Thailand's Clean Electricity Transition

How accelerated deployment of renewables can help achieve Thailand's climate targets

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Abstract

Since the publication of its latest Power Development Plan (PDP) in 2020 (PDP 2018 Revision 1), Thailand has considerably increased its emissions reductions objectives, announcing a net zero greenhouse gas emissions target for 2065 and carbon neutrality for 2050. As the power sector is a large part of the country's emissions, and because it has a key role to play in decarbonising other sectors, meeting these targets is possible only if the power sector is decarbonising too. This report hence analyses how Thailand can achieve its clean electricity transition, by comparing the planned trajectory of the PDP with the emissions targets, and providing an assessment of the gaps. Building upon the current PDP, this report analyses how the Thai power system can decrease its emissions to meet the targets by increasing the amount of wind and solar PV in its system, and how it can integrate these variable renewable energy sources efficiently.

This report concludes work area one of the joint work programme among the Electricity Generating Authority of Thailand (EGAT), the Ministry of Energy of Thailand and the International Energy Agency (IEA), and has benefited from data and input from the Thai counterparts. The analysis is based on a PLEXOS model of the Thai power system that has been developed by the IEA in cooperation with EGAT.

Acknowledgements, contributors and credits

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Executive summary

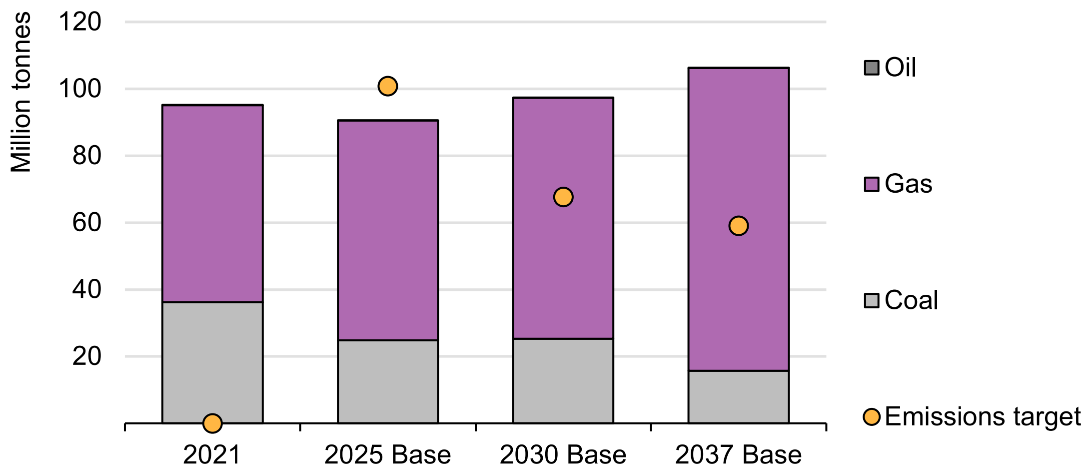
Decarbonising Thailand's power system is crucial to its net zero strategy

During the 26th Conference of the Parties in 2021, Thailand committed to reach carbon neutrality by 2050, and net zero greenhouse gas emissions by 2065. The country's 2022 long-term low greenhouse gas emission development strategy (LT-LEDS) focuses on the energy sector, which is the highest-emitting sector with 69% of the total GHG emissions in 2018. The power sector is key to the strategy, since electricity currently accounts for 35% of energy sector carbon emissions, and further electrification will be essential for reducing industry, transport and buildings sector emissions. In 2021, 66% of Thailand's generation mix was covered by natural gas and 17% by coal, while low-carbon sources provided only 12%. A rapid scale-up of clean generation will therefore be needed to align power sector development with Thailand's climate commitments.

Thailand's climate policy ambitions will require updates to the PDP

The power sector in Thailand is planned centrally through the Power Development Plan (PDP). The current version of this plan, PDP 2018 Revision 1 (hereafter "PDP 2018"), was published in 2020, before Thailand updated its climate objectives, and is not yet aligned with the new emissions targets. Based on the generation buildout in PDP 2018 emissions would exceed the targets by 44% in 2030 and 80% in 2037.

CO_2 emissions from the Thai power sector, 2021, 2025, 2030 and 2037



Source: IEA based on data from EGAT.

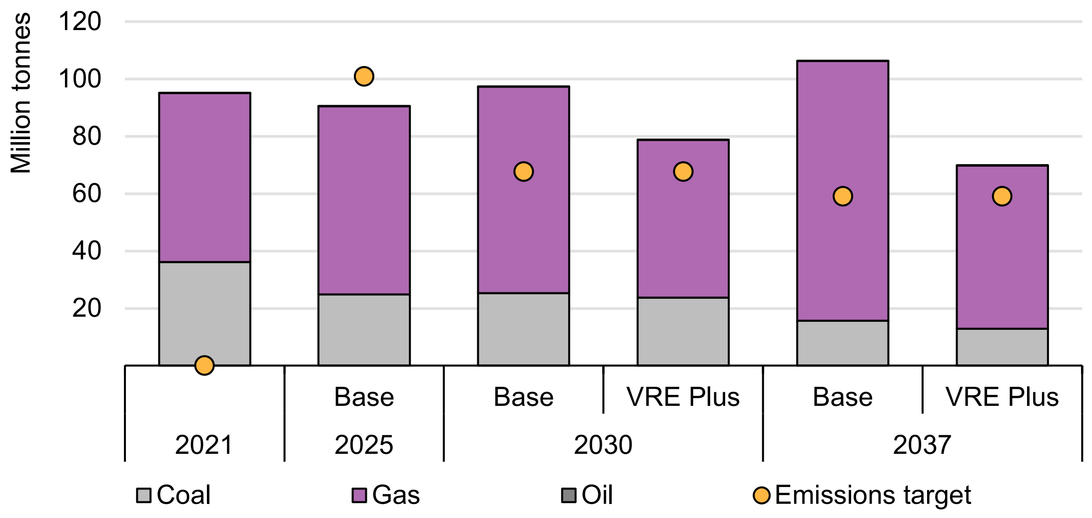
The main reasons for emissions surpassing the targets are expansion of coal and gas capacity – 16 gigawatts (GW) total – and insufficient clean electricity expansion – 18.8 GW of renewables – to drive the required reductions. Based on the current PDP and the EGAT's demand projections from 2022, power sector carbon emissions would rise 12% above 2021 levels by 2037. These demand projections integrate energy efficiency measures planned by the Thai government and the use of power for cooling and transportation, and result in a 4% average annual growth rate from 2021 to 2037.

The Thai government has announced a planned update to the PDP, in the frame of the broader new National Energy Plan. To support this update, we have modelled the Thailand power system to 2037 and assessed the potential to meet the new climate targets by increasing the deployment of solar PV and wind (VRE Plus scenario) in comparison with the PDP 2018 (Base scenario). We also assess the flexibility required to integrate this additional variable renewable energy (VRE) generation.

Accelerated deployment of renewable energy can allow Thailand to reach its climate targets

In the VRE Plus scenario, deploying an additional 32 GW of wind and solar capacity by 2030, and a further 42 GW on top by 2037, with reduced buildout of thermal plants forms the basis of Thailand reaching its climate targets.

CO_2 emissions from the Thai power sector under baseline and VRE Plus scenarios



Source: IEA analysis based on data from EGAT.

The share of VRE in generation is 28% in 2030 and 40% in 2037. This additional VRE generation alone decreases carbon emissions of the power sector by 29% in 2030 and 41% in 2037, relative to the Base scenario in each year. The deployment of VRE alone in this scenario is, however, not yet sufficient, as emissions still exceed targets by 1% in 2030 and 6% in 2037.

Increased flexibility is the key to effectively integrating high VRE shares

In the VRE Plus scenario, by 2030 the power system will require additional flexibility sources. The daily imbalance between supply and demand increases, leading to higher levels of curtailment if flexibility is not increased – reaching 4% of available VRE generation in 2030 and 16% in 2037.

In addition, as Thailand's renewable resources are largely located away from demand centres, by 2037 in the VRE Plus scenario the magnitude of imports and exports between regions increases.

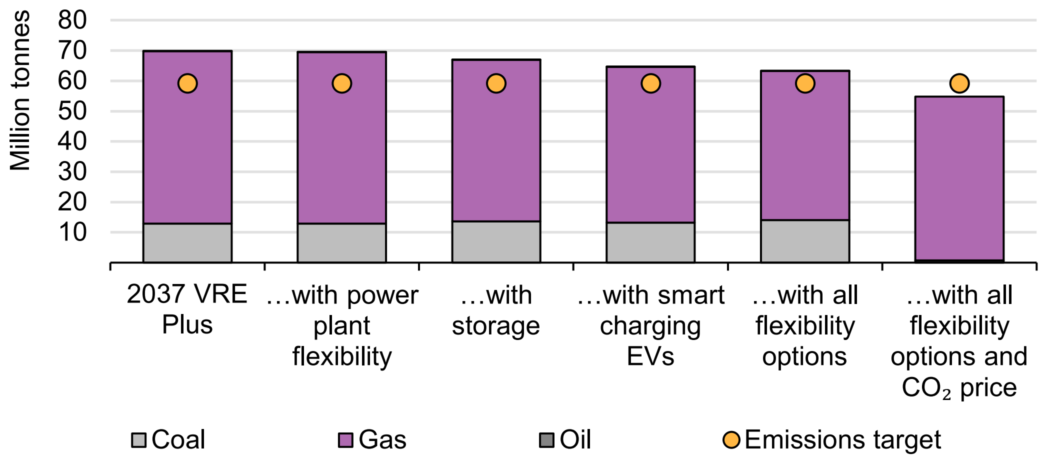
To accommodate the decentralised, variable and uncertain nature of VRE resources, and to reduce curtailment rates, it will hence be crucial to increase the Thai power system's flexibility. This will increase utilisation of VRE electricity, improving the business case for VRE generators, and further lower the share of fossil fuels in the power mix.

Flexibility options provide the best results when combined

Power system flexibility can be derived from several different sources including the grid, power plants, storage and demand-side resources. Reaching the 2037 emissions targets in the VRE Plus scenario depends on several flexibility assets, particularly storage and managed electric vehicle (EV) charging. These allow reliable and cost-efficient power system operation.

Storage and flexible EV charging help meet peak demand, while reducing periods of negative net demand by absorbing excess VRE. This has the additional benefit of reducing operating costs and lowering CO_2 emissions due to the increased use of low-carbon electricity.

CO_2 emissions in the 2037 scenario, under various flexibility options



Source: IEA analysis based on data from EGAT.

In addition, the deployment of VRE will require grid expansion to transport renewable electricity to demand centres. Appropriate price signals will also be important, both for investment in these clean energy technologies and for the appropriate operation of a low-carbon power system. In this respect, our analysis shows that combining storage and smart EV charging with a carbon price ensures demand is shifted to periods of high VRE availability.

Key policy recommendations

- **Prioritise policy measures and technologies that enable a rapid and cost-efficient decarbonisation of the power system.** As outlined by this study, focusing on actions to enable the rapid scale-up of VRE and power system flexibility enables Thailand to achieve its climate targets.

- **Provide policy certainty through updating the PDP and adapt frameworks and technical regulation.** Setting frameworks for appropriate VRE curtailment, as well as adapting grid codes and operational practices to VRE, will allow the power system to readily integrate growing shares of VRE generation.
- **Enable access to existing flexibility and incentivise new sources of flexibility.** Consider renegotiating or converting contracts to reduce contractual barriers resulting from take-or-pay fuel contracts. Create incentives for developing and operating storage in a system-friendly way. Unlock flexibility from demand response by making use of digital technologies.
- **Ensure power sector planning is integrated within infrastructure development plans.** Developing more integrated planning practices, such as between generation and transmission, or between the transportation and the power sector, allows the optimisation of deployment of renewables, grids and charging infrastructure.

Introduction

Thailand is located in Southeast Asia and has a population of over 71 million. Its neighbour countries are Myanmar to the north-west, Laos to the north-east, Cambodia to the east and Malaysia to the south. Viet Nam, Indonesia and India share maritime borders with the country. Bangkok, the country's capital, is also its most populous city with over 10 million inhabitants.

Thailand's GDP was USD 438 billion (constant 2015 USD) in 2021. Its economy is strongly export-dependent, with exports accounting for over 70% of its GDP. After the Covid-19 pandemic decreased the country's GDP in 2020, its economy is now recovering with a growth of 1.5% in 2021 and 2.6% in 2022, driven by an increase in exports and the recovery of tourism, as well as growth in domestic demand.

Thailand's energy demand per capita has seen a strong growth since 2000, similar to many of its neighbour countries of the Association of Southeast Asian Nations (ASEAN). The region is at the centre of global economic growth and energy demand. Indeed, Southeast Asia's electricity demand increased by 5.5% in 2022, and is expected to continue rising by 4-6% per year until 2025. This demand growth is currently largely met by fossil fuels.

In Thailand, gas is the main fuel used for electricity generation. While the country was, in the 1990s, a self-sufficient natural gas producer, Thailand's gas demand nearly doubled since 2000 while production from gas fields in the Gulf of Thailand dropped, and it now imports a large part of its gas consumption. Its gas self-sufficiency hence dropped to 63% in 2020 (from 90% in 2000). Thailand is a net importer of electricity, which it trades with its neighbours Lao PDR, Cambodia, Malaysia and Myanmar. The country had an overall energy self-sufficiency of 50% in 2020.

Thailand put its power system's decarbonisation at the centre of its low emission strategy

At the latest Conference of the Parties (COP27) in Egypt in 2022, Thailand updated its nationally determined contribution as a follow-up to the previously, at COP26 in 2021, announced targets of carbon neutrality by 2050 and net zero GHG by 2065. A target GHG emissions reduction of 30% by 2030, compared with the projected business-as-usual level, was announced and the revised long-term low GHG emission development strategy (LT-LEDS) submitted. With this LT-LEDS, the country shifted the targeted peak in GHG emissions from 2030 to 2025.

The document pinpoints the energy sector, the largest emitting sector in the country with 69% of the total GHG emissions in 2018, as the main priority to achieve these targets. Indeed, Thailand's energy supply is largely fossil fuel based, with oil (42%), natural gas (27%) and coal (13%) contributing to 82% of the total energy supply in 2020.

In the IEA Net Zero Emissions by 2050 Scenario, globally, the power sector is the first to decarbonise thanks to mature and available technology, and it can help other sectors decarbonise by electrifying. Thailand's LT-LEDS outlines a similar path, in which low-carbon electricity is used to decarbonise the buildings, transportation and industrial sectors. In Thailand, the power sector is currently the biggest emitter and represents 35% of the total energy sector's CO_2 emissions, followed by the transport and the industry sectors. The Thai power supply is provided mostly by gas (66% of total domestic generation in 2021) and coal (17%). Decarbonising Thailand's power sector is hence a crucial part of its net zero strategy.

In 2021, renewables accounted for 12% of the domestic generation mix in Thailand. The LT-LEDS outlines targets of having 50% of new power generation capacity in 2050 be renewable, and in terms of the generation mix, 68% of the mix should be renewable by 2040 and 74% by 2050. The strategy further elaborates on the strong role of transport electrification and storage, as well as the role of biofuels for both power – through biomass-fired power plants equipped with carbon capture, utilisation and storage (CCUS) and industrial heating applications. For the decarbonisation of the transport sector, one of the government's main targets is that EVs[1] represent 30% of the market, and that internal combustion engines are phased down after 2035. Although currently, the share of EVs in Thailand is below 1% (there were 36 775[2] battery electric vehicles registered by January 2023, while there were about 20 million vehicles registered in total), the year 2022 saw strong year-on-year growth in the sales of EVs in the country, thanks to policy incentives and tax rebates.

Updating power sector plans to match the new climate policy targets

To reach its updated, more ambitious, emissions targets, Thailand will have to ramp up its low-carbon electricity resources while ensuring the supply for growing electricity demand. Among the technologies mentioned in Thailand's LT-LEDS, one of the key assets for the low-carbon power system is the deployment of VRE sources and especially, in the context of Thailand, solar PV, which has a high

[1] Including battery electric vehicles and plug-in hybrid vehicles
[2] These data include light-duty vehicles, trucks, buses and two- and three-wheelers such as motorcycles and tuk-tuks.

potential in the country. Indeed, VREs are mature generation sources and provide abundant, low-cost and clean electricity.

To plan the development of the Thai power system, a central document, the National Energy Plan, provides the main directives. This plan combines five action plans, of which PDP, jointly prepared by the Ministry of Energy and the EGAT, and endorsed by the National Energy Policy Council. The latest version, published in 2020, is PDP 2018 revision 1 (PDP 2018) and goes from 2018 to 2037. Alongside this document, the Energy Efficiency Development Plan, the Alternative Energy Development Plan, the Natural Gas Plan and the Oil Plan outline more details in each of the subtopics. The Thai government is currently reviewing these plans to provide an update, which is expected for completion in the course of 2023. Indeed, as our analysis will highlight, with the current PDP, the new emissions targets cannot be reached. This study hence provides inputs to support Thailand in drafting a plan that allows it to reach the new objectives.

Analysing requirements for Thailand's clean electricity transition

In this study, we build upon previous IEA work on grid integration of renewables in Thailand and Thailand's power system flexibility to assess how the country can reach its recently updated emissions targets and how it can reliably operate a system with higher shares of VRE. Indeed, the variable character of wind and solar PV requires a shift in the way the power system is operated and planned. Power system flexibility will be crucial to allow the system to react quickly and reliably to variations in power supply.

In this study, after a presentation of the current Thai power system's structure, generation mix and demand profiles, we analyse the capacity expansion and flexibility requirements for Thailand's accelerated clean electricity transition and which assets are needed to meet them. We thereby updated the PLEXOS Integrated Energy Model developed for previous analysis and assessed the power system in 2025, which corresponds to the year of the targeted peak in emissions, 2030, a mid-term milestone in the power system emissions targets, and 2037, the end year of the PDP. We further provide a set of recommendations at different time horizons to provide Thai policy makers with guidelines as to which measures should be taken at which times for a successful transition.

Thailand's power sector

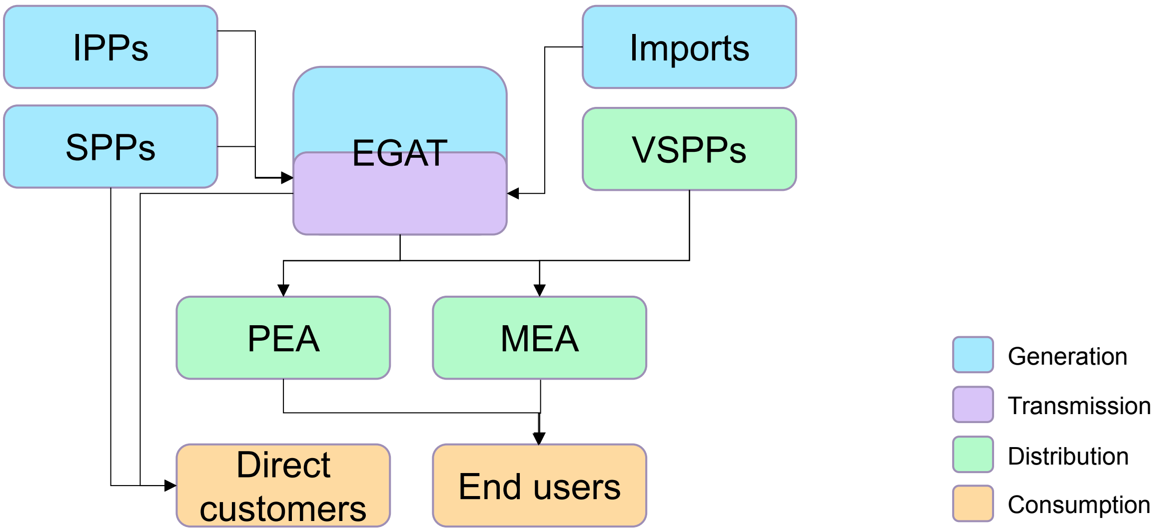
Thailand's power sector is structured as an enhanced single-buyer model

Several stakeholders are involved in Thailand's power sector, including the Ministry of Energy, the Energy Regulatory Commission (ERC), the government-owned utility EGAT, two distribution companies and independent power producers (IPPs).

The Ministry of Energy's role is formulating policy and strategy to ensure energy security and affordability, and sustainable energy in the country. The ministry is split into four departments, of which the Department of Alternative Energy Development and Efficiency and the Energy Policy and Planning Office. that are, together with EGAT and the ERC, responsible for preparing the PDP. The ERC regulates energy industry operations and promotes the use of renewable energy and energy efficiency.

EGAT, as a vertically integrated utility in Thailand's enhanced single-buyer model, has the responsibility to perform central planning of the Thailand power system. Its role is to allow for adequate generation, transmission and flexibility measures to meet its growing demand. It owns 34.5% of the power system's total generation capacity. The authority further acts as the single buyer of electricity from IPPs, small power producers (SPPs) and neighbouring countries.

Current structure of the Thai power system



Note: VSPPs = very small power producers; PEA = Provincial Electricity Authority; MEA = Metropolitan Electricity Authority.

IPPs and SPPs are both connected to the transmission network. The difference between the two is the size, as IPPs have a capacity greater than 90 MW and SPPs a capacity between 10 MW and 90 MW. Distributed generators are called very small power producers (VSPPs).

