

An Irresponsible Path to Net Zero: A Critique of Draft PDP 2026

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by

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Abbreviations

CAPEX	Capital Expenditure
CBAM	Carbon Border Adjustment Mechanism
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CEPCI	Chemical Engineering Plant Cost Index
CPI	Consumer Price Index
ECB	European Central Bank
EGAT	Electricity Generating Authority of Thailand
EPPO	Energy Policy and Planning Office
ERC	Energy Regulatory Commission
FID	Final Investment Decision
FIT	Feed-in Tariff
GDP	Gross Domestic Product
GWh	Gigawatt-hour
HTR-PM	High-Temperature Gas-Cooled Reactor Pebble-Bed Module
IEA	International Energy Agency
IEEFA	Institute for Energy Economics and Financial Analysis
INL	Idaho National Laboratory
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
JKM	Japan Korea Marker
kWh	Kilowatt-hour
LCOE	Levelized Cost of Electricity
LNG	Liquefied Natural Gas
LT-LEDS	Long-Term Low Greenhouse Gas Emission Development Strategy
MMBtu	Million British Thermal Units
MMscfd	Million Standard Cubic Feet per Day
MtCO ₂ e	Million Tonnes of Carbon Dioxide Equivalent
MWe	Megawatt Electrical
MWh	Megawatt-hour
NBTC	National Broadcasting and Telecommunications Commission
NDC	Nationally Determined Contribution
NEA	Nuclear Energy Agency
NEI	Nuclear Energy Institute
NEPC	National Energy Policy Council
NETL	National Energy Technology Laboratory
O&M	Operation and Maintenance
OPEX	Operating Expenditure
PDP	Power Development Plan
PEA	Provincial Electricity Authority
PPA	Power Purchase Agreement
SMR	Small Modular Reactor
tCO ₂ e	Tonne of Carbon Dioxide Equivalent
TWh	Terawatt-hour
UAMPS	Utah Associated Municipal Power Systems

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Climate Finance Network Thailand (CFNT) is a think tank and a network of like-minded individuals headquartered in Bangkok, devoted to propelling sustainable financial practices and assisting in Thailand's transition toward a low-carbon economy in line with 1.5°C climate target. CFNT's primary objective is to help catalyze impactful climate finance through solution-based research, stakeholder engagement, and network building. Our goal is to assist Thailand's financial sector to be more responsive to the challenges of climate change. By uniting forces with like-minded partners, CFNT endeavors to help shape a financial landscape that aligns with global sustainability goals and fosters a resilient, green, and inclusive economy.

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Key Takeaways

- Draft Power Development Plan 2026 ("PDP2026") purports to bring Thailand to meet 2050 net zero target, the first PDP that stretches this long. The route it proposes, however, is irresponsible in the unnecessary and hidden costs. That is not because renewables are expensive but because of how the plan is designed around them.
- The biggest decisions are not on the table. Through 2037, every proposed scenario adds the same 50,900 MW of new capacity, including 9,100 MW of new gas (up from 6,300 MW in PDP2024) and 540 MW of refurbished lignite. The choice on offer begins only after the commitments that matter most are locked in.
- The risks from higher gas imports are locked in from the start. In every scenario, gas demand rises above the level the plan itself marks as an Liquefied Natural Gas (LNG) import risk in the early 2030s. Thailand's LNG imports have already roughly doubled since 2021. We estimated that a high-price year for LNG could add THB 0.38 to 0.44/kWh to Case 4's 2050 gas cost, compared with a median-price year.
- The medium term, years 2038-2050 or "Phase 2" in PDP2026 terminology, relies on technologies Thailand has not yet built. For example: Case 4 purports to capture 21 million tons of CO₂ equivalent per year, about a third of all Carbon Capture and Storage (CCS) facilities operating worldwide today. Once transport, storage and the energy penalty are counted, capture may cost up to 57% more than the plan assumes. Small Modular Reactors (SMRs) in all scenarios are planned at 9,000 MW, with operating cost assumptions below half of international estimates and no fallback.
- One unnamed technology may prove decisive in which case gets selected. The plan reserves 2,500 to 3,000 MW for an unspecified power source and prices it at the system average, which makes it tariff-neutral by construction. The candidates the plan does name, which are long-term energy storage, green hydrogen electrolysis with fuel cells, and other new clean technologies, suggest steep investments between THB 225 to 540 billion. Estimated tariffs under Cases 1, 3, and 4 differ by less than THB 0.01/kWh, so this one assumption could be enough to tip the comparison.
- A more responsible and fairer PDP2026 is possible with greater transparency and changing assumptions to be more in line with technological progress. Phase 1 plan (2026-2037) should be revised to use practical alternatives and prevent any unnecessary fossil lock-in, phase 2 (2038-2050) plan should price carbon and LNG risks realistically, and name and cost every technology. Even using the plan's own numbers, Case 3 – the renewables-pathway case – is the most cost-effective plan all along; adding clarity and realistic assumptions will distance it further from the pack and prove it to also be the most responsible to the public and Thailand's net zero future.

Introduction

Thailand's Power Development Plan (PDP) sets out the country's planned electricity generation mix and, in doing so, shapes the power sector's emissions over the following 20 to 25 years. The plan currently in force is PDP2018 Revision 1 (released in October 2020). Its intended successor, PDP2024, was released for consultation in mid-2024 but never came to pass. The draft PDP2026, released on September 8, 2026, is therefore the second attempt in three years to replace a plan that is now six years old and sorely outdated.

The changes between the two drafts (draft PDP2024 vs. draft PDP2026) are substantial and, in several respects, welcome. The horizon extends from 2037 to 2050, aligning the plan for the first time with the national 2050 net-zero target. Lower assumed GDP growth and negative population growth reduce the 2037 business-as-usual forecast by 7.9% for energy and 4.0% for peak load. The base year moves from 2019 to 2025, capturing the shift in system peak time to around 9:00 p.m., which directly affects how much solar generation counts toward meeting peak load. Planning regions increase from five to seven, electric vehicle and data center demand is treated explicitly for the first time, and the Reserve Margin requirement gives way to a Loss of Load Expectation (LOLE) standard of no more than one day per year, which is better suited to a system with a growing share of variable renewable energy.

Those improvements are not in dispute. The difficulty lies in how the different scenarios (called "cases" in PDP2026) are presented as "options" to the public. All four cases build an identical 50,900 MW between 2026 and 2037 (called "Phase 1" in the plan), at identical reliability and identical tariffs, and diverge only afterwards. Within that block, new combined-cycle gas capacity rises from 6,300 MW in PDP2024 to 9,100 MW here. The real question is what each case actually costs, and who pays.

The plan's own figures answer part of it already. Case 3, the renewable pathway without carbon capture, is the cheapest of the four cases and carries the lowest exposure to liquefied natural gas (LNG) price risk, yet Case 4 is presented as the "balanced" option without a clear explanation of what that balance actually means and at what cost. Case 1, meanwhile, is held to a weaker emissions target than the other three, which makes every compliant pathway look expensive by comparison. It should be dropped from the plan, since any case that makes Thailand fail its own net zero commitment cannot be considered a realistic option.

Where does the extra cost hide? We will show in Section 2 (Phase 1) of this brief that it partly lies in the years already locked in: by the early 2030s, gas demand rises above the level the plan itself marks as an LNG import risk, and lignite is set to outlast its expected fuel supply, yet no case tests an earlier phase-out of coal. In Section 3 (Phase 2), we will also show that part of it lies in a bet on uncertain technologies Thailand has yet to build: capturing up to half of today's global CCS volume, at up to 57% above the assumed cost, alongside 9,000 MW of largely unproven SMRs. This Phase 2 section also finds it in a technology with no name, priced so that it can never look expensive, yet decisive enough to change which case wins. Section 4 (Conclusion) proposes a responsible way forward.

One thing to note before the sections that follow. The plan's technology cost table assumes almost no further decline in renewable and storage CAPEX after 2037, while thermal capital costs rise in real terms over the same period. That assumption feeds directly into the retail tariff on which the four cases are compared, and it works against the renewable pathway. Our findings below are conservatively based on the plan's own numbers, and correcting this asymmetry would strengthen them. The analysis that follows tests a single proposition: decarbonization under PDP2026 would be expensive not because renewable energy is costly, but because of how the plan would be designed around it. This is why we call draft PDP2026 "irresponsible."

Phase 1 (2026-2037): Irresponsible fossil lock-in

Draft PDP2026's four cases diverge only after Phase 1 in the plan which covers 2026-2037. Through 2037, major assumptions include data center demand, gas including LNG expansion, imported hydropower, and committed coal capacity.

Data centers

Data center growth is an important source of demand uncertainty in draft PDP2026. The plan considers 6,799 MW, 8,811 MW and 19,808 MW, carries the lower two into its scenarios, and projects 42,468 to 55,744 GWh of Data Center electricity demand in 2050.¹ PDP2026 does not clearly show how the MW figures map to the GWh projections or to system costs. MW denotes power at a point in time or requested connection capacity, whereas GWh denotes electricity consumed over time; the two are not interchangeable.

