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Examining Cracks in Emerging Asia's LNG-to-Power Value Chain

Governments and Investors Face Upfront Project Barriers and Long-term Financial Risks

Executive Summary

Over the past two years, spot market prices for liquefied natural gas (LNG) in Asia have hit all-time lows, followed by record highs. As a result of the exorbitant prices experienced during winter 2020 and fall 2021, price-sensitive LNG importers in emerging Asia have faced a choice between buying unaffordable, economically burdensome cargoes or imposing energy and power shortages on households and businesses. These wild price fluctuations have demonstrated—perhaps more clearly than ever before—the immense challenges that highly volatile, US dollar-denominated LNG markets present for nearly every emerging Asian energy market.

Yet, many forecasting agencies anticipate the region will be one of the largest growth markets for LNG demand globally over the next two decades. The combination of declining domestic gas reserves in the region and high GDP growth expectations has spawned an overwhelming pipeline of proposed LNG-related infrastructure projects, including import terminals and LNG-fired power plants. Project sponsors and the broader LNG industry have framed LNG as a cheap, reliable "bridge fuel" to help countries reduce coal consumption.

For many project developers and countries, LNG is a bridge that may never be built.

For many project developers and countries, however, LNG is a bridge that may never be built. Fundamental project, country, and financial market constraints in emerging Asia are likely to significantly reduce the pipeline of feasible LNG-related projects and prevent rapid, sustained growth in regional LNG demand. While a minority of projects may be completed, capital for LNG investments will be highly limited due to credit risks and the fundamental lending capacity of the project finance market.

This report examines the proposed pipeline of LNG-to-power projects in seven countries: Vietnam, Thailand, the Philippines, Cambodia, Myanmar, Pakistan, and Bangladesh. It begins by discussing the broader macroeconomic and financial risks associated with an increasing dependence on imported LNG. These risks are summarized in the table below.

Key Economic and Financial Risks of LNG Imports			
Risk		Description	Country Examples*
1)	Commodity Price Volatility	The inherent volatility of global gas markets significantly impacts delivered gas and power prices.	Thailand, Bangladesh, Pakistan
2)	Foreign Exchange Volatility	US dollar-denominated commodity charges expose consumer prices to macroeconomic impacts, mostly felt through inflation.	Thailand, Bangladesh, Pakistan
3)	Higher Power Tariffs for End-Users	In markets that pass through fuel price fluctuations to end-users, imported LNG can raise final gas and power tariffs.	Thailand, Philippines, Cambodia
4)	Higher Government Subsidy Burdens	In subsidized markets, government entities must pay for fuel price fluctuations via additional national budget allocations.	Vietnam, Bangladesh, Pakistan, Myanmar
5)	Declining Economic Competitiveness of Domestic Industries	Higher fuel costs can raise industrial operating costs, hurting regional competitiveness. Country commitments to LNG may force multinationals with corporate sustainability targets to relocate.	Thailand, Bangladesh, Vietnam
6)	Fuel Supply Insecurity	Disruptions in global LNG trade can cause gas shortages. High prices can force buyer countries out of spot markets, causing fuel shortages. Even countries with long-term supply contracts face fuel shortages if exporters opt to divert cargoes into higher-priced spot markets.	Bangladesh, Pakistan, Thailand
7)	Imported Fossil Fuel Lock-in Limits Renewables Penetration	Fixed LNG offtake volumes and power plant capacity payments can cause long-term dependence on imported fossil fuels, limiting each country's ability to benefit from declining renewables energy costs.	Emerging Asia
8)	Stranded Asset Risk for LNG-to-Power Investments	Volatile global fuel prices and pentration of low-cost renewables can limit utilization of LNG-to-power assets. Renewed growth in domestic gas production can reduce the need for LNG import assets.	Emerging Asia
9)	Limited Project Financing Available for Fossil Gas Assets	The supply of money for a given market is not endless. Commercial banks have prudential lending limits, which can limit their exposure to just one or two infrastructure projects.	Emerging Asia
10)	Growth of Sustainable Investing Makes Long-term LNG Financing Unreliable	Cross-border financiers--including MDBs and bilateral development institutions--are under increasing pressure to support global decarbonization and sustainable development.	Emerging Asia

Note: Boxes with a '' include only countries that currently import LNG, though all emerging Asian countries may be susceptible to these risks in the future.*

This report then provides a more realistic assessment of future LNG developments in the region based on:

- **Project fundamentals**, such as whether an individual project is needed, has positive location attributes, makes use of technology that makes both economic and technical sense, and yields the least risk in execution.

- **Country market fundamentals**, such as the efficacy of energy sector planning, governance and regulation, gas and power pricing regimes, and economic outlook. These factors affect the timely and balanced completion of projects and the willingness of financiers to fund them.

- **Financial market constraints.** A final screen of the remaining projects considers limitations on the bank lending market. The valuation of remaining projects following project and country fundamentals assessment is compared to country credit risk and bank market risk appetite. The project finance market is significantly constrained in terms of available funds due to prudential factors like individual country lending limits, sector exposure, and single-project limits. The evolution of sustainable lending and investing principles may also constrain the availability of funds.

Based on this screening analysis, IEEFA finds that 62% of LNG import terminal capacity and 61% of gas-fired power capacity is unlikely to be built due to unfavorable fundamental project and country-level factors.

This significantly reduced pipeline of LNG-related infrastructure proposals is likely to shrink even further, since projects will still have to compete for project finance capital, which is severely constrained by prudential limits on banks' exposure to individual countries, sectors, and borrowers. **After comparing the valuation of feasible projects to credit risk appetite in the commercial lending sector, IEEFA found that 20% of the remaining portfolio may need to shift its financial close date due to lending market capacity constraints, and 6% of power plant capacity is unlikely to be realized due to funds being unavailable.**

Based on a fundamental screening, 62% of LNG import terminal capacity and 61% of gas-fired power capacity is unlikely to be built.

In total, within the study countries, only 38% of the announced LNG terminal capacity and 34% of the announced gas-fired power capacity have the potential to be built.

These remaining projects will still have to navigate each country's unique market, financial, and regulatory risks. These risks are examined in the seven countries included in this report. Two longer case studies for Vietnam and Bangladesh are also provided, as these country markets exemplify many risks relevant to other countries in the region. The former is expected to begin importing LNG at scale in the near term, while the latter has recently started importing LNG and is seeking incremental supply growth. The combination provides clear insights into the causes and consequences of increasing reliance on imported gas for power generation.

Other key lessons regarding the potential economic impacts and market implications of LNG in the region include:

- **LNG price volatility demonstrated over the past two years can raise the cost of power delivered to nearly US$300 per megawatt-hour (MWh)**, well above the long-term, all-in levelized cost of several recent auction-based solar PV projects completed in the region, which have yielded prices below US$40/MWh. Moreover, natural gas cost represents only the short-run marginal cost of operating the LNG-fired power plant. In contrast, the comparative solar tariffs cover both capital and operating costs over the project lifetimes.

- **LNG importers must also consider foreign exchange volatility in final tariffs for LNG-based power generation.** A +/-20% change in fuel prices, combined with a +/-10% change in foreign exchange rates, can increase or decrease the final LNG-based power price by US$18-30/MWh. In the highest capital and operating cost scenarios for gas-fired power plants, the final power price can increase from US$115/MWh to over US$145/MWh when accounting for unfavorable fluctuations in fuel prices and foreign exchange rates.

- **Prudential limits on the commercial banking sector constrain banks' exposure to individual countries, sectors, and projects.** Bank lending limits can be hit within a single transaction for large infrastructure investments like LNG-to-power projects. Project finance banks' risk appetite for countries in emerging Asia is constrained by the opportunity cost incurred by requirements to provide higher capital adequacy to back those loans. Taken together, these limitations make project finance more expensive and less available, leading to funding competition amongst LNG project sponsors. Further, such constraints foster *de facto* regional competition for debt capital, creating winners and losers amongst country markets.

- **Multilateral development banks (MDBs) are unlikely to save the day for LNG projects, while bilateral financing will be limited to specific sponsors.** MDBs are often mandated to perform strictly catalytic roles in country-level economic development, so lending rules typically limit their participation in private sector transactions to 25% of project cost—even if their lending policies permit funding fossil fuel projects. Bilateral development institutions increasingly provide larger shares of project transactions—at times 50% or more—but such funding is typically limited to their domestic corporations' investment projects and equipment suppliers.

Multilateral development banks are unlikely to save the day for LNG projects.

- **The lending capacity of domestic banks in sub-investment grade markets is extremely limited.** Most large projects must still rely on a high level of cross-border financing.

- **About 99% of the proposed gas-fired power capacity in the region uses combined cycle gas turbines (CCGTs) rather than more operationally flexible open cycle gas turbines (OCGTs).** Technical and contractual inflexibilities, such as LNG take-or-pay requirements and rigid power capacity payments, may hinder the penetration of low-cost domestic renewables.

- **Gas and power subsidies exacerbate offtaker credit risks, undermining the bankability of LNG contracts.** An increased reliance on higher-priced LNG, along with additional import infrastructure costs, may undermine the fiscal credibility of state-owned gas companies or require asking government exchequers for support. Greater fiscal strain from LNG costs may mean that state-owned companies face a higher risk of defaulting on payments to LNG suppliers and terminal operators.

- **A resurgence of domestic gas production in the region presents a major stranded asset risk for LNG import infrastructure.** What is often framed as "energy shortages" in emerging Asia can be more accurately described as inefficient pricing regimes that limit domestic gas production and artificially inflate the need for imported LNG.

- **Nascent regulatory regimes and preexisting gas and power monopolies may thwart private sector involvement in national LNG-to-power value chains.** Decision-making and market planning in both the gas and power sectors can often be reactionary and prone to quick changes based on market developments. LNG-to-power investors in the region have been repeatedly stonewalled by changing regulations and resistance from legacy monopoly players.

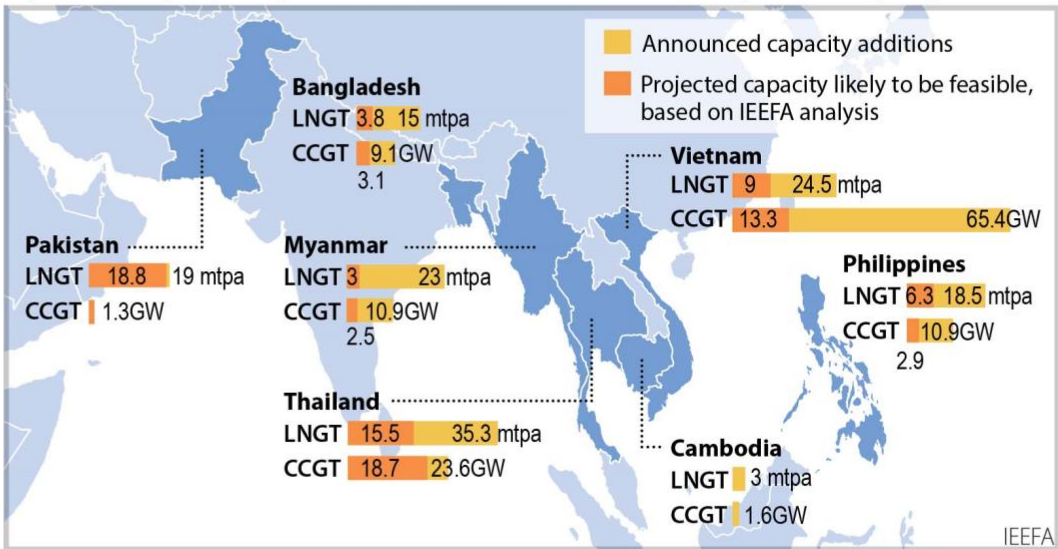
The report proceeds as follows: Section 1 details the impact of LNG imports on national value chain economics, focusing on the effect of fuel and foreign exchange rate volatility on delivered LNG and LNG-based power prices. Section 2 provides the methodology for IEEFA's analysis of the proposed pipeline of LNG-related infrastructure investments in emerging Asia. Section 3 provides the results of IEEFA's assessment of project and country fundamentals and details the extent to which the pipeline of investment proposals in the region shrinks following basic feasibility factors. Section 4 outlines the specific market risks facing each of the seven countries included in the report and discusses several risks common to multiple countries throughout the region. Section 5 discusses the

A resurgence of domestic gas production in the region presents a major stranded asset risk for LNG import infrastructure.

financial limitations of the commercial project finance lending market, and constraints on the participation of MDBs and bilateral development institutions. The remaining two sections of the report are dedicated to case studies of the gas and power sectors in Vietnam and Bangladesh, both of which demonstrate many of the market and financial risks associated with a buildout of LNG infrastructure.

Emerging Asia: Few LNG-to-Power Projects Are Feasible

Per IEEFA's analysis, Pakistan and Thailand may expand LNG imports despite cost. Most announced LNG projects in Vietnam are unrealistic, while the Philippines will struggle to expand LNG imports beyond replacement capacity. Bangladesh wrestles with LNG economics amidst power overcapacity.



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Introduction: Is LNG-to-Power a Development Path Forward or a Dead End?

As countries around the world set more ambitious decarbonization targets and commit to reducing coal consumption, emerging markets in Asia are searching for new energy sources to fuel economic growth. Many countries aim to improve self-reliance, sustainability, and affordability—measured in both environmental and fiscal terms.

However, old habits die hard. The default arrangement for electric service expansion has historically been to connect large, centralized generation facilities to distant communities via high-voltage transmission lines. Coal-fired power plants have served as the backbone to these grid compositions, but many countries now perceive LNG as the most convenient replacement fuel.

Asia currently has a total of 539 million tonnes per annum (mtpa) of LNG receiving terminal capacity, with an additional 41 mtpa expected online in 2022.[1] Further downstream, Asia's electric power industry has built 77 gigawatts (GW) of gas-fired turbines over the past decade, split almost evenly between independent power producers (IPPs) and state-owned enterprises (SOEs). Given the region's increasing attraction to natural gas, investors have proposed greatly increasing these figures within the next 5-7 years.

China is set to become the world's largest LNG importer this year, while India is rapidly adding capacity. Behind these giants, the remainder of emerging Asia is collectively expected to be the largest growth market for gas.[2] [3] [4] LNG imports are already underway in Bangladesh, Pakistan, and Thailand, and large amounts of additional capacity have been announced. Tentative first imports commenced in Myanmar. A first terminal is under construction in Vietnam, with large fleets of terminals and power plants proposed over the coming decade. Decisions to import gas are ongoing in Cambodia and the Philippines.

This report examines the proposed pipeline of LNG-to-power projects in seven countries: Vietnam, Thailand, the Philippines, Cambodia, Myanmar, Pakistan, and Bangladesh.[5] In total, these countries are reviewing proposals for 139 mtpa of LNG

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[1] International Gas Union. World LNG Report 2021. June 3, 2021. Numbers refer to the entire region.

[2] International Energy Agency. Gas 2020. June 2020.

[3] Wood Mackenzie. How Asia changed the global LNG market in the space of a year. April 21, 2021.

[4] S&P Global. Asia is key growth area for US LNG even after 2020 impacts, market experts say. February 11, 2021.

[5] Indonesia and Malaysia are not a primary focus of this report given their unique position as major LNG exporters in the region, and the fact that neither country is anticipated to become a significant net importer of LNG until the late 2030s-2040s. Both countries face a geographical disconnect within their borders between gas producing and gas consuming regions, meaning that shares of indigenously produced LNG have historically been used to meet rising domestic demand. However, both state-owned oil and gas utilities—Petronas (Malaysia) and Pertamina (Indonesia)—will face financial incentives to continue exporting LNG to realize higher margins in

terminal capacity and 99GW of gas-fired power capacity. Each of these investments could entail significant long-term financial commitments, as well as national economic impacts, for each country market over the next several decades.

Amidst this buildout of LNG infrastructure, the global LNG market is currently experiencing the most dramatic, disconcerting commodity price volatility the industry has ever seen. Prices have skyrocketed from their lowest point in May 2020 to their highest levels ever in October 2021.[6] As wealthier buyers in Europe and Northeast Asia competed for cargoes before and during the winter 2021 buying season, price-sensitive buyers in emerging Asia have been priced out of the market,[7] resulting in gas shortages, fuel switching, and power outages for households and businesses.[8] [9]

LNG prices have skyrocketed from their lowest point in May 2020 to their highest levels ever in October 2021.

The global gas industry paints LNG as a solution, not a problem. Proponents argue today's price volatility means the world needs more LNG, not less: Boosting LNG supply can keep prices low and stable, while boosting demand can help countries transition away from dirty coal to cleaner, cheaper renewable energy sources.[10] [11]

High expectations regarding emerging Asia's LNG demand growth over the coming decades are arguably backed by macro-fundamentals driving energy demand and

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global markets, given low regulated prices in their respective domestic markets. Should domestic production continue to decline, or LNG export sales contracts are not renewed, both countries could meet a higher share of domestic gas demand with indigenous LNG supplies, prolonging their shift to net LNG importing status. For more on gas developments in Indonesia, please see: IEEFA. The economics of Indonesia's diesel power plant to gas conversion plan are problematic. August 26, 2021.

[6] In September 2021, the Platts' Japan-Korea Marker (JKM), the benchmark spot price for Asia, reached US$34.47 per million British thermal unit (MMBtu)—higher than the previous record of US$32.50 set in January 2021. In October, the JKM price for November delivery spiked higher to US$56.326/MMBtu, surpassing US$50 for the first time ever.
Reuters. Asian LNG spot price reaches record high of $34.47/mmbtu - Platts data. September 30, 2021.
S&P Global. JKM LNG prices surge past $50/MMBtu mark as European gas crisis intensifies. October 6, 2021.

[7] Reuters. COLUMN-LNG's massive spot prices in Asia are paid by few buyers: Russell. October 7, 2021.

[8] See, for example: The News. Gas deficit looms large as PLL fails to procure eight LNG cargoes. October 12, 2021.

[9] S&P Global. Bangladesh to tap into costlier Asian spot LNG market amid acute energy shortages. September 20, 2021.

[10] S&P Global Platts. LNG seen having key role in energy transition despite record high prices. October 5, 2021.

[11] Bloomberg. Gas Leaders Urge More Investment in Supply to Avert Shortages. November 2, 2021.

upstream realities that are putting pressure on supplies. Domestic natural gas production is declining in several South and Southeast Asian countries, and the gas industry hopes that LNG imports can extend the life of existing gas infrastructure. GDP growth is driving higher levels of energy demand, leaving a growing gap between the supply and demand for natural gas. Moreover, some governments are excited by the potential for foreign investment and potential opportunities to rapidly expand energy supplies.

Domestic natural gas production is declining in several South and Southeast Asian countries.

One key question, however, remains unanswered: *Will current gas crises and the growing gas supply-demand gap in emerging Asia materialize into actual investments in LNG-to-power infrastructure?*

To date, very few proposed projects in the markets covered by this study have successfully navigated the gauntlet of financial, market, and regulatory risks necessary to secure financial close. It appears many developers, including companies with little experience in developing highly complex LNG-to-power projects, have underestimated the extent of these risks they may be required to bear. Many expected the financing of LNG projects to mirror earlier coal negotiations, in which governments and SOEs were often willing to provide generous contractual terms, long-term fuel and power offtake commitments, and government guarantees necessary to appease financiers' concerns and shield investors from market risks.

On the contrary, however, the LNG market has moved in the opposite direction. Government buyers have sought to limit their exposure to inflexible power and gas capacity payments and fuel price volatility. At the same time, the LNG industry has moved toward shorter, more flexible contracts for buyers aiming to improve energy self-sufficiency by reducing long-term obligations to purchase imported fuels.

Without the protection of long-term contracts to shelter industry proponents from project risks, the buildout of LNG infrastructure in emerging Asia has proceeded at a sluggish pace. Despite repeated industry claims about the ability of LNG to rapidly ameliorate countries' energy woes at only a small fuel premium, the development of LNG infrastructure in Asia to date has been a slow, expensive endeavor.

Some countries in the region, such as the Philippines, Vietnam, Cambodia, and—to a certain extent—Myanmar, have little to no existing midstream gas infrastructure, despite decade-long efforts to support regasification and pipeline projects. Countries that have successfully built new LNG infrastructure, such as Bangladesh and Pakistan, often struggle to realize the purported economic benefits of doing so. Volatility in global LNG markets has saddled countries with unaffordable fuel prices. In subsidized markets, this has forced governments to confront the dilemma of either paying higher energy subsidies or halting LNG imports altogether.[12] In markets where fuel prices are passed down to gas and power end-users, LNG volatility can raise household and industrial energy prices, potentially hindering economic growth in price-sensitive countries.

Many emerging Asian markets have historically produced their own gas at low negotiated prices, and their businesses and residential consumers have factored such artificially low charges into their own economics. Greater reliance on international price benchmarks could lead to substantially higher fuel prices. In subsidized markets, this could mean bloated government energy subsidies that hurt the fiscal credibility of SOEs. Project sponsors without government guarantees will be exposed to the creditworthiness of public counterparties—an often unacceptable risk proposition for international financial institutions.

Volatility in global LNG markets has saddled countries with unaffordable fuel prices.

In more market-based gas and power pricing regimes, in which price fluctuations are passed to end-users, LNG-fired power plants may face greater competition from the continually decreasing costs of renewable resources. LNG importers could face unexpected competition in the event of a resurgence in domestic gas production. An often-overlooked feature of emerging Asian markets is that many countries have significant domestic gas reserves. However, failed pricing negotiations between government agencies and upstream gas companies have repeatedly inhibited new field developments. Perceived "energy shortages"[13] in the region can often be more accurately described as inefficient pricing of domestic resources, which has distorted the "need" for imported fuel.

The result is a glaring Catch-22: To support LNG demand growth in price-sensitive markets, governments will likely face higher subsidy payments to maintain historically low prices for consumers. Higher subsidies, however, can negatively impact the creditworthiness of state-owned agencies purchasing LNG and LNG-derived electric power, hindering the bankability of contracts needed for LNG-to-power developers to secure financing. On the other hand, governments may consider passing fuel costs through to the end consumer by raising gas and power tariffs. However, pushing highly volatile, foreign currency-linked energy prices through to consumers will have inflationary impacts, undermining purchasing power and possibly eroding the global competitiveness of domestic industries.

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[12] S&P Global. Bangladesh to tap into costlier Asian spot LNG market amid acute energy shortages. September 20, 2021.
[13] Wall Street Journal. Behind the Energy Crisis: Fossil Fuel Investment Drops, and Renewables Aren't Ready. October 17, 2021.

Meanwhile, countries that commit to long-term imports of a volatile, dollar-denominated commodity may risk currency depreciation during times of high fuel prices. Eroding exchange rates would constrain a nation's purchasing power and make it more difficult to service existing dollar-denominated loans or obtain new ones. This could make any LNG build-out self-limiting: early investments could make it harder to finance new projects.

Countries that commit to long-term imports of a volatile, dollar-denominated commodity may risk currency depreciation during times of high fuel prices.

This report closely examines the current proposed pipeline of LNG-related infrastructure in emerging Asia. It considers the viability of each proposed investment in the region on a project, country, and financial level. It assesses the implications of increased reliance on imported LNG on national value chain economics.

The report concludes that the pipeline of feasible LNG-related projects in the region is likely to narrow significantly when considering the myriad financial, market, and country risks that must be overcome. While a minority of projects may be completed, capital for LNG investments will be highly constrained due to credit risks and the fundamental lending capacity of the project finance market. Whether project sponsors can find other sources of capital in sufficient quantity and on reasonable terms remains to be seen. Financiers must be willing to fund long-term carbon-emitting energy sources and be attracted to the economic value propositions assets pose. Even then, fiscal-economic constraints may limit the size and number of foreign currency-denominated energy payment commitments each emerging Asian country can realistically support.

The combination of these factors is likely to reduce the scope of regional LNG developments. The most powerful determinant, however, may be the LNG-to-power value chain's all-in, lifecycle cost, which is not cost competitive with wind or solar power on a US dollars per megawatt-hour (MWh) basis. In the long run, the gap between expensive, recurring LNG costs and the downward price trajectory of renewables will become even starker.

Section 1: The Impact of LNG on National Energy Value Chain Economics

The inherent volatility of LNG can have detrimental impacts on both the energy sector and macroeconomic growth in developing countries. Highly volatile, US dollar-denominated LNG markets present immense challenges for nearly every emerging Asian economy. Most countries in the region have energy tariff regimes rigidly fixed on a set schedule, meaning that when prices rise, direct government subsidies compensate fiscal imbalances and/or by forcing state utilities into deficit operations.

On the other hand, when price changes are passed through to end-users, such as in the Philippines, consumers bear price swings directly. If prices increase significantly, price-sensitive end-users may decide electricity is unaffordable, impacting economic productivity. Energy-intensive industries may experience higher operating costs, putting them at a competitive disadvantage to businesses in other countries with lower energy costs.

In both pass-through cost and subsidized markets, the citizens of importing countries pay—either through consumer tariffs or national budget subsidies. This limits the funds that importing countries can devote to equally pressing needs. Governments may borrow money to help pay for energy supplies, but loans are repaid from public budgets. Public budgets in many emerging Asian countries depend on continued economic growth to fill their coffers. Stable and sustainable energy costs are therefore critical to economic planning and prosperity.

Highly volatile, US dollar-denominated LNG markets present immense challenges for nearly every emerging Asian economy.

The inherent volatility of LNG undermines these desired outcomes. Over the past two years, LNG spot market prices have swung from below US$2/MMbtu to over US$56/MMBtu,[14] placing LNG importing countries like Bangladesh and Pakistan in the unenviable position of having to decide between purchasing such economically harmful cargoes or going without energy altogether.[15] [16] By increasing reliance on imported LNG, countries expose their economy and—if subsidies are abundant—their national budget to global commodity markets risks.

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[14] LNG Prime. Asian spot LNG price hits new record. October 7, 2021.

[15] Reuters. Bangladesh pays record prices for two LNG cargoes for Oct -sources. October 8, 2021.

[16] India, which is about 40% exposed to spot LNG prices for its import capacity, is turning away cargoes. S&P Global Platts. High LNG prices put spotlight on India's exposure to global gas market volatility. October 15, 2021.

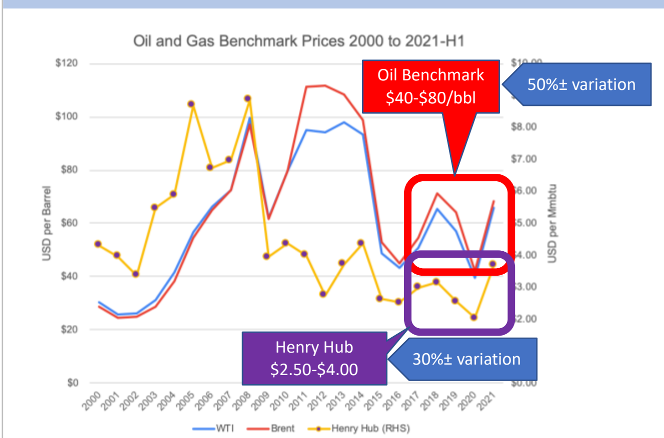
In addition to fuel price volatility, fossil fuel importing countries must also consider volatility in foreign exchange markets since imported fuel costs are denominated in US dollars. Domestic currency fluctuations against the US dollar could lead to rapid inflationary pressures, potentially devastating the economic sustainability of emerging Asian economies, reminiscent of the 1997 Asian financial crisis. Therefore, it is critical to understand the pass-through costs of the LNG-to-power value chain, not only regarding fuel price volatility but also in terms of fluctuating exchange rates and inflationary pressure.

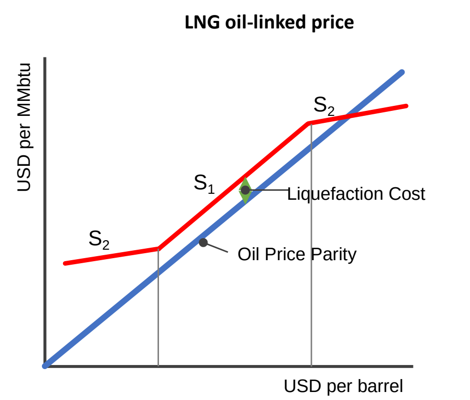
Dynamics of the Gas-to-Power Value Chain in Asia

LNG prices are volatile in both spot markets and via long-term oil-linked supply contracts. LNG purchasers often seek long-term LNG supply contracts to limit their exposure to volatile spot market prices. The formulas used in such contracts, while more stable, do not result in fixed prices. Figure 1 below illustrates that prices of Henry Hub and oil-linked LNG supply contracts have fluctuated 30% and 50%, respectively, over the past five years.[17] As of November 2021, both benchmarks were at the high end of the range. LNG purchases in emerging Asia, therefore, require significant allocations of foreign currency.[18]

Figure 1: Standard LNG Long-Term Pricing Formulas

World oil price linked formula:	$Price_{LNG}$ = (**$Price_{Oil}$** x Slope) + Liquefaction Charge where S_1 = 11%-15%, $S_2 \cong$ 50% S_1
US natural gas market linked formula:	$Price_{LNG}$ = (115% x **Henry Hub**) + (Liquefaction Charge x [1+**inflation**])



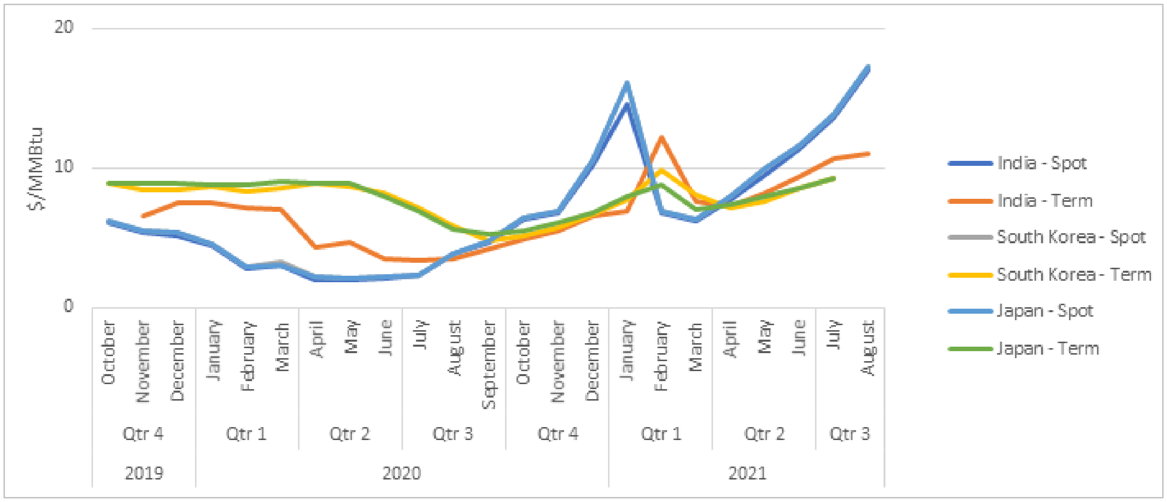


Sources: Oil and gas historic benchmark prices. 10-year Henry Hub, Brent Crude and West Texas Intermediate Crude. Price formulas: The Pricing of Internationally Traded Gas – LNG Pricing in Asia, Flowers, A and Liao, J., Oxford Institute for Energy Studies, 2012. Graphics: IEEFA.

[17] While clearly, Figure 1 shows that commodity prices have been even more volatile over the wider timeframe presented, the majority of emerging Asia's LNG import decisions have been framed within the context of the last five years of market activity.
[18] The typical Henry Hub pricing formula provides for an additional adjustment in the form of an index to US-based inflation.

Spot market prices are far more volatile. As shown in Figure 2 below, Asian spot LNG prices since the beginning of 2021 have dramatically diverged from prices paid under long-term contracts. Countries that have opted for a larger percentage of their supplies from spot markets—in particular Bangladesh and Pakistan—have been forced to decide between paying exorbitant prices or going without energy at all.

Figure 2: Comparison of Long-term LNG Contract versus Spot Cargo Prices in Major Asian Markets



Source: Adapted from IHS Markit LNG Analytics.
Note: Spot prices are delivered specifically to the ports of Dahej (India), Sakai (Japan), and Incheon (South Korea).

