road Transportation in Major NGV Markets through 2030



Note: Major NGV markets include China, India, EU-27, the U.S., Russia, Iran, Pakistan, and Argentina
Source: Citi Research estimates

[4] IEA (May 2020), *Tracking Transport 2020*
[5] Including China, India, EU-27, US, Russia, Iran, Pakistan and Argentina

(b) High Hopes in Freight Vehicles

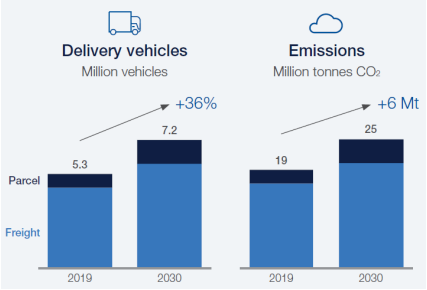
Natural gas is stored onboard as either compressed natural gas (CNG) or LNG. Due to its higher energy density, LNG is more popular in heavy-duty applications for which maximum fuel capacity and extended driving range are required. Meanwhile, CNG trucks have seen more applications in short-distance deliveries.

Decarbonizing the urban "last-mile delivery" will likely take more than one pathway, and companies are taking CNG into their future delivery fleets. With rising urbanization and higher penetration of online shopping — not to mention growth in same-day delivery and narrowing delivery windows — demand for last-mile/kilometer delivery could increase by nearly 80% between 2020 and 2030, according to the World Economic Forum.[6] That is a conservative estimate. By 2030, there could be 7.2 million delivery vehicles in the top 100 cities globally, up 36% from 2019, and an extra 6 million tons of CO_2 emissions in an "unguided adoption" scenario.

While BEVs are taking the spotlight in the effort to cut vehicle emissions, CNG trucks are being added to companies' investment portfolios. In February 2021, Amazon ordered over 700 CNG heavy-duty trucks (HDTs) for deliveries from warehouses to distribution centers. In 2019, UPS ordered over 6,000 NGVs to be delivered over the next three years and announced they would operate 61 natural gas fueling stations by the end of the year. These are just two examples, amid a growing number of announcements from delivery companies regarding CNG trucks.

Besides corporate efforts, government policies have been key to pushing the transition to NGVs and away from diesel. In 2019, 70% of heavy-duty vehicles sold worldwide were in markets with fuel economy and CO_2 emission standards, up from less than 50% in 2016, according to the International Energy Agency (IEA). The European Union started CO_2 standards for HDVs in July 2019, while China kick-started its "National Six" fuel standards in 2019, just two years after it last upgraded to the "National Five" fuel standards.

Figure 19. 2030 'Unguided Adoption' Scenario for Urban Last-mile Delivery (Top 100 Cities)



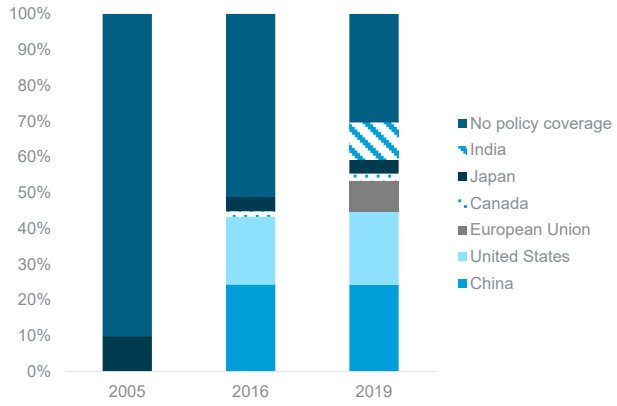
Source: World Economic Forum,

(c) The Environmental and Economic Cases for NGVs

Environmentally, rising NGV penetration is largely driven by the need to reduce air pollution. Replacing diesel with natural gas in trucks could help reduce nitrous oxide (NOx) in tailpipe emissions by 85% and completely remove sulfur oxide (SOx) emissions. It could cut CO_2 emission by between 5% and 20% compared to diesel, depending on the engine type.

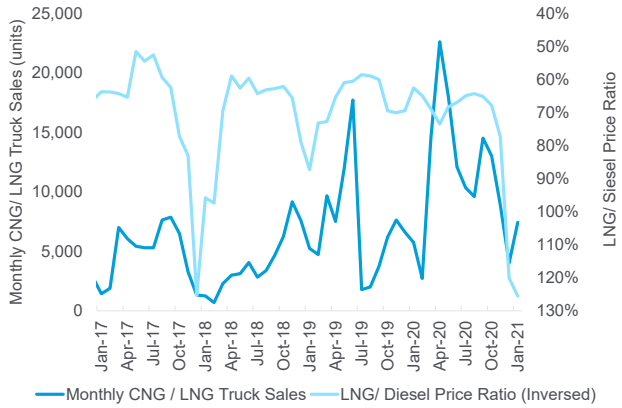
[6] World Energy Forum (Jan 2020), *The Future of the Last-Mile Ecosystem*.

Figure 20. Heavy-Duty Vehicle Sales in Countries with Adopted Fuel Economy (and/or GHG/CO_2) Standards, 2005-2019



Source: IEA, Citi Research

Figure 21. During Periods of LNG Price Spikes, Worsened Economics Tend to Slow Chinese CNG/ LNG Truck Sales



Note: Truck sales include tractor, trucks and incomplete trucks covering the full spectrum of vehicle weights; price ratio is based on retail vehicle used LNG price and Grade Zero diesel wholesale price in Beijing, considering engine efficiency
Source: Bloomberg, Citi Research

Economics is further strengthening the case for truck operators to switch from diesel to CNG/ LNG. Anecdotally, the payback period for LNG truck operators in China is usually 1-2 years, as cheaper operating costs from lower fuel charges gradually make up for the higher initial capital expenditure. It is even more lucrative for trucks that run longer distances. Our own estimate suggests LNG trucks could save ~35% per kilometer compared to diesel trucks based on current price levels in China.[7] That's close to the 40% savings estimated by the Indian government.

(d) Russia's Holistic NGV Development Plan

With its vast natural gas resources, Russia is a major proponent of using natural gas as a road transport fuel. It started promoting natural gas in the transport sector in 2013, with annual gas sales at CNG filling stations growing to nearly 0.8-bcm/y in 2019 from 0.4-bcm/y in 2013. At the federal level, subsidies were offered for the purchase of NGV equipment, while at the local level, 50 constituent entities implemented regional programs to develop local NGV markets.

According to Russia's NGV Fuel Market Development Subprogram approved in 2018, Russia's natural gas consumption in the transport sector could grow by nearly four-times to 2.7-bcm/y between 2019 and 2024. [8] Given underdeveloped gas refilling infrastructure was deemed to have hindered NGV market development in the past, the plan also aimed for a total of 1,273 stationary methane refilling stations by 2024. That's nearly triple the 447 gas refilling stations in Russia in 2019.

[7] We take the wholesale Grade 0 diesel price and retail LNG price in Beijing as of 3/18/2021 in our calculation. The choice of Grade 0 diesel meets China VI emission standards.

[8] https://sustainability.gazpromreport.ru/en/2019/2-our-operations/26-natural-gas-vehicle-fuel-market-development/

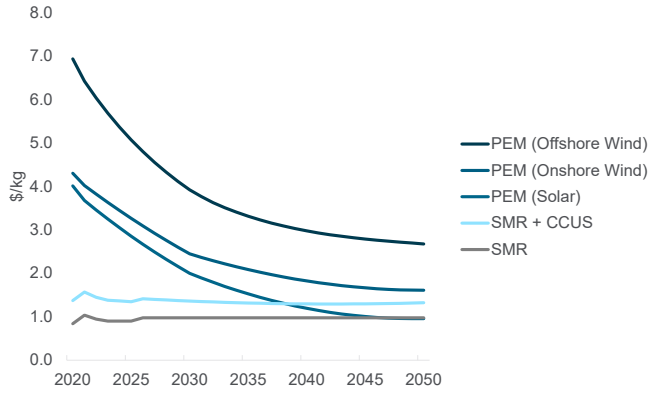
By 2030, Russia's annual sales of natural gas as a vehicle fuel could increase to 9.4-bcm/y, with 2,300 CNG/ LNG filling stations for private car owners as well as an additional 70 LNG stations for trucks, buses, and ships.[9] NGV market development in Russia should expand natural gas usage in not only road vehicles, but also sea and river vessels, as well as mainline and shunting locomotives. On top of that, starting with public transport and public utilities transport, Russia's plan will also focus on both private passenger cars and heavy-duty trucks. Such a holistic market development plan had Russia's deputy Prime Minister and Minister of Energy, Alexander Novak, pin down an additional 30-75-bcm/y of gas demand as vehicle fuel between 2025 and 2040.

(5) Hydrogen Production

Hydrogen virtually exploded into the global Energy Transition dialogue in 2020, as attention snowballed rapidly to its potentially enormous versatility. **Three possible end use areas include power generation, transportation, and heavy industry,** with additional potential in space heating and other uses. Hydrogen might, in fact, be the second most versatile fuel source next to oil, and is far more environmentally friendly. Hydrogen's storability makes it an obvious choice for clean power, both on its own and as a potential substitute for batteries when combined with renewables, especially in larger-scale transportation, as well as in power. An obvious first step in transportation is incorporating hydrogen fuel cells into new energy vehicles. Uses in heavy vehicles such as buses and trucks (and even trains) are potentially more promising than personal vehicles given the prohibitive weight of batteries. In heavy industry, such as steel making, its use as a zero-carbon source of energy, especially for use in heating, is driving investments. By the end of 2020, the number of countries setting targets for hydrogen use grew to 30 countries, including the U.S. and Saudi Arabia and the UAE in the Middle East.

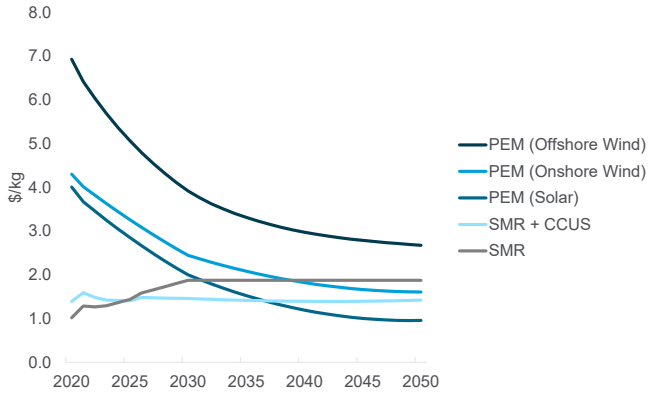
There are two main ways to produce "non-emitting" hydrogen: fossil fuel-based steam methane reforming (SMR) with CCUS (which produces blue hydrogen) or using renewable energy to power electrolyzers that produce hydrogen (which produces green hydrogen). The economics of hydrogen projects are a risk for investors, who are largely making investments based on their high-probability assumption that electrolyzer costs will fall at a rate similar to the efficiency gains achieved in installed photovoltaic cells between 2010 and 2020.

Figure 22. Levelized Cost of Hydrogen (LCOH) without Carbon Prices, Projected to 2050



Source: NREL, DOE, IEA, Citi Research

Figure 23. LCOH with Carbon Prices, Projected to 2050



Source: NREL, DOE, IEA, Citi Research

[9] https://minenergo.gov.ru/node/13712

Prices of green hydrogen (produced from electrolyzers powered by renewables) are still costlier than grey hydrogen (natural gas + SMR) as well as blue hydrogen (SMR + CCUS), and should remain so for the foreseeable future. For example, prices of grey and blue hydrogen today in the U.S. are 70-90% less than those for green hydrogen. Over the next decade, grey hydrogen and blue hydrogen should remain more cost competitive than green hydrogen. This is true even when we add carbon prices. To see how the cost of blue hydrogen could change, we gradually raise our carbon price assumptions over time from a theoretical $20/metric tonne CO_2 (tCO_2) now to $100/$tCO_2$ by 2030, which is the high price assumption needed to meet the goals of the Paris Agreement, according to separate studies by the World Bank and IEA. Even with a carbon price, blue hydrogen could break even with grey hydrogen by 2025 at a carbon price of $60/$tCO_2$. Enhancing excitement was the publicity generated around the export of the first-ever shipment of "blue" ammonia from Saudi Arabia to Japan for use in carbon-free electricity generation. (See our Citi GPS report Financing a Greener Planet Vol 1 for more on the Hydrogen Moment).

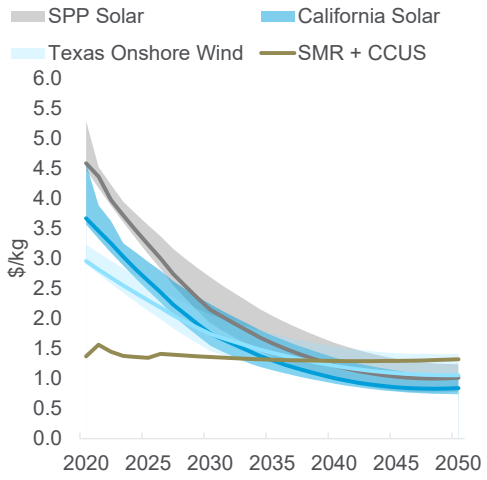
Natural gas can play a competitive role here and will most certainly do so for much of this decade. The cost of green hydrogen should decline rapidly in the years ahead, when economies of scale and other technological advances should help to shave the capital cost of electrolyzers significantly. But this will not happen overnight. It remains an open question whether green hydrogen will fall to the $1/kilogram (kg) level of gray hydrogen today, and if so, when. The U.S. National Renewable Energy Laboratory (NREL) estimates that electrolyzer costs should drop from $900/kW to $400/kW by 2030, and could even fall to $100/kW in the out years, perhaps by 2050, with substantial R&D efforts. Lower capital expenditure on electrolyzers, combined with an levelized cost of energy (LCOE) for utility-scale solar PV at less than $20/MWh, could lower green hydrogen's levelized cost of hydrogen (LCOH) to parity with blue hydrogen by around 2035-40, if there is not a carbon price. This also assumes the cost of solar PV, as well as other renewable energy, continues to fall.

A carbon price would also improve the competitive position of green hydrogen. At $100/$tCO_2$, green hydrogen, based on PEM (polymer electrolyte membrane electrolysis) technology powered by utility-scale solar PV, could cost less than grey hydrogen sometime just after 2030 and be competitive with blue hydrogen perhaps by 2035. Onshore wind, due to its relatively more expensive LCOE than solar, could break even with grey hydrogen sometime closer to 2040.

We have reviewed both the current and projected estimates of the relative costs of hydrogen, in which we distinguish these relative costs depending on whether carbon pricing raises the costs of today's inexpensive grey and blue hydrogen processing into the future. However, location and the multiple uses for the hydrogen produced lead to significant variability depending on access to renewables (and which renewable energy source) among other factors. For example, both iron ore and battery minerals mining as well as steel manufacturing can benefit from green hydrogen to the degree mining can benefit from sunny areas like Northwestern Australia, or manufacturing can benefit from windy areas like at the Baltic and North Sea (where hydropower already abounds).

While there are many measures of when the costs of green hydrogen will get to the level of fossil fuel-derived hydrogen with or without CCS, almost no one believes it will get there by 2030 for blue hydrogen and, for grey hydrogen, without CCS some believe it will not happen until 2050. Moreover, much of the hype around hydrogen omits the likelihood of significant competition between hydrogen and battery power in at least two critical areas: storage for power generation and the areas of the transportation sector. Other obstacles include storage mechanisms and distribution pipelines. In early 2020, before the EU published its plans for 2050 and China published the outline of its ambitious plans for 2060, the Hydrogen Council detailed the enormous potential funding gaps based on its estimates of the changing cost structure of hydrogen in the future. Looking at global requirements of some 70 gigawatt (GW) of incremental renewable power generation, it forecast subsidy requirements against alternatives of some $20 billion. It added $6 billion of subsidies for carbon capture & storage (CCS), $30 billion for transport and $17 billion for heating. Generating private finance requires significant coordination between governments, reasonability regulatory stability, standardization, and multiple tax or other credit incentives.

Figure 24. U.S. Hydrogen Production Costs Based on Different Technologies



Source: NREL, Citi Research

In all, gas can play a critical role in the Energy Transition in multiple ways. Renewables and energy storage need time to ramp up in scale, especially when fossil fuels still supply nearly 85% of global energy demand. The enhanced LCOE of natural gas + CCUS still looks to be highly competitive vs. renewables + storage in many places in the next 10 and perhaps 15 years or more. The potential for greater urbanization in developing economies demands more energy within a small footprint, wherein gas could be a vital source of energy supply. Gas could be key to reducing emissions in the shipping sector through LNG bunkering. Gas could also remain strongly competitive for years to come as the world builds a hydrogen economy. LCOHs based on grey hydrogen look to remain more economic than green hydrogen until both LCOEs of renewables and costs of electrolyzers fall much further.

(C) Decarbonizing the Process from Wellhead to Generation

Perhaps the single most important hurdle facing natural gas in its quest to become part of the Energy Transition is greenhouse gas emissions. These emissions include carbon gases generated through the combustion process and methane leakage during the production and/or transport process. The cleaner-burning property of natural gas is considered a positive versus coal and oil, but net-zero commitments from many countries effectively render natural gas unusable in many places as long as it continues to contribute to GHG emissions.

Decarbonizing upstream and downstream segments of the natural gas industry could reduce or remove stigma. This would involve substantially improved monitoring of methane leakage and its reduction at the upstream production and midstream transportation parts of the supply chain, in addition to carbon capture utilization and storage (CCUS), carbon accounting, and other methods. A case in point is Qatar, which is already moving ahead through reporting emissions from wellhead to delivery, as well as integrating CCUS in its North Field East Expansion. In its contract with Singapore's Pavilion Energy, Qatar would need to measure and report LNG-related emissions from wellhead to delivery. Renewables could also help power the liquefaction process.

Carbon capture, utilization, and storage (CCUS) is one solution for removing GFG emissions for the natural gas industry that is both technically and economically feasible solution, but securing public support is key. While CCUS has generally secured policy support, having public understanding and support is crucial. The Clean Energy Ministerial's (CEM's) Key Financing Principles for CCUS (2020) underscore that clear communication about the benefits of CCUS is needed to build public support for what remains a somewhat unknown set of technologies for the wider population. Suspicion and backlash from the public could both stymie policymaking and the prospects for rapid growth of this crucial decarbonization pathway. Economies of scale and technological improvements could also help deliver significant cost reductions at future CCUS facilities. Figure 11 in section B illustrates the competitiveness of natural gas combined cycle power plants with CCUS.

