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Thailand Renewable Grid Integration Assessment

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Foreword

Solar and wind power have taken off at a dramatic pace in Thailand as a result of sustained policy support, coupled with a rapid decline in costs. Industrial and commercial facilities rapidly adopted solar power generation for internal consumption once the government developed this option and offered an attractive tax allowance. However, the growth of variable renewable energy (VRE), such as solar and wind poses challenges to the stability of the power grid. Technical and commercial issues have emerged concerning the availability of resources to compensate for the variable and partly unpredictable outputs of VREs. In addition, questions have arisen about allocating costs and designing an appropriate tariff structure. Thailand's commitment under COP21 is to bring the share of renewable energy to 30% of the country's final energy consumption by 2036. How to address these challenges and smoothly integrate an increasing share of VRE is therefore a priority for Thailand's power sector.

The Ministry of Energy of Thailand (MoEN) and The International Energy Agency (IEA) have collaborated since 2007 on diverse areas of energy policy, from energy security and emergency preparedness, to energy policy analysis and the scaling-up of low-carbon energy technologies. At the 2015 IEA Ministerial meeting, Thailand became an Association member of the IEA. In the area of renewable integration, Thailand's power system operator has participated in the IEA Grid Integration of Variable Renewables (GIVAR) Advisory Group since 2017.

Given the recent growth of VRE in Thailand and the potential ramifications of its increasing role for Thailand's electricity sector, the MoEN started a program of work with the IEA in July 2017 to provide analytical support to assess the impact of growing shares of VRE in the generation mix as well as to develop mitigation strategies. The results reported here in Thailand Renewable Grid Integration Assessment examine how both the technical and economic aspects are impacted in several different scenarios of VRE penetration. This publication recommends policies, mechanisms, and tools to mitigate these impacts in the Thai context, based on international experience and global best practice. We believe the analyses will be invaluable to the achievement of Thailand's long-term ambitious renewable energy target and will provide vital support for the country's vision of "Stability, Prosperity and Sustainability".

This report, with its detailed technical and economic analysis, policy recommendations, and extensive stakeholder consultation, represents a "high-water mark" for Thailand-IEA co-operation. As a next step, we now plan to undertake a detailed regional study of renewables integration in Southeast Asia, looking not only at Thailand but also at all the other countries in the region. We would like to express our appreciation to everyone who contributed to the success of this project and look forward to building even stronger ties between the IEA and Thailand in the years ahead.

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- **DEDE:** Ms. Munlika Sompranon (Director, Energy Cooperation Section), Ms. Rungrawee Yingyuad, (Head of Wind Energy group), Ms. Tarntip Settacharnwit (Senior Professional Scientist), Ms.Charuwan Phipatana-phuttapanta (professional scientist), Ms. Bunprapha Prawet and Mr. Warote Chaintarawong.

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Comments and questions on this report are welcome and can be addressed to SIR@iea.org.

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Executive summary

Background, objectives and project scope

Thailand is experiencing an accelerated uptake of variable renewable energy (VRE), particularly solar photovoltaics (PV). With this increase in VRE, both in utility scale and distributed installations, there are growing concerns over the short- and long-term impacts of VRE on the power system. Against this background, the Ministry of Energy (MoEN) officially requested the International Energy Agency (IEA) to carry out the **"Thailand Renewable Grid Integration Assessment Project"**. The project has been supported by the Electricity Generating Authority of Thailand (EGAT) in order to assist relevant stakeholders in the energy sector including the Energy Policy and Planning Office (EPPO), the Department of Alternative Energy Development and Energy Efficiency (DEDE), the Office of the Energy Regulatory Commission (OERC), Metropolitan Electricity Authority (MEA), Provincial Electricity Authority (PEA) and EGAT itself.

The primary objectives of this project are to support the reliable and cost-effective uptake of renewable generation in Thailand by identifying integration challenges and possible mitigation options; provide support by sharing international and regional best practices for integrating VRE resources; conduct quantitative and qualitative analyses on the impact and value of VRE in the power sector; and facilitate domestic and international dialogue through capacity-building workshops and training.

The analytical study covers three different work streams:

1. **Techno-economic grid integration assessment** – Modelling the power system with solar and wind energy resources under different deployment scenarios for 2036, the target year of the long-term Power Development Plan (PDP) 2015. The overall generation mix is based on the latest available in PDP 2015. Different levels of VRE and flexible resources are added to the power system (as defined in the PDP baseline scenario for 2036) to identify priority areas for preparing the system for increased quantities of VRE.
2. **Distributed energy resources (DER) analysis** – The technical and economic potential for distributed solar photovoltaic (DPV) in Thailand as well as the potential economic impacts of deployment on utilities and ratepayers under current tariff regimes were analysed. On this basis, recommendations were derived on how to approach reforms to wholesale and retail pricing of electricity.
3. **PDP assessment and VRE system cost analysis** – This includes an assessment of long-term power system planning practices and recommendations for possible enhancement based on international best practice. The analysis also features an assessment of system effects and associated cost implications.

Current context of Thailand's power system and VRE penetration

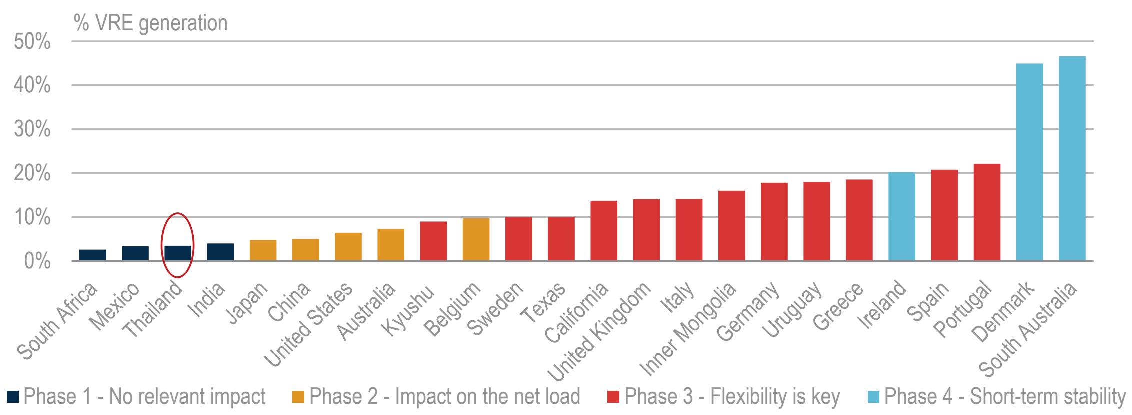
The current level of VRE generation is relatively low by international standards

In the region of the Associated Southeast Asian Nations (ASEAN), Thailand is the most advanced country in terms of VRE penetration, as well as the development of grid infrastructure, advanced operational practices, and deployment of other flexibility options. This notwithstanding, the current level of VRE generation is relatively low by international standards at 4% (Figure ES 1). Previous IEA analysis has identified distinct phases of VRE integration, differentiated by the impact VRE has on power system operation. Generally speaking, there are four phases of VRE system integration:

- **Phase 1 –** The first set of VRE plants are deployed, but they are basically insignificant at the system level; effects are very localised, for example, at the grid connection point of plants.
- **Phase 2 –** As more VRE plants are added, changes between load and net load[1] become noticeable. Making upgrades to operational practices and making better use of existing system resources are usually sufficient to achieve system integration.
- **Phase 3 –** Greater swings in the supply-demand balance prompt the need for a systematic increase in power system flexibility that goes beyond what can be relatively easily supplied by existing assets and operational practices.
- **Phase 4 –** VRE output is sufficient to provide a large majority of electricity demand in certain periods; this requires changes in both operational and regulatory approaches. Regarding operations, this relates to the way the power system responds immediately following disruptions in supply or demand to maintain system stability. Regarding regulations, it may involve rule changes so that VRE is enrolled to provide frequency response services, or the relaxation of take-or-pay contracts for power purchase and/or fuel procurement contracts.

In Thailand, VRE generation is becoming noticeable to the system operators; therefore, Thailand can be considered to be in Phase 1, approaching Phase 2 of VRE integration (Figure ES 1).

Figure ES 1 • Selected countries, including Thailand, by Phase, 2016



Note: China = the People's Republic of China. Kyushu is one of the large islands in Japan located in the southwest.
Source: Adapted from IEA (2017c), *Renewables 2017: Analysis and forecasts to 2022*.

Key message • Thailand is considered to be in Phase 1 and approaching Phase 2 of VRE integration. While most countries are in Phases 1 or 2, some power systems are experiencing later phases.

Thailand's electricity system is flexible from a technical standpoint, but institutional and contractual constraints limit the mobilisation of this flexibility

The current power system in Thailand can be considered to have relatively high system flexibility. The system can handle high ramping requirements which usually occur during evening peak periods. The ***generation fleet*** appears to be flexible given a moderate share of hydropower and a high share of combined-cycle gas turbine (CCGT), together with an overall large reserve margin. However, the ***operating characteristics*** of the CCGT and coal power plants – particularly minimum generation, ramp rates and start up times – suggest that flexibility can be significantly

[1] Net load is the difference between forecasted load and generation from VRE.

enhanced by upgrading operating protocols and, in some cases, through retrofit projects. Domestic hydropower plants also have a very high minimum generation level.

However, inflexibilities relating to the operating characteristics of power plants are not only due to technical constraints. They are also caused by:

- current power purchase agreement (PPA) stipulations between EGAT and private power producers that constrain operations of conventional power plants.
- the structure of fuel supply agreements according to the Master Gas Sale Agreement (MGSA), which requires minimum-take-or-pay obligations for fuel purchases by EGAT power plants, forcing some EGAT power plants to operate when it is not economic for the power system.

The existing transmission system in Thailand appears to be very flexible, given a number of advanced transmission equipment and protection schemes. However, transmission strengthening will be required to accommodate new generation, both according to the capacity targets proposed in the PDP 2015 and under higher renewable energy targets (RETs).

There are two additional aspects that could create a relevant barrier to VRE uptake in Thailand if not addressed with priority. The first relates to technical connection standards (i.e. grid codes), the second to the establishment of a dedicated renewable energy control centre.

At present, there are several grid codes for the power system in Thailand that have been established separately by the transmission and distribution utilities (EGAT, MEA and PEA). They are not fully consistent regarding the technical requirements and could be enhanced to ensure their consistency to accommodate for future increases of VRE. The regulator (OERC) can play a key role in improving the consistency of grid codes between EGAT, MEA and PEA, and ensuring that stakeholders comply with the grid codes, particularly the operational standards, in order to maintain the stability of the overall power system.

Moreover, Thailand does not currently have a dedicated control centre for managing renewable energy generation. The establishment of a renewable energy control centre should be expedited in order to enhance visibility and controllability of VRE in the context of increasing shares of wind and solar in Thailand.

Recommendations – current power system and possible short-term actions

- ***Unlock existing power plant flexibility*** by enhancing fossil fuel procurement contracts between PTT and EGAT to promote more flexible operation and by reviewing options to make contractual arrangements between EGAT and private power producers more flexible.
- ***Develop and implement a harmonised, national grid code*** in a collaborative process among EGAT, PEA and MEA, to be led by OERC and informed by external independent experts.
- ***Establish a national renewable energy control centre*** that has access to state-of-the-art real-time VRE generation data and short-term production forecasts, and integrate real-time VRE analysis insights into the operation of the Thai power system.

Grid integration assessment of Thailand’s future power system

For the techno-economic grid integration assessment work stream, production cost modelling is employed to simulate the optimal operation of Thailand’s power system in 2036. The generation mix is largely based on assumptions from the PDP 2015, which provides power demand forecasts and a generation and transmission capacity expansion plan to 2036. Installed generation capacity has been forecasted to grow from around 46 000 MW in 2017 to 70 000 GW in 2036. Renewable generation capacity is forecasted to increase from around 10 000 MW to 19 000 MW over the same period. In addition to the PDP scenario, different VRE deployment scenarios for 2036 are analysed and compared in order to understand the operational and economic impacts associated with greater VRE deployment, as well as the efficacy of different flexibility options in power systems with a significantly higher VRE penetration.

System flexibility becomes an important factor for system operations and planning with increasing shares of VRE in Thailand's future power system.

The core modelling scenarios consider different levels of VRE deployment, whereas additional modelling scenarios consider different flexibility options for a higher VRE deployment scenario. Broadly speaking, the flexibility options can be considered under the following categories:

- **Unlocking system flexibility** – changes to future gas contract commitments (between PTT and EGAT) to relax take-or-pay stipulations; changes to PPA to enable more flexible operations, including higher ramp rates, lower minimum generation levels and shorter start-up times for conventional power plants.
- **Deploying new flexibility options** – integration of electric vehicles (EVs) with smart charging, demand-side management (DSM), battery storage and pumped storage hydropower (PSH).

Box ES1 • Modelling different scenarios of wind and solar penetration

Power sector modelling can play a crucial role to analyse the potential impacts of different policy and planning choices. There are different types of power sector modelling tools to examine the power sector at different time horizons to address distinct analysis questions. In this report, production cost modelling is employed to simulate the optimal operation of Thailand's power system, with the modelled generation mix and transmission system largely based on the existing investment plan. The model is used to assess the technical and economic impacts of different levels of VRE deployment on the 2036 Thai power system, and also to better understand the efficacy of various flexibility options to support VRE integration in a cost-effective and reliable manner. The power system is simulated for a full year at 30-minute time resolution, with operational decisions co-optimised with spinning reserve requirements, and with a high level of detail captured for both the generation fleet and the transmission system.

Three core scenarios in the modelling exercise consider different levels of wind and solar penetration (see Table ES 1). The Base scenario corresponds to the 2036 power system as envisioned in the 2015 PDP. Two further scenarios – RE1 and RE2 – are used to explore the impacts of increasing shares of VRE in Thailand, with RE2 featuring the highest VRE deployment levels. The RE2 core scenario is further explored with additional eight scenarios with different flexibility options.

Table ES 1 • Core scenarios used for the modelling analysis

Scenario	Description
Existing (2016)	Based on 2016 load and available generation, for validation purposes
Base	2036 scenario using existing official government targets of 6 GW solar and 3 GW wind; all other aspects based on 2015 PDP; flexible gas contracts (no take-or-pay terms)
RE1	2036 scenario with 12 GW solar and 5 GW wind; all other aspects are the same as Base scenario
RE2	2036 scenario with 17 GW solar and 6 GW wind; all other aspects are the same as Base scenario

Note: Eight additional scenarios under RE2 consider different flexibility options as detailed in the main report, (see Table 4.1).

Under the VRE deployment level modelled in the RE2 scenario, the future power system in Thailand in 2036 would be considered to be in Phase 2 or perhaps Phase 3 of VRE integration, due to changes in the net demand profile that induce higher ramping requirements in both the 30-minute and 3-hour ranges. In this phase, system flexibility becomes an important factor for system operations and planning.

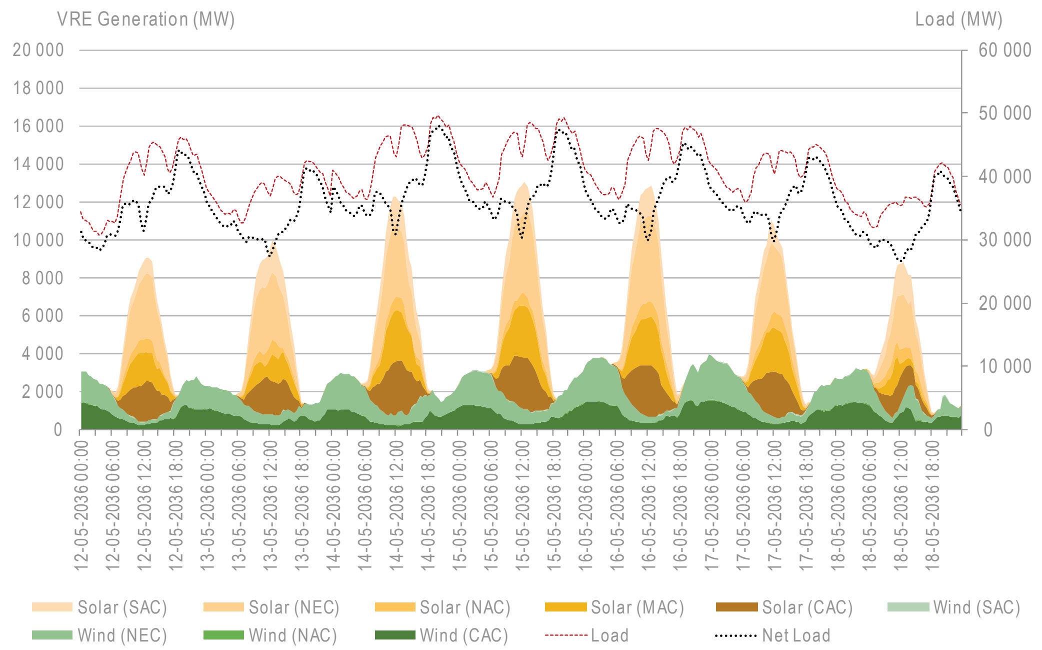
Solar and wind resources have highly complementary generation profiles in Thailand, contributing to different peak demand patterns

Based on the modelling exercise and the assumptions put forth in the core scenarios, monthly VRE penetrations are expected to be highest in November to January (approximately 8% in the Base scenario, 16% in RE1 and 20% in RE2), and they are lowest in September and October (approximately 5% in the Base scenario, 8% in RE1 and 11% in RE2). Solar generation is quite consistent throughout the year, whereas wind generation has greater variation due to local weather patterns in Thailand. The annual average of VRE penetration also varies between different regions (Table ES 2). The north-eastern region has the highest annual average VRE penetration due to a greater availability of VRE sites that are suitable for development and stronger transmission infrastructure.

Table ES 2 • Annual average VRE penetration in different regions across core modelling scenarios

Regions	Average Annual VRE penetration (%)		
	BASE	RE1	RE2
Central (CAC)	4%	8%	11%
Metropolitan (MAC)	1%	3%	4%
Southern (SAC)	6%	9%	12%
Northern (NAC)	6%	12%	18%
North Eastern (NEC)	24%	45%	59%
NATIONAL	**6%**	**11%**	**14%**

Figure ES 2 • VRE generation, load and net load profiles during a high-demand period in the RE2 scenario



Key message • There is a high contribution of solar towards Thailand's midday peak demand, while the wind profile generally ramps up during the evening as demand increases.

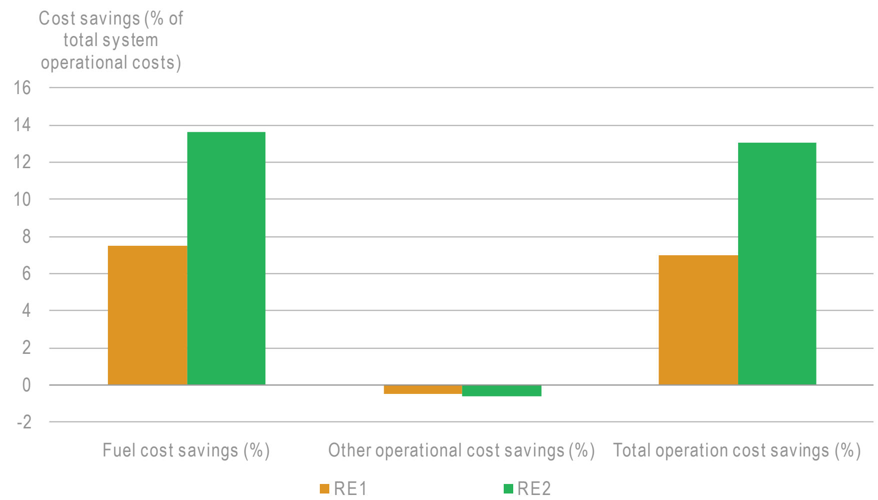
The modelling results also suggest that wind and solar resources have highly complementary generation profiles to one another, allowing a contribution to both midday peak demand and evening peak demand, particularly during the annual peak period (Figure ES 2).

Thailand's future electricity system is expected to have sufficient flexibility options to accommodate higher shares of VRE generation

During the seasonal peak demand period, which occurs in mid-May, there is sufficient generation to handle the high demand, although some of the peaking plants such as expensive diesel gas turbines (GTs) need to be dispatched. This day-time peak period also coincides with the high solar PV output periods. Additional VRE is shown to benefit the system by displacing fossil fuel associated with operating conventional generation, particularly CCGT and OCGTs. With increasing VRE penetration, conventional generators are required to cycle more frequently as well as operate near their operational limits (i.e. ramp rates and minimum generation), but the system can still reliably accommodate such requirements.

The relaxation of inflexible gas supply and power purchase contracts, which feature minimum take-or-pay gas requirements and limited operational characteristics of power plants, can substantially reduce fuel costs and thus total system operational costs (around 8-15%) (Figure ES 3). This is due to avoiding non-merit order dispatch as the share of VRE increases, when gas-fired power plants must be operated instead of the more economic generators, such as hydropower, wind and solar, in order to meet take-or-pay gas supply requirements. More flexible power plant operational characteristics, particularly lower minimum generation levels, can allow more VRE generation, further reducing fossil fuel costs and avoiding VRE curtailment.

Figure ES 3 • Cost savings in RE1 and RE2 scenarios due to increased flexibility of gas supply contracts



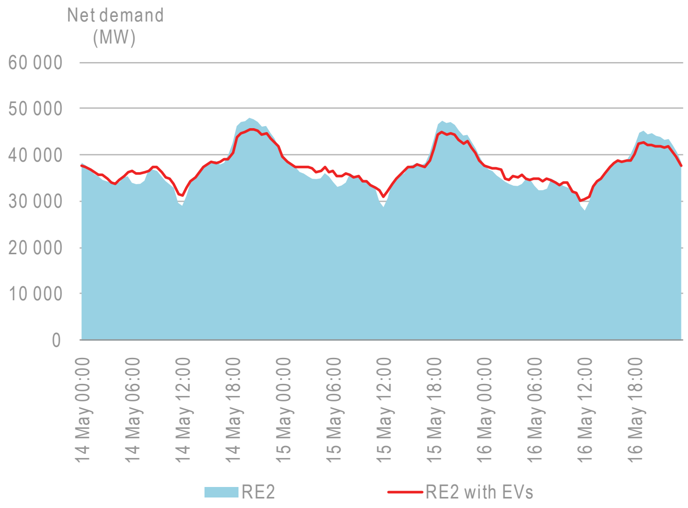
Note: *Other operational cost* includes import hydro cost, ramping cost, start-up and shutdown costs and variable O&M costs.

Key message • Inflexible long-term gas contracts significantly increase total system operational costs.

Additional demand-side flexibility options can help to shift peak demand and further reduce total system operational costs

Cases with different flexibility options, including demand-side management (DSM), smart EV charging and battery storage options, were also analysed for the RE2 scenario – 1.2 million EV units and 400 megawatts (MW)/1 600 megawatt hours (MWh) battery storage in 2036. These flexibility options demonstrated a range of operational and economic benefits to the Thai power system, particularly during high-demand periods. These options could also potentially offset conventional generation investment requirements, such as for CCGT and coal power plants (Figure ES 4).

Figure ES 4 • Impact of smart EV charging during the peak net load period in the RE2 scenario



Key message • Smart EV charging for the EV fleet projected by EGAT in 2036 can help to shift peak demand and reduce operational costs.

Recommendations – Gird integration of VREs in Thailand's future power system

- **Ensure flexible future contractual arrangements** for governing power plant fuel procurement and PPA so they do not hinder the optimal dispatch of the power system.
- ***Upgrade system operational practices*** as VRE deployment grows through promoting "faster" dispatch of the power system, with more frequent updates of schedules closer to real time and reduced dispatch intervals for power plants, including small power producer (SPP) plants.
- ***Improve the flexibility of conventional power plants*** through retrofit projects and changes to operational practices to improve key flexibility characteristics including ramp rates, minimum generation levels and start-up times. In particular, the high minimum generation levels of hydropower plants can be reduced.
- ***Facilitate the deployment of demand side options*** including DSM, smart EV charging, and battery and pumped hydropower storage as the level of VRE increases since these options can enhance system flexibility in a reliable manner while reducing total system operational costs.

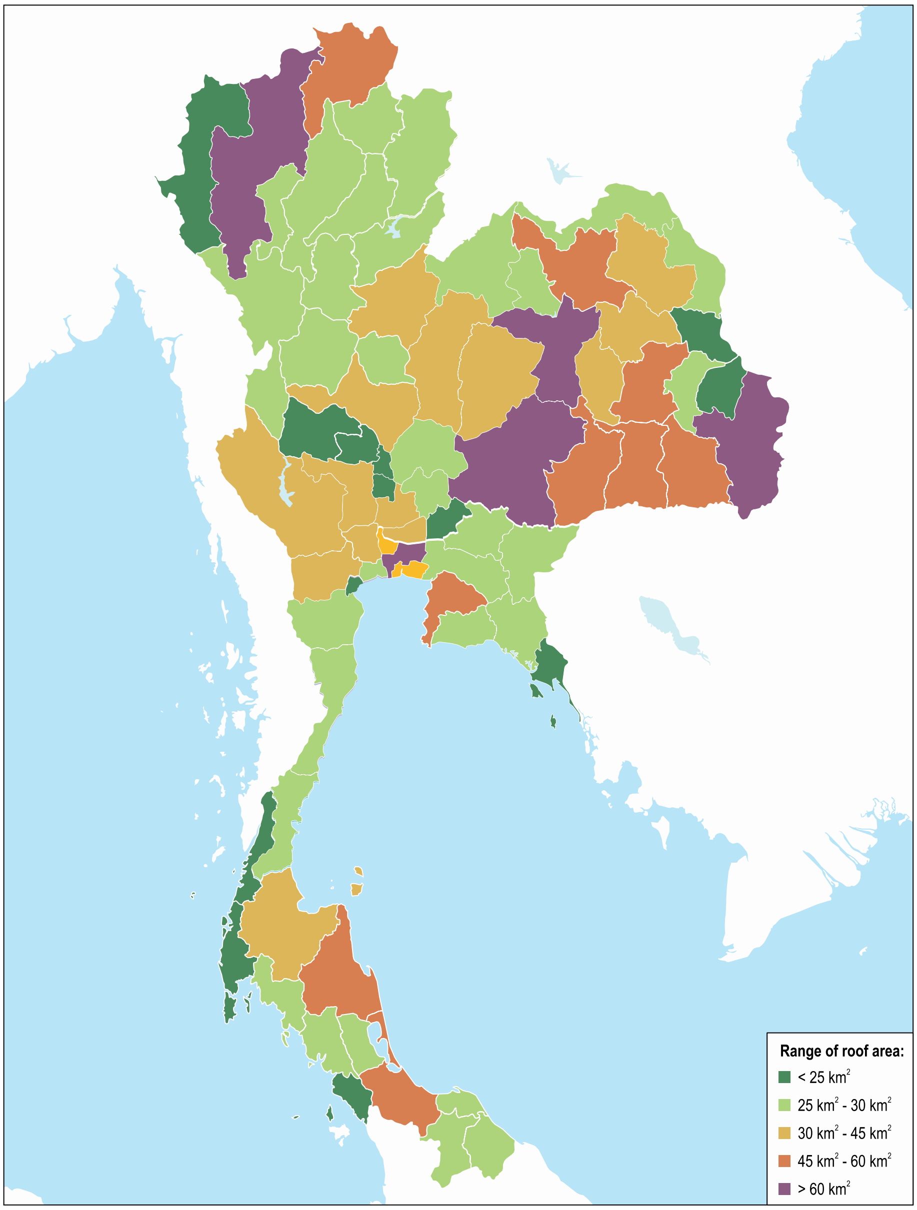
Distributed energy resources (DER) in Thailand

Available rooftop area is not a relevant constraint for the uptake of DPV

The DPV analysis features an estimation of the gross maximum technical PV potential in Thailand. A second part of the analysis investigates the economic impact resulting from achieving specific DPV deployment targets, including the impact of DPV on regulated retail tariffs.

The total gross maximum technical rooftop potential is estimated at 2 383 km^2 (Figure ES 5). While this estimate omits rooftops that are unsuitable based on orientation, a number of factors may reduce the amount of suitable rooftop area in Thailand. Rooftops may not be suitable if they are not structurally sound enough to support a DPV system or if part of the surface is not available due to the existence of other infrastructure, e.g. heating ventilation and cooling installations on the rooftop. There are also notable limitations associated with the technical absorption capacity of the distribution grid to accommodate DPV that were not assessed in this analysis. The potential is thus referred to as a gross maximum technical potential because it does not consider all factors that may lead to unsuitability of a roof for installing DPV systems. This gross maximum technical potential should not be interpreted as a recommendation for target setting, even in the long term. However, even with these caveats and limitations, this analysis indicates that rooftop area is not a relevant constraint for the DPV deployment. Even if only 10% of the gross maximum technical potential were suitable for DPV deployment and were installed– a conservative estimate – that would correspond to more than the current total peak demand of Thailand power system.

Figure ES 5 • Distribution of estimated roof-top area per province



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Key message • Bangkok, Nakhon Ratchasima, Ubon Ratchathani and Khon Khaen were estimated to have the greatest rooftop surface area available for PV installations.

Changes to wholesale and retail pricing schemes could facilitate a long-term, sustainable uptake of DPV

A second analysis in this work stream investigated the total economic impact of achieving two different DPV deployment targets. The first is determined using the Alternative Energy Development Plan (AEDP) 2015, assuming 2 800 MW of DPV deployment by 2025. The second target is based on the RE2 scenario, assuming that the total of 17 000 MW of solar energy is deployed as rooftop installations. A simplified market diffusion model was used to establish the deployment path towards the target. This also allowed an assessment of the distribution of net economic impacts across utilities, as well as the impact of DPV on retail tariffs. Customers are categorised into residential customers (RES), small general service (SGS), medium general service (MGS), and large general service (LGS).

In the short term, the SGS, MGS and LGS customers have greatest economic potential for DPV deployment. However, due to the sheer number of customers, the residential customer sector of PEA has the largest overall long-term DPV potential. While this segment currently shows longer payback periods for DPV systems than other customer groups, the economic potential for DPV deployment rises as installation costs decrease.

In order to establish and analyse a future DPV deployment path, several combinations of remuneration and cost reductions are examined. The remuneration level is referred to as the buyback rate and varies between 0.00, 1.00, 2.00 and 2.73 THB/kWh. This is modelled assuming a net billing arrangement, i.e. any electricity fed into the grid is remunerated at the buyback rate while the rest is self-consumed and offsets consumption from the grid and its associated costs. All customer groups have been modelled using average load profiles per group, and DPV installations are sized to enable the majority of output to be self-consumed. Thus, buyback rates were seen to have limited significance driving the economic potential for DPV. These findings also depend on the modelled metering and billing arrangement for DPV (net billing), as opposed to net energy metering or buy-all, sell-all schemes. Moreover, the analysis only analysed buyback rates below or at the average wholesale electricity price. Different assumptions on the match with customer demand, system sizing, buyback rate and metering and billing arrangements may lead to a higher importance of the buyback rate.

The analysis demonstrates a relevant aspect in the distribution of economic impacts across PEA, MEA and EGAT, which are uneven. PEA and MEA are both buyers and sellers of electricity: wholesale buyers of electricity from EGAT, and sellers of that same electricity to retail customers. When a DPV customer uses their own generated electricity, PEA and MEA forgo only the lost re-sale margin for that energy. If the buyback rate for DPV electricity is below the wholesale electricity price, DPV grid injections may actually be economically attractive to PEA and MEA compared to the wholesale supply from EGAT. Due to the DPV energy generated, EGAT, on the other hand, experiences DPV deployment as a pure loss of revenue irrespective of the buy-back rate, because of a lost sale to PEA and MEA regardless of how it is used.

This uneven split of costs and benefits is due to the structure of Thailand's electricity industry, and also issues surrounding the design of the wholesale electricity price. It is currently not sufficiently differentiated by time and location to ensure that economic incentives for the different stakeholders are well-aligned with overall system needs. Changes to the structure of the wholesale electricity pricing would protect EGAT from revenue losses associated with DPV.

Under the current structure, both PEA/MEA and EGAT are able to recover any net revenue losses via an automatic adjustment mechanism that adjusts electricity rates to maintain a target rate of return. This means that ultimately, ratepayers shoulder any possible net revenue losses.

However, in the scenarios analysed (AEDP 2025 and RE2 scenarios), DPV deployment leads to only insignificant increases in retail electricity rates compared to a non-DPV baseline.

Recommendations – distributed energy resources in Thailand

- ***Determine appropriate remuneration for DPV grid injections.*** Understanding the system value of DPV injections is an important first step in fostering system friendly and cost-efficient deployment. Such value calculations could account for reduced operational costs or avoided grid investments associated with DPV but would require a comprehensive understanding of the network conditions at different times and locations. Analysis of DPV remuneration should also consider alternatives in metering and billing arrangements.
- ***Reform wholesale electricity tariffs***. A first step towards creating a more disaggregated pricing structure is to obtain more information on the cost of electricity generation for EGAT at any given point in time. A second step could be to account for systematic differences in the cost of electricity provision in different locations. The introduction of a more disaggregated wholesale price could also be a useful stepping stone in further reforming the overall electricity market structure.
- ***Enhance time-dependent retail pricing***. Retail prices should be designed to provide fair and appropriate incentives to both network users and DPV owners. The deployment of smart and or intelligent meters makes it possible to communicate this value to end users and use data measurements at more regular intervals to apply them in billing processes

PDP assessment and VRE system costs

Upgrades to existing methodologies could make planning processes in Thailand more suitable for higher shares of wind and solar PV

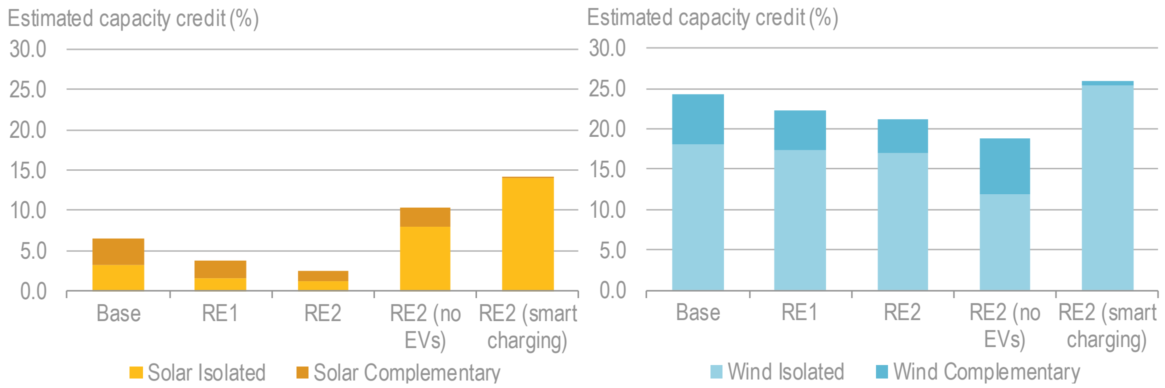
An assessment of the practices, processes and tools used in the formulation of the PDP identified possible areas of improvement in planning. The assessment covers the process by which RETs are set in Thailand, the approach used by system planners to determine reserve margins, and the methodology for determining the capacity value (referred as “dependable capacity” in Thailand) of VRE resources.

It was found that the current planning process in Thailand could limit the potential of RETs since possible transmission expansion for the locations with high VRE resources are not integrated in detail. Thus more integrated and co-ordinated planning frameworks that include consideration generation, transmission and distribution networks, as well as demand side and electrifications of other sectors, can help identify appropriate options for the future power system.

The methodology for setting reliability and reserve margin criteria can also be significantly improved. The existing approaches used are largely based on deterministic criteria. Adopting a fully probabilistic assessment could result in lower costs while maintaining system reliability.

The current approach used to determine capacity credit (i.e. dependable capacity) of VRE resources is concentrated on two typical peak demand periods (afternoon and evening), which led to underestimation or overestimation. As a part of this analysis, a capacity credit which considers the top 2% of load periods was calculated – it demonstrated that the VRE contribution to capacity requirements is strongly dependent on the load pattern, VRE generation patterns and flexibility options (e.g. smart EV charging) (Figure ES 6). Thus, it would be most accurate to consider capacity credit in a scenario-specific manner, rather than the use of a single number.

Figure ES 6 • Estimated capacity credit for wind and solar across various scenarios



Key message • The average capacity credit for wind is higher and more stable than solar in the 2036 scenarios, with solar dropping off rapidly with increasing VRE penetrations. Implementation of measures to promote system flexibility can boost the capacity credit of VRE resources.

VRE deployment can reduce the average cost of electricity generation, even when accounting for integration effects, but the cost of solar and wind in Thailand should be reduced to international benchmarks

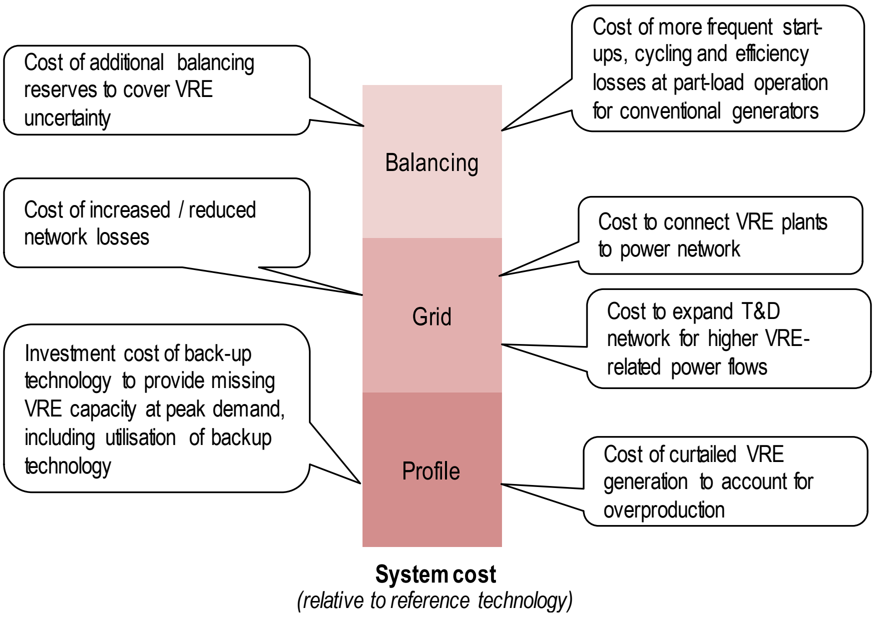
Past investments in power plants in Thailand have exceeded needs for meeting incremental electricity demand. There are a number of possible reasons for this, including overestimated demand projections, underestimation of the impact of energy efficiency, and unexpected structural economic shifts. This means that a least-cost development of the Thai power system over the short term could require very little, if any, additional investment in power generation – renewable or non-renewable. Non-generation alternatives to addressing any local reliability issues (such as expanded transmission) should be considered on an equal footing with generation investments. In order to understand the economic impacts of integrating VRE into a power system, an assessment of its system-level effects is included in the analysis.

Generation costs for various technology options are most commonly expressed in the levelised cost of electricity (LCOE), representing the average lifetime cost for providing a unit of output (MWh). However, the LCOE approach does not account for some important aspects of power generation such as: timing, location, and technical characteristics of the equipment used. Therefore, additional metrics that account for the interactions between these power plants and the rest of the electrical system are employed.

In this analysis, three causes for costs that correspond to specific properties of VRE are defined to measure the economic impact of VRE system integration (Figure ES 7):

- **Profile costs**: the effects associated with the temporal pattern of VRE generation, in particular the non-availability of VRE during periods when demand is close to available generation capacity, possible periods of surplus VRE, and reduction in the utilisation of other power plants.
- **Grid costs:** costs reflect the delivery of VRE to demand, which are associated with transmission constraints and losses, and incurred due to the location of generation in the power system.
- **Balancing cost**: costs associated with short-term uncertainty of VRE generation, which involves deviations from generation schedules, for example, due to VRE forecast errors.