Emerging Asian countries primarily consume natural gas in the power sector, meaning that increasing reliance on LNG can have significant knock-on effects on electricity prices. Increases in market-linked gas costs greatly impact the fuel-related costs per megawatt-hour (MWh) cost of electricity, as shown in Figure 3 below. The area graph shows the price of LNG volumes—measured in dollars per million British thermal units (MMBtus)—converted into an electricity price (US$/MWh), based on the conversion efficiency of combined cycle gas turbine (CCGT) power plants, measured in heat rate (Btu/kWh). LNG prices in Figure 3 show free on board (FOB) prices, which do not include shipping or regasification terminal costs. Moreover, the chart only shows the *marginal* fuel costs associated with running the power plant and does not show all-in costs needed for capital recovery, fixed operations and maintenance (O&M), and variable O&M.[19] [20] Long-term LNG contract rates have run between US$7-11/MMBtu over the past few years,

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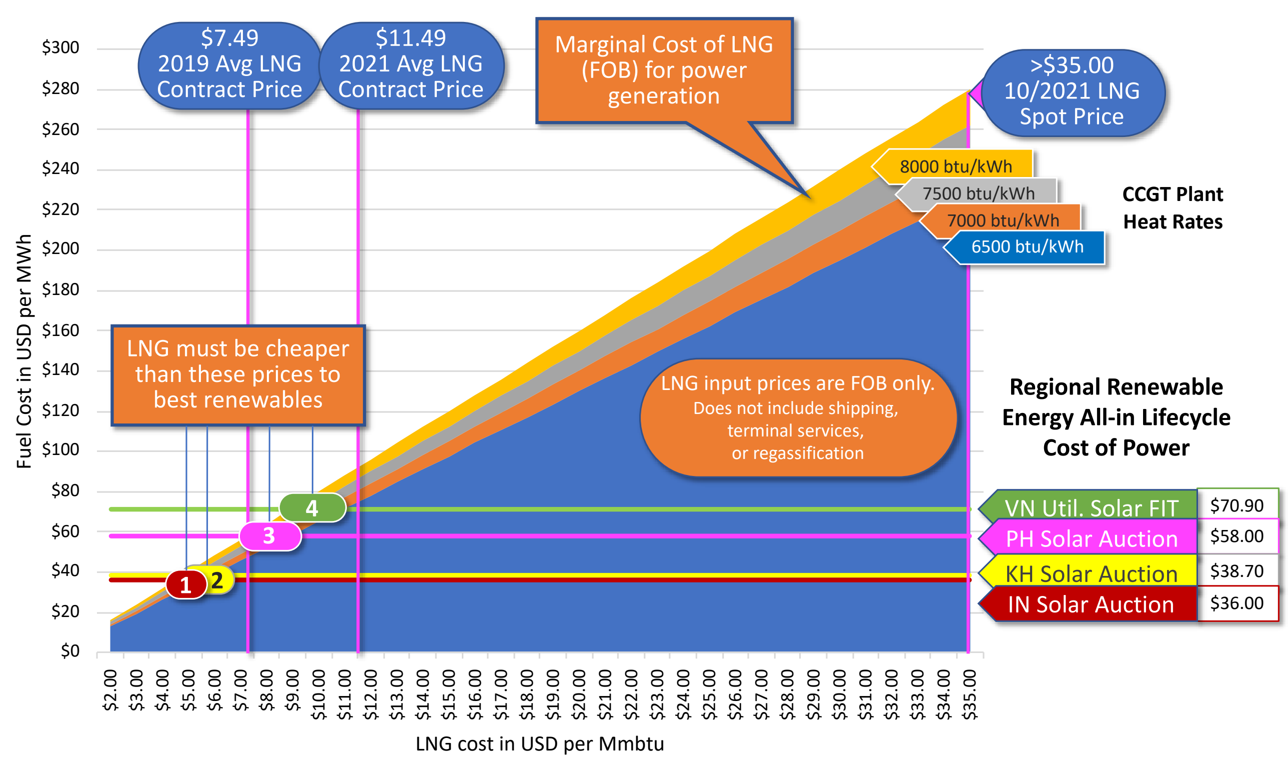
[19] Capital recovery, fixed and variable O&M costs were removed from this figure since these costs may vary significantly from market to market, by scale of plant, or other site-specific or equipment-specific variables. For gas-fired power plants, the fuel cost is the major component of cost in any event; according this presentation serves to provide clarity on with regard to the impact LNG cost has on power production.
[20] Short-run marginal costs (SRMC) represent the tariff that the power plant must earn to recoup only the costs associated with producing one additional unit of power, i.e., fuel costs. Long-run

trending towards the US$10-12 range. Spot rates, meanwhile, have fluctuated much higher, ranging from US$15-35/MMBtu.

Figure 3: Cost of LNG per MMBtu That Would Be Required to Match Renewable Energy LCOE, Using a Range of CCGT Plant Heat Rates



Number	Comparative Renewable Project	LNG FOB price in US$/MMBtu required to match Renewable LCOE	
		@ 8000 Btu/kWh	@ 6500 Btu/kWh
1	India (IN) Solar Auction 3/2021	$4.50	$5.54
2	Cambodia (KH) Solar Auction 2/2019	$4.84	$5.95
3	Philippine (PN) Solar Auction 2/2018	$7.25	$8.92
4	Vietnam (VN) Feed-in Tariff 4/2020	$8.86	$10.91

CCGT = combined cycle gas turbine. FOB = Free on board. FIT = Feed-in-Tariff. LCOE = Levelized Cost of Energy.

Source: LNG-CCGT gas-to-power conversion cost: IEEFA analysis. Heat rate range represents base load operation at the low end of the range (6500 btu/kWh) and load following support at the upper end of the range (8000 btu/kWh). Renewable energy tariff sources: Cambodia: Asian Development Bank. "ADB supported project in Cambodia achieves lowest ever tariff in ASEAN." September 5, 2019. India: The Hindu Business Line. "Four renewable developers declared winners in SECI's 1,200 MW wind power tender." September 2, 2021. Vietnam: Electricity of Vietnam.

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marginal costs (LRMC) represent the all-in price that the power plant must earn to recover all costs associated capacity and energy expenses, i.e., fixed capital costs, as well as fixed and variable O&M.

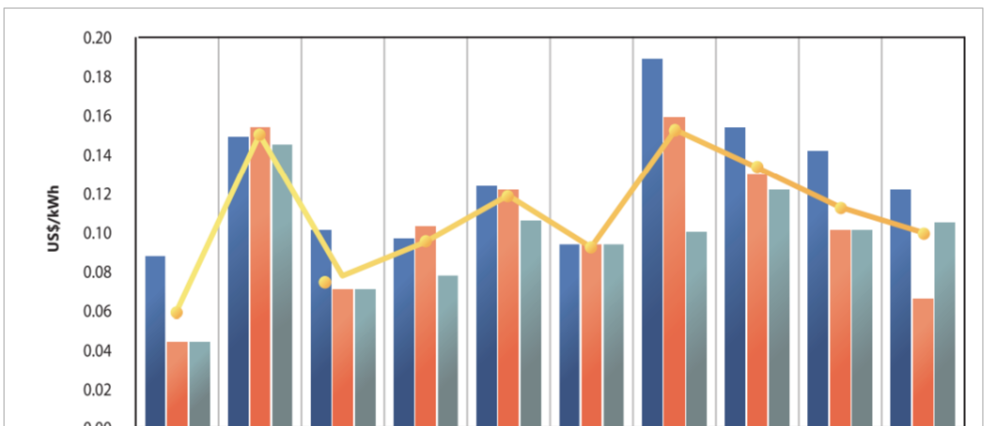
To provide a scale of these LNG costs, Figure 3 also compares the converted LNG fuel cost in US$/MWh to the long-term levelized costs of several solar PV projects completed in the region. The renewable energy cost covers both capital and operating costs over the lifetime of the project. These prices do not change over the life of the power purchase contract. Meanwhile, the natural gas cost shown is only for the *marginal operating cost*, adjusted for both market prices and exchange rates on a regular basis. Accordingly, there is potentially very large energy cost risk for relying on LNG for any country in the region, regardless of the pricing formula.

Tariff Systems

Gas and power pricing regimes in each country determine if ratepayers or taxpayers bear commodity price risks. Nearly all LNG gas sales agreements have pass-through cost mechanisms to the downstream LNG buyers. Subsequently, almost all power purchase agreements (PPAs) for IPPs have pass-through mechanisms on fuel and inflation for variable costs. The entire gas-to-power value chain relies on these pass-through mechanisms for commodity, operation, and investment costs to ensure end users and/or government subsidies pay for the full cost of supply.

Among developing market countries, only Cambodia fully passes through costs to consumers. Countries like Thailand and the Philippines follow closely behind, though with cross-subsidized tariff structures to support energy access to low-income, low-consumption customers. Not coincidentally, end-users in these countries pay among the highest power tariffs in ASEAN (see Figure 4 below). Box 1 below examines the impact of higher energy costs associated with LNG on industries.

Figure 4: Electricity Rates in ASEAN Countries, August 2020

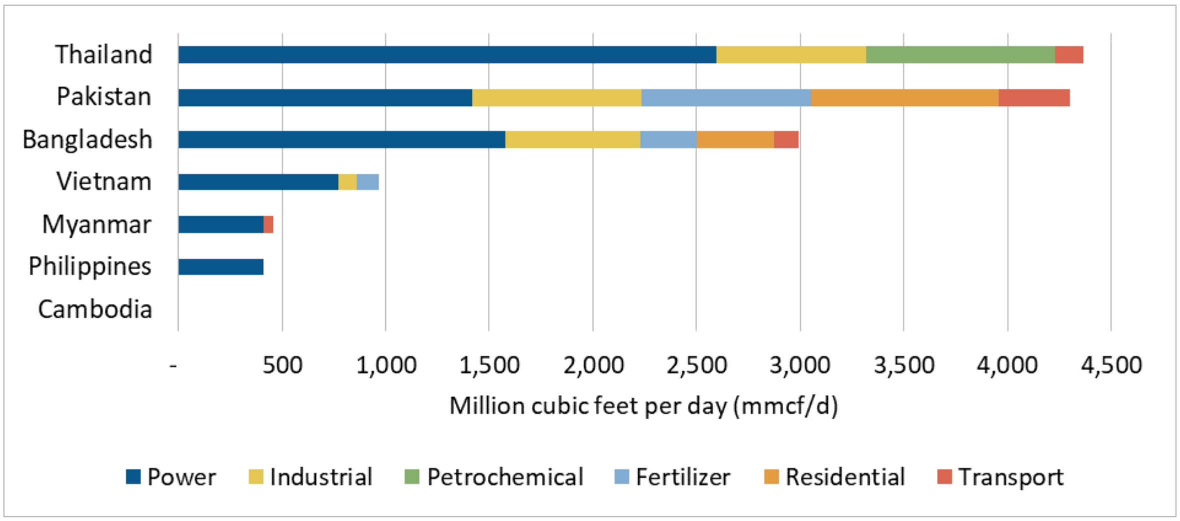


	Brunei	Cambodia	Indonesia	Laos PDR	Malaysia	Myanmar	Philippines	Singapore	Thailand	Vietnam
Residential	0.088	0.149	0.101	0.097	0.124	0.094	0.189	0.154	0.142	0.122
Commercial	0.044	0.156	0.071	0.103	0.122	0.094	0.159	0.130	0.101	0.066
Industrial	0.044	0.145	0.071	0.078	0.106	0.094	0.100	0.122	0.101	0.105
Average	0.059	0.150	0.081	0.093	0.117	0.094	0.149	0.135	0.115	0.098

Source: Philippines Energy Plan (2018-2040).

Thailand passes through energy costs to end-users and consumes more natural gas than any other country in emerging Asia (see Figure 5 below). Therefore, the shift from reliance on domestically produced gas to more expensive imported LNG could have outsized negative repercussions on the Thai economy. Higher input and operating costs may hurt the regional competitiveness of the Thai industrial and petrochemical industries, which consume 17% and 21% of the country's gas, respectively. In addition, the industrial sector accounts for 44% of power demand. Unsurprisingly, Thai industry groups have long argued that greater reliance on imported LNG would hurt regional competitiveness, arguing in favor of energy diversification and investment in new technologies.[21]

Figure 5: Natural Gas Consumption in Emerging Asian Countries (2019)



Source: Compiled from Thailand Energy Policy Planning Office. Energy Statistics. 2020; Bangladesh Hydrocarbon Unit, Energy and Mineral Resources Division. Energy Scenario 2018-19. 2020; Economic Research Institute for ASEAN and East Asia (ERIA). Myanmar Energy Outlook 2040. October 2020; Oxford Institute for Energy Studies. Emerging Asia LNG Demand. September 2020; US Energy Information Administration. Philippines Country Report. November 2020.

By contrast, many countries have fixed tariff regimes adjusted infrequently, which are designed to protect consumers from market price changes. Countries with fixed tariffs also tend to have state-owned vertically integrated utilities, which have some flexibility to bury energy sector inefficiencies and price distortions within their, or their subsidiary, balance sheets. This is fiscally unsustainable for the utility unless the government provides additional budgetary support. Additional budget allocations pass energy costs to the taxpayer, rather than the power consumer.

[21] EnerData. Thailand's gas conundrum. June 19, 2014.

Figure 6: Tariff Regimes in Asian Countries

Countries With Pass-through Energy Price Mechanisms	Countries With Mostly Fixed Tariffs (No/Limited Pass-through)
Japan	India
South Korea	Pakistan
Taiwan	Bangladesh
Thailand	Indonesia
Philippines	Vietnam
Cambodia	Myanmar

Note: Philippines—Pass through refers primarily to customers on the Luzon grid. India—Both the central government and each state has a regulatory authority that sets tariffs for various consumer categories. These adjustments are increasingly governed by formulas but still require the consent of the regulator who accounts for affordability in its decision making.

Box 1: LNG and Industry: Gasifying Countries Into Non-competitiveness?

Some developing country markets in Asia have historically used tariff mechanisms to cross-subsidize residential consumers at the expense of industrial customers. While this approach has been beneficial, it means that industries may bear a larger share of the operating cost increases associated with an increased dependence on expensive imported LNG.

However, the regulatory environment in many countries is not favorable for installations of behind-the-meter power generation sources, particularly renewables. As a result, industries have little choice but to consume higher-priced, higher carbon-emitting energy sources locked in for the long-term. While this is environmentally detrimental, it is also economically harmful for several reasons.

Imagine a multinational company—or a local company that is a supply chain contractor to a multinational—operating in a country that has decided to focus on LNG-based power generation as the primary energy supply. The government also has restrictions on self-generation using renewables. But the multinational, under pressure from its global shareholders, has committed to operating on 100% renewable energy and/or greening its supply chain within a certain timeframe. Rather than creating conditions for the company to meet its commitment, the government is actively erecting barriers. That business then faces a hard decision on whether to continue operating in that country.

Why? First, national energy policy has made it difficult for the company to meet its sustainability commitment, which may be a huge liability for its share price. Inability to meet green targets may also limit the company's growth prospects should it aim to issue green/sustainability-linked bonds.

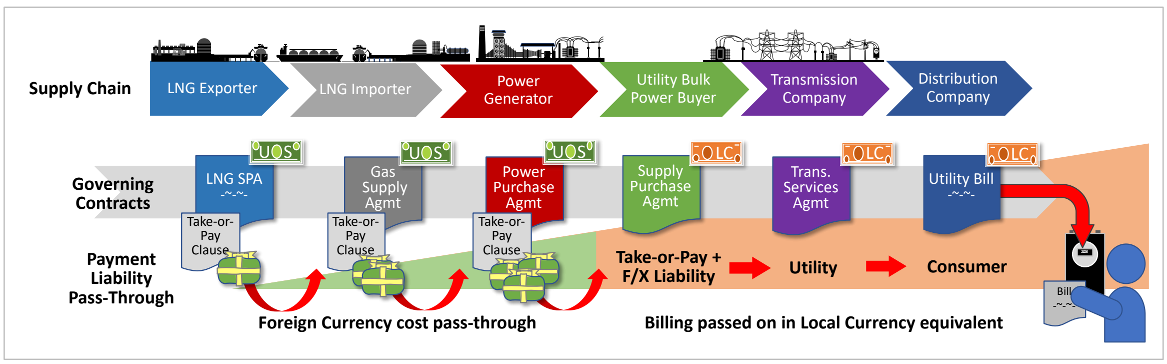
Second, and more fundamentally, even if the company decided to ignore its sustainability mandate, the government's energy supply choices, focused on LNG, have increased energy costs and variability.

Third, the aforementioned cross subsidies add to energy costs. The government's energy supply and pricing choices have increased the company's production costs, making its product less competitive in the global marketplace. Therefore, it is reasonable to expect that the multinational would be willing to shut down and relocate to a more cost- and policy-friendly country, leading to job losses and reducing foreign direct investment. The domestic supply chain partner, experiencing increased production costs, might lose its lucrative relationship with the multinational, leading to layoffs or even bankruptcy.

The Value Chain Creates a Payment Chain

Each component of the LNG-to-power value chain adds to the final cost of power for end-users. Final LNG costs include fuel costs, shipping costs, receiving infrastructure costs, and costs associated with storage or regasification for delivery to the gas transmission system. Final LNG-based electric power prices also include the cost of power generation capacity, transmission, and distribution.[22] Each step in the supply chain is governed by a contract between seller and buyer. Contracts are typically governed by "take-or-pay" clauses, which require the buyer to either take the amount of commodity provided or pay a minimum agreed contractual amount (see Figure 7 below).[23]

Figure 7: LNG-to Power Supply Chain Cost Build-Up to the Consumer



Note: SPA = supply and purchase agreement.

Figure 8 below provides a more detailed build-up of costs for end-users. The build-up analysis is based upon a) the average, long-term contract LNG supply cost for 2019, when LNG was generally less expensive; and b) the average long-term contract LNG prices for 2021, which are significantly higher. The precise costs to

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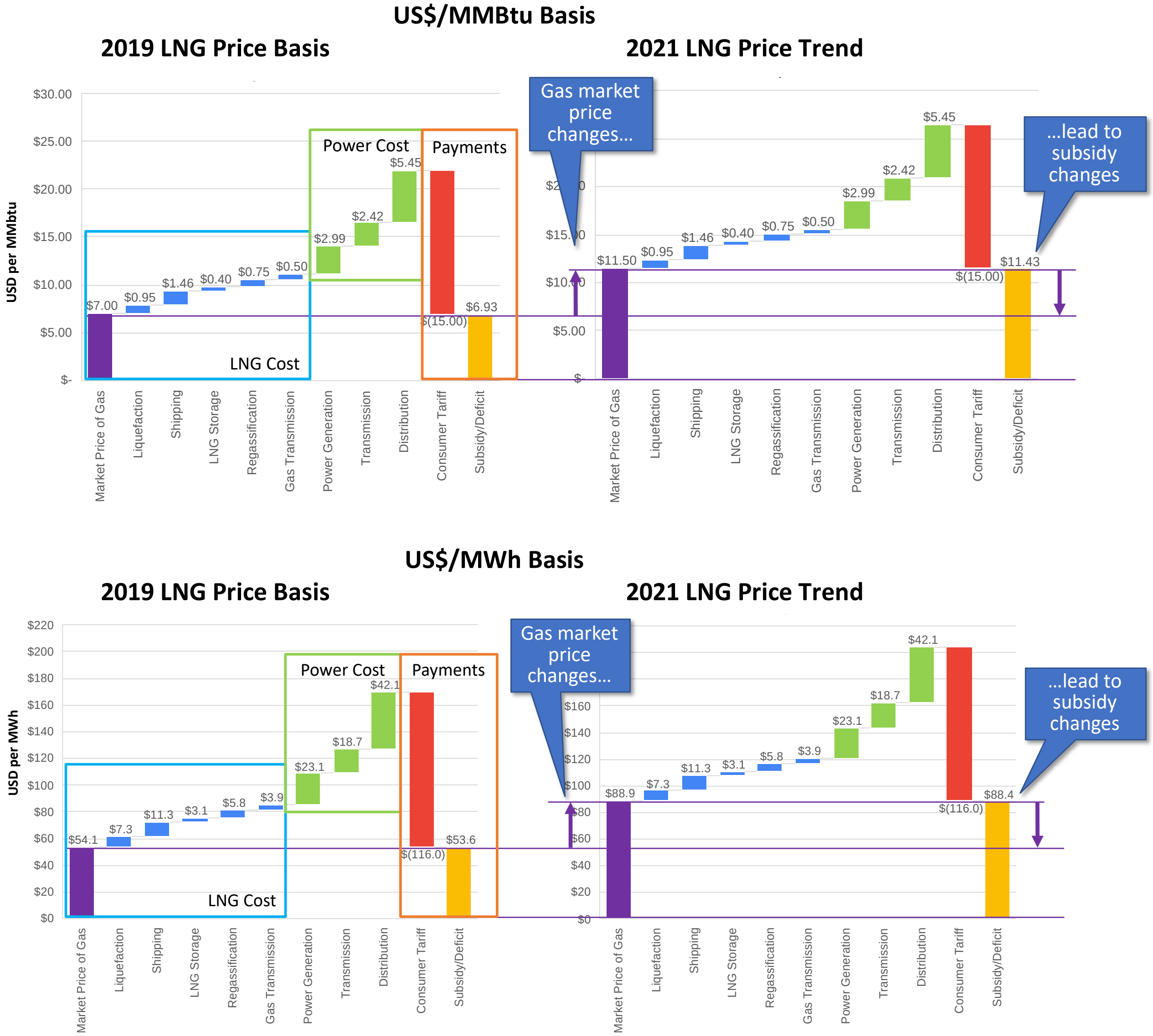
[22] For a more detailed view of each component of the gas-to-power value chain, refer to Appendix A. The annex provides incremental price build ups from the gas field to the consumer, showing a range of prices encountered regionally.
[23] The minimum required payment is meant to cover the investment cost of the supply infrastructure, inclusive of a minimum return on capital.

LNG individual importing markets may vary, but the relative magnitude of the incremental charges reflects the range of charges currently experienced in regional markets. For the convenience of comparison, two sets of charts are provided: one calculated in US$/MMBtu and the other in US$/MWh.

The tariff figure, represented in red in Figure 8, is the blended average of the currently delivered energy tariff from countries in this study. The yellow bar at the far right of each graph represents either the subsidy that governments in fixed tariff markets would have to pay to cover cost changes or, in pass-through tariff markets, the increase in end-user electricity costs.

Fuel price changes are directly passed through to the consumer via regular utility bill adjustments in countries with adjustable tariff mechanisms. As a result, end-users face significant challenges in budgeting for investments in power-intensive equipment and predicting operational costs. In tariff-controlled markets, such as Bangladesh or Vietnam, the burden of price and exchange rate fluctuations ultimately falls on the national budget. Major, rapid price variations can create considerable fiscal budget stress, potentially depriving funds from other vital government programs. As Figure 8 shows, holding all other variables used in this example constantly, a US$4.50/MMBtu change in fuel supply costs nearly doubles the required subsidy to cover the gap or the incremental pass-through cost to consumers.

Figure 8: LNG-to-Power Value Chain Cost Build-up to End Customers, 2019 vs 2021 LNG



LNG Costs

- LNG price is the average of all-Asia pricing, FOB basis. Sources: IHS Markit, IEEFA analysis
- Shipping is the average cost amongst South, Northeast and Southeast Asian destinations from Mideast, Australia, and US Gulf Coast. Source: Capra Energy.
- Regasification and terminal costs are the average of recent FSRU transactions in Pakistan and Bangladesh. Sources: Trade press, Refinitiv deal reporting.

Electricity Costs and Tariff Charges

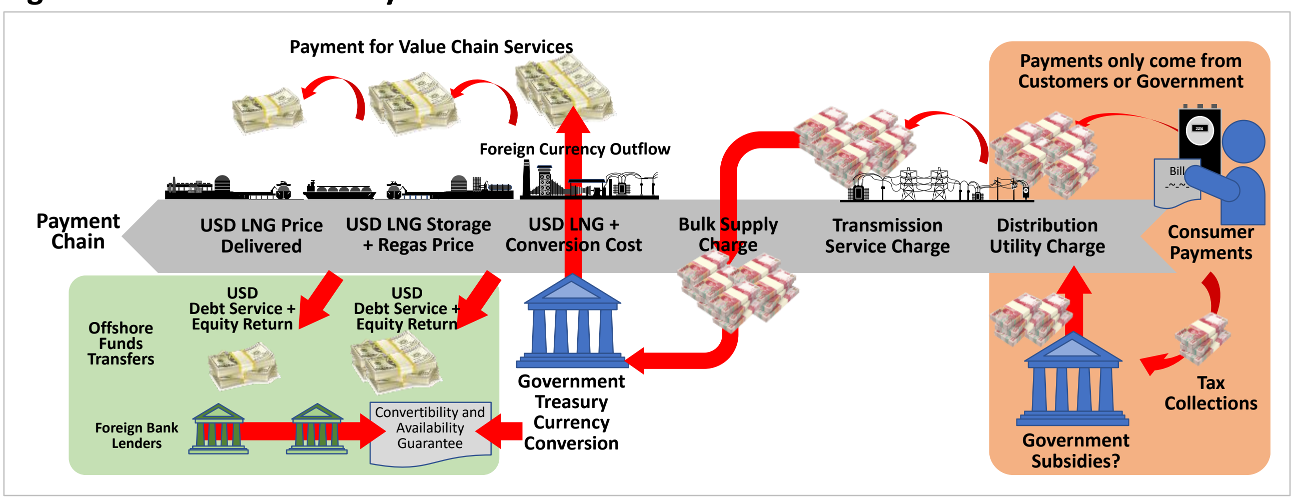
- Transmission and distribution charges are the average for Indonesia, Philippines, and Vietnam. Sources: PLN, Meralco, and EVN reporting.
- Tariff rate is the average of the average system tariff realized in Indonesia, Philippines, and Vietnam. Sources: PLN 1H-2021 investor report, 04 August 2021; Meralco 3Q-2021 investor report; EVN tariff posting, 29 September 2021.

Impacts of Exchange Rate and LNG Fuel Index Price Movements

In addition to commodity price fluctuations, LNG importing countries must also consider volatility in foreign exchange rates. LNG export, shipping, LNG receiving and regasification, and most power generation facility costs are denominated in US dollars.[24] The electricity price is typically converted into local currency once power is delivered to the transmission grid. The total amount of local currency depends on the exchange rate from US dollars that is applicable at the moment of the transaction. This means the power purchaser faces a constantly changing cost in terms of local currency. The volatility of LNG supply costs compounds this uncertainty.

Final energy bills are paid by end-users or the government (see Figure 9). In both cases, tariffs are collected in local currency and must be converted back into US dollars before they flow offshore to commodity suppliers, lenders, and equity investors. Thus, while there may have been a great influx of foreign direct investment capital during the project's inception, there is an ongoing and potentially far larger net exodus of both foreign capital and foreign exchange expenses during operations.

Figure 9: LNG-to-Power Payment Chain



Currency exchange rates can fluctuate significantly each year, materially impacting the final invoice received by governments or consumers. US dollar-denominated capital and commodity-linked charges expose consumer prices to macroeconomic impacts, mostly felt through the inflationary price effects that foreign currency creates. Since November 2020, the average currency volatility was

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[24] The reason for this is that the global LNG markets have priced their supply in US dollars and, for the vast majority of the LNG-to-power infrastructure, the cost of construction and the investment capital—whether debt or equity—is denominated in US dollars. Accordingly, parties involved in the supply chain expect payments back in US dollars.

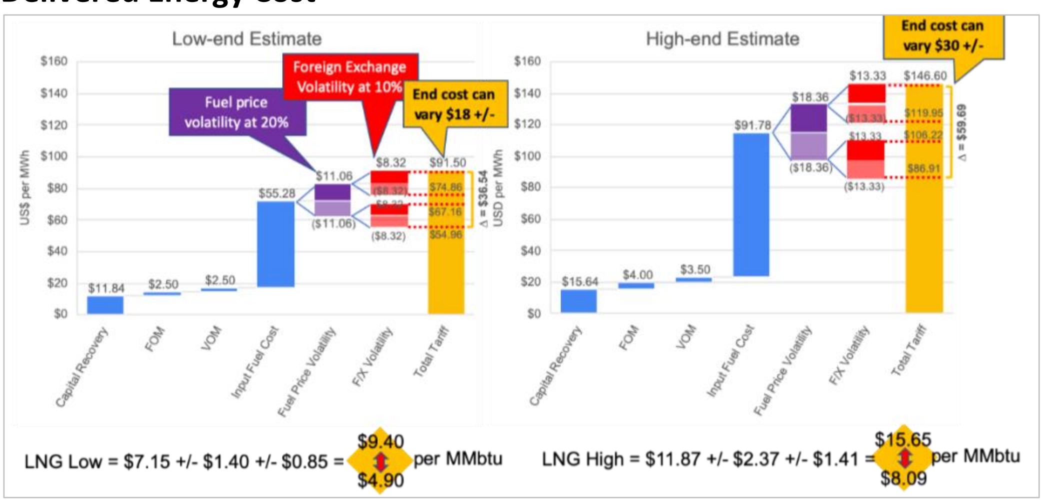
+/-6% in the core Asian markets of this study.[25] Over longer time periods, however, the standard deviation of most of the region's currencies was far larger. For illustration purposes, this study examines the impact of a +/-10% change of exchange rates on all-inclusive energy costs.

Figure 10 below shows the range of delivered electricity prices resulting from input LNG costs and exchange rate variations. To assess the impact of changes in the price of energy delivered to the grid from the LNG-to-power value chain, exchange rate movements were coupled with a fluctuation in the price of LNG. Our analysis looked at a +/-20% change of LNG price (the actual range of LNG price fluctuation over the past two years was considerably greater). As shown previously in Figure 1, oil benchmarks—including dated Brent crude and Japan Crude Cocktail (JCC)—fluctuated +/-50%, while Henry Hub prices varied +/-30%.

Two LNG price scenarios were fed into the gas-to-power value chain to determine the total power cost. First, a "low-end estimate," which assumes a long-term LNG contract locked in at year-end 2019 average price of US$7.15/MMBtu delivered ex-ship (DES).[26] Second, a "high-end estimate," which assumes a long-term LNG contract locked in at year-end 2021 price of US$11.87/MMBtu DES.

Volatility in oil and gas benchmarks applies only to the LNG price. By contrast, foreign currency exchange rate changes apply more broadly to the fuel, capital recovery fee, and fixed operating costs of *both* the LNG import terminal *and* the power generation facility.

Figure 10: Impact of Fuel Price and Foreign Exchange Volatility on Delivered Energy Cost



Source: IEEFA analysis. Refer to Appendix B for assumptions on CCGT plant costs. FOM = Fixed operations and management. VOM = Variable operations and management.

Note: Fuel price and exchange rate parameters are likely to move in tandem, since increases in fuel input costs have inflationary economic impacts.

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[25] Applied 1-year volatility analysis using NYU Stern School V-lab GARCH model.
[26] In contrast to FOB, DES refers to the cost of LNG inclusive of shipping rates to the buyer's destination.

Figure 10 shows that a 20% increase in the fuel basis plus a 10% adverse movement of exchange rates could add US$18-30/MWh to the final power price. Thus, in the low-end scenario, what was originally a delivered energy cost of US$72.12/MWh could end up as high as US$91.50/MWh. In the high-end scenario, these changes from an original delivered energy cost of US$114.92/MWh, up to as high as $145.60/MWh. Of course, the opposite is also true: the all-in cost of energy delivered could drop US$18-30/MWh during buyer-supportive LNG price and exchange rate environments.

Application of the 20% basis change and a 10% exchange rate movement to just the LNG price is shown at the bottom of Figure 10. LNG prices range from US$4.90-9.40/MMBtu in the low-end scenario and from US$8.09-15.65/MMBtu in the high-end scenario.

While optimistic governments tend to look at the potential price-down part of the scenario, there is always an equal and opposite possibility of all-costs trending higher. Sustained high costs can have an inflationary impact. This creates the potential for a negative feedback loop that further erodes exchange rates, leading to even higher costs to the domestic economy.

Section 2: Methodology

Database of Projects

IEEFA compiled a detailed list of proposed gas-fired power projects and import terminal projects throughout the countries included in this study. Data came various research and industry sources and was thoroughly cross-checked.[27] The raw dataset comprised all projects formally announced either by sponsors or government entities. Project details included: project name, location, phasing (if applicable), capacity per phase, project sponsors, completion date estimate,[28] and cost.

For projects proceeding in phases, an assumed two-year gap was applied between the commissioning of each phase, unless project announcements specified otherwise. Subsequent phases benefitted from being labeled as 'brownfield expansions.'

Investment costs for each project were estimated based on a compilation of parameters derived from industry sources, with adjustments made for project- and country-specific factors:

- **Capital cost.** Capital costs were based on the configuration the investor group announced they would use for their project. For LNG terminals, the choice was amongst onshore, FSRU with jetty, or FSRU with offshore mooring. For power projects, cost was adjusted based on the scale of the plant proposed.

- **Greenfield or brownfield.** Brownfield developments benefited from a reduced capital cost due to leveraging existing site infrastructure.

- **Scale factor.** Smaller projects have a higher per-unit cost than larger-scale projects.

- **Market adjustment factor.** An adjustment was made to overall cost based on historical performance of EPC contractors in delivering projects in each country market, which could cover propensity for projects encountering delays, cumbersome permitting requirements, opaque or delayed customs procedures, etc.

Appendix E provides details of each of the key parameters used for cost build-up and assessment.

[27] Sources used to compile the database included: Global Energy Monitor; Refinitiv Infrastructure 360, IJ Global, and S&P Global/Platts. The status of individual projects was corroborated and updated from numerous industry trade journals, local and international news reports, government sector reporting, and directly from corporate announcements.
[28] Commercial operations date estimates were updated per latest industry news reports, government regulatory approvals, and/or sponsor announcements.