Further, many producers are already looking to reduce their operational footprints. This includes Scope 1 emissions (all direct emissions from the activities of an organization or under their control) and Scope 2 emissions (indirect emissions from electricity purchased and used by the organization) through eliminating flaring and methane leakages, and using renewables to power some of their operations. The energy needed to liquefy natural gas could very well come from renewables.

There are good prospects for large-scale infrastructure making headway in the U.S. for CCUS, including a multi-fold increase in pipelines bringing CO_2 from the point of production to the point of use or storage. Expanded use of 45Q tax credits for the capture or disposal of CO_2, a functional equivalent of a high carbon price, and a 5-year extension of these credits, is prompting support among both Republicans and Democrats in the U.S. Congress and Senate, governors of more than 20 states, unions, and businesses, which could add significantly to the role of natural gas in the Energy Transition.

A solution to methane leakage is also becoming clearer, including how much methane leakage exists, given historical difficulties around measurement. The uncertainty around how much methane leakage there is and where it is leaked casts a shadow over how polluting natural gas truly is. However, new technology will soon be able to track the approximate size and location of methane leakage globally to resolve those leaks. Satellite and drone methane leakage detection technology promises to improve surveillance of methane and CO_2 emissions, helping to reduce and eliminate leakages of these potent GHGs (see, for instance, the European Space Agency's Sentinel-5P satellite, and GHGSat on facility-level monitoring).

Applying offsets is another option to reduce GHG emissions, but offsets would have to satisfy the "additionality" principle and be strictly verified. At times, it is more efficient to reduce GHG emissions elsewhere. The additionality principle requires that, without the revenue from offsets, a carbon reduction project would not have happened. But a number of offset projects in the past would have taken place even without the additional revenue coming from the sale of offsets, leaving offsets with a bad reputation as more of a means to raise revenues. Thus, to ensure that the natural gas produced would be considered truly decarbonized, offsets would have to come from credible sources, satisfying stringent verification processes, and the additionality principle.

Next, in light of the potential for demand and the strategies for tackling GHG emissions, we discuss the options for the natural gas industry. We then present views from both a Russian and a U.S. perspective, followed by additional thinking on the way forward.

(D) Options for the Gas Industry: Band Together to Manage Supply or Expand Demand

Gas producers confront the prospect of either having their gas fields and facilities becoming stranded assets or unlocking the value of gas in ways that embrace the Energy Transition. This section discusses (1) how a supply management strategy could work while global gas demand is still sticky for now, and (2) how a demand-side strategy that embraces the Energy Transition, facilitated by a formation of a development bank, for example, could be a highly attractive option.

(1) A Supply Management Strategy

Citi Commodity's research report *Global Gas: War and Peace* hypothesized that supply management, particularly the formation of a gas-OPEC, in supporting prices could garner potential support. Once deemed next to impossible, the report spurred renewed interest in a gas-OPEC, mirroring how the oil OPEC+ functions. **Section (E) on Russian perspectives details some of this supply-side strategy.**

Although there were arguments in the past indicating the formation of a gas-OPEC was exceedingly unlikely if not close to impossible, we believe these arguments will no longer apply in the emerging environment. Earlier, there was a lack of spot pricing, since LNG was effectively priced against oil, with plenty of destination-restricted contracts, and the market was simply not global. It was also argued that given the cost structure and integrated nature of individual projects and the dominance of large companies in controlling liquefaction, transportation, and regasification, supply could not be easily curtailed. What it takes is strong state participation in the national industry. Both the world's largest exporter of combined pipeline gas and LNG (Russia) and the world's largest exporter of LNG (Qatar) now fit that bill. The coordination of supply by the two is now a possibility where it never was before.

However, as has been in the case in oil, it appears that small exporting countries could gain more by "free-riding" on the price increase because of larger exporters cutting exports.

This leaves Russia and Qatar as countries that could theoretically stick together, *implicitly*, to engage in coordinated, collective export cuts, as small exporters generally would not be too committed to such cuts. However, since only two countries would be committed to export management in most cases, then why formalize this arrangement when its existence publicly could invite more regulatory scrutiny?

Qatar's situation vis-à-vis the global market has shifted. Its LNG development historically was largely not amenable to cartelized decision-making. While it became a major exporter of LNG, each of its initial LNG projects was co-financed by international oil companies and other firms (often offtakers), with different ventures serving distinct markets.

The consolidation and internationalization of Qatar's gas plays were the inevitable result of a changing market structure and the limits of the domestic resource base. Domestically, Qatar has decided to raise the 77-mtpa of domestic liquefaction capacity to 126-mpta by 2027, with initial production in 2024. Qatar's quest to dominance is helped by other projects, including, the 70/30 Golden Pass joint venture with Exxon, and others globally.

Qatar's new international position, bolstered by its national oil company taking a more direct role in the management of all LNG exports from its home base, puts it in a potentially good position to want to maximize revenue via cooperation with Russia. Acting alone, any action by Qatar to defend prices could be undercut by Russia if Russia decided to export more. However, by coordinating with Russia, Qatar's market power and export revenues could be much greater. Eventually, a Gulf pricing hub could be become viable, but also liquid, as Qatar's 126-mtpa (~16-bcf/d) of LNG capacity possibly by 2027 would make up 20% or more of global LNG supply.

(2) Promoting Energy Transition and Gas Market Stability Can Work Together: "GECF" as a Development Bank

Every major gas producer has talked about growing demand, but growth has been more subdued than desired or expected in recent years, even with the surging gas demand in the winter of 2020-21 due to seasonally extreme cold weather in Asia. Growing new demand is a chicken-and-egg problem, such as in LNG bunkering where there is not enough infrastructure but infrastructure does not come without demand. Building liquefaction facilities, infrastructure that bridges supply and demand, and facilities that consume gas often involve high capital costs. Some gas consumers simply balk at the high price tag.

To reach 'escape velocity' out of this subdued demand growth environment, producers should think out-of-the-box: look at long-term value-chain economics rather than project-level economics; look at consumer strategy instead of production economics; think more about standardization to lower costs; and think more about pollution — an immediate and present danger — and climate change that has been dominating. Reducing sulfur, nitrogen, and particulate matter emissions are key to addressing public health and the environment directly and immediately. Higher gas use helps to attain these objectives.

Protecting market share and creating new markets require (1) protecting existing markets and (2) potentially creating loss leaders to attract baseload demand. In protecting existing markets, it is abundantly clear that, with the top three markets consuming ~60% of global LNG and the top six markets consuming ~85%, gas suppliers should not do anything that alienates their major customers or gives up market share. Addressing energy security concerns, including supply routes and local storage facilities, would be key to retaining customers.

Creating loss leaders to attract baseload demand, such as by supporting the building of infrastructure and consumption facilities, is already done by many firms in the consumer sector but is not commonly considered by the energy industry. This is the classic consumer sector strategy broadly applied by the sector. Examples include: (1) printers and razor blades, where a piece of low-cost hardware or low initial purchase cost would help bring back customers for refills; (2) a banks' money-losing deposit segment, which helps to attract customers for other services; (3) the mobile phone operating system, where Android or other systems are free, but the value comes from the platform.

While individual producers or a small group of producers have reached out to gas consumers about creating demand, pooling these efforts across the industry could be more effective. Having one or only a few companies developing the infrastructure is not enough. Pooling the resources of as many gas producers as possible is key. Growing baseload demand is a ***public good*** for gas producers. While companies or countries have talked about creating demand, they are pursuing this strategy largely at the individual company or country level, but much less at collectively.

Thus, instead of an OPEC that cuts production to support prices, which is anti-competitive, energizing and galvanizing GECF members to provide strong financial and technical support to grow demand could be crucial — hence, the formation of a development bank function could be more effective. It is critical to reducing free-riding as much as possible by having everyone pitch in toward the provision of public good for the sector.

Major gas importers could be supportive of such efforts because some of them have stated publicly their desire to have more demand globally to entice sufficient supply to be developed. For diversification of supply and diversification of fuel mixes, traditional gas importers like Japan, perhaps South Korea, and others could be supportive of such measures. Japan has multi-billion dollar programs in support of gas development as well. The support can consist of underwriting the actual capital costs of the facility or infrastructure, or in reducing financing costs.

The economics could be compelling. By 2025, "global gas", comprising the global LNG and European gas markets, should be a ~1,200-bcm/y (~116-bcf/d) market, up from about 1,000-bcm/y (~96-bcf/d) in 2020. Using European coal-to-gas switching elasticity as a proxy for global gas price elasticity of demand, while cutting ~10-bcm/y of supply should lift global gas prices by ~$1/MMBtu (as detailed in section E), increasing demand by ~10-bcm/y instead of cutting supply should achieve the same or very similar price impacts. The revenue involved is enormous. A $1/MMBtu change in a ~120-bcf/d market is ~$44 billion per year. For comparison, if oil is not oversupplied by ~1-mb/d, then prices could be much higher. The cost of burning an additional ~10-bcm/y of gas is ~$1.5 billion at $4/MMBtu gas, or ~$1.8 billion at $5/MMBtu gas. Here are some sector examples:

- **Power**: Burning ~10-bcm/y more gas requires about 7-GW of new gas-fired generation, which could cost ~$7 billion, assuming an overnight cost of $1,000/kW based on U.S. construction costs, a heat rate of ~7-MMBtu/MWh or an efficiency of ~49%, and a capacity factor of 80%. While GECF does not have to give away power plants for free, supporting half of the capital cost could be beneficial to the beneficiary country. Electrification of the global economy should ensure robust electricity demand going forward.

- **LNG in transportation**: Build the infrastructure using the collective resources of as many gas producers as possible to pool the cost and solve the chicken-and-egg problem.

Ideally, co-developing supply, midstream, and demand projects, by matching their respective asset lives, could facilitate the use of gas as a transition fuel on the demand side, build infrastructure that could help with a future hydrogen economy, and make use of the gas resource. There are certainly carbon-regulation risks, but a high carbon price should hurt coal much more and gas could continue to substitute for coal and back up renewable energy generation.

Most important, for natural gas to be part of the Energy Transition, producers must invest to capture methane leakage and eliminate flaring to demonstrate their commitment to the Energy Transition, which fits well with sustainable development goals of multilateral development banks.

Development Banks: How They Work

The principle goal of multilateral development banks (MDBs) is to provide financing assistance with the aim of achieving sustainable development goals and promote human and social capital development. In the process, MDBs also provide knowledge, technology, and expertise to the local communities that carry out the development projects. MDBs, both on the global level and the regional level, commonly share the mandates of fostering economic and social development and supporting regional cooperation and integration. There are many sectors involved, ranging from energy and infrastructure, to technology, finance, and education. However, depending on the history and sometimes the geographic locations and levels (global vs. regional vs. country), banks do have different specializations, in particular at the regional level. For example, the more recently-established (compared to the long history of MDBs since 1940s) Asian Infrastructure Investment Bank (AIIB) primarily focuses on investment projects in infrastructure. The European Bank of Reconstruction and Development (EBRD) has a mission to promote market-oriented economies in Central and Eastern Europe.

MDBs are built as collaborative partners that can provide scaled-up and low-cost services by pooling resources from key stakeholder countries and avoiding waste and duplication. Governments around the world have come to realize the rising global challenges in social, economic, and environmental realms, which would be almost impossible to be solved by individual countries alone. By pooling resources and sharing the responsibility, MDBs are set up as cooperatives to provide international "public goods" and reduce cross-border externalities.

The business model of MDBs allows them to mobilize resources for development from international capital markets. MDB's source their 'paid-in' capital from their member governments at negotiated ratios and then against their capital base. MDBs borrow resources from international capital markets through public bond issuance, private placements, and syndicated loans. These borrowings are raised on market terms and hence need to be lent on market terms as well. This is called the "hard loan window". They fund their daily operating costs from proceeds earned on non-concessional loans to borrower countries. MDBs also have "soft loan windows", which are usually separate funds that are supported by donors which provide grant resources that are highly concessional. The capital resources for development mainly come from either borrowing directly on their own account and then re-lending to the borrowing countries, or guaranteeing the repayment of funds that the market is going to provide directly to borrowing countries. Apart from the direct lending operations, MDBs financial structure and financing capabilities enable them to leverage their capital finance in many forms, such as equity investment and guarantees. This is more common in MDBs' private sector operations.

MDBs have unique mechanisms for allocating financing to make their investments more effective in achieving their missions. They also focus specifically on development projects, which usually find it hard to attract private finance due to their high risks. The multilateral shareholder structure allows donor governments and countries of operations to discuss and agree the criteria for providing multilateral finance before the funds are provided. This is because usually the lending countries are also stakeholders of the MDBs. In an institution that is owned by governments and serves a wide range of members in the region or across the region, stakeholders would naturally have the resources to learn from each other and have extensive cross-country experience in development policy and reform. Borrowers, also potentially the shareholders of the MDBs, will tend to find the conditionality and monitoring imposed by MDBs more "acceptable" than if they are being imposed purely from a financial institution.

There are also rising calls for more collaboration among MDBs. There are multiple benefits to doing so. MDBs at different regions, having different strategic priorities and areas of expertise, can share work experience, research analysis, technology and database on shared development issues across regions. Allowing sister institutions to lead in certain practices and strengthen the collaborations and experience sharing would help to realize economies of scale and extend their scope in services.

The following two sections, section (E) on the Russian response written by FIEF and section (F) on the U.S. response written by Citi, discuss how two of the largest global natural gas players, with very different stances toward the market, would drive the global natural gas sector in critical ways. They differ in how they approach pricing, market structure, resource development, and geopolitics.

(E) A View from Russia: Evolving Market Structure & Firm Response

Market stability: How might producers stabilize the market?

Marcel Salikhov
Alexey Gromov
Alexey Belogoryev
Alexander Titov
Victor Kurilov

Unlike the global oil market, regional gas markets lack special mechanisms based on coordinated actions by gas suppliers. Instead, the regional gas markets exist in a kind of "primordial" supply chaos. The Gas Exporting Countries Forum (GECF), an international government organization established in 2008 to increase the level of coordination among its 19 member countries, was initially suspected of becoming a "gas OPEC." However, despite its 13-year history, this expectation was not met. Instead, the Forum mainly serves as a platform for non-public discussions, not developing sensitive market solutions.

However, the volatile gas price dynamics of 2019-20 and early 2021 creates a prerequisite for closer cooperation in the future. The aim of such collaboration may be reducing emerging imbalances and ensuring an acceptable level of price volatility. In our opinion, there are three main scenarios or strategies for producers in the current unfavorable and poorly predictable conditions:

1. Market chaos (i.e., "just let the market do its job")
2. Gas production/export curtailments (i.e., "gas OPEC")
3. Other coordinated actions (i.e., "soft coordination").

We think the most rational of these scenarios is the "soft coordination" strategy. However, this coordination can take various practical forms. All GECF countries are afraid of losing their market share in regional markets due to competition with each other and from U.S. LNG. The paradox of the *prisoner's dilemma*, where individual actions in a decision-making process can sometimes create worse outcomes than cooperation, is well known in the oil market. But in the gas market, it may be even more extreme.

A rising trend as we enter the Energy Transition is the risk of producer cooperation. A significant factor that can deter joint actions by the primary gas producers is the growing pressure on gas markets from climate and low-carbon policies, especially in Europe. Any active actions by gas producers may be perceived as an additional risk and may lead to a deterioration of gas's already controversial reputation in the current low-carbon Energy Transition framework.

Why GECF?

GECF may serve as a valuable platform in the future for producer coordination. We consider all scenarios mentioned above in the example of GECF without specifying any particular change in the organization in the future. However, this kind of reasoning is conditional. Depending on the circumstances, the GECF may change its composition, the number of member countries, and the mechanisms for making collective decisions.

In all scenarios, we assume that the U.S., Canada, Norway and other developed countries will not join such a "producer association" due to geopolitical and antitrust reasons. At the same time, presumably, they also will not interfere with the creation of such a market balancing mechanism since it is also economically beneficial for them, as has been the case in their historical attitudes toward OPEC (the Organization of the Petroleum Exporting Countries) and OPEC+ (a loosely affiliated entity consisting of the 13 OPEC members and 10 of the world's major non-OPEC oil-exporting nations, led by Russia).

Unlike OPEC and the OPEC+ agreement, there is no equivalent of Saudi Arabia inside the GECF — a leader whose voice would be historically decisive due to its market share and the world's largest spare capacity. Qatar and Russia are unlikely to make significant decisions for the gas markets within only bilateral negotiations. In theory, initial GECF decisions should be made collective, but this would make them difficult to adopt, given the member countries' contradictions in objectives.

We highly doubt that any producers will unilaterally curtail gas production or exports to balance the market. Given the current disunity of gas producers and their lack of tools to influence the market, the possibility of timely, rapid, and effective actions by gas exporting countries in the short and medium term looks doubtful. All the options discussed below can start working at the earliest in 2023-24.

Market Chaos

This describes the current situation. In the market chaos scenario, producers do not take any coordinated actions to influence markets. There are various reasons why this behavior exists:

1. Countries do not want to cooperate, given it is easier for them to fight for market share and expansion.
2. Governments try, but cannot agree because of deep political contradictions and lack of confidence in each other.
3. Gas producers' coordinated actions are blocked by the consuming countries using antitrust regulation rules.

Currently, the first factor is the most critical one. The second is developing and the third one is a possibility. In the "market chaos" scenario, producers may take some coordinated actions to stimulate demand. However, relatively low and unstable prices will hold back aggregate supply. Such a scenario is possible but risky for investors. Its main consequences are high and unpredictable gas price volatility.