Figure ES 7 • Components considered to quantify system effects of VRE generation relative to a reference technology



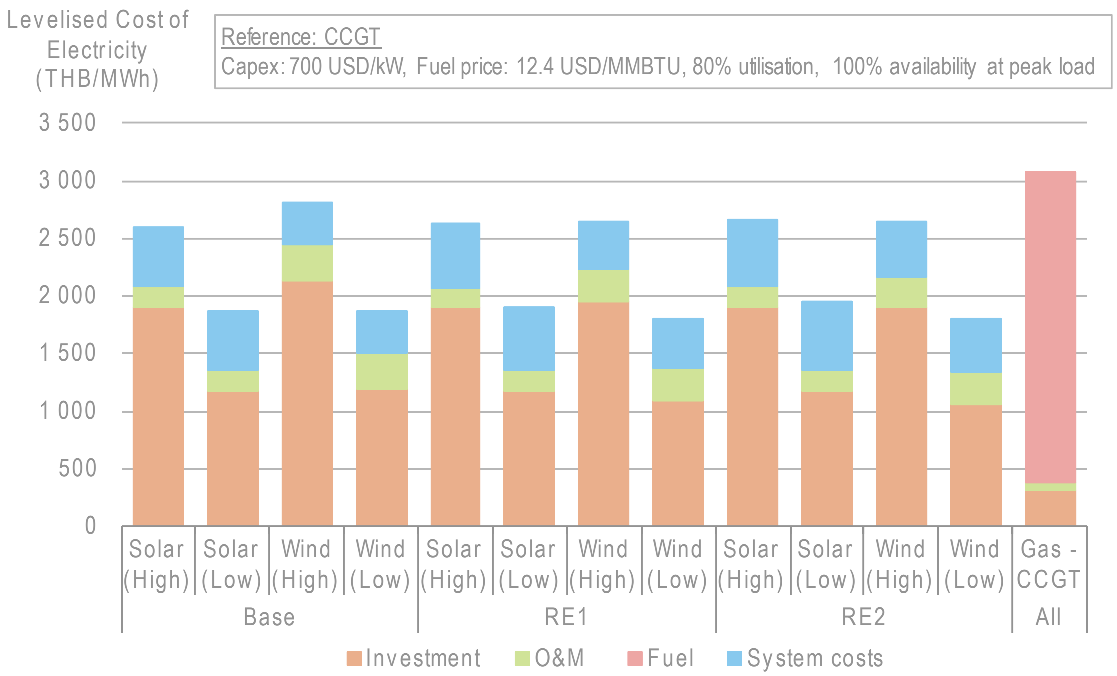
Key message • Profile, grid and balancing costs consider several components relevant for VRE system integration.

The LCOE of VRE electricity is the primary driver of the overall impact of VRE on system costs. Current remuneration levels for RE in Thailand – notably for wind and solar power – appear high compared to international benchmarks. Further analysis is needed to understand the underlying reasons for these cost differences. In any case, competitive mechanisms for price discovery (such as auction schemes) should be prioritised to lower the cost of VRE in the context of Thailand.

In the longer term, a cost-benefit approach was used to compare the total cost of VRE with CCGT and supercritical coal for cases with high and low VRE investment costs. When accounting for system effects, wind and solar PV were found to be cheaper than CCGT in all scenarios, but more expensive than coal. The low VRE investment cost case offers a much larger net savings relative to CCGT and only a small net cost relative to coal (Figure ES 8). Although it is beyond the scope of this analysis, the reduction in carbon dioxide (CO_2) can be illustrated in further analyses.

The total system cost approach finds that with low investment costs, VRE reduces the cost of the overall system in all scenarios due to fuel savings, even without considering any capacity contribution from VRE. This reflects the high level of gas generation in the Thai system. The large cost difference of VRE relative to CCGT found in the system cost and cost-benefit analyses demonstrate a net savings. Inclusion of capacity credit for VRE further increases this net savings.

Figure ES 8 • Comparison of system LCOE in the Base, RE1 and RE2 scenarios for low and high investment costs for renewable energy in 2036



Key message • Even when accounting for integration effects, the cost of new wind and solar plants is below the cost of the reference CCGT, mainly driven by the high fuel costs of the reference CCGT.

An analysis was carried out to determine the cost level for new VRE plants at which adding them brings a net economic benefit to the power system in the short term. Making a number of simplifying assumptions, it was found that the cost of VRE generation would need to fall below approximately 2 250 Thai baht (THB)/MWh (70 USD/MWh) in order to reduce overall cost to consumers. This metric considers the relevant system costs of VRE integration, as described above. The main determinant for this benchmark level is the value of the avoided fuel costs, which are set to the current average spot market price for liquefied natural gas (LNG) imports in Thailand.

Recommendations – Power system planning process and VRE system costs

- ***Adopt a fully integrated planning process***, where VRE capacity expansion is integrated with conventional capacity expansion and transmission grid planning exercises. Feedback loops between different specialised models for each task of the planning analysis is recommended.
- ***Update the methodology which accounts for VRE capacity credit*** to account for effects of a different future load shape, as well as synergies between wind and solar PV deployment.
- ***Compare the cost of VRE in Thailand systematically to international benchmarks***, in order to identify the main differences and cost drivers.
- ***Reduce the contracted price of VRE in Thailand*** by adopting a competitive procurement framework for utility-scale plants (i.e. VRE auctions with long-term PPAs).

1. Introduction

Background of the study

Thailand is experiencing an accelerated uptake of variable renewable energy (VRE),[2] in particular solar photovoltaics (PV), as a result of technology improvement, rapid cost reductions and policy support. With the increase of VRE, both utility-scale and distributed installations, there are growing concerns over the impact of such technologies on the power sector in both the short and long term. While additional VRE deployment can support the achievement of policy objectives such as increased energy security, reduced environmental impacts, and, in some cases, a more cost-effective energy supply, it can also bring challenges. Depending on the amount of deployed capacity and the flexibility of the power system, power systems may face new operational challenges associated with managing the additional variability and uncertainty introduced by VRE generation. These new challenges increase the importance of novel planning and operational practices, as well as of the policy and regulatory mechanisms that account for VRE and enable their integration into the power systems. In addition, in the current context of Thailand, the growth of VRE – in particular, the potential for a rapid uptake of distributed photovoltaics (DPV) – is raising questions about the financial sustainability of the current structure of the electricity sector and the various state-owned enterprises and privately owned power producers that participate in it.

The current trends of VRE growth are reflected in the most recent power sector planning processes in Thailand. In its latest planning cycle (conducted in 2015), the government set a target in the Power Development Plan (PDP) 2015 and Alternative Energy Development Plan (AEDP) 2015 to increase VRE capacity, particularly solar PV and wind, to almost 10 GW by 2036 (PDP, 2015; DEDE, 2015). This is an increase of approximately 7 GW, compared to 2016 capacity levels. Since 2015, Thailand has launched a new planning cycle: the PDP 2015 is under revision, and VRE capacity targets are expected to be revised upwards. At the time of writing, there is still uncertainty regarding the proposed capacity mix and the VRE targets. A revised PDP is expected to be finalised in 2018.

In this context, in July 2017 the Ministry of Energy (MOEN) officially requested the International Energy Agency (IEA) to provide support on the study of the impact of VRE and mitigation strategies under the project entitled "Thailand Grid Renewable Integration Assessment". This publication reports on the results of that project. The project was supported by the Electricity Generating Authority of Thailand (EGAT) in order to assist other government agencies in the energy sector including the Energy Policy and Planning Office (EPPO), the Office of Energy Regulatory Commission (OERC), Department of Alternative Energy Development and Efficiency (DEDE), Metropolitan Electricity Authority (MEA), and the Provincial Electricity Authority (PEA).

[2] VRE includes all variable renewable generation technologies: wind, solar PV, concentrating solar power without thermal storage, and run-of river hydro. Wind and solar PV are the most commonly deployed VRE technologies today and share a number of similarities. Therefore, VRE refers to wind and solar PV in this report unless stated otherwise.

Objectives and scope of project

The primary objectives of this project are to:

- Support the reliable and cost-effective uptake of renewable generation in Thailand by identifying barriers to renewable deployment and expected integration challenges, as well as proposing possible options to address these challenges.
- Provide support by sharing international and regional best practices for integrating VRE resources, drawing upon the IEA's network of international experts.
- Conduct quantitative and qualitative analyses on the expected impact and value of VRE in the power system.
- Facilitate domestic and international dialogue through capacity-building workshops and training.

The principal project results are summarised in this report and cover techno-economic and policy analyses as well as suggestions and recommendations for enhancing the ability of the power system in Thailand to prepare for a future of increasing levels of VRE.

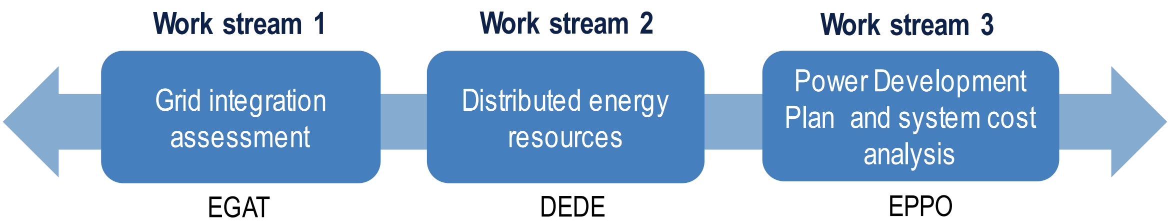
Scope of work and key government stakeholders

The scope of work can be categorised into three main streams:

- **Work stream 1:** grid integration assessment.
- **Work stream 2:** distributed energy resources (DERs).
- **Work stream 3:** Power Development Plan and VRE system cost analysis.

The primary government partner agencies in these areas are EPPO, DEDE and EGAT, respectively. These organisations have also served as the official contact points for the respective work stream (Figure 1.1).

Figure 1.1 • Primary work streams for Thailand Grid Renewable Integration Assessment project



Key message • The three work streams were directly related to the three government agencies (EGAT, DEDE and EPPO) that act as the project reference group.

Work stream 1: Grid Integration assessment

For work stream 1, a detailed simulation of power system operation was conducted, with a focus on the Thai power system in 2036 as the target year of the PDP, while using real 2016 power system data for model validation. The model, which was set up in PLEXOS, simulates the optimal operation of power plants based on detailed techno-economic characteristics and operating constraints at 30-minute intervals for a full year. Large power plants are represented by individual generating units (i.e. at the *sub*-power plant level), while smaller power plants (small power producers [SPPs], very small power producers [VSPPs]) are aggregated by region.

Wind and solar profiles are based on high-resolution modelling analysis conducted on a 15-minute basis at 3 x 3 kilometre (km) geographical resolution over a ten-year period.

The analysis consists of three core scenarios: Base, RE1 and RE2; additional flexibility scenarios were explored to understand the impact of various power flexibility measures and strategies. These flexibility scenarios include contractual and technical flexibility of power plants as well as the role of innovative technology options, including pump storage hydro (PSH), battery-electric vehicles (EV), and demand-side management (DSM). While the Base scenario was designed to reflect the vision for the 2036 power system proposed in the 2015 PDP, the RE1 and RE2 scenarios represent the same system but with increased shares of wind and solar, in which RE2 has the highest wind and solar penetration. These scenarios have been recommended and agreed upon by EGAT, EPPO and DEDE. The analysis concludes with recommendations for relevant operational changes to support VRE integration, as well as a discussion of options to increase system flexibility.

The rationale for the establishment of a renewable energy (RE) control centre and related issues in the context of Thailand are also presented under this work stream. This includes a description of the specific roles and functions of such centres, as well as a potential pathway for establishing an RE control centre in Thailand. International experiences and examples of RE control centres are also provided.

Work stream 2: Distributed energy resources (DER)

Work stream 2 provides deeper insights into the potential for DPV in Thailand, including an estimate of the maximum technical potential via an analysis of total available rooftop area using satellite data. It also provides a multi-stakeholder economic impact assessment of DPV deployment for Thailand, adopting the perspective of EGAT, PEA, MEA and ratepayers, and exploring different future deployment scenarios for DPV. Furthermore, this work stream also examines potential tariff options that may become appropriate as the share of DER increases.

This work stream aims to inform planning processes for the uptake of DERs as well as provide recommendations for tariff and institutional reform.

Work stream 3: Power Development Plan (PDP) and VRE system costs

This work stream was designed to provide a qualitative assessment of the methodologies currently employed for power system planning in Thailand and to provide examples of international best practices relevant for the further evolution of planning processes. Results of this qualitative assessment, presented during the November 2017 interim meeting, are also included in this report.

In order to inform ongoing planning processes, a simplified approximation of the capacity credit of wind and solar, as well as an estimate of VRE system costs, were also conducted. Importantly, it is outside the scope of this project for the IEA to recommend a set of future generation mixes for Thailand. To address this issue, the analysis in this report builds on the latest available official scenario, the 2015 PDP. The analysis estimates the overall additional costs of adding VRE to the Thai power system, including broader system effects that may impact overall customer bills. Some of the scenarios formulated in work stream 1 are used to analyse the total power system cost and cost-benefit analysis presented under this work stream.

Report structure

This document outlines the objectives, scope, methodological approach and analysis results of the project. It also provides a collection of the key findings. Chapter 2 provides an overview of the electricity sector in Thailand. Chapter 3 presents an assessment of the flexibility of the existing power system in Thailand. Chapter 4 provides an overview of the analytical approach and general methodology for each work stream. Chapter 5-7 present main findings of the three project work streams. Chapter 8 concludes by presenting key findings and providing recommendations from both public policy and operational perspectives in the context of Thailand.

The annexes (A-E)[3] provide details on:

- Annex A: the concept of the phases of VRE integration and the timescales of system flexibility
- Annex B: an overview of the methodology used to produce wind and solar resource data across Thailand.
- Annex C: detailed methodology of the three work streams
- Annex D: additional results
- Annex E: production cost model validation.

References

EPPO (Energy Policy and Planning office) (2015), *Thailand Power Development Plan 2015 -2036: PDP2015*, Thailand Ministry of Energy.

DEDE (Department of Alternative Energy Development and Efficiency) (2015), *Alternative Energy Development Plan: AEDP2015*, DEDE, Thailand Ministry of Energy.

[3] The annexes are available upon official request. They are not included in the report.

2. Thailand's power system: Background and context

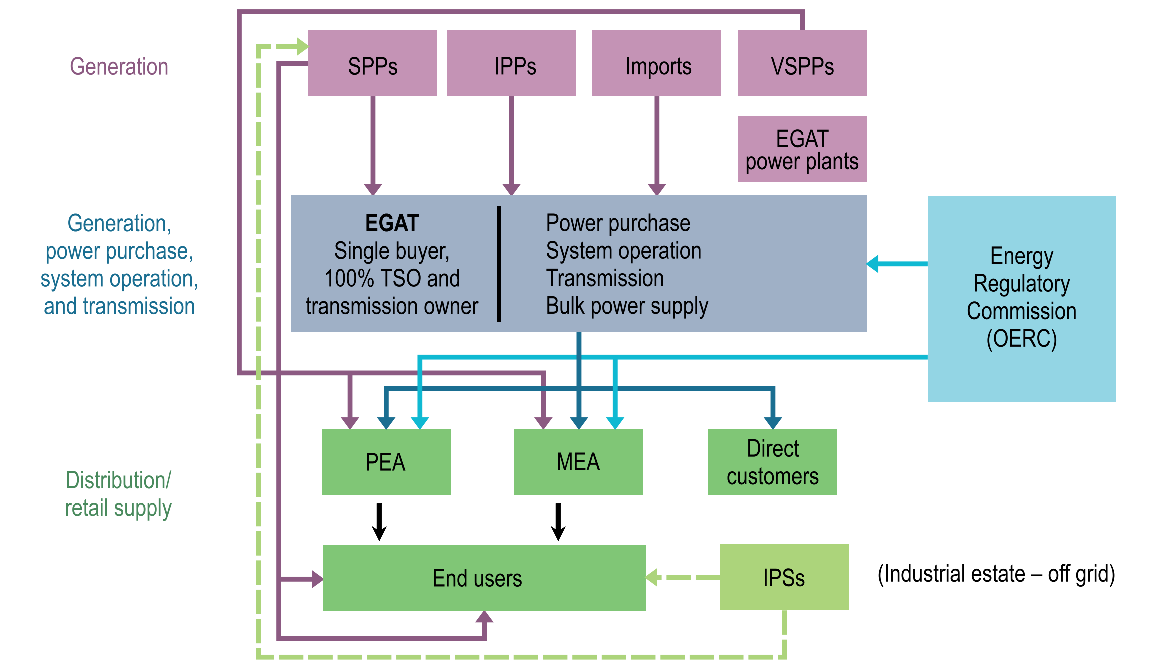
This chapter provides an overview of the power system in Thailand. It introduces institutional, operational and regulatory aspects covering generation, transmission, distribution and retail activities. An overview of power sector planning and the existing renewable energy (RE) targets are also provided, alongside information on current retail electricity tariffs.

Institutional arrangements in the power sector

Thailand's electricity industry is structured under an "Enhanced Single Buyer Model". Under the model, the government-owned Electricity Generating Authority of Thailand (EGAT) is responsible for transmission system operation and electricity generation. EGAT also acts as the single buyer, purchasing bulk electricity from private power producers, which consist of independent power producers (IPPs), small power producers (SPPs), and neighbouring countries. IPPs are generators connected to the EGAT transmission network that have a committed capacity greater than 90 megawatts (MW), whereas SPPs are those that have committed capacity greater than 10 MW but not more than 90 MW.

As a single buyer, EGAT sells wholesale electricity to two distribution utilities, Metropolitan Electricity Authority (MEA) and Provincial Electricity Authority (PEA), as well as a small number of direct industrial customers and neighbouring utilities (Figure 2.1). MEA is responsible for power supply to Bangkok and metropolitan areas, whereas PEA is responsible for the remainder of the country. Generators that are connected to MEA and PEA systems are called "very small power producers (VSPPs)", which have capacity equal to or less than 10 MW.

Figure 2.1 • Contractual arrangements in Thailand's power sector



Note: TSO = transmission system operator; IPSs = independent power supply.

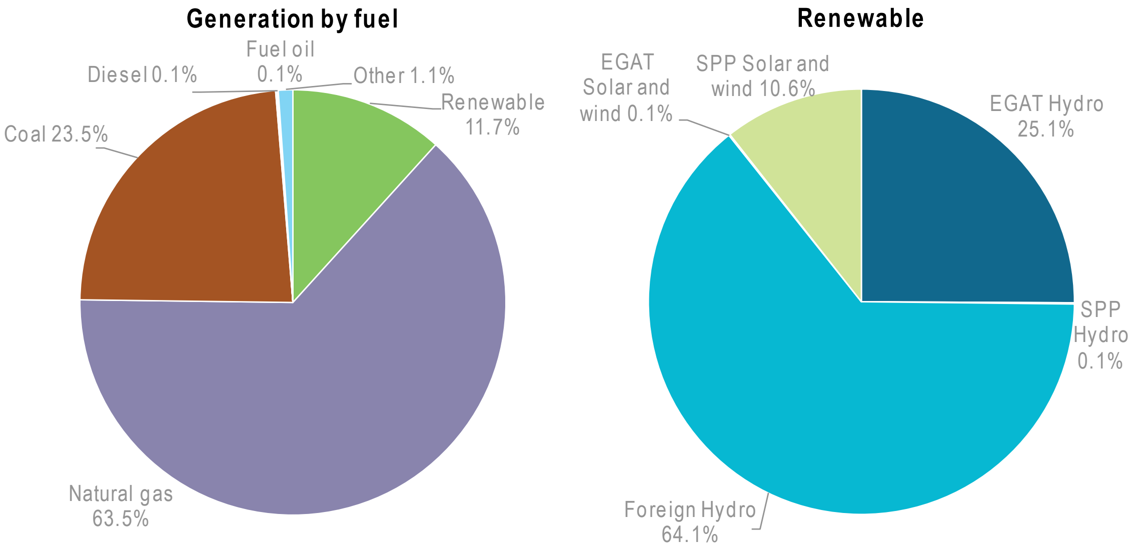
Sources: Adapted from EGAT (2018), "Renewable Energy Integration in Thailand Current Status and Challenges", presentation at the IEA Grid Integration of Variable Renewables Advisory Group (GIVAR) meeting, June 2018.

Key message • There are a number of contractual and financial relationships between participants in Thailand's "Enhanced Single Buyer Model".

Generation and transmission sectors

The major fuel types utilised for electricity generation in Thailand in 2017 were natural gas, which accounted for approximately 65% of total generation, and coal at approximately 20% of generation. Renewable energy contributed 12% of generation in 2017, which was predominantly hydropower. Hydropower consists of both foreign imports from Lao People's Democratic Republic (PDR) and EGAT's hydropower power plants (Figure 2.2). Solar and wind generation accounted for the relatively small share of renewable generation at 10%.

Figure 2.2 • System generation (energy) mix by fuel type, 2017



Note: System generation includes imports from neighbouring countries.

Source: EGAT (2018), "Renewable Energy Integration in Thailand Current Status and Challenges", presentation at the IEA Grid Integration of Variable Renewables Advisory Group (GIVAR) meeting, June 2018.

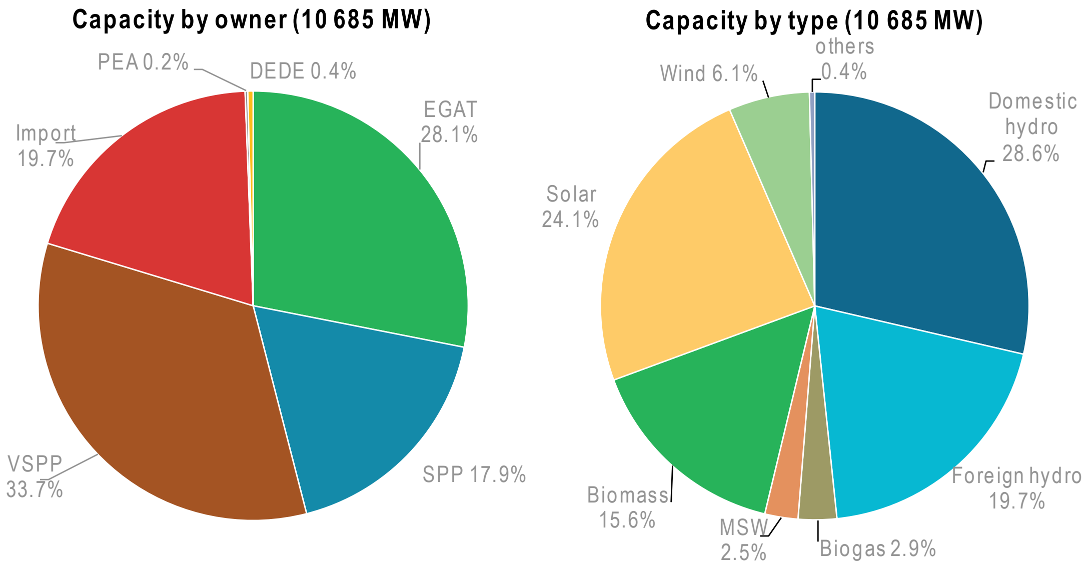
Key message • Thailand's generation mix is dominated by gas-fired generation.

In terms of renewable generation capacity (MW) in Thailand, the total installed capacity in 2017 was approximately 10 gigawatts (GW) (Figure 2.3). The share of capacity was mostly hydropower, both domestic and foreign, which accounted for around 50%. The share of solar and wind generation capacity was around 30%.

The high voltage transmission networks (500 kilovolts [kV] and 230 kV) are owned and operated by EGAT. The primary 500 kV transmission lines carry bulk electricity from generation sources located in the north, north-east, east and west to the major demand centres in Bangkok and the metropolitan and central areas (Figure 2.4). The 230 kV lines have the highest aggregate transformer capacity, whereas the 500 kV transmission circuits represent around 30% of total transformer capacity (Table 2.1). In addition, EGAT also operates 115 kV transmission lines as well as a very small number of 69 kV lines.

Thailand also imports a significant amount of electricity from Lao PDR via 230-kV and 500-kV transmission lines, from both hydropower and coal-fired power plants contracted under power purchase agreements. Moreover, there is a high-voltage direct current (HVDC) connection with Malaysia in the southern part of Thailand with a capacity of 300 MW. This HVDC interconnection not only provides energy exchanges but has also been set to automatically provide response in the events of low frequency (from 49.75 Hz).

Figure 2.3 • Renewable generation capacity in Thailand, 2017



Note: DEDE = Department of Alternative Energy Development and Efficiency; MSW = municipal solid waste.

Source: EGAT (2018), "Renewable Energy Integration in Thailand Current Status and Challenges", presentation at the IEA GIVAR meeting, June 2018.

Key message • The majority of available renewable generation capacity in Thailand is hydropower. The share of solar and wind capacity is already significant, and it is expected to increase in the coming years.

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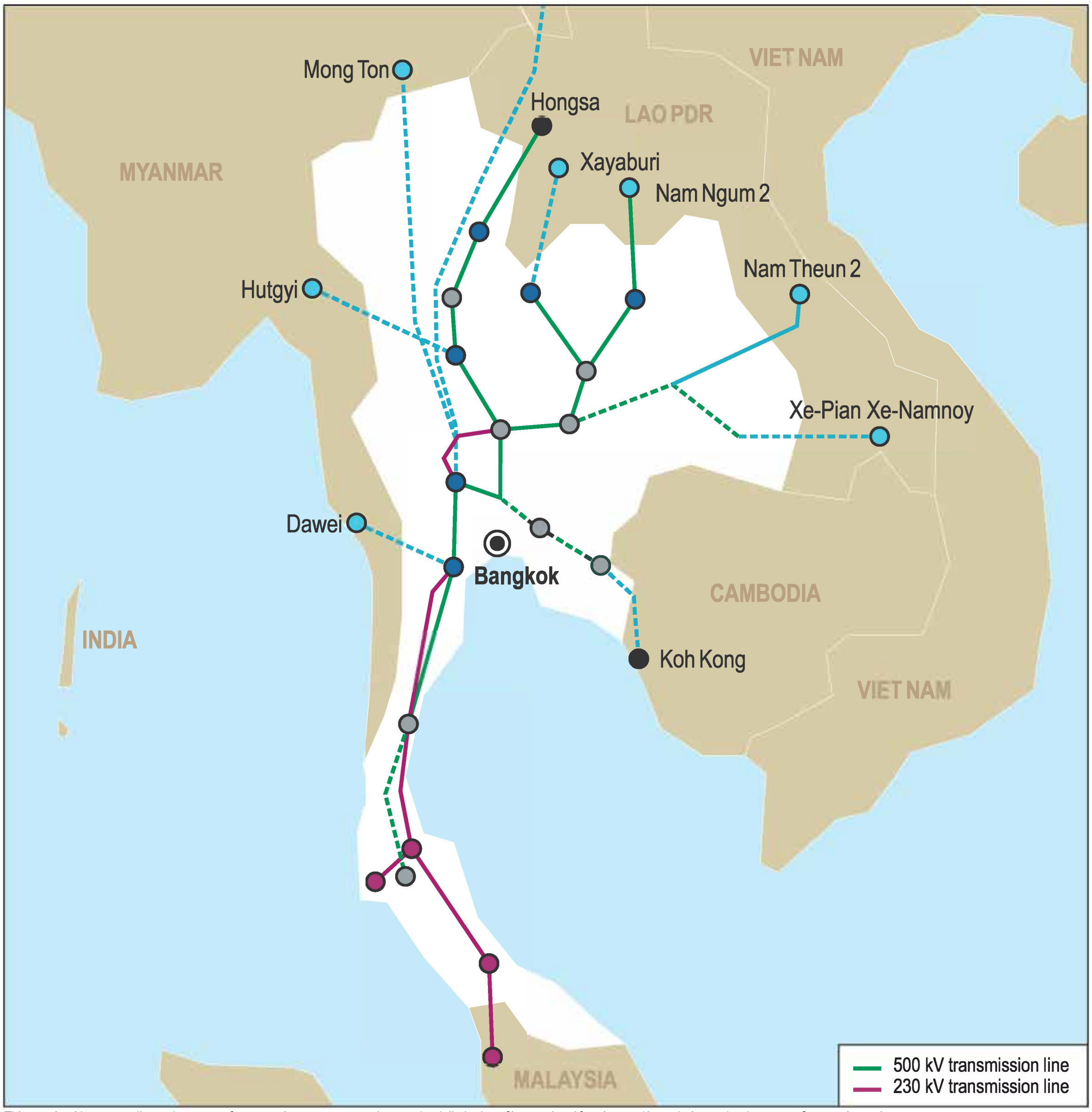
In general, Thailand's transmission grid appears to be relatively robust and reliable. Multiple transmission circuits supply the major load centres in different regions, particularly in the central and metropolitan areas. The transmission grid, therefore, has the potential to be an important flexibility resource as the share of solar and wind generation increases. However, the extent to which the transmission grid will be useful to support variable renewable energy (VRE) integration will also depend on the region, each of which has different resources and infrastructure, and future generation and transmission plans to achieve cost-effectiveness while maintaining system reliability (see Chapter 7 for detail).

Figure 2.4 • An overview of Thailand's main transmission system



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Note: Green dashed line = uncommitted plan for cross-border interconnection.

Source: Updated from IEA (2016), Thailand Electricity Security Assessment 2016.

Key message • Thailand's transmission grid is relatively robust.

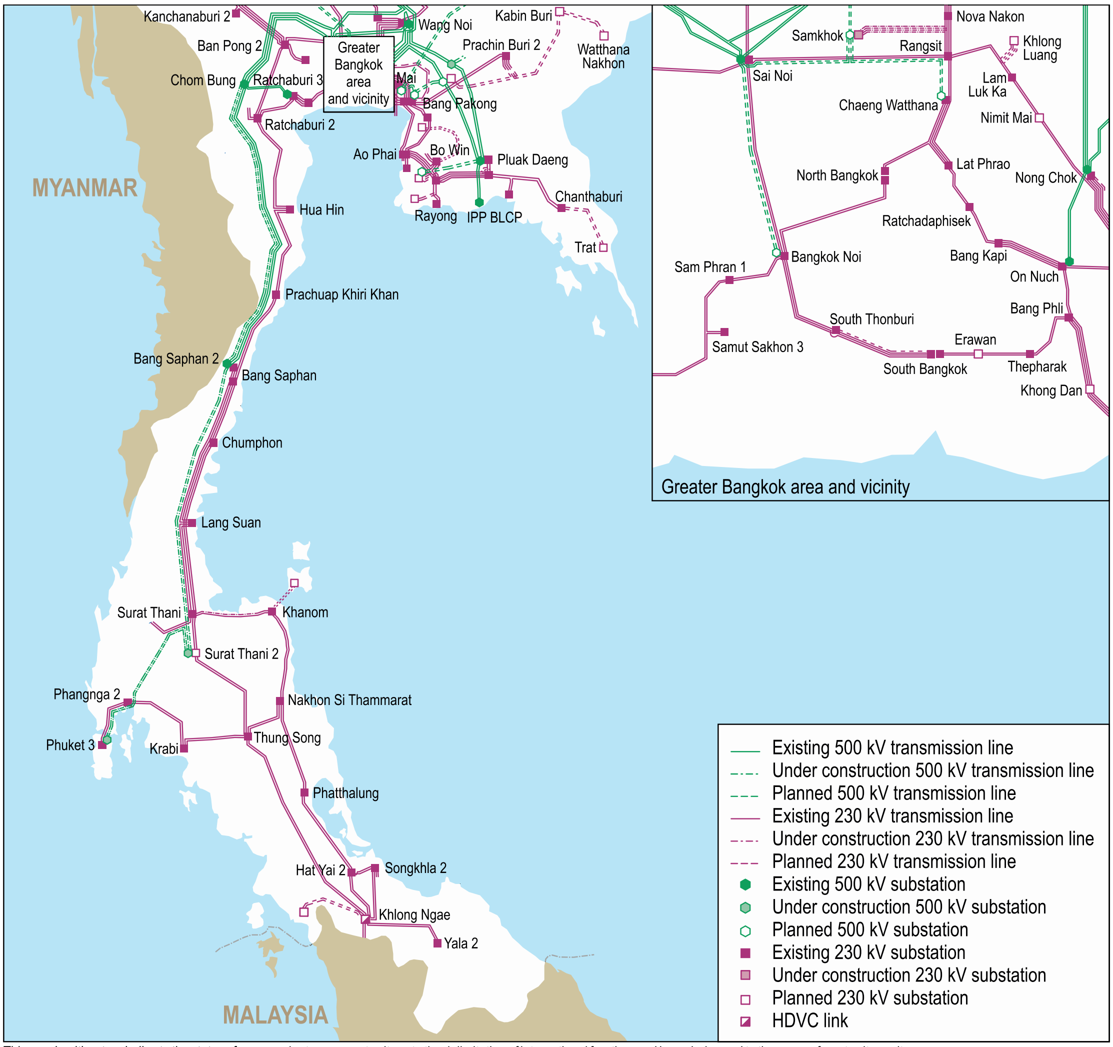
Table 2.1 • Thailand's transmission system

Voltage level (kV)	Line length (circuit-km)	%	Number of substations	%	Transformer capacity (MVA)	%
500	5 892 022	17.6	18	8.04	35 199.75	31.85
300 (HVDC)	23 066	0.07	-	-	38.02	0.35
230	14 500 256	43.3	79	35.27	60 100.01	54.38
132	8 705	0.02	-	-	133.4	0.12
115	13 041 428	38.95	127	56.95	14 693.16	13.3
69	18 800	0.06	-	-	-	-

Note: km = kilometre; MVA = megavolt-amp.

The southern region of Thailand is perhaps the most challenging region for maintaining reliable system operation and stability, owing largely to its partly electrically isolated geography, which only allows for radial connections with the central regions without the possibility to connect to other regions. The transmission lines connecting with the central regions play a significant role in maintaining system stability and security (Figure 2.5). This was in evidence in 2013 during a blackout event in the southern region of Thailand during an evening peak-demand period. The blackout was a result of a several issues, including the unplanned outage of a circuit of the central-south 500-kV transmission line, faults on another circuit, and a malfunction of the protection scheme of the HVDC interconnector with the Malaysian system. A number of technical options and operational practices have since been implemented to further strengthen the reliability and security of the system and to reduce the risk of contingency events. These include the implementation of transmission flow limits based on the in-depth stability analysis with N-1 criteria, as well as the deployment of special protection schemes, load-shedding schemes, and high-voltage transmission devices such as static VAR compensators (SVCs) and shunt capacity at a number of substations.

Figure 2.5 • Detailed schematic of Thailand's transmission network in the southern region



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: Adapted from EGAT (2017), Thailand Transmission Map

Key message • The partly electrically isolated southern region is the most challenging area of the Thai transmission system in which to ensure reliable operation.

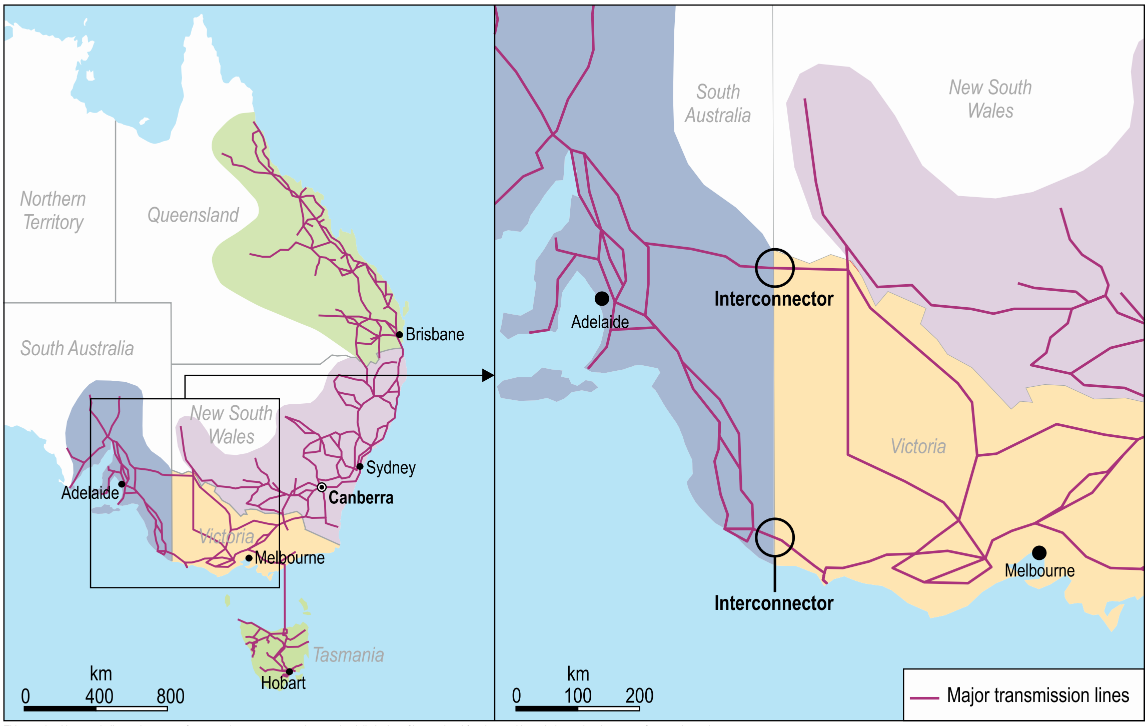
Box 1.1 • South Australia's 2016 blackout event

The southern region of Thailand is rather similar to South Australia in the Australian National Electricity Market (NEM), which relies on the interconnectors to Victoria as one of the factors with which to maintain the stability of the system (Figure 2.6). A state-wide blackout also recently occurred in South Australia, owing to extreme circumstances that included severe weather conditions, which caused multiple transmission line faults; voltage dips; significant reductions in generation output; and an increase in imported power from Victoria, which activated a special protection scheme that tripped the interconnector offline.

Wind generation, which had the highest share of generation at the time, successfully rode through grid disturbances, based on the operational criteria specified in the grid code. However, the control settings of the wind turbines in the event of *multiple* disturbances created certain challenges during this situation. See the final Australian Energy Market Operator (AEMO) report of the event for additional detail (AEMO, 2017).

As VRE capacity increases in the southern region of Thailand, there are a variety of specific measures that could be taken to ensure reliability, with many lessons learned available from South Australia.

Figure 2.6 • Regional boundaries for the Australian National Electricity Market (NEM) (left) and zoom in for South Australian and Victoria (right)



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: Adapted from AEMO (2016), *Regional Boundaries for the National Electricity Market.*

Note: Tasmania is not included in the map.

Key message • Interconnectors between South Australia and Victoria play an important role in ensuring system security and stability.

Power sector planning and current renewable energy targets

Thailand's power sector planning is part of the Thailand Integrated Energy Blueprint (TIEB) 2015-36, which includes the Power Development Plan (PDP), Alternative Energy Development Plan (AEDP), Energy Efficiency Plan (EEP), and oil and gas plans (Figure 2.7). The plans are set in accordance with the National Economic and Social Development Plan (NESDP).

Figure 2.7 • Thailand Integrated Energy Blueprint (TIEB) for 2015-36

	Description	Impact
Energy Efficiency	• **Remove subsidies** to convey market price signal • **Accelerate EE execution** via benchmarking, accountability and enforcement	• Achieve 30% **energy intensity reduction** (vs. 0.5% p.a. increase over last 10 years)
Conventional power (PDP)	• **Rebalance power mix** with clean coal technology deployment for half of all new thermal plants	• Reach **30% coal in power mix** vs. 20% today • **20% clean coal** vs. only normal coal today
Renewables (AEDP)	• **Three-pronged approach for cost effective scale up of renewables:** - Drive: Biomass and waste - Pace: Solar - Monitor: Wind	• **Achieve cost < LNG** parity for 20% RES share in power mix (vs. ~8% today)
Biofuels (AEDP)	• **Improve yield** to limit imports and benefit rural community	• **~20% substitution in transport** (vs. 4% today) • Up to THB 50 Bln/y GDP impact
Oil and Gas	• **Counter production decline** with E&P activity stimulus policies ("Reimagine Gulf of Thailand")	• Limit domestic gas **decline rate at ~2-5%** p.a. (vs.-11% BAU)

Source: EPPO (2015), *Overview of Thailand Integrated Energy Blueprint.*

Note: BAU = business as usual; E&P = exploration and production; EE = energy efficiency; GDP = gross domestic product; LNG = liquefied natural gas; and THB = Thai Baht.

Key message • Thailand's energy plans consist of five key areas that are developed in conjunction with one another, particularly PDP, AEDP and EEP.

With greater volatility of energy commodity prices, a rising concern over energy security, and the increasingly compelling cases made for renewables, the dynamics shaping the energy policy landscape in Thailand have evolved rapidly. The primary objectives of national energy policies are centred on enhancing the country's energy security by diversifying the energy mix and strengthening the supply of diminishing fossil fuels, while keeping energy prices at affordable rates and minimising the adverse impacts of energy production and consumption on the environment and society.

With respect to power sector planning, this task largely falls under the PDP while the RE targets are developed in the AEDP. As a rule, the PDP is developed in conjunction with the AEDP and EEP in order to ensure that these plans align and are consistent with the overall objectives of the nation in terms of energy security, costs and environment.

There have been many efforts to make PDP, AEDP and EEP as integrated as possible. For example, the RE target established in the AEDP was based on the electricity demand, heat, and biofuel demand forecast, which would make the total share of RE in 2036 approximately 30% (DEDE, 2015). The AEDP not only includes a requirement on planning exercises to achieve a 30% share of renewables, but also specific carve-outs for different RE technologies. Although AEDP 2015 is one of the measures for Thailand to deliver its pledge of reducing greenhouse gas emissions, a closer harmonisation of climate and energy policies could help realise their interrelated objectives.

