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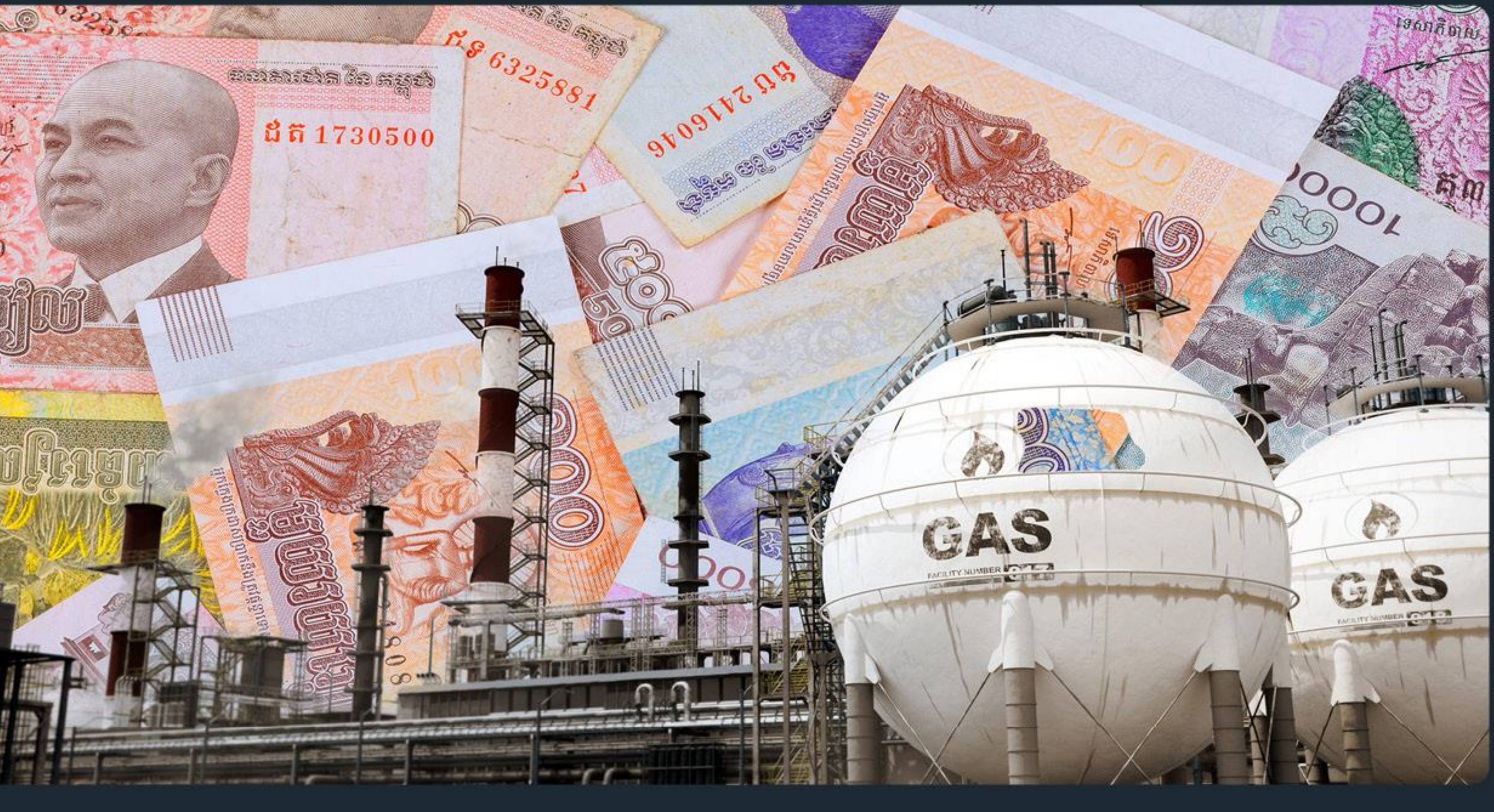
Cambodia at a Crossroads: An Economic Assessment of LNG-to-Power Plans

Managing risks to energy security, reliability, and affordability

Sam Reynolds, Research Lead, LNG/Gas, Asia
Christopher Doleman, LNG/Gas Specialist, Asia



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Key Findings

In recent years, liquefied natural gas (LNG) markets have been highly unstable due to geopolitical disruptions, severe weather, supply outages, and other factors. For emerging Asian countries, an inability to secure affordable LNG supplies resulted in fuel and power shortages. Rising LNG supply will lower prices this decade, but fuel costs are unlikely to fall enough to compete with other electricity sources in Cambodia.

LNG imports will increase Cambodia's fuel import bill and potentially hinder government efforts to reduce electricity tariffs. Recent LNG prices have been more than double imported coal prices, demonstrating the high costs of switching from coal to LNG. LNG importation has a history of increasing electricity prices in other Asian markets.

Cambodia has multiple options for buying LNG that entail various risks for energy security and cost. For example, spot markets can be highly risky during global market volatility, whereas long-term contracts can incur penalties if LNG is not needed. Developing an LNG procurement strategy will require careful consideration of these tradeoffs.

Cambodia's small LNG demand is likely to increase the cost per unit of delivered LNG. During the earlier, limited demand stages of value chain development, the country may consider building smaller infrastructure, including small-scale import terminals or containerized LNG configurations. However, small-scale concepts could result in significantly higher per-unit LNG costs.

Executive Summary

Over the past two decades, rapid economic growth and electrification in Cambodia have driven substantial changes in the country's electricity system. Electricity demand has grown at a blistering 16% per year since 2009, driven by high Gross Domestic Product (GDP) growth and nationwide electrification efforts. Meanwhile, the country's power mix has evolved from a system largely dependent on fuel oil in the 2000s, hydropower in the 2010s, and, more recently, coal.

However, due to the global transition from coal and recent financial challenges for new coal plants, the country is set to begin a new phase of power sector development. Recent government plans envision significant increases in renewable energy capacity — toward a goal of generating 70% power from renewables by 2030 — as well as the introduction of liquefied natural gas (LNG) and its associated infrastructure. Although natural gas has historically not played any role in the country's energy system, the government now expects LNG-fired power capacity to reach 900 megawatts (MW) in the 2030s, while some forecasts see it reaching 2,700MW by 2040 and 8,700MW by 2050.

The push to build large LNG-fired power plants largely stems from a concern that renewables like wind and solar do not provide uninterrupted, dispatchable power. LNG is considered a necessary transition fuel for grid reliability as electricity demand continues to rise.[1] However, this report finds that the share of wind and solar generation in Cambodia has significant potential to increase without jeopardizing grid operations. Moreover, establishing an LNG supply chain will likely require rigid, long-term contracts that lock-in fossil fuel infrastructure for decades.

However, high dependence on LNG could jeopardize national energy security rather than improve it. LNG has proven unreliable for many emerging Asian nations, which often struggle to purchase the fuel when global prices spike. Even if global prices fall, LNG is highly unlikely to compete with other sources of energy in Cambodia, including solar, wind, hydropower, and coal. Cambodia is especially likely to pay above-market rates for its LNG supplies as a potential new market entrant with limited bargaining power, uncertain LNG requirements, and lower demand.

This report provides an overview of Cambodia's power sector plans and global LNG markets, as well as key considerations for the country's energy security and affordability as plans for LNG importation materialize.

Section 1 discusses recent trends in the country's power sector. **Section 2** examines recent global LNG market trends, focusing on the experience of emerging Asian LNG importers. **Section 3** assesses the volumes and costs of various proposals for LNG imports. **Section 4** examines recent cost trends in the Cambodian power sector and the potential impact of LNG-fired power generation on end-user tariffs. **Section 5** provides an overview of various LNG procurement strategies and their

[1] Kingdom of Cambodia. Long-Term Strategy for Carbon Neutrality. December 2021. Page 14.

tradeoffs. Finally, **Section 6** reviews various configurations for LNG importation, including smaller-scale and containerized LNG concepts.

Key findings of this report include:

- **In recent years, LNG markets have been highly unstable due to geopolitical disruptions, severe weather, outages at supply facilities, and other factors.** For emerging Asian countries, an inability to secure affordable LNG supplies resulted in fuel and power shortages. Over the past two years, extreme volatility in global LNG markets has demonstrated the evident risks of LNG importation for developing economies.
- **Global LNG supply is likely to increase this decade, but fuel costs are unlikely to fall to competitive levels for Cambodia's power generation**. For LNG-fired power to compete with other sources of electricity generation in Cambodia, LNG prices would likely have to fall to below US$5 per million British thermal units (MMBtu). However, prices have rarely fallen this low, as exporters typically require a selling price of US$7-8/MMBtu to recover production costs. As of August 2024, LNG prices in Asia were roughly US$14/MMBtu, and Cambodia could pay above-market rates given its small demand, uncertain LNG requirements, and inexperience with LNG procurement.
- **LNG imports may involve a steep increase in Cambodia's fuel import bill.** Recent LNG prices have been more than double imported coal prices, demonstrating the high costs of switching from coal to LNG. Operating just one 900MW LNG-fired power plant could cost between US$361 million (mn) and US$722mn (KHR1.48-2.95 trillion [tn]) per year for the fuel alone.
- **Relying on LNG for power generation could increase electricity tariffs, hindering government efforts to reduce rates.** At current fuel prices, the cost of LNG-fired power generation could be more than five times that of recent solar projects in Cambodia. Case studies of other Asian markets show that LNG importation can cause electricity prices to increase while complicating power sector development.
- **Cambodia has multiple options for buying LNG that entail various risks.** Cambodia could buy LNG from spot markets, short-term contracts, or long-term contracts. Each approach faces important tradeoffs for energy security and cost. For example, spot markets can be highly risky during global market volatility, whereas long-term contracts can incur penalties if LNG is not needed. Developing an LNG procurement strategy will require careful consideration of these tradeoffs.
- **Cambodia's LNG demand is likely to remain small, which could increase the cost per unit of delivered LNG.** Since LNG demand will likely remain limited in the early stages of value chain development, Cambodia may consider building smaller infrastructure, including small-scale import terminals or containerized LNG configurations. However, small-scale concepts could result in significantly higher per-unit LNG costs.

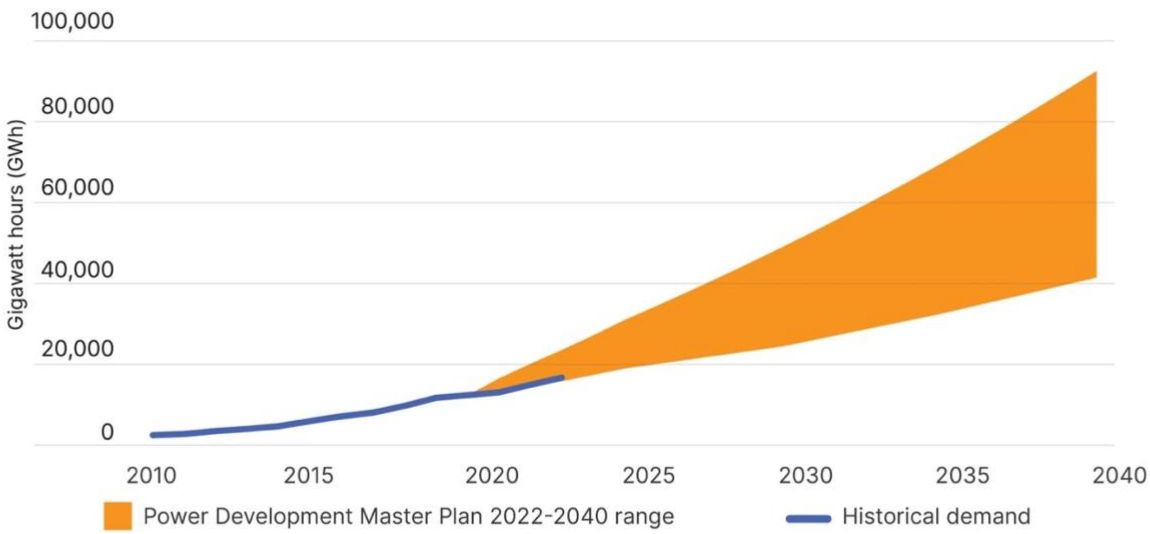
1. Overview of Cambodia's Power Market

I. Electricity Demand and Supply Growth

Over the past two decades, Cambodia has experienced remarkable growth. From 1995 to 2019, the country's GDP increased at an average annual rate of 7.6%, making it one of the fastest-growing economies worldwide.[2] Meanwhile, the share of Cambodian households with access to electricity increased from just 5%[3] in the mid-1990s to over 88%[4], making it one of the world's fastest electrifying countries.[5, 6] Power demand has grown at 16% per year since 2009.[7]

Economic growth is likely to continue driving electricity demand higher in the coming years as Cambodia aims to graduate from Least Developed Country (LDC) status by the end of the decade.[8] The government's Power Development Master Plan (PDMP) 2022-2040 envisions electricity demand rising 8.7% per year through 2030[9], and 7.2% annually through 2040.[10]

Figure 1: Historical and Planned Electricity Demand Range in Cambodia's PDMP 2022-2040



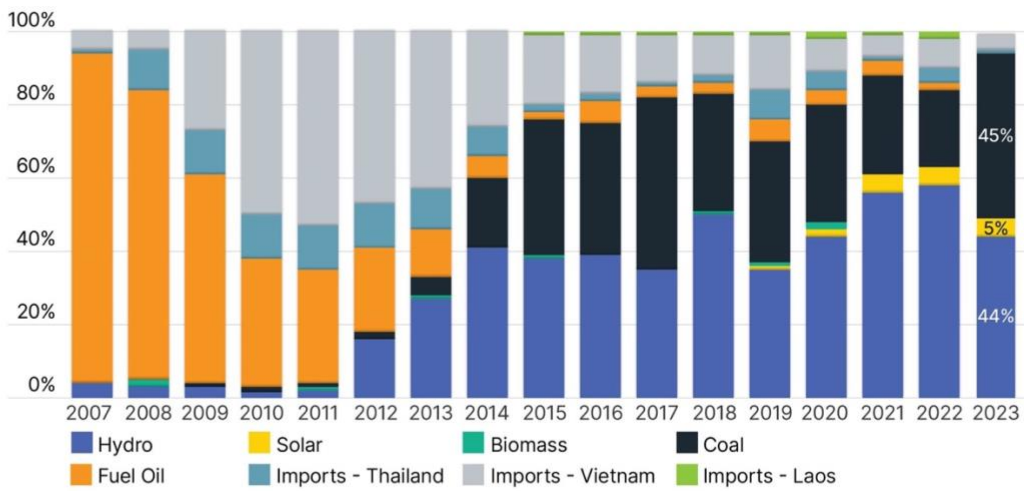
Source: EAC; PDMP 2022-2040.

[2] World Bank. The World Bank In Cambodia. April 2024.
[3] Rapid expansion of electricity access has been due largely to off-grid electrification programs, expansion of the distribution network, and the diversification of generation capacity. International Monetary Fund (IMF). World Economic Outlook, Steady but Slow: Resilience amid Divergence. April 2024. Page 142.
[4] World Bank. Mini Grids in Cambodia – A Case of a Success Story. November 2017. Page 07.
[5] World Bank. Access to electricity (% of population) – Cambodia. Date Accessed: 31 May 2024.
[6] Asian Development Bank (ADB). National Electrification Efforts in Cambodia. 2023. Page 42.
[7] Electricity Authority of Cambodia (EAC). Salient Features of Power Development in the Kingdom of Cambodia Until December 2023. 2024. Page 02.
[8] Khmer Times. Cambodia's graduation from LDC set for 2029. 10 April 2024.
[9] A medium-growth, base scenario projects that electricity demand may reach 30,080 GWh by 2030, up from 16,751 GWh in 2023, as reported by the EAC. Ministry of Mines and Energy (MME). Cambodia Power Development Master Plan 2022-2040. September 2022. Page 07; EAC. Salient Features of Power Development in the Kingdom of Cambodia Until December 2023. 2024. Page 02.
[10] A high-growth scenario without energy efficiency improvements could see electricity demand increase 10.6% annually to 92,527GWh.

Cambodia's electricity mix has evolved from a system powered primarily by fuel oil in the 2000s, hydropower in the 2010s, and, more recently, coal. Following severe drought-induced electricity shortages in 2019, the government advanced three new coal-fired power projects and agreed to purchase imported coal power from neighboring Laos.[11, 12, 13] The government also said it has no plans to dam the mainstream of the Mekong River in the coming decade, reflecting a goal to diversify from hydropower.[14]

One 700MW coal plant was brought online in 2022[15], causing the share of coal in the country's generation mix to rise to 45% in 2023. The remaining share of the country's power was met by hydropower (44%), solar (5%), and imports from neighboring countries (see Figure 2 below).

Figure 2: Historical Power Generation Mix of Cambodia



Source: IEEFA calculations based on EAC and ADB.

The push for new coal capacity sparked outcry from major global brands operating in Cambodia[16], and coal projects have since faced extensive delays and financial difficulties.[17] In 2021, the government said there were no plans to build new coal plants beyond those already approved[18], and a long-term strategy to achieve net-zero emissions by 2050 was submitted.[19, 20] The same year,

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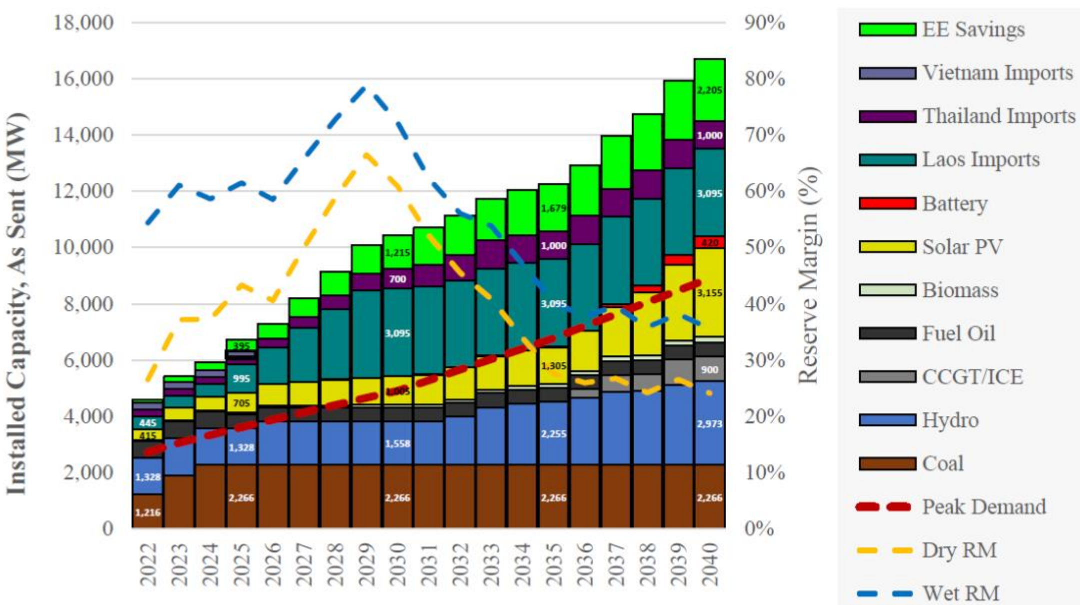
[11] The fuel plant referred to is the Kandal Province heavy fuel oil plant.
[12] The three coal plants referred to above include the 700MW Botum Sakor plant, the 700MW CIIDG-Huadian Sihanoukville plant, and the 265MW Han Seng plant. Xinhua Net. Cambodian gov't approves construction of 2 coal-fired power plants. 07 February 2020; The People's Map. CIIDG–Huadian Sihanoukville Coal Power Plant. 05 October 2021.
[13] Xinhua Net. Lao grid to deliver electricity to Cambodia. 11 November 2019.
[14] VOA Cambodia. Cambodian Official: No New Dams Planned for Mekong Mainstream Before 2030. 17 March 2020.
[15] Phnom Penh Post. China-backed 700MW coal power station online: HSPGC. 20 December 2022.
[16] VOA Cambodia. Global Brands Say Future Orders at Risk Given Cambodia's Increasing Coal Power. 12 August 2020.
[17] Southeast Asia Globe. Counting on coal: Cambodia's fossil fuel push flounders with delays. 25 October 2023.
[18] Asia Nikkei. Cambodia minister vows no new coal plants beyond those approved. 01 November 2021.
[19] Cambodia Ministry of Environment. Seeing the forest for the trees: Cambodia commits to achieving carbon neutrality by 2050. 18 January 2022.
[20] Chinese President Xi Jinping committed to halting financing and construction of new overseas coal-fired power plants. United Nations News. China headed towards carbon neutrality by 2060; President Xi Jinping vows to halt new coal plants abroad. 21 September 2021.