We believe that **GECF member countries will try to move beyond this scenario in the coming years.**

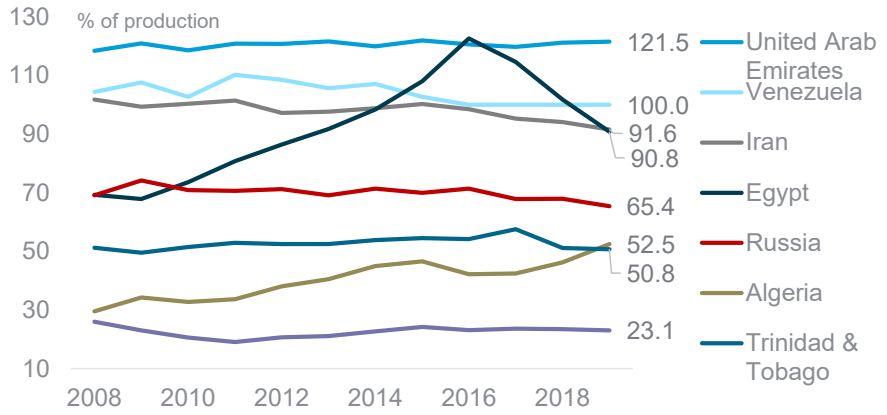
Gas Production Curtailments

This is a "gas OPEC" scenario since it assumes the same market balancing tool that OPEC countries have actively used since the 1970s and by the OPEC+ Agreement since 2017. However, any international political mechanism is historically determined, and its appearance is close to the historical context. OPEC is a unique phenomenon that we do not believe can be replicated in the gas markets. Among other things, OPEC's existence and relative effectiveness are based on the already mentioned unique role of Saudi Arabia in the oil market, which has no counterpart in the gas markets.

Artificial restrictions on gas production intended for pipeline export do not make practical sense for most GECF countries. These deliveries are still carried out mainly based on long-term contracts (LTCs) that provide certain flexibility in gas withdrawal and have "take-or-pay" conditions. Limiting production is even less helpful for the LNG market, where it would be more appropriate to instead regulate the volume of liquefaction itself.

Besides, the share of gas produced for export can vary due to the large and often growing domestic market in most counties.

Figure 25. Share of Domestic Consumption in Gas Production in Key GECF Countries



Source: FIEF based on BP

The only four GECF countries that could potentially curtail gas production for export are Qatar, Algeria, Trinidad and Tobago, and Russia. But none of them is ready for this due to a combination of economic, technological, and political reasons.

Thus, it seems unlikely the GECF will move to voluntary gas production quotas.

Gas Export Curtailments

It is more likely the GECF might be able to agree to curtail gas exports. To do this would require radical change in the organization's nature and a lot of effort specifically by Russia, Qatar, and Algeria, among other key countries. This scenario is hardly a reference one, but it is theoretically possible.

The most difficult aspects of this scenario include:

- Mutual accounting of restrictions on the supply of pipeline and liquefied natural gas.
- The possibility of limiting supplies from LNG plants, which in most cases have foreign investors, lenders, and co-owners.
- Distribution of quotas between different countries, taking into account the fundamental differences in their export capabilities.

Possible export curtailments will also require a strictly obliged GECF member country agreement around export quotas and could contradict the conditions of each country's LTCs and other potential obligations, including investment in crucial gas projects.

Other Coordinated Actions

The most rational scenario is a kind of "soft" form of collective action given the specifics of the GECF and the objective weakness of any other attempts to coordinate gas producers.

We see at least three such "soft" forms of coordinated actions from the leading gas suppliers:

- **Establish a GECF gas hub.**
- **Coordinate a "free-float" gas volume sales** (not covered by LTCs or other contracts) on a common GECF electronic trading platform (ETP) or using a GECF trading house (TH).
- **Stimulate gas demand** by joint producers' actions.

A New Gas Hub?

A common historical trend is the geographical location of liquid hubs near major gas consumption centers. In other words, most hubs tend to be close to consumers, not to gas production centers. However, the growing role of hubs in international gas pricing requires exporters to take proactive actions to maintain partial control over pricing. One option for such activities may be the formation of their own gas hub. Based on export opportunities, transport and financial infrastructure availability, and domestic market developments, the most likely points for creating such a hub would be the Persian Gulf or North Africa.

The main problem of "producer-based" hubs is whether customers will come there. What would encourage a consumer to buy gas at a hub far away from a consumption center? If such a hub existed today, one assumption could be that Asian buyers would be interested in it due to the lack of their own pricing centers. However, all key Asian consumer countries (China, Japan, India, etc.) attempt to form their pricing points, independent of European or U.S. (Henry Hub) benchmarks.

Electronic Trading Platform (ETP)

An ETP's primary purpose is to sell natural gas free float volumes or LNG within the spot and forward transaction markets. The latter considers a combination of supplies from several sources to a specific point of delivery. So, producers can try to create a "seller's market" on the electronic trading platform by selling gas and LNG from each country on auction terms, when one seller deals with a group of buyers.

A gas price Index could be a sufficient price indicator for gas sales on an ETP, which could be included as an analytical tool in the gas pricing data of Argus, Platts, and other price reporting agencies.

Another option for producers is to create a single trading channel. It could be a non-profit agent, including a "trading house" that sells and balances free-float gas at the different regional trading hubs. Such a trading house could aggregate free gas volumes from various exporting companies and sell these volumes in gas hubs around the world at the highest prices (preferably in the framework of forwarding deals).

Almost all gas-producing countries depend heavily on foreign technologies for their development plans, including offshore fields, multi-company fields with a high proportion of sulfur, LNG production, and, in part, the construction of deep-water gas pipelines. Foreign gas companies involved with the shareholders of project companies may have a negative perception of the free float centralized use through the GECF unified trading platform, preferring their own sales instruments instead.

Boosting Demand

New demand generation is one of the most promising areas of gas producers' efforts. It is especially essential for new and rapidly growing consumer countries in Asia and Africa. However, the creation of new demand almost always involves a single producer who invests in new consumer objectives to obtain a long-term market for their gas. Speaking with respect to the collective efforts of exporting countries, we mean the possibility of implementing, first of all, major investment projects for the development of gas supply infrastructure (regasification terminals, gas transmission, and gas distribution networks) for common use.

How Much Free-Float Gas Will be Available by 2025?

For all scenarios of gas producers' collective actions, the availability of free-float gas is of crucial importance. Its value determines the potential influence of producers on the total supply and price environment.

We make estimates of free-float gas available in GECF counties by 2025. We analyze the gas production structure (the distribution between domestic consumption and contractual obligations) for gas exporters to estimate free float. Calculations of free float are based on forecasts of domestic production and consumption in GECF countries and forecasts of contracted export volumes whether by LNG or pipeline. We assume that 70% of LNG export contracts with an expiration date in 2021-25 will be maintained and 100% of such pipeline export contracts will be extended. As a result, contracted export volumes will increase by 12% after six years, and export capacities are expected to increase only by 2% by 2025.

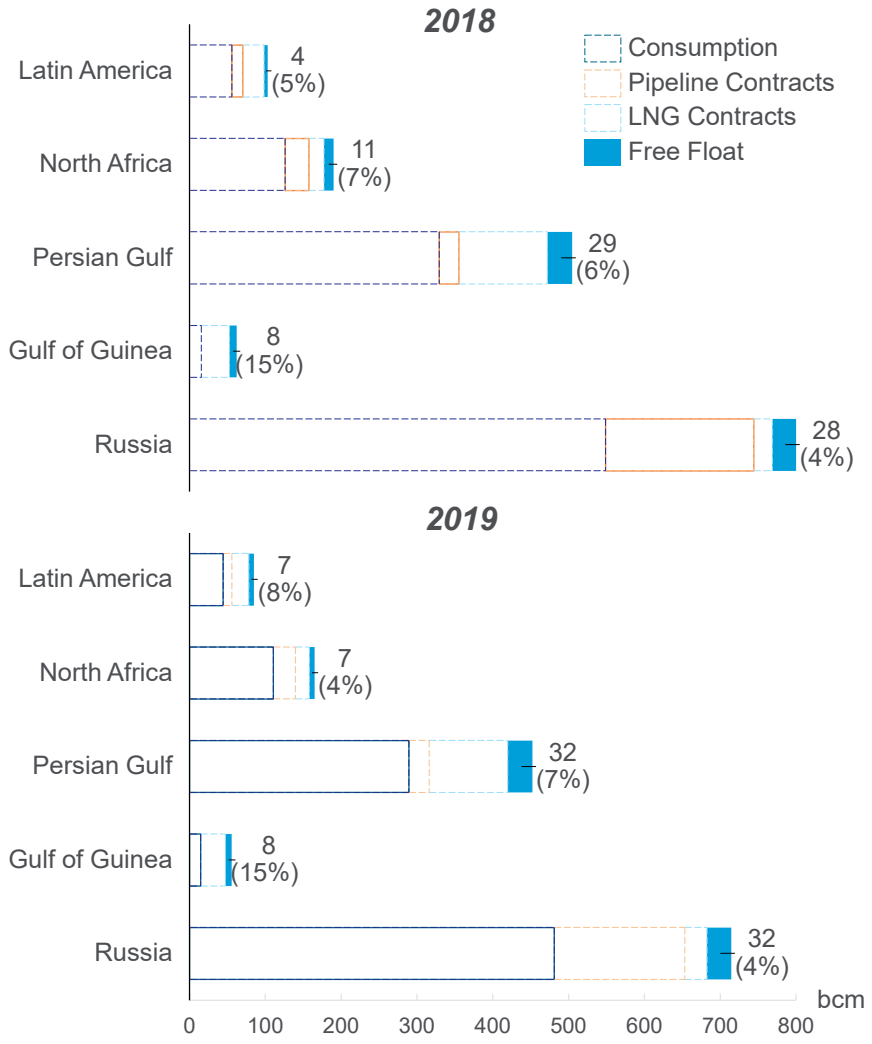
For our estimates, we use national statistical sources and publications such as Argus Media and Oxford Energy Studies for information on pipeline gas contracts. Country LNG export commitments were taken from the Wood Mackenzie database. Our analysis does not consider the internal structure of contracts, for example, "take-or-pay" conditions. Using these inputs, free float is calculated according to the following formula:

Free Float = Production + Importing Contracts - LNG Exporting Contracts - Pipeline Exporting Contracts - Internal Consumption

Free-float gas in the GECF countries is calculated in the range of 4% to 15%. If the Gulf of Guinea (the smallest market) is excluded, the range narrows to 4-8%. In absolute terms, the largest free-float volume is in regions with the highest gas production such as Russia and the Persian Gulf (~32 bcm each). For Latin America, North Africa, and the Gulf of Guinea, the free float level of gas is ~5-10 bcm.

Thus, only Russia and the Gulf countries have any real opportunity to influence the market by limiting their free float gas supply. In North Africa, low growth rates in gas production, combined with growing consumption and significant contractual obligations, will keep free float low for the foreseeable future.

Figure 26. Gas Production Structure in Gas Exporting Countries and Free Float for Regional Gas Hubs (bcm)

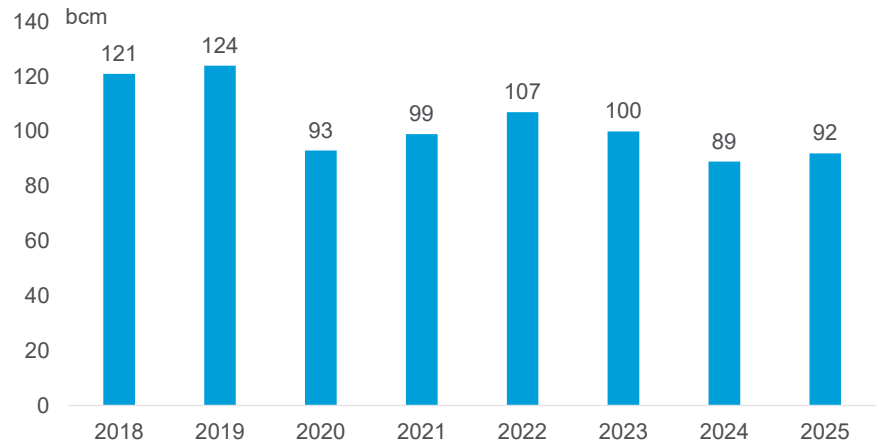


Source: GECF, BP, FIEF, OIES, Wood Mackenzie, Argus Media
* Latin America incl. Peru, Persian Gulf incl. Oman

Traditional gas exporters will have significant free float volume (~100 bcm) to influence markets. In 2021-23 free float is estimated at 99-107 bcm per year compared to 124 bcm in 2019. The main drivers in the decline of available free float available will be in Russia and Iran. Russia is expected to increase contracted export volumes to China, while Iran will have to satisfy increased domestic demand. In 2024-25 free float is expected to be 89-92 bcm per year due to an additional decline of non-contracted gas production, mainly in Russia, Iran, and Algeria.

By 2025-30, GECF countries can manage even more than 100 bcm per year of free float due to increasing sales in spot markets under oversupply conditions. A significant number of long-term contracts will also terminate in the 2020s.

Figure 27. Free Float Estimates of GECF Members



Source: FIEF estimates

Market Influence Analysis

Free float available is one part of the equation. Another part is what the price effect will be in terms of any kind of supply changes. Price effect is based on an estimate of the price elasticity of supply.

Impacts of Supply Cuts on Prices in Europe: Elasticity Assumptions

According to FIEF estimates, the elasticity of European natural gas prices on the market balance is in the range of 3.4 -4.6 (versus Citi's estimate for elasticity of 12 under the $4/MMBTU scenario). Our 3.4-4.6 estimate is based on time series regressions for 2011-19 based on deliveries and natural gas consumption in Europe. The source of data on the market balance was Citi Research estimates of supply and demand in Europe.

Price Elasticity Assumptions

We estimate several linear regressions and use oil prices as a factor of substitution between different types of fuels, changing the set of regressors and time periods.

The final equation is the following:

$$dlog\ (price) = -0.062 -\cdot 3.416 \cdot \frac{balance}{supply} + 0.843\ dlog\ (oil\_price)$$ (R^2=0.82)

gas_price – Dutch TTF price, $/MMBTE; R

$balance$– the difference between supply and consumption in Europe, bcm per year;

$supply$–natural gas deliveries in Europe, bcm per year;

oil_price– Brent price, $ per barrel.

The lower bound is estimated using Brent oil price's growth rate as an additional factor. The higher bound for the elasticity was calculated using a restricted form of the regression.

Citi's estimates are based on a two-pronged approach, first using a regression between power demand and factors including TTF (title transfer facility), API2 coal and European carbon (EUA), followed by a check with the power generation stack. Due to transmission constraints, market and price outcomes in power markets might not necessarily follow what a static power supply-power demand analysis at the continental level would produce.

There is a great deal of uncertainty over elasticity estimates in 2025-30. On the one hand, price elasticity can increase after GECF countries impose restrictions on free float export sales as GECF countries will not substitute the production cuts of their partners. On the other hand, new LNG capacity may lead to oversupply in the market. Under these conditions, elasticity will decline. In comparison to Citigroup's estimates, FIEF's estimates are conservative.

Quantitative Effects of GECF Coordination

We expect that a market coordination scenario using free-float volume is more likely to respond in the medium term period due to potential oversupply and low natural gas prices. European TTF gas prices can stabilize in the $3/MMBtu level and even lower. However, there will be a high price volatility, which can generate disincentives for demand and investments in the industry.

Participating countries would need to cut export supply in the range of 29-40 bcm per year to increase the price of gas by $1 per MMBTU. In 2025-30 these measures would increase Europe's TTF gas price from $3/MMBTU to $4/MMBTU, but they would not stimulate additional supply from the U.S. LNG plants and other LNG producers as this price level is not high enough to stimulate LNG production.

Overall, measures under gas production/export curtailment and "soft" coordination scenarios would increase the export revenue of GECF countries by roughly $10-20 billion, or 15-30% during a period of low prices ($3/MMBtu). We calculate the overall effect assuming the TTF price will rise from $3 to 4 per MMBtu due to free float supply restrictions by GECF counties. According to FIEF estimates for price elasticity, getting an increase in the TTF's price of $1 per MMBTU requires a cut to exports of 29-40 bcm per year by GECF countries (equivalent to 5-7% of export volumes) under the export curtailment scenario. If we assume the Citigroup estimate for price elasticity, only 2% of exports will need to be curtailed.

"Soft coordination" measures through implicit coordinated export cuts will generate smaller effects, but will also need smaller export/production volume cuts. Extra export revenues are estimated at around the $10 billion level under export cuts of 1-2%. Coordinating "free-float" gas volume sales will provide additional premium and not impose substantial export restrictions. It is also less risky for GECF countries on the legal and antitrust front.