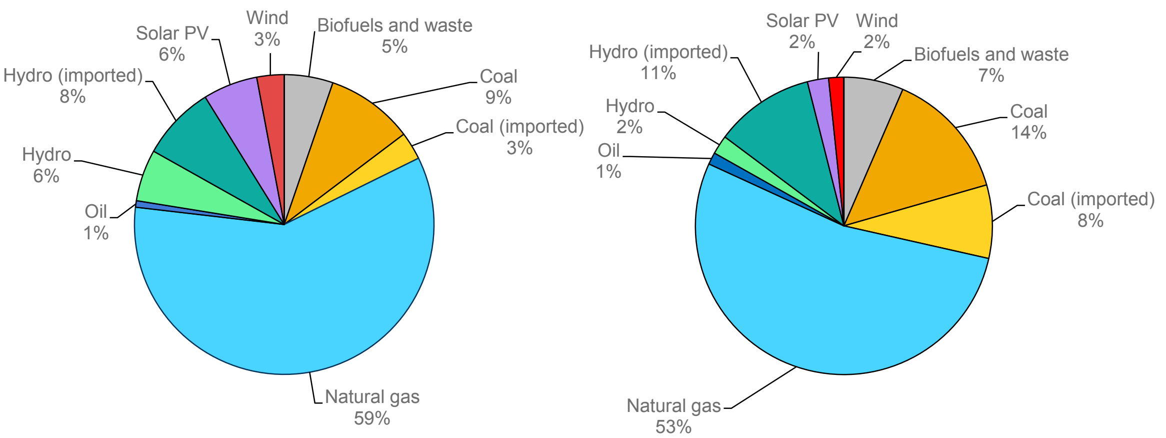
Two distribution utilities exist in Thailand, the MEA and the PEA. EGAT sells wholesale electricity to them, as well as to a few direct industrial customers and utilities in neighbouring countries. The MEA then supplies consumers in Bangkok and the metropolitan area, while the PEA supplies the rest of the country.

Most of Thailand's power generation is fossil fuel based

By December 2022, the installed generation capacity in Thailand was of 49 GW, of which 72% was fossil fuel based, with a majority (59% of the total capacity) being gas power plants. EGAT owns 16 GW (35%) of that capacity, while IPPs account for 33% and SPPs for 20%. The rest (12%) is made up by imports.

Looking at the domestic electricity generation mix in 2021, natural gas took the main share with 66%, followed by coal (17%), bioenergy (8%) and hydro (2%). Wind and solar power each contributed to 2% of the total generation. Thailand, however, also imports hydropower and coal power from its neighbours Lao PDR and Malaysia. When including these imports in the mix, the hydropower share increases to 13% of the total and the coal power share to 22%, and the natural gas share decreases to 53%.

Installed capacity (left) and electricity generation (right) in Thailand by fuel, imports included, 2021



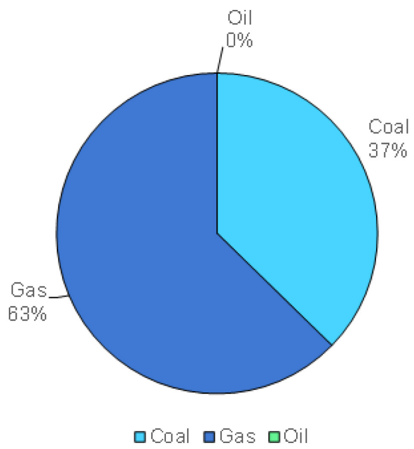
Source: IEA analysis based on data from EGAT.

Thailand is also involved in sub-regional multilateral trading efforts that aim to integrate ASEAN member states into a common ASEAN power grid to improve energy security, and increase the shares of variable renewables the system can integrate. The country acts as wheeling country in the Lao PDR-Thailand-Malaysia-Singapore Power Integration project (LTMS-PIP), under which up to 100 MW of hydro electricity are exported by Lao PDR to Singapore since June 2022, via Thailand and Malaysia. It also participates in the Greater Mekong Subregion integration effort.

In 2022, in a context of lower domestic gas production, import disruptions and high gas prices, the country experienced gas supply challenges which led the ERC to increase part of the electricity price, the fuel tariff, and the government to extend the lifetime of some of its coal-fired power plants and increase the use of oil for power. As a new gas power plant of four 660 MW units is currently under construction and will start operations in 2023 and 2024, gas will keep a predominant role in the power system in the short term.

Thailand's carbon intensity was 464 g CO_2/kWh in 2021, which is close to the global average of 462 g CO_2/kWh. Due to the large share of gas in its fuel mix, Thailand's carbon intensity remains lower than the average of the Southeast Asia region, which is at 601 g CO_2/kWh. To compare within the region, Indonesia, for example, had a share of 61% of coal in its power mix in 2021 and hence reached a carbon intensity of 756 g CO_2/kWh, while Lao PDR, which had a larger share of renewable electricity in its mix (74% in 2021) reached a lower carbon intensity of 309 g CO_2/kWh.

Power sector CO_2 emissions in Thailand, 2021

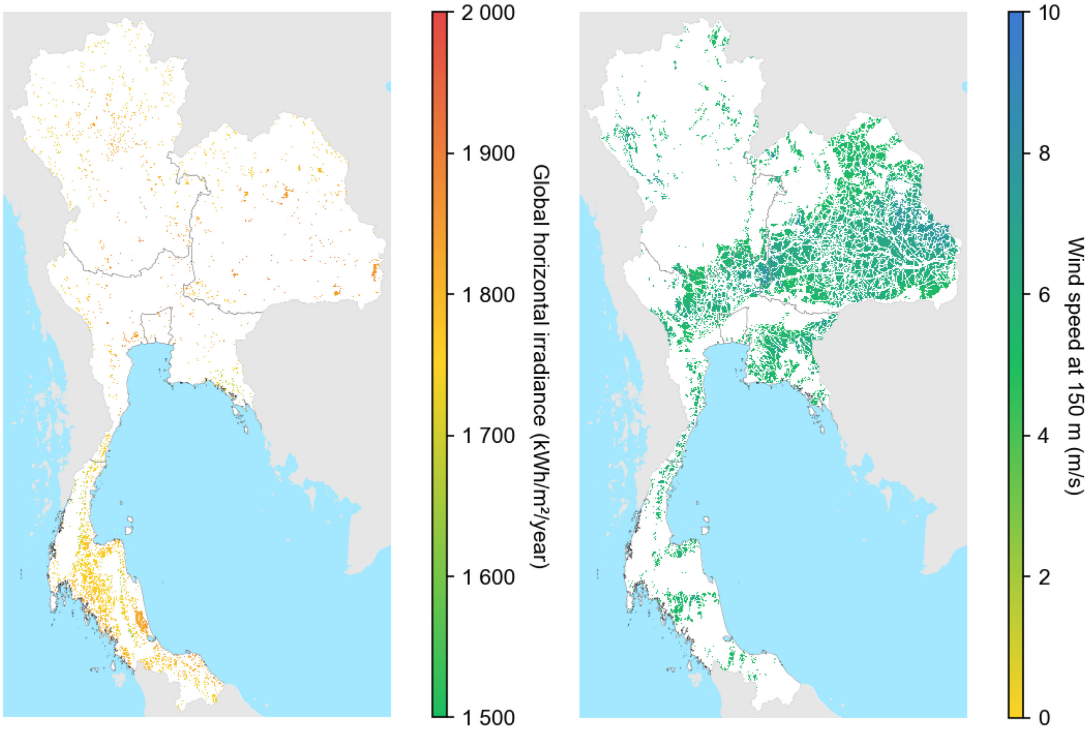


Source: IEA analysis based on data from EGAT.

Thailand can build upon its variable renewable energy resources to decarbonise its power mix

One key pillar of Thailand's power system decarbonisation is its solar PV potential. Indeed, the country has high solar irradiance, especially in the northeast and southern part of the country, and high daily solar exposure. The country has high potential for utility-scale solar PV deployment, and previous IEA analysis showed that the country also has strong potential for rooftop solar. It was demonstrated that with 10% of the available estimated rooftop surface used for distributed PV, the capacity hosted would be larger than the system's current peak demand.

Solar (left) and wind (right) potential in Thailand's power system's five control regions



Note: Each pixel represents a 3x3 km^2 area which can be used for development of wind or utility solar PV, with an assumption of land use per capacity of 9 MW/km^2 for wind and 30 MW/km^2 for utility solar PV and a land use factor of 0.5 which attempts to capture non-technical factors that may restrict the use of certain land for renewable energy development. Spatial analysis has been performed which excludes sites based on certain land use and land cover, proximity to infrastructure (e.g. roads, railroads and airports), protected areas and terrain (e.g. elevation and slope). Full details can be found in the Annex.

Sources: IEA analysis based on data from DTU, World Bank Group, Vortex, ESMAP (2021); Solargis, World Bank Group, ESMAP (2021); ESA Climate Change Initiative (2021); UNEP-WCMC (2021).

In addition, the country can develop its wind power capacity, for which the highest potential is located in the north-eastern region of the country. However, as there is a discordance between the location of the wind and solar PV resource and the demand centres that are located towards the centre of the country, the transmission of the clean power towards demand centres will have to be considered, as our analysis will further highlight in the next chapter.

The current targets of Thailand's Alternative Energy Development Plan (AEDP) 2018-2037 acknowledge the role of solar PV as a major renewable electricity source, with solar PV being the largest capacity addition planned.

Comparison of installed renewable capacity in 2021 with the targeted capacity of Thailand's AEDP in 2037

Fuel	2021 capacity	2037 target capacity
Solar PV	2.9 GW	15.6 GW
Wind	1.4 GW	3 GW
Hydro	2.7 GW (excl. imports)	3 GW
Biofuels and waste	2.6 GW	5.8 GW

Source: IEA analysis based on data from EGAT and Climate Policy Database (2019), Alternative Energy Development Plan (2018-2037) Thailand.

In addition, after the start of operations of a first 45 MW floating solar PV plant on the Sirindhorn Dam in October 2021, EGAT is targeting the addition of 15 further floating PV plants on dams, reaching a total capacity of 2.7 GW of floating solar PV.

Installing solar PV on the water means less land is needed to develop it, while increasing yields thanks to the cooling effect of the water. Furthermore, adding solar PV to a system with hydropower allows harnessing interesting synergies between the two technologies, as they have strong seasonal complementarity. However, a common misconception is that these synergies can be used only when hybridising the two plants. Recent IEA analysis showed that while hybrid PV can bring additional advantages, one has to be aware of the drawbacks as well and ensure to maximise each technology's benefits.

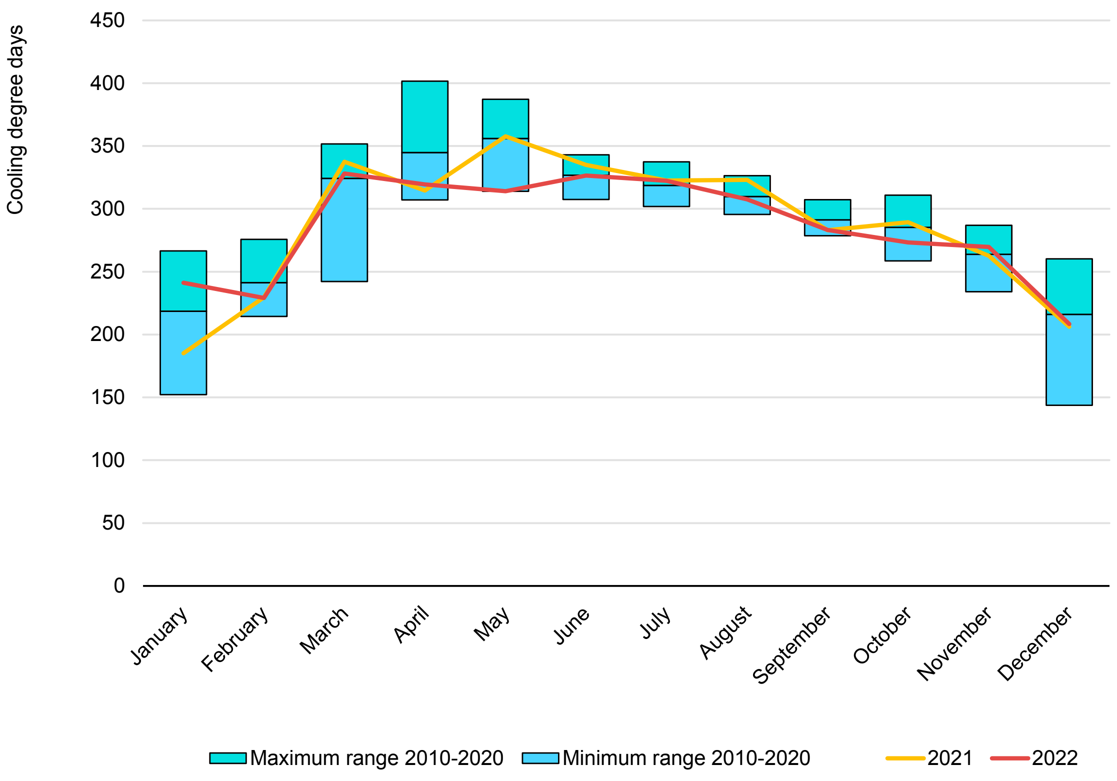
One of the drawbacks of co-locating solar PV with other technologies such as hydro or batteries is that the chosen location may not be the optimal one for either of the technologies. While adding PV to an existing hydro dam has advantages such as reducing transmission interconnection costs, it can also create adverse effects such as it not being the most optimal location in terms of resource availability.

Electricity supply and demand patterns are influenced by seasonal effects

Thailand has a tropical climate with three main climate seasons; the summer, from mid-February to mid-May; the rainy season from mid-May to mid-October; and the winter, from mid-October to mid-February. Seasonal monsoon winds influence the precipitation and temperature of the country. With over 3 000 cooling degree days[3] per year, and fewer than 5 heating degree days per year, demand is much more affected by cooling than heating in Thailand.

Temperatures in Thailand are highest in the months of March to May, during the summer season. This period corresponds to the months in which yearly peak demand is usually recorded. For example, in 2022 and 2021, peak demand occurred in April. These patterns in demand coincide with the increase in cooling degree days that reach a yearly peak from March to May.

Monthly cooling degree days in Thailand, 2010-2020 range compared with 2021 and 2022

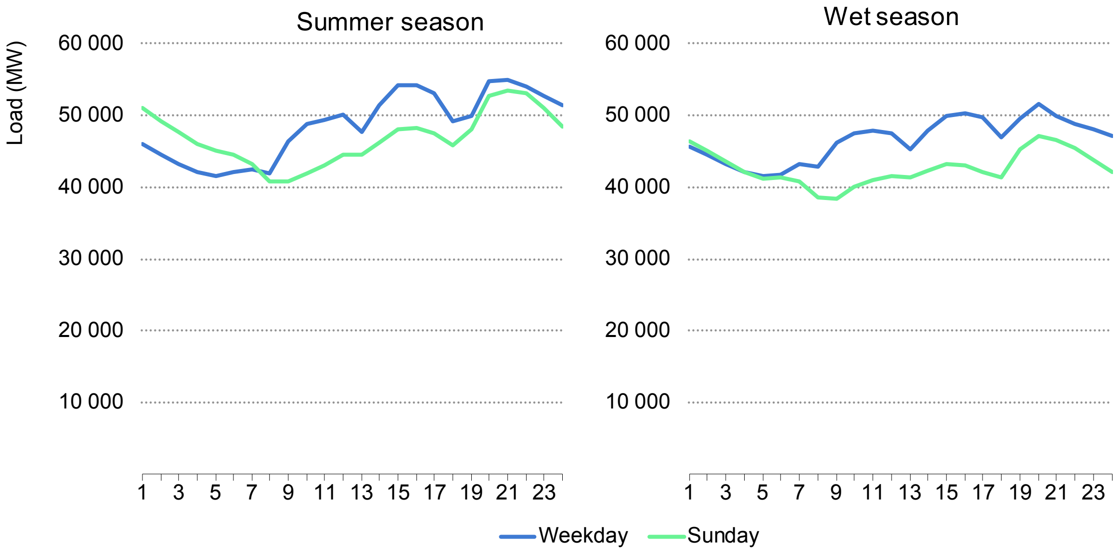


Source: IEA (2023), Weather for Energy Tracker.

[3] Cooling degree days and heating degree days are a metric used to capture weather-induced space heating and cooling needs. To illustrate, a cooling degree day is measured by taking the difference between the outside temperature and the reference temperature (18°C in this case).

The Thai daily demand patterns have a morning peak, an afternoon peak, and an evening peak. The latter one tends to be more pronounced than the first two, a tendency that is increasing as self-consumption of rooftop solar PV is growing in the country. Generally, the daily load is higher in the summer than in the wet season, correlated with the higher cooling needs.

Typical daily load pattern in Thailand for a weekday and a Sunday, in the summer season (left) and the wet season (right)



Note: The profiles correspond to 20 and 25 April 2021 (summer season) and 14 and 19 September 2021 (wet season).
Source: IEA analysis based on data from EGAT.

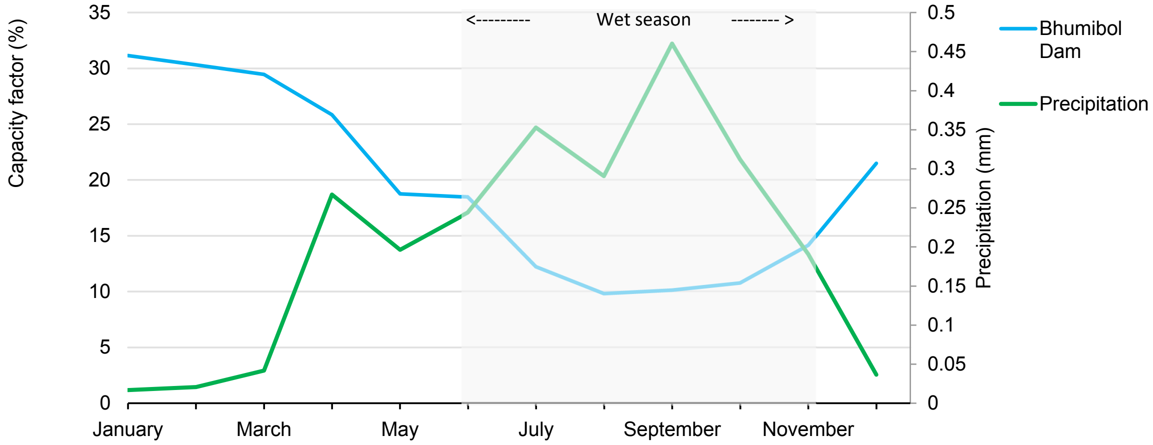
The main difference between weekends and weekdays is that the morning and afternoon peaks are not as pronounced on the weekend, which leads to a stronger ramping towards the evening peak. The highest half-hour upward ramp was on a weekend evening peak, on Saturday, 23 October 2021 at 18:00 at 2 764 MW. The highest half-hour downward ramp was on Wednesday, 17 March 2021, at 12:00, at -2 088 MW.

Thailand's climate further influences the availability of clean generation technologies such as hydropower and solar PV. In countries with a tropical climate especially, there is a seasonal pattern to take into account. Hydropower is generally more available in the wet season, which has higher precipitation, while solar PV is less available due to the higher cloud cover. As wind and solar PV availability generally both drop during the rainy season, these two resources do not complement each other on the seasonal level in tropical climates. It is also of interest to note that while these general seasonal patterns apply in the whole country, regional disparities exist, with for example higher precipitation at the eastern coast during the southwest monsoon which may affect power plant operation in that region.

While hydropower operations can be restricted by water management rules that ensure the water resource is available for other uses such as irrigation, they are a dispatchable source of clean electricity that can offer cost-effective flexibility solutions of different timescales.

In Thailand, hydropower plants do not always produce more hydroelectricity in the wet season (when the water resource is plentiful) than in the summer and winter, as their operations can be adjusted to tailor to other uses.

Monthly capacity factors for the Bhumibol hydropower plant in Thailand (left axis) and precipitation (right axis), 2021



Source: IEA analysis based on data from EGAT and IEA (2023), Weather for Energy Tracker.

To illustrate, when looking at the Bhumibol Dam's operations, we see that it is operated at lower capacity factors in the wet season. This is because the irrigation demand in the wet season is low and the reservoirs are storing water for the drier seasons. Operating the plant like this also allows the operators to regulate the water flows to prevent flooding during the rainy season.

The 2.8 GW of hydropower capacity installed in the Thai power system is a key asset in the power system's existing flexibility – which will be of growing importance as the power system decarbonises and as shares of VRE sources increase. Indeed, as recent IEA analysis demonstrates, hydropower will, together with thermal fleets, be the main source of seasonal flexibility in high VRE systems.

The Thai power system has large power plant flexibility, but flexibility requirements are bound to increase

Assessing existing and upcoming power system flexibility needs is essential for the reliable operation of a power system and is especially important as shares of VREs increase. Indeed, power system flexibility facilitates the reliable and cost-effective management of variability and uncertainty in supply and demand.

The six phases of VRE integration framework developed by the IEA allows the identification of the type of flexibility needed at each stage of VRE integration. The requirements vary in timescales and magnitude, depending on the existing power system flexibility, and the VRE penetration.

Assessing the three building blocks of power system flexibility (technical, contractual and operational) allows for a clear overview of the current capabilities of the power system.

Technical flexibility can be provided by power plants, electricity networks and interconnection, energy storage, demand response and distributed energy resources. It can be improved by operational practices, which can unlock technical flexibility by improving data collection and real-time monitoring, for example. Previous IEA analysis has shown that the Thai power system has significant latent technical flexibility and a high reserve margin that would allow the power system to integrate up to 15% of VRE by 2030. This is mainly due to its gas and hydro generation fleet and its transmission network.