The Screening Process

From the raw list of project data, adjustments were applied to identify projects likely to proceed based on an assessment of project fundamentals, country-related factors, and financial market factors. Each of these screening factors is discussed in more detail below.

Project Fundamentals

The first screening illustrated whether projects had the potential to be fundamentally sound, based on answers to the following questions:

- How does the proposed size and timing of project roll outs mesh with demand? Can the project be phased? Does phasing impact feasibility?
- Where are projects located? Are they near demand centers?
- What is the proposed scale and technical configuration of the project? How will those impact project economics?
- Is there nearby infrastructure such as ports, pipelines, or transmission lines?
- Are there competing projects near the proposed project? Are all projects justified from a demand perspective in that region?
- What is the track record of proponents undertaking investments? Have they previously implemented projects of similar size and characteristics? Do they have established relationships with project finance banking institutions?

Country Market Fundamentals

As a further part of the fundamentals screen process, an additional set of screening factors was applied, examining the proposed project within the country context. These market fundamental factors affect the timely and balanced completion of projects and the willingness of financiers to fund them.

- What is the current state of development of natural gas and the electric power sectors in the country? Are there competing sources of energy, existing or potential?
- How many infrastructure projects of similar size, scope, and cost have been financed in the past ten years? How long did those transactions take to close? What were the profiles of investors and lenders in those projects? What types of terms were negotiated?
- How has the country's currency been performing in the global market?
- What is the current sovereign credit rating? What is the current market perception of sovereign risk?

Other country-level factors considered included:

- **Efficacy of Energy Sector Planning.** Lack of objectivity and opacity in system planning leads to proposed investment pipelines that appear removed from economic and fiscal reality. Such distortions can originate from favoritism to one solution over another, incentives from foreign governments or investors to secure deals, limited understanding of the full chain of economic and fiscal impacts, and even potentially corrupt elements within selection processes.

- **Governance and regulation.** Highly subsidized tariff regimes may inflate demand beyond economically justifiable levels. Investors may seek government guarantees and backstops to account for fuel price fluctuations and other risks without a robust cost pass-through mechanism. Such guarantees can detract from a country's ability to close multiple projects consecutively. Moreover, regulatory failure to approve timely tariff adjustments or reimburse duly incurred costs can hurt transaction prospects.

Highly subsidized tariff regimes may inflate demand beyond economically justifiable levels.

- **Economic outlook and stability.** Economic growth conditions affect the ability and willingness of a national government to pay for large-scale investment in energy infrastructure. Endemic subsidies have distorted demand and private investment decisions, making it difficult for governments to rebalance the energy equation. Taking on larger and longer amounts of foreign currency denominated liabilities, coupled with large foreign currency denominated imported fuel costs, creates the potential for economy-wide destabilization during negative economic cycles.

Financial Market Constraints

A final screen was applied to consider the limitations of the project finance lending market, which is often constrained in terms of available funds due to prudential factors such as individual country lending limits, sector exposure, and single-project limits. The rapidly evolving nature of sustainable lending and investing principles may also constrain the availability of funds to certain categories of energy sector investments, as a growing number of financial market participants aim to minimize or eliminate support for all forms of fossil-fueled energy. However, for purposes of this analysis, only prudential market constraints were applied.

An overview of lending market fundamentals is discussed in **Section 6**, with a detailed treatment of the matter presented in **Appendix B**. The end result of applying this market lending capacity screen is that, particularly for mid-to-lower credit rating markets, there may be a limit to total number and size of deals that can be completed. In some cases, that constraint may be in place for consecutive years.

Section 3: Assessment Results

Headline Numbers

From 2021 to 2030, proposed capital investments in emerging Asia of US$110 billion would, if realized, yield 139 mtpa of LNG import capacity and nearly 99GW of gas-fired power generation capacity. Based on IEEFA's analysis, fewer than half of proposed investments may ever progress on project fundamentals alone, leaving a prospective US$45 billion worth of LNG-related projects—51 mtpa of LNG terminal capacity and 42 GW of power generation—to compete for financing. Figure 11 below illustrates how far portfolios were cut, both in LNG receiving terminals and gas turbine projects.

Figure 11: Aggregate Gross and Net Potential LNG-to-Power Portfolios (2021-2030)

		Gross Announced Projects	After Fundamental Screening		After Financing Constraints	
			Net Result	% of Gross	Net Result	% of Gross
Total Proposed Investment	US$mn	$109,390	$42,375	39%	$37,690	34%
LNG Receiving Terminals	mtpa	139.1	52.6	38%	52.6	38%
	US$mn	$21,660	$8,400	39%	$8,400	39%
Power Plants	GW	98.7	38.3	39%	33.2	34%
	US$mn	$87,730	$33,975	39%	$29,290	33%

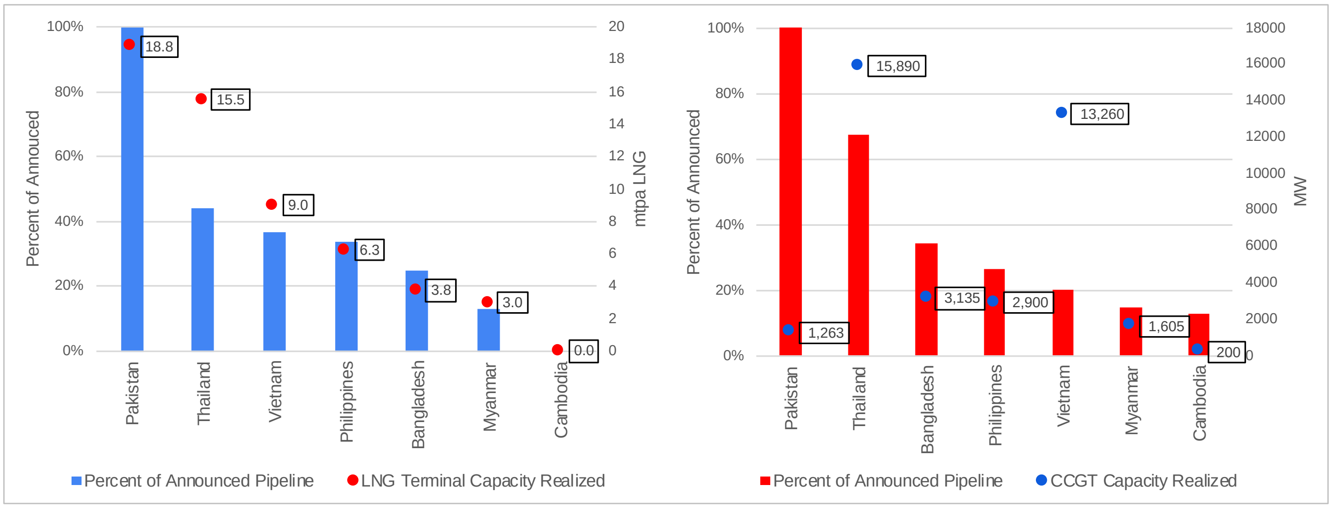
Source: IEEFA analysis.

As shown in Figure 11 above, overall, only 38% of LNG terminal capacity and 39% of power project capacity is feasible based on project and country fundamentals. Figure 12 provides a country-wise breakdown of the impact of screening on announced LNG and power projects as well as a cumulative expected capacity development across the countries of study.

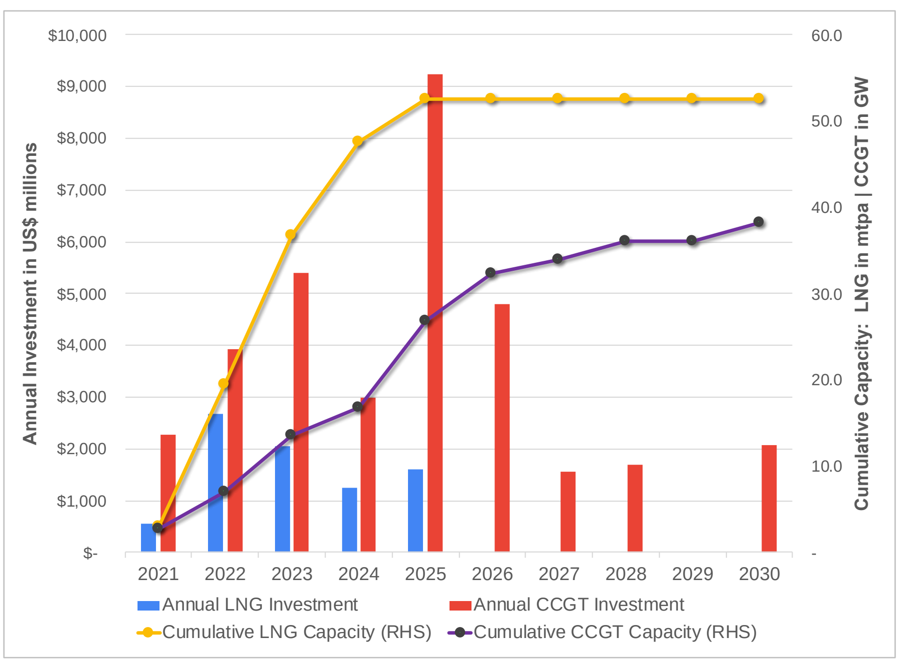
Figure 12: Project Fundamentals Screening Results

LNG Terminal Capacity 2021-2030
Percentage of Announced and Capacity Possible

CCGT Capacity 2021-2030
Percentage of Announced and Capacity Possible



LNG Terminal and Gas-fired Power Plants
Annual Investment and Cumulative Capacity Added



Source: IEEFA analysis.

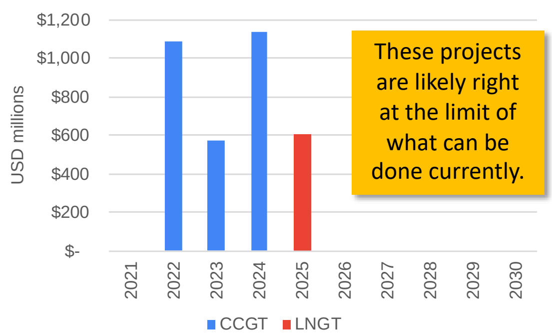
After considering fundamental project and country-level factors, IEEFA compared the project lending capacity available for each country market with the total dollar value of funding sought, and the concentration of that funding demanded year-to-year. These figures were then compared to country credit risk and bank market risk appetite. Financial market considerations led to a further 5% reduction in power projects in our study, to a level of 34% of that which has been announced.

Country Assessments

Country-level summaries of the aggregate assessments in Figure 12 appear below.[29]

Bangladesh

Projected Feasible Investment in LNG and CCGT



	CCGT	LNGT
Investment	$2,793	$603
Capacity	3135 MW	3.8 mmt

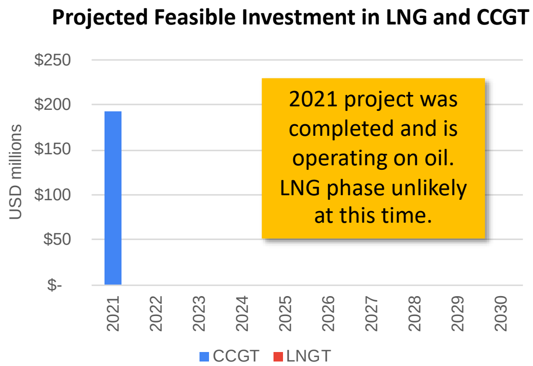
	Investment (US$mn)	Capacity
LNG Terminals		
Announced	$2,234	15 mtpa
IEEFA net projected	$603	3.8 mtpa
Projected / Announced	27%	25%
Power Generation		
Announced	$8,802	9,135 MW
IEEFA net projected	$2,793	3,135 MW
Projected / Announced	34%	34%
Total Investment		
Announced	$10,436	
IEEFA net projected	$3,396	
Projected / Announced	33%	

Bangladesh has engaged in a power generation investment spree over the last several years, spurred on by bilateral largess in coal-fired power projects. Domestic and foreign partners have also created the first LNG import terminal. With an additional land-based LNG terminal under development, downstream investors aim to add incremental CCGT projects to the grid. IEEFA estimates that the more moderate sized CCGT plant investments adjacent to established brownfield sites are more likely to succeed, rather than multi-billion-dollar, multi-phase integrated LNG-to-power projects.

Bangladesh is reaching its saturation point for power generation capacity. Current estimates indicate a medium-term demand for power near 20,000 megawatts (MW) by 2025. After the completion of currently under construction coal, nuclear, and gas-fired power plants, the country could have an additional 36GW of capacity. Therefore, there is little justification for new plant additions of any type in the foreseeable future.[30]

[29] These country assessments are proprietary to IEEFA. Each country covered in this paper has detailed case studies that address energy sector development issues and their attendant economics. The first two of these case studies—Bangladesh and Vietnam—appear after Section 4 of this paper. Case studies on the remaining countries will be made available periodically over time.
[30] A detailed case study of the LNG, natural gas, and power situation in Bangladesh is presented after Section 4.

Cambodia



	CCGT	LNGT
Investment	$193	--
Capacity	200 MW	-

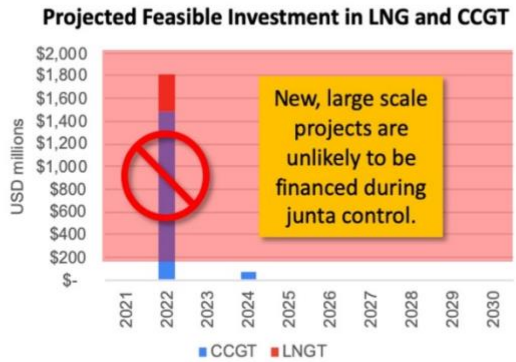
	Investment (US$mn)	Capacity
LNG Terminals		
Announced	$334	3 mtpa
IEEFA net projected	$0	--
Projected / Announced	0%	0%
Power Generation		
Announced	$1,431	1,600 MW
IEEFA net projected	$193	200 MW
Projected / Announced	14%	13%
Total Investment		
Announced	$1,756	
IEEFA net projected	$193	
Projected / Announced	11%	

In mid-2021, private investors commissioned the 200MW Kandal HFO-fired power plant with intentions to add a second 200MW phase, at which point they would convert both plants to run on LNG. Earlier 2021, financing closed on a Chinese-sponsored, bilaterally funded 700MW coal-fired power plant in Sihanoukville, slated for completion in 2024. Between these projects, and some smaller projects proposed, incremental power demand will largely be satisfied over the medium term.

Unless there is a major shift in economic growth or fiscal stability, IEEFA's analysis sees Cambodia's LNG-to-power pipeline cut from announcements by 100%, with no gas-fired power generation being developed.

Although a 3mtpa FSRU tied to the 1,200MW CCGT project has been announced, it is unlikely to materialize. The credit guarantee requirements of an LNG-to-power value chain investment of this size, combined with the government's credit demands of the Sihanoukville coal-fired project, would likely preclude the LNG investment. Due to scale, the Kandal facility could not support a large LNG import terminal on its own.

Myanmar



	CCGT		LNGT	
	Pre-Coup	Post-Coup	Pre-Coup	Post-Coup
Investment	$1,557	$73	$335	$0
Capacity	1605 MW	75 MW	3.0 mmt	0 mmt

	Investment (US$mn)	Capacity
LNG Terminals		
Announced	$3,527	23 mtpa
IEEFA net projected	$335	3 mtpa
Projected / Announced	10%	13%
Power Generation		
Announced	$9,940	10,915 MW
IEEFA net projected	$1,557	1,605 MW
Projected / Announced	16%	15%
Total Investment		
Announced	$13,467	
IEEFA net projected	$1,892	
Projected / Announced	14%	

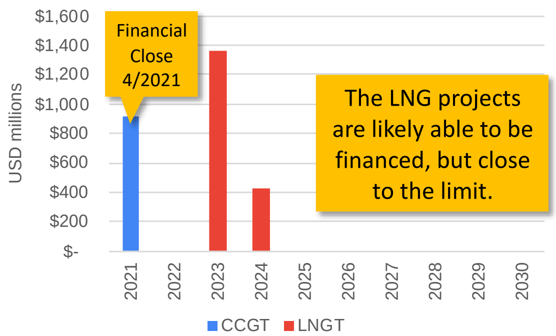
Note: The numbers above represent potential investment should the political environment stabilize and international players reconsider investing in Myanmar.

Myanmar's first wave of LNG-fired investments began operations in the second half of 2020, centered around the Thilawa Industrial Park. A 125,000m3 FSRU is anchored at the Yangon River-based port under a 15-year contract. Completion of the 475MW Thaketa and 350MW Thanlyin gas-fired power projects has spurred the first tentative LNG imports. The plan was to greatly increase downstream generation capacity through the addition of a 1,250MW CCGT power plant at Thilawa, however, those plans came to a screeching halt upon the advent of the military-led coup in February 2021.

Given the current military rule in Myanmar, IEEFA does not see any major projects going forward due to governments and international investors boycotting support for the regime. Only bilateral deals with China or perhaps Thailand may proceed, but only under specific circumstances. Should political stability return to Myanmar, the table above indicates the prospective, narrowed pipeline of projects that could advance. At this time, however, investment is likely to be zero.

Pakistan

Projected Feasible Investment in LNG and CCGT



	CCGT	LNGT
Investment	$914	$1,792
Capacity	1263 MW	18.8 mmt

	Investment (US$mn)	Capacity
LNG Terminals		
Announced	$1,893	19.8 mtpa
IEEFA net projected	$1,792	18.8 mtpa
Projected / Announced	95%	95%
Power Generation		
Announced	$859	1,263 MW
IEEFA net projected	$914	1,263 MW
Projected / Announced	106%	100%
Total Investment		
Announced	$2,752	
IEEFA net projected	$2,705	
Projected / Announced	98%	

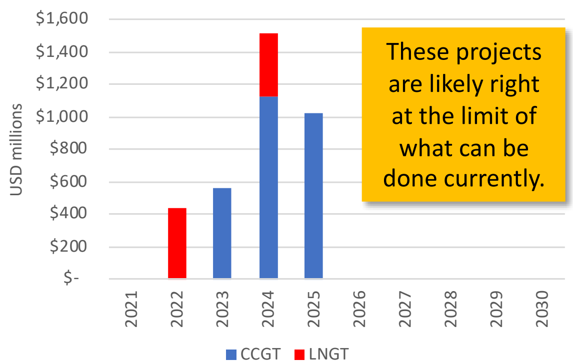
Pakistan has considerable and diversified demand for LNG, given its history of domestic gas production. To remedy declining domestic production, the country has turned toward LNG imports to make up demand-supply gaps. Based on information from IEEFA's database, three additional FSRU projects are slated to move ahead and enter service over late 2022 to 2024. More import projects have also been announced. The total of these projects could add between 14-19mtpa of LNG import capacity.

While there appears to be sufficient demand for additional LNG, the biggest issue facing the energy sector is whether the country can afford cargoes. Pakistan's gas sector economics suffer from a distorted and cross-subsidized pricing regime that favors fertilizer production and domestic consumption with highly discounted pricing. This has created wasteful consumption patterns. Moreover, there are large quantities of unaccounted for gas flowing from the transmission and distribution system. While Pakistan could require additional imports of LNG to supply existing and incremental demand, it is unclear at this time where sufficiently guaranteed revenues will come from to back these US dollar-denominated purchases.

One CCGT power project reached financial close during 2021 and will proceed to implementation. Three import projects are currently in the financing stage and four have construction permissions in place from the government. Construction will likely occur despite LNG pricing challenges and Pakistan market credit quality struggles.

The Philippines

Projected Feasible Investment in LNG and CCGT



	CCGT	LNGT
Investment	$2,709	$838
Capacity	2900 MW	6.3 mmt

	Investment (US$mn)	Capacity
LNG Terminals		
Announced	$2,879	18.5 mtpa
IEEFA net projected	$838	6.3 mtpa
Projected / Announced	29%	34%
Power Generation		
Announced	$9,557	10,900 MW
IEEFA net projected	$2,709	2,900 MW
Projected / Announced	28%	27%
Total Investment		
Announced	$12,437	
IEEFA net projected	$3,547	
Projected / Announced	29%	

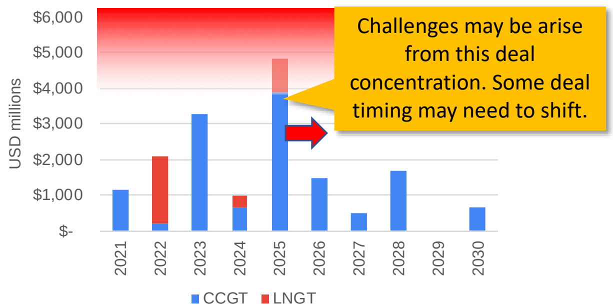
The Philippines' domestic natural gas production from the Malampaya gas field is dedicated to five geographically clustered CCGT plants. But Malampaya is in a state of terminal decline, with production projected to end this decade. As such, the country aims to replace Malampaya production with LNG.

The Philippines has roughly 3,460MW of gas-fired power generation capacity, which could require up to 5mtpa of LNG import capacity to continue operations. This volume could be handled by one—maybe two—import projects. To justify the 18.5mtpa of proposed LNG import capacity, downstream sources of demand would need to be created from scratch. The country has no existing gas transportation or distribution infrastructure outside of the few kilometers onshore in Batangas Bay.

On the power generation side, new coal-fired power plants have been commissioned in the past several years that have satisfied incremental power demand growth. New sources of renewable energy have also provided additional supplies. Domestic conglomerates invested in existing CCGT capacity are attempting to expand gas-fired power capacity and scale up LNG import capacity. IEEFA assumes one additional CCGT plant with attendant LNG important capacity may be developed.

Thailand

Projected Feasible Investment in LNG and CCGT



	CCGT	LNGT
Investment	$13,557	$3,129
Capacity	15890 MW	15.5 mmt

	Investment (US$mn)	Capacity
LNG Terminals		
Announced	$6,257	35.3 mtpa
IEEFA net projected	$3,129	15.5 mtpa
Projected / Announced	50%	44%
Power Generation		
Announced	$19,889	23,576 MW
IEEFA net projected	$13,557	15,890 MW
Projected / Announced	68%	67%
Total Investment		
Announced	$26,146	
IEEFA net projected	$16,686	
Projected / Announced	64%	

Thailand has benefited from substantial domestic gas production from the Gulf of Thailand and a large incremental supply boost from offshore Myanmar. Until 2011, those two sources combined to supply the country with 47 Billion cubic meters (Bcm) of natural gas in 2020. Now, LNG imports are ramping up to augment those sources.

Natural gas accounts for 53% of total power generation. That number will grow even higher, as 6,000MW of CCGT capacity was commissioned in mid-2020. Another 6,000MW of capacity has reached financial close and is under construction for completion between late 2023-2024. At the same time, Thailand has developed a large and growing petrochemical industry that relies on natural gas as a feedstock. Over 20% of annual gas demand is dedicated to petrochemical processing.

Thailand's domestic gas fields have entered terminal decline, with an estimated 5-7 years of supply remaining at their current high production rates. Accordingly, Thailand began augmenting its domestic supplies with modest LNG imports in 2011. In 2020, imports reached 7.5mtpa.[31] Declining domestic production, coupled with incremental natural gas demand growth, means Thailand could require an additional 20-25mtpa of import capacity by 2030. Accordingly, numerous state-owned and private sector investors have announced LNG import projects on the supply side, totaling 35mtpa.

Over the past decade, the Thai infrastructure finance market has grown substantially, leading to near complete domestic self-sufficiency for debt capital. At this point, only the largest single investment projects may require some form of cross-border financial participation. That said, prudential lending limits may constrain domestic market capital availability. IEEFA analysis shows a peak of prospective viable LNG-related import and power generation investment in 2025, requiring nearly US$5 billion in financing in that year alone. That may be the tipping

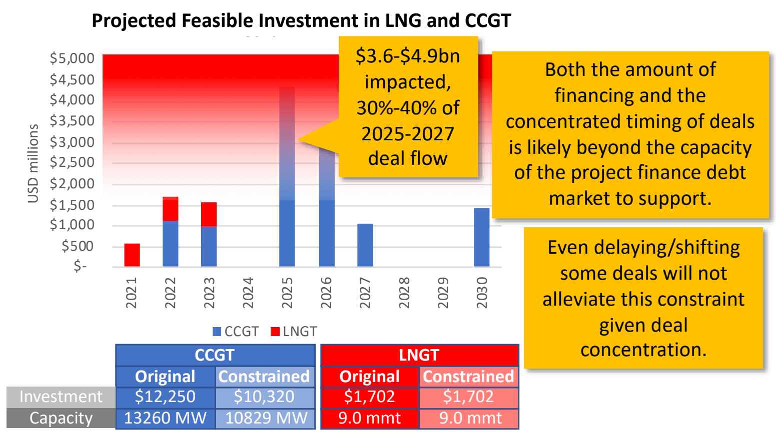
[31] BP. BP Statistical Review of World Energy 2021. September 2021.

point where domestic banks meet their exposure limits to specific borrowers and economic sectors.

Increased reliance on LNG imports may negatively impact the Thai economy. As the Thai economy grows more dependent on volatile LNG to drive economic activities, businesses and other consumers may struggle to manage their energy costs while remaining competitive in the global marketplace. Will the country be able to bear the burden of ever-increasing US dollar-denominated energy inputs and the inflationary effects that may have on the industry?

IEEFA's Thailand country analysis indicated that a significant percentage of announced LNG import projects would proceed. While CCGT project prospects are lower than the announced pipeline, approximately one-third of the viable CCGT proposals would replace aging generation capacity, which will be retired once new units are commissioned.

Vietnam



	Investment (US$mn)	Capacity
LNG Terminals		
Announced	$4,395	24.5 mtpa
IEEFA net projected	$1,702	9 mtpa
Projected / Announced	39%	37%
Power Generation		
Announced	$59,673	65,411 MW
IEEFA net projected	$12,253	13,260 MW
Projected / Announced	21%	20%
Total Investment		
Announced	$64,069	
IEEFA net projected	$13,955	
Projected / Announced	22%	

Vietnam is the largest prospective market for LNG imports and gas-fired power plants. However, significant coal-fired, solar, and wind capacity have been added in the past five years. This has created significant competition amongst LNG-related projects—as well as amongst provincial and central government ministries looking to host these investments—to gain a first mover advantage. This has led to a cacophony of competing claims of progress and project viability, most of which is unfounded.[32]

Financing in Vietnam has struggled over many years. Since 2011, only five large, limited recourse power sector transactions have been completed, all coal-fired power plants (see Figure 13 below). The three most recent projects were bilaterally backed by Japanese, Korean, and Chinese government interests. At 60% of debt, their participation levels far exceeded standards for private market transactions. Private companies from those countries were involved in the project equity and

[32] A detailed case study of Vietnam's energy market is provided after Section 4.

supply, and benefited from BDI insurance cover.[33] [34]

Figure 13: Vietnam Power Project Finance Transaction History

Project Name	Deal Type	Financial Close Date	Bilaterals Involved	Total Project Cost	Equity		Debt		% Bilateral Backed
					Amount	Percent	Amount	Percent	
Mong Duong	Fully Private	Jul 2011	None	$1,934	$815	42%	$1,119	58%	0%
Vinh Tan 4	SOE (EVN Gen Co 3)	Oct 2014	Korea	$1,752	$842	48%	$910	52%	33%
Nghi Son 3	Bilateral	Apr 2018	Japan, Korea	$2,454	$556	23%	$1,898	77%	60%
Van Phong	Bilateral	Apr 2019	Japan	$2,605	$605	23%	$2,000	77%	60%
Nam Dinh 1	Public-Private JV	Dec 2019	China	$2,530	$640	25%	$1,890	75%	60%

Source: IJ Global, Refinitiv Infrastructure 360. Note: Dollar figures in US$mn.

It is unlikely that similar arrangements for the coal plants will be available to LNG-to-power value chain investments. IEEFA's analysis has accounted for one or two bilaterally supported deals and/or projects financed via strong relationship banking. Fully private sector project transactions will face the greatest financing constraints.

The Government of Vietnam is also highly reluctant to provide guarantee support for new projects. It has repeatedly rejected guarantees for recent power transactions and is likely to maintain the same position on LNG transactions. Per-project debt totals listed in Figure 13 will therefore be a challenge to match for LNG-to-power transactions. These debt amounts can be considered the upper limit for a project finance transaction within a given year for assessment purposes. IEEFA placed an annual debt arrangement limit of about US$2 billion. Country, sector, and single project lending limits for foreign commercial banks will restrict the amount of capital available.[35]

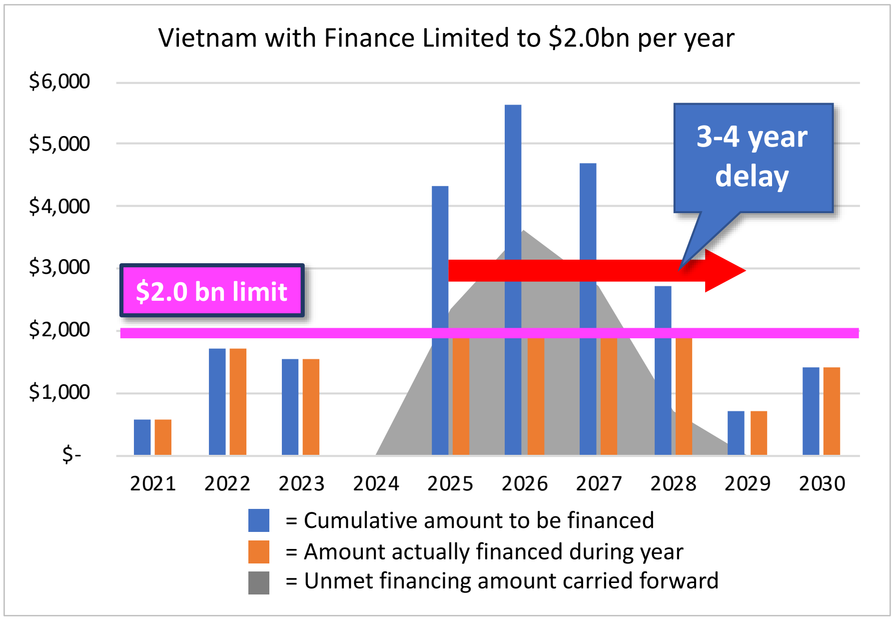
Vietnam is the market in this study most impacted by project lending market constraints. Even after reducing the LNG-fueled pipeline by 78%, remaining projects are still likely to consume available lending headroom amongst project finance lenders in the Vietnamese energy market. The US$2 billion constraint means that for the largest projected transaction years from 2025-2027, between US$2.3bn-3.6bn of projected transactions may need to be deferred if they can close financing at all. Cumulatively, over $8 bn of transaction volume is impacted.

[33] Only Mong Duong in 2011 was a "typical" fully private, limited recourse project finance transaction. In 2014, financing was provided to state-owned EVN's subsidiary Power Generation Company 3. After that, many banks globally began to exit coal-fired power projects, leaving Vietnam's subsequent deals reliant on bilateral arrangements.

[34] It should be noted that all the renewable energy transactions financed in Vietnam in the past five years have been backed by a generous, government-sponsored feed-in tariff which have made the financial economics of those deals very clear.

[35] These bank market constraints are discussed in Section 5 and in further detail in Appendix B.

Figure 14: Constraints of Vietnam LNG and CCGT Projects With a $2.0bn per Year Ceiling on Project Arrangements



Note: Refers to limitations pure commercially termed project finance. Outsized finance allocations from bilateral institutions may change these outcomes.
Source: IEEFA analysis.

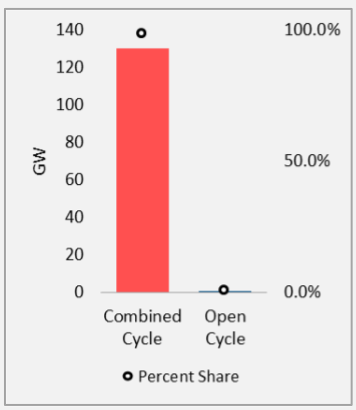
Box 2: The Role of Gas-for-Power: Flexibility or Baseload?

In Asia, power sector planning has traditionally focused on transmitting power generated from large, centralized coal-fired power plant end-users. Coal plants have operated at baseload levels to ensure stable power supply, keep operating costs low, and adhere to technical limitations on their ability to accommodate changes in power supply and demand. With the global shift away from coal, planners have used LNG-fired power plants in similar baseload roles.

The deployment of renewable energy technologies, however, requires operational flexibility. Certain gas-fired power plant designs are more flexible than others. Combined cycle gas turbines (CCGTs) are larger plants based on one or two gas turbines with a common steam turbine (1+1 or 2+1 configurations). Waste heat from the gas turbine is used to run the steam turbine. CCGTs are the most efficient and cost-effective gas technology for large, consistent power generation, but face greater technical restrictions on operational flexibility. For example, CCGTs can take 30 minutes to four hours to ramp up to full power output, according to figures from the International Renewable Energy Agency (IRENA). CCGT flexibility is limited by the steam generator, steam turbine, and the balance of the plant.