Figure 28. Summary: Effects of Coordination Measures

Elasticity Scenario	Quantitative Effect	Export Curtailment vs. Market Chaos	"Soft Coordination" vs. Market Chaos
FIEF - Low	Increase in GECF export revenues ($ bln)	15.0	8.7
	(%)	24%	14%
	Decrease in GECF export volumes (bcm/y)	40.0	12.0
	(%)	-7%	-2%
FIEF - Middle	Increase in GECF export revenues ($ bln)	16.5	10.8
	(%)	27%	18%
	Decrease in GECF export volumes (bcm/y)	29.0	12.0
	(%)	-5%	-2%
Citi - High	Increase in GECF export revenues ($ bln)	19.0	14.1
	(%)	31%	23%
	Decrease in GECF export volumes, (bcm/y)	11.0	6.0
	(%)	-2%	-1%

Source: FIEF estimates

Figure 29. TTF Price is Assumed to Rise from $3 to $4 per MMBtu (Low Elasticity = 3.4)

Country	Export Volume (Bcm/y)	Share of Total	Volume Change (Bcm/y)	Price Change ($/MMBtu)	Export's Revenue Difference				
					Before	After	Difference	Volume Effect	Price Effect
Russia	248	43%	12	0.43	26.3	33.3	7.0	-1.3	8.3
Qatar	125	21%	6	0.21	13.2	16.8	3.5	-0.7	4.2
Algeria	52	9%	3	0.09	5.5	7.0	1.5	-0.3	1.7
Malaysia	33	6%	2	0.06	3.5	4.4	0.9	-0.2	1.1
Indonesia	28	5%	1	0.05	3.0	3.8	0.8	-0.1	0.9
Nigeria	28	5%	1	0.05	3.0	3.8	0.8	-0.1	0.9
Trinidad	17	3%	1	0.03	1.8	2.3	0.5	-0.1	0.9
Oman	14	2%	1	0.02	1.5	1.9	0.4	-0.1	0.5
New Guinea	10	2%	1	0.02	1.1	1.3	0.3	-0.1	0.3
Brunei	9	2%	0	0.02	1.0	1.2	0.3	0.0	0.3
UAE	7	1%	0	0.01	0.7	0.9	0.2	0.0	0.2
Angola	5	1%	0	0.01	0.5	0.7	0.1	0.0	0.2
Peru	5	1%	0	0.01	0.5	0.7	0.1	0.0	0.2
Egypt	2	0%	0	0.00	0.2	0.3	0.1	0.0	0.1
Total	**583**		**29**	**1.00**	**61.8**	**78.2**	**16.5**	**-3.1**	**19.6**
					Percent changes		*26.6%*	*-5.0%*	*31.7%*

Source: FIEF Estimates

Figure 30. TTF Price is Assumed to Rise from $3 to $4 per MMBtu (Middle Elasticity = 4.6)

Country	Export Volume (Bcm/y)	Share of Total	Volume Change (Bcm/y)	Price Change ($/MMBtu)	Export's Revenue Difference				
					Before	After	Difference	Volume Effect	Price Effect
Russia	248	43%	5	0.43	26.3	34.4	8.1	-0.5	8.6
Qatar	125	21%	2	0.21	13.2	17.3	4.1	-0.3	4.3
Algeria	52	9%	1	0.09	5.5	7.2	1.7	-0.1	1.8
Malaysia	33	6%	1	0.06	3.5	4.6	1.1	-0.1	1.1
Indonesia	28	5%	1	0.05	3.0	3.9	0.9	-0.1	1.0
Nigeria	28	5%	1	0.05	3.0	3.9	0.9	-0.1	1.0
Trinidad	17	3%	0	0.03	1.8	2.4	0.6	0.0	0.6
Oman	14	2%	0	0.02	1.5	1.9	0.5	0.0	0.5
New Guinea	10	2%	0	0.02	1.1	1.4	0.3	0.0	0.3
Brunei	9	2%	0	0.02	1.0	1.2	0.3	0.0	0.3
UAE	7	1%	0	0.01	0.7	1.0	0.2	0.0	0.2
Angola	5	1%	0	0.01	0.5	0.7	0.2	0.0	0.2
Peru	5	1%	0	0.01	0.5	0.7	0.2	0.0	0.2
Egypt	2	0%	0	0.00	0.2	0.3	0.1	0.0	0.1
Total	**583**		**11**	**1.00**	**61.8**	**80.8**	**19.0**	**-1.2**	**20.2**
					Percent changes		*30.8%*	*-1.9%*	*32.7%*

Source: FIEF Estimates

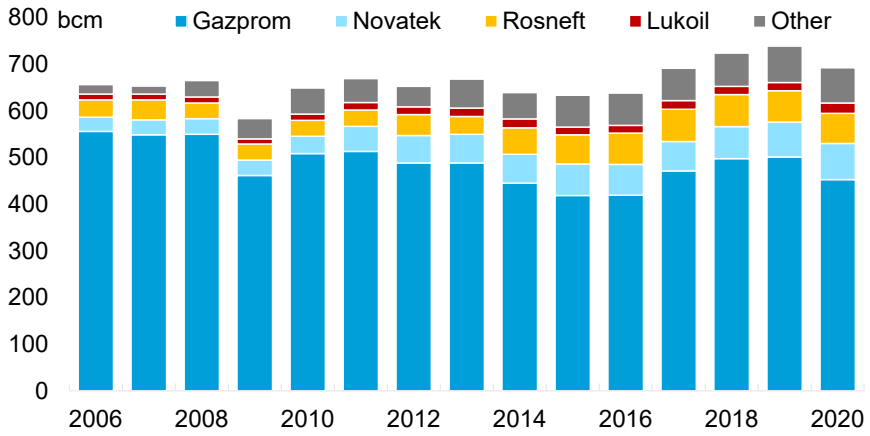
Gas and LNG Strategies of Russian Companies amid the Energy Transition

Russia Outlook

Russia is one of the world's largest natural gas producers and exporters. In 1965, after large gas fields were discovered in Siberia, the government established the Ministry of Gas Industry of the USSR which included companies involved in upstream operations, transportation, and distribution. In 1989, the Ministry of Gas Industry was transformed into the Gazprom Concern, which was later transformed into an open joint-stock company which was privatized. Currently, the Russian government controls 50.23% of Gazprom's equity. Gazprom is the largest gas producer and the owner and operator of the UGSS (Unified Gas Supply System).

Gazprom has a legal monopoly on the export of natural gas from Russia. The primary rationale behind this decision was a desire to get the maximum pricing power for Russian gas and a fear of domestic producers starting to compete with each other on external markets. Authorities were afraid that multiple export channels would bring prices down and lead to lower tax revenues for the Russian government.

Figure 31. Natural Gas Production in Russia by Company



Source: Company data, CDU, IEF estimates

Independent gas producers produce 32-35% of Russia's production. In 2020, their share increased to 34.6% from 32.1% in 2019 as Gazprom decreased its output. The largest independent producers include Novatek, which is the largest LNG producer and uses its output as a feed gas for LNG. Novatek among others are also large players serving the domestic gas market and targeting mostly industrial customers. Other Russian companies have lobbied several times to get the rights for pipeline exports but could not change the rules. (For a discussion about these companies and challenges to the Gazprom monopoly see below).

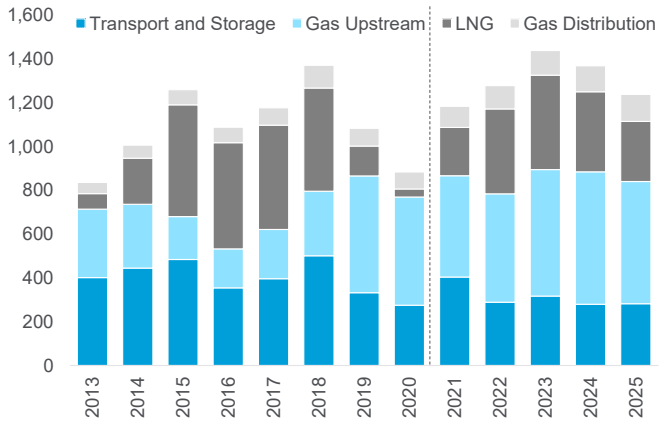
Gazprom recently shifted (with some difficulties) towards spot pricing for its European exports. Traditionally Russia relied on long-term oil-linked contracts for its supplies. Changes in the European legislation and increased competition with other supply sources forced Gazprom towards hybrid pricing, including spot market indexation and legacy oil indexation. This shift helped to increase exports from 148 bcm in 2010 to 232 bcm in 2019.

Currently the share of oil indexation in the export contracts of Gazprom is about 25% and will continue to decline. We believe that Gazprom generally adheres to a strategy of maintaining and increasing its share in the European market through price competition with LNG. Gazprom's effective prices in target markets are lower than corresponding spot prices on trading floors. Gazprom will continue to pursue this strategy.

Gazprom concentrated on building pipeline infrastructure over the last decade. The strategic priority for new investments for Gazprom was building new pipeline routes to deliver gas to Europe without relying on Ukrainian transit. The company expanded its ability to market in Northwest Europe by the original Nord Stream pipeline (2012). The Turkstream pipeline was launched in late 2019 to supply to Turkey and the EU's southern countries. More recently, the ambitious and expensive Nord Stream 2 faced increasing challenges with growing U.S. opposition imposing new sanctions.

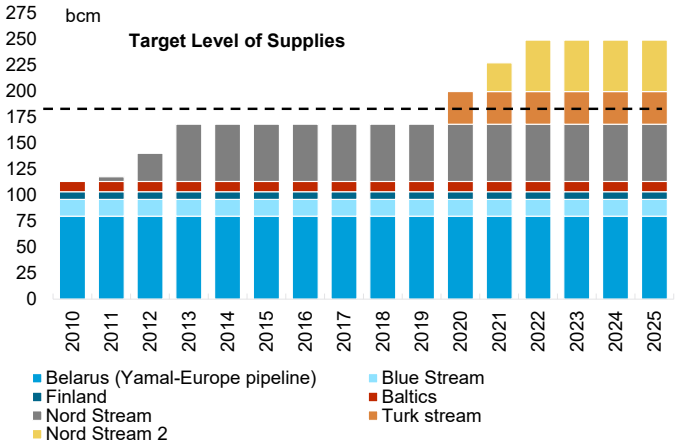
But since the project is almost finished, there is a strong rationale to complete it. Overall, in the 2020s, Russia will have excessive ability to supply Europe. It also means that various options to manage supply are possible.

Figure 32. Investments of the Russian Gas Industry by Segment, 2013-2025F (RUB bn)



Source: Rosstat, company data, FIEF estimates & forecasts

Figure 33. Russia's Pipeline Capacity in Europe Excluding Transit through Ukraine



Source: Company data, FIEF estimates and forecasts

LNG Strategies of Russian Companies

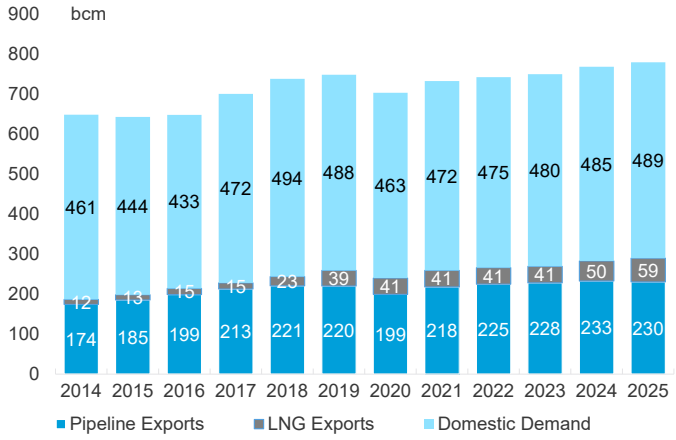
In 2013, amendments to Russia's gas export law resulted in independent producers potentially gaining the right to export LNG but not pipeline gas. Changes specifically allowed state-owned companies besides Gazprom and some private players, like Novatek, to get the right to export LNG. The right was not universal, thus later private and even state-owned players could not secure rights for LNG exports. But, under new conditions, LNG projects have become the main instrument for monetization of gas reserves for companies other than Gazprom.

The main driver for developing LNG projects has become the possibility of gas exports, otherwise not available, and attractive tax conditions. Compared to pipeline gas exports, the main benefit is that LNG exports from Russia are exempt from export duty (30%). Other advantages include access to cheap feed gas and proximity to target markets (this explains the construction of several medium-scale LNG projects in the Baltics).

Over the last few years, many Russian companies have tried to build LNG plants for export. But most of the projects under discussion have remained on paper. There are several reasons why there are still not many functional LNG projects in Russia despite various players' favorable conditions and desires.

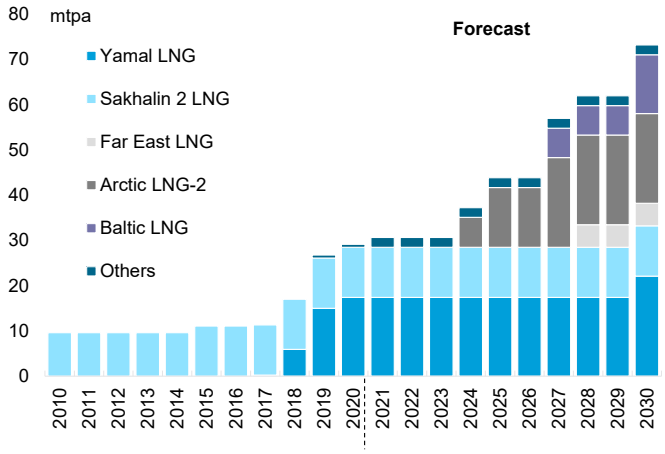
- *First,* there is still no universal right for LNG exports for private companies. An investor still needs to get permission for LNG exports.
- *Second*, sanctions against Russian companies have become a critical limitation and a significant risk factor. Sanctions complicate project financing and also create technological risks. In particular, Novatek began to actively develop domestic technologies for liquefying gas due to concerns that the future supply of equipment may be restricted.

Figure 34. Major Parameters of the Russian Gas Industry



Source: Gazprom, FTS, FIEF estimates & forecasts

Figure 35. Russian LNG Capacity by Project



Source: Company data, FIEF estimates and forecasts

In total, Russia plans to produce up to 112 million tonnes of LNG per year by 2035 without considering promising projects for which investment decisions have not yet been made. Official plans of the government assume that Russian LNG production will reach 140 million tonnes by 2035, but we think that these targets are too optimistic.

Novatek

Novatek, an independent gas producer, has become a successful and globally influential LNG players. The company is a primary beneficiary of changes to legislation made in 2013.

The company built the largest LNG plant in Russia, Yamal LNG. The state has also supported the project with generous tax breaks and investment assistance. LNG and gas condensate are exempt from export duty, and the project has received mineral extraction tax (MET) (production tax) breaks and property tax holidays. Fiscal incentives have significantly improved the economics of the project for private investors. One of Novatek's LNG investment projects' distinctive features is broad participation by foreign partners as minority shareholders and project financing from foreign shareholders and other financial players. Novatek has successfully used this strategy for Yamal LNG and plans to expand it to new projects.

Novatek plans to put into operation two more projects. In September 2019, Novatek made the final investment decision (FID) for Arctic LNG-2, but the market conditions have deteriorated since then. The total cost of the project will be around $20-21 billion. The company still plans to put the first train into operation by 2023, an ambitious target.

Obsky LNG is another large planned project for Novatek. It should be a relatively small plant of 4.8 million tonnes per year (mmtpa). Its distinctive feature is a reliance on Russian equipment and technologies for liquefication. Novatek has not made the FID for the project yet.

Overall, Novatek plans to produce 57-70 million tonnes of LNG by 2035 and improve its position as one of the largest global LNG players.

Gazprom

Gazprom got involved in the LNG business by buying 50% of the Sakhalin-2 project in 2007. But the company has not put new LNG into its strategic priorities ahead of focusing on building new pipelines to Europe and China. The company is currently building a medium-scale LNG project (KS Portovaya, 1.5 mmtpa), which should be put into operation in 2021. Other large LNG projects of Gazprom remain speculative.

Gazprom considered several possible options for the construction of new LNG over the last years.

- One of Gazprom's high-profile but not implemented projects is Vladivostok LNG in the Far East. Gas for the Vladivostok LNG was initially planned to be supplied from the Power of Siberia gas pipeline, but then Gazprom reoriented feed gas to the Sakhalin-3 fields (Kirinskoye and Yuzhno-Kirinskoye). Sanctions against Gazprom and a lack of its own funds have postponed the projects. Gazprom is currently considering turning Vladivostok LNG into a medium-scale project aimed at the bunkering segment in Asia-Pacific.

- Baltic LNG was under consideration starting in 2015, in partnership with Shell. In 2019, Shell withdrew from the project as Gazprom changed the project's concept, which now provides for the full integration of the LNG and the gas processing plants. The projects' partner currently is RusGazDobycha, a relatively small local company.

- Another possibility for Gazprom is adding a third train (5.4 mmtpa) to the Sakhalin-2 project. A significant problem is the lack of feed gas. Sakhalin-2 partners have tried to reach an agreement with Sakhalin-1 partners (Exxon Mobil and others) but could not get a deal, so the future of the third train for Sakhalin-2 is uncertain.

Other Russian Companies

Other Russian companies have made several attempts to get into LNG with different partners in different locations, but they do not have any operational capacity yet.

The most probable project is Far East LNG, which is the expansion of the Sakhalin-1 oil production sharing agreement (PSA) project into a new LNG plant. Tax benefits for implementation and other incentives are vital factors for the successful implementation of the project. If Far East LNG construction is included in the PSA agreement's perimeter, this will significantly increase its attractiveness for shareholders. However, the final decision on the project has not yet been made. Still, in September 2020, the Sakhalin-1 consortium signed a front-end engineering design (FEED) contract with TechnipFMC.

Attempts were made to implement the Pechora LNG project in the Nenets Autonomous Okrug in 2015-17, but the rights to export LNG from this project could not be obtained. Another limiting factor was that Gazprom out-bid competitors for licenses for developing neighboring fields for feed gas, which diminished the possible resource base for the project.

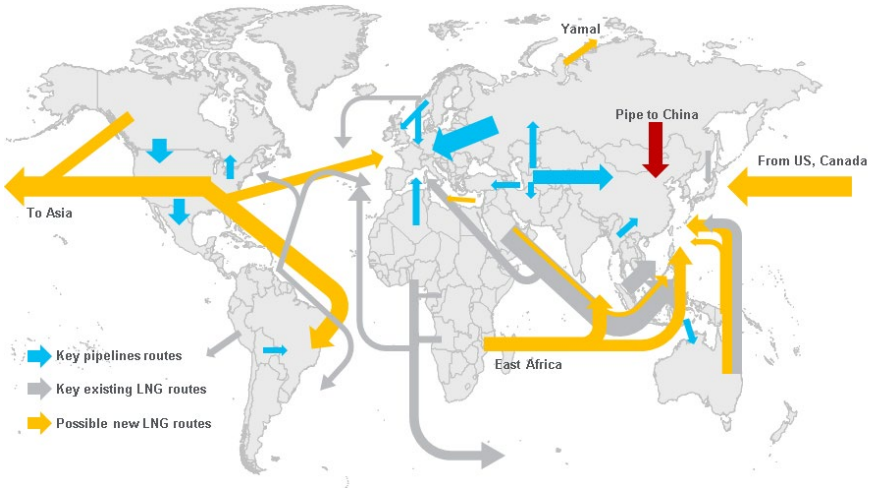
There have been considerations to export LNG from the Arctic and Far East. But these plans have also encountered opposition from Gazprom. After 2030, two new LNG projects in the Arctic and Far East are expected to launch. But the resource base and financing schemes for these plans are not yet established.

(F) A U.S. View: Market-based Reaction, Ample Shale Gas to Keep Supply Adequate at the Right Price

Citi Commodities Team
Ed Morse
Anthony Yuen
Eric Lee
Maggie Lin

U.S. LNG exports, the introduction of Henry Hub pricing as the basis of these exports, and a lack of destination clauses have far-reaching impacts, including (1) bringing gas-indexed pricing to the global market and (2) redrawing global natural gas geopolitics.

