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Thailand's Natural Gas Crossroads: Strategic Risk Mitigation for a Carbon-Neutral Era

CASE for Southeast Asia

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Thailand's Natural Gas Crossroads:
Strategic Risk Mitigation for a Carbon-Neutral Era

Analysis
Thailand's natural gas crossroads:
Strategic risk mitigation for a carbon-neutral era

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About CASE
The Clean, Affordable and Secure Energy for Southeast Asia (CASE) project supports power sector transitions in Indonesia, Thailand, Vietnam and the Philippines through evidence-based analysis and narrative change. The project supports decision-makers, industry leaders and consumers in enacting strategic reforms in the power sector in pursuit of the Paris Agreement goals and a just transition.

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EXECUTIVE SUMMARY

Thailand is currently revising its long-term energy strategy to deliver clean, affordable and secure energy for its people and economy. A critical aspect of this process is aligning the update of the country's latest national energy action plans (including the Power Development Plan (PDP) 2024 and Gas Plan 2024) with its commitment to carbon neutrality by 2050 and net-zero emissions by 2065. However, a major challenge is the limited planning horizon, which currently only has action planning up to 2037. This creates significant uncertainties and risks about how the country will proceed in the last mile towards carbon neutrality until 2050. This is particularly critical for the future role of natural gas in Thailand, which currently generates 57% of the country's electricity and has historically been a key energy resource driving its economic development. While natural gas is a cleaner fuel compared to oil and coal, it remains the main source of CO_2 emissions in Thailand's energy sector.

Global Context and the Need for Alignment

The question of a future role for natural gas is particularly relevant in the context of global climate action. At COP28, the international community committed to transitioning away from fossil fuels in energy systems in a just, orderly and equitable manner to achieve net-zero by 2050. COP29 further emphasised the critical importance of financing the energy transition and the need for public-private partnerships. To align with these global commitments, Thailand must adopt a coherent mid-term transition strategy particularly in the power sector. This will be crucial to ensuring the success of its long-term pathways to net-zero, while also providing an important opportunity to build a more resilient economy.

However, concerns exist regarding the alignment of current energy plans with Thailand's climate goals. Specifically, the current draft PDP and Gas Plans 2024 appear misaligned with the Long-Term Low Greenhouse Gas Emission Development Strategy (LT-LEDS) submitted to the United Nations Framework Convention on Climate Change (UNFCCC). These energy plans indicate that Thailand is likely to maintain high natural gas demand (i.e., keeping natural gas share at 41% of electricity generation mix by 2037) on its path to carbon neutrality. This high reliance on gas in the power sector may not be aligned with the recommendations of Thailand's revised LT-LEDS and other carbon-neutrality studies, which suggest reaching a natural gas share of less than 20% by 2050 to meet carbon neutrality. In addition, academia, private sector associations and civil society organisations have raised concerns about the significant economic risks associated with these energy plans underlined that they may not be sufficient to facilitate the transition needed to achieve carbon neutrality by 2050. They recommend that the planning horizon for these plans be extended beyond 2037 to provide a complete policy roadmap towards 2050.

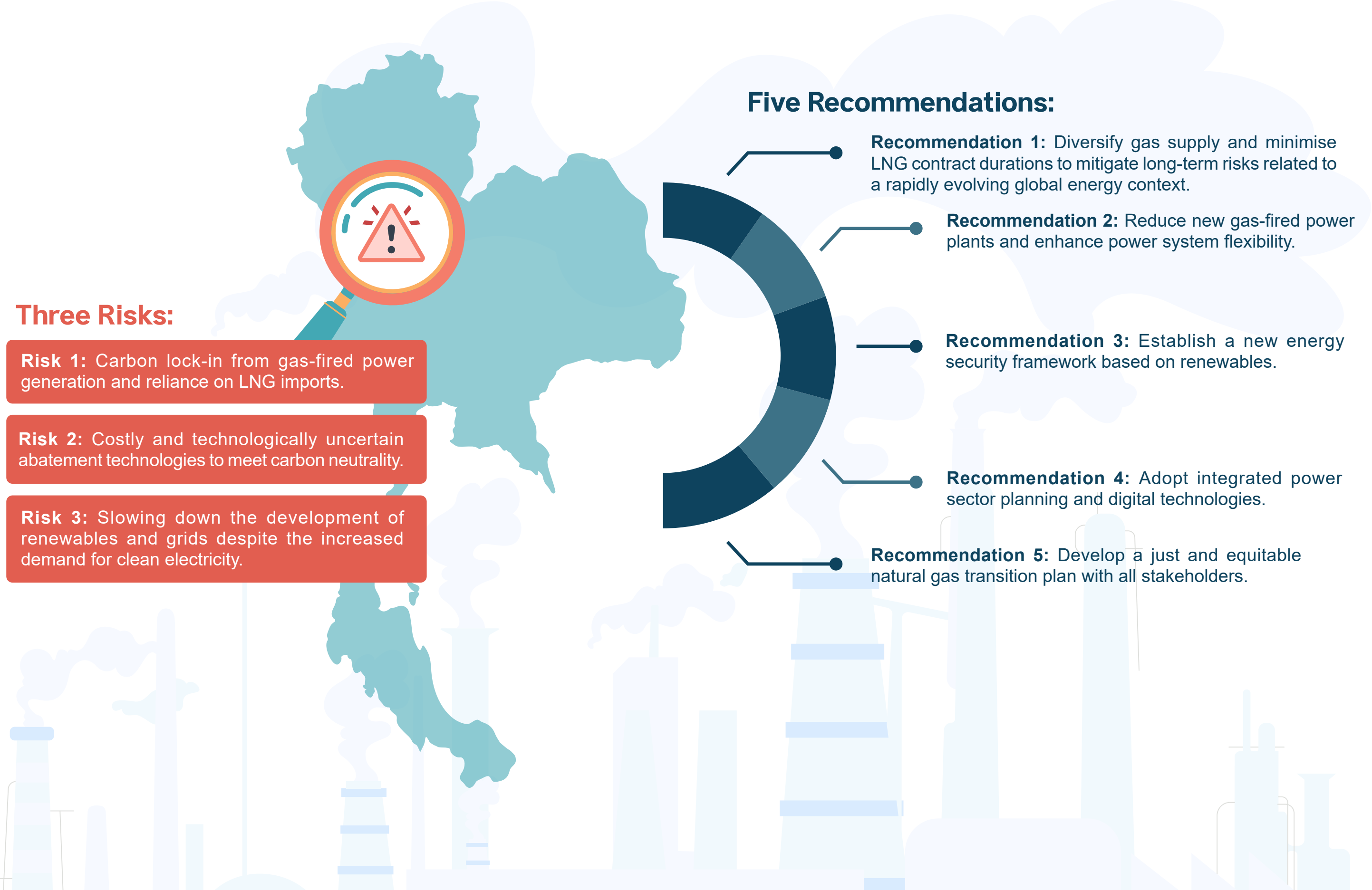
Uncertain Enabling Factors and Potential Risks

Despite these apparent inconsistencies, some stakeholders argue that a high natural gas demand pathway could still be compatible with climate targets, contingent upon the realisation of several key but uncertain enabling factors. Identified through stakeholder interviews, these factors include the expectations of sustained low gas prices, coupled with the economic feasibility of hydrogen and carbon capture and storage (CCS) technologies and increased domestic gas supply from a successful resolution of the Overlapping Claims Area (OCA) with Cambodia. While these enabling factors could enhance the short-term economic returns on existing fossil-fuel infrastructure, they may also pose substantial mid to long-term economic risks.

Objective of This Report

This report assesses the key risks associated with a high natural gas demand pathway, as outlined in the draft national energy action plans, and discusses potential risk mitigation strategies. It builds on exchanges with stakeholders and aims at fostering a policy debate on potential risks, implications for gas industry players, and the impact on Thailand's long-term goals. This report is intended to provide a foundation for further discussion on the transition of the gas sector in Thailand's path to carbon neutrality.

The report highlights three major risks of maintaining high natural gas demand pathway in the power sector and proposes five key recommendations to mitigate those risks and facilitate the gas sector's transition in line with long-term development objectives.



Three Risks:

Strong natural gas reliance for power generation poses risks of insecure supply, high costs, environmental impacts and technological uncertainties.

Risk 1: Carbon lock-in from gas-fired power generation and reliance on LNG imports.

For four decades, natural gas extracted in Thailand has been a source of energy security and low-cost electricity for Thailand. Consequently, Thailand has established a large portfolio of long-term power purchase agreements (PPAs) with gas-fired generators. In 2024, 60% of all installed power generation capacity (corresponding to 33.1 Gigawatts (GW)) were gas-fired power plants covered by long-term PPAs. In addition, the country plans to add 6.3 GW of new gas-fired power plants according to the recent draft energy plans.

However, the expansion of gas-fired power generation under the existing PPAs contract structure risks locking in carbon-intensive infrastructure for the next 20 to 25 years. The PPAs and gas supply contracts – designed to mitigate risks for producers – could ultimately become a significant financial burden on consumers and have a lasting negative impact on rising electricity tariffs. An expansion of the natural gas infrastructure would also likely delay the deployment of renewables, while increasing Thailand's reliance on imported liquefied natural gas (LNG) as domestic gas production continues to decline. Long-term projections of LNG prices are increasingly uncertain, in part due to geopolitical conflicts and trade tensions. Since Thailand's electricity price pass-through mechanism shifts rising LNG costs to consumers, unexpected spikes in international gas prices could exacerbate the financial pressure on Thailand's state-owned utilities, as well as on Thailand's end-consumers, as seen since mid-2021.

Risk 2: Costly and technologically uncertain abatement technologies to meet carbon neutrality.

The production and consumption of natural gas emits greenhouse gases (GHGs) all along the value chain. Currently, Thailand emits about 51.8 million tonnes of CO_2 ($MtCO_2$) from using natural gas in the power sector and 19.7 $MtCO_2$ from the industrial sector. This corresponds to 401 gCO_2 for generating one kilowatt-hour (kWh) of electricity, an emission level slightly below Vietnam (471 gCO_2 per kWh, despite a share of coal that is significantly lower in Thailand).

The current draft energy plans project natural gas demand at 4 747 million standard cubic feet per day (MMSCFD) in 2037, which is the same level as today. That means GHGs from natural gas are not likely to decline much by 2037. To reach net-zero, those emissions would need to

Three Risks:

be abated either at the source (e.g., through the production of Hydrogen) or at the power plant level through carbon capture, utilisation and storage (CCUS). These abating technologies are still immature and costly and are bound to technical constraints that limit capture rates below 100%. Effectively, additional carbon sinks would be required to compensate for the remaining emissions. A long-term pathway relying on high gas demand with CCUS technology is therefore likely to increase the cost of electricity generation and risks falling short of carbon neutrality targets because of the remaining emissions that may not be compensated by sufficient carbon sinks by 2050. This would increase the risk of carbon lock-in.

Risk 3: Slowing down the development of renewables and grids despite the increased demand for clean electricity.

Low-carbon technologies, such as solar and wind power combined with battery storage, already have the technological maturity to decarbonise the power sector at lower costs. In addition, low-carbon electricity is a cost-efficient enabler for decarbonising applications in transport and industrial sectors through direct electrification (e.g., electric vehicles and electrified heat). A strong reliance on gas in the power sector would therefore limit the decarbonisation potential through electrification and put more pressure on other sectors to decarbonise at a potentially higher cost. Faster development of renewable-based electrification would reinforce industrial competitiveness. It would meet internal demand for green electricity (e.g., corporations committing to purchasing 100% renewable electricity) and external demand (e.g., demand for green industry products, through international regulation such as the Carbon Border Adjustment Mechanism (CBAM) implemented in the EU).

According to current plans, however, Thailand aims at reaching a share of less than 8% of utility-scale solar and wind power in the electricity generation mix by 2030, which is significantly lower than the anticipated world average of 30% at this time horizon. The plans also focus on the development of distributed energy resources including rooftop solar and vehicle-to-grid systems, but without concrete targets. New capacity additions of large utility-scale solar and wind power (i.e., 23.6 GW of solar and 5.3 GW of wind) is expected between 2031 and 2037, which is not synchronised with the need to rapidly scale up new demands for clean electricity before 2030. Planning low renewables development in the mid-term would also delay the need for new grid and battery infrastructure, ultimately also slowing down further renewables development efforts.

Potential adverse impacts of high gas demand pathways on the energy trilemma goals

Risk Factors	*Energy Security*	*Energy Equity*	*Environmental Sustainability*
Risk 1: Carbon lock-in from gas-fired power generation and reliance on LNG imports	• Less diversified energy sources and electricity generation • Insecure gas supply with increasing import dependency • Insecure domestic gas supply with reliance on new national gas resources to be explored on overlapping claims area	• High electricity tariffs from lock-in gas-fired power contracts and exposure to volatile LNG prices • Fewer opportunities for cheaper renewables and unfair market participation in electricity sector • High stranded asset costs of gas infrastructure expansion embedded in electricity tariffs	• CO_2 and methane emissions • High electricity grid-emission factor • Impacts of LNG terminals and gas leakage on biodiversity • Air pollution from gas power plants
Risk 2: Costly and technologically uncertain abatement technologies to meet carbon neutrality	• Increased carbon lock-in with dependence on natural gas value chain • Less adoption of renewables in the electricity generation mix	• Likely increased electricity tariff through the reliance on currently immature and costly abatement technology options such as hydrogen and CCUS • Third-party acceptance and societal impacts and costs of abatement technologies • New skill development needed for hydrogen and CCUS • Unequal benefits of abating technologies	• CO_2 emissions and leakage from abatement technologies • Infeasible pathway to achieve carbon neutrality and net-zero pledges
Risk 3: Slowing down the development of renewables and grids despite the increased demand for clean electricity	• Insufficient supply of renewable electricity to meet increasing demand for clean electricity • Lack of adequate planning for energy storage, advanced grid infrastructure and smart technologies • Inability to leverage the resilience advantage of distributed energy resources	• Clean electricity available at more expensive cost • Negative impact on industry competitiveness • Unequal access to clean electricity, disproportionately affecting low-income households and small businesses • Less access to mitigation funds	• Inefficient development of transmission and distribution system to accommodate higher renewable electricity • Limit deeper decarbonisation options needed to achieve climate commitments through electrification

Five Recommendations:

To align with Thailand's carbon-neutral goals and mitigate the risks from a strong reliance on natural gas, a set of holistic measures are required for phasing down from natural gas in a timely, just and equitable manner.

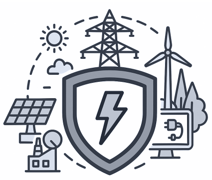
Recommendation 1: Diversify gas supply and minimise LNG contract durations to mitigate long-term risks related to a rapidly evolving global energy context.

To build a more resilient energy supply, Thailand should pursue a diversification strategy, given the rapidly evolving energy landscape, characterised by a global increase in renewable energy and the geopolitical risks that impact energy prices. The projected sharp increase in global LNG export capacity over the coming years, led by the United States, will apply downward pressure on prices. However, significant variations in delivered costs are anticipated across different projects, with several requiring price levels that may be unappealing to emerging economies to recover investment and operation costs. In the short- to mid-term, as Thailand's exposure to LNG imports rises, priority should be given to diversifying suppliers and establishing a balanced portfolio of contracts of various durations (e.g., long, short and spot contracts). This would mitigate economic and carbon lock-in risks. In addition, joint purchasing initiatives between PTT Public Company Limited, Thailand's state-owned energy company, and other LNG shippers could leverage bargaining power to reduce LNG import prices. However, regulatory measures to reduce monopoly power by existing market players are also needed. Pursuing new sources of domestic gas production such as under the OCA with Cambodia could, in principle, increase gas supply security. However, this strategy is bound to several economic uncertainties, would not solve any mid-term supply constraints, and would come with a risk of locking-in investments and stranded assets.

Five Recommendations:

Recommendation 2: Reduce new gas-fired power plants and enhance power system flexibility.

Reducing both existing and new gas-fired power contracts can help mitigate carbon lock-in and avoid an expensive pathway to carbon neutrality. This includes deferring investments in 6.3 GW of new gas-fired power plants scheduled between 2028 and 2037 and replacing them with increased renewable capacity, as outlined in the PDP 2024. Baseload generation is incompatible with a modern, renewables-based power system and would significantly raise electricity supply costs. Given Thailand's already high reserve margin (about 50% of contractual capacity,) accelerating renewable deployment would be more cost-effective and prevent long-term gas contracts lock-in. Renegotiating existing gas-fired PPAs and gas supply contracts, in alignment with renewable expansion, would further reduce gas supply costs and improve power system flexibility. This could be achieved by adjusting current take-or-pay requirements, lowering minimum off-take volumes, and instead compensating for flexibility and other ancillary services. Enhancing gas power plant flexibility would also strengthen grid resilience by providing rapid-response capabilities and backup power for a modern renewables-based power system. A new system adequacy paradigm, supported by contractual arrangements for strategic reserves and the promotion of capability requirements, rather than firm capacity, could significantly reduce reliance on gas peaking plants and additional gas-fired capacity while facilitating the integration of variable renewable energy sources.



Recommendation 3: Establish a new energy security framework based on renewables.

Renewables are cheap domestic resources that reduce fossil-fuel dependency and enhance energy security. Harvesting national renewable power generation requires the establishment of a new supply security framework, based on power system flexibility and advanced grid planning. The deployment of solar PV and wind capacity should be synchronised with the transformation of the existing power system infrastructure. New investments in flexibility options, such as grids and energy storage, must be incentivised, and new operational and planning practices must be adopted to leverage the potential of flexible generation and flexible demand. Renewable targets and incentives for distributed energy resources such as rooftop solar, distributed storage and smart electric vehicle (EV) charging should be proactively planned and promoted as low-cost domestic supply and demand-side flexibility options. Policies should promote advanced grid infrastructure, smart technologies to ensure system stability, and electricity market reforms (e.g., a more dynamic time-based tariff for grid reliability) to ensure a cost-effective and reliable modernisation of the power system.

Five Recommendations:

Recommendation 4: Adopt integrated power sector planning and digital technologies.

Integrated power sector planning should be adopted to ensure a cost-optimal transition to carbon neutrality, considering the increasing electrification of the transport and industrial sectors (e.g., more electric vehicles and heat pumps) and the economics of distributed energy resources (e.g., distributed PV and battery energy storage) to meet the growing demand for clean electricity. A more dynamic interaction between transmission and distribution grid utilities will be critical to better integrate demand response, distributed generation, battery storage and EV solutions for the benefit of the power system. Digital technologies (e.g., smart charging technologies, real-time data from smart meters) and smart regulations (e.g., time-varying tariffs) will unlock the potential of all flexibility options, particularly demand response from the commercial and industrial sectors, as well as reduce peak loads and provide system services to balance the grid.

Recommendation 5: Develop a just and equitable natural gas transition plan with all stakeholders.

Despite the gas sector's economic importance, Thailand lacks a gas transition plan, increasing the risk of over-investment in gas-related activities that conflict with carbon neutrality goals. This could lead to high costs of stranded assets, and insufficient preparation for a just transition. A comprehensive natural gas transition plan should set clear targets for reducing gas demand in both the power and industrial sectors, while defining transition strategies to mitigate economic and workforce impacts. In addition, completing sector liberalisation, as well as adjusting the gas and electricity tariff structure, could facilitate and economically support the transition role of natural gas, increasing market participation in the energy sector and ensure fair risks and costs pass-through to consumers. A new regulatory and market structure would help align incentives and ensure a fair and transparent transition to further integration of renewable capacity in the power sector.

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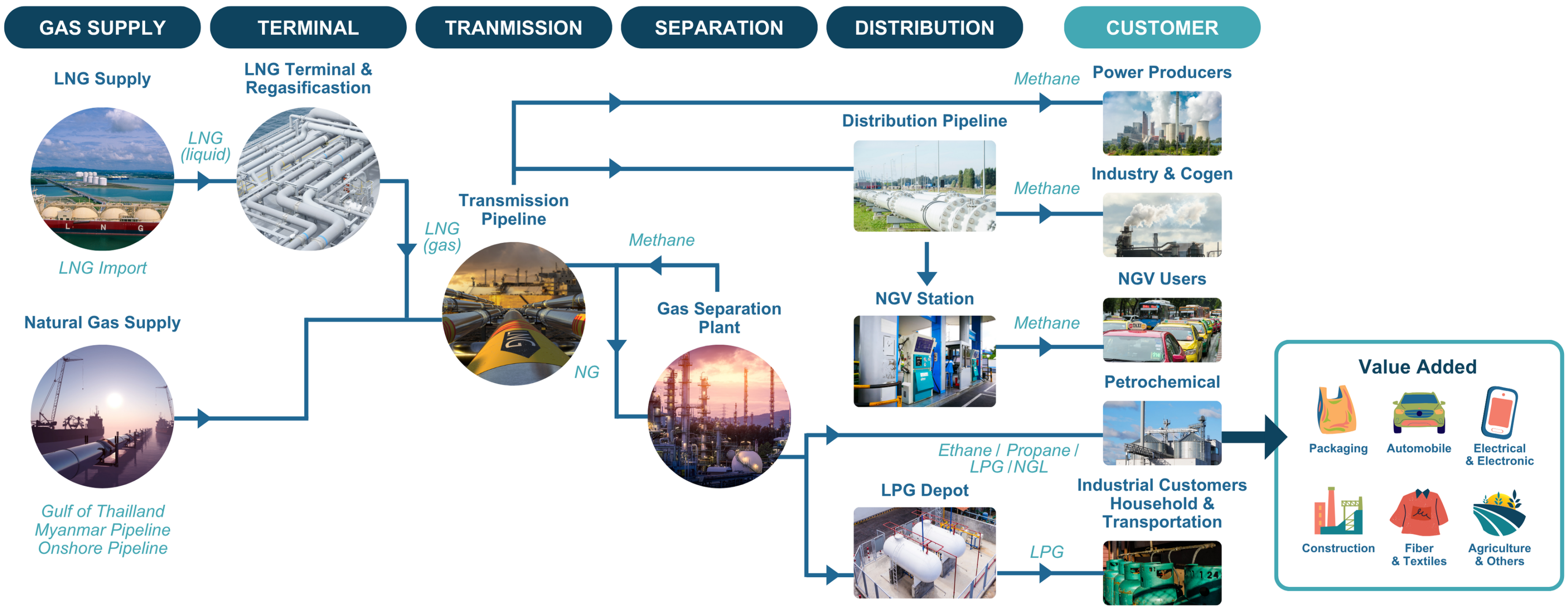
1. INTRODUCTION

A. Natural gas has played a vital role in Thailand's energy independence, but the global drive for decarbonization now poses challenges to its energy landscape and economic competitiveness.