Open-cycle gas turbines (OCGTs), by contrast, are smaller plants that only involve a single gas turbine and do not reuse waste heat. OCGTs are more expensive to operate due to their lower thermal efficiencies, especially with higher-priced LNG, but higher per-unit costs are partially offset by lower capital costs. OCGTs can reach full capacity in 5-11 minutes, making them better suited for dispatch during peak demand periods and to accommodate changes in renewable energy output. As illustrated below, however, most proposed utility-supplying gas-fired power projects in emerging Asia are CCGTs—over 130,000MW of CCGT capacity, compared to just 825MW of OCGT capacity.

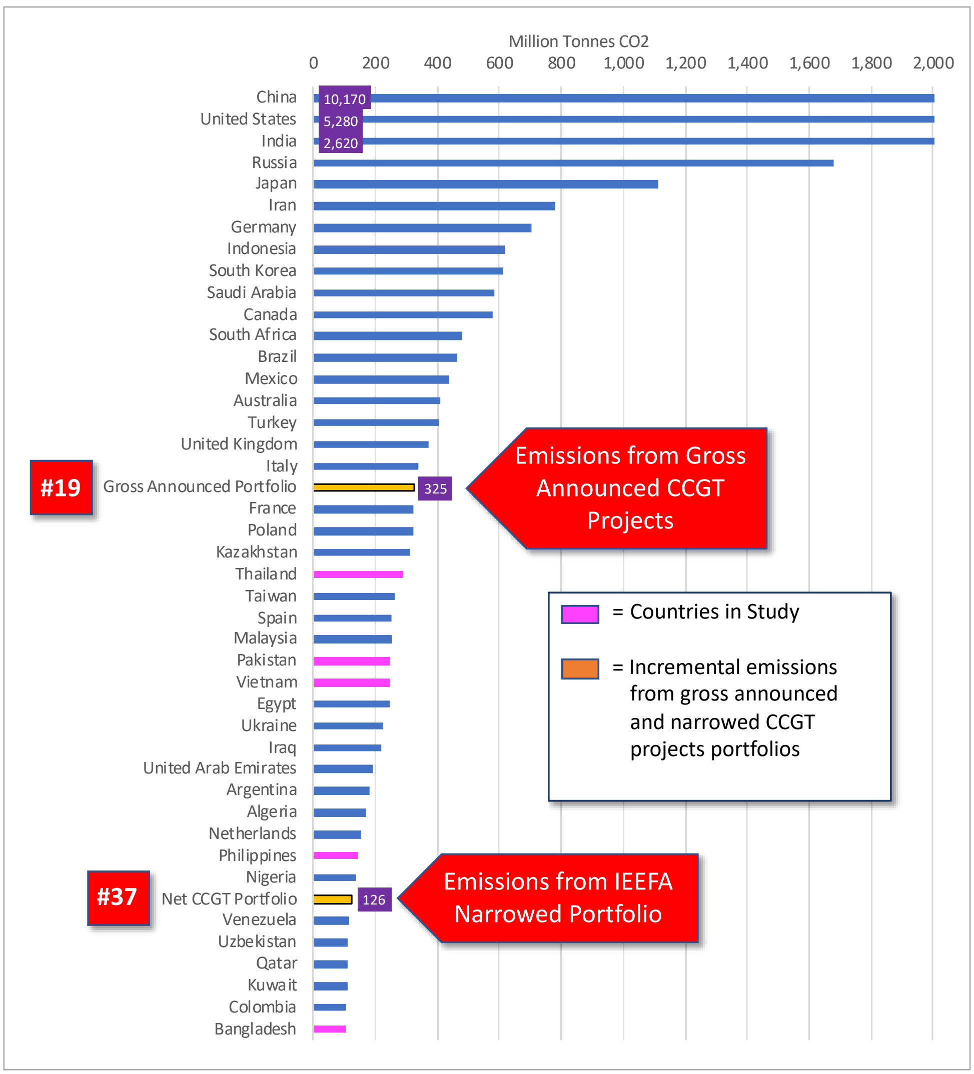
In addition to the technical characteristic of gas plants, flexibility also depends on contractual arrangements between customers and suppliers of gas and power. Fuel supply contracts typically involve long-term take-or-pay arrangements, which require offtakers to pay for fuel regardless of whether it is needed. PPAs, meanwhile, involve capacity charges that must be paid whether power is produced or not. Shorter, less rigid take-or-pay contracts for smaller gas volumes may improve gas plants' ability to operate flexibly but may also make it more difficult to provide investors with the long-term certainty needed to guarantee debt servicing and capital cost recovery.



Incremental CO_2 Emissions from Proposed CCGTs

The vast majority of this proposed capacity is *additional*, meaning that these proposed assets are adding to total national generation capacity rather than replacing retired capacity. Thus, even IEEFA's narrowed-down portfolio of potential additions, if realized, could add approximately 126 million tonnes of CO_2 to global emissions. This would represent a 0.4% increase over 33.1 gigatonnes of global emissions in 2018 (see Figure 15).[36]

Figure 15: CO_2 Emissions Rank of Proposed CCGT Projects in Study Countries



Source: 2018 global emissions data from Our World in Data. CO_2 and Greenhouse Gas Emissions. August 2020. Estimated emissions from narrowed Asian CCGT portfolio: IEEFA analysis.

[36] CO_2 emissions for 2018 by country emissions from all sources. Estimated emissions from the CCGT portfolio are based on a blended LNG CO_2 content given that the countries amongst the study group source gas from multiple exporters, each with differing CO_2 ratings.

Box 3: The Impact of Private Lending Capacity on Project Realization in Vietnam

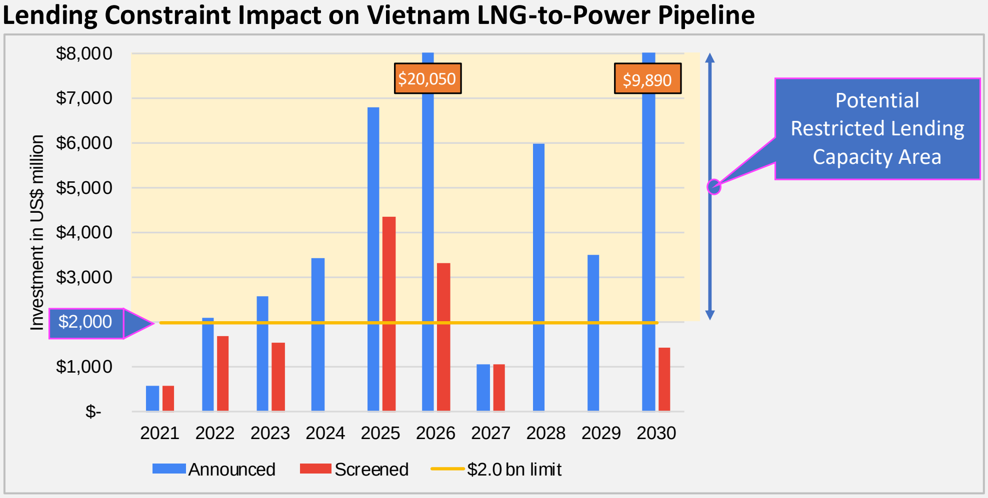
Vietnam is perhaps the country most severely impacted by commercial market lending constraints. The announced deal pipeline for Vietnam is the largest in the region, totaling US$64 billion across both LNG terminals and CCGT plants (US$4.4 LNG + US$59.6 CCGT).

IEEFA's first pass assessment on pipeline viability cut those prospects by 78% to US$14.0 billion (LNG 60% to US$1.7bn and CCGTs 79% to US$12.3bn). The limited capacity of commercial lending markets will trim viable projects even further. Most proposed projects in Vietnam aim to achieve financial close from 2025-2027, and developers are looking for between US$2.2bn to US$4.7bn of arranged financing each year. Due to portfolio prudential limits, however, bank lending markets may only provide about US$2.0 billion in energy sector exposure in Vietnam for any given year, meaning that only 50-70% of the proposed transactions during that time period are likely to lose out on arranging funds. Even if multilateral development banks (MDBs) contribute an additional ~25-30% to funds (as their own institutional rules limit their participation), prospective transaction funding in any given year will still fall short by 20-50%.

The preceding numbers also assume that the commercial project finance market, now and through 2030, remains fully open to funding unabated natural gas-fired power plants. This is unlikely to remain the case following the green funding commitments and grey carbon restrictions set at the recent UNFCCC COP26. A reduced lending market for natural gas means fewer projects—in Vietnam and elsewhere—can be done over a multi-year timeframe, due simply to prudential portfolio limits and a lack of willing lenders.

It is worth noting that no large, private project finance energy sector transactions have been closed in Vietnam for years. Even when deals were getting done, it was challenging. The government did not easily provide the types of terms and conditions project investors and lenders needed to close deals. After so many years, government decision-makers are unlikely to be acclimated to such requirements; historically, this sort of misunderstanding has delayed deal closures for years if they close at all. On all sides of the negotiating table, the path forward will be a challenge in Vietnam.

Lending Constraint Impact on Vietnam LNG-to-Power Pipeline



Source: IEEFA analysis

Section 4: Market Risks for New LNG Infrastructure in Emerging Asia

Each country has unique economic, political, and market challenges to energy infrastructure development, which project sponsors must navigate to secure financing. IEEFA analyzed each country's energy growth strategy and prospects, with a summary of findings in the table below. Following the table is a discussion of several common barriers that stand out on a regional level, which may impede the ongoing wave of LNG-to-power projects.

Country	Proposed	Feasible	Major Market Factors and Risks for LNG-to-Power Assets
Pakistan	1.2 GW 19.8 mtpa	1.2 GW 18.8 mtpa	• Gas and power underpricing exacerbates LNG-to-power credit risks and inflates gas demand. Recurring non-payment and default issues plague gas and power value chains. • Electricity grid constraints contribute to circular debt and limit private sector energy investments. Non-payment issues undermine the bankability of PPAs. • Regulatory risks may continue to hinder private sector LNG investments and involvement in the gas value chain. Projects often face multiple year permitting delays. • Delayed gas transmission projects prevent LNG terminal connection to large offtakers.
Bangladesh	9.1 GW 15.0 mtpa	3.1 GW 3.8 mtpa	• Rising gas and power subsidies increase default risks within the LNG-to-power value chain. Low regulated tariffs put increasing financial strain on state-owned enterprises. • Regulatory whiplash has paralyzed LNG developments. Technical roadblocks and price volatility have caused the government to reverse course on LNG procurement plans. • Generation overcapacity and renewables deployment threaten thermal power plant utilization. Inadequate grid infrastructure exacerbates thermal plant underutilization. • New LNG import terminals will require significant gas pipeline investments.
Vietnam	65.4 GW 24.5 mtpa	13.3 GW 9.0 mtpa	• Recent gas finds with significant recoverable reserves threaten the need for LNG assets, but domestic production will depend on pricing negotiations with upstream companies. • New public partnership and investment laws limit public guarantees and state exposure to fuel price volatility, requiring developers to bear more market risk. • Lack of a common gas pricing regime handicaps domestic gas and LNG developments. Case-by-case gas pricing creates regulatory gridlock and deters investment. • Competition with coal and renewables adds uncertainty for gas plant utilization.
Thailand	23.6 GW 35.3 mtpa	15.9 GW 15.5 mtpa	• Tariff reforms have contributed to the growth of private LNG investments, but higher fuel costs passed through to end-users could hinder long-term LNG demand. • Delays in the implementation of open-access rules for existing gas and LNG infrastructure may impede private sector regasification projects and LNG imports. • The Overlapping Claims Area with Cambodia may contain large gas reserves, but field development has been delayed by political volatility and bilateral negotiations. • Renewables deployment may limit long-term take-or-pay contracts for new gas plants.
Philippines	10.9 GW 18.5 mtpa	2.9 GW 6.3 mpta	• Limited contractual opportunities for gas-fired power plants can hinder project financing, since project sponsors without a PPA face price and LNG volume uncertainty. • Nascent and evolving legal regimes do not provide certainty for long-term cost recovery. Lack of demand in non-power sectors further amplifies risks for LNG investments. • LNG fuel price pass through can raise end-user power tariffs and undermine economic growth. Low-cost renewables deployment threatens LNG-fired power plant utilization.
Cambodia	1.6 GW 3.0 mtpa	0.2 GW 0.0 mpta	• Rising government subsidies for electricity consumption mean that investors may be increasingly exposed to the country's sub-investment grade credit rating. • Electricity grid constraints and lack of gas infrastructure limit the buildout of LNG-to-power facilities. Project sponsors must build own-use grid facilities, adding to costs. • The lack of existing laws and regulations specifically governing the mid- and downstream gas sectors may limit foreign interest in potential investments.
Myanmar	10.9 GW 23.0 mtpa	2.5 GW 3.0 mtpa	• Gas and power subsidies, along with the government's reluctance to grant sovereign guarantees, limit Myanmar's ability to attract investment in energy infrastructure. • The future of Myanmar's energy sector is uncertain after recent political developments.
Totals	**122.8 GW** **139.1 mtpa**	**38.3 GW** **56.3 mtpa**	

(light yellow)	Indicates power plant capacity
(light pink)	Indicates LNG import terminal capacity

Offtaker Credit Risks Resulting from Underpriced Gas and Power May Limit Bankability of Contracts

As LNG purchases increase, utility wholesale and retail natural gas buyers risk credit quality deterioration. As discussed in Section 2, wholesale and retail gas prices regulated below the cost of supply can put financial strain on SOEs, which become dependent on government budgetary allocations to recoup fuel expenditures. An increased dependence on higher-priced LNG, along with additional import infrastructure costs, may therefore harm the fiscal credit capacity of state-owned gas companies, adding to the risk of default on payments to LNG suppliers and terminal operators.

In Pakistan, non-payment risks have directly impacted LNG suppliers. Due to delays in government subsidies, unaccounted for losses in the gas delivery system, and inefficient bundled retail prices for various sectors, gas distribution companies have been unable to generate sufficient revenues to repay fuel suppliers, causing them to default on payments to state-owned LNG importers. Persistent non-payment risks may deter financing for companies aiming to participate in the country's LNG-to-power value chain.

In Pakistan, non-payment risks have directly impacted LNG suppliers.

Bangladesh has faced similar issues despite efforts to hike gas tariffs. In July 2019, the government instituted the largest ever rate hike on gas prices, specifically to cover the state-owned oil and gas company Petrobangla's rising costs associated with LNG imports. Despite the politically controversial tariff increase, the move was reportedly still insufficient to cover the company's LNG import bill.[37] The creditworthiness of future gas offtake contracts could therefore hinge on the government's willingness to further increase subsidies or raise gas tariffs.

LNG-linked power generation prices increase fiscal demands on state-owned utility buyers, unless they can identify means to recover those foreign-currency driven costs. Power tariffs regulated below the cost of supply have put similar pressure on state-owned electricity distribution companies. In many cases, low power tariffs can represent utilities' largest source of financial strain, causing them to rely on direct government subsidy allocations. Without sovereign guarantees, project sponsors able to secure PPAs with a state-owned utility will be exposed to the company's credit profile—a more severe risk proposition when considering the high cost of power generated from imported LNG.

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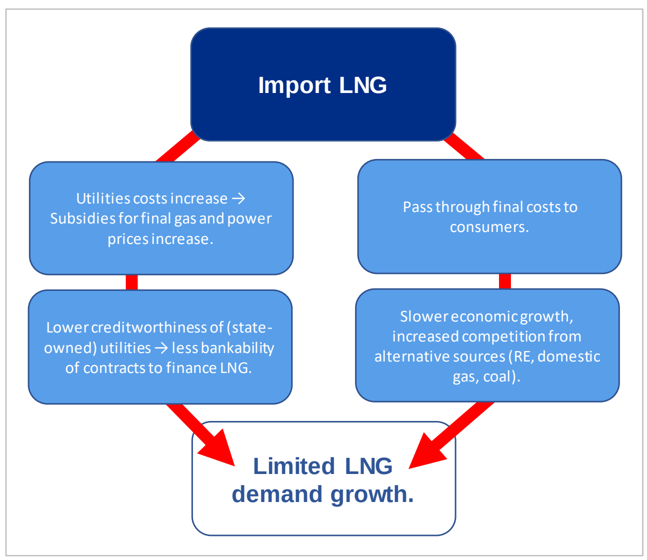
[37] As a result of mounting LNG costs, Petrobangla has sought additional government relief. The Financial Express. Petrobangla seeks support to make up for bills inclusive of LNG imports. February 4, 2021.

Despite recent power tariff increases in Vietnam, for example, the timing and certainty of continued tariff increases remains in doubt, raising investor concerns about the creditworthiness of state-owned power offtaker Vietnam Electricity Group (EVN). Higher-priced LNG is likely to involve substantial increases in the cost of power, since prices for domestically produced gas have historically been set at very low levels. Recent legal amendments to existing investment laws in Vietnam have removed sovereign guarantees for public-private partnership (PPP) and independent power projects, further complicating power project negotiations.

In contrast, Thailand's successful gas and power tariff reforms have buoyed investor sentiments. The country's power regulator has largely allowed full pass through of electricity costs for the last 15 years, giving EGAT, the state-owned power distribution company, a strong credit rating relative to other utilities in the region.[38] Gas prices, meanwhile, are passed through to gas offtakers on a cost-plus basis. A greater reliance on LNG could increase the country's weighted average cost of gas. For a summary of gas and power pricing regimes in emerging Asian markets, see Appendix D.

Underpriced Gas and Power Tariffs Distort LNG Demand and Disincentivize the Supply of Other Available Energy Resources

Most of the study countries suffer negative effects from poor economic pricing signals on demand for LNG. Tariff subsidies impact both consumers and suppliers in domestic energy markets. On the demand side, tariffs regulated below the cost of supply can artificially inflate the consumption of higher-priced LNG. As discussed above, overconsumption raises government subsidy burdens, potentially harming the creditworthiness of state-owned gas and power offtakers.



Low regulated gas prices in Bangladesh have skewed incentives in favor of gas-fired power generation, even though the efficiency of many of the country's state-owned gas-fired power plants is extremely low.[39] In countries such as Bangladesh, Pakistan, and Indonesia, generous contractual terms and low regulated prices have also led to overcapacity issues, in which

[38] Fitch Ratings. Electricity Generating Authority of Thailand. January 15, 2021.

[39] State-owned utility gas plants in Bangladesh consume 11–12 cubic feet of gas per kWh on average, compared to 6–7 cubic feet for a typical combined-cycle power plant. By contrast, IPPs within Bangladesh typically meet the lower consumption number. World Bank. In the Dark: How Much Do Power Sector Distortions Cost South Asia, p.41. 2019.

state-owned utilities are required to pay for thermal generation capacity even when plants are not producing power.

As subsidized tariffs inflate LNG demand, tariff hikes may have the opposite effect, boosting the economic competitiveness of alternative energy resources, such as coal and renewables relative to LNG. In particular, renewables are cheaper on a capital cost basis and cheaper on a lifecycle basis than both domestic and imported gas. Tariff increases to accommodate higher-priced LNG will only prove the case for renewables faster, thereby presenting a considerable risk to sustained LNG demand growth in emerging Asian countries and limiting the need for new LNG infrastructure.

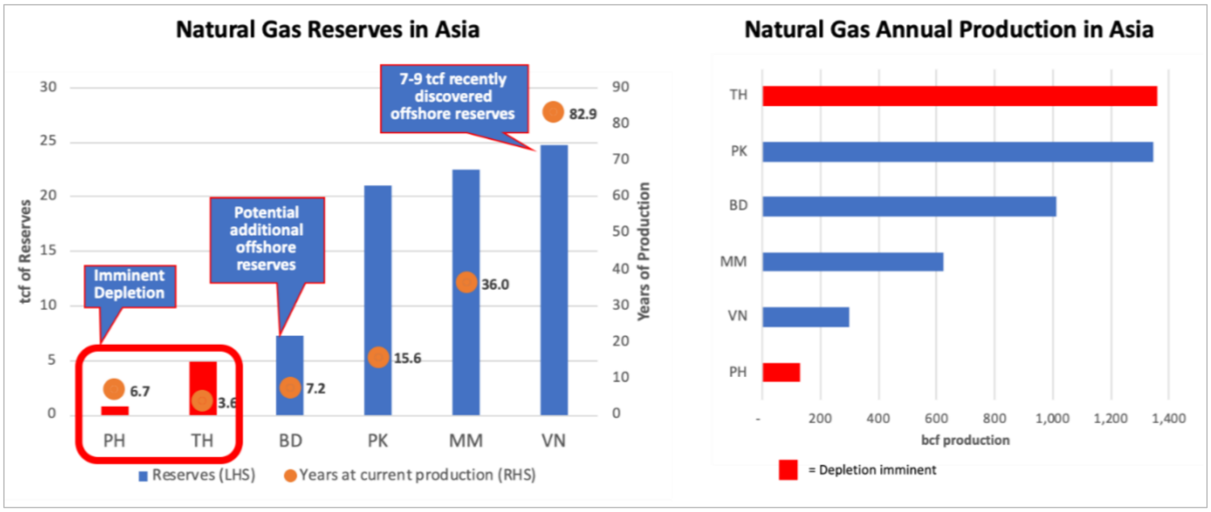
On the supply side, low regulated gas prices limit the profitability of domestic gas production, raising LNG import requirements. What is often perceived by the LNG industry as "gas shortages" in emerging Asia can often be more accurately described as inefficient gas pricing that limits domestic production (discussed further in the next section), distorting the need for imported LNG.

A Resurgence of Domestic Gas Production in the Region Represents a Major Stranded Asset Risk for LNG Import Infrastructure

Nearly all countries in this study have domestic natural gas reserves; few are producing near their potential. Many countries in the region—including Pakistan, Bangladesh, Vietnam, the Philippines, and Thailand—are experiencing declining domestic gas production despite most having large recoverable oil and gas resources. In the Philippines and Thailand, field depletion is expected within the next three to five years, driving their respective searches for LNG-based supply as gas-for-gas replacements. Bangladesh, Myanmar, Pakistan, and Vietnam, by contrast, all have material current domestic natural gas production with highly significant reserves in the ground (see Figure 16 below).[40] To understand the risks facing LNG infrastructure investments, it is critical to examine why countries with recoverable gas reserves are considering LNG at all.

[40] United States Energy Information Agency, 2021.

Figure 16: Natural Gas Reserves and Production Amongst Study Countries



Source: US Energy Information Administration.

If gas producing countries get their exploration pricing right, there may be a domestic production boom. For Bangladesh and Vietnam, the answer lies foremost in gas production pricing structures, which are beset by what the upstream industry has characterized as unrealistic and uneconomic wellhead price expectations. Bangladesh has promising shallow and deepwater fields offshore in the Bay of Bengal, but successive rounds of attempted development have been hampered by what foreign partners have viewed as unworkably low prices. Successive exits by Australia's Santos in 2019, Korea's Posco in 2020, and Singapore company KrisEnergy in January 2021 are just the latest setbacks for the country's domestic gas supply aspirations.[41] [42] Failed offshore bid rounds in 2008 and 2012 were also due to poor pricing terms.

In Vietnam, pricing negotiations between the government and international oil companies have hindered the development of large domestic fields since the early 2000s. In 2015, Chevron exited its stake in the "Block B" field—a campaign that would have supplied 640,000m^3 of gas per day[43] [44]—after a 12-year pricing debate with the state-owned oil and gas company PetroVietnam (PVN). The 2019 Ken Bau discovery off Central Vietnam may contain 7-9 Trillion cubic feet (Tcf) of new reserves, a 45% increase of national potential reserves.[45] [46] The field is nearshore and away from competing territorial claims with China, but development will hinge on the ability of gas producers to negotiate prices with PVN.

[41] Upstream Online. Bangladesh exploration block relinquished in new blow to country's E&P sector. January 18, 2021.
[42] Offshore Magazine. Partners exit Bangladesh offshore block. January 19, 2021.
[43] Argus Media. Chevron exits Vietnam's upstream. June 18, 2015.
[44] Offshore Engineer. Chevron sheds Vietnam assets. June 18, 2015.
[45] Offshore Energy. Eni confirms gas potential in discovery offshore Vietnam. July 27, 2020.
[46] Ken Bau represents the largest gas discovery in Southeast Asia in the last two decades.

Pakistan has significant gas reserves, but at its current high production rate of 1 Tcf per year, roughly 12 years of domestic production remain, assuming no additional exploration. Pakistan's gas consumption is also high, primarily due to an artificially low consumer pricing scale amongst residential customers and the fertilizer industry. This has led to uneconomic uses of gas. Meanwhile, the power sector and industrial customers often struggle to obtain quality supply with delivery pressures often below serviceable thresholds. Additional exploration will remain difficult as foreign exploration and production companies exit the country.[47]

Myanmar earns about 30% of foreign generated revenues (about 11% of total national revenue) from the sale of approximately 1.8 Tcf of gas per year via pipeline to Thailand.[48][49] Gas prices range from US$5.20-8.88/MMBtu—an advantageous deal for Thailand compared to LNG imports.[50] Myanmar's domestic gas demand remains nascent and scattered. Roughly 20% of the offshore gas production is allocated to domestic consumption.[51] The current scale of demand within Myanmar fluctuates widely and has not warranted significant investment in additional pipelines. Recent political developments have muddied the outlook for infrastructure investment commitments.

Recent findings in the international scientific community have demonstrated the incompatibility of new oil and gas field developments with global climate goals.[52][53] However, any resurgence in domestic gas production in emerging Asia, would present a major risk for the utilization of LNG import infrastructure. New sources of domestic gas production could very quickly turn LNG-related infrastructure into stranded assets, posing a significant financial risk for investors and financiers. While it is unlikely that new gas discoveries will affect medium-term outlooks for LNG in the region, infrastructure buildouts to support upstream developments could threaten the long-term growth of LNG imports.

Nascent Regulatory Regimes and Preexisting Monopolies May Thwart Private Sector Participation in LNG-to-Power

Many countries in emerging Asia currently lack mature regulatory and legal regimes necessary to provide revenue certainty for large-scale infrastructure investors. Decision-making and market planning in both the gas and power sectors

[47] Australia's BHP Billiton, Austria's OMV, and Italy's ENI have all sold their positions, which now rest with local investors. Reuters. BHP agrees to sell Pakistan gas business. February 15, 2015. Euro Pétrole. OMV closed the divestment of OMV Pakistan. June 29, 2018.
ENI had invested significantly in exploration offshore but curtailed the campaign after weak results. Upstream Online. Italian giant Eni streamlines its upstream portfolio. March 10, 2021.
[48] Myanmar Times. Myanmar oil and gas revenue forecast to decline in 2020-2021. July 22, 2020.
[49] US Energy Information Administration. Thailand Country Analysis. 2021.
[50] Those gas sales today account for one-third of Thailand's supply. IHS Markit. Thailand's PTT secures 30-year gas supply deal from Myanmar. August 3, 2010.
[51] It is unclear whether the entire 20% is consumed or remarketed.
[52] International Energy Agency. Net Zero by 2050: A Roadmap for the Global Energy Sector. May 17, 2021.
[53] International Energy Agency. Do we need to change our behaviour to reach net zero by 2050? October 29, 2021

can often be reactionary and prone to quick changes based on market developments. In addition, licensing and permitting delays can inhibit progress for project sponsors, especially when existing state-owned monopolies are resistant to allowing new players to participate in gas and power marketing functions. While many countries in the region have attempted to institute regulations to allow greater private sector participation in LNG projects and fuel procurement, new investors have been repeatedly stonewalled by changing regulations and resistance from legacy monopoly players.

Many countries in emerging Asia currently lack mature regulatory and legal regimes necessary to provide revenue certainty for large-scale infrastructure investors.

In Pakistan, for example, government regulators have recently attempted to ease third-party access rules for LNG import terminals and pipeline infrastructure, which would effectively allow private companies to buy and market LNG to domestic consumers. However, state-owned gas distribution companies have delayed signing gas transportation agreements to permit access to existing infrastructure. Recently, a gas distribution company vetoed the expansion of an existing FSRU, due to concerns the FSRU owner would aim to sell excess gas to private offtakers.[54] [55]

Similarly, Thailand has been trying to institute open access since the late 1990s, but the state-owned oil and gas company PTT has maintained its monopoly over gas supply and distribution. Although the state-owned electricity utility, EGAT, was recently allowed to purchase its own LNG cargoes, the Thai government cancelled a long-term gas supply agreement between EGAT and Malaysian LNG supplier Petronas due to concerns about oversupply in the domestic market. Companies aiming to use domestic gas infrastructure must negotiate third-party access agreements with PTT on a case-by-case basis, likely delaying the buildout of LNG import terminals not sanctioned by PTT.

Government reversals on planned LNG terminal import projects in Bangladesh have led to the cancellation of numerous private projects. In October 2018, the government announced it would commission just one additional onshore LNG import terminal, effectively cancelling at least 12 other private terminal proposals at various stages of development. The decision demonstrates that rapid changes in official plans for regasification infrastructure can thwart LNG-to-power projects, even those in advanced stages. LNG projects in emerging Asia are particularly vulnerable to such regulatory risks, especially in countries such as the Philippines and Cambodia, which lack comprehensive legal regimes that govern the down- and midstream natural gas industries.

[54] The Express Tribune. SSGC refuses to allow Engro to utilise excess capacity. September 4, 2021.
[55] IHS Markit. Pakistan loses larger FSRU at Engro Elengy terminal. September 10, 2021.

In the power sector, the lack of standardized PPA terms, along with lengthy offtake negotiations, have deterred power sector investments in Vietnam. Some recent PPAs for large thermal power plants in Vietnam have taken over a decade to negotiate. Moreover, recent amendments to existing investment laws for both PPPs and IPPs have rescinded more favorable PPA terms for private sponsors, suggesting that future PPA negotiations could take even longer. Project-by-project PPA negotiations for LNG-to-power projects are likely to place a hard limit on the speed of LNG developments, hindering the flow of finance to LNG-related infrastructure projects.

In the power sector, the lack of standardized PPA terms, along with lengthy offtake negotiations, have deterred power sector investments in Vietnam.

Natural Gas Pipeline Network Constraints May Delay LNG Import Projects, Even in More Developed Gas Markets

The lack of existing natural gas infrastructure in many emerging Asian markets is an often-overlooked difficulty that could delay the rapid expansion of LNG demand. Since natural gas in most emerging Asian countries is consumed primarily in the power sector, existing transmission and distribution networks are typically insufficient to supply other anchor markets, such as the industrial or residential sectors. Lack of distribution supply capability has deterred industry from considering investments in natural gas equipment or processes, even if gas may be more appropriate for their operations. Moreover, limited pipeline capacity may hinder the connection of multiple regasification terminals in a single location.

In the Philippines, for example, nearly all natural gas demand is concentrated in the power sector and physically constrained to Batangas Bay in Luzon. There is no existing transportation infrastructure that might supply other consumers in the industrial or commercial sectors. As a result, LNG terminal project sponsors must secure offtake agreements with one of five existing natural gas-fired power plants in the anchor market. Any demand growth depends on the buildout of more gas-fired power capacity. The lack of a diverse range of LNG customers adds uncertainty to the expansion of LNG import capacity in the country, likely causing delays or cancellations of regasification projects. In August 2021, for example, an integrated LNG-to-power project was cancelled due to the project sponsor's inability to secure offtake agreements from large customers. The project was consequently unable to secure financing.[56]

[56] Business World. Lack of financing stalls P82.5-B LNG project of Batangas Clean Energy. August 23, 2021.

Even in more mature natural gas markets with diverse demand profiles from various economic sectors, existing pipeline infrastructure may be insufficient to support multiple LNG import terminals. In Pakistan, for example, LNG terminal project sponsors and gas distribution companies agree that more egress capacity will likely be necessary to support new FSRUs in Port Qasim, where all the proposed terminals are located. However, large gas transmission projects have been met with cancellations or delays. The Gwadar-Nawabshah pipeline proposed as part of the China-Pakistan Economic Corridor was cancelled in June 2017, while the North-South pipeline from Port Qasim to demand centers in northern Punjab has yet to reach financial close. Construction could take an additional three years.

Other markets, such as Vietnam, Bangladesh, Cambodia, and Myanmar, require significant pipeline upgrades to reach large demand centers. Medium-term LNG demand growth could therefore be limited without the rapid expansion of gas network infrastructure.

Electricity Grid Constraints in Countries Could Limit the Integration of LNG-fired Power Plants

Along with existing gas network constraints, power grids often cannot support the addition of multiple large-scale thermal power plants. In several countries, the commissioning dates of various thermal power projects have been delayed by the inability to construct new transmission capacity. Given that most natural gas demand in the region is dependent on power sector offtakers, lack of sufficient grid infrastructure is likely to complicate the buildout of LNG-to-power facilities due to project-on-project risk.