External indicators vary widely. According to reports in August and September 2026, the Ministry of Energy reports applications of about 35,000 MW; the Provincial Electricity Authority (PEA) has received about 26,000 MW applications against around 3,000 MW of its network capacity.² Operators holding National Broadcasting and Telecommunications Commission (NBTC) licenses report about 1,059 MW of capacity.³ In the United States, Wood Mackenzie estimates that utilities and grid operators are likely to commit to about 28 percent of 1,066 GW requested, with many requests described as phantom or long-shot proposals.⁴ This does not imply that Thailand will face the same rate, but it supports treating applications as potential rather than realized demand.

The second uncertainty is how data center demands translate into system requirements. Draft PDP2026 does not specify whether the MW figures mean grid demand, requested connection capacity or total demand including Direct Power Purchase Agreements (PPAs), under which a large user contracts directly with a generator; it also changes the data center and energy-efficiency assumptions together.⁵ Although the plan describes data centers as baseload, it does not show how much of the 9,100 MW of new gas or 14,500 MW of battery storage is planned to support them.⁶ This makes the incremental generation, network and fuel costs difficult to identify.

The potential scale could nevertheless be significant. If all projected 2050 data center electricity demand were supplied by combined-cycle gas, the LNG equivalent would be about 53 to 70 percent of Thailand's 2024 LNG imports (Appendix A.2).⁷ This is an illustration, not a forecast. The National Energy Policy Council (NEPC) has adopted the principle that data centers should bear their own costs and approved a dedicated tariff ("Type 9") in principle.⁸

The proposed Type 9 tariff is therefore a constructive step. News reports of the government's announced plans describe a separate data center charge, including imported LNG at actual prices, with a fuel charge component above THB 5 per unit when LNG exceeds USD 23/MMBtu.⁹ The remaining

¹ Draft PDP2026, slides 13 and 14.

² Ministry of Energy statement reported by The Standard (16 September 2026); PEA statement reported by MGR Online (7 September 2026); Thanseetakij (2026).

³ Naichang Mashare (11 September 2026), NBTC certificate records.

⁴ Bloomberg (12 August 2026), citing Wood Mackenzie.

⁵ Draft PDP2026, slide 14.

⁶ Draft PDP2026, slides 9 and 31.

⁷ EPPD, Table 3.1-1; Appendix A.2.

⁸ Government Public Relations Department (2026); Spring News (2026); Energy Regulatory Commission (2026), Ft disclosure document.

⁹ Thanseetakij (28 August 2026).

issue is whether the tariff also recovers capacity, reserve, balancing, network, loss and backup costs rather than leaving them elsewhere in the pooled system.¹⁰

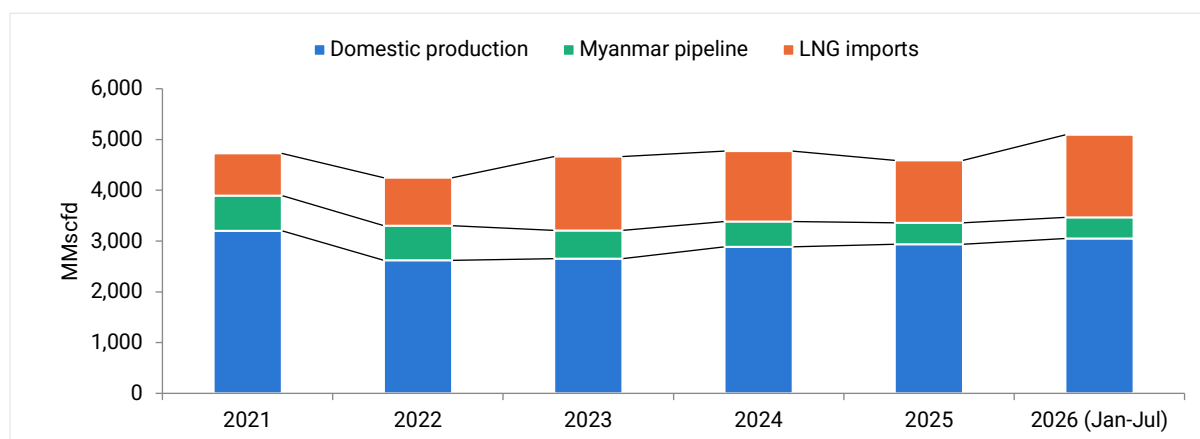
It remains unclear whether data center-related costs are excluded from the pooled Ft (fuel adjustment charge – a variable energy adjustment added on top of the base electricity tariff) and how Direct PPA users pay for backup and grid use. The Energy Regulatory Commission (ERC) has said existing and new operators will face the same rates, with criteria due by the end of 2026.¹¹

The final PDP and tariff design could therefore show the additional capacity, fuel and network investment under each data center case, vary data center demand separately from energy efficiency, and enumerate incremental costs that Type 9 tariff covers.

LNG price exposure

Draft PDP2026 identifies LNG imports as a potential risk in the Phase 1 plan between 2026-2037. Its gas-demand chart marks 2,000 MMscfd as a threshold and labels any demand above it as LNG import risk, without explaining how that threshold was set. Gas demand is projected to rise above this threshold in the early 2030s and stays above it through 2037.¹² EPPO data shows that LNG imports rose from 829 MMscfd in 2021 to 1,628 MMscfd in the first 7 months of 2026, while Myanmar pipeline gas fell by about 41 percent (Figure 1).¹³ Yet draft PDP2026 does not disclose enough of the underlying gas balance to show the underlying LNG quantity and price assumptions.

Figure 1 Thailand gas supply by source, 2021 to Jan-Jul 2026



Source: EPPO

Case 4 illustrates why this issue matters beyond 2037: it uses 1,904 MMscfd of gas in 2050, compared with 794 MMscfd in Case 3.¹⁴ The Yadana contract is reported to end in 2028, while Case 4 is described as “using domestic gas at full potential” without disclosing domestic gas volume.¹⁵ The resulting LNG requirement therefore cannot be inferred from draft PDP2026.

¹⁰ Energy Law Center Thailand (2026), “Power of The Act: อำนาจการกำหนด Data Center”, InfoQuest.

¹¹ Bangkok Biz News (2026).

¹² Draft PDP2026, slide 37.

¹³ EPPO, Table 3.1-1.

¹⁴ Draft PDP2026, slide 37.

¹⁵ Energy News Center (2024); MGR Online (2023); Draft PDP2026, slide 37.

The procurement structure matters as well as volume. Spot LNG is bought close to delivery date at prevailing prices, while long-term contracts commit volumes for years against an index. In 2023, 5.1 of Thailand's 11.3 million tonnes of LNG imports (45%) were reported as long-term supply and 6.2 million tonnes (55%) as spot purchases, so the same LNG volume can carry very different price exposure.¹⁶

Long-term contracts can reduce spot-price exposure, but they do not remove price risk: replacement contracts may be indexed to oil, Henry Hub or Japan Korea Marker (JKM) and create long-term volume obligations.¹⁷ Draft PDP2026 does not publish the contracted share or index assumed in each case. The planning question is therefore how much LNG is required, how much is contracted, on what index and for how long.

Trends of LNG price matters as much as volume. Rystad Energy's independent GasMarketCube outlook, expressed in real 2026 prices, suggests that Asian spot LNG prices could decline from around USD 16/MMBtu in 2026 to approximately USD 6 to 7/MMBtu in the early to mid-2030s, before rising toward about USD 11/MMBtu from around 2040.¹⁸ The International Energy Agency (IEA) estimates around 345 billion cubic meters per year of new export capacity already under construction is expected to come online between 2025 to 2030, which could support market easing; it also says Middle East conflict and damage to Qatar's LNG infrastructure could delay that effect by at least two years.¹⁹ This is one plausible external outlook, not a PDP2026 assumption.

Thailand's tariff history provides context for this transmission channel. Pool Gas (the constructed price used in the electricity tariff) blends Gulf of Thailand, Myanmar and LNG prices, so cheaper domestic and pipeline gas can dampen the effect of higher LNG prices; the degree depends on the source mix. In September 2022, imported LNG cost about THB 1,307/MMBtu against THB 649/MMBtu for Pool Gas.²⁰

Recent Ft calculations are consistent with this relationship, but do not isolate LNG as the only driver. For September to December 2026, the spot LNG assumption was revised from USD 18.6 to 17.6/MMBtu after PTT Public Company Limited (PTT), following a review with the Electricity Generating Authority of Thailand (EGAT), lowered the estimate; the fuel component fell by THB 0.0500/kWh. Earlier in 2026, the assumption increased from USD 11.6 to 18.8/MMBtu while the fuel component rose by THB 0.2355/kWh, although other inputs also changed (Figure 2).²¹

¹⁶ Energy News Center (2023).

¹⁷ Bangkok Post (2012); Malay Mail (2016); EPPO, LNG infographic; S&P Global Commodity Insights (2024).