However, the same analysis showed that the access to Thailand's power system flexibility is hindered by its contractual barriers. Contractual flexibility is defined as the flexibility provided by underlying contractual structures and institutions, which then facilitates the use of technical flexibility of the system. In Thailand, where fuel supply and power purchase contracts with minimum take-or-pay quantities prevent the use of other more cost-efficient resources, some of the available technical flexibility cannot be accessed due to these contractual barriers.

Main flexibility priorities by renewable integration phase

Phase	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Phase 6
Main Priority	Typically no system flexibility issues	Short-term flexibility	Short-term and medium-term flexibility	Ultra-short-term, medium-term and long-term flexibility	Long-term flexibility and very long-term flexibility	Very long-term flexibility

With its existing technical flexibility and low shares of VRE (4% in 2021), the Thai power system is currently in phase 1 approaching phase 2. This means that while most of the time, the VRE is not noticeable to the system, there are specific periods of time in which the difference between the load and the net load becomes noticeable. Such periods can for example be when high solar PV and low electricity demand coincide. In these periods, power system flexibility becomes increasingly important.

Thailand has ambitious emissions targets for 2030 and 2037, and we will show in the following analysis that to reach them, VRE shares will have to increase beyond the 15% VRE share the power system can integrate currently, with no further changes to its technical and contractual practices.

Flexibility will hence be crucial for Thailand's power system decarbonisation, and we will analyse which assets can contribute to a cost-efficient and optimal deployment of this flexibility in the future power system.

A vision of a decarbonised power system in Thailand

As a centrally planned and operated power system, the Thai power system relies on its PDP to identify the necessary projects for development to meet projected demand growth and ensure a reliable and secure power system. However, the current PDP, PDP 2018 revision 1 (PDP 2018), is out of date and is not sufficient to achieve the strengthened climate goals updated by the Thai government at the 27th Conference of the Parties (COP27), which have thereafter been translated to firm targets for emissions for the power sector.

This chapter presents the requirements for the Thai power system to achieve these targets, analysing the needed accelerated VRE deployment as well as which additional means are needed to integrate more VRE into the Thai power system.

Thailand's updated CO_2 emissions targets for the power sector

Year	Emissions target (million tonnes CO_2 eq)
2021	96
2025	100.9
2030	67.7
2035	63.2
2040	59.1
2045	53.0
2050	47.4

Note: 2021 is not a target but based on historical emissions as reported by EGAT.
Source: EGAT.

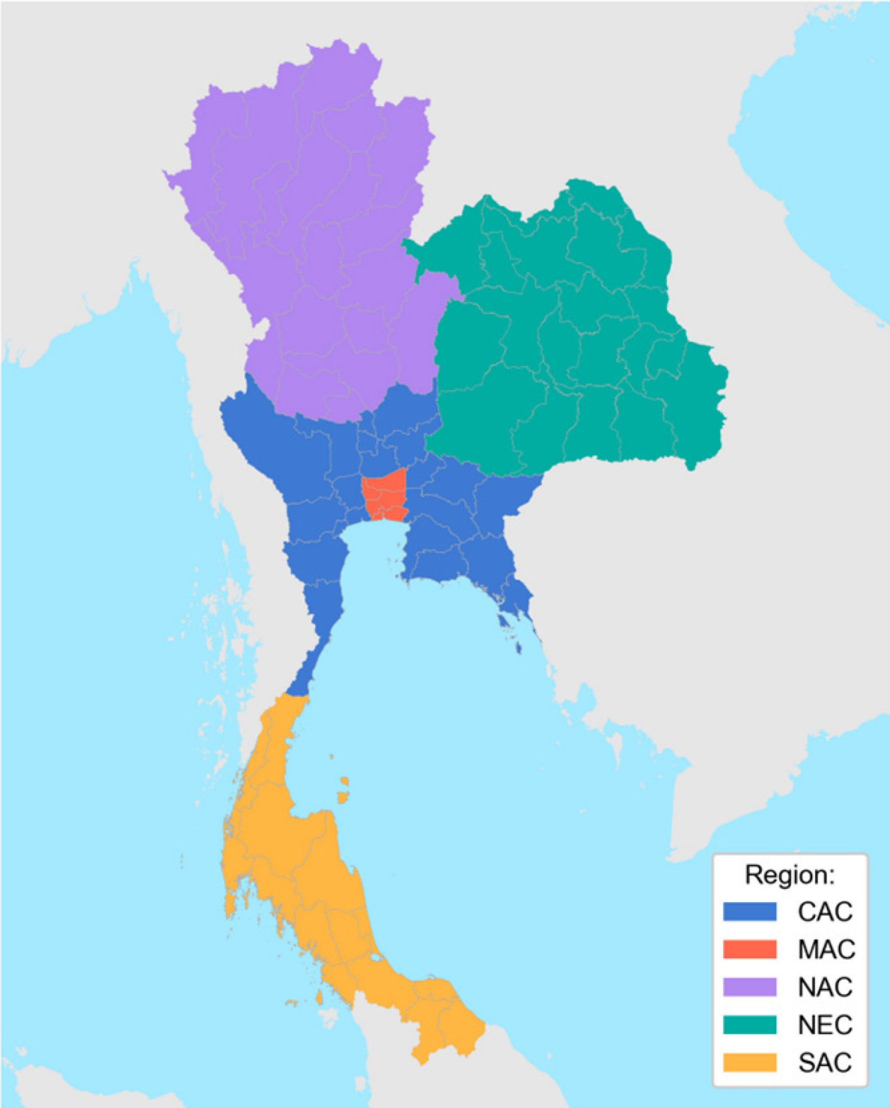
In order to explore the requirements for Thailand to achieve its outlined emissions targets, two main scenarios were developed to determine the gap between current policy objectives and the PDP 2018, and to highlight possible priorities for stakeholders of the Thailand power sector in order to achieve these targets. This work is performed in the PLEXOS Integrated Energy Model, taking advantage of both its production cost and capacity expansion modules, and builds upon previous modelling exercises performed for Thailand[4]. as it tries to explore the

[4] See IEA (2018), Thailand Renewable Grid integration Assessment and IEA (2021), Thailand Power System Flexibility Study.

flexibility requirements of a Thai power system that better reflects Thailand's strengthened ambitions of decarbonisation. The model represents Thailand based on five main control regions within the EGAT, corresponding with the spatial disaggregation of demand data provided by EGAT:

- Central (CAC)
- Metropolitan Bangkok (MAC)
- Northern (NAC)
- North-Eastern (NEC)
- Southern (SAC)

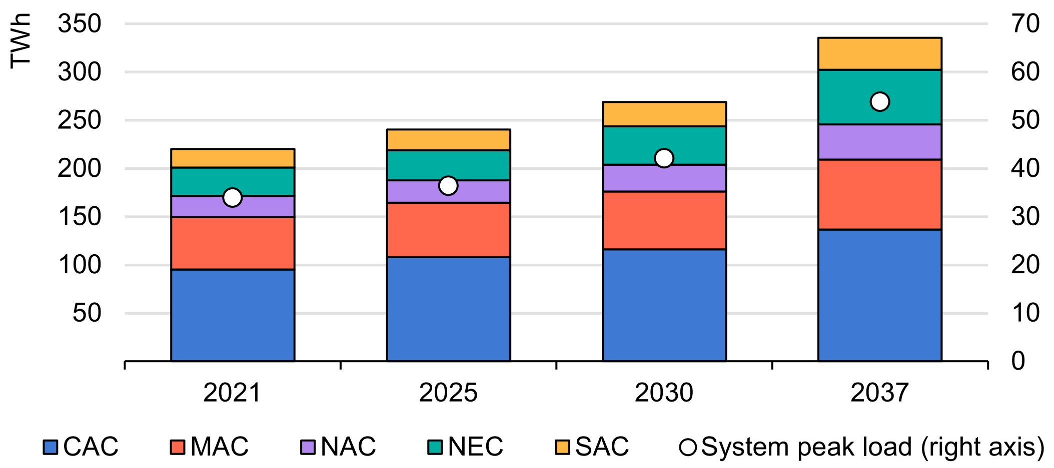
Representation of the five control regions in Thailand's power system



Source: EGAT.

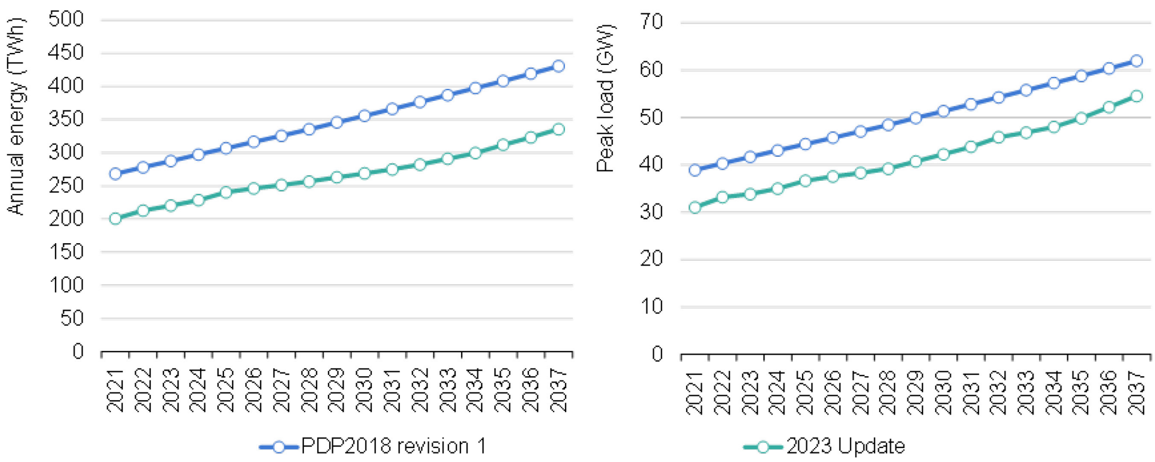
Demand is represented at a regional level, with an hourly resolution and is based upon updated projections from the Energy Policy and Planning Office (EPPO) that have been prepared for the forthcoming update to their PDP. This, importantly, includes updated projections for EVs and energy efficiency.

Annual demand by region and system peak load, 2021, 2025, 2030 and 2037



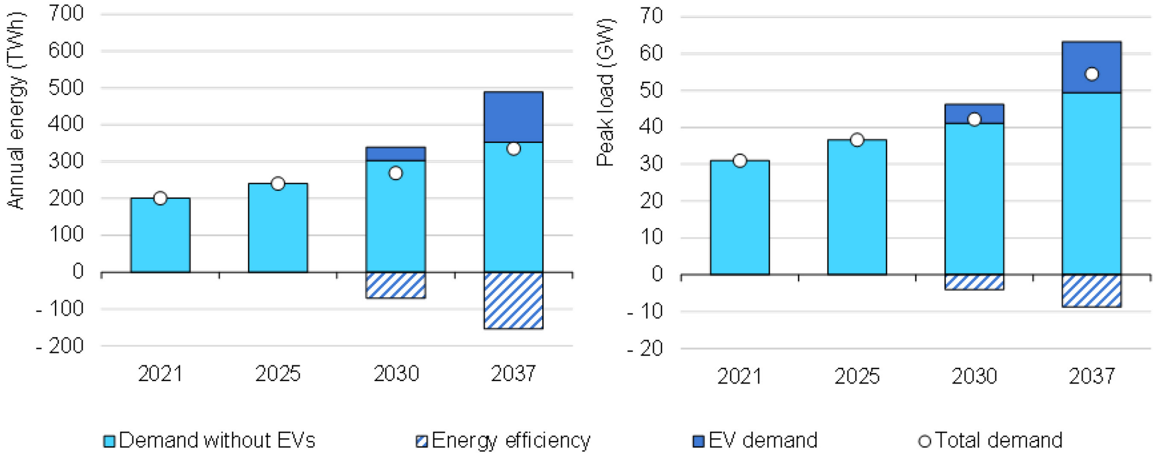
Source: IEA based on data from EGAT (2020), PDP 2018 Revision 1.

Annual demand by region and system peak load according to the PDP 2018 and 2023 update to demand projections



Source: IEA based on data from EGAT (2020), PDP 2018 Revision 1.

Contribution of electric vehicles and energy efficiency to both annual (left) and peak (right) demand for the 2023 update of demand



Source: IEA based on data from EGAT (2020), PDP 2018 Revision 1.

The model considers two main scenarios based on three different modelling years (2025, 2030 and 2037), in addition to the validation of the model against historical values based on 2021. The first of the two main scenarios is the Base case, which considers the development of the capacity mix as per the PDP 2018, and represents a business-as-usual reference case for the development of the Thailand power system. Meanwhile, the second scenario, VRE Plus, considers an alternative capacity mix that takes into account the deployment of wind, solar PV and the necessary flexibility options (specifically storage and inter-regional transmission) in order to meet the emissions targets for the Thailand power sector. This scenario is still based around the PDP 2018; however, it removes any uncommitted thermal generation, as identified by EGAT, from the capacity mix. Importantly, this scenario does not re-optimise the PDP 2018 and so its results are only indicative, and aims to demonstrate how VRE can empower Thailand to achieve its policy objectives to decarbonise the power sector.

Overview of the main modelling scenarios

Scenario	Year	Description
Validation	2021	Historical capacity mix
Base	2025 2030 2037	Capacity mix based on PDP 2018 revision 1
VRE Plus	2030	The capacity mix deviates from the Base scenario with accelerated VRE deployment to meet Thailand's emissions target. This includes the removal of 6.9 GW of uncommitted

Scenario	Year	Description
		thermal generation that would have come online between 2030 and 2037.
	2037	Different flexibility options (grid expansion, storage, power plant flexibility and smart charging EVs) are also explored in order to assess their benefit for accommodating higher shares of VRE.

Generation is represented at plant level for all large thermal and hydro plants, while small and distributed power plants (as provided by EGAT) are aggregated at both technology and regional level. The technical characteristics of the plants are based on data provided by EGAT when available or, in their absence, based on generic characteristics from international data. Contractual constraints for individual generators and their fuel supply, as represented in power purchase agreements, are also captured. This includes take-or-pay fuel contracts for gas supply and the contractual constraints for operation of IPPs, which are often set well below their actual technical limits.

The modelling exercise consists of two components:

- Capacity expansion, whereby the optimal amount of VRE and flexibility options (inter-regional grid reinforcement, storage) are found in order to meet Thailand's emissions targets in the modelled years.
- Production cost model, to explore the flexibility requirements around increased VRE production and the benefits of different flexibility options. This model is deterministic, using only a single weather year and a single set of outage patterns for generators. It is therefore unable to appropriately assess system adequacy.

The locations for new solar and wind plants as specified in the modelling scenarios are estimated using a wind and solar site selection methodology that takes into account the location of the best resource, annual demand in each region, proximity to existing transmission, terrain (i.e. slope and elevation), protected areas, and current land use and land cover. The capacity necessary for the achievement of the emissions targets is determined using the capacity expansion model, but with a fixed ratio of 3:1 for solar PV to wind in order to capture the status quo of the maturity of the technology within Thailand as reflected in the PDP 2018. In addition, due to the limited amount of land for VRE development in densely populated regions (e.g. CAC and MAC), 20% of the solar PV capacity is assumed to come from rooftop PV, with the siting of this capacity based on population-weighted sampling of rooftop area, estimated using statistical analysis of rooftop area and population density. Full details for VRE modelling and siting are provided in the Annex.

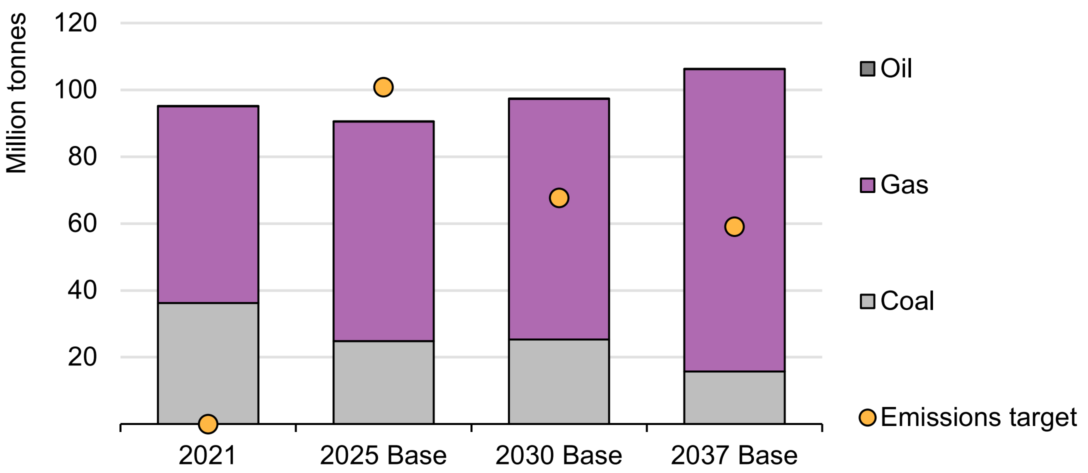
The transmission network is represented in terms of the available transfer capacity among these control regions as determined in the PDP 2018. However, in the case of the VRE Plus scenario, the necessary reinforcement of inter-regional transmission to connect new sources of supply and demand is also determined using the capacity expansion model. Finally, additional storage as needed for flexibility is also determined from the capacity expansion model; however, due to the complexity in cost and siting information with regard to pumped storage hydropower, it considers only battery energy storage systems at grid level of either one-hour, four-hour or eight-hour duration.

More details on the representation of the Thailand power system and the methodology for modelling can be found in the Annex.

Plans for the power sector need to be updated to reflect new policy ambitions

There is a large gap between the capacity expansion plans outlined in the current PDP and those required to achieve peak emissions in 2025 as outlined by the Thailand government at COP27. Despite a drop in domestic emissions between 2021 and 2025 due to a decline in domestic coal-fired generation (and subsequent increase in imports of coal-fired generation from Lao PDR), the continued growth in demand thereafter would lead to an increase in CO_2 emissions under the Base scenario. This would mean that despite being able to achieve emissions targets for 2025 in the business-as-usual Base scenario, the system as planned for 2030 and 2037 would not be able to both meet demand and its emissions targets in those years with a generation mix as per the PDP 2018. The Thai power system would therefore need a significant amount of additional low-carbon generation capacity to allow for both meeting of its updated policy objectives and growing electricity demand.

CO_2 emissions from the Thai power sector, 2021, 2025, 2030 and 2037



Source: IEA analysis based on data from EGAT.

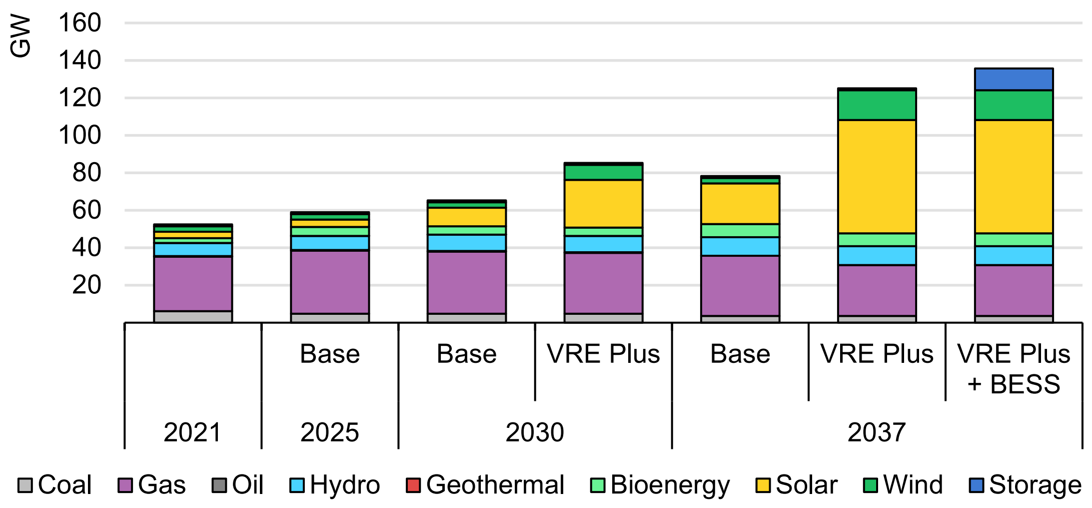
These results have been obtained by comparing the results of the Base scenario, which assumes the same capacity mix as specified by the PDP 2018 against the CO_2 targets for the power sector. While primarily based on the PDP 2018, it also uses updated demand projections as prepared by the load forecast committee at EPPO for ongoing updates to the PDP.

According to the most up-to-date projections, annual demand is expected to increase at an annual average of 4% year-on-year from 2021 to 2037. At the same time, peak demand is expected to increase at 4.5% year-on-year over the same period, with this stronger growth being driven by the electrification of new end-use demands such as residential cooling and EVs. This, however, is under a scenario where EV demand is not incentivised to move to periods of low net demand, therefore providing flexibility to the system (as discussed later in the chapter).

An alternative capacity mix will be required for Thailand

Our analysis shows that 32 GW of additional variable renewable capacity (relative to 2021) is needed for Thailand to meet its 2030 CO_2 emissions targets, as demonstrated by our VRE Plus scenario, while a further 42 GW on top of this would be required for 2037. This would also change the regional make-up of supply due to the distribution of renewable resources (with more details found in the Annex).