For example, an LNG-to-power project in the Philippines initially expected online in 2011 was unable to connect to the grid, despite reportedly being over 90% complete in 2020.[57] In 2017, the project sponsor, Energy World Corporation, is awaiting the completion of a substation to connect to the grid, expected by end-2022.[58] The LNG-to-power project is now targeting a 2024 in-service date, though confidence remains low the project will come to fruition.[59]

Similarly, in Bangladesh, the Payra coal-fired power plant has been unable to supply its full output to the grid since the completion of its two 660MW units in October 2020 due to a lack of transmission line capacity. An ongoing transmission project has faced construction difficulties and is not expected online until April 2022. However, the government is still responsible for paying generation capacity payments of more than US$15 million per month to the plant, even though less than

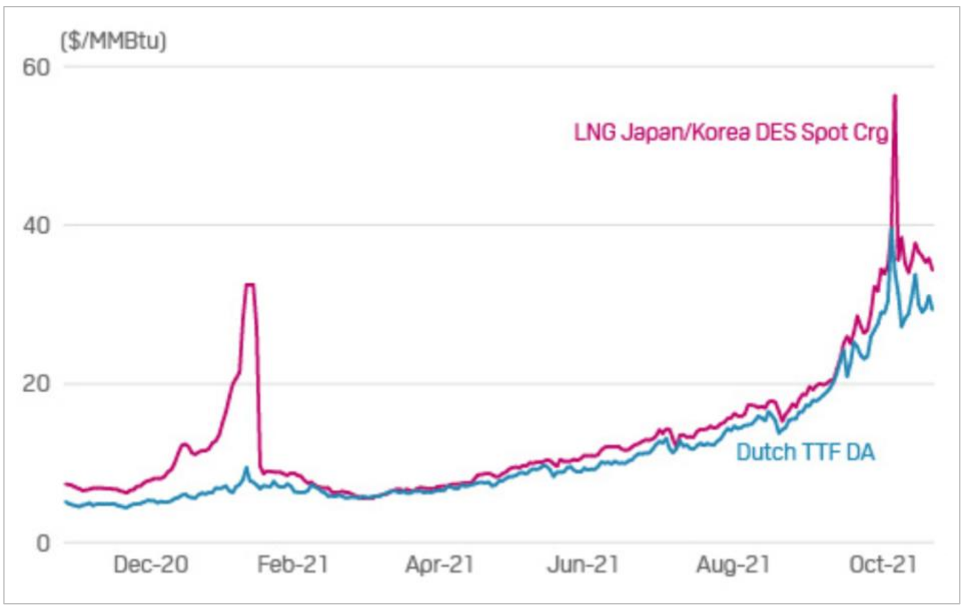
[57] Business Mirror. Is the government serious in having 'green' power in our energy mix? December 30, 2020.
[58] IEEFA. No Guaranteed Future for Imported Gas in the Philippines. May 2021.
[59] Business Mirror. Is the government serious in having 'green' power in our energy mix? December 30, 2020.

half of its total capacity can supply power to the grid.[60] [61]

LNG Volatility Could Paralyze Decision-Making and Hinder Demand in Price-Sensitive Markets

Over the past two years, price fluctuations have caused policymakers in emerging Asia to question both pricing strategies and decisions to rely more heavily on LNG for power generation. Section 2 discussed the impact of the inherent volatility of LNG prices on national value chain economics. From a regulatory and national strategic standpoint, however, such volatility may affect government decision-making based on the outlook of global prices. Figure 17 illustrates just how volatile the past two years have been.

Figure 17: Volatility in Global Gas Prices



Source: S&P Global Platts.

From 2018 to 2020, numerous countries, including Bangladesh, Pakistan, and Thailand, cancelled long-term contract negotiations to take advantage of what they perceived to be sustained low LNG prices in the spot market. However, given the spot market's inherent volatility, countries have reconsidered long-term contracts and restarted negotiations following what they are now classifying as unexpected price increases. Thailand, for example, cancelled a long-term supply contract with Petronas during 2020 in favor of spot purchases. Similarly, Bangladesh appeared to shift in favor of spot market purchases when it scrapped long-term supply contracts with Pertamina and AOT Energy in 2019. However, due to extreme price levels at

[60] Dhaka Tribune. Govt fails to take power from Payra plant, counts huge loss in capacity payment. July 30, 2021.
[61] The Business Post. Payra power plant operating at 50% capacity. September 21, 2021.

the end of 2020 and during the summer of 2021, Bangladesh has sought new contract deals, sparking interest from numerous potential suppliers.[62]

Volatile LNG prices also affect LNG suppliers' incentives, as those with existing long-term contracts may seek more profitable spot market opportunities during times of market tightness. Over the past two years, suppliers have diverted term cargoes from South Asia into the spot market when prices are high enough to cover contractual penalties and generate greater returns. Recently, Italian oil major Eni reportedly cancelled a long-term cargo to Pakistan in August 2021. Though the reasons for the cancellation are unclear, some suspect the company aimed to take advantage of US$18/MMBtu spot prices, compared to the ~US$9/MMBtu price of the long-term cargo. Due to high and fluctuating LNG prices, countries may reconsider planned buildouts of LNG infrastructure in favor of alternative energy sources.

[62] Hellenic Shipping News. Four firms lobbying Bangladesh high-ups for long-term LNG supply deals. August 12, 2021.

Section 5: Financial Constraints on Private Sector Energy Projects

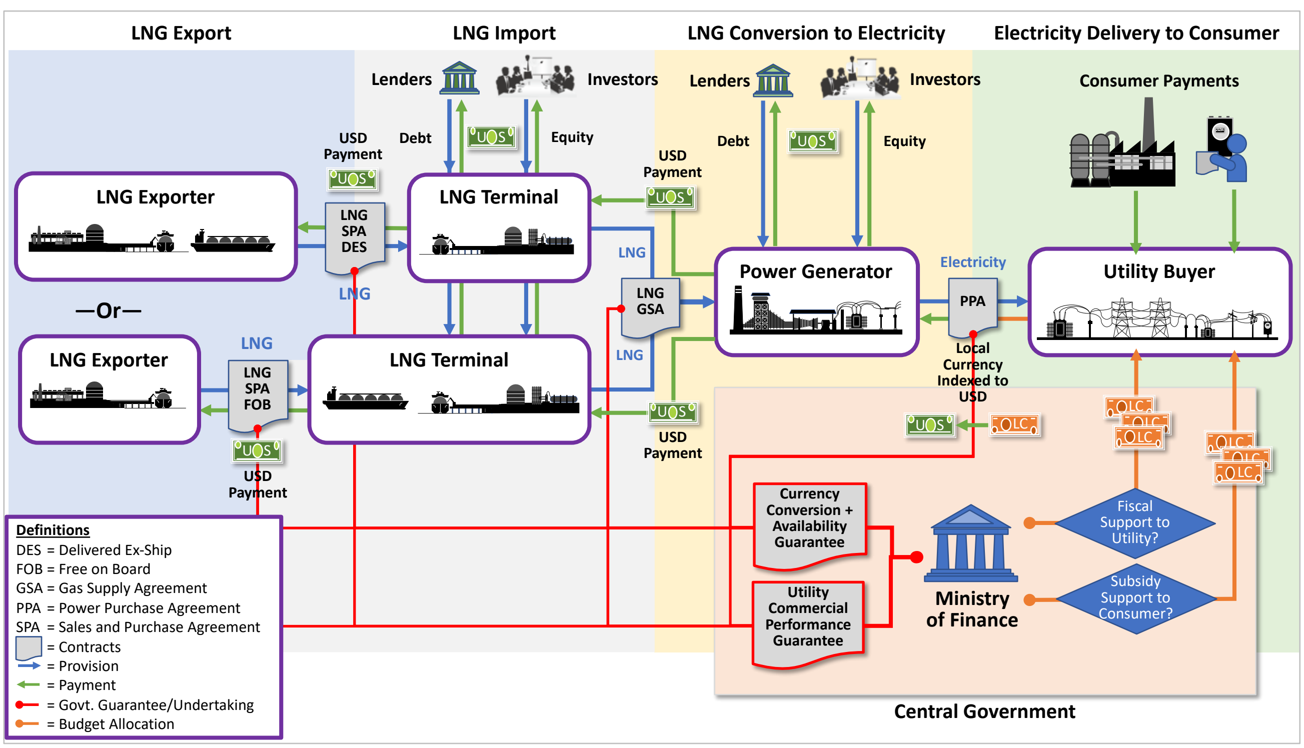
Making project announcements is the easy part, but signing financing agreements to realize them is incredibly difficult. In gauging the momentum of specific projects, there is a big difference between signing a memorandum of understanding with a developer and the details required to see a final financing agreement executed. This section introduces some of the constraints, considerations, and requirements demanded from financiers, which taken together, can conspire to limit the amount of funds available and number of projects that can be financed over time.

The following sections summarize the issues that can constrain the availability of finance in a given country market for a given project. A more in-depth discussion of the factors that contribute to these constraints is provided in **Appendix B**.

Project Context

LNG-to-power infrastructure typically involves a series of projects, often with multiple investing and lending parties. An LNG receiving terminal can be its own project with its own investors and lenders. Similarly, a power generation facility can also have its own owners and lenders. At times, the two are integrated. Regardless of configuration, commercial contracts string together components of the LNG value chain (see Figure 18.)

Figure 18: Overview of the LNG-to-Power Value Chain Contractual Obligation Structure



At each step in the value chain, ownership of the LNG commodity is transferred. Contracts define the minimum and maximum quantities of energy exchanged,[63] the quality and reliability of those services, and the duration for which that exchange will take place. These contracts are either denominated in or indexed to US dollars.

In countries with sub-investment grade sovereign credit ratings, financiers often seek guarantees and assurances from the government that sufficient foreign exchange will be available throughout the loan life. They also seek assurances that the national utilities purchasing the energy—most of which in the region are state-owned—will honor contracts. Given that lenders provide between 60-80% of the project's total investment cost via loans, they must be assured that nothing will stand in the way of receiving debt service payments over the project lifetime. These sovereign guarantee arrangements can create significant contingent liabilities for state-owned entities and for the governments that stand behind them.

Project Debt Capital

Project debt typically represents the majority of capital for a project. Therefore, lenders require solid security and protections before agreeing to fund. Project finance transactions typically require voluminous contractual documentation developed over a lengthy structuring and analytical process. This need arises because a project-based loan is made to a newly-created entity whose sole purpose is to build and operate a newly created asset, and whose only source of revenue—and therefore, debt repayments—comes from operating that asset reliably for many years. Lenders, particularly private commercial lenders, are allergic to writing down their assets, let alone lose them. Thus when they consider a loan in a project finance transaction context, the stakes are high.

To approve a project-based loan, lenders' credit committees and treasury managers must examine project fundamentals, the experience of the sponsors, lenders' relationship with the sponsors, key risk-sharing partners, and the macroeconomic and political stability of the country.

The supply of bank lending money for a given market is not endless, especially in countries with sub-investment grade sovereign credit ratings. Prudential limits—whether imposed by international capital adequacy standards or as part of a bank's internal credit policy—can constrain bank lending to an individual country, within a given sector, against a particular credit, to a given entity, and to a single project. These limits can be hit very quickly for infrastructure investments, often by a single project.

Accordingly, lenders must carefully choose the projects and project parties they support. When faced with a choice, lenders will often support their bank's long-term

[63] As discussed in Section 1, "take-or-pay" provisions are a common feature of sales and purchase contracts. They stipulate that either the purchaser takes delivery of a minimum amount of the commodity or it pays for it anyway. This sets the minimum amount of cash flow each transaction party can expect for operating its project and forms the basis for repaying lenders and equity providers.

relationship clients into deals, rather than take a gamble on an unknown or inexperienced sponsor group. Similarly, between countries, banks would rather support a project in a country with a track record of previous project successes and that provides a reliable, objective, and transparent regulatory environment.

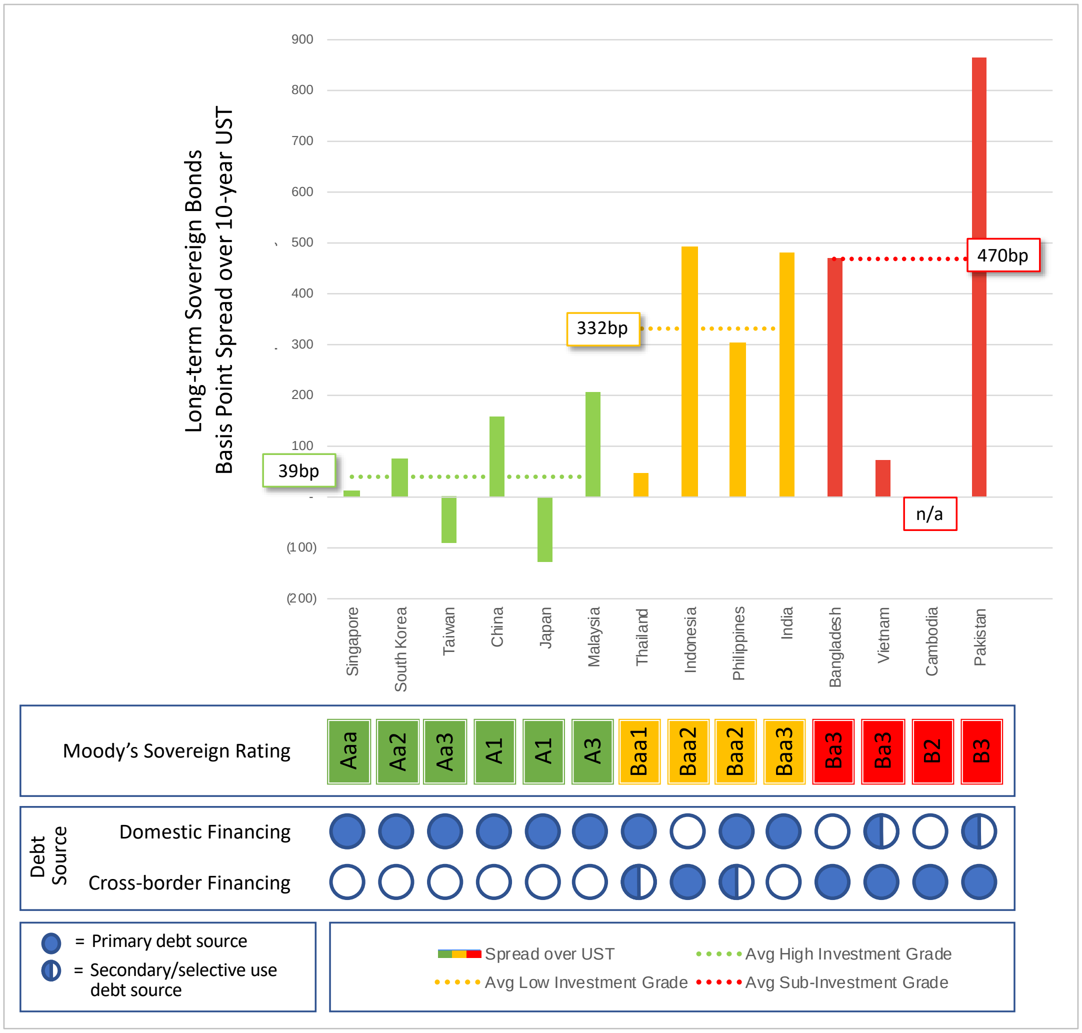
Country Risk Considerations

Debt capital market perception of sovereign risk governs in debt pricing. Sovereign credit ratings only tell part of the story when it comes to risk. Capital markets do not view each country's risk the same, even if two countries hold the same credit rating. Lenders take their own view, even if major credit rating agencies rate the country as "investment grade" and "stable."

The pricing spread for a sovereign's debt issuances compared to a similar tenor US Treasury note provides a vivid illustration of perceived country risk (see Figure 19 below). For example, Malaysia has a solid investment grade rating, but the market perceives a mix of heightened political and economic risk, thus assigning a spread far higher than similarly rated sovereigns. Thailand and Vietnam may currently have higher risk macroeconomic or fiscal statistics, but the margins quoted show that the market believes their growth and development trajectories are robust, potentially leading to credit quality improvements. In weaker credit countries, such as Bangladesh and Pakistan, the market has divergent perceptions of risk. The market clearly believes Bangladesh is risky, but it appears more stable than Pakistan, which has nearly double the priced-in risk.

These spreads betray credit rating agency outlooks for long-term risk in each country, with some margins greatly out of line with same-rated countries elsewhere in the world. When looking at whether they will extend a project loan in a given country, bank credit committees take a similar view as the bond market and will price in that risk, adding it to the underlying project risk. This leads to higher prudential risk capital provisioning, thus limiting the quantum of lending available, even despite levying a higher margin on the loan.

Figure 19: Comparison of Asia Regional 10-year Sovereign Bond Spreads Over 10-year US Treasury Notes



Sources: Ratings are taken from Moody's Investor Service sovereign ratings publication as of September 20, 2021. US Treasury Rate 10-year note spread quotes were sourced from Trading Economics as of the same date. Sources of debt finance were compiled through IEEFA research examining 15 years of project financing transactions.

Limitations on Cross-Border Project Finance

The lower the credit rating of a country, the more difficult it is to raise debt and the fewer projects that can be financed. In a project context, the cost of debt capital is where lenders' perception of risk becomes clear. That 'cost' is measured both in the pricing of the loan and in the tenor of the debt term available. The issue of country risk is most important when a project must rely on cross-border borrowing to meet its capital needs. Generally, as the rating of a country goes down, the interest rate margin grows and the time over which a lender is willing to extend credit shrinks. Credit cost and time are directly impacted by prudential credit risk management policies and minimum risk capitalization regulations imposed on these lenders by, for example, the Bank for International Settlements.[64]

The credit risk perception of a project-based loan will always be higher than the sovereign rating of the country in which that project is situated. In lower-income country markets, this makes the financing challenge even greater. In such cases, governments may have to provide backstop assurances or guarantees to the project's lenders. Typically, these assurances come from the host country's ministry of finance and will provide funding support in the event of government-related default under the project agreement. While this may push the project across the financing finish line, it also creates substantial long-term contingent liabilities, which the government must manage. As a government approves more guarantees, the size and risk of contingent liabilities grow—that is, unless the country's growth and stability trajectory remains consistently positive.

Multilateral Development Banks May Not Save the Day

Multilateral development banks can help guide private capital into more challenging countries, but they have limits on their participation. For projects seeking to attract private sector energy infrastructure investments, multilateral development banks (MDBs)[65] have a potential catalytic role to play. MDBs were established to provide concessionally priced and termed loans to sovereign governments for specific projects in critical economic sectors,[66] and institutional arms often co-finance private sector investments in infrastructure and industry.[67] As such, they have historically worked as a bridge between private investors and developing country governments to negotiate conditions suitable to both sides. When conditions are particularly challenging, MDBs may step in with guarantees or other forms of external credit support.

Despite their proven tools and track records, MDBs have limited ability to act repeatedly at a large scale. For sovereign operations, MDBs only support a small number of individual projects each year, spread over several economic sectors. Moreover, MDB lending rules often limit their participation in private sector transactions to a certain percentage—typically 25% of the total project cost. MDBs may collaborate to raise this percentage. Even then, however, their

Despite their proven tools and track records, MDBs have limited ability to act repeatedly at a large scale.

[64] See Bank of International Settlements minimum capital requirements as recommended by the Basel Committee on Banking Supervision.
[65] For example, the World Bank Group, the Asian Development Bank, and the Asian Infrastructure Investment Bank.
[66] MDBs also provide grants for technical assistance to governments to design policy, management, and project solutions.
[67] The MDBs played an important role in supporting government recovery plans both in the wake of the 2008 Global Financial Crisis and during the COVID-19 pandemic.

combined total should still be below 50%, as their role is to catalyze as much private capital participation as possible. Private funding must be mobilized to fill the remaining gap, ideally as the majority participant in the funding structure.

The ability of each MDB to undertake repeat private sector support transactions in one country is limited by this catalytic mandate. The goal is to help a country create the conditions to attract private capital on its own. MDBs should help for the initial one or two projects, after which their role should fade away, leaving the sector self-sufficient. If every infrastructure deal in a given country requires MDB support, then the conditions do not exist for sustainable private sector participation. From an MDB board and management perspective, such a situation would be a failure. Accordingly, in a given market, MDB private sector window funding could support perhaps at most two similar projects, unless there is some extraordinary and overriding development angle that extends beyond simply supplying more energy.

The Role of Bilateral Development Institutions in Emerging Asia

Bilateral Development Institutions have played an outsized role in financing fossil fuel assets in the past decade and emerging Asia has come to rely upon it; that mechanism may be coming to an end. Bilateral Development Institutions (BDIs) aim to advance their national interests through cross-border cooperation. BDIs undertake economic development work similar to MDBs but do not necessarily adhere to the same principles and protections as MDBs, allowing them to pursue their interests more aggressively. They often support their own domestic corporations' investment projects or equipment sales to third countries by providing export credits or investment loans to projects.

Bilateral Development Institutions have played an outsized role in financing fossil fuel assets in the past decade.

BDIs used to play a complementary role in project finance and MDB co-finance. However, such institutions increasingly operate alone, often taking on projects that MDBs may reject.[68] The percentage participation of BDIs in individual infrastructure transactions has grown over the past five years. Historically, BDI and MDB contributions were similar, around 20%-25% of the project cost. Now, BDIs increasingly fund 50% of transactions and are essential—rather than merely catalytic—to projects reaching financial close.

[68] Most notably, the majority of large coal-fired power projects throughout Asia have been funded by BDIs.

North Asian bilateral development banks have expanded their roles in emerging Asia, bucking prudency and lending limit trends. China, Japan, and Korea have been the largest players in the region by far, steadily increasing per-project loans over the past decade. Japanese and Korean BDIs also tend to make deals appear more commercial in nature, as their monies typically support Japanese or Korean private sector investors and/or equipment suppliers engaged in public-private partnerships abroad.

Chinese BDIs, meanwhile, are regularly willing and able to deliver up to 100% of required financing, either through guarantee support to Chinese commercial lenders or by taking entire amounts onto their books. Such funding may not even require an equity contribution and can be 100% debt. These arrangements are typically done via the borrowing country's state-owned utility, which receives the investment. Chinese DFIs typically only provide this level of funding if Chinese companies are the sole providers of equipment and construction for the project.

MDBs and BDIs are under increasing pressure and scrutiny to support global decarbonization and sustainable development.

As with MDBs, however, BDIs are under increasing pressure and scrutiny to support global decarbonization and sustainable development. The Government of China's pledge to no longer fund overseas coal-fired power plants is a direct response to this changing environment.[69]

Domestic Bank Market Lending Benefits and Challenges

Countries with a more robust domestic lending market can rely more heavily on domestic banks to support projects. In such cases, loans are typically provided in local currency, thus minimizing or eliminating a project's foreign exchange risk. Referring back to Figure 19, all the higher investment grade markets (indicated in green) rely primarily on their domestic financial institutions to fund capital projects. Such well-established domestic banking systems have larger capitalization, robust risk management, and broader portfolios to spread risk. However, even in these markets, their financial institutions remain constrained on sector and borrower exposure, due to the need to comply with the Basel Committee on Banking Supervision risk assessment and capital adequacy requirements.[70]

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[69] People's Republic of China President Xi Jinping's address to the 75th UN General Assembly, September 21, 2021.

[70] Note that nearly all central banks in Asia have adopted some form of the Basel Committee on Banking Supervision prudential requirements and have imposed them on their domestic banks as a condition of their operating license. Further, interbank business and transactions have developed a high dependency on having their counterpart institutions comply with Basel conventions as a prerequisite for conducting business.

Low investment grade domestic bank markets may face concentration risk constraints. In low investment grade markets (indicated in yellow in Figure 19), reliance on domestic lending institutions hinges on the maturity of the banking system. Thailand has become nearly self-sufficient for project-level lending, except for only the largest dollar value investments. The Philippines has rapidly maturing financial institutions and risk management systems that are increasingly self-sufficient. However, the Philippines suffers from a high concentration of domestic conglomerates that invest in projects across almost every economic sector. This quickly exposes the banking system to single borrower and single sector lending limits determined by the Philippine Central Bank.

Projects in sub-investment grade markets will likely still need to rely on cross-border financing. Domestic lending capacity is extremely limited in sub-investment grade markets (shown in red in Figure 19). If capacity does exist, it may not be in sufficient amounts over long enough lending periods to make a project viable. Pakistan, for example, has well-run commercial banks, but their low capitalization does not reliably permit loans large enough to meet the funding requirements of larger infrastructure projects. Therefore, most large projects must still rely on cross-border borrowing.

The Bottom Line: Bank Debt Capital for Projects Can Be Limited, Especially in Developing Markets.

For private lenders, risk-linked prudential limits constrain the volume and frequency of institutional lending to specific borrowers, sectors, and markets. A lender that has reached its credit risk limits can no longer participate in that market. That restriction remains until (a) creditors sufficiently pay down their borrowings; (b) the lender sells portions of the loan asset to other parties with risk headroom; and/or (c) changing market conditions improve overall credit risk ratings, at which point statutory capital is no longer a limitation and lending can resume.

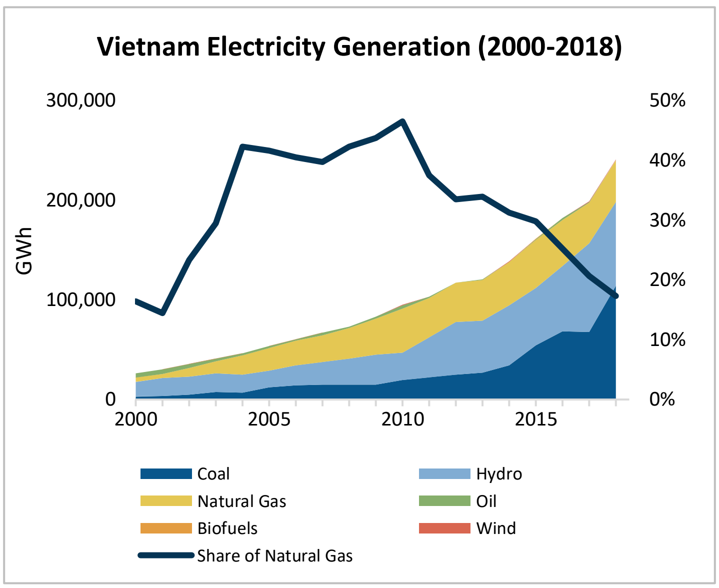
Case Study: Vietnam

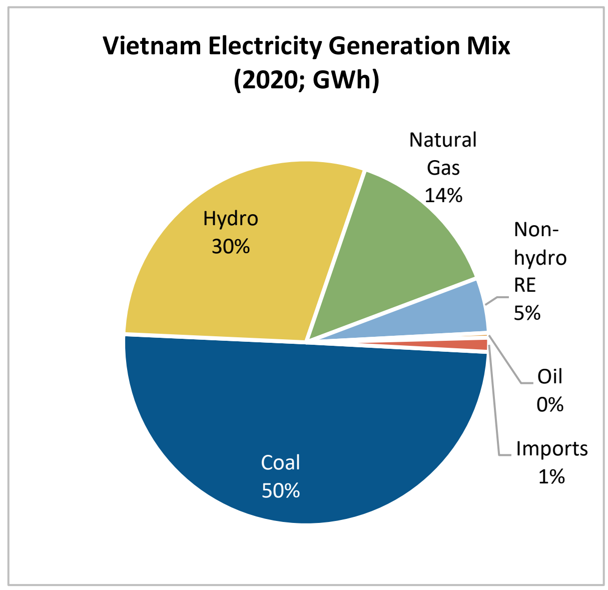
Context of Natural Gas Demand

Vietnam is considered one of the most promising growth markets for LNG due to a growing gas supply-demand gap, high forecasted GDP growth, and rapid urban population growth, amongst other factors. Over the last decade, Vietnam's energy demand growth has exceeded the average annual GDP growth of 6%, and the government is aiming for 6.5-7% GDP growth through 2025.[71]

In 2020, Vietnam consumed 8.7Bcm of natural gas, accounting for 7.6% of total energy demand. The majority of demand is power sector driven (80%), with smaller consumption from the fertilizer and industrial sectors (11% and 9%, respectively).[72] As a result, the buildout of natural gas infrastructure is heavily dependent on commercial and financial developments in the power sector.

Figure 20: Vietnam Electricity Generation Statistics





Source: International Energy Agency (IEA), BP Statistical Review of World Energy.

In recent years, coal and hydropower have accounted for the dominant share of electricity generation, while the share of natural gas has declined significantly since 2010 (see Figure 20 above). Vietnam currently has ten gas-fired plants, contributing 7GW of generation capacity. Minimal gas-fired capacity has been brought online since 2011, though an early draft of the country's eighth Power Development Plan

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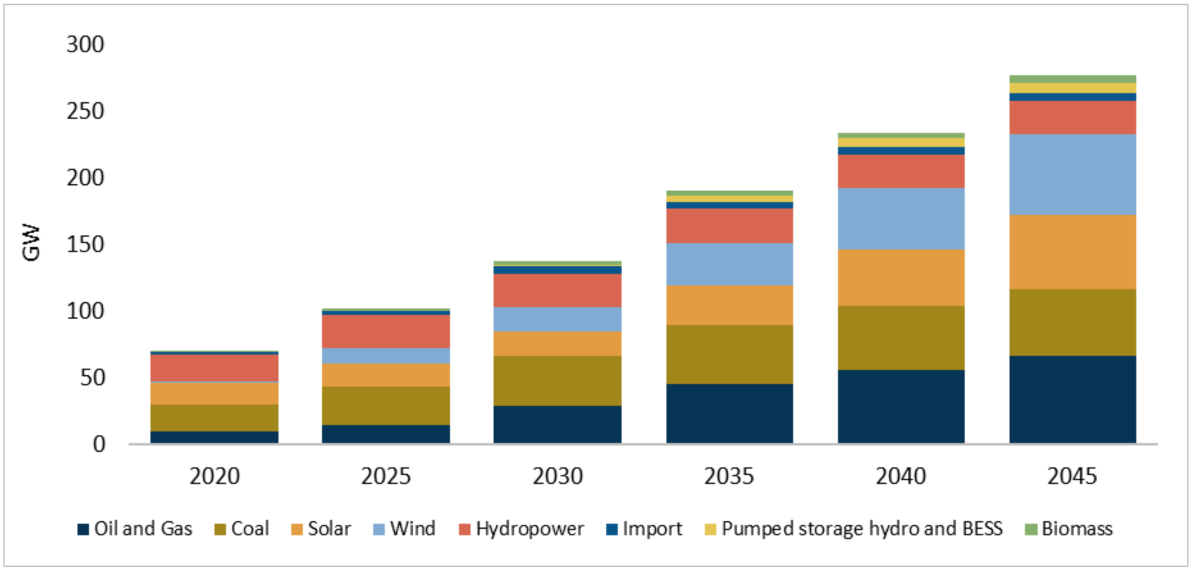
[71] Vietnam National Assembly. Resolution 16/2021/QH15 on the Five-Year Socio-Economic Development Plan for 2021-2025. July 27, 2021.
[72] Oxford Institute of Energy Studies. Emerging Asia LNG Demand, p. 126. September 2020.

(PDP8) for 2021-2030 envisions the addition of 21GW over the next decade and 55GW by 2045 (see Figure 21.)[73] [74]

Figure 21: Vietnam Power Mix According to February 2021 Draft of PDP8



Source: Vietnam Ministry of Trade and Industry (MOIT)
Note: A subsequent draft of PDP8 released in September 2021 raised the target for installed coal-fired capacity, primarily at the expense of planned wind power capacity. For more details regarding the most recent PDP8 draft, please see: IEEFA. Defying global financial trends, Vietnam pivots back to coal power. September 29, 2021.