Driven by the 1970s global oil crises, Thailand sought to reduce its reliance on imported oil and achieve greater energy security (Tisdale, 1996). This drive led to the 1981 discovery of natural gas in the Gulf of Thailand for its first use for electricity generation (EGAT, 2021). Natural gas rapidly became the dominant fuel for power generation, fuelled by further discoveries and development in the Gulf of Thailand and the Malaysia-Thailand Joint Development Area (ANGEA, 2024). Beyond electricity, natural gas offered Thailand a reliable and domestically sourced fuel to support rapid industrial growth and added value to the petrochemical sector (Stithit, 2021). Historically, Thailand's grid emissions were comparable to those of Japan and South Korea (Carbon Footprint, 2022). However, growing global pressure for decarbonisation now challenges the long-term role of natural gas and raises questions about viability and economic competitiveness.

Thailand’s Gas Value Chain



B. Continuing to rely on natural gas at the current levels poses challenges for Thailand's carbon neutrality goals.

One of the most critical challenges facing the reliance on natural gas towards carbon neutrality goals is the need to significantly reduce greenhouse gas (GHG) emissions from the natural gas value chain. This includes the process of exploration, production, transportation, storage, and distribution of natural gas which emit carbon dioxide (CO_2) and methane (CH_4).

Thailand has pledged to achieve carbon neutrality by 2050 and net-zero emissions by 2065, implying that Thailand will need to reduce CO_2 emissions from its current annual level of 247.7 million tonnes of CO_2 ($MtCO_2$) in 2022 (EPPO, 2024a) to less than 95 $MtCO_2$ (estimated carbon sink allocated to the energy sector out of total 120 $MtCO_2$ capacity) by 2050 (MONRE, 2022).

While natural gas is a cleaner fuel compared to oil and coal, it is still the main source of CO_2 emissions in the Thai energy sector. In 2022, natural gas emitted 30% of total CO_2 emissions from the Thai energy sector (about 74.1 $MtCO_2$) (EPPO, 2024a). Natural gas emits 51.8 $MtCO_2$ from electricity generation and 20 $MtCO_2$ from the industrial sector. The emissions from the natural gas value chain present significant challenges for the cost and feasibility of achieving climate targets for Thailand.

C. Natural gas once provided low-cost electricity in Thailand, but today's reliance on LNG imports risks high electricity tariffs driven by insecure supply and volatile LNG prices.

Natural gas has been a source of low-cost electricity in Thailand for more than four decades, thanks to large domestic gas resources from the Gulf of Thailand. As domestic gas production has declined due to resource depletion, Thailand's electricity generation relies more on the import of liquefied natural gas (LNG) and Thailand is vulnerable to high electricity costs from the volatile global LNG market.

Declining domestic natural gas production and the high prices of imported LNG significantly contributed to a record-high electricity price of 4.72 baht per kilowatt hour (kWh) in 2022, compared to the previous record-high of 3.96 baht in 2014 (Praiwan, 2022). The Russian-Ukraine crisis in recent years has contributed to skyrocketing LNG prices. To recover these costs, the Thai state-owned utility Electricity Generating Authority of Thailand (EGAT) has imposed higher electricity tariffs in order to pay off accumulating debts of about 100 000 million baht, as of August 2024 (ERC, 2024b). To clear this debt by the end of December 2024, the electricity tariff was expected to rise by 44% to 6.02 baht per unit in the last four months of 2024 (See Annex 1). This trend is expected to drive volatility in future electricity tariffs, as global geopolitical factors increasingly affect LNG imports needed to fulfil minimum off-take obligations in power purchase contracts.

Thailand's current energy plans depend on LNG imports and potential new gas sources for more than half of the natural gas supply, which will consequently raise concerns of insecure gas supply and high electricity tariffs due to fluctuating LNG import prices.

D. Reducing natural gas demand is key to Thailand's carbon neutrality and mitigating risks of supply insecurity and high LNG import cost.

Policy changes to reduce gas-fired power generation will significantly lower carbon emissions in the electricity sector and decrease reliance on imported LNG, as natural gas-fired power plants account for most of the natural gas in Thailand.

In 2023, 62% of daily natural gas use was for electricity generation (EPPO, 2024a). Reducing natural gas demand in electricity generation would reduce CO_2 emissions directly from power generation and its supply chain. Additionally, a cleaner electricity grid will also strengthen decarbonisation efforts in the transport and industrial sectors. This includes replacing oil with electric vehicles powered by cleaner electricity and transitioning from industrial fossil fuel-based heating to heat pumps or electric boilers.

Multiple energy scenario models (see Annex 2) indicate that for Thailand to achieve carbon neutrality, the share of natural gas in electricity generation must drop below 20% by 2050, down from 59% in 2023. However, the draft Power Development Plan (PDP 2024) projects that natural gas will still account for 41% of electricity generation by 2037. Under this plan, total natural gas demand for power generation is estimated at 2,824 MMSCFD in 2037, which is slightly higher than in 2023 (EPPO, 2024a).

While reducing the share of natural gas in electricity generation is crucial for carbon neutrality, there is no clear strategy on when and how this transition will occur. It also remains uncertain how Thailand will reduce the gas share to less than 20% by 2050 and what role natural gas will play from 2037 onwards in supporting carbon neutrality.

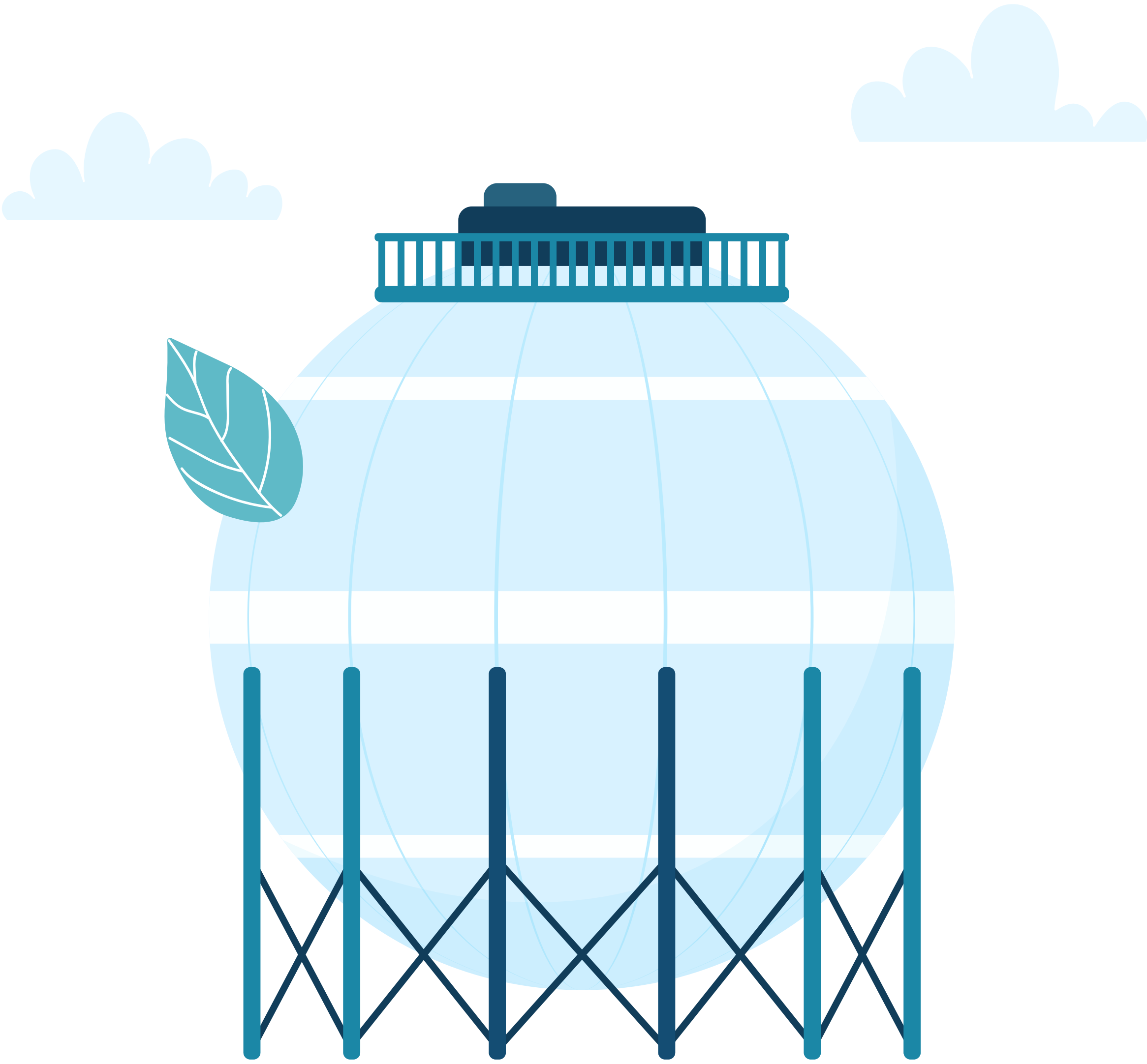
E. Transforming natural gas is essential to achieving the energy trilemma goals: energy security, energy equity and environmental sustainability.

Thailand has benefited from the use of natural gas for several decades that have helped the country meet all energy trilemma goals: ensuring reliable and secure energy, providing low-cost and affordable electricity and reducing the use of oil and coal in the energy sector. However, without redefining the role of natural gas, its continued use as energy security could lead to adverse impacts on energy equity and environmental sustainability goals in the long term. The risks stem from increasing dependence on LNG imports and high GHG emissions across the natural gas supply chain. Fluctuating LNG prices could also exacerbate energy costs, strain potential government subsidies, and disrupt LNG trade flows.

Thailand has prioritised energy security in policies and discussions on the role of natural gas, leading to a high-demand pathway reflected in the draft PDP 2024 and Gas Plan 2024. However, maintaining natural gas demand for electricity generation at current levels over the next 13 years is likely to negatively impact all three dimensions of the energy trilemma in the long term.

F. This report highlights the risks of high natural gas demand on the path to carbon neutrality, the potential impacts of risks on energy trilemma goals and potential risk mitigation strategies.

This report aims to foster a policy debate on the potential risks associated with high natural gas demand in the power sector in the draft energy plans (2024) and potential risk mitigation strategies to reduce negative impacts on the energy trilemma goals. Section 2 of this report provides snapshots of the natural gas industry landscape and analyses the risks associated with the draft energy plans through the lens of risk impacts on the energy trilemma in Section 3. Section 4 explores potential risk mitigation strategies and discusses the role of natural gas towards carbon neutrality, including the challenges of an LNG trading hub. Implications for gas industry players are discussed in Section 5 and policy suggestions are summarised in Section 6.

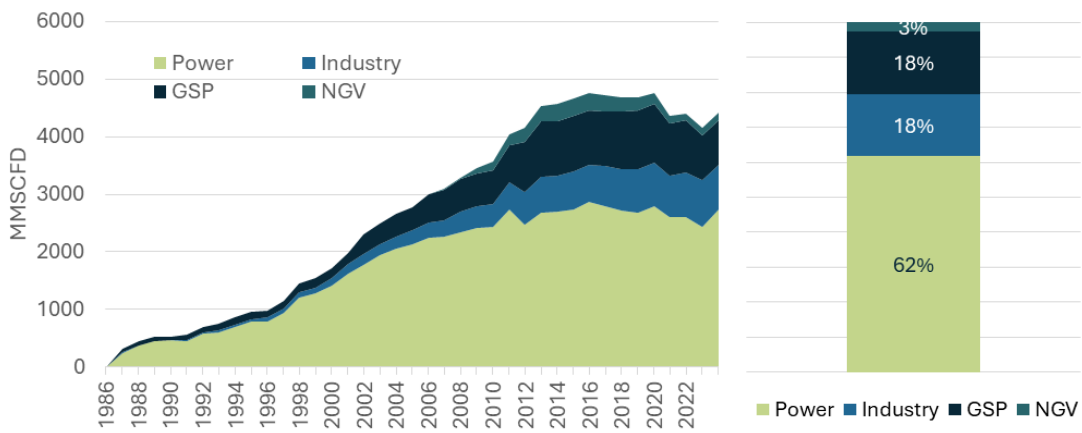


2. THAILAND'S NATURAL GAS INDUSTRY LANDSCAPE

2.1 Natural gas demand

The demand for natural gas in Thailand mainly comes from electricity generation (62%), followed by the petrochemical (18%) and industrial sectors (18%).

Natural gas demand in Thailand, 1986 - 2023



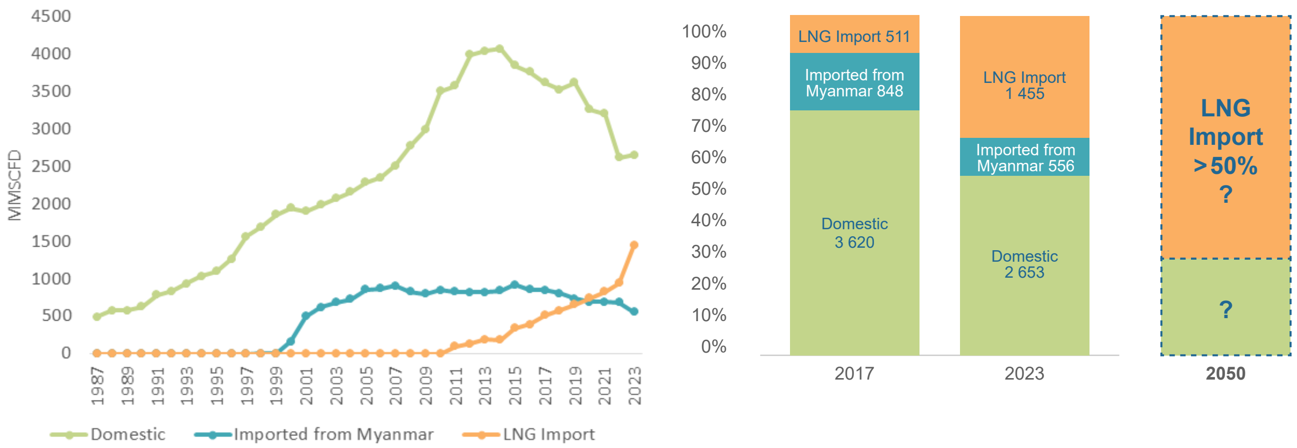
Source: (EPPO, 2024b)

As commercial renewable energy technologies become more available, natural gas demand in electricity generation is expected to decline on the pathway towards carbon neutrality. However, decarbonisation options for the industrial sector and petrochemicals are less mature and more costly in comparison to the electricity sector.

2.2 Natural gas supply

Thailand has benefited from a domestic natural gas supply for more than 40 years, but it has declined in the past decade due to the depletion of resources. In 2023, domestic production accounted for 57% of total natural gas supply of 4 664 MMSCFD. The LNG import share tripled from 10% in 2017 to 31% (or 11.5 million tonnes of LNG) in 2023.

Natural gas supply in Thailand, 1986 - 2023



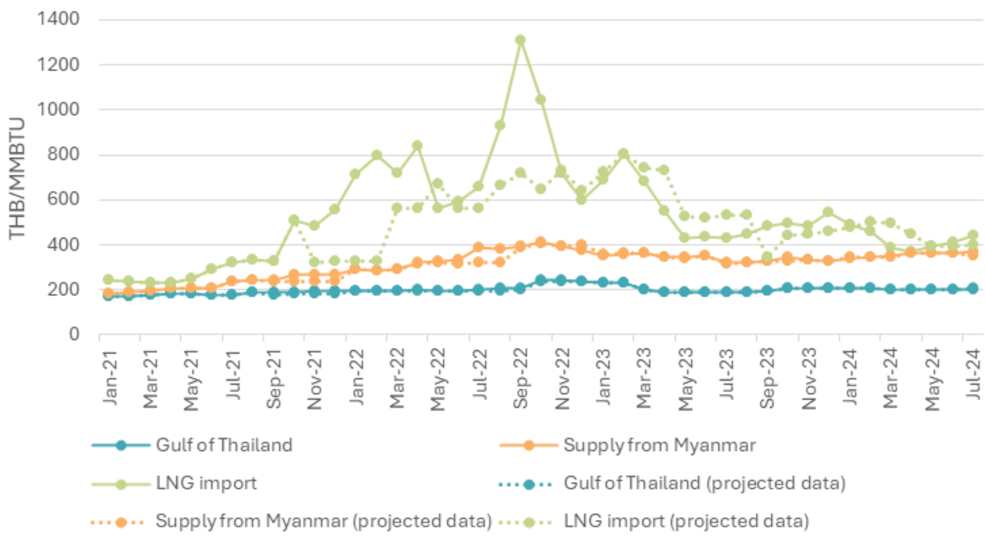
Source: (EPPO, 2024b)

Without new discovery of domestic gas and extended imported gas supply contracts from Myanmar, Thailand is expected to increasingly rely on LNG imports to meet future energy demand, which could threaten energy security from an insecure gas supply and increase exposure to volatile LNG prices.

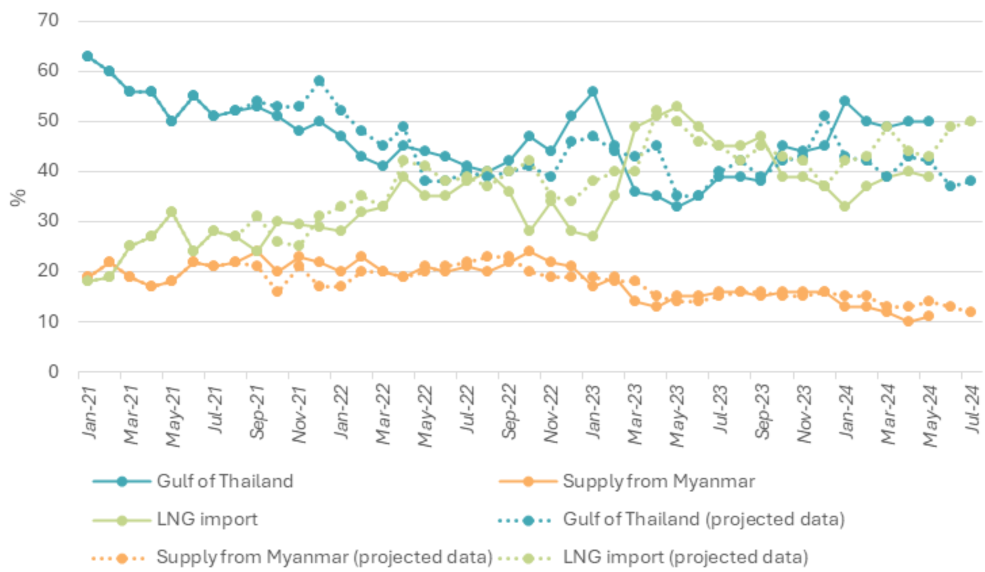
2.3 Natural gas prices

Natural gas prices in Thailand were historically low and stable; however, a decline in domestic gas production and more reliance of LNG imports have significantly raised Thailand's gas prices. The surge in LNG import prices following Russia's war against Ukraine has also contributed.

Natural gas prices in Thailand, January 2021 - July 2024 (in million BTU compared to projected data)



Actual natural gas supply in Thailand (compared to planned data)



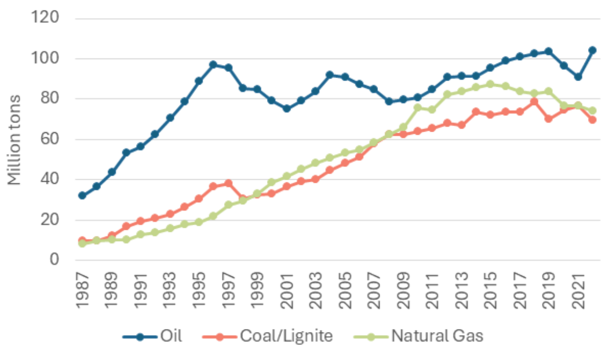
Source: (EPPO, 2024b)

Due to a declining domestic gas supply and higher reliance on LNG imports, the gas pool price passed through to electricity cost is expected to be volatile in the future. This stems from LNG import costs that are vulnerable to uncontrollable external and global geopolitical factors.