Generation capacity mix across all years and alternative capacity scenarios for 2030 and 2037



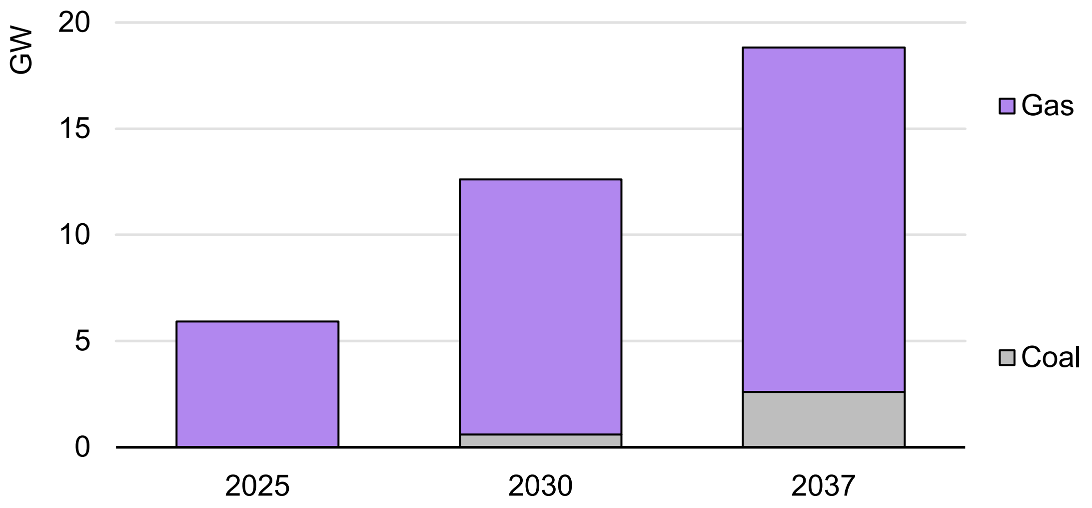
Source: IEA analysis based on data from EGAT.

This required capacity expansion of VRE can also reduce the investment into the construction of additional fossil fuel power plants. Indeed, the PDP outlines significant capacity expansion of its thermal fleet between 2021 and 2037, including 13.4 GW of gas and 2.6 GW of coal. With an accelerated buildout of VRE as necessary to meet emissions targets, a significant amount of this capacity could be both realistically and economically replaced when combined with appropriate flexibility measures that firm up this capacity (as discussed later). However, this would require a dedicated least-cost capacity expansion model and assessment of system adequacy in order to fully evaluate. The presented exercise is therefore more limited than this, and instead tries to evaluate:

- The required amount of VRE necessary in addition to the capacity outlined in the current PDP 2018 that would be necessary to achieve Thailand's emissions targets.
- How this level of VRE penetration impacts the flexibility requirements of the system, and how much flexibility (specifically storage and grid expansion) would be necessary to accommodate these growing shares of VRE and enable the achievement of Thailand's emissions targets.

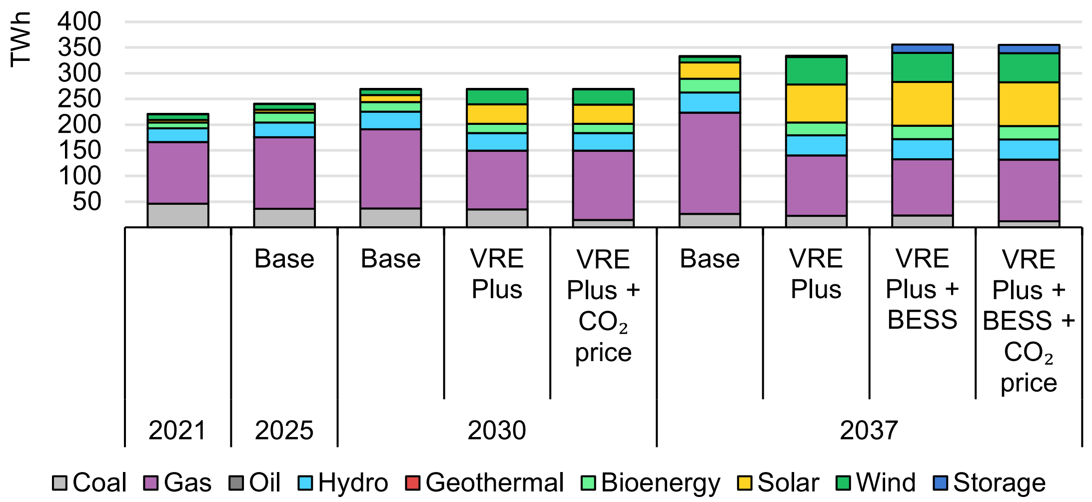
Nevertheless, based on the evaluation of the PDP 2018, all uncommitted thermal plants from the PDP that are built after 2030 are removed, effectively removing 2 GW of coal and 4.9 GW of gas-fired generation. The end result is a much larger share of generation from renewable resources, which would account for more than 60% of generation.

Cumulative gross capacity additions of thermal plants as planned in the PDP 2018 revision 1



Source: IEA analysis based on data from EGAT.

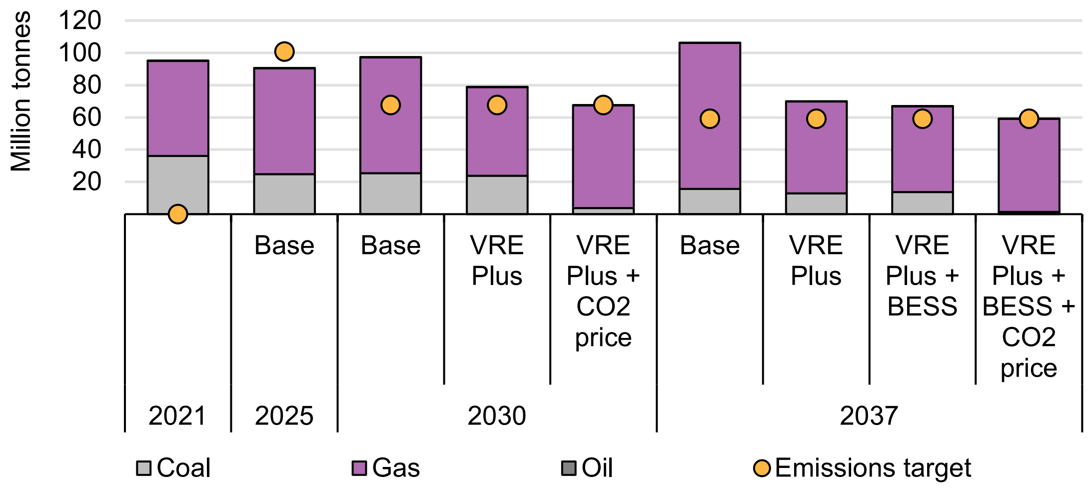
Generation share per technology under the Base and VRE Plus scenarios



Source: IEA analysis based on data from EGAT.

While in 2030, the deployment of VRE alone in the VRE Plus scenario is sufficient to meet the emissions targets, by 2037 this changes as higher shares of VRE necessitate increased system flexibility to better accommodate its variable generation and adequately displace thermal generation.

CO_2 emissions from the Thai power sector under baseline and VRE Plus scenarios without additional flexibility



Source: IEA analysis based on data from EGAT.

Accelerated deployment of VRE capacity can be reached through several short-term actions. These actions, related to financing, integrated planning, operational adaptation and technical regulations, are discussed in more detail in the next chapter. These actions can help facilitate timely investment in VRE and the efficient operation of a system with higher shares of VRE in Thailand.

While this may be sufficient for Thailand to achieve a large part of its emissions reductions in 2030 and 2037, our analysis shows that to reach these targets, the sole deployment of VRE will not be enough. Indeed, as more VRE is deployed, the flexibility requirements begin to surpass that of the inherent system flexibility, which is today provided predominantly by Thailand's flexible power plants in the form of hydro and gas-fired generation.

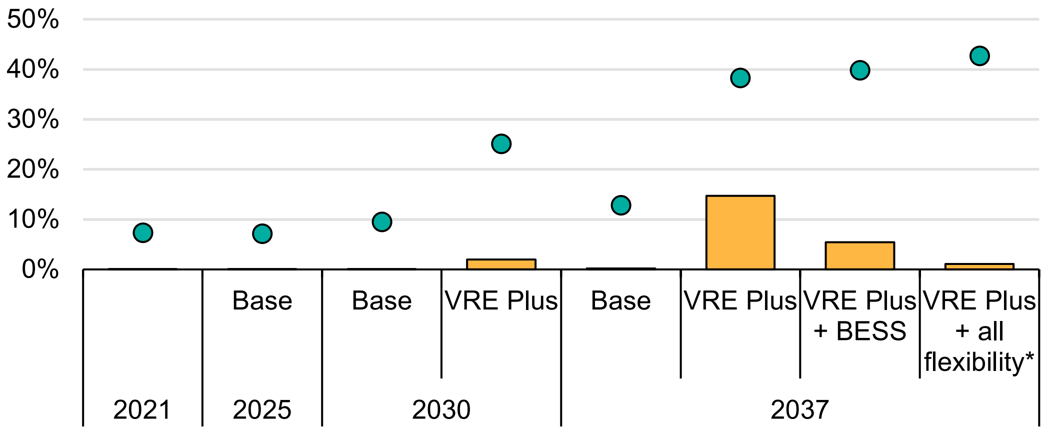
Therefore, appropriate policy, regulatory and operational frameworks will also be required that adequately enable and incentivise flexibility from various resources such as storage, demand-side response and energy efficiency. As an example, price signals will be required, not only for investment in these clean energy technologies, but also for the appropriate operation of a low-carbon power system. It should also be noted that increased interconnection with neighbouring systems and multilateral trade are excluded from the model; however, this would increase the flexibility of the system in a number of ways, including the smoothing of variability (from both VRE and demand) as well as enabling the sharing of different flexibility resources. The different frameworks that can enable flexibility, including multilateral trade, are discussed extensively in the following chapter.

Adequate price signals will be required to drive the necessary investment in clean energy technologies

As greater shares of VRE are deployed, there will be a need to develop and modernise the Thailand power system so that it is more flexible and better able to accommodate the variability, uncertainty and decentralised nature of VRE generation in a cost-effective and reliable manner. This flexibility can be derived from a number of different resources including the grid, power plants, storage and demand-side resources. The necessary capacity of these resources has been explored through the use of a capacity expansion model that determines the optimal expansion of additional VRE resources and flexibility options in the modelled years in order to meet system constraints on total emissions.

Under the Base scenario, the Thailand system appears to have sufficient flexibility to accommodate the described shares of VRE in 2030 (9.4%) and 2037 (12.8%). One indicator for flexibility is the level of curtailment of the VRE resources as the level of VRE capacity that is deployed increases. Under the Base scenario, this remains low as the system derives flexibility from its power plants, which comprise a relatively flexible fleet of hydro and gas-fired generation, while further complemented by its 1 GW pumped storage hydro plant in Lam Takong.

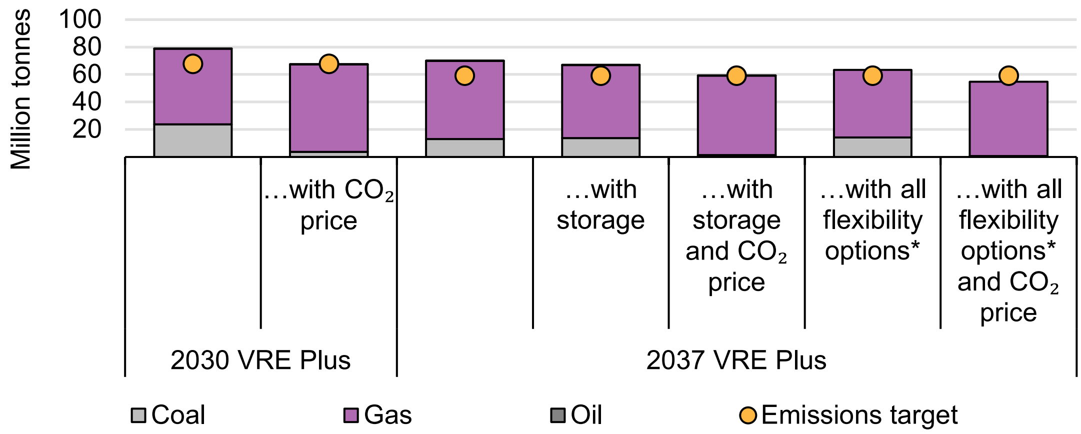
Shares of variable renewables and curtailment rate across the Base and VRE Plus scenarios, 2021, 2025, 2030 and 2037



*all flexibility options = power plant flexibility, additional BESS and smart charging EVs
Source: IEA analysis based on data from EGAT.

Under the VRE Plus scenario, the system flexibility requirements increase, as indicated by the higher levels of curtailment, as the daily imbalance between demand and VRE production increases. While curtailment can be considered an economic factor (representing a loss for utility or developer, depending on the offtake agreement), within the context of Thailand, it also represents a threat to the achievement of its emissions targets as curtailed generation needs to be substituted by other dispatchable resources which are often thermal plants. However, in 2030 under the VRE Plus scenario, curtailment has only a marginal impact on emissions and Thai power sector targets are met even without any additional flexibility. However, this is ensured only through the inclusion of a carbon price that both incentivises investment in the required additional VRE capacity (32 GW in 2030, 74 GW in 2037) and ensures that the operation of the power system accounts for the set emissions targets. For the purpose of this analysis, the CO_2 price (USD 20/tonne in 2030 and USD 90/tonne in 2037) was determined as an output of the model, which increases as the emissions target for Thailand tightens and the need for clean energy investment accelerates.

Total CO_2 emissions under the VRE Plus scenario with and without CO_2 pricing and various flexibility measures



*all flexibility options = power plant flexibility, additional BESS and smart charging EVs
Source: IEA analysis based on data from EGAT.

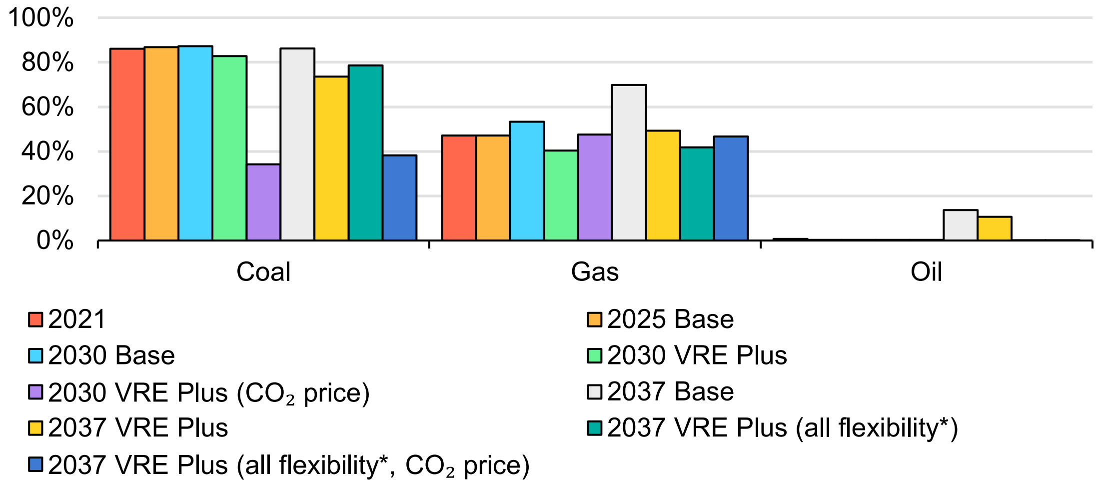
While the system in 2030 under the VRE Plus scenario appears to be flexible enough to accommodate the larger shares of VRE with flexibility from the system as planned by the PDP 2018, the addition of new flexibility options helps to better accommodate these shares and as a result reduces both operating costs and emissions. Due to the relatively short-term horizon to 2030, this analysis is limited to the deployment of battery storage (one-, four- and eight-hour duration) and increased power plant flexibility through targeted retrofits and more flexible operation of IPPs, which are often contractually constrained well below their technical limits. The optimal level of storage deployment was then found to be 2.4 GW of four-hour duration storage. In its deployment it helps reduce annual operating costs by USD 48 million (0.7%) relative to the system with no additional flexibility.

Both measures help to decrease curtailment, which in turn helps to decrease emissions and lower operating costs. In the case of power plant flexibility, the lower minimum stable level helps to create more space for VRE production during periods of low demand as it is able to ramp down lower while remaining online to provide production during periods of peak demand. It is also able to better meet system ramping requirements which increase with the deployment of VRE. Meanwhile, storage allows for the shifting of peak demand into periods of low net demand, typically around solar production in the middle of the day.

Ambitious emissions targets require a suite of flexibility measures to ensure efficiency and reliability

As the emissions targets for Thailand further tighten towards 2037, two key challenges arise which need to be addressed by system planners and system operators alike. First, the tightening emissions targets for later years begins to limit the system flexibility that one can readily derive from thermal plants. Additionally, uncommitted thermal plants which were planned for commissioning during the period 2030-2037 are removed. These plants were meant to account for both energy and peak capacity requirements, which increase by 3.5% and 4.1% per year respectively. This means that both the energy and capacity from these plants need to be replaced by clean energy alternatives.

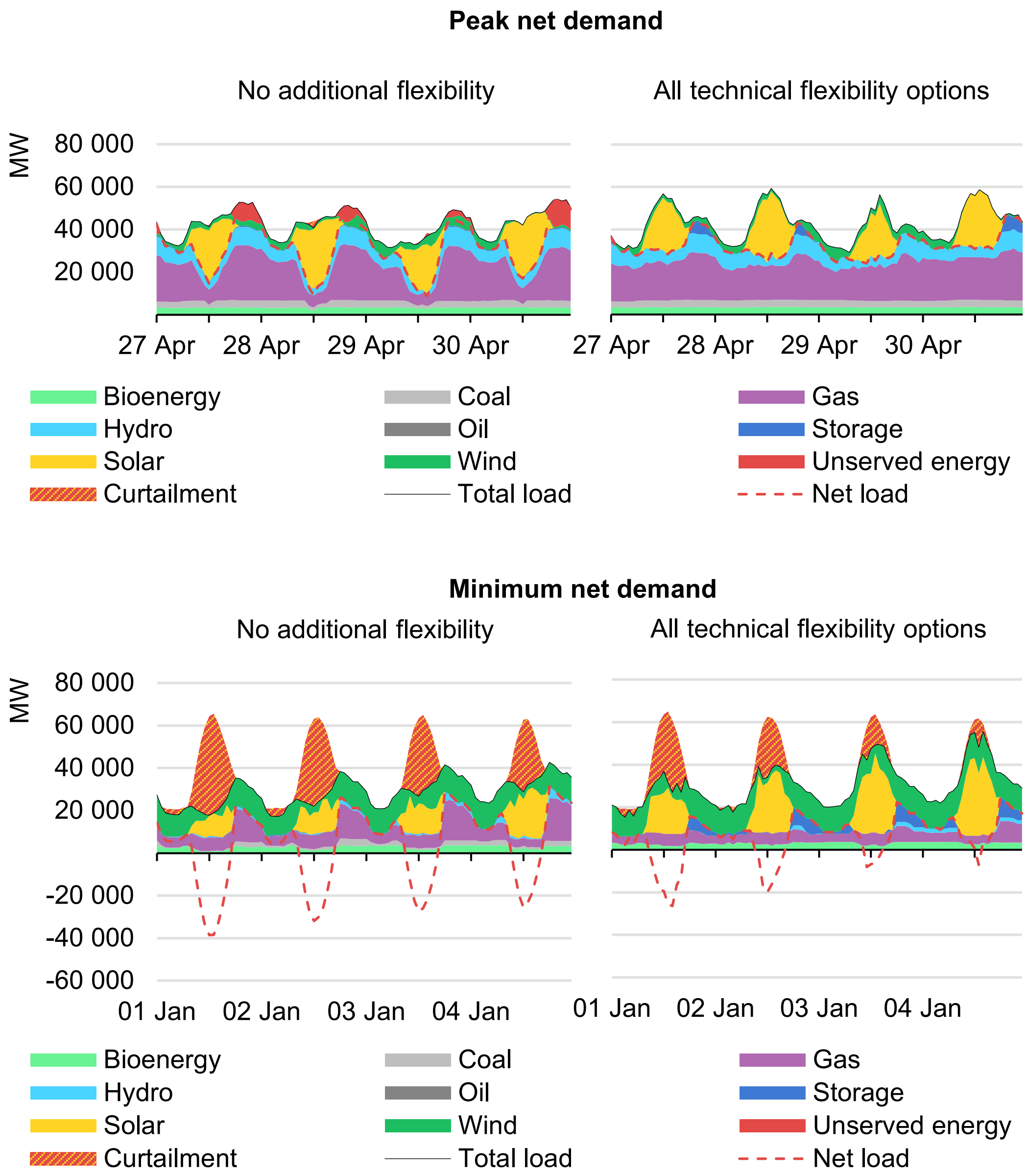
Evolving capacity factor of thermal capacity in different years under both Base and VRE Plus scenarios with different flexibility measures



*all flexibility = case with all technical flexibility options

A good indication of system flexibility needs can be provided by looking at a generation stack of the system during periods of system stress (e.g. periods of peak or minimum net demand). On analysis of the modelled system under the VRE Plus scenario, one sees that despite a growing installed capacity of VRE, this capacity (which is 75% solar PV) makes very little contribution towards peak periods, due to the combination of low wind generation during this period and an evening peak demand during which solar PV production makes little to no contribution. This results in a system that has insufficient capacity to meet peak demand requirements during certain periods without additional flexibility, especially from storage or smart charging EVs which help to shift demand to better match VRE production.