For electricity, the RE target was set based on an assessment of fuel potential and the ability of the Thai electricity system to integrate RE resources. According to the AEDP, the factors that have been taken into consideration include an electricity demand forecast, the capacity of transmission lines (existing and planned to be commissioned by 2024), a merit order based on levelised cost of electricity (LCOE), and RE zoning. The RE target for electricity is set at 20% of installed capacity by 2036, with solar being the largest RE resource (Table 2.2). Notably, the RE target is expected to increase in the upcoming PDP.

Based on the 2036 RE targets, the expected annual installed RE generation capacity is assumed to be constantly increasing from 2017-36 (Figure 2.8). With this approach, there were no official targets in the short or medium terms, which might provide a benchmark to assess progress in achieving the longer-term 2036 targets.

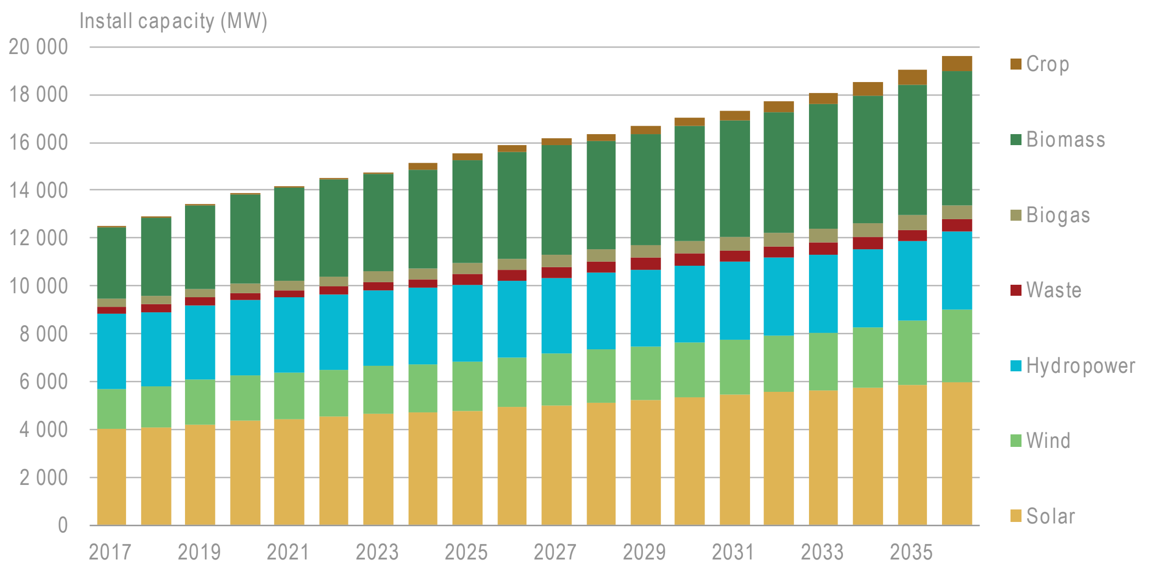
Table 2.2 • Current RE status and 2036 targets by fuel types

Fuel type	Solar	Wind	Hydro	Waste	Biogas	Biomass	Crop	TOTAL (MW)	Share of capacity (%)
Capacity in 2014 (MW)	1 298.5	224.5	3 048.4	65.7	311.5	2 514.8	-	**7 490.4**	**9.9%**
Target at 2036 (MW)	6 000.0	3 002.0	3 282.4	500.0	600.0	5570.0	680.0	**19 634.4**	**20%**

Note: *Hydropower* includes both large and small hydropower facilities. *Waste* includes municipal solid waste (MSW) and industrial waste.

Sources: DEDE (2015), *Alternative Energy Development Plan: AEDP2015.*

Figure 2.8 • Thailand's RE targets by fuel types, 2017-36



Source: DEDE (2015), *Alternative Energy Development Plan: AEDP 2015.*

Key message • Thailand's RE installed capacity is expected to constantly increase in the next 15-20 years.

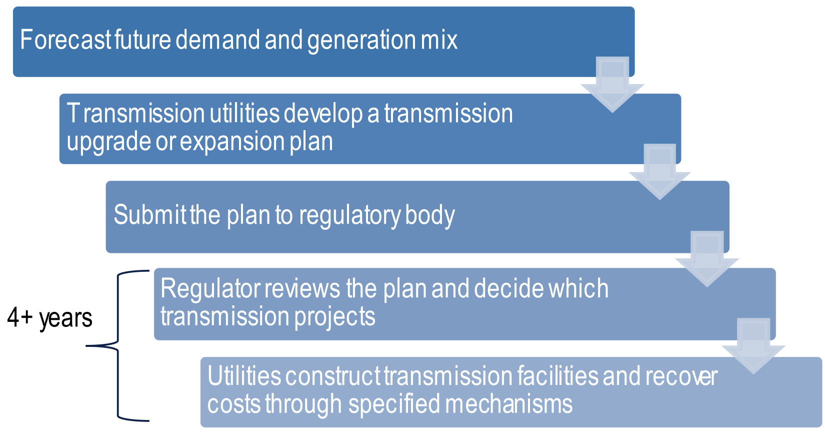
With the global energy landscape becoming increasingly complex amid the ongoing energy transition, any energy-related plan should consider adopting a certain level of flexibility in its approach in order to adapt to fast-changing circumstances, but, more importantly, it should align itself as much as possible with key high-level political objectives and agendas at national, regional and international levels. This would require the regular and periodic updating of the AEDP to adjust the direction and pace of alternative energy deployment.

The approach for site selection and zoning in the AEDP, which is an important factor as the share of VRE increases, was based on the merit order of RE technologies, the demand in the area under consideration, and the limitations of the transmission system. This approach assigns an amount of capacity of each RE technology in each zone. However, this RE zoning process did not account for several important factors, including the transmission planning in the PDP. This could potentially result in network congestion and reduce the confidence of RE project developers (see Chapter 7 for more detailed discussion).

As stipulated in PDP 2015, EGAT has the obligation to purchase all the electricity generated from RE sources. This requires EGAT to upgrade and expand its transmission networks to ensure they are capable of accommodating a growing share of VRE from, for instance, solar and wind. This is particularly relevant for the central, southern, north-eastern and northern regions. The plan was based on a grid stability assessment and the development of RE development zones, in connection with the plan for transmission expansion. However, with regard to the zoning practice, it appears that the planning process gave priority to biomass while other RE sources were built into the plan based on the biomass-centric modelling results. This approach misses the optimisation of different types of RE sources, notably wind and solar, due to their potential complementarity, and matching with load profiles. In addition, the grid stability study was conducted based on the existing and planned conventional generators and transmission grid data, but did not holistically consider VRE. Although the PDP, AEDP and EEP appear to be integrated to determine the RE targets, there are some outstanding issues pertaining to methodological consistency and to the sequential approach which links the plans. Potential steps to further improve and integrate Thailand's power sector planning processes are explained in Chapter 7.

With respect to transmission planning, the process in Thailand is still based on a traditional cost-based approach where the transmission plan has to be approved by the regulatory body, a process that can take several years (Figure 2.9).

Figure 2.9 • Generalised schematic of traditional transmission planning process



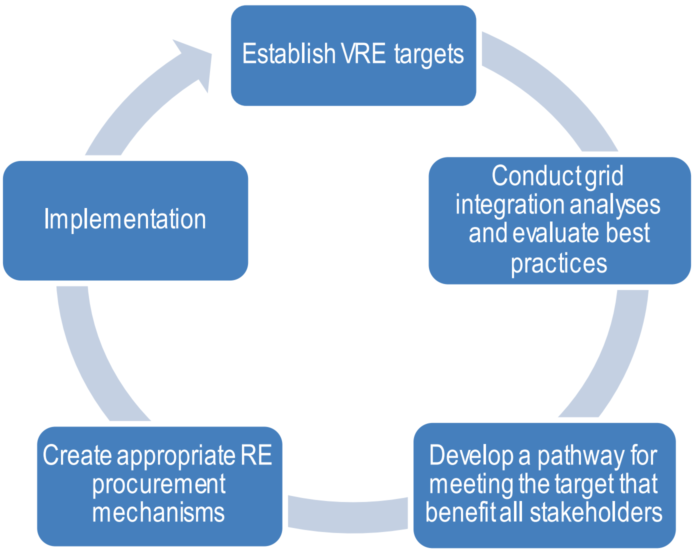
Key message • Traditional grid planning approaches have long lead times and are not fully integrated with generation developments, especially at rising shares of VRE.

Transmission planners faces a challenging situation as VRE penetrations increase in power systems. This is primarily because VRE projects can be developed relatively quickly compared to transmission infrastructure. As a result, transmission congestion and VRE curtailment can result from the over-development of VRE in some areas. This problem has already occurred in countries such as Brazil, Chile and the People's Republic of China (IEA 2017a; IEA 2017b).

With respect to setting VRE targets, improving the current approach used by the DEDE, EPPO and EGAT would require greater collaboration from all electric utilities including MEA and PEA. Although the existing approach adopted by the EPPO and DEDE takes into consideration the transmission network, they do not consider operational issues relating to the system flexibility or the deployment of specific flexibility measures, which are important as the share of VRE increases.

In this context, long-term planning and VRE target-setting exercises should ideally involve grid integration analyses (i.e. production cost modelling) (Figure 2.10). Such grid analytics will become increasingly important as both an operational "real-time" tool and in support of long-term planning. By considering grid integration aspects, planners can help to successfully integrate VRE while maintaining the stability and security of the power system. Grid integration analysis using production cost modelling for the year 2036 is one of the key components of this report, and it is presented in detail in Chapter 5. A more holistic approach to RE target setting – including RE zoning and the assessment of the existing PDP – is described in additional detail in Chapter 7.

Figure 2.10 • Process which involves grid integration studies for VRE target setting



Source: Adapted from GTG (2015), *Scaling up Renewable Energy Generation: Aligning Targets and Incentives with Grid Integration Considerations*.

Key message • Grid integration studies can help increase stakeholder confidence in the capacity of the power system to meet high RE targets.

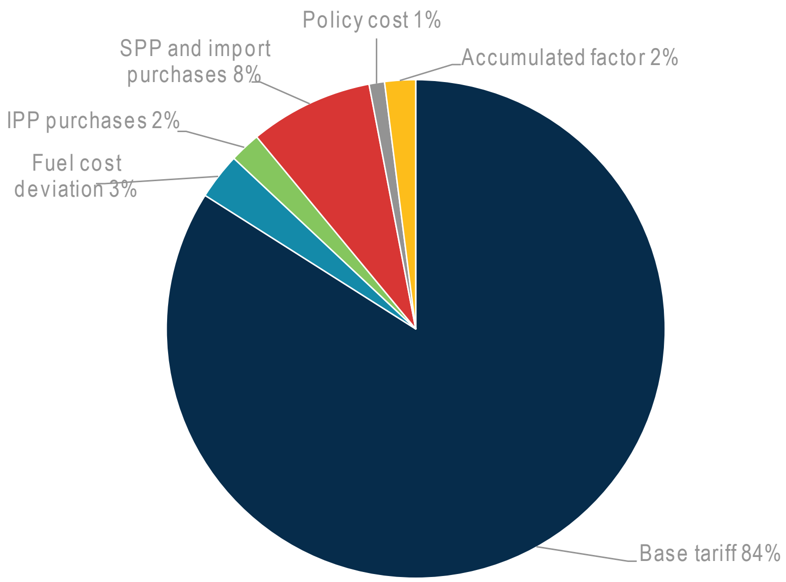
Distribution and retail sectors

MEA and PEA operate the distribution network and are in charge of selling electricity to retail consumers. These entities purchase electricity from EGAT at a regulated wholesale price that is same regardless of location. MEA and PEA have been under an obligation to purchase VSPP output at technology-specific feed-in tariffs (FiTs).

Retail tariffs in Thailand are designed to collect two broad components of power system costs: a base cost component (known as the "Base Tariff"), which is updated every three to five years, and a "variable" component, which is updated every four months (known as the "F_t"). The base cost component comprises fixed costs associated with generation, transmission and distribution, as well as an estimate of expected variable costs for the rate period. The variable component includes deviations in fuel costs from the *ex-ante* estimate in the Base Tariff; purchases from IPPs, SPPs and VSPPs; and policy expenses. The latter encompasses costs for the Power Development Fund, a cross-subsidy mechanism between utilities primarily aimed at redistributing income from EGAT and MEA to PEA. This cross-subsidy occurs because Thailand has a uniform retail tariff policy, meaning that retail tariffs remain equal across the country for a given customer class (i.e. MEA and PEA tariffs are equal). A breakdown of regulated power system cost components can be seen below in Figure 2.11.

Thai utility revenues are determined by rate-of-return regulation, which is reflected on the base component of the tariff. This part includes EGAT's total costs for generation and transmission, MEA and PEA's distribution and retail expansion cost, as well as operations and maintenance (O&M) costs, and return on invested capital (ROIC) of the three network owning entities.

Figure 2.11 • Retail rate cost components



Source: OERC (2014), "Thailand's Electricity Tariffs and Cross Subsidy between Urban and Rural Supply", pubs.naruc.org/pub.cfm?id=538EC127-2354-D714-51A4-37854F6F28FC

Key message • Thailand's power system cost components are mostly contained within the Base Tariff.

At present, Thailand has eight regulated retail tariff schedules with different subcategories: Residential Customers, Small General Service (SGS), Medium General Service (MGS), Large General Service (LGS), Specific Business Service, Non-Profit Organization, Agricultural Pumping, and Temporary Service. A special additional schedule for electric vehicle (EV) charging was introduced on 11 November 2017. As mentioned earlier, these retail tariffs are uniform across the country. Additionally, tariffs schedules are defined by a customer's normal monthly consumption. The tariff schedules are provided below (Table 2.3. and Table 2.4). Retail tariffs are discussed in more detail in Chapter 6 on DPV.

Table 2.3 • Tariff schedule

Residential Customers									
Normal under 150kWh/month			Normal above 150 kWh/month			Time of Use Tariff			
Min kWh	Max kWh	THB/kWh	Min kWh	Max kWh	THB/kWh	Voltage	Energy on-peak THB/kWh	Energy off-peak THB/kWh	service charge THB/month
0	15	2.35	0	150	3.25	< 12 kV	5.8	2.64	38.22
16	25	2.99	151	400	4.22	12 - 24 kV	5.11	2.6	312.24
26	35	3.24	400		4.42				
36	100	3.62							
101	150	3.72							
151	400	4.22							
400		4.42							
Fixed monthly charge THB/month		8.19	Fixed monthly charge THB/month		38.22				

Small General Service							
Normal rate			Time of Use Tariff				
Voltage	Energy charge THB/kWh	Service charge THB/month	Voltage	Energy on-peak THB/kWh	Energy off-peak THB/kWh	service charge THB/month	
At voltage under 12 kV			<22 kV	5.8	2.64	312.24	
First 150 kWh	3.25	46.16	22-33 kV	5.11	2.6	46.16	
Next 250 kWh	4.22	46.16					
At voltage 12 -24 kV	3.91	312.24					

Medium General Service							
Normal rate				Time of Use Tariff			
Voltage	Demand charge THB/kW	Energy charge THB/kWh	Service charge THB/month	Demand charge THB/kW	Energy on-peak THB/kWh	Energy off-peak THB/kWh	Service charge THB/month
<12 kV	221.5	3.2	312.24	210	4.36	2.66	312.24
12-24kV	196.26	3.17	312.24	132.93	4.21	2.63	312.24
>69 kV	175.7	3.14	312.24	74.14	4.13	2.61	312.24

Large General Service								
Time of Day Rate					Time of Use Tariff			
Voltage	Demand Peak THB/kW	Demand partial THB/kW	Energy charge THB/kWh	Service charge THB/month	Demand charge THB/kW	Energy on-peak THB/kWh	Energy off-peak THB/kWh	Service charge THB/month
<12 kV	332.71	68.22	3.2	312.24	210	4.36	2.66	312.24
12 -24 kV	285.05	58.88	3.17	312.24	132.93	4.21	2.63	312.24
>69 kV	224.3	29.91	3.14	312.24	74.14	4.13	2.61	312.24

Specific business service								
During meter installation				Time of Use Tariff				
Voltage	Demand charge THB/kW	Energy charge THB/kWh	Service charge THB/month	Voltage	Demand charge per kW	Energy on-peak THB/kWh	Energy off-peak THB/kWh	Service charge THB/month
<22 kV	276.64	3.2	312.24	< 12 kV	210	4.36	2.66	312.24
22-33kV	256.07	3.17	312.24	12 -24 kV	132.93	4.21	2.63	312.24
>69 kV	220.56	3.14	312.24	> 69kV	74.14	4.13	2.61	312.24

Non-Profit organisation								
Normal Rate				Time of Use Tariff				
Voltage		Energy charge THB/kWh	Service charge THB/month	Voltage	Demand charge per kW	Energy on-peak THB/kWh	Energy off-peak THB/kWh	Service charge THB/month
<12 kV				<12 kV	210	4.36	2.66	312.24
	0 - 10 kWh	2.83	20					
	11 kWh and over	3.92	20					
12 -24 kV		3.61	312.91	12 -24 kV	132.93	4.21	2.63	312.24
> 69kV		3.44	312.91	>69 kV	74.14	4.13	2.61	312.24

Agricultural Pumping							
Normal Rate			Time of Use Tariff				
Consumption	Energy charge THB/kWh	Service charge THB/month	Voltage	Demand charge per kW	Energy on-peak THB/kWh	Energy off-peak THB/kWh	Service Charge THB/month
0 - 100 kWh	2.09	115.16	<22 kV	210	4.33	2.64	228.17
101 kWh and over	3.24	115.16	22-33 kV	132.93	4.18	2.6	228.17

Temporary Service		EV-Charging				
Normal Rate		Time of Use Tariff				
	Energy charge THB/kWh	Voltage	Demand charge per kW	Energy on-peak THB/kWh	Energy off-peak THB/kWh	Service charge THB/month
At any voltage level	6.83	<22 kV	210	4.32	2.63	312.24
		22-33kV	132.93	4.18	2.6	312.24
		>69 kV	74.14	4.1	2.58	312.24

Source: BOI (2018), Utility costs, www.boi.go.th/index.php?page=utility_costs

Table 2.4 • Windows for time of use pricing

For all tariff schedules, excluding Large General Service	Large General Service – schedule 7
On-peak	**Peak**
09:00–22:00 on Mon-Fri and Royal Ploughing Day (RPD)	18:30–21:30 every day
Off-peak	**Partial**
22:00–09:00 on Mon-Fri and RPD	08.00–18:30 every day (Demand charge considers only the excess demand over peak recorded on peak period)
	Off Peak
0 to 24 Weekends, National Holidays (except compensation holidays), Labour Day and if RPD falls on weekend.	21:30–08:00 every day

Source: BOI (2018), Utility costs, www.boi.go.th/index.php?page=utility_costs

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3. Grid integration context of the existing power system in Thailand

HIGHLIGHTS

- In the Association of Southeast Asian Nations (ASEAN) region, Thailand is the most advanced country in terms of variable renewable energy (VRE) penetration as well as the development of grid infrastructure, advanced operational practices, and deployment of other flexibility options.
- The annual energy penetration of VRE in Thailand is less than 4%, and VRE generation is increasingly noticeable to the system operators. Based on previous International Energy Agency (IEA) analysis (IEA, 2017a), which has identified different phases of VRE integration differentiated by the impact VRE has on power system operation, Thailand is considered to be approaching Phase 2 of VRE integration.
- The current power system in Thailand has a mixture of flexibility and inflexibility attributes. Thailand's generation fleet appears to be quite technically flexible in nature, given a moderate share of hydropower resources and a high share of combined-cycle gas turbine (CCGT) resources, combined with an overall large reserve margin.
- The operating characteristics of CCGT and coal-fired power plants – particularly minimum generation levels, ramp rates, and start-up times – suggest that the current fleet's flexibility could be significantly enhanced.
- Current power purchase agreements (PPAs) and fossil fuel procurement contracts prevent dispatchable generators in Thailand from operating more flexibly.
- At present, there are several grid codes for the power system in Thailand, established separately by the transmission and distribution utilities (EGAT, MEA and PEA). Development and implementation of a harmonised code could help to facilitate a more cost-effective and reliable VRE integration.
- Thailand does not currently have a dedicated control centre for renewable energy (RE). Expediting the establishment of a RE control centre would enhance visibility and controllability of VRE in the current context in Thailand.

This chapter provides a conceptual overview and discussion of VRE grid integration in the context of the existing power system in Thailand. The grid connection codes in use in Thailand are summarised with recommendations for changes as the level of VRE increases. In addition, this chapter discusses the potential roles and functions of a prospective RE control centre in Thailand.

Grid integration context of the existing Thailand's power system

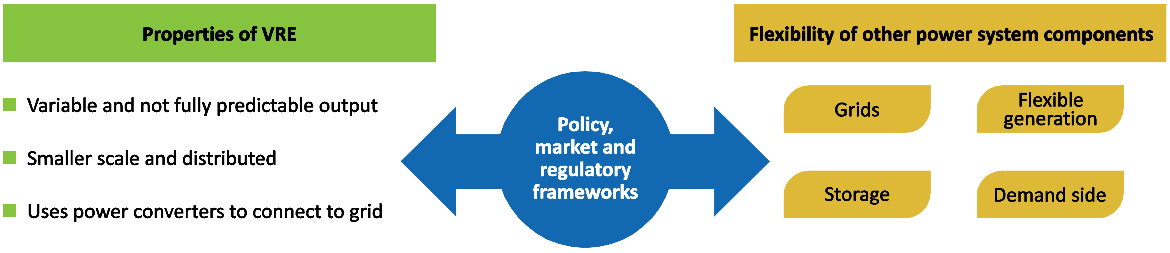
Integrating VRE into the power system in a reliable and cost-effective manner requires more sophisticated approaches than traditional power system operation and planning. The impact of VRE depends largely on the VRE penetration level and the context of the power system, including the size of the system, available flexibility resources, and operational practices.

Flexibility has historically been an important requirement for power systems to balance supply and demand, including following unexpected contingencies such as plant and transmission outages. Securing the provision of system flexibility has become increasingly important as the share of VRE generation increases. The primary unique properties of VRE are (1) output variability, (2) partial output unpredictability, (3) smaller scale in capacity compared to conventional generation, and (4) connection to the grid via power converters.

Presently, the main sources of flexibility in most power systems are dispatchable power plants and transmission grids. Pumped storage hydropower (PSH) can also make a significant contribution. In the near future, battery storage technologies and large-scale demand-side options may also become primary sources for flexibility.

Policy and regulatory frameworks also play an important role by influencing how the flexibility of the power system and properties of VRE can interact (Figure 3.1) (IEA, 2017a). Such frameworks can help to unlock (and in some cases, compensate) latent power system flexibility resources to help balance load and VRE.

Figure 3.1 • Interactions between VRE properties and power system flexibility



Source: IEA (2017a), *Getting Wind and Sun onto the Grid: A Manual for Policy Makers.*

Key message • VRE integration challenges are influenced by the interaction of VRE properties and the flexibility of the power system.

System flexibility addresses a set of issues that spans a wide range of timescales relevant to the power system, from sub-seconds to years. Table 3.1 indicates six relevant timescales (IEA, 2018).

Table 3.1 • Different timescales of issues addressed by power system flexibility

Flexibility type	Ultra short-term flexibility/ stability	Very short term flexibility	Short-term flexibility	Medium-term flexibility	Long-term flexibility	Very long-term flexibility
Timescale	Sub-seconds to seconds	Seconds to minutes	Minutes to hours	Hours to days	Days to months	Months to years
Issue	Ensuring system stability (voltage, and frequency stability) at high shares of non-synchronous generation	Ensuring short-term frequency control at high shares of variable generation	Meeting more frequent, rapid and less predictable changes in the supply/ demand balance, system regulation	Determining operation schedule of the available generation resources to meet system conditions in hour- and day-ahead time frame	Addressing longer periods of surplus or deficit of variable generation, mainly driven by presence of a specific weather system	Balancing seasonal and inter-annual availability of variable generation with power demand
Has relevance for following areas of system operation and planning	Dynamic stability (inertia response, grid strength)	Primary and secondary frequency response, which include AGC	AGC, ED, balancing real time market, regulation	ED for hour-ahead, UC for day-ahead timeframe	UC, scheduling, adequacy	Hydro-thermal co-ordination, adequacy, power system planning

Notes: AGC = automatic generation control; ED = economic dispatch; UC = unit commitment.

Source: IEA (2018), *Status of Power System Transformation 2018: Advanced Power Plant Flexibility.*

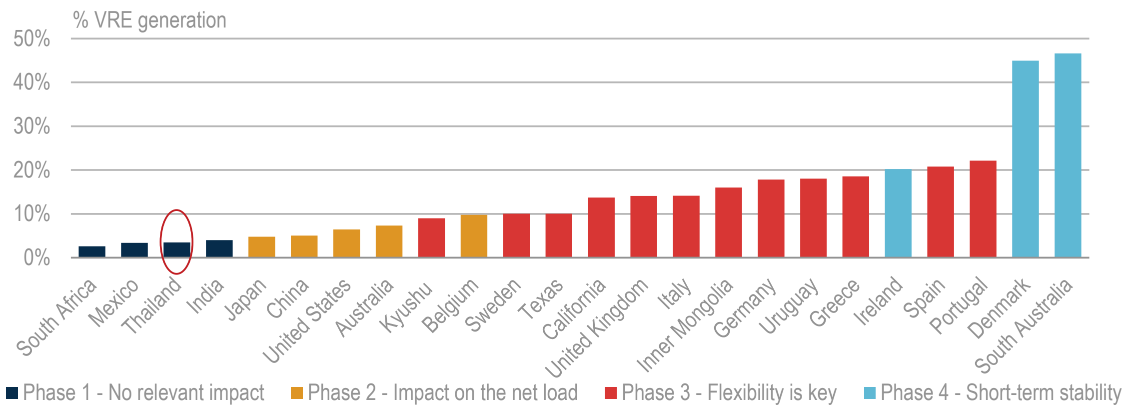
Phases of VRE integration

Previous International Energy Agency (IEA) analysis has identified different phases of VRE integration, which are differentiated by the impact VRE has on the power system as the VRE share increases (for details, see Annex A of this report and, for a detailed discussion, *Getting Wind and Sun onto the Grid* [IEA, 2017a]). Generally, there are four phases, characterised not by a specific penetration level of VRE, but by the main integration issues that are experienced. It is important to note that a variety of system-specific factors influence how effectively a power system can integrate VRE and thus influence in which phase the system is. These include a variety of technical factors, system operation practices, regulatory requirements, and supply-demand fundamentals. To successfully manage the different phases of VRE integration, there are a range of technical options, changes to operational practices, and shifts in regulation and market design (IEA, 2017b). Details of the different phases of VRE integration are provided in Annex A.

Countries can be categorised according to their VRE deployment phase. Today, even the most advanced countries are dealing with issues related to Phase 4 (when power system stability becomes relevant), while the vast majority of countries in the world, including Thailand, are in Phases 1 or 2 (when VRE is either not yet relevant at the all-system level or is only becoming noticeable). The phase categorisation is context-specific and thus depends not only on the share of VRE but also on other characteristics of the system. It is possible for a larger system to be in a earlier phase, while a certain region or subsystem has already reached a later phase. For example, despite the generally low share of VRE in Australia – and correspondingly moderate challenges – South Australia experiences very high penetrations of VRE and faces Phase 4 issues (Figure 3.2). Moreover, all else being equal, smaller systems will tend to fall into later phases than large systems, e.g. Ireland is in Phase 4 even though it has a lower annual VRE share than Spain, which is in Phase 3 (when flexibility becomes a priority).

In the ASEAN region, Thailand is the most advanced country in terms of VRE penetration as well as the development of grid infrastructure, operational practices, and other flexibility options.

Figure 3.2 • Select countries (including Thailand) listed by VRE penetration and integration phase, 2016



Source: Adapted from IEA (2017c), *Renewables 2017: Analysis and Forecasts to 2022*.

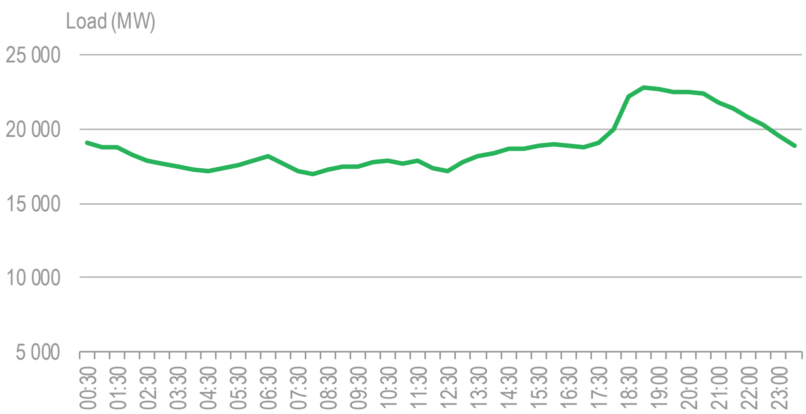
Note: Kyushu is one of the largest islands in Japan located in the south-west.

Key message • Thailand is considered to be in Phase 1 and approaching Phase 2 of VRE integration. While most countries are in Phases 1 or 2, some power systems experience aspects of the later phases.

VRE integration phase and the flexibility of the existing power system

Given the current VRE level in the system (less than 4%), the number of technical options available, and its robust transmission grids, Thailand is approaching Phase 2 of VRE integration, when VRE generation is becoming noticeable to the system operators. There have been some changes to the overall demand pattern, particularly peak demand, which occurs primarily in the afternoon, which is most likely a result of VRE. However, during the past year the number of days with afternoon peak demand has declined significantly. In fact, there are days where the lowest demand, which usually occurred in the early morning (around 4 am), has shifted to the afternoon, particularly during public holidays (Figure 3.3).

Figure 3.3 • Typical daily load pattern on Sundays and public holidays in Thailand



Source: EGAT data.

Key message • Relatively high ramping is required in the evening peak on Sundays and public holidays.

Moreover, during the afternoon and evening peak periods, the ramping requirements tend to be at their highest. Nevertheless, the system can still handle such circumstances given the existing technical flexibility options (i.e. conventional power plants and transmission grid) and operational practices.

In terms of the ramping requirement in the existing system in Thailand, Table 3.2 shows the maximum upward and downward ramp in 2016 for different time periods (30 minutes, 1 hour, 2 hours, and 3 hours) and the percentage of daily peak demand.

Table 3.2 • Maximum ramp up and down requirements in Thailand's power system, 2016

	30 minutes	1 hour	2 hours	3 hours
Max ramp up (MW)	**2 409.3 MW**	**3 819.9 MW**	**5 275.3 MW**	**6 631.7 MW**
Time (ending)	20-11-2016 17:30	18-04-2016 08:00	18-04-2016 08:30	18-04-2016 09:30
% of daily peak	**11%**	**14%**	**19%**	**24%**
Max ramp down (MW)	**1 868.2 MW**	**2 679.5 MW**	**3 781 MW**	**4 314 MW**
Time (ending)	22-12-2016 11:30	29-04-2016 17:00	29-04-2016 17:00	19-09-2016 00:00
% of daily peak	**8%**	**9%**	**13%**	**17%**

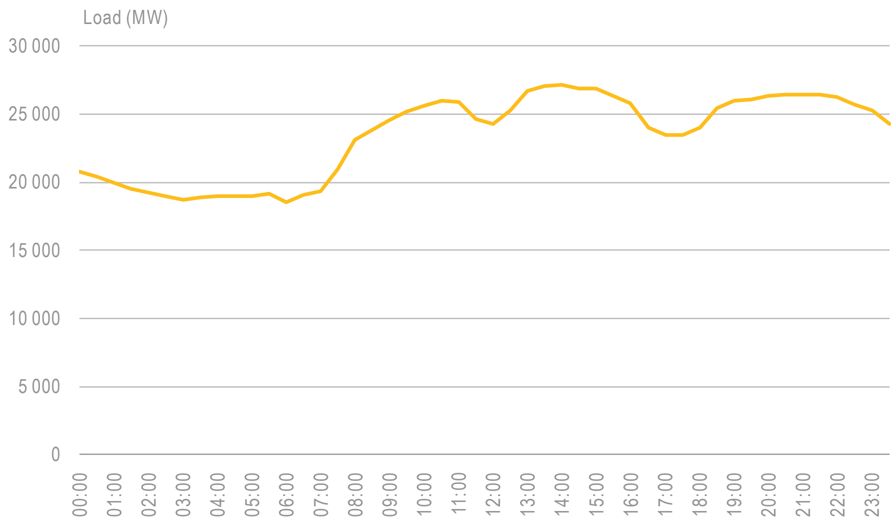
Note: Maximum ramp up for different time periods occurred on different days.

Source: EGAT data.

For the 30-minute time period, the maximum upward ramp occurred during the evening peak hours at approximately 2 400 MW, which is equivalent to an average 80 MW/minute ramp. Typically, during such a period, hydropower plants are dispatched to meet the upward ramp, given their fast ramp rates in conjunction with other generation technologies. For the 3-hour period, the maximum upward ramp was around 6 600 MW, which occurred in the morning from

06.30 to 09.30 (Figure 3.4). The maximum 3-hour upward ramp was around 24% of the daily peak demand. The maximum 30-minute downward ramp was 1 868 MW, which is around 62 MW/minute while the maximum 3-hour downward ramp was 4 314 MW.

Figure 3.4 • Load curve on the date when the 3-hour maximum ramping requirement occurred, 2016



Source: EGAT data.

Key message • Thailand's power system was sufficiently flexible to meet the maximum 3-hour upward ramping requirements in 2016.

The current power system in Thailand has a mixture of flexible and inflexible attributes. The generation fleet appears to be quite technically flexible, given a moderate share of hydropower and a high share of CCGT, combined with an overall large reserve margin. The operating characteristics of CCGT and coal-fired power plants – particularly minimum generation levels, ramp rates, and start-up times – suggest that the current fleet's flexibility could be significantly enhanced (Table 3.3). The inflexible operating characteristics are a result not only of the technical aspects, but also of the constraints under current PPAs.

Because of the relatively high ramp rates and fast start-up times, hydropower generation is a highly flexible generation resource in Thailand. Hydropower is dispatched as peaking generation during high-demand periods. However, the minimum generation levels of these plants are very high, owing to irrigation requirements as well as to technical constraints such as turbine vibration. According to international standards, the minimum generation and start-up time of other conventional technologies appear to be high, while ramp rates are moderately low.

Table 3.3 • Fleet-wide average operating parameters of conventional technologies in Thailand, 2016

Technology	Key operating parameters.		
	Minimum generation (% of capacity)	Ramp rate (MW/minute)	Warm start time (hours)
CCGT	61%	20	6
Coal	55%	9	5.4
OCGT	55%	10	0.5
Thermal gas	47%	13	9.5
Hydro	75%	47	-
Hydro (imports)	85%	64	0.1
Diesel	34%	8	0.7
Fuel oil	27%	3	8

Source: EGAT data.

The key operating characteristics of typical power plant technologies in Thailand's system (e.g. CCGT; coal; open cycle gas turbine (OCGT); and hydropower) are generally less flexible compared with the typical international average values of the same technology (Table 3.4). This is particularly the case for minimum generation levels, which are relatively high for most technologies, particularly hydropower. PPA terms also contribute to such inflexible operational characteristics. The scenario of contract flexibility with flexible operational characteristics is also analysed in this report, as will be explained in the following chapters.

Table 3.4 • Typical average operating parameters of different technologies

Technology	Key operating parameters.					
	Minimum generation (% of capacity)		Ramp rate (MW/minute)		Warm start time (hours)	
	Typical	Retrofit	Typical	Retrofit	Typical	Retrofit
CCGT	45%	30%	21	56	1.6	0.5
Coal	37%	20%	21	60	6	2.6
OCGT	35%	20%	29	60	0.7	0.3
Hydro	15%	-	60	-	-	-

Sources: IEA (2017d), *Energy Technology Perspectives 2017 – Catalysing Energy Technology Transformations*; NREL (2012), *Power Plant Cycling Cost*; Gonzalez-Salazar et al. (2018), *Review of the Operational Flexibility and Emissions of Gas- and Coal-Fired Power Plants in a Future with Growing Renewables;* Siemens (2017), *Flexibility of Coal- and Gas-Fired Power Plants*; Agora Energiewende (2017), *Flexibility in Thermal Power Plants – With a Focus On Existing Coal-Fired Power Plants*.

Table 3.4 also shows how retrofitting power plants in order to enhance key operating parameters improves technical flexibility. For example, in a coal-fired power plant, this could be implemented via advanced monitoring and control techniques (the so-called advanced state-space unit control) and other technical interventions (e.g. condensate throttling; partial deactivation of heat pump preheaters and optimisation of the feedwater; aid and fuel controls), as were implemented at RWE's Neurath power plant in Germany (for details, see IEA, 2018).

Importantly, the existing Thai power system is still sufficiently flexible to effectively respond to ramping requirements for different time periods, particularly during the evening peak periods. However, with the rising share of VRE and distributed energy resources, system ramping requirements are expected to increase due to larger changes in net load and increased net load variability. For example, in the California system, the 3-hour upward ramps in the evening are generally greater than 50% of the daily peak demand, which indicates the need for faster ramping resources (Loutan and Zhou, 2018). Future ramping requirements will also be analysed for the power system in 2036 in Chapter 5.

The existing transmission system appears to be very flexible, given that Thailand's grid is relatively strong with a number of advanced transmission equipment and protection schemes. However, transmission strengthening will be required to accommodate new generation, both from the Power Development Plan (PDP) and as a result of higher renewable targets.

In terms of the power system flexibility timescales, the existing Thai power system can be considered to possess ultra-short- and very short-term flexibility, which covers the timescale from sub-seconds to minutes (shown in Table 3.1) although the share of VRE is still very small. The system possesses dynamic stability and robust grid strength as well as adequate primary and secondary response mechanisms. The main approaches for dynamic stability and frequency control for Thailand's grid include:

- speed droop or governor action
- secondary control – operator dispatching and automatic generation control (AGC)
- quick start generators

- cross-border high-voltage direct current (HVDC) frequency limit control (FLC) function – beginning to import when the frequency drops to 49.75 Hz
- pumped hydropower storage shedding based on under frequency (UF) relay – when frequency drops to 49.5 Hz and 49.3 Hz
- load shedding scheme based on UF relay – five different steps from 49.0 - 47.9 Hz.

From short- to very long-term flexibility timescales, the existing system has some flexibility limitations due to the constraints from PPAs, which restrict power plants from operating more flexibly due to the contracted operating characteristics of the power plants (Table 3.3). In addition, fossil fuel contracts, particularly natural gas, specify a minimum take-or-pay amount that consequently restricts the economic dispatch of power plants. The value of relaxing some of these contractual constraints will be explored in Chapter 5.

System flexibility characteristics and options

In addition to the capability of power plants to maintain system stability and frequency in the sub-second to minute timescales, there are other technological options and operational practices that influence the flexibility of Thailand's power system. These options are grid infrastructure, control systems, storage options and demand response (DR):

- Grid infrastructure
  - Strong and reliable transmission network with significant protection schemes. There are a number of special protection schemes (SPS) that have been developed, including generation shedding and load shedding. The SPS have also been regularly updated by EGAT.
  - Successfully built out a transmission grid to connect the regions with high generation levels to the regions with high demand.
  - Transmission tools for voltage control, including shunt reactors, capacity banks, and synchronous condenser mode from certain hydropower generating units.
- Control systems and real-time monitoring
  - System operators have direct control of power plants, transmission lines and high-voltage substations in real time.
  - AGC to automatically control power plants to balance supply and demand.
  - Flexible Alternating Current Transmission System (FACTS) to enhance controllability and transfer capability.
  - Implementation of dynamic line rating scheme to increase the limit of transmission line capacities.
- Storage
  - PSH from five hydropower generating units with a total capacity of 900 MW.
  - Pilot projects of battery storage (described in more detail in Annex D).
- Demand-side response
  - Time of use pricing has proven effective in shifting industrial consumption (but may require further adjustment to support wind and solar integration).
  - Interruptible tariff programs for large industrial consumers that allows the system operator to reduce customer loads during contingencies.
  - Based the recent DR (phase I and II) study commissioned by the Energy Regulatory Commission (ERC), which was conducted by Chiang Mai University, there is a high potential of DR across different sectors.