Figure 36. Map of Future Global Gas Flows



Source: Citi Research
Note: Schematic only; size of arrows is not reflective of actual flow; arrow directions indicative only

The current associated gas growth spurt could last through 2021 due to the still-large amount of flared gas in the Permian, but associated gas production may not grow sizably again until years later. If oil prices settle post the pandemic at $45-50/bbl, total U.S. liquids production would likely grow by ~0.4-m b/d annually after 2022 (after falling by 2.5-3-m b/d). That in turn would imply associated gas production growth of perhaps 800-mmcf per year.

First, the rise of the U.S. as a major exporter has led to explosive growth of the LNG spot market.

- **The lack of destination clauses breaks the monopolies or oligopolies of LNG suppliers of the old regime**. Bilateral supply deals and destination clauses restricting the resale or redirection of global gas had given suppliers de facto monopoly or oligopoly power within regions. The lack of destination clauses with U.S. LNG, which now make up ~20% of total supply capacity, first eroded then broke apart these regional monopolies or oligopolies.

- **A vibrant spot market would create pricing hubs that erode oil-index pricing globally.** The fundamental issue today is that we have "price oranges" based on "apple prices". Similarly, why should the world price natural gas on the basis of oil prices? It is only a matter of time before the spot market takes over global gas pricing, given (1) the more than 10-fold increase in JKM trading[10] in the last couple of years; (2) the vast majority of European gas being gas-indexed versus oil-indexed; and (3) the refusal of many existing gas importers to sign long-term deals, particularly those based on oil. Together, these changes should continue to lead to more trading, transactions, and hedging activities, driving the growth of a global LNG spot market in a virtuous cycle.

In addition to Henry Hub, other price points within the U.S. could become increasingly important, business models could change, and contract terms could get more innovative. A U.S. Gulf Cost Free on Board LNG price (FOB U.S. LNG (USGC))[11], which bypasses all infrastructure costs (pipe + liquefaction), could emerge as a key benchmark. Through shipping arbitrages, FOB U.S. LNG (USGC) prices would be tied to global prices, including Asian JKM LNG and European TTF prices[12]. When global LNG is in oversupply, this USGC price and Henry Hub or other U.S. onshore gas price would directly affect each other. This is because low global LNG prices, and therefore low USGC prices, would put pressure on U.S. onshore prices, including Waha (Permian Basin), as demand for U.S. LNG would be low, as seen during the pandemic. Thus, U.S. onshore prices would have to fall in tandem with a re-opening of the U.S. LNG export arbitrage. When global gas prices are high, demand for U.S. LNG would increase, thereby lifting U.S. onshore prices. Other onshore USGC prices close to major LNG terminals could also be options.

U.S. prices could be the basis of a whole contract or be part of a hybrid contract with other prices involved. Some LNG offtakers currently want a mix of energy prices, such as oil, TTF, or JKM gas, as part of their contracts. Netback pricing is an option, where U.S. producers could receive a netback, or export parity price, from Asian JKM or European TTF prices. Business models have become more diversified, including increasing use of the tolling model and more integrated models more common globally, with offtakers taking equity stakes. There are, therefore, numerous paths for the pricing, economics, and business for U.S. LNG to take.

Second, buyers both in Asia and Europe already see a secure source of supply in U.S. exports versus exports that pass through the Strait of Hormuz in the Persian Gulf and those via pipeline from Gazprom (although a seasonal hurricane risk has also emerged and the freeze offs in February 2021 point to other incremental climate change risks). It makes a great deal of difference to buyers in these regions that much of the incremental new supply is coming from a diversity of countries rather than just countries like Russia and Qatar. A continued erosion of market power and geopolitical influences affecting existing exporters is inevitable. Low political risk and gas-indexation of U.S. LNG prices appeal to importing countries looking for leverage in negotiation with other LNG suppliers.

---

[10] Platt's JKM, is the LNG benchmark price assessment for spot physical cargoes. It reflects the spot market value of cargoes delivered ex-ship into Japan, South Korea, China, and Taiwan.

[11] FOB U.S. LNG (USGC) prices aim to measure the value of LNG sold on a 'free on board' (FOB) basis on the U.S. Gulf Coast (USGC). Free on board includes the cost of delivering the gas to the nearest port.

[12] TTF or Title Transfer Facility, is a virtual trading point for natural gas in the Netherlands and allows gas to be traded within the Dutch Gas network.

Thus, potential high-cost liquefaction projects globally, outside of the U.S., that have not (yet) reached final investment decisions may face more headwinds in obtaining capital, signing contracts, and receiving favorable contract terms. Besides the push toward gas-index pricing and away from oil linkages, the high cost of greenfield projects clearly presents greater risk in exploration, production, and terminal construction, unlike U.S., or to some extent Canadian projects, which are mostly brownfield and whose back-up reserve sizes are more certain.

Shale Will Come Back and Could Dominate Again…at the Right Price

Shale oil and gas have upended global energy and geopolitics, but the pandemic-induced collapse of oil and gas prices and the politics associated with the Energy Transition are transforming the U.S. shale industry. To illustrate the impact of shale, U.S. liquids — including crude oil, natural gas liquids (NGLs), biofuels, and refinery gains — comprised ~20% of global oil supply at its peak, compared with less than 10% prior to the shale revolution. The abundance of natural gas has also induced the development of U.S. LNG exports, which now make up ~20% of global LNG supply capacity, compared with the U.S.' status as an importer just several years ago.

Since shale oil and gas resources are vast, productivity should stay robust, breakeven costs should remain contained, and the foundation of shale should remain sound. Whether shale production thrives depends on the re-investment rates of producers, which currently depend on prices. However, a return to climate-change-related policy under President Biden could change that within three or four years. Please see the report Will US Shale Oil and Gas Ever Regain Their Dominance for further details.

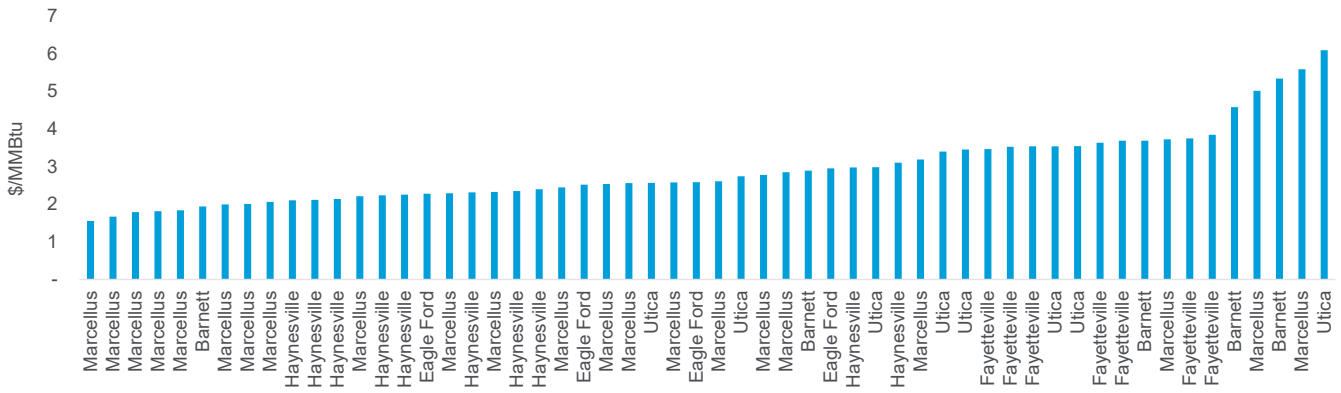
- **(a) Productivity should stay robust, with "parent-child" production issues likely offset by new mitigation strategies.** As new wells are drilled, "parent-child" production issues supposedly would lead to weaker production in the new "child" wells. Brute force and technological advances have helped raise initial production (IP) rates in recent years. Mitigation strategies look to be increasingly available to deal with production issues, including optimized development strategies on spacing and staggering wells, and improved fracturing design and completion methods.

- **(b) Breakeven costs of shale gas are mostly in the $2-3/MMBtu range**. Well and production costs should fall as the sector restructures. However, there is a strong possibility of the Northeast U.S. being bottlenecked in the future, leading to a greater reliance on shale gas plays on or closer to the U.S. Gulf Coast to drive production, thereby helping to push prices toward $3/MMBtu or above. But it looks very unlikely that the market needs to tap plays with breakevens above $4/MMBtu.

- **(c) Reinvestment rates, after remaining low over the next couple of years, should rebound.** Even as producers prioritize cash generation, after a couple of years of strengthening their balance sheets some might start to spend more to capture profitable opportunities. However, there could be uncertainty on which types of producers would lead natural gas production in the future. Supermajors and large independents generally have healthier balance sheets and are more disciplined than other types of firms, and should have better financial strength over time to drive production. However, as publicly traded companies, they are also subject to greater scrutiny on ESG issues. On the private side, although there could be more deep-pocketed private equity-backed producers looking to acquire and expand, they only make up a subset of private producers.

Nonetheless, many also do not have to confront (as much) ESG pressure, so they could capture opportunities as long as they are profitable.

Figure 37. U.S. Shale Natural Gas Cost Curve



Source: Wood Mackenzie, Citi Research

Thus, while it is reasonable to say that U.S. natural gas prices should remain in the $2-3/MMBtu range, in evaluating the competitiveness of U.S. gas globally, oil prices also matter. If oil prices stay low, then the shortage of U.S. associated gas production would require higher U.S. natural gas prices to boost U.S. gas production from dry gas plays. The "call on the U.S." shale oil looks to be well within the range of U.S. oil production that corresponds to the $40-55/bbl band. Although geopolitical and other supply-demand risks (including public policy) would dictate where prices ultimately fall, breakevens for U.S. shale would be much lower than fiscal breakevens of most OPEC+ countries. The continued reliance on U.S. shale in the future would therefore support associated gas production.

Higher U.S. prices would then lift price floors of European and Asian gas prices via U.S. LNG exports. Either a scenario of low oil prices, or restrictions on upstream drilling or midstream construction/operation, could help raise U.S. natural gas prices.

Conclusion

By finding the right product/market fit, innovating its processes and reinventing its business practices, natural gas can be integral to the Energy Transition. Natural gas is under threat from the very creative destruction process that once helped it to displace oil and coal in power generation, space heating, and industrial processes. Nonetheless, the value proposition of gas remains strong, particularly in several key demand growth areas: (1) ensuring energy and power grid supply reliability through power generation and as a form of long-term energy storage; (2) providing power within a small footprint just as emerging markets continue to urbanize; (3) serving as a fuel in shipping and road transportation, mainly in freight; and (4) producing hydrogen as industries cut their emissions. However, to make these value propositions possible and realize the useful potential of natural gas, it is necessary to curb and capture emissions from natural gas — an important reality the industry recognizes and on which it is taking action.

Geopolitical and market-structure consequences are profound, particularly between Russia and the U.S. Perspectives from each of these countries are helpful in understanding how the market could evolve. Economically, the Russian perspective illustrates how the volatile price dynamics of 2019-20 and early 2021 create prerequisites for global natural gas-producing countries to cooperate more closely in the future — a notion that many in the past thought was impossible due to the fragmented nature of natural gas markets. The most rational of these future scenarios might turn out to be the "soft coordination" strategy on supply from these gas-producing countries. Further, FIEF's detailed analysis shows that, while Russia's vast natural gas resources position the country to dominate global supply to Europe and China via pipelines and to places all over the world via LNG, Russia and its gas-market actors also need to confront the realities of the Energy Transition and a more market-based global natural gas landscape. This is where the U.S. perspective comes in. Citi expects the U.S., also with substantial natural gas resources, to similarly dominate the global natural gas market but by driving and fostering a market-based approach. This simultaneously would remake the global market to become more market-driven, countering the "soft-coordination" strategy, and allow the U.S. to be flexible in reacting to the pace of the Energy Transition. Geopolitically, the consequences are profound: using supply dominance to wield political influence, which has worked well in the past, is now under threat. The defense of supply dominance matters not only to the economics of energy supply but also to geopolitics.

Could there be a third way beyond this head-to-head supply-side competition between Russia and the U.S., and beyond the conventional supply-side thinking? Global natural gas producers are beginning to confront the prospect of either having their gas fields and facilities becoming stranded assets or unlocking the value of gas in ways that embrace the Energy Transition. Besides the kind of supply management strategy that market participants are most accustomed to, a demand-side strategy that embraces the Energy Transition, facilitated by a formation of a development bank, for example, in establishing and financing natural gas applications within the context of Energy Transition, could become a highly attractive option. In the end, it's all about finding an optimal equilibrium that best meets the needs of consumers and suppliers, while achieving the goal of the Energy Transition.

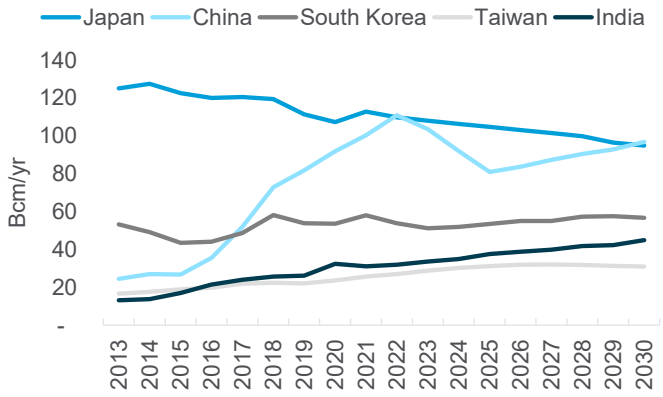
Appendix I: Regional Demand Analysis and Competitive Analysis between Gas and Renewables

This section examines each of the major demand markets in greater depth and the competition between renewables and natural gas in the power sector.

Asia

Emerging markets in Asia, led by India, should propel future global demand growth, but volumes should be less than those bought by traditional Asian buyers in East Asia, such as China and Japan. On the one hand, demand growth in East Asia should slow in the next decade, particularly due to rising shares of power generation from renewables. For China, higher pipeline gas imports and rising domestic production amid slower domestic demand growth should moderate LNG imports. On the other hand, gas imports in emerging Asian economies, such as India, should keep rising due to macroeconomic growth driving energy demand, rising urbanization lifting city gas demand, depleting domestic gas reserves and weak production widening gaps between demand and supply, and supportive environmental policies looking to reduce emissions. **Nonetheless, meeting energy demand growth in developing countries, be it via LNG imports or other forms of energy, would require substantial investments.**

Figure 38. . LNG Imports of Key Asian Economies (2013-2030)



Source: Bloomberg, Jodi, Wood Mackenzie, Citi Research

China's Gas Demand and Imports Likely to Slow in the Coming Years

The Chinese gas market is changing. Growth of gas demand and imports has slowed, while production is ramping up. More important, China pledges a net-zero future by 2060. The government has reduced its previously substantial support for gas over time. The low-hanging fruit of coal-to-gas switching has been picked as well. The government now advocates a more flexible policy on energy use: gas is still a part, but not necessarily the primary focus, of the energy growth mix. Production has also surged, helped by supportive policies, cost reduction, favorable economics, and technological advances. Nonetheless, these developments do not mean lower absolute domestic gas demand, but more of a growth slowdown.

Through these measures, China would be able to slow or reverse its reliance on energy imports, especially when national and supply security is becoming more important regarding China's energy supply. The vast majority of China's LNG imports have to pass through the South China Sea. Although China is diversified in its sources of LNG, it is not diversified over the transit route of LNG imports. China does not want to rely heavily on a single supply source. Thus, strong growth in gas imports could very well be a thing of the past. We examine these issues in-depth in the following reports: please see Global Gas: It's All about China for our initial take on the structure of China's demand trajectory and Global Gas: Made in China for our views on production, based on an engineering approach.

India: Robust LNG Import Growth Expected, but Not the "Next China"

Similar to China, the future of India's gas demand growth hinges heavily on policy support and infrastructure construction to make gas "competitive" versus alternative fuels. Overall, partly due to environmental and climate change reasons, India has set a target to increase the share of natural gas in its primary energy mix from the current 5.6% to 15% by 2030. This is a rather aggressive target given the sizable gap, especially when compared with China, which had mentioned a similar target by 2030 but gas consumption had already reached 8.3% in 2019. Nevertheless, the government's efforts in promoting gas applications, including infrastructure build-outs and market deregulation, should help gas demand growth in the medium to long term.

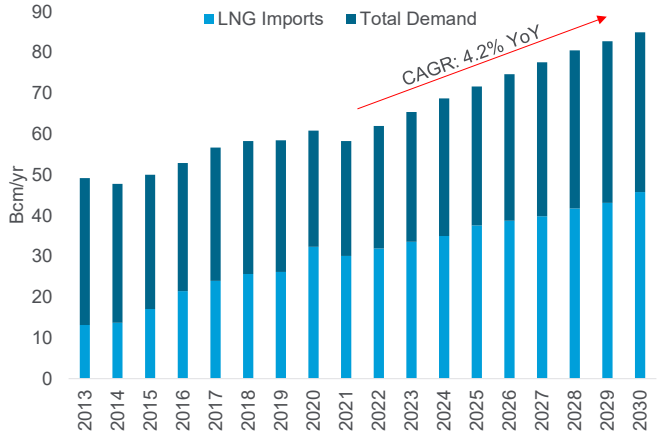
It is reasonable to expect natural gas demand to grow at a cumulative annual growth rate (CAGR) of 4-5% year-over-year in the next decade and reach 85 million cubic meters (bcm) by 2030 from ~60-bcm in 2019, driven partly by industrial applications, due to continued economic growth, industrial capacity expansions, and policy directives. An example of a policy directive is the recent government bans on pet coke and coal gas use in the Gujarat's Morbi area, resulting in a substantial jump in gas demand. More broadly, there could be a ban on fuel oil and pet coke use across the country in the next decade, as part of an effort to reduce pollution. The pipeline network expansion should also help lift industrial demand. Currently, industrial users — including refineries and fertilizer and petrochemical plants — located on the east coast have very few pipelines to connect to the broader gas network. Bloomberg reports that India should be increasing its infrastructure investments, including pipelines and terminals. More than double the current length of the transmission pipelines are under construction or proposed and the same for expansions of regasification terminals.