China, which has provided the largest source of financing for Cambodia's power sector, announced it would no longer finance coal projects abroad.[21]

II. Power Development Master Plan (PDMP) 2022-2040

Figure 3: PDMP 2022-2040, Installed Capacity



Note: CCGT/ICE refers to gas-fired, combined-cycle gas turbine and internal combustion engine power capacity that will likely require LNG imports.
Source: MME. PDMP 2022-2040. September 2022. Page 10.

The latest PDMP for 2022 to 2040, prepared in cooperation with the Asian Development Bank (ADB), focuses primarily on renewable energy to meet electricity demand growth and energy efficiency. The plan expects capacity to increase more than threefold to over 14 gigawatts (GW) by 2040, with 28% coming from imported sources, up from 14% in 2023. PDMP 2022-2040 does not break down the specific generation sources for these imports, but they are expected to be a mix of coal and hydroelectric sources.[22]

The Cambodian Ministry of Mines and Energy (MME) has stated a goal of generating 70% of the country's electricity from renewables by 2030.[23] However, PDMP 2022-2040 will likely fall short of

[21] As of 2018, nearly three-quarters of Cambodia's electricity was generated from facilities built or financed by Chinese players. All of the coal plants approved following the 2019 outages involved Chinese investors, contractors, and/or financiers. Moreover, Chinese companies had reportedly built about 8,000 kilometers of transmission lines in the country by 2019. That year, China was owed 48% of Cambodia's US$7.22 billion in outstanding foreign debt. Global China Pulse. Chinese Energy Investment in Cambodia: Fuelling Industrialisation or Undermining Development Goals? 02 May 2021.
[22] Laos expects to add almost 6GW of extra generation by 2030 from predominantly hydro (4.3GW), and a mix of coal and renewable sources. Lao News Agency. Laos, Cambodia further energy cooperation. 18 January 2024.
[23] Phnom Penh Post. 70% green energy by 2030: Gov't. 14 December 2023.

this goal. Excluding imported sources, it proposes that renewables' capacity share will increase to 28% by 2030 and 44% by 2040.

The plan relies heavily on solar deployment, which more-than-doubles to 1GW by the end of the decade and increases over sevenfold to almost 3.2GW by 2040. Wind power was not included in the most recent power development plan but has become an increasingly important focus for the government.[24] In June 2024, the government announced advancements for the country's first two wind farms, a 100MW plant in Mondulkiri and an 80MW plant in Kampot. Both projects are expected to be commissioned in 2024.[25, 26] According to the Asia Wind Energy Association, wind power remains "one of the least explored renewable resources in Cambodia."[27]

PDMP 2022-2040 also includes storage and fossil-fired resources to balance variability in solar generation. This includes new battery energy storage system (BESS) installations, which reach 200MW by 2030 and 420MW by 2040. By 2040, domestic coal provides almost 2.3GW of capacity. However, this does not include proposed coal imports from Laos, meaning the plan likely understates Cambodia's potential reliance on coal-fired generation for flexibility. The current plan also aims to commission 900MW of LNG-fired power capacity in the 2030s, though some anticipate a more significant role for LNG.

III. Proposed Role for LNG

Natural gas has historically not played a role in Cambodia's power mix. Until recently, Cambodia had no record of using natural gas or operating gas-related infrastructure. However, optimism has grown in recent years regarding the ability of new LNG-to-power projects to help the country meet rising electricity demand.[28]

Following widespread power outages in 2019, the government hired Japan's Chugoku Electric to prepare an urgent PDMP for 2020 to 2030.[29, 30] That plan primarily called to introduce 3,600MW of new LNG-fired capacity by 2030, and 9,600MW by 2050.[31, 32, 33]

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[24] Khmer Times. Cambodia shifts focus to solar and wind energy to meet rising power demand. 03 November 2023.
[25] Power Technology. Power plant profile: Kampot Wind Project_Blue Circle, Cambodia. 31 May 2024.
[26] Power Technology. Power plant profile: Mondulkiri Wind Farm, Cambodia. 17 June 2024.
[27] Asia Wind Energy Association. Cambodia. 2024.
[28] Natural Gas World. Optimism builds in Cambodia's LNG-to-power sector. 14 July 2021.
[29] MME. Cambodia Power Development Master Plan 2022-2040. September 2022. Page 02.
[30] According to a 2019 Chugoku Electric bond offering, development of Cambodia's master plan was part of a company strategy to engage in "unearthing/concretising cases for future investment in hydroelectric, thermal, and other power stations. Amid a sluggish [Japanese] domestic power market, the Group will be working to strengthen its earning power through investment and participation in new overseas power generation business." Chugoku Electric Power Company. Offering Circular. 21 August 2019. Page 73.
[31] ERIA. Cambodia Country Report. March 2021. Page 57.
[32] World Bank. Cambodia Climate Change Institutional Assessment. 2023. Page 52.
[33] In 2022, the Japan International Cooperation Agency (JICA) and Chugoku Electric released materials to help MME and EAC evaluate Independent Power Producer (IPP) proposals, including training documents to support Cambodia's adoption of LNG. Japan International Cooperation Agency and Chugoku Electric. Cambodia Power Economics and Planning Advisor Training for Capacity Building on IPP Project Evaluation. June 2022.

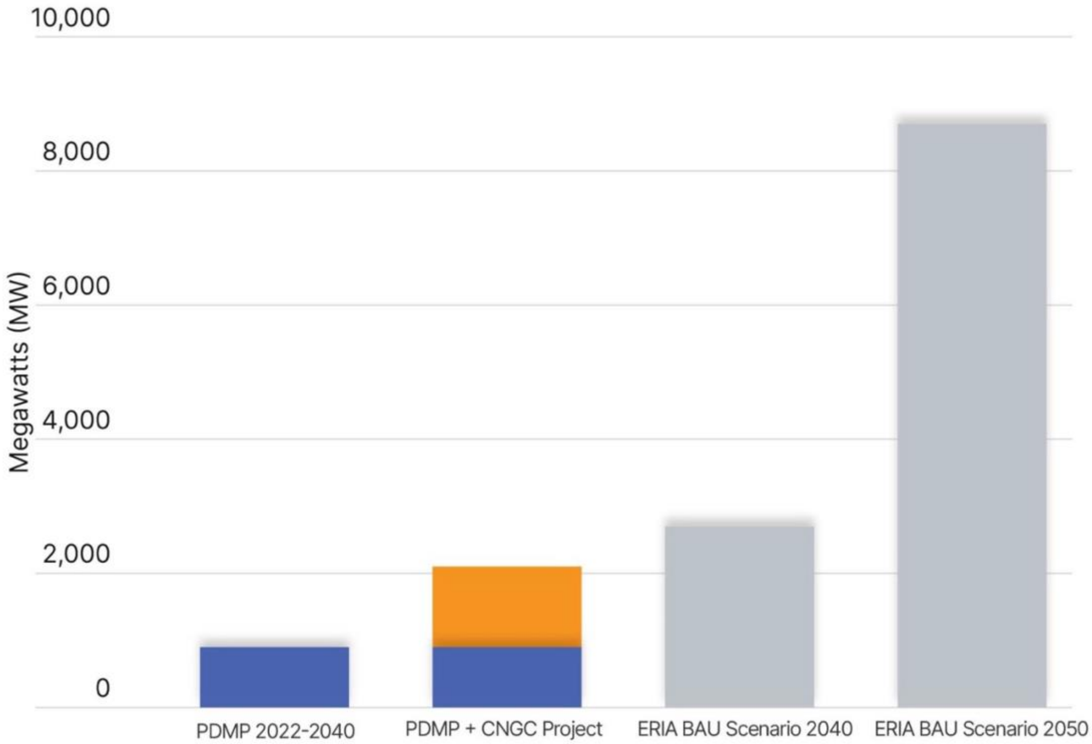
Also in 2019, the Cambodian Natural Gas Corporation (CNGC), a natural gas operator established in 2015, drafted a three-phase plan for natural gas development in Phnom Penh. In 2020, CNGC imported the country's first LNG shipment via International Organization for Standardization (ISO) tanks from the China National Offshore Oil Corporation (CNOOC), which served as a trial for distribution to industrial consumers.[34, 35] The company also planned to complete a 1,200MW LNG-fired power plant and a 3 million tonnes per annum (MTPA) import terminal by 2023.[36, 37] However, there has been no reported progress as of June 2024.

Narratives about the benefits of LNG imports remain strong in Cambodia. The country's long-term plan for carbon neutrality, released in December 2021, calls for "substantial investment in combined-cycle gas turbine (CCGT) power plants and LNG import capacity."[38] In November 2023, Cambodian officials announced the cancellation of a 700MW coal project in favor of an 800MW gas-fired power plant.[39]

Moreover, the Economic Research Institute for ASEAN and East Asia (ERIA) stated in a 2023 report that under a business-as-usual (BAU) scenario, LNG was expected "to dominate" Cambodia's fuel mix, accounting for 54.9% of generation by 2050.[40, 41] Under ERIA BAU forecasts, Cambodia would add 2,700MW of LNG-fired power capacity by 2040, and 8,700MW by 2050.[42, 43]

[34] Cambodia Natural Gas Corporation. Company Profile. 2023.
[35] CNGC imported another small-scale LNG shipment from Thailand's PTT in 2021. Cambodia Natural Gas Corporation. Company Profile. 2023.
[36] S&P Global. Analysis: COVID-19 delays Cambodia's LNG ambitions after initial imports from China. 01 October 2020.
[37] Global Energy Monitor. Cambodia LNG Project. Date Accessed: 30 September 2024.
[38] Kingdom of Cambodia. Long-Term Strategy for Carbon Neutrality. December 2021. Page 12.
[39] Power. Cambodia Cancels Coal Plant in Favor of Gas-Fired Facility. 29 November 2023.
[40] ERIA. Energy Outlook and Energy-Saving Potential in East Asia 2023 – Cambodia Country Report. 2023. Page 101 and 105.
[41] ERIA is an international research organization based in Jakarta, Indonesia that was originally proposed by Japan's Ministry of Economy, Trade, and Industry. ERIA maintains strong financial and political support from the Japanese government. ERIA. History. Date Accessed: 04 June 2024.
Asia Nikkei. Japan-led Asian green initiative works to scale up transition finance. 18 December 2023.
[42] ERIA. Energy Outlook and Energy-Saving Potential in East Asia 2023 – Cambodia Country Report. 2023. Page 101.
[43] Notably, under ERIA's "Low-carbon Energy Transition" scenario, Cambodia would have 2,700MW of natural gas-fired capacity by 2040, but zero gas-fired power capacity in 2050. ERIA. Energy Outlook and Energy-Saving Potential in East Asia 2023 – Cambodia Country Report. 2023. Page 101.

Figure 4: Scenarios for LNG-fired Power Capacity

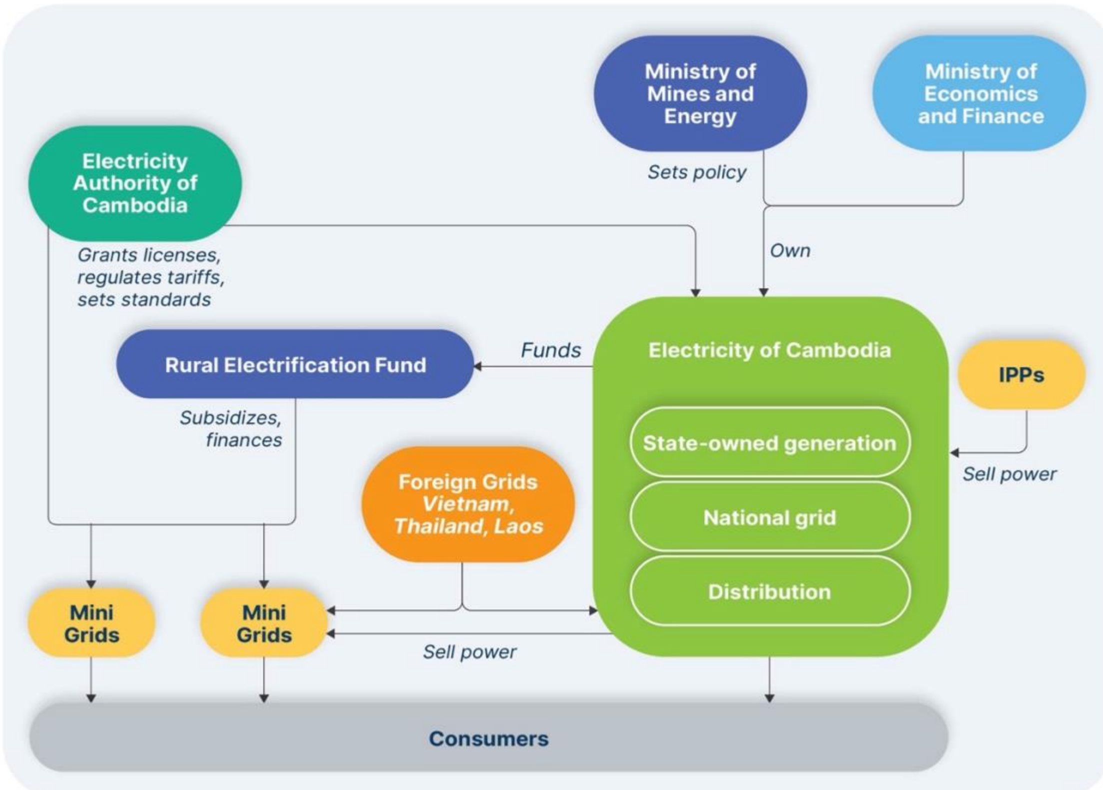


Source: MME. Power Development Master Plan 2022-2040. September 2022; CNGC; ERIA. Energy Outlook and Energy-Saving Potential in East Asia 2023 – Cambodia Country Report. 2023. Page 101.

IV. Power Market Regulation in Cambodia

Cambodia's 2001 Electricity Law separates power sector responsibilities between the MME and the Electricity Authority of Cambodia (EAC). MME develops government policy, strategies, and standards for the energy sector, while EAC, an independent regulatory body, issues power market rules and regulations, awards licenses, and sets tariffs.

Figure 5: Cambodia's Power Market Structure



Source: World Bank. Mini Grids in Cambodia: A Case Study of a Success Story. November 2017. Page 10.

Electricite du Cambodge (EDC) is the vertically-integrated, state-owned utility responsible for power generation, transmission, and distribution. The company's service area is concentrated around Phnom Penh, while privately-owned Rural Electricity Enterprises (REEs) distribute power to rural areas.[44] Over the past decade, the expansion of high-voltage transmission lines and REEs' connection to the national grid improved electricity quality and reduced the cost of supply. EDC is now the single buyer for the national grid, while REEs provide distribution and retail services.

Electricity tariffs are set by respective electricity providers but require approval from the EAC. Tariffs are based on a full-cost recovery principle, with generation and fuel costs typically accounting for the largest share of retail tariffs.[45] Rural tariffs are generally much higher than tariffs in urban areas due to higher costs of supply, fuel transportation, load factors, power losses, and risk premiums, among other factors.[46]

[44] By the end of 2022, there were 416 REEs. ADB. National Electrification Efforts in Cambodia. November 2023. Page 20.
[45] ERIA. Cambodia's Electricity Sector in the Context of Regional Electricity Market Integration. April 2012. Page 149.
[46] ERIA. Cambodia's Electricity Sector in the Context of Regional Electricity Market Integration. April 2012. Page 149.

Historically, the government refrained from subsidizing electricity consumption as cost recovery tariffs allowed EDC to remain profitable without government support.[47] In February 2015, however, the government instituted an electricity tariff reduction plan to spur economic growth. Since then, the government subsidy burden has reportedly increased from US$51mn in 2017 to US$130mn in 2023.[48, 49] As a result of lower regulated tariffs and high imported fuel costs, EDC reported its first annual loss in 2022.[50]

Despite EDC's historically strong credit quality compared to state-owned utilities in neighboring countries, recent years have demonstrated the challenges of balancing electricity price reductions while relying heavily on imported fossil fuels. A growing subsidy burden means that investors in Cambodia's electricity sector could be increasingly exposed to the country's credit profile, currently rated B2 by Moody's Investor Service.[51] Moreover, given the significantly higher costs of LNG relative to other energy sources (discussed in Section 3), adopting LNG could exacerbate the government subsidy burden and EDC's financial difficulties.

[47] White & Case. Prospects for LNG-to-power in Cambodia. 20 May 2021.
[48] Khmer Times. Government spends $51 million to lower electric bills. 24 January 2018.
[49] Phnom Penh Post. $130M set for electricity subsidies. 23 November 2023.
[50] Khmer Times. Kingdom's power supplier may face $100 million loss. 07 July 2022.
[51] Khmer Times. Moody's maintains 'Stable' outlook for Cambodia. 20 May 2021.

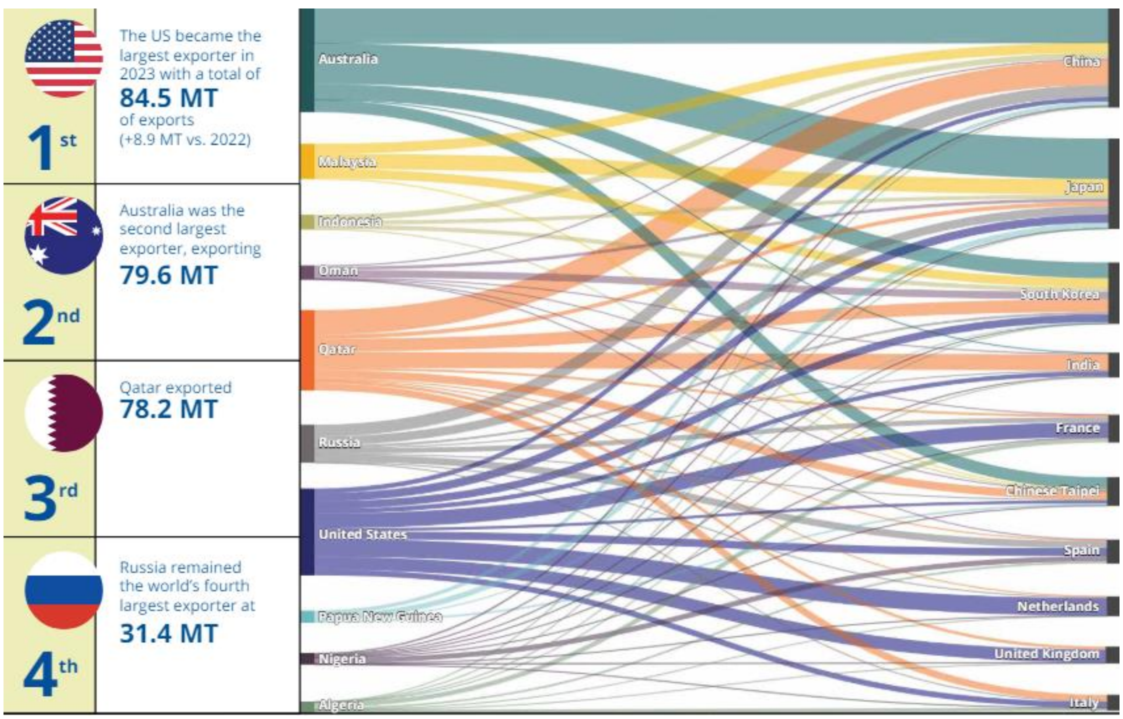
2. Global LNG Market Overview

Before assessing the impacts of LNG imports on Cambodia's energy system, understanding fundamental trends in the global LNG market is critical. This section provides an overview of the demand-supply environment and market outlook, key trends in LNG procurement and contracting, and the impact of recent LNG market volatility on emerging Asian markets.

I. LNG Supply and Demand Trends

Global LNG trade increased by 2.1% in 2023 to 401MTPA, compared to 5.5% in 2022.[52] Historically, Asia and Europe have driven global demand growth. The largest exporting and importing countries are shown in Figure 6 below. In Southeast Asia, Malaysia and Indonesia also export large volumes of LNG.

Figure 6: LNG Trade Flows, 2023



Source: International Gas Union (IGU). Annual Report. 2024. Page 20.

Global nameplate LNG liquefaction capacity was 474MTPA in 2023 and is expected to rise by 193MTPA through 2028.[53] This represents a 40% increase in global supply capacity — the fastest

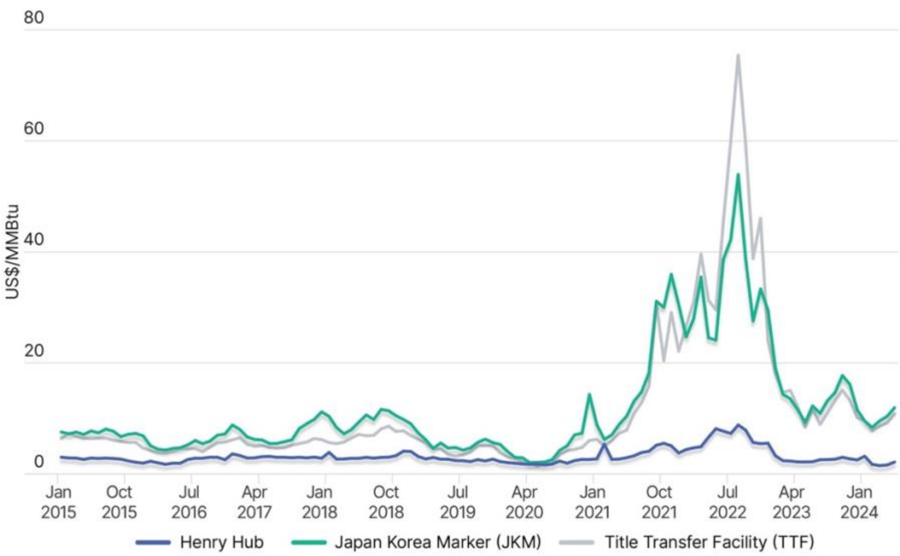
[52] Kpler. Commodity Terminal. Date Accessed: 30 September 2024.
[53] IEEFA. Global LNG Outlook 2024-2028. 25 April 2024.

rate of growth in the industry's history — with additions concentrated mainly in the United States (U.S.) and Qatar.

II. LNG Pricing and Contracting Trends

In recent years, LNG markets have experienced prolonged instability due to geopolitical disruptions, severe weather patterns, outages at supply facilities, and other factors. During the outbreak of the COVID-19 pandemic, low demand caused LNG prices to fall below US$2 per MMBtu — their lowest point on record. Prices then spiked to over US$30/MMBtu and remained high and volatile through 2021 due to various factors, including weather conditions and major liquefaction outages (see Figure 7).

Figure 7: Monthly Average Natural Gas and LNG Prices



Source: EIA; Investing.com.

In 2022, the Russian invasion of Ukraine skyrocketed LNG prices. As Russia slashed pipeline gas shipments to Europe, European buyers shifted to purchasing record volumes of LNG. This rapid increase in European demand sent prices to their highest levels ever. In Asia, spot market prices briefly surpassed US$90/MMBtu.[54, 55] Prices in Asia and Europe have since decreased to US$12/MMBtu but remain above historical averages.

Rising LNG demand and limited supply, particularly in the wake of the Russian invasion of Ukraine, have transformed LNG trade into a seller's market. As a result, buyers in recent years have procured

[54] The LNG spot market — as opposed to trading via long-term contracts — refers to a market in which LNG volumes are bought and sold for immediate or near-term delivery, typically for a period of 30 days or less.
[55] The Business Times. Shell's flagship LNG trading made nearly US$1b loss in Q3. 03 November 2022.

LNG according to more traditional pricing structures and contract terms, which are more favorable for supplier revenue generation and financing. Recent LNG procurement trends include:

1. *Brief decline of spot market trading.* Before 2021, the share of LNG traded on a spot and short-term basis had risen to 40%, up from 20% a decade prior.[56] In 2021 and 2022, however, record high spot market prices caused a reversion to long-term contract volumes, as buyers sought to reduce exposure to spot volatility. The share of spot and short-term trades rebounded in 2023 following lower and more stable prices.
2. *Longer duration LNG contracts.* Between 2018 and 2020, the average duration of LNG purchase contracts decreased from 16.4 years to 11.7 years.[57] However, buyers returned to lengthier contracts in 2022 and 2023 to ensure more stable, long-term pricing outlooks. As a result, the average duration of contracts increased to 17.6 years in 2023.[58]
3. *A return to fixed destination contracts.* Before 2020, the share of fixed destination contracts was just 22%, as the growth of flexible LNG supply, mainly from the U.S., enabled a departure from more rigid shipping terms.[59] However, 78% of contracts signed in the first half of 2023 contain fixed destination clauses. Looking ahead, the share of flexible destination clauses is likely to increase as buyers aim to optimize portfolios and secure interregional arbitrage opportunities.[60]
4. *Portfolio players account for a larger share of purchase contracts.* Since 2021, portfolio players who buy and resell LNG to capitalize on price differentials in various gas markets have been the largest counterparties to new long-term LNG purchase contracts. The largest LNG aggregators include Shell, TotalEnergies, and BP. However, a variety of smaller companies, including many Japanese utilities, are also accumulating LNG contracts, aiming to resell LNG in demand growth markets.[61]

III. Recent Experience of Emerging Asian LNG Importers

As an increasingly global commodity, LNG market disruptions in one region can severely impact energy security and affordability in others. For example, Europe's significant LNG buying following Russia's invasion of Ukraine in 2022 limited flows to Asia and caused Asian LNG prices to skyrocket. This proved particularly detrimental for South and Southeast Asian economies, which are typically more exposed to spot markets than more experienced LNG importers. Exposure to record spot market prices and less favorable LNG procurement contracts deterred and prevented many emerging economies from purchasing LNG. Demand from emerging Asian countries fell 15% in 2022, ending a period of multi-year growth.

[56] GIIGNL. Annual Report. 2024. Page 16.
[57] GIIGNL. Annual Report. 2024. Page 25.
[58] GIIGNL. Annual Report. 2024. Page 25.
[59] IEA. Global Gas Security Review. July 2023. Page 53.
[60] IEA. Global Gas Security Review. July 2023. Page 53.
[61] IEEFA. Japan's largest LNG buyers have a surplus problem. 11 March 2024.

Table 1 shows the change of LNG imports in 2022 alongside real GDP and real GDP per capita on a purchasing power parity (PPP) basis. The table suggests that countries with incomes below 20,000 PPP experienced a significant decrease in LNG imports[62], reflecting a high sensitivity to volatile LNG prices. Wealthier, more experienced LNG importers were less affected or even increased LNG imports.[63]

Table 1: Economic Indicators and Change in LNG Imports, 2022

Region	GDP (constant billion 2017 PPP)	GDP per capita (constant 2017 PPP)	Change in LNG imports 2022
Bangladesh	1,072	6,263	-13%
Cambodia	76	4,534	N/A
China	25,684	18,188	-19%
India	10,079	7,112	-17%
Japan	5,235	41,838	-2.7%
Myanmar	230	4,250	-100%
Pakistan	1,268	5,377	-18%
Philippines	992	8,582	N/A
Singapore	609	108,036	16%
South Korea	2,352	45,560	0.9%
Taiwan	1,583	66,150	2.8%
Thailand	1,255	17,508	31%
Vietnam	1,119	11,397	N/A

Source: World Bank World Development Indicators; Kpler; IEEFA Calculations.

In **Pakistan**, an inability to afford LNG cargoes resulted in gas and power shortages, stunting economic growth in key sectors and straining critical foreign exchange reserves. Suppliers to Pakistan and India repeatedly defaulted on long-term contracts, forcing buyers into expensive spot markets or causing them to forego cargoes altogether. At the same time, the Pakistan rupee incurred significant devaluation due partly to the rising cost of energy imports.[64] While commodity prices were 2.5 times higher than two years prior in US dollar terms, a 22% devaluation of the domestic currency increased fuel cost by 3.4 times in local terms.

Since 2022, **Bangladesh** has faced challenges securing financing for its energy import bill. High prices during the crisis led to Bangladesh's power and energy sectors racking up a US$5 billion (bn) energy import bill by the end of 2023.[65] However, with the currency reserves of the Bangladesh central bank falling below US$20bn, the country turned outward for assistance.[66] The International

[62] Other than Thailand, which was undergoing domestic production problems that led to higher calls on LNG imports, China's drop in imports is mainly driven by lower demand resulting from strict COVID-19 containment policies that year.
[63] Singaporean imports from Indonesia were disrupted in the early stages of 2022, prompting higher LNG imports. S&P Global. Singapore's power utilities may switch to LNG on Indonesian piped gas curtailments. 15 October 2021.
[64] While this breaks down the depreciation causes in 2023, the logic also applies to the year 2022. Best Diplomats. Factors Contributing To The Fall Of Pakistani Rupee in 2023. 07 October 2023.
[65] The Financial Express. Power, energy sectors saddled with $5.0b outstanding payment amid dollar crisis. 24 December 2023.
[66] Bangladesh Bank. Foreign Exchange Reserve (Monthly). Date Accessed: 15 June 2024.

Monetary Fund (IMF) and the International Islamic Trade Finance Corporation (ITFC) approved loan packages to help combat inflation and maintain energy imports.[67, 68] The loans helped avoid a currency crisis, but growing reliance on LNG could double Bangladesh's fuel import bill by 2030.[69] The IMF loan stipulates that Bangladesh should increase electricity tariffs and end all power subsidies, which may have detrimental impacts on the regional competitiveness of key economic sectors.[70]

Following Russia's invasion of Ukraine, **Thailand**, the largest LNG importer in Southeast Asia, had little choice but to increase LNG purchases due to declining domestic production and pipeline imports. Consequently, the country faced high imported fuel costs and limited access to cheaper supplies.[71] Power tariffs in the country reached their highest level ever as expensive fuel import costs were passed to end users.[72] Toward the end of the year, Thailand temporarily stopped buying spot market LNG, opting instead to purchase other liquid fuels, delay decommissioning of coal plants, and increase renewable energy procurement.

In 2022, LNG imports to **Myanmar** fell to zero due to unaffordable prices and political unrest. The country began importing LNG in June 2020 at record-low LNG prices to commission 750MW of LNG-to-power facilities. However, without long-term LNG procurement contracts[73], Myanmar remained entirely exposed to spot market prices. Moreover, payments to the plant operator were denominated in local currency, causing significant convertibility risks for US dollar-denominated LNG payments. In 2021, soaring LNG prices, financial risks to the plant operator, and a military coup challenged the viability of LNG, leading the government to cease LNG operations.[74]

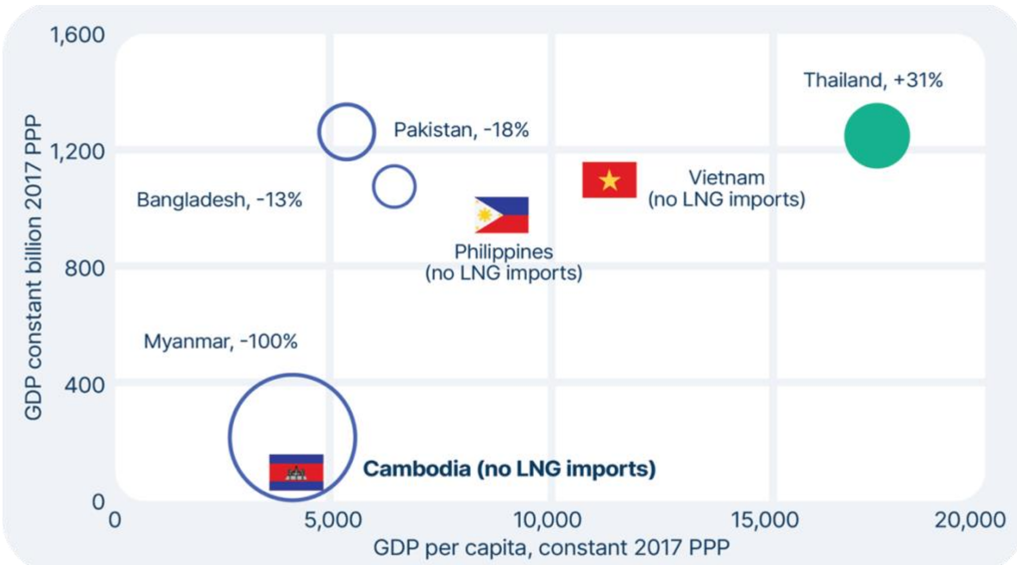
VI. Implications of Recent LNG Market Trends for Cambodia

The recent LNG price volatility demonstrates the clear risks of LNG importation for emerging Asian economies. Higher prices lowered demand growth and prevented some countries from buying LNG entirely, resulting in fuel and power shortages. Visualizing emerging and prospective LNG importers in a bubble chart illustrates the potential challenges in securing LNG supplies for Cambodia in the future (Figure 8 below).[75] Myanmar, Cambodia, Vietnam, and the Philippines are similar macroeconomically to the countries that experienced financial difficulty in securing LNG supplies

[67] Anadolu Ajansı. IMF agrees to provide Bangladesh with $1.15B as 3rd installment of its multi-billion-dollar loan program. 05 August 2024.
[68] Reuters. ITFC signs deal to fund $2.1 bln of Bangladesh oil, gas imports. 07 February 2024.
[69] The Business Standard. Bangladesh secures $2.1b loan for energy imports. 07 February 2024.
[70] The Daily Star. Power price to go up four times a year. 03 May 2024.
[71] Reuters. Analysis: Thailand faces perfect storm as it seeks more LNG supply. 16 March 2022
[72] Bangkok Post. Electricity bills to surge as power tariff hits all-time high. 20 June 2022.
[73] ERIA. LNG Infrastructure Development and Financing in Select ASEAN Countries: The Philippines, Viet Nam, Indonesia, and Myanmar. November 2021. Page 40.
[74] The coup prompted international sanctions against the military government, causing significant depreciation of the Myanmar Kyat, reduced domestic electricity demand, and a domestic boycott of electricity bill payments. These factors challenged the ability of the government to pay the power producers, VPower and CNTIC, to cover the rising cost of LNG imports. The Irrawaddy. Two Power Plants in Myanmar's Biggest City Shut Amid Coup's Financial Fallout. 13 October 2021; World Bank. In the Dark: Power Sector Challenges in Myanmar. August 2023. Page 13.
[75] The chart limits the scope of the axes to output under 1,600 billion 2017 PPP and incomes under 20,000 2017 PPP, while imposing the coordinates of the three prospective LNG importers.

during the 2022 geopolitical turmoil. While Cambodia has goals to increase per capita income levels above US$13,846 by 2050[76, 77, 78], the country would remain in the comparative window of Figure 8.

Figure 8: LNG Import Change in 2022 Mapped Against Real Output and Income Level



Note: Bubble size shows change in LNG imports in 2022; transparent bubbles show declines in imports and opaque bubbles show a growth in imports. Since the Philippines, Vietnam, and Cambodia did not import LNG in 2022, they are represented as flags, not bubbles, to illustrate real output and income level.
Source: World Bank Development Indicators; Kpler; IEEFA Calculations.

The anticipated growth of LNG supply through 2030 may improve Cambodia's ability to procure LNG flexibly and at lower prices. However, the long-term LNG market outlook is more challenging to determine. LNG is increasingly traded on a spot and short-term basis, but the experience of emerging Asian markets in recent years has revealed the economic risks of spot market exposure. While more traditional contract structures may relieve Cambodia's energy security concerns, inflexible terms could inhibit responses to domestic or international energy market changes. This could lead to higher fuel bills that would eventually have to be passed onto end users, challenging the ability of Cambodian regulators to reduce tariffs and boost economic growth.

[76] Cambodia is targeting a status graduation from lower middle-income to upper middle-income by 2030 and high-income by 2050. East Asia Forum. Overcoming constraints to inclusive growth in Cambodia. 30 January 2024.
[77] High-income status begins at US$13,846. However, note that the binning for World Bank's classification by income is not in purchasing power parity (PPP) like the figures in this chart, but in Gross National Income (GNI) per capacity. World Bank. The World Bank in Middle Income Countries Overview. Date Accessed: 25 September 2024.
[78] Based on the World Bank income classification system and Cambodia's GNI per capita of US$1,690 in 2022, this would require a 2.64-fold increase in incomes this decade and an eight-fold increase in incomes between now and 2050. A similar increase in GDP per capita would put Cambodia at an income level close to Vietnam on this chart. World Bank. The World Bank in Middle Income Countries. April 2024.

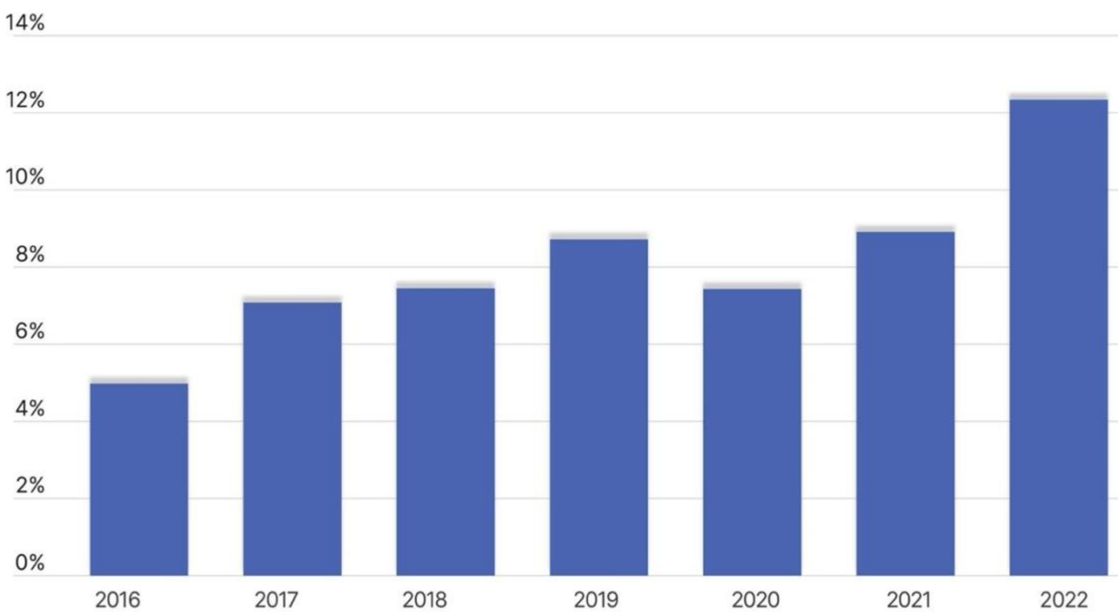
3. Cambodia's Potential LNG Demand and Annual Import Costs

This section examines the LNG volumes and costs required for various scenarios of LNG adoption in Cambodia. Due to high LNG costs relative to other fuels, LNG importation is likely to significantly increase in the country's fuel import bill, which has grown as a share of GDP in recent years alongside higher coal dependence. Additionally, this section provides a high-level overview of gas and power pricing regimes in select Asian economies, which ultimately determine how LNG costs are shared along the LNG-to-power value chain.

I. Cambodia's Historical Fuel Import Bill

Cambodia's fuel import bill and energy demand have grown concurrently over the past decade. Cambodia produces no natural gas and relies almost entirely on fossil fuel imports. Since 2016, the country's annual fuel import bill has increased nearly four-fold to roughly US$3.4bn in 2023.[79] Notably, the country's fuel import bill as a share of GDP has increased from 5% in 2016 to 12.3% in 2022, indicating a higher fuel cost per unit of economic output (Figure 9 below).[80]

Figure 9: Cambodia Fuel Imports as a Share of GDP

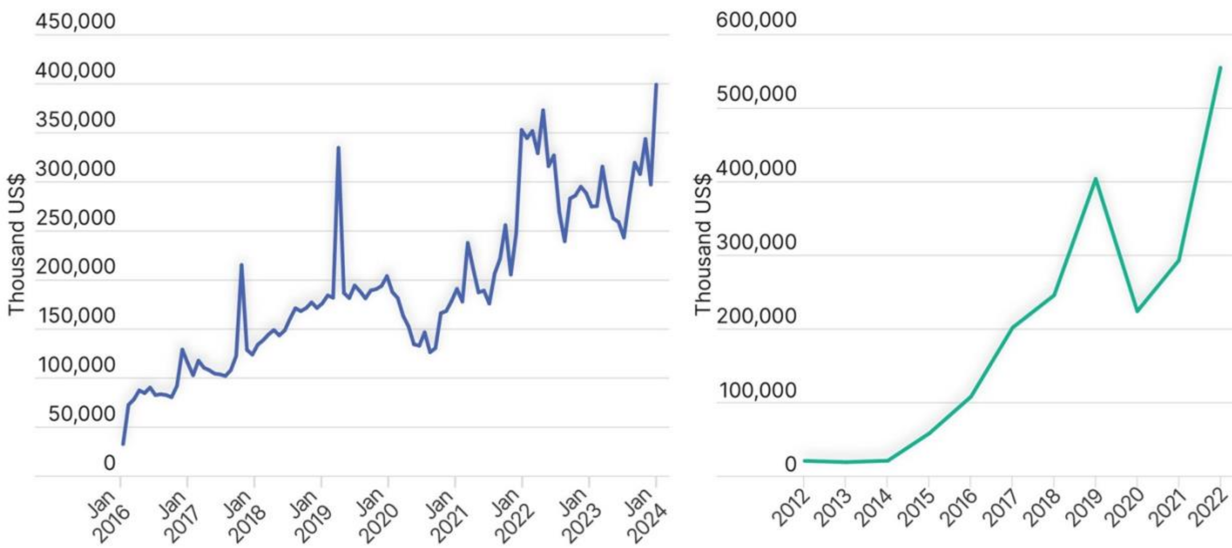


Note: This does not include Cambodia's electricity imports from neighboring countries.
Source: IEEFA calculations based on data from the World Bank and Cambodia General Department for Customs and Excise.

[79] IEEFA calculations based on data from Cambodia's General Department of Customs and Excise.
[80] IEEFA calculations based on World Bank GDP data and fuel import data from Cambodia's General Department of Customs and Excise.

Over this period, coal imports have increased by nearly 15 times.[81] The total value of Cambodia's coal imports was reportedly US$555mn in 2022, up from US$20mn a decade earlier. Cambodia imported less coal in 2022 compared to 2021, but the country's coal import bill nearly doubled due to higher coal prices in the global market. Rising fuel prices in 2022 caused inflation in Cambodia to spike to more than double the historical 10-year average.[82]

Figure 10: Cambodia's Monthly Fuel Import Bill (left); Annual Coal Import Bill (right)



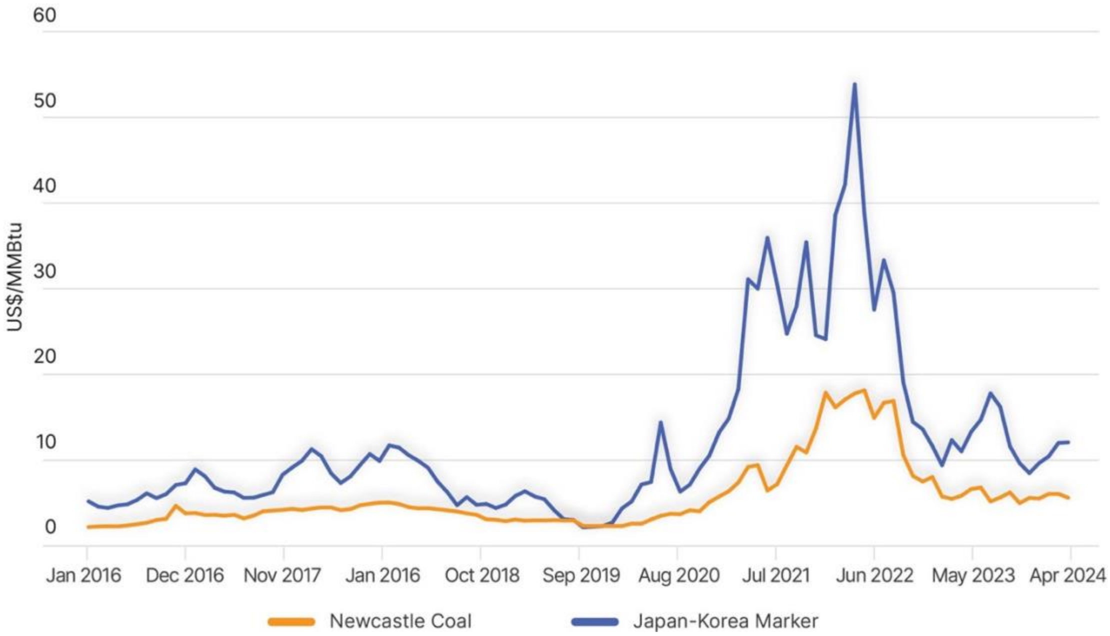
Source: Cambodia General Department of Customs and Excise; UN Comtrade.

II. LNG Costs Would Likely Entail Sharp Increases in Cambodia's Fuel Import Bill

LNG importation may involve a steep increase in Cambodia's fuel import bill. Since 2016, LNG prices have averaged US$12.11/MMBtu, more than double the average Newcastle coal price of US$5.54/MMBtu. At this LNG price, a single 72,000 metric tonne shipment of imported LNG would cost US$46.7mn (KHR193.6bn).

[81] According to trade data from UN Comtrade. UN Comtrade. Date Accessed: 06 June 2024.
[82] World Bank. Cambodia Economic Update. December 2022. Page 05.

Figure 11: Monthly Average Coal and LNG Prices



Source: Investing.com

LNG prices are also relatively volatile, owing partly to lower liquidity in spot markets compared to other seaborne bulk commodities. After falling below US$2/MMBtu in mid-2020, LNG prices skyrocketed following the Russian invasion of Ukraine to a monthly average of US$54 in August 2022. The value of a single cargo from the U.S. to Europe went from near zero in mid-2020 to over US$200mn in 2022 before falling back to roughly US$25mn in 2023. Analysts have noted that no other internationally bulk-traded commodity has experienced this kind of extreme instability.[83]

LNG prices have leveled off since 2022 but remain above historical averages, and geopolitical disruptions will likely remain a persistent risk. For example, consultancy Rystad Energy noted in April 2024 that the unlikely closure of the Strait of Hormuz could cause LNG prices to surpass US$100/MMBtu[84], and in May 2024, Australian LNG export company Woodside said that market "instability" and "volatility is not over."[85]

Extreme volatility makes it challenging to forecast long-term LNG prices. Through 2028, prices are likely to decline from current levels due to a flood of new LNG export capacity coming online globally, particularly in Qatar and the U.S.[86] Falling LNG prices will likely reduce the pricing spread

[83] Makholm, Jeff D. The Liquefied Natural Gas (LNG) Puzzle: A Singular and Misunderstood Commodity in World Trade. November 2023. Page 02.
[84] Bloomberg. Asia Gas Prices Rise Near Highest in 2024 Amid Conflict Risk. 17 April 2024.
[85] Bloomberg. Conflict-Fueled Energy Swings Aren't Over, Woodside CEO Says. 20 May 2024.
[86] IEEFA. Global LNG Outlook 2024-2028. 25 April 2024.

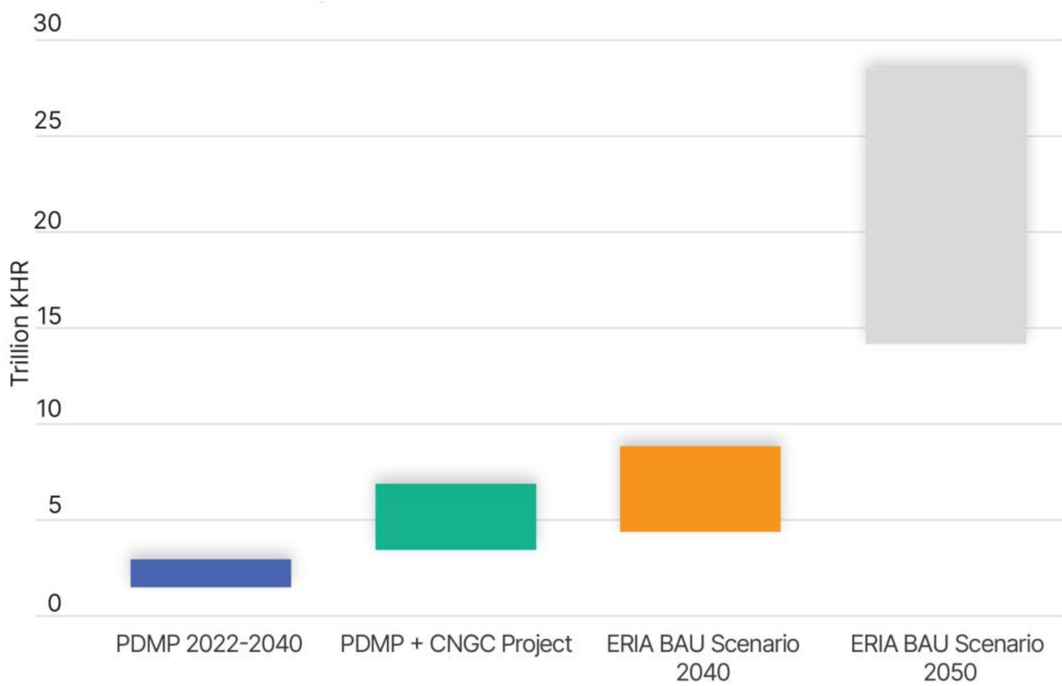
between LNG and coal prices, increasing the competitiveness of imported LNG in power generation for Asian importers.

The International Energy Agency's (IEA) 2024 World Energy Outlook contains LNG pricing scenarios for various global climate policy trajectories. Under a Stated Policies Scenario (STEPS)[87], the IEA anticipates LNG prices delivered to Japan falling from US$13/MMBtu in 2023 to US$8.3/MMBtu in 2030 and rising slightly to US$8.7/MMBtu in 2050.[88] Under a lower global gas demand scenario, prices could fall to US$6.8/MMBtu in 2030 and US$6.2/MMBtu in 2050.

III. LNG Volumes Required Under Cambodia's Power Development Scenarios

This section provides a summary of the LNG volume that might be required under various scenarios of LNG-to-power integration, as well as the total cost under long-term price trajectories.[89]

Figure 12: Cambodia's LNG Import Bill Under Various Scenarios



Source: IEEFA calculations based on scenarios identified on Page 12.

[87] The IEA's Stated Policies Scenario (STEPS) "provides a sense of the prevailing direction of travel for the energy sector based on a detailed reading of the latest policy settings in countries around the world." International Energy Agency (IEA). World Energy Outlook 2024. October 2024. Page 78.
[88] International Energy Agency (IEA). World Energy Outlook 2024. October 2024. Page 90.
[89] As of 14 June 2024, the Japan-Korea Marker was US$12.095/MMBtu.

By 2030, operating 900MW of LNG-fired power capacity at baseload levels would require roughly 0.84MTPA. At long-term wholesale LNG prices of between US$8-16/MMBtu, Cambodia's LNG import bill could range between US$361mn and US$722mn (KHR1.48-2.95tn) annually. Although operating LNG-fired power plants below baseload levels would reduce volume requirements, delivered LNG prices to Cambodia will likely be at the higher end of the range due to contract pricing terms and per-unit infrastructure costs for smaller-scale import supply chains (discussed in Sections 5 and 6).

Under a scenario in which CNGC also brings a 1,200MW LNG-to-power project online, Cambodia's LNG import requirements could rise to 2.0MTPA. This would entail LNG costs between US$843mn and US$1,685mn (KHR3.45-6.89tn) annually.

Using the ERIA's BAU scenarios for LNG development in Cambodia (2,700MW of gas-fired capacity by 2040 and 8,700MW by 2050), total LNG import requirements could reach 2.53MTPA in 2040 and 8.14MTPA in 2050. By 2040, this would entail a total annual LNG import bill between US$1,083mn and US$2,167mn (KHR4.43-8.86tn). By 2050, Cambodia's LNG import bill could reach as high as US$3,490mn and US$6,981mn (KHR14.28-28.55tn).

IV. Impact of Foreign Exchange Volatility

Due to the dollarization of globally traded energy commodities, energy price surges can significantly shift the trade balance of importing countries and put pressure on currency value. The value of Cambodia's riel relative to the US dollar has been stable in recent years due partly to the high dollarization of the Cambodian economy. However, the National Bank of Cambodia (NBC) has engaged in a slow process of de-dollarization to increase monetary autonomy.[90] Increasing dependence on LNG imports may present new challenges to the stability of the domestic currency amid recent monetary objectives.

V. Distribution of LNG Costs through the LNG-to-Power Value Chain

The distribution of LNG costs and financial impacts along the supply chain depends mainly on domestic pricing regulations in the gas and power sectors. Fixed tariff regimes are designed to protect consumers from market price changes. Energy sector inefficiencies and price distortions are borne by public or private companies in the supply chain. This may prove fiscally unsustainable, requiring cost recovery mechanisms or government budgetary support.

In contrast, high fuel and power costs in pass-through pricing regimes can have broader negative economic repercussions. For example, higher energy costs can lead to increased input and

[90] Khmer Times. De-dollarization makes headway despite challenges. 25 March 2024.

operating costs for critical industries, hurting competitiveness. Table 2 provides a high-level overview of gas and power pricing regimes in select Asian countries.

Table 2: Gas and Pricing Regimes for Select Asian Countries

	Gas Pricing Regime	Power Pricing Regime
Philippines	Domestic production linked to oil prices, and LNG prices linked to spot market due to lack of long-term contracts. Gas costs passed through to consumers via power contracts.	Full cost pass-through to consumers. Limited subsidization of off-grid consumers.
Singapore	Piped gas prices linked to fuel oil. LNG import prices linked to oil and spot market rates. Costs fully passed through to consumers.	Cost pass-through to end-users without subsidies
Thailand	Wholesale and retail gas prices are based on a cost-plus pricing regime, which is composed of wellhead or LNG delivered prices, a marketing margin, and transmission and distribution tariffs.	Fuel prices passed through to consumers via a fuel tariff mechanism, which is added to a base power tariff composed of capacity and variable costs. Cross-subsidies and subsidies for lower income groups.
Vietnam	Wholesale and retail prices are determined in negotiations between state-owned gas utility and counterparties.	Government regulated tariffs are adjusted every three months. State-owned utility can increase tariffs up to 5% without government approval.
South Korea	Although LNG procurement costs have historically been passed through to end-users, prices are regulated at wholesale and retail levels.	Government regulated tariffs prioritize price stability to shield economy from inflationary impacts of higher fuel prices. Retail rates set below cost of service has resulted in financial distress for state-owned electric utility in recent years.
Japan	Retail gas market liberalized in 2017. End-user prices are determined by competition between gas sellers, except in cases where incumbent gas retailer maintains a monopoly position. Wholesale gas prices typically passed through to end-users.	Price competition in retail electricity market. Government introduced subsidies on retail tariffs in 2022 to shield economy from inflationary impacts of rising input costs.
Bangladesh	Wholesale prices based on weighted average of imported and domestically produced gas. Retail prices regulated below cost, leading to high subsidy burden.	Regulated retail tariffs set below wholesale cost of production.
Pakistan	Gas prices regulated at wholesale and retail levels. Fixed retail prices set by regulator according to consumer classes. Imported LNG regulated separately from domestic gas and sold at wholesale prices determined by regulator.	Fixed tariffs established by regulators, based largely on political considerations rather than long-run capital cost recovery.

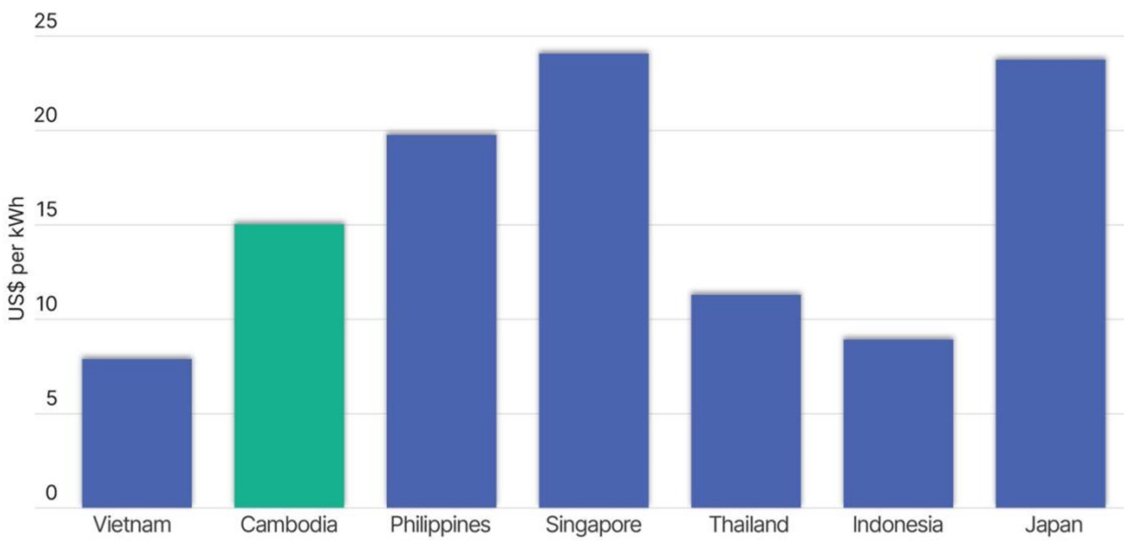
4. Impact of LNG on Cambodia's Electricity Generation Costs

Cambodia has historically set power tariffs according to a full cost recovery principle, meaning that fuel suppliers, power generators, and distribution utilities have recouped imported fuel costs via retail electricity tariffs. In establishing an LNG-to-power value chain in Cambodia, maintaining full cost recovery in power pricing would ultimately burden end users with higher LNG costs.

This section examines Cambodia's current power rates, recent efforts to reduce prices, and the likely price impacts of introducing LNG-fired power. It also provides case studies on the Philippines, which recently began importing LNG for power generation, and Vietnam, which is exploring risk-sharing arrangements to mitigate economic challenges caused by LNG volatility.

I. Power Pricing Trends in Cambodia

Figure 13: Residential Electricity Tariffs in Select Asian Countries[91]



Source: Vietnam Electricity (EVN); EAC; Meralco; SP Group; ERC; PLN; TEPCO; IEEFA calculations.

Cambodia's power prices are among the highest in Southeast Asia because of a lack of subsidies (Figure 13) and its fragmented power system that lacks high-voltage transmission connections.[92] Historically, the high cost of diesel oil for power generation also contributed to higher prices.[93]

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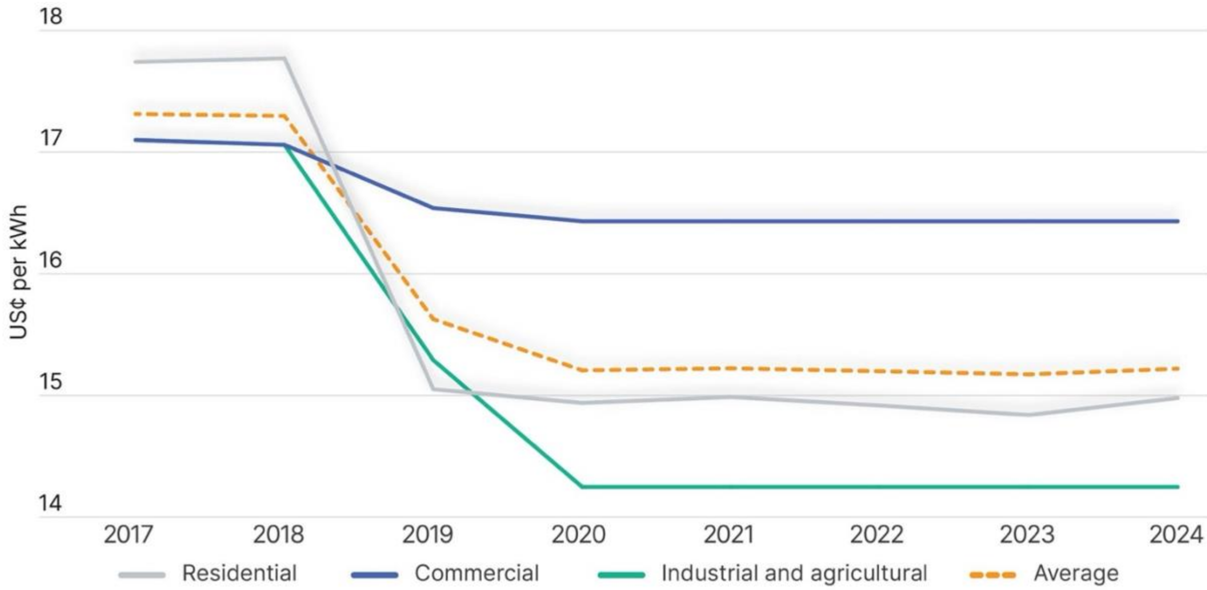
[91] Tariffs for Cambodia, Singapore, Thailand, and Indonesia are on a per unit basis. For Japan, the Philippines, and Vietnam, to account for fixed and other charges, the tariff is calculated for a household that consumes 200kWh per month.
[92] Historically, Cambodia's retail prices were double the supply cost of generating electricity, suggesting that transmission and distribution could constitute around half, or about US¢10/kWh, of the electricity tariff for residential customers in 2015, which is even higher than the tariff in some countries. Cambodia Solar Power Project (RRP CAM 50248) – Sector Overview.
[93] International Trade Administration, US. Cambodia - Country Commercial Guide - Energy; Power Generation Equipment. 02 February 2024.

Figure 14: Historical Cambodian Electricity Tariffs[94]



Source: EAC.

In 2015, Cambodia began to actively reduce tariffs and stimulate economic activity.[95] The average electricity tariff fell by 12% from US$0.1731 per kilowatt hour (kWh) (see Figure 14) in 2017 to US$0.1521/kWh in 2020. One of the main reasons for this reduction was the phase-down of expensive diesel-fired power from over 90% generation in 2007 to 3% in 2017. The government turned to cheaper, larger-scale power sources like hydropower and coal-fired power plants, and grid interconnections with neighboring countries.

For example, the 246MW Stung Tatay hydroelectric project started production in 2015 and has agreed to supply EDC with power at US$0.0745/kWh[96], and the 400MW Lower Sesan II Dam, which commenced operations in late 2018, has a 40-year agreement to sell power to EDC at US$0.0695/kWh.[97] While little is known about the power purchase agreements (PPAs) of many existing projects and regional interconnections, recent coal PPA proposals were priced at US$0.077/kWh.[98, 99]

However, efforts to reduce power tariffs have stalled since 2020. Higher coal prices during the pandemic recovery and following Russia's invasion of Ukraine prevented further tariff reductions. As

[94] Rates are for households and business or industrial activity in Phnom Penh. EAC. Salient Features of Power Development in the Kingdom of Cambodia Until December 2023. 2024.
[95] Khmer Times. High electricity bills push every Cambodian to the brink of despair. 04 April 2022.
[96] AIDDATA. Project ID: 32192. Date Accessed: 13 June 2024.
[97] AIDDATA. Project ID: 62217. Date Accessed: 13 June 2024.
[98] Khmer Times. Cambodia's coal commitments delay greener, cheaper power options. 14 June 2022.
[99] Some undisclosed sources believe that coal PPAs could be as low as US$0.0743/kWh.

a result, average consumer tariffs have remained stable at roughly US$0.15/kWh. As part of its 7th Mandate, the MME aims to maintain affordability by holding tariffs constant until 2028.[100]

The addition of cheaper, large-scale generation could allow for further tariff reductions in the future. Solar PPAs have made significant price reductions in Cambodia. For example, in 2017, a 10MW solar PPA was signed at US$0.091/kWh. Two bilateral PPAs for US$0.076/kWh quickly followed in late 2018 and early 2019.[101]

In July 2019, competitive auctions for the National Solar Park Project in Cambodia resulted in the lowest price for any solar project in Southeast Asia at just US$0.03877/kWh for the first 60MW phase.[102] The second 40MW phase price was even lower at US$0.026/kWh in April 2022.[103] Much of the auction success can be attributed to the ADB which provided loan guarantees on the capital costs for grid connections to the solar park.

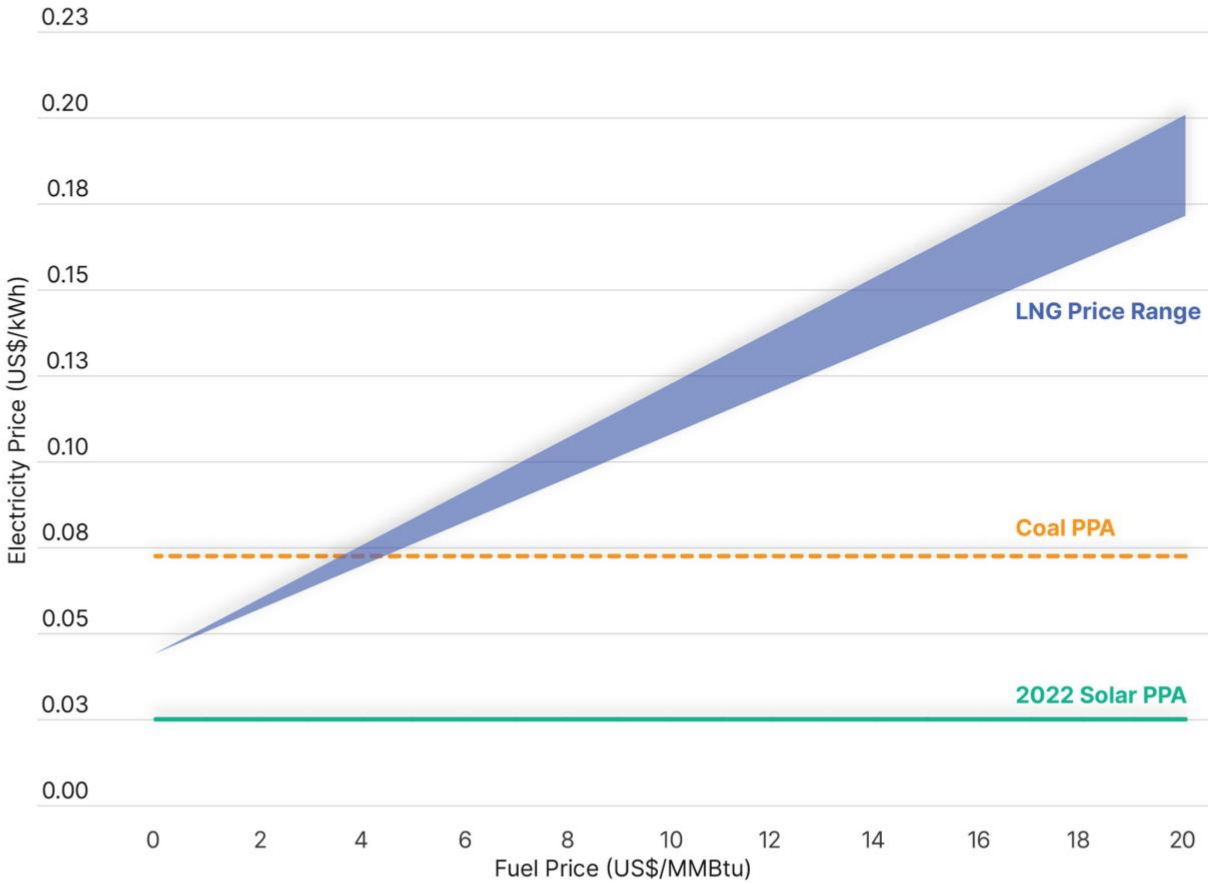
II. Levelized Cost Analysis of LNG-to-Power

Utilizing LNG for power generation may jeopardize efforts to reduce Cambodia's electricity prices. IEEFA estimates that operating an 800MW LNG-fired power plant at baseload capacity and current global LNG prices of US$12/MMBtu would yield a levelized cost of generation between US$0.123/kWh and US$0.141/kWh.

Under the aforementioned long-term pricing scenarios from the IEA (see page 25), LNG-fired power would still be more expensive than other power sources in Cambodia. For example, a price of US$8.4/MMBtu would likely result in a final levelized generation cost between US$0.10-0.113/kWh. Notably, Cambodia may pay premiums on market rates for delivered LNG supplies considering its status as an inexperienced, emerging market buyer and the higher per-unit LNG costs of small-scale infrastructure (discussed in Sections 5 and 6).

[100] MME. Policy Dialogue 7th Mandate: National Assembly Royal Government of Cambodia. 04 December 2023.
[101] Climate Investment Funds (CIF). From Carbon to Competition: Cambodia's Transition to a Clean Energy Development Pathway. June 2020. Page 22.
[102] PV Magazine. Cambodia tender secures lowest solar power price in Southeast Asia. 06 September 2019.
[103] ADB. ADB-supported National Solar Park in Cambodia Connects to Grid. 15 November 2022.

Figure 15: Levelized Cost of LNG-Fired Power Generation at Various Fuel Prices



Note: The range of LNG prices is based on a range of LNG-fired power plant efficiencies.
Source: IEEFA calculations.

III. Impact of Fuel and Capital Costs

To achieve grid parity, the delivered price of LNG to Cambodia would likely have to fall below US$4.8/MMBtu. Since 2016, monthly average spot LNG prices in Asia have rarely dropped below US$5/MMBtu (see Figure 11). Although spot market LNG prices could decrease dramatically in an oversupplied market, they are unlikely to remain competitive for Cambodia's power sector. This is because LNG exporters face a breakeven cost of delivering LNG to Asia that is typically above rates that might be necessary to price LNG into the power sector.

For example, the delivered cost of U.S. LNG to Asia will likely be US$7-8/MMBtu. It would be even higher from Australia, East Africa, and Canada due mainly to higher feedgas and liquefaction costs.[104] Only Qatar, the world's lowest-cost LNG producer, could deliver LNG at a price that might enable it to compete with Cambodia's coal-fired power generation. However, Qatar typically sells

[104] IEEFA. LNG is not displacing coal in China's power mix. 25 June 2024.

LNG under contracts linked to oil prices (see Section 5), meaning delivered prices would likely exceed the cost of production.

Table 3 provides a sensitivity analysis for the levelized cost of electricity (LCOE) of an LNG-fired power plant at various fuel and capital costs. At fuel costs higher than US$7/MMBtu, LNG-to-power plants are unlikely to be competitive with electricity generation alternatives in Cambodia.

Table 3: Sensitivity of LNG-to-power LCOE to Fuel and Capital Costs (US$/MWh)

		Fuel Costs (US$/MMBtu)					
		4	7	10	13	16	19
Capital Costs (%)	4	49.2	68.7	88.2	107.7	127.2	146.7
	7	53.9	73.4	92.9	112.4	131.9	151.4
	10	59.0	78.5	98.0	117.5	137.0	156.5
	13	64.6	84.1	103.6	123.1	142.6	162.1
	16	70.4	89.9	109.4	128.9	148.4	167.9
	19	76.5	96.0	115.5	135.0	154.5	174.0

Source: IEEFA calculations.

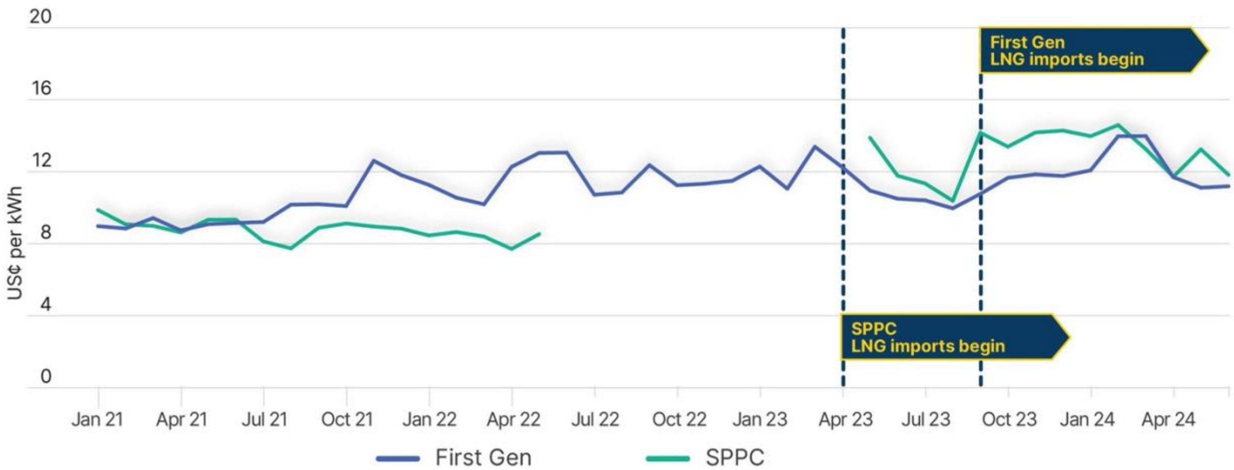
Under non-concessional financing terms, capital costs for LNG projects in Cambodia may be high due to risk premiums on the cost of debt and equity. The sovereign default spread, which estimates sovereign risk added to a base rate cost of debt, has been assessed at 5.99%. The Secured Overnight Funds Rate (SOFR), which provides a base rate for US dollar-denominated loans, was 5.33% on 07 June 2024. Meanwhile, an equity risk premium of 12.65% may be assumed on top of the base rate cost of equity. IEEFA assumes a weighted average capital cost (WACC) of over 16%.

IV. Case Study: Impact of LNG Imports on Generation Costs in the Philippines

The case of the Philippines, which recently began importing LNG due to a shortage of indigenous gas production, demonstrates the inflationary impacts of LNG imports on power generation costs. Figure 16 shows the cost of gas-fired power generation from plants contracted by the Manila Electric Company (Meralco), the country's largest power distribution utility. Average prices from South Premiere Power Corporation (SPPC), which operates the Ilijan gas-fired power plant, increased 49% following a complete shift from domestic gas to LNG in May 2023.

Meanwhile, First Gen, which owns and operates four natural gas-fired power plants, began importing LNG in September 2023. The company is currently blending LNG with indigenous gas from the Malampaya field, likely softening the impact of LNG imports on generation costs. Still, average generating costs from First Gen plants have increased 12% since imports began. The company has repeatedly delayed importing LNG cargoes as it seeks regulatory clearance for the full pass-through of LNG costs.[105, 106]

Figure 16: Average Generating Cost for Gas-fired Power Plants to Meralco[107]



Note: SPPC's Ilijan power plant was on outage for most of 2022 after the ceasing of domestic gas supply. LNG imports began in May 2023.[108]
Source: Meralco.

Overall, gas generation comprises a fifth of Meralco's power supply, and the total generating cost from gas-fired power plants has risen 15% since the introduction of LNG.[109] Depending on production from the Malampaya field, LNG may play a larger role in meeting gas-fired generation requirements. This will likely put further pressure on generating costs and electricity tariffs, which have increased by approximately 33% since 2021. Controlling the inflationary impact of LNG on electricity prices in the Philippines will require securing lower-cost LNG, increasing domestic gas supply, and/or reducing gas-fired generation requirements by increasing output from lower-cost generation.

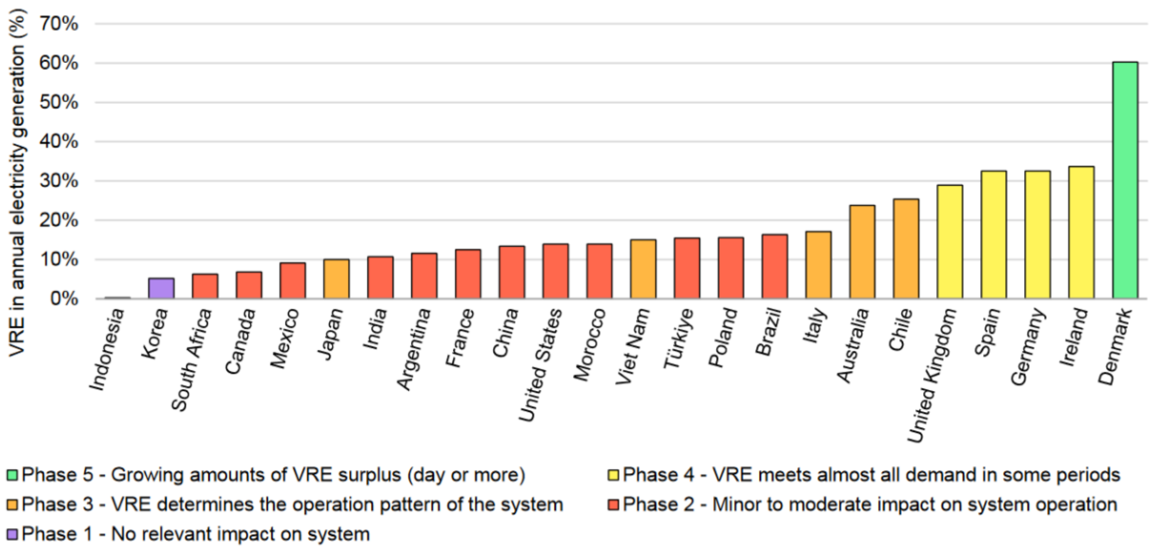
V. The Role for LNG-to-Power Plants: Baseload or Balancing?

Power sector planning in Asia has traditionally focused on developing large, centralized coal-fired plants operating at baseload levels to ensure stable power supply, keeping operating costs low, and leveraging the regional availability of low-cost coal. However, the global movement to decarbonize power systems has simultaneously restricted coal development and encouraged higher deployment

[105] Manila Standard. First Gen reviewing fourth LNG shipment. 29 February 2024.
[106] Power Philippines. First Gen delays fifth LNG shipment pending regulatory approvals. 08 July 2024.
[107] First Gas Power Corporation (First Gen) average generating cost is the average per unit generating costs for power sold from Santa Rita, San Lorenzo, and San Gabriel power plants. South Premiere Power Corp. (SPPC) is average per unit generating costs for baseload, mid-merit, and emergency power supply agreements (PSAs) from the Ilijan power plant; costs are omitted for the extended Ilijan outage between June 2022 and April 2023.
[108] Philippine News Agency. SMC sees reopening of Ilijan power facility in May. 28 April 2023.
[109] Calculated as the average per unit generating cost for Meralco's total electricity supply from January 2021 until LNG imports began to feed the Ilijan power plant in May 2023. Meralco. Rates Archives. Date Accessed: 02 July 2024.

targets for renewable energy capacity. While Asian power planners are turning to LNG-fired power plants to replace coal cancellations, they should consider what assets can provide flexible generation for their higher renewable deployment targets.

Figure 17: Countries in Phases of Renewables Integration, 2022



Source: IEA.

The IEA classifies variable renewable energy (VRE) integration into six phases based on the challenges electricity grids face at various levels of wind and solar generation (see Figure 17).[110] With 5% of its electricity supply currently coming from solar, variable renewables are classified as not imposing any relevant impact on Cambodia's power system (Phase 1 above).

However, this share of solar is likely to increase soon. The PDMP 2022-2040 calls for solar to increase from 9.4% capacity currently to 11% by 2030 and 22% by 2040.[111] Furthermore, achieving Cambodia's ambitions of generating 70% of power from renewable sources this decade could result in higher solar deployment and the introduction of wind into future power plans.[112]

Greater integration of solar and wind will likely push Cambodia's electricity grid into higher phases, indicating that grid operations will have to evolve to accommodate variable renewables output. This includes the utilization of flexible generation to ramp up quickly, and the dislocated nature of the country's power system may require more remote flexibility to balance intermittency.

[110] IEA. Renewables 2023. January 2024. Page 77.
[111] MME. Cambodia Power Development Master Plan 2022-2040. September 2022.
[112] Phnom Penh Post. 70% green energy by 2030: Gov't. 14 December 2023.

Table 4: Comparison of Typical Gas-Fired Power Plant Characteristics

Parameter	CCGT	OCGT	ICE
Typical role	Baseload	Peaking	Flexibility
Typical size (MW)	550	50 - 240	9.7 - 296
CAPEX (US$/kW)	850 - 1,300	700 - 1,150	747.5
Fixed O&M (US$/kW-yr)	10 - 25.5	10 - 17.0	15
Variable O&M (US$/MWh)	2.75 - 5	3.5 - 5	7.5
Capacity factor (%)	30 - 90	10 - 15	10 - 40
Heat rate (Btu/kWh)	6,750 - 7,500	8,000 - 9,800	7,198
Ramp-up time	1 - 4 hours	5 - 11 min	2 - 5 min
Minimum load (%)	20 - 50	20 - 50	20%
Average ramp rate (% nominal power capacity per minute)	2 - 11	8 - 15	>100
Minimum uptime	4 hours	10 - 30 min	< 1 min
Minimum downtime	2 hours	30 - 60 min	5 min

Note: Capex refers to capital expenditures.
Source: Lazard; Wartsila; IRENA.

Gas-fired power plants can provide operational flexibility, but certain 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. Waste heat from the gas turbines 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 (see Table 4). For example, CCGTs can take one to four hours to ramp up to full power output.

By contrast, Open-Cycle Gas Turbines (OCGTs) 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, 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 accommodating changes in renewable energy output.

Gas-fired Internal Combustion Engines (ICEs) provide a more flexible alternative, such as ramping up to full capacity in under a minute. They can also achieve higher capacity factors than OCGTs, albeit at higher variable costs. Additionally, the modular nature of the technology allows users to tailor the size of the plant to end-user requirements.[113]

Despite OCGTs and ICEs being more suitable technologies to complement ambitious variable renewable deployment strategies, most of the planned capacity in Asia is in the form of CCGTs. According to data from Global Energy Monitor, Asian utilities are planning to build over 158,100MW of CCGT capacity, compared to just 1,130MW of OCGT and 200MW of ICE capacity.[114]

This trend could partly be due to the established contractual arrangements between customers and suppliers across the LNG-to-power chain that favor long-term commitments stabilized by government guarantees over flexibility. Fuel supply contracts typically involve long-term take-or-pay arrangements requiring power plants to pay for fuel regardless of whether it is used to produce electricity. PPAs, meanwhile, involve local utilities agreeing to pay a minimum capacity charge whether the power is produced or not. Arrangements on fuel cost pass-through mechanisms also need to be embedded in these agreements to ensure that investors in the import terminals, power plants, and utilities can operate their business models confidently. This often involves governments providing expensive financial guarantees to smooth out price differences during periods of excessive market volatility.

Achieving Cambodia's ambitious 2030 target of generating 70% of electricity with renewables by 2030 may require an evolution of this contracting structure. Shorter, less rigid take-or-pay contracts for smaller gas volumes could improve gas plants' ability to operate flexibly but may also make it challenging to provide investors with the long-term certainty needed to service debt and recover capital costs. The government will also need to address fuel suppliers' uncertainty surrounding an attempt to develop LNG import terminals around an anchor LNG-to-power facility providing flexible services.

While PDMP 2022-2040 does not specify the technology type for its initial 900MW of LNG-fired capacity, recent trends suggest that CCGTs may be used. If Cambodia develops an LNG-to-power value chain underpinned by long-term agreements, it could be difficult to justify investments in the less-utilized but more flexible OCGT and ICE units.

The following case study on Vietnam demonstrates that a rigid take-or-pay structure can increase the costs of electricity generation, eventually requiring higher electricity tariffs or government subsidies. For lower-income countries like Cambodia, this can create macroeconomic distress, a result that emerging markets like Vietnam are actively trying to avoid.

[113] An engine can be as small as 9.7MW, and parallel engines can easily multiply the size of the facility to as high as 300MW. There is also an option to add combined cycles to the facilities. Moreover, additional capacity or combined-cycle ability can be added later than its initial construction. Wartsila. White Paper: Combustion engine power plants. 2011.
[114] GEM. Global Oil and Gas Plant Tracker. February 2024.

VI. Case Study: The Complexities of Risk Sharing in Vietnam's LNG Value Chain

LNG price volatility has resulted in countries taking measures to protect consumers and state-owned enterprises from price surges by setting upper limits on gas and power prices. For example, Vietnam has hesitated to allow the full pass-through of fuel prices in its ongoing PPA negotiations. This has been an obstacle between the main PPA counterparties, including investors in LNG-to-power plants and the state-owned buyer, Vietnam Electricity (EVN).

The Vietnamese government is actively working to reform its markets to foster PPA development to complete 22GW of LNG-to-power projects by 2030. The government recently clarified that it would allow fuel cost pass-through to consumers in PPAs[115], and later set a price ceiling of US$12.98/MMBtu for LNG to provide price clarity and consumer protection.[116] The government also set a 70% take-or-pay requirement in PPAs for "the debt repayment period," but restricted the duration of this period to seven years to limit the adverse impacts of higher LNG costs on utility tariffs and consumer welfare.

Despite this development, many issues remain.[117] A debt repayment period of seven years is too short for project developers and their potential lenders. Financing the project would require debt with matching tenors for seven years, which would yield a prohibitive upfront repayment schedule, resulting in significant increases in the electricity tariff.

Meanwhile, fuel cost pass-through is permitted through a formula that utilizes parameters such as average fuel contract prices, plant efficiencies, and the age of power facilities. Restrictions on full fuel cost pass-through could lead to counterparty disagreements, delaying PPAs. The government may need to provide guarantees to arrive at acceptable fuel price levels across parties.

Signing a long-term PPA for 70% of a costly LNG-fired power plant will introduce substantial risk for EVN if there is lower power demand or displacement by cheaper renewable power sources. Conversely, project developers would have to sell 30% of their power on the wholesale market, which could see prices fall as lower-marginal-cost solar is deployed.

Consequently, new LNG-fired power plants may face extensive delays despite the recent commissioning of LNG import terminals in Vietnam. PPA negotiations for build, operate, and transfer projects in Vietnam are notoriously long, with coal-fired PPAs taking 10-12 years to complete.[118] Until the government provides more clarity on risk sharing between project developers, debtors, and EVN, Vietnamese gas buyers may be unable to secure long-term LNG supplies.

[115] S&P Global, Vietnam's draft policies for gas/LNG and renewables underpin market reforms. 24 April 2024.
[116] Bao Dautu. Khung giá trần điện khí LNG năm 2024 là 2.590,85 đồng/kWh. 27 May 2024.
[117] Energy Intelligence. Vietnam's LNG Growth Challenged by Volatile Prices, Clean Energy. 28 May 2024.
[118] Vietnam Investment Review. OneEnergy proposed as sole investor of Vung Ang 2 thermal power plant. 05 June 2018.

5. Strategic LNG Procurement Considerations

Strategic LNG procurement is critical for securing supply and competitive prices. However, various approaches to LNG procurement have important advantages and disadvantages. The chosen strategy depends on the importer's risk appetite for key commercial terms, including volume commitments, pricing, offtake duration, and other factors. This section overviews select LNG procurement considerations related to Cambodia's energy security, including contract duration, price indexation, and contract flexibilities.

Contract Duration. New LNG market entrants generally procure LNG via long-term sales and purchase agreements (SPAs), which typically last 10 to 25 years, or through spot market trades and short-term contracting arrangements.[119] Table 5 below provides a high-level overview of the pros and cons of each approach.

Table 5: Comparison of Long-term vs. Short-term LNG Procurement Strategies

Parameter	Advantages	Disadvantages
Long-term SPAs	Designed for supply security, as well as price and volume stability.	Volatility in global market conditions can leads to contracting disputes that may disadvantage emerging market buyers.
	Flexibilities can be included in contracting terms to suit the requirements of each counterparty.	Take-or-pay commitments are typically between 95-100% and are relatively inflexible. Such commitments may be at odds with flexible downstream demand, resulting in added costs.
	Long-term price formulas may shield buyers from volatility in spot markets, and price reviews may be included in SPAs that allow parties to revise contract prices under certain conditions.	SPAs lock-in a fixed pricing formula that may prevent buyers from benefitting when spot market prices fall.
Short-term and Spot Market Trades	Provides greater flexibility in timing and volume of cargoes that can complement flexible downstream demand.	Spot market cargoes may not be available at desired prices when needed.
	Allows buyers to take advantage of potentially oversupplied spot market conditions.	Exposes buyers to volatility in spot markets stemming from, for example, geopolitical disruptions and supply outages, among other factors.
	Short-term and spot market procurement allows for potentially greater diversity of supply sources.	May require more frequent negotiations and operational capacity.

Source: IEEFA.

Given the uncertainty surrounding Cambodia's LNG demand and the role of LNG-fired power plants in the country's power mix, long-term offtake commitments will be challenging given the inflexible take-or-pay guarantees required. As a result, Cambodia may need to initially source cargoes from

[119] Note that importers may also procure LNG via direct investment and equity offtake from an LNG export facility. However, this is often more suited to mature buyers due to the expertise, experience, and financial risk management required.

the spot market while determining the minimum required volumes. Spot market exposure, however, poses clear risks in terms of supply security and price stability, as demonstrated by the experience of other emerging Asian LNG importers in recent years.

Price Indexation. Historically, pricing formulas in LNG contracts have primarily been linked to oil via a percentage slope, which effectively converts oil prices per barrel into an LNG price per MMBtu.[120] In 2016, 75% of LNG imports were linked to oil prices, with slopes typically ranging from 11-16%.[121] The agreed upon slope will depend on various factors, including the market environment at the time of negotiations, the leverage of the parties involved, and other contractual terms, such as risk allocation between buyer and seller, and delivery flexibilities.

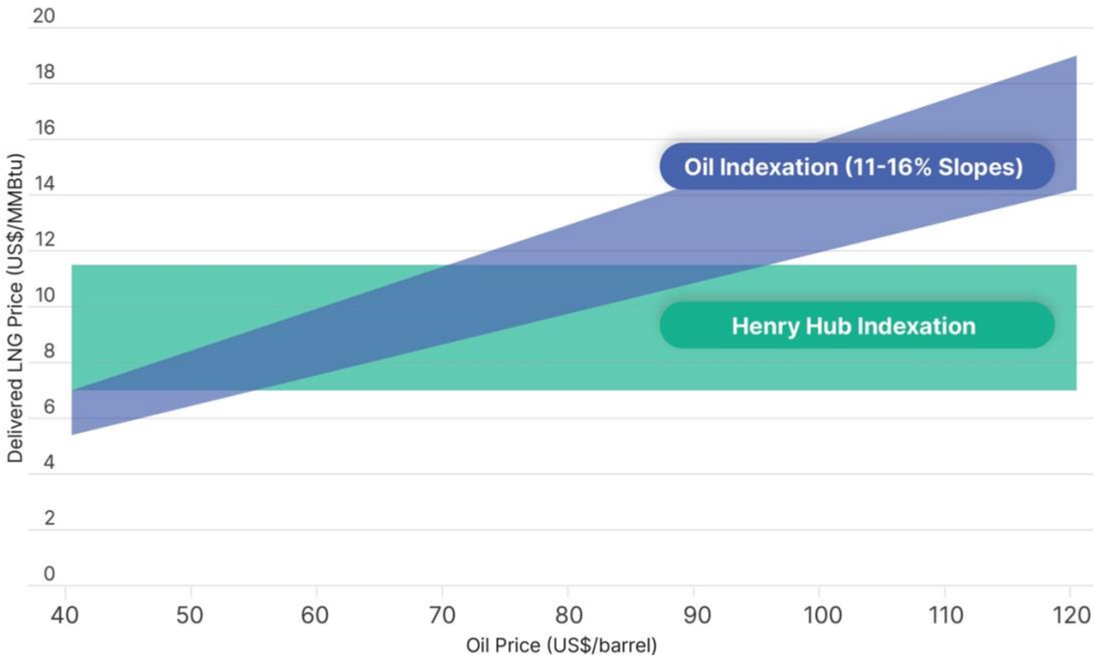
Although oil-linked LNG still accounts for 70% of volumes delivered to Asia[122], its global share has fallen to 50% due to the rise of natural gas trading hubs with sufficient liquidity to serve as competitive LNG pricing benchmarks.[123] Most contracts signed by LNG exporters in the Middle East and Asia are still indexed to oil prices.

In contrast, Henry Hub has emerged as a key indexation benchmark in the U.S. alongside the rapid growth of the country's LNG exports. LNG contracts with U.S. facilities typically include cost components for gas feedstock (e.g., the Henry Hub price), plus liquefaction, transportation, and regasification. Under a tolling structure common in U.S. contracts, LNG buyers are responsible for feedgas procurement and LNG transport, only paying a fixed fee to use a liquefaction facility.

Figure 18 shows delivered prices of oil-indexed and Henry Hub-indexed LNG at various slopes and cost assumptions for U.S. LNG price components.

[120] For example, a 10% slope at an oil price of US$80/barrel would result in an LNG price of US$8/MMBtu. A slope of 17.24% represents oil parity, passing the full value of the oil price to the LNG buyer.
[121] OGEL. Trends in LNG Supply Contracts and Pricing Disputes in the Asia Pacific Region. Page 23.
[122] IGU. Wholesale Gas Price Survey 2024 Edition. 23 April 2024. Page 23.
[123] IGU. Wholesale Gas Price Survey 2024 Edition. 23 April 2024. Page 10.

Figure 18: Delivered Prices of Oil and Henry Hub-Indexed Contracts



Note: The Henry Hub price range includes the following assumptions: Liquefaction fees of US$2.5-3.5/MMBtu, feedstock costs of US$2.5-5.0/MMBtu, transportation and regasification costs between US$2-3/MMBtu. Cambodia's shipping and regasification costs may be higher due to the additional per-unit costs of small-scale LNG infrastructure (discussed in Section 6).
Source: IEEFA.

Although more non-conventional pricing alternatives have emerged in recent years, such as the Japan-Korea Marker (JKM) indexation, oil and Henry Hub-linkages are considered the most established. Table 6 provides a high-level summary of the advantages and disadvantages of both indices that are most relevant to Cambodia.

Table 6: Comparison of Oil and Henry Hub Indexation

Parameter	Advantages	Disadvantages
Oil Indexation	Pricing reviews typically included in oil-indexed contracts.	Destination restrictions are more common in oil-indexed contracts, limiting trading opportunities.
	Delivered prices reflect international oil fundamentals, rather than U.S. domestic gas supply-demand balances.	Delivered LNG prices reflect oil market fundamentals, not gas.
	Shorter delivery timelines due to geographical proximity of Asia-Pacific and Middle East LNG exporters.	Relatively more exposure to international geopolitical risks.
	Fewer contractual flexibilities can support lower indexation and delivered LNG prices.	Higher share of delivered price is indexed, compared to U.S. contracts containing fixed liquefaction fees.
Henry Hub Indexation	High degree of volume flexibility under U.S. tolling model.	Liquefaction fees are locked in regardless of offtake volume, and contracts do not typically allow for reviews of liquefaction fees.
	U.S. domestic gas prices are relatively insulated from global geopolitical risks.	Buyer is typically responsible for shipping arrangements on FOB terms.
	Henry Hub linkage provides opportunity for LNG buyers to diversify pricing benchmark exposure.	Henry Hub prices are derived fundamentals in U.S. domestic demand and supply, rather than market dynamics in Asia.
	Destination flexibility of FOB contracts allows for trading opportunities.	Length of delivery distance to Asia and risk of outages at US liquefaction facilities in the Gulf Coast during hurricane seasons.

Source: IEEFA.

Contractual Flexibilities. Even under low price assumptions for oil and Henry Hub indices (shown in Figure 18), the delivered LNG price under long-term contracts is unlikely to fall below levels that might make LNG-fired power plants competitive with alternatives for baseload electricity generation (as discussed in Section 4). Instead, LNG-fired power plants will likely serve mid-merit or peaking roles, complicating volume and delivery requirements and requiring buyer optionality in LNG procurement contracts. Table 7 below shows several key categories of contractual flexibilities.

Table 7: Select Categories of Flexibility in LNG Contracts

Contract Term	Description	Examples
Pricing Flexibility	Choice of price indexation.	S-Curves, which adjust contract slopes above/below specified oil prices. Can protect the buyer when oil prices rise above the pivot point.
		Pricing caps or floors.
	Complex pricing formulas with embedded optionality.	Price-out-of-range provisions, which call for parties to discuss pricing in good faith if oil prices fall outside a specified range.
Volume Flexibility	Flexibility to lift or deliver different LNG volumes.	Take-or-pay quantities. The minimum annual quantity that a buyer must take or pay for. Historically, this is 95-100%, though buyers can negotiate lower figures under certain conditions.
		Upwards Quantity Tolerance (UQT). Entitle the buyer or seller to increase annual contract quantities.
		Downwards Quantity Tolerance (DQT). Entitle the buyer or seller to reduce annual contract quantities.
Locational Flexibility	Flexibility to deliver cargoes to different locations.	Diversion rights, including FOB delivery to anywhere or DES rights to deliver within a fixed subset of locations. Diversion rights allow buyers to manage volume commitments, enter into swap transactions, or take advantage of price arbitrage by selling into higher-priced markets.
Timing Flexibility	Flexibility to adjust timing of cargo deliveries.	An SPA may allow for seasonal distribution of cargo deliveries, allowing buyers to take more volumes during specified times. Some SPAs make include "make up" rights that allow buyers to postpone deliveries to later in the year.

Source: IEEFA analysis based on Timera Energy and OGEL.

Buyer optionality can affect seller revenue and profitability, usually resulting in a premium for delivered LNG to compensate sellers for additional risk. However, quantifying the value of various LNG contract terms is not straightforward. It will depend on multiple factors, including the global market at the time of negotiations, prevailing buyer/seller sentiment, and the bargaining power of counterparties.[124] Inexperienced buyers may have weaker bargaining power in negotiations due to limited knowledge, less leverage, and fewer relationships with sellers, among other factors.

In sum, while longer-term contracts with limited flexibilities may best serve Cambodia's energy security needs, the uncertain demand and role of LNG in the country's power sector may require flexible terms that result in higher delivered prices. Cambodia can source individual cargoes from spot markets, though the risks of doing so are evident following extreme spot market volatility over the past three years.

LNG Price Volatility and Contractual Disputes. Recent history illustrates that emerging LNG adopters may also find it challenging to secure LNG even in the presence of long-term contracts. Relatively low-demand, emerging LNG importers, with lower credit ratings than wealthier incumbent importers, can have difficulty securing favorable contract conditions in long-term SPAs. This can lead

[124] Timera Energy provides a case study on the buildup of LNG contract value by source of flexibility. Timera Energy. LNG contract valuation case study: 'flex ain't free'. 08 March 2021.

to clauses that essentially obviate the availability and affordability advantage that a long-term contract is meant to address for LNG buyers.

In 2022, for example, Pakistan had two long-term contracts with global commodity traders, Gunvor and Eni.[125] Following Russia's invasion of Ukraine, LNG prices rose so high that both companies defaulted on deliveries to Pakistan, opting instead to resell shipments into higher-priced markets elsewhere. The contractual penalties for defaults were effectively too low to discourage trading behavior.

As a result, Pakistan could not afford replacement cargoes from the spot market, causing gas and power shortages that devastated economic activity. Although the global gas crisis has largely subsided, Pakistan still struggles to procure cargoes from spot markets. Due to the country's high credit risk, LNG suppliers typically offer to sell cargoes at significant premiums to market rates. In late 2023, for example, Pakistan LNG Ltd. secured a cargo at a 13% premium and rejected several offers to supply cargoes at a 30% to 37% markup throughout the year.[126] In 2023, the country announced it would no longer commit to building new LNG-to-power projects.[127]

Even with more secure long-term contracts, emerging LNG importers could still be exposed to spot markets due to supplier flexibilities embedded in contracts. For example, LNG suppliers to Bangladesh exercised downward quantity tolerances in late 2021 to reduce deliveries to the country and free up volumes for trading.[128] Bangladesh has also faced a history of spot market premiums that led to LNG tender cancellations and nationwide gas shortages (see Section 5).[129, 130]

Cambodia does have a more favorable credit rating (B2) than Pakistan (Caa2).[131, 132] While this suggests that Cambodia could secure spot cargoes without a significant premium, there is still a risk that volatile LNG market conditions could threaten Cambodian energy security, even with long-term LNG procurement contracts.

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125 Bloomberg. How Energy Traders Left a Country in the Cold. 14 December 2023.
126 Bloomberg. Pakistan Faces Gas Crunch After Deciding Not to Buy Pricey LNG. 01 August 2023.
127 Reuters. Exclusive: Pakistan plans to quadruple domestic coal-fired power, move away from gas. 14 February 2023.
128 S&P Global. Qatar, Oman to reduce 2022 LNG deliveries to Bangladesh. 02 December 2021.
129 S&P Global. Bangladesh cancels Nov LNG tender, likely to cancel Dec on high prices offered. 23 October 2020.
130 Bangladesh continues to face spot price premiums in 2024. S&P Global. Bangladesh leans towards long-term LNG contracts with recent deals. 01 February 2024.
131 Moody's. Cambodia, Government of Credit Rating. 16 May 2024.
132 Moody's. Pakistan, Government of Credit Rating. 28 August 2024.

6. Infrastructure Analysis for Cost Efficiency and Energy Security

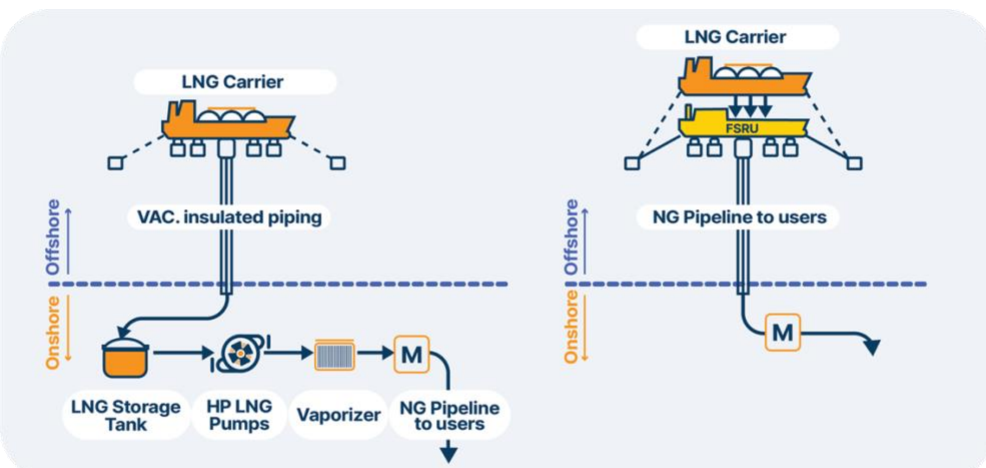
Alongside developing a strategic LNG procurement plan, expanding import infrastructure suited to Cambodia's potential LNG demand will be critical for energy security and cost efficiency. LNG value chains have traditionally required significant capital outlays for import and transportation infrastructure. High demand and economies of scale over extended periods have been critical for reducing per-unit gas costs.

Over the last decade, however, the industry has developed smaller-scale solutions, including floating storage and regasification units (FSRUs) and virtual pipelines, designed to cater to smaller markets with varying demand characteristics. This section overviews various configurations for LNG importation, including onshore and offshore terminals and smaller-scale and containerized LNG concepts.

I. Onshore Terminals and FSRUs

There are generally two types of LNG import terminals: onshore terminals and FSRUs. A hybrid option involves using an LNG carrier as a floating storage unit (FSU) with regasification equipment placed onshore or mounted to a marine berth. However, FSU configurations are less common globally due likely to additional upfront costs.[133] Figure 19 provides a high-level comparison of land-based and FSRU configurations, with key considerations for Cambodia discussed in detail below.[134]

Figure 19: Onshore (left) vs. FSRU (right) Import Terminal Configurations



Source: Offshore Magazine. Review of LNG terminal options shows advantages of FSU facilities. 15 September 2017.

[133] However, the degree to which FSUs will increase capex is not well known. ADB. Project Number: 53193-001: Democratic Socialist Republic of Sri Lanka: Supporting Feasibility Study and Survey to Adopt Liquefied Natural Gas (LNG) Power Generation to Diversify Energy Mix. June 2021. Page 40.
[134] Due to a lack of data on the cost consideration of FSU configurations, this report will only compare onshore terminals to FSRUs.

Table 8: Project Consideration Comparison for Onshore Terminals and FSRUs[135]

	Onshore terminal	FSRU
Project timelines	36 to 50 months	12 to 36 months
CAPEX (US$ million)	550 to 750	75 to 750
Charter OPEX (US$ million per year)	N/A	33 to 110
Other OPEX (US$ million per year)	7.3 to 15	7.3 to 16
Flexibility	Site permanence offers no locational flexibility, but flexible to expanding storage and regasification capacity.	Land and port locational flexibility, but capacities limited to the size and parameters of the vessel.
Availability	More long-term supply security. Can operate during inclement weather.	Unable to operate during inclement weather. Flexibility could cause availability and affordability issues during tight LNG carrier markets.
Storage	Typically, higher capacity, with the ability to expand capacity.	Limited to the size of the vessel.

Note: OPEX refers to operating expenditures.
Source: ADB, Offshore Magazine, Trafigura, SAARC, media sources, and IEEFA calculations.

Capital cost comparison. FSRUs typically cost US$75-750mn, compared to between US$550mn and US$750mn for onshore terminals (see Table 8). These potentially lower upfront cost estimates come with important caveats. First, FSRU costs vary widely according to project-specific conditions and construction parameters. For example, the Hong Kong FSRU cost HK$8bn (US$1bn), but it was a relatively larger vessel.[136] Meanwhile, the cost to deploy floating import terminals in Germany in 2022 became double the original estimate as the project process revealed more concrete cost estimates.[137]

Operating cost comparison. Another consideration is the higher operating costs of FSRUs, mostly due to vessel leasing rates. Chartering an FSRU can cost between US$33mn and US$73mn per year. Over time, leasing costs can eliminate cost competitiveness compared to onshore terminals, though this can be avoided if the operator purchases the vessel.

Unit costs. Depending on the demand profile, the present value of regasification costs per unit may range from roughly US$1/MMBtu to over US$4/MMBtu, in the event of low terminal utilization.[138, 139]

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135 The cost estimates in this table are gathered and estimated based on the assumption of a 3-MTPA sized LNG import facility.
136 The Standard. More stable power thanks to offshore LNG terminal. 31 October 2023.
137 Euractiv. Twice as expensive: The high cost of Germany's floating LNG terminals. 21 November 2022.
138 EIA. Natural Gas Weekly Update. 06 September 2017.
139 World Bank. Introduction of Liquefied Natural Gas (LNG) in Central America. April 2015. Page 55.

While onshore terminal storage and regasification can often be expanded to meet demand depending on the land footprint, the lower scalability of FSRUs may incur higher per-unit costs if capacity is unused.

Construction timelines. Deployment of FSRUs can take between 12 and 36 months, compared to up to 50 months for construction of onshore terminals. The construction of a new FSRU can take up to 32 months. However, converting an LNG carrier into an FSRU or chartering an existing FSRU can reduce these lead times (see below). Shorter project lead times are due largely to the construction taking place in controlled shipbuilding environments compared to the site-specific assembly of onshore terminals.[140]

Vessel chartering. Chartering FSRUs and FSUs can further reduce capital outlays and timelines, though this will depend on the global availability of vessels. After Russian pipeline flows fell significantly in 2022, Europe chartered most of the available FSRUs on the market[141], and by 2023, prospective adopters were unable to charter any vessels.[142] As a result, prospective FSRU adopters must wait for the completion of newbuild units or LNG carrier conversions.[143]

While FSRUs and FSUs are flexible assets that can provide regasification, storage, and marine transport services, asset operators mainly bear this advantage. During periods of tightness for LNG carrier services, higher LNG charter rates could turn this flexibility into a detriment for potential offshore adopters who cannot afford their own vessel or outbid richer charterers for FSRU or FSU services.

Vessels are often chartered for ten years at a time, and attempting to charter during tighter LNG carrier markets can result in higher operating costs for LNG importers.[144] Charter rates can be highly volatile during periods of high LNG or supply disruptions, which can lead to a doubling of daily operating costs. In 2022, for example, average charter rates for FSRUs more than doubled following Europe's rush to secure LNG supplies.[145] Potential adopters must navigate such volatility to ensure availability of potential FSRU and FSU units.

A higher supply of FSRUs and FSUs could alleviate some of these pressures. At the end of 2023, the global LNG carrier fleet included 51 FSRUs and 8 FSUs.[146] However, more stringent emission standards from the International Maritime Organization (IMO), cost pressures, and technological

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[140] However, shipyard bottlenecks can extend FSRU delivery timelines. IGU recently cited shipyard bottlenecks as a potential risk to LNG market development. IGU. 2024 World IGU Report. 26 June 2024. Page 17.
[141] IGU. 2023 World LNG Report. 12 July 2023. Page 87.
[142] Kpler. FSRUs a preferred option to onshore LNG import terminals amid decarbonization pursuit. 02 June 2023.
[143] Kpler. FSRUs a preferred option to onshore LNG import terminals amid decarbonization pursuit. 02 June 2023.
[144] Timera. How FSRU's are impacting LNG market evolution. 09 July 2018.
[145] IGU. 2024 World IGU Report. 26 June 2024. Page 70.
[146] International Group of Liquefied Natural Gas Importers (GIIGNL). GIIGNL 2024 Annual Report. 03 June 2024.

advancements have left over 200 LNG carriers ill-suited to meet evolving standards.[147, 148] Converting some of these to FSRUs could improve availability and affordability for emerging LNG adopters.[149, 150]

Reliability. FSRUs typically require calm oceanic conditions for LNG unloading, meaning inclement weather and meteorological events can threaten safe operations. Bangladesh's experience suggests that FSRUs can experience frequent, unexpected outages that challenge the reliability of import services compared to onshore terminals.[151, 152]

Technical glitches, equipment problems, and weather disruptions led to several FSRU outages in Bangladesh, resulting in gas disruptions lasting days to months.[153, 154, 155] During these outages, gas users across the economy were impacted by shortages. Rotating blackouts were common, causing businesses, factories, and households to endure hours without electricity. Although the government raised gas tariffs by 179% in 2023 to fund solutions to these chronic supply issues[156], outages persist. In May 2024, Cyclone Remal thrashed a stray structure into the Summit FSRU, prompting the operator, Summit Group, to send the vessel to Singapore for repairs and plunging the country into another acute supply shortage.[157] The FSRU returned from repair in early July, but a series of technical failures and challenging conditions dragged out the recommissioning of the facility until mid-September.[158, 159]

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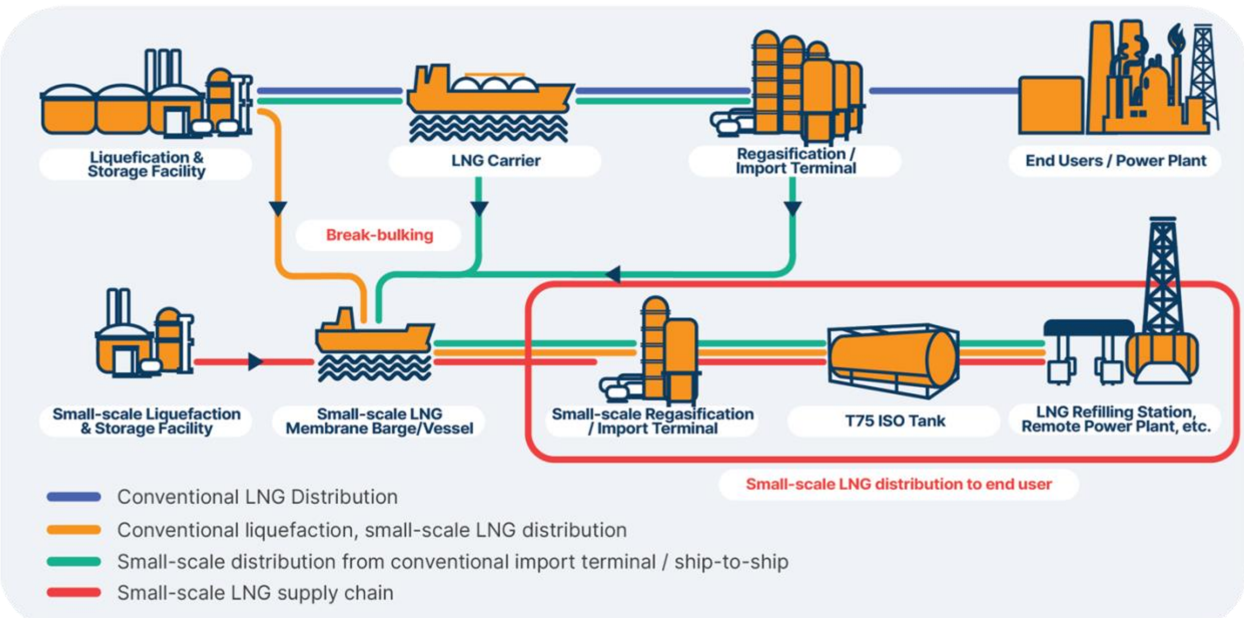
[147] Asia Pacific Energy Research Centre (APERC). OGSS17: Changing LNG Market Dynamics – Implications for Supply Security in the APEC Region. September 2020. Pages 28 to 42.
[148] APERC. OGSS19: Oil and gas security during the energy transition. September 2023. Page 37.
[149] Of the three FSRUs on the orderbook in by the end of 2023, one is a conversion project. GIIGNL. GIIGNL 2024 Annual Report. 03 June 2024. Page 29.
[150] Inefficient vessels could also be commercially repurposed as FSUs without undergoing any conversion work. The regasification systems onboard FSRUs typically require some conversion work in shipyards. An FSU-based offshore terminal requires the erection of a regasification system outside the FSU unit. Offshore Magazine. Review of LNG terminal options shows advantages of FSU facilities. 14 September 2017.
[151] The rest of this section will discuss Bangladesh's experience with FSRUs, but the reliability issues can also apply to FSU import offshore terminals. For example, in May 2024, inclement weather from Typhoon Aghon led AG&P to unmoor its FSU to avoid damages to the vessel, prompting a shutdown of the facility. However, outages were avoided by increasing supply from the domestic Malampaya gas field to unaffected power plants. Offshore Energy. Philippine gas field braves typhoon with no disruption in supply. 06 June 2024.
[152] An emerging solution to inclement weather is to build gravity-based regasification structures (GBSRUs). While only one is in operation worldwide in Italy, there are several plans to introduce the technology to inclement weather areas, like India and Vietnam. Crown LNG. Analyst & Investor Day Presentation. February 2024.
[153] In 2018, tube leakages in the FSRU Excellence delayed the introduction of gas supply for months, with rough weather challenging and extending the repair timeline. Dhaka Tribune. Technical glitch holds back LNG supply yet again. 23 July 2018.
[154] In November 2021, the Summit LNG FSRU went offline for three months due to a ruptured mooring line. In May 2023, as the arrival of Category-5 Cyclone Mocha led to a three-day disruption for the Summit LNG FSRU, and an eight-day hiatus for the FSRU Excellence. Specialists from Belgium had to be flown in to moor the Summit FSRU in a manner that reduced its downtime, while the FSRU Excellence needed to propel away from the storm without such a mooring. Gas Outlook. Cyclone Mocha exposes weakness of Bangladesh LNG. 13 June 2023.
[155] In early 2024, the overhauling of both FSRUs left the country short of gas supply for months, and complications following the repair of the FSRU Excellence led to an unintentional maintenance overlap. Gas Outlook. Bangladesh gas crisis worsens as FSRUs cease operations. 19 February 2024.
[156] Gas Outlook. Bangladesh gas crisis worsens as FSRUs cease operations. 19 February 2024.
[157] Rotating blackouts in June 2024 have lasted several hours a day, impacting industrial production, vehicle chagrining and general consumer welfare. The Business Post. Gas crisis, maintenance issues cause nationwide power outage. 28 June 2024.
[158] Daily Sun. Summit LNG Terminal ready for gas supply to national grid. 12 September 2024.
[159] The Summit FSRU returned to service in the middle of September 2024 after being out of commission for 3.5 months. BDNews. Summit's LNG terminal resumes production after over 3 months. 16 September 2024.

Unlike Bangladesh, Cambodia does not have supplementary gas supplies to help alleviate the crisis. Any economic activity or household well-being that depends on gas-fired electricity or gas as a fuel or feedstock will bear the brunt of disruptions directly.[160]

II. Small-Scale and Containerized LNG

High LNG demand is typically required to reduce the per-unit cost of delivered gas from traditional LNG facilities. However, the LNG industry has also aimed to develop smaller-scale concepts to improve the economic efficiency of import projects in more remote markets and sectors that may lack existing natural gas infrastructure. Figure 20 shows how LNG can be delivered to smaller demand centers.

Figure 20: Small-scale LNG Supply Chain



Source: SSB Cryogenic.

Yet, small-scale LNG (ssLNG) remains a niche segment mainly limited to China and small coastal cities in East Asia. In China, ssLNG has been used as a diesel replacement for long-distance trucking in inland regions. Although diverse strategies have been explored in various markets and sectors, ssLNG has struggled to gain traction globally due to competition from lower-cost options and diseconomies of scale.[161] This is reflected in the composition of the global LNG natural gas carrier (LNGC) fleet. As of 2019, more than 500 vessels were in the fleet, while the International Gas Union

[160] While a typhoon impacting Cambodia from its west coast is highly unlikely, Bangladesh's journey is a warning of the potential energy insecurity that tail-end weather events can bring to FSRU adopters. World Data. Typhoons in Cambodia. 06 June 2024.
[161] IEEFA. Indonesia's Small-Scale LNG Power Plant Conversion – A Triple Hit for PGN? August 2021. Page 13.

(IGU) listed just 40 small-scale LNGCs.[162] Meanwhile, the average capacity of LNGCs had increased from 140,000 cubic meters (m^3) in the 2000s to more than 160,000m^3 in 2020.[163] Key cost considerations for Cambodia are examined below.

Table 9: Various LNG Demand Sizes and Infrastructure Requirements

	Small-scale	Mid-scale	Large-scale
LNG Demand (MTPA)	0.1-1	1-3	>3
Regasification Capacity (MTPA)	0.1-1	1-3	>3
Shipping Vessel Capacity (cubic meters)	<30,000	30,000-138,000	138,000-267,000
Value Chain Elements for Onshore Projects	Small-scale jetty; small-scale LNG carrier; bullet storage tanks; ISO containers; LNG trucks	Small and medium-sized jetties; single, double, or full containment tanks for storage	Jetty (that supports large LNG carriers); onshore tanks (>150,000 cubic meters); large regasification modules
Value Chain Elements for Offshore Projects	Floating barges and small-scale FSRUs	FSRUs and FSUs (with regasification on jetty)	FSRUs and FSUs
Key Markets	LNG bunkering; diesel replacement in power and industrial sectors; remote demand	Small demand from diesel replacement in power and industry; demand balancing	Large power utilities; industrial consumers; LNG traders

Source: Adapted from APEC Energy Working Group.

Capital costs: Small-scale LNGCs (ssLNGC) have lower upfront capital requirements, although their cost per unit of LNG storage capacity can be significantly higher than that of large-scale carriers, owing to diseconomies of scale. For example, small carriers with a storage capacity of 2,500m^3 may cost US$23mn or roughly US$9,200/m^3. By contrast, a large-scale carrier with a tank size of about 145,000m^3 may cost US$200mn or US$1,379/m^3. The capital costs of various carrier sizes are shown in Table 10, along with their daily charter cost.

[162] Ibid.
[163] IEEFA. Indonesia's Small-Scale LNG Power Plant Conversion – A Triple Hit for PGN? August 2021. Page 12.

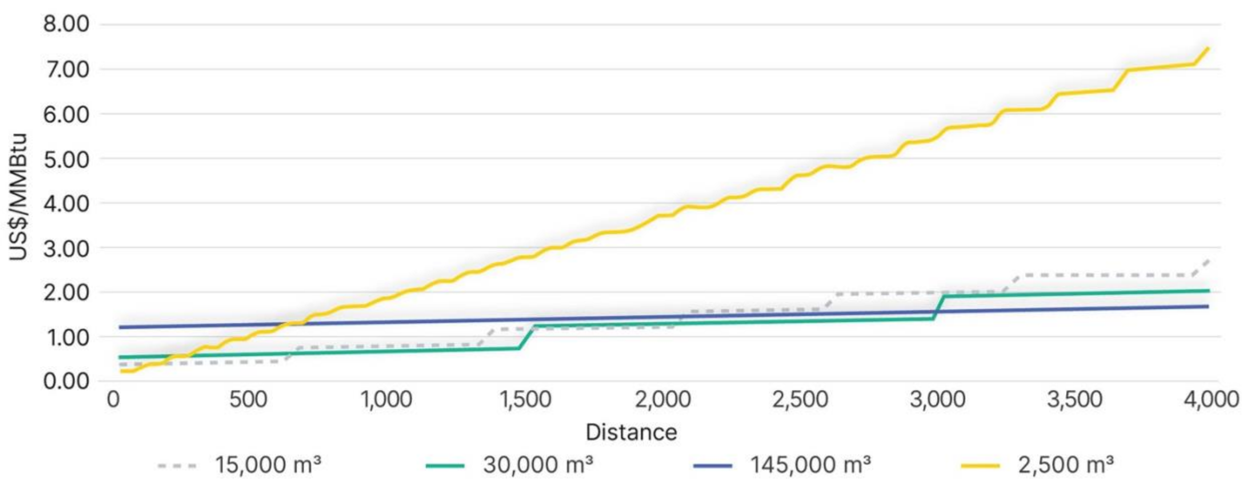
Table 10: Cost Comparison for Various LNGC Sizes

	Units	Vessel Size			
		Small		Medium	Large
Cost Category	m³	2,500	15,000	30,000	145,000-200,000
Optimal Delivery Distance	nautical miles	0-100	2,100	3,050	>3,050
CAPEX	US$ million	23	50	85	200
CAPEX per m³	US$/m³	9,200	3,333	2,833	1,379
Annualized CAPEX	US$ million	2.34	5.09	8.66	20.37
Annualized OPEX	US$ million	0.92	2	3.4	8
Total Annual Cost	US$mill/year	3.26	7.09	12.06	28.37
Total Annual Cost per m3	US$/m³	1,304	473	402	196
Daily Charter Cost	US$/day	8,939	19,432	33,034	77,727
Daily Charter Cost per m³	US$/day/m³	3.58	1.30	1.10	0.54

Source: APEC.Page 60.

Unit costs of small-scale shipping: Along with the size of the carrier, the per-unit cost of delivered gas is also highly dependent on the distance between the LNG source and the offtake. Longer distances effectively mean that more ssLNGCs are required to meet sustained demand, which renders ssLNGCs increasingly uncompetitive at longer distances. The Asia-Pacific Economic Cooperation (APEC) Energy Working Group illustrates the steeper cost curve for ssLNGCs with 2,500m³ (see Figure 21).[164]

Figure 21: Economic Comparison of Vessel Sizes Considering Distance



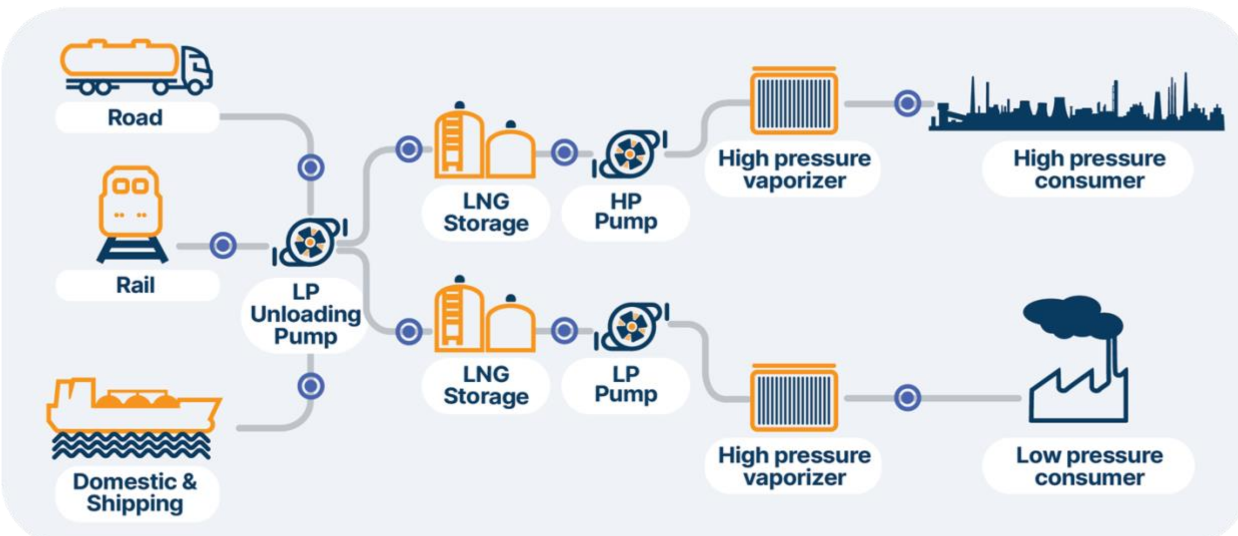
Note: Sourced from the Galway group; distance units are in nautical miles.
Source: APEC, Page 49.

[164] APEC. Study on Optimal Use of Small-scale Shallow-draft LNG Carriers and FSRUs in the APEC Region. April 2020. Page 49.

Containerized LNG and Virtual Pipelines: In emerging markets lacking physical gas transportation infrastructure, "virtual pipelines" can deliver gas via alternative modes, including shipping, trucking, and rail. Virtual pipelines often involve LNG delivery in ISO containers, which requires moving the container rather than pumping LNG into specialized vessels. Using ISO containers, LNG can be carried by cargo trucks, trains, and barges.[165] Marine shipments of LNG in ISO containers can be unloaded at existing port infrastructure rather than through specialized import terminals.

The ISO tanks are typically 40 feet long and carry 33 tonnes of LNG.[166] They can be transported aboard regular cargo vessels to satellite storage and end-use facilities. Using cryogenic pumps, LNG is unloaded from the ISO tanks and regasified through vaporizers near end-use sites rather than at large, centralized regasification sites. Figure 22 shows the various supply chain components of satellite end-use facilities.

Figure 22: Major Components of Containerized LNG



Source: Council on Energy, Environment and Water. Page 08.

Containerized LNG delivery can have numerous advantages compared to large-scale systems, particularly for countries that lack existing natural gas infrastructure. As noted above, the total upfront capex requirements for smaller-scale infrastructure may be lower. Small-scale systems are scalable and movable, which can be adjusted as demand develops. In many cases, containerized LNG may be cost-competitive with incumbent liquid fuels like diesel and liquified petroleum gas (LPG).

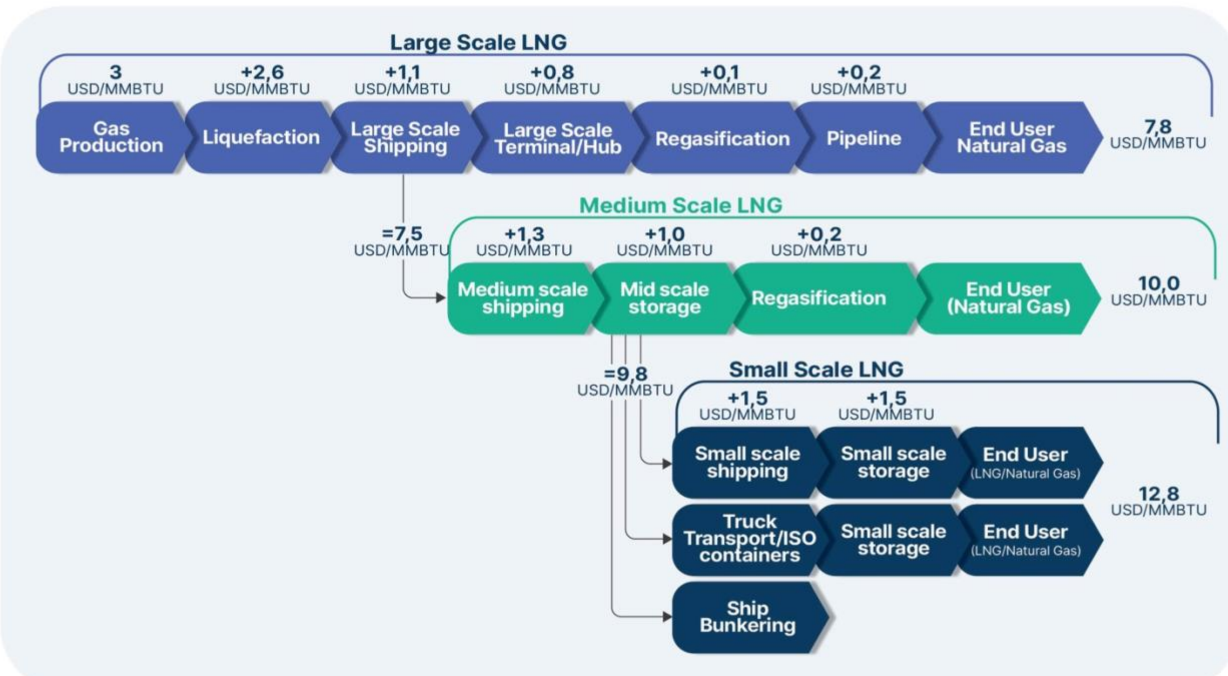
However, there are notable drawbacks. As virtual pipeline networks rely on trucking, rail, or maritime transportation, they can be susceptible to weather disruptions, accidents, public disorder, labor strikes, and other unplanned events. Moreover, the technical complexity, variety of supply chain

165 Cryogenic Industries. Establishing a Virtual Pipeline for Developing Natural Gas Markets. Spring 2016.
166 Erasmus Commodity & Trade Centre. Small-scale LNG: A red herring or a hidden opportunity?. August 2023. Page 03.

configurations, distance from LNG sources, and uncertainty of demand profiles, among other factors, make it challenging to estimate the impact of containerized supply chains on the final delivered price of gas.

The final cost of LNG at its destination depends on the length and number of components involved in the supply chain. LNG logistics company Wartsila provides an overarching estimate of the per-unit costs of small and containerized LNG assets, demonstrating that the introduction of medium and small-scale components into the large-scale LNG supply chain can add approximately US$5.3/MMBtu to the delivered cost of LNG (Figure 23).[167] The Council on Energy, Environment and Water similarly found that containerized LNG distribution from an import terminal in India can add US$4.59/MMBtu to the delivered cost at distances of 1,000 kilometers.[168] These figures are used as examples and would vary widely depending on the configuration of Cambodia's chosen LNG delivery network.

Figure 23: Typical Values for Additional Costs in the LNG Logistics Chain



Source: Wartsila.

[167] Wartsila. The LNG Logistics chain. 2017.
[168] Council on Energy, Environment and Water. Small-Scale LNG for Expanding Natural Gas Access in India. April 2021. Page ii.

Conclusion

While Cambodia's emergence as an LNG importer will likely coincide with a supply glut later this decade, policymakers will still need to actively manage the risks of bringing an inherently volatile commodity to their energy system. Embracing LNG-to-power projects requires careful deliberation to ensure energy remains secure, reliable, and affordable. Efforts should be made to ensure that the chosen LNG contract procurement strategy, import infrastructure configuration, and power plant technology are best able to help the country realize its targets of 70% renewable capacity by 2030 and carbon neutrality by 2050.

This report contains case studies that are useful examples for Cambodia to extract insights from as a lower-income, emerging LNG importer in Asia. These will aid in tailoring LNG-to-power projects to Cambodia's unique and evolving energy circumstances. Without careful consideration, introducing LNG could undermine the achievement of government macroeconomic and power sector targets and challenge the country's ability to meet its longer-term energy objectives.

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

About the Authors

Sam Reynolds

Sam Reynolds, a Research Lead with the Institute for Energy Economics and Financial Analysis (IEEFA), focuses on the economic, financial, and climate risks associated with natural gas and liquefied natural gas (LNG) infrastructure developments in emerging Asia.

He is the author of several studies concerning the region's transition to renewable energy, stranded asset risk in the natural gas sector, and the macroeconomic risks associated with a greater regional dependence on imported LNG. sreynolds@ieefa.org

Chris Doleman

Christopher Doleman is an LNG/Gas Specialist, Asia, focusing on the economic, financial and climate implications of developing the natural gas value chain throughout Asia.

Christopher previously spent five years at the Asia Pacific Energy Research Centre (APERC) in Japan identifying collaborative opportunities across Asia Pacific Economic Cooperative (APEC) members to achieve common energy goals. As a former market analyst and energy modeller, he analyzed how developments in policy, energy markets and technology shape energy systems and affect energy security. cdoleman@ieefa.org

Institute for Energy Economics and Financial Analysis