Generation stack during the period of peak and minimum net demand, demonstrating the impact of flexibility options in VRE Plus scenario in 2037



During periods of lower demand, and especially minimum demand around weekends and holidays, the growing imbalance between supply and demand becomes more evident as large amounts of both solar PV and wind production need to be curtailed to ensure the balance of supply and demand. Although this already occurs in 2030, this becomes much more evident in 2037 as there are many periods where VRE production exceeds demand (i.e. negative net demand). At the same time, the system must also accommodate must-run generation and the technical constraints of other dispatchable generation. Therefore, there is need to either curtail this excess generation or shift demand to better align with VRE production. Here again, flexibility from storage and smart charging EVs can help to reduce curtailment and therefore the efficiency of deployed VRE generation while also reducing the need for thermal generation during the evening peak. Increased power plant flexibility also helps to make more efficient use of remaining thermal plants through lower minimum stable levels that allow for these plants to reduce their output to lower levels while remaining online in order to provide generation during periods of lower VRE production.

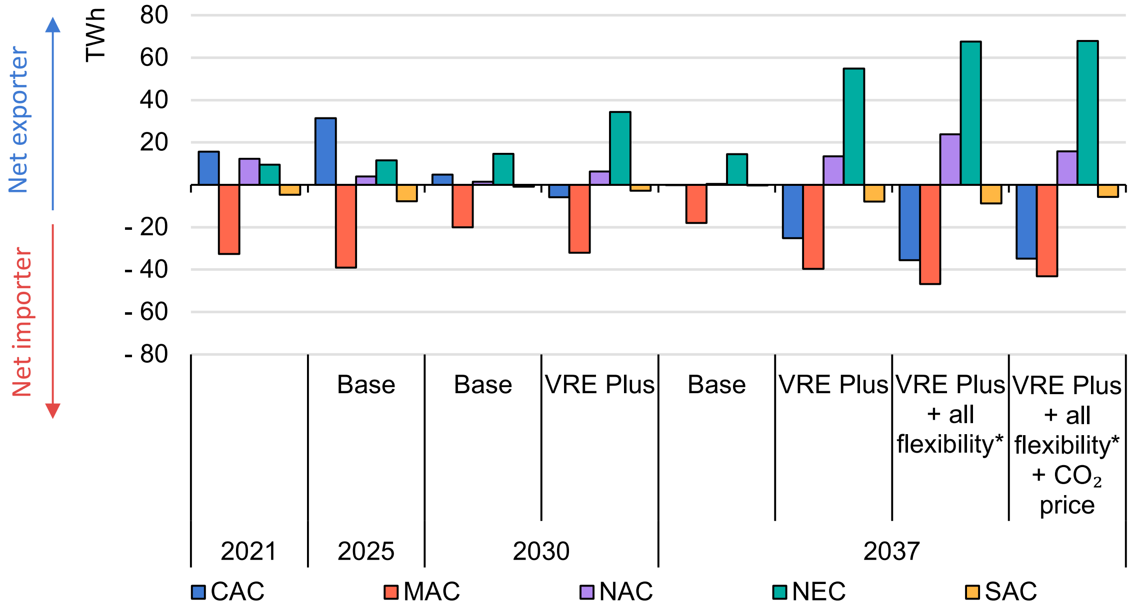
An overview of the flexibility options explored for this analysis are presented in the table below. These flexibility measures are not exhaustive, and instead aim to demonstrate the impact of specific measures as included within the scope of the model, while further measures (e.g. broader demand-side response, increased interconnection and multilateral trade) are discussed qualitatively in the following chapter. The operational impact of the flexibility measures as reflected in the above generation stacks demonstrate the contribution of flexibility measures as well as the technical requirement for curtailment, which is necessary as a final measure to balance supply and demand and to accommodate other sources of inflexibility in the system due to technical requirements of generators (must-run, minimum stable levels, etc.) and reserve requirements.

Overview of flexibility measures explored in VRE Plus scenario in 2037

Flexibility measure(s)	Description
Grid	Expansion of grid to allow for new inter-regional power flows. Determined by capacity expansion model.
Power plant flexibility	Power plant retrofits and contractual constraints for the operation of IPPs are considered that allow for lower minimum stable level and faster ramp rates for conventional thermal plants.
Storage	Deployment of battery storage (11.8 GW, six-hour duration). Determined by capacity expansion model.
Smart charging of EVs	50% of EV demand is assumed to be enabled to be shifted across the day.

Results show that there are limited benefits of additional power plant flexibility, as the system at the modelled timescales have very little impact on curtailment or operational cost savings (<0.1%). However, both additional storage (~11.8 GW with an average duration of six hours) and smart charging of EVs can help better accommodate new generation from wind and solar PV by shifting demand from peak periods where the system is stressed into periods of low demand and high VRE production. This is in addition to the expansion of the grid necessary to support the power flows from new VRE resources to demand, with certain regions (e.g. NEC) becoming important net exporters while others (e.g. CAC) becoming net importers. Note that the transmission model considers transfer capacity between regions only, and therefore these values are only indicative.

The evolution of net imports/exports across control regions under the different modelling scenarios, 2021, 2025, 2030 and 2037



*all flexibility = case with all technical flexibility options.

The suite of flexibility measures is important for the system across multiple dimensions, as it increases system adequacy (as peak demand requirements decrease and unserved energy reduces to zero), lowers curtailment levels (<1% with all measures) and reduces the operating costs of the system, with total savings in excess of USD 2 billion or 19.4% relative to the costs without any additional flexibility options (i.e. 2037 VRE Plus scenario).

System adequacy

As greater levels of VRE are deployed, its overall contribution towards peak demand will start to decrease as there is a concentration of production in certain periods. This is especially evident with solar PV production which follows a diurnal production cycle with a peak around midday. As a result, there is a need to enhance this low-cost and clean power supply with flexibility measures that can help it to contribute to periods of system stress (e.g. peak net demand, heavy outages), increasing the economic efficiency of these resources while allowing greater contribution during peak periods.

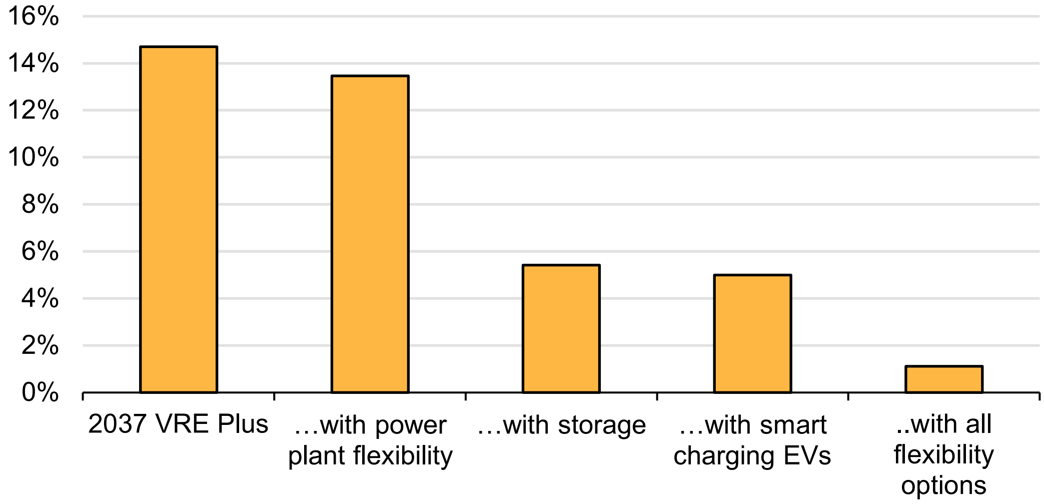
All flexibility measures are shown to make a contribution towards decreasing unserved energy (1% of total demand) in the system in 2037 under an accelerated VRE scenario, though the main contribution comes from smart charging EVs and storage, which if deployed together can greatly enhance system reliability. While the use of smart charging EVs for system flexibility could help reduce the system peak capacity requirements, the level of flexibility that can be provided by EVs has its own element of uncertainty around driver behaviour, the availability of charging infrastructure and the influence of incentives on charging, as discussed in the following chapter.

Importantly, these results are only indicative as they have not performed a full system adequacy study which should use a stochastic approach that considers multiple weather years and outage patterns to assess system reliability across multiple uncertainties.

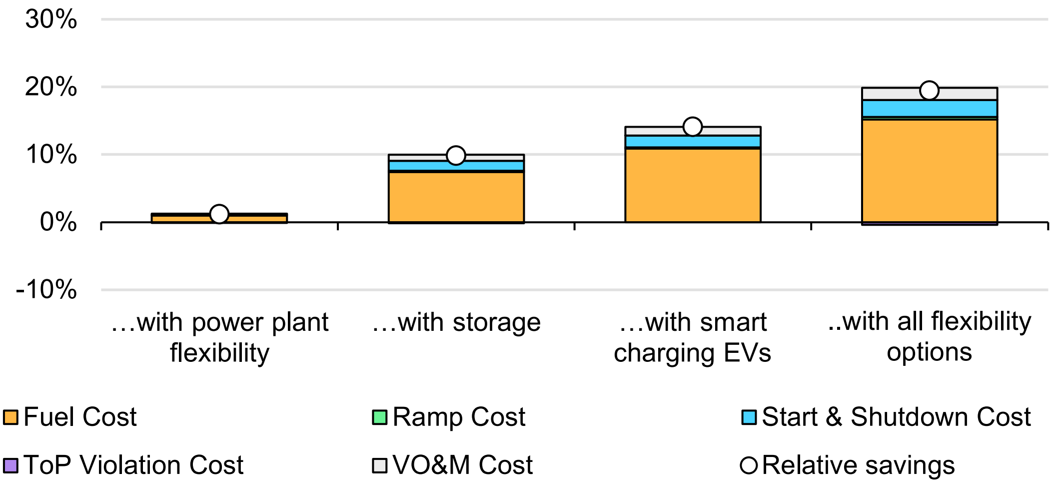
Operational efficiency

In addition to bolstering system adequacy, system flexibility also helps to increase operational efficiency of the system which has a number of downstream benefits. Reducing curtailment during periods of low net demand, and allowing the contribution of VRE towards peak demand, there can be considerable savings on operational costs, with the bulk of these savings coming from avoided fuel costs. However, by also allowing more stable operation of conventional power plants, it can equally reduce start-up and shutdown costs, while also reducing associated variable operation and maintenance costs.

Curtailment rate under the VRE Plus scenario in 2037 with various combinations of additional flexibility measures



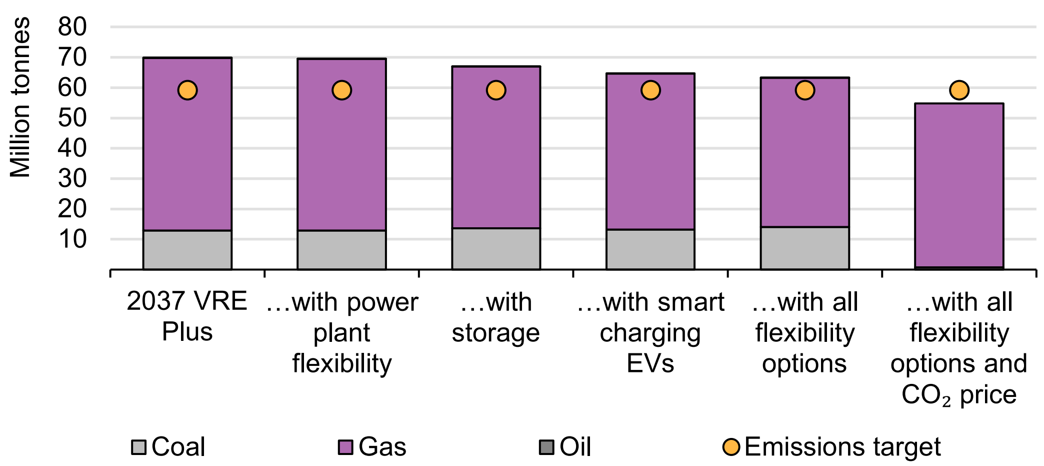
Cost savings due to flexibility measures relative to the 2037 VRE Plus scenario without any additional flexibility options



*ToP = take-or-pay contract, VO&M = variable operation and maintenance

Importantly, these measures are also vital for achieving the stated emissions targets. These would need to be achieved with some type of mechanism to both incentivise investment into low-carbon resources, and for fuel-switching for the lower carbon intensity operation of the system (discussed further in the following chapter). To demonstrate this, a carbon price is included in the model. However, even with a carbon price (as determined by the model and set at USD 90/tonne in 2037), any less efficient use of its VRE generation capacity would result in a higher reliance on its dispatchable thermal fleet. As a result, curtailment is not only an economic consequence of inflexibility, but also a potential risk for Thailand in achieving its stated emissions targets.

CO_2 emissions from the Thai power sector under Base and VRE Plus scenarios in 2037



Towards full decarbonisation of Thailand's power system

Our study assesses how Thailand's power system can achieve its emissions targets by rapidly expanding its VRE capacity. To achieve this transformation of the power system, policy makers will need to take a number of measures to both enable rapid VRE deployment and improve the power system's flexibility, tapping into existing and new sources.

First, a supportive policy and regulatory environment will be essential to enable VRE deployment. This includes creating a favourable environment for investment in VRE, adapting technical regulations and developing more integrated planning. Second, the flexibility available from existing assets can be tapped more effectively by adapting operational practices, reducing inflexibility arising from contractual arrangements, and adopting good curtailment practices that contribute to power system flexibility while maximising the use of VRE. Third, further sources of flexibility will be needed for optimal integration of VRE – coming from the four sources of technical power system flexibility: power plants, demand response, energy storage, and grids.

Policy and regulation need to support VRE deployment

To facilitate the deployment of the large capacities of VRE as required by this study, several actions related to operational adaptation, technical regulations and frameworks for integrated planning can be taken by policy makers as of now.

Ensuring sufficient investment into low-carbon energy and providing price signals that encourage its optimal use

The deployment of a large amount of VRE capacity will require large upfront investment as these technologies require high capital expenditure. The cost at which financing can be obtained is hence one of the critical components in establishing the overall costs.

It is crucial for policy makers to ensure investors have certainty on the political framework and potential support systems, and their perennity. Clear deployment targets, for example through an annual capacity addition target in development plans, can help to provide certainty to investors. Updating the PDP to reflect the new emissions targets will hence be a key step in ensuring regulatory certainty.

Another consideration is to re-assess connection costs, which have been pointed out as a main barrier for VRE deployment in Thailand. In addition to providing certainty, policy support through tax incentives, tariffs, or auctions can be used. Globally, a trend of using more and more competitive set remuneration schemes for renewables plants has been seen.

Furthermore, policy makers can look into price signals to incentivise the use of low-carbon electricity. For example, when using managed charging of EVs, it should be ensured that the charging occurs in priority in times of high VRE availability. There are several options to do so, starting from implementing static electricity pricing by period of day – for example through time-of-use tariffs – to more dynamic pricing that varies on a more granular basis, depending on the current status of the grid.

By setting prices that reflect the true value of different energy sources, Thailand's power system stakeholders can make better-informed decisions about how to allocate resources and optimise the use of available capacity. In our analysis, we have shown that a carbon price is one way to ensure a drop in carbon emissions, by incentivising the shift to low-carbon energy. This confirms results from previous IEA analysis that showed that carbon pricing can effectively reduce emissions in Thailand's power system. The advantage of implementing a full carbon price is that it creates price signals for the whole value chain that can lead to change in behaviours. It is however possible to design the mechanism differently to reduce impact on lower-income households, for example by using an implicit shadow price mechanism that would integrate the price solely on the dispatch of power plants.

Further possibilities include locational pricing, which involves setting prices that reflect the costs and benefits of energy generation and consumption at specific locations within the grid. This can help incentivise investment in flexible and other enabling technologies, such as batteries, that can help balance supply and demand at the local level, thereby reducing the need for more expensive grid infrastructure.

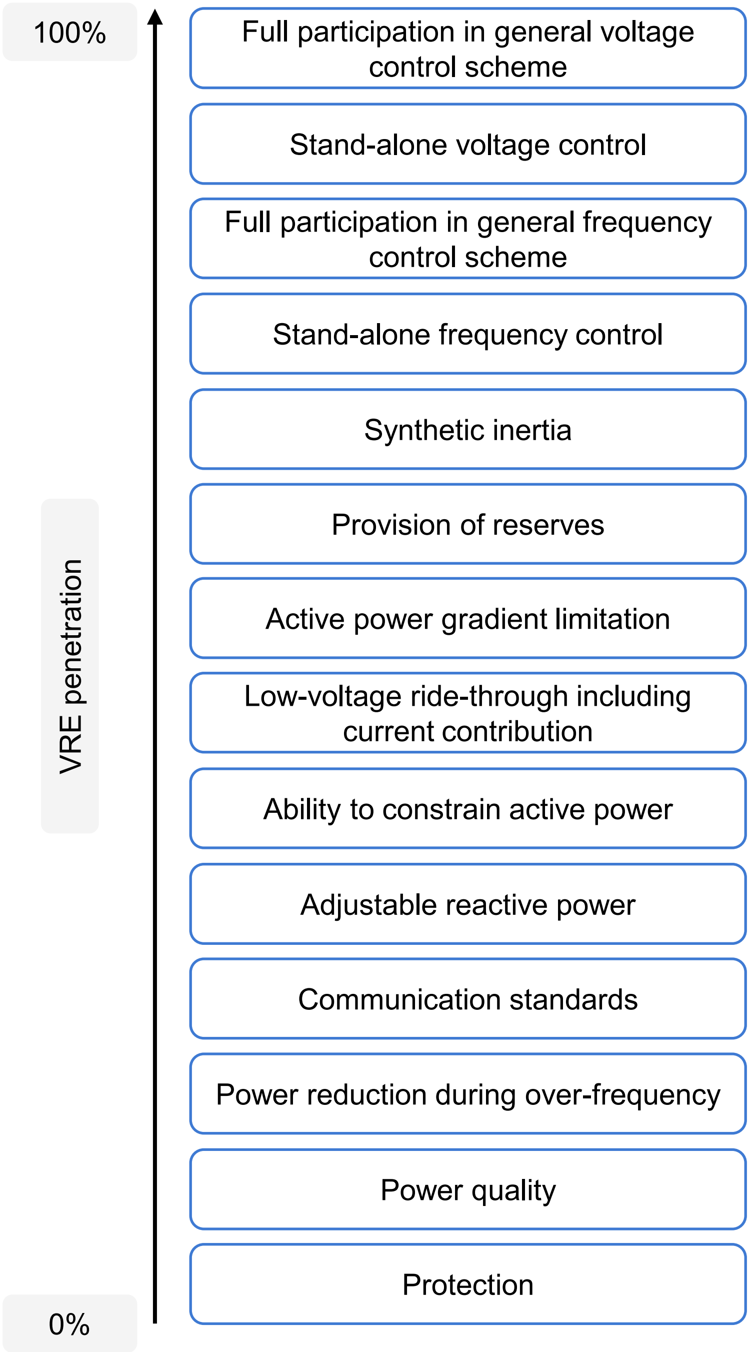
Adapting technical regulations for the integration of VRE

Grid (connection) codes define technical regulations for interconnection and behaviour of all assets in the network. Grid codes may impact VRE integration and the security of supply of electricity so they should be adapted and include all technologies including distributed energy resources. However, it is important to balance the benefits and costs of requirements set in the grid code. Having too many requirements might increase investment needs for VRE projects and slow down their uptake, while not having enough could compromise the operational security of the network.

In Thailand, the design of grid codes is identified as one of the barriers to the country's achieving its excellent potential for PV deployment. Indeed, Thailand has several grid codes, defined by its transmission utility EGAT and its two distribution utilities Provincial Electricity Authority (PEA) and Metropolitan Electricity Authority (MEA), that could be harmonised to facilitate processes and reviewed to accommodate for distributed resources. This would also allow for effective coordination among the three entities. Updates in 2019 to the EGAT grid code have started addressing gaps by providing specific connection requirements for VRE such as requiring data with increased granularity.

In reviewing the codes, policy makers should be careful to keep a balance between the changes required and the additional costs created by new requirements. In the case of Thailand for example, the highest priority in updating the codes is to ensure that the grid codes are harmonised, and that they are technology neutral to avoid putting up barriers to any new technologies such as distributed resources. Additional requirements should be added progressively, as VRE shares increase in the system. For instance, power reduction during over-frequency requirements is always needed, but simulation models, as well as post-mortem analysis of previous events, would detail the specific requirements for each type of asset in the system. Setting a requirement for synthetic inertia and requiring full participation in frequency and voltage control activities may not be necessary at low VRE penetration levels but may become essential at high and very high VRE penetration levels.

Technical requirements in grid codes, depending on the VRE penetration



Source: IEA based on Ackermann et.al. (2017), The Role of Grid Codes for VRE Integration into Power Systems.

To illustrate, the Mexican grid code previously did not require frequency control participation from VRE generators but did require them to stay connected under frequency excursion events. However, as VRE in the country has increased, a second iteration of the grid code has been published and requires all VRE generators to actively participate in frequency control activities. Similarly, FERC

ORDER 842 in the United States requires all new generators, including VRE, to be capable of providing primary frequency response as a precondition for grid connection.

Integrated planning of the power sector to manage the increased system complexity

While decarbonising, Thailand's power system will not only be impacted by the large amounts of VRE, but also by the electrification of end uses (such as transportation and cooling), the increased amount of distributed resources, and the deployment of flexibility assets. In the VRE Plus scenario with all flexibility assets, the power system changes from having a few large highly predictable generators and load centres, to having a much higher number of non-traditional assets interacting with one another. To ensure a smooth and cost-optimal transition to such a system, policy makers should apply an integrated power sector planning approach.

Integrated planning approaches include integrated generation and network planning and investment, integrated planning across a diversity of supply and demand resources, integrated planning between the electricity sector and other sectors, and interregional planning across jurisdictions and balancing areas.