Beyond 2030, residential and city gas demand should rise, thanks to expansions of city gas networks as households connect to the broader gas grid. In transportation, relative cost advantages by switching from diesel and petrol to compressed natural gas (CNG) should support gas demand. However, electric and other alternative vehicles could limit CNG transport's long-term growth beyond 2030. This could be an open question, given the need to build out a reliable power grid. A lag between a power grid build-out and power demand growth could dampen demand growth for electric vehicles and reinforce demand for natural gas.

Domestic natural gas production should grow at a slower pace than demand, given limited investments in upstream gas exploration. Thus, with continued demand growth, LNG imports should keep climbing, possibly doubling between 2020 and 2030, reaching 49-bcm/y by 2030. Production in 2020 could fall by 7% year-over-year amid low oil and gas prices. However, production from 2021-24 could then rise by 5% year-over-year, given robust output from current promising fields.

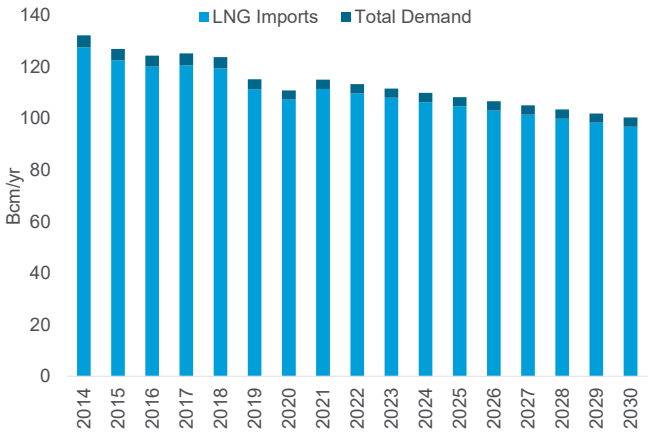
Production growth beyond 2025 could slow, as output from these fields decline while new capital expenditure in exploration remains limited. Without investments in new projects, production in the 2025 to 2030 period could flat-line, which should support LNG import growth, perhaps at a rate of 8-9% year-over-year (or 3-bcm year-over-year) to meet rising demand.

Figure 39. India' s Rising Gas Demand to be Mainly Met by LNG Imports Over the Next 10 Years



Source: Bloomberg, Jodi, Wood Mackenzie, Citi Research

Figure 40. Japan's Gas Demand and LNG Imports are Expected to Decline in the Next Decade



Source: Bloomberg, Jodi, Wood Mackenzie, Citi Research

Japan: Gas Demand to Slow on Declining Power and City Gas Demand

Natural gas demand should shrink this decade to 100-bcm/y by 2030 from a high of 132-bcm/y in 2014 shortly after the Fukushima accident that shut down the country's nuclear fleet. LNG imports could fall at a CAGR of -1.5 to 2% year-over-year from 2022 to 2030. Demand should fall because of a gradual slowdown in economic growth, rising nuclear power generation displacing gas-fired generation, and a moderation in city gas demand as the population ages. The country's latest energy strategic plan to 2030 not only recognizes these trends, but also lays out the fundamental change in energy structure by promoting renewables as a way to cut GHG emissions. All these point to a gradual decline in gas consumption. Bloomberg indicates that 17GW of nuclear reactors should come back online by 2040, but there is a risk here given how slow the process of returning to nuclear power has been. Nonetheless, despite the gradual fall, natural gas currently still accounts for more than 40% of total power generation. Japan is also diversifying its sources of LNG imports, given its high reliance on imports and hence high geopolitical risk.

Despite the expected demand decline, the government's policy to promote hydrogen production and demand might unlock additional LNG demand but uncertainties remain. Hydrogen could be produced domestically by converting gas through a steam methane reforming (SMR) process. Hydrogen could also come from outside Japan, such as the case of importing ammonia from Saudi Arabia or Australia, where ammonia is a hydrogen carrier more suitable for long-haul transport. The ammonia sourced earlier in 2020 from Saudi Arabia when that country pioneered long-haul exports of hydrogen to Asia, reportedly came from converting hydrocarbons into hydrogen before being turned into ammonia, with the emitted carbon dioxide captured. This is a so-called "blue hydrogen", where hydrocarbon is the feedstock and the carbon emitted is captured. Saudi Arabia

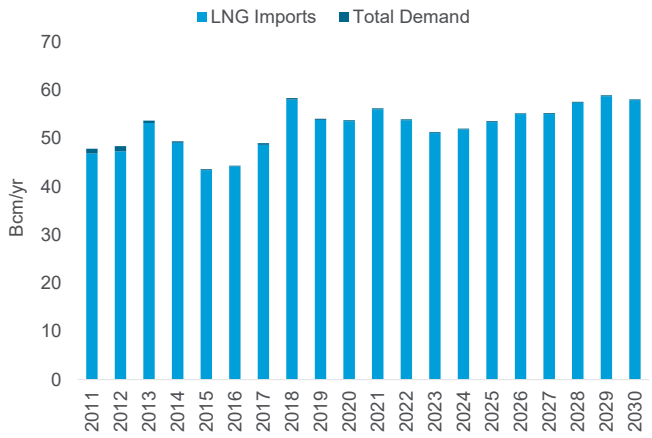
additionally is developing green hydrogen production which takes renewable energy to power electrolyzers to produce hydrogen.

South Korea: Flat Demand Growth Possible After 2023

Natural gas demand from 2021 to 2030 should rise gradually, converging around 55-bcm/y. President Moon announced in September 2020 the country would shut an additional 30 coal plants by 2034, with 10 of them closed by 2022. Meanwhile, the number of solar and wind facilities should triple between 2019 and 2025. LNG should then help fill the gap left by retiring coal plants.

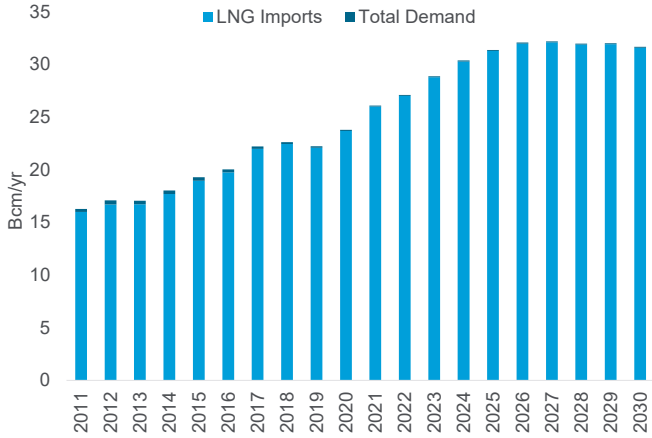
The country's hydrogen ambition, like Japan's, might raise LNG demand incrementally above the base case. **However, the feasibility of the target is in question**. Korea's 2019 hydrogen roadmap, which aims to produce 6.2 million fuel cell electric vehicles and roll out at least 1,200 refilling stations by 2040, could raise LNG imports by ~5-mtpa, or ~6.8-bcm, by 2040 to meet the fuel demand, based on Bloomberg's analysis. If reached, this LNG demand for hydrogen production could be a bullish demand scenario. However, the economics of hydrogen versus other fuels, the need for government support, and infrastructure investments all make this future uncertain.

Figure 41. South Korea's Gas Demand to Rise Modestly as Some Coal Plants Would be Retired



Source: Bloomberg, Jodi, Wood Mackenzie, Citi Research

Figure 42. Taiwan LNG Imports Will Continue to Grow During 2020-28



Source: Bloomberg, Jodi, Wood Mackenzie, Citi Research

Taiwan: LNG Imports Should be Supported by Rising Demand and Declining Domestic Production

Natural gas demand should continue to climb through to the middle of this decade, supported by government policies, such as phasing out nuclear power plants. A net addition of ~10GW of new gas generation capacity by 2028 should also help to lift gas demand, though offset by ~25GW of new renewable energy by 2025. Gas demand should reach 32-bcm/y by 2027 from ~26-bcm in 2020, leading to an equivalent or greater increase in LNG imports, especially as domestic production should decline sharply between 2020 and 2024. LNG imports grow at an annual CAGR of 6% year-over-year during this period.

LNG imports could climb further if the government presses hard on its "nuclear-free" goal by 2025, though the feasibility of this campaign promise is questionable. The government's nuclear-free plan would require up to 13GW of new LNG-fueled generating capacity. Three gas-fired projects, with a total capacity of 3.9GW, are under discussion and environmental impact assessments, and could come online by 2023 — a rather ambitious target. A large electricity provider in Taiwan, hopes to import LNG directly for the first time. However, opposition from local and environmental groups have delayed the online dates of some projects.

Europe: Decarbonization Goal to Lower Demand Longer Term

Europe's decarbonization goal, including in the heating sector and the eventual use of hydrogen produced from electrolyzers powered by renewables, should keep domestic gas demand weak. Higher imports of LNG in the future might be a function of falling local production, but more so a result of excess gas globally. Excess LNG globally would lower gas prices so much that coal-to-gas switching would lift demand, while sufficiently low prices, as seen in 2020 in particular, would displace other sources of natural gas, such as pipeline gas on more expensive contracts. Our supply/demand balance analysis shows an uptick in Europe's LNG imports in the out years because excess LNG would be sent to Europe, given its massive and flexible power and gas markets. However, more retirements of coal-fired power plants should make coal-to-gas switching more difficult. This means gas prices would have to move even more to induce an increase or decrease in gas-to-coal or coal-to-gas switching in the power sector.

Middle East & North Africa (MENA)

MENA's appetite for LNG looks likely to slow as new gas discoveries and strategy reform raise local production, turning importers to exporters, while domestic gas demand growth slows due to subsidy cuts, efficiency gains, and availability of renewable energy. The industry has taken for granted that LNG demand in MENA can only grow in the years to come, particularly in place of oil for power generation. However, new gas discoveries and new gas development strategies are damping expectations instead. What makes this region more significant than others with larger LNG demand is how it could turn key countries from being importers into exporters. For countries bordering the Mediterranean, such as Egypt and Israel, major offshore discoveries provide them with sizeable future resources. Kuwait, Saudi Arabia, and the UAE are all increasing their domestic production. Saudi Arabia appears to have shelved plans to buy into upstream gas production abroad as well as into liquefaction and expansion of its global trading activities to LNG. Meanwhile, subsidy cuts have lifted natural gas prices, helping to slow growth. Yet, reverse osmosis (RO) desalination, which is gaining interest in the region, also uses less energy. The growth of renewables, particularly solar, just as costs have kept falling, provides another source of power generation. Thus, gas demand growth should slow.

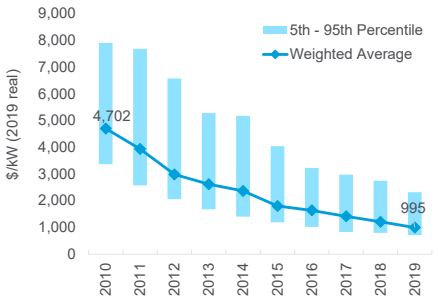
Latin America

Latin America once had great hopes but has since slowed. Mexico has a growing reliance on imports from the U.S., particularly via pipelines. Mexico recently approved an export terminal to be constructed on a brownfield site on the west coast of the country. Its dependence on LNG continues to weaken. Argentina looks to become an exporter as well.

Rising Market Shares of Renewable Energy Should Challenge Gas' Market Shares

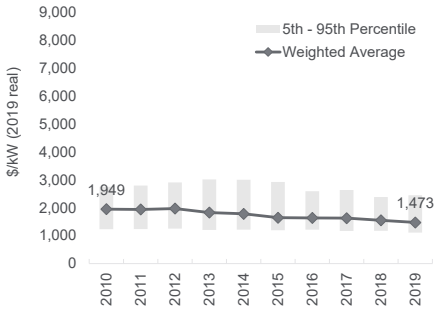
Besides policy support and the general public's increasing preference for clean energy, the large and steady drop of solar and wind installed costs has helped to attract massive capital inflows. Installed costs of utility-scale solar photovoltaic (PV) has shrunk by almost 80% over the past decade, while both onshore and offshore wind saw a 20% drop in installed costs over the same period. In 2019, new utility-scale solar PV projects, after several years of massive capacity growth, had lower costs than onshore wind on a weighted average basis. Costs of offshore wind appear to be on a sharper downward trend over the last four years. In a virtuous cycle, greater investments, in turn, led to continued improvements in economies of scale. Solar and wind continued to draw most of the annual global investments in renewable capacity in 2019 and into 2020 Together, they represented over 80% of total renewable energy investments, including hydro, over the past two years. The phase-out of subsidies for solar and onshore wind is a direct result of the cost competitiveness reached by both technologies.

Figure 43. The Rapid Decline in Installed Costs for Utility-Scale Solar PV…



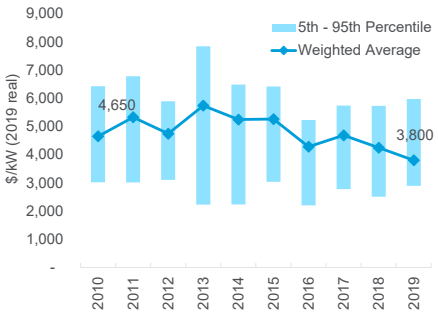
Source: IRENA, Citi Research

Figure 44. …Versus the Stable Installed Cost for Onshore Wind…



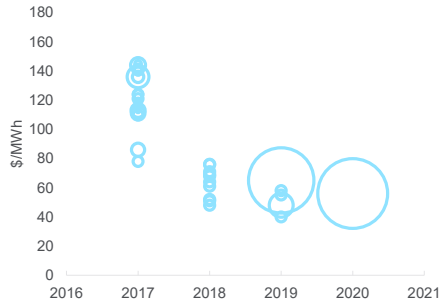
Source: IRENA, Citi Research

Figure 45. …and the Recent Drop in Installed Cost for Offshore Wind



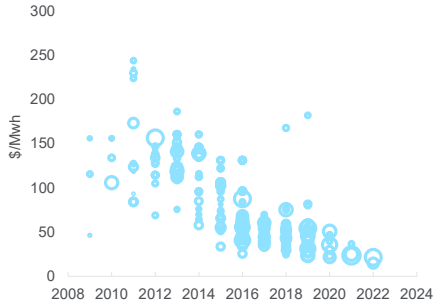
Source: IRENA, Citi Research

Figure 46. China Solar PV Auction Prices (bubble size indicates relative auction capacity)



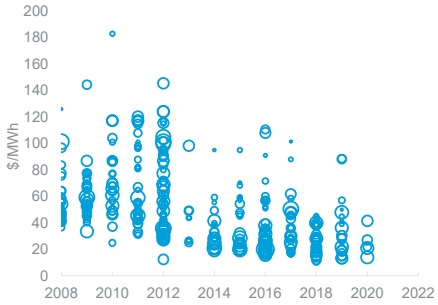
Note: Bubble size indicate relative auction capacity
Source: BNEF, Citi Research

Figure 47. U.S. Initial Offtake Prices by Power Purchase Agreement Signing Date for Solar PV



Note: Bubble size indicate relative contract capacity
Source: BNEF, Citi Research (*PPA = Power Purchase Agreement)

Figure 48. U.S. Initial Offtake Prices by Power Purchase Agreement Signing Date for Onshore Wind



Note: Bubble size indicate relative contract capacity
Source: BNEF, Citi Research

However, the market share of hydropower, despite its more favorable, steady generation profile compared with intermittencies of wind and solar, has been falling and should continue to decline, even though absolute hydro capacity should still rise. Unlike the growth in solar and wind capacity, the volume of new hydro capacity added each year shrunk from 47GW in 2013 to just 13GW in 2019. The technology of hydro is very mature and after decades of developments most of the locations readily suitable for hydro generation have already been tapped. China remains the only large region still increasing hydro capacity relatively aggressively. Since 2013, nearly 40% of all hydro generation construction globally took place in China. China also plans to build a 60GW hydro power complex in Yarlung Tsangpo in Tibet. Beyond this, the world could be running out of easy locations for new projects.

Appendix II: Regional Assessments on Natural Gas Use in Transportation

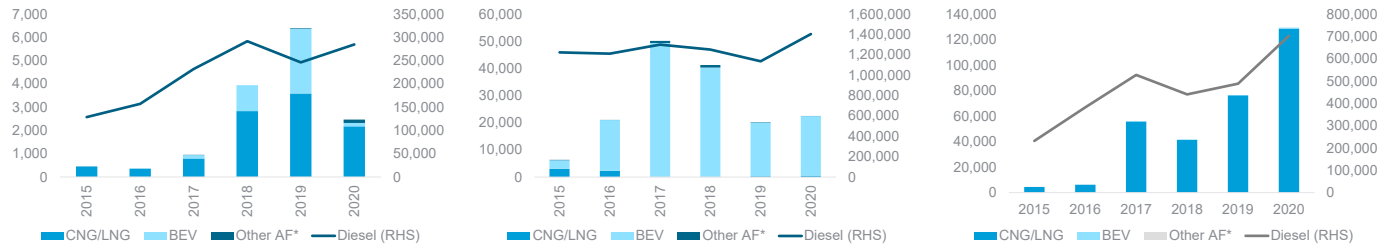
In addition to illustrating environmental and economic benefits earlier in the report, here we highlight concrete developments and examples across freight and passenger vehicles, looking into markets globally, including China, India, Iran, and Russia, but also Europe and the U.S. to see what is being developed, how they are deployed, and what are key success factors.

China

Natural gas vehicles (NGVs) are mostly prevalent in heavy-duty trucks (HDTs) and tractors[13] in China. Among all the alternative-fuel[14] HDTs sold in 2020, 88% are NGVs. That number is even higher for tractors, at 99%. While diesel trucks continue to dominate in China, NGVs have successfully gained market share, especially in the tractor sector. They made up 15% of total sales of domestic-made semi-tractors in 2020, up from 2% in 2015. Diesel-powered semi-tractors, in the meantime, saw their market share of total annual sales fall from 98% in 2015 to 84% last year. It is worth noting that, in the light-duty truck (LDT) sector, battery electric vehicles (BEVs) significantly outperform NGVs. In 2020, 97% of alternative-fuel LDTs sold were BEVs, while only 2% were NGVs.

Stringent policies to fight air pollution helped drive the NGV market in China. In July 2018, China rolled out a three-year action plan for clean air, calling for the retirement of 1 million medium- and heavy-duty outdated diesel trucks by the end of 2020. Diesel trucks were also banned in shipping hubs like the Port of Tianjin, the largest port in Northern China. By the end of 2018, China had the world's largest fleet of NGVs (including trucks, buses and passenger cars etc.), with 6.7 million units, up from 5 million in 2015. Various policies were implemented by local governments to provide subsidies and cut taxes and toll fees.