Context of Domestic Gas Supply

Vietnam has 625Bcm of proved reserves—the third most in Southeast Asia behind Indonesia and Malaysia, and enough to last for over 74 years at Vietnam's current rate of production.[75] [76]

Two large, undeveloped domestic fields—Block B and Ca Voi Xanh (Blue Whale)—could produce nearly 10Bcm/y when operational but have faced significant delays.[77] Development of the 76.5Bcm Block B field experienced a major setback in 2015 when Chevron sold its operating stake in the project to the country's state-owned oil

[73] IEEFA. There will be no smooth sailing for LNG investors in Vietnam. January 19, 2021.
[74] Approximately 90% of gas demand is concentrated in southeast region of the country, with 10% from the southwest and only a small fraction of demand located in the country's northeast. World Bank Group. Vietnam: Maximizing Finance for Development in the Energy Sector. December 2018.
[75] British Petroleum. Statistical Review of World Energy 2021, p. 34. 2021.
[76] Gas production has come primarily from four major basins, with a total of 48 producing gas fields and 15 fields in development as of 2017. Public-Private Infrastructure Advisory Facility (PPIAF). Vietnam: Roadmap for Natural Gas Market Development, p. 36. May 13, 2016. PetroVietnam has partnered with several international companies in production sharing contracts, including Gazprom and Rosneft (Russia), Mitsui and METI (Japan), KNOC (Korea), PTTEP (Thailand), and ONGC (India).
[77] Block B was discovered in 1997 and Ca Voi Xanh was discovered in 2011.

and gas company PVN, due largely to unsuccessful pricing negotiations (discussed further below).[78]

ExxonMobil owns a 64% stake in the Ca Voi Xanh field, estimated to contain 150.1Bcm of gas.[79] Although the project was expected online as early as 2022, Exxon has indicated its desire to divest due to failed pricing negotiations, the project's complex dependence on four proposed gas-to-power projects for gas offtake, and high carbon dioxide levels, which add to gas processing costs. In addition, political complications regarding the field's proximity to China's territorial claims in regional waters have delayed progress.[80] [81]

In 2020, Italian oil company Eni announced the discovery of the Ken Bau field off the coast of northern-central Vietnam. The field is expected to contain 198.2-254.9Bcm of gas—about 113.3Bcm of which is expected to be recoverable—making it one of the largest discoveries in Southeast Asia in 20 years.[82] The field is located near the shore, easing concerns about competing territorial claims, and PVN has estimated that operations could begin as soon as 2028.[83]

Domestic gas production is expected to peak around 2026 despite significant indigenous reserves. Progress developing new blocks has been slow and could be more expensive than existing fields.[84] Moreover, PVN has had difficulties attracting new upstream investors due to rigid production sharing terms, high offshore development costs, and low regulated downstream gas prices.

Instead, the government has actively promoted LNG imports. Vietnam does not currently import LNG, but the government anticipates LNG imports reaching 10mtpa by 2030 and 32mtpa by 2045.[85] Two LNG terminals are currently under construction: The privately-owned and operated Hai Linh LNG terminal will have an initial 2-3mtpa throughput capacity and is expected online in 2022. The Thi Vai LNG terminal, meanwhile, is owned by PVN subsidiary PV Gas and is also expected online in 2022 with a 1mtpa capacity in its first phase.[86] [87]

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[78] The project was then expected to be sanctioned by 2017 but was again delayed by pricing and political considerations. Energy Voice. Glimmers of hope for giant Vietnam offshore gas project. May 17, 2021.
[79] The field is so large that Exxon reportedly wanted to develop an LNG export project, though the idea was rejected by the Vietnamese government. Energy Voice. Eni discovery dents value of ExxonMobil's Blue Whale in Vietnam. September 9, 2020.
[80] Wall Street Journal. Exxon Debates Abandoning Some of Its Biggest Oil and Gas Projects. October 20, 2021.
[81] Oil and gas operations offshore Vietnam have been ceased in the past due to bilateral tensions. The Diplomat. China's Pressure Costs Vietnam $1 Billion in the South China Sea. July 22, 2020.
[82] Energy Voice. Eni strikes one of the biggest gas finds in Southeast Asia for 20 years. July 30, 2020.
[83] Hanoi Times. Vietnam discovers oil & gas well with record reserves. July 31, 2020.
[84] IEEFA. Vietnam's EVN Faces the Future: Time to Get Renewables Right, p. 21. September 2020.
[85] Vietnam Ministry of Industry and Trade. Draft PDP8. February 2021.
[86] IEEFA. Vietnam's EVN Faces the Future: Time to Get Renewables Right, p. 21. September 2020.
[87] PV Gas. PV Gas accelerates the completion of LNG terminal to commence imports from 2022. November 12, 2021.

New Public-Private Partnership and Investment Laws Require Developers to Bear More Market Risk

Vietnam currently accounts for the vast majority of gas-fired power capacity additions planned throughout Southeast Asia. IEEFA has noted that at least 22 projects with a combined 65GW of capacity were at various stages of development as of December 2020.[88] SOEs including EVN and PVN are leading the push for LNG facilities in partnership with international investors. As of November 2021, no private projects have reached financial close.

Vietnam currently accounts for the vast majority of gas-fired power capacity additions planned throughout Southeast Asia.

Despite market hype in Vietnam,[89] two laws that recently took effect have reined in generous contractual terms for both build-operate-transfer (BOT) and IPP projects, potentially delaying a rapid buildout of LNG-to-power facilities.

Under the BOT model,[90] power project developers in Vietnam have typically received generous contractual terms from the government, including take-or-pay arrangements for the plant's full capacity, sovereign guarantees covering the event of non-payment by EVN, and the applicability of foreign laws in dispute settlements. But the Public-Private Partnership (PPP) Law, which entered into force in January 2021, ended several of these terms for infrastructure projects. For example, the new law requires Vietnamese law to govern disputes and is silent on the eligibility of sovereign guarantees in the event of SOE non-payment. These changes effectively require project sponsors to bear more market and regulatory risks and could extend already notoriously long negotiation timelines for BOT projects.[91]

Without sovereign guarantees, BOT projects will be increasingly exposed to EVN's credit profile, currently rated 'BB' by Fitch Ratings.[92] While EVN's financial position

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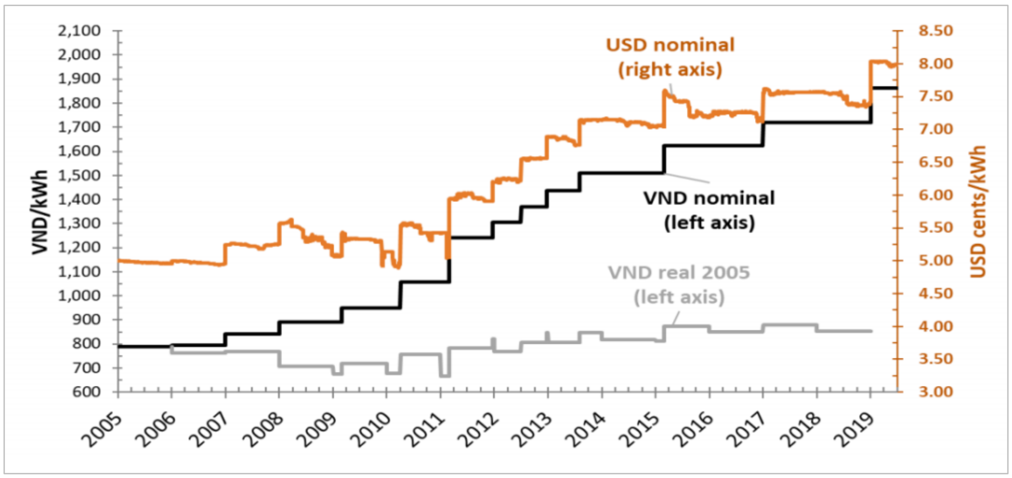
[88] IEEFA. There will be no smooth sailing for LNG investors in Vietnam. January 19, 2021.
[89] IEEFA. There will be no smooth sailing for LNG investors in Vietnam. January 19, 2021.
[90] BOT projects are a form of PPP, in which the government grants a concession to a private developer to build and operate a power plant for a 20–30-year period. Control of the project is then returned to the government entity.
[91] As of October 2020, at least 19 ongoing BOT projects were reportedly delayed. Allens. Report: Vietnam LNG sector update, p. 5. October 13, 2020.
Recent PPA negotiations for coal-fired power plant BOT projects have taken 10-12 years. For example, negotiations for the Song Hau 2 and the Vung Ang plants began in 2008 and 2009, respectively. Vietnam Investment Review. OneEnergy proposed as sole investor of Vung Ang 2 thermal power plant. June 5, 2018.
The Edge Markets. Toyo Ventures executes US$3.23b Vietnam power plant contract after 12-year wait. December 29, 2020.
[92] Fitch Ratings. Fitch Revises Outlooks on Vietnam's PVN, EVN and Six EVN Subsidiaries to Positive; Affirms 'BB' IDRs. April 7, 2021.

has improved in recent years,[93] the biggest strain on the company's balance sheet concerns retail prices set below the cost of power production. EVN has raised tariffs three times since 2015, most recently in March 2019, when average prices were increased 8.4% to VND 1,876/kWh (US$0.08/kWh) to offset higher input prices from coal, gas, and foreign exchange (see Figure 22 below).[94] Tariff increases since 2017 have been critical to sustaining EVN's financial performance, increasing revenues by VND 59.4 trillion (US$2.5 billion).

Figure 22: Vietnam's Nationally-Determined Average Retail Tariff Excluding Value-Added Tax (2005-2019)



Source: World Bank, "Learning from Power Sector Reform Experiences – Vietnam." March 1, 2020.

While recent tariff increases have boosted lender confidence in EVN, consumer tariffs remain well below EVN's cost of supply. The World Bank estimates full cost recovery rates would be US$0.12/kWh,[95] rising to US$0.14/kWh in the early 2020s to accommodate higher operational costs.[96] Higher LNG imports could involve a substantial increase in the cost of power compared to domestically sourced gas. Without sovereign guarantees for BOT projects, investors will be increasingly wary of EVN's ability to pass on fuel costs through adjustments to regulated retail power rates, the timing of which remains difficult to predict.

Like the new PPP Law, the new Investment Law, which also took effect in January 2021, does not have a specific provision that enables sovereign guarantees for IPP projects. Moreover, take-or-pay clauses have recently been approved on a case-by-

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[93] IEEFA. EVN delivers strong 2020 financial performance by optimizing Vietnam's dynamic generation mix. July 30, 2021.

[94] EVN's tariff increases are overseen by the government, and the Ministry of Industry and Trade (MOIT) has veto power over tariff increases of 5-10%. Tariff increases beyond 10% must be approved by the Prime Minister's office. IEEFA. Vietnam's EVN Faces the Future: Time to Get Renewables Right, p. 5. September 2020.

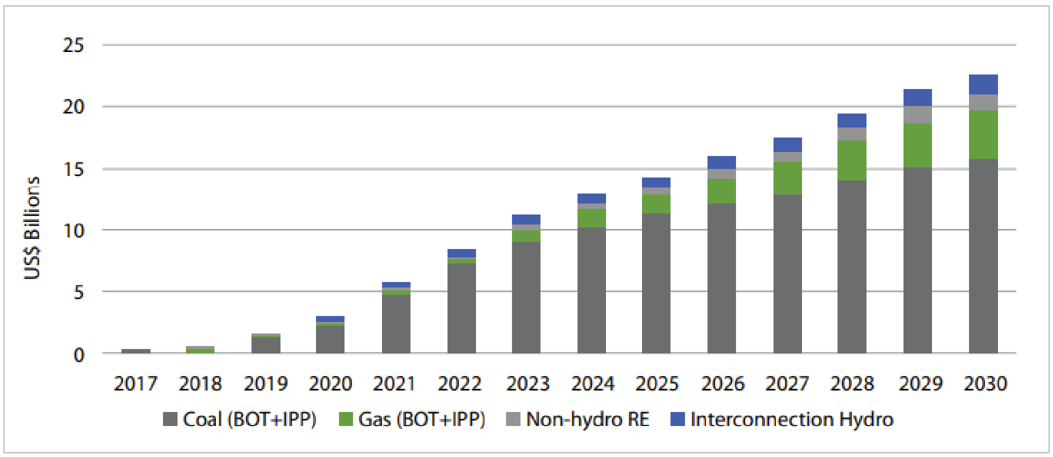
[95] World Bank. Learning from Power Sector Reform Experiences: The Case of Vietnam, p. 33. March 2020.

[96] World Bank. Vietnam: Maximizing Finance for Development in the Energy Sector, p. 33.

case basis, subject to the Prime Minister's approval, meaning IPP generators could be forced to compete on the wholesale power market without a guaranteed power price. IPPs would essentially be forced to bear merchant risk for the full capacity of the power plant, which is unlikely to be bankable for international financiers.

The new law is also unclear on government guarantees and foreign exchange convertibility.[97] Without guarantees on foreign exchange convertibility, investors could be exposed to losses if the Vietnamese dong is devalued against the US dollar, and any limitations on the availability of US dollars in the domestic market could present currency conversion challenges. Projections by the World Bank anticipate that demand for foreign currency in the energy sector could rise to US$23 billion per year, up from ~US$2 billion in 2019 (see Figure 23 below).

Figure 23: Estimated Foreign Exchange Convertibility Requirements (2017-2030)



Source: World Bank. "Vietnam - Maximizing Development Finance for the Energy Sector." December 2018.
Note: The World Bank assumptions are based on 31 GW of planned BOT/IPP coal projects and 7 GW of coal. The model assumes an 80% capacity factor for gas and coal, an average tariff of 8 cents/kWh, an average tariff of 7 cents/kWh for hydro interconnection, and 90% FOREX convertibility.

Lastly, legal questions remain about the ability of private companies to import LNG. PV Gas was recently granted exclusive LNG importing rights to serve two CCGT power plants.[98] However, it is unclear how long this exclusivity will apply and whether it will apply for other proposed LNG-fired power plants. Foreign companies will likely need licenses from the government to import LNG, adding to project timelines.

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[97] IEEFA. Beyond the Noise: Setting the Right Expectations for Vietnam's LNG Project Pipeline. January 2021.
[98] Allens. Report: Vietnam LNG sector update, p. 7. October 13, 2020.

Lack of a Common Gas Pricing Regime Handicaps Domestic Upstream and LNG Developments

Natural gas in Vietnam is priced on a case-by-case basis, deterring foreign investment in upstream production, creating regulatory gridlock, and distorting investment signals for end-users.

PVN is the primary state-owned actor in the country's oil and gas sector and accounts for ~20% of Vietnam's GDP.[99] [100] The company negotiates wellhead prices according to a cost-plus model and signs back-to-back purchase and sales agreements bilaterally with offtakers. The government approves gas transmission and distribution tariffs, while end-user tariffs are negotiated between PVN and the customer. Wellhead prices for associated and non-associated gas have historically been around US$1.25-5/MMBtu, respectively.[101]

The costs of new domestic gas developments are compared to historical negotiated wellhead prices rather than the current cost of alternative fuels. While low prices in the past have been due to low development costs associated with easily accessible gas resources, the government has also resisted agreeing to adjust their gas pricing approach to accommodate higher development costs associated with deeper, more pocketed, and/or more complex offshore reservoirs.[102]

Tariff negotiations have impeded new offshore developments. For example, Chevron and three partners expressed interest in developing the aforementioned Block B gas field and signed initial front-end engineering and design (FEED) contracts with PVN in 2009. Despite years of negotiations, however, Chevron and PVN were reportedly unable to agree on a price for the gas, with the former requesting a price of US$8-10/MMBtu.[103] Chevron sold its stake in the project to PVN in 2015. Development of the field is now being pursued by a partnership of PVN, Mitsui Oil Exploration (Japan), and PTTEP (Thailand). The use of historical domestic prices as benchmarks in negotiations with suppliers has also delayed the Cau Voi Xanh project.[104]

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[99] Public-Private Infrastructure Advisory Facility (PPIAF). Vietnam: Roadmap for Natural Gas Market Development, p. 66. May 13, 2016.
[100] With at least 32 subsidiary companies, PVN acts as a vertically integrated monopoly in every sector of the oil and gas industry. Its roles include upstream exploration, production, and sale of gas; aggregation, purchasing, and distribution of gas; downstream use of gas for power plants and fertilizer industries owned by PVN; and oversight of the gas sector, including regulation of end-user prices.
[101] The Lantau Group. Gas Pricing in Southeast Asia, p. 22. September 10, 2014.
[102] According to a market development roadmap prepared by the World Bank, "The evaluation of new gas projects against alternatives appears to use historic gas prices as a benchmark rather than the costs of current alternative fuel options – coal, imported LNG, fuel oil or distillate. *There appears to be no consideration of externalities such as pollution/greenhouse costs, taxation or the impact on balance of payments of indigenous versus imported fuels in the evaluation of gas projects and the determination of the 'economic price' for gas*" (emphasis added). PPIAF. Vietnam: Roadmap for Natural Gas Market Development, p. 90. May 13, 2016.
[103] The Lantau Group. Gas Pricing in Southeast Asia, p. 25. September 10, 2014.
[104] PPIAF. Vietnam: Roadmap for Natural Gas Market Development, p. 90. May 13, 2016.

By importing LNG, Vietnam will likely be a price taker in the global market due to its relatively small size compared to mature gas markets. As a result, tariff negotiations between the importer and gas offtaker are likely to center on the costs associated with the regasification infrastructure rather than the global fuel price. Using historical domestic prices as a standard negotiating position is therefore unlikely to result in a rapid buildout of LNG facilities,[105] given that recent LNG prices in Asia have far exceeded domestic benchmarks even without factoring the cost of regasification and transportation infrastructure.

Buildout of natural gas infrastructure in Vietnam is heavily challenged by competing coal and renewable projects.

Since Vietnam's power sector is the primary offtaker for gas, gas sales agreements and LNG terminal use agreements are closely linked to the bankability of PPAs with EVN. Bankable PPAs ensure power producers generate revenue sufficient to repay fuel suppliers and help determine gas volumes required for import. Challenges securing PPAs for power producers are therefore directly linked to the ability of gas importers to sell regasified volumes and finance LNG infrastructure. As a result, the already difficult regulatory environment and lengthy project timelines in the power sector are likely to complicate gas pricing negotiations.

There are numerous alternatives to the current project-by-project gas pricing methodology in Vietnam. Options include pricing gas against alternative fuels, such as coal or oil; pooling gas from various sources into a weighted average price; or competitive pricing based on the ability of customers, particularly power generators, to pay. While it is beyond the scope of this report to recommend methodologies, the lack of a comprehensive pricing regime is likely to delay negotiations for LNG imports, especially when factoring in extended timelines for power plant PPAs. Moreover, any willingness to raise prices for domestic gas producers could limit the need for highly volatile LNG imports, negatively impacting the ability of LNG import assets to generate returns and service debt.

Competition with Coal and Renewables Adds Uncertainty for Gas Plant Utilization

The buildout of natural gas infrastructure in Vietnam is heavily challenged by competing coal and renewable projects. Vietnam has undergone a rapid buildout of renewable energy projects in the last two years. The February 2021 draft of PDP8 set a target of achieving a 29% share of non-hydro renewable energy in the generation mix by 2030. This is a significant increase from the11% set in 2016 in the PDP7,[106] and involves the construction of 18-19GW each of wind and solar

[105] PPIAF. Vietnam: Roadmap for Natural Gas Market Development, p. 90. May 13, 2016.
[106] Agora Energiewende. Energy transition in Vietnam: Progress and prospects. March 19, 2021.

power over the next decade. EVN's 2020 financial results suggest the recent surge in solar deployment has already led to a lower utilization of gas-fired power plants.[107]

Although the government has stated its intention to reduce reliance on coal, there are still at least 8GW of coal projects under construction as of February 2021. Lower-priced competing power sources could push LNG-fired generation back on the merit order into more uncertain mid-merit and peaker roles depending on global LNG prices. As a result, LNG plant loads will vary considerably, undermining both utilization certainty and gas volume requirements. This could limit the willingness of power offtakers (EVN) to commit to long-term take-or-pay commitments that would otherwise support the bankability of PPAs.

[107] IEEFA. Vietnam's EVN Stands Out With a Strong 2020 Financial Performance, p. 5. July 2021.

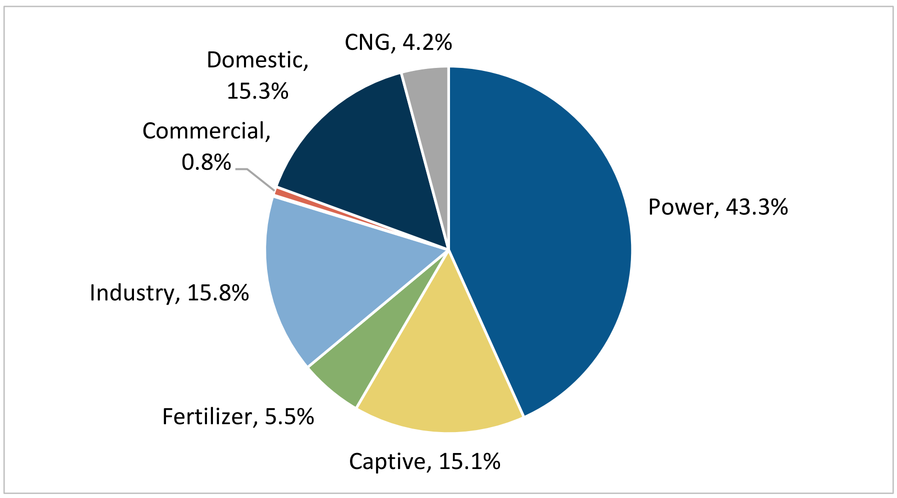
Case Study: Bangladesh

Context of Natural Gas Demand

Natural gas and LNG provide over 60% of Bangladesh's total primary energy demand.[108] In 2020, the country consumed 30.4Bcm of natural gas, comprising 24.7Bcm of domestically produced gas and 5.7Bcm of imported LNG.

The country's 11.45GW of natural gas and LNG-fired power capacity account for the largest share of natural gas demand (see Figure 24 below). However, other sectors also rely heavily on gas, including industrial and residential sectors. In the electricity mix, natural gas provided 60.2% of total electricity generation in FY2020-21. This is significantly lower than 2010, when the natural gas provided nearly 95% of the country's power.[109]

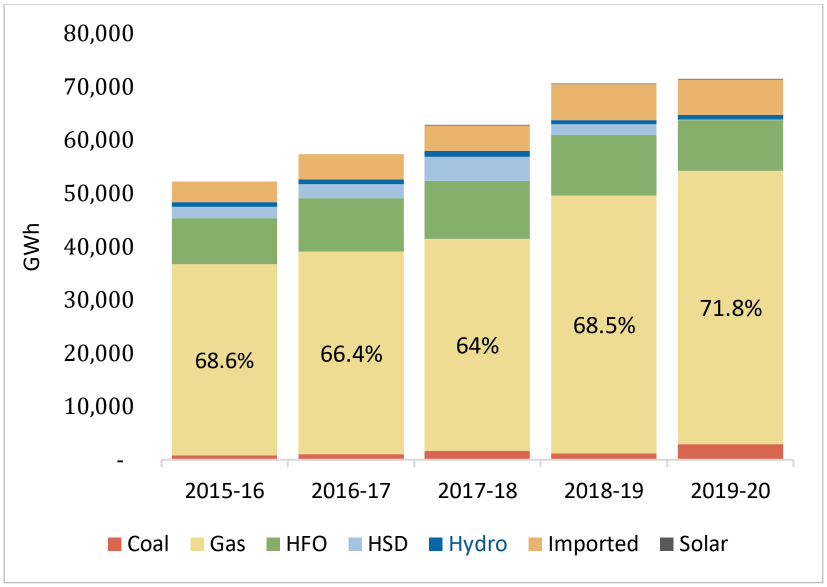
Figure 24: Bangladesh Gas Consumption by Sector (FY2018-19)



Source: Petrobangla, Annual Report 2019.

[108] Bangladesh Ministry of Power, Energy, and Mineral Resources. Hydrocarbon Unit, p. 1. August 27, 2021.
[109] World Bank. In the Dark: How Much Do Power Sector Distortions Cost South Asia?, p. 73. 2019.

Figure 25: Bangladesh Generation Mix and Percent of Gas (2015-20)

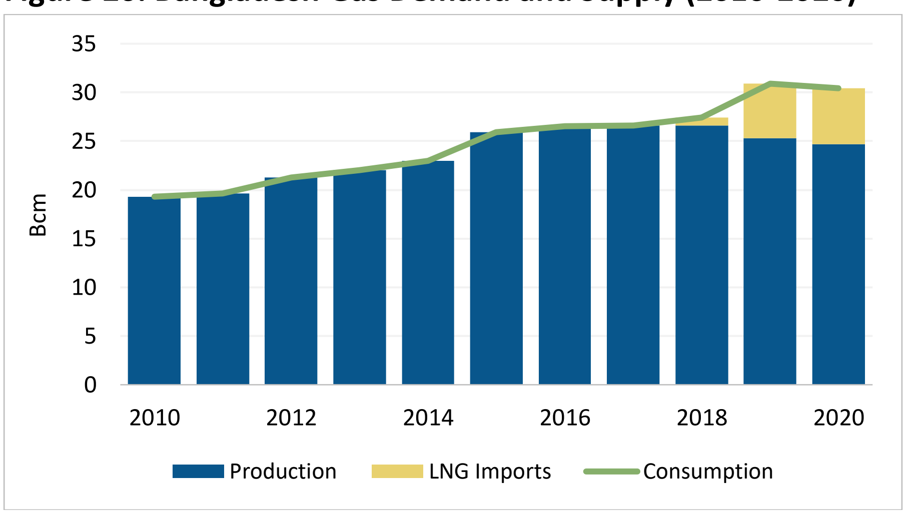


Source: Bangladesh Power Development Board (BPDB) Annual Report. HFO = Heavy fuel oil, HSD = High-speed diesel.

Context of Domestic Gas Supply

Bangladesh has developed 27 commercial gas fields since 1955. As of May 2021, 20 gas fields are producing 64.5 million cubic meters per day.[110] Annual domestic gas production in Bangladesh has declined from a peak of 26.6Bcm in FY 2017 (see Figure 26 below).

Figure 26: Bangladesh Gas Demand and Supply (2010-2020)



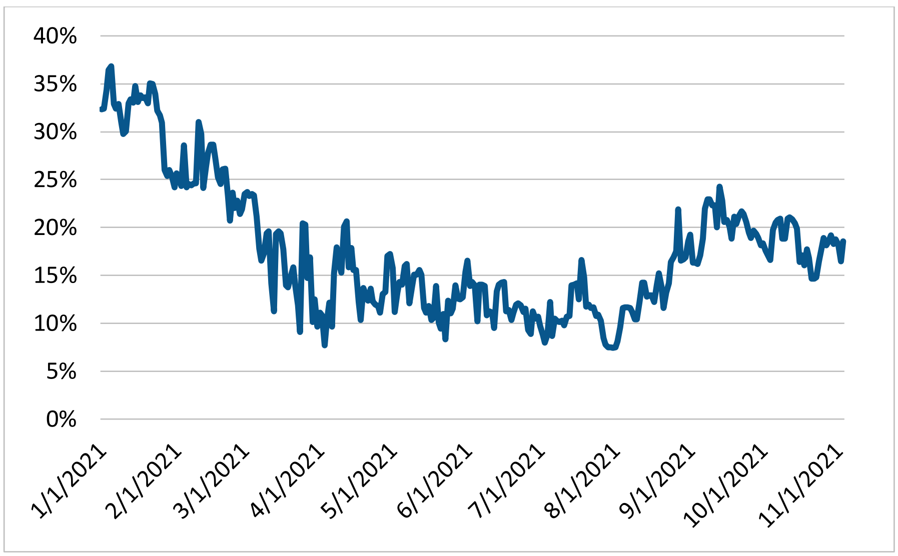
Source: BP Statistical Review of World Energy.

[110] This is down from a daily production peak of 2.75 Bcf/d in mid-2017. The Daily Star. Is Bangladesh running out of gas resources? May 21, 2021.

Bangladesh has 100 billion cubic meters of proved natural gas reserves.[111] [112] At the current rate of production, this is enough to last only another 4.5 years.[113] Petrobangla estimates an additional 198.2Bcm of probable reserves,[114] meaning domestic gas production could last until early next decade at the current rate of production. Experts have argued that the country contains one of the least explored prospective gas basins in the world, as the country has drilled only 28 exploratory wells in the past 20 years.[115] [116]

Bangladesh's economy has experienced chronic gas shortages since 2014, owing to domestic production shortfalls, midstream infrastructure constraints, gas theft, and unaffordable global LNG prices.[117] [118] Gas shortages have in turn caused electricity shortages and asset stranding due to the country's heavy reliance on gas for power. In January and February 2021, over 25% of gas-fired power capacity was stranded specifically due to fuel shortages (see Figure 27 below).[119]

Figure 27: Daily Stranded Gas Capacity Due to Fuel Shortages



Source: BPDB, Daily Generation Statistics.

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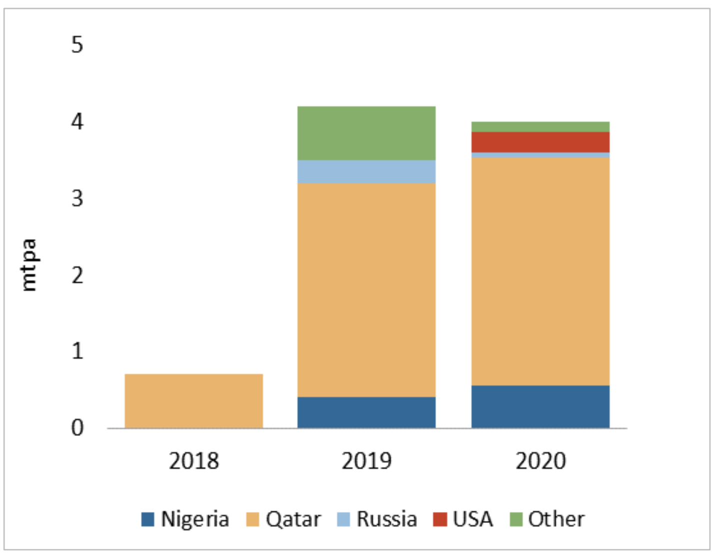
[111] BP. Statistical Review of World Energy 2021, p. 34. 2021.
[112] "Proved reserves" (1P) indicates over 90% certainty of commercial extraction. "Probable reserves" (2P) indicates at least 50% certainty, and "possible" (3P) indicates at least 10% certainty of commercial extraction. Evaluate Energy. What are 3P Oil & Gas Reserves and Why Are They Important? December 6, 2013.
[113] BP. Statistical Review of World Energy 2021, p. 34. 2021.
[114] Petrobangla. Annual Report 2020, p. 71. October 14, 2021.
[115] The Daily Star. Is Bangladesh running out of gas resources? May 21, 2021.
[116] In August 2021, the state-owned Bangladesh Petroleum Exploration Company (BAPEX) announced the discovery of a new gas field estimated to contain 1.9 Bcm of probable reserves. Business Standard. Energy-starved Bangladesh discovers new gas field worth over $148 mn. August 10, 2021.
[117] Dhaka Tribune. Dhaka's gas crisis likely to linger despite government efforts. May 24, 2018.
[118] The Financial Express. What the Texas energy crisis means for Bangladesh's energy security. March 22, 2021.
[119] The BPDB records daily generation and de-rating data along with contributing factors.

There is currently no offshore domestic gas production in Bangladesh. However, estimates for probable offshore reserves have reached as high as 200Tcf.[120] While offshore exploration and production could potentially eliminate the country's gas shortages, regulatory and pricing frameworks have deterred new activity. International oil companies have claimed that the tariff offered by Petrobangla is too low to encourage new drilling, and production sharing contracts allow for very little gas exports, leaving companies dependent on revenues from the domestic market.[121] [122]

As a result, the country began importing LNG through an FSRU owned by Petrobangla in August 2018. In April 2019, the private company Summit Group commissioned a second terminal. Both terminals have a 3.75mtpa throughput capacity and are located in Moheshkhali.

In 2020, Bangladesh imported 4.2mtpa of LNG (see Figure 28 below). Petrobangla currently imports LNG via two long-term contracts with Qatargas and Oman Trading International (see Figure 29 below), as well as the spot market with 21 eligible suppliers.[123] [124] The government is aiming to import 35mtpa by 2030.[125]

Figure 28: Bangladesh LNG Imports by Supplier



Source: International Gas Union Annual Reports.

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[120] World Bank. In the Dark: How Much Do Power Sector Distortions Cost South Asia?, p. 82. 2019.
[121] The government has tried to revamp offshore exploration by offering more lenient production sharing terms, though interest has remained lukewarm.
[122] Two prospective offshore producers—Santos (Australia) and Posco (Korea)—abandoned their shallow water blocks in December 2019 and December 2020, respectively. Dhaka Tribune. Two recently-relinquished offshore gas blocks remain unexploited. March 1, 2021.
[123] Dhaka Tribune. LNG import: Foreign companies seek long-term deals, but experts want competitive bidding. August 26, 2021.
[124] In February 2021, Qatar Petroleum reached a 10-year gas sales and purchase agreement with Vitol Asia to provide Bangladesh with an additional 1.25mtpa.
[125] Oxford Institute for Energy Studies (OIES). Emerging Asia LNG Demand, p. 60. September 2020.

Figure 29: Bangladesh's LNG Import Term Contracts

Seller	Buyer	ACQ (mtpa)	Start Date	End Date	Format	Terms
Qatargas-RasGas III T2	Petrobangla	2.5	2018	2033	DES	12.65% slope of the three-month average Brent price plus a 50-cent
Oman Trading International Portfolio	Petrobangla	1	2019	2029	DES	11.9% Brent slope plus 40 cent constant
Qatar Petroleum Portfolio	Vitol	1.25	2021	2031	DES	

Source: Various media reports. ACQ = Annual contract quantity.