Integrated generation and network planning and investment can allow for an easier deployment of VRE and other technologies by uncovering solutions for proactive network development, which often has longer lead times than VRE. To illustrate, in Texas, the creation of Competitive Renewable Energy Zones allowed the start of grid expansion works towards the identified zones before the start of VRE construction.

In a system with higher VRE and controllable demand, more sophisticated adequacy assessments will be required. Probabilistic Monte Carlo assessments are increasingly being used by some regions such as Australia, Belgium, and the European Union, to take into account the impact of many uncertainties evaluated together.

Furthermore, promoting closer communication between transmission and distribution planners will be crucial for the transformation of the power system. Demand response, distributed generation, EVs and other distributed energy resources will require a more dynamic interaction between transmission and distribution planners and operators, as well as between the power sector and other sectors such as transportation. For example, while the uptake of EVs and their charging infrastructure may put strains on the power system, integrated planning of the two sectors can allow these distributed resources to be turned into benefits for the power system, as highlighted by our analysis in the smart EV charging scenario.

Integrated planning can bring many benefits to the power sector and the broader energy sector. There are several examples around the world of attempts to coordinate planning of natural gas and power networks. The European Commission has urged electricity planners to collaborate with gas partners within ENTSOG (European Network of Transmission System Operators for Gas) to establish a shared set of assumptions. This requires utilising a uniform analytical foundation for their individual ten-year network development plans, which would serve as the groundwork for evaluating the costs and benefits of various gas and electricity network expansion or reinforcement initiatives.

The Integrated System Plan in Australia

The Integrated System Plan (ISP) of the Australian Energy Market Operator (AEMO)'s provides a roadmap for the Australian national energy market in the form of a framework for the country's power sector decarbonisation. Its overarching purpose is "to establish a whole-of-system plan for the efficient development of the [national energy market (NEM)] power system that achieves power system needs for a planning horizon of at least 20 years for the long-term interests of the consumers of electricity".

It considers the energy and environmental policies of the country such as the emissions reduction targets, the renewable energy targets, and policies affecting renewable energy zones, distributed energy resources, energy efficiency and EVs. It uses projected trends in demand and generation and the projected increase in interaction of the power system with distributed energy resources. It further looks into transmission, generation, demand response and storage, and the role each can play. It outlines and defines new renewable energy zones and integrates power system requirements into planning to ensure resource adequacy and capability, as well as electricity security. It further integrates sectors that are linked to the power sector, such as transport, gas and hydrogen to make use of synergies.

Five scenarios were developed for the ISP, spanning a range of plausible futures, from a scenario with slow change in which the decarbonisation objectives are not met, up to a scenario ("hydrogen superpower") in which strong global action is combined with significant technological breakthroughs. Consultations of energy industry stakeholders have concluded that the Step Change scenario, which combines rapid consumer-led transformation and co-ordinated economy-wide action, is the most probable. While all scenarios were modelled, that selected one is used as the most-likely basis throughout the ISP.

Based on the assessment of these scenarios, the ISP identifies an optimal development plan that outlines required transmission projects and sets out preparatory activities and renewable energy zones needed for planning.

Source: AEMO (2022), 2022 Integrated System Plan – for the National Electricity Market.

Operational and contractual measures can boost flexibility from existing sources

Increasing flexibility of the power system will also be essential to support the rapid growth of VRE. An important step to achieve this is to ensure that existing flexibility of the system is able to be fully tapped. In Thailand, both operational practices and contractual arrangements serve as a barrier to fully utilise the flexibility inherent in its current fleet of power plants. In addition, appropriate use of curtailment of VRE can act as a source of system flexibility.

Improving operational practices to take advantage of the technical capabilities of existing and future assets in the network

With growing shares of VRE in the generation mix, the operation of existing assets will be impacted in that these plants will have to change plant output, start and shut down quickly, or also turn output down to lower levels than previously more rapidly. While in some cases, retrofits are needed to allow plants to improve their technical flexibility, changes in operational practices are a first, low-cost step to access more flexibility from existing assets.

By updating power system scheduling closer to real time, the uncertainty and variability that the operators see from VRE technologies in the net load can be reduced. International experience has shown that closer scheduling of generators would reduce the operational reserves that the system would require to cover due to the variability and uncertainty of VRE. For example, in Germany, the increased trading of 15-minute products led to a reduction in the real-time deviations being met by balancing reserves. This also provides better signals for storage and fast-response demand resources. In turn, this could lead to substantial operational cost reductions in the day-ahead unit commitment and dispatch programme, as well as the intra-day redispatch. In Thailand, typical economic dispatch is close to real time. However, long-term power purchase agreements (PPAs) (for example with small power producers that make up a large portion of current PPAs) can lock in inflexible contracted operating characteristics that could be reviewed to allow for system operation with increased VRE.

These updated operational practices should be based on accurate forecasting of VRE resources, which tend to be more accurate the closer they are to real time. Therefore, allowing the update of forecasting during the scheduling would remove some of the uncertainty of the net load.

Implementing centralised system-level forecasting of VRE generators in the entire system, in addition to an independent forecast for each power plant has proven to be effective in other power systems. Indeed, thanks to the centralised forecasting the system operator gets information on aggregated renewable generation variability and can accurately consider availability of each VRE plant. Combined with high quality plant-level forecasts, this will ensure cost-efficient and reliable scheduling of generation, as well as ensuring the adequate amount of reserves.

Several regions around the world have established renewable control centres to ensure system operators can control and monitor VRE production. One of the first centres was created in Spain, the control centre for renewable energy (CECRE) which is owned and operated by the grid operator. This centre monitors VRE power plants with an installed capacity higher than 5 MW. The centre provides short-term forecasts of VRE and monitors their real time operation, including active and reactive power, as well as voltage level at point of interconnection.

Policy makers can make use of regulation to incentivise accurate VRE forecasting, by increasing time granularity through multi-period-settling arrangements for example, or by implementing penalties for absolute errors in forecasting. Multi-period-settling arrangements aim to incentivise accurate forecasting by providing financial incentives, while the second option is to penalise plant operators when their plant-level forecast is outside the allowed average error.

Reducing contractual barriers to increase the access to existing technical flexibility

Previous IEA analysis identified contractual flexibility as a barrier to Thailand's power system becoming more flexible. In Thailand, high minimum take levels in PPAs prevent the downward flexibility of the power system, which hence cannot use VRE generation in times of high VRE availability, especially in off-peak times. Fuel supply contracts with daily take-or-pay arrangements further reduce the flexibility of the system.

Current operational practices schedule power plants according to their merit order costs, except for generators that have secured PPAs. These generators are typically dispatched ahead of generators without PPAs, as these contracts usually contain minimum take volumes, disrupting the economic optimisation of operations. This is especially noticeable during off-peak periods.

Some possible solutions have been explored in previous IEA analysis, such as the renegotiation of existing PPA contracts where the minimum take volume is reduced, while remunerating flexibility and other ancillary services that the current power plants provide, as well as the modification of existing take-or-pay requirements in fuel supply contracts.

Other options that aim to isolate the physical dispatch of power plants from the existence of the above-mentioned PPA long-term contracts exist, including:

- Establishing **a financial market for PPAs** that is separate from physical dispatch of power plants. Generators and consumers would negotiate the price and volumes of the electricity sale, but the dispatch of the power plants would be determined by a market-based dispatch system
- Using a **market-based dispatch system without regard for contractual obligations**, and compensating generators with PPAs when their electricity is not dispatched due to their marginal costs being higher than other power plants in the system.

Implementing any of the prior mentioned solutions can be a challenging task due to the required institutional framework changes, modification to the current contract structures and the legal considerations. Policy makers should ensure investors retain certainty on their returns, which can be enabled through high enough flexibility rewards to reduce total system operation costs. It is also worth noting that some of these options would perhaps require other mechanisms, such as some sort of capacity or flexibility market to work to avoid the "missing money" problem.

Fuel supply contracts in Thailand's power system flexibility

The Thai power system relies heavily on gas-fired generation, with 66% of its domestic power generation being gas-fired in 2021. Gas-fired power plants, especially those with combined cycle gas turbine technology, are known for their flexibility and relatively fast ramp rates and can be an asset for a power system's flexibility. However, commercial constraints, such as onerous take-or-pay obligations in fuel supply contracts, can limit this flexibility, as is the case in Thailand.

Indeed, the country's gas demand is met by national production, pipeline imports from Myanmar, and liquefied natural gas (LNG) imports. LNG imports are projected to increase in response to decreasing domestic gas production, and EGAT has acquired access to the country's only LNG receiving terminal that allow the utility to import LNG. However, EGAT's ten-year gas purchase contract with the state gas company PTT includes daily minimum take-or-pay obligations that can result in gas-fired turbines being used to generate electricity even when it may not be the most cost-effective option (for example in cases of low demand and high VRE availability), therefore reducing the system's flexibility to adjust to varying renewable generation.

A possible solution could be to place the risk of daily gas requirements with PTT, for example by moving to longer observational periods for the take obligation. EGAT would be charged a higher margin to compensate PTT for taking the risk, and PTT could in turn mitigate this risk by managing upstream contracts. At the next contract review, one option could also be to negotiate to reduce the minimum daily take-or-pay contractual volume.

Source: IEA (2021), Thailand Power System Flexibility Study.

Curtailment management to improve the integration of high shares of VRE

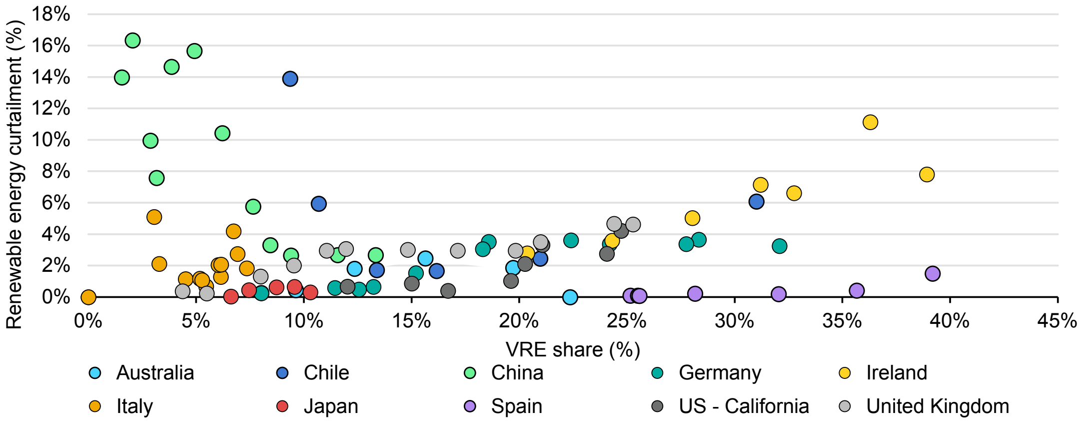
Our analysis has shown that within the VRE Plus scenarios, curtailment rates increase considerably, indicating missing flexibility of the power system. However, while it is important, for economic and environmental viability of VRE generation, to minimise unnecessary curtailment, it is also important to ensure the system operator's ability to intervene and curtail output where needed for system stability.

Curtailment is done to balance the supply and demand of electricity and can be caused by transmission congestion, lack of transmission access, excess of generation, voltage problems at the point of interconnection, or other interconnection problems. It can reduce the economic efficiency of VRE projects, as curtailed energy represents lost revenue for project owners, unless a compensation scheme is put into place. Second, it can discourage investment in VRE projects, or make projects more expensive, if investors, including financial institutions, see a high risk of curtailment. However, VRE curtailment could also provide benefits to the system. When equipped with advanced controls and power electronics VRE that is purposely curtailed could provide ancillary services to the system, including frequency regulation, voltage support, ramp rate control, and participation in frequency response and voltage control activities, which can reduce the need for other, dedicated, solutions.

While improving the flexibility of the power system allows to significantly reduce curtailment in the VRE Plus scenarios, some level of curtailment is still required as a final balancing measure, as shown by the net load curve in the previous chapter. Finding the optimal level of VRE curtailment rather than reducing curtailment to zero should therefore be the target of power system development plans.

To illustrate, today, curtailment in large renewable energy markets is typically between 1.5% and 4%.

VRE shares in generation and technical curtailment for selected countries



Notes: Data points represent officially reported curtailed or constrained energy and combines various schemes depending on the country. VRE refers to solar PV and wind unless otherwise specified. Italy includes only wind. Spain includes PV, wind, CSP and biomass technologies. The United Kingdom includes only wind. "Technical curtailment" refers to the dispatch-down of renewable energy due to network or system reasons. Dispatched-down energy due to economic or market conditions is not included in this chart.
Source: IEA (2023), Renewable Energy Market Update – June 2023.

Several points related to curtailment management should be taken into account by policy makers and planners. From an operational perspective, they should ensure that PPAs with power generators enable the system operator to curtail outputs when needed. As curtailment increases however, compensation for curtailment may be necessary to avoid disincentivising investment in VRE projects. Long-term contracts that explicitly share the risk of curtailment between generators and off-takers is one of the solutions commonly seen.

To reduce compensation costs and ensure the efficient use of the low-carbon electricity produced by VRE, measures to minimise curtailment – and hence to increase power system flexibility – should be taken.

In Thailand, as we noted above, VRE resources are located away from demand centres. Transmission expansion, a measure discussed below, can hence reduce curtailment by enabling the transport of VRE generation to these demand centres.

Measures already mentioned in the above section such as improving the accuracy of forecasts bringing the scheduling of power generators closer to real time, and improving the management of operational reserves, as well as increasing automation signalling, further allow for curtailment minimisation.

Lastly, incentivising the deployment of assets providing flexibility such as storage or demand response also contributes to reducing curtailment, as our analysis showed with the combination of battery storage and EV smart charging. Policy measures related to the deployment of these assets are described in the next section.

Additional sources of power system flexibility will be needed

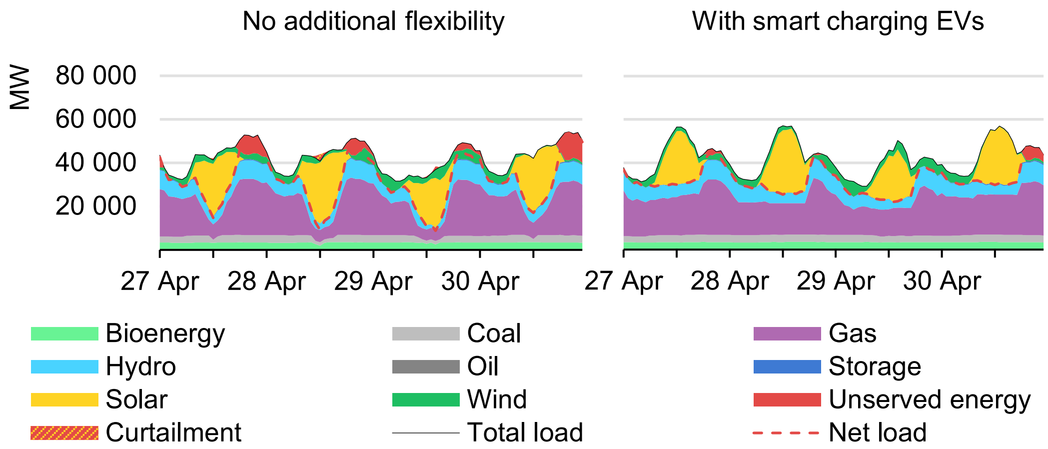
In addition to tapping existing flexibility, this study illustrates the role of battery energy storage systems and smart EV charging in improving the power system's flexibility. These flexibility sources help to meet peak demand, make use of excess VRE electricity, and reduce unserved energy, contributing to both meeting emissions targets and providing reliable supply of electricity. Additional flexibility benefits can be obtained by modernising and expanding the grid. Finally, we discuss the potential role of low-carbon dispatchable technologies such as hydropower, nuclear, carbon capture, and low-carbon fuels that sit outside the scope of the techno-economic analysis in this report.

Unlocking further flexiblity through digital technologies and enabling demand response from electric vehicles

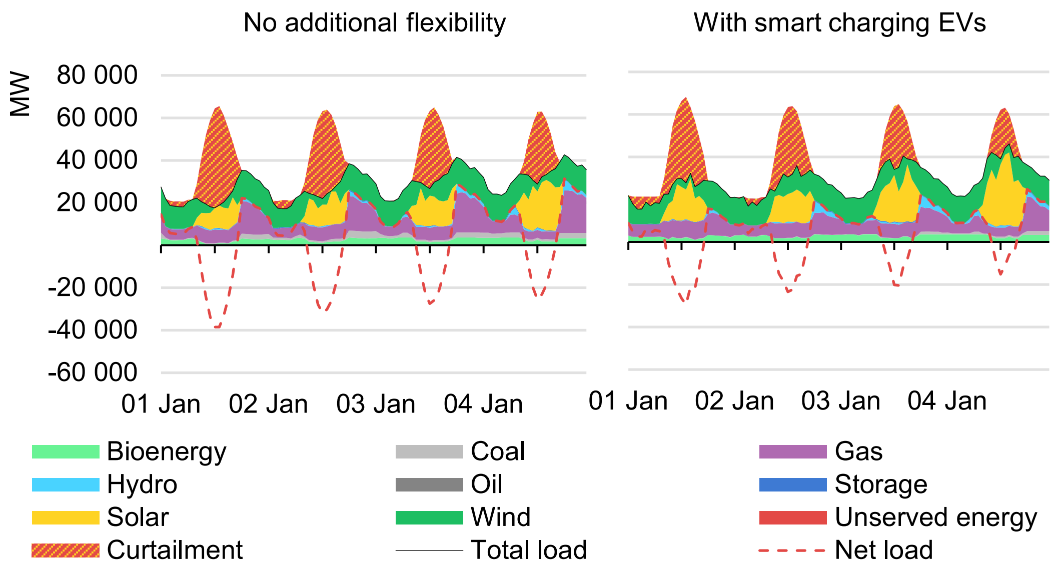
When 50% of the EVs are using managed charging in the VRE Plus scenario, significant flexibility benefits are obtained, the system adequacy and operational efficiency of the power system is improved, and emissions are reduced.

Indeed, while the additional demand from EVs can at first sight challenge the power system – by increasing peak demand – the vehicles are a strong flexible demand resource. When enabled to shift their charging demand across the day, EVs can help reduce peak demand and make use of excess VRE generation in times of low demand. In Thailand, with its abundant solar resource, this would especially be interesting for the mid-day peak in solar PV generation, where workplace charging would be key. However, unlike storage, the contribution of EVs will be much more uncertain, influenced by a number of different factors such as driver behaviour, charging infrastructure, and the influence of various incentives on charging behaviour.

Generation stack during the period of peak net demand in 2037 under VRE Plus scenario, without and with smart charging of 50% of the EVs



Generation stack during the period of minimum net demand in 2037 under VRE Plus scenario, without and with smart charging of 50% of the EVs



Digitalisation is crucial when deploying EVs in a grid-friendly way, as managed charging can be put in place only when deploying smart charging technologies, coupled with the right pricing signals.

Digitalisation plays an important role in **unlocking additional flexibility** in the system, at transmission and distribution levels. It may allow for new services to be offered to the power system, especially through the connection, control and aggregation of the demand side. For example, distributed demand-side assets could provide fast-frequency response, and distributed batteries or EVs could provide inertial response. When enabled through digital technologies, connected, distributed energy resources become visible and can be monitored by operators, controlled remotely and aggregated to provide system services.

Digitalisation can **enable the creation and use of demand response programmes** to balance the grid. With real-time communication through smart meters, peak demand can be reduced by adjusting building consumption in real time and providing fast-response and ancillary services to the grid. To encourage flexible operation on the demand side, proper remuneration and procurement of resources and other ancillary services may be necessary.

Initially, demand-side response should prioritise large commercial and industrial sectors, as they have a greater impact per consumer. However, unlocking flexibility on distribution grids may become necessary in the future, which will require greater engagement of small consumers. Regulations can encourage the development of aggregators that interact between end users at the distribution level and the power system operator at the transmission level. Appropriate regulation should also ensure that some of the economic benefits of procuring flexibility at the distribution level are passed on to the end users.

By leveraging digitalisation technologies, EGAT could better manage the variability and uncertainty of VRE, reducing the need for costly physical upgrades to transmission infrastructure and enabling more efficient and effective use of existing resources. While currently still being at the beginning of the deployment of digital technologies, the country has started to implement pilot projects and initiatives within its Smart Grid Plan for 2015-2036, for example deploying 116 000 smart meters in the city of Pattaya and the Thailand 4.0 initiative that aims to develop 100 smart cities.

Digitalisation can provide significant benefits to the power system at any point of the system transformation, but will be highest after 2030 in our scenarios, when VRE penetration is higher and additional flexibility is required.

Deploying EVs in a grid-friendly way

Thailand's ambitious transport electrification targets include 30% of the domestic vehicles production being electric by 2030 (the so-called 30@30 policy), installing 12 000 fast charging stations and 1 450 battery swapping stations for its numerous two-wheelers (49% of all battery EV registrations are two-wheelers) by 2030, as well as aiming to reach 100% EVs in new car sales by 2035.

Incentives created to reach these targets include tax subsidies and duty reductions. These showed first successes with a year-on-year growth of 223% in the sales of battery EVs in the cumulative third quarter of 2022. 2022.

As EV stocks grow, policy makers should consider the implications for the grid and make sure that the deployment of charging infrastructure is co-ordinated with the planning of the power grid. As such, EGAT has included EVs in its updated demand projections. The impact of this new demand on the grid can, however, vary strongly depending on charging patterns of EV drivers. For example, in most developed EV markets where personal cars are the dominant segment, most charging occurs at home during the evening or night. In the absence of measures to mitigate grid impacts of EV charging, this charging directly contributes to the evening peak demand. However, solutions exist, and EVs can become an opportunity when the technology to integrate them smoothly with the grid is provided.