Figure 49. China Annual Sales of Heavy-duty Trucks (Left), Light-duty Trucks (Middle), and Domestic-made Semi-tractors (Right)



Source: Bloomberg, Citi Research (Other AF* = Other Alternative Fuel Vehicles)

[13] Bloomberg data categorize Chinese commercial vehicles into truck, incomplete truck, tractor, bus and incomplete bus. Here we look at NGVs and BEVs within the categories of truck (excluding incomplete truck) and tractor.

[14] Alternative-fuel include NGVs, BEVs, plug-in hybrids, hybrids, fuel cell vehicles, etc.

China implemented its most stringent emission standards to all heavy-duty vehicles (HDVs) in 2021, providing additional stimulus to speed up the transition to NGVs. The China VI emissions standards, one of the most stringent in the world, took effect on July 1, 2019. It was actually implemented in two phases, with China VI-a, phase one, applied to gas-powered HDVs in July 2019 and rolled out to cover new urban HDVs in July 2020. Diesel HDVs will be subject to the China VI-a starting July 1, 2021. Thus, by July 2021, all HDVs will be subject to the China VI-a emissions standards. Note that gas-powered HDVs again are subject to more advanced emission criteria. Phase two of the China VI standard, also called China VI-b, was applied to all gas-powered HDVs starting January 1, 2021. Sinopec estimates that during China's 14th Five-Year Plan, the number of CNG/LNG HDVs (possibly including tractors, trucks, and incomplete trucks) could double to 1-1.2 million, leading to an extra gas demand of 16-25-bcm/y. This is likely achievable, given that total LNG HDV sales reached 135k in 2020, lifting the total number of LNG HDVs in China close to 600k by the end of 2020, according to some market participants.

LNG vehicles are likely going to drive China's gas consumption growth for road transportation going forward, even though they are starting from a lower base than CNG vehicles. Of the ~60-bcm gas consumption for road transportation in 2020, over 40-bcm was for CNG vehicles, according to SCI99, a Chinese consultant. Yet a BNEF report[15] shows CNG passenger vehicles are losing ground to BEVs as national-level policies have gradually shifted in favor of BEVs. Total cost of ownership (TCO) for BEVs was lower than CNG vehicles in 2020, both for private cars and taxis. Therefore, we have kept a flat CNG gas demand for our demand forecasts. Nonetheless, we do expect a very robust gas demand growth for LNG vehicles, which could probably double to over 40-bcm/y by 2025.

India

Citing LNG's benefits including as less vehicle pollution and import bill savings, India's government demonstrated its support by laying out a plan for the country's first set of LNG fueling stations in November 2020. According to estimates by the Indian government, it can save truck operators Rs200k Indian rupees (~$2,700) per year for each truck they switch from using diesel to LNG. Therefore, despite higher upfront costs of LNG trucks, investments by truck operators could be paid back in 3 to 4 years with these annual savings. According to the government's plan, LNG supplies from the initial batch of 50 LNG stations are meant for heavy vehicles and buses, but the government's plan aims for 1,000 LNG stations by the end of 2023.

The market size could be significant: over the longer term: 10% of the trucks[16] India could be running on LNG, leading to 20-25 mcm/d (7-9 bcm/y) of LNG demand from heavy vehicles by 2035. This equates to 20% of current Indian annual imports of LNG, as well as 11% of its total annual consumption of natural gas. If India would have 1,000 LNG stations by the end of 2023, then LNG stations will be spreading across all major roads, industrial hubs, and mining areas in India, with one LNG station every 200-300km.

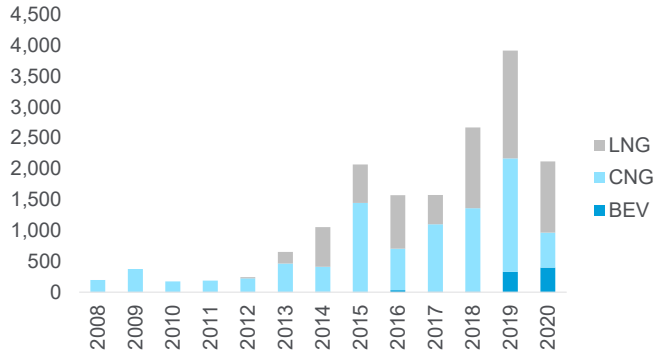
[15] BNEF (February 2021), *China's Natural Gas Vehicles Are Getting Pushed Out by EVs.*
[16] Press release by India's Ministry of Petroleum & Natural Gas on Nov 19, 2020. https://pib.gov.in/PressReleseDetailm.aspx?PRID=1673998.

Policy support, along with the roll-out of natural gas infrastructure, could lead to a two to three-fold increase in India's natural gas consumption for road transportation from ~4-bcm/y, in 2019 to 8- 14-bcm/y, by 2030[17]**.** Our colleagues covering the Indian Oil & Gas sector estimate the current fleet size of India's NGVs is ~ 4 million, with ~2,500 CNG refueling stations. The number of CNG stations is likely going to grow 4x to 10,000 over the next decade, based on awarded city gas licenses in the past few years. This signals there is still great headroom for growth of CNG vehicles in India, even for personal mobility vehicles, while EVs could take a long time to catch up in India (see report: Indian Downstream - OMCs' Time Will Come). The combination of both sustained CNG strength and nascent LNG growth have therefore underpinned our optimistic gas demand outlook for road transportation in India.

Europe

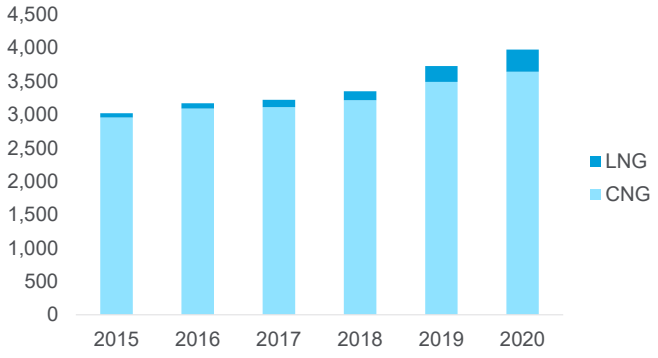
Among EU alternative fuel heavy-duty fleets[18]**, CNG/LNG trucks are dominant. Together, there are nearly 25,000 CNG/LNG heavy-duty trucks within the EU as of 2020, more than 70% of the alternative fuel heavy-duty fleet.** CNG alone accounts for 56% of the total alternative fuel heavy-duty fleet within the EU, with nearly 20,000 vehicles. In the most recent three years though, LNG looks to be catching up with CNG, albeit from a much lower base, with ~4,200 new registrations over 2018-20, more than the ~3,700 new CNG registrations.

Figure 50. Annual New Registrations of Heavy-duty Vehicles in the EU



Source: European Alternative Fuels Observatory, Citi Research

Figure 51. Total Number of CNG/LNG Refueling Stations in the EU



Source: European Alternative Fuels Observatory, Citi Research

The prevalence of CNG/ LNG among alternative fuel heavy-duel vehicles is underpinned by the EU's CO_2 standards for heavy-duty vehicles that came into force in 2019. The standards targeted a 15% reduction of CO_2 emitted by new trucks from the baseline of the EU average in the reference period (7/1/2019–6/30/2020) from 2025 onwards, and 30% reduction from 2030 onwards.

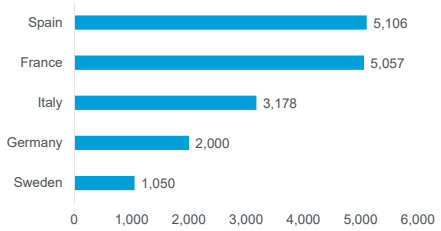
[17] In 2019, India's natural gas demand for transportation was ~4-bcm/y according to IEA. Source: IEA (February 2021), *India Energy Outlook 2021*.

[18] According to European classification for vehicle category, heavy-duty vehicles include N2 and N3. N2 refers to vehicles used for the carriage of goods, having a maximum mass exceeding 3.5 tonnes but not exceeding 12 tonnes; N3 refers to vehicles used for the carriage of goods, having a maximum mass exceeding 12 tonnes. EU alternative fuel vehicles include power sources such as battery electricity, CNG / LNG, hydrogen, LPG and plug-in hybrid.

According to estimates by the European Commission, by 2025, these rules could double the EU's LNG demand from trucks to 1 million toe/yr[19], compared to 500k toe/yr without these rules. Then by 2030, LNG demand from trucks could even reach 4.4 million toe/yr, from a baseline demand of just 1.3 million toe/yr.

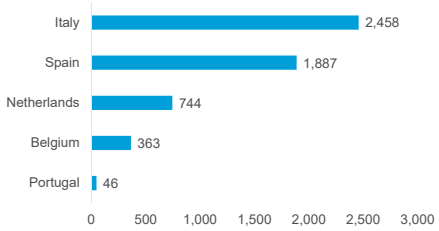
Italy stands out among its peers within the EU both in terms of the number of CNG/ LNG vehicles and refueling stations, and also annual new vehicle registrations. It has more than 1,400 CNG/ LNG refueling stations as of 2020, 70% more than Germany, which came in second in the number of refueling stations within the EU. It also dominated new vehicle registration for both CNG and LNG in 2020, solidifying its lead in LNG trucks, and closing the gap with France and Spain in CNG trucks. Italy's NGV success depends on government subsidies for both CNG/LNG vehicles and fuels, road tax exemptions, as well as proactive promotion programs from Italy's energy infrastructure operators.

Figure 52. TOP 5 EU Countries with Most CNG Heavy-duty Vehicles (2020)



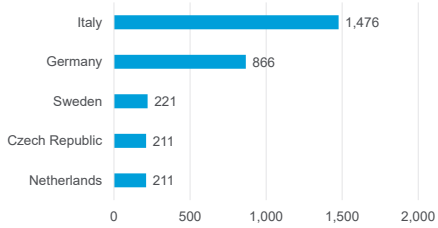
Source: European Alternative Fuels Observatory, Citi Research

Figure 53. TOP 5 EU Countries with Most LNG Heavy-duty Vehicles (2020)



Source: European Alternative Fuels Observatory, Citi Research

Figure 54. Top 5 EU Countries with Most CNG / LNG Refueling Stations (2020)



Source: European Alternative Fuels Observatory, Citi Research

EU gas demand for road transportation could potentially double and triple by 2025 and 2030, respectively. Current gas demand for road transportation is ~3-bcm/y according to GECF[20], the majority of which is likely from CNG vehicles, judging by the relative size of CNG and LNG fleets. In fact, more than 90% of gas refueling stations in EU are for CNG as of 2020. Aggregating member states' estimates, the European Commission has suggested that CNG vehicles could double in fleet size by 2025 with further growth by 2030. LNG HDVs are expected to grow at an even faster pace until 2030. This has taken us to ~7-bcm/y and over 10-bcm/y of gas demand forecasts for road transportation by 2025 and 2030.

The upcoming Euro 7 emission standard, which is planned for the fourth quarter of 2021, could introduce uncertainty to this outlook. Some automakers suggest that current Euro 7 proposals are essentially a back-door way of banning internal combustion engines (ICEs) in the years to come. While the exact details are still under discussion, we do note that similar "ICE bans" adopted by some EU member states seem to have only focused on passenger cars and light commercial vehicles.

[19] Metric Tonnes of Oil Equivalent per year (toe/yr).
[20] GECF (April 2020), The Future of Natural Gas in Road Transport and Its Role for a Decarbonized Mobility Agenda in Europe.

Figure 55. ICE Vehicle Phase-out Targets by EU Member States

	Year	Vehicle Category*	Target Vehicle Types*	Policy Document**
Norway	2025	Passenger cars, light commercial vehicles, urban uses	New vehicle sales 100% zero-emission	National Transport Plan 2018–2029 (2017)
Netherlands	2025	Urban buses	New vehicle purchases 100% zero-emission	Mission Zero (2019)
	2030	Passenger cars	New vehicle sales 100% zero-emission	
Denmark	2030	Passenger cars	No new gasoline or diesel vehicle sales	Climate and Air Plan (2018)
	2035		No new gasoline, diesel, or plug-in hybrid vehicle sales	
Iceland	2030	Passenger cars	No new gasoline or diesel vehicle registrations	Iceland's Climate Action Plan for 2018–2030 (2018)
Ireland	2030	Passenger cars	No sales of new fossil fuel vehicles	Climate Action Plan 2019 (2019)
Slovenia	2030	Passenger cars, light commercial vehicles	No new registrations of vehicles with CO_2 emissions above 50 g/km	Market Development Strategy for the Establishment of Adequate Alternative Fuel Infrastructure in the Transport Sector in the Republic of Slovenia (2017)
Sweden	2030	Passenger cars	No sales of new gasoline or diesel vehicles	Climate Policy Action Plan (2019)
France	2040	Passenger cars, light commercial vehicles	No sales of new fossil fuel vehicles	Mobility Guidance Law (2019)
Spain	2040	Passenger cars, light commercial vehicles	New vehicle sales 100% zero-emission	Draft Law on Climate Change and Energy Transition (2020)
Germany, Baden-Wuerttemberg	2050	Passenger cars	New vehicle sales 100% zero-emission	IZEVA commitment (2015), not yet reflected in national Climate Protection Plan

Source: ICCT, Citi Research (*Terminologies used in official policy documents; ** Publication date)

South Asia and Latin America

Pakistan's natural gas demand in the transport sector could potentially grow from ~2bcm/y in 2019 to over 6-bcm/y by 2030.[21] However, the path is likely to be choppy, as Pakistan struggles with declining domestic production and constrained LNG imports over the coming years, while gas usage in the transport sector also ranks low on the government's priority list.

In contrast, the abundance of shale gas at Vaca Muerta has prompted Argentina to promote natural gas in the transport sector, which could see its demand grow from ~2.5-bcm/y to over 8-bcm/y.[22] There are ~2,200 CNG filling stations in Argentina in 2020, with ~1.8 million NGVs. Under the "CNG Green Corridor" plan by Enargas (National Gas Regulatory Entity of Argentina), more refueling points will be added to support heavy vehicles, so that there could be one refueling station every 350km.

Small-size Passenger Car: A Special Case in Iran

Unlike elsewhere, where efforts are focused on replacing diesel bus/trucks with NGVs, the focus in Iran has been, and seems to remain, on replacing gasoline-powered passenger vehicles with CNG. Besides battling air pollution, the insufficient number of oil refineries and therefore domestic gasoline supplies historically also help to drive NGV growth[23].

[21] https://www.naturalgasworld.com/south-asias-shifting-ngv-opportunities-lng-condensed-69325.
[22] http://www.ngvjournal.com/s1-news/c4-stations/green-corridors-argentina-plans-to-introduce-natural-gas-in-heavy-transport/.
[23] Kartikeya Singh (March 2019), *Pathways for Developing a Natural Gas Vehicle Market*, Retrieved from https://www.csis.org/analysis/pathways-developing-natural-gas-vehicle-market.

Natural gas demand from CNG vehicles in Iran has increased from 19-mcm/d in 2017 to 24-mcm/d so far in 2021,[24] with more to come, as the country rolls out a national scheme to convert ~1.5 million gasoline-powered public vehicles to CNG hybrids starting from 2020. This took place, ironically, over a period when Iran's refining capacity and gasoline surplus grew, as did skyrocketing gasoline export sales. Over 83k public vehicles have reportedly[25] been converted between March 2020 and March 2021, while the government has also started a new program to convert taxi fleets and private passenger vehicles registered in ride-hailing apps. The Supreme Economic Council has also made the conversion of public vehicles free of charge, providing strong incentives to speed up the process.

With nearly 4 million NGVs and an annual CNG demand of 8 to 9-bcm/y in Iran in 2020, the additional 1.5 million converted CNG public vehicles could boost CNG demand to 12-bcm/y. This is still within Iran's CNG refueling capacity as of 2020, which is able to refill over 40-mcm/d of CNG, or ~15-bcm/y. Therefore, further upside to our demand forecast is possible, with the continuing efforts to convert taxi fleets and private passenger vehicles.

Transit Buses

CNG buses are generally competitive against battery-electric buses (BEBs) with lower costs and greater reliability, underpinning its growing penetration in U.S. bus market. The US National Renewable Energy Laboratory (NREL) has been tracking BEB and CNG bus performances at the Foothill Transit in Los Angeles since 2014 with regular progress reports every 6 months. Their latest report covering July-December 2019 shows that CNG is cheaper to buy and operate with lower fuel and maintenance costs. More importantly, CNG buses could be more reliable in terms of availability[26] and miles between road calls (MBRC).[27] CNG's advantages have manifested themselves in the U.S. bus fleet data, as they increased their market share from 16% in 2015 to 21% in 2020. The past 5 years saw U.S. added over 2,000 CNG buses to over 14k in total, while BEBs only added 760 units. The number of diesel buses in the U.S. fell slightly, but as the total U.S. bus fleet shrank even more, their market share was stable. With nearly 35k diesel buses still running in the U.S., or ~50% of U.S. bus fleet, that's a big market that is up for grabs.