Rising Gas and Power Subsidies Increase Default Risks Within the LNG-to-Power Value Chain

Petrobangla is currently the sole importer of LNG in Bangladesh. However, high LNG prices relative to domestically produced natural gas have placed increasing financial stress on Petrobangla, which directly subsidizes the difference between low regulated prices and imported fuel costs. Gas tariffs for power producers in Bangladesh are some of the lowest in the world,[126] resulting in a bias toward gas-fired power production on the demand side, while limiting interest in the domestic upstream sector.

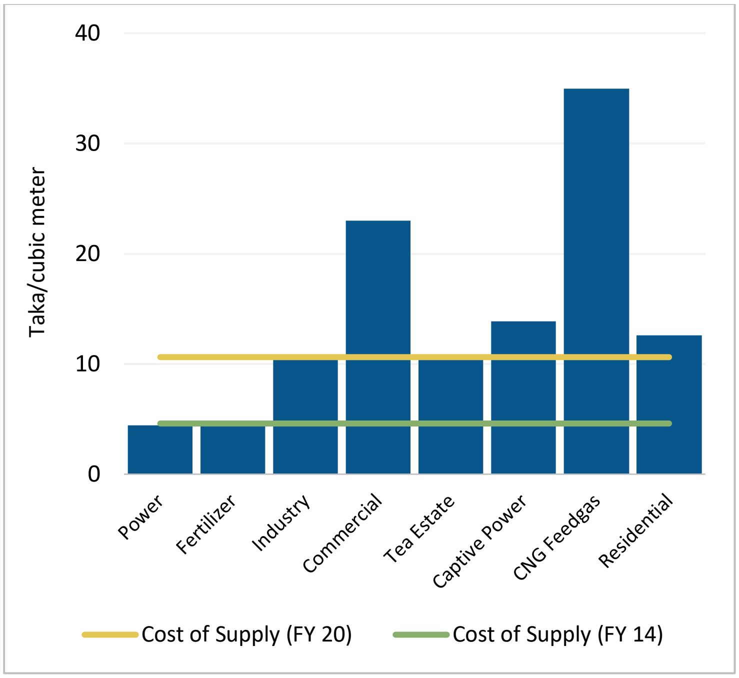
In July 2019, the Bangladesh Energy Regulatory Commission (BERC)[127] increased retail weighted average gas prices by 32.8%—the largest ever price hike on regulated gas tariffs—to mitigate losses incurred by Petrobangla due to increasing LNG imports.[128] [129] Weighted average prices were increased from Taka 7.38 per cubic meter to Taka 9.80.[130] The move sparked a strong political backlash from businesses and government opposition parties, but was reportedly still not enough to cover Petrobangla's estimated US$5.2 billion (Tk. 438.4 billion) LNG import bill.[131]

Figure 30 below shows the average cost of supply in FY 2014 (green line) and FY 2020 (yellow line) for Titas Gas Transmission and Distribution Ltd.—a subsidiary of Petrobangla and the country's largest gas transportation company. These supply costs are compared to retail tariffs under the new policy. The power and fertilizer

[126] International Finance Corporation (IFC). Creating Markets in Bangladesh: Unleashing the Private Sector to Sustain Development Success. June 2021.
[127] BERC is the independent regulatory authority responsible for overseeing retail tariffs and operations in electricity, gas, and oil.
[128] S&P Global. Analysis: Biggest ever gas price hike in Bangladesh to foot LNG import bill. July 2, 2019.
[129] International Finance Corporation (IFC). Creating Markets in Bangladesh: Unleashing the Private Sector to Sustain Development Success, p. 73. June 2021.
[130] The Financial Express. BERC raises gas prices from today. July 1, 2019.
[131] S&P Global. Analysis: Biggest ever gas price hike in Bangladesh to foot LNG import bill. July 2, 2019.

sectors, which combined accounted for nearly 50% of gas consumption in FY 2020, clearly pay well below the cost of supplying natural gas.

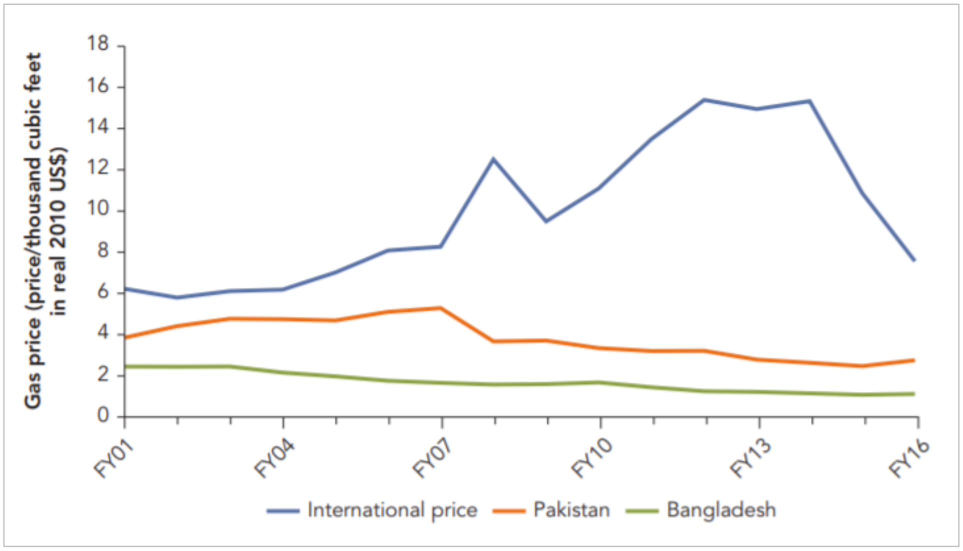
Figure 30: 2020 Gas Tariffs vs. Cost of Supply for Titas Gas



Source: Titas Gas Transmission & Distribution Company Annual Report 2019-2020, IEEFA calculations.

As the country's reliance on LNG imports increases, the cost of supply is likely to continue to increase, while future decisions to increase gas tariffs to ease the financial burden on Petrobangla are likely to be met with strong political and commercial resistance. Weighted average gas tariffs have historically been far below international benchmarks (see Figure 31 below).

Figure 31: Bangladesh Gas has Been Historically Priced Below International Benchmarks

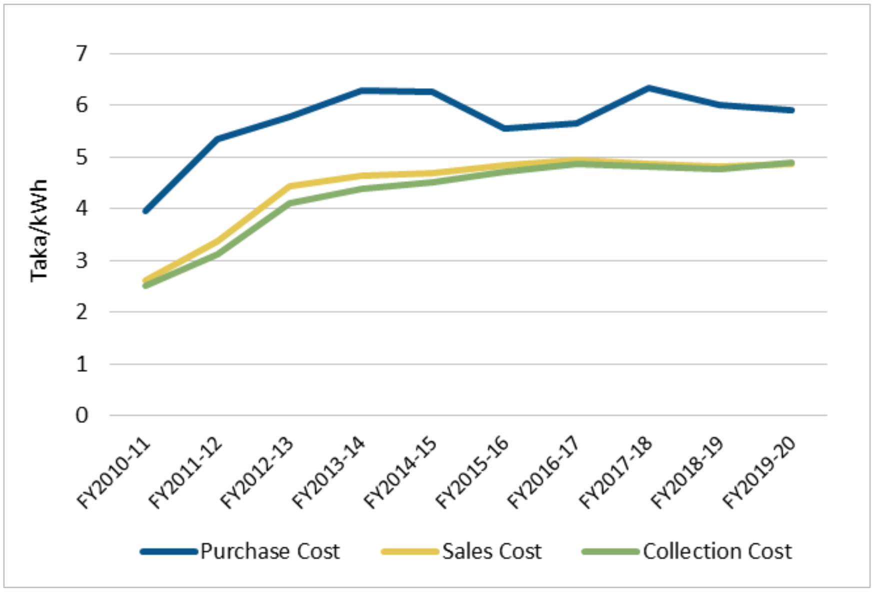


Source: World Bank, "In the Dark: How Much Do Power Sector Distortions Cost South Asia?"

Similar credit risks plague Bangladesh's power sector, as the government's regulated power tariffs are below the long run marginal cost of power generation. Average retail tariffs are set to less than the wholesale cost of power (see Figure 32 below), requiring the government of Bangladesh to provide a budget subsidy directly to the Bangladesh Power Development Board (BPDB).[132] Subsidies for the power sector in FY2018-19 were US$936 million, up from US$530 million in FY 2018-19. In FY2020-21, subsidies reached US$1.37 billion, according to the BPDB.[133] Furthermore, it has been reported that the current FY2021-22 subsidy is on course to reach US$2.33 billion.[134] Continued increases in the government-allocated power subsidies put pressure on the SOEs' creditworthiness, increasing the risk of government default on payments to electricity generators.

[132] The BPDB is the state-owned entity responsible for procuring power from generating subsidiaries and IPPs.
[133] The Financial Express. Bangladesh's power subsidy to hit Tk 200b. November 17, 2021.
[134] Ibid.

Figure 32: Bangladesh Power Prices are Regulated Below Long Run Marginal Costs of Generation



Source: IEEFA calculations based on BPDB Annual Reports.

The government has signaled its awareness of the growing subsidy burden in both the gas and electricity sectors. The country's 8th Five Year Plan calls for the removal of fossil fuel subsidies.[135] Tariff reforms, along with greater market-based pricing of both gas and electricity in Bangladesh could, in IEEFA's view, reduce overall demand for LNG and LNG-based power and encourage greater deployment of renewable energy. This is because renewable energy sources such as wind and solar do not receive capacity payments and have experienced rapid capital cost declines, both of which could help reduce government exposure to fossil fuel mid and downstream assets.

Regulatory Whiplash Has Paralyzed LNG Developments

To ease the financial burden of LNG imports on Petrobangla, the government drafted a policy in June 2019 to allow private companies to import LNG.[136] Regulatory developments, however, have stymied private sector-led buildouts of LNG import terminals.

At least eight private LNG import proposals at various stages of development were effectively cancelled in October 2018, when the government announced it would only pursue one additional onshore import terminal. The decision was reportedly due to complications involving the startup of the country's first offshore LNG import

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[135] "Proper pricing of fossil fuel energy products is also essential to promote production and use of clean fuel options and to meet the environmental goals of Bangladesh…" Government of the People's Republic of Bangladesh, Bangladesh Planning Commission. 8th Five Year Plan July 2020-June 2025. December 2020.
[136] The Financial Express. Private importers free to sell LNG to other users. June 26, 2019.

facility. Rupantarita Prakritik Gas Co. (RPGCL), a division of Petrobangla that oversees LNG imports, launched a tender for the 7.5mtpa terminal in early 2019.

Twelve companies were shortlisted for the project in June 2019. In January 2021, RPCGL finalized contracts with Tokyo Gas to conduct a feasibility study and prepare a Request for Proposal for qualified bidders.[137] Continued delays in the bidding process and uncertainty regarding private sector involvement in the import of LNG will likely hinder the buildout of new regasification capacity in the medium term.

Due to the low-price global LNG environment prior to winter 2020, Bangladesh opted to take advantage of low spot market prices instead of proceeding with long-term LNG supply contracts. The government cancelled a contract with AOT Energy in 2019 and has not yet finalized a supply contract with Indonesia's Pertamina. RPGCL also announced in October 2020 that the country would import two spot cargoes per month, up from one, due to low spot prices. However, the company abandoned this plan following the dramatic increases in winter 2020 LNG spot prices, in which regional spot market prices rose to record levels. Petrobangla found itself unable to afford LNG cargoes and cancelled spot tenders in November and December. The cancellations resulted in gas shortages throughout the country.[138] The events have sparked a shift in focus back to long-term contracts, with several companies reportedly lobbying for new long-term deals.[139] [140]

New LNG Import Terminals Will Require Significant Gas Pipeline Investments

Delays in bolstering the country's natural gas pipeline system have prevented the onset of new LNG import terminals.[141] According to officials from the state-run gas transmission operator Gas Transmission Company Ltd. (GTCL), insufficient pipeline capacity caused Petrobangla to operate the existing FSRUs at roughly 50% capacity during their initial years of operation.[142] Although the terminals had a combined daily throughput capacity of 28.3 million cubic meters per day, pipeline offtake capacity before April 2020 was roughly 18.4 million cubic meters per day.

Despite recent pipeline capacity additions near Moheshkhali,[143] there are still limitations on the availability of gas transmission pipelines to more distant areas. As

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[137] Tokyo Gas Engineering Solutions Corporation. TGES and Nippon Koei signed Contract of "Techno-Economic Feasibility Study, Engineering Services and Tender Management Services for Construction of a Land Based LNG Terminal at Matarbari, Cox's Bazar" (Bangladesh). January 29, 2021.

[138] New Age Bangladesh. Gas crisis hits Bangladesh consumers. January 22, 2021.

[139] Hellenic Shipping News. Four firms lobbying Bangladesh high-ups for long-term LNG supply deals. December 8, 2021.

[140] The Financial Express. Bangladesh ditches spot LNG buy, reverts to term deals. August 27, 2021.

[141] Many of the western and northern areas with high gas demand lack sufficient access to the country's gas transmission network.

[142] S&P Global. Bangladesh overcomes pipeline hurdles to boost LNG re-gasification capacity. April 28, 2020.

[143] Completion of the Chittagong-Feni-Bakhrabad pipeline in April 2020, however, added 800 Mcf/d of offtake capacity, easing utilization concerns for the two existing FSRUs.

a result, GTCL is currently constructing at least three additional transmission pipelines in northern and western regions of the country.[144] [145] Based on IEEFA calculations, recently completed and ongoing gas transmission projects will cost a total of US$12 billion (Taka 1 trillion). Financing has been provided primarily from various Petrobangla subsidiaries and regional development finance institutions (see Figure 33 below).

Figure 33: Bangladesh Pipeline Projects Recently Completed and Under Developments

Name	Length (km)	Diameter (inch)	Cost (Taka)	Cost (USD)	Source of Finance	Status
Projects Completed in FY2019-20						
Anwara-Fouzdarhat Gas Transmission Pipeline	30	42	72,099,990,000	865,199,880.00	GTCL, TGTDCL, KGDCL & BGDCL	Complete
Mirershorai Economic Zone			39,862,000,000	478,344,000.00	KGDCL	Complete
Projects Under Implementation						
Moheshkhali-Anowara Parallel Gas Transmission Pipeline	79	42	131,472,000,000	1,577,664,000.00	GTCL, KGDCL, TGTDCL, BGDCL & SGFL	Complete as of Feb 2020
Dhanua-Elenga and Bangabandhu Bridge-Nalka Gas Transmission Pipeline	67	30	82,851,380,000	994,216,560.00	GoB, GTCL and JAICA	52 km complete, land acquisition and COVID-related delays
Chattogram-Feni-Bakhrabad Parallel Gas Transmission Pipeline	181	36	247,941,000,000	2,975,292,000.00	GoB, GTCL and ADB & AIIB	Complete as of Dec 2020
Moheshkhali Zero Point (Kaladiarchar)-CTMS (Dhalghatpara) Gas Transmission Pipeline	7	42	30,177,000,000	362,124,000.00	TGTDCL, BGDCL, KGDCL & GTCL	Complete as of Feb 2020
Bogura-Rangpur-Sayedpur Gas Transmission Pipeline	150	30	137,855,000,000	1,654,260,000.00	GoB and GTCL	Under development
Padma Bridge (Railway) Gas Transmission Pipeline	6.15	30	25,380,000,000	304,560,000.00		Design stage
Projects to be Implemented						
Bakhrabad-Meghnaghat-Haripur Gas Transmission Pipeline	50	42	133,918,000,000	1,607,016,000.00	GoB and owned funds of Petrobangla, TGTDCL, BGDCL & GTCL	Environmental studies in progress
Installation of GTCL off-transmission stations and modification			68,796,000,000	825,552,000.00	GTCL, TGTDCL, KGDCL, BGDCL, JGTDSL & PGCL	Environmental studies in progress
2nd Bangabandhu Bridge (Railway) Transmission Pipeline	10	30	30,186,000,000	362,232,000.00	GTCL	Technical studies in progress
		Total	**1,000,538,370,000**	**12,006,460,440**		

Source: Gas Transmission Company Limited (GTCL).

Generation Overcapacity and Renewables Deployment Threaten Thermal Power Plant Utilization

The government's 8th Five Year Plan (8FYP), approved in December 2020, points to a focus on "energy efficiency gain, renewable energy and financial sustainability," marking a change in tone from previous power development plans focused on fossil fuel-based generation buildouts. The 8FYP recognizes the country's growing power overcapacity issue, which has resulted in underutilized plants and financial strain on the government due to mandatory capacity payments that must be paid regardless of how much plants are used.

Overall power capacity utilization in the country has fallen from 48.2% in FY2015-16 to just 40% in FY2019-20 (see Figure 34 below). In FY2020-21, overall utilization recovered slightly to 41.7%. However, gas and LNG-fired power plant utilization dropped to 48.3% on higher oil-fired power plant operations due to LNG price increases during end-2020 and early 2021.

[144] Gas Transmission Company Limited (GTCL). Annual Report 2019-2020, p. 62.
[145] Eight more projects for southwestern regions are in planning stages, according to GTCL's FY 2019-20 Annual Report.

As utilization rates fall, the average cost per unit of power rises due to mandatory capacity payments. In IEEFA's view, the burden of capacity payments for fossil fuel power generators has threatened the financial sustainability of the power system.

Figure 34: Bangladesh Power Plant Utilization Factors (2015-2020)

	Utilization				
	2015-16	2016-17	2017-18	2018-19	2019-20
Coal	38.7%	46.1%	36.9%	26.8%	29.6%
Gas	53.6%	49.3%	48.3%	50.7%	53.3%
HFO	37.7%	40.8%	36.0%	27.3%	19.5%
HSD	23.0%	34.1%	37.4%	16.9%	1.2%
Hydro	47.7%	48.7%	50.8%	36.1%	40.9%
Imported	72.7%	88.6%	82.7%	66.7%	65.7%
Solar	--	--	14.4%	13.4%	18.6%
Total	**48.2%**	**48.2%**	**45.7%**	**42.5%**	**40.0%**

Source: IEEFA calculations based on BPDB Annual Reports. HFO = Heavy fuel oil, HSD = High-speed diesel.

The 8FYP also recognizes the high costs of imported fossil fuels on the country's power sector. According to the plan, "the increasing reliance on imported fuel… (higher priced LNG and imported coal) will continue in the future, and so will increase the production cost of electricity, unless efficiency and other cost measures are taken."

Inadequate Grid Infrastructure Could Continue to Add to Thermal Plant Underutilization

While overcapacity issues can result in plants sitting idle for long periods of time, a lack of sufficient grid infrastructure can also lead to low utilization rates. For example, although both units of the US$2.48 billion, 1,320MW Payra coal-fired power plant were complete as of October 2020, delays in the transmission line upgrade project have meant that half of the available capacity from the first 660MW unit can be supplied to the grid.[146]

However, the government is still responsible for capacity payments to the plant of US$15 million (Tk. 130 crore).[147] According to one official from the Power Grid Company of Bangladesh (PGCB), "So, the delay in transmission project's execution means the cost escalation in the guise of capacity payment."[148] Transmission line project delays have reportedly been due to issues crossing the Padma River. The project is now targeting a December 2021 completion date, though PGCB officials

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[146] New Age Bangladesh. Payra power plant set to become economic burden on Bangladesh. March 14, 2020.
[147] Dhaka Tribune. Govt fails to take power from Payra plant, counts huge loss in capacity payment. July 30, 2021.
[148] Dhaka Tribune. Govt fails to take power from Payra plant, counts huge loss in capacity payment. July 30, 2021.

have recognized that the start-up date could be delayed further.

To make matters worse, the same transmission project is required to connect another 1,320MW plant under construction, the Rampal coal-fired power plant, to the grid. The first unit of the Rampal facility is targeting operations by March 2022, meaning that capacity payments for unusable capacity could double if the transmission line is delayed again. If more coal and LNG-fired power plants come online, capacity payments for underutilized facilities will likely rise over the next decade.

Conclusion: For Many Countries and Investors, LNG Is a Bridge That May Never Be Built

Energy sector planners in emerging Asia face an unenviable multitude of competing goals, including national energy security, affordability, self-sufficiency, and environmental sustainability. The LNG industry has framed imported gas as the be-all-end-all solution to these goals—a cheap, reliable "bridge fuel" to help countries reduce coal consumption and transition to cleaner renewable energy sources. Many policymakers in the region have subscribed to this narrative to fuel economic growth and compensate for declining domestic gas production.

On the contrary, IEEFA found that the highly volatile, US dollar-denominated LNG markets complicate economic growth and fiscal sustainability for emerging Asian countries. Often, the marginal operating costs of LNG-fired power plants exceed the all-in lifecycle capital and operating costs of renewable energy plants. Moreover, even modest fuel price and exchange rate movements can drastically change the final delivered price of power. IEEFA found that a +/-20% exchange rate movement and a +/-10% change in the fuel price—both moderate assumptions compared to volatility in recent years—can add or reduce power prices by US$18-30/MWh. In high-end cost estimate scenarios for natural gas plants, this could raise the price of power from US$115/MWh to over US$145/MWh. These costs are either paid via subsidies from SOEs or by the end-users themselves. Either way, the citizens of LNG importing countries pay through taxes or tariffs.

Highly volatile, US dollar-denominated LNG markets complicate economic growth and fiscal sustainability for emerging Asian countries.

For price-sensitive countries in emerging Asia, such volatility and unpredictability may have significant negative economic repercussions. Still, the LNG industry's excitement around perceived opportunities in the region has spawned an unrealistic pipeline of proposed LNG projects at various stages of development. But despite declining domestic gas production among several countries in the region and resulting gas shortages, only a few proposed projects have successfully navigated the gauntlet of financial, market, and regulatory risks necessary to secure financial close.

Based on project-by-project and country-level assessments of LNG infrastructure proposals across the region, it is clear that a majority of the announced investment pipeline is unlikely to be realized. In this analysis, IEEFA examined project-level factors, such as the experience of sponsors, project locations, phasing, and the existence of associated infrastructure, among others. This report also examined country-specific factors, such as macroeconomic outlook, efficacy of energy sector planning, gas and power pricing regimes, and sovereign credit rating. Overall, IEEFA found that based on these considerations, 63% of the proposed import terminal capacity is unlikely to reach completion, as well as 64% of power plant capacity.

The remaining 37% of terminal capacity and 36% of power generation capacity may still struggle to get off the ground, since these projects will still have to compete for project finance capital, which is severely constrained in developing country markets. This is because foreign commercial banks are typically subject to prudential lending regulations that limit their exposure to individual countries, sectors, and borrowers. To assess lending capacity, IEEFA compared the total value of remotely feasible projects to banks' country credit risk and bank market risk appetite. This led to a further 6% reduction in possible projects.

MDBs are unlikely to provide significantly more than 25% of per-project lending requirements due to their catalytic mandates, while BDIs typically back their home country investors and industries. Both are under significant pressure to adhere to emerging global low-carbon or net-zero standards. As time goes on, fewer cross-border lenders will be willing to support fossil fuel projects. Domestic lending institutions may be asked to step in to support local projects, but that may not be within reach of their capitalizations. Further, those domestic institutions may also conclude, like their foreign counterparts, that supporting fossil energy projects may not be prudent business policy. Countries looking to grow their energy sources must determine the most sustainable, reliable funding pathway for infrastructure growth. If not, LNG may be a bridge fuel that never gets built.

As time goes on, fewer cross-border lenders will be willing to support fossil fuel projects.

Appendix A: Guide to the LNG Gas-to-Power Value Chain

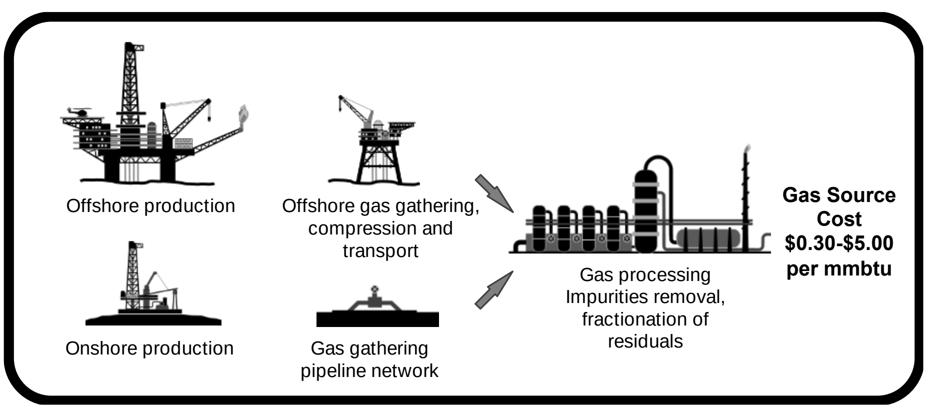
The following annex provides an overview of the LNG gas-to-power value chain and outlines the technical and financial assumptions used in the report's analysis.[149] Figure 35 provides a summary of the overarching capital cost factors analyzed, explained in greater detail below.

Figure 35: Attributes Used to Derive Capital Costs for LNG and Power Generation Infrastructure

Attribute	LNG Terminal	Power Plants
Scale	Throughput capacity	Generation capacity
Type	FSRU or land-based	CCGT or OCGT
Site	Greenfield or brownfield expansion	
EPC source	Domestic or cross border	
Funding source	Domestic, foreign, or mixed	
Regulatory regime	Independent, pass-through or restricted tariffs	
Country risk	High investment grade, low investment grade,	

1. Gas Production and Processing

The upstream portion of the LNG supply chain runs from field production to processing, in which gas is processed to a specific quality standard suitable for conversion into LNG. This report relies on average costs from various established LNG exporting sources. In general, gas from easily accessible conventional onshore developments is significantly cheaper than remote and/or ultra-deepwater offshore plays.[150 151]

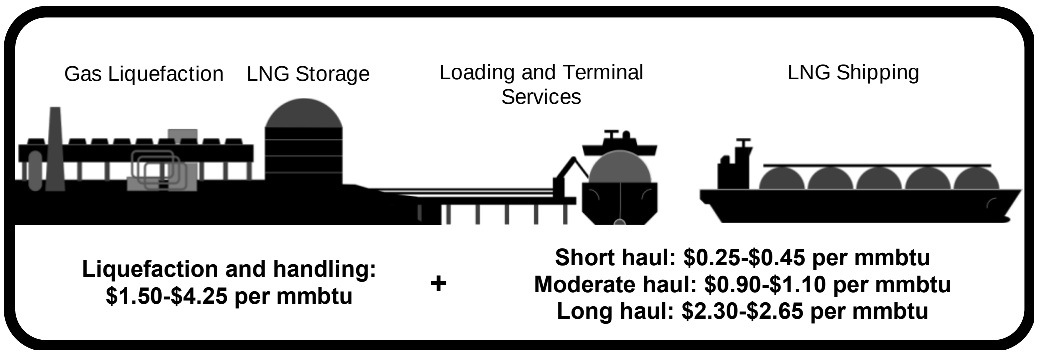


[149] Price ranges for various steps in the LNG-to-power value chain were derived from multiple industry research sources, along with original research and analysis.
[150] Qatar has amongst the lowest cost natural gas sources globally while the northern coast of Australia and the Russian Arctic Circle fields are at the higher end of the cost range.
[151] Hydraulic fracturing ("fracking")/tight gas plays add to source costs for onshore fields.

2. Liquefaction, Loading, and Transportation of LNG

Liquefaction charges depend on the scale of the liquefaction train used and their configuration. Suppliers may opt for mega-scale trains, as is the case in Qatar, or numerous small modular trains, as is the case for some suppliers on the US Gulf Coast. Liquefaction fees can vary widely depending on the size and remoteness of the facility.

LNG costs are typically quoted on a free on board (FOB) basis, which includes all costs up to ship loading, exclusive of shipping and regasification expenses at the point of delivery. Shipping costs depend on carrier size, chartering day-rates, shipping lane transit fees, and the ship's distance to the customer.



3. Receiving, Storage and Regasification

Receiving terminal costs primarily depend on whether the importer uses a conventional onshore terminal or a floating storage and regasification unit (FSRU). Due to storage tank construction, onshore terminals with a berthing/unloading jetty are typically more expensive and time consuming. Costs depend primarily on the number and size of storage units required, as well as jetty length and berthing configurations. While onshore configurations add time and cost, they are designed to operate in all weather conditions, benefiting from sheltered harbor for LNG offloading.

FSRU costs are materially lower when the LNG transfer anchorage point is in a calm water harbor compared to a remote, open water mooring mast. Storage volume and the FSRU's regas throughput capacity also impact costs. Compared to onshore terminals, FSRUs are quick to procure, can access shipping finance vehicles, have locational flexibility, and can be replaced by larger or smaller units. However, ship-to-ship gas transfer operations can be hazardous in inclement weather, and more exposed offloading facilities face higher risks.[152] [153]

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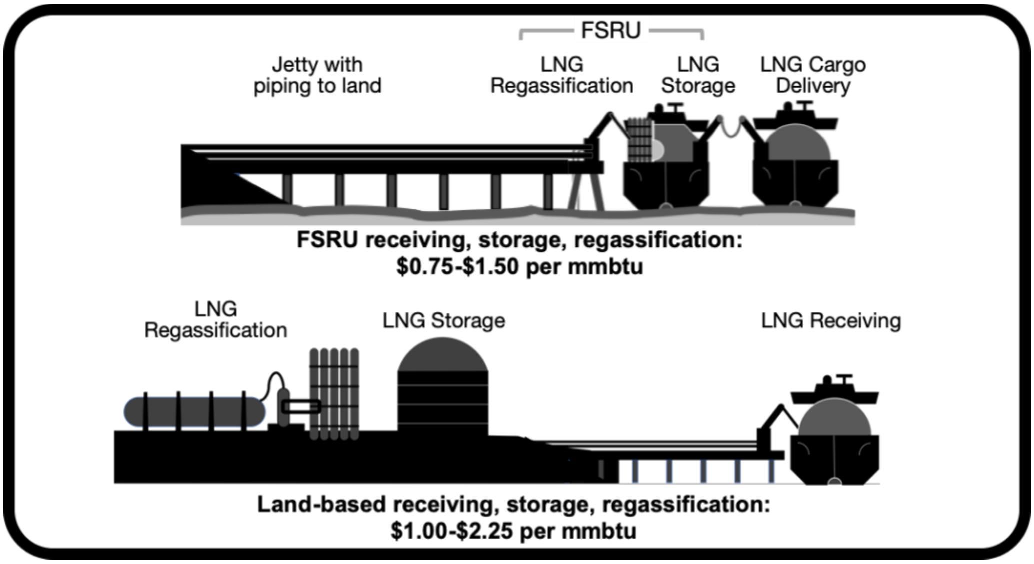
[152] This is particularly true for single point subsea moorings, wherein ships may rotate freely in open water.

[153] There are many configurations for FSRU berthing and LNG transfers (e.g., single point moorings with turrets or towers, remote jetty islands, shallow water or deep water, rough seas or calm). Configurations are based on a combination of harbor/mooring conditions and proprietary



4. Power Generation

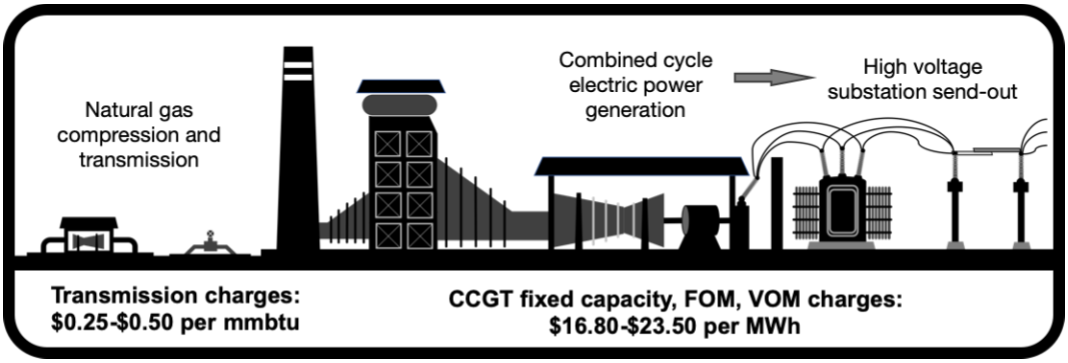
CCGT power plants have a relatively narrow band of costs per MW, assuming similar unit sizes. By contrast, full plant construction costs—including civil works, balance of plant, cooling and control systems, etc.—are more site-specific and can vary widely. For the purposes of this analysis, plant sizes are assumed to be larger, utility-scale turbines ranging from 275-525MW per turbine. Cost adjustments are made in the analysis depending on:

- **Plant scale in MW**. Larger plants tend to have greater scale economies.
- **Number and configuration** of gas turbines (GT), heat recovery steam generators (HRSG), and steam turbines (ST). Typical GT:HRSG:ST configurations are 1:1:1 or 3:3:1.
- **Cooling systems used**. Once-through water systems are the most effective, but also the most environmentally impactful. Air cooling systems are used in low water availability areas, but consume significant energy to achieve the necessary temperature drops.
- **Ambient operating temperature and humidity where the plant is located**. High temperature and humidity conditions common in Southeast Asia can reduce plant output 5%-10%, adding to operational costs by reducing output efficiency.