Inflexibility aspects of the power system

However, from the economic and institutional aspects, there are some inflexible aspects of the Thai power system that could pose some challenges as the share of VRE increases. These inflexibility factors can be briefly summarised as follows:

- Time variability
  - Absence of short-term wholesale electricity price signal for generators and distributors.
  - Time of use pricing for some customers exists, but current pricing scheme does not reflect recent changes to variability in demand and supply due to the uptake of wind and solar generation, nor is there a mechanism in place to update this in the future.
- Geographic variability
  - No reflection of location in wholesale electricity prices for the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA) from the Electricity Generation Authority in Thailand (EGAT) (as far as current analysis has shown).
- High uncertainty in demand forecasts
  - This is due to a number of factors, including demand fluctuations and changes in the demand pattern because of increasing VRE deployment and independent power supply (IPS) utilisation, which is extremely challenging to forecast given the existing systems. This obstacle occurs for daily, monthly and yearly planning.
- Operating reserves and system services requirement with no separate compensation
  - Currently there is no separate compensation for generators to provide ancillary services across the different timescales ranging from inertia to frequency response.
  - The existing interruptible tariff program mentioned above only managed to attract few participants due to unattractive price incentives, unclear guidelines and a lack of co-ordination between the transmission and distribution operators.
- Fuel and power purchase contracts
  - Take-or-pay gas contract between EGAT and PTT under the Master Gas Sale Agreement (MGSA) specifies that the minimum amount of take of gas can pose obstacles to flexible operation, particularly when the existing system has a high reserve margin. EGAT, the system operator, has experienced a number of situations that required them to dispatch out of merit order by dispatching gas-fired generators rather than other more economical generators because of the minimum take requirements.
  - Long-term PPAs with independent power producers (IPPs) are one of the main sources of system inflexibility due largely to the inflexible contracted operating characteristics of power plants, particularly high minimum generation levels, low ramp rates, long start-up times, and the specified maximum number of daily cycles. Originally, such PPAs were established in the late 1990s to attract private investors when electricity demand was growing rapidly and the system had a low capacity reserve margin. However, the structure of the PPAs has not been altered in line with changes in the demand and supply situation.
  - Long-term PPAs with small power producers (SPPs) are also inflexible and can be costly for the system due to high contract prices; relatively high feed-in tariff (FiT) and adders offered to RE plants; and take-or-pay obligations. In addition, the generator profiles of SPPs are fixed for different periods, and SPPs cannot be dispatched to meeting the variability of supply and demand in the system.
- Strong separation between the transmission and distribution system utilities

- A lack of co-ordination can raise operational challenges at higher shares of distributed generation. The issue also includes a lack of adequate co-operation among EGAT, MEA and PEA. The Office of Energy Regulatory Commission (OERC) can play a key role in influencing increased collaboration among EGAT, MEA and PEA.

Grid connection codes

In general, grid codes provide the rules for the operation and planning of the power system by ensuring operational stability, security of supply, and proper co-ordination of all components. With an increasing share of VRE, it is becoming increasingly important to upgrade grid codes because of VRE sources' unique characteristics and the way they are connected to the grid (via power electronics) relative to conventional generators. The behaviours of VRE are not only dictated by their design, but also by the way they are programmed to operate. The function of a grid connection code covering VRE is to provide technical requirements for wind and PV plants when connecting to a country's electricity grid (IRENA, 2016).

At present, there are several grid codes for the power system in Thailand which have been established separately by the transmission and distribution utilities (EGAT, MEA and PEA). These grid codes can be categorised according to transmission and distribution levels and by the types of generators (IPP, SPP and very small producer [VSPP]) as follows:

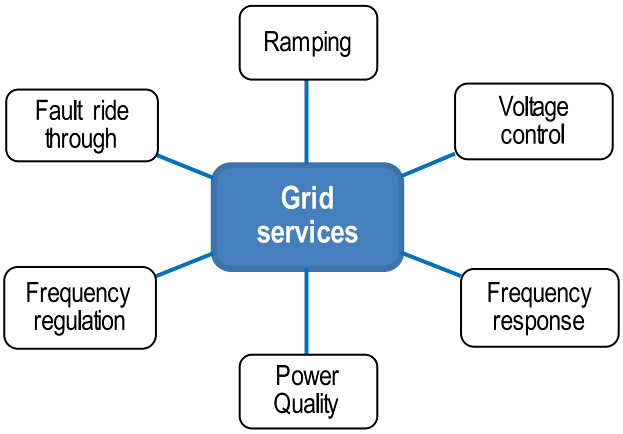
- **EGAT:** connection and operation codes for IPP, EGAT power plants, SPP, IPS, MEA and PEA; service code.
- **MEA:** VSPP connection code, VSPP operation code, VSPP service code.
- **PEA**: VSPP connection code, VSPP operation code, VSPP service code.

The service codes are the specifications and conditions related to the use of electrical networks. The operation and connection codes, on the other hand, focus mainly on technical requirements from generators in order to maintain the stability of the power system at both transmission and distribution levels. These codes contain technical details including, for example, planning procedures, connection conditions, protection requirements, monitoring and testing protocols, demand forecast requirements, operation planning requirements, contingency planning requirements, generator models for CCGT and thermal power plants, and protocols for exchanging operational information and generation scheduling information.

Despite the detail of the grid connection codes of EGAT, MEA and PEA, a number of areas remain that could be improved, not only to accommodate the increasing amount of wind and solar PV, including a need to seek consistency and alignment across all grid codes. In the case of roof-top PV, under the current policy settings first established in 2014, two distribution utilities (MEA and PEA) are obliged to purchase electricity via a regulated FiT, using a different grid code for each distribution network. On the other hand, EGAT, who is responsible for transmission system operation, has a different grid code that does not allow reverse power flow from the distribution network to the transmission network. This position is unlikely to remain tenable with an increasing share of distributed renewables, and updating the regulatory framework should be a priority or else it may endanger security of supply and hamper investment in the energy sector.

In terms of accommodating the increasing amount of VRE, the grid connection codes should be improved based on the specific requirements. Although there is a broad set of detailed technical standards in the existing codes, they do not define the technical performance desired from VRE generators with sufficient specificity. In terms of grid services that would be required from both conventional and VRE generators, the grid code should contain six technical aspects to increase system flexibility (Figure 3.5). Such grid services (ancillary services) could be mandated and/or financially incentivised.

Figure 3.5 • Essential grid services from both conventional and VRE generators in the grid code



Key message • Requirements for providing essential grid services (ancillary services) should be specified in the grid code for both conventional and VRE generators.

Another key aspect for consideration is the commitment of generators to comply with the grid code, particularly the operational standards, in order to maintain the stability of the system. In Thailand, the grid codes for medium and large generating plants, including IPPs and SPPs, require power plants to provide system services such as governor droop, fault ride through (FRT), and frequency response, especially during contingency events. Therefore, there must be measures to periodically test the capability of generating plants to ensure that their settings comply with these requirements. Otherwise, there is a possibility that generators will vary their settings, resulting in a potential failure to comply with the requirements to provide system services when called upon. Such circumstances could have a substantial negative impact during contingency events, which has happened in the past. It is the responsibility of both the system operator (EGAT) and the regulator (OERC) to ensure that power plants comply with the grid codes.

A detailed account of the relevant factors needed for a grid code depends on many factors, including VRE deployment considerations, technical properties of the existing system, and current regulatory and market frameworks, which are highly context specific.[4]

The requirements of the grid code for VRE generators can be categorised based on the phase of VRE deployment and also on technical requirements, including, for example, protection systems, communication systems, power quality, voltage and frequency ranges of operation, frequency and active power control, spinning reserve requirements, VRE forecasting, FRT, and synthetic inertia (Table 3.5).

[4] The detail of relevant factors to consider in developing a grid code that is suitable for VRE can be found in the study by the International Renewable Agency (IRENA, 2016).

Table 3.5 • Incremental technical requirements for different phases of VRE deployment

	Always	Phase One	Phase Two	Phase Three	Phase Four
Technical requirements	- protection systems - power quality - frequency and voltage ranges of operation - visibility and control of large generators - communication systems for larger generators	- output reduction during high frequency events - voltage control - FRT capability for large units	- FRT capability for smaller (distributed) units - communication systems - VRE forecasting tools	- frequency/ active power control - reduced output operation mode for reserve provision	- integration of general frequency and voltage control schemes - synthetic inertia - stand-alone frequency and voltage control

Source: IEA (2017a), *Getting Wind and Sun onto the Grid: A Manual for Policy Makers*.

Germany provides a relevant example of the improvement of grid code and collaboration between transmission system operators (TSOs) and distribution system operators (DSOs). During the last decade, renewables developed in Germany at a much faster pace than did standards and grid codes. The old low-voltage grid code required a frequency setting that had a significant impact on system security. In addition, the low-voltage guidelines were developed without the participation of TSOs, and there was a lack of communication between stakeholders. Details of this example are provided in Annex A.

As indicated in Table 3.5, the controllability and visibility of VRE generators are essential regardless of the phase of VRE integration. This would involve developing communication systems and architecture that have features such as supervisory control and data acquisition (SCADA), AGC capability, and relevant forecasting systems (both centralised and decentralised). Most of these technologies have already been in operation in the Thailand’s existing power system, except for the forecasting systems. These could be implemented as part of the renewable control system, which is discussed in detail in the next subsection.

Renewable energy control centres

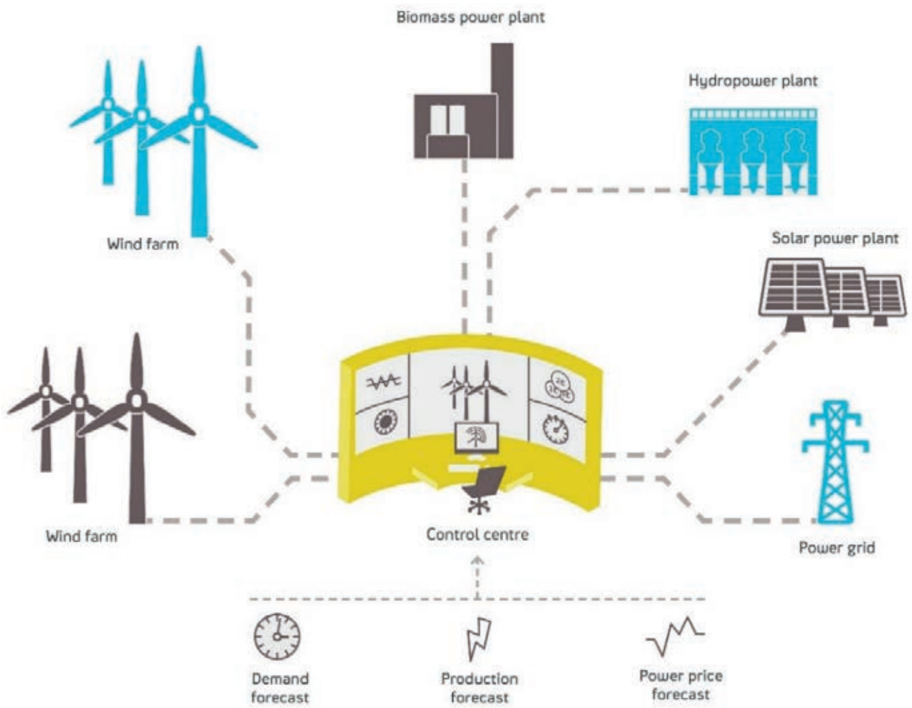
International best practices uniformly suggest that the output of wind and solar power plants should be reflected in the wider planning of power systems and explicitly considered in power system operation. The system operator must have visibility (i.e. data) on what these power plants are doing in real-time, so it can plan the operation of dispatchable power plants accordingly. The system operator must also be able to curtail a portion of VRE output at critical moments; this is crucial for the operator to be able to perform its primary objective of upholding security of supply. With increasing penetration of solar PV and wind generation in the power system, a RE control centre may become an important feature to consider. The main purpose of an RE control centre is to provide the system operator with state-of-the art tools to carry out real-time monitoring and operating of RE plants in the power system and its control areas. For example, the Spanish system operator has dedicated a section of its control centre to monitor and control VRE output effectively.

In general, the major functions of the RE control centre include (Figure 3.6):

- real-time monitoring and control to supervise the operation of VRE plants
- forecasting of wind and solar generation from days-ahead to minutes before real time, to be supplied to the system operation and load dispatching centres

- interaction and communication with the system operation control centres
- RE generation data recording and analysis.

Figure 3.6 • General functions of a renewable energy (RE) control centre



Source:Statkraft.

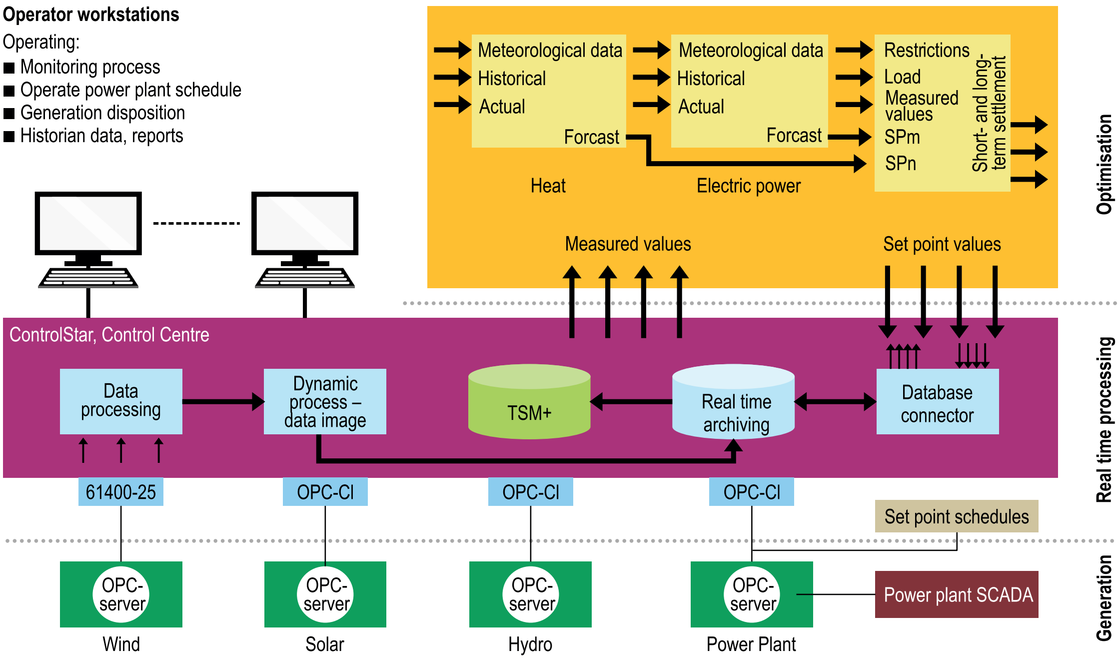
Key message • A RE control centre integrates relevant information for operational planning and real-time control of RE power plants.

The control centre with an advanced underlying telemetric system is one of the most important setups to simulate the various mechanisms by implementing the right data analytic tools. The quality of the control centre is highly dependent on the data being delivered. Therefore, it is also essential to implement the corresponding telemetry (telecommunication networks) to monitor and control all relevant devices throughout the energy supply system. Transmission operators with an energy management system (EMS) solution tend to have more transparency about their network compared to distribution system operators, where the implemented SCADA solutions largely do not have any visibility of the medium voltage and low voltage grid.

The control centre should be seen as service centre for the national energy market with benefits to all stakeholders. Figure 3.7 demonstrates the functional structure of a RE control centre, presenting a future proof solution that caters for all possible regulatory frameworks.

Forecasting, a critical element of all power systems, is especially important with VRE, which requires a flexible system. System operations can be improved by adopting advanced forecasting solutions in the control centre. Using advanced forecasts in grid operations can help predict the amount of wind or solar energy available and reduce the uncertainty of the available generation capacity, while reducing the amount of conventional generation that must be held in reserve.

Figure 3.7 • The functional structure of a RE control centre for ensuring a future proof solution that functions in all possible regulatory frameworks.



Note: CI = client; DBC = database connecter; OLE = object linking and embedding; OPC = OLE for process control; SPm = set point m; SPn = set point n; and TSM = times series management.

Key message • The features of the control centre include monitoring, controlling, forecasting, optimisation and historical data analysis.

Forecasts and optimisations are more accurate the closer they are to real time. System operators use accurate forecasts to determine unit commitment and reserve requirements, which can minimise ramping requirements of fossil fuel plants and the need for operating reserves, potentially creating significant system cost savings. Co-ordinated and integrated planning in a state-of-the-art control centre helps decision makers anticipate how variable RE might affect the grid and its operations, and what options would optimise costs across a system. Forecasts enable:

- better estimation of the actual need for reserves
- day-ahead estimation of supply-demand balance
- better use of the production capacity – more use of manual reserves
- increased transparency for the market and its operation
- meteorological weather forecasts, which are received from multiple external providers and include temperature, wind speed and direction, and solar irradiation data.

Grid codes also play an important role for RE control centres since they can specify both hardware and procurement agreements to be designed in advance to support the power system, thereby reducing the financial burdens of retroactive requirements. Creating a model grid code underlying the control centre operations can serve as a guide to evaluate what changes are needed for each system.

Criteria to consider when implementing an RE control centre

- The use of forecasts requires operational changes. Grid operators need to be aware and convinced of the benefits of integrating forecast data in daily operations.

- Robust grid codes to accommodate variable RE require sophisticated big data analytics and communication infrastructure. Decision-making systems need to be updated, and new programs are required to develop institutional capacity.
- Although codes set in advance minimise retroactive requirements to generators, codes set when penetration is low can unnecessarily burden variable RE technologies. Striking a balance in timing represents a key challenge when developing new grid code requirements.

- Using new grid codes that reflect state-of-the-art engineering-based practices is preferable to building from existing codes that draw from older or out-of-date practices.
- Every system is different, which precludes a uniform recommendation and adoption of a model grid codes. System-specific analyses are needed.

Actions to implement a new control centre

- Develop and combine national and regional forecasting systems.
  - Identify advanced forecasting methods and their benefits.
  - Provide public support for research and development to improve forecasting methods and put them in the public domain.
  - Support outreach on forecasting benefits and training on best practices for grid operators, both for the transmission (EGAT) and at distribution levels (MEA and PEA).
  - Encourage efforts to research, and continually improve forecasting techniques.
  - Work with regulators to require that all VRE generators participate in forecasting, which necessitates that generators provide frequently updated data.
- Consider and implement codes and standards that meet interregional and international requirements to enable greater penetration of variable RE generation.
- Support work with regulatory commissions to evaluate model grid codes, recommend changes, and implement recommendations.

Best practices and international experiences

Best-practice planning for state-of-the-art control centres do comprise an inherently complex set of activities that are undertaken in some countries by multiple groups and jurisdictions for a given power system. For instance, the approach to planning differs widely when comparing Australia, Europe and the United States. However, the main trends are clearly an approach to centrally plan. When preparing to implement a centrally managed control centre, a few key principles can help address the operational challenges associated with increased VRE deployment that may arise.

Spain

In Spain, Red Eléctrica de España (REE) established a Control Centre of Renewable Energies (CECRE) in 2006, a globally pioneering initiative to monitor and control renewable generation using real-time information. The CECRE has played a major role in that country's leadership in terms of VRE integration. It consists of an operations desk at which operators supervise RE production on a continuous basis, with the objective of maximising RE production while maintaining system reliability. From the CECRE, all large VRE power plants can be controlled, if necessary, through Subsidiary Generation Control Centres around Spain which also collect real-time data and channel these to CECRE.

Through the CECRE, the system operator receives the telemetry of 98.6% of the wind power generation installed in Spain every 12 seconds, of which 96% is controllable (with the ability to adapt its production to a given set-point within 15 minutes). This is achieved through the aggregation of all the distributed resources of more than 55 megawatts (MW) in renewable energy sources control centres (RESCCs), and the connection of RESCCs with CECRE. This hierarchical structure, together with the software applications developed by REE, is used to analyse the maximum wind power generation accepted by the system. Monitoring and controlling VRE generation in real time decreases the number and quantity of curtailments, maintaining the quality and security of the electricity supply while maximising the amount of RE being integrated into the power system.

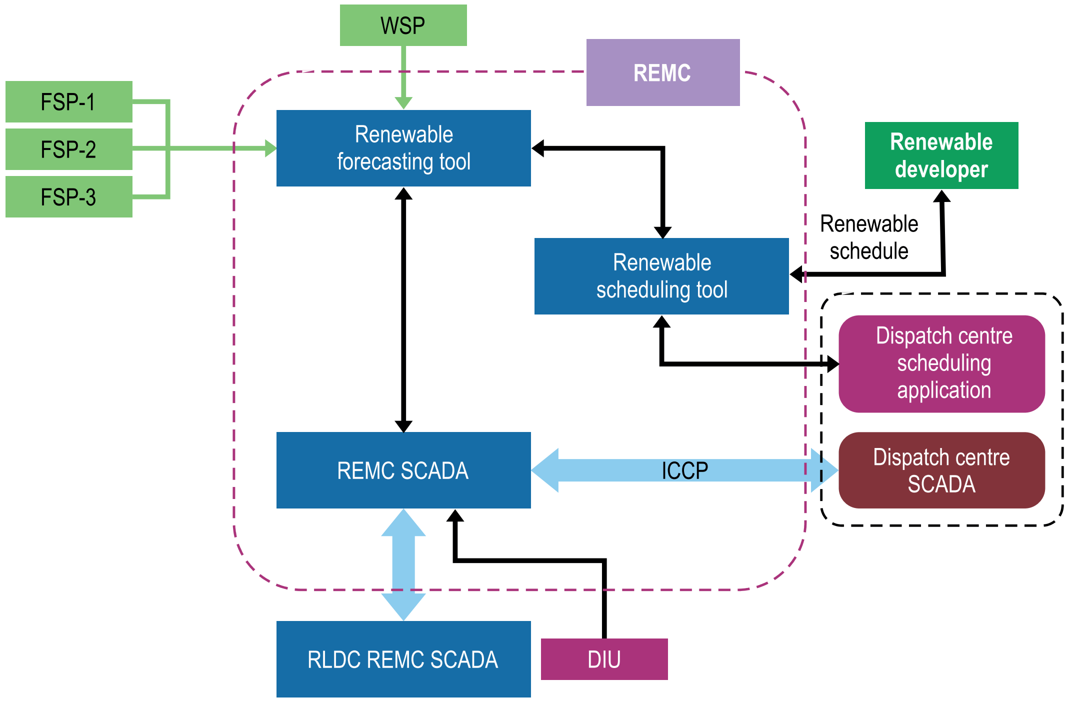
Figure 3.8 • CECRE's control room

Source: REE (2016), *Safe Integration of Renewable Energies*.

India

With a solar and wind generation target of 160 GW by 2022, India is planning to set up Renewable Energy Management Centres (REMCs) across the system to accommodate expected increases in RE penetration. The functions of REMC include RE forecasting, online geospatial monitoring of RE generation, scheduling and real-time control and monitoring (which are currently lacking at the load dispatching centres at both national and state levels), and future readiness for advanced functions such as virtual power plants and storage. In addition, the REMCs will co-ordinate with relevant load dispatch centres and integrate with real-time measurement and information flow (GIZ, 2017). The architecture of the REMCs are shown in Figure 3.9.

Figure 3.9 • Renewable Energy management Centres (REMC) architecture in India



Note: DIU = data interface unit; FSP = forecasting service provider; ICCP = inter-control centre protocol; and WSP = weather service provider.

Source: Adapted from GIZ (2017), *Report on Forecasting, Concept of Renewable Energy Management Centres and Grid Balancing.*

Key message • The architecture of a renewable management centre consists of several important modules.

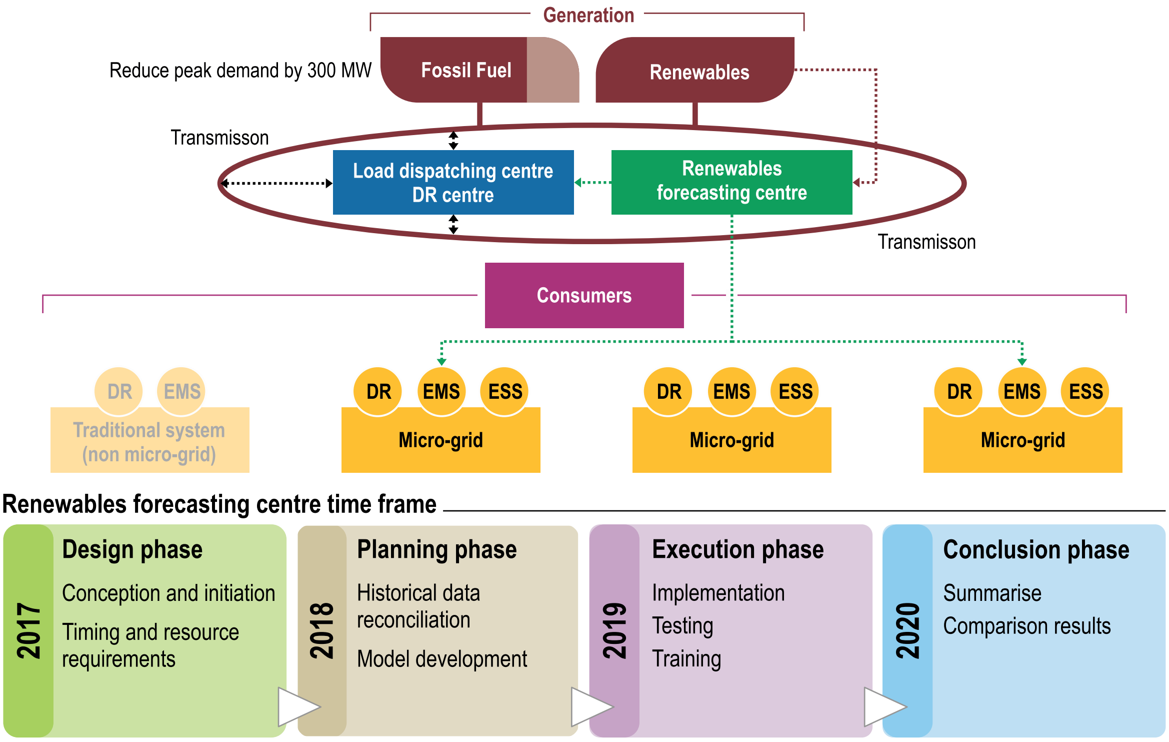
Adoption of the RE control centre in Thailand

The unique challenge for Thailand will be a real-time or near real-time data exchange between the different control centres of PEA, MEA and the EGAT centre operator. For example, load aggregations and DR systems implemented with smart grid initiatives need to share their data with the control centres. Forecasting systems should be implemented by both the control centres and VRE generating plants, where the data are provided to the control centres. The forecasting and optimisation information should then be provided to all relevant stakeholders. Thailand's smart grid plan, which indicates the existence of both RE and DR control centres, is shown in Figure 3.10.

A strong ICT environment following international standards and interoperability definitions is central to a RE control centre in Thailand, which should include such main components as SCADA, forecasting, optimisation, and telemetry. The telemetry required should be operated in a licenced environment with a fixed spectrum allocation for the national energy market, and engagement with the National Broadcasting and Telecommunications Commission (NBTC) in the overall design process of the control centre solution.

Because the plan also involves a DR centre, demand aggregators will play a key role in the establishment of both DR and RE control centres in Thailand, although it is unclear at present what types of entities will be allowed to perform this role. During the DR pilot events in 2014 and 2015, MEA and PEA undertook the role as demand aggregators and communicated directly with EGAT. This arrangement may continue, at least initially. However, a framework that allows third-party demand aggregators may be more appropriate, given the potential conflict of interests involving EGAT, MEA and PEA as both dispatchers and electricity suppliers.

Figure 3.10 • Thailand's RE forecasting and DR control centre project



Note: EMS = energy management system; ESS = energy storage system.

Source: Adapted from EGAT (2018), "Renewable energy integration in Thailand current status and challenges".

Key message • Thailand's smart grid plan is still in the planning phase and is expected to be completed in 2020.

One of the challenges in DR programs is the lack of suitable metering infrastructure. Third-party demand aggregators can address this concern by investing in metering infrastructure for their customers.

In terms of DPV, generally it is not necessary to send online consumption and production information to the control centres. For example, in Denmark, a 24-hour file with quarterly net metrics for all installations is provided once per day. With advanced forecasting systems, online measurement from smaller production units is not necessary. On the other hand, a high concentration in solar parks necessitates more accurate forecasts for the locations.

From the standpoint of power system operation, achieving the same system-wide solar PV penetration with a very large number of very small-scale systems can be more challenging than doing so with a smaller number of larger installations. This is partly because it is more difficult to maintain the same degree of control on smaller systems; in addition, state-of-the-art rooftop systems are generally less sophisticated than larger plants when it comes to providing supportive system services. Faced with a very large number of very small-scale systems, Germany, for example, is moving towards a requirement for even more sophisticated capabilities than these. This is taking place through reforms to its grid code, which provides the application guide for the connection of distributed generation to distribution networks (VDE, 2011). The ability of the system operator to control a sufficient amount of generation capacity, including VRE, is crucial to maintain security of supply at growing shares of VRE.

International experience shows that it is most effective to have dedicated RE control centres to co-ordinate with RE plants rather than using the transmission and distribution system operators. The possibility of establishing RE control centres will depend on the roadmap and regulatory frameworks that OERC is currently considering.

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4. Analytical approach and methodology

HIGHLIGHTS

- Because power sector does not allow for real-world experiments, power sector modelling can play a crucial role in analysing the potential impacts of different policy and planning choices. There are different types of power sector modelling tools to examine the power sector at different time horizons to ask distinct questions for analysis, which are long-term capacity expansion, production cost and short-term technical modelling.
- Production cost modelling is employed to simulate the optimal operation of Thailand's power system for a full year in 2036 at a 30-minute time resolution, with the modelled generation mix and transmission system largely based on the infrastructure investment plan put forth in Thailand's Power Development Plan (PDP) 2015. The model is used to assess the impact of different levels of variable renewable energy (VRE) deployment on the 2036 Thai power system as well as to better understand the efficacy of various flexibility options to support VRE integration and reduce system operational costs.
- The flexibility options considered consist of contractual and technical aspects. The contractual option of relaxing the fuel supply and power purchase contracts were analysed to enable optimal dispatch and operations of power plants that have higher ramp rates, lower minimum generation levels, and shorter start-up times. Technical flexibility options explored include electric vehicles (EV), demand-side management (DSM) resources, battery storage and pumped storage hydro (PSH).
- Due to the possibility of a large-scale adoption of distributed solar photovoltaics (DPV) in Thailand, there are concerns among relevant stakeholders regarding the affect of DPV on the power system. This chapter describes the analytical methodology employed to create estimates of rooftop DPV: (1) maximum gross technical potential, (2) maximum economic potential, and (3) the economic impact of rooftop DPV on Thai utilities and ratepayers.
- The chapter offers a detailed evaluation to practices, processes and tools used in long-term power sector planning exercises in Thailand. It discusses both qualitative and quantitative approaches to this task, including a three-pronged analysis process for a better understanding of the total system cost impact of VRE resources on the Thai power

This chapter provides an overview of the methodology and approach to the analysis in each work stream introduced in Chapter 1. For work stream 1, the basic scenario assumptions and details of the power system operational model are shown. For work stream 2, details are provided on how rooftop solar technical and economic potentials are calculated, as well as the governing assumptions that underpin the economic impact analysis. For work stream 3, the focus is on the PDP and the methodology employed for calculating capacity credit and system costs.[5] The data sources used in the analysis and assumptions across the work streams such as fuel and technology costs are provided in Annex C.

[5] Importantly, the work streams have cross linkages where appropriate; for example, the estimate of system costs in work stream 3 builds on detailed modelling from work stream 1.

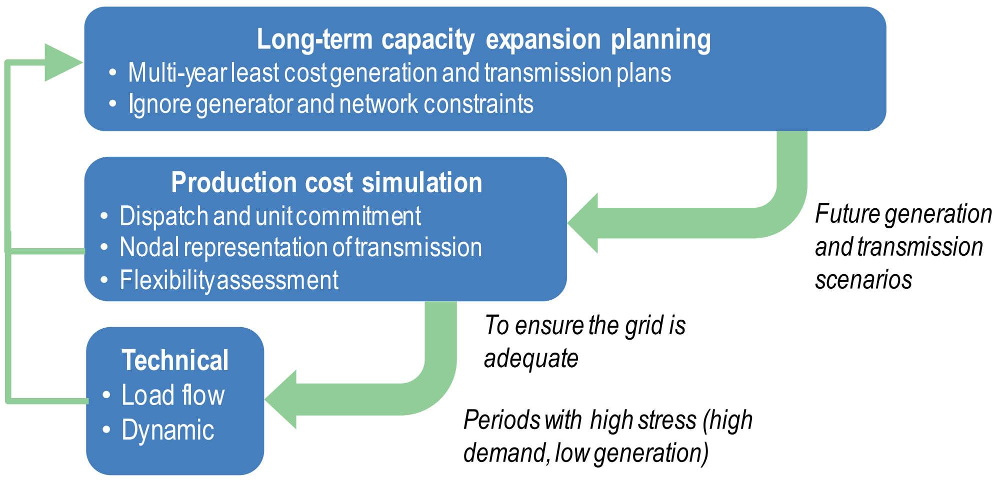
Power sector modelling and scenario analysis

Power sector modelling is an important approach to understanding the capability and flexibility of a power system to accommodate VRE. Power sector modelling tools are important for conducting grid integration analyses, which help to uncover various operational, economic and policy-related considerations of VRE deployment. They are particularly useful for informing the design of long-term renewable energy (RE) targets, as briefly mentioned in Chapter 2. Power sector modelling can be used to inform decisions at various levels of the power system, including:

- **Technology level** – Informing long-term infrastructure investment decisions on the supply- and demand-side of the power sector, including comparative assessments of technologies.
- **Grid level** – Informing decisions to deploy transmission and distribution infrastructure. This aspect is particularly relevant from both a planning and operational standpoint when considering cost-effective strategies to support the integration of VRE.
- **Stakeholder level** – Helping to formulate plans, policies and strategies by involving a wide range of energy sector stakeholders, and communicating technical outcomes and strategies.
- **Policy level** – Identifying and testing the efficacy of policies that may enable greater uptake and successful implementation of long-term RE targets in the most cost-effective manner.

Real-world experiments are not possible in the power sector, therefore, power sector modelling can play a crucial role when analysing the potential impacts of different policy and planning choices. There are different types of power sector modelling tools to examine the power sector at different time horizons, from long-term capacity expansion (years to seasons), production cost (days-to-minutes) and technical modelling (minutes to seconds) (Figure 4.1). Although these models have different purposes, they can be developed and analysed in a consistent and integrated manner, particularly as the share of VRE increases, in order to promote economically efficient outcomes (for more detail, see IEA, 2018).

Figure 4.1 • Linking power system models with different time horizons



Key message • There are different kinds of power sector modelling tools that can be used in a co-ordinated and integrated manner.

Production cost modelling for Thailand's power system in 2036

In this report, production cost modelling is employed to simulate the optimal operation of Thailand's power system in 2036, with its generation mix based largely on the PDP 2015 (EPPO, 2015). Production cost modelling simulations are performed at a 30-minute time resolution and co-optimised with spinning reserve requirements to capture a reasonable level of detail in terms of both the generation fleet and the transmission system. It is used to assess the impact of different generation mixes on the 2036 Thai power system and also to better understand the future operation of the power system as planned under the PDP 2015. Different scenarios for 2036 are analysed and compared in order to understand the technical and economic impacts associated with greater VRE deployment and the role of different flexibility options. Importantly, the production cost modelling exercise is used primarily in work stream 1; however, the results of that analysis are also used in work stream 3 to inform system cost estimates (described later in this chapter).

A capacity expansion planning analysis was not conducted since the analysis is based on the existing expansion plan put forth in the PDP 2015. Technical network reliability modelling – which focuses on a detailed simulation of the transmission system in a very short time frame (i.e. seconds) to provide snapshots of specific operational states – is also beyond the scope of the project. Nevertheless, these aspects, particularly capacity expansion, could be important subjects of future work.

Description of production cost modelling scenarios

The core modelling scenarios consider different levels of VRE deployment. Additional scenarios, which consider different flexibility options, are explored for the highest VRE deployment scenario (Table 4.1). The Base scenario corresponds to the 2036 Thai power system proposed in the PDP 2015. This is expanded upon in the following subsection, with further details in Annex C.

Renewables and flexibility scenarios

There are three core scenarios: Base, RE1 and RE2. While the Base scenario simply assumes that existing 2036 capacity targets are met (as per the PDP 2015), two further scenarios – RE1 and RE2 – are used to explore the operational and economic implications of increasing the share of VRE generation in Thailand. The amount of wind and solar included in these scenarios is based on detailed feedback received from relevant stakeholder groups in Thailand, following several Project Reference Group meetings, and considering current potential assessments. The choice of sites for VRE deployment is explained in a subsequent subsection. Importantly, note that the usage and examination of the RE1 and RE2 scenarios is by no means an endorsement of these deployment figures by the International Energy Agency (IEA) for planning purposes.

The grid expansion needed between different regions in 2036 is also considered in the modelling because this aspect has not been included in the PDP 2015. Also not considered in detail in PDP 2015 is long-term transmission expansion; thus, a simplified engineering-based transmission expansion approach for 2036 has been conducted. In addition to the three core scenarios, the impact of different flexibility options for the RE2 scenario are examined, with a number of key questions explored (Figure 4.2). Options to unlock existing technical flexibility and deploy new flexibility infrastructure are discussed, including:

- **Unlocking system flexibility**: Changes to future gas contract commitments (between PTT and Electricity Generating Authority of Thailand [EGAT]) to relax take-or-pay stipulations; changes to power purchase agreement (PPA) to enable more flexible operations, including higher ramp rates, lower minimum generation levels and shorter start-up times for conventional power plants.[6]

- **Deploying flexibility options**: Integration of electric vehicles (EV) with smart charging, DSM resources, battery storage and PSH are explored.

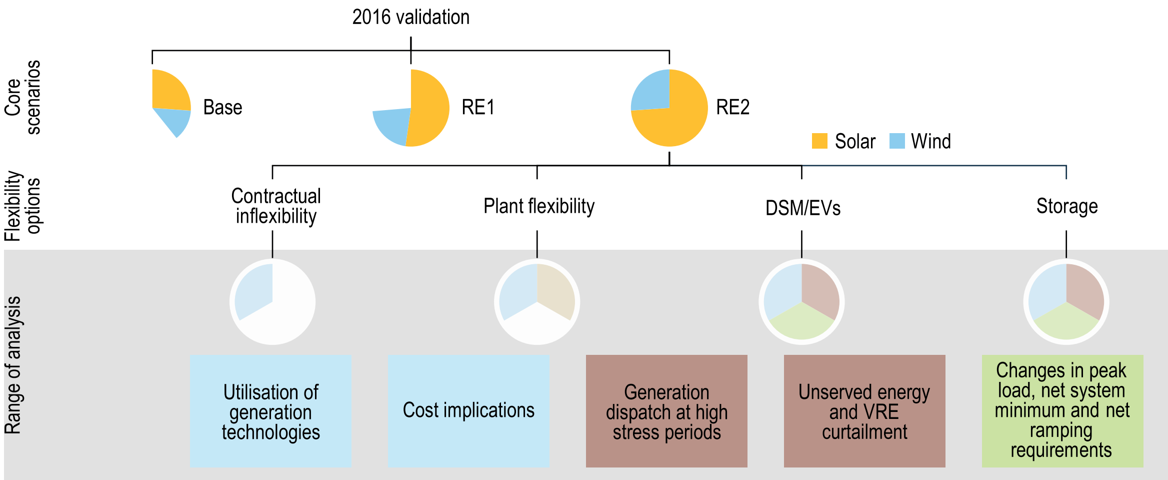
As discussed in Chapter 3, these flexibility options were determined based on the context of Thailand's power sector, considering possible flexibility improvements that are both technical and contractual in nature. Details of the modelling scenarios are provided in Annex C.