Figure 56. Bus Performance Evaluation (Foothill Transit, Los Angeles, Jul-Dec'19)

	BEV	*CNG*
Fuel Cost ($/mile)	0.43	0.33
Total Maintenance Cost ($/mile)	0.53-0.84	0.42
Availability	66-79%	91%
Purchase Cost ($)	890k-905k	575k
Miles between Road Calls (MBRC)	6-8k	26k

Source: NREL, Citi Research (*MBRC = Miles between road call)

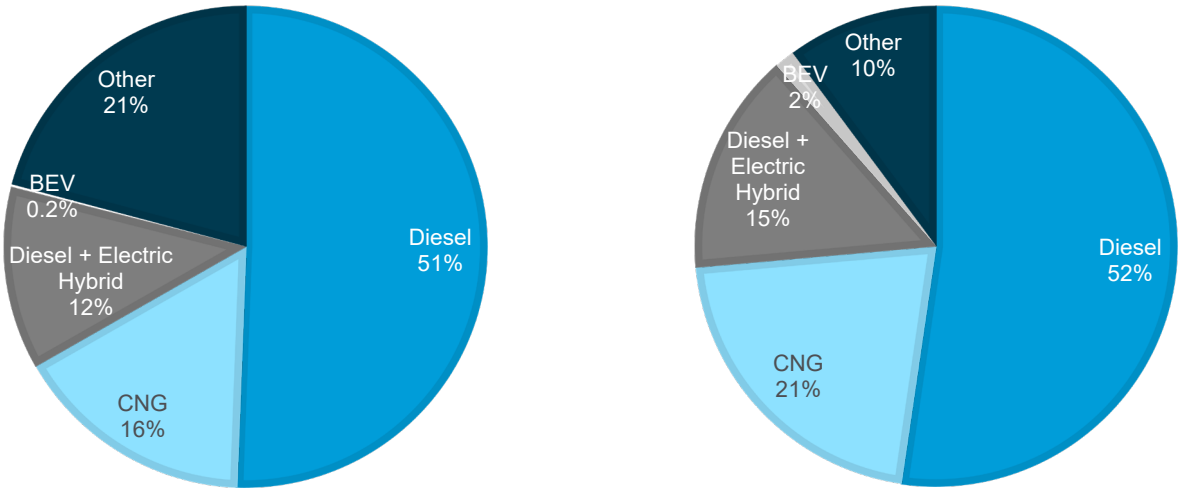
[24] Press release by National Iranian Oil Refining and Distribution Company (NIORDC) on March 3, 2021. http://en.niordc.ir/index.aspx?fkeyid=&siteid=77&pageid=358&newsview=12608.

[25] https://www.tehrantimes.com/news/459004/Over-83-000-public-transport-vehicles-turned-dual-fuel-since

[26] Availability is the percentage of days that buses are available out of days that they are planned for passenger service. Transit agencies typically have a target of 85% availability.

[27] Miles between road call (MBRC) is the average distance between vehicle failures. A failure of an in-service bus will cause the bus to be replaced on route or a significant delay in schedule.

Figure 57. US CNG Penetration in Bus* Segment – 2015 (Left), 2020 (Right)



Source: American Public Transportation Association, Citi Research (* including bus, commuter bus and rapid transit)

Gas demand for transit buses in the U.S. could potentially rise by 50~60% over the next 10 years. Currently, the overall market size of natural gas in road transportation in the U.S. is modest, with only ~2-bcm/y of gas demand in 2020, according to the U.S. Energy Information Administration (EIA). The transit bus sector ranks the second-largest, following the freight truck sector. In its *2021 Annual Energy Outlook*, EIA sees gas demand for transit buses in the U.S. growing from 0.5-bcm/y in 2020 to ~0.8-bcm/y in 2030. Similarly, the freight truck sector is likely to add another 0.4-bcm/y of demand between 2020 and 2030, equivalent to ~30% growth.

Yet, the growth trajectory will very much hinge upon policy developments. According to the American Jobs Plan, also known as President Biden's infrastructure plan, $174 billion will be spent on developing electric vehicle markets, nearly 30% of the total budget for the transportation sector. The plan, if passed, would electrify at least 20% of yellow school buses, and replace 50,000 diesel transit vehicles (potentially with electric vehicles), with the end goal of 100% clean buses in the U.S. Measures will also be taken to electrify the federal fleet, including the U.S. Postal Service (USPS).

Appendix III: Additional Materials on Multi-lateral Development bBanks (MDBs)

Below are selected projects from the World Bank Group (WBG) and the Asian Infrastructure Investment Bank (AIIB), illustrating the mission and functions of projects by MDBs. MDBs have an advantage in financing infrastructure, where projects usually take long and government support is key.

In WBG, apart from the development work in all major sectors, they also produce research, analysis, and collect data globally to support their practical work. For example, WBG sets up the Human Capital Project (HCP), which is a global initiative to accelerate better investment in people for greater equity and economic growth. Along with these efforts, WBG also collects human capital data and creates a Human Capital Index (HCI), which is downloadable on the website. This index is designed to capture the amount of human capital a child born today could expect to attain by age 18, given the risks of poor health and poor education in the country he/she lives. The Index therefore serves as a benchmark to assess the human capital costs. The benefit of having the data and analysis from the index is that it provides a clearer vision of where the investment should go to maximize the effectiveness of the development work. According to the Index, nearly one-third of changes in the HCI over the past decade are due to gains in health, followed by upper secondary enrollment at schools. This means that giving children a well-nourished, clean and basic education is key to unlocking their potential and increasing human capital. WBG then linked their daily operations with key initiatives in Africa and Middle East to scale up financing in projects that aim for improving access to health care, apprenticeship training and women empowerment in the regions. The Bank also steps up in building knowledge and partnerships in the regions, with further studies and research in malnutrition, poverty, labor markets to raise people's awareness and provide new insights into addressing human capital challenges.

Since the establishment of AIIB in 2016, there have been 101 approved projects with $21.5 billion in approved financing in the leading sectors in energy, transportation, and financial inclusion. AIIB has a specific strategy on mobilizing private capital for infrastructure. The long-term aim is to position itself as a "go-to" institution for providing infrastructure financing solutions and catalyzing private capital. The Bank is planning to achieve this goal through three key activities. The first is to pursue and execute transactions based on third-party referrals and investable non-sovereign projects. Then the Bank will lead in transactions, which means the Bank will originate, structure, and execute stand-alone deals. In the third phase, the Bank will start to create the market by creating deal flows. As an infrastructure-focused bank, AIIB is also involved in public-private partnerships (PPP). In a more recent project approved in September 2020, AIIB is responsible for providing $150 million project financing to a Special Purpose Vehicle (SPV) company in Indonesia to support the Government of Indonesia in a Satellite PPP project. The project aims to provide fast internet access to remote areas in Indonesia.

AIIB's goal is to optimize borrowing costs over the medium to long term and it has various funding sources. Issuance will be via a combination of USD Global benchmark bonds, Eurobonds, and private placements in various markets. AIIB's lending investments are made via sovereign and non-sovereign loans, equity participations, and guarantees. While sovereign-backed loans make up the foundation of the Banks instruments and AIIB usually co-finance projects with other lenders (such as WBG), the Bank is taking progressive approach to expand its non-sovereign backed financing. The terms and conditions will be set on a commercial basis and reflect the expected risk to the AIIB and market conditions. AIIB also has a portion of its instruments in equity investments, but the maximum limit on equity investments will be up to 10% of available capital.

Figure 58. A Summary of a Selection of Global and Regional Development Banks

Global Development Banks	Founded Time	Number of Members	Key Missions
European Investment Bank (EIB)	1958	27	Investment focus on climate and environment, development, innovation and skills, small businesses, infrastructure, and cohesion
International Fund for Agricultural Development (IFAD)	1977	177	Invests in small-scale agriculture and inclusive rural development
International Investment Bank (IIB)	1970	9	Facilitates connectivity and integration between the economies of the Bank's member states in order to ensure sustainable and inclusive growth and the competitiveness of national economies
New Development Bank (NDB)	2014	5	Mobilizes resources for infrastructure and sustainable development projects in BRICS and other emerging economies
OPEC Fund for International Development (OFID)	1976	12	Strengthens infrastructure and human capacity across inter-related fields such as energy, transportation, agriculture, water and sanitation, health, and education
World Bank Group: IBRD and IDA	1944	190	Ends extreme poverty by decreasing the percentage of people living on less than $1.90 a day to no more than 3% Promotes shared prosperity by fostering the income growth of the bottom 40% for every country
Regional Development Banks			
African Development Bank (AfDB)	1964	81	Spurs sustainable economic development and social progress by mobilizing and allocating resources for investment, and providing policy advice and technical assistance to support development efforts
Asian Development Bank (AsDB)	1966	68	Assists its members by providing loans, technical assistance, grants, and equity investments to promote social and economic development
Asian Infrastructure Investment Bank (AIIB)	2016	103	Invests in sustainable infrastructure and other productive sectors in Asia and beyond
European Bank for Reconstruction and Development (EBRD)	1991	69	Commits to furthering progress towards "market-oriented economies and the promotion of private and entrepreneurial initiative"

Source: Development Bank Websites, Citi Research

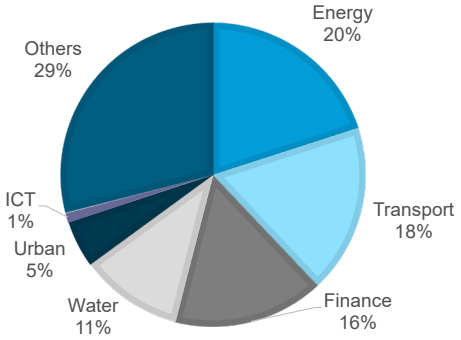
The project approval process at AIIB show that the Bank screens projects carefully, does project due diligence, and also monitors compliance after the implementation. The first step of the project approval process starts from strategic screening, which goes through the Screening Committee. In particular, the Board of Directors' approved financial policies require approvals to be based on use of loan proceeds for intended purpose. After the projects are initially screened, there is project due diligence which affirms project viability. At the implementation stage, the Bank will carry out the environmental and social impact assessments to ensure compliance with AIIB's ESG policy.

Figure 59. AIIB Balance Sheet (as of June 30, 2020)

Assets		Liabilities and Equity	
Investment Operations Portfolio	4.075	Equity	20.091
Treasury Liquidity Portfolio	22.305	Borrowings	6.641
Others	0.714	Other Liabilities	0.362
Total	27.094	**Total**	27.094

Source: AIIB, Citi Research

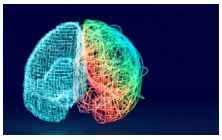
Figure 60. Loans by Value- sector. Projects Approved as at August 20, 2020



Source: AIIB, Citi Research

Citi Global Perspectives & Solutions (Citi GPS) is designed to help our clients navigate the global economy's most demanding challenges, identify future themes and trends, and help our clients profit in a fast-changing and interconnected world. Citi GPS accesses the best elements of our global conversation and harvests the thought leadership of a wide range of senior professionals across the firm.

All Citi GPS reports are available on our website www.citi.com/citigps



Technology at Work v6.0
The Coming of the Post-Production Society
June 2021

Future of Money
Crypto, CBDCs and 21st Century Cash
April 2021

Bitcoin
At the Tipping Point

March 2021

Electric Vehicle Transition

February 2021

The Global Art Market and COVID-19
Innovating and Adapting
December 2020

The Holistic Case for Investment in Girls

October 2020

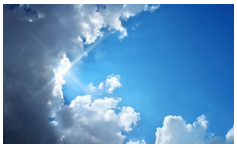
Negative Interest Rates
Where Is the Real Limit to Cheap Money?
July 2020

Technology at Work v5.0
The New Normal of Remote Work
June 2020

Hard to Abate Sectors & Emissions
The Toughest Nuts to Crack
May 2021

Systemic Risk
Systemic Solutions for an Interconnected World
April 2021

Financing a Greener Planet
Volume 1
Volume 2
February 2021



Investment Themes in 2021

January 2021

Education: Fast Forward to the Future

October 2020

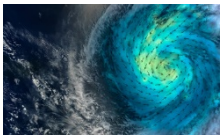
Closing the Racial Inequality Gaps

September 2020

ePrivacy & Data Protection
Data Privacy & its Influence on AI Ethics, Competition & Tech Evolution
July 2020

5G and Mobile Operators
Is Virtual Becoming Real?
April 2020

Closing the Loop on Global Recycling
Finding a Global Solution to the Patchwork of Recycling
February 2020



Building a TCFD With Teeth
What the Markets Need to Price Climate Risk
February 2020

Experiential Commerce
A Brave New World
January 2020

Corporate Finance Priorities 2020
January 2020

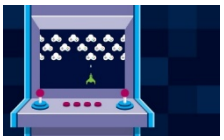
The Global Art Market
Drivers of Evolution

December 2019

Digitizing Governments
The Journey to Enacting a Digital Agenda
October 2019

Energy Darwinism III
The Electrifying Path to Net Zero Carbon
September 2019

Factory of the Future
Flexible, Digitized, and Sustainable
July 2019



Video Games: Cloud Invaders
Bracing for the Netflix-ization of Gaming
June 2019

Bank X
The New New Banks
March 2019

Disruptive Innovations VII
Ten More Things to Stop and Think About
February 2020

Banking the Next Billion
Digital Financial Inclusion in Action
January 2020

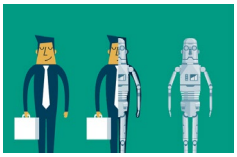
Investment Themes in 2020
January 2020

Car of the Future v4.0 – 2020 Update
The Race for the Future of Networked Mobility
January 2020

Education: Power to the People
Exploring Opportunities for Private Capital in Education
November 2019

Electric Aircraft
Flightpath of the Future of Air Travel
September 2019

For Better Or Worse, Has Globalization Peaked?
Understanding Global Integration
August 2019



Technology at Work v4.0
Navigating the Future of Work
June 2019

Managing Cyber Risk with Human Intelligence
A Practical Approach
May 2019

2019 Corporate Finance Priorities
January 2019

IMPORTANT DISCLOSURES

This communication has been prepared by Citigroup Global Markets Inc. and is distributed by or through its locally authorised affiliates (collectively, the "Firm") [E6GYB6412478]. This communication is not intended to constitute "research" as that term is defined by applicable regulations. Unless otherwise indicated, any reference to a research report or research recommendation is not intended to represent the whole report and is not in itself considered a recommendation or research report. The views expressed by each author herein are his/ her personal views and do not necessarily reflect the views of his/ her employer or any affiliated entity or the other authors, may differ from the views of other personnel at such entities, and may change without notice.

You should assume the following: The Firm may be the issuer of, or may trade as principal in, the financial instruments referred to in this communication or other related financial instruments. The author of this communication may have discussed the information contained herein with others within the Firm and the author and such other Firm personnel may have already acted on the basis of this information (including by trading for the Firm's proprietary accounts or communicating the information contained herein to other customers of the Firm). The Firm performs or seeks to perform investment banking and other services for the issuer of any such financial instruments. The Firm, the Firm's personnel (including those with whom the author may have consulted in the preparation of this communication), and other customers of the Firm may be long or short the financial instruments referred to herein, may have acquired such positions at prices and market conditions that are no longer available, and may have interests different or adverse to your interests.

This communication is provided for information and discussion purposes only. It does not constitute an offer or solicitation to purchase or sell any financial instruments. The information contained in this communication is based on generally available information and, although obtained from sources believed by the Firm to be reliable, its accuracy and completeness is not guaranteed. Certain personnel or business areas of the Firm may have access to or have acquired material non-public information that may have an impact (positive or negative) on the information contained herein, but that is not available to or known by the author of this communication.

The Firm shall have no liability to the user or to third parties, for the quality, accuracy, timeliness, continued availability or completeness of the data nor for any special, direct, indirect, incidental or consequential loss or damage which may be sustained because of the use of the information in this communication or otherwise arising in connection with this communication, provided that this exclusion of liability shall not exclude or limit any liability under any law or regulation applicable to the Firm that may not be excluded or restricted.

The provision of information is not based on your individual circumstances and should not be relied upon as an assessment of suitability for you of a particular product or transaction. Even if we possess information as to your objectives in relation to any transaction, series of transactions or trading strategy, this will not be deemed sufficient for any assessment of suitability for you of any transaction, series of transactions or trading strategy.

The Firm is not acting as your advisor, fiduciary or agent and is not managing your account. The information herein does not constitute investment advice and the Firm makes no recommendation as to the suitability of any of the products or transactions mentioned. Any trading or investment decisions you take are in reliance on your own analysis and judgment and/or that of your advisors and not in reliance on us. Therefore, prior to entering into any transaction, you should determine, without reliance on the Firm, the economic risks or merits, as well as the legal, tax and accounting characteristics and consequences of the transaction and that you are able to assume these risks.

Financial instruments denominated in a foreign currency are subject to exchange rate fluctuations, which may have an adverse effect on the price or value of an investment in such products. Investments in financial instruments carry significant risk, including the possible loss of the principal amount invested. Investors should obtain advice from their own tax, financial, legal and other advisors, and only make investment decisions on the basis of the investor's own objectives, experience and resources.

This communication is not intended to forecast or predict future events. Past performance is not a guarantee or indication of future results. Any prices provided herein (other than those that are identified as being historical) are indicative only and do not represent firm quotes as to either price or size. You should contact your local representative directly if you are interested in buying or selling any financial instrument, or pursuing any trading strategy, mentioned herein. No liability is accepted by the Firm for any loss (whether direct, indirect or consequential) that may arise from any use of the information contained herein or derived herefrom.

Although the Firm is affiliated with Citibank, N.A. (together with its subsidiaries and branches worldwide, "Citibank"), you should be aware that none of the other financial instruments mentioned in this communication (unless expressly stated otherwise) are (i) insured by the Federal Deposit Insurance Corporation or any other governmental authority, or (ii) deposits or other obligations of, or guaranteed by, Citibank or any other insured depository institution. This communication contains data compilations, writings and information that are proprietary to the Firm and protected under copyright and other intellectual property laws, and may not be redistributed or otherwise transmitted by you to any other person for any purpose.

IRS Circular 230 Disclosure: Citi and its employees are not in the business of providing, and do not provide, tax or legal advice to any taxpayer outside of Citi. Any statements in this Communication to tax matters were not intended or written to be used, and cannot be used or relied upon, by any taxpayer for the purpose of avoiding tax penalties. Any such taxpayer should seek advice based on the taxpayer's particular circumstances from an independent tax advisor.

NOW / NEXT

Key Insights regarding the future of Natural Gas

COMMODITIES

The market for natural gas is currently driven by long-term contracts and oil-equivalent pricing. / The market of the future will likely be dominated by one of two dominated either by (1) supply-led mechanisms such as "soft coordination" or export curtailments or (2) demand-led mechanisms including increased spot-based pricing.

SUSTAINABILITY

In the green economy, commodities such as oil and coal are on a trajectory to become stranded assets based on their carbon emissions. / With significantly less greenhouse gas emissions than other fossil fuels, natural gas can be combined with technology, such as carbon capture, utilization and storage (CCUS) to create a nearly zero-carbon emissions.

URBANIZATION

As the global trend continues to be towards increased urbanization, power needs will continue to increase to cities. / Natural gas facilities for power generation have a much smaller footprint than generation from solar or wind.