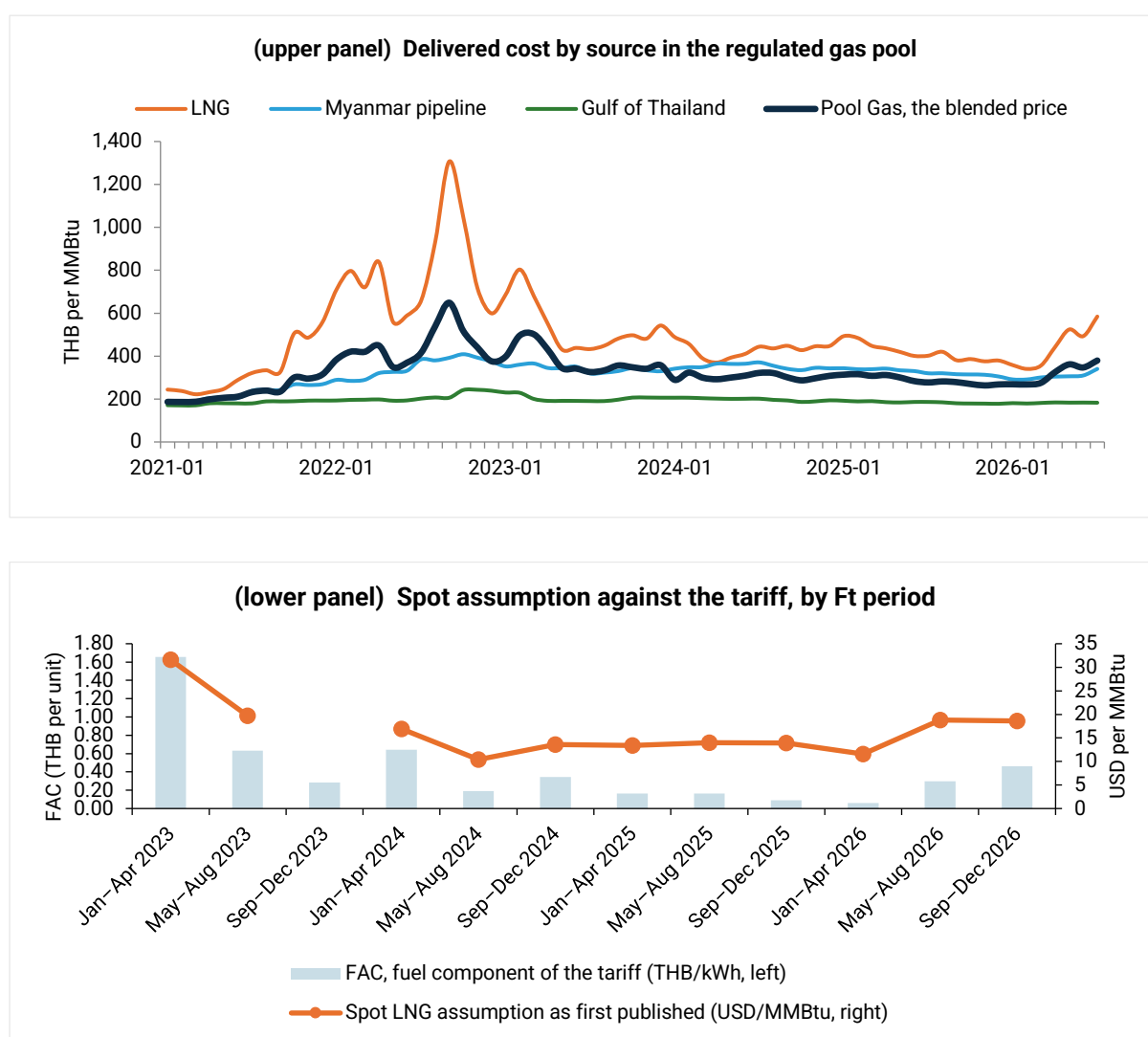
¹⁸ Rystad Energy (2026), GasMarketCube outlook.

¹⁹ IEA (2026), Global LNG Capacity Tracker; IEA (2026), Gas Market Report, Q2 2026.

²⁰ EPPO, Pool Gas price series.

²¹ Energy Regulatory Commission (2026), Ft documents (Appendix A.3.2).

Figure 2 Gas-price inputs to Thailand's regulated electricity tariff



Source: ERC Ft disclosure and consultation documents; EPPO Pool Gas series; calculations by the authors.

Historical Pool Gas prices provide a further sensitivity check: applying 2020 and 2022 gas prices to Case 4's 2050 gas demand gives a lower and a higher gas cost, respectively (Appendix A.3.3).²² This shows how exposed Case 4 is to gas prices; it is not a forecast of how power plants will run.

A complementary sensitivity varies LNG's share of the gas mix. The plan describes Case 4 as using domestic gas at full potential, and its 2050 gas demand sits below the 2,000 MMscfd threshold, but it publishes no path for domestic and Myanmar supply.²³ With Myanmar pipeline gas already down about 41 percent since 2021 and the Yadana contract reported to end in 2028, we test Case 4 with today's LNG share rather than assume it will need little LNG. If LNG makes up 38.4 percent of the gas supply, its latest share in the Pool Gas published by the ERC, the range of spot LNG prices the ERC has assumed since 2023 moves Case 4's 2050 gas cost, expressed per unit of electricity, from about

²² EPPO, Pool Gas price series; Draft PDP2026, slide 37; Appendix A.3.3.

²³ Draft PDP2026, slide 37.

THB 0.079 to 0.089/kWh below the median-price result to THB 0.385 to 0.435/kWh above it (Appendix A.3.4).²⁴ These examples indicate why gas mix and LNG price assumptions matter.

In our calculations, long-term contracting reduces high-price exposure but can raise cost when spot prices are low. If 45.1 percent of LNG were contracted, matching Thailand's reported 2023 long-term share, the extra cost in a high-price year falls to about THB 0.211 to 0.239/kWh above the median-price result.²⁵ The final PDP should publish each case's annual domestic/Myanmar/LNG split, contracted LNG share and price assumptions.

Imported hydropower

Imported hydropower can reduce gas use and emissions, but a larger role also increases exposure to hydrological risk. Thailand had 4,462 MW of imported hydropower in 2025 and draft PDP2026 adds 3,407 MW by 2037.²⁶ For September to December 2026, Laos purchases are expected to supply 18.8 percent of Thailand's electricity, including 12.9 percent from hydropower.²⁷ A dry-year case would therefore be a useful stress test.

A peer-reviewed study of the 2016 Laos and Thailand system illustrates the mechanism: it estimated that a severe drought would reduce hydropower output by about 4,000 GWh, raise production costs by about USD 120 million and increase emissions by about 2.5 MtCO₂ in one year.²⁸ The 2030s system will differ, but these are the types of exposure a dry-year case could test.²⁹

This is particularly relevant around the evening peak, which draft PDP2026 places around 9:00 p.m., when solar output is unavailable.³⁰ Drought could constrain imported hydropower at the same time; if gas replaces part of the shortfall, fuel cost and emissions may rise.³¹ A dry-year case could therefore test both adequacy and replacement-fuel cost.

Approved hydro and solar-plus-storage tariffs are numerically close, but they are not like-for-like measures of system value: the resources differ in timing, firmness, transmission, contract structure and drought exposure (Appendix A.4).³²

Coal and lignite

The key issue is that draft PDP2026 treats 540 MW of lignite as committed capacity in every case, meaning no early coal phase-out is considered. The plan does not name the plant, but 540 MW matches the contracted capacity of Mae Moh Units 12 and 13, whose refurbishment was approved by the National Energy Policy Council in August 2025 with retirement reported for 2048.³³

The refurbishment has a stated rationale. The Council reported the Mae Moh measures as reducing Ft by about THB 0.0367/kWh, or THB 9,566 million a year, while EGAT presents the project as a pollution-control upgrade and as maintaining about 1,200 MW of local capacity.³⁴ Published project-cost figures differ greatly: EGAT's 2026 draft tender starts at THB 12.32 billion, while an EGAT

²⁴ Energy Regulatory Commission (2024), Ft disclosure document; news release; EGAT (2024), ERC hearing document; Thai PBS (2025); Thansettakij (2025); EPP0, Pool Gas price series (Appendix A.3.4).

²⁵ Energy News Center; Bangkok Post; Malay Mail; Rystad Energy (2026), GasMarketCube (Appendix A.3.4).

²⁶ Draft PDP2026, slides 24 and 25.

²⁷ Energy Regulatory Commission (2026), Ft public hearing document for September to December 2026.

²⁸ Chowdhury et al. (2021); ESS Open Archive.

²⁹ Draft PDP2026, slides 24 and 25.

³⁰ Draft PDP2026, slides 11 and 31.

³¹ Chowdhury et al. (2021); ESS Open Archive.

³² Draft PDP2026, slide 23; Appendix A.4; EPP0 (2022), NEPC meeting 157; MGR Online (2022); Energy Regulatory Commission, FIT 2022-2030 program; Department of Alternative Energy Development and Efficiency.

³³ Government Public Relations Department (2025); Draft PDP2026, slide 25; EGAT, Mae Moh Power Plant.

³⁴ Government Public Relations Department (2025); Lanna Post (12 November 2025).

executive cited a project budget of about THB 25,000 million in 2025.³⁵ The tender may cover only part of the project, and neither source breaks the budget down.