Indeed, using EVs for demand response can add a strong source of flexibility. The ability of EVs to absorb excess solar PV generation at midday is particularly interesting for Thailand, through incentives to shift charging towards the day, which can for example be implemented through time-of-use tariffs.

Policy makers should take initiatives to facilitate grid integration of EVs. At early stages of EV growth, these initiatives include **ensuring that EVs are visible to the operator** (through data sharing practices for example) and **controllable**, and that operators are **involved in the choice of charging infrastructure location**. To unlock EV flexibility, **managed charging strategies**[*] that allow shifting charging times or modulate charging power **should be encouraged**.

To facilitate the deployment of these strategies, **policy measures should be taken in parallel to incentives for EV and charging infrastructure uptake,** ensuring that the minimum standards for charging points and vehicles facilitate their smart charging readiness. Indeed, a point to consider in optimising the use of EV flexibility is that the larger the number of EVs available for aggregation, the higher the potential EV flexibility will be. Aggregation is hence key and should be facilitated through **standards and interoperability**. Policy makers can use incentives and regulations to set standards and interoperability.

The IEA has prepared a framework for the grid integration of electric vehicles, which allows policy makers to assess which measures to prioritise for an efficient grid integration of EVs, depending on the state of the deployment of EVs and the system's need for flexibility. The IEA also released a web tool to generate the demand profile corresponding to EV charging.

*Managed charging, as opposed to "unmanaged" charging, includes passive measures such as time-of-use tariffs, active control with unidirectional charging (V1G), active control with bidirectional charging to a building or house (V2B/H), and active control with bidirectional charging to the grid (V2G), as well as, for battery swapping, active control with battery stations (S2G or B2G). Further information can be found in the IEA's policy manual on grid integration.

Source: IEA (2022), Grid integration of electric vehicles – A manual for policy makers.

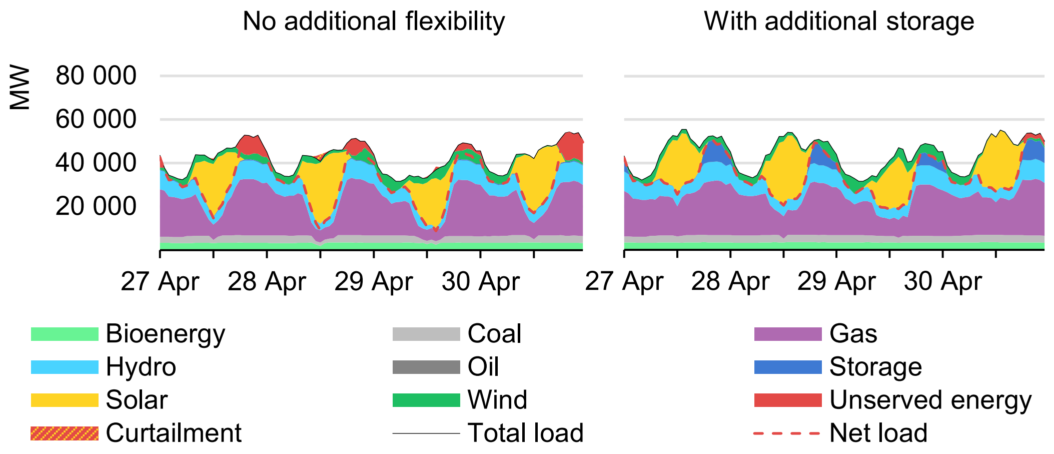
Storage helps meet capacity needs and achieve emissions targets

Our modelling determined that deploying battery storage of 11.8 GW with an average duration of six hours in the VRE Plus scenario in 2037 allows capacity needs and emissions targets to be met, and reduces curtailment. Indeed, when looking at the generation stack during the periods of peak and minimum net demand, one can see that in both periods, storage increases the use of solar PV and reduces periods of negative net demand. In the low demand period, this diminishes the need for curtailment and decreases the use of gas generators. In the peak demand period this ensures a reliable provision of electricity, without unserved energy.

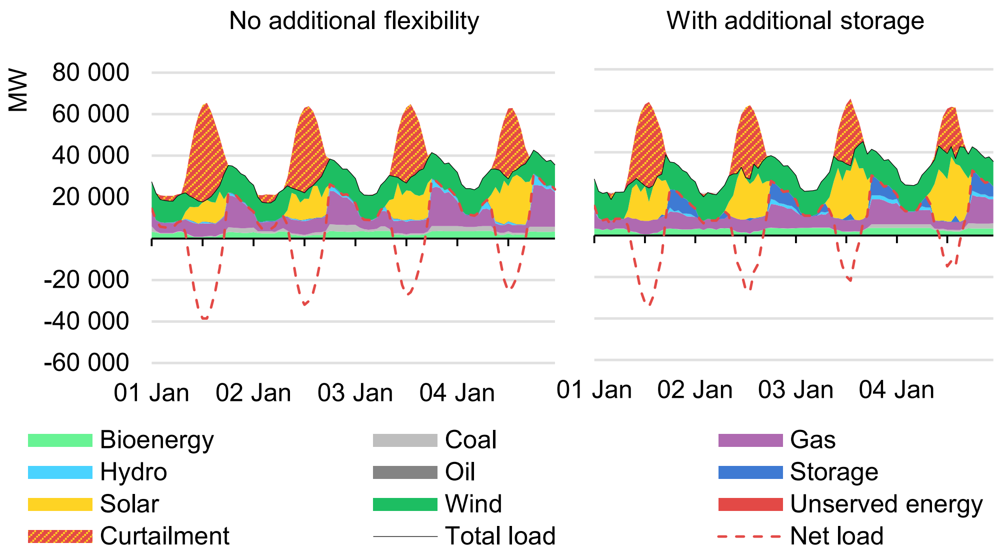
Storage indeed may bring a number of benefits to power systems, including short-term balancing and operating reserves, ancillary services for grid stability, and deferral of investment in new generation, transmission and distribution assets. Our analysis highlighted the amount of storage that will be needed in the modelled scenario; however, planning strategies should investigate the different applications of storage, and notably directing investment on transmission or distribution levels.

Indeed, batteries are a popular and widely used short-term storage technology that can be deployed at the transmission or distribution level and have a large spectrum of applications. They can perform split-second discharge and charge cycles to support voltage and frequency regulation, and depending on their size, provide peaking capacity, smooth VRE output, provide intra-day energy shifting for VRE generation, and help defer transmission and distribution investments. Behind-the-meter storage systems can provide services both to the consumer – who could shift their consumption to reduce bills, and, when paired with rooftop solar PV, optimise their use of low-carbon electricity – and to the wider grid, provided they are enabled to do so.

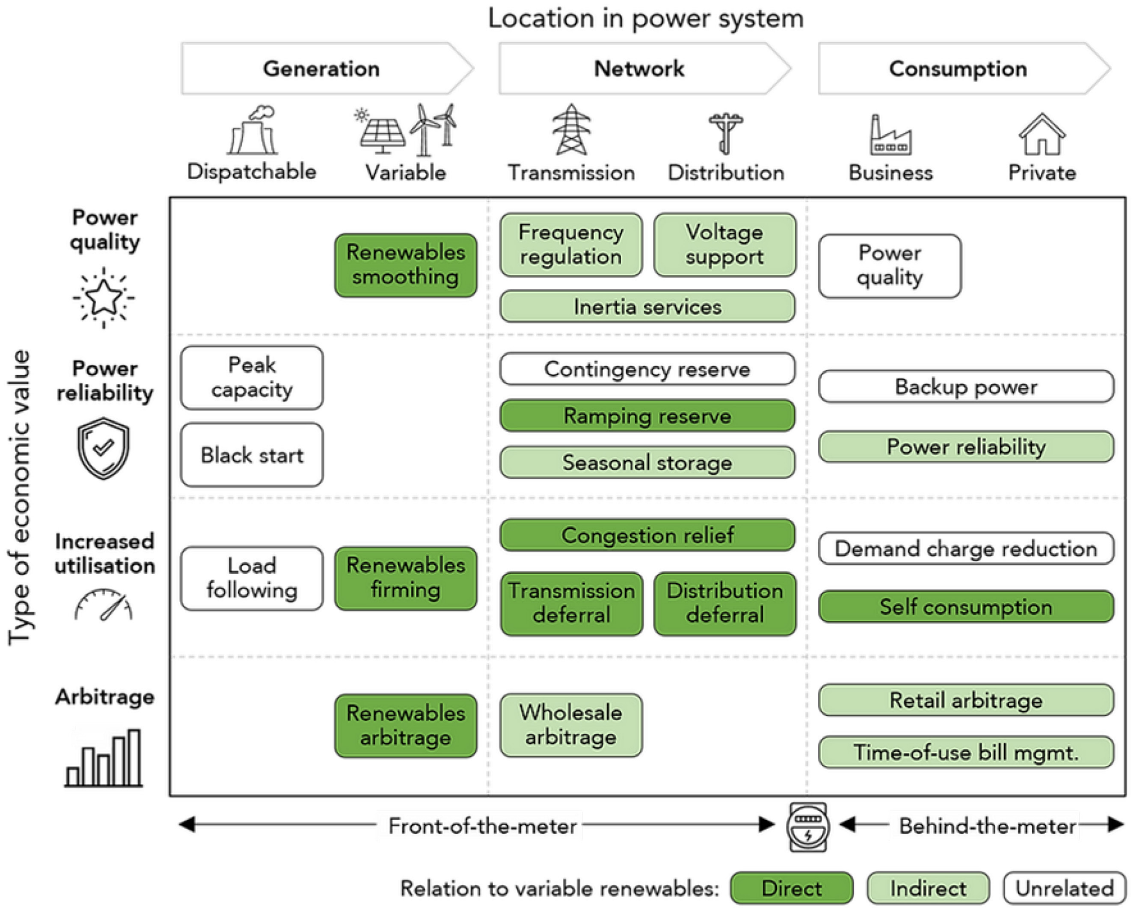
Generation stack during the period of peak net demand in 2037 under VRE Plus scenario, without and with additional storage capacity of 11.8 GW



Generation stack during the period of minimum net demand in 2037 under the VRE Plus scenario, without and with additional storage capacity of 11.8 GW



Overview of the 23 most common electricity storage applications



Note: The storage applications are represented along the dimensions: Location within power system (x-axis), type of economic value (y-axis) and relation to variable renewable electricity generation (colour).
Source: Schmidt and Staffell (2023), Monetizing Energy Storage, Oxford University Press.

Indeed, to take full advantage of batteries, it is important for policy makers to make sure owners of batteries receive price signals that reward grid-friendly behaviour, such as charging in times of excess VRE generation. Furthermore, the assets should be visible to system operators and aggregation allowed to make the most of the services provided. Policy makers should hence look into updating operational practices and lowering regulatory barriers to facilitate the use of storage.

To ensure that energy storage contributes to decarbonisation of the power system, it is essential to pair storage with carbon pricing or other mechanisms that ensure low-carbon generation technologies are prioritised. Our modelling results demonstrate that if CO_2 externalities are not properly accounted for (i.e. without carbon pricing), the system may rely on cheap fossil fuel generation to charge batteries and discharge them during peak net load, potentially undermining emissions targets. While storage may still offer benefits in deferring the need for capacity expansion, it is imperative to address emissions directly through appropriate pricing mechanisms or carbon constraints.

Fast-response batteries can offer substantial advantages in stabilising the power grid, particularly in the face of high levels of VRE sources. However, to fully realise the potential benefits of these assets, it is crucial to compensate battery owners for the services they provide to the grid. In a market-based framework, greater temporal and geographic precision in pricing mechanisms could represent an effective solution. In non-market environments, it may still be possible to calculate prices that can efficiently direct investments to the locations where they are most needed by the power system.

Batteries are not the only technology for storage. Pumped hydro storage (PSH) is equally a large source of flexibility and tends to have longer storage durations than batteries (e.g. ten or more hours). PSH can provide ancillary services and short-term flexibility, and can also support power system stability due to its synchronous nature. PSH can store energy across days or even months, particularly if associated with larger reservoir systems which can make it interesting for countries reaching higher phases of VRE integration that may require seasonal energy storage. The applicability of PSH depends on site availability, and costs can vary substantially.

Expanding and upgrading the transmission system allows further VRE penetration and improves reliability

The grid is a strong contributor to power system flexibility. Two main levers exist to improve the flexibility it can provide – grid expansion, and upgrades to control technologies.

Additional transmission lines allow the transfer of surplus VRE generation to areas with higher demand or lower VRE generation, which is of particular interest for Thailand to ensure that the VRE generation from the North-Eastern region can be transported to net importing regions. Furthermore, looking from a system-level, the interconnection of larger surfaces allows a reduction of aggregated production variability of VRE as for example cloud density can vary from one plant location to another.

Expanding the grid further, cross-border, would even further improve the flexibility of the overall system and its ability to integrate VRE. Thailand already is engaging in bilateral electricity trade with its neighbours, and the region has a goal of integrating their power systems within the ASEAN power grid. Thailand is involved as wheeling country within the Lao PDR-Thailand-Malaysia-Singapore power integration project, from which policy makers can continue building towards establishing multilateral power trade in the region. Key requirements to establish multilateral power trading in ASEAN include:

- Political needs such as for agreements between governments as well as political will.
- Technical requirements such as harmonised grid codes, wheeling charge methodologies, provisions for third-party access, and data and information sharing.
- Institutional requirements including new responsibilities for existing entities and the potential need for new institutions to be responsible for functions such as market organisation.

Such cross-border connections can potentially utilise either alternating current (AC) or high-voltage direct current (HVDC) technologies. AC interconnections require synchronisation between the connected power systems, which comes with additional complexity but can also improve frequency stability. HVDC transmission lines allow for asynchronous interconnection of two power systems, and may allow for cheaper transfer of power over long distances, e.g. over 500 km. Advanced high-voltage technologies that combine with HVDC such as voltage source converters can also provide multiple services to support network stability.

Modernising the grid is the second lever to improve the flexibility and stability networks can provide. It is particularly important to address the shift from synchronous to converter-based technologies resulting from the increasing amount of VRE in the system, which reduces the availability of rotating machines and hence the contribution of generators to system strength. Several technological solutions exist to overcome this issue, among them, flexible alternative current transmission systems (FACTS) are a family of devices and systems that provide dynamic control over the power flow and voltage levels on the grid. They can help mitigate some of the technical challenges and improve the reliability of a system with high shares of VRE. FACTS devices such as static var compensators (SVC) and static synchronous compensators (STATCOMs) can help maintain voltage stability by providing reactive power support to the grid, thereby reducing the likelihood of voltage collapses. Synchronous condensers, which also belong to the FACTS family, provide inertia, and short-circuit power through their motors, similarly to synchronous generators, but rotate freely without producing electricity. An established technology, their deployment is one of the solutions to system stability being used in countries such as Australia, Denmark, Germany, and Italy.

Dispatchable low-carbon technologies support net zero transitions

This study has analysed how an increased deployment of VRE can allow Thailand's power system to reach the set emissions targets in 2030 and 2037, reflecting the important role of VRE in achieving net zero transitions globally. Dispatchable low-carbon generation technologies such as hydropower, nuclear and thermal generators with carbon capture or low-carbon fuels will also play an important role in net zero transitions, supporting cost-effective and reliable integration of VRE generation, as well as providing stability to the network.

Hydropower is today the largest renewable generation source globally. The technology has a unique position from a flexibility perspective, as it can provide large amounts of capacity-driven short-term flexibility, as well as capacity and energy-driven medium and long-term flexibility. Pumped hydro storage can provide ancillary services such as frequency regulation, reserves, voltage support and black start and is hence very valuable to system operations. While it has high capital expenditure, it remains a cost-competitive option for storage that needs to be planned ahead to take into account construction times. Within its alternative energy development plan for 2018-2037, Thailand aims to add 3 GW of hydropower to its power system by 2037. In addition, expanding interconnection with neighbouring countries with large hydropower potential such as Lao PDR can further increase the system-wide flexibility.

Today, nuclear power is the second-largest source of low-carbon power in the world, after hydropower. It is an established, large-scale low-emissions energy source and can therefore play a strong role in decarbonising power systems worldwide and providing dispatchable generation to power systems.

However, it is also a technology with extremely high capital costs and policy risk. Government involvement is hence needed to ensure financing of new power plants, and government planning should take into account the long construction times associated to the technology. While neither the current PDP (2018 revision 1) nor the long-term low greenhouse gas emission development strategy mention nuclear as part of the technologies playing a role in the future power system, the United States recently announced that it would help Thailand develop small nuclear reactors to help with net zero goals.

Thermal generation today provides the bulk of electricity demand globally – as well as in Thailand, where coal, gas and oil power together account for 83% of the domestic power mix. However, the emissions of these power plants must decrease strongly for Thailand to achieve its emissions targets, and we can see from our analysis that in the VRE Plus scenarios, coal power plants especially see a strong decline in emissions due to reduced utilisation.

While decarbonising the power system, existing thermal power plants can be either repurposed to provide grid flexibility services, retrofitted for the use of low-carbon fuels or with CCUS, or retired. The benefit of repurposing or retrofitting is that it can help to reduce emissions from existing thermal generation assets and provide a source of flexible capacity to support the integration of VRE, while avoiding the economic consequences of early retirement.

The use of low carbon hydrogen and ammonia in fossil fuel power plants has the potential to play a significant role in decarbonising the power sector. These fuels can provide dispatchable power capacity during peak demand periods and support system services to ensure energy security and capacity adequacy, avoiding costly disruptions in energy supply. In addition, they can substantially reduce greenhouse gas emissions, depending on how they are produced.

In Thailand, where the state-owned oil and gas company PTT recently announced investing into the production of green hydrogen, hydrogen and other low-carbon fuels could have a role in the long-term where they could complement the existing power system's flexibility, as the technology related to the co-firing with low-carbon fuels needs to mature first in order to be fit for the ASEAN region's high price sensitivity. Further, until the health and risk factors associated with handling large amounts of hydrogen or ammonia are solved, the future development of the power system with these technologies cannot be certain.

Lastly, retrofitting coal plants with CCUS technology presents a promising solution for preserving existing assets, including transmission infrastructure, while also advancing the decarbonisation pathway. To determine the suitability of coal plants for retrofits, several criteria may be considered. Generally, younger plants are more cost-effective to retrofit per megawatt than older ones, while larger units offer economies of scale. In addition, supercritical and ultra-supercritical power plants are better candidates for retrofits as they can achieve higher efficiencies, resulting in lower marginal costs.

One major drawback of CCUS projects is the significant capital cost required. However, CCUS retrofits can be implemented either for the entire facility or a portion of a plant, which reduces the capital investment required for such a transformation.

Recommendations

Our techno-economic analysis shows that Thailand can reach its power sector emissions targets in 2030 and 2037 by deploying additional VRE capacity as well as flexibility solutions to support their integration from 2030. The most urgent priorities for policy makers are actions to enable the necessary rapid scale-up of solar PV and wind capacity and ensure the power system can accommodate it, including:

- **Encouraging investment in low-carbon energy**. A first priority is updating the Power Development Plan to reflect Thailand's net zero goals. While high-level pledges and targets have an important role, it is essential to translate these into detailed sectoral planning to guide development and provide policy certainty to support investment. This process could consider reducing the pipeline of thermal plants planned in PDP 2018 Rev 1, including those plants that are planned to come online before 2030. New carbon-intensive assets risk seeing declining operating hours and profitability which in turn would increase the costs of energy transition. Other aspects to consider include assessing connection costs, using competitive remuneration schemes to procure VRE capacity, and introducing price signals that encourage the use of low-carbon electricity.
- **Looking into options to reduce barriers to flexibility that are induced by take-or-pay fuel contracts**. Fuel contracts and PPAs with minimum take requirements can impose significant downward inflexibility on the power system and result in unnecessary curtailment as well as higher operating costs and emissions. While existing agreements should be respected, a number of options can be explored to support increased economic dispatch including contract renegotiation, conversion to financial contracts and compensating deviations from contractual settings.
- **Setting a framework for appropriate VRE curtailment that supports the system**, that clearly defines how curtailment risk is shared among stakeholders. It is important that system operators can use curtailment of renewables as a flexibility measure to manage issues such as transmission congestion and maintain system stability. At the same time, curtailment can lead to loss of revenue for plant owners and increased costs for consumers, and other options such as more flexible operation of power plants should be preferred. A clear framework for how the curtailment risks will be handled will help to provide clarity for investments.