2.4 Natural gas emissions

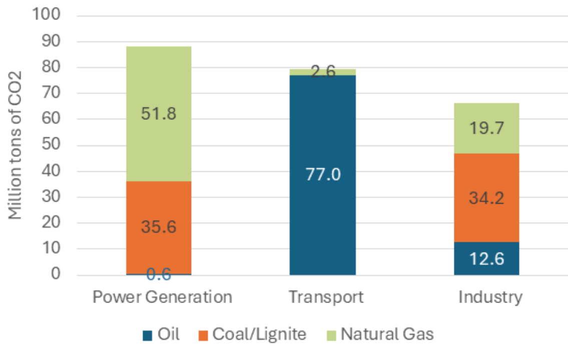
Besides oil and coal, natural gas is one of the main sources of CO_2 emissions in the energy sector. In 2022, Thailand emitted 247.7 $MtCO_2$, where 74.1 million tonnes are from natural gas or 30% of the total (51.8 from electricity generation and 20 from the industrial sector).

CO_2 emissions by energy type in Thailand, 1987 - 2022



Source: (EPPO, 2024b)

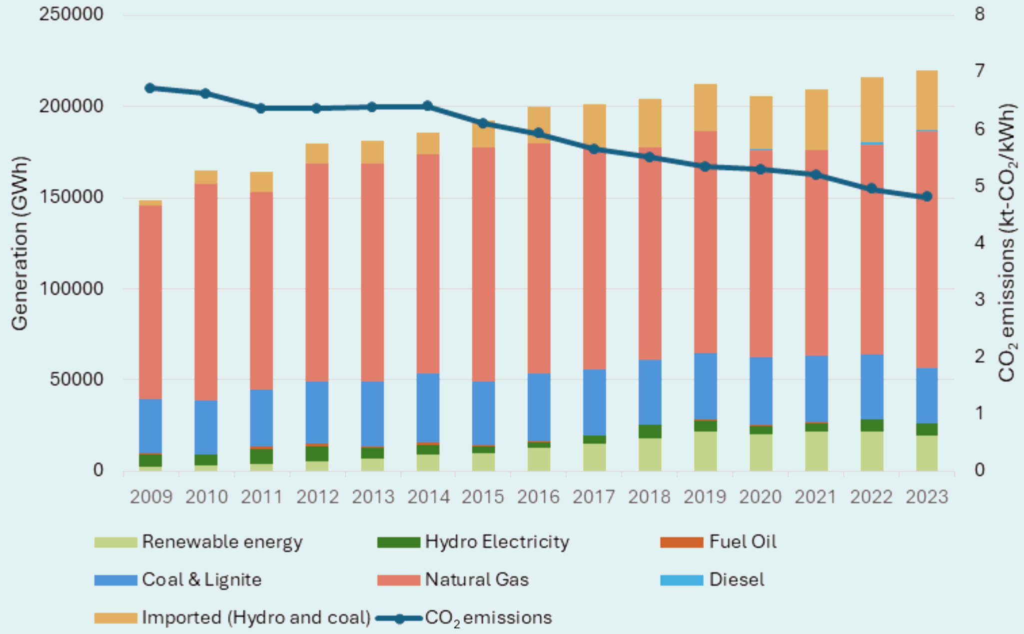
CO_2 emissions from energy sector in 2022, total 248 $MtCO_2$



Source: (EPPO, 2024b)

Thailand would incur high costs for abatement technologies for the use of natural gas in the long term. Also, a high share of natural gas in electricity generation reduces the benefits of decarbonisation through the electrification of transport and industrial sectors which have fewer available decarbonisation technology options.

CO_2 emissions per kWh and fuel mix of Thailand's generation



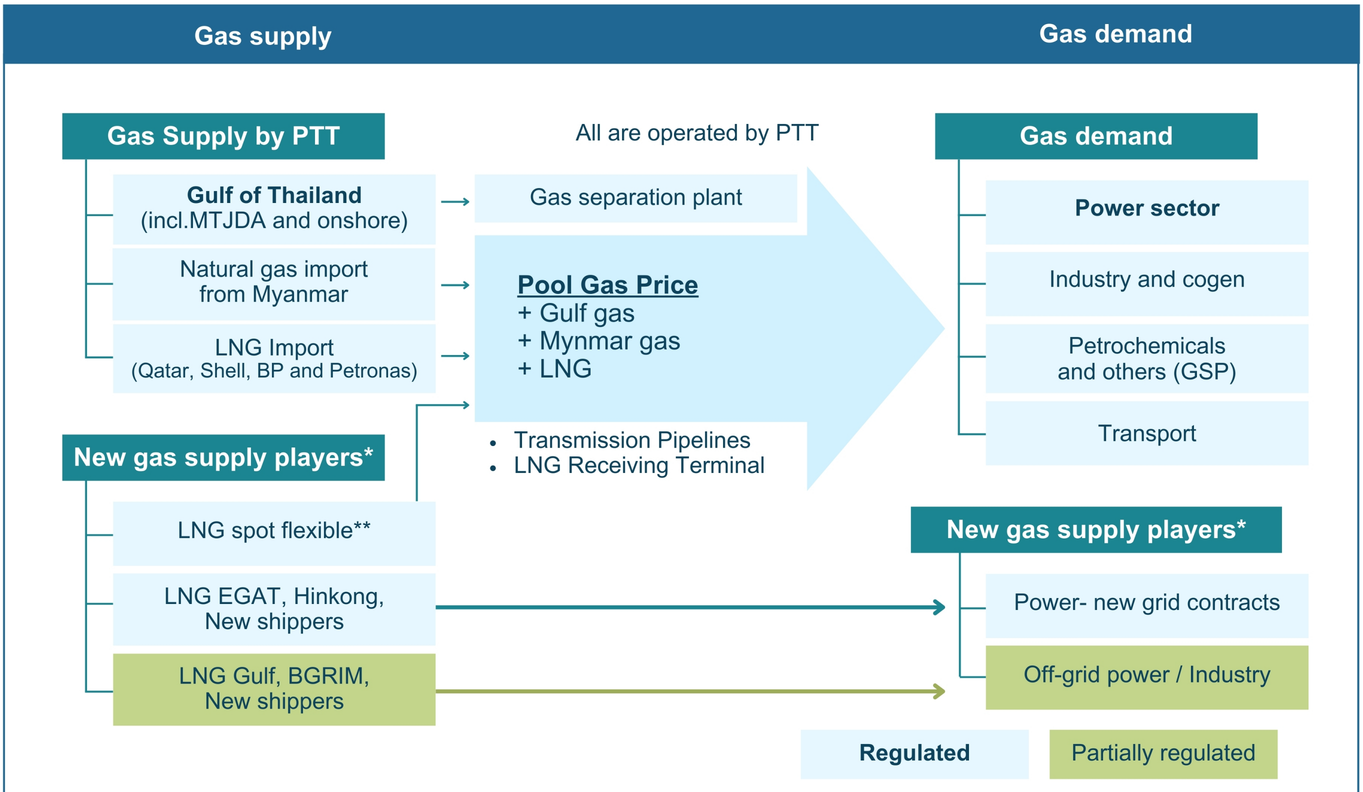
Source: (NEIC, 2023)

Thailand has consistently reduced its CO_2 emissions per kilowatt-hour (kWh) of electricity generated. This reduction is primarily due to a decrease in the proportion of coal in the energy mix, coupled with an increase in renewable energy sources. Whilst the share of natural gas has shown some fluctuations, it has slightly decreased in recent years. This trend reflects Thailand's efforts to diversify its energy portfolio and transition towards cleaner sources of electricity generation. However, the pace of change may not be quick enough to maintain economic competitiveness in a world rapidly transitioning to low-carbon technologies.

2.5 Regulatory and market structure

Thailand is liberalising its natural gas industry from the existing highly monopolised and regulated structure. Since 2021, eight new shippers have been awarded licences for LNG imports under Phase II of the natural gas liberalisation plan (See Annex 3). Meanwhile, other key players remain subject to strict regulations.

Thai Natural Gas Industry Structure



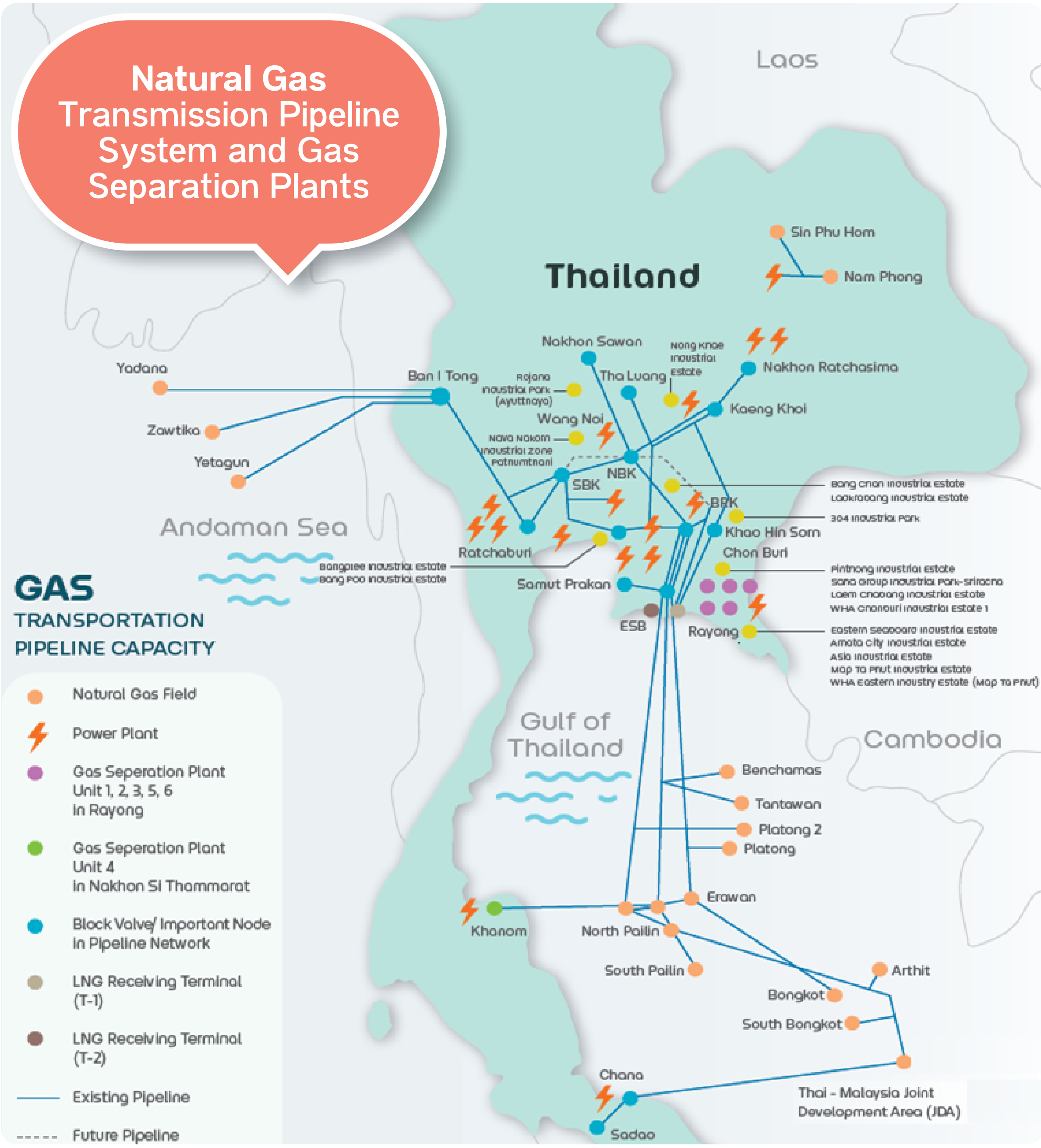
*8 new LNG shippers with granted licences (including PTT, EGAT, GULF, HKH, BGRIM, EGCO, PTTGL and SCG) under the liberalisation of gas industry Phase II

**PTT will open the bidding to procure spot LNG when the spot LNG price is lower than the pool price, regulated by ERC

Source: Illustrations from EPPO and PTT

2.6 Natural gas infrastructure

In Thailand, natural gas transmission pipeline systems (connecting gas production fields and LNG receiving terminals to distribute to power producers, gas separation plants and industries) are solely owned and operated by PTT Plc and regulated by Thailand's Energy Regulatory Commission (ERC). The transmission pipeline runs a total length of 4 750 kilometres. Currently, Thailand has two LNG Receiving Terminals in commercial operation (with a total LNG regasification capacity of 19 MTPA) at Map Ta Phut in Rayong. The LNG Receiving Terminal 3 Phase I is currently under construction with a capacity of 10.8 MTPA which will increase the total LNG capacity to about 29.8 MTPA in the future.



Source: (PTT, 2024)

3. ENERGY PLAN RISKS AND IMPACTS ON THE ENERGY TRILEMMA

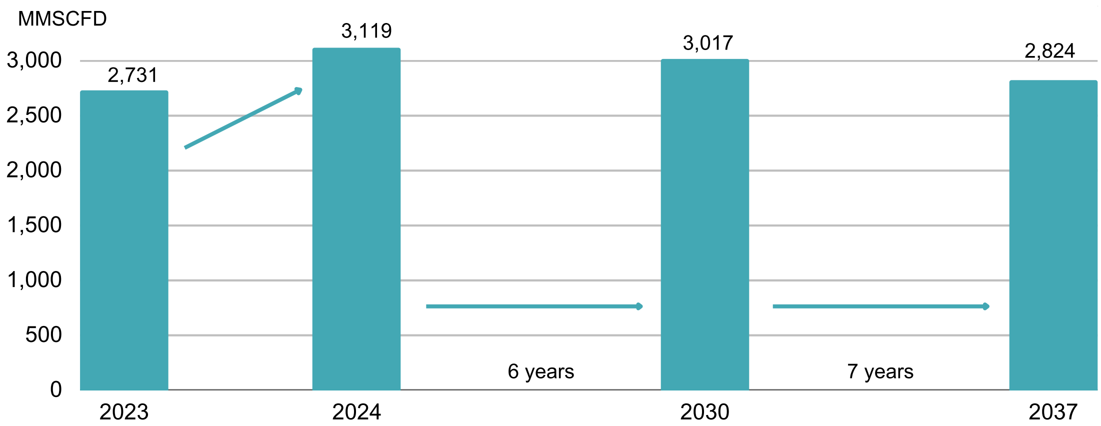
This section analyses critical risks associated with current energy plans and their potential negative impacts on the energy trilemma goals: energy security (such as import dependency); energy equity (such as fair and affordable electricity prices); and environmental sustainability (such as CO_2 and methane emission reductions or net-zero pledges) based on a framework described in Annex 4.

Thailand's energy strategy maintains a high reliance on natural gas on the pathway towards carbon neutrality but lacks a clear plan for its role in the final phase (2037 - 2050).

Following the draft PDP and Gas Plan (2024), natural gas is expected to play a dominant role in the electricity generation mix with a share of 41% of electricity generation by 2037 (EPPO, 2024a); meanwhile the share of renewable energy is targeted at 51% by 2037. Thailand plans to increase its gas-fired power generation capacity from 21 480 MW in 2023 to 27 780 MW in 2037 to meet projected electricity demand. Accordingly, natural gas demand for the electricity sector is expected to be 2 824 MMSCFD in 2037, the same level as today in the next 13 years. In addition, Thailand will need to rely more on LNG imports due to declining domestic gas production to meet demand from the electricity sector.

Furthermore, there is no estimated transition pathway for natural gas during the years 2037 to 2050 under the existing energy action plan. To reach carbon neutrality by 2050, Thailand would require sufficient abating technologies, e.g., hydrogen production at the source or carbon capture, utilisation and storage (CCUS) at the power plant level. Additional carbon sinks would be required to compensate for the remaining emissions to meet climate commitments.

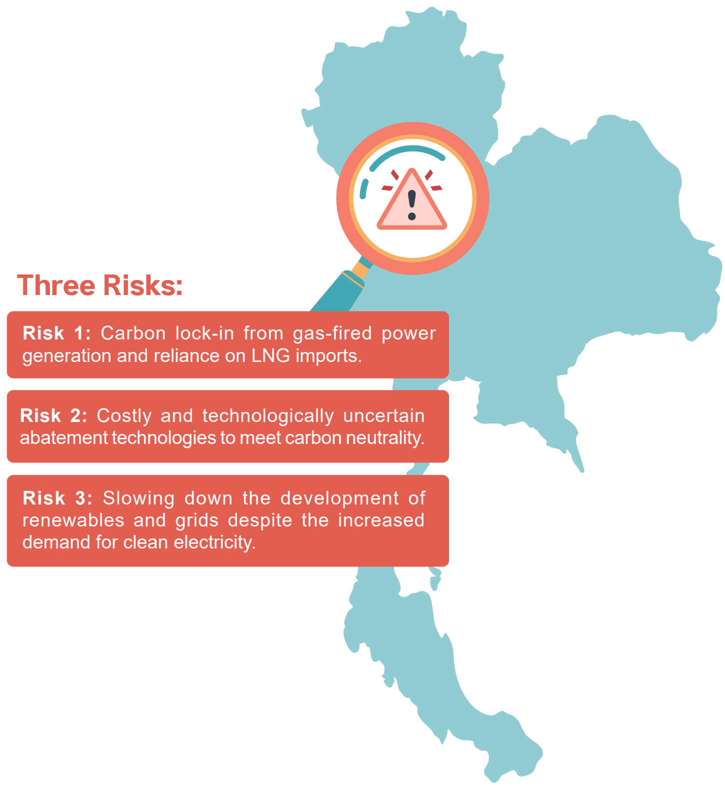
Natural gas demand from the electricity sector



Year	2023	2024	2030	2037
Gas installed capacity (MW)	31 330	33 128	29 542	27 780

Source: (EPPO, 2024a)

While current energy action plans aim to meet carbon neutrality with efforts prioritised to meet energy security needs, there are three potential critical risks associated with the plans currently under discussion (i.e., a high gas demand pathway) that could adversely affect all three energy trilemma goals.



Risk 1: Carbon lock-in from gas-fired power generation and reliance on LNG imports

Currently, gas-fired power generation makes up 58% of the country's electricity generation. As of 2024, Thailand has a contracted gas-fired capacity of 33 128 MW and plans to add newly contracted gas-fired power plants with an additional capacity of 6 300 MW from 2028 to 2037. These additional gas-fired power plants outlined in PDP 2024 will increase the risk of carbon lock-in and reliance on LNG imports to meet the demand of natural gas in the power sector.

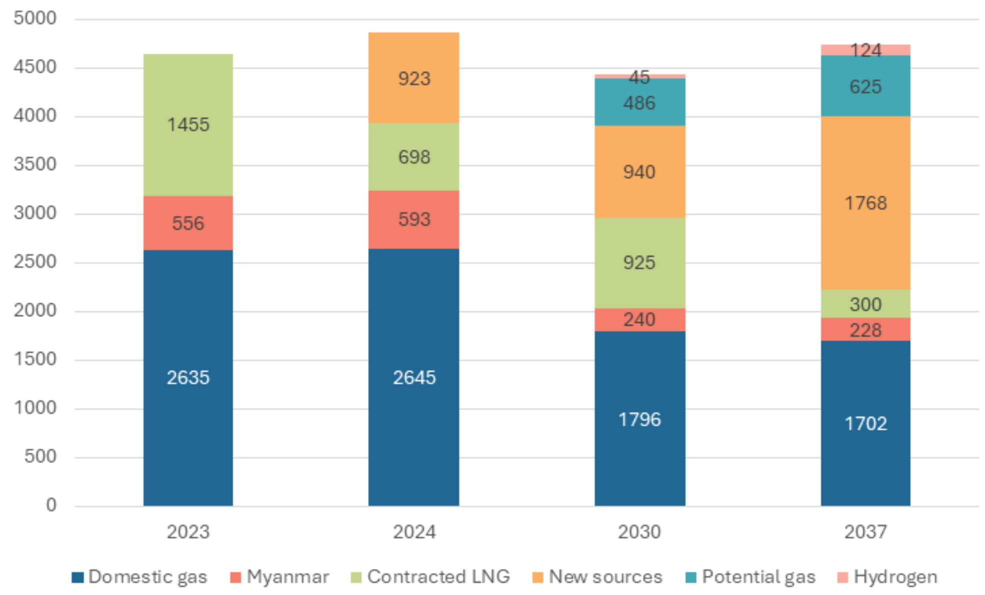
Increasing gas-fired power generation today poses significant risks of locking in carbon-intensive infrastructure and long-term financial burdens for tomorrow. Decisions made now will have lasting negative consequences on electricity tariffs. The planned expansion of gas-fired power plants will further lead to carbon lock-in PPAs and gas supply contracts in Thailand for the next 20-25 years. These long-term commitments to natural gas could delay the transition to renewables by reducing future capacity for renewable integration as minimum obligations for gas-fired capacity grow.

By 2030, the cost of solar photovoltaics (PV) and battery energy storage technologies, which have already reached the commercial operation level in terms of technology readiness, could drop rapidly and become more competitive with new gas-fired power plants (see Annex 5). A high reliance on locked-in gas capacity and infrastructure increases the risk of stranded assets making it more challenging to switch to cheaper renewables, follow a cost-optimal path, and curtail gas usage in the near and medium term.

Thailand's planned expansion of gas infrastructure

Types	*Existing capacity (Dec 2023)*	*Approved capacity*	*Revised PDP 2024*
Pipeline systems	4 570 kilometres	4 904 kilometres	Increase capacity for new gas-fired power plants
LNG terminal	19 million tonnes/year	29.8 million tonnes/year	31.8 million tonnes/year FSRU/LNG terminal 2 million tonnes/year
Gas separation plants	2 870 MMSCFD	2 910 MMSCFD	

Thailand's planned natural gas supply by source



Source: (EPPO, 2024c; EPPO, 2024d)

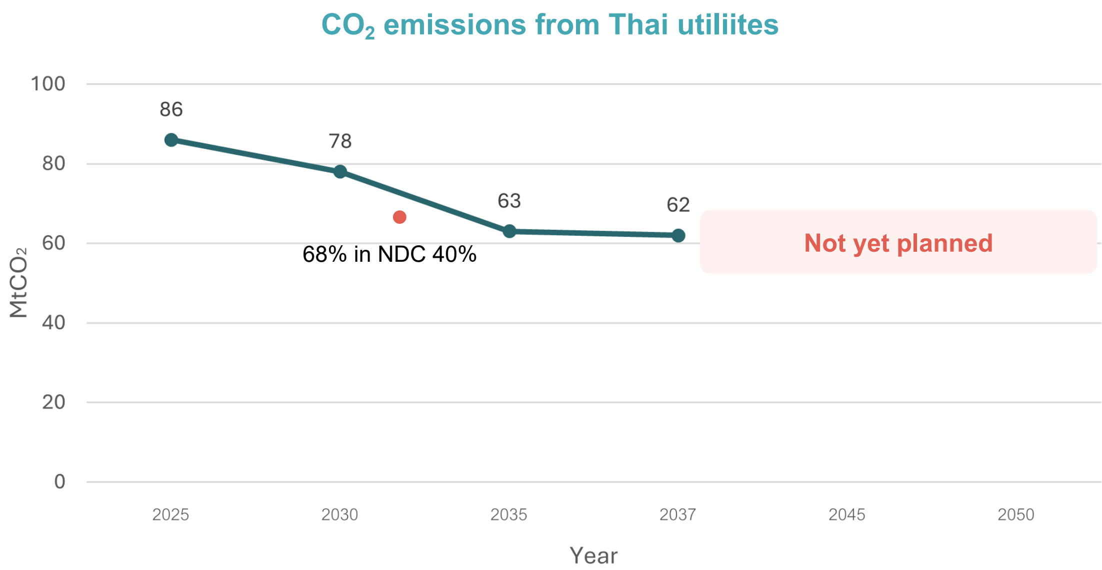
Thailand expects natural gas demand to be 4 747 MMSCFD in 2037, similar to today's levels. However, LNG imports are expected to increase significantly to meet demand, in order to offset declining domestic gas production. The share of natural gas supply from new sources and LNG imports is planned at 59% of supply in 2037, compared to 31% in 2023. Increased reliance on LNG imports exposes Thailand to the risk of volatile electricity tariffs due to fluctuations in global LNG prices. These fluctuations can be driven by uncertain market conditions and geopolitical events, as demonstrated by the 2022 energy crisis triggered by the Russia-Ukraine war, which significantly impacted LNG prices and contributed to rising electricity tariffs in Thailand.

The risks from carbon lock-in and reliance on LNG imports for gas-fired power generation could adversely affect the three energy trilemma goals as follows:

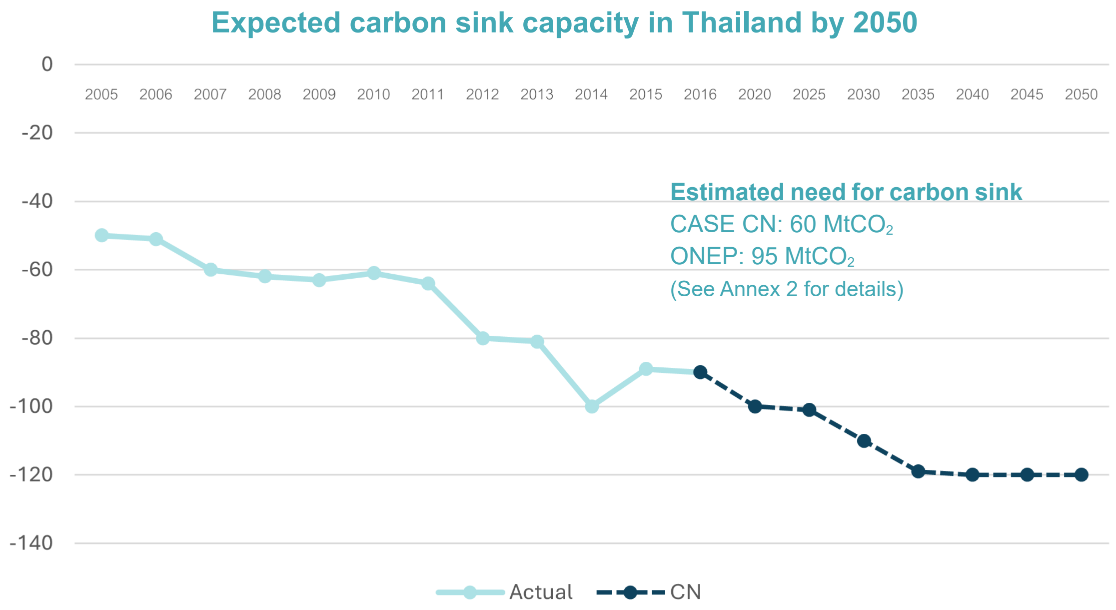
Energy Security	• **Reduced energy diversification from the** expansion of gas-fired generation with a 25-year PPA term and long-term gas supply contracts, delaying renewable energy deployment. • **An insecure natural gas supply with a high LNG import dependency:** A reduced gas supply from uncertain long-term global natural gas demand, supply chain disruptions and geopolitical risks would discourage investments in long-term natural gas supply and LNG-related infrastructure (EFI Foundation, 2024). • **Insecure domestic gas supply with reliance on new national gas resources:** Declining domestic gas reserves in Thailand and Myanmar create supply uncertainties. Many fields are in a post-plateau production phase, meaning they may no longer meet contracted delivery volumes. Additionally, disruptions in Myanmar further threaten supply reliability (PTT, 2024). Securing new national gas resources to be explored on overlapping claims area with Cambodia and Malaysia is also subject to high uncertainties.
Energy Equity	• **Higher electricity tariffs due to long-term gas contracts and exposure to volatile LNG prices.** The 2021 - 2023 price spikes from the Russia-Ukraine crisis revealed the financial risks, causing Thai electricity tariffs to surge by 44% in one quarter to repay accumulated LNG-related debt (100 billion baht) (ERC, 2024a). While LNG prices may decline in the short term due to falling global demand and increasing supply, risks remain from emission-related export costs and geopolitical disruptions that could cause unexpected price fluctuations. • **Limited market access for renewable energy** as renewable power producers could not equitably participate in the market and compete fairly with large gas-fired power producers who benefit from capacity expansion quotas and long-term contracts. • **Higher stranded asset risks,** as expanding gas infrastructure locks in costs that will be embedded in electricity tariffs. This could limit Thailand's ability to transition to more cost-effective renewable alternatives, preventing the electricity sector from following a cost-optimal pathway in the near and medium term.
Environmental Sustainability	• **CO_2 and methane emissions** from the natural gas value chain. For example, CO_2 emissions from gas-fired power plants and methane emissions from LNG shipping. • **High electricity grid-emission factor** due to the reliance of gas in electricity generation. Considering the entire life cycle emissions, one kWh of electricity generated in Thailand from national resources emits about 401 gCO_2 (NEIC, 2023). If this gas is imported from Europe and extracted through fracking technologies, the emissions could range from 420 to 750 gCO_2/kWh, including power plant combustion (Hauck, et al., 2019). This is lower than the emissions resulting from burning coal (in Thailand about 820 gCO_2/kWh) (UNECE, 2021), but still comparatively high. This high electricity grid emission factor constrains further decarbonisation through electrification of the industrial and transport sectors. • **Impacts of LNG terminals and gas leakage on biodiversity** (NRDC, 2023) • **Air pollution from gas power plants** (SEI, 2021)

Risk 2: Costly and technologically uncertain abatement technologies to meet carbon neutrality

Thailand has planned to rely on 66% of its electricity generation from the use of natural gas (53%) and coal (13%) by 2030 and reduce the share of natural gas to 41% and coal to 7% by 2037 (EPPO, 2024d). Electricity generation is estimated to emit about 62 $MtCO_2$ per year by 2037, and there are no concrete targets for the use of natural gas and coal going forward to 2050. This plan for high demand of natural gas would increase the need for abatement technologies such as hydrogen production at the source and CCUS technologies at the power plant level to reduce CO_2 emissions from the natural gas supply chain. However, these abatement technologies are still immature and costly and are bound to technical constraints that limit the capture rate below 100%. So effectively, additional carbon sink capacity (depending on Land Use, Land-Use Change and Forestry or LULUCF) would be required to compensate for the remaining emissions.



Source: (EPPO, 2024c; EPPO, 2024d)



Source: (ONEP, 2022)

As fossil fuels will still be needed for some energy and industrial processes by 2050 because of limited technological alternatives, additional carbon sink capacity is needed to absorb the remaining carbon emissions to meet carbon neutrality. Thailand has estimated the need for increasing and maintaining the carbon sink capacity level at 120 MtCO2 by 2050 to offset CO2 emissions from the energy sector (emitted 95.5 MtCO2) and Industrial Processes and Product Use (IPPU) sector (emitted 23.8 MtCO2) in 2050 (ONEP, 2022). However, there are several risks and uncertainties associated with carbon sink capacity such as wildfires turning carbon sinks into an emission and pollution emitter (Nikonovas & Doerr, 2023). Therefore, a high gas demand pathway could lead to a costly and technologically uncertain path to meet carbon neutrality.

The risks of a reliance on currently immature and costly abatement technologies to reduce emissions from gas-fired power generation to meet climate goals could adversely affect aspects of the energy trilemma goals as follows:

Energy Security	• **Increased carbon lock-in** with prolonged dependence on natural gas on a pathway towards carbon neutrality. • **Less adoption of low-cost renewables in a diversified electricity generation mix** as resources are diverted away from more cost-effective and existing proven technologies (such as solar PV and wind) towards more expensive abating technologies (such as hydrogen and CCUS).
Energy Equity	• **Likely increased electricity tariff.** Abatement technologies incur significant upfront costs for infrastructure and potentially reach economic feasibility by 2040. They are likely to be more expensive than renewables such as solar PV and wind until 2040. The levelised cost of CO2 capture could be as high as 100-180 USD/tCO2 for natural gas used in electricity generation depending on the cost of capital. The levelised cost of electricity for gas plants equipped with CCUS can be 1.5-4 times higher than those of solar PV and wind (IEA, 2023c). • **Concerns about impacts of abatement technologies** such as the risk of hydrogen explosions, community impacts of CO2 leakage from storage sites and potential health risks (Bohacikova & Pérez, 2024; Raoof Gholami, 2021). • **Skill development for hydrogen and CCUS deployment** require education and training programmes with investment and equitable access to opportunities. • **Unequal benefits of abating technologies** as large industrial facilities are likely to have access to subsidies and incentives for the development of these technologies as opposed to renewable projects for low-income households or small businesses.
Environmental Sustainability	• **CO2 emissions and leakage from abatement technologies** such as hydrogen and CCUS: While large companies consider the risks of CO2 to be relatively low and manageable, concerns of CO2 leakage from the small number of CCS pilot projects worldwide, given the limited public data available, remain as potential risks to public safety and drinking water. • **Infeasibility to achieving carbon neutrality and net-zero pledges** due to challenges in developing abatement technologies → Most CCS applications in the electricity sector are at a demonstration stage and have yet to reach technical and commercial feasibility. The development of CCUS technologies faces challenges such as economic viability from high up-front investment, a lack of carbon pricing policies in place, long lead times and risks associated due to project complexity (IEA, 2023c). → The deployment of CCU in Thailand is generally even more complex and challenging than CCS because its implementation is hindered by various factors, including laws and regulations. Thailand is still in the process of developing a comprehensive policy framework that addresses issues such as carbon pricing, investment incentives, and infrastructure development.

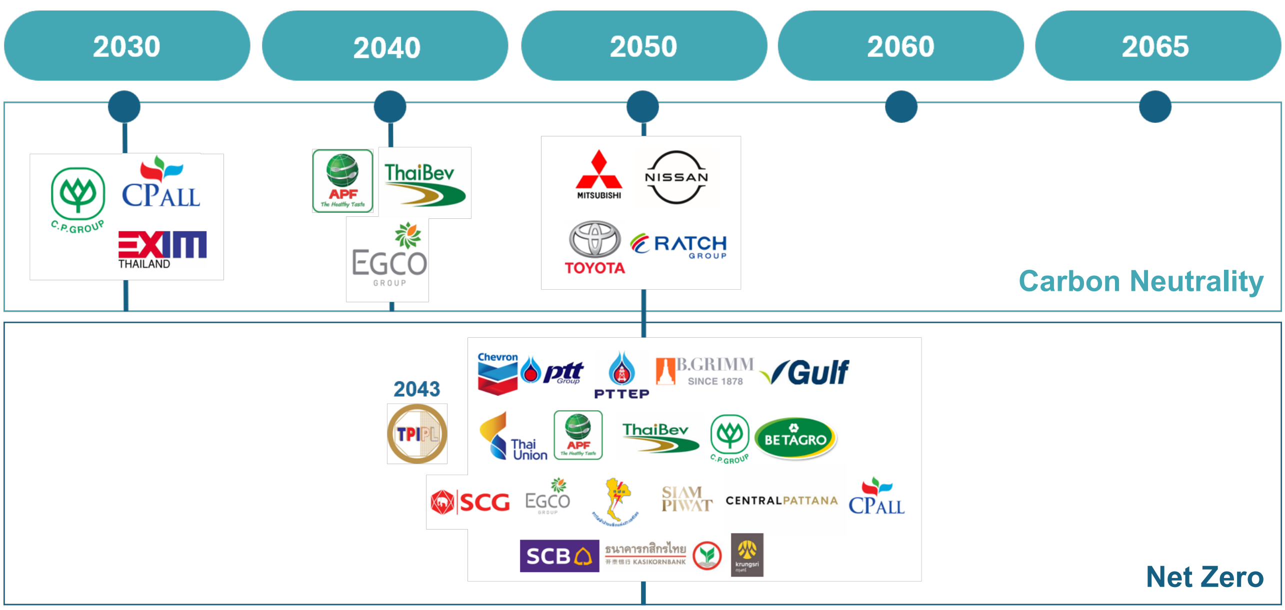
Urgency of Near-Term Decisions for Long-Term CCUS and Hydrogen Deployment

CCUS technologies are possibly paired with gas-fired power generation to reduce emissions. Even using green hydrogen to replace natural gas is a possible alternative. There is some expectation on medium-term hydrogen cost decline due to renewable electricity (input) cost decline, and the expectation on electrolyser cost decline in the coming decade. As some estimates suggest hydrogen and CCS can potentially reach economic feasibility by 2040 and beyond, deployment of hydrogen and CCS to reduce emissions are possible since the long-term strategy plan and PDP include them around 2040. However, policy decision towards 2040–2050 must be made in the near term to prepare to deploy these technologies in time as planned.

Risk 3: Slow development of renewables to meet the increased demand for clean electricity

As a greater number of countries have increasingly pledged net-zero targets, the number of global companies setting net-zero targets grew about 123% during the last three years to 929 companies in June 2023 (Net Zero Tracker, 2023). Many Thai corporations in various industrial sectors have also announced carbon neutrality and net-zero commitments at the organisational level, further emphasising the urgent need for clean energy solutions to support these goals. In addition, the carbon border adjustment mechanism (CBAM) implemented by Europe and under consideration by the U.S. and China will significantly increase the demand for clean electricity. Meanwhile, corporate members of RE100, the global corporate renewable energy initiative who have committed to 100% renewable electricity, have required their suppliers throughout the supply chain to align with the 100% renewable energy target.

Thai companies with climate targets



Faster development of renewable-based electrification would reinforce industrial competitiveness and investment attractiveness particularly for companies engaged in the global supply chain, by meeting both internal demand from corporations committing to purchase 100% renewable electricity and external demand from international regulations such as CBAM implemented in the EU. However, options to access renewable electricity remains quite limited in Thailand as the electricity grid contains high carbon content from gas-fired power generation.

Low-carbon technologies, such as solar and wind power combined with battery storage, currently have the technological capability to decarbonise the power sector at lower costs. In addition, low-carbon electricity can be a cost-efficient enabler for decarbonising applications in the transport and industrial sectors through direct electrification (e.g., electric vehicles or EVs and electrified heat). An over-reliance of natural gas in the power sector would therefore limit the ability for deep decarbonisation through electrification and put more pressure on the other sectors to decarbonise potentially at higher costs.

New additions of solar and wind capacity planned in the draft PDP 2024 (e.g., addition of large new capacity expected after 2030) may be too late to meet today's demand for clean electricity, leading to insufficient planning for integration of higher renewable development and grid modernisation. Furthermore, Thailand has no targets and well-designed programmes for rooftop solar and distributed storage deployed by end-users, which could play a crucial role for companies to meet increased demand for clean electricity through decentralisation and provide demand-side flexibility to the Thai power system.

Increased demand for clean electricity, insufficient plans for higher renewable integration and grid modernisation could adversely affect energy equity and environmental sustainability dimensions of the energy trilemma goals as follows:

Energy Security	• **Insufficient supply of renewable electricity to meet increased demand for clean electricity** as centralised electricity has a high grid emission factor and new large capacities of solar and wind are only expected after 2030. • **Lack of adequate planning for higher renewable integration** as energy storage, advanced grid modernisation and smart technologies may not be planned in a timely manner to synchronise renewable generation with demand reliably to ensure system stability. • **Inability to leverage the resilience advantage of distributed energy resources** as most decentralisation options are prohibited by existing law and regulations and there are no well-designed programme incentives for rooftop solar, distributed storage and smart EV charging for end-users.
Energy Equity	• **Clean electricity available at more expensive costs** stem from factors such as limited renewable energy infrastructure, the need for storage to address intermittency, and financing challenges for renewable projects. Additionally, the new Utility Green Tariff (UGT) provides opportunities to access renewable electricity at premium costs due to contractual guarantees for renewable supply. • **Potential negative impact on industry competitiveness,** driven by the dominance of gas-fired power generation, which limits the ability of Thai industries to compete with high electricity grid-emission factors in global markets prioritising low-carbon supply chains, RE100 initiatives and ESG requirements for accessing lower costs and innovative finance. • **Unequal access to clean electricity,** disproportionately affecting low-income households and small businesses. • **Less access to mitigation funds.**
Environmental Sustainability	• **Inefficient development of transmission and distribution system** to accommodate higher renewable electricity. New addition capacity of renewables in the current draft energy plans are only expected after 2030 and distribution utilities struggle to estimate increasing distributed resources. • **Limited deeper decarbonisation options** which are needed to achieve climate commitments through electrification.

4. RISK MITIGATION STRATEGIES

This section explores potential risk mitigation strategies for each of the identified risks associated with current energy plans and further discusses the role of natural gas in the electricity sector towards carbon neutrality, including challenges for the role of an LNG trading hub in Thailand.

4.1 Potential risk mitigation strategies

As analysed in the previous section, Thailand is facing three critical risks associated with a high gas demand pathway based on the recent draft PDP and Gas Plan (2024). These risks could adversely affect energy security, energy equity and environmental sustainability of the energy trilemma goals. Potential risk mitigation strategies for each identified risk factor are summarised in the below table.

Risk factors	*Potential risk mitigation strategies*
Risk 1: Carbon lock-in from gas-fired power generation and reliance on LNG imports	• Reduce natural gas demand in the medium term • Transform the role of natural gas to increase flexible operations • Ensure transparency and negotiate for flexible contractual agreements • Ensure supply and price stability of LNG imports • Ensure fair and equitable gas pricing structure • Explore new gas resources to reduce LNG imports
Risk 2: Costly and technologically uncertain abatement technologies to meet carbon neutrality	• Prepare for an accelerated and sustained decarbonisation pathway • Reduce GHG emissions along natural gas supply chains • Develop CCUS roadmap and regulations • Implement carbon pricing mechanisms • Repurpose gas pipeline infrastructure • Enhance international cooperation on innovation and cross-border storage of CO_2 • Fair and equitable allocation of carbon sink capacity to sectors with limited decarbonisation options.

Risk factors	*Potential risk mitigation strategies*
Risk 3: Slow development of renewables to meet the increased demand for clean electricity	• Enhance direct power purchase agreement (DPPA) • Support decentralisation programmes to meet increased electricity demand and provide demand-side flexibility • Plan to accelerate more additions of new renewable capacity to the grid before 2030 • Introduce Utility Green Tariff

Potential Mitigation Strategies for Risk 1

- **Reduce natural gas demand in the medium term:** A structural reduction of natural gas demand in the medium term could ease pressure in securing a gas supply and mitigate risk exposure to the fluctuations of the global natural gas and LNG market (IEA, 2024b). This includes plans to replace additional gas-fired power generation in the next three to seven years with increasing renewable capacity under PDP 2024, and to enhance flexible renewable integration and demand-side flexibility.
- **Increase flexible operations by transforming the role of natural gas:** This could provide opportunities for more renewable integration, along with a plan for cost-effective integration into power systems, including grid planning and flexibility measures through both the supply and demand side. By prioritising demand-side management and grid flexibility measures, the need for new gas-fired plants diminishes, reducing reliance on volatile gas supplies and supporting decarbonisation efforts. While the role of natural gas in electricity generation should be reduced due to the availability of cheaper alternative technologies at the commercial level, natural gas could play an increasing role in replacing coal in industrial applications.
- **Ensure transparency and negotiate flexible contractual agreements:** Openness about the terms of PPAs does not only ensure fair competition, but also competitive procurement and ultimately lower costs (WEC, 2024). The renegotiation of existing gas-fired PPAs and gas supply contracts, synchronised with renewable build-up, would reduce gas supply costs and increase the flexibility of the Thai power system. Existing fuel supply and power purchase contracts with minimum take-or-pay conditions pose significant contractual barriers for benefiting from technical flexibility from gas power plants and the use of more cost-efficient resources (IEA, 2023c). In addition, negotiating improved PPA terms with gas-fired power generation would help reduce the demand of natural gas during a gas crisis and incentivise flexible power plants to support greater integration of renewables, leading to lower electricity costs. Furthermore, improving contractual agreements for gas-fired power plants (e.g., reducing the duration of PPAs) would increase the capacity of the power sector to adapt to future energy market changes and technological advancements more flexibly.

- **Ensure supply and price stability of LNG imports:** Diversifying LNG-importing countries and contract duration (such as long-, medium- and short-term and spot contracts) could help secure the supply of LNG imports. The optimal ratio of term contracts and spot LNG should be determined through a careful analysis of the demand growth, LNG market conditions, risk tolerance, and economics. Thailand has currently secured imports of LNG through five long-term contracts by PTT and two short-term contracts by new LNG shippers. PTT and EGAT have also procured imported LNG through the spot market (Lew & Yeo, 2024). PTT procures spot LNG during low-price periods. To ensure price stability of LNG imports to reduce unit import price and risks associated with international price surges, joint purchasing initiatives between PTT and other LNG shippers could leverage bargaining power to reduce LNG import prices, and diversifying the spot contract price indexation could mitigate international natural gas spot price surge risks (IEA, 2024b).

Thailand's LNG import portfolios as of June 2024

Companies	*Contract Type*	*Volume (million tonnes/year)*	*Start Year*	*End Year*
PTT- Qatar	Long-term	2	2015	2034
PTT- Petronas	Long-term	1.2	2017	2036
PTT- Shell	Long-term	1	2017	2037
PTT- PTTGL	Long-term	1	2026	2045
PTT- BP	Long-term	1	2017	2041
EGAT	1-year	0.9	2024	2024
EGAT	2-year	0.5	2025	2027
Hin Kong	2-year	0.5	2024	2026

- **Ensure a fair and equitable gas pricing structure:** Thailand has adjusted the natural gas pricing structure by using the pool gas price for gas separation plants (effective January 2024) and allocated domestic gas production for residential electricity users during the energy crisis to reduce the burden of high LNG import costs on the electricity tariff (PTT, 2024).

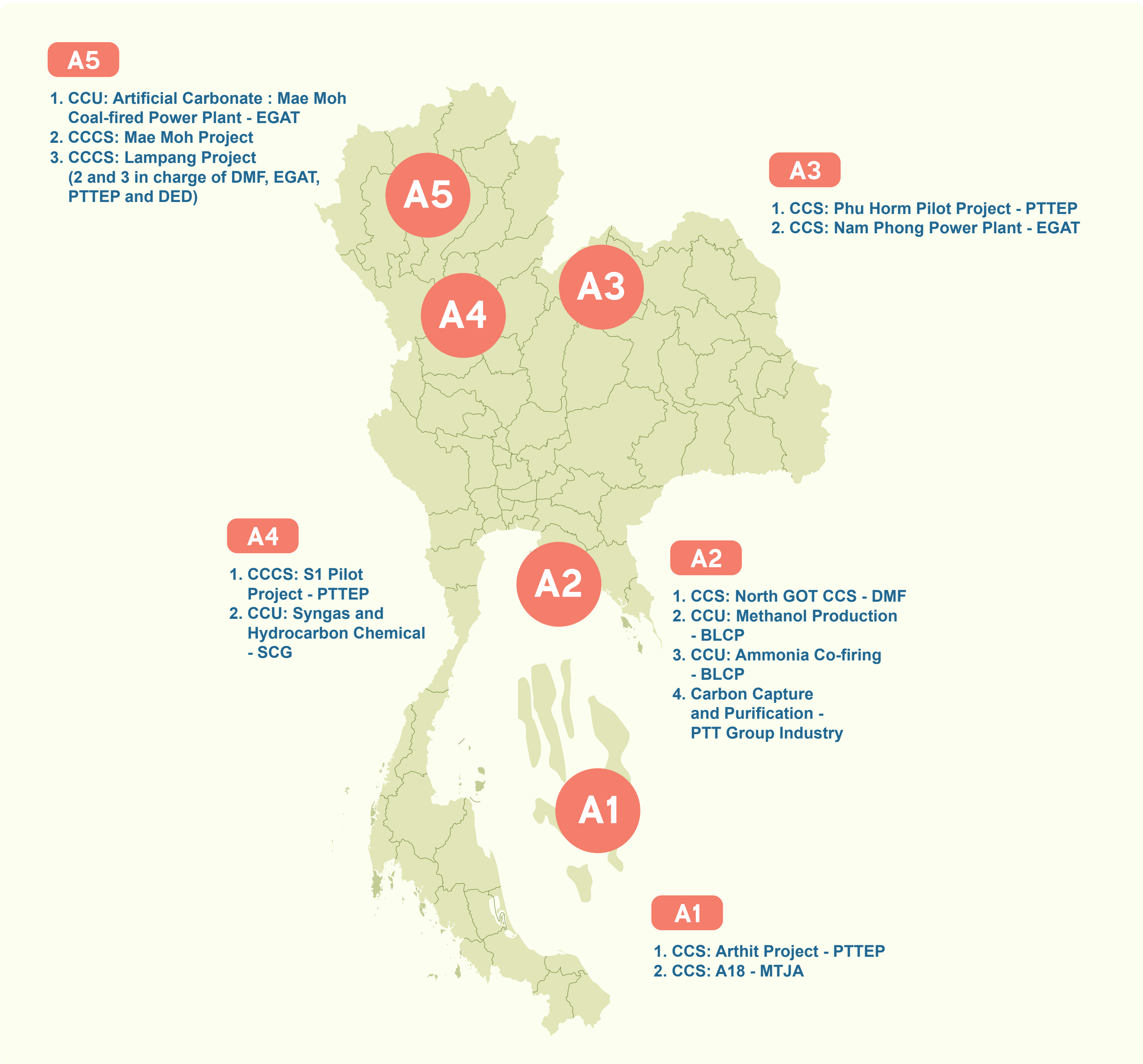
- **Explore new gas resources to reduce LNG imports:** Successful negotiation between Thailand and Cambodia to explore new natural gas resources under the Gulf of Thailand could reduce the need for LNG imports, potentially importing 11 trillion cubic feet of natural gas (Mathew, 2024). However, the success rate could be very low due to historical disputes with Cambodia, and it could take more than 10 years to realise commercial exploration. These uncertainties could increase the risk of relying on an insecure gas supply and increase the volatility of both LNG volume and price making it difficult to meet the contracted power demand on time. While this potential mitigation strategy may reduce LNG imports in the short-term, it could also conflict with and impose long-term risks towards greater climate and environmental sustainability goals.

Potential Mitigation Strategies for Risk 2

- **Prepare for a deeper and sustained carbon emission reduction pathway:** Early, accelerated and sustained carbon emission reductions could reduce the need for uncertain and costly abatement technologies and a carbon sink capacity to reach climate goals. This could mean implementing mechanisms to stop the expansion of fossil fuel projects where alternative renewable technology solutions exist, particularly in the electricity sector. In addition, putting more effort into energy efficiency and circularity measures to reduce energy demand could play a major role in sustainably deepening the decarbonisation pathway. Delayed mitigation actions could increase the risk of cost escalation, locked-in infrastructure, stranded assets and infeasibility of achieving climate goals, increasing the economic losses and environmental damage from climate change impacts (IPCC, 2023).
- **Reduce GHG emissions along natural gas value chains:** It is crucial to reduce GHG emissions from natural gas-related operations and to develop new technology options such as CCUS in gas applications, low-emission hydrogen and hydrogen-based fuels and biomethane and biogas (IEA, 2023d). Emissions must be cut along the natural gas value chain to achieve net-zero pledges. International cooperation is central to facilitating the reduction of GHG emissions from gas and LNG supply chains, including establishing commonly agreed upon measurement, monitoring, reporting and verification (MMRV) mechanisms and sharing best practices and attracting financial flows to emission reduction projects (IEA, 2024c).
- **Repurpose the gas pipeline infrastructure:** Thailand's existing gas pipeline infrastructure can potentially be repurposed to fast-track the deployment of CO_2 and hydrogen infrastructure (IEA, 2023d). Thailand has planned to blend 5% hydrogen into the gas pipeline within the period 2030 to 2037. However, gas industry players raised several technical concerns about the efficiency and quality of gas for industrial usage. See Annex 6 for challenges in hydrogen development.

- **Develop a CCUS roadmap:** The Department of Mineral Fuels (DMF) under the Ministry of Energy is developing a national CCUS roadmap. Meanwhile, there are eight CCS, four CCU and one carbon capture purification pilot projects for upstream activities, power plants and the cement industry. Data analysis is underway to identify potential CO_2 storage areas and a CO_2 hub for emissions from Map Ta Phut (Department of Mineral Fuel, Ministry of Energy, 2023). There is not yet publicly estimated CCS capacity needed for Thailand by specific industrial sectors. In addition, given the mention of CCUS in Thailand's long-term GHG reduction strategy, it is imperative to integrate CCS technology into the national energy plan. This integration should include clear policy targets, financial incentives, and public awareness campaigns to promote CCS adoption and innovation.

CCS, CCU and carbon capture purification pilot projects under a national CCUS roadmap



Source: (DMF, 2023)

- **Establish CCUS regulations:** Thailand is drafting CCS-specific laws and regulations relating to petroleum activities. While Thailand's Petroleum Act provides a basic framework for CO_2 management within petroleum operations, it falls short of comprehensively addressing CCUS across all sectors. Existing legislation like the Coastal Resource Act, Minerals Act, and Environmental Act cover various non-E&P activities, but regulatory gaps remain (Sutabutr, 2024). For instance, CO_2 pipeline transportation, capturing systems in electricity generation, and storage outside petroleum concession areas lack clear legal frameworks. This poses challenges for obtaining necessary rights and licences for CCUS project implementation, particularly for surveying and utilising potential storage sites. Therefore, dedicated CCUS regulations are crucial in facilitating broader adoption to achieve national decarbonisation goals.
- **Enhance international cooperation:** International cooperation plays a crucial role in advancing CCUS technology by facilitating knowledge sharing, coordinating research efforts, and pooling resources for R&D funding. This collaborative approach accelerates innovation, leading to cost reductions and improved efficiency in carbon capture, transport and storage. Furthermore, international cooperation is essential for establishing cross-border CCUS projects, which involve capturing CO_2 in one country and transporting it to another for permanent storage (ACE and JOGEC, 2023). This mechanism allows nations without suitable geological formations to participate in carbon reduction initiatives by utilising the storage capacity of neighbouring countries.
- **Fair and equitable allocation of carbon sink capacity:** This involves explicitly assigning portions of the available carbon sink to various sectors, prioritising those with the greatest challenges in reducing emissions. Hard-to-abate sectors, where viable alternatives to fossil fuels are currently limited or unavailable such as the industrial or aviation sector, should be given priority access to carbon sink resources.

IEA policy tools to address challenges to CCUS deployment

Challenge	Policy categories to address challenge	Specific policy tools
Economic Viability	• Cost reduction measures • Regulation of industrial activities • Revenue support • International collaboration	• Grants • Tax credits • Loan support • State-owned enterprises • Carbon pricing and leakage policy • Public procurement • Low-emissions mandates • (Carbon) contracts-for-difference • Regulated asset base • Emerging market and developing economy considerations: concessional finance, sustainable debt, and multilateral funding instruments
Lead times	• Enabling legislation and rules	• One-stop shop for permitting • Clear permit approval timelines • Internal regulatory capacity • Precompetitive resource assessments • Data sharing and transparency requirements • Community engagement requirements
The innovation gap	• Cost reduction measures • International collaboration	• RD&D • Platforms for international co-operation • Foreign direct investment for technology co-development
Project complexity	• Enabling legislation and rules • Strategic signalling • International collaboration	• Long-term storage liability • Competitive solicitations for CCUS Hubs • One-off backstop agreements for first movers • London Protocol specifications • Definition of high-quality removals • Robust measurement, reporting and verification mechanisms

Potential Mitigation Strategies for Risk 3

- **Enhance direct power purchase agreement (DPPA):** To meet growing demand for renewable electricity and to attract foreign investment in energy-intensive data centres, Thailand approved a DPPA pilot project for trading renewable electricity (2,000 MW in June 2024), which allows businesses to purchase electricity directly from renewable energy producers. Scaling up pilot projects and broadening the targeted business base would unlock peer-to-peer trading opportunities for renewable energy projects and meet the demand of clean electricity for business.
- **Meet increased electricity demand and provide demand-side flexibility by supporting decentralisation programmes:** Thailand's net-billing rooftop solar programme for the residential sector ended in June 2024 and there are no similar programmes for the business and industrial sectors. Businesses and factories are permitted to install rooftop solar panels for self-consumption, but they do not inject excess electricity to the grid. Thailand's Board of Investment (BOI) provides incentives for solar installations. A well-designed rooftop solar programme for businesses and the industrial sector would facilitate investments in rooftop solar and distributed storage and reduce adverse impacts on the grid and equity concerns (CASE, 2024). Well-designed decentralised programmes such as rooftop solar, distributed storage and smart EV charging would reduce threats from unregistered installations and enable the country to benefit from the emerging growth of these distributed energy resources (DER) technologies. These decentralised programmes could play a crucial role to provide demand-side flexibility and reduce peak loads from end-users.
- **Plan to accelerate more additions of new renewable capacity to the grid before 2030:** As costs of solar and wind are rapidly declining, Thailand could benefit by accelerating the addition of new renewable capacity to the grid before 2030. Timely implementation of the plan to increase flexible operations of gas-fired generation and other measures such as battery energy storage would reduce the grid-emission factor and meet increased demand for clean electricity.
- **Introduce the Utility Green Tariff (UGT):** Thailand introduced the UGT in early 2024 with the price of renewable electricity at a level that is slightly higher than the normal electricity tariff (in the range of 4.2-4.56 baht per kWh). This new tariff scheme aims to meet increasing renewable electricity demand by businesses in Thailand (estimated at 10 GW) driven by the requirement of EU's CBAM and companies' campaigns towards carbon neutrality (Praiwan, 2024). While the UGT provides a channel for corporations to access renewable electricity at a premium, participation in the programme raises concerns about double-counting of emissions (ERC, 2024a). Since the renewable energy procured through UGT is already accounted for in national grid emissions reporting, corporations may face challenges claiming these reductions towards international obligations. This limitation undermines the effectiveness of the UGT in meeting the rising demand for clean electricity from corporations seeking to reduce their carbon footprint and enhance their competitiveness in a global market.

4.2 Role of natural gas in the electricity sector towards carbon neutrality

Potential risk mitigation strategies for each identified critical risk discussed in Section 4.1 highlight the need to reduce gas-fired power generation in the medium and long term, or to shift to a faster transition towards carbon neutrality. This section discusses challenges to reducing natural gas demand for electricity generation in Thailand and potential solutions to support a more cost-effective and sustained carbon emission reduction pathway to carbon neutrality.

Reducing the share of natural gas and increasing the share of renewables in electricity generation are key risk mitigation strategies for Thailand to achieve carbon neutrality in 2050, compared to several existing carbon neutral scenarios.

In November 2022, Thailand submitted its revised long-term strategy (LT-LEDS)[1] to the UNFCCC to attain carbon neutrality and net-zero goals, in which the projection for the share of natural gas in electricity generation was to be less than 20% in 2050 in a carbon-neutral scenario (ONEP, 2022). This projection is in line with other existing carbon-neutral scenarios from multiple studies. Accordingly, the LT-LEDS set up milestones to increase the share of renewable electricity to 68% by 2040 and 74% by 2050.

The draft PDP (2024) plans to maintain the share of natural gas in electricity generation at 41% by 2037, a reduction from the current share of 57%, while aiming to increase the share of renewable electricity to 51% by 2037. Compared with the LT-LEDS and other existing carbon neutral scenarios, the draft plan struggles to reduce gas-fired power generation and accelerate the renewable energy share at a faster pace during the final phase of 2037 to 2050 to align with levels indicated by other carbon-neutral scenarios. This indicates that the current draft plan may set inadequate targets for reducing the share of natural gas and increasing the share of renewable electricity by 2037, leading to potential risks of failing to achieve carbon neutrality by 2050.

[1] Thailand's long-term low GHG emission development strategy (LT-LEDS) submitted by the Office of Natural Resource and Environmental Policy and Planning (ONEP), Ministry of Natural Resource and Environment

Reducing the share of natural gas in electricity generation could raise several challenges for practical implementation that require a comprehensive set of solutions to enable cost-effective integration for higher shares of renewables and a just transition for industry gas players.

A faster transition pathway, in which the share of natural gas in electricity generation falls below 20% by 2050, to align with other existing carbon-neutral scenarios, raises several concerns, particularly the reliability of renewable electricity to replace gas-fired power generation. According to an IEA analysis (2023), the Thai power system could currently integrate up to 15% of variable renewable energy in the next five years (by 2030) because of the technical flexibility of its existing gas and hydro generation fleets. However, Thailand would not fully benefit from the technical flexibility from existing thermal power plants due to contractual barriers, particularly existing power purchase contracts with minimum take-or-pay requirements. This section identifies key three challenges and possible solutions to increasing the renewable energy share and reducing gas-fired power generation in Thailand. Solutions would require new policy and regulatory initiatives for an energy transition towards a modernised future cost-effective energy system. This could include the reform of existing policies and regulations, investments in modernising grid infrastructure, new market mechanisms and integrated sectoral planning.

Challenge 1: Existing contracts and already approved gas infrastructure investments have locked Thailand into a high demand and high supply for natural gas pathway in the long term.

Thailand's existing commitments in the form of PPAs for gas-fired power generation and 25-year term gas supply contracts have prevented Thailand from pursuing the most cost-effective path to carbon neutrality, such as switching to cheaper renewable technologies. Existing gas infrastructure commitments could become stranded if a low gas demand pathway is pursued. The contractual commitments and the high level of electricity reserve capacity (almost 50% of contractual capacity in 2023) in Thailand have resulted in high demand for natural gas (i.e., increasing LNG imports) and lower targets for renewable capacity. The inflexible contractual terms, such as minimum take requirements or daily take-or-pay, could be a major barrier to the increased deployment of variable renewables, leading to unnecessary curtailment and higher operating costs, as well as inflexibility in the power system (IEA, 2023c). Furthermore, these contractual obligations are committed to long-term capacity payment rather than energy payment, likely pressuring the continued dispatch of gas plants to meet the long-term obligation.

Potential solutions to address challenges

- **Reduce new gas-fired power generation and incentivise gas power plants to provide power system flexibility**

The additions of new gas-fired power generation should be deferred or removed in Thailand's energy plans to avoid new lock-in and regrettable contractual commitments. Any new gas-fired power PPAs should also have terms of less than 25 years to flexibly adapt to future energy market changes and technological advancements. The role of gas turbines in their operating paradigm should support variable renewable generation. For example, covering mid and peak load rather than all year (NewClimate Institute and Agora Energiewende, 2024). The design of new contracts or other cost-recovery mechanisms in existing gas-fired power plants that consider flexibility requirements along with increasing renewables will be required to support the transition (CASE, 2022). Furthermore, the flexibility of gas-fired power plants could enhance the resilience of the electricity grid by providing rapid response capacities (ramping up and down) and backup power for modern power systems. Comprehensive planning of flexible operations with strategic contractual arrangements and other flexibility measures, such as demand-side management, has the potential to reduce the reliance on gas peaking plants and additional gas-fired power capacity, while accommodating the integration of variable renewable energy sources.