The remaining question is whether refurbishment is the most cost-effective way to provide those services. Draft PDP2026 does not compare the committed 540 MW with a case of early phase-out plus alternative mixes of generation, storage, transmission or demand-side management.³⁶

Fuel supply after around 2040 is another uncertainty in draft PDP2026. The units are due to retire in 2048, while EGAT expects existing Mae Moh lignite reserves to run out around 2040 and is studying underground mining.³⁷ Draft PDP2026 does not show assumptions about the fuel source, cost, or availability after existing reserves are depleted.

Lignite emits about three times as much CO₂ per unit of electricity as a new gas plant, so a future carbon price would affect it far more than gas.³⁸ Yet the plan's cost comparison includes no carbon cost at all, only base costs, the cost of integrating renewables and CCS costs (slide 40). Keeping Mae Moh Units 12 and 13 running until their reported retirement in 2048 therefore rests on carbon remaining unpriced for more than two decades, even though the Cabinet has approved in principle a draft Climate Change Act that includes a carbon tax and emissions trading.³⁹ Draft PDP2026 does not examine this risk.

Draft PDP2026 has not shown why Mae Moh must run until 2048.⁴⁰ Before locking in the refurbished units, the final PDP should test an early phase-out case and compare Mae Moh with other ways of meeting local demand in the North, including renewables with storage.

Mae Moh is not the only coal in the system. Coal and lignite, including imported coal and power bought from Laos, are expected to supply about 17 percent of electricity in September to December 2026, yet none of the four cases considers retiring any of them earlier.⁴¹ Thailand's NDC 3.0 uses preliminary abatement costs of about USD 11/tCO₂ for early coal phase-out and about USD 57/tCO₂ for "CCS/CCS Hub (Offshore)."⁴² These are not like-for-like measures, and the NDC does not identify the capture source for the offshore estimate. CCS cost depends strongly on the CO₂ concentration of the source stream: natural-gas processing can involve relatively concentrated CO₂, whereas post-combustion capture at a gas-fired power plant must separate CO₂ from flue gas containing only about 3 to 5 percent CO₂.⁴³ The USD 57 figure should therefore not be read as an estimate for CCS at a gas-fired power plant. The narrower point is that early coal phase-out is already one of the lowest abatement-cost mitigation options in Thailand's NDC 3.0.⁴⁴

In short, the draft PDP2026 discloses no early coal phase-out case, two cases include carbon capture, and the committed 540 MW is common to all four. The final plan should clarify whether an early coal phase-out case was modeled, and the basis for the published choices.⁴⁵

³⁵ EGAT (2026), Draft TOR No. EGAT 3/2569-MM12-13RP, starting price THB 12,320,000,000 including VAT; Lanna Post (12 November 2025), quoting EGAT's Assistant Governor for Power Generation 2.

³⁶ Government Public Relations Department (2025); Draft PDP2026, slide 25.

³⁷ EGAT Mae Moh (10 February 2025); EGAT (2024); Government Public Relations Department (2025).

³⁸ IPCC (2006), 2006 IPCC Guidelines, Vol. 2, Ch. 2, Table 2.2.

³⁹ Department of Climate Change and Environment (2 December 2025); Matichon (2 December 2025); Khaosod (6 May 2026) (draft under Council of State review).

⁴⁰ Draft PDP2026, slides 25 and 31; Government Public Relations Department (2025).

⁴¹ Energy Regulatory Commission (2026), Ft public hearing document for September to December 2026 (13 July 2026), Table 2: imported coal 8.06 percent, lignite purchased from Laos 5.90 percent and EGAT lignite 2.92 percent of generation, <https://www.erc.or.th/th/listen-to-opinions/601>.

⁴² Thailand's NDC 3.0 (2025).

⁴³ IPCC (2005); U.S. DOE NETL; IEA (2020).

⁴⁴ Thailand's NDC 3.0 (2025), table of mitigation measures and preliminary abatement costs, pp. 12–14.

⁴⁵ Draft PDP2026, slides 25 and 28 to 31; EGAT, Mae Moh Power Plant.

Carbon pricing

Draft PDP2026 itself lists carbon rules as one of five pressures reshaping Thailand's power planning (slide 4), yet it puts no price on the emissions its cases still produce. Its tariff comparison counts only base costs, renewable-integration costs and CCS costs (slide 40). Thailand is preparing its own carbon price: the Cabinet approved the draft Climate Change Act, including a carbon tax and emissions trading, in principle in December 2025, but the law is still not proposed in parliament as of early October 2026.⁴⁶

These unpriced emissions are a hidden cost. Case 4 still emits 19.1 MtCO₂e in 2050, even after capturing 21 Mt with CCS (slide 42). At the EU CBAM price of EUR 75.28/tCO₂ (about THB 2,875), they would cost the equivalent of THB 0.132 to 0.150/kWh in 2050, against THB 0.115 to 0.130/kWh for Case 3.⁴⁷ Each figure is a range because draft PDP2026 gives two forecasts of 2050 electricity demand, 414,766 GWh and 366,945 GWh (slide 15), without saying which one each case uses; lower demand spreads the same carbon cost over fewer units. At Singapore's current carbon tax of SGD 45/tCO₂e (about THB 1,173), Case 4 would carry THB 0.054 to 0.061/kWh, and at Thailand's excise level of THB 200/tCO₂, which today covers only petroleum products, THB 0.009 to 0.010/kWh (Figure 3).⁴⁸ These figures are for 2050 only, the one year for which the plan publishes emissions for each case.⁴⁹

Some of these emissions are likely to come from plants built in Phase 1, when every case adds the same 9,100 MW of new gas plants (slide 29). The issue of who pays is left open. Thailand's tariff passes generation and fuel costs through to consumers, through the base tariff and the Ft, so households and businesses would likely carry this cost unless the plan says otherwise.⁵⁰

For exporters, carbon costs will be paid one way or another. Goods such as steel, aluminum, cement and fertilizers imported into the EU since January 2026 are charged for their embedded emissions, less any carbon price already paid where they were made.⁵¹ For cement and fertilizers, this includes emissions from the electricity used to make them, so a more carbon-intensive grid raises the bill.⁵² Without a meaningful Thai carbon price, that money goes to the EU instead of staying in Thailand.

⁴⁶ Draft PDP2026, slide 4 (carbon rules among five pressures on power planning) and slide 40 (tariff comparison of base, RE and CCS costs); Department of Climate Change and Environment (2 December 2025); Matichon (2 December 2025); Khaosod (6 May 2026) (draft under Council of State review).

⁴⁷ European Commission, price of CBAM certificates, Q2 2026 (EUR 75.28/tCO₂), converted at the ECB reference rate of THB 38.187/EUR, see Appendix A.1; calculations by the authors; full results in Appendix A.5.

⁴⁸ National Climate Change Secretariat Singapore, carbon tax (SGD 45/tCO₂e for 2026–2027); Excise Department, press release 6/2568 (THB 200/tCO₂e, petroleum products); converted at the ECB reference rates of THB 38.187 and SGD 1.4647 per EUR (21 September 2026), see Appendix A.1; calculations by the authors.

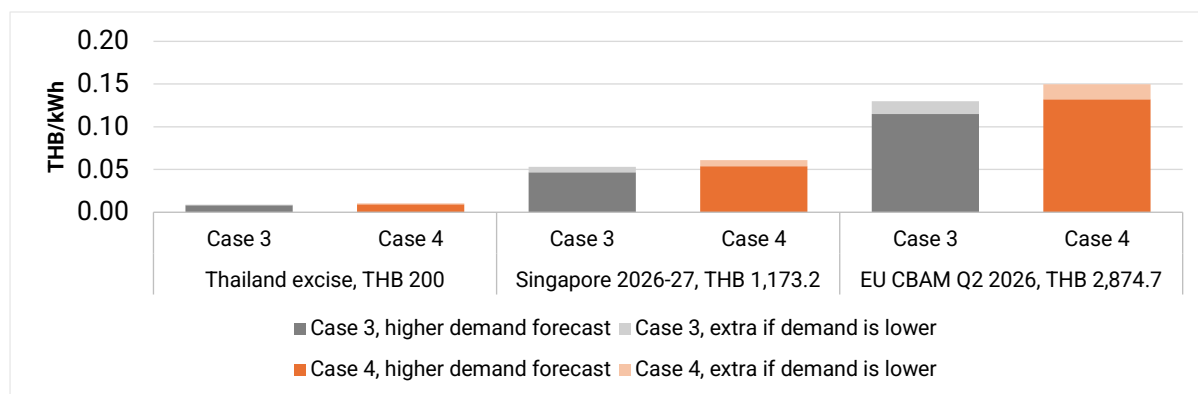
⁴⁹ Draft PDP2026, slides 15, 36 and 42.

⁵⁰ Draft PDP2026, slide 29 (9,100 MW of new CCGT in 2026–2037, common to all cases); Energy Regulatory Commission (2026), Ft public hearing document for September to December 2026 (fuel and power purchase costs passed through to consumers via the Ft).