In addition to ensuring the stage is set for rapid VRE deployment, policy makers in Thailand need to ensure that the necessary frameworks are being established to allow VRE to be integrated into the power system as it reaches higher penetrations. Increasing instalments of wind and solar PV will add to the importance of how they interact with the system, which is set through grid codes, and the need to access existing flexibility in the power system as well as bring new sources of flexibility online. Actions to achieve this include:

- **Ensuring technical regulations are prepared for the increase in VRE**, especially with regards to grid codes. Beyond the EGAT's updates to the grid code in 2019 to increase the visibility of VRE assets on the system, different grid codes among EGAT, the Metropolitan Electricity Authority and the Provincial Electricity Authority could be harmonised. As VRE penetration increases it will be important to strike a balance, ensuring the technical capabilities needed to efficiently operate the system while avoiding excessive requirements that may be a barrier to deployment.
- **Adapting operational practices to better integrate VRE**. While Thailand's typical economic dispatch is close to real time and provides a good basis for integrating renewables, long-term PPAs can lock in inflexible contracted operating characteristics that limit system flexibility. Good-quality, centralised VRE forecasting should also be integrated into scheduling as this reduces deviations and allows for smoother and more cost-effective integration.
- **Developing more integrated planning practices**. Integrated planning should incorporate climate targets and be regularly updated. One priority of integrated planning is to ensure infrastructure development is co-ordinated – e.g. between generation and transmission – and takes account of diverse supply and demand resources including a range of low-carbon technologies and the demand side. It can also address links between sectors such as transportation and electricity, better co-ordination between transmission and distribution planning, and inter-regional planning across jurisdictions and balancing areas. As Thailand moves to higher shares of VRE and demand resources, the suite of modelling approaches should include advanced reliability assessments.
- **Establishing frameworks for demand response to contribute to system flexibility**. This includes deployment of digital technologies to unlock flexibility from distributed energy resources, such as managed charging for EVs. In addition, pricing structures to reward charging during periods that benefit this system such as high solar production are critical in order to incentivise system-friendly behaviour. Allowing for aggregation of demand-side resources is likely to be critical for full activation of demand response, in particular for smaller consumers.
- **Ensuring appropriate incentives for developing and operating storage infrastructure to integrate renewables**. To support the deployment of batteries and gain their full benefit, battery owners need to receive price signals that reward behaviour that benefits the power system. It will also be important for the system operator to have visibility over these assets. Price signals to encourage the use of low-carbon electricity are particularly important for storage to ensure that these assets support emissions reductions.
- **Modernising the grid and addressing barriers to grid development**, as well as supporting initiatives to increase regional interconnection. Modernising the grid, including consideration of advanced technologies to support inverter-based

generation, can improve its robustness and flexibility to integrate renewables. In addition to integrated planning to ensure grid and renewables development are co-optimised, and since grid development often faces long lead times and delays, it is critical to ensure grid development is able to proceed in a timely way.

Annex

Modelling details

Power sector modelling approach and assumptions

The Thailand power system was modelled using both the production cost and capacity expansion modelling functionality in PLEXOS© Integrated Energy Model.[5] This is an industry standard, optimisation-based power system modelling tool that allows for both detailed production cost modelling and long-term capacity expansion modelling. The following description of the model pertains to single representation of the Thailand power system that is consistent for the use of both functionalities within the model, although additional information is provided for the long-term capacity expansion functionality in the next section.

The model employs a temporal resolution of an hour, using forecasted hourly demand profiles as provided by EPPO, while the techno-economic characteristics of power plants (including imports), hydropower energy constraints, VRE production profiles, fuel supply constraints, operating reserves, transmission lines and are also represented.

Thailand's power system is represented in the model according to the main "area control" regions designated by the EGAT. These comprise five main control regions, and a further disaggregation of the Central region based on EGAT operational procedures due to its large size.

The model represents Thailand based on five main control regions within EGAT, corresponding with the spatial disaggregation of demand data provided by EGAT:

Central (CAC)

Metropolitan Bangkok (MAC)

Northern (NAC)

North-Eastern (NEC)

Southern (SAC)

[5] PLEXOS© is an energy market simulation package for modelling the power system over different time frames, ranging from long-term generation capacity expansion to short-term dispatch and unit commitment.

Data sources for power system modelling set up

Data source	Generation	Transmission network	Demand
Official source (i.e. EGAT)	• Net capacity per generation technology (existing / planned) • Key operating characteristics of generating plants: *average heat rates for existing plants* • Fuel costs for current and future years • Daily gas take-or-pay contracts • Fuel prices • Hydro energy constraints	• Existing and future network topology (lines/voltage) for Thailand (split into 5 nodes)	• Forecasted hourly demand profiles for 2021, 2025, 2030 and 2037 • Energy efficiency and EV projections per region • EV charging hourly profiles
Public domain or IEA data/ analysis	• Wind & solar time series for representative locations for the future scenarios.		
Global data assumed	• Key operating characteristics of generating plants: *ramp rates, min/max generation, average heat rate of future plants, min up/down times*		

Power plant operational costs consist of fuel cost, start-up cost, variable operating and maintenance cost and ramping cost. All costs are based on those reflected in EGAT PPAs, except for ramping cost, which reflects wear and tear costs due to increased cycling based on international data. In order to manage the simulation times of the model, we assumed start-up costs based on a "warm" cooling state[6] of units only, while assuming a simple heat rate based on generating units at full load. Other power plant characteristics that we modelled include plant outage rates (both forced outages and maintenance) and repair times, and technical constraints of the generating units including ramp rates, run-up rates, minimum up/down times and minimum stable levels (MSLs). While EGAT provided data on ramp rates, run-up rates and MSLs for existing units, we used international data for the other characteristics.

Long-term capacity expansion modelling

Long-term capacity expansion modelling was limited to the expansion of VRE (wind and solar PV), batteries and inter-regional transmission in order to determine the required capacity of these technologies to allow for Thailand to reach its emission targets for the power sector in 2025, 2030 and 2037.

[6] Generating unit start-up costs and start-up times will depend on how long the unit has been shut down, with units described as either hot, warm or cold. These times will vary according to generation technology

Meanwhile, for the long-term capacity expansion modelling, a sampled chronology was used, which reduces the 365 days into 3 sampled days per month (i.e. 36 days across the year) to reduce its computational requirements to solve the model. The choice and parameters of this chronology was to find a trade-off that allowed accounted for computational requirements but also allowed for intra-daily flexibility requirements to be appropriately represented that resulted in a better representation of VRE and flexibility options.

Capacity expansion was performed for single years (2025, 2030, and 2037) only and therefore did not consider the optimal roll-out of these technologies across the entire planning horizon. As a result, the investment costs used for the various technologies were for the modelled year only.

Representation of the Thailand power transmission networks

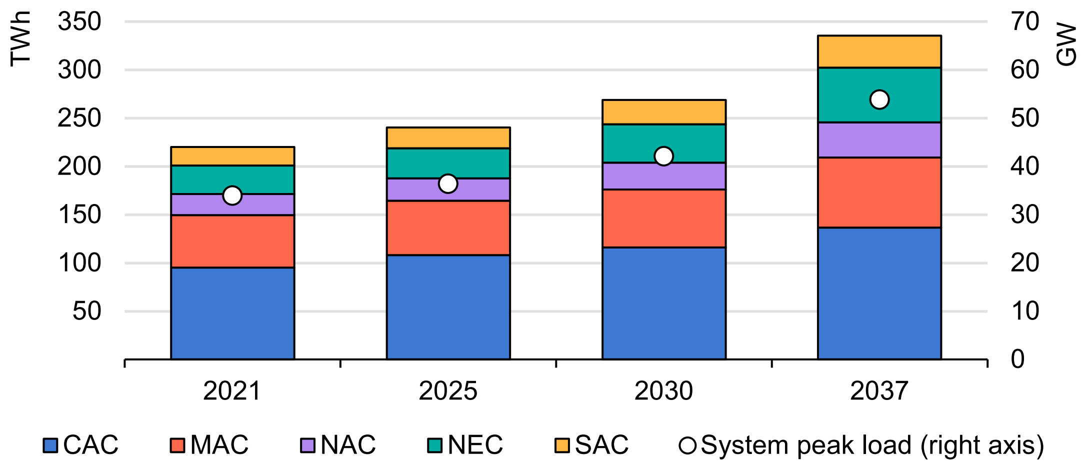
The model represents Thailand based on five main control regions within the EGAT, corresponding with the spatial disaggregation of demand data provided by EGAT: namely Central (CAC), Metropolitan (MAC), Northern (NAC), North-Eastern (NEC) and Southern (SAC).

The transmission system is based on both the existing and planned transmission network up until 2037. The transmission is only modelled as transfer capacities between the different regions, using transfer capacities as provided by EGAT. Losses were not explicitly modelled, but instead considered to be part of the input demand. Interconnectors with neighbouring Laos PDR and Malaysia were not explicitly included in the model. Instead, generation from Laos PDR under bilateral PPAs were modelled explicitly as part of either the Northern or North-Eastern region (depending on the interconnected region). Meanwhile, the 300 MW HVDC interconnector with Malaysia to the Southern region was explicitly excluded due to its current use being primarily reserved for emergency situations due to high prices.

Modelling demand and reserves

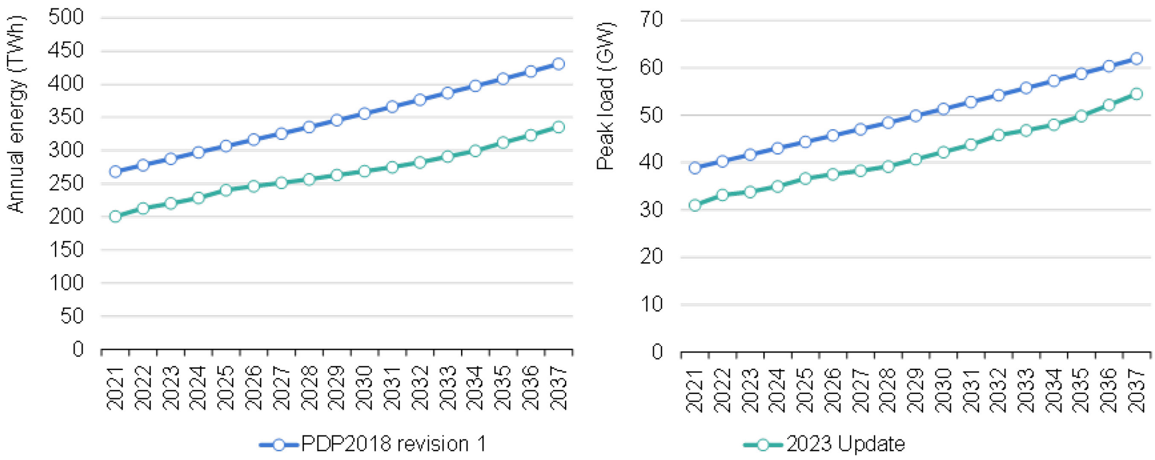
Future demand I represented at a regional level, with an hourly resolution and is based upon updated projections from the EPPO that have been prepared for the forthcoming update to their PDP. This, importantly, includes updated projections for EVs and energy efficiency.

Annual demand by region and system peak load, 2021, 2025, 2030 and 2037



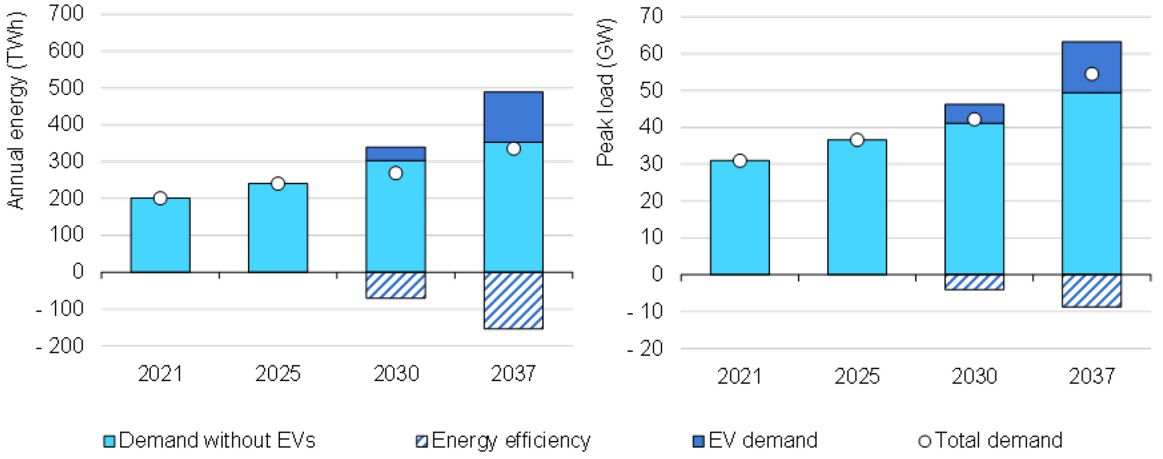
Source: IEA based on data from EGAT (2020), PDP 2018 Revision 1.

Annual demand by region and system peak load according to the PDP 2018 and 2023 update to demand projections



Source: IEA based on data from EGAT (2020), PDP 2018 Revision 1.

The contribution of electric vehicles and energy efficiency to both annual (left) and peak (right) demand for the 2023 update of demand



Source: IEA based on data from EGAT (2020), PDP 2018 Revision 1.

Operating reserves are also explicitly modelled, allowing for co-optimisation with the unit commitment economic dispatch solution. The spinning reserve requirement is based on EGAT's current, system-wide requirement of 1 500 MW load risk during peak periods and 700 MW during off-peak periods.

Representation of generation mix

The generation mix in Thailand in 2037 is based on the planned retirements and new builds from the PDP 2018 revision 1, which includes EGAT and IPP power plants. These plants consist of various generation technologies which are defined according to a number of techno-economic characteristics and operating constraints which are based on either information provided by EGAT or, in its absence, industry-best practice. Broadly speaking, and in the context of Thailand, these can be divided into conventional thermal, hydro and VRE plants. In addition, there a number of SPPs of various technologies, aggregated at a regional level and that run according to specific patterns as provided by EGAT. In general, the following parameters of the aforementioned plants are modelled:

- Minimum stable level
- Run-up rates
- Ramp rates
- Average heat rates
- Outage rates (both forced and maintenance) with mean time to repair (MTTR)
- Minimum up and down times
- Average start-up costs

- Variable Operation & Maintenance (O&M) costs

In addition to the above-mentioned characteristics, the fuels used by specific generators or sets thereof are also modelled. This includes the fuel prices (as expanded upon in the following section pertaining to data) and fuel constraints.

As it relates to hydro, generators are separated into one of three groups:

- Run-of-river (RoR) plants with daily pondage schemes
- Plants with large reservoirs
- Off-stream (standalone) pumped storage hydro (PSH) schemes

In the case of hydro plants, seasonality of their inflows is captured with monthly resolution based on average values from historical data provided by EGAT. In the case of RoR plants, the monthly availability of hydro energy is spread evenly across the days over which a pondage scheme can regulate on a daily basis. Meanwhile, large reservoirs can optimally regulate its output across the month. However, a certain portion (30%) of minimum hydro generation (daily for reservoir, hourly for run-of-river with pondage) is also defined based on assumed environmental flow constraints for the river systems on which the hydro plants are located.

Meanwhile, wind and solar PV profiles are based on historical resource profiles that have been aggregated. In all cases, spatial distribution of the generation is captured by assigning the appropriate generator to one of the five regional nodes. However, solar and wind profiles have additional spatial resolution which is captured by the high-resolution resource data used as an input, as explained in the following section.

Modelling scenarios of increased VRE penetration

The model considers two main scenarios ("Base" and "VRE Plus") based on three different modelling years (2025, 2030 and 2037), in addition to the validation of the model against historical generation and demand values for 2021.

The first of the two main scenarios is the "Base" case, which considers the development of the capacity mix as per the PDP2018 revision 1 ("PDP2018"), and represents a business-as-usual reference case for the development of the Thailand power system Meanwhile, the second scenario, "VRE Plus", considers an alternative capacity mix that considers the deployment of wind, solar PV and the necessary flexibility options (specifically storage and inter-regional transmission) in order to meet the emission targets for the Thailand power sector.

The optimal deployment of VRE and flexibility to meet the emissions targets was deployed in an iterative manner. Firstly, a long-term capacity expansion model was used with a constraint on emissions and with candidate wind and utility-scale solar PV plants. The ratio of solar PV to wind builds was assumed to be constrained to 3:1.

Following from this, a VRE site selection methodology was followed (as discussed in the following section), with a new siting of future wind and solar PV generation, while also assuming a certain portion (20% in all regions except MAC where it was 90%) of solar PV to be rooftop PV. Following from this, the optimal deployment of flexibility options (transmission and battery storage) with was determined using the capacity expansion model.

Modelling of wind and solar generation

Wind and solar PV generation profiles are produced from ERA5 reanalysis data to produced hourly generation profiles for wind, rooftop solar PV and utility-scale solar PV.

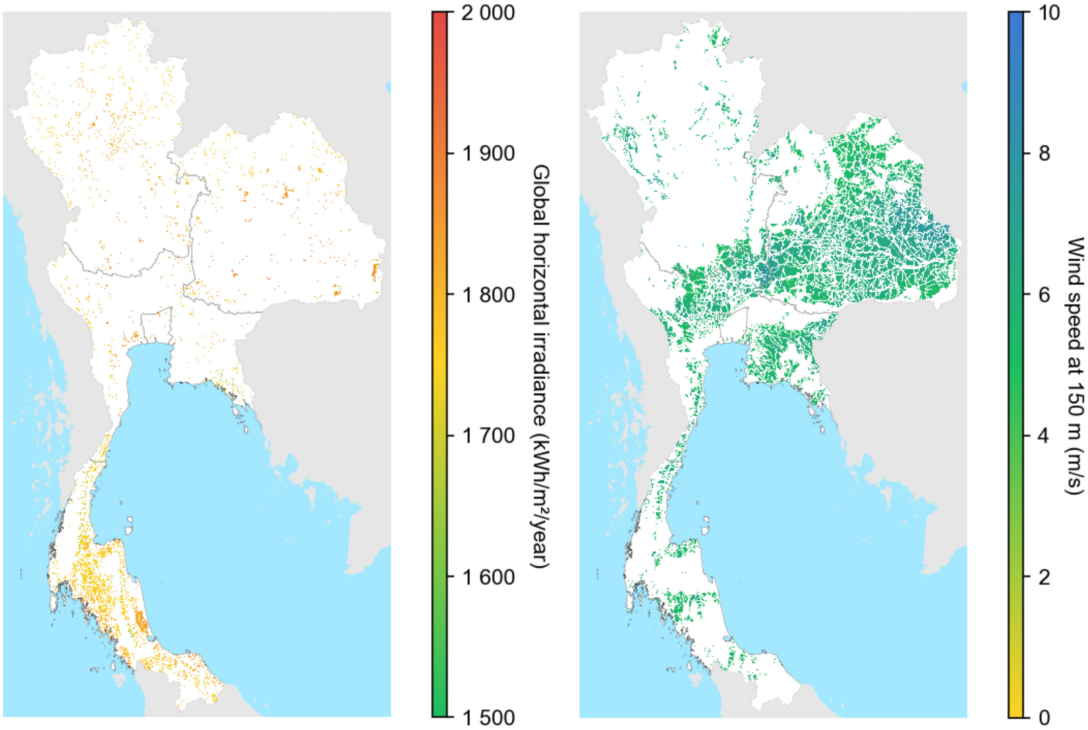
In order to site potential new generation for wind and solar PV, a site selection methodology is employed that takes into account resource quality, exclusion areas, the vicinity to existing transmission, and proximity to load centres. Exclusion areas are based on the following criteria:

- protected areas (World Database on Protected Areas),
- current land use and land cover (land-use data from the European Space Agency for 2021),
- Areas in the immediate vicinity of roads, airports and railways, including a buffer zone

For wind, an average wind speed cut-off of 5 metres per second (m/s) is used. The model assumes that mixed land use is possible for onshore wind, given the low land footprint of the turbine base. A land-use factor of 9 MW/km^2 and 30 MW/km^2 was assumed for wind and solar respectively.

To take account of non-technical barriers to land use, the model assumes that only 50% of the technically available land can actually be used for solar and wind projects.

Solar (left) and wind (right) potential in Thailand's power system's five control regions



Note: Each pixel represents a 3x3 km^2 area which can be used for development of wind or utility solar PV, with an assumption of land use per capacity of 9 MW/km^2 for wind and 30 MW/km^2 for utility solar PV and a land use factor of 0.5 which attempts to capture non-technical factors that may restrict the use of certain land for renewable energy development. Spatial analysis has been performed which excludes sites based on certain land use and land cover, proximity to infrastructure (e.g. roads, railroads and airports), protected areas and terrain (e.g. elevation and slope).

Sources: IEA analysis based on data from DTU, World Bank Group, Vortex, ESMAP (2021); Solargis, World Bank Group, ESMAP (2021); ESA Climate Change Initiative (2021); UNEP-WCMC (2021).

Abbreviations and acronyms

AEDP	Alternative Energy Development Plan
ASEAN	Association of Southeast Asian Nations
BESS	battery energy storage system
CCUS	carbon capture, utilisation and storage
CAC	Central (one of the 5 control regions of Thailand)
COP	Conference of the Parties
EGAT	Electricity Generating Authority of Thailand
EPPO	Energy Policy and Planning Office
ERC	energy regulatory commission
EV	electric vehicle
GDP	gross domestic product
GHG	greenhouse gas
IPP	independent power producer
LT-LEDS	long-term low greenhouse gas emission development strategy

LTMS-PIP	Lao PDR-Thailand-Malaysia-Singapore Power Integration project
MAC	Metropolitan Bangkok (one of the 5 control regions of Thailand)
MEA	Metropolitan Electricity Authority
NAC	Northern (one of the 5 control regions of Thailand)
NEC	North-Eastern (one of the 5 control regions of Thailand)
PDP	Power Development Plan
PEA	Provincial Electricity Authority
PPA	power purchase agreement
PSH	pumped hydro storage
SAC	Southern (one of the 5 control regions of Thailand)
SPP	small power producer
VRE	variable renewable energy
VSPP	very small power producer

Glossary

bbl	barrel
bbl/d	barrels per day
bcm	billion cubic metres
bcm/yr	billion cubic metres per year
cm/s	centimetres per second
gCO_2	gram of carbon dioxide
gCO_2/kWh	grams of carbon dioxide per kilowatt hour
GJ	gigajoule
Gt/yr	gigatonnes per year
$GtCO_2$	gigatonne of carbon dioxide
$GtCO_2$/yr	gigatonnes of carbon dioxide per year
GW	gigawatt
GWh	gigawatt hour

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