Additional market and site-specific factors were included in the project-by-project analysis, such as whether the site was greenfield or a brownfield expansion and proximity to fuel supply source. Country-specific factors were also considered, such as the availability of domestic heavy construction contractors, reliance on domestic

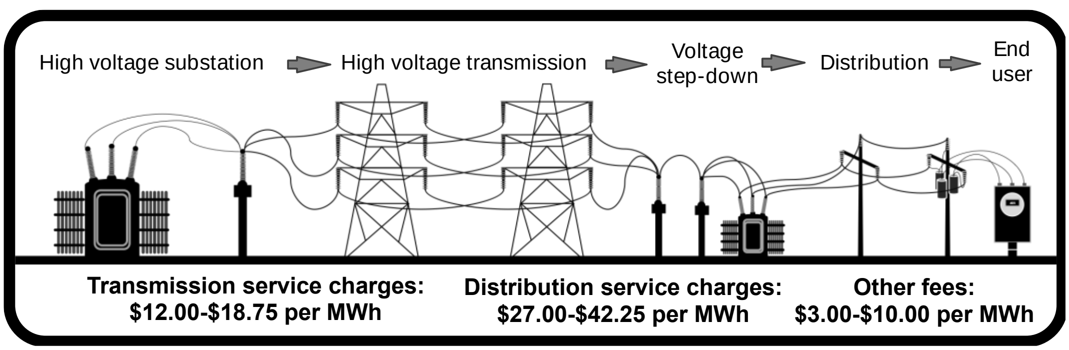
mooring designs. In general, costs are higher for more complex mooring and transfer configurations.

or offshore financing, the country risk rating and governance matters, and a more subjective measure of ease of implementing, supplying, commissioning, and completing large infrastructure projects in each country.



6. Electricity Transmission and Distribution (T&D)

The report develops a generalized overall cost buildup of the electricity T&D service chain to assess the all-in cost to the consumer and/or investor- or government-owned utilities. T&D tariff charges in several markets were averaged to provide ranges, shown in the figure below. These numbers only provide a general order of magnitude addition to the total power bill, and were not used to assess the feasibility of a given power or gas import project.



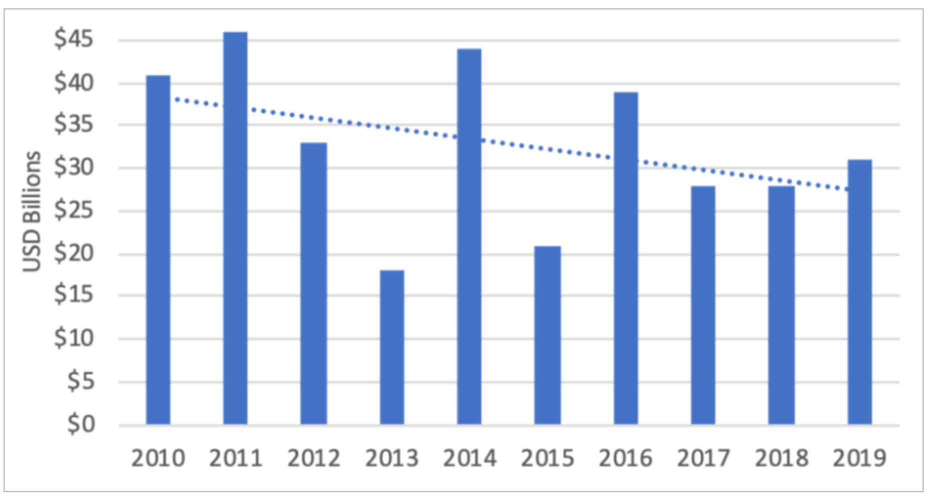
Appendix B: Project Finance Lending: Market Considerations and Constraints

Funding for Downstream LNG and Power Projects

Unlike corporate financing methods commonly used for the upstream oil and gas sector, downstream LNG import, transmission, and electric power generation projects typically rely on limited-recourse project financing. This involves establishing special purpose vehicles (SPVs), which are made up of consortia of shareholding partners focused on a single project. SPVs are legally distinct companies, meaning their performance does not impact each investor's broader operating businesses.

Privately invested, project-financed power generation projects have a well-established track record throughout Asia.[154] However, the project finance lending market has tightened and become more conservative since the 1997 Asian financial crisis, with fewer banks participating in the limited recourse space (see Figure 36 below). Therefore, it is critical to examine the conditions facing project finance transactions today and place them in the context of the huge pipeline of LNG-to-power deals proposed across Asian markets.

Figure 36: Asia Pacific Project Finance Lending Volume



Source: Adapted from Global Infrastructure Hub, October 2020.

Why Project Finance for Downstream Projects?

Corporate bond issuances fund most upstream oil and gas investments[155] because companies undertaking these investments are typically large, publicly traded, or

[154] Some the first, lowest cost, and most successful independent power projects globally are based in the region. Meghnaghat and Bibiyana in Bangladesh, Phu My 2.2 in Vietnam, and more recently Mingyan in Myanmar all achieved low prices and created precedent-setting contractual deal structures, mobilizing unprecedented amounts of foreign capital in their host countries.
[155] Namely exploration, production, and processing.

nationally owned enterprises. This means investors in the global oil market well understand their operations and financial viability.

For downstream projects, however, a project-by-project approach is more common. The context of LNG projects is often very country- and sub-region specific. New markets are either being established or there are large leaps in demand growth. LNG project sponsors, therefore, do not benefit from the visibility the global commodity market provides for risk and price discovery. As a result, LNG receiving terminals are typically financed on a limited recourse basis—much like the power generation facilities with which terminals are often associated.[156] [157]

Global required investment in energy infrastructure is often cited in the trillions of dollars. Policymakers and civil society can become numb to the meaning and magnitude of these figures, but financial lending for project infrastructure is not so cavalier. On the contrary, bank-based lenders are extremely constrained in project-based lending, particularly in developing country markets.

Developing countries face significant challenges attracting private capital to fund infrastructure expansions, and capital available in any given year is highly constrained. Multiple projects undertaken over a relatively short period may impact the ability of newer projects to secure financing. A brief review of how banks approach project finance lending in terms of their institution's overall credit portfolio demonstrates why.

Lending Basics

Banks make money by creating loan portfolios measured in multiples of their available capital.[158] By maintaining adequate capital reserves, banks ensure they have enough available capital to protect themselves from insolvency whenever a negative market movement imperils loan recovery from creditors. If banks loosen lending limits too much, they may not have enough capital to cover their losses during a market plunge.[159] As a result, national and international regulations have established prudency requirements for banks to back up their risks, known as risk-adjusted statutory capitalization protection of loan portfolios. For example, members of the Basel Committee on Banking Supervision are required to have a certain level of statutory capital in reserve as insurance against creditor defaults.[160]

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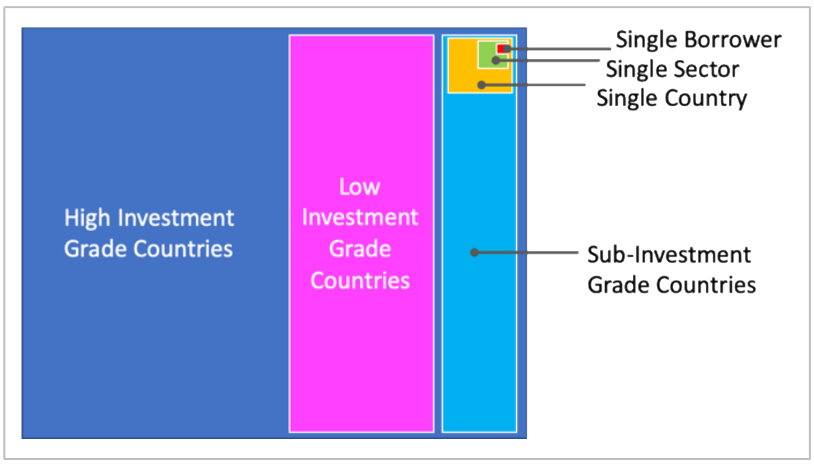
[156] LNG ship-based finance, by contrast, is on an asset-secured basis due to the mobile nature of vessels, supported in certain circumstances by long-term charters.
[157] Onshore LNG terminals are linked to a specific geographic location within their host country market, while FSRU-based LNG receiving terminals have a blend of land-based and ship-based asset financing (see footnote 3). The jetty, piping and, at times, additional onshore storage units are fixed, site-specific assets, whereas the FSRU itself can be unmoored and moved.
[158] This is known as a capital adequacy ratio, which ensures that banks have enough available funds on hand to absorb a reasonable amount of losses before becoming insolvent and consequently losing depositors' funds.
[159] This happened during the US Savings and Loan Crisis of the 1980s, as well as the Global Financial Crisis of 2008.
[160] Currently, the global banking market is moving on the third round of Basel prudential minimum capital allocations under the Basel III agreement (September 20, 2010).

Risk Allocation and Prudential Limits on Bank Portfolios

Banks, especially large global financial institutions, allocate capital into various risk buckets, with the smallest buckets containing the highest risk loans. The level of risk is often determined by credit rating of the borrower. For countries, banks consider sovereign debt credit ratings. Countries with the highest credit rating have the largest number of lenders willing to lend money at the most competitive, lowest interest rates for the longest periods. Countries with the lowest credit ratings, in contrast, have few lenders willing to provide loans. When high-risk countries can secure loans, they are typically in much smaller amounts, at higher interest rates, for shorter time periods.

The cost of lending to sub-investment grade markets is higher is due to prudency. Banks must keep a larger percentage of capital on hand to cover the risk of default for that high-risk loan. Because banks cannot lend that reserve capital, and because that required reserve capital is higher than the same loan in an investment grade market, the bank must earn a higher margin to cover the opportunity cost of the reserve capital.

Figure 37: Illustrative Bank Prudential Portfolio Allocation



Source: IEEFA.

The Challenge of Lending in Sub-Investment Grade Markets

The percentage of a bank's lending portfolio tends to be lowest in sub-investment grade countries (see Figure 37 above). Banks are also limited in how much they can lend to single countries within that share. There are additional limits to specific sectors, like energy, and limits on the amount any single borrower can receive, whether a company or a project.

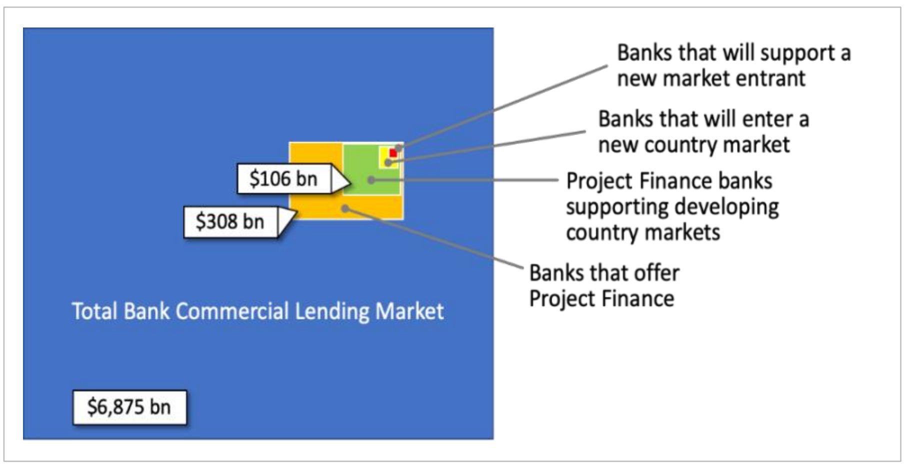
The risk analysis is more stringent for limited recourse project finance transaction structures used to fund LNG terminals and power generation facilities. Unlike corporate loans, which are secured by the entirety of a borrower's corporate operations, project finance loans rely solely on the successful operations of an individual project. In project finance, therefore, lenders take extra care to account for all possible risks and contingencies during both ordinary operations and in cases of trouble.[161]

Project Finance Is a 'Boutique' Subset of Overall Commercial Lending

Project finance loans are analytically demanding and require specialized teams, so only a small subset of commercial banks provide them. Even those banks tend to severely limit the portfolio allocation to project finance loans as a percentage of their overall lending portfolio (see Figure 38 below). Fewer than half of project finance institutions worldwide participate in cross-border developing country transactions. Banks that do provide project finance loans in developing markets must be assured the deal will be realized within a reasonable timeframe, with the least possible risk, and that the project will perform dependably throughout its life.

Familiarity with a given country's project lending market breeds comfort, as well as caution. An experienced bank knows the potential advantages and pitfalls in a given country. It knows the domestic political, financial, and corporate environment, and the characteristics of a deal that could get completed.

Figure 38: Scale of Project Finance Market Versus Total Market



Source: IEEFA.
Note: 2019 Global bank lending market figure used to represent favorable pre-COVID market conditions. Sources: Total market: Research and Markets, Jan 2021. Project Finance market and emerging market share: Refinitiv, Global Project Finance Review 2020. Banks entering new countries, supporting new clients: IEEFA estimates from review of Project Finance International historic league table data, 2010-2020.

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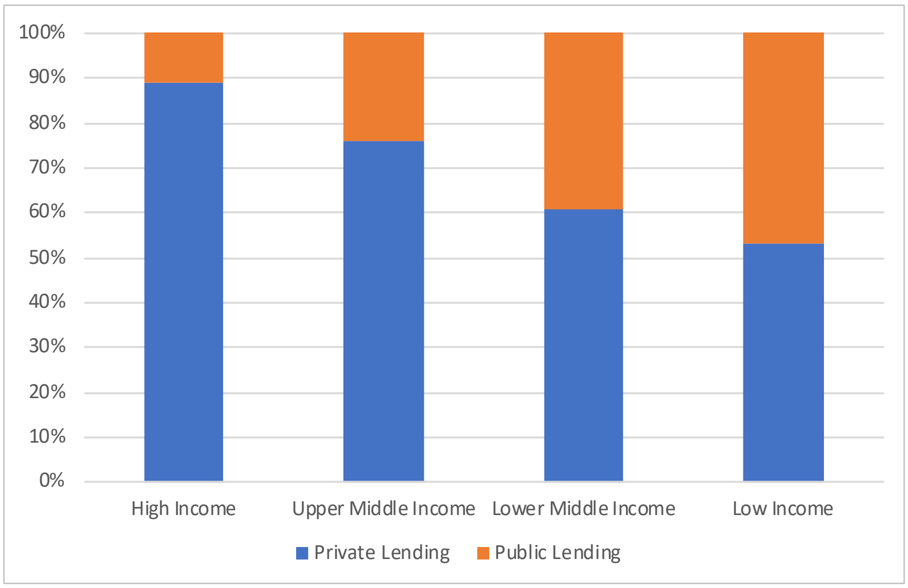
161 This level of attention to detail is what leads to project finance transaction contractual documentation running into the hundreds of pages.

Higher Risk Markets Require a Larger Percentage of Public Financial Support

Since attracting private capital in developing country markets is more difficult, public budgets and lending vehicles are responsible for a higher percentage of overall financing (see Figure 39 below). Sound sector planning, and objective and transparent project selection and procurement processes, are therefore more important from both technical and economic perspectives. These measures make it easier for investors to approve projects and their risk.

Figure 39: Source of Infrastructure Investment by Country Income Group



Source: Global Infrastructure Hub, October 2020. Income groups determined by World Bank definition.

Putting Project Finance Lending Volumes Into Perspective

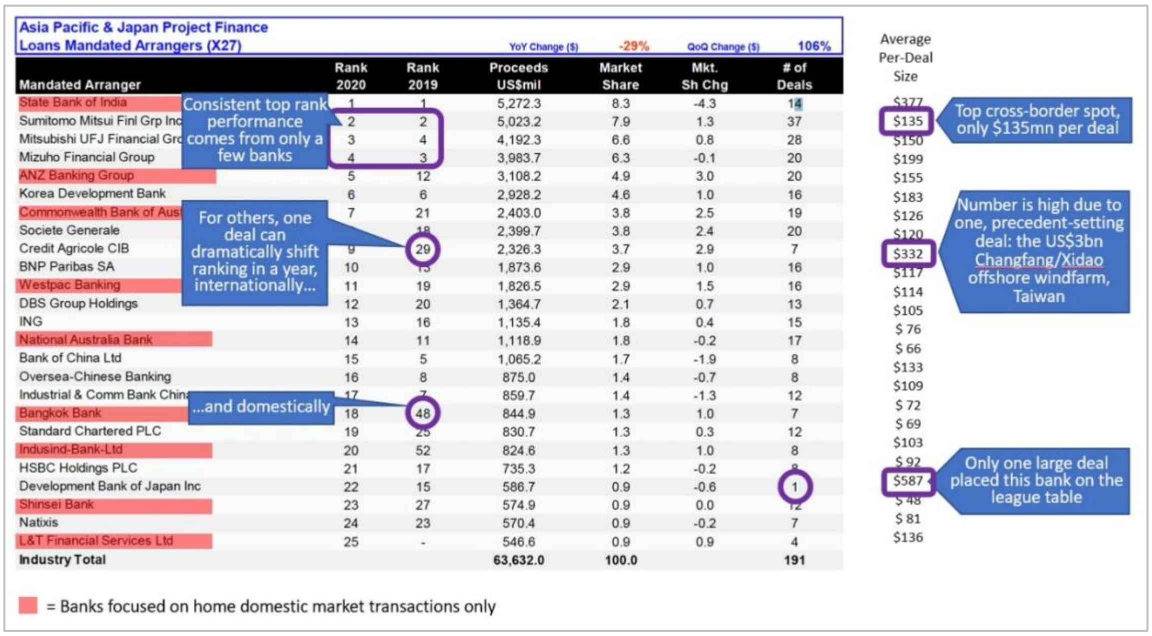
The Basel III capital adequacy commitments mean that banks are stingy regarding the final loan amount in a developing country market remains in their asset portfolio. As a result, the larger syndicated project finance loans may have several dozen participants amassed to get each bank's "take-and-hold" loan-level down to manageable minimums within individual prudential limits.[162] These final hold numbers are shockingly low compared to US$ multi-billion deal sizes.

According to Refinitiv, for example, the top lead arranger in 2020 operating cross-border in Asia Pacific was Sumitomo Mitsui Financial Group (SMFG).[163] SMFG arranged US$5,023 million in project debt across 37 deals (50% of which were located in its home market of Japan), for an average of just US$135 million per deal

[162] "Take and hold" refers to the basis on which a lender acquires loans without intention to resell.
[163] All figures here refer to Refinitiv's *Global Project Finance Review*, Full Year 2020.

(see Figure 40 below).[164] The top 10 regional project finance deals in 2020 totaled over US$29 billion of debt, but only *one* was a cross-border transaction—a US$2.58 billion loan in Indonesia. The others were either in developed country markets or in completely domestically banked markets, like India. Assuming the main underwriters of the Indonesian deal each took on $150 million of project debt, 17 banks would have been needed to complete the transaction within the private lending market. That represents a significant portion of all project finance institutions open for business in developing Asia for just one project.

Figure 40: 2020 Asia-Pacific Project Finance Lead Arrangers and Their Average Deal Size



Asia Pacific & Japan Project Finance Loans Mandated Arrangers (X27) — YoY Change ($) -29% — QoQ Change ($) 106%

Mandated Arranger	Rank 2020	Rank 2019	Proceeds US$mil	Market Share	Mkt. Sh Chg	# of Deals	Average Per-Deal Size
State Bank of India	1	1	5,272.3	8.3	-4.3	14	$377
Sumitomo Mitsui Finl Grp Inc	2	2	5,023.2	7.9	1.3	37	$135
Mitsubishi UFJ Financial Gr	3	4	4,192.3	6.6	0.8	28	$150
Mizuho Financial Group	4	3	3,983.7	6.3	-0.1	20	$199
ANZ Banking Group	5	12	3,108.2	4.9	3.0	20	$155
Korea Development Bank	6	6	2,928.2	4.6	1.0	16	$183
Commonwealth Bank of Aus	7	21	2,403.0	3.8	2.5	19	$126
Societe Generale	[illegible]	18	2,399.7	3.8	2.4	20	$120
Credit Agricole CIB	9	29	2,326.3	3.7	2.9	7	$332
BNP Paribas SA	10	[illegible]	1,873.6	2.9	1.0	16	$117
Westpac Banking	11	19	1,826.5	2.9	1.5	16	$114
DBS Group Holdings	12	20	1,364.7	2.1	0.7	13	$105
ING	13	16	1,135.4	1.8	0.4	15	$ 76
National Australia Bank	14	11	1,118.9	1.8	-0.2	17	$ 66
Bank of China Ltd	15	5	1,065.2	1.7	-1.9	8	$133
Oversea-Chinese Banking	16	8	875.0	1.4	-0.7	8	$109
Industrial & Comm Bank Chin	17	7	859.7	1.4	-1.3	12	$ 72
Bangkok Bank	18	48	844.9	1.3	1.0	7	
Standard Chartered PLC	19	25	830.7	1.3	0.3	12	$ 69
Indusind-Bank-Ltd	20	52	824.6	1.3	1.0	8	$103
HSBC Holdings PLC	21	17	735.3	1.2	-0.2	8	$ 92
Development Bank of Japan Inc	22	15	586.7	0.9	-0.6	1	$587
Shinsei Bank	23	27	574.9	0.9	0.0	12	$ 48
Natixis	24	23	570.4	0.9	-0.2	7	$ 81
L&T Financial Services Ltd	25	-	546.6	0.9	0.9	4	$136
Industry Total			**63,632.0**	**100.0**		**191**	

= Banks focused on home domestic market transactions only

Project Financiers Value Transparency and Competition

Deal structuring is important. Bankers will take greater confidence when approached by a consortium that has (a) won the deal through a fair, competitive bid; (b) taken time to tighten up the details of its supply agreement or PPA; (c) locked in an EPC contract with reputable suppliers and construction contractors; and (d) has an extensive operating track record (or is partnered with an expert who does) in that emerging market or similar markets.

Project Financiers Value Experience and Favor Existing Clients

Given banks' prudential limits, and due to the size of projects proposed in the fossil fuel supply and fossil-based power generation space, a typical commercial project

[164] The average deal size tends to decrease with lead arranger rankings (see Figure 40). For example, the 24th ranked player, Natixis Bank, had an average deal size of $81 million.

finance bank could support just one deal in a given country within a multi-year timeframe. Therefore, they must be highly selective. Banks need to know that the sponsors are credible. They need to know the project is necessary and has government support (or energy market support, in the case of competitive supply markets).

As a result, bankers tend to follow their best, most experienced relationship clients into a deal, eschewing newcomers to the country market or the sector. Partnering with a relationship client slightly reduces lender risk, as the banker knows their counterpart can structure a deal successfully, complete and operate projects, and repay loans. This brings comfort to the lender's credit committee, and that fillip of confidence may permit the bank to follow the client into a new country market.

A lack of experience and previous relationships, on the other hand, is likely to be a non-starter for most top-tier lending banks. Many of the announced transactions across Asia have been proposed by small, first-time players. These newcomers may have an attractive investment angle in the country where they seek to invest, or they may claim to have the political backing of their home country's government.

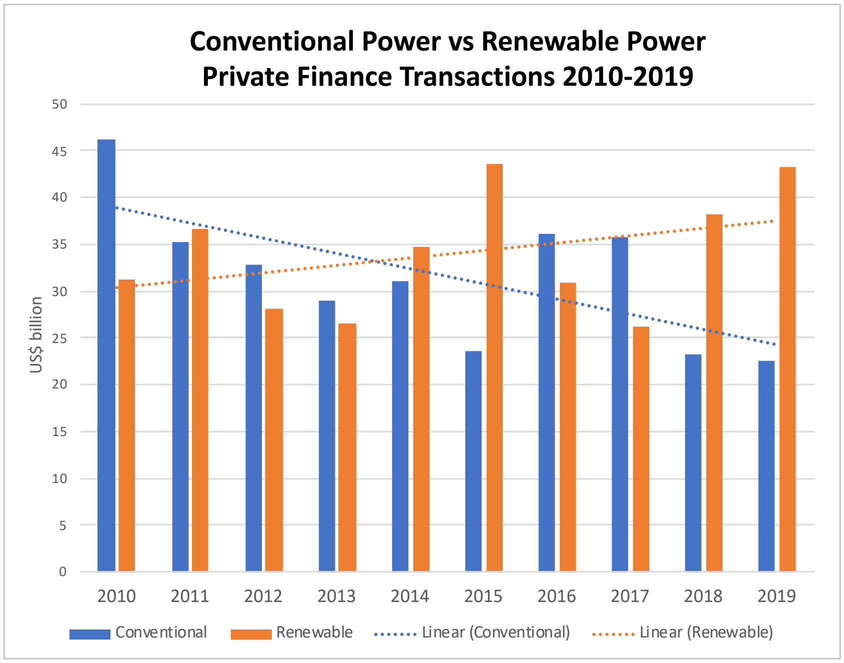
However, these small advantages, are not enough to complete a deal, as the biggest challenges lie in the project and its operating financial structure. Billion-dollar transactions involve multiple layers of contracting and performance arrangements to satisfy the investor consortium. Project sponsors must demonstrate that equity capital is in hand, with additional capital in reserve to weather cost overruns, overcome completion delays, and demonstrate resilience to lenders and the government. Sponsors must also arrange air-tight sale and purchase contractual structures with the counterparty to assure lenders that cash will flow throughout the contract term, regardless of political or economic developments. Emerging markets are often notoriously difficult to navigate, even for the most experienced developers. Therefore, sponsor credibility is of the highest importance to financiers who are being asked to fund 60%-80% of a billion-dollar project.

Where Will Project Finance Lenders Direct Their Money?

Money is flowing into energy, but it is increasingly directed toward the renewable energy space. Figure 41 below shows clearly that conventional power project financing in Asia is rapidly declining, while financing for renewables is growing. With the growing attention to sustainable investing, backed by emerging green investment taxonomies and environmental, social, and governance (ESG) reporting guidelines, these trends will likely accelerate.

Absent unrestricted flows of bilateral development aid, there is a practical limit to the size and/or number of privately funded fossil fuel-based projects that a developing market country can realize in a given year or over consecutive years. This is because risk exposures do not reset on a calendar basis. Loans must either be paid off over time or sold down to free up prudential limit headroom. The only other way to create lending space is the continued growth, advancement, and credit improvement of a country's energy sector, and the credit strength of the country in which the investment sits.

Figure 41: Trends in Project Finance Lending in Asian Markets



Source: Global Infrastructure Hub, October 2020.

Appendix C: Sovereign Credit Ratings for Asian Countries

Country	S&P	Moody's	Fitch
Bangladesh	BB-	Ba3	BB-
Cambodia	B	B2	n/r
China	A+	A1	A+
India	BBB-	Baa3	BBB-
Indonesia	BBB	Baa2	BBB
Japan	A+	A1	A
Laos	n/r	Caa2	CCC
Malaysia	A-	A3	BBB+
Pakistan	B-	B3	B-
Philippines	BBB+	Baa2	BBB
Singapore	AAA	Aaa	AAA
South Korea	AA	Aa2	AA-
Taiwan	AA	Aa3	AA
Thailand	BBB+	Baa1	BBB+
Vietnam	BB	Ba3	BB
United States	AA+	Aaa	AAA

Appendix D: Gas and Power Pricing Regimes in Emerging Asian Countries

	LNG Buyer	Gas Pricing Regime	Power Offtaker	Power Pricing Regime
Pakistan	PSO and PLL	Wholesale: Oil-linked prices from domestic fields passed through to gas distributors. LNG prices regulated separately. Retail: Prices for residential and fertilizer sectors cross-subsidized by power, industrial, and transportation sectors.	NTDC	Regulated retail prices set according to cost-plus pricing and subsidized with tariff differential subsidy set by Government of Pakistan.
Bangladesh	Petrobangla	LNG and domestic gas prices blended and set at a weighted average prices. Retail prices are regulated below cost of supply.	BPDB	Retail tariffs set at regulated prices below wholesale costs.
Vietnam	PV Gas	Wellhead prices are negotiated on a cost-plus basis, while T&D tariffs are approved by the government at each stage of development. Sales prices are set on a case-by-case basis in negotiations with end-users.	EVN	Power price negotiated with each plant. End-user tariffs are set by the government, often below the cost of supply.
Thailand	PTT	Oil-linked prices passed through to gas offtakers based on cost-plus pricing.	EGAT	Power costs passed through to end-users based on cost-plus pricing regime.
Philippines	Private companies	Oil-linked prices passed through to gas offtakers on contractual basis.	Private companies	Full cost pass through to end-users.
Cambodia	CNGC	Prices set on a case-by-case basis.	EDC	Retail prices for national grid set according to cost of supply, with cross subsidies from large, urban end-users to smaller households and rural customers. Fuel costs passedd through according to monthly adjustments.
Myanmar	MOGE	Wellhead prices negotiated in production sharing agreements. Pipeline exports linked to various indices. Domestic prices set at 10% discount to export prices. Gas prices for power sector are subsidized.	MEPE	Retail prices subsidized at below market costs.
Indonesia	PGN	Domestic LNG prices shifting from oil-indexed to regulated, fixed prices.	PLN	Retail prices subsidized at below market costs.
Malaysia	Petronas	Gas subsidies for power and non-power sectors removed gradually in favor of netback pricing mechanisms. The price of gas volumes consumed above specific levels is unregulated.	TNB	Low-income groups subsidized and cross-subsidized, though government aims to reduce subsidies

Source: Compiled by authors

Note: Pakistan State Oil (PSO); Pakistan LNG Ltd. (PLL); National Transmission & Despatch Company (NTDC); Bangladesh Power Development Board (BPDB); PetroVietnam Gas (PV Gas); Vietnam Electricity (EVN); Petroleum Authority of Thailand (PTT); Electricity Generating Authority of Thailand (EGAT); Cambodia Natural Gas Corp. (CNGC); Électricité du Cambodge (EDC); Myanmar Oil and Gas Enterprise (MOGE); Myanma Electric Power Enterprise (MEPE); Perusahaan Gas Negara (PGN); Perusahaan Listrik Negara (PLN); Petroliam Nasional Berhad (Petronas); Tenaga Nasional Berhad (TNB).

Appendix E: Cost and Operating Assumptions Used for LNG Calculations

The table below lists the cost parameters used for this analysis. These provide an optimistic view of LNG plant costs and operations. For example, based on load cycling, conversion efficiencies of an LNG-fired plant overall would likely be lower, requiring greater fuel consumption and increasing cost. Ambient regional temperatures and humidity would likely penalize output by 5-10%, adding to per-kWh fuel consumption. Land-based terminals can be 50-100% more expensive than FSRUs. However, this analysis aims to stress the relative value of LNG facilities against alternative energy sources, based on reasonably favorable LNG conditions.

Cost Category	Description
Power Plant Costs	
Capital Cost:	
H-Class Gas Turbine, combined cycle, 1100MW class; 3:3:1 GT, HRSG, ST configuration	Ranging from US$920-1,040/kW installed. EPC costs adjusted for developing Asia markets, with lower land, civil, and certain balance of plant costs and higher offshore management cost.
Assumed Operating Parameters:	
Plant load factor	75%. This assumes the plant is operating for 75% of the year at full-load at optimal efficiency.
Heat rate	6,370 btu/kWh with 2.8% auxiliary load and no hot weather capacity penalty was used to calculate fuel consumption.
Financing Costs	
Risk Premium	Premium applied based on country-by-country risk assessment
Debt	Ratio: 75% debt Term: Construction plus 15 years Interest: 10-year UST + 300 basis points
Construction period	30 months
LNG Supply Chain Costs	
LNG receiving terminal type	FSRU with jetty mooring, calm water
Greenfield site, all-in cost	US$100mn-120mn per mtpa
LNG commodity costs	Primary analysis variable. Goal was to determine the impact of changes in LNG cost on a full cost recovery electricity tariff. Cost of LNG taken FOB, which is inclusive of exporter gathering, processing, liquefaction, storage and loading costs.
Shipping costs	Average of short-, medium-, and long-haul transit times, yielding a US$1.46/MMBtu blended rate. US$85,000 per day charter rate with 17kts speed.
Storage and regas costs	Based on the FSRU, no onshore storage. US$0.75/MMBtu fee.

Sources:

- *CCGT parameters: Sargent and Lundy/US EIA 2020; International Energy Agency 2020.*
- *LNG terminal parameters: Refinitiv project finance transaction reports, GIIGNL Annual Report 2021, industry trade journal reporting.*
- *LNG costs: Historic index data, Henry Hub, Brent, JCC: macrotrends; IHS Markit. Pricing formulae and adjustments: Flower and Liao 2012; IHS Markit. Shipping cost: Capra Energy.*
- *Financing parameters: Moody's; Refinitiv project finance transaction reports; NYU Stern; worldgovernmentbonds.com*
- *Risk premium: Applied using NYU Stern Damodar country risk model to calculate each country's risk premium.*

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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