⁵¹ Regulation (EU) 2023/956 establishing a carbon border adjustment mechanism, Article 9 (carbon price paid in the country of origin) and Annex I (goods covered).

⁵² Regulation (EU) 2023/956 establishing a carbon border adjustment mechanism, Annex II (indirect emissions from electricity count for cement and fertilizers).

Figure 3 Carbon-price sensitivity, Case 4 against Case 3, under draft PDP2026's 2050 demand forecasts of 366,945 GWh (Base-Low) and 414,766 GWh (Base-High) (THB/kWh)



Note: The dark part of each bar uses the higher demand forecast; the light part shows the extra cost per kWh under the lower forecast.

Sources: Draft PDP2026, slides 15 and 42; European Commission; NCCS Singapore; Excise Department; ECB; calculations by the authors.

Phase 2 (2038–2050): Playing dice with taxpayers' money

The true cost of CCS

Carbon Capture and Storage (CCS) is a technology for mitigating greenhouse gas emissions by capturing CO₂, whether at its point source during industrial processes or directly from ambient air, prior to its transport and storage in a secure subsurface location, such that it is not released into the atmosphere. The Global CCS Institute states that CCS can capture up to 90 percent of CO₂ generated by industrial processes.⁵³

The International Energy Agency (IEA) reports that CCS projects currently in operation have a combined capacity of approximately 62 MtCO₂ per year worldwide, including 7.2 MtCO₂ per year in the Asia-Pacific region, with the United States hosting the largest CCS projects at a total capacity of 26.8 MtCO₂ per year.⁵⁴

In Thailand's case, CCS technology is addressed in both the NDC Action Plan, as a technology for reducing greenhouse gas emissions in the power generation sector,⁵⁵ and the LT-LEDS, which identifies the use of CCS in bioenergy and biomass-based power plants as a key factor in achieving the country's net-zero emissions target by 2050.

At present, no CCS project is operational in Thailand; the only project to have reached Final Investment Decision (FID) is PTT Group's CCS project at the Arthit gas field, which received FID and is expected to commence operations in 2028, capturing approximately 1 MtCO₂ per year. However, this

⁵³ Global CCS Institute (2026), CCS 101 | Global CCS Institute

⁵⁴ IEA (2026), CCUS Projects Explorer – Data Tools - IEA

⁵⁵ DCCE (2024), NDC Action Plan on Mitigation 2021 – 2030 – แผนการเปลี่ยนแปลงสภาพภูมิอากาศและสิ่งแวดล้อม

project involves installing CCS on a natural gas processing stream, whose CO₂ concentration differs substantially from CO₂ from power generation activities.⁵⁶

The CO₂ concentration has a direct bearing on the cost and cost-effectiveness of deploying CCS technology: the lower the CO₂ concentration in the gas stream, the greater the energy required to separate CO₂, resulting in a higher cost per unit of CO₂ captured.⁵⁷ In natural gas processing, CO₂ concentration varies by gas source; in the case of the Arthit gas field, the CO₂ concentration is approximately 32 percent⁵⁸ compared with approximately 13.2 percent for coal-fired power plants⁵⁹ and 4.10 percent for natural gas-fired power plants,⁶⁰ respectively. For this reason, the cost of CO₂ capture in natural gas processing is much lower than in power generation.

In Phase 2 (2038-2050) of the draft PDP2026, CCS would be deployed to capture 32 MtCO₂ per year under Case 2 and 21 MtCO₂ per year under Case 4. This represents a gargantuan level of deployment, since under either case Thailand would become one of the largest CCS operators in the world when compared with the volumes currently captured by other countries.

The critical question is the extent to which CCS imposes costs on the electricity system, especially cost burden borne by the public as tariff. Draft PDP2026 sets the cost assumption for CCS technology at USD 135, equivalent to THB 4,590 per tonne of CO₂. However, a review of the relevant literature on CCS capture costs shows that the cost of constructing and operating a capture facility, referred to as the "capture cost," covers only construction, capital cost, and operating and maintenance cost. It must be calculated together with the energy penalty, i.e. the energy cost required to operate the CCS equipment, as well as the transport cost and storage cost, in order to arrive at the "avoided cost," which reflects the full cost of reducing CO₂ emissions to the atmosphere through CCS technology.⁶¹

For Thailand's case, using figures adapted from the National Energy Technology Laboratory (NETL, 2023),⁶² we estimate that the capture cost could reach approximately USD 93.6 per tonne of CO₂.⁶³ NETL (2023) also indicates that the energy penalty increases fuel cost by approximately 12 percent relative to a plant without CCS. This cost varies with the volatility of LNG prices: the resulting energy-penalty sensitivity is USD 29.4, 34.6, and 59.7 per tonne of CO₂ avoided under the low, base, and high price cases, respectively.⁶⁴

As for transport and storage costs, the CCUS Hub project plans to construct infrastructure to transport and store CO₂ using approximately 70 km of pipeline, carrying captured CO₂ from onshore to an offshore injection platform, at a cost of approximately USD 40–60 per tonne of CO₂ with substantial government subsidy.⁶⁵

Summing all cost components yields an avoided cost of USD 163–213.3 per tonne of CO₂, or up to 58% higher than the PDP's assumed cost of USD 135 per tonne of CO₂. PDP2026 states that installing CCS under the USD 135 per tonne of CO₂ cost assumption would raise the average retail electricity tariff over 2027–2050 by THB 0.0592 per unit of electricity under Case 2 and THB 0.0242 per unit under Case 4, equivalent to only 1.5% of the retail electricity price under Case 2 and 0.6% under Case 4.

⁵⁶ PTTEP (2025), PTTEP moves forward with Thailand's first CCS project at Arthit field to advance the national Net Zero goal | PTTEP

⁵⁷ IISD (2023), The Bottom Line: Why the cost of carbon capture and storage remains persistently high

⁵⁸ DBS Treasures (2025), PTT Exploration & Production: Thailand's first CCS project at Arthit field

⁵⁹ NETL (2013), CO₂-Capture-Tech-Update-2013-Post-Combustion-Solvents.pdf

⁶⁰ NETL (2023), Methodology for Estimating Performance and Cost of Natural Gas Combined Cycle (NGCC) Plants with Carbon Capture

⁶¹ Ibid.

⁶² Ibid.

⁶³ Assuming an H-frame turbine with a 90% CO₂ capture rate, a retrofit difficulty factor of 1.09, and a capacity factor of 65%, escalated to 2026 present value using the Chemical Engineering Plant Cost Index (CEPCI) for construction-related cost items and Thailand's Consumer Price Index (CPI) for operation and maintenance (O&M) items

⁶⁴ Assuming that 45.1 percent of LNG supply (5.1 Mt of 11.3 Mt) is procured under long-term contract at an approximate price of USD 12.4 per MMBtu, while the remaining 54.9 percent (6.2 Mt of 11.3 Mt) is procured as spot LNG at USD 10.40, 14.00, and 31.58 per MMBtu under the low, base, and high price cases respectively. Additional details in/on the 'LNG price exposure' section and Appendix A.3.

⁶⁵ Twarath Sutabutr (2024), Carbon Capture Storage and Utilisation (CCUS) Development in Thailand

However, this proportion is inexplicably averaged over the plan's Phase 1 (2026 –2037), the 12 years during which CCS is not yet deployed in the power sector, causing the cost of CCS as a share of retail electricity sales to appear lower than it actually is. Under PDP2026's electricity demand assumptions of 366,945 GWh and 414,766 GWh for the low and high cases, respectively (Slide 15 of draft PDP2026), if CCS were used to reduce 21 MtCO₂ under Case 4, which sets the total retail electricity cost under Case 4 in 2050 at THB 4.34 per unit, the cost of CCS would be approximately THB 0.247–0.279 per unit, equivalent to 5.7–6.4% of the electricity tariff in 2050.

Furthermore, if the CCS avoided cost is USD 213.3 per tonne of CO₂ as per our estimates above, the resulting incremental cost per unit of electricity would be THB 0.391–0.442 per unit, equivalent to 8.71–9.81% of the 2050 electricity tariff. Furthermore, if Thailand relies on LNG even more in the future, particularly in gas-heavy cases, the energy penalty associated with CCS would carry greater a fuel-cost risk as LNG prices rise, due to a greater need for CCS.