Table 4.1 • Modelling scenarios for different levels of RE and flexibility options

Scenario	Classification	Scenario name	Description
1	Validation	Existing (2016)	Based on 2016 load and available generation, for validation purposes
2	Core	Base	2036 scenario using existing official t targets of 6 GW solar and 3 GW wind; all other aspects based on 2015 PDP; flexible gas contracts (no take-or-pay terms)
3	Core	RE1	2036 scenario with 12 GW solar and 5 GW wind; flexible gas contracts (no take-or-pay terms)
4	Core	RE2	2036 scenario with 17 GW solar and 6 GW wind; flexible gas contracts (no take-or-pay terms)
4.1	*Contractual flexibility*	*Fuel contract inflexibility (RE2 – fuel contract)*	• *Impact of the take-or-pay gas contracts*
4.2	*Technical and contractual flexibility*	*Power purchase and fuel contract flexibility (RE2 – PPA and fuel contract)*	• *Flexible gas contracts (no take-or-pay terms)* • *Flexibility in PPA and plant characteristics (more flexible operating characteristics including minimum generation, ramp rates and start-up times)*
4.3	*Technical flexibility*	*Electric vehicles (EVs) (RE2 – EV)*	• *With flexibility in gas take-or-pay contract* • *Inflexible PPA and plant characteristics* • *With EV (1.2 million units)* • *Comparing unmanaged and smart EV charging options*
4.4	*Technical flexibility*	*Industrial demand side management (DSM) (RE2 – DSM)*	• *With flexibility in gas take-or-pay contract* • *Inflexible PPA and plant characteristics* • *With DSM options for steel and cement loads*
4.5	*Technical flexibility*	*Battery storage (RE2 – Battery)*	• *With flexibility in gas take-or-pay contract* • *Inflexible PPA and plant characteristics* • *With battery storage options (400MW/1 600 MWh) to provide peak shifting and peaking capacity*
4.6	*Technical flexibility*	*Pumped storage hydropower (PSH) (RE2 – PSH)*	• *With flexibility in gas take-or-pay contract* • *Inflexible PPA and plant characteristics* • *With PSH, both domestic and foreign hydropower*
4.7	*Technical and contractual inflexibility*	*EVs, DSM and storage (RE2 – EV, DSM, Storage)*	• *With flexibility in gas take-or-pay contract* • *Inflexible PPA and plant characteristics* • *With EVs, DSM and storage options*
4.8	*Technical and contractual flexibility*	*PPA and fuel contract flexibility, EVs, DSM and storage (RE2 – all flex options)*	• *With flexibility in gas take-or-pay contract* • *Inflexible PPA and plant characteristics* • *With EVs, DSM*

[6] Start-up times are defined as the time period from when the generator receives a signal to start-up operation from the system operator until the generator reaches its minimum generation level. In terms of its representation in the model, only the ramp rate from when the generator synchronises to the grid is captured.

Figure 4.2 • Scenario tree depicting the analysis of different flexibility options



Key message • Scenarios exploring the efficacy of different system flexibility options build upon the RE2 core scenario to assess the benefits that each can provide under higher shares of VRE generation.

Model validation

A validation scenario for 2016 was assembled to better understand how well the production cost model used in this analysis depicted the Thai power system. Results from the validation scenario were compared with actual operational data from Thailand's power system in 2016. This allowed for comparison of operational patterns observed in the production cost model with the real system, and informed efforts to calibrate modelling parameters, helping to ensure that any limitations to the model could be identified and taken into account in the analysis.

In general, the model was found to be similar to the actual system, particularly the energy mix from different technologies. There are some modest differences in outputs from hydropower and coal- and gas-fired generation resources, which are likely due to the fact that maintenance and outages were not included in the model. In addition, the use of dynamic reserves calculations in the modelling is different to the current system for reserves determination in Thailand, which is still based on deterministic approach. Details of the model validation are provided in Annex E.

Work stream 1: Grid integration assessment

This section describes the assumptions that have been made for the power system in Thailand in 2036 as well as the modelling methodology that was used. The approach to VRE site placement is also described.

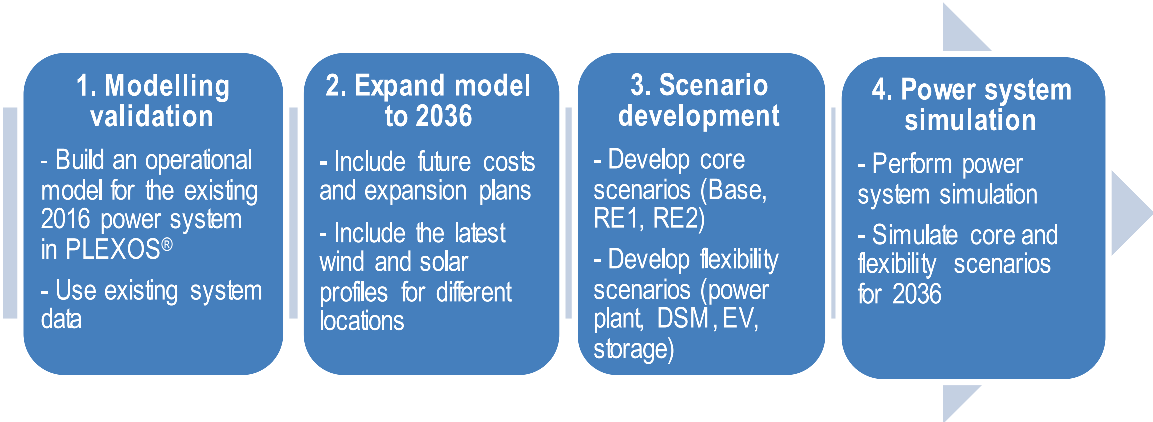
The grid impact assessment consists of two main components:

- a pre-analysis step based on historical load and generation data to validate the model
- a detailed assessment using production cost modelling for different scenarios.

Both components of the analysis are based on detailed data for the Thai power system provided mainly by EGAT, which is the same set of data that was provided to the Energy Policy and Planning Office (EPPO). Wind and solar generation series for different locations across Thailand are provided by Vaisala, as explained in Annex B. Modelling was performed using the PLEXOS©

Integrated Energy Model,[7] an industry standard, optimisation-based, power system modelling tool, that allows for detailed production cost modelling. There are other production cost modelling tools with similar features, such as PROMOD, SDDP and Balmorel, but their detailed features are somewhat different. See Figure 4.3 for the four main steps in the process for the grid integration assessment work stream.

Figure 4.3 • Steps for simulating the power system in 2036 for different scenarios



Key message • Simulation of a power system for a grid integration assessment requires systematically approached and well-formulated simulations.

A temporal resolution of 30 minutes is used for forecasted demand profiles, the techno-economic characteristics of power plants (including imports), hydropower energy constraints, transmission lines, and VRE generation profiles.

The power system of Thailand is represented in five main control regions: Central (CAC), Metropolitan (MAC), Northern (NAC), North-Eastern (NEC) and Southern (SAC). However, according to EGAT's operational procedures, the Central region is disaggregated even further due to its large size, with the Central-North (CAC-N), Central-East (CAC-E) and Central-West (CAC-W) regions resulting in seven separately modelled control areas, as shown in Figure 4.4.

The transmission system is based on the existing network in 2016, with the addition of EGAT-planned inter-regional connections until 2023. The foreign interconnections with the Lao People's Democratic Republic (Lao PDR) in the northern and north-eastern regions, and Malaysia in the south, are also considered. Due to the lack of transmission network expansion plans for the period beyond 2023, additional lines were assumed based on iterative simulations performed in PLEXOS, seeking the minimum amount of transmission infrastructure necessary to avoid the excessive transmission congestion that causes unserved energy.

While the transmission network is represented in the model, only active power flows are considered; detailed grid stability analysis is outside the scope of this project. Additionally, no capacity expansion model was developed. Thus, this analysis does not include any verification of the PDP 2015 expansion plan, nor does it attempt to develop a new expansion plan considering higher shares of renewables. Further details on the modelling are provided in Annex C.

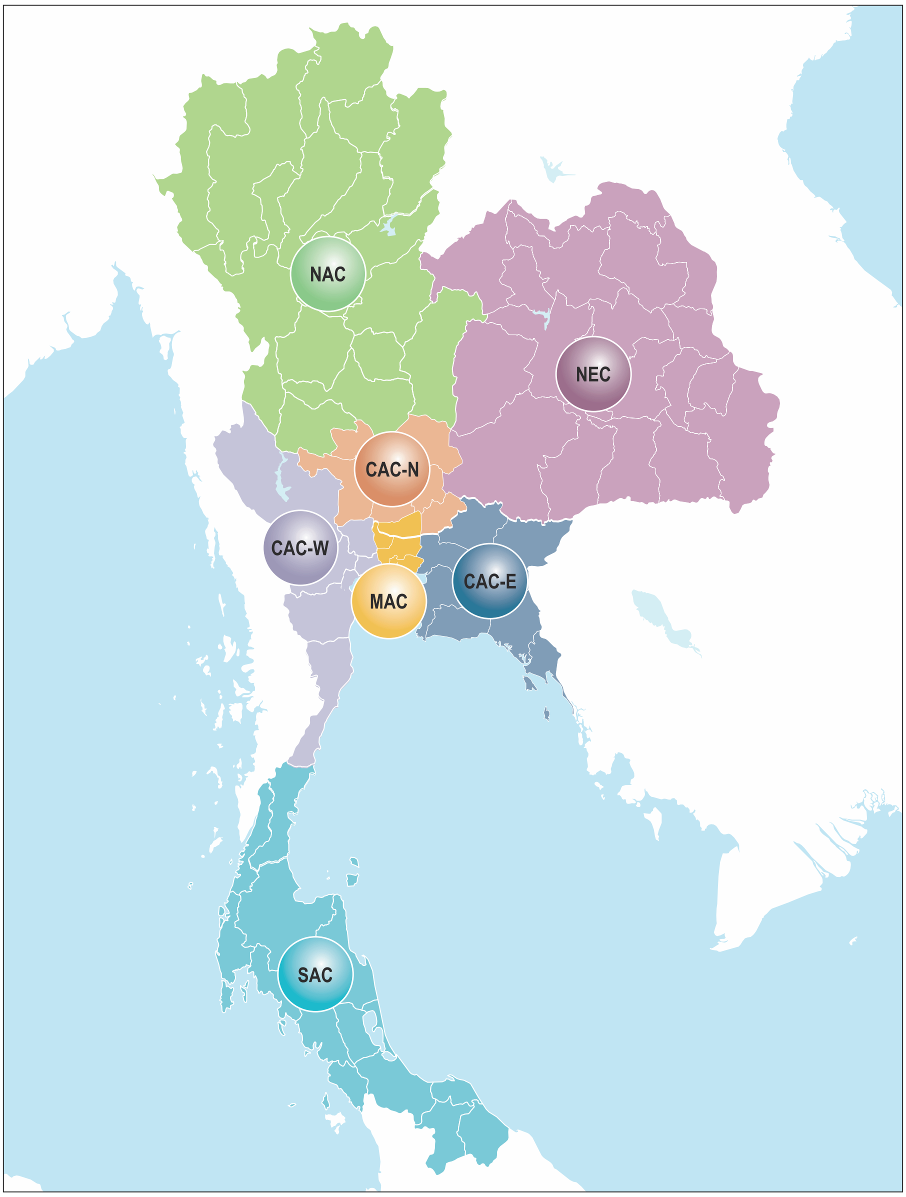
The main data used for the modelling were obtained from the relevant electric utilities and governmental departments, including: EGAT, EPPO, Department of Alternative Energy

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

Development and Energy Efficiency (DEDE), Provincial Electricity Authority (PEA), Metropolitan Electricity Authority (MEA) and the Office of the Energy Regulatory Commission (OERC). Literature reviews were also conducted to ensure that the data provided are consistent with international standards. In addition, data sources from the IEA *World Energy Outlook* (*WEO*) and *Energy Technology Perspective* (*ETP*) were employed, including: fuel costs, operational and maintenance (O&M) costs, and investment costs for some technologies. Consistent data were used across all three work streams. These data include time-series demand and generation, power plant technical characteristics, transmission and distribution network characteristics, wind and solar generation profiles, fuel costs, and power plant fixed and variable costs. Details of the input data are provided in Annex C.

The total installed capacity and the share of each generation technology used in the modelling of the core scenarios are shown in Table 4.2.

Figure 4.4 • Representation of the seven regions comprising the Thailand power system



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Key message • Power system operation in Thailand is separated into seven zones for the modelling.

Table 4.2 • Share of generation capacity of each technology used in the modelling

Types	Base		RE1		RE2	
	GW	%	GW	%	GW	%
Biomass	3.5	4.7	3.4	4.2	3.4	3.9
CCGT	22.1	30.1	22.2	27.2	22.1	25.3
CHP	4.9	6.7	4.9	6	4.9	5.6
Coal	10.0	13.6	10.0	12.3	10.0	11.4
GT (Diesel)	1.5	2	1.5	1.8	1.5	1.7
Hydro	16.8	22.8	16.7	20.5	16.7	19.1
Nuclear	2.0	2.7	2.0	2.5	2.0	2.3
OCGT	0.6	0.8	0.6	0.7	0.5	0.6
Solar PV	6.0	8.2	12.0	14.7	17.0	19.4
Thermal gas	3.3	4.5	3.3	4.1	3.3	3.8
Wind	3.0	4.1	5.0	6.1	6.0	6.9
TOTAL (GW)	**73.5**	**100**	**81.5**	**100**	**87.5**	**100**

Note: Thermal gas power plants are assumed to exist in 2036 based on the PDP, which stated the year of replacement but did not specify the types of generation technologies; CHP = combined heat and power; GT = gas turbine; OCGT = open cycle gas turbine; PV = photovoltaics.

Site selection for wind and solar PV power plants

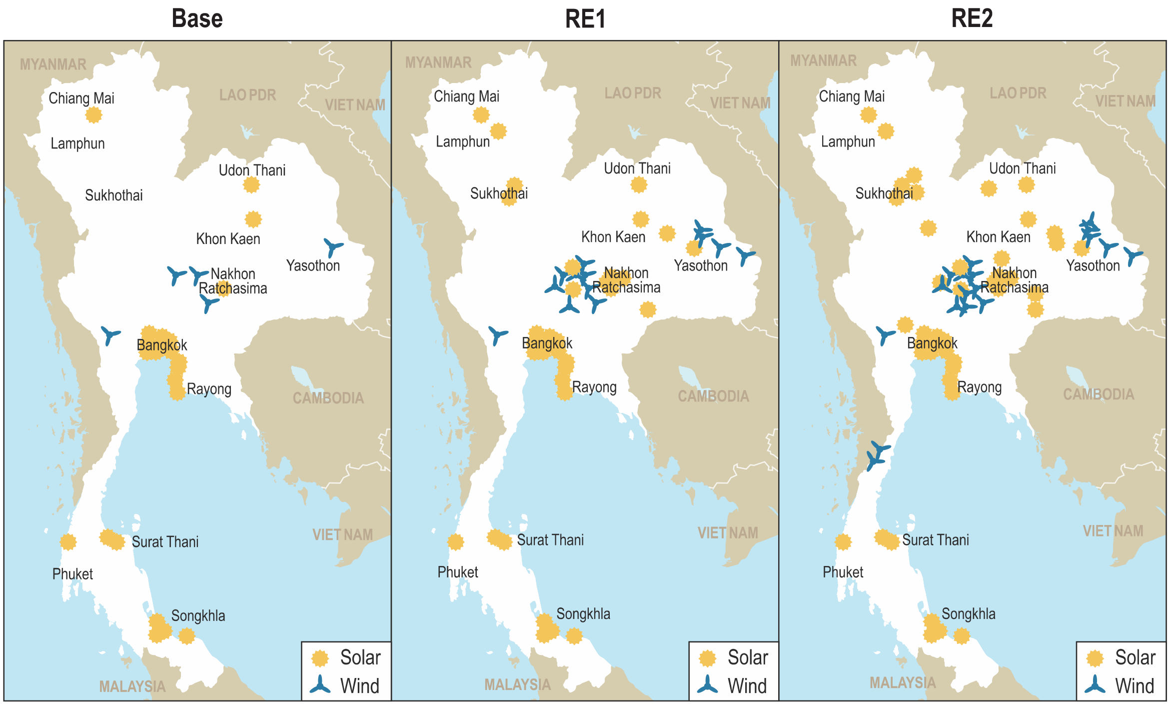
The locations of wind and solar PV power plants have been determined in three ways. For existing and planned projects, the co-ordinates and project size have been used directly from a current database (BNEF, 2018) with corresponding wind and solar resource data being employed. For DPV, four to six locations from each of the ten largest population centres were used, with the installations in each site scaled according to the renewable energy total for each scenario.

For the additional utility sites required to make up the additional capacity in the RE1 and RE2 scenarios, sites were selected based on renewable resource quality and their proximity to transmission infrastructure. The VRE site selection process also considers the site suitability by excluding areas that are protected, prohibited, and/or with challenging landscapes such as mountains, national parks, and agricultural land. The selected utility sites of wind and solar PV plants, as well as DPV, for each scenario are shown in Figure 4.5.

The wind and solar data used consist of simulated 15-minute generation over a ten-year period during 2007-16 in Geographic Information System (GIS)-compatible, 2-arc-minute grids (i.e. roughly 3-km geographical resolution) over the same period as the load profile in order to capture possible correlation. For wind potential, the wind speed was simulated for two different hub heights: 100 and 150 metres. At the time of this writing, these data are the latest and most up-to-date simulated wind and solar generation information available for Thailand.

The wind and solar PV resource maps across the country are shown and described in more detail in Annex B, including the verification of the accuracy of the data as well as a comparison with the data collected by DEDE in 2009 (Janjai, 2014).

Figure 4.5 • Locations of wind and solar PV power plants for the scenarios in 2036



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Key message • The proposed locations of solar and wind power plants are spread across Thailand.

Work Stream 2: Distributed Energy Resources

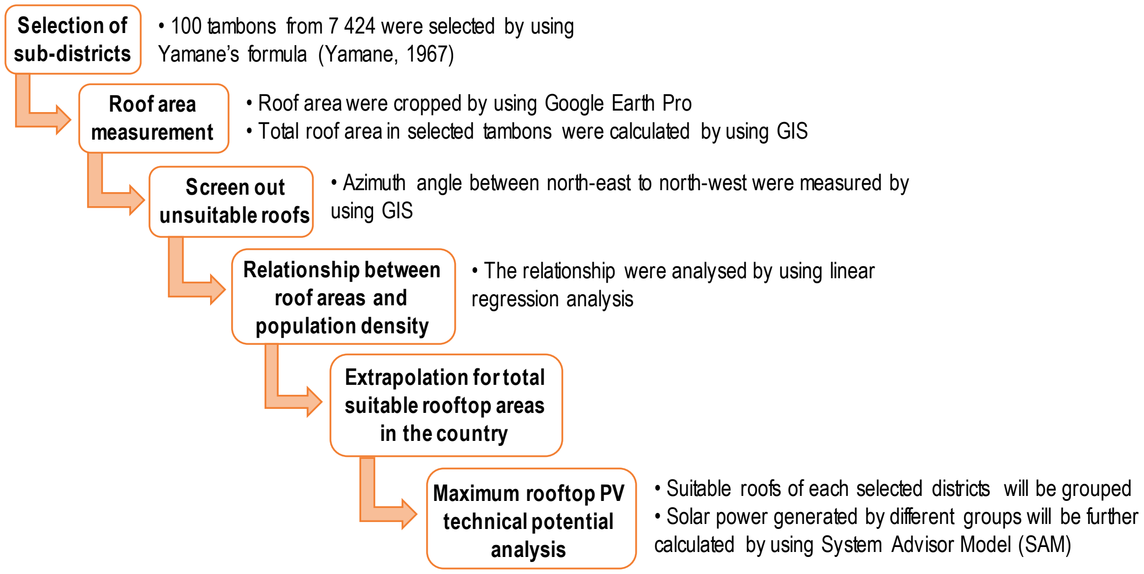
There are three main tasks in this work stream, which are to:

- estimate the gross technical potential for rooftop DPV deployment in Thailand
- evaluate the economic impacts of DPV on Thai utilities, which are EGAT, MEA, and PEA as well as on ratepayers
- explore the policy implications of retail tariff structures and buyback rates for DPV customers.

Technical potential estimation for rooftop DPV in Thailand

This section of work stream 2 quantifies the technical potential for solar PV systems to be deployed on rooftops in sub-districts in Thailand. The technical potential for rooftop PV was estimated measuring rooftop area in statistically representative sub-districts (tambons) using Google Earth Pro Data, Google Maps, GIS and applications of statistical methods. The methodology consists of six main steps (Figure 4.6) (see Annex C for details of the methodology).

Figure 4.6 • Methodology for assessing rooftop PV technical potential



Key message • There are six key steps for determining the rooftop PV potential.

Estimation of economic impacts of DPV on utility revenues and tariff options

Due to the possibility of adopting high PV, there are concerns from relevant stakeholders regarding the technical and economic impacts of PV and issues in the planning process. Therefore, it is important to address these points in order to move forward and utilise PV most effectively in the power system.

There are two tasks undertaken in this portion of the analysis:

- evaluate the economic impacts of rooftop PV on the Thai utilities (EGAT, MEA and PEA) and ratepayers given two deployment targets: Alternative Energy Development Plan 2015 (AEDP) (DEDE, 2015) and RE2.
- understand the policy implications of the buyback rate for rooftop PV generation, as well as explore different tariffs for rooftop PV using cost-benefit analysis.

The analysis considered the four groups of consumers that share the highest customer subscriptions and have high potentials to install rooftop solar PV in Thailand (as of December 2015).[8] These groups consist of residential customers (RES), small general service (SGS), medium general service (MGS), and large general service (LGS). These groups account for the majority of customer subscriptions in Thailand. Table 4.3 below presents the modelled system size per customer group. The load shapes of each customer group were scaled to match their peak demand to the capacity of the DPV systems. The capacity of the DPV systems for each customer group was defined through stakeholder consultation.

[8] The analysis builds on a previous study (Tongsopit et al., 2017) by selecting four groups of customers for the analysis. The four groups of customers have the highest adoption of DPV and a higher likelihood – based on economic reasons – to install DPV in Thailand.

Table 4.3 • PV size per customer group

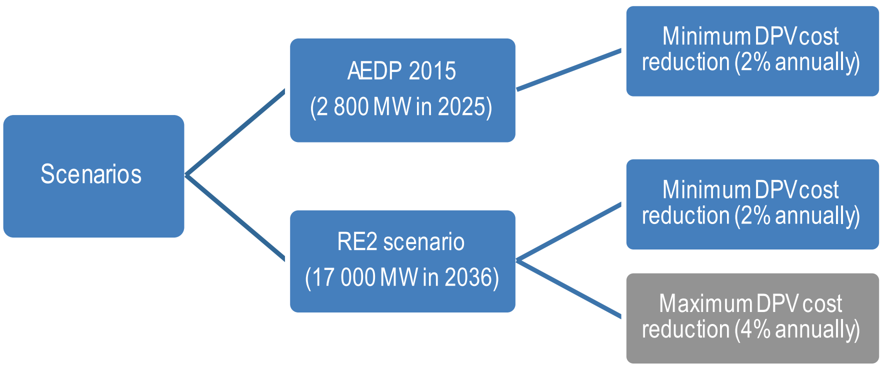
Groups	Peak load (kW)	DPV size (%peak load)	DPV size (kW)
Residential scale (RES)	5	100	5
Small general service (SGS)	5	100	5
Medium general service (MGS)	200	50	100
Large general service (LGS)	2 000	50	1000

Various net billing buyback rates and cost-reduction combinations were used to estimate the development of economic potential towards the selected DPV deployment targets. Under net billing, DPV generation is primarily self-consumed, and excess generation is exported into the grid and compensated at a pre-determined buyback rate. Exported electricity is modelled to be purchased at buyback rates of 0.00 THB/kWh, 1.00 THB/kWh, 2.00 THB/kWh, and the average EGAT wholesale rate of 2.73 THB/kWh. (Additional detail on the assumed payback periods used for market diffusion calculations is available in Annex C.)

Figure 4.7 outlines the scenarios used for the analysis. Two main economic impact scenarios were considered, the AEDP 2015 target for 2 800 MW of DPV deployment in 2025 and the RE2 scenario, which is used in the work stream 1 with a deployment target of 17 000 MW. This analysis builds on previous Joint Graduate School of Energy and Environment (JGSEE) analysis and uses a range of combinations as outlined below. The expected economic potential of the minimum-cost reduction and zero-buyback scenario was found to be closest to both the RE2 and AEDP in terms of economic potential. Thus, this scenario was selected and scaled down to study the economic impact of DPV deployment:

- maximum PV cost reduction: 4% DPV cost reduction annually; additional DPV installations in future years are calculated based on these reduced costs and changes to retail tariffs
- minimum PV cost reduction: 2% DPV cost reduction annually; additional DPV installations in future years are calculated based on these reduced costs to retail tariffs.

Figure 4.7 • Selected deployment scenarios in economic analysis



Key message • Two main scenarios are used in the economic analysis.

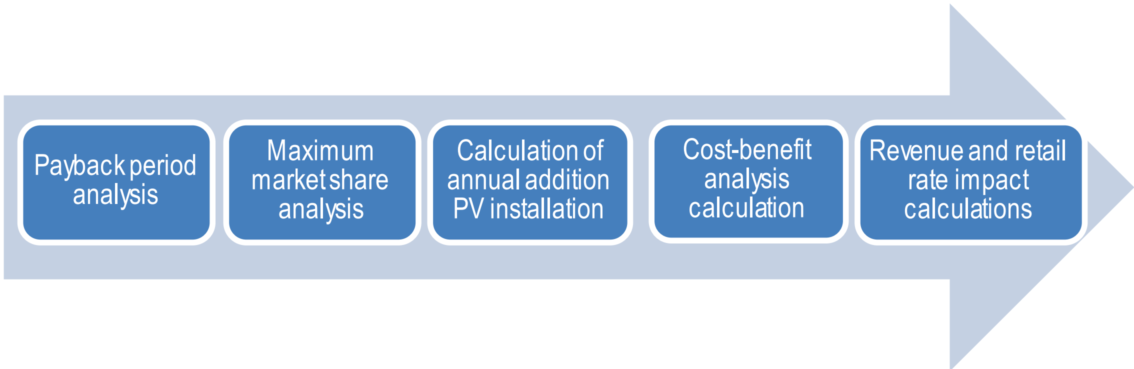
One crucial aspect of the analysis was the selection of a simplified approach to estimating the potential economic impact, based on pre-defined deployment targets. This ignores the fact that, in reality, as DPV grid injections displace grid purchases, EGAT, MEA and PEA's revenue base decreases, and retail rates need to be adjusted to maintain their regulated rate of return. This adjustment in turn affects the economic attractiveness of DPV installations. In principle, increasing retail rates that are due to negative revenue impacts on utilities are expected to lead to more installations, thus compounding the effect over time. While this is a very important dynamic to study, it complicates the connection between analytical results and policy recommendations because of the difference between the *ex post* economic potential and the original DPV deployment target.

For this reason, the economic impacts on utility revenues are first analysed according to a deployment path that is not dependent on retail rate updates. This has a further advantage of shedding light on the distribution of impacts across utilities, depending on the relation between wholesale rate, retail rate, and buyback rate.

In a further step, these revenue impacts are passed onto consumers through retail rate adjustments in five-year instalments. This reflects the current nature of rate design in Thailand, which allows for retroactive cost recovery in the following regulatory period. More importantly, this highlights the issue that, while utilities may see some degree of revenue impact as a result of deploying DPV, additional costs are ultimately passed onto consumers.

Figure 4.8 shows the framework diagram of the DPV analysis. Briefly described in Table 4.4 are the five main steps in assessing the economic impact of rooftop PV in Thailand. (Details of each step are explained in Annex C.)

Figure 4.8 • DPV economic analysis framework diagram



Key message • The methodology for estimating the economic impact consists of a number of related calculations.

Table 4.4 • The main features of each of the main analysis steps

Key approaches	Description
1. Payback period calculation	• Perform payback period analysis of rooftop PV for each customer group (RES, SGS, MGS and LGS) using System Advisor Model (SAM).
2. Maximum market share determination	• Define the PV adoption scenario to input to CBA modelling. • Apply customer adoption model to forecast PV adoption in Thailand. • Forecast is based on relationship between the willingness of technology adoption and payback period (Beck, 2009). • The number of customers of each group was used as a technical potential to convert the maximum market share to maximum PV adoption in MW.
3. Annual growth in DPV economic potential	• Annual additional PV adoption for each scenario was addressed using a technology penetration curve called the "Bass Diffusion Model" (Bass, 1969). • The Bass model provides an explanation of the forces behind the exponential growth stage (the first half of the S-curve) and the saturation stage (the second half of the S-curve). • The DPV installation as of 2017 was taken as the starting point of the annual additional DPV adoption, as summarised in Table 4.5.
4. Cost-benefit analysis (CBA)	• Assess the magnitude of the net revenue impact on utilities due to DPV deployment. The cost and benefit components for each utility are provided in Annex C.
5. CBA interpretation in terms of impacts on utility revenue and retail rates	• Calculate average retail rate increase required to collect otherwise lost revenue associated with DPV deployment.

Table 4.5 • Current rooftop DPV installation as of 2017

Rooftop installed capacity (MW)	Customer group				TOTAL
	RES	SGS	MGS	LGS	
MEA	11.6	11.6	16.9	37	77.1
PEA	16.6	16.6	24.3	53.1	110.6
GRAND TOTAL					**188.3**

Work stream 3: PDP assessment and VRE system cost analysis

In this work stream, the current approaches that were applied in developing Thailand's PDP 2015 and AEDP 2015 are assessed as well as several other aspects of power sector planning in Thailand. The work stream also focuses on examining the methods used for determining reserve margins and forecasting electricity consumption. In addition, in order to inform the ongoing process of the PDP revision, an analysis on VRE capacity credit and system cost value (costs and benefits) is also conducted for select scenarios.

Assessment of power system planning for the PDP

An assessment of power system planning processes is conducted from multiple viewpoints, which that are relevant for increasing VRE deployment in Thailand:

- determining power sector reliability and reserve margin criteria
- assessing frameworks and tools used for power system planning
- assessing the existing methodology for determining the capacity value (or capacity credit) of VRE resources (referred to as "dependable capacity" in Thailand).

Based on the analyses, and in reference to successful examples of planning practices in other countries (Mexico, South Africa and France), possible approaches to improve the current power system planning are recommended for Thailand.

Capacity credit estimation for wind and solar

Although outside the original scope of the project, the IEA conducted a simplified estimation of VRE capacity credit since it became increasingly clear that the capacity credit, especially of solar PV and wind, is highly relevant for power sector planning, and it appeared to be under significant debate in Thailand as to how it is best calculated. This method is an elaboration of the method used for the IEA *World Energy Outlook*[9] (IEA, 2017). The methods used for determining the capacity credit of solar PV and wind in Thailand are provided in detail in Chapter 7.

The capacity credit of a power plant can be defined as the amount of additional load that can be served due to the addition of the generator to a power system while maintaining the same level of reliability (Keane et al. 2011). It is generally expressed as a fraction of the nominal power plant capacity.

$$\text{Capacity credit}=\frac{\text{Additional load (MW) met at same level of reliability}}{\text{Installed capacity of additional generator}}$$

This can also be thought of as the contribution that a generator makes towards capacity adequacy for peak demand. It is important to understand that the capacity credit of wind and

[9] See section 4.1.3 in the methodology documentation available on: www.iea.org/media/weowebsite/2017/WEM_Documentation_WEO2017.pdf.

solar is not a single number that can be calculated and then applied in all cases. This is a strong difference compared to conventional resources. The capacity credit of VRE changes with the share of VRE and geographical distributions of resources as well as with the loss of load probability (LOLP) of the system. Key factors which capacity credit depends on include:

- renewables resource profiles
- geographical distribution of generators
- underlying power system load shape
- interactions with existing wind and solar generation.

These aspects are essential to understanding the outcomes of a capacity credit analysis and how system-specific they are. The underlying load shape has a critical impact on the relative capacity credits of solar and wind. In a system where the peak occurs in the afternoon, solar has the potential to provide a strong contribution to capacity adequacy. Conversely, in a system where peak demand occurs consistently after sunset, solar will have little or no capacity credit. On the other hand, wind resources tends to be stronger in the evening and night time, and thus wind will have a higher capacity credit for evening peaking systems.

This influence of the load shape also explains how the capacity credit changes with increasing penetration of wind and solar. The impact of each new MW of solar or wind will depend on the *net* load shape of the system (i.e. the load less VRE generation), which changes as more solar and wind are installed.

For the same reason, there are also interactional effects between wind and solar resources – in a system with an afternoon peak that is only moderately higher than the evening peak, solar can shift the net load peak into the evening, where the capacity credit of wind is higher. Thus, when their contribution to peak capacity is considered together, both technologies may provide a stronger contribution than each considered in isolation. These principles lead to two different ways to consider the capacity credit of VRE: *average capacity credit* and *marginal capacity credit*.

The average capacity credit approach estimates the total contribution to peak requirements that all installed solar and wind generation provide for a given system. This is useful to understand the overall contribution of VRE to resource adequacy for that system and can then be used to estimate overall system costs. The methodology to estimate the average capacity contribution compares the load duration curve without VRE to the net load duration curve for the VRE penetrations in each of the modelling scenario. This enables the overall impact on the net load (and thus to peak dispatchable generation requirements) to be captured. For this assessment, a strict 10th percentile criterion was imposed, which estimates capacity credit based on the contribution that wind and solar exceed 90% of the time for the top 2% of load periods. In order to include the interaction of solar and wind, the net load curve for each is separately compared with the total load curve, and then the difference from their combined curve is divided evenly between the two technologies.

The marginal capacity credit instead looks at the contribution of one additional MW of solar or wind, given the existing installed capacity. It is useful to consider what capacity value new generation will provide for a given penetration level of wind and solar. In this case, around 20 000 combinations of different levels of VRE penetration (measured as a percentage of electricity demand, not accounting for any curtailment, from 0% to 50% in 0.5% increments) and shares of solar PV (going from using only wind power, so 0% solar PV, to using only solar PV, i.e. 100% also in 0.5% increments) were considered. For each combination of VRE share and solar PV share, net load was calculated for the 2036 load curve used in the scenario analysis in the grid impact assessment section. For each of the calculated net load time series, the 2% of time periods with the highest net load were selected. For each time period, the average combined capacity factor of wind and solar was calculated. The 50th percentile of these values is then used for each wind and solar penetration level as an indicator of their combined capacity contribution. The results of the assessment are presented in Chapter 7.

Quantifying system economic effects of VRE

In order to understand the economic impacts of integrating VRE into a power system, assessment of its system level economic effects is necessary. Generation cost for various technology options is most commonly expressed in levelised cost of electricity (LCOE), representing the average lifetime cost for providing a unit of output (MWh). However, the LCOE approach does not account for some important aspects of power generation, particularly the timing, location, intertemporal aspects and operational characteristics of the technology. Therefore, particularly to evaluate VRE, additional metrics that account for the interactions between these power plants and the rest of the power system can be employed.

Adding VRE will trigger two different groups of economic effects in the power system:

- **An increase in some costs.** This includes the cost of VRE deployment itself (i.e. the LCOE), costs for additional required grid infrastructure, and/or increased costs for providing balancing services. This group can be termed *system costs* or additional costs.
- **A reduction in other costs.** Depending on circumstances, cost reductions might occur due to reduced fuel costs for conventional generators, reduced carbon dioxide (CO_2) and other pollutant emissions costs, a reduced need for other generation capacity, a reduced need for transmission infrastructure, and/or reduced transmission system losses. This group can be termed *benefits* or avoided costs.

Three different ways to express system effects – the balance of the aforementioned costs and cost reductions – are used in this report:

- **System cost analysis**: Often, the addition of VRE capacity is compared to alternative forms of new generation, such as CCGT or coal plants. This approach calculates the system effects associated with VRE compared to other generation options; it can be helpful for comparing different technologies to each other.
- **Cost-benefit assessment**: Adding up all additional and avoided costs indicates the overall cost-benefit of adding VRE. This comparison is useful to understand whether adding VRE can help reduce customer bills. Note that this comparison only covers economic impacts of VRE integration and does not include other factors, for example, reduction of CO_2 emissions.
- **Total power system costs**: The all-encompassing method to account for all relevant system effects is to calculate total power system costs, including both capital and operational costs for different scenarios with varying amounts of VRE.

Concepts of each approach are briefly presented below, and the details are explained in Annex C. For further information, please refer to the IEA Wind and PVPS (2018).

System cost analysis methodology

VRE technologies have specific characteristics that affect their contribution to power system operation and investment compared to conventional generation technologies (IEA, 2014). Three properties are perhaps the most relevant:

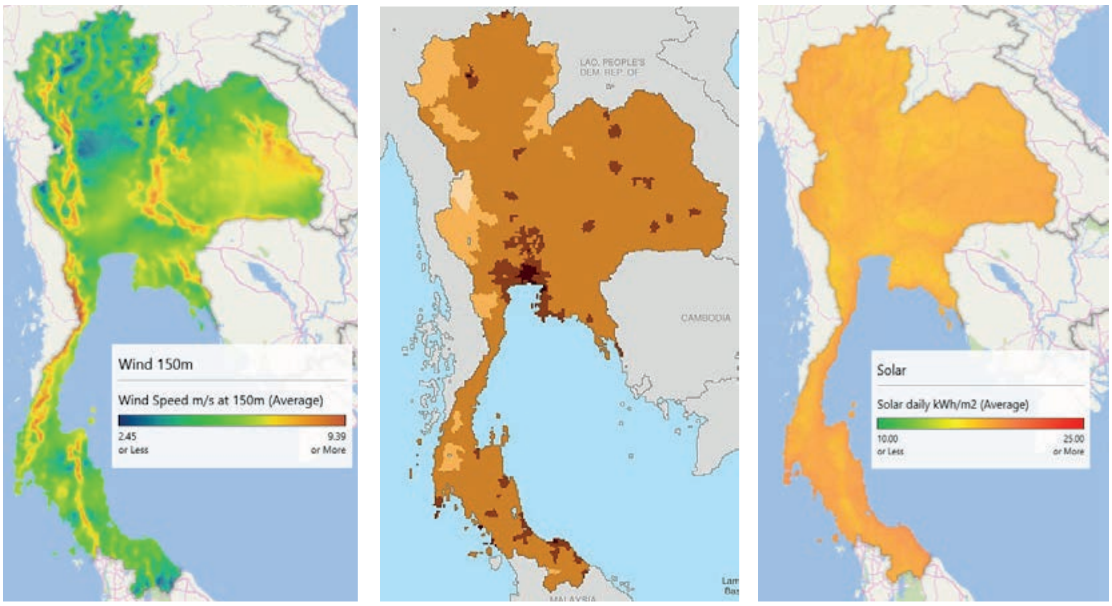
- **Variability** – available power output fluctuates with availability of primary resource (wind or sun).
- **Location constraints** – resource quality differs by location and primary resource cannot be transported.

- **Uncertainty** – the exact availability profile of the resource can only be predicted with high accuracy in the short-term.

These properties affect the interaction of VRE power generation with the electrical system. It is possible to define three cost categories that correspond to these properties: profile costs, grid costs and balancing costs (Ueckerdt et al., 2013; Hirth et al. 2015).

- **Profile costs**: These describe the effects associated with the temporal pattern of VRE generation in the medium term, in particular, the non-availability of VRE during periods when demand is close to available generation capacity, possible periods of surplus VRE generation, and reduction in the utilisation of other power plants. These costs involve reserve capacity to provide sufficient capacity during peak periods and the cost of curtailing solar and wind.
- **Grid costs:** Costs reflect the delivery of VRE to demand, which are associated with transmission constraints and losses, and incurred due to the location of generation in the power system (Figure 4.9). It covers the costs of upgrading the transmission and distribution network to ensure sufficient capacity during periods of peak generation.
- **Balancing cost**: Costs associated with the short-term uncertainty of VRE generation, which involves deviations from generation schedules, for example, the costs to balance forecast errors of VRE; the cost of providing reserve and cycling; and start-up and shutdown costs to accommodate VRE.

Figure 4.9 • Comparison of VRE resource availability for wind (left) and solar (right) with population density (middle)

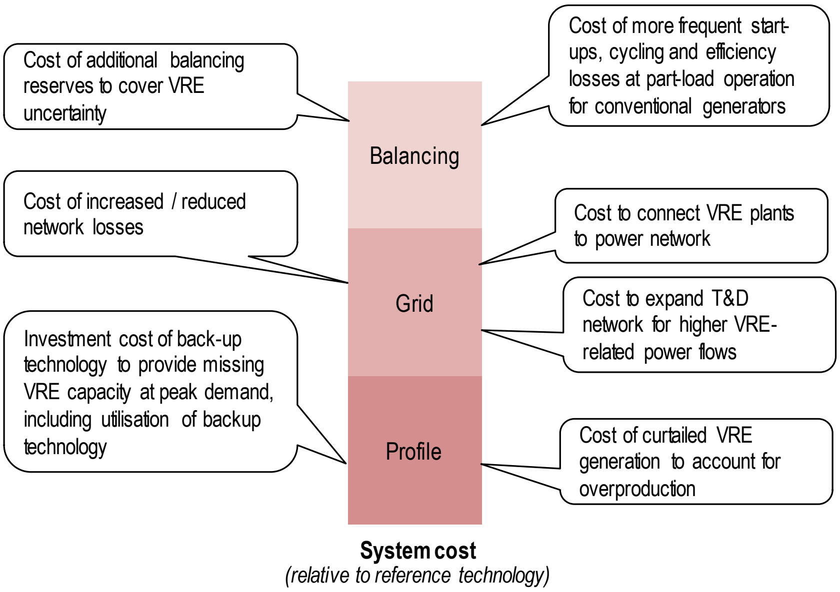


Key message • Discordance between geographical distribution of VRE resource and population density can incur grid costs for transporting the VRE.

The three cost components of the system costs only considered the costs associated with each component while the benefits are not directly considered in this analysis since the purpose is to compare the costs of VRE with reference technology, which is assumed to be CCGT. The methodology of system costs is explained in detail in Annex C.

Figure 4.10 summarises the discussed system cost components of VRE generation and shows which factors are considered for calculating system costs in this analysis.

Figure 4.10 • Components considered in quantifying system cost of VRE generation relative to a reference technology



Key message • Profile, grid and balancing cost encompass the primary components relevant for system integration of VRE.

Note that there are a number of other positive and negative system effects, which could be considered; however, only major issues that are typically considered in policy makings are considered in this analysis. In addition, grid reinforcement costs are estimated based on operational simulations in PLEXOS© and general assumptions on the cost of grid connection.[10]

Calculating these different cost categories explicitly requires defining a reference technology to which VRE impacts are compared and then quantifying the difference between the reference and the VRE case. This is highly complex and requires making a number of ad hoc assumptions. The resulting system costs directly depend on the choice of benchmark technology. Examining system costs for only VRE does not provide useful information in itself. For this report, a reference technology of a CCGT with a capacity factor of 80% and grid connection costs of 0 THB/kW are used as a reference. **Unless otherwise stated, all system costs expressed in this report are valid only relative to this reference.**

System costs are the costs incurred because of interactions between a power plant and the rest of the power system. Therefore, they not only depend on the characteristics of VRE technologies but also on the power system into which they are integrated and the power system's flexibility to adapt. Also, additional system costs do not only apply to VRE, but also to all the generators in the power system (e.g. large nuclear plants requiring contingency reserves). However, the analysis in this report only calculates the system cost of VRE by assuming that the system cost of a reference technology is negligible, since comparing system costs of all the technologies is beyond the scope of this study.

[10] A full stability analysis would be needed to inform the exact grid cost implications because such analysis helps to explain what kind of additional transmission would be needed to reduce congestion and losses to an acceptable level – however, these considerations are beyond the scope of this study.

It is crucial to note that the reduction in utilisation of conventional plants is a highly contentious area, especially regarding cost allocation, i.e. the question of "who should pay". When there is additional VRE deployed on a power system, it can have a considerable impact on power system operations, for example, if existing power plants are dispatched less than previously expected. These changes must be sharply distinguished from the long-run costs associated with meeting demand, even at times when wind and solar PV are not available. Long-term costs should ultimately inform long-term planning choices, and there are many options to reduce such costs with innovative flexibility measures. In turn, the short-run cost-effectiveness of adding VRE can critically depend on what capacity is already present. Moreover, the ownership structure has a key impact, determining who bears any costs incurred and whether they are passed on to consumers.

For the calculation of system costs, the impact on reducing full-load hours of existing generators is not taken into account. Rather, a comparison is made between adding the reference technology (CCGT at 80% capacity factor) and adding VRE plus the amount of "back-up" capacity needed to provide the same amount of firm capacity. This analysis can help inform the question: "Is it cheaper to build a CCGT or wind/solar?" but not the analysis question: "Should we build anything at all?"

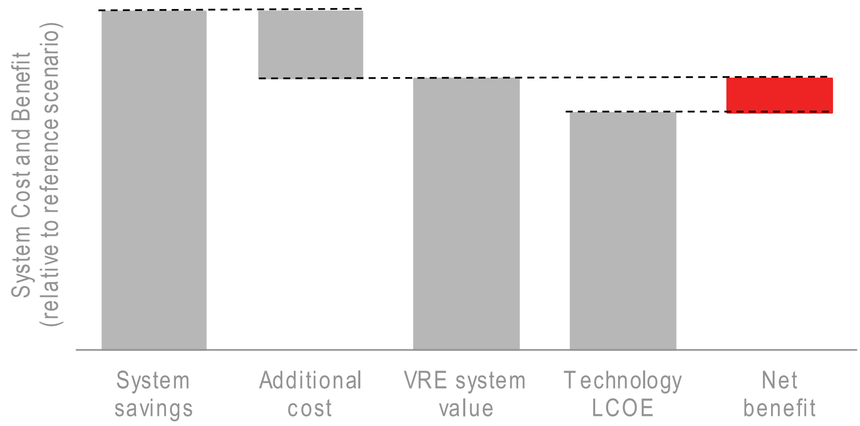
The system costs of different scenarios of VRE (Base, RE1 and RE2) are also analysed as well as the potential role of the flexibility options, particularly smart EV charging, in reducing the system costs.

Cost-benefit analysis

System value is defined as the overall benefit arising from the addition of a wind or solar power generation source to the power system; it is determined by quantifying positive and negative impacts on the system and summing them together. This system value can then be compared to the generation cost of VRE. This cost-benefit comparison answers the question of whether adding a certain technology to the system brings more benefits than costs (IEA, 2016, Figure 4.11). If system value is larger than generation costs of VRE, there will be a net benefit. Conversely, if system value is lower, there will be a net cost.

This approach can analyse the effect of adding VRE capacity (or any other technology) to the system compared with any alternative scenario, including the option of not building any new generation. Two types of cost-benefit analyses are carried out for this report, a short-term analysis and a long-term analysis. A short-term analysis focuses on the alternative of not building any new generation at all. Here the primary benefit of VRE is avoiding fuel consumption. A long-term analysis compares the costs with the benefits of adding VRE capacity, including a reduced need for building other technologies as a result of the capacity contribution from VRE. However, because a complete future reference scenario was not available for this report, the long-term analysis is based on comparing the given VRE deployment scenario with two assumed scenarios; one is the addition of a CCGT, and the other is supercritical coal. The approach does not take into account policy-related costs and benefits, such as surcharges of feed-in tariff programs that could be added onto electricity bills, or reductions of CO_2 emissions.

Figure 4.11 • Approach to quantify net benefit of VRE generation



Source: Adapted from Hirth et al. (2015), *Integration Costs Revisited – An Economic Framework of Wind and Solar Variability.*

Key message • Net benefit is the difference between the system savings and the sum of additional costs and LCOE.

Total power system cost analysis

This report also contains an analysis of the ***total power system cost*** for the modelled scenarios described in Table 4.1. Total power system costs are defined in this analysis as the sum of annuitised capital expenditure (CAPEX) and operational expenditure (OPEX) for the given power system (generation, transmission and distribution) and its particular operational pattern, assuming that the entire system is built as a greenfield system in 2036. Although it is not able to capture the impacts of a legacy power system infrastructure and the timing of investment decisions, at the same time by treating all scenarios with the same methodology it does provide an insight into the relative total costs between low and high VRE cases. By using this approach, the analysis estimates the impact of VRE penetration and flexibility measures on the long-term cost of the power system.

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5. Grid integration assessment of Thailand's future power system

HIGHLIGHTS

- Higher shares of wind and solar generation can lower overall system operating costs in Thailand, primarily through reducing fuel costs as renewables replace gas-fired generation. Ensuring fuel supply, and establishing sufficiently flexible power purchase contracts, will help to secure cost savings.
- Because wind and solar output have highly complementary generation profiles to one another, as shown in the modelling, they contribute to both midday peak demand and evening peak demand.
- As penetration of variable renewable energy (VRE) increases, so does the expected variability in net demand. This results in an increased cycling of conventional generators and the need to use more expensive peaking capacity to meet ramping requirements.
- Net ramping requirements in 30-minute, 1-hour, and 3-hour periods increase with higher shares of VRE generation. However, the Thai power system – as currently planned for in 2036 via the PDP 2015 – is still capable of accommodating such requirements.
- Conventional power plants, such as coal and combined-cycle gas turbine (CCGT), will be required to provide ramping services and will be increasingly cycled with a higher share of VRE. While conventional plants in Thailand are technically capable of meeting ramping requirements, their ability to do so may currently be limited because of the nature of the fuel supply arrangements and power purchase agreements, which constrain operations.
- Enhancing flexibility – whether through augmenting technical (i.e. supply side and demand side), contractual, or operational characteristics of the power system – allows supply and demand variability to be effectively matched, resulting in a more reliable and cost-efficient operation of the power system.
- A scenario in which fuel supply and power purchase contracts are made more flexible in 2036 produces the most significant cost savings across all modelled scenarios. Relaxing contractual constraints will optimise the dispatch of generation, resulting in a marked reduction in overall fuel costs as well as operation and maintenance (O&M) costs.
- Based on the modelling performed, it is evident that the 2036 Thai power system could be in Phase 3 of VRE integration, where system flexibility becomes an important factor.

This chapter analyses the modelling results of the Thai power system in 2036 under different scenarios of VRE deployment, including a number of flexibility options as described in Chapter 4. The main objective of this effort is to understand how solar and wind generation could affect the Thai power system and, thereafter, to assess the operational and economic benefits of flexibility options in accommodating higher shares of VRE generation. The main components of the analysis are as follows:

- comparing key results between the Base, RE1 and RE2 scenarios, which are the core scenarios that are based on the Power Development Plan (PDP) 2015 (EPPO, 2015)
- comparing results for RE2 with scenarios of the same VRE deployment and additional flexibility options deployed, considering both technical and contractual flexibility options
- conducting a VRE phase assessment of different scenarios in 2036, which evaluates modelling outcomes based on a number of criteria which are provided in Annex A.

The core scenarios are assessed on both an operational and economic basis. The operational aspects include the dispatch of power plants, the provision of reserves, and power flows on the transmission infrastructure. This chapter focuses particularly on power system operation during periods of high system stress, which are the peak and lowest demand periods, and the periods of steepest ramping requirements, with a particular focus on upward ramping requirements. The economic analysis focuses on how this affects operational costs, which links to the broader system cost analysis in Chapter 7.

The flexibility options explored under the RE2 scenario include augmenting the flexible operating characteristics of conventional power plants; demand-side management (DSM), with a focus on industrial demand-side response; electric vehicles (EVs) with smart charging; pumped storage hydropower (PSH); and battery storage.

Contribution of solar and wind generation to Thailand's power system in 2036

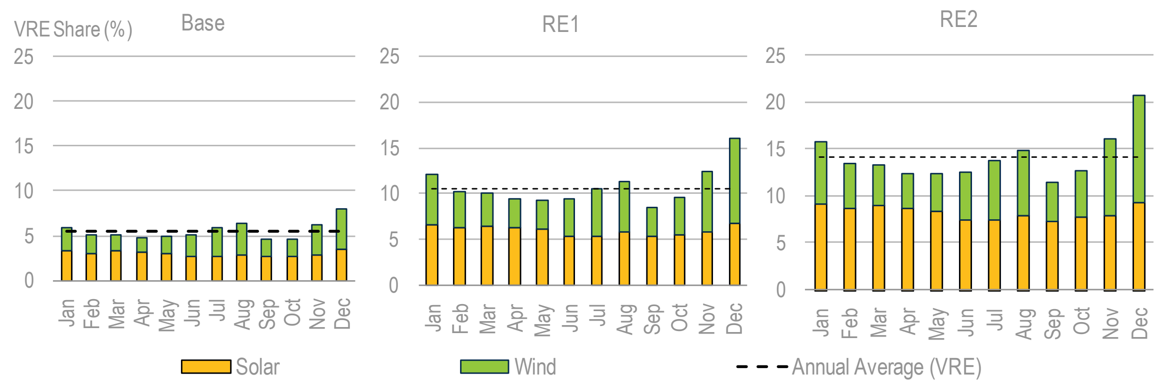
This section analyses the contribution and impact of VRE for the core scenarios. This includes examining the seasonal and locational variation of VRE and the operational impact of VRE, with a focus on the highest and lowest demand periods, the impact on ramping requirements, operational reserve requirements, transmission system operation, and power plant utilisation.

Locational and seasonal impact of VRE in Thailand

The amount of solar and wind generation and their penetration levels in the modelled scenarios of Thailand vary by month (Figure 5.1). For every scenario, VRE penetrations are highest in November to January: approximately 8% in the Base scenario, 16% in RE1, and 20% in RE2; and they are lowest in September and October: approximately 5% in the Base scenario, 8% in RE1, and 11% in RE2.

The solar generation simulated in the model is relatively consistent throughout the year; however, its highest output occurs during the less rainy seasons in Thailand, from December to May. Wind penetration varies more significantly, with the highest penetration observed in December and the lowest in May, June, July and October. This is due to the distinct monsoon seasons in different regions in Thailand.

Figure 5.1 • Monthly and average share of VRE penetration for different scenarios

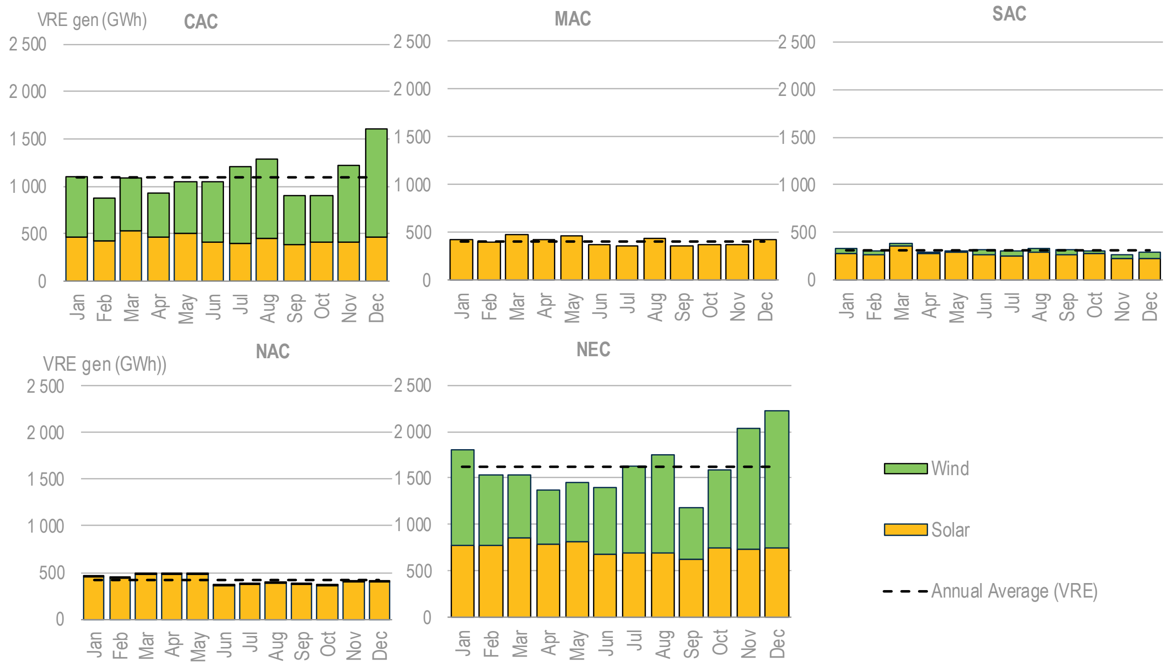


Key message • VRE penetration in Thailand varies by month throughout the year.

Seasonal surpluses and deficits of VRE generation are a characteristic of power systems that may require additional flexibility options, such as seasonal storage to cover the mismatch during periods of low VRE output and high demand, and vice versa. Depending on the availability of hydropower plants with large reservoirs or VRE with complementary seasonal output, the seasonality of VRE generation output can be a major challenge to power system operation.

Solar and wind generation vary across different regions in Thailand (Figure 5.2). The Central (CAC) and North-Eastern (NEC) regions have more VRE generation than other regions in the modelling scenarios because of the greater availability of sites that are suitable for development and stronger transmission infrastructure. The seasonal variation of VRE generation for the modelled scenarios is greatest in the NEC region, largely due to the difference in monthly wind generation, which is lowest in September. On the other hand, the monthly solar generation output is relatively constant for every region, which is consistent with the averaged result for the whole of Thailand. As a result, all regions dominated by solar generation, i.e. the Northern (NAC), Metropolitan (MAC), and Southern (SAC) control regions, are expected to have a seasonally consistent output of VRE generation.

Figure 5.2 • Monthly VRE generation in different regions for the RE2 scenarios



Key message • VRE generation varies between regions due to different wind and solar resource characteristics.

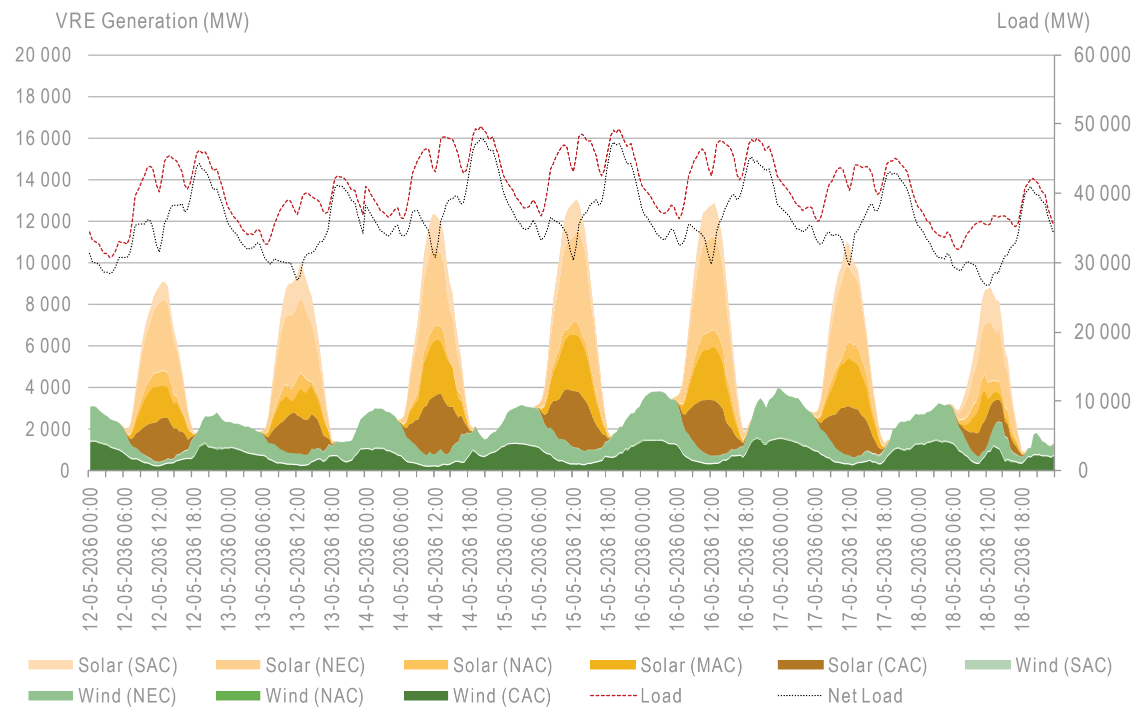
The yearly average of VRE penetration is calculated as the ratio of annual generation from VRE against total generation. When calculated thus, the NEC has the highest yearly average VRE penetration, around 59% for the RE2 scenario (Table 5.1) due to relatively high installed VRE compared with total generation from other technologies. The lowest VRE generation and penetration are experienced in the MAC region, owing to the limited potential of VRE sites, particularly for utility-scale plants. In NAC, the penetration is relatively high, but mostly from solar as previously shown.

Table 5.1 • Annual average VRE penetration in different regions in Thailand across core modelling scenarios

Regions	Average VRE penetration (%)		
	BASE	RE1	RE2
Central (CAC)	4%	8%	11%
Metropolitan (MAC)	1%	3%	4%
Southern (SAC)	6%	9%	12%
Northern (NAC)	6%	12%	18%
North-Eastern (NEC)	24%	45%	59%
TOTAL	**6%**	**11%**	**14%**

The contribution of each VRE technology during peak demand periods and its correlation with demand patterns can be visualised by comparing VRE generation profiles with the total demand profiles (Figure 5.3). It is important to view these results, which are largely influenced by the geographic distribution of VRE resources and the assumed load shape in 2036, within the context of the assumptions as presented in Chapter 4. Solar generation output, which generally occurs in the afternoon, is shown to have a high correlation with the afternoon peak demand. Wind generation is present throughout the day but generally ramps up during the late evening and provides a better contribution to the evening peak. In this regard, the modelling suggests that the solar and wind generation patterns in Thailand complement each other, with solar providing a stronger contribution during the day and wind contributing more in the evening.

Figure 5.3 • VRE generation profiles versus the demand profile during an example week in the RE2 scenario

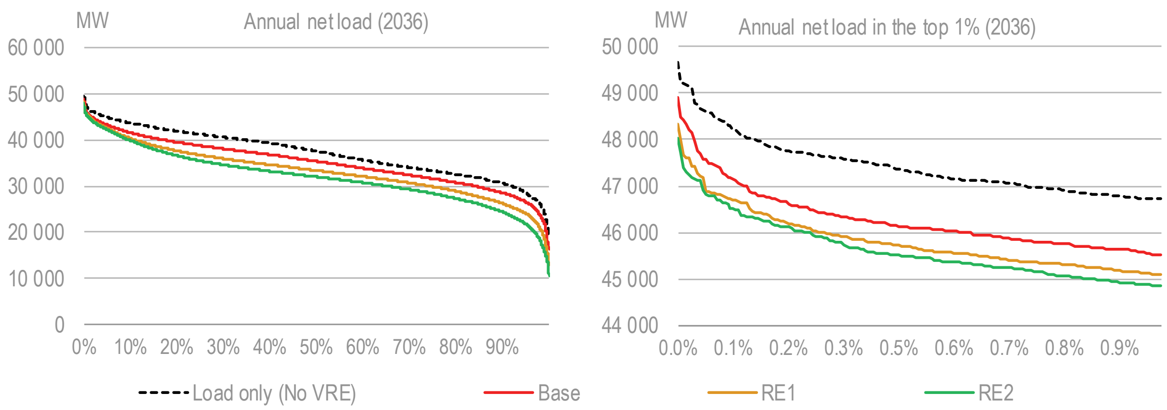


Key message • There is a high contribution of solar towards Thailand's midday peak demand, while the wind profile generally ramps up during the evening as demand increases.

An examination of the net load duration curve (LDC) for the different scenarios allows for a more generalised overview of the contribution of VRE generation during the peak periods for the modelled period (Figure 5.4). For the top 1% of peak demand, the contribution of VRE appears to be moderate as the share of VRE increases. As VRE penetration increases from 12% (RE1) to 16% (RE2), the additional contribution of VRE during peak periods is more moderate than the increase from 6% (Base) to 12% (RE1).

The net LDCs also shed some insight on how VRE changes the annual net load profile. These results show that the gap between the highest and lowest net demand increases, with the inflections in the curves becoming steeper. This corresponds with lower minimum net load periods resulting from VRE and a tendency towards steeper ramps, which will be discussed in more detail.

Figure 5.4 • Net annual LDC for core scenarios (left); zoom-in of net annual LDC for top 1% of load (right)



Key message • The net load duration curve shows the contribution of VRE during peak demand periods.

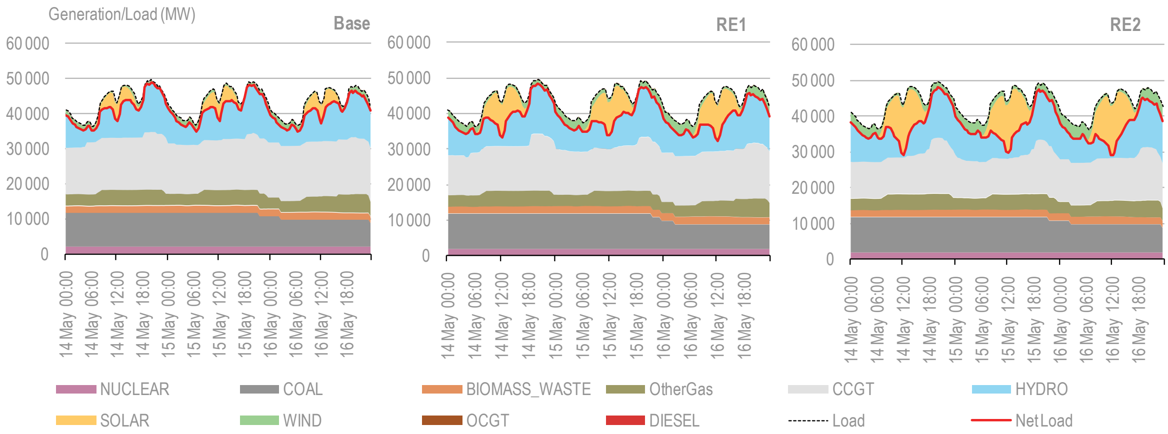
Operational impacts of different VRE penetrations in 2036

The operational impact of solar and wind generation is examined for the core scenarios (Base, RE1 and RE2) with different VRE penetrations. As previously described, VRE can have a number of operational impacts on the power system. These are explored in the following subsections.

Operation during highest and lowest demand periods

A power system should be able to respond adequately under the periods of increased stress that occur in response to high demand, high ramping requirements, contingency events, and a range of other conditions. These periods often provide an indication of the capability and strength of the power system to accommodate high shares of VRE generation. During the peak demand period, which occurs in mid-May, there is sufficient generation to handle the high demand, although some of the peaking plants such as diesel gas turbines (GTs), which are system's least economical units, need to be dispatched. This peak period, which occurs in May, also coincides with the high solar photovoltaic (PV) output periods (as shown in Figure 5.1). Additional VRE is shown to benefit the system by displacing conventional generation, particularly CCGT plants since they are operated as load following plants (Figure 5.5).

Figure 5.5 • Generation output by technology during the period of peak demand (14-16 May 2036)



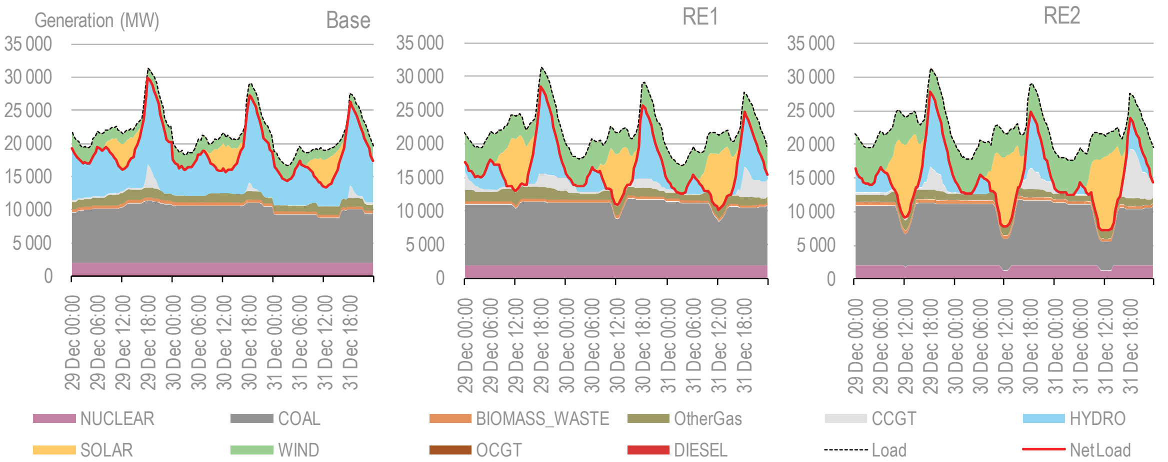
Note: *Other gas* refers to combined heat and power (CHP) from small power producer (SPP) and thermal gas power plants.

Key message • VRE generation displaces CCGT generation with little effect on other thermal generation. Additionally, it reduces net system peak demand but also creates an evident trough in net demand around midday.

During the period of minimum load, which occurs at the end of year, the traditional baseload plants, including coal and nuclear, are required to cycle more often as well as operate near the minimum generation (Figure 5.6). As VRE penetration increases, this effect is amplified because of the greater variation in net load, resulting in the shutdown of some coal units and increased cycling of nuclear generation output.

During this period, hydro generation output is less as the share of VRE increases in the RE1 and RE2. However, hydro is required to cycle more frequently, and to a greater degree, due to its flexibility in ramping and start-up time. CCGTs must completely shut down in the minimum demand periods.

Figure 5.6 • Generation output by technology during the period of minimum demand (29-31 December)



Key message • VRE generation displaces generation from cheap, inflexible coal and nuclear units during the period of minimum load.

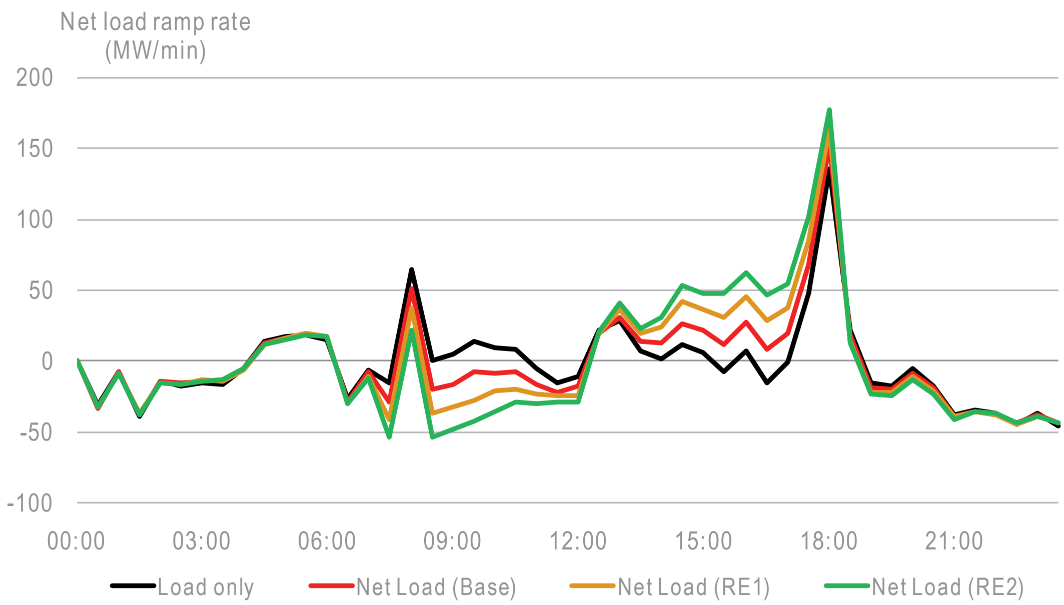
Ramping requirement impacts

VRE generation can have a significant effect on system ramping requirements because of its variability and partial unpredictability. Generally, as VRE penetration increases, the variability of VRE resources leads to greater ramping requirements. However, VRE outputs can also be beneficial to the power system, such as through the correlation between wind generation and peak demand in the evening. The extent of VRE's contribution to the power system depends on the unique characteristics of both the demand profile and VRE generation, which include a range of various social, economic and geographical factors. However, an opposing interaction, such as an increase in load coinciding with a decrease in solar generation in the evening, can pose a considerable challenge for system operation.

The highest net ramp is observed during the evening peak, which is between approximately 120-180 MW/minute for the three scenarios (Figure 5.7). This net ramp rate increases with higher shares of VRE, with a 16% increase between the RE2 and Base scenarios.

The impact of VRE on the 30-minute upward ramping requirements across the entire year for all scenarios is presented in Appendix D.

Figure 5.7 • Net load ramping during day of peak net demand ramp rate

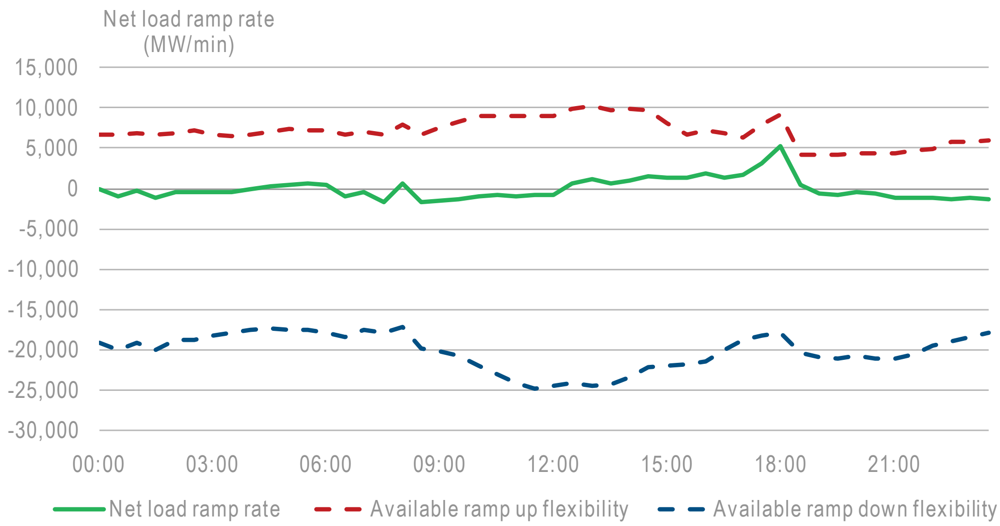


Key message • Highest observed ramping requirement occurs in the evening peak, and its magnitude increases with higher shares of VRE.

The ramping requirement is an important consideration since it helps to inform the total amount of operational flexibility required to support power system operations. As an increase in VRE generation can increase the ramping requirements, this is a deciding factor for whether the system has sufficient flexibility to accommodate higher shares of VRE. While this flexibility can come from a number of sources such as demand response (DR) and storage, the core scenarios only consider the inherent flexibility in power plants in 2036.

In order to evaluate power plant flexibility, the upward and downward flexibility in the period of peak ramping is analysed against the ramping requirements for the RE2 scenario (Figure 5.8). The result suggests that the Thai power system in 2036 would have sufficient technical flexibility to meet both upward and downward ramping requirements. While the spare flexibility for upward ramping is significantly tighter than downward ramping, this is not deemed a concern due to the availability of hydropower plants to provide a source of quick-start generation. This can be observed through the increased use of hydropower as ramping requirements increase because of higher shares of VRE generation, as shown in Annex D (Figure D.3).

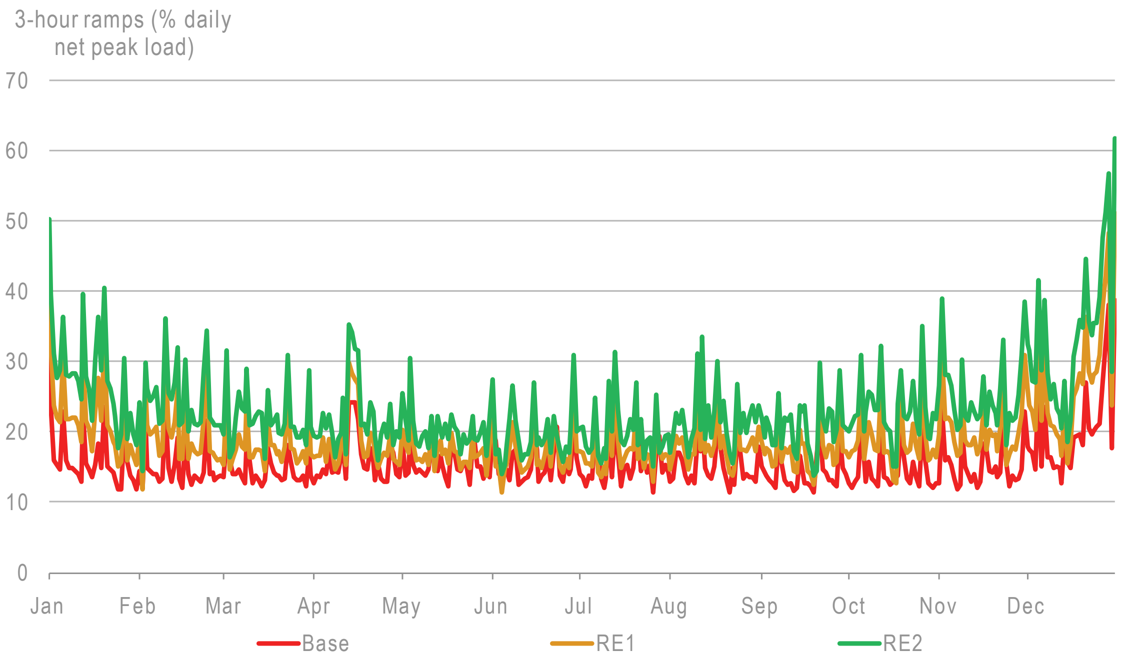
Figure 5.8 • Net 30-minute ramping and spare upward and downward ramping flexibility in the 2036 Thai power system for RE2 scenario



Key message • Thailand's power system in 2036 appears to have an adequate amount of ramping capability to accommodate the increased VRE deployment.

In addition to short-term ramping requirements, the occurrence of longer duration ramping events can be challenging for system operation. Thus, it is important to assess the effect of VRE generation on longer-term ramping requirements. The daily 3-hour ramping requirements are presented for different scenarios of VRE penetration (Figure 5.9). The highest 3-hour ramp requirements, which are around 50% to 60% of the daily peak demand, occur during the long holiday periods at the end of the year when the net demand is generally low during the day and rises sharply beginning in late afternoon. The maximum 3-hour ramps increase from 39% of the daily net demand in the Base scenario to 62% in RE2. These are significantly higher than the historical ramping requirement in Thailand in 2016, which was around 25% (as shown in Chapter 3). However, modelling results suggest the system can still reliably accommodate such ramping requirements.

Figure 5.9 • Daily peak 3-hour upward ramping as % of daily peak demand throughout the year



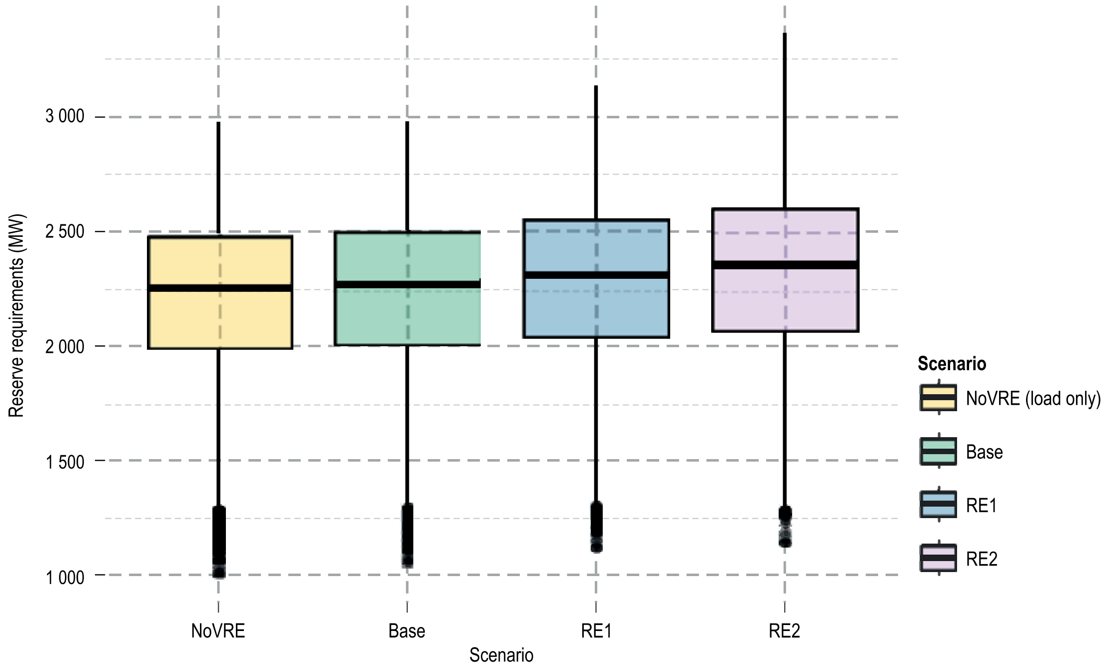
Key message • Higher shares of VRE has a significant impact on the 3-hour ramp rates. However, the Thai power system is shown to have sufficient flexibility to meet these ramping requirements.

Operating reserve requirement impacts

Operating reserves are procured to ensure system security and reliability vis-à-vis a number of system uncertainties. Although these uncertainties are addressed by different reserve products at different operational timescales, these products can all be grouped under the term "operating reserves". While reserve requirements are often static based on the largest single system contingency during peak or off-peak periods (e.g. loss of generator or main network component), they can also include dynamically calculated components to account for both demand and VRE forecast uncertainty. To analyse the potential impact of VRE generation on operating reserves, a conservative reserve requirement has been assumed in the model, based on the geometric sum of load (6%) and VRE forecast uncertainty (12% for wind and 15% for solar). These are all grouped as a single reserve product with an activation time of 10-minutes.

The results show that while reserve provision is higher as VRE penetration increases, load continues to be the determining factor for reserve requirements, even in the highest renewables case (Figure 5.10). The comparison of reserve requirements for Base and RE2 scenarios with current EGAT requirements is shown in Annex D.

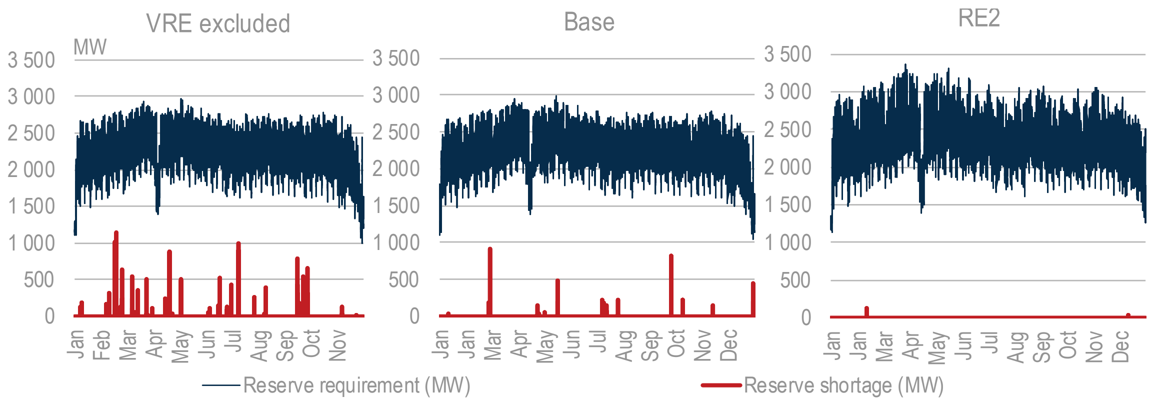
Figure 5.10 • Annual reserve requirements in different VRE scenarios



Key message • Spinning reserve requirements increase as shares of VRE increase. However, load remains the primary driver of spinning reserve requirements in Thailand, even under high VRE deployment.

Based on the specified reserve requirements, increased VRE leads to higher reserve requirements (11% increase between Base and RE2 scenarios), however, it also means that there are fewer reserve shortages, which are also smaller. Overall, the result is greater system reliability (Figure 5.11).

Figure 5.11 • Reserve shortfall versus requirement for different VRE penetrations

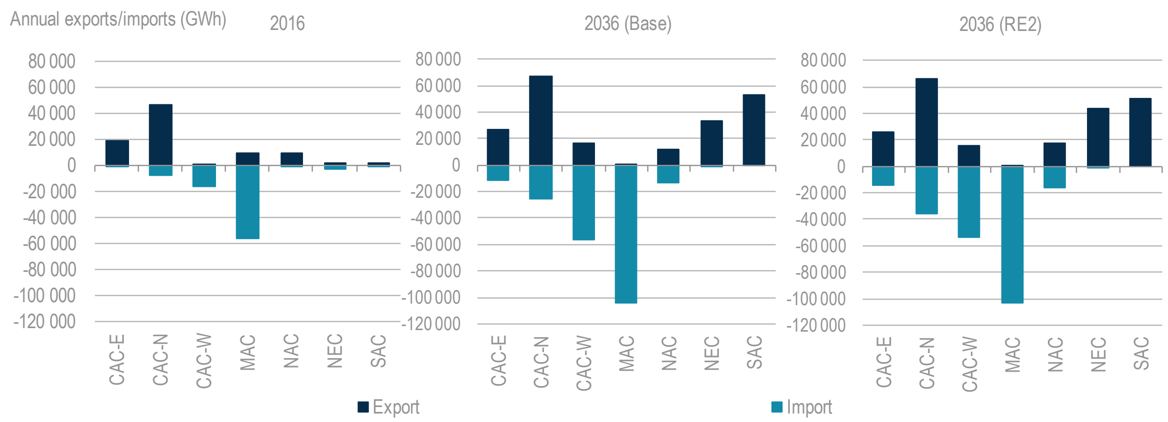


Key message • As the share of VRE increases, reserve shortages are less frequent despite a higher reserve requirement. Thus, VRE results in a higher overall level of system reliability.

Transmission system impacts

According to the PDP 2015, the amount of generation in each region will change significantly, resulting in changes to the observed flows on the future transmission grid and the amount of power exported to and imported from various regions (Figure 5.12). The most notable difference from the current situation is the shift in the SAC region from mostly importing electricity to becoming an exporter to the central regions. This is due to the SAC's relatively high generation capacity and capacity reserve margin.

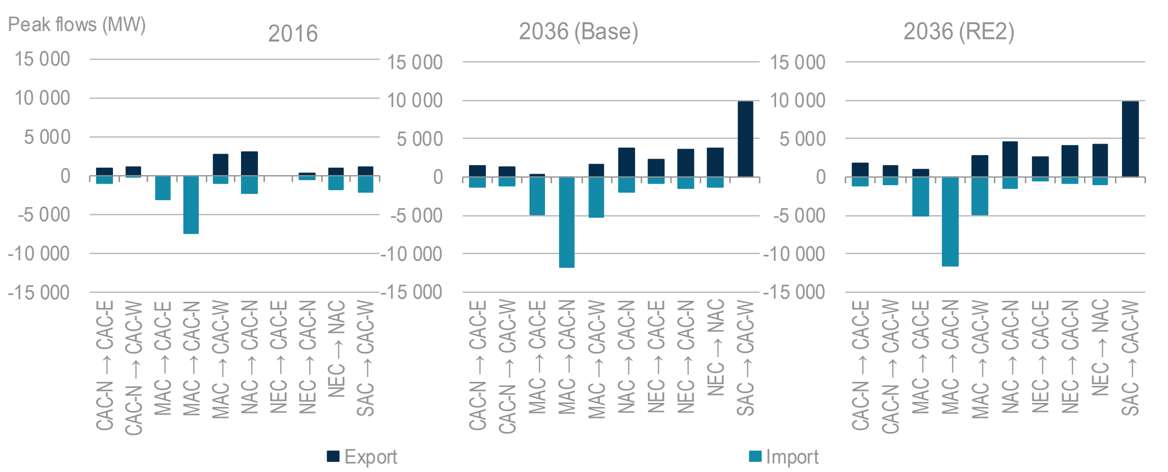
Figure 5.12 • Annual imports/exports per region in both 2016 and 2036



Key message • Imports and exports from most regions grow proportionally with demand between 2016 and 2036 The exceptions are the NEC and SAC regions because of a marked change in the generation mix in these regions. The impact of VRE on imports and exports is relatively small.

Due to the lack of detailed transmission network expansion plans beyond 2023 in the PDP 2015, additional transmissions lines were assumed in the power system model, based on iterative simulations performed in PLEXOS. The goal was to seek the minimum amount of transmission infrastructure necessary to avoid the excessive transmission congestion that caused unserved energy.[11] This resulted in further strengthening the 500 kV network between the CAC-W and SAC regions and the parallel corridors between the NEC and CAC to accommodate the significant increase in peak flows on these corridors (Figure 5.13).

Figure 5.13 • Peak flows on the transmission network



Key message • Generally, peak flows increase with higher share of VRE although the effect is relatively small in magnitude.

[11] Transmission bottlenecks were identified via iterative runs of the production cost model. In order to relieve congestion on the network, transmission additions (based on the parameters of existing lines) were modelled and flows assessed over iterative simulations.

While losses have not been explicitly modelled, they have been calculated post-simulation in order to give an idea of the impact of different VRE penetration levels on losses, with a gradual increase as the share of VRE increases. This increase in losses can be attributed to the change in power flows on the transmission network as VRE replaces conventional generation sources. This is illustrated in additional detail in Annex D.

Impact on power plant utilisation

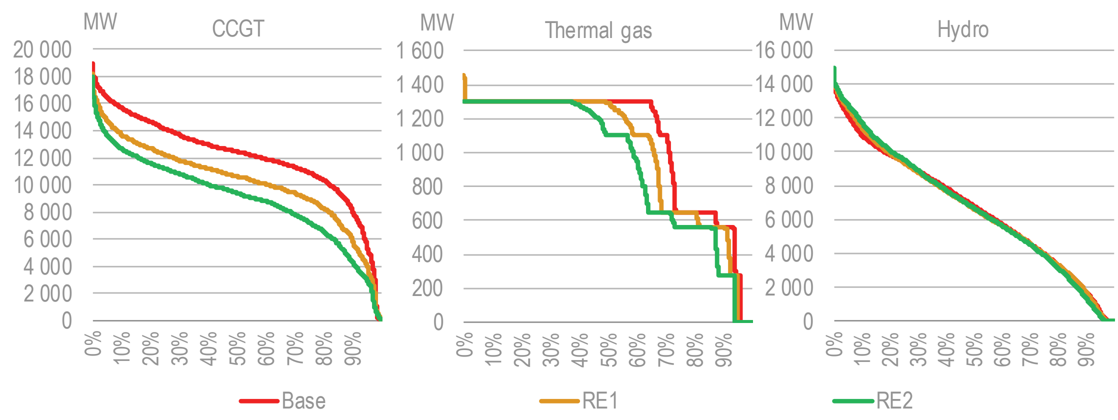
While both cost impacts and the effect on system operation at peak and minimum demand periods have been explored, the results have not shown how the utilisation of different generation technologies changes as the share of VRE increases. The annual generation duration curve (GDC) of different technologies displays the utilisation trend, which is influenced by the operational and economic characteristics of generation technologies (Figure 5.14).

The greatest noticeable difference on generator utilisation resulting from increased VRE deployment is on the operation of CCGTs and thermal gas plants, where relatively large amounts of energy are displaced by wind and solar PV generation (as represented by the area under the duration curves). There are some slight changes in the operation of hydropower as the use of this energy-constrained resource is shifted slightly to balance supply and demand with a greater share of VRE.

For nuclear and coal-fired generation, the GDCs are largely inelastic throughout the year since they are operated as traditional baseload.[12] These two technologies are largely inelastic to the increase of VRE generation in the core scenarios. The GDCs are almost identical with only very slight changes in the volume of energy (<0.3%) observed between different scenarios.

GDCs for all generation technologies can be found in Annex D.

Figure 5.14 • Generation Duration Curves (GDCs) of select technologies for different VRE scenarios



Note: Thermal gas power plants are assumed to exist in 2036 based on the PDP 2015, which stated the year of replacement but not the type of generation technologies.

Key message • Generation from CCGTs and thermal gas plants are displaced by wind and solar as the share of VRE increases.

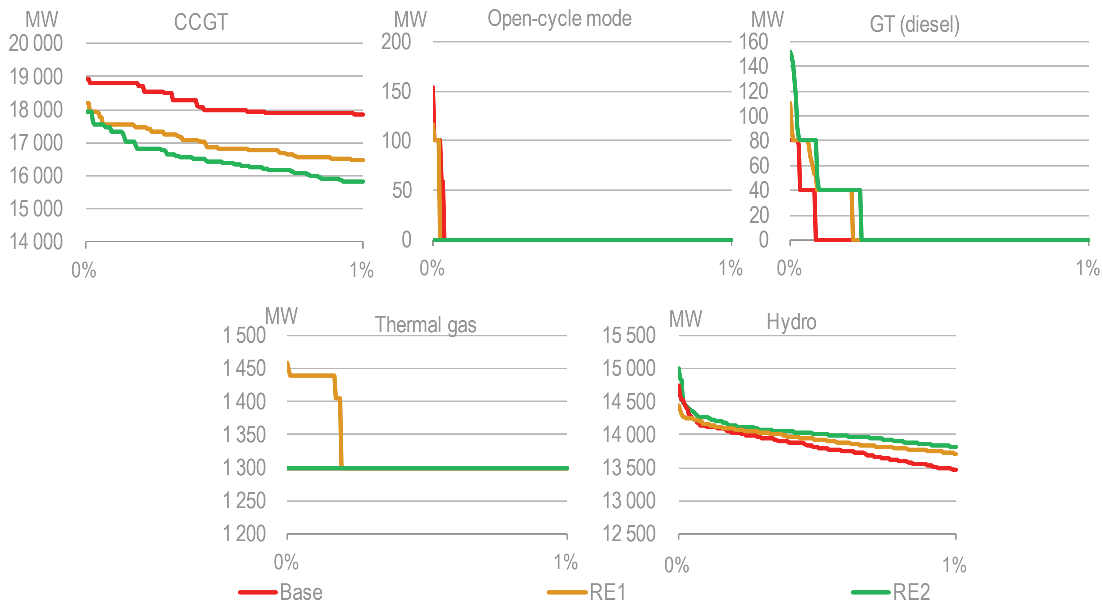
In terms of the operation during the period of peak generation, the GDCs for the top 1% suggest that there are only subtle changes to their peak utilisation for different VRE penetrations

[12] This is illustrated in Annex D.

(Figure 5.15). CCGTs face the greatest changes, since their peak generation is reduced by around 700 MW in RE1 and 1 000 MW in RE2 when compared to the Base scenario.

Utilisation of diesel-fired GTs increase both in the total volume of generation and magnitude of peak generation as the share of VRE increases (a 20-MW increase and a 50-MW increase in peak generation levels in RE1 and RE2, respectively, from the Base scenario). The more expensive generation from diesel GTs exceeds that of CCGTs in open cycle mode due to their unavailability during the high system-stress periods, which require more flexible operation (e.g. a high ramping event), when most CCGTs are operating in combined-cycle mode. There is also a higher peak utilisation of hydropower generation as VRE generation increases.

Figure 5.15 • GDCs of all technologies in the top 1% for different VRE scenarios.



Key message • The generation during peak periods changes as the share of VRE generation increases, especially as a large amount of CCGT generation is displaced by wind and solar PV.

It should be noted that this result is in the context of a power system with a healthy capacity reserve margin that is well above the PDP-specified planning margin, even when the potential capacity contribution of VRE generation is not considered. As such, this result would be expected to change in a system with an optimised capacity expansion with full consideration of all available demand- and supply-side resources, including VRE generation.[13]

Flexibility options to accommodate VRE integration

A number of flexibility measures exist that can help with the integration of VRE. These options can be considered as either technical or contractual options. As described in Chapter 4, contractual flexibility options include relaxing fuel and power purchase agreement (PPA) that otherwise prevent optimal generation dispatch. Technical options include increasing the flexibility of generating plants, particularly their operational characteristics. Other technical

[13] As this analysis excludes a verification or re-optimisation of capacity expansion plan in Thailand, it is likely that the more subtle results observed may change with a different generation mix. The capacity reserve margin is shown in Annex D.

flexibility options are stronger and smarter grids, electricity storage technologies, and demand-response resources.

In this modelling, the flexibility options that are evaluated include the following (as presented in Table 4.1 in Chapter 4):

- fuel supply contract flexibility *(RE2 – fuel contract)*
- enhanced flexibility of conventional generating units through improved power purchase and fuel supply contracts *(RE2 – PPA and fuel contract)*
- managed EV charging load *(RE2 – EV)*
- demand-side management (DSM) of industrial (steel and cement) loads *(RE2 – DSM)*
- deployment of additional battery storage *(RE2 – battery)*
- additional deployment of PSH plants at new foreign hydropower sites*(RE2 – PSH)*
- combination of managed EV, DSM and storage *(RE2 – EV, DSM, storage)*
- combination of power purchase and fuel contract, EV, DSM and storage *(RE2 – all flex options)*.

Note that some of the flexibility scenarios including DSM are separately presented in detail in Annex D.

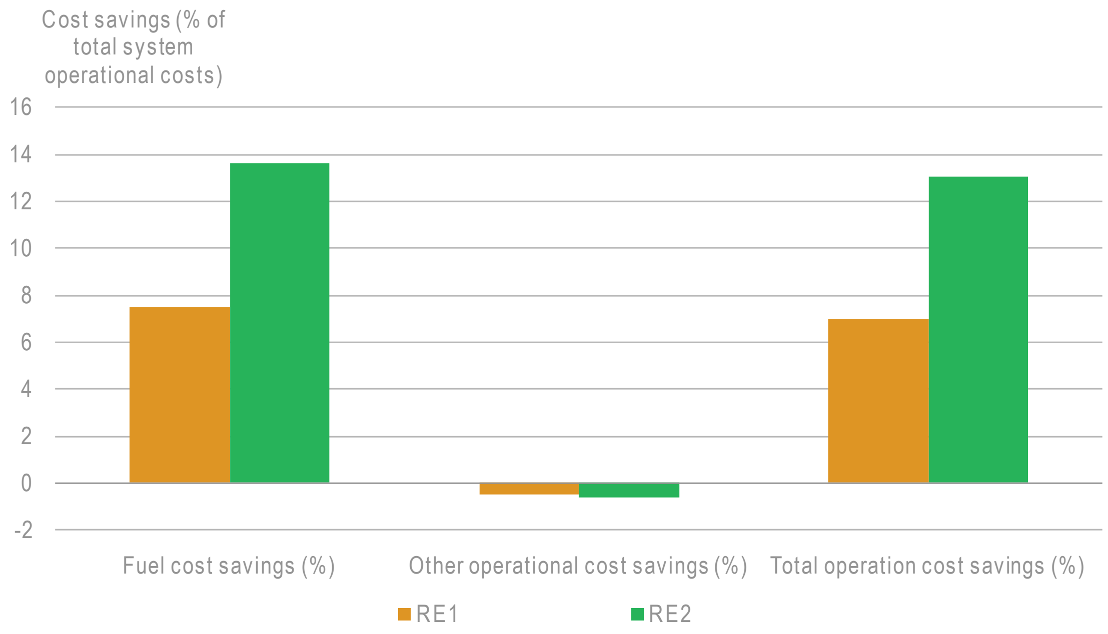
Fuel supply contract flexibility

Boosting institutional flexibility is a key strategy for encouraging power system transformation. A key benefit of VRE generation is the ability to reduce the use of high-cost fuels, which in Thailand's case is natural gas. Gas supply contracts with minimum take-or-pay requirements can be a source of inflexibility, reducing the cost savings potential that could be available from replacing thermal generation with low-cost VRE generation. Currently, gas-fired generation in Thailand is supplied via inflexible take-or-pay contracts.

To explore the cost risk associated with inflexible contracts, a gas take-or-pay requirement is added to each of the RE1 and RE2 scenarios, based on the long-term gas commitments with relevant liquefied natural gas (LNG) suppliers. The operating cost is then compared with the core RE1 and RE2 scenarios. A comparison of the results shows that contractual flexibility on fuel supply contracts has the potential to reduce around 8-15% of future fuel costs (Figure 5.16).

This is largely a result of avoiding non-merit order dispatch practices as the share of VRE increases, where the gas-fired power plants have to be operated instead of the more economic generators, in order to meet the gas supply requirement. This demonstrates the potential value in ensuring that future contractual arrangements do not hinder cost-effective system operation. However, it is also likely that a contract with more flexible terms may have a higher unit cost. This highlights the importance of integrated planning that considers all available supply- and demand-side resources and associated cost trade-offs.

Figure 5.16 • Operational cost savings in RE1 and RE2 scenarios due to the flexibility of gas supply contracts



Note: *Other Operational cost* includes import hydro cost, ramping cost, start-up and shutdown costs, and variable O&M costs.

Key message • Inflexible long-term gas contracts may significantly increase system operational costs.

Improved power plant flexibility through modified power purchase contracts

One of the challenges in high VRE systems is increased variability in the net load. High VRE systems can see both periods of much lower net load than would occur otherwise and steeper ramps. Conventional generators with high minimum stable levels exacerbate this challenge: during periods of low net load, it becomes necessary to either turn off some generators or curtail VRE generation. If a rapid ramp-up is then required to meet a high net load period later in the day, this will necessitate keeping those same generators on during the period of low net load and thus some level of VRE generation to be curtailed in order to create headroom for them. While the results from the previous section showed that power plants in Thailand have sufficient flexibility to accommodate higher shares of VRE generation, it is still useful to assess the additional benefits of further enhancing the flexibility of power plants.

The modelled 2036 Thailand power system has an average minimum generation level of conventional plants of around 47% for CCGT, 43% for thermal generators and 65% for hydropower (Table 5.2). Decreasing the minimum generation level is one of the key aspects to increasing the flexibility of the Thai power system.

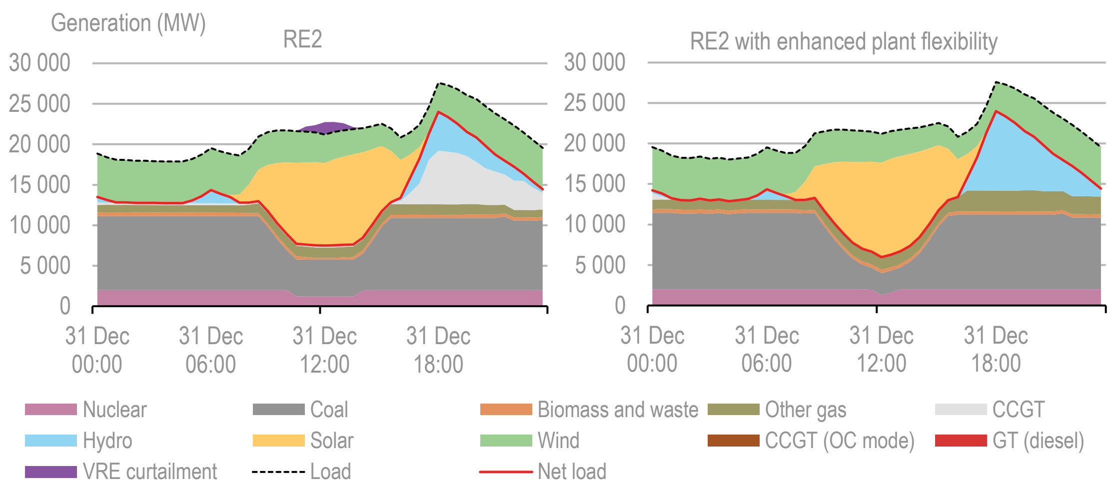
Additionally, other technical flexibility of plants such as ramp rates, start-up times and minimum up/down times can also be improved by plant retrofit and/or operational practices (IEA, 2018). In this report, the potential impact and benefits of flexible plant operating characteristics are modelled for the high renewable scenario (RE2).

Table 5.2 • Original and simulated minimum generation levels of conventional generators

Technology	Average minimum generation level (% of capacity)	
	Core scenarios	Power purchase and fuel contract flexibility scenario *(RE2 – PPA and fuel contract)*
CCGT	47%	30%
OCGT	27%	20%
Coal	43%	20%
Diesel	34%	30%
Hydro	65%	13%
Nuclear	60%	20%
Thermal gas	44%	20%

Detailed analysis of generator dispatch during the period of lowest net load, which also corresponds with the highest 3-hour ramp, shows that a reduced minimum generation allows a larger amount of VRE generation to be dispatched, avoiding VRE curtailment (Figure 5.17). In the higher flexibility scenario (right), the lower minimum generation level enables conventional plants (especially coal-fired plants) to decrease to a lower generation level, creating headroom for lower cost solar to generate. As there is ample spare capacity and inherent power plant flexibility in the modelled system, VRE curtailment is only around 5 gigawatt hour (GWh) or 0.01% in the RE2, which is not a significant concern based on international standards. Additional flexibility also allows for higher utilisation of more economic plants, which allows for further operational savings (this topic will be discussed in more detail later in this chapter).

Figure 5.17 • Impact of additional plant flexibility (right) for the RE2 scenario relative to the Base scenario (left) in the period of lowest net load



Key message • Lower minimum generation levels allow lower cost, inflexible generation to operate at lower levels, preventing VRE curtailment and reducing system operational costs.

Additionally, due to the flexibility of the gas supply contract, CCGTs are not required to be operated as much as in the Core scenario, where CCGTs are must operate due to fuel contract inflexibility. This allows hydropower plants, which have extremely low operating costs, to be better utilised and managed, particularly in the evening peak periods when ramping requirements are very steep. The annual hydropower generation is similar for both scenarios, but the resource is dispatched more frequently during periods of system stress.

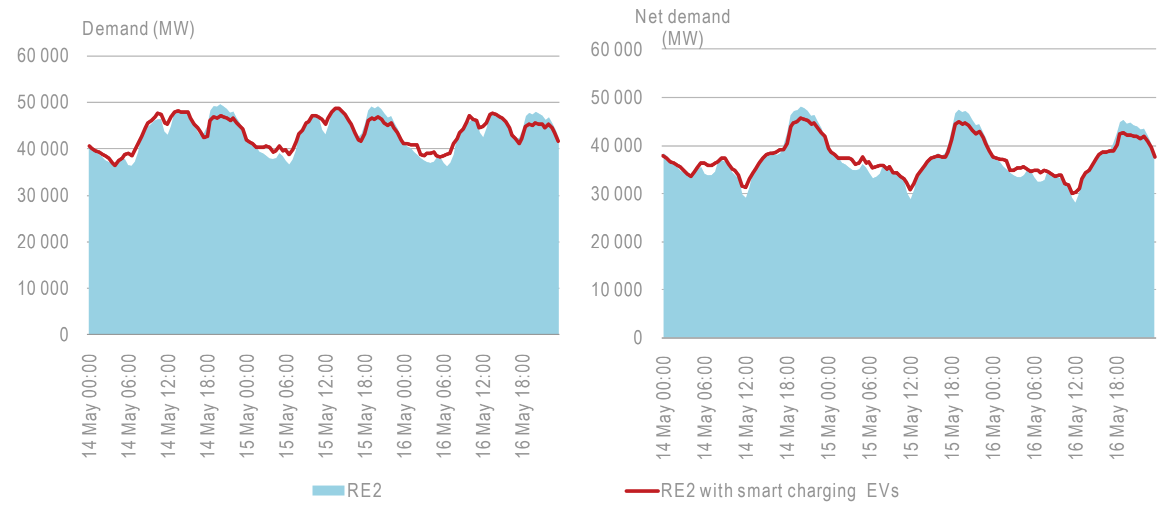
Although there is a slight increase in thermal gas generation (classified as “other gas” along with CHP) in the RE2 scenario during this period, across the entire year the generation from thermal gas is lower in the power purchase and gas contract flexibility scenario (*RE2 – power purchase and fuel contract*) due to their relative high costs.

EV and demand-side options

In order to analyse the potential benefits of DSM for the Thai power system, both smart EV charging and responsive loads from large industrial customers (i.e. steel and cement) are modelled. This involves defining a portion of the load (as per an assumed profile and regional distribution) and allowing its full operational optimisation within a 24-hour window, as discussed in detail in Annex C.[14] While both industrial DSM and EV charging loads are modelled, these yielded similar results. Therefore, only the smart EV charging flexibility scenario *(RE2 – EV)* is explored in this chapter, with further results available in Annex D.

An examination of the peak load period for 2036 demonstrates the ability of smart EV charging to help shift loads (Figure 5.18). This is a natural outcome given that smart EV charging occurs during the peak solar output periods, resulting in a decrease in net system demand as EV charging shifts away from the evening peak. Such smart EV charging reduces the need for peaking generation while also helping to reduce fuel consumption by enabling more VRE generation to be utilised.

Figure 5.18 • Impact of smart EV charging during the peak net load period in the RE2 scenario



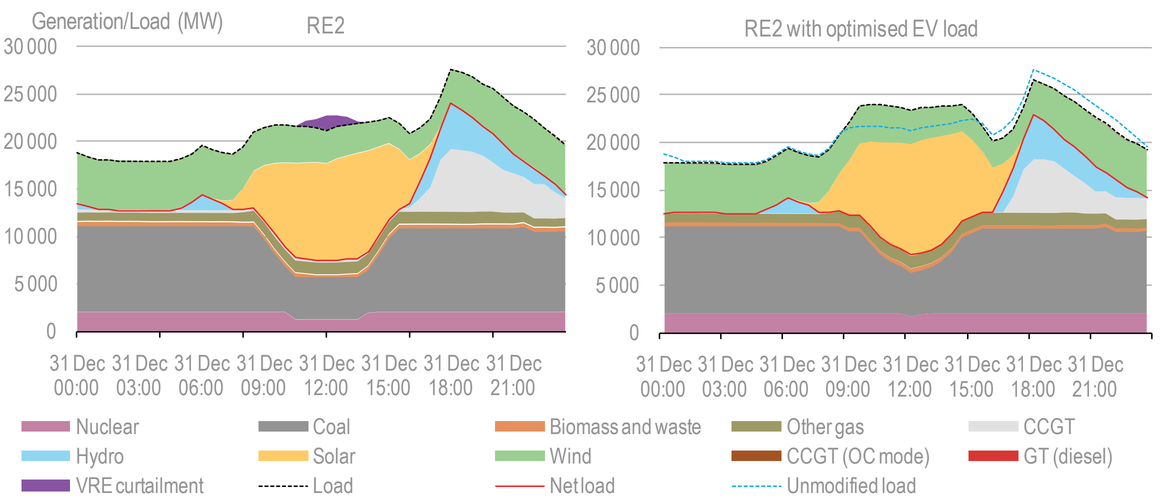
Key message • Smart EV charging can help to shift peak demand and reduce operational costs.

Examining the detailed dispatch data during the week of lowest net load demonstrates how a flexible load can contribute to the system during periods of high VRE generation. Smart EV

[14] It is important to note that this scenario of DR deployment represents an optimistic case, since there would be certain constraints in the amount of load shifting available due to pricing schemes and other economic considerations. Therefore, the results of this scenario should be considered an upper ceiling on the benefits of DSM for both EV charging and large industrial customer participation.

charging increases the overall volume of low-cost generation utilised in the system while also preventing curtailment of VRE generation (Figure 5.19).

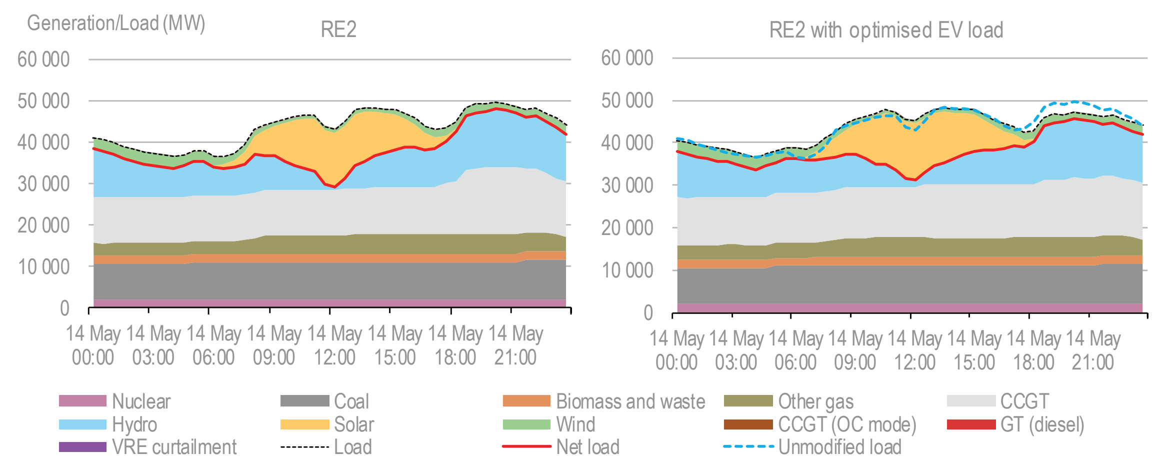
Figure 5.19 • Impact of flexible EV load during the period of lowest net load in the RE2 scenario (right) relative to the RE2 without smart EV charging (left).



Key point • Smart EV charging and flexible industrial loads can help to avoid curtailment and increase the utilisation of low-cost conventional generation.

Dispatch during the peak load day shows how load is flexibly shifted into the middle of the day to eliminate both VRE curtailment and increased cycling resulting from inflections in demand, while also reducing evening peak demand and the need for the peaking capacity that would otherwise be required (Figure 5.20). The combination of these benefits would lead to cost savings driven by avoided fuel and start-up costs.

Figure 5.20 • Impact of smart EV charging during the period of peak demand in the RE2 scenario (right) relative to the RE2 scenario without smart EV charging (left).



Key message • Flexible EV charging reduces the evening peak which can reduce the cycling of online generators.

Storage options

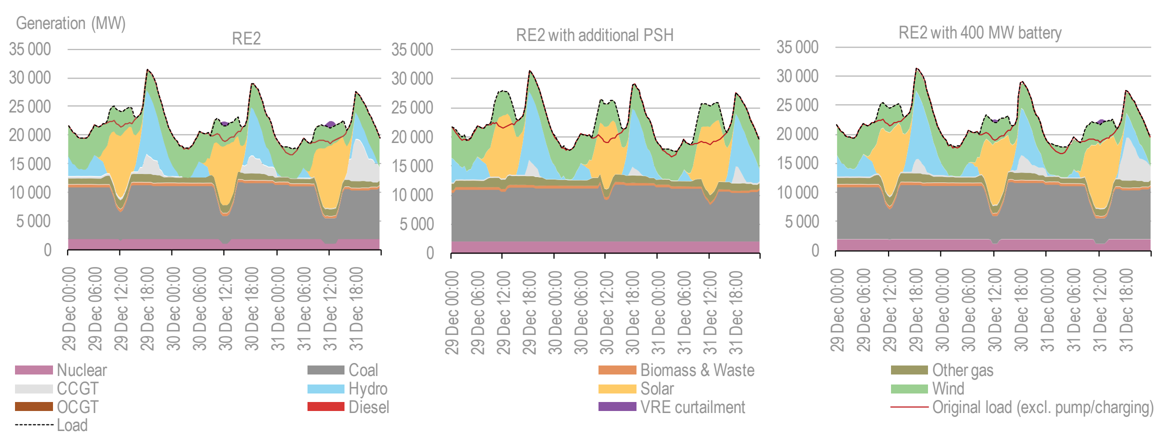
The PDP 2015 includes the addition of new PSH plants with more flexible loading than the existing PSH available in the Thai power system. However, the PDP did not clearly specify the capacity of PSH from imported reservoir hydropower plants from Lao People's Democratic (PDR). These generators with PSH capability can act as an important source of flexibility in a higher VRE system, allowing energy to be stored at times of high VRE production and discharged at times of high net load, as observed during the period of minimum net system demand (Figure 5.21). By aligning the pumping profile with the dispatch during the period of lowest net load, the PSH resources can operate both during the middle of the day when solar generation is high, reducing possible VRE curtailment.

Two options of additional storage are modelled and analysed to assess their potential benefit to the system in a high VRE scenario:

- Conversion of a proportion of PDP-specified hydropower imports (60%) from Lao PDR to PSH schemes, which adds 4 200 MW of pumping capacity in the NEC region. These sites are assumed to have a relatively low capital cost for conversion since the reservoirs would be existing and test the upper limit of the possible benefit from additional energy storage.
- Additional battery storage of 400 MW/1 600 MWh in the Southern region.[15]

Notably, due to its very large pumping capacity, additional PSH can reduce curtailment while also allowing cheaper, inflexible generation to operate at maximum capacity. The smaller charging capacity of the battery does not result in a large amount of VRE curtailment (Figure 5.21).

Figure 5.21 • Impact of storage deployment on system operation during the period minimum net system demand



Key message • PSH allows VRE generation to be stored for later use when net load is high.

When analysing the change that occurs when using different technologies, due to the deployment of new storage projects, there is very little noticeable effect on the amount of generation observed annually for most technologies, except for thermal gas generation – in this case, a considerable portion is displaced by both additional PSH and battery storage (Figure 5.22).

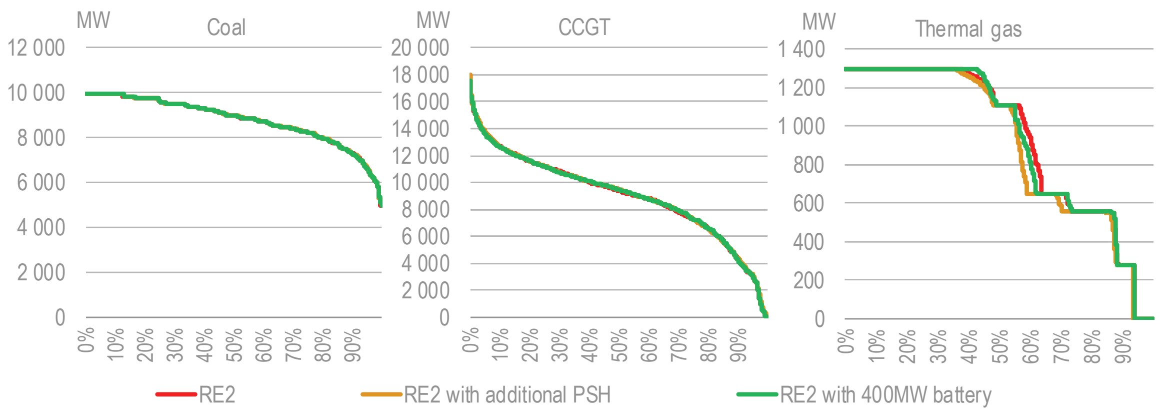
[15] The multiple benefits of batteries – particularly to increase reliability in poorly connected regions, avoid transmission upgrade requirements, and displace peaking generation – were considered most relevant for the Southern region. While it may also be beneficial to place energy storage in NEC due to the high modelled VRE penetration, PSH would be expected to be a lower cost option where it is possible to include pumping capabilities in an already-planned hydropower project.

However, for the top percentile of the GDCs for each generation technology, the battery storage flexibility scenario actually displaces a large portion of the peak utilisation of CCGTs (383 MW), with an increase in use of CCGTs in open-cycle mode only (148 MW) and diesel (58 MW) during the peak period (Figure 5.23).

Considering the width of the spike for the open-cycle gas turbines' (OCGTs) usage (just one hour with an additional use of 200 MW capacity), this result could be interpreted as supportive of replacing an entire CCGT plant by supplementing the 400-MW battery storage with another 200 MW of capacity. This would also yield the additional benefits of load shifting and other potential ancillary services, which are not modelled in this analysis (e.g. fast-responding reserves, voltage support, deferral of distribution grid investment) to take advantage of increasing shares of VRE. The same benefits, however, are not observed for PSH: the PSH flexibility scenario does not actually add any additional capacity into the system – rather, it only adds pumping capability to planned foreign hydropower plants. This is reflected in the cost savings of the two storage scenarios, where the PSH has very little effect, while the smaller battery storage leads to savings in both fuel and cycling costs.

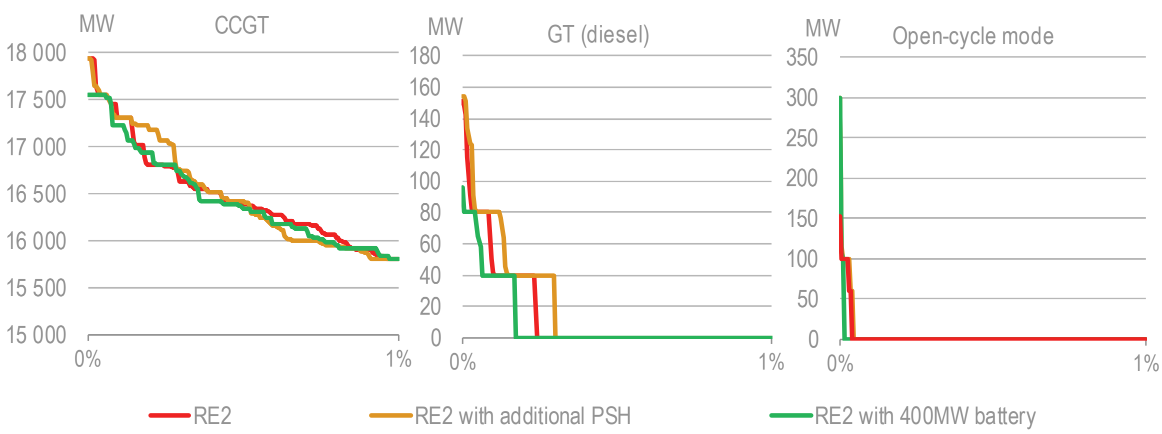
Duration curves for all generation technologies can be found in Annex D.

Figure 5.22 • GDCs of select generation technologies with different amounts and types of storage



Key message • PSH and battery storage have little impact on the general use of the majority of generation technologies, except for the displacement of generation from gas-fired steam turbines.

Figure 5.23 • GDCs of key generation technologies for the top percentile



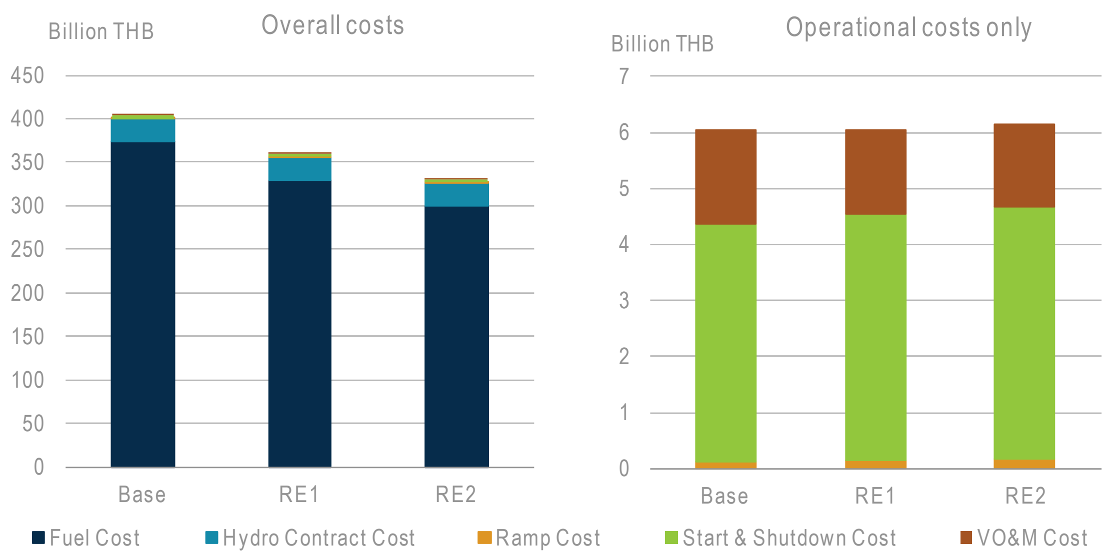
Key message • Battery storage provides an additional system benefit by displacing a significant amount of peaking capacity, while also providing additional system benefits of load shifting.

Economic impact of 2036 VRE deployment scenarios

The impact of VRE on total operational costs for the core and flexibility scenarios are examined in this section, including a detailed look at individual cost components such as ramping and start-up costs. The total system costs, which include the capital expenditures, are assessed in Chapter 7.

Based on the modelling outcomes, the primary expected economic impact of VRE generation on power system operations is a fuel cost savings. However, the greater variability of supply also leads to increasing cycling costs of generators (i.e. additional start-up, shutdown, and ramping costs). The modelled scenarios of Thailand indicate that the fuel cost savings are significantly larger than the increased cycling costs, exhibiting an observable upward and downward trend with increased VRE penetration in ramping and fuel costs, respectively (Figure 5.24).

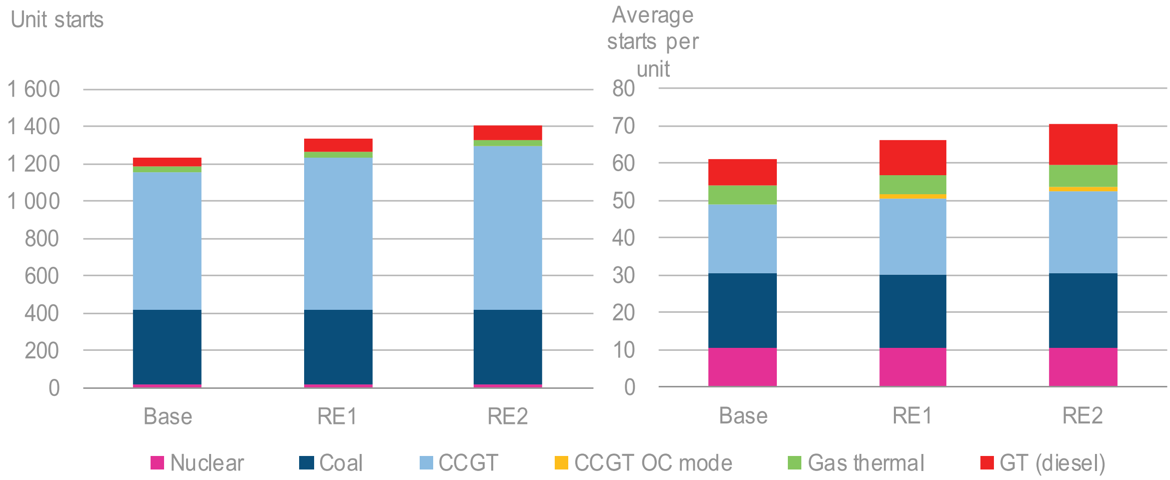
Figure 5.24 • Total operational costs for different scenarios



Key message • The largest economic impact of VRE is the savings associated with avoided fuel costs. The magnitude of these savings significantly outweighs the additional costs associated with increased cycling of thermal generators needed to integrate VRE.

The rise in start-up and shutdown costs is the most notable of the cycling costs. It is driven by an increase in the cycling of gas generation as VRE penetration increases (Figure 5.25). While this is certainly an increased cost, it also demonstrates the inherent flexibility of the power plant fleet in Thailand to accommodate higher shares of VRE with relatively small economic impact. However, as the capacity factor of gas generation decreases, it is also feasible that some generators may become financially unsustainable, or, if planning processes are able to understand better these impacts, some future CCGT plants may not be built at all. CCGTs face the highest number of starts given its high generation share, which is between 25-30% of total generation in the three scenarios. CCGTs are operated as mid-merit load-following plants, given their operational flexibility attributes relative to coal and nuclear. As the level of solar and wind generation rises, the number of starts of CCGT as well as diesel GTs increases, resulting in higher cycling costs.

Figure 5.25 • Number of unit starts (both total and average per unit) across different technologies

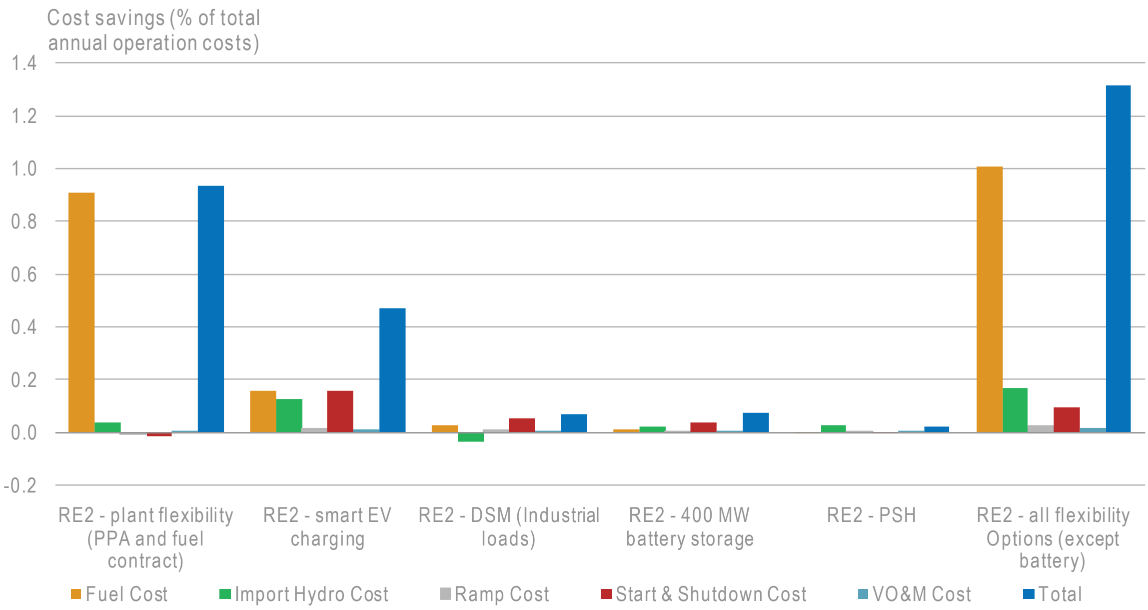


Key message • Unit starts become more frequent for CCGTs and diesel GTs at higher shares of wind and solar while coal and nuclear generation are largely unaffected.

Economic impact of flexibility options

Each of the different flexibility options modelled have a different impact on the amount of additional operational savings that can be achieved in a high renewables scenario (see Figure 5.26). Whereas boosting power plant flexibility has the largest impact, it is worth noting that these economic impacts occur within the context of the details captured in the model. Therefore, additional benefits may be likely when capturing aspects such as multiple-scheduling time frames, (e.g. hour-ahead, day-ahead, real-time) where start-up times becomes a further cost burden because of an inflexibility that prevents adapting to more accurate forecasts as one approaches real-time dispatch.

Figure 5.26 • Cost savings due to added flexibility in the RE2 scenario



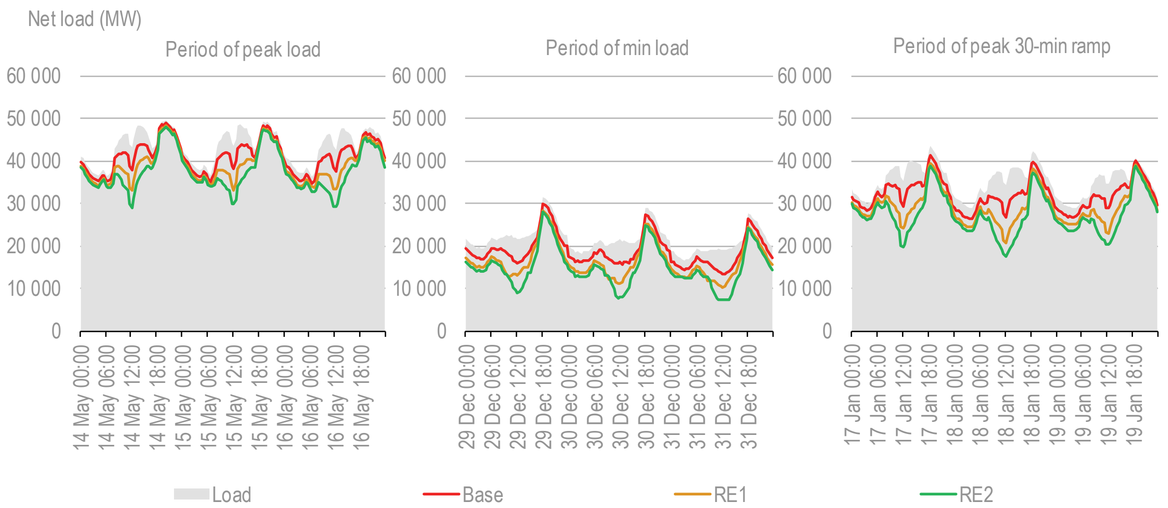
Key message • Flexibility options reduce system operational costs (particularly fossil fuel costs) while integrating VRE.

When modelling a system that includes all of the considered flexibility options, positive savings were observed across all cost components, showing that these options are complementary to one another (Figure 5.26).

VRE integration phase assessment for 2036

Considering the Base scenario for 2036, Thailand is expected to have a 6% share of annual VRE generation, which would be a small increase from the 4% share in 2016. This is largely because of a significant growth in load and conventional generation capacity based on the PDP 2015. In the Base scenario, VRE generation has a noticeable impact on the net system demand, with a midday trough and evening peak emerging (considering the concepts discussed in Chapter 3). This impact becomes more obvious with additional VRE generation, as shown in the RE1 and RE2 scenarios (Figure 5.27). Comparing the Base scenario in 2036 with the existing system in 2016, it is evident that despite a relatively small increase in VRE share, the impact of VRE on net demand becomes more apparent and significantly affects the net system ramping requirements (Figure 5.27). This places the Base scenario firmly in Phase 2 (and perhaps approaching Phase 3) of VRE integration due to the importance of flexibility options, as explained in Chapter 3 and Annex A.

Figure 5.27 • Net system demand curves at various periods of system stress for three different VRE scenarios



Key message • In 2036, the effect of VRE generation on net system demand becomes noticeable in all renewable scenarios although it is more prominent in higher penetration scenarios.

Considering the 3-hour ramps observed for all core scenarios, the peak ramp relative to the peak daily net load increases from 39% in the Base scenario to 51% and 61% in RE1 and RE2 scenarios, respectively, as presented in earlier in the chapter (Figure 5.9). As net system ramp rates increase beyond a certain point, it becomes less economic for the generation fleet to provide the necessary ramping in "business-as-usual" operation, resulting in an additional cycling of generation and the prolonged use of more flexible peaking generation. Therefore, as further renewables are added, the benefit of the various flexibility options allows the system to realise the full potential of cost savings resulting from VRE. This is despite the system already having the ramping flexibility sufficient to accommodate this generation as shown earlier in the chapter (Figure 5.8).

For the RE2 scenario, the net system demand develops two distinct peaks and troughs, and a significant 3-hour ramping requirement that, at certain periods, exceeds 60% of the daily peak load. This requirement is similar to the current 3-hour upward ramping in the California Independent System Operator, which is more than 50%, indicating the need for fast ramping resources (Loutan and Zhou, 2018).

This result, combined with the efficacy of the tested flexibility options, places the system in the RE2 scenario soundly in Phase 3 of VRE integration. This is especially noticeable with the deployment of peak shifting technology (storage and DSM), which not only allows significant savings in operating costs, but also shows the benefit of a possible investment deferral for peaking capacity not utilised. While flexibility options have not explicitly been tested for the RE1 scenario, the effect of VRE generation on both its net load and net system ramp requirements is very similar to RE2, therefore also placing it in Phase 3 of VRE integration, although at a slightly earlier stage.

Recommendations and action priorities

Operational aspects

- Ambitious solar and wind penetration targets are possible compared to the existing targets in the PDP 2015. From an operational standpoint, high VRE targets are possible in Thailand, as long as the power system has sufficient system flexibility based on the generation mix proposed in the PDP.
- Conventional power plants can be retrofitted to improve their operational characteristics and provide additional flexibility to the power system, reaping significant economic benefits, particularly as the share of VRE increases. The essential characteristics of power plants that can be improved include ramp rates, minimum generation level, and start-up times. In addition, changes in certain plant operational practices can enhance the flexibility of power plants without the need to undertake retrofit projects.
- Hydropower plants have a number of valuable flexibility characteristics. However, their minimum generation should be significantly decreased through both technical enhancements and changes to PPA.
- Thermal plants such as coal and CCGT will be required to provide the balance of ramping; they will be cycled up and down more often owing to a higher share of VRE. Their ability to do this may currently be limited because of the nature of contractual arrangements with private power producers. To fully utilise all available power plant flexibility, PPA should avoid contractual stipulations that undermine the technical ability of these plants.
- Demand-side options, including DSM, storage, and smart EV charging, can increase the flexibility of the power system in a cost-effective manner. These options should be endorsed as the level of VRE increases.
- Wind and solar output have very complementary profiles to one another, allowing a combined contribution to both afternoon and evening peaks. Although the modelled system in 2036 has sufficient flexibility to accommodate higher shares of VRE, additional economic benefits can still be gained from other flexibility options such as enhanced power plant flexibility, battery storage, and demand-side management. Therefore, it is suggested that these technologies be included in Thailand's capacity expansion plans where their full potential can be utilised.

Economic and institutional aspects

- Increasing the VRE penetration of the Thai power system will reduce the total operating costs of the system, which consists primarily of fossil fuel costs.
- Institutional and contractual issues that currently limit available flexibility include PPA with private power producers and gas supply contracts, which prevent optimal power system operation. In this sense, it is important to ensure that future contractual arrangements do not hinder the cost-effective operation of the power system.
- Boosting system flexibility through enhanced power plant flexibility, contractual flexibility, and/or deployment of demand-side measures (including storage) can reap economic benefits through more flexible and efficient operation. Therefore, these options should be fully considered by necessary regulatory frameworks in order to facilitate and promote the use of flexibility options and measures.
- Institutional arrangements will be important to ensure that changes in the generation mix in capacity expansion planning exercises, as well as adjustments to future power purchase contracts and fuel supply contracts, can be integrated without unintended consequences for power system stakeholders.

References

EPPO (Energy Policy and Planning office) (2015), *Thailand Power Development Plan 2015 -2036 (PDP2015)*, Thailand Ministry of Energy.

IEA (International Energy Agency) (2018), *Status of Power System Transformation 2018: Advanced Power Plant Flexibility*, OECD/IEA, Paris.

Loutan, C. and H. Zhou (2018), *Flexible Capacity Needs and Availability Assessment Hours Technical Study for 2019*, California Independent System Operator (CAISO). www.caiso.com/Documents/Agenda-Presentation-2019DraftFlexibleCapacityNeedsAssessment.pdf.

6. Distributed energy resources – Technical potential, cost benefit analysis and rate impacts

HIGHLIGHTS

- Available rooftop area is not a relevant constraint for the uptake of distributed solar photovoltaics (DPV) in Thailand. Even if only 10% of all available estimated rooftop surface was used for DPV, this would host a capacity larger than the system's current peak demand. However, other constraints could limit how much DPV can be used in practice.
- In the short term, the small, medium and large general-services customers have the strongest incentive to deploy DPV in Thailand. Due the sheer number of customers, the residential customer segment in the Provincial Electricity Authority (PEA) has the largest overall long-term DPV potential. While this segment currently shows longer payback periods for DPV systems than other customer groups, it is a very relevant segment for the long-term planning for DPV.
- The buyback rate for DPV electricity under a net billing scheme has a relatively low impact on DPV deployment in the long term because all customer groups are modelled to use relatively high proportions of the electricity from DPV systems to directly offset their demand. Consequently, the design of residential tariffs is important to guide the uptake of DPV on a sustainable path.
- The Electricity Generating Authority of Thailand (EGAT) is modelled to experience the greatest maximum revenue impact over time compared to Metropolitan Electricity Authority (MEA) and PEA because it experiences lost sales for every kilowatt hour (kWh) of DPV generation, regardless of whether DPV generation is self-consumed or exported to the distribution grid.
- Achieving the Alternative Energy Development Plan's 2025 DPV target of 2 800 megawatts (MW) will result in only a minimal impact on utility revenues and retail electricity rates.
- Following the results of the analysis, it is recommended that the Thailand take action steps in the following three areas:
  - implement a time- and location-specific wholesale electricity pricing scheme
  - modify retail electricity tariffs with more differentiated time-of-use rates
  - modify buyback rate to a value-based remuneration scheme for DPV.

This chapter summarises the results from work stream 2, which consists of two sections. The first section estimates the gross maximum technical potential for rooftop PV in Thailand, based on an estimation of available rooftop area. The second section of the analysis investigates economic impacts of increasing shares of distributed PV on different stakeholder groups (see Chapter 4 for methodology).

Assessing the country's technical potential for rooftop PV can be a useful exercise for obtaining a clear picture of the scale of the country's solar energy resources and its potential contribution to the power system. Complementing this with an analysis of the economic impact of DPV under various deployment scenarios will allow policy makers to understand better the link between policy decisions to support DPV deployment and the wider impact of these decisions on utility revenues and retail electricity rates for consumers**. It is important to note**

that this analysis provides neither forecasts nor recommendations for a target for distributed PV in Thailand.

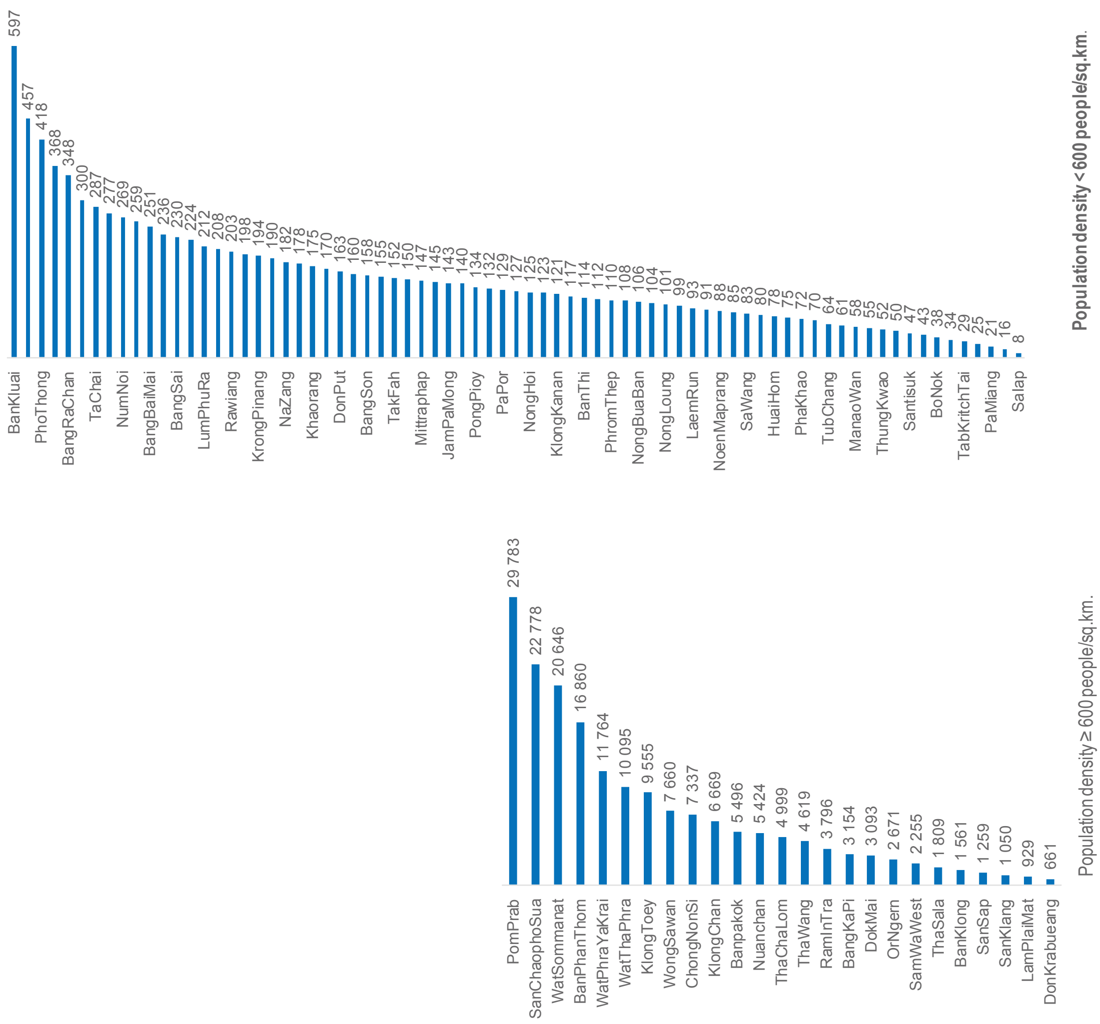
Based on these findings, this chapter concludes with a number of recommendations for DPV remuneration and retail electricity tariff reforms.

Technical potential estimate of rooftop DPV in Thailand

Relationship between population and rooftop area

100 sub-districts (*Tambons*) were selected for technical potential analysis based on their population density to analyse technical potential of rooftop PV (Figure 6.1).

Figure 6.1 • Population density in selected sub-districts



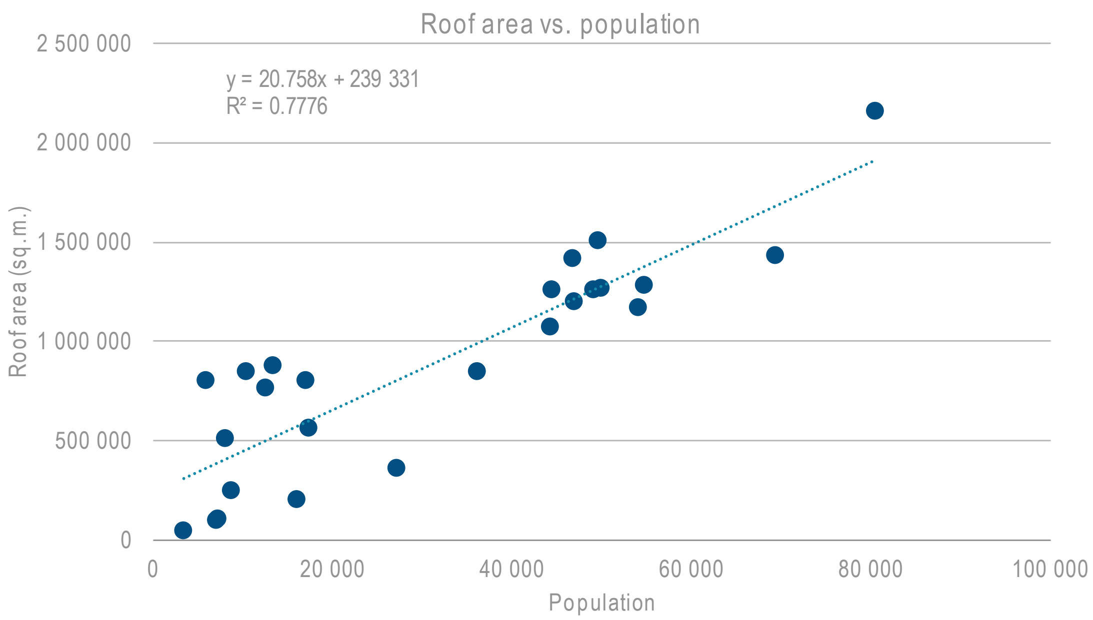
Key message • Studying the difference in population density between urban and rural areas provides a useful starting point to map a representative relationship between population and rooftop area.

A simple random sampling method was used for the sub-districts. The sample size was determined based on the population and the level of precision as explained in Annex C (Yamane, 1967). It was estimated that with 90% confidence level, the sample size of 100 sub-districts were required to represent the total sub-districts.

In order to obtain representative estimates of the relationship between population density and rooftop area, it was necessary to separate the selected sub-districts into two groups. The threshold chosen was below and above 600 persons per square kilometre (km^2). Following this distinction, two representative estimates were made, one for urban areas and one for rural areas, which could be extrapolated to the whole of Thailand using a linear regression analysis. Figure 6.2 shows the scatter diagram plot of the observation values and the fitted line with R-squared equal to 0.78.

The estimates displayed in Figure 6.2 indicate that in sub-districts with population densities equal to or above 600 persons per km^2, each additional inhabitant is associated with an increase of about 21 square meters (m^2) of rooftop area. It should be noted that this accounts for all roof areas, not just residential dwellings.

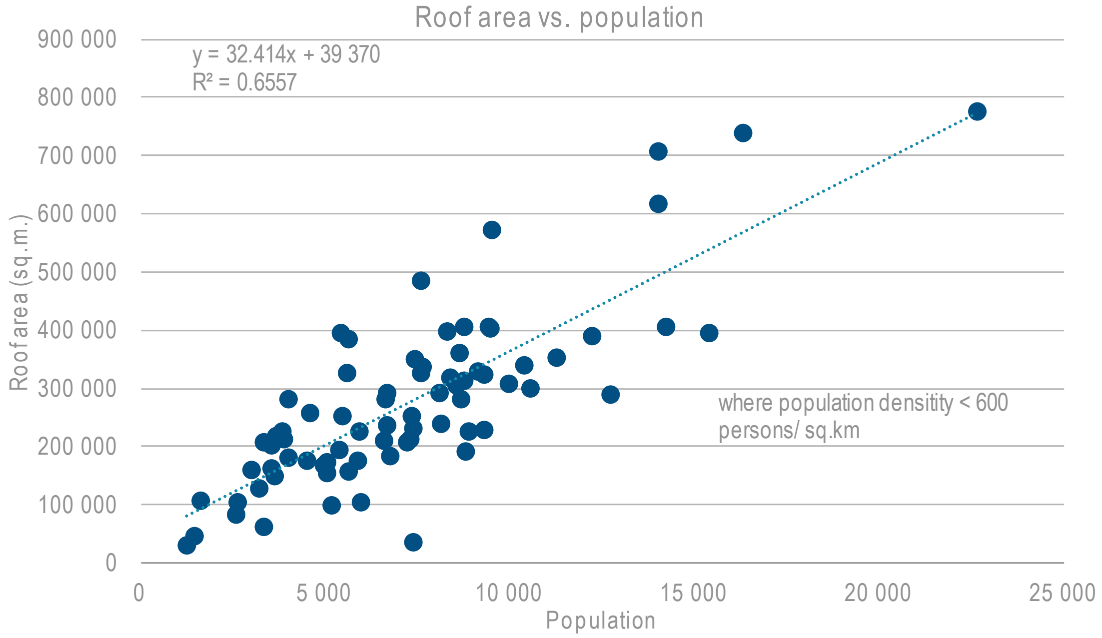
Figure 6.2 • Relationship between roof area and population, population density ≥ 600 persons/km^2



Key message • There is a positive relation between population and rooftop area in areas with high population densities.

Figure 6.3 shows a similar estimation for sub-districts with population densities below the 600 person/m^2 threshold. Here the lower R-squared value of 0.66 indicates a looser fit of the linear model. This could be due to the wide range of land use in less densely populated areas. In this case, as indicated in Figure 6.3, each additional inhabitant is associated with an increase of about 32 m^2 of rooftop area.

Figure 6.3 • Relationship between roof area and population, population density < 600 persons/km²



Key point • The higher variability relationship between population and rooftop area in less densely populated areas in Thailand reflects greater land availability in rural areas.

Total estimated rooftop area

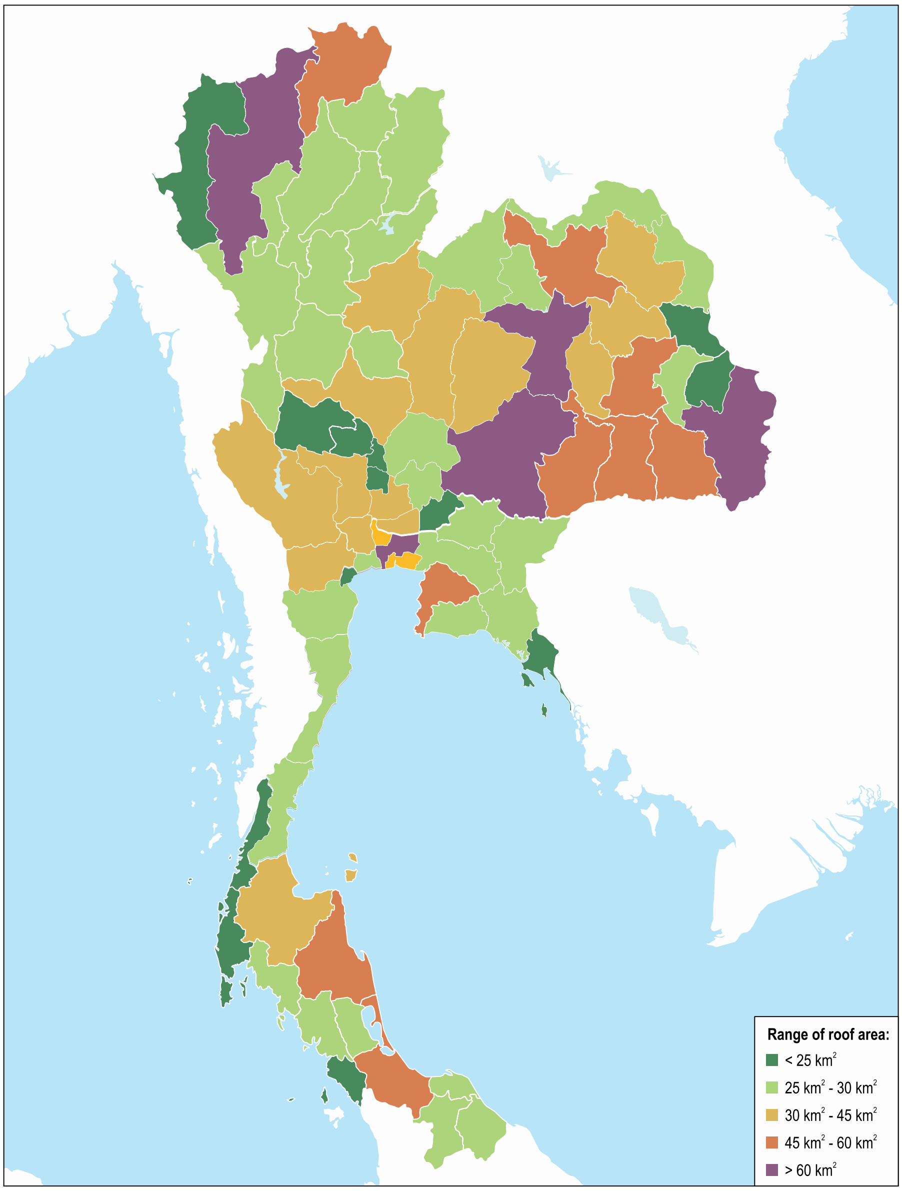
The estimates presented above were used to extrapolate total available rooftop area in Thailand, considering the different relationship for rural and urban areas. The total suitable rooftop area amounts to approximately 2 383 km². Within this group, Bangkok accounts for an available rooftop area of 158.82 km², or about 10% of the city's total surface. Bangkok is followed by Nakhon Ratchasima, Ubon Ratchathani and Khon Khaen with more than 60 km².

Total estimated gross maximum technical potential for rooftop PV

The total rooftop area does not directly translate into a technical potential for solar PV. A number of factors reduce the amount of suitable rooftop area available for PV deployment. The estimate already omits roofs that are unsuitable based on orientation. However, roofs may not be strong enough to support a DPV system, or part of the surface may not be available for a variety of other reasons, e.g. heating and air-conditioning units on rooftops. There are also limitations associated with the technical absorption capacity of the distribution grid that were not assessed in this analysis. The potential is thus referred to as a gross maximum technical potential because it does not consider all factors that may lead to the unsuitability of a roof. It also does not consider deployment limitations arising from distribution grid hosting capacity.

The total gross maximum technical rooftop potential is estimated at 2 383 km². Even if only 10% of this potential were used, over 38 gigawatts (GW) of distributed solar PV could be installed, more than the current peak demand of the Thai power system. This analysis thus indicates that rooftop area is not a relevant constraint for the buildout of DPV in Thailand. However, other constraints, in particular, the technical ability of the distribution grid to host large amounts of solar PV, may lead to a lower potential estimate.

Figure 6.4 • Distribution of estimated rooftop area per province



Key point • Bangkok, Nakhon Ratchasima, Ubon Ratchathani and Khon Khaen are estimated to have the greatest rooftop surface area available for DPV installations.

Economic impact estimate of rooftop PV in Thailand

The present section aims to improve understanding of the potential economic and retail rate impacts resulting from DPV deployment. Assessing the long-term implications of DPV requires making a number of assumptions. As explained in Chapter 4, an important source of complexity is the current tariff structure in Thailand. The revenue losses that PEA, MEA and EGAT might incur through DPV will ultimately be compensated by an increase in the electricity tariffs via the revision of the base tariff component every five years.

This means that under the current tariff scheme, the economic attractiveness of DPV in 2036 will depend on how much DPV is added to the system and on possible changes in the base rate. In order to deal with this issue, two specific scenarios were selected for further assessment: firstly, the DPV penetration foreseen in the Alternative Energy Development Plan (AEDP) 2015 and, secondly, a level of DPV that is in line with the RE2 scenario of this study.

The following three-part approach was taken in order to avoid the limitations of feedback loops between DPV attractiveness and economic impact. The first part of the analysis involved looking at the development of economic potential for DPV deployment. This relied on analysis of potential market deployment paths depending on factors such as the buy-back rate and reductions in installation cost. To simplify the analysis, Bass curves were scaled, based on a previous analysis carried out by the Joint Graduate School of Energy and Environment (JGSEE) at King Mongkut's University of Technology Thonburi (KMUTT), to meet either the AEDP or RE2 scenario targets.

Second, the net impact on utility revenues was analysed, without taking into account rate adjustments, to shed light on the distribution of net impacts across MEA, PEA and EGAT.

For the last step, the cumulated net revenue impacts on utilities after each five-year period, were added on the retail rates of the following regulatory period based on expected demand, to better reflect the dynamic of utility cost recovery in Thailand and illustrate the compounding effect of increasing DPV deployment on retail rates.

A further refinement of the approach would be to iteratively calculate the change to the base rate after each five-year period and then recalculate the economic attractiveness of DPV. By relying on a pre-determined level of DPV – in line with the AEDP 2015 and the RE2 scenario – this simplified methodology can be applied because the amount of DPV in 2036 is an assumption of the analysis rather than a result.

Baseline assumptions

This analysis considers four types of consumers to understand total economic potential of DPV, namely: residential consumers (RES), small general service (SGS), medium general service (MGS), and large general service (LGS). Table 6.1 below presents a summary of the assumptions used to model economic potential using NREL's System Advisory Model (SAM). The load data was based on the actual load profiles for each customer groups for MEA and PEA (MEA 2015; PEA 2015).[16]

Table 6.1 • Baseline assumptions for economic potential assessment for each customer type

Customer class	RES	SGS	MGS	LGS
Peak load (kW)	5	5	200	2 000
System size (kW)	5	5	100	1 000
System cost (THB/W)	50	50	45	35
Operating cost (THB/year)	5 000	6 000	10 000	50 000
MEA baseline installed capacity	11.6	11.6	16.9	37
PEA baseline installed capacity	16.6	16.6	24.3	53.1

Note: All customer classes modelled using average load profiles. For a detailed breakdown of applicable retail tariffs refer to Table 2.3 in Chapter 2 based on the following: Residential and SGS potential was calculated assuming retail tariff for consumption above 150kWh/month without time of use tariffs. MGS and LGS TOU using 12.24 kilovolt (kV) tariff schedule in MEA and 22.33kV in PEA.

[16] In terms of the size of DPV, REC and SGS, customers are assumed to invest in 5 kW DPV with assumed hourly peak-load of 100% of the DPV installed capacity in a year. For the remaining consumer groups, the size of DPV installations is assumed to be equal to 50% of the hourly peak demand.

Economic impact has been estimated by accounting for the costs and benefits to MEA, PEA and EGAT, resulting from DPV deployment. In summary, the net impact for MEA and PEA results from the costs incurred due to the lost margin between wholesale electricity price and retail rates, while the benefits consist of the avoided cost of electricity losses, avoided investment, and the margin between buy-back rate and retail price of PDV output resold to other consumers. For EGAT, costs stem from the lost margin between avoided fuel cost and avoided wholesale sales, while the benefits account for avoided reinforcement investments.

Assessment of economic potential of DPV

As outlined in Chapter 4, payback periods were calculated to inform further calculations on the maximum economic potential of DPV adoption across different customer groups. The payback period depends on the savings customers can achieve via a DPV system on their electricity bills, the remuneration level for electricity fed into the grid (i.e., the volume of exported electricity multiplied by the buyback rate), and the cost of the DPV system itself, which is assumed to reduce on an annual basis over the multi-year analysis period. Different payback periods were also calculated to reflect the effect of varying buyback rates for exported DPV electricity and changes in the cost of acquiring and installing DPV systems. This information was then integrated in the SAM to calculate the payback period for each customer class for each year of the analysis period. By integrating the payback periods into the Bass adoption model as outlined in the methodology chapter, it is possible to determine maximum economic potential per customer group under different scenarios.

It should be stressed that the maximum economic potential estimates calculated in this analysis are neither forecasts nor recommendations for a target for distributed DPV in Thailand. Rather, they were obtained by extrapolating current economic trends into the future. The analysis is used to inform the deployment pathways for the analysis of revenue impacts. No systematic assessment of the technical implications of DPV deployment was made.

Table 6.2 shows the maximum economic potential (in MW) for DPV at the end of AEDP in 2036. In MEA's area, an amount of DPV between 7 483 and 7 844 MW was assessed to be economically rational for prospective customers, assuming maximum installation cost reductions. The total of potential for economically rational DPV deployment reduces to between 5 946 and 6 271 MW under the minimum cost-reduction assumptions, with the range depending on the chosen buy-back rate for exported DPV generation. In the PEA's jurisdiction, the range of economically rational installations ranges between 25 345 to 28 943 MW for the maximum cost reduction scenario and between 18 6668 to 21 818 MW under minimum cost-reduction scenario. On average from all scenarios, PEA accounts for 77% of the maximum economic potential for DPV, while MEA accounts for the remaining 23%.

Table 6.2 • Maximum economic potential of DPV in Thailand calculated for 2036

	Maximum cost reduction				Minimum cost reduction			
Buy-back rate	**0.00 THB/kWh**	**1.00 THB/kWh**	**2.00 THB/kWh**	**2.73 THB/kWh**	**0.00 THB/kWh**	**1.00 THB/kWh**	**2.00 THB/kWh**	**2.73 THB/kWh**
MEA (MW)	7 483	7 618	7 749	7 844	5 946	6 066	6 185	6 271
PEA (MW)	25 345	26 688	28 003	28 943	18 668	19 836	20 984	21 818
Overall country (MW)	32 828	34 306	35 752	36 787	24 614	25 902	27 169	28 089
PV adoption (country level; energy basis)	12.4%	13.0%	13.6%	13.9%	9.3%	9.8%	10.3%	10.7%

Quantifying the maximum potential impact of DPV deployment on utility revenues under 2025 AEDP targets

In AEDP 2015, DPV deployment scenario projects a total maximum DPV deployment of 2 800 MW by 2025, with 900 MW and 1 900 MW installed in MEA's and PEA's jurisdictions, respectively.[17] Table 6.3 presents the yearly impacts on utility revenues in 2025. Importantly, for this portion of the analysis, rather than formulating a market adoption estimate, DEDE deployment targets are simply assumed and analysed for their economic impact. In this case, the deployment shares for each customer group were determined according to the mix resulting from minimum cost reduction and zero buy-back scenario.

EGAT sees the greatest impact from DPV deployment both in absolute terms and relative to the expected revenues in 2025. Comparing these losses to the projