

TRILATERAL ENERGY SECURITY COMMITTEE

Unlocking Gas-to-Power in Southeast Asia: Triad Support and Market Stability

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for American Energy**
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Trilateral Energy Security Committee (TESC)

The Trilateral Energy Security Committee (TESC) is a collaborative effort led by experts from the Hamm Institute for American Energy, Oklahoma State University Global (OSU Global), the Korea Energy Economics Institute (KEEI), and the Institute of Energy Economics, Japan (IEEJ). The TESC's goal is to assess holistically the current state of energy resources, dependence, and vulnerabilities, to address the energy security risks impacting South Korea, Japan, and the U.S., and provide policy recommendations to help mitigate those risks.



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Table of Contents

Executive Summary.....	1
1. Introduction	2
2. Southeast Asia: Where and Why Gas is Needed.....	4
2.1 Where Gas Demand Arises.....	4
2.2 Why Gas Is Needed: Functional Roles and Benefits within the Energy System	6
3. Conditions for Realized Demand: GFPPs and LNG-to-Power Foundations.....	8
4. Constraints on Demand Realization.....	10
4.1 Gas Availability	13
4.2 Liquefaction and Export.....	14
4.3 Import and Regasification	16
4.4 Power Plant Development.....	17
4.5 Power Distribution	20
4.6 Supply Chain Interdependencies and Feedback Effects	21
5. Southeast Asia’s Challenges to Gas Demand Realization	22
5.1 Projected LNG Import Demand in Southeast Asia.....	22
5.2 Viet Nam	23
5.3 The Philippines.....	25
5.4 Thailand	26
5.5 Indonesia	27
5.6 Malaysia.....	29
6. Strategic Role of the US–Japan–Korea Triad.....	31
6.1 Strengthen LNG Supply Security and Diversification.....	32
6.2 Address Supply Chain and Project Bankability Bottlenecks.....	33
6.3 Align Gas-to-Power Financing with Decarbonization Goals via Trilateral Consortia.....	35
7. Implications and Future Work	36
References	38

Executive Summary

Natural gas is expected to remain an important component of the global energy system as electricity demand grows, countries pursue energy security objectives, and power systems integrate greater shares of variable renewable energy as part of decarbonization policy goals. Gas-fired power plants (GFPPs) provide reliable and dispatchable generation, can respond relatively quickly to changes in electricity demand, and produce lower carbon dioxide emissions than conventional coal-fired generation. These functions are particularly relevant in Southeast Asia, where rapid electricity demand growth is creating incremental demand for new energy supply and many governments are pursuing power-sector plans that expand renewable energy, reduce reliance on coal, and retain a role for gas-fired generation during the transition. For the US, Japan, and the Republic of Korea (hereafter referred to as South Korea) (collectively, the Triad), these emerging markets present both a strategic opportunity and a shared challenge: supporting reliable and secure gas-to-power development while addressing the constraints that can prevent projected gas need from becoming realized demand. This report examines these constraints through a GFPP supply chain analysis, complemented by Southeast Asian country case studies, and identifies areas for targeted trilateral coordination.

Projected gas need does not automatically translate into realized gas or liquefied natural gas (LNG) demand. For projected demand to materialize, the full gas-to-power system must be bankable, buildable, and achievable on schedule. Fuel must be available and affordable; receiving and pipeline infrastructure must deliver gas to power plants; projects must secure financing, regulatory approvals, long-lead equipment, and engineering, procurement, and construction (EPC) capacity; and completed plants must connect to the grid and operate under commercial arrangements that allow fuel and capital costs to be recovered. Because these conditions are interdependent, a chokepoint at any one point can delay or prevent demand from materializing.

We explore the above dynamics through two visualization techniques. Through a concept map, we highlight the broader feedback between demand and investment: weakness in realized demand can soften demand projections, affect upstream investment decisions, and contribute to price volatility. Over time, these dynamics can slow the development of a deeper and more mature global LNG market. Then, through a supply chain map, we identify several current and potential disruptive chokepoints. Current chokepoints include LNG shipping, gas turbines and other equipment, EPC and trades workforce, financing, regulatory approval, and permits required for power plant development, grid, and consumers. Potential chokepoints include gas processing, pipelines, storage, and LNG export and import terminals, which could become more binding as demand grows. These pressures are compounded by competition from data centers, renewable energy projects, industrial facilities, grid expansion, and other infrastructure development for many of the same equipment, contractors, skilled workers, and grid connections.

The Southeast Asian country case studies complement the supply chain analysis by showing that, while countries across the region face many of the same GFPP supply chain constraints, domestic market and regulatory conditions significantly affect the realization of projected gas demand. Electricity market structures, offtake arrangements, fuel cost recovery, dispatch rules, and regulatory certainty can

determine whether projects become bankable and advance. Fuel economics also vary substantially across the region; where domestic alternatives such as coal remain inexpensive, imported LNG may struggle to compete. Southeast Asian gas markets also differ considerably: some have long-established gas-to-power systems, while others are only beginning to develop LNG import and generation capacity, and some remain gas producers and exporters even as mature fields decline and domestic supply pressures increase.

Our findings point to three priorities for trilateral coordination. First, the Triad should strengthen LNG supply security and diversification by combining growing US LNG supply with Japanese and South Korean offtake, financing, and portfolio-management capabilities, while improving shipping flexibility, cargo coordination, and regional preparedness for future supply disruptions. Second, the Triad should address supply chain and project bankability bottlenecks by improving access to constrained turbines and other equipment, strengthening procurement coordination, pairing public financing with targeted credit and foreign-exchange risk mitigation, and supporting government-to-government engagement on more bankable power purchase agreements (PPAs), cost-recovery mechanisms, and regulatory frameworks. Third, the Triad should align gas-to-power financing with decarbonization goals by prioritizing projects that support renewable integration, lower-emission generation, and energy security, while using end-to-end trilateral consortia to combine US LNG supply with Japanese and South Korean financing, technology, project development, and EPC capabilities in partnership with local stakeholders. Such cooperation addresses practical energy needs and supports longer-term gas-to-power development while also deepening the Triad's strategic engagement with Southeast Asia to accomplish geopolitical and economic aims.

1. Introduction

Natural gas is expected to remain a critical component of the global energy system over the coming decades. It has been globally promoted as a lower-emission alternative to coal and for more than two decades regarded as a “transition fuel” because it can provide reliable baseload or intermediate generation, as well as dispatchable electricity, all while supporting gradual decarbonization (International Energy Agency [IEA], 2019a; ASEAN Centre for Energy [ACE], 2024). This is because natural gas combined-cycle gas turbines generally emit substantially less carbon dioxide than conventional coal-fired generation and offer considerably greater operational flexibility (IEA, 2025). In many power systems, natural gas plants operate between traditional baseload sources, such as nuclear, coal, and some hydropower, and peaking resources used during periods of highest demand. Natural gas can be supplied directly by pipeline or, particularly for long-distance maritime transport, as LNG, which is natural gas cooled into liquid form for storage and maritime transport.

The continued demand for natural gas is driven, particularly across newly industrializing economies, by structural system needs including rapidly growing electricity demand, evolving climate policies, energy security objectives, industrial development, and the integration of variable renewable energy. While natural gas is not a zero-carbon fuel, it performs functions that many energy systems require during the

transition toward lower-carbon energy, both within and beyond the power sector, and produces fewer emissions than other fossil fuel alternatives (IEA, 2019a). At the same time, geopolitical disruptions, changing technology costs, and the realities of integrating more renewables are also reshaping both the pace and geography of future gas demand. The IEA projects that global natural gas demand will continue to grow through 2030, with Asia accounting for approximately half of the increase, while the power and industrial sectors remain the principal sources of new demand (IEA, 2025). However, while industrial gas demand is an important component of the broader natural gas outlook and is discussed as context in Section 2, this report focuses specifically on the gas-to-power pathway and the supply chain supporting gas-fired power generation.

Unlike many traditional baseload plants, which can be slow or costly to start, stop, or adjust, GFPPs can ramp output up or down relatively quickly in response to changes in electricity demand. This flexibility also allows them to balance variable wind and solar generation, provide backup capacity during unexpected supply shortfalls, and support higher renewable energy penetration without compromising system reliability. This role is particularly important for Southeast Asia, where the competitiveness of renewable energy depends not only on generation costs, but also on the overall electricity system costs such as those associated with transmission development, energy storage, including batteries and backup capacity. These system-cost challenges underscore the essential role for gas-fired power even as wind and solar become cheaper.

The robustness of future gas demand, however, varies across regions and sectors, and the demand is often bifurcated into incremental demand and substitution demand. Incremental demand arises from entirely new system requirements, including expanding electricity consumption driven by economic growth, urbanization, industrial development, electrification, and the increasing need for flexible generation to complement renewable energy. By contrast, substitution demand reflects fuel switching, where natural gas replaces more carbon-intensive fuels such as coal and oil in electricity generation and industry.

Countries can experience both types of demand increases concurrently when facing sustained growth alongside carbon reduction policy goals. Total demand is generally strongest where it is supported by explicit policy objectives such as energy security, industrial expansion, diversification of fuel supplies, and power system reliability. These conditions are particularly evident across much of Southeast Asia, where rapidly growing electricity demand creates incremental demand for new generation alongside substitution demand, while the replacement of aging power plants, including older gas-fired capacity, creates additional investment needs. Renewable deployment remains insufficient in scale and is often constrained by transmission limitations, electricity storage availability, and grid flexibility. In these markets, gas-fired generation provides not only the scalable generation capacity to sustain rapid economic growth, but also dispatchable capacity capable of responding quickly to fluctuations in electricity demand and renewable output, supporting grid stability while reducing dependence on coal. Conversely, gas demand is more uncertain in markets where rapid renewable deployment, declining electricity storage costs, stronger carbon policies, or slower economic growth reduce the need for new gas-fired capacity. Growth or reduction in natural gas demand does not automatically translate into growth or reduction in

LNG demand. LNG demand, among other fundamentals, also depends on the infrastructure and commercial arrangements needed to import, regasify, distribute, and consume LNG. Future demand therefore depends not only on fuel economics but also on infrastructure investment, LNG import capacity, market design, financing conditions, and the pace of renewable integration (IEA, 2025; IEA, 2026d).

In the US, abundant shale gas production and associated gas from oil development have expanded over the past two decades, supporting new demand and fundamentally altering regional and global gas and LNG trade patterns through increased supply availability. However, while US gas development has substantially expanded global upstream supply, the downstream stages of the supply chain continue to face significant constraints, including but not limited to LNG shipping, receiving infrastructure, GFPPs, turbines and other long-lead equipment, EPC capacity, financing, grid connection, dispatch, and consumer affordability. Recent disruptions in the Middle East and the Strait of Hormuz have underscored vulnerabilities in LNG supply and transport, while cost increases, equipment backlogs and downstream power-sector constraints continue to delay projects.

To examine how these constraints arise across the supply chain, this report develops a GFPP supply chain map that traces the full pathway from gas production and LNG transport through power plant development, grid connection, and final consumption. The analysis identifies the current chokepoints at each stage of the supply chain and assesses how constraints at one node can delay or prevent gas demand from being realized elsewhere in the system. The report illustrates how these interdependent chokepoints affect emerging Southeast Asian markets through country case studies, and concludes by identifying where coordinated action by the US, Japan, and South Korea could provide targeted value.

2. Southeast Asia: Where and Why Gas is Needed

Southeast Asia is emerging as one of the world's most important gas and LNG demand centers. Although renewable energy deployment is accelerating across the region, natural gas continues to play a critical role in supporting electricity systems, industrial development, and energy security. Future gas demand is not driven simply by economic growth or population increases only; it also arises from specific sectors and system functions that require reliable, flexible, and dispatchable energy. Understanding where gas demand originates and why it is needed provides a clearer picture of the region's future gas and LNG requirements and highlights where investment opportunities are likely to emerge.

2.1 Where Gas Demand Arises

2.1.1 Power Systems: Grid Balancing and Capacity Firming

The power sector is the largest source of natural gas demand in Southeast Asia. Electricity consumption continues to rise across the region, driven by economic growth, urbanization, industrialization, digitalization, and rising household incomes. Meeting this growth will require substantial additions to generation capacity from a range of technologies, including renewable energy and gas-fired power (ACE, 2024).

In this report, we focus on the five largest electricity markets in Southeast Asia: Indonesia, Viet Nam, Malaysia, Thailand, and the Philippines. These markets differ considerably in their existing generation mixes and reliance on natural gas. Thailand and Malaysia already depend heavily on gas-fired generation, while Indonesia, Viet Nam, and the Philippines rely more heavily on coal but are also developing additional gas and LNG-to-power capacity. At the same time, renewable energy deployment is expanding across all five markets.

Figure 1 shows electricity consumption in the five largest Southeast Asian electricity markets from 2000 to 2025, together with projected consumption for the period between 2030 and 2050. Electricity consumption increased steadily across all five countries over the past two decades. Growth was particularly rapid in Indonesia and Viet Nam, reflecting their strong economic growth and rising electricity demand.

Figure 2 presents the electricity-generation mix in each of these markets from 2000 to 2025. Indonesia, Viet Nam, and the Philippines rely heavily on coal, while natural gas plays a central role in electricity generation in Thailand and Malaysia. Renewable energy is also becoming increasingly important, particularly hydropower in Viet Nam and Malaysia.

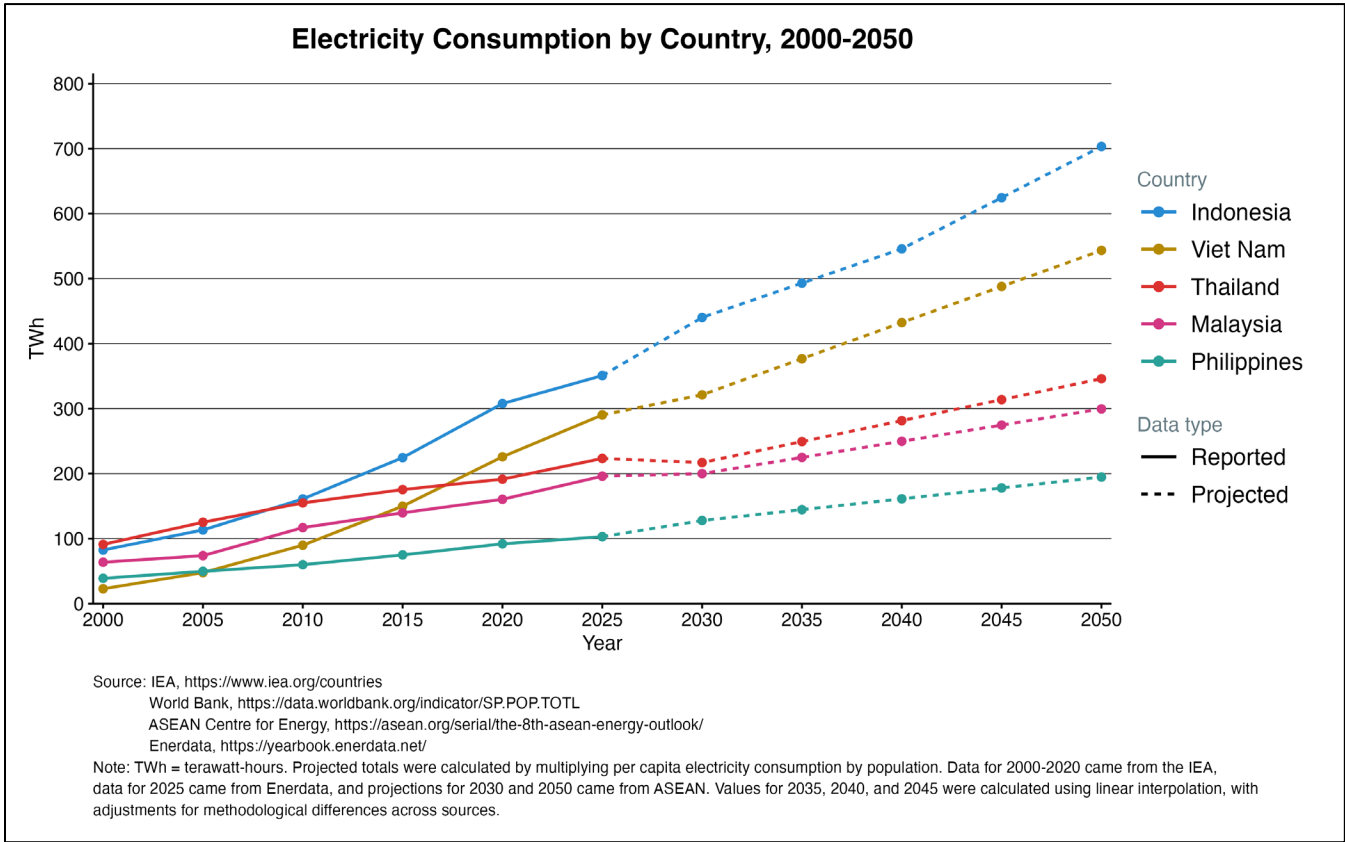


Figure 1: Electricity Consumption by Country, 2000-2050

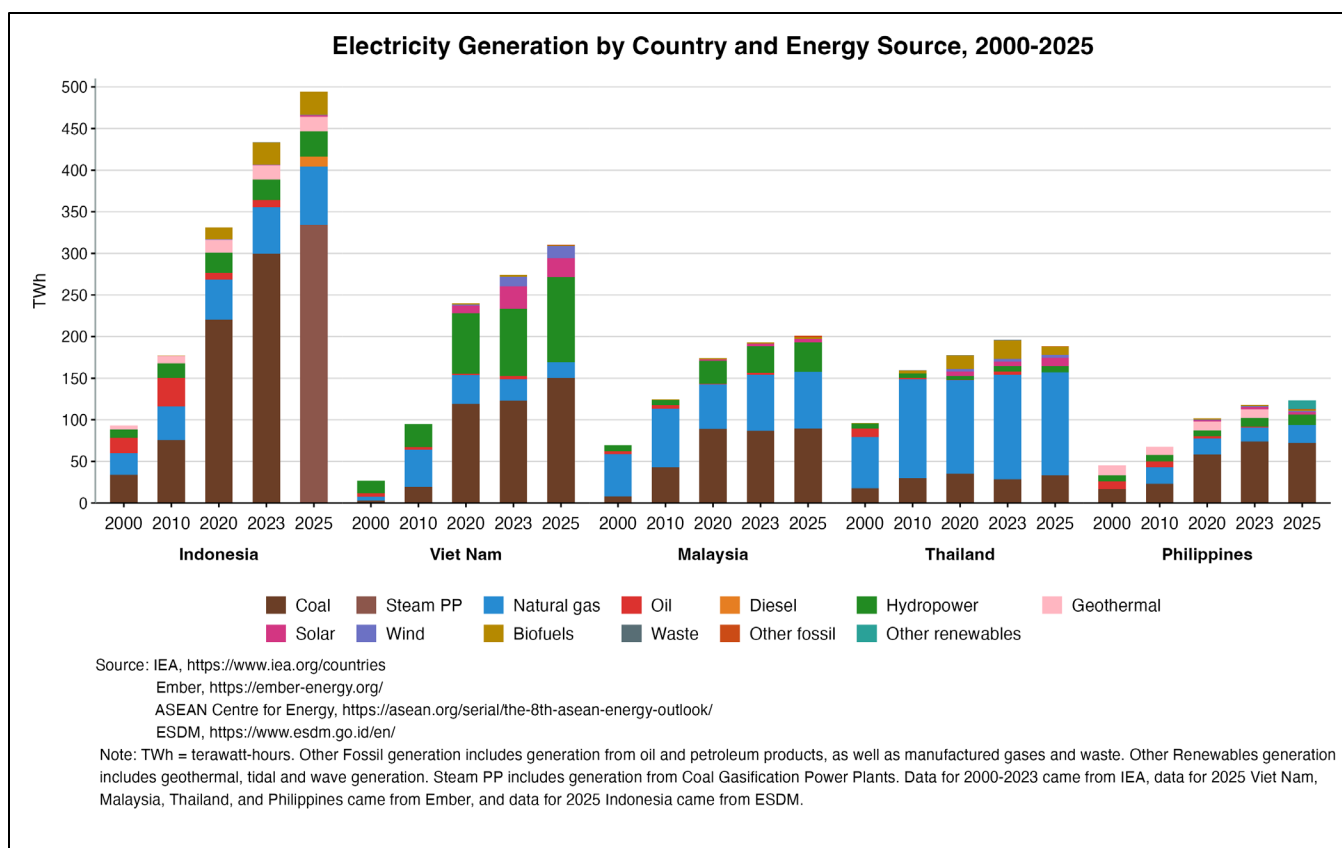


Figure 2: Electricity Generation by Country and Energy Source, 2000-2025

2.1.2 Industrial Sectors: Process Heat and Feedstock

Beyond the power sector, natural gas demand in Southeast Asia arises from industries that require both reliable thermal energy and chemical feedstocks. Major industrial users include petrochemicals, fertilizer production, oil refining, chemicals manufacturing, food processing, and other energy-intensive industries. In these sectors, natural gas is used to provide process heat, steam generation, and feedstock inputs for the production of ammonia, methanol, and other chemical products (Manaloe et al., 2025).

Consequently, industrial gas demand is driven not only by economic growth and industrialization but also by the technical requirements of production processes that require continuous, controllable, and cost-competitive energy supply. In several Southeast Asian economies, particularly Malaysia, Indonesia, and Thailand, natural gas supports large industrial clusters and export-oriented manufacturing activities. Malaysia's petrochemical and chemical industries and Thailand's petrochemical and industrial corridors represent important sources of sustained incremental gas demand (Manaloe et al., 2025; ACE, 2024).

2.2 Why Gas Is Needed: Functional Roles and Benefits within the Energy System

This section examines the functions that natural gas performs within Southeast Asia's energy systems, focusing on the power system. These functions are divided into four broad categories: 1) providing reliable and dispatchable electricity generation; 2) enabling renewable energy scale-up; 3) replacing higher-emission alternatives; and 4) strengthening energy security through supply diversification.

2.2.1 Providing Reliable and Dispatchable Electricity Generation

The most important contribution of natural gas lies in providing reliable and dispatchable electricity generation. Electricity systems must continuously match supply with demand, including during periods of peak consumption, unexpected plant outages, or other supply disruptions. Compared with coal plants, which are generally better suited to continuous operation, modern GFPPs can start and adjust output more rapidly in response to changes in electricity demand and supply, making them well suited to providing flexible and dispatchable generation (IEA, 2020, 2026d), especially where variable renewable generation penetration is growing.

In practical terms, gas-fired generation acts as a “system stabilizer,” providing operating reserves, supporting frequency control, meeting peak demand, and responding to sudden changes in electricity supply or demand. Even under ambitious decarbonization pathways, many Southeast Asian countries are expected to retain substantial gas-fired generation capacity because no commercially scalable alternative currently offers the same combination of flexibility, operational maturity, and affordability (IEA, 2026d). Thus, future gas demand is increasingly linked not only to the volume of electricity generated from gas, but also to the reliability and flexibility services that GFPPs provide.

2.2.2 Enabling Renewable Energy Scale-Up

One increasingly important application of this flexibility is supporting the integration of variable renewable energy. Paradoxically, growing renewable energy deployment often increases the short- and medium-term value of gas-fired generation. Solar and wind generation are inherently variable and weather-dependent. During periods of low renewable output or rapid fluctuations in supply, dispatchable backup generation becomes essential. GFPPs can provide this balancing function more effectively than coal plants due to their operational flexibility, while allowing other non-variable low-carbon generation, such as nuclear power, to operate efficiently at baseload.

As Southeast Asia seeks to achieve renewable energy targets while maintaining system reliability, gas serves as a bridging resource that enables higher renewable penetration without compromising grid stability. This relationship is particularly relevant in Viet Nam, the Philippines, Indonesia, and Thailand, where renewable energy targets are expanding rapidly while electricity demand continues to grow (IEA, 2026d). In these markets, gas should not be viewed solely as a competing fuel to renewables; rather, it often functions as a complementary technology that facilitates renewable integration.

2.2.3 Replacing Higher-Emission Alternatives

Natural gas also supports energy transition objectives by replacing fuels associated with either higher carbon emissions or higher economic costs. In the power sector, gas can displace aging coal and oil-fired generation, reducing local air pollution and lowering carbon intensity. Compared with coal, natural gas produces substantially lower carbon dioxide emissions when combusted for electricity generation, while GFPPs can also offer greater operational flexibility. In industrial sectors, gas often replaces fuel oil and

diesel while offering operational advantages and lower emissions (IEA, 2019a), with further emissions reductions when paired with carbon capture and storage.

2.2.4 Strengthening Energy Security Through Supply Diversification

Natural gas and LNG can also contribute to energy security by helping Southeast Asian countries diversify their fuel and supply sources. Several countries in the region are seeking to reduce dependence on a single fuel source and diversify their energy portfolios. Historically, many electricity systems relied heavily on coal, domestic natural gas, hydropower, and imported oil. Increasing exposure to fuel-price volatility, drought risks affecting hydropower generation, and concerns regarding coal emissions have encouraged governments to diversify fuel supplies through expanded natural gas and LNG imports. Southeast Asia is projected to become a net natural gas importer as early as 2027, increasing the importance of access to diversified external sources of supply (ACE, 2024).

LNG can support this diversification by allowing importing countries to source gas from multiple producing countries and regions. This can reduce reliance on declining domestic gas fields and limit exposure to disruptions concentrated in a single supplier or region. The diversification benefit is particularly relevant relative to oil: around 60% of Southeast Asia's crude-oil imports come from the Middle East, compared with roughly one-third of its natural-gas imports (IEA, 2026d). LNG can therefore provide an additional source of geographic supply diversification, although it remains exposed to global market disruptions and maritime chokepoints.

Southeast Asian countries increasingly view LNG infrastructure as a strategic energy security asset (ACE, 2024). LNG import terminals, floating storage and regasification units (FSRUs), and new pipeline investments provide greater flexibility in fuel sourcing and reduce reliance on domestic gas fields that are gradually declining. LNG therefore becomes increasingly important not only as an energy commodity but also as a strategic tool for maintaining supply security across the region (ACE, 2024).

3. Conditions for Realized Demand: GFPPs and LNG-to-Power Foundations

The global supply chain for new GFPPs has been operating under tight sellers' market conditions. Demand for gas turbines, other long-lead equipment such as transformers and specialized electrical components, EPC services, and construction capacity exceed available delivery capacity, with these resources also facing competing demand from other industries. This build-side constraint is unfolding as gas-fired generation is expected to expand: earlier in 2026, the IEA projected global gas-fired electricity output to grow at an accelerated annual rate of 2.6% in 2026–2030 (IEA, 2026a). Demand for new gas-fired capacity is strongest in the US, driven by data centers requiring quick solutions for 24/7 electricity at scale, manufacturing, electrification, aging-plant replacement, and grid-reliability requirements, while Middle Eastern and Asian markets are also adding gas-fired capacity because of rapid electricity demand growth, oil-to-gas switching, and coal-to-gas switching.

Furthermore, the 2026 Middle East and Strait of Hormuz disruptions have added a separate fuel-side risk to this already constrained buildout environment. The disruptions worsened the global gas market outlook

by tightening LNG balances, increasing spot price volatility, disrupting regional supply and shipping, and delaying the expected easing of global LNG supply (IEA, 2026b, 2026e). At the same time, the supply shock has been partly offset by stronger LNG production outside the Gulf and weaker import demand from China. The IEA notes that while LNG loadings from Qatar and the United Arab Emirates fell sharply after the Strait of Hormuz disruption, higher output from new projects in North America and Africa, together with improved feedgas availability from legacy producers in Africa, Asia, and Russia, offset roughly three-quarters of the decline in Gulf LNG deliveries between March and June 2026 (IEA, 2026e).

The Middle East and Strait of Hormuz disruptions also affected the demand side of the gas market. The disruption to LNG flows through the Strait of Hormuz raised spot prices and contributed to lower gas consumption in key LNG-importing markets (IEA, 2026e). In Asia, higher LNG prices and concerns over supply availability prompted demand-side measures and fuel-switching policies, including slowing the progress of gas-to-coal switching in the power sector (IEA, 2026e), amid worsening affordability and uncertainty over future supply availability. As a result, the IEA expects 2026 global natural gas demand to decline, with demand falling in Asia, Europe, and the Middle East (IEA, 2026e).

These developments underscore that stable and reliable LNG supply is important for sustaining LNG demand, but fuel availability alone is not sufficient. Affordability must also be reasonably predictable, and projected demand can materialize only if the broader gas-to-power system is capable of converting available fuel into sustained electricity generation.

Key insight: *For projected gas and LNG demand to materialize, among other conditions, the full gas-to-power system must be bankable, buildable, and achievable on schedule. Gas-to-power projects also require commercial arrangements that define how fuel is procured, how electricity is sold, and how fuel costs are recovered through tariffs, PPAs, or other offtake mechanisms.*

For gas-to-power demand to materialize, four interdependent conditions must align: commercial, financial, infrastructure, and regulatory. Commercially, projects require credible offtake arrangements and an affordable and sustainable price level that supports both demand and investment. Financially, projects must be bankable under prevailing interest rate, currency, and risk-allocation conditions. On the infrastructure side, LNG receiving and regasification capacity must be able to bring gas into the domestic system, GFPPs must be completed, and transport linkages must connect fuel supply to end users. Finally, regulatory approvals, grid interconnection, and dispatch rules must allow GFPPs to operate at utilization levels sufficient to generate sustained fuel demand and revenue.

Key insight: *These requirements are interdependent: weakness at any one point can delay, reduce, or prevent the conversion of projected gas need into realized demand. Weakness in realized demand can signal softer demand projections, affect upstream investment decisions, and contribute to price volatility. Ultimately, this slows the pace at which the global LNG market matures and develops sufficient depth and volume (Trilateral Energy Security Committee [TESC], 2026).*

Figure 3 is a concept map illustrating the conditions required for projected gas need to translate into realized gas demand and the feedback between realized demand and future gas investment.

From Projected Gas Need to Realized Demand: Conditions for Demand Realization and Future Investment

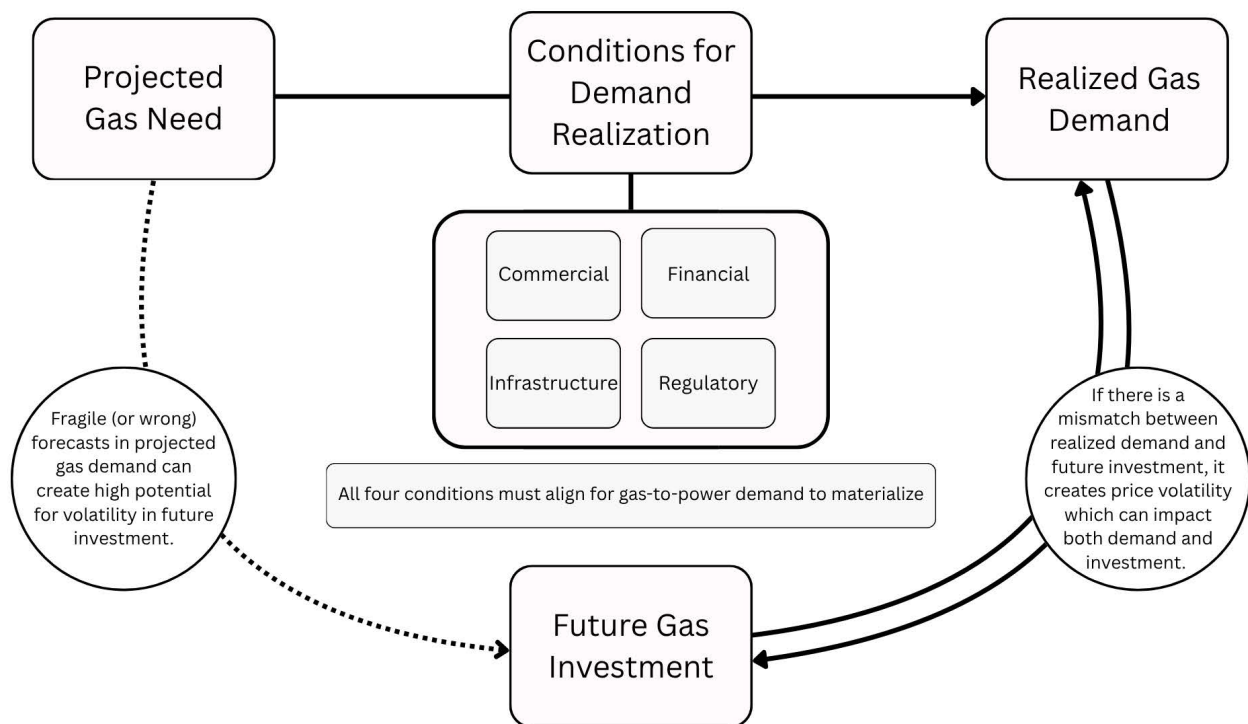


Figure 3: Concept Map of Projected Gas Need, Demand Realization, and Future Gas Investment

4. Constraints on Demand Realization

The most vulnerable points along the global GFPP supply chain are identified in a supply chain map (Figure 4). The map divides the gas-to-power supply chain into five major stages: gas availability, liquefaction and export, import and regasification, power plant development, and power distribution. Each stage contains nodes that must function in sequence for projected gas demand to become realized gas-to-power generation.

The supply chain map identifies the chokepoints. “Current chokepoints,” shown in red, are constraints currently having a significant impact on the global supply chain, as evidenced by factors such as capacity limitations, congestion, supply disruptions, project delays, or significant cost pressures. “Potential chokepoints,” shown in yellow, are nodes where constraints are not currently causing significant constraints but could become more consequential as demand grows, capacity tightens, or market conditions evolve. Other nodes are classified as enabling nodes, meaning that they perform a necessary role in the supply chain but are not identified as significant current or foreseeable constraints. The

classification is based on a qualitative assessment of the current severity of constraints, drawing on industry reports and expert interviews.

Chokepoints control the movement of the broader system. For example, a delayed turbine order can postpone power plant completion, an unfinished LNG terminal can strand generation capacity, an unbankable PPA can prevent financial close, and unfavorable dispatch economics can reduce actual gas burn even after assets are built. The supply chain map therefore identifies the points at which timing, capacity, cost, or coordination failures can delay, reduce, or prevent gas demand from materializing.

Key insight: *A constraint at any one node can slow or stop the movement of the broader gas-to-power system even when other parts of the supply chain are available. Multiple constraints can also occur simultaneously and interact with one another, causing delays, capacity limitations, or cost pressures at different stages to compound across the supply chain.*

The supply chain map also reveals that many of the constraints affecting gas-to-power development extend beyond the gas-fired power sector itself. Several of the critical inputs needed to develop gas-fired power projects are shared with other rapidly expanding energy and infrastructure sectors.

Key insight: *Gas-to-power projects are not competing only within the gas-fired power sector. They are also competing with data centers, renewable energy projects, industrial facilities, grid expansion, other infrastructure projects for the same scarce equipment, EPC contractors, skilled labor, and grid connection. These cross-industry supply chain bottlenecks reflect a broader, long-term underinvestment in industrial capacity and project-execution resources across the energy and infrastructure system.*

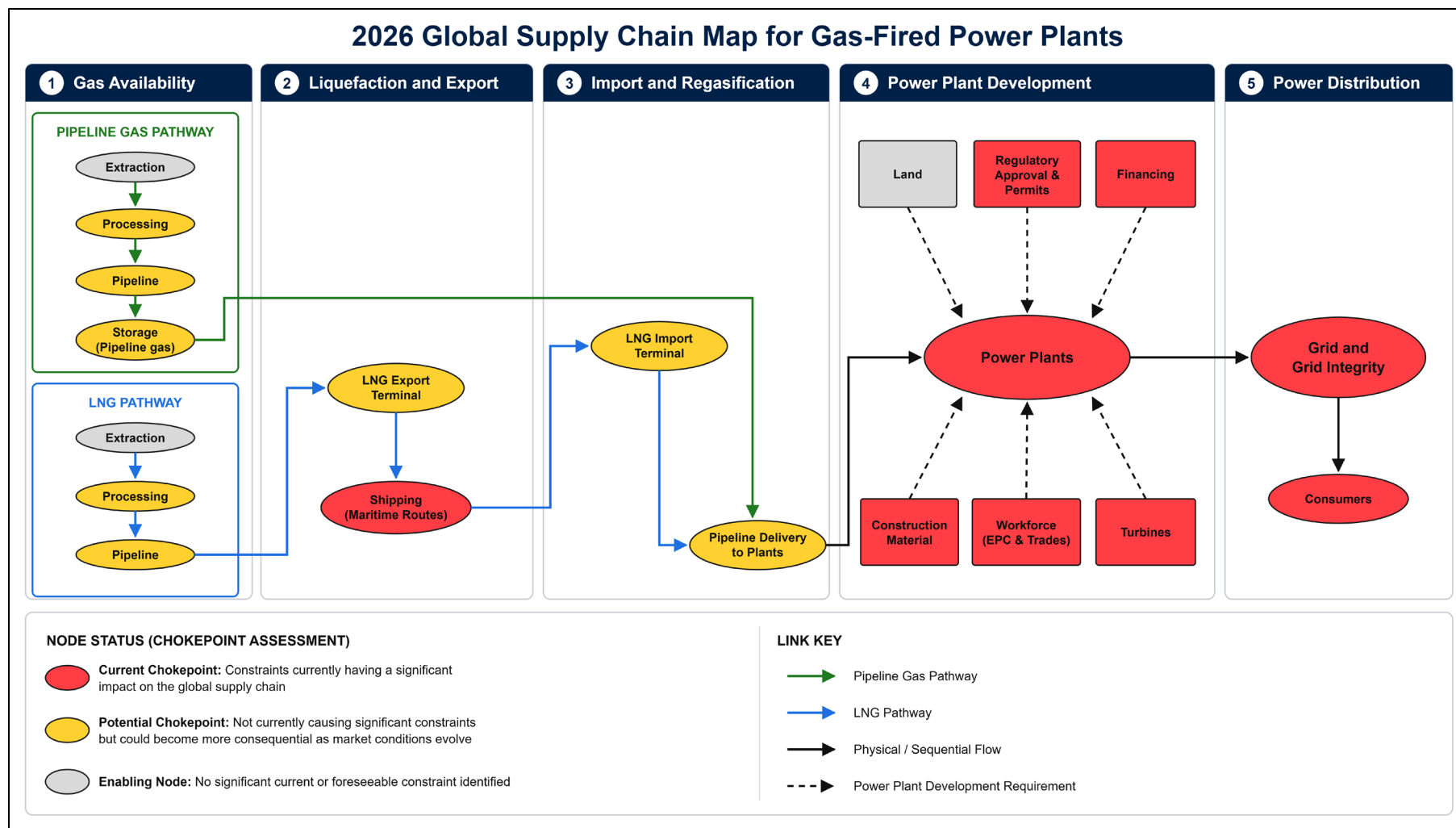


Figure 4: Global Supply Chain Map for GFPPs

4.1 Gas Availability

The first stage is gas availability. This stage captures whether sufficient natural gas can be produced, processed, and transported to domestic markets or LNG export terminals. Both the pipeline gas and LNG pathways begin with extraction and processing, after which pipelines move treated gas toward storage facilities, power plants, or liquefaction facilities. In this stage, supply-side processing, pipelines, and pipeline storage are potential chokepoints because gas is generally able to flow where it is needed today, but emerging capacity pressures, reflected in announcements of processing facility expansions and major pipeline investments, especially in regions with growing data center demand, could create constraints as demand grows. For LNG, the subsequent liquefaction, export, and maritime shipping processes are discussed separately in Section 4.2.

4.1.1 Extraction – Enabling Node

Natural gas is produced from conventional fields, shale and tight formations, associated gas, and offshore reservoirs. Despite the global distribution of natural gas reserves, production for export is concentrated in a relatively small number of countries, including the US, Russia, Iran, China, Canada, Qatar, Australia, Saudi Arabia, Norway, Nigeria, and Algeria (IEA, n.d.-d). This concentration means that disruptions in major producing regions can affect the volume and price of gas available to international markets. Supply is also affected by the natural depletion of mature fields and by the investment and development timelines required to bring new production online. Because new upstream capacity can take years to develop, production may not be able to respond quickly to unexpected increases in demand or disruptions elsewhere in the market.

4.1.2 Processing – Potential Chokepoint

Raw gas must be treated to remove contaminants, liquids, and other components before it can move through pipelines, enter liquefaction facilities, or fuel GFPPs. Processing is classified as a potential chokepoint because existing capacity is not currently causing a significant constraint on the supply chain, but localized capacity pressures could become more consequential if production grows faster than the midstream infrastructure needed to process and transport the gas. This dynamic is particularly relevant in oil-producing regions such as the Permian Basin, where large volumes of associated gas are produced alongside crude oil (US Energy Information Administration [EIA], 2026b). Gas output may continue even when local gas prices are low, increasing pressure on available processing and takeaway capacity.

4.1.3 Pipeline (Supply Side) – Potential Chokepoint

Pipelines are a potential chokepoint because they determine whether processed gas can move from production regions to storage, LNG export terminals, domestic markets, or GFPPs. In many cases, pipeline and storage constraints may be more important than upstream gas supply itself (Hamm Institute for American Energy, 2026).

The US illustrates this point. Planned US pipeline additions in 2026–2027 are concentrated in Texas and are intended to move Permian gas toward LNG export terminals, power users, industrial users, and other

demand centers (EIA, 2026a). In the Permian Basin, gas output has grown faster than pipeline capacity needed to move it out of the region, putting downward pressure on Waha prices (Shafto 2026). These localized pressures demonstrate how pipeline capacity can become a more significant constraint if infrastructure expansion does not keep pace with rising production and demand.

4.1.4 Storage (Pipeline Gas) – Potential Chokepoint

Pipeline gas is stored in underground facilities to balance relatively steady production against seasonal and short-term changes in demand. Storage is classified as a potential chokepoint because available capacity or withdrawal capability could become insufficient to provide the flexibility needed to balance supply and demand as gas demand and infrastructure requirements grow (American Gas Association, 2025; Hamm Institute for American Energy, 2026). In the US, underground storage capacity has remained relatively flat despite growth in gas production, pipeline capacity, and demand, while localized capacity and withdrawal limitations are emerging in some high-demand regions (American Gas Association, 2025).

4.2 Liquefaction and Export

The second stage is liquefaction and export, which applies specifically to LNG. This stage captures the infrastructure needed to convert pipeline gas into LNG and move it into international markets. It includes LNG export terminals, where natural gas is liquefied, stored, and loaded onto vessels, as well as maritime shipping.

4.2.1 LNG Export Terminal – Potential Chokepoint

LNG export terminals integrate the infrastructure needed to liquefy natural gas, store the resulting LNG in cryogenic tanks, and load it onto LNG carriers for export. Liquefaction capacity determines how much available pipeline gas can be converted into LNG for international markets, while storage and loading facilities provide the operational link between continuous liquefaction and vessel departures.

Globally, liquefaction capacity is expanding significantly, with around 345 bcm per year of new LNG export capacity expected to come online between 2025 and 2030 from projects that had already reached final investment decision and were under construction as of 2025 (IEA, 2026c). This substantial capacity expansion suggests that liquefaction capacity is not currently a broad structural constraint.

However, LNG export terminals are a potential chokepoint because the concentration of large volumes of liquefaction capacity at major facilities creates vulnerability to prolonged facility-level disruptions. The 2026 Middle East conflict demonstrated this risk in Qatar, where two liquefaction trains at Ras Laffan, representing about 17% of the country's LNG capacity, were extensively damaged and are expected to require three to five years to repair (IEA, 2026cn). The IEA estimates that the damage could result in a cumulative loss of 50–90 bcm of LNG supply between 2026 and 2030, while delays to Qatar's planned capacity expansion could further reduce expected supply growth (IEA, 2026b). By August 2026, some undamaged liquefaction trains at Ras Laffan had resumed operations at low levels, partly to avoid exceeding available LNG storage capacity while exports through the Strait of Hormuz remained constrained (Bloomberg, 2026).

Furthermore, LNG export terminals require multibillion-dollar investment decisions and sufficient demand commitments to achieve bankability, in addition to lengthy preparatory studies and construction timelines that typically require at least three to five years and often longer, sometimes exceeding a decade from the conceptual stage. This means that new LNG supply cannot materialize overnight to meet new demand, whether driven by underlying market growth or, especially, by disruptions to existing supply.

4.2.2 Shipping (Maritime Routes) – Current Chokepoint

Shipping is a current chokepoint for LNG because unlike pipeline gas, LNG must move through a limited number of major maritime routes and physical chokepoints. This vulnerability had already become apparent through constraints on major shipping routes, including drought-related restrictions at the Panama Canal and security-related disruptions affecting Suez Canal transit. These constraints persisted despite the growth of US LNG exports and became particularly evident during the 2026 Middle East conflict. Global LNG markets had begun to rebalance during the 2025/26 heating season, as LNG trade grew by 12% year-on-year, supported by new liquefaction projects, particularly in North America. However, the conflict and de facto closure of the Strait of Hormuz disrupted this easing by temporarily removing almost 20% of global LNG supply and sharply increasing price volatility (IEA, 2026b).

Importantly, the current shipping constraint is primarily associated with disruption to maritime routes rather than a structural shortage of LNG carriers. Prior to the conflict, the LNG shipping market was characterized by excess vessel capacity and record-low charter rates, reflecting rapid fleet growth, delays in new LNG supply projects, and shorter average voyage times (Timera Energy, 2025). Vessel availability therefore does not appear to be the primary current constraint, although continued geopolitical disruptions affecting major maritime routes can still restrict LNG flows and tighten shipping conditions by forcing rerouting and extending voyage times. The shipping market could also tighten later in the decade as global LNG supply expands and demand for vessel capacity increases (Timera Energy, 2025).

The closure of the Strait of Hormuz reduced LNG supplies from Qatar and the United Arab Emirates by more than 300 million cubic meters per day after March 1, 2026, and a loss of over 2 billion cubic meters of gas supply every week (IEA, n.d.-c). As affected Asian buyers competed for a smaller pool of LNG cargoes, natural gas prices increased sharply, and some countries adopted gas rationing (IEA, n.d.-c). Spot LNG and gas prices in Europe and Asia doubled between late February and late March 2026 (IEA 2026d).

In March, QatarEnergy declared force majeure to affected LNG buyers after halting LNG production, stating that it was not legally liable for failing to deliver some contracted cargoes because the disruption was caused by events beyond its control (QatarEnergy, 2026). Despite the force majeure declaration, QatarEnergy subsequently purchased 33 US LNG cargoes to help offset the disruption and supply some of its buyers (Rashad et al., 2026). This matters for Asian LNG importers because even when LNG is contracted, disrupted deliveries may still need to be replaced with supply cargoes procured from the spot or short-term market. In addition, many Asian long-term LNG contracts are indexed to oil prices (Joseph, 2023), meaning that higher crude prices from the Hormuz disruption could feed into contract LNG prices with a lag of several months (Thomton et al., 2026b).

4.3 Import and Regasification

The import and regasification stage refers to the receiving-side infrastructure that converts imported LNG into gas that can be delivered to GFPPs or other end users. In LNG-importing markets, this includes ports, LNG import terminals, storage, regasification, and pipeline delivery to the power plant. In domestic gas-producing markets, such as the US, it includes pipeline interconnections, metering and pressure regulation, storage or balancing infrastructure, and pipeline laterals that deliver gas-to-power plants. Because pipeline transport is discussed in Section 4.1, the discussion below focuses primarily on LNG import infrastructure.

4.3.1 LNG Import Terminal – Potential Chokepoint

Imported LNG must pass through an import terminal where cargoes are received, stored, regasified, and sent out into the domestic gas system or through dedicated pipelines to end users. These functions are typically planned as part of an integrated LNG import terminal rather than as independent stages. Depending on the terminal design, this can include ports, berths, jetties, mooring and unloading systems, cryogenic LNG storage tanks, regasification facilities, metering and gas-quality systems, and send-out infrastructure. Constraints in any of these components can reduce the amount or reliability of gas that the terminal can deliver downstream. The terminal can therefore become a chokepoint when import capacity does not keep pace with LNG demand, terminal development is delayed, or operational constraints limit receiving, storage, regasification, or send-out capacity.

FSRUs have become increasingly important because they provide a relatively fast and flexible alternative to land-based LNG import terminals. By combining LNG storage and regasification in a single vessel, FSRUs can significantly reduce upfront capital costs and land-use requirements (Gas Exporting Countries Forum, 2026). They can also reduce planning complexity, community impact, and permitting timelines (Cartwright and Spilleth, 2026; Gas Exporting Countries Forum, 2026). FSRU deployment timelines are often 1–2 years, compared with construction periods of 4–7 years for many onshore terminals (Gas Exporting Countries Forum, 2026). These characteristics make FSRUs particularly suitable where import capacity is needed quickly, gas demand is relatively small or uncertain, or capacity is required on a temporary or transitional basis. In some cases, an FSRU can also serve as an interim solution while a permanent land-based terminal is developed. Their mobility provides additional flexibility by allowing regasification capacity to be redeployed as market conditions, demand centers, or offtake arrangements change (Gas Exporting Countries Forum, 2026). Europe’s rapid deployment of FSRUs following Russia’s invasion of Ukraine demonstrates how floating infrastructure can expand LNG import capacity quickly in response to a supply disruption (Cartwright and Spilleth, 2026).

However, FSRUs also involve tradeoffs. Despite lower upfront capital investment than many onshore terminals, FSRUs can have higher operating costs and greater exposure to harsh weather and marine conditions (Reynolds and Doleman, 2024). In Asia, FSRUs are less widely used by the largest LNG importers, including China, Japan, South Korea, India, Taiwan, and Thailand, but have become more attractive in emerging markets in Southeast Asia. However, these countries also face elevated exposure

to severe tropical storms, creating operational risks for floating import infrastructure. Similar to the challenges of LNG export terminals discussed in Section 4.2.1, LNG import terminals require substantial upfront investment and long development timelines before becoming operational, which could create similar constraints.

4.3.2 Pipeline (Downstream) – Potential Chokepoint

This node of pipeline delivery to plants includes send-out pipelines from LNG terminals or FSRUs, transmission pipelines, distribution networks, compression and metering facilities, and dedicated laterals to GFPPs. Regasified gas must still reach the plant at the required volume, pressure, reliability, and timing. Pipeline delivery is classified as a potential chokepoint. A country may secure LNG cargoes and develop import capacity, but gas-fired generation can still be constrained if the necessary pipeline connections to power plants are delayed or insufficient. LNG import terminals, downstream pipelines, and GFPPs are often considered together in planning, particularly where a large onshore LNG terminal depends on power sector demand to support its scale. However, these components may be developed, owned, and financed by different project sponsors or regulated under different fiscal regimes, making coordination of capacity, development timelines, and operations important.

4.4 Power Plant Development

The fourth stage is power plant development. This stage captures the major requirements for a GFPP to be developed and constructed. Because GFPPs are the primary focus of this report, this stage is broken down into greater detail than other parts of the supply chain. The discussion of land, regulatory approval, permitting, financing, construction materials, and workforce in this section focuses specifically on their role in power plant development, although these are cross-cutting requirements that also apply to infrastructure elsewhere in the supply chain.

4.4.1 Land – Enabling Node

Land is classified as an enabling node because access to a suitable site is necessary for power plant development, but land availability is not identified as a chokepoint. A plant site must satisfy several conditions at once, including proximity to gas supply, grid interconnection, water or cooling access, environmental suitability, local acceptance, and air-quality requirements. Existing power plant or industrial sites can offer advantages because some of the necessary land and supporting infrastructure may already be available. For example, in the US, Georgia Power is adding new natural gas generation at its existing Plant Yates site, where the company has highlighted the ability to use existing property and infrastructure (Georgia Power, 2025). At the same time, securing land can affect individual project timelines. In Viet Nam, land acquisition was among the challenges encountered during development of Nhon Trach 3 and 4, the country's first LNG power plants (VnEconomy, 2024; Anh, 2025).

4.4.2 Regulatory Approval and Permitting – Current Chokepoint

Projects must comply with power-sector requirements, siting rules, environmental obligations, interconnection procedures, and site-specific permitting requirements, which may include air, water-use

or discharge, stormwater, construction, and zoning approvals. Predictability and consistency in these regulatory and permitting frameworks are important for project development, particularly where projects extend across multiple years and political cycles. Regulatory approval and permitting are current chokepoints because uncertainty, changing requirements, or prolonged approval processes increase project costs, delay financing and construction, and weaken lender confidence.

Recent experience in Viet Nam illustrates how these constraints affect LNG-to-power development. Several planned LNG power projects had yet to select investors because of delays in investment-policy approvals and tendering, alongside challenges involving land clearance, local planning adjustments, and other development procedures. Industry and government representatives highlight the complexity of navigating multiple investment, bidding, construction, environmental, and planning laws, which increase project costs and development timelines (VietnamPlus, 2025).

4.4.3 Financing – Current Chokepoint

Financing is a current cross-cutting chokepoint across the supply chain, particularly at the plant stage. Developers must reach financial close, secure credit support, and commit capital early enough to reserve long-lead equipment such as gas turbines and transformers, contract EPC capacity, and absorb permitting or construction-delay risk. Rising construction costs, extended delivery schedules, permitting uncertainty, unsecured fuel supply, weak PPAs, and inadequate tariff structures can undermine project bankability.

Key insight: *The financing constraint is not simply whether capital exists, but whether lenders believe the full gas-to-power system can reach commercial operation on time and recover fuel, capacity, and construction costs through reliable revenue mechanisms.*

In many emerging markets, including Southeast Asia, private investment alone may be insufficient to deliver gas-to-power projects at scale. Governments may therefore need to establish more bankable frameworks through long-term PPAs, capacity payments, minimum-dispatch guarantees, public investment in supporting infrastructure, credit support, or other forms of risk sharing. Without such mechanisms, entry into the sector can remain extremely difficult. In one case, the Japan Bank for International Cooperation (JBIC) financed Jawa 1 in Indonesia, which JBIC described at the time as Asia's first integrated power plant and FSRU project financed through a project-finance structure. Before beginning negotiations on the financing arrangements, JBIC and the investors negotiated the detailed terms and conditions of the PPA with the state-owned utility PLN to ensure the project's bankability (Japan Bank for International Cooperation, n.d.).

4.4.4 Turbines – Current Chokepoint

Gas turbines are one of the most important chokepoints in the current market. Global gas turbine orders totaled 110 GW at the end of 2025, while global manufacturing capacity was only 60–70 GW (Thomton et al., 2026a). Around the pandemic period, Original Equipment Manufacturers (OEMs) sharply reduced production capacity. Although manufacturers are now expanding capacity again, the supply–demand imbalance has persisted. This imbalance has impacted both price and lead times. It has contributed to

steep turbine price increases, with prices expected to reach US\$600/kW by the end of 2027, a 195% increase from 2019 levels (Thomton et al., 2026a). Because gas turbines represent around 20–30% of combined-cycle project costs, they are the largest single driver of gas plant cost escalation (Thomton et al., 2026a).

The advanced large-turbine market is also concentrated among the three OEMs: GE Vernova, Siemens Energy, and Mitsubishi Heavy Industries. Although all three manufacturers have expanded manufacturing capacity (Rochas, 2026), lead times remain long, at around five years compared with roughly two years in 2021 (Rochas, 2026; Crooks, 2026). Developers increasingly need to order or reserve turbines very early in the project-development cycle. Securing a manufacturing slot may require an upfront payment of approximately 20–30% of the agreed purchase price, creating a substantial early financing requirement. Whereas EPC contractors previously often procured turbines as part of the overall construction contract, developers or governments increasingly need to secure turbine slots. Given these constraints, EPC contractors tend to prioritize projects that have already secured turbine manufacturing slots and demonstrated overall project viability. Steam turbines also face long lead times and similar procurement hurdles, and their market is concentrated among many of the same major manufacturers. These changes in procurement practices mean that turbine availability increasingly has to be addressed much earlier in the project development process (Patel, 2025).

Key insight: *Gas turbines remain a major component of power plant procurement, but long lead times and competition for manufacturing slots have shifted the need to secure turbines much earlier in project development, with reservation fees creating an additional early-stage financing constraint.*

4.4.5 Construction Material – Current Chokepoint

Construction materials and electrical equipment are also current chokepoints. Generator step-up transformers (GSUs) and power transformers are among the largest bottlenecks in the power plant supply chain (Boucher, 2025). Power transformer lead times have doubled from pre-2022 levels to roughly 2.5 years (Patel, 2025). Gas-insulated switchgear (GIS) faces similar constraints. However, transformers and switchgear differ from gas turbines in that they are available from a broader range of vendors, including Chinese manufacturers. Tariffs and volatile prices for electrical steel and copper also continue to raise input costs (Patel, 2025; Boucher, 2025). These constraints matter because even if turbines are available, a plant cannot connect reliably to the grid without transformers, electrical systems, and balance-of-plant equipment.

As a result of these constraints, total project costs may exceed the budgets established during the feasibility-study stage, sometimes requiring renewed government approval for publicly supported projects. These cost increases can delay final investment decisions and lead developers or governments to reassess project costs, design, timing, or overall viability.

Furthermore, these constraints are intensified by competition from other sectors. Data centers, renewable energy projects, transmission expansion, grid modernization, and industrial facilities all require overlapping electrical equipment, including transformers, switchgear, cables, electrical steel, and copper.

As a result, gas-fired power projects are competing not only with other power plants, but with a broader infrastructure buildout for the same constrained material and equipment base. The effects of equipment shortages may be particularly acute in emerging markets. When manufacturing capacity is constrained, suppliers tend to favor projects in established markets that can provide greater commercial certainty, secure financing, and commit to early equipment reservations. Projects in Southeast Asia may therefore struggle to compete for limited gas turbine and electrical equipment production slots.

4.4.6 Workforce (EPC and Trades) – Current Chokepoint

Workforce availability is another current chokepoint. Multiple LNG, power, data center, and infrastructure projects compete for the same EPC contractors, engineers, construction firms, and skilled trades (Patel, 2025). The labor issue extends beyond engineering. Welders, electricians, operators, technicians, and construction personnel are all critical to future project execution. Competition across sectors is already contributing to labor shortages and increasing demand for technical graduates and workforce development pipelines (Hamm Institute for American Energy, 2026). In this context, EPC and skilled-trade availability can limit how many projects can be built at once, even when equipment has been ordered and financing is in place.

4.5 Power Distribution

In the power distribution stage, grid connection is essential because a completed gas-fired plant cannot deliver usable electricity without interconnection, transmission capacity, substations, and transformers. However, for LNG demand to materialize, the electricity must also be dispatched and paid for at prices that recover fuel, capacity, and infrastructure costs.

4.5.1 Grid and Grid Integrity – Current Chokepoint

The grid node includes transmission lines, substations, transformers, interconnection facilities, dispatch systems, and distribution networks needed to move electricity from GFPPs to demand centers, in parallel with ancillary services and resources, such as battery storage, required to maintain grid stability, especially as the share of variable renewable electricity increases. The grid is a current chokepoint because existing constraints including insufficient transmission and interconnection capacity, transformer shortages, and delayed interconnection approvals can prevent new generation from connecting, dispatching reliably, or delivering electricity to demand centers.

Gas-fired projects may also compete with renewable generation, data centers, storage projects, and other large loads for limited interconnection capacity, transmission upgrades, and electrical equipment. In the US, new power plants must undergo transmission impact studies before they can connect to the grid (Lawrence Berkeley National Laboratory, 2026). These studies determine whether new transmission equipment or grid upgrades are needed and assign the costs of those upgrades (Lawrence Berkeley National Laboratory, 2026). Grid interconnection therefore can delay gas-fired capacity even after fuel supply, permits, financing, and equipment are secured.

4.5.2 Consumers – Current Chokepoint

The consumer node represents electricity demand, affordability, payment capacity, and tariff recovery. Gas-fired power generation depends not only on physical delivery, but also on whether utilities, industrial users, or retail consumers can pay for electricity at prices that recover fuel, capacity, and infrastructure costs. The consumer node is a current chokepoint because uncertain electricity demand, tariffs that do not fully recover costs, exposure to volatile fuel prices, and weak utility finances can undermine the commercial viability of gas-fired generation.

Recent LNG market tightening increased the cost of gas-fired generation in Southeast Asia and contributed to fuel switching, while affordability pressures and subsidies remain significant (IEA, 2026d). Many of these markets are highly price-sensitive, meaning that the cost of electricity must be affordable for the average citizen in these economies. Therefore, the negotiation of commercial contracts between the fuel supplier, power producer, and electricity offtaker is critical. These negotiations are often more flexible in free markets than in regulated markets, where a state-owned utility may be the sole purchaser of electricity.

Key insight: *In price-sensitive Southeast Asian markets, gas demand depends on balancing electricity affordability with adequate cost recovery.*

One way power companies may address these commercial constraints is by integrating gas-fired generation into a broader portfolio of power assets. In markets such as the Philippines, companies that own GFPPs, renewables, and hydropower can coordinate firm and variable generation, optimize dispatch and electricity trading, and spread commercial risk across multiple assets. GFPPs can provide firm capacity when renewable output is low, while lower-cost renewable and hydro generation can reduce the portfolio's overall cost of electricity. This integrated approach can improve returns on capital and make gas-fired generation more commercially viable than if it were developed and operated as a stand-alone asset.

4.6 Supply Chain Interdependencies and Feedback Effects

The consumer node also links the end of the supply chain back to the beginning, through a cyclical, feedback-driven relationship. Downstream gas consumption affects upstream investment because producers, processors, pipeline developers, and LNG suppliers are more likely to commit capital when they see durable, creditworthy demand.

Key insight: *If emerging gas-to-power markets in Southeast Asia become deeper and more reliable, with predictable dispatch, bankable offtake, and tariff structures that allow cost recovery, the gas market can “thicken.” More buyers, sellers, contracts, infrastructure links, and price signals can strengthen the investment signals needed to support future upstream gas supply.*

This aligns with the broader maturation of LNG markets: LNG trade is moving away from rigid, destination-restricted, oil-indexed contracts toward a more flexible and diversified structure (Hamm Institute for American Energy, 2026). A thicker market reduces demand uncertainty, supports longer-term contracting,

and creates stronger investment signals for upstream extraction, processing, pipeline capacity, liquefaction, and LNG delivery. In this way, realized downstream demand can reinforce upstream supply development, while weak utilization, poor cost recovery, or uncertain dispatch can weaken investment signals and constrain future gas availability.

5. Southeast Asia's Challenges to Gas Demand Realization

The following country case studies illustrate how chokepoints across the gas-to-power supply chain affect Southeast Asian markets. They also highlight the specific challenges each country faces in developing gas supply and import infrastructure, advancing power projects, and ensuring that new gas-fired capacity can operate reliably.

5.1 Projected LNG Import Demand in Southeast Asia

Figure 5 provides an indicative range of projected LNG import demand that could emerge across the five markets examined in this report. Across the three illustrative scenarios, combined LNG imports could reach approximately 23–40 Mt by 2030. The Time Trend scenario reflects declining domestic gas production without additional fuel substitution; the Growth Substitution scenario additionally assumes that gas replaces 50% of post-2024 growth in coal- and oil-fired generation; and the Retirement Substitution scenario assumes that gas replaces a further 15% of the existing coal- and oil-fired fleet by 2030. These estimates represent projected import requirements rather than guaranteed realized demand; the country cases that follow demonstrate how commercial, infrastructure, financing, regulatory, and supply chain constraints could shift actual LNG demand toward the lower end of this range.

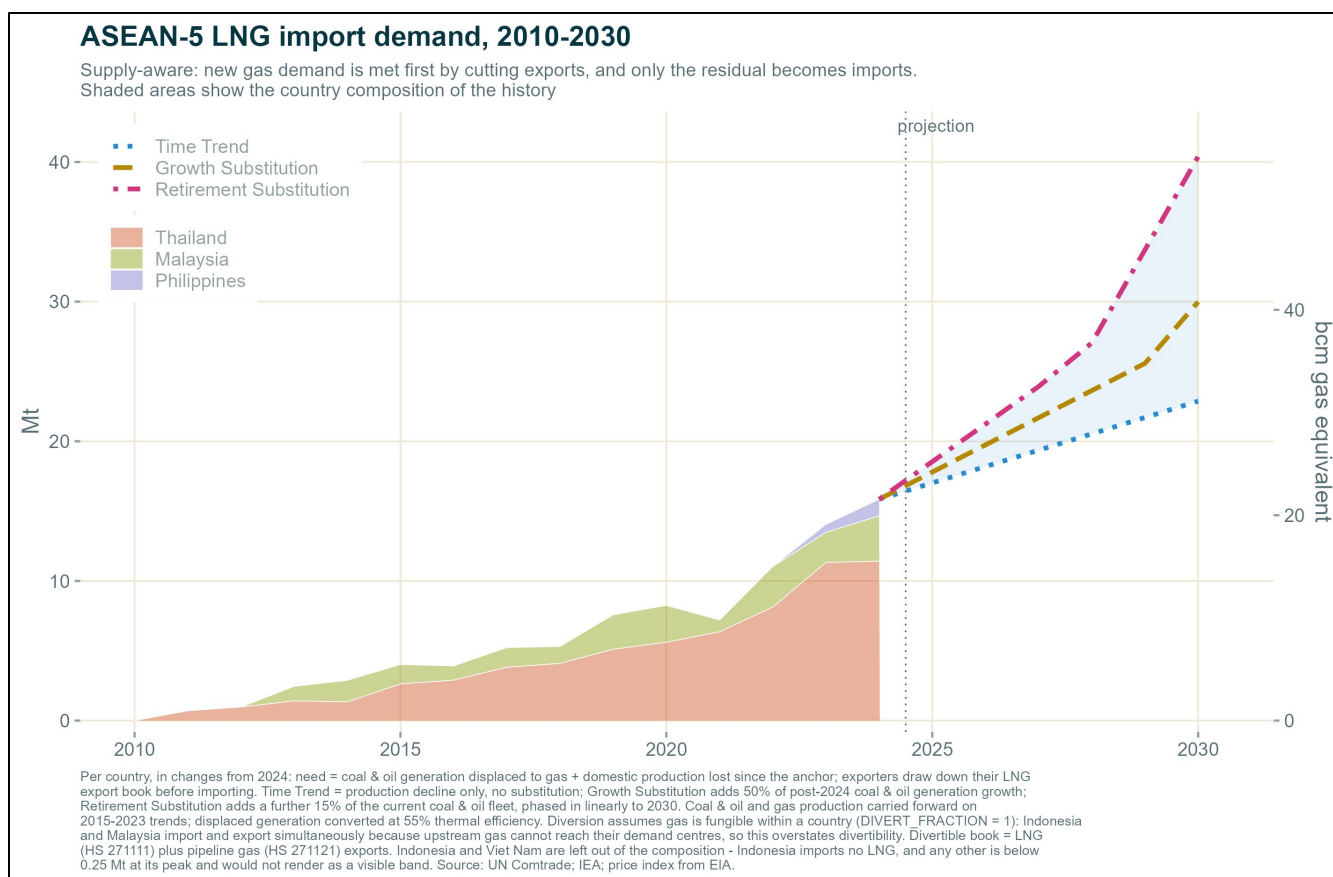


Figure 5: Illustrative Range of Projected LNG Import Demand in ASEAN-5, 2010-2030

5.2 Viet Nam

Viet Nam is one of Southeast Asia's largest prospective LNG-to-power markets. In 2023, Viet Nam's electricity was generated from coal (45%), hydropower (29%), solar (10%), natural gas (10%), and wind (4.2%) (IEA, n.d.-f). As one of world's top 20 coal producers, its electricity system remains heavily dependent on coal, but rapidly growing electricity demand, declining availability of domestic gas, and plans to expand renewable generation have led the government to assign a substantial role to domestic gas and LNG-fired generation. Viet Nam's Revised Power Development Plan 8 (PDP8) sets ambitious targets to expand gas-fired generation while gradually reducing the role of coal. With domestic gas reserves declining, LNG-fired power projects are central to meeting these targets. Viet Nam began importing LNG in 2023, and its first two LNG-fired power plants, Nhon Trach 3 and 4, became operational in late 2025 (Loc, 2025; Anh, 2025). The revised PDP8 also lists 14 additional LNG-to-power projects (B&Company 2025), and imported LNG is projected to account for up to 12% of power by 2030 (Asia Natural Gas and Energy Association, n.d.).

However, converting these targets into operating capacity remains difficult. The central constraint is the commercial and regulatory framework needed to make LNG-to-power projects bankable. Many LNG-to-power projects remain stalled not because of technological limitations or a lack of initial investor interest, but because project risks are not allocated in a way that makes them bankable (Reynolds, 2025; Phong,

2025; Payne and Ewing, 2026; Tran, 2026). Viet Nam's electricity transmission and distribution system is dominated by Viet Nam Electricity (EVN), the state-owned power utility and principal electricity purchaser. Developers face unresolved land-acquisition procedures, uncertain PPAs, the absence of a capacity payment mechanism, limited guarantees that EVN will dispatch or purchase sufficient electricity, and no clear framework for coordinating LNG procurement with power offtake (Phong, 2025).

In particular, PPAs may commit EVN to purchasing too little electricity each year to provide developers with predictable cash flow. This makes it difficult to secure financing, especially given volatile LNG prices and the high fixed costs of LNG terminals and power plants. Investors have therefore called for capacity charges that would compensate plants for remaining available even when they are not fully dispatched (Phong, 2025). Regulators, however, are concerned that such payments could distort the electricity market and shift excessive costs onto EVN and consumers (Phong, 2025).

The Nghi Son LNG project illustrates how these risks can prevent investor interest from translating into committed capital. The project required a bid guarantee equal to 1% of total project cost, or approximately USD 22 million. When combined with a potentially similar fee to reserve scarce gas turbines, developers could be required to commit substantial capital before securing a bankable PPA. Although several major international companies expressed interest, two bidding rounds failed to attract formal submissions, and international bidding was ultimately cancelled.

Viet Nam has introduced policy reforms intended to address some of these concerns. Decree 56 allows fuel costs for domestic-gas- and imported-LNG-fired power plants to be reflected in PPA prices, which may help developers recover volatile fuel costs (S&P Global Energy, 2025). However, investor uncertainty remains because the minimum contracted electricity output was set at 65% for up to ten years, below the level sought by some developers (S&P Global Energy, 2025). In 2026, the government proposed raising this level to 75% and extending the maximum period to 15 years. However, some investors continue to view the proposed terms as insufficient to ensure project bankability and have sought contracted output levels of 85–95% for 20–25 years (OpenGov Asia, 2026; Tran, 2026). LNG-fired projects require predictable electricity offtake and cost recovery to repay capital expenditures, fuel costs, and financing obligations. Without reliable tariff recovery or guaranteed electricity purchases, GFPPs may be built but operate below expected levels, weakening both project bankability and actual LNG demand.

These commercial and regulatory challenges are compounded by infrastructure and equipment constraints. Gas turbine procurement has become an important constraint in Viet Nam. As of 2025, only two projects have reportedly secured turbine reservations, while many others remain in preliminary development and may face delays because of global supply chain constraints (Reynolds, 2025; Tran, 2026). LNG-to-power projects also require substantial lead time to secure suitable sites and develop receiving terminals, as local planning, land clearance, environmental assessment, and the allocation of land and marine areas can delay project implementation.

Viet Nam also shows that operating capacity does not automatically translate into realized LNG demand. Investors in LNG-fired power projects have struggled to find buyers because EVN, Viet Nam's sole power

purchaser, prioritizes cheaper electricity sources such as hydropower over higher-cost LNG generation (Bac and An, 2025; Tran, 2026). As a result, LNG-based electricity accounted for only 6.6% of total power mobilization in the first seven months of 2025, down from 8.2% a year earlier (Bac and An, 2025). This demonstrates that gas-fired capacity does not automatically create gas demand. If LNG-fired plants are too expensive to dispatch, lack firm offtake, or cannot pass through fuel costs, then actual gas consumption may remain below expectations.

5.3 The Philippines

The Philippines is an emerging LNG market seeking to replace declining production from the Malampaya gas field, support rising electricity demand, and gradually reduce its heavy dependence on coal. The Philippine Energy Plan 2023–2050 targets a major shift in the generation mix by 2050, with natural gas supplying 35% of electricity generation by 2050, compared with 51% from renewables and 14% from coal (Republic of the Philippines Department of Energy 2023, 89). The country began importing LNG in 2023 and has developed receiving infrastructure linked to its existing gas-fired fleet. In 2025, Excellent Energy Resources Inc. (EERI)'s LNG-fired power plant in Batangas became fully operational, marking the Philippines' first major addition of gas-fired capacity since 2016 and supplementing its five pre-existing GFPPs (Flores, 2025; Reynolds, 2025).

However, EERI remains an exception. Several other proposed greenfield LNG-to-power projects in the Philippines remain largely in early development, and another project is not expected to enter operation this decade (Reynolds, 2025). A central obstacle is the difficulty of securing long-term commercial offtake agreements needed to support financing and project development (Reynolds, 2025, 2026). Unlike Viet Nam, where EVN remains the principal electricity purchaser, in the Philippines, the commercial contracts are awarded based on the competitive selection processes (CSP), where distribution utilities choose the bidder offering the lowest-cost power (Reynolds, 2025). LNG-fired projects must therefore demonstrate that they can provide electricity at competitive prices while managing exposure to volatile LNG costs and other project risks. High LNG prices and uncertain fuel costs can make it difficult for early-stage projects to secure the contracts needed to advance, creating a typical chicken-and-egg dilemma.

Recent project setbacks illustrate the importance of these commercial constraints. Energy World Corporation's proposed Pagbilao LNG-to-power project had secured gas turbines and reached an advanced stage of physical development, but lacked a long-term PPA and remained exposed to wholesale electricity market and LNG-price volatility (Reynolds, 2026). In 2026, the company sold the project's turbines to a US buyer, effectively ending the proposed power project. Similarly, Enx Energy cancelled its proposed 1.1 GW LNG-to-power project in 2025 after difficulties securing long-term offtakers (Reynolds, 2026). These cases show that access to long-lead equipment alone is insufficient if a project cannot establish a viable commercial structure and secure predictable electricity revenues.

These commercialization challenges are compounded by equipment supply constraints. Most remaining proposed LNG-to-power projects in the Philippines are still in the early planning stages and are unlikely to have secured turbines and other long-lead equipment (Reynolds, 2025). Global gas turbine manufacturing

backlogs and rising equipment costs could therefore create an additional source of delay for proposed projects.

5.4 Thailand

Thailand has the most established gas-to-power systems in Southeast Asia, built since the 1980s around domestic offshore gas and later supplemented by pipeline imports from Myanmar and the Malaysia–Thailand Joint Development Area. As domestic production declined and demand for natural gas increased, Thailand began importing LNG in 2011 and has since developed a diversified supply portfolio. In 2024, its largest LNG suppliers were Qatar, the US, Australia, Malaysia, and Indonesia (World Bank WITS, 2024). Natural gas currently serves as the backbone of Thailand’s power sector, accounting for nearly 64% of electricity generation, compared with approximately 14% from coal (IEA, n.d.-e).

At the same time, Thailand is pursuing a gradual energy transition and reducing gas dependence through the draft National Energy Plan (NEP) aimed at increasing renewable energy deployment, improving energy efficiency, and achieving carbon neutrality by 2050 and net-zero emissions by 2065 (ACE, 2024). However, because these renewable resources are inherently intermittent and variable, their growing deployment is expected to increase the need for flexible and dispatchable generation resources. Consequently, natural gas is expected to remain a critical complement to renewable energy in Thailand by providing the balancing, reserve, and peak-load services needed to maintain grid stability as solar and wind deployment expands (ACE, 2024; Ranjan et al., 2025).

Thailand’s challenge is therefore not constructing a greenfield LNG-to-power system, as in Viet Nam or the Philippines, but managing an already large gas-fired fleet while its traditional fuel-supply model changes. Domestic offshore gas and pipeline imports from Myanmar have historically supported Thailand’s gas-fired generation, but declining domestic and regional supplies have increased reliance on more expensive, imported LNG (Reynolds and Doleman, 2026). Thailand must therefore manage both the maintenance and replacement of its existing fleet and the growing exposure of gas-fired electricity to global fuel prices and supply-chain risks.

Thailand is currently preparing a new Power Development Plan (PDP) covering 2026–2050. The previously proposed Draft PDP 2024 was not finalized, but it provides an indication of the direction previously under consideration: it proposed adding approximately 6.3 GW of gas-fired capacity between 2028 and 2037, even while seeking to expand renewable generation and strengthen Thailand’s emissions-reduction targets (Asian Power, 2026). However, achieving this level of gas-fired expansion would be difficult for several reasons.

First, Thailand is experiencing electricity overcapacity. Demand has grown more slowly than expected, partly because the economy has not expanded as quickly as assumed in earlier power plans (Reynolds and Doleman, 2026). At the same time, increased solar generation has reduced the need to dispatch some GFPPs. Thailand’s installed solar capacity more than doubled during 2025, while gas-fired generation and gas demand declined (Reynolds and Doleman, 2026). As a result, Thailand continues to maintain more generation capacity than it currently needs.

A second challenge is Thailand's growing dependence on imported LNG. The Draft Gas Plan 2024 projected that LNG imports could increase by 73% and supply approximately 43% of national gas requirements by 2037 as domestic production and Myanmar pipeline imports decline (Reynolds and Doleman, 2026). In 2025, LNG cost more than twice as much as domestic gas and approximately 29% more than Myanmar pipeline gas (Reynolds and Doleman, 2026). Unlike domestic and regional pipeline supply, LNG exposes Thailand more directly to international price volatility, shipping disruptions, foreign-exchange risk, and competition for cargoes. These risks raise the cost of gas-fired generation and can ultimately be transmitted to electricity consumers.

A third challenge is the availability and cost of new generating equipment. The turbine order backlogs and shortages of materials, components, and skilled labor are increasing the costs and development risks for Thailand's proposed GFPPs. Nearly all planned Thai gas projects have experienced delays, and Electricity Generating Authority of Thailand (EGAT) cancelled tenders for three proposed projects in 2025 (Reynolds and Doleman, 2026).

Furthermore, much of Thailand's existing gas fleet is already underutilized. In 2025, seven of eleven privately owned GFPPs operated at capacity factors below 10% (Reynolds and Doleman, 2026). In October 2025, the National Energy Policy Council suspended three gas-fired facilities and delayed the commissioning of another plant, citing excess electricity supply (Asian Power, 2026). Although pausing their operation reduces fuel and operating expenses, generators may continue to receive capacity payments to cover their fixed costs under long-term power-purchase agreements. These costs are recovered through the electricity system and ultimately passed on to consumers through the base tariff (Reynolds and Doleman, 2026).

For Thailand, therefore, the central question is whether additional gas-fired capacity is economically justified when existing plants are underused, LNG dependence is increasing, and equipment costs and lead times are rising. Thailand will need to reassess electricity-demand assumptions, determine which aging plants genuinely require replacement, and clarify the role of gas as renewable generation expands.

5.5 Indonesia

As Southeast Asia's largest economy and electricity market, Indonesia is one of the region's most strategically important potential gas markets. Its power sector remains heavily dependent on coal, which accounted for approximately 69% of electricity generation in 2023, compared with just 13% from natural gas (IEA, n.d.-a). This is driven by the country's abundant and cheap domestic coal resources. In 2023, Indonesia ranked as the world's third largest producer of coal, with historically lower coal generation costs, and a long-standing policy emphasis on energy affordability and security (EIA, 2025; Kresna, 2026).

Indonesia's Electricity Supply Business Plan (RUPTL) for 2025–2034 proposes approximately 69.5 GW of additional generation and storage capacity, including 42.6 GW of renewable energy, 10.3 GW of storage, 10.3 GW of gas-fired capacity, and 6.3 GW of coal-fired capacity (Business Indonesia, 2025). Renewables and storage therefore represent approximately 76% of planned capacity additions. The plan consequently represents a gradual diversification of Indonesia's power mix, with a greater emphasis on renewable

energy and storage, while still providing for new coal- and gas-fired capacity. As variable renewable generation expands, flexible gas-fired power could play an important role in balancing the system and supporting grid reliability across Indonesia's geographically dispersed island networks. The government has also expressed an ambition to position Indonesia as a regional center for AI development (Tech in Asia, 2025). The expansion of data centers could increase demand for reliable electricity.

However, the most fundamental constraint on greater gas-fired generation is the cost competitiveness of domestic coal. Indonesia already has an established coal supply chain and caps the price of coal sold to power producers. This price cap provided an estimated IDR 58.5 trillion in support in 2024, helping to keep electricity tariffs low (Suharsono et al., 2026). Gas, and particularly imported LNG, must therefore compete against coal whose cost to the power sector is supported by domestic pricing policy. As a result, coal may continue to have a significant cost advantage over gas even as Indonesia seeks to diversify its power mix. Absent changes that reduce this structural advantage, such as stronger carbon pricing, changes to domestic coal pricing, or more stringent decarbonization requirements, imported LNG may struggle to compete economically with coal for sustained power sector dispatch.

The underutilization of Indonesia's existing gas-fired fleet illustrates this challenge. Between 2018 and 2024, Indonesia added 6.3 GW of gas-fired capacity to reduce its reliance on coal for baseload generation. However, instead of displacing coal, GFPPs were forced out of the power mix because of high operating costs and constrained domestic gas supplies. As a result, GFPPs operated at an average capacity factor of approximately 30% in 2024 (Yustika, 2025). Low utilization weakens the commercial case for additional gas-fired capacity because plants must recover their fixed costs over fewer operating hours. The proposal under RUPTL to add additional gas-fired capacity could therefore compound existing underutilization unless electricity demand, gas delivery infrastructure, fuel availability, and plant dispatch increase accordingly.

Gas availability presents a related challenge, although Indonesia has so far sought to address domestic supply pressures primarily through its own gas and LNG resources rather than through large-scale imports. Although Indonesia remains a major natural gas producer and LNG exporter, production from some mature fields is declining while domestic gas demand is increasing (Churchman, 2025). Gas supplies are also geographically dispersed across Indonesia's archipelago and are not always located near the principal electricity-demand centers (EIA, 2025). Indonesia has occasionally imported small quantities of LNG, including from the US, but it has primarily addressed domestic supply pressures by redirecting cargoes from its own LNG export facilities to domestic buyers (Churchman, 2025).

The Tangguh LNG project illustrates this domestic-priority approach. 75% of Tangguh Train 3's annual LNG production is allocated to the domestic market through PLN, with the remaining 25% contracted to Kansai Electric of Japan (Asian Development Bank, 2025b). In 2026, BP expected to deliver 89 LNG cargoes from Tangguh to the Indonesian market, equivalent to approximately 71% of the country's domestic LNG demand (Nugraha, 2026). More broadly, as of July 2025, 69% of existing gas output was already allocated to the domestic market, while much of the remaining production was committed under long-term LNG export contracts (Bachtiar, 2026). The possibility of greater import dependence would expose the power

sector to international LNG prices and disruptions in global shipping and fuel supply. Given coal's cost advantage and the government's preference for utilizing domestic gas and LNG supplies, imported LNG is likely to remain a relatively expensive source of fuel rather than an automatic replacement for declining domestic gas or a competitive alternative to cheap coal.

Affordability and government support for electricity tariffs further reinforce this cost constraint. In 2024, the Indonesian government provided approximately IDR 177 trillion, or around USD 11 billion, in electricity subsidies and compensation, an increase of about 24% from the previous year (Yustika, 2025). This support includes compensation for electricity that the state utility PLN sells below cost to customers whose tariffs are not formally subsidized (Suharsono et al., 2026). Because PLN cannot always pass the full cost of electricity generation to consumers, greater reliance on relatively expensive gas or imported LNG could increase either government support requirements or financial pressure on the utility.

These conditions mean that Indonesia's gas-to-power challenge is fundamentally one of economics and commercialization rather than simply building additional generating capacity. New projects must be supported by reliable and competitively priced gas supplies, sufficient pipeline or LNG infrastructure, predictable dispatch, and electricity tariffs or subsidies that allow PLN and project developers to recover their costs.

In the case of the integrated Jawa 1 power plant and FSRU project, JBIC itself participated in negotiating the detailed terms and conditions of a 25-year PPA with PLN before beginning negotiations on the financing arrangements (Japan Bank for International Cooperation, n.d.). JBIC considered the PPA critical to the success of the project because revenue from electricity sales to PLN under the agreement represented the project's only source of cash flow. Jawa 1 therefore demonstrates that gas-to-power projects can advance when fuel supply, infrastructure, long-term electricity offtake, and financing arrangements are aligned. However, without these conditions, and while domestic coal retains a substantial cost advantage, additional gas plants risk joining an existing fleet that already operates well below its technical capacity.

Gas-fired generation may therefore play a more targeted role in Indonesia, including providing system flexibility, serving regions where alternative sources are less practical, and utilizing available domestic gas and LNG, while a larger role for imported LNG would likely depend on changes in relative fuel economics or stronger decarbonization policies.

5.6 Malaysia

Malaysia occupies a distinctive position in Southeast Asia's gas market as both a major LNG exporter and a country preparing for a more import-dependent future. Natural gas currently plays a central role in the country's power system, accounting for roughly 35% of electricity generation, while coal remains the largest source at approximately 45% (IEA, n.d.-b). Gas is expected to remain an important transition fuel as Malaysia expands renewable energy under the National Energy Transition Roadmap (NETR) and gradually reduces its reliance on coal, providing flexible and dispatchable generation to support balancing, reserve, and grid-reliability needs (Government of Malaysia, 2023; Tenaga Nasional Berhad, n.d). At the same time, declining production from mature offshore fields and growing domestic demand are expected

to reduce export availability and could contribute to a gradual shift from net gas exporter to net importer during the 2030s (ACE, 2024).

Malaysia already has one of Southeast Asia's most established gas-to-power systems, including domestic gas production, processing facilities, GFPPs, LNG receiving terminals, and an extensive pipeline network. Malaysia's principal challenge is therefore not establishing a greenfield gas-to-power system, but maintaining adequate and affordable fuel supplies as electricity demand rises and production from fields serving its principal demand centers declines.

First, although Malaysia remains a major LNG producer and exporter, its gas reserves, infrastructure, and demand are unevenly distributed. Much of Malaysia's LNG production is located in Sarawak, whereas the country's largest concentration of electricity demand and gas-fired generation is in Peninsular Malaysia. Peninsular Malaysia and Sabah may therefore need to increase LNG imports even while Malaysia as a whole continues to export LNG (Azhar and Zainul, 2026).

This supply challenge will become more important as Malaysia reduces its reliance on coal. The government intends to retire half of the country's coal-fired capacity by 2035 and eliminate coal-fired generation by 2044 (Azhar and Zainul, 2026). GFPPs are consequently expected to remain important as dispatchable sources of electricity that can replace retiring coal capacity, meet growing demand, and balance increasing amounts of variable renewable generation. Malaysia is expected to add approximately 6–8 GW of gas-fired capacity by 2030, equivalent to roughly a 40%–50% increase from its existing gas-fired fleet (Varadhan and Tang, 2025). This expansion is being driven in part by rapidly rising electricity demand from data centers, particularly in Peninsular Malaysia.

Second, like other markets, Malaysia also faces constraints on procurement of plant equipment. Malaysia has launched competitive procurement processes for new GFPPs. However, these plans are already being affected by the global shortage of large gas turbines. Some developers have secured manufacturing slots, but others face delays because equipment is unavailable or because manufacturers require large upfront deposits that can reach approximately one-third of the turbine price (Aziz, 2026). Securing a turbine slot does not, however, guarantee that a project will ultimately proceed, as developers must also obtain the necessary regulatory approvals and permits. Delays or uncertainty in the approval process can therefore leave developers holding costly equipment reservations for projects that are not yet authorized to move forward.

Third, regulated domestic gas pricing remains a major policy challenge. Regulated gas prices have protected power producers and consumers from the full cost of internationally traded LNG. At the same time, they have also weakened incentives for upstream production, midstream infrastructure investment, and independent LNG imports (Azhar and Zainul, 2026). Malaysia introduced third-party access to its gas infrastructure in 2017, allowing companies other than PETRONAS, the state-owned energy company, to import LNG, use existing regasification terminals and pipelines, and sell gas directly to consumers (Zainul and Aziz, 2023). In practice, however, participation has remained limited, partly because major utilities and independent power producers continue to receive gas through long-term contracts with PETRONAS

and independent importers must compete with regulated domestic prices (Zainul and Aziz, 2023). Although gas prices for non-power consumers have been liberalized, power-sector gas prices are expected to remain regulated until at least the end of 2027 (Azhar and Zainul, 2026).

Malaysia therefore faces a difficult trade-off: keeping gas prices below the cost of new supply could discourage the LNG imports and infrastructure investments, while passing the full cost of imported LNG through to electricity tariffs could create affordability concerns and increase costs for consumers.

6. Strategic Role of the US–Japan–Korea Triad

There is a confluence of interest among the actors. The US seeks to expand export destinations and market opportunities for US LNG while strengthening its strategic and economic engagement in the region. South Korea and Japan have an interest in managing seasonal and off-peak fluctuations in LNG demand, while also pursuing, in parallel, efforts to “thicken” the market and facilitate smoother financing and project execution through trilateral cooperation. Southeast Asian countries, meanwhile, can benefit from reliable supply diversification that supports decarbonization policy goals and from more flexible LNG sourcing arrangements that ease reliance on large, rigid long-term commitments. Reducing excessive dependence on any single external partner in the region can also help preserve economic resilience and strategic autonomy as countries navigate broader regional geopolitical and maritime tensions and pursue their longer-term energy transitions.

However, many of the critical hurdles for GFPPs, such as state utility pricing, heavy subsidies, and restrictive regulatory frameworks, are fundamentally sovereign policy choices. This means that for the Triad to be effective in addressing hurdles in the GFPP supply chain, actions must be aligned with the goals of the downstream markets, targeted where they can have the greatest impact, and work to strengthen broader strategic relationships in the region.

Trilateral cooperation should also recognize the changing role of gas in Southeast Asian power systems. Rather than treating LNG and gas-fired generation as a long-term substitute for coal, cooperation should focus on the role of gas as a flexible power source and transition fuel that can support renewable energy expansion, in addition to meeting the fast-expanding need for electricity to support economic growth ambitions. This includes sharing policy and operational experience on how gas-fired generation can be integrated in ways that remain consistent with Southeast Asian countries’ decarbonization objectives. Building a shared understanding of this role can help align trilateral cooperation with both regional energy-security and longer-term energy-transition goals.

As one example, the Triad can combine US LNG supply, either directly or indirectly, and other elements of the gas-to-power supply chain with Japanese and South Korean experience in LNG procurement, project development, financing, and supply-chain management. This combination can help address selected project development constraints and strengthen regional energy security. Such cooperation would also reinforce existing trilateral commitments to critical infrastructure and economic resilience, allowing the

Triad to maintain a strong strategic presence in the region. To advance these shared goals, we present three recommendations that consider the alignment of interests and the corresponding challenges.

6.1 Strengthen LNG Supply Security and Diversification

Southeast Asia's gas demand is expected to become increasingly dependent on LNG imports as production from mature regional fields declines and energy demand continues to grow alongside strong GDP growth. At the same time, the 2026 Middle East conflict demonstrated the risks of relying heavily on energy supplies transported through the Strait of Hormuz. Each member of the Triad has complementary strengths that can help strengthen regional LNG supply security.

As the world's largest LNG exporter, the US can provide Southeast Asian markets, either directly or indirectly, with a growing source of LNG outside the Middle East, as part of a broader diversification strategy. Southeast Asian importers should retain access to a geographically diverse portfolio that may also include suppliers such as Australia and other non-Middle Eastern producers, depending on price, availability, contractual flexibility, and shipping conditions.

One area of cooperation is to leverage long-term Japanese and South Korean offtake commitments in combination with Southeast Asian demand to support investment in additional US LNG supply. More stable and predictable LNG demand in Asia strengthens investment signals across the US upstream, pipeline, and liquefaction supply chain. Recent agreements demonstrate this type of commitment, with JERA and KOGAS both securing long-term US LNG supplies (JERA, 2025; Kawasaki et al., 2025).

While Japanese and South Korean companies have substantial long-term offtake commitments for US LNG, their participation further upstream in US gas production and liquefaction development has been more limited. Greater investment in these segments strengthens the supply base supporting Asian LNG imports. Liquefaction facilities are particularly important because they are capital intensive and complex to develop, yet are essential for converting US gas production into LNG available to importers such as Japan and South Korea. In the nearer term, US Gulf Coast LNG projects provide a commercially established channel for expanding this cooperation. Japanese and South Korean companies can support additional LNG supply through long-term offtake commitments as well as financing and equity participation in these projects.

In the longer term, Alaska LNG provides another potential model of this cooperation. The project has attracted preliminary interest and offtake commitments from Asian buyers, including companies in Japan, South Korea, Taiwan, and Thailand (Golubkova and Obayashi, 2026), providing a potential foundation for broader trilateral cooperation. Such cooperation could diversify Asian LNG supply away from Middle Eastern or Suez transit chokepoints while providing the commercial commitments needed to support investment in US gas production, pipelines, and liquefaction capacity. At the same time, the project must demonstrate that it can deliver LNG at a competitive cost and provide energy security and economic benefits proportionate to any public support it receives. If the delivered cost of LNG is substantially higher than available alternatives, the strategic rationale alone would not justify the financial burden on governments, consumers, or taxpayers.

A second area of cooperation is to build greater shipping and commercial flexibility around these LNG portfolios. Japan and South Korea should contribute their extensive experience in LNG procurement, shipping, terminal operations, portfolio management, and supply security planning. Cooperation between the two countries has already moved beyond general discussion: in 2025, JERA and KOGAS completed an LNG cargo swap project, and in March 2026, they signed an agreement to strengthen supply-demand coordination, optimize shipping and terminal operations, and explore additional cargo swaps (Lee, 2026; JERA, 2026). Building on this experience, Japanese and South Korean utilities and trading companies should make greater use of cargo swaps, diversions, delivery-schedule adjustments, and shipping and terminal optimization to respond to seasonal and regional changes in demand. Where such arrangements generate commercial or logistical benefits, mechanisms for benefits sharing help create incentives for participating companies.

This broader shipping and portfolio flexibility could also provide Southeast Asian importers with access to additional flexible LNG supply. Where contractual terms, commercial incentives, and domestic supply conditions permit, Japanese and South Korean buyers could redirect or resell cargoes to Southeast Asian markets when they have surplus volumes or when regional logistics make alternative delivery more efficient. This helps Japan and South Korea manage fluctuations in their own LNG demand while allowing Southeast Asian importers to access initial or incremental volumes without necessarily meeting all of their LNG requirements through large, long-term contracts directly with upstream suppliers (IEA, 2019b; JERA, 2025).

These shipping and portfolio management capabilities also support stronger regional contingency planning for future LNG supply disruptions. This should include discussion of crisis-response mechanisms such as cargo diversion, cargo swaps, shipping coordination, and other contingency arrangements. A broader and more flexible portfolio of supply strengthens the region's ability to respond to disruptions without creating dependence on any single supplier or route. The Triad could also support practical capabilities in newer LNG-importing markets, including FSRU operations, storage and regasification, and LNG contract and portfolio management. These measures could help reduce institutional and operational risks.

6.2 Address Supply Chain and Project Bankability Bottlenecks

The central challenge for executable gas-to-power projects is not simply creating new demand, but addressing the constraints that prevent viable projects from becoming bankable and moving into execution. These constraints arise both from supply chain bottlenecks, such as gas turbine shortages and long project development timelines that increase costs and create uncertainty over equipment availability, and from commercial and regulatory weaknesses, including underdeveloped power-market frameworks and insufficient revenue certainty. Technical solutions alone are therefore insufficient to address these constraints. We suggest that the Triad pursue coordinated supply chain, financial, regulatory, and government-to-government support to improve fiscal regimes, project execution, and bankability, while ensuring that support remains aligned with Southeast Asian countries' energy security and longer-term energy-transition objectives.

One priority is to strengthen the gas turbine supply chain. The three governments should support manufacturers' efforts to expand production capacity where commercially justified and explore ways to improve access to manufacturing slots for viable projects in Southeast Asia. However, capacity expansion must also account for the cyclical nature of turbine demand and the risk that manufacturers could be left with excess capacity if current demand growth is not sustained. Government support should therefore focus not simply on encouraging additional manufacturing capacity, but also on reducing the risks and uncertainties that affect OEM investment decisions, including by improving visibility into future project pipelines and supporting credible, bankable demand. In practice, this could include reducing policy uncertainty through clearer power sector and fuel supply frameworks, providing targeted support for turbine reservations for viable projects, and using credit enhancement or public financing tools to help projects reach financial close and translate projected demand into credible equipment orders.

In parallel, closer coordination among OEMs, EPC contractors, project developers, utilities, and financial institutions helps viable projects secure gas turbine manufacturing slots earlier and more effectively. A procurement coordination mechanism increases confidence in the Southeast Asian gas-fired power project pipeline, including expected equipment demand, project timelines, financing status, technical requirements, lead times, and procurement schedules. Where appropriate, the Triad should also support efforts to reduce design and procurement inefficiencies through reference designs, common specification ranges, or partial standardization, rather than attempting to fully standardize project specifications across different markets. Similar coordination should extend beyond turbines to transmission and distribution equipment required for grid interconnection, including transformers, high-voltage cables, and switchgear, where procurement constraints also delay project execution.

Beyond new equipment procurement, the Triad could also explore greater coordination in the management of strategic turbine stocks. Power plant and LNG operators often maintain spare turbines for maintenance or emergency needs. Where equipment is technically compatible, mechanisms to pool or share these stocks across projects could improve equipment availability and add greater flexibility and fluidity to the turbine supply chain. Such arrangements could be developed in coordination with OEMs to address technical compatibility, ownership, warranty, and logistical requirements.

A second priority is to address the commercial and regulatory constraints that weaken project bankability. Public financing and export-credit support should be paired with technical and government-to-government engagement on PPA structures, capacity payment mechanisms, government guarantees, foreign-exchange risk, fuel-cost recovery, and, where applicable, direct power-purchase arrangements (DPPAs). Rather than relying primarily on direct subsidies, the Triad should also explore targeted credit-enhancement mechanisms that reduce specific risks preventing otherwise viable projects from advancing. These include support for early-stage development costs, turbine reservation fees, and credit enhancement for projects that have credible PPAs and cost-recovery structures in place. Foreign-exchange risk mitigation should also form part of the financing package, including through instruments such as FX guarantees or other currency-risk mitigation mechanisms, particularly where dollar-denominated capital and fuel costs are matched against local-currency PPA revenues.

Financing support alone, however, cannot resolve all project bankability constraints. Many of these barriers arise from domestic regulation and the allocation of risk between utilities, governments, and developers. Government-to-government engagement and institutional cooperation should support Southeast Asian countries seeking to develop more bankable regulatory frameworks while respecting domestic policy priorities. This is particularly important in markets where volatile gas prices and uncertain dispatch levels make it harder for projects to achieve predictable revenues.

6.3 Align Gas-to-Power Financing with Decarbonization Goals via Trilateral Consortia

Public financing for new gas-to-power projects is becoming increasingly selective as financing institutions seek to align their support with climate and energy-transition objectives. This creates an additional bankability challenge for projects that cannot demonstrate how they fit within longer-term decarbonization pathways. Trilateral support should therefore be targeted toward projects that demonstrate a strong energy security rationale and contribute to objectives such as replacing

with financing potentially structured to reflect these transition benefits. Trilateral cooperation should also include information sharing on high-efficiency combined-cycle gas turbine (CCGT) technologies, methane management, and potential future linkages with hydrogen and carbon capture, utilization, and storage to help clarify how gas-to-power projects can fit within longer-term transition pathways.

Aligning projects with these objectives also broadens the potential financing base. Multilateral development banks increasingly assess natural gas projects against climate and transition criteria. For example, the Asian Development Bank (ADB) provides selective support for natural gas projects under its revised energy policy and considers their consistency with emissions-reduction and longer-term decarbonization pathways (Asian Development Bank, 2023, 2025a). Structuring projects to meet these criteria therefore improves their compatibility with multilateral financing. Where projects qualify, participation by institutions such as ADB alongside US, Japanese, and South Korean public financiers and commercial lenders helps address bankability concerns by mobilizing additional capital and distributing financing risk across a broader group of institutions.

For projects that demonstrate a credible energy security and transition rationale, we propose an end-to-end consortium model for selected Southeast Asian markets. Under this model, a South Korean or Japanese company should serve as lead developer and partner with companies from the other two countries that provide complementary capabilities. A US partner should support LNG supply, while Japanese and South Korean participants contribute regional project development experience, financing, power-generation technology, and EPC execution. Major equipment should be supplied by US, Japanese, or South Korean manufacturers with suitable technology and project experience, while experienced South Korean and Japanese EPC contractors should support project delivery. The consortium should then approach Southeast Asian governments and utilities with an integrated package combining fuel supply, infrastructure development, financing, generation equipment, and construction. By bringing complementary capabilities together within a single project structure, this consortium model reduces execution risk, strengthen project bankability, and better align commercial objectives with the broader

strategic goals of the US, Japan, and South Korea. The consortium structure would need to be tailored to individual markets and developed in partnership with local stakeholders, including state utilities, local project and infrastructure developers, and government agencies. Local participation is particularly important for aligning project design and financing with domestic regulatory frameworks, power-market requirements, and energy-transition priorities.

Viet Nam's O Mon 4 project illustrates how companies from different countries can contribute complementary capabilities within a single gas-to-power project. The 1,155 MW combined-cycle plant will use domestic gas from the offshore Block B development, while a consortium led by South Korea's Doosan Enerbility and Viet Nam's PECC2 is responsible for EPC delivery and Japan's Mitsubishi Power will supply the gas turbines (Mitsubishi Power Asia Pacific, 2025; Kim, 2025). Although O Mon 4 is not itself a US–Japan–South Korea trilateral project, it demonstrates how project development, EPC expertise, and generation technology from different countries can be combined within a single project structure. A trilateral consortium model builds on this type of complementary participation by adding capabilities such as US LNG supply and coordinated financing where appropriate.

7. Implications and Future Work

These areas of cooperation highlight the value of a coordinated trilateral approach in gas-to-power development in Southeast Asia. The Triad cannot eliminate the commercial, regulatory, financing, and infrastructure constraints that shape the global GFPP supply chain and project development in Southeast Asia, many of which ultimately depend on decisions by Southeast Asian governments and market participants. However, by combining complementary strengths in LNG supply, procurement, financing, project development, generation technology, and EPC execution, the US, Japan, and South Korea can help reduce selected bottlenecks, improve the viability of credible projects, and strengthen regional energy security. Such cooperation also deepens the Triad's economic and strategic engagement with Southeast Asian countries by demonstrating a capacity to respond to practical energy needs while supporting longer-term gas-to-power development.

This report establishes a high-level framework for understanding how different parts of the GFPP supply chain interact and shape gas-to-power development in Southeast Asia. It identifies the principal chokepoints in the global supply chain and provides illustrative case studies of the region's largest markets, which we believe points to three areas for future research. First, project-level assessment or an in-depth analysis of any single segment, such as a detailed evaluation of GFPP development or turbine manufacturing, would provide more actionable suggestions. These studies could include more detailed supply chain analysis, expanded Petri mapping, or analysis using the Cluster Factor Analysis Framework (CFAF). Project level analysis could also be extended beyond gas-to-power to examine industrial gas demand in Southeast Asia.

Second, future research could also develop a more systematic framework for assessing and tracking the GFPP supply chain chokepoints over time, using observable indicators such as lead times, price increase, project delays, and capacity utilization or congestion. Building on the recommendations in Section 6, a

further extension could examine their implementation in greater detail by identifying potential lead and supporting actors, implementation timelines, indicators of success, and candidate pilot markets. Together, these areas of future work would move the analysis from a high-level mapping of constraints and areas for cooperation toward a more detailed framework for prioritization and implementation.

Third, the crisis-response mechanisms discussed in Section 6.1, including cargo diversion, cargo swaps, and coordinated shipping and terminal operations, point toward a broader avenue for future work: the feasibility of a trilateral LNG strategic reserve framework. Rather than relying solely on physical storage tanks, such a framework could define reserves as a coordinated chain of contractual rights spanning gas supply, firm pipeline and liquefaction capacity, shipping, and receiving terminals across the three countries, building on precedents such as Japan's Strategic Buffer LNG program and EU gas storage regulation. Assessing the commercial, legal, and operational feasibility of this concept, including how such a framework could extend the supply security benefits described in this report to Southeast Asian partners during future disruptions, would be a natural extension of the present analysis and a strong candidate for future phase research.

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