SMR: Not as cheap as advertised

Small Modular Reactors (SMRs) are advanced nuclear reactors with a power generation capacity of up to 300 MW(e) per unit. They can be sited in locations where large-scale nuclear power plants cannot be deployed, and their components can be manufactured off-site before being shipped and installed at the plant location, an approach expected to reduce both construction cost and construction time compared to conventional nuclear power plants.⁶⁶

SMRs have attracted extensive discussion both in the private sector and at the policy level. The Nuclear Energy Agency (NEA) reports that 127 SMR designs currently exist worldwide;⁶⁷ however, to date only two SMRs are currently in operation: the HTR-PM model (210 MWe) in China, which began construction in 2012 and reached commercial operation in 2023, and the KLT-40S model (35 MWe) in Russia, which began construction in 2007 and reached commercial operation in 2020.⁶⁸

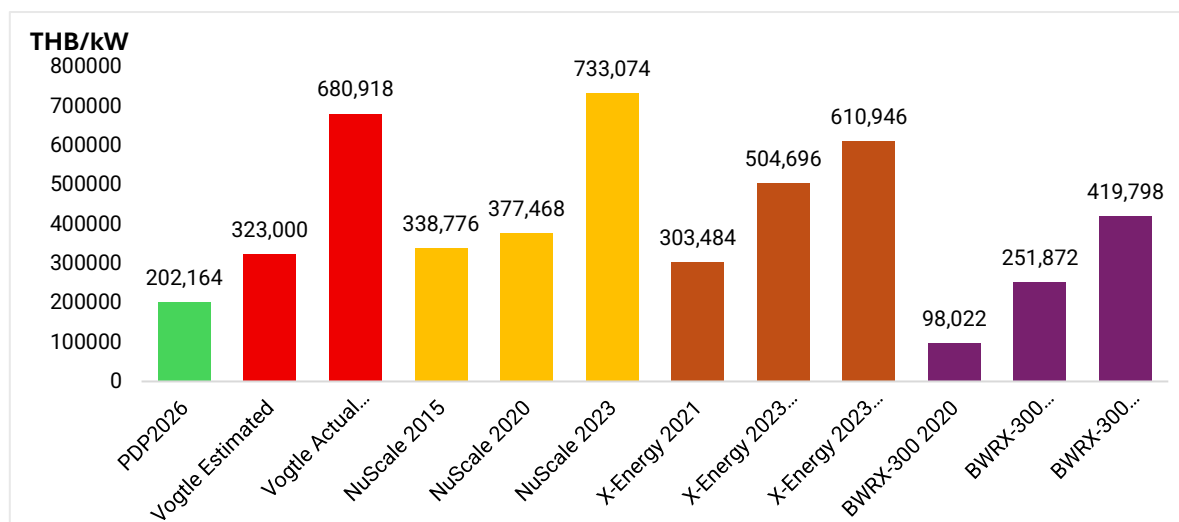
In Thailand's case, draft PDP2026 plans for a total SMR capacity of 300 MW by 2037, expanding thirtyfold to 9,000 MW by 2050, at an estimated capital expenditure (CAPEX) of 202,164 THB/kW – a figure lower than the construction costs observed in many other projects. Moreover, SMR projects have frequently experienced substantial cost overruns during actual construction; for example, the cost of NuScale's SMR project more than doubled between 2015 and 2023.

⁶⁶ IAEA (2023), What are Small Modular Reactors (SMRs)? | IAEA

⁶⁷ NEA (2025), Nuclear Energy Agency (NEA) - The NEA Small Modular Reactor Dashboard: Third Edition

⁶⁸ World Nuclear Association (2026), Small Modular Reactor (SMR) Global Project Tracker - World Nuclear Association

Figure 4: SMR construction cost as projected under PDP2026, compared with other projects in which costs increased once projects began⁶⁹



Source: IEEFA (2024), Small Modular Reactors Still Too Expensive, Too Slow and Too Risky.

In addition, PDP2026 projects SMR operating expenditure (OPEX) at only 1% of CAPEX, equivalent to 1,785 THB/kW-year – a figure substantially lower than that found in other studies. For instance, the Idaho National Laboratory (INL, 2024) estimates a range of approximately 4,012–7,344 THB/kW-year,⁷⁰ while the Nuclear Energy Institute (NEI, 2026) reports actual operating costs for nuclear power plants of approximately 5,766.4 THB/kW-year.⁷¹ Furthermore, SMRs are likely to face even higher costs per unit of electricity, as they do not benefit from the economies of scale enjoyed by large-scale power plants.

Figure 4 compares the construction costs of several SMR plants, which rose substantially above initial estimates. For example, NuScale (the Carbon Free Power Project of Utah Associated Municipal Power Systems, UAMPS) was an SMR project that was launched in 2015 before encountering costs far exceeding initial projections, owing both to forecasting error and to post-pandemic commodity and materials inflation, as well as rising interest rates during the construction period.⁷² The same pattern has occurred in other SMR projects: Argentina's CAREM began construction in 2014 and was expected to enter operation by 2017, but has since encountered budgetary problems and remains unfinished to this day.⁷³

The tendency for cost forecasts to fall short of actual costs constitutes a significant risk that could prevent SMR power plant projects from being completed as planned. Furthermore, the regulations governing nuclear power in Thailand do not yet extend to the use of nuclear energy for electricity generation, which will require additional time to prepare the necessary legislation and to build public acceptance of nuclear energy, over and above the time required for the construction process.⁷⁴

The combined cost and regulatory risks, together with the scale of the planned SMR build-out (300 MW by 2037 and, in particular, 9,000 MW by 2050), which may require the construction of up to 30 separate 300 MW SMR units, may prevent the SMR program from delivering electricity at the capacity

⁶⁹ Converted at an exchange rate of 34 THB per US dollar, consistent with the rate used in PDP2026.

⁷⁰ INL (2024), Microsoft Word - INL-RPT-24-77048_GAIN_AdvReactorCosts 4-9-24

⁷¹ Calculated using an exchange rate of 34 THB per US dollar, consistent with the rate used in PDP2026, and a capacity factor of 93%.

⁷² Leipner et al. (2023), Lessons learned from the recently cancelled NuScale-UAMPS project – Clean Air Task Force

⁷³ Schneider et al. (2025), The World Nuclear Industry Status Report 2025.

⁷⁴ Plangtrakul et al. (2025), Thailand Explores Small Modular Reactors for Energy Future

currently anticipated. PDP2026 should therefore specify a clear contingency alternative, supported by adequate justification, namely a lower-cost option capable of supporting the realization of Net Zero target.

BloombergeNEF (2025) examined the levelized cost of electricity (LCOE), a standard metric for comparing the lifetime cost of electricity generation across technologies and found utility-scale solar to be the least-cost source of bulk electricity generation in Thailand, at an LCOE of USD 33–75 per MWh, compared with USD 79–86 per MWh for a new CCGT plant and USD 74–96 per MWh for a new coal-fired plant.⁷⁵

Table 1 presents the LCOE of electricity generation across technologies under consideration. It shows that utility-scale solar is currently the least-cost option, and that solar paired with battery storage, which enhances the stability of solar-generated electricity, is expected to become progressively less expensive over time. Thermal power plants, by comparison, are more costly and emit greenhouse gases into the atmosphere, thereby impeding the achievement of the Net Zero target. While the installation of CCS can reduce greenhouse gas emissions by up to 90 percent, it does so at the expense of a higher cost of electricity generation; hydrogen-blended combustion, meanwhile, yields comparatively limited emissions reductions. Furthermore, the volatility of LNG prices renders the cost of gas-fired generation variable and difficult to control. SMRs, although emission-free, are subject to uncontrolled cost escalation, extended construction timelines, and costs several times higher than those of alternative technologies.

For these reasons, an increased share of solar generation constitutes a more appropriate means of delivering SMRs' 9,000 MW of planned capacity.

Table 1 LCOE of electricity generation across technologies⁷⁶

Technology	LCOE (\$/MWh) 2025	LCOE (\$/MWh) 2030	LCOE (\$/MWh) 2050
Gas-fired power plant (CCGT)	79–86	77–84	78–85
Coal-fired power plant	74–96	76–100	80–105
Utility solar	33–75	25–43	16–24
Utility solar + battery storage	62–114	44–80	29–57
Wind power plant	75–166	59–123	42–74
Wind power plant + battery storage	125–173	94–126	62–80
Small Modular Reactor	372		

Source: BNEF

Peak irresponsibility: reliance on an unnamed technology

Perhaps the utmost sign of irresponsibility is the fact that draft PDP2026's Phase 2 relies on a technology it does not name. For the last 5 years of the plan, 2046 to 2050, it reserves 2,500 to 3,000 MW for an energy source said to have the characteristics of a fossil or nuclear plant without greenhouse gas emissions. In capacity terms, the block is small, at about 1.0 to 1.5% of the 2050 system (253.1 GW in Case 3 and 206.1 GW in Case 4). Its weight comes from the type of capacity it is purported to supply. Firm, dispatchable, emission-free capacity is the hardest resource to secure in a net-zero grid, and it is scarce in every case. The only new large-scale resource in the plan that meets this description is small modular reactors (SMRs), planned at 9,000 MW by 2050. Measured against

⁷⁵ BloombergeNEF (2025), BNEF

⁷⁶ *ibid.*

SMRs, the unnamed block is equivalent to roughly 28 to 33% of the program. It is also about twice the combined allocation for offshore wind (1,000 MW), new geothermal (156 MW) and the first SMR phase (300 MW), all of which the plan names, costs and schedules.

The new technology allocation matters for a second reason. The competing cases are separated by very small margins, with average retail tariffs in Cases 1, 3 and 4 differing by less than 0.01 baht/kWh (3.8267, 3.8297 and 3.8364). As the following subsections show, the block is priced in a way that makes it appear inexpensive. An assumption of this kind may be enough to decide which case looks optimal. In this sense, the plan's preferred long-term future rests on a technology whose existence, cost and timing are all unestablished.

Unnamed with a price

The plan names three candidates: long-term energy storage, green hydrogen electrolysis with fuel cells, and other new clean technologies. The first two form a single hydrogen pathway, converting electricity to hydrogen, storing it, and later turning it back into electricity. This pathway relies on a supply chain that does not yet exist in Thailand. The third category is open-ended by design, leaving the allocation without a defined technology. The plan also does not specify which characteristics it has in mind, whether firmness, dispatchability, ramping capability or grid inertia.

A planning model cannot dispatch or price a resource without its capital cost, operating cost, fuel cost, and availability. The plan provides these for every other technology, including SMRs at 178,500 baht/kW and CCS at USD 135/tCO₂ in 2050. The new technology allocation is the only resource of this size without its own cost entry. This raises a basic question: how can a technology without a name carry a price in the electricity tariff?

Fake price leading to fake net-zero costs

The plan answers the question by assuming the block costs the same as the average cost of the entire system. A resource priced at the system average adds little or nothing to the average tariff, because it can never appear more expensive than the system it joins. The block is therefore close to tariff-neutral by assumption. This follows from the stated method, not from any evidence about technology.

However, neutrality in its own price does not mean neutrality in its effect on the system. In the PDP2026 cost table, the closest firm clean options, geothermal at 155,000 baht/kW and SMR at 178,500 baht/kW in 2050, cost about four times as much as a CCGT at 40,018 baht/kW. A firm clean resource priced at the system average is therefore cheaper than the alternatives it would otherwise replace. We infer, though we cannot confirm with existing PDP2026 disclosures, that this lowers the reported cost of the net-zero cases, which lean most heavily on firm clean capacity in their final years. Given how narrow the tariff gaps are, the ranking of the cases may not be robust to this single assumption.

No pathway and no fallback

The plan treats other unproven technologies very differently. For SMRs, at least, it sets out a phased pathway and acknowledges that preparation, regulatory review and construction will take more than ten years. For CCS, it describes the full chain of capture, transport and storage and attaches an explicit cost per tonne. The unnamed block receives neither a timeline nor a price. It has no milestones, no indication of who would build or own it, and no point at which the government would

judge whether the technology is ready. If it is to be operating by 2046, key decisions would need to be taken in the 2030s, and the plan offers no framework for taking them.

The plan does not appear to address what would happen if such unnamed technology were not available in time. One plausible substitute would be additional gas generation, as gas is currently the main firm resource that can be deployed at scale within a relatively short period. If so, this could slow emission reductions during the years when the plan expects them to fall most rapidly, and could increase reliance on imported LNG, a risk the plan itself recognizes. Net-zero cases, particularly Case 3 (without CCS), may therefore be more exposed to this uncertainty than their headline results indicate.

Estimating costs from the named candidates

The PDP2026 cost table does not cover any of the named candidates, so we can only infer costs from the closest figures it does provide. For hydrogen, the plan provides no hydrogen storage costs. A 2022 study for the US Department of Energy estimates a 3,800 kg stationary liquid hydrogen tank at about USD 620,000, close to a manufacturer's quotation of USD 600,000, or roughly USD 163 or THB 5,542 per kilogram.⁷⁷ Assuming 50% fuel cell efficiency, delivering 2,500 to 3,000 MW for 24 hours would require 60 to 72 GWh, or about 3,600 to 4,300 tonnes of hydrogen. This implies that storage alone would cost about THB 20 to 24 billion, excluding electrolysis, liquefaction, fuel cells, and boil-off losses. Lithium batteries are not typically used for storage of this duration, so the figure should be read as indicative only. It does, however, suggest that costs could rise considerably if storage were expected to provide the kind of firm supply associated with conventional plants. For firm clean generation more broadly, applying the plan's 2050 geothermal and SMR capital costs gives about 390 to 540 billion baht. For green hydrogen, the plan provides neither a fuel cell cost nor a hydrogen price. Because hydrogen adds a fuel cost that the other references exclude, this option would most likely sit at or above the upper end of the range.

Taken together, the named candidates point to a capital cost of roughly 225 to 540 billion baht, compared with about 100 to 120 billion baht for the same capacity built as CCGT. The upper end approaches the roughly 700 billion baht in grid integration costs that the plan presents as the main economic weakness of Case 3 (high renewables). An unnamed technology may therefore cost almost as much as the costs the plan uses to argue against higher renewable penetration, yet these costs are not mentioned anywhere in draft PDP2026.

Conclusion

Draft PDP2026 at least gets the destination right. Net zero by 2050 is now written into Thailand's power plan for the first time. The updated demand, reliability and regional planning methods are also genuine improvements. The question this report raises concerns the route, which we can only conclude as "irresponsible" after examining assumptions and the lack thereof.

Our findings show three signs of irresponsibility. The first irresponsibility is that the most consequential choices are made in Phase 1, in which the public has no option. Phase 1 plan (2026-2037) commits 9,100 MW of new gas and 540 MW of lignite. The second irresponsibility is that real risks are left unpriced and therefore hidden from the public. LNG volatility, carbon costs and

⁷⁷ Houchins, C. and James, B.D. (2022). Hydrogen Storage Cost Analysis. Strategic Analysis Inc., DOE Project ST235. The estimate assumes 2,500 to 3,000 MW delivered continuously for 24 hours, with fuel cells at 50% efficiency, so each kilogram of hydrogen (33.3 kWh/kg) yields about 16.65 kWh based on . All hydrogen is assumed usable, with no boil-off, and costs are in 2022 US dollars. Larger tanks and underground storage are not considered. Calculation: 60–72 GWh ÷ 16.65 kWh/kg × USD 163/kg = USD 590–710 million.

drought do not enter the picture; each of them would likely weigh most on the two gas-reliant cases (Case 2 and 4). Third, unproven technologies are costed as if they were settled. CCS may cost up to 57% more than assumed. SMR operating costs sit well below international benchmarks. In what we call “peak irresponsibility,” an unnamed technology enters the tariff at no premium.

None of these calls for a different target. Together, they call for a fairer and more responsible test of the cases the plan already contains. The recommendations below would allow the final plan to show which route to net zero costs Thai electricity users least.

1. **Reopen Phase 1, the 2026–2037 period.** All four cases are identical until 2037, yet this is the period that decides the 2035 emissions milestone under NDC 3.0 and locks in 9,100 MW of new gas capacity. The final plan should present alternative energy mixes for this period.
2. **More realistically price the risks the plan already names.** The plan should apply a common carbon price and an LNG price band to all cases, publish each case's gas balance by source, its contracted LNG share and its price index, and add a dry-year hydropower case.
3. **Put cost assumptions on an equal footing.** The plan should cost CCS in full, including energy penalty, transport and storage, and benchmark SMR costs against delivered projects, with a contingency if either falls short. It should also test faster battery cost declines than the 14% assumed for 2037 to 2050, backed by market reforms that reward storage flexibility.
4. **Name and price the unnamed technology for the final 5 years.** The plan should name and cost the 2,500–3,000 MW allocation under explicit upper and lower bounds, set decision milestones in the 2030s, and model a scenario in which it is not delivered.
5. **Strengthen the grid integration narrative.** All cases meet the reliability criterion, so reliability cannot be used to rank them. Integration challenges, particularly predictable solar, are likely to depend as much on system operation capability as on technology, and the plan should enumerate the specific measures needed to support Case 3.

Appendix

A. Calculation Methodology

A.1 Scope, denominators and exchange rates

For system-wide single-year 2050 sensitivities, annual costs are converted to a per-unit electricity equivalent using the two 2050 electricity-demand forecasts in draft PDP2026 (slide 15), Base-Low (366,945 GWh) and Base-High (414,766 GWh). Because the plan does not state which forecast each case uses, results are presented as ranges; the higher per-unit value uses Base-Low. These single-year 2050 sensitivities are not added to, or treated as directly comparable with, the plan's average retail tariff over 2027 to 2050. Plant-level calculations, the data center gas conversion, historical drought effects and observed ERC tariff periods retain their own appropriate denominators.

All USD-denominated assumptions in CFNT calculations, including the LNG price sensitivities, are converted at THB 34 per USD, the rate implied by draft PDP2026's CCS assumption of USD 135 and THB 4,590 per tonne of CO₂ and the rate used elsewhere in this report. Figures quoted from ERC tariff calculations, such as spot LNG assumptions in USD per MMBtu and fuel components in THB per unit, are reported as the ERC published them and are not reconverted. The Singapore carbon-price benchmarks are converted at about THB 26.07 per SGD, the cross rate of the European Central Bank reference rates of THB 38.187 and SGD 1.4647 per EUR, and the EU CBAM benchmark at THB 38.187 per EUR.

A.2 Data center demand: gas-equivalent illustration

Draft PDP2026 projects data center demand in both MW and GWh, but the two sets are not presented as matched values for the same case. We therefore do not assume how many hours a year data centers run at full load. To illustrate scale only, the 2050 data center electricity-demand figures are converted into the gas and LNG that would be required if the load were supplied entirely by a combined-cycle plant at the efficiency used in the plan.

Input	Low case	High case	Basis
Data center electricity demand, 2050	42,468 GWh	55,744 GWh	Draft PDP2026
Gas equivalent	735 MMscfd	965 MMscfd	At implied CCGT heat rate of 6,319 Btu/kWh
LNG equivalent	5.6 Mt/yr	7.3 Mt/yr	48 MMBtu per tonne
Share of Thailand's 2024 LNG imports	53%	70%	Illustrative comparison only

The calculation does not imply that data centers would be supplied by dedicated gas plants. It is used only to indicate the possible scale of incremental fuel demand. The allocation of capacity, network, reserve and balancing costs is a separate question.

Source: Draft PDP2026, EPPO, CFNT analysis

A.3 LNG supply and price exposure

Draft PDP2026 does not publish how much of Case 4's 2050 gas would come from the Gulf of Thailand, Myanmar or LNG, so we do not guess. Instead, we apply the LNG shares of the Pool Gas recently published by the ERC to Case 4's gas demand. Non-LNG gas is priced at the average Gulf of

Thailand and Myanmar price, weighted by volume, and LNG is priced either at spot prices or under long-term contracts priced against oil. These present-day inputs are sensitivity assumptions, not a forecast of the 2050 gas mix.

A.3.1 Long-term and spot LNG

Thailand imported 11.3 Mt of LNG in 2023, of which 5.1 Mt was reported as long-term supply and 6.2 Mt as spot purchases. Publicly reported Qatargas and Petronas agreements also illustrate that some contracts signed in the 2010s expire within the planning horizon. These references are not treated as a complete register of Thailand's contracted LNG.

Source: Ministry of Energy via Energy News Center; S&P Global Commodity Insights; Bangkok Post; Malay Mail.

A.3.2 Observed tariff transmission

Past ERC tariff calculations show how LNG prices have fed into the electricity tariff, but they do not isolate LNG as the only cause. In the September to December 2026 revision, the spot-LNG assumption fell from USD 18.6 to USD 17.6/MMBtu and the fuel component fell by THB 0.0500/kWh. Earlier in 2026, the assumption rose from USD 11.6 to USD 18.8/MMBtu while the fuel component rose by THB 0.2355/kWh, although other inputs also changed.

A.3.3 Historical Pool Gas sensitivity

Case	2050 gas demand	2020 price vs 2026	2022 price vs 2026
Case 3 (Net Zero by RE)	794 MMscfd	THB 0.0776 to 0.0877/kWh lower	THB 0.0852 to 0.0963/kWh higher
Case 4 (Net Zero by RE & CCS)	1,904 MMscfd	THB 0.1861 to 0.2103/kWh lower	THB 0.2042 to 0.2309/kWh higher

The benchmark is the average Pool Gas price for January to August 2026. Gas demand and the fuel mix are kept as the plan reports them, so this shows how exposed each case is to gas prices; it is not a forecast of how power plants will run. Each result is shown as a range for the plan's Base-High and Base-Low 2050 demand forecasts.

Source: ERC/EPPO Pool Gas series.

A.3.4 Illustrative Case 4 procurement scenarios

Draft PDP2026 does not publish Case 4's 2050 split between domestic gas, Myanmar gas and LNG. The scenarios therefore use recent ERC Pool Gas LNG shares and, where shown, the 45.1% long-term share reported for Thailand's 2023 LNG imports. These are present-day reference proportions, not PDP2026 assumptions.

Reference LNG share (ERC Pool Gas)	Illustrative long-term share of LNG	Low spot	Base spot	High spot
38.4%	0%	0.4310 to 0.4871	0.5098 to 0.5762	0.8947 to 1.0113
38.4%	45.1%	0.4507 to 0.5095	0.4940 to 0.5584	0.7052 to 0.7971

Units: THB/kWh of 2050 system electricity under the plan's Base-High and Base-Low 2050 demand forecasts. Spot LNG = USD 10.4/14.0/31.58 per MMBtu (low/base/high); the base is the median of the ERC's spot assumptions since 2023. Term LNG ≈ USD 12.4/MMBtu, read approximately from Rystad Energy's long-run Asian contract price set at 13.9 percent of the oil price; it is illustrative, not an observed Thai contract price. USD prices use THB 34/USD. At a 38.4% LNG share, 45.1% long-term cover reduces the extra cost in a high-spot-price year from THB 0.3849 to 0.4351 to THB 0.2112 to 0.2387/kWh compared with the base spot price.

The scenarios are illustrative, not predictive; they show how LNG share, contract structure and price basis affect estimated cost under the stated assumptions.

Source: ERC Pool Gas source split; Ministry of Energy 2023 LNG split; ERC spot-LNG assumptions; Rystad Energy GasMarketCube Asia oil-index (13.9%) reference, approximate chart reading by CFNT.

A.4 Imported hydropower

The hydropower analysis focuses on dry-year exposure and the evening peak. The cited drought study is used to establish the mechanism only; its numerical effects are not transferred directly to the 2030s system.

Measure	Value	Basis
Existing imported hydropower, 2025	4,462 MW	Draft PDP2026
New imported hydropower, 2026-2037	3,407 MW	Committed capacity
Laos purchases, Sep-Dec 2026	18.8%	Share of Thailand generation/purchases
Laos hydropower, Sep-Dec 2026	12.9%	Share of Thailand generation/purchases
Severe-drought study: hydropower output	about -4,000 GWh	2016 Laos-Thailand system
Severe-drought study: production cost	about +USD 120m	2016 system
Severe-drought study: emissions	about +2.5 MtCO ₂	2016 system

Approved tariffs are useful references, not like-for-like system costs: Luang Prabang is THB 2.8432/kWh, Pak Beng THB 2.9179/kWh and ground-mounted solar with battery storage THB 2.8331/kWh. The resources differ in firmness, generation profile, transmission, hydrological exposure and contract structure.

Source: Draft PDP2026 slides 11, 24 and 25; ERC Ft public hearing document for September to December 2026; Chowdhury et al. (2021), Earth's Future; EPPO/NEPC tariff decisions; ERC solar-with-storage FiT program.

A.5 Carbon-price sensitivity

The carbon-price sensitivity asks a simple question: if each tonne of residual emissions carried a carbon cost, how much would that add to electricity cost in 2050? Four reference prices are applied to the emissions that Cases 3 and 4 still produce in 2050 (16.6 and 19.1 MtCO₂e, slide 42). Figure 3 in the main text shows three of them; the Singapore 2024–25 rate, replaced in January 2026, is included here for reference. Each annual cost is converted to THB/kWh using the plan's two 2050 demand forecasts, Base-High (414,766 GWh) and Base-Low (366,945 GWh) (slide 15), because the plan does

not say which forecast each case uses. Each result is therefore a range: the lower value uses Base-High and the higher value uses Base-Low. The range reflects the demand forecast, not uncertainty in the carbon price.

Reference	Case 3	Case 4	Case 4 less Case 3
Thailand excise, THB 200/tCO ₂ e	0.0080 to 0.0090	0.0092 to 0.0104	0.0012 to 0.0014
Singapore 2024-25, THB 651.8/tCO ₂ e	0.0261 to 0.0295	0.0300 to 0.0339	0.0039 to 0.0044
Singapore 2026-27, THB 1,173.2/tCO ₂ e	0.0470 to 0.0531	0.0540 to 0.0611	0.0071 to 0.0080
EU CBAM Q2 2026, THB 2,874.7/tCO ₂ e	0.1151 to 0.1300	0.1324 to 0.1496	0.0173 to 0.0196

Units: THB/kWh. None of these reference prices is presented as a forecast of a Thai power-sector carbon price. The THB 200 figure is a domestic excise reference applying to petroleum products, Singapore provides regional policy benchmarks, and EU CBAM is an external benchmark applying to goods entering the EU. The cost of CCS itself is examined in Section 3 (Phase 2).

Source: Draft PDP2026; Excise Department; Singapore National Climate Change Secretariat; European Commission; ECB reference rates; CFNT analysis.

A.6 Cost of CCS

We estimate the CCS avoided cost at USD 163–213.3 per tonne of CO₂. Using this cost, we calculate the resulting impact on the retail electricity tariff in 2050 under both a CCS cost of USD 213.3 per tonne of CO₂ and a CCS cost of USD 135 per tonne of CO₂, as assumed by the (draft) PDP2026. This calculation employs assumptions drawn from data specified in PDP2026, namely: national electricity generation of 366,945–414,766 GWh per year (low–high case); a required CO₂ capture volume of 21 MtCO₂ per year; and a retail electricity tariff of THB 4.34 per kWh. An additional assumption of a 6% grid loss factor is also applied.

Input	Value	Unit
Total CO ₂ to capture	21.0	MtCO ₂ /yr
CCS avoided cost (PDP 2026)	135.0	USD/tCO ₂
CCS avoided cost (CFNT-Low)	163.0	USD/tCO ₂
CCS avoided cost (CFNT-High)	213.3	USD/tCO ₂
National electricity generation (low)	366,945	GWh/yr
National electricity generation (high)	414,766	GWh/yr
Grid loss factor	6.0	%

Source: Draft PDP2026 slides 15 and 35, CFNT analysis.

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