Potential solutions to address challenges

- **Negotiate to remove contractual barriers for higher integration of renewables**

The renegotiation of gas-fired PPAs and daily take-or-pay gas supply contracts could increase the technical feasibility of gas-fired power plants to accommodate better integration of renewables. This could be achieved by modifying existing take-or-pay requirements in gas supply contracts, reducing the minimum off-take volumes, and remunerating the provision of flexibility and other ancillary services instead (IEA, 2021; IEA, 2023b).

- **Repurpose existing gas-fired power plants and gas pipelines**

Existing gas-fired power plants could be repurposed to provide grid flexibility services or retrofitted for the use of low-carbon fuels such as hydrogen or with CCUS to reduce emissions and avoid early retirement (IEA, 2023b). Any new investment in gas-fired power plants should be H2-ready to prepare for the transition towards hydrogen (CASE, 2022). Decisions on repurposing gas pipelines for hydrogen[2] would need further analysis, considering the cost and efficiency of applications for the power and industrial sectors.

Challenge 2: Energy security concerns on the reliability and costs of variable renewable energy integration have led to the slow development of renewable energy and a modernised grid infrastructure.

Renewable electricity has the technological maturity to reduce fossil-fuel dependency and contribute to diversified domestic energy sources that are key determinants of energy security in today's modernised energy system. However, policymakers and related stakeholders have raised concern on the reliability and integration costs of renewable energy sources, particularly solar and wind, for the transition away from gas-fired power plants. Integrating renewables into the existing power system structure could prove costly and unreliable if it lacks comprehensive grid planning and proper incentives for building up flexible power system options. As a result, the targets set for solar PV in Thailand's draft energy plans are significantly lower than its potential.

To fully realise the benefits of renewables in reducing LNG imports and increasing energy security with more diversified domestic sources, it is essential to accelerate the adoption of higher renewable energy targets and deployment, together with the establishment of a new security supply paradigm based on renewable resources, power system flexibility and advanced grid planning.

[2] Examples of limits and options from a case study in Germany (Télessy, Barner, & Holz, 2024)

Potential solutions to address challenges

- **Increase renewable targets and unlock barriers for renewable deployment**

Setting higher targets for renewable energy will not only increase the feasibility of achieving carbon neutrality and meeting the increasing demand for clean electricity but will also provide regulatory and market certainty for renewable energy projects. These certainties will reduce the risks of renewable energy projects, lowering financial costs and attracting more investment. Aligning with renewable energy targets, competitive procurement (or reverse auction) and regulatory and policy instruments (such as tax incentives) could be implemented to support renewable energy projects at cost and scale. These also include policy supports on appropriate renewable energy siting and improving transmission and distribution systems to accommodate higher renewable electricity grid stability measures.

- **Establish a new supply security paradigm for Thailand's power sector based on national renewable resources**

A new supply security paradigm, based on national renewable resources, power system flexibility and advanced grid planning, is needed to ensure power system reliability and better cost-effectiveness of using variable renewable energy sources. The timeline for the deployment of solar PV and wind capacity in the integration plan into the power system should be coherent. Each phase of variable energy integration will require different technologies and enabling policies (see Annex 7). Power system flexibility measures include energy storage solutions, flexible contracts for thermal power plants, demand-side management and cross-border power trading. Enabling policy, regulatory and market design instruments for these measures would provide both flexible demand and supply options for the cost-effective and reliable integration of renewables into the power system (IEA, 2024b). In addition, policies promoting advanced grid infrastructure, smart technologies to safeguard system stability and electricity market reforms (e.g., introducing a more dynamic time-based tariffs for grid reliability) are imperative for ensuring cost-effective and reliable diverse energy sources into the power system, and become necessary for energy system reliability (WEC, 2024).

Potential solutions to address challenges

- **Adopt integrated power sector planning and digitalisation technologies**

Integrated power sector planning should be adopted to ensure a cost-optimal transition to carbon neutrality, considering the increasing electrification of the transport and industrial sectors (e.g., more electric vehicles and heat pumps) and the economics of distributed energy resources (e.g., distributed PV and battery energy storage) in meeting the demand for clean electricity. Integrated power sector planning also includes integrated planning across a diversity of supply and demand resources, integrated generation and network planning, and inter-regional planning across jurisdictions and balancing zones (IEA, 2023c).

A more dynamic interaction between transmission and distribution utilities will also be critical for planning the integration of decentralised solutions such as demand response, distributed generation and EVs for the benefit of the power system. Rooftop PV and distributed energy storage could play an important role in reducing the need for new gas-fired generation to meet the growing end-user demand for electrification and clean electricity. In addition, as the transformation of the power system is moving to the distribution edge, digital technologies (e.g., smart charging technologies, real-time data from smart meters) and smart regulations (e.g., dynamic time-varying tariffs) will unlock the potential of all flexibility options, particularly demand response from the commercial and industrial sectors, as well as reduce peak loads and provide system services (e.g., inertia response) to balance the grid (IEA, 2023c).

Challenge 3: Thailand lacks a just transition plan for natural gas towards carbon neutrality, a roadmap for full gas liberalisation and a fair and equitable pricing structure of natural gas and electricity tariffs.

Thailand has no existing plan for a natural gas transition to achieve carbon neutrality by 2050 despite the economic relevance of the gas sector and its expected fundamental transformation over the next 25 years. The current draft energy plans under discussion expect natural gas demand in MMSCFD to be the same level as today until 2037 and with no direction from 2037 to 2050. This increases the risk of over-investment in gas-related activities that are inconsistent with carbon neutrality goals, leading to high costs of stranded assets and inadequate preparation of the gas industry for a just transition. Additionally, a roadmap for full gas liberalisation does not currently exist. Thailand is in Phase II of its plan to promote competition in the natural gas industry, granting eight new shippers with licences to import LNG. While liberalising the gas market alone can bring certain benefits, such as increased competition and investment, it is not enough to realise the full potential of energy market liberalisation in Thailand. That is unless the electricity market is liberalised in Phase III, the final phase of the plan.

Potential solutions to address challenges

- **Develop a just gas transition plan with all stakeholders**

A just and equitable natural gas transition plan developed with all stakeholders would provide a long-term roadmap to sector transformation. This could include targets for reducing natural gas demand in the power and industrial sectors and transition strategies to mitigate the impacts on the gas industry. The transition role of natural gas should be prioritised in the plan to support increased deployment and integration of renewable capacity in the power sector.

- **Ensure fair and equitable gas liberalisation plan and pricing structure of natural gas and electricity tariff**

The liberalisation of both the electricity and gas markets is crucial for Thailand to increase competition, boost investment and economic growth, and enhance energy security. In addition, the completion of sector liberalisation, as well as the adjustment of the gas and electricity tariff structure could facilitate and economically support the transition role of natural gas, increasing market participation in the energy sector and ensuring fair risks and costs pass-through of natural gas price and electricity price to consumers. A new regulatory and market structure would help align incentives and ensure a fair and transparent transition to further integration of renewable capacity in the power sector.

4.3 Challenges for the role of an LNG trading hub

Thailand envisions becoming a Regional LNG Hub, with government support focused on achieving this goal with the Natural Gas Industry Liberalisation Phase II. This phase aims to promote competition in the natural gas industry (i.e., increasing the number of LNG importers) and investment in a new LNG terminal infrastructure.

Initially, the LNG terminal acted as a tool to diversify the energy mix and reduce the risks related to price volatility and supply disruptions. It also contributed to meeting peak demand, assuring a steady and dependable supply of electricity. To encourage investment in the LNG terminal, the government has authorised PTT to construct facilities and granted them permission to transfer expenses onto electricity bills. Thailand is attempting to establish an LNG hub on the theory that LNG regasification units and tankage will eventually be at overcapacity as natural gas usage declines. The regional LNG hub could then enable Thailand to continue using the previously constructed infrastructure. With an increase in the flow of gas trade through the hub, Thailand could strengthen the natural gas industry and enhance regional and national gas security. Moreover, Thailand has the advantage of not requiring natural gas reserves to support its energy strategy.

Current LNG regasification facility:

The LNG regasification facility in Thailand currently has a capacity of 19 MTPA (Terminals 1 & 2) and is expected to expand (with Terminal 3) to reach 30 MTPA by 2028. Thailand's LNG terminals have the potential to develop into a regional LNG hub due to their capability, particularly Terminal 1, to provide a variety of LNG services. Thailand offers even more flexibility regarding LNG trading in the region because the LNG regasification terminal's design allows capacity expansion to 46 MTPA if the need for LNG arises.

However, the logic for creating an LNG hub has always been complex because the LNG terminal was initially constructed for Thailand's gas security rather than based on economic considerations, given that Thailand was then dealing with the long-term trend of reliance on LNG and natural gas. In addition, the recent reality of LNG market uncertainty and price volatility may contradict the initial objective of using the LNG terminal to reduce risks related to price volatility and supply disruption.

Considering the regulated market's current rate of regasification, Thailand also needs to address the LNG terminal operation barrier with a comprehensive assessment of LNG infrastructure and carefully examine whether additional LNG tankage is necessary for Thailand as these costs will be passed through to electricity bills. Setting up a large-scale LNG trading hub should consider the following enabling environment:

- Create a highly flexible and fluid spot market that satisfies LNG hub requirements.
- Encourage a sizable number of LNG market participants.
- Modify current LNG facilities so they have the infrastructure that can accommodate a variety of services required by both domestic and trading businesses.
- Enact laws and regulations that facilitate LNG trades and the liberalisation of the gas market.

Based on the recent draft energy action plans (2024), Thailand is likely going to pursue high natural gas demand in the electricity sector on its path to carbon neutrality. The demand for natural gas in the power sector is estimated at 2 824-3 119 MMSCFD from 2024 to 2037 (EPPO, 2024a), which would require a sizable proportion of LNG import supply. The ERC may consider adding more LNG tankage facilities to the already-invested regasification plants to meet natural gas demand. These additional investments would be passed through to electricity bills for energy security purposes.

However, the government could alternatively consider risk mitigation strategies (discussed in Section 4.2) that align with carbon neutral scenarios to reduce natural gas demand in the power sector to less than 20% by 2050 with a faster transition to renewables. This pathway is a more challenging task for an LNG regional hub. One approach could be to keep LNG terminals operational during peak shaving (strategic reduction of electricity or gas consumption during periods of high demand). However, in this scenario, if demand continues to decline, Thailand will have to consider exporting excess LNG while demand is still high in other neighbouring countries. In this situation, Thailand might attempt to develop into a small-scale LNG hub or a bunkering centre for LNG and consider the prospect of integrating with the gas-to-liquids (GTL) or gas-based petrochemicals industries in the future.

A. Discussions for a high gas demand pathway

Although LNG capacity appears to be sufficient to meet domestic demand, Thailand should continue to evaluate whether it still needs to modify its LNG infrastructure, such as adding more LNG tanks or receiving terminals, etc., to improve service continuity and simultaneously increase the potential of becoming a regional hub for LNG.

Rather than quickly becoming a hub for LNG trading, Thailand has an excellent opportunity to establish an LNG hub for distribution or logistics in its early stages. This approach differs from Singapore's attempt to establish an LNG trading hub with its own pricing system, which shifted to LNG bunkering due to lack of traders.

It might be more practical to develop the Thailand hub first into a physical logistics gas hub before becoming a fully operational financial or commercial hub. Thailand could also become the LNG trading centre of the CLMV (Cambodia, Laos, Myanmar, and Vietnam) region, which are available markets.

To support LNG trading, it may be necessary to build additional tanks and modify the receiving and exporting ports. It should be noted, though, that further investments can only be justified by LNG trading. Consequently, they should not increase electricity bills, as the current LNG infrastructure is considered sufficient for current operations. Thailand risks having its LNG infrastructure turn into a stranded asset if it fails to consider all economic factors.

Some countries in the region may decide to use less LNG, since each country's policies vary, and there is potential removing LNG from unique systems will take different lengths of time. The door is therefore open for Thailand to seize this opportunity to provide an LNG trading hub service at a time when other nations might still wish to utilise intermittent LNG without having to invest in LNG projects.

B. Discussions for a faster transition pathway with lower gas demand path

The faster transition pathway presents a more vulnerable situation as natural gas would constitute less than 20% of Thailand's electricity generation, a much smaller percentage than a high gas demand pathway.

Given Thailand's sizable LNG infrastructure and the trend of natural gas being substantially reduced from the fuel mix, a clear strategy is required to keep LNG terminals from becoming stranded assets. Considering that LNG consumption is decreasing, there will be underutilised space in LNG storage tanks and regasification capacity available for services. As such, Thailand will unavoidably need to establish an LNG hub as soon as practically feasible to ensure the current LNG terminals are used to their full potential.

Thailand has an opportunity to use the stranded LNG terminal assets for trading, which is heavily dependent on LNG flow passing through the region. Thailand's demand for LNG is declining while it varies – and in many cases, even grows – in other countries within the region. The argument that ASEAN countries heavily reliant on coal might transition to natural gas strengthens the case for a Thai trading hub. This shift could create regional demand, with Thailand positioned to provide readily available natural gas supplies.

In addition, one of a few challenging resolutions exists for modifying the operations of existing LNG terminals before they become stranded assets including diversifying the terminals to be a small-scale LNG trading hub for CLMV (Cambodia, Laos, Myanmar and Vietnam) markets. Given that demand for LNG cargoes in the region is comparatively lower than that of the global market, a small-scale LNG business could be a viable option. Thailand could benefit from its advantageous location, which is accessible to these countries and offers lower expenses for logistics. LNG terminals can make independent investments for commercial purposes if a commercial contract or agreement requires them to rent their facilities for trading purposes, much like Singapore's Pavilion Energy obtaining access rights to the Jurong Island LNG terminal to operate LNG breakbulk, vessel cool-down services, and small-scale LNG.

However, repurposing LNG terminals for trading necessitates additional costs and raises questions about technical feasibility without significant reinvestment, which itself risks future stranding. Thorough feasibility assessments and strategic planning are crucial to navigate the associated challenges and ensure long-term viability.

A more challenging alternative would be for Thailand to acquire natural gas equities in supplier countries for wet LNG. This approach could ensure a continuous supply of feedstock for the petrochemical industry, preventing the stranding of existing LNG infrastructure. However, it is crucial to recognise that this merely delays the inevitable transition away from fossil fuels. Furthermore, acquiring new fossil fuel assets could exacerbate the long-term challenges associated with carbon emissions and climate change. While this strategy offers a temporary solution, Thailand must continue to actively explore and invest in sustainable alternatives to ensure a resilient and environmentally responsible energy future.

Ultimately, Thailand should continue to assess whether it still needs to make changes to its LNG infrastructure, such as revamping tanks and receiving terminals, to improve service continuity and expand its potential to become a regional LNG hub to handle changes in natural gas demand, particularly when they result in a tight market later.

5. IMPLICATIONS FOR GAS INDUSTRY PLAYERS

Thailand is pursuing high ('**Uphold**') gas demand (a 41% share of gas-fired generation) for the electricity sector on its path to carbon neutrality. As discussed in the previous section, this 'Uphold' path could face critical risks that negatively impact the energy trilemma objectives. Potential risk mitigation strategies for the 'Uphold' path highlight the need for a faster transition ('**Drift**') towards carbon neutrality, indicating a significant reduction in the share of gas-fired generation to less than 20% in the power sector in 2050 to achieve carbon neutrality.

Understanding the potential impacts of the '**Uphold**' and '**Drift**' pathways on gas industry players is crucial for stakeholders to make informed decisions and adapt their strategies to mitigate the impact of the risks of the transition to carbon neutrality. This section assesses the potential low ('L'), medium ('M') and high ('H') impacts of both pathways on business viability, risk factors, and employment levels for key gas industry stakeholders. Stakeholders in the gas industry consists of three primary sectors: upstream (exploration and production (E&P) activities), midstream (the separation and delivery of gas through gas separation plants, pipelines and LNG terminals), and downstream (end-users including gas-fired power plants, industrial plants and petrochemical facilities).

5.1 Business viability factors

Given the government's stake in certain gas industry players, one of the major concerns is that reducing natural gas demand could significantly affect business viability for gas industry players. Concerns related to the business continuity, existing and planned infrastructure investment, and new opportunities in the gas sector have been expressed by government agencies and industry players.

Uphold

Impact Level of gas player	E&P	LNG shippers	GSP (PTT)	Gas pipeline	LNG terminals	Users (Gas-power plant)	Users (Industrial plant)	Feedstocks (Petrochem)
Gas business continuity	Medium Positive	Medium Positive	Medium Positive	Medium Positive	Medium Positive	Medium Positive	Medium Positive	Medium Positive
Already invested infrastructure (Stranded Assets)	High Positive	High Positive	High Positive	High Positive	High Positive	High Positive	High Positive	High Positive
New gas related investment opportunities	Medium Negative	Low Positive	Medium Negative	Medium Negative	Low Positive	Medium Negative	Medium Negative	Medium Negative

Drift

Impact Level of gas player	E&P	LNG shippers	GSP (PTT)	Gas pipeline	LNG terminals	Users (Gas-power plant)	Users (Industrial plant)	Feedstocks (Petrochem)
Gas business continuity	High Negative	High Negative	High Negative	High Negative	High Negative	High Negative	Medium Negative	High Negative
Already invested infrastructure (Stranded Assets)	High Negative	High Negative	High Negative	High Negative	High Negative	High Negative	High Negative	Low Negative / High Negative
New gas related investment opportunities	Medium Negative	Medium Negative	Medium Negative	Medium Negative	Medium Negative	Medium Negative	Medium Negative	Medium Negative

Positive Impacts
● Low Positive ● Medium Positive ● High Positive

Negative Impacts
● Low Negative ● Medium Negative ● High Negative

5.1.1 Business viability

Uphold: Although gas demand remains high, the global trend towards low-carbon emissions could slightly decrease gas demand, potentially moderating the positive impact on the gas industry. This could lead to **medium positive** impacts on E&P, LNG shippers, gas separation plants (GSP), gas pipelines, LNG terminals, gas-fired power plants, industrial plants, and petrochemical feedstocks.

Drift: Gas demand is likely to decrease significantly, resulting in direct **high negative** impacts on E&P, LNG shippers, GSP, gas pipelines, and LNG terminals. Industrial users may be able to mitigate the negative impacts by switching to alternative resources, resulting in **medium negative** impacts. Petrochemical feedstocks could face **high negative** impacts as companies would switch to bio-based alternatives, requiring significant infrastructure changes.

5.1.2 Infrastructure Utilisation

Uphold: High gas demand would ensure **high positive** utilisation of existing infrastructure, benefiting E&P, LNG shippers, GSP, gas pipelines, LNG terminals, gas-fired power plants, industrial plants, and petrochemical feedstocks.

Drift: **Low negative** impacts are expected for petrochemical feedstocks as they may need to find new sources. However, **high negative** impacts could arise if companies switch to bio-based alternatives, requiring significant infrastructure changes. For E&P, LNG shippers, GSP, gas pipelines, LNG terminals, gas-power plants, and industrial users, the impact could be **high negative** due to stranded assets and the need for new investments in alternative energy resources.

5.1.3 New Investment Opportunities

Uphold: Despite high domestic demand, all gas industry players anticipate challenges as the global push for carbon reduction continues. To remain viable, they must invest significantly in technologies that reduce the carbon footprint of natural gas. Upstream and midstream players (E&P, GSP, pipelines) can maintain their current business models with significant CCUS investment or diversify into hydrogen-related ventures, though the latter's effectiveness for carbon reduction is contingent on the hydrogen production method. Downstream, gas-powered plants and industrial users face high CCS investment costs, potentially hindering product competitiveness. Individual CCS investment is currently infeasible, requiring large-scale projects driven by policy and financial incentives. This presents a **medium negative impact** on these stakeholders. LNG shippers and terminals will likely maintain operations due to continued gas demand, potentially expanding into hydrogen import with additional investment. This signifies a **low positive impact** for these stakeholders.

Drift: With a potential shift away from gas, all players could be forced to reassess their investment plans, potentially leading to stranded assets and financial losses. In addition, they may need to invest in abatement technologies to meet regulatory requirements to operate, even with reduced gas demand, further straining their financial resources. However, there could be opportunities to invest in low-carbon gas alternatives or related technologies, leading to **medium negative** impacts.

5.2 Risk factors

The carbon neutral pathway presents a complex landscape with several potential risks that need to be carefully considered. Government agencies and gas players typically highlight four main risks: volatility of global gas prices, depletion of domestic gas reserves, full implementation of climate change legislation and carbon pricing, and potential impact of non-tariff mechanisms.

5.2.1 Global gas price vulnerability

Uphold and Drift: If gas prices become volatile, the gas business will face challenges that will directly affect most gas players. E&P companies and users, including both industrial plants and petrochemical companies that require feedstock, will be **highly negatively impacted**. LNG shippers, acting as intermediaries, would experience a **low negative impact** as they are less directly affected by price fluctuations. Gas-fired power plants would also see a **low negative impact** due to the cost structure of electricity tariffs, which allow them to pass on increased costs to consumers.

	Uphold								Drift							
Impact Level of gas player	*E&P*	*LNG shippers*	*GSP (PTT)*	*Gas pipeline*	*LNG terminals*	*Users (Gas-power plant)*	*Users (Industrial plant)*	*Feedstocks (Petrochem)*	*E&P*	*LNG shippers*	*GSP (PTT)*	*Gas pipeline*	*LNG terminals*	*Users (Gas-power plant)*	*Users (Industrial plant)*	*Feedstocks (Petrochem)*
Global gas price vulnerability	High Negative	Low Negative				Low Negative	High Negative	High Negative	High Negative	Low Negative				Low Negative	High Negative	High Negative
Depleting domestic gas supply / security	High Positive	High Positive	High Negative	Medium Negative	High Positive	Medium Negative	Medium Negative	High Negative	High Negative	Low Positive	High Negative	High Negative	Low Positive	Medium Negative	Medium Negative	High Negative
Fully implementing of climate change act / carbon pricing	High Negative	Low Positive	High Negative	High Negative	High Negative	High Negative	High Negative	High Negative	High Negative	Low Negative	High Negative	High Negative	High Negative	High Negative	High Negative	High Negative
CBAM (EU/US/China)							Medium Negative	High Negative							Medium Negative	High Negative

Positive Impacts
● Low Positive ● Medium Positive ● High Positive

Negative Impacts
● Low Negative ● Medium Negative ● High Negative

5.2.2 Depleting domestic gas supply / security

Uphold: The depletion of domestic supply could have a moderately positive impact on LNG shippers and terminals. This is because the increased reliance on imported LNG would likely increase their business opportunities and utilisation rates. However, GSPs would face **high negative** impacts as reduced domestic gas production would directly affect their core business. Gas pipelines could experience **medium negative** impacts due to potentially lower utilisation rates resulting from reduced domestic gas supply, although imported LNG could still be distributed via pipelines to meet high demand. Gas-fired power plants and industrial plants, as users, might also encounter **medium negative** impacts. While they could still access alternative gas resources, the cost of these imports could be higher than domestic gas, potentially leading to increased costs for consumers. The E&P industry would face **high negative** impacts, as the need to find new reserves becomes more pressing. Petrochemical companies that rely on gas as a feedstock would also face **high negative** impacts due to the higher costs associated with importing feedstock.

Drift: LNG shippers and terminals might only see **low positive** impacts. While the depletion of domestic gas reserves could still create more demand for LNG imports, these opportunities could be limited by if Thailand's gas consumption declines which might force them to seek opportunities outside the country. Gas power plants and industrial plants could face **medium negative** impacts. Although domestic gas resources might be sufficient to meet reduced demand, they may be under pressure to further reduce their emissions. E&P companies would continue to face **high negative** impacts, as they would still need to find new reserves for their core business, even with lower demand. Petrochemical companies would continue to face **high negative** impacts due to the higher cost of imported feedstocks. GSP and gas pipelines would face **high negative** impacts. GSP would be affected by both depleting indigenous gas resources and low gas demand, while gas pipelines would be impacted with decreased gas demand and competition from LNG truck deliveries, potentially leading to lower utilisation rates.

5.2.3 Fully implementing the climate change act/carbon pricing

Implementing the climate change act/carbon pricing would have significant implications for the gas business, regardless of whether gas demand remains high or declines. The full implementation of climate change regulations or carbon pricing mechanisms would pose a **high negative** impact on most gas players including E&P companies, GSP, pipeline operators, LNG terminals, and end-users (including industrial plants, gas power plants, and petrochemical companies) all of which engage in activities that emit carbon dioxide. LNG shippers would be less affected as costs are passed through to electricity prices due to existing contracts.

Uphold: It may be economically viable to invest in technologies to reduce carbon emissions. However, the costs of these investments could be substantial, affecting profitability.

Drift: The sector's overall carbon emissions might be lower. However, companies would still face the difficult choice of either investing in emissions reduction technologies that may not be economically viable with lower demand or facing fines or carbon prices. This could further squeeze their already tight margins. LNG shippers, acting as intermediaries, would likely experience a **low negative** impact. They might face higher trading costs, but their overall operations would be less directly affected by carbon pricing than other gas players.

5.2.4 International trade measures related to carbon emissions

Uphold and Drift: The introduction of international trade measures tied to carbon emissions could have varied impacts on companies that export products to countries that prioritise reducing their carbon footprint. Industrial users might experience a **medium negative** impact, as they are likely to have alternative options to reduce emissions, such as switching to cleaner energy sources or adopting more efficient processes. However, petrochemical feedstock companies could face a **high negative** impact. These companies rely heavily on carbon-intensive processes, and adapting to stricter emissions regulations could necessitate significant changes to their core business models, potentially leading to substantial costs or even jeopardising their operations.

5.3 Employment

The chosen carbon-neutral pathway will directly impact the gas business, influencing its trajectory and employment opportunities. A shift away from natural gas could lead to a decline in the industry and associated job losses. However, it is important to consider that new jobs may be created in emerging sectors like renewable energy and hydrogen production, potentially offsetting these losses. This transition presents both challenges and opportunities for the workforce, requiring proactive measures to ensure a just and equitable shift towards a carbon-neutral future.

	Uphold								*Drift*							
Impact Level of gas player	***E&P***	***LNG shippers***	***GSP (PTT)***	***Gas pipeline***	***LNG terminals***	***Users (Gas-power plant)***	***Users (Industrial plant)***	***Feedstocks (Petrochem)***	***E&P***	***LNG shippers***	***GSP (PTT)***	***Gas pipeline***	***LNG terminals***	***Users (Gas-power plant)***	***Users (Industrial plant)***	***Feedstocks (Petrochem)***
Job losses	●	●	●	●	●	●			●	●	●	●	●	●		

Positive Impacts
● Low Positive ● Medium Positive ● High Positive

Negative Impacts
● Low Negative ● Medium Negative ● High Negative

Uphold: Even if the gas business continues, the transition towards cleaner energy sources is likely to require upskilling and reskilling of the workforce. This could lead to a **medium negative** impact on all players, as some employees may find their skills no longer relevant and face job losses.

Drift: A significant shift away from gas would likely lead to a contraction of the industry, resulting in a **high negative** impact on employment for all players. Companies may be forced to downsize or close, resulting in substantial layoffs and job losses. There would still be a need for upskilling and reskilling, but opportunities for re-employment in the gas sector may be limited.

6. SUMMARY AND RECOMMENDATIONS

The role of natural gas in Thailand's power system over the next 25 years will be critical to the success of Thailand's path to carbon neutrality. It has the potential to drive or delay the energy transition towards achieving carbon neutrality by 2050 and net-zero emissions by 2065 as pledged at COP26 in 2021.

The recent draft energy action plans indicate that Thailand is pursuing high gas demand for the power sector on its path to carbon neutrality. Some stakeholders argue that such a high natural gas demand path could be compatible with climate targets, but only if various critical and unclear enabling factors materialise. According to stakeholder interviews, these factors include expected low gas prices, hydrogen and CCS technology feasibility and regulations and increased domestic gas supply from a successful OCA resolution with Cambodia. Such expected enabling factors could potentially affect certain economic benefits to Thailand and avoid the costs of stranded assets related to Thailand's existing fossil-fuel infrastructure. Nevertheless, substantial risks could arise from relying on these uncertain enabling factors. Therefore, this report identifies three critical risks associated with this high gas demand path and the impacts on the energy trilemma and discuss potential risk mitigation strategies that align with the Nationally Determined Contributions (NDCs) goals to achieve climate commitments.

Compared with the LT-LEDS and other existing carbon neutral scenarios, the draft plan under discussion may struggle to reduce a significant share of gas-fired power generation and quickly increase the renewable energy share to the levels indicated by other carbon-neutral scenarios during the last mile from 2037 to 2050. This indicates that the current draft plan may set inadequate targets for reducing the share of natural gas and increasing the share of renewable electricity by 2037, leading to potential risks of not achieving carbon neutrality by 2050.

Key Risks of Heavy Reliance on Natural Gas in Thailand's Energy Transition

Risk Factors	*Energy Security*	*Energy Equity*	*Environmental Sustainability*
Risk 1: Carbon lock-in from gas-fired power generation and reliance on LNG imports	• Less diversified energy sources and electricity generation • Insecure gas supply with increasing import dependency • Insecure domestic gas supply with reliance on new national gas resources to be explored on overlapping claims area	• High electricity tariffs from lock-in gas-fired power contracts and exposure to volatile LNG prices • Fewer opportunities for cheaper renewables and unfair market participation in electricity sector • High stranded asset costs of gas infrastructure expansion embedded in electricity tariffs	• CO_2 and methane emissions • High electricity grid-emission factor • Impacts of LNG terminals and gas leakage on biodiversity • Air pollution from gas power plants
Risk 2: Costly and technologically uncertain abatement technologies to meet carbon neutrality	• Increased carbon lock-in with dependence on natural gas value chain • Less adoption of renewables in the electricity generation mix	• Likely increased electricity tariff through the reliance on currently immature and costly abatement technology options such as hydrogen and CCUS • Third-party acceptance and societal impacts and costs of abatement technologies • New skill development needed for hydrogen and CCUS • Unequal benefits of abating technologies	• CO_2 emissions and leakage from abatement technologies • Infeasible pathway to achieve carbon neutrality and net-zero pledges
Risk 3: Slowing down the development of renewables and grids despite the increased demand for clean electricity	• Insufficient supply of renewable electricity to meet increasing demand for clean electricity • Lack of adequate planning for energy storage, advanced grid infrastructure and smart technologies • Inability to leverage the resilience advantage of distributed energy resources	• Clean electricity available at more expensive cost • Negative impact on industry competitiveness • Unequal access to clean electricity, disproportionately affecting low-income households and small businesses • Less access to mitigation funds	• Inefficient development of transmission and distribution system to accommodate higher renewable electricity • Limit deeper decarbonisation options needed to achieve climate commitments through electrification

These adverse impacts of the risks could be much higher than expected in the future due to global uncertainties in the gas market and the severity of climate change impacts that may trigger more international trade restrictions and carbon pricing on fossil fuel activities. In addition, the power sector plan towards carbon neutrality should provide long-term directions that correspond to a future energy system despite disruptions from national and international political changes from new elections.

Key risk mitigation strategies for the energy plans currently under discussion are driving the consideration to shift to an accelerated and sustained carbon emission reduction or a faster transition path to carbon neutrality, deferring new natural gas power plants in the medium and long term for Thailand. As indicated by several existing carbon neutral scenarios, the share of natural gas in the electricity generation mix should be less than 20% in 2050 compared to a current 57% share.

Summary of potential mitigation strategies for each risk

Risk factors	*Potential risk mitigation strategies*
Risk 1: Carbon lock-in from gas-fired power generation and reliance on LNG imports	• Reduce natural gas demand in the medium term • Transform the role of natural gas to increase flexible operations • Ensure transparency and negotiate for flexible contractual agreements • Ensure supply and price stability of LNG imports • Ensure fair and equitable gas pricing structure • Explore new gas resources to reduce LNG imports
Risk 2: Costly and technologically uncertain abatement technologies to meet carbon neutrality	• Prepare for an accelerated and sustained decarbonisation pathway • Reduce GHG emissions along natural gas supply chains • Develop CCUS roadmap and regulations • Implement carbon pricing mechanisms • Repurpose gas pipeline infrastructure • Enhance international cooperation on innovation and cross-border storage of CO_2 • Fair and equitable allocation of carbon sink capacity to sectors with limited decarbonisation options.
Risk 3: Slow development of renewables to meet the increased demand for clean electricity	• Enhance direct power purchase agreement (DPPA) • Support decentralisation programmes to meet increased electricity demand and provide demand-side flexibility • Plan to accelerate more additions of new renewable capacity to the grid before 2030 • Introduce Utility Green Tariff

Thailand has faced several challenges in revising national energy plans and targets to align with climate change commitments. Although natural gas has historically provided energy security for electricity generation in Thailand, it is also the largest source of CO_2 emissions and a significant contributor to methane emissions. It has been a source of low-cost electricity in Thailand over the past decades, but 2022's volatile LNG import prices and a higher share of LNG imports because of declining domestic gas production have raised significant concerns about insecure gas supply and higher electricity tariffs through the pass-through mechanism of higher LNG prices.

Thai stakeholders[3] prioritise the following three criteria for choosing the energy pathway towards carbon neutrality: ensure reliable electricity and energy security to meet growing demand; reduce the risks of insecure gas supply, fuel price volatility, and insufficient carbon sinks; and align with global technology and cost trends towards carbon neutrality. However, expanding gas-fired power generation today poses significant risks of locking in carbon-intensive infrastructure and long-term financial burdens, with lasting adverse impacts on electricity tariffs. This lock-in power capacity and infrastructure for natural gas could delay the transition to renewables towards carbon neutrality and increase Thailand's risks to rely increasingly on imported LNG. It is prudent to reduce and transform the role of natural gas now to avoid potentially high stranded asset costs in the future and risks of not achieving carbon neutrality.

Reducing the share of natural gas in electricity generation could raise several challenges for practical implementation that require a comprehensive set of solutions to enable a cost-effective integration for higher shares of renewables and a just transition for industry gas players. A summary of key challenges and potential suggestions to enable a faster transition pathway is provided below.

[3] From a survey gathered from a public forum held in June 2024, conducted by CASE Thailand, from XX participants

Summary of key challenges associated with a faster transition pathway

Challenges	*Potential risk mitigation strategies*
1. Existing contracts and already approved gas infrastructure investments have locked Thailand into a high demand and high supply for natural gas pathway in the long term	• Reduce new gas-fired power generation and incentivise gas power plants to provide power system flexibility • Negotiate to remove contractual barriers for higher integration of renewables • Repurpose existing gas-fired power plants and gas pipelines
2. Energy security concerns on the reliability and costs of variable renewable energy integration have led to slow development of renewable energy and modernised grid infrastructure	• Increase renewable targets and unlock barriers for renewable deployment • Establish a new security of supply paradigm for the power sector based on national renewable resources. • Adopt integrated power sector planning and digitalisation technologies
3: Thailand lacks a just transition plan for natural gas towards carbon neutrality, a full gas liberalisation plan roadmap and a fair and equitable pricing structure of natural gas and electricity tariff	• Develop a gas transition plan with all stakeholders • Ensure fair and equitable gas liberalisation plan and pricing structure of natural gas and electricity tariff

Further research into potential risk mitigation strategies and solutions to address the challenges associated with the current energy system is needed:

- Comparative evidence on the economic costs associated with a high gas demand path versus a faster transition path aligned with other carbon-neutral scenarios. This helps to inform the decision on a non-regrettable path to carbon neutrality and mitigate the risks of stranded asset costs.
- A study on the optimised portfolio of LNG import contracts that could reduce risks from the fluctuations of the LNG market, including the implementation of market-based mechanisms needed to support the gas liberalisation plan.
- A roadmap for establishing a new security of supply paradigm for Thailand, based on national renewable resources, power system flexibility and advanced grid planning. This includes recommendations on how to meet the Loss of Load Expectation (LOLE) requirement to accommodate increasing renewable energy integration in a reliable and cost-effective way.
- Studies on how to improve gas pricing and electricity tariff structures to provide the right incentives for a carbon-neutral path and ensure fair market competition and fair pass-through of fuel and infrastructure costs to consumers.
- A technical and economic analysis on the benefits of rooftop solar and distributed storage as a source of power supply and demand-side flexibility in reducing the grid and electricity costs.
- To study the potential roles of the ASEAN Power Grid for power system flexibility and stability on the path to carbon neutrality.

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Annex 1: The LNG price crisis and its impact on electricity tariffs

In May 2024, Thai baht depreciation and low electricity generated from hydropower led to a higher dependency of natural gas procurement. Even though natural gas procurement gradually went to normal levels, Thailand still depended on importing LNG spot to compensate for decreasing natural gas in Myanmar. However, the spot price on the global market increased following higher demand at the end of the year. This caused the estimation of fuel price, electricity procurement cost and Fuel Adjustment Cost (FAC) to be higher from September to December 2024, compared to the previous period. Additionally, the fuel price has continuously risen since the end of 2021, and the ladder Fuel Adjustment Charge (Ft) rate has been alleviating the effects on customers for more than a year, affecting the EGAT to procure loans for the cost of electricity generation.

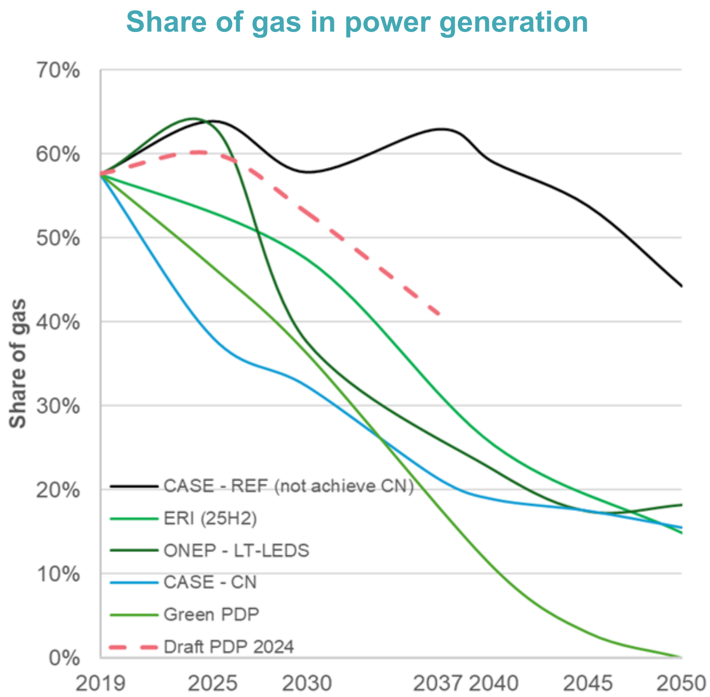
On 10 July 2024, the Energy Regulatory Commission (ERC) considered the result of the Ft calculation in the September to December 2024 period, regarding the situation of decreasing electricity generation from hydropower plants and coal power plants, the higher tendency of LNG spot, the lower exchange rate (Thai baht appreciation), and Accumulate Factor (AF) cost for EGAT, in order to maintain sustainable and stable operation and periodic loan payment including considering AF cost of natural gas (AFgas) of state enterprises (PTT and EGAT) following a Cabinet Resolution. The increasing Ft cost will affect the average electricity bills across the country which is classified in accordance with the quantity of consumption, as in the table below.

Compared to the present Ft (average base electricity charge 3.7833 Baht/unit)* (1 baht = 100 satang)	***Electricity charge May–Aug 2024 following the ERC Resolution 27 Mar 2024 (baht/unit) [1]***	***The impact on electricity charge (baht/unit)***	
		Base electricity charge + Ft Sep – Dec 2024 [2]	**Change [2] - [1] (per cent)**
(1) EGAT's report and return AF_{gas}: Ft 222.71 satang/unit	**418** (Ft = 39.72 satang/unit)	**6.01**	+1.83 (+43.78%)
(2) FAC + repay AF 3 instalments & AF_{gas}: Ft 113.78 satang/unit		**4.92**	0.64 (+17.70%)
(3) FAC + repay AF 6 instalments & AF_{gas}: FT 86.55 satang/unit		**4.65**	+0.47 (+11.24%)

Remark: In Case #1: Full FAC Repayment, EGAT and state enterprises involved in natural gas operations will receive full repayment for all fuel adjustment costs (FAC) incurred during the energy crisis (September 2021 – April 2024). This repayment, covering varying natural gas prices, will result in a higher base electricity charge. Similarly, Case #2: Repayment in 3 Instalments and Case #3: Repayment in 6 Instalments also involve full cash repayment for all natural gas price variations, ultimately leading to an increased base electricity charge.

Source: (ERC, 2024b)

Annex 2: Thailand's carbon-neutral scenarios



Energy modelling scenarios	*Key assumptions*
CASE – REF: Thailand's Energy System Transition Based-on Reference Scenario	This scenario aligns with existing policies (e.g., PDP 2018 rev1), as of the report's publication in 2022. It assumes no significant acceleration or enhancement of the current policy measures. Under this scenario, the share of natural gas in the power generation mix remains dominant, accounting for approximately 50% in 2050. Solar PV, while increasing its contribution from 10% in 2030 to 32% in 2050, is insufficient to drive a transformative shift in the energy system. This scenario clearly indicates that, without substantial policy changes, Thailand will not achieve its carbon neutrality target by 2050.
ERI (25H2): Introduction of Hydrogen Blending in Natural Gas and Solar PV with BESS	The primary objective of this study is to reduce carbon emissions in Thailand's power sector. The approach includes blending hydrogen as the fuel for conventional combined cycle gas turbine (CCGT) units. The study evaluated four different blending ratios of hydrogen to natural gas (0%, 25%, 50% and 75%) with hydrogen cost based on blue hydrogen. In this report, the 25% hydrogen blending scenario has been identified as the most viable option. This scenario closely mirrors the 0% hydrogen case in terms of capacity, with 13 300 MW of CCGT capacity added to the system under emission constraints. However, it requires fewer PVBESS units than the 0% scenario, resulting in reduced carbon emissions and electricity costs. While the immediate differences are modest, the change will become noticeable over time. This scenario also leads to a reduction in natural gas consumption, lowering its share in the overall fuel mix to 14% by 2050. It is important to note that the study does not account the cost associated with retrofitting existing natural gas infrastructure to accommodate hydrogen blending.

Energy modelling scenarios	Key assumptions
ONEP – LT-LEDS: Thailand's Long-Term Low Greenhouse Gas Emission Development Strategy (LT-LEDS)	To achieve its carbon neutrality target by 2050 and net-zero emissions by 2065, Thailand's LT-LEDS emphasises reducing reliance on fossil fuels. For the power sector, the advanced combined cycle gas turbines and systems blending natural gas with hydrogen were considered. According to LT-LEDS projections, the share of natural gas in the electricity generation mix is expected to decline significantly, from 54% in 2020 to 18% in 2050. Meanwhile, renewable energy is projected to dominate the mix, increasing its share to an estimated 74% by 2050.
CASE - CN: Thailand's Energy System Transition Based-on Carbon Neutrality 2050 Scenario	The CASE-CN scenario outlines a clear policy direction emphasising RE and sustainable industry development, positioning Thailand as a leader in the energy transition. This scenario is driven by a cost-optimal transformation of the energy system, ensuring uninterrupted electricity supply while pursuing the carbon neutrality target. It incorporates the feasibility of electrifying end-use sectors, such as transport and industry sectors, to reduce emissions comprehensively. By 2050, RE is projected to dominate the power generation mix, contributing approximately 70%. This shift reduces the share of natural gas to less than 20%.
Green PDP: SWITCH Modules (of PDP 2018) in Thai version	The Green PDP scenario integrates several low-carbon technologies into the power grid, resulting in a declining reliance on natural gas. The model is designed around the simultaneous optimisation of investment and dispatch decisions, ensuring both economic efficiency and system reliability. The analysis demonstrates that it is feasible to phase out natural gas-based generation entirely by 2050. This can be achieved while maintaining a reliable RE system through the deployment of advanced technologies such as energy storage, demand response and enhanced grid operations.
Draft PDP 2024: Power Development Plan 2024 (draft)	In response to the changes in Thailand's economic growth projections, evolving energy demand patterns and the increased focus on reducing carbon emissions to achieve carbon neutrality by 2050, the draft PDP 2024 represents a significant revision from the previous PDP 2018 rev1. One of the key strategies to manage natural gas usage is blending natural gas with hydrogen to generate electricity. The share of natural gas in the electricity generation mix is projected to decline from 57% in 2023 to 53% by 2030 and further to 41% by 2037. On the contrary, the share of RE in generation mix will increase to 33% and 51% in 2030 and 2037, respectively.
CASE – Green Gases Scenario	The Green Gases scenario examines the role of higher RE proportions in replacing fossil gas within the power sector, emphasising the use of "green gases" like hydrogen. According to the modelled net-zero pathway, the share of fossil gas declines dramatically, with gas turbines transitioning to a secondary role, primarily as a system backup to ensure reliability. Under this scenario, hydrogen gradually replaces fossil gas, working alongside battery energy storage system to support a reliable and low-carbon energy system. *Note: While specific shares of gas usage in particular years are not provided, the total final energy consumption of fossil gas reaches zero by 2070, highlighting its complete phase-out as well as the significant growth in hydrogen use (CASE, 2024).*

Source: (CASE, 2022; Diewvilat & Audomvongseree, 2022;
ONEP, 2022; ONEP, giz & TU, 2022; TU, FES, TCC & Pro Green, 2022)

Annex 3: Natural gas liberalisation plan

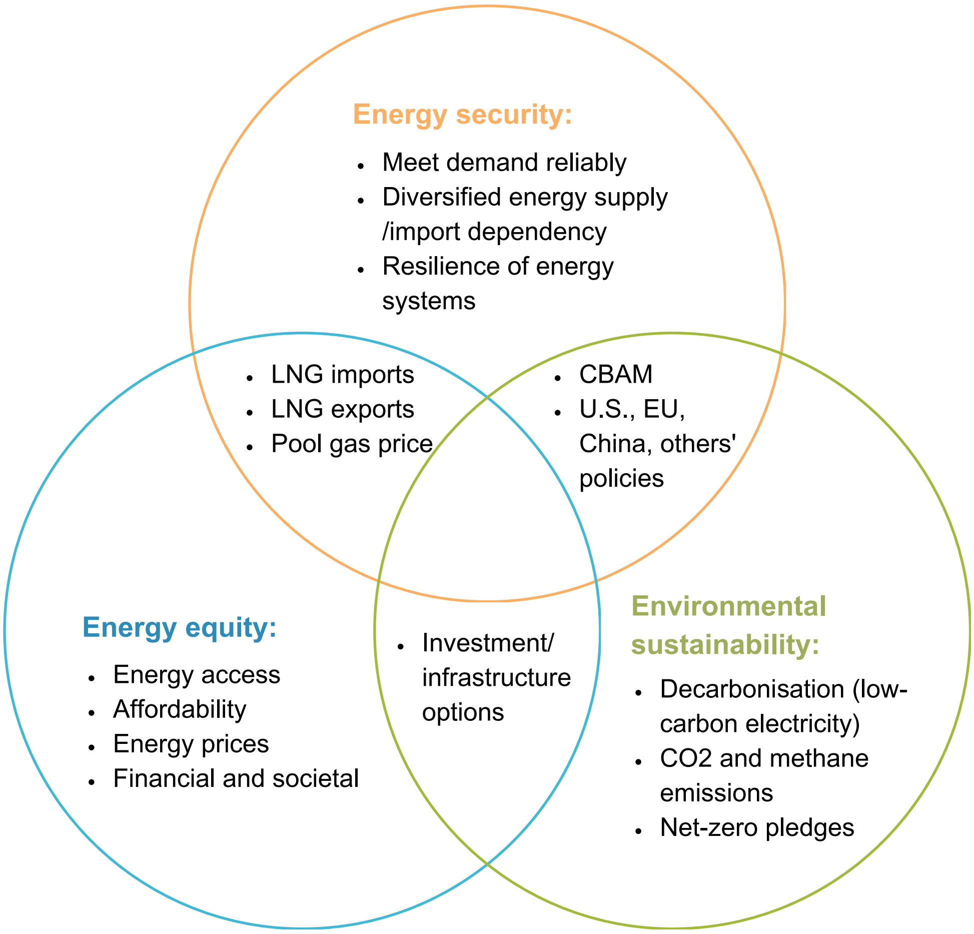
This annex provides an overview of the natural gas liberalisation plan, including progress made during Phase I and Phase II (e.g., licences for new shippers and TPA). The natural gas liberalisation plan has objectives to ensure supply security, promote competition in the natural gas business and reduce energy prices.

Phase 1 *Approved* ***Pilot project*** ***(Completed in 2020)***	***Phase 2*** *Approved* ***Pre-liberalisation*** ***(Current - In progress)***	***Phase 3*** ***Full-scale liberalisation*** ***(Under study)***
• Facilitating the transition from the existing structure to a more competitive framework. • Pilot project is initiated to test obstacles and various constraints.	• Opening the gas sector to new private entrants, including LNG importation, procurement, and distribution, with designated roles such as Shippers and Pool Managers. • Established a pool manager by ERC to ensure transparent pricing and contract management in the regulated natural gas market.	• Increased participation of LNG importers and Shippers enhances market readiness for heightened competition. • Promoting competition within the electricity industry is essential to fostering free competition across the energy sector.

Complying with the Energy Business Act of 2007, ERC has developed the Third-Party Access Code (TPA Code) to provide a common framework for licence holders in the natural gas supply, wholesale, and other energy sectors to access or connect with the gas transmission system.

Annex 4: A framework for assessing the impacts of risks on the energy trilemma

Natural gas and the impacts on 'energy trilemma' framework



Source: Illustrations from (WEC, 2024) (EFI Foundation, 2024)

World Energy Trilemma Indicators

Energy trilemma	*Potential risk mitigation strategies*
Energy security	• **Security of supply and demand** (i.e., diversity of primary energy supply, import dependence) • **Resilience of energy systems** (i.e., diversity of electricity generation, energy storage, system stability and recovery capacity)
Energy equity	• **Energy access** (i.e., to electricity, to clean cooking) • **Quality energy access** (i.e., access to modern energy) • **Energy affordability** (i.e., electricity prices, gasoline and diesel prices, natural gas prices, affordability of electricity for residents)
Environmental sustainability	• **Resource productivity** (i.e., final energy intensity, efficiency of power generation and T&D) • **Decarbonisation** (i.e., CO_2 emissions trend, low-carbon electricity generation) • **Emissions and pollutions** (such as CO_2 intensity, PM2.5, PM2.0, CH4 per capita)
Country context	• **Macroeconomic stability** • **Governance** (effectiveness of government, political stability, rule of law, regulatory quality) • **Stability for investment and innovation** (foreign direct investment net inflows, ease of doing business, perception of corruption, efficiency of legal framework in challenging regulation, intellectual property protection and innovation capacity)

Source: Illustrations from (WEC, 2024)

Annex 5: Technology readiness and LCOE update

A. Technology readiness

Renewables and energy storage: Solar PV, onshore wind and lithium-ion storage battery have already reached the market uptake level (commercial operation and integration needed at scale), while pumped storage is the only energy storage technology that is at a mature (proof of stability) level.

- Power > Hydropower
- Power > Organic rankine cycle (geothermal)
- Power > Flash process (geothermal)
- Power > Dry steam (geothermal)

11 Mature (4/55)

- Power > Pumped storage

11 Mature (1/55)

- Power > Onshore wind
- Power > Crystalline silicon PV
- Power > Solar tower
- Power > Parabolic trough (solar)
- Power > Thin film
- Power > Multi-junction cell PV
- Power > Floating solar PV
- Power > Concentrated PV
- Power > Tidal stream-Ocean current
- Power > Tidal range
- Power > Kalina process (geothermal)

9-10 Market uptake (11/189)

- Power > Battery storage system with grid-forming inverter
- Power > Flywheel
- Power > Lithium-ion storage battery
- Power > Molten salts storage

9-10 Market uptake (4/189)

CCUS and CO_2 management: Most CCUS and CO_2 management technologies are still at a demonstration and prototype level.

Power >
Post-combustion: chemical absorption (coal with CCUS)

9-10 Market uptake (1/189)

CO_2 storage >
Pipeline

CO_2 storage >
Saline formation

9-10 Market uptake (2/189)

Power >
Post-combustion: chemical absorption (natural gas with CCUS)

Power >
Pre-combustion: physical absorption (coal with CCUS)

Power >
Oxy-fuelling (coal)

Power >
Post-combustion: solid adsorption (coal with CCUS)

Power >
Post-combustion: solid adsorption (biomass with CCUS)

Power >
Post-combustion: chemical absorption (biomass with CCUS)

7-8 Demonstration (6/158)

CO_2 transport >
Shipping

CO_2 storage >
Depleted oil and gas reservoir

CO_2 storage >
Advanced monitoring technologies

CO_2 capture >
Solid DAC (S-DAC)

CO_2 transport >
Shipping

7-8 Demonstration (5/158)

Power >
Post-combustion: membranes polymeric (coal with CCUS)

Power >
Supercritical CO_2 cycle (natural with CCUS)

Power >
Supercritical CO_2 cycle (coal with CCUS)

Power >
Chemical looping combustion (coal)

5-6 Large prototype (4/100)

CO_2 capture >
Liquid DAC (L-DAC)

CO_2 storage >
Dissolved CO2 injections

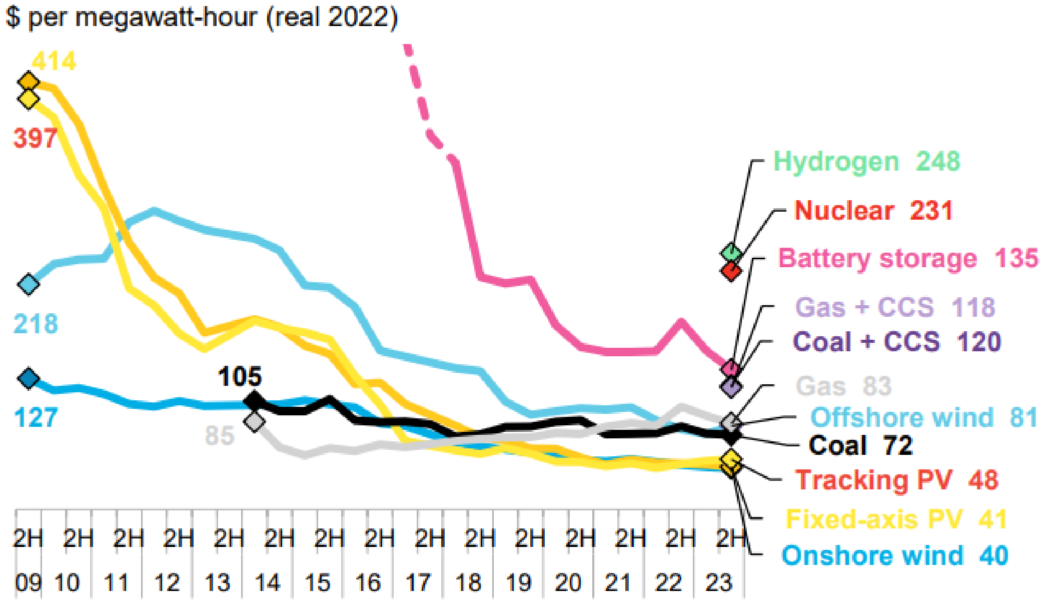
5-6 Large prototype (2/100)

LCOE update

Solar PV and onshore wind have emerged as the cheapest sources of newly built power generation, which have made them highly competitive compared to traditional fossil fuels since 2018. The cost of battery storage, which could enhance the reliability of renewable energy integration through grid services such as load balancing and frequency regulation, has dropped rapidly.

Meanwhile, coal and gas-fired power plants equipped with Carbon Capture and Storage (CCS) technologies are significantly more expensive, partly due to low concentration of CO_2 from power plants. The cost of coal and gas with CCS is almost triple that of solar and onshore wind power.

Global levelisedb cost of electricity benchmark
for the years 2009-2023

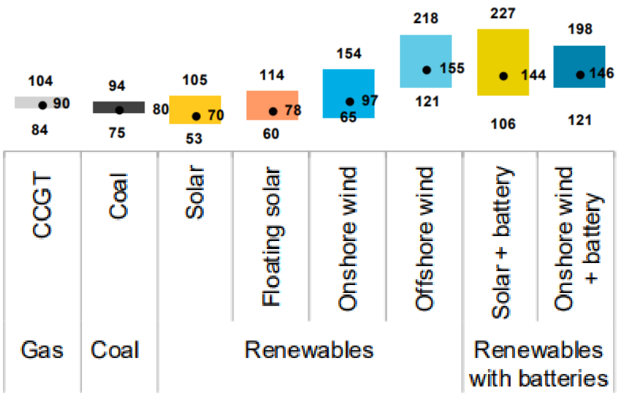


Source: https://assets.bbhub.io/professional/sites/24/Clean-Energy-Ministerial-Factbook-2024.pdf (Page 20)

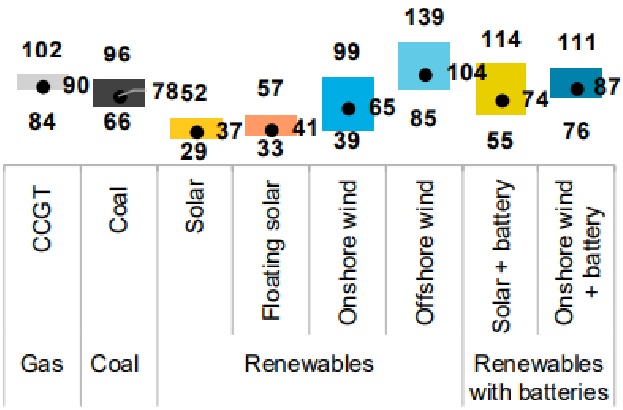
Note: The global benchmarks are capacity-weighted averages using the latest country estimates, apart from nuclear, hydrogen and carbon capture and storage (CCS), which are simple averages. Offshore wind includes offshore transmission costs. Coal- and gas-fired power include carbon pricing where policies are already active. Levelised costs of electricity (LCOEs) do not include subsidies or tax-credits. LCOEs shown by financing date. 'PV' stands for photovoltaic solar.

By 2030, BNEF estimates that a solar plus battery storage project (expected LCOE to fall to $55-114/MWh by 2030 and $33-72/MWh by 2050) could become cost competitive against a new coal and gas power plant in Vietnam as shown below (BNEF, 2023).

Levelised cost of electricity of new power plants in Vietnam in 2023, by technology



Levelised cost of electricity of new power plants in Vietnam in 2030, by technology



Source: https://assets.bbhub.io/professional/sites/24/20231020_Vietnam-TCF-report-with-factsheets-EN.pdf (Page 6, 7)

Note: Solar and onshore wind plus batteries modelled with a four-hour battery. CCGT is combined-cycle gas turbine.

Annex 6: Challenges for hydrogen development

The domestic hydrogen supply may not be sufficient to meet demand and requires strong policy support. Given its limited availability, hydrogen should be reserved for applications in the hard-to-abate sector.

Challenges for hydrogen development in Thailand

High cost	Technological immaturity	Low production & conversion efficiency
Insufficient renewable electricity	Policy & regulatory uncertainty	Lack of standards & certification
	Chicken-and-egg problem	

High cost: The cost of clean hydrogen, particular green hydrogen, is still high relative to high-carbon fuels. Not only regarding the cost of production but the costs of transporting, converting and storing hydrogen as well. Adopting clean hydrogen technologies for end-use can be expensive and CCS has yet to be deployed at scale.

Technological immaturity: Some technologies in the hydrogen value chain required for decarbonisation still have a low level of technological readiness and need to be proven at scale. For instance, gas turbines that operate exclusively with hydrogen are not currently available off the shelf, and when it comes to maritime trade, there is only one prototype vessel that can transport liquid hydrogen.

Low production & conversion efficiency: Hydrogen production and conversion incur significant energy losses at each stage of the value chain, including production, transport, conversion and use. Moreover, production of blue hydrogen is energy-intensive, adding to overall energy demand.

Insufficient renewable electricity: By 2050, the production of hydrogen with electrolysers may consume close to 21,000 TWh, almost as much electricity as is produced globally today. As more end-use sectors are electrified, a lack of sufficient renewable electricity may become a bottleneck for green hydrogen.

Policy and regulatory uncertainty: Although over 140 countries have pledged to achieve net-zero emissions within the coming decades, the speed with which these goals will be achieved remains uncertain. Stable, long-term policy frameworks are needed to support development and deployment at scale.

Lack of standards and certification: Countries lack institutionalised mechanisms to track the production and consumption of any shade of hydrogen and identify its characteristics (e.g., origin and life-cycle emissions). Moreover, hydrogen is not counted in official statistics of total final energy consumption and the economic value of clean hydrogen's contribution to emission reductions is not recognised.

The hydrogen infrastructure paradox: Without demand, investments remain too risky for wide-scale production that could reduce costs, but without economies of scale the technology remains too costly.

Annex 7: Policy measures for higher integration of VRE

Measure to integrate VRE	Phase of VRE integration					
	1	2	3	4	5	D
Enhance power plant capability						
Retrofit conventional power plants	Limited	Common	Common	Widespread	Widespread	Widespread
Flexible offtake and upstream fuel contracts	Limited	Limited	Common	Widespread	Widespread	Common
Increase VRE technical requirements	Common	Widespread	Widespread	Widespread	Widespread	Common
Forecasting						
VRE generation	Common	Widespread	Widespread	Widespread	Widespread	Widespread
Net load	Limited	Common	Common	Widespread	Widespread	Common
Power flows	Limited	Common	Common	Common	Common	Common
Demand-side measures						
Industrial demand response	Common	Widespread	Widespread	Widespread	Widespread	Widespread
Commercial demand response	Limited	Common	Widespread	Widespread	Widespread	Common
Residential demand response	Limited	Limited	Common	Common	Widespread	Limited
Steer location of new demand	Limited	Limited	Limited	Common	Common	Limited
Modify system operation rules						
Allow VRE curtailment	Limited	Common	Common	Common	Widespread	Limited
High granularity/closer to real time	Limited	Common	Common	Widespread	Widespread	Common
Least-cost dispatch	Common	Widespread	Widespread	Widespread	Widespread	Common
Capacity mechanism	Limited	Common	Common	Common	Common	Common
Establish balancing market	Limited	Common	Common	Widespread	Widespread	Common
Establish ancillary service market	Limited	Common	Common	Common	Widespread	Limited
Enhance use of interconnection	Limited	Common	Common	Widespread	Widespread	Common
Enhance grid capacity and use						
Install stability support devices(STATCOMs, SYNCONs)	Common	Common	Common	Common	Widespread	Common
Interconnection/redundancy/mesh	Widespread	Widespread	Widespread	Widespread	Widespread	Widespread
Reinforcement	Common	Widespread	Widespread	Widespread	Widespread	Widespread
Allow VRE curtailment	Common	Widespread	Widespread	Widespread	Widespread	Widespread
Power flow control	Limited	Common	Widespread	Widespread	Widespread	Widespread
Steer location of new VRE	Limited	Common	Common	Widespread	Widespread	Common
Storage						
Pumped hydro	Common	Widespread	Common	Common	Widespread	Common
Battery energy storage	Limited	Common	Common	Widespread	Widespread	Widespread
Long-duration storage	Limited	Limited	Limited	Limited	Common	Limited

Implementation of measure

- Limited
- Common
- Widespread

Source: (IEA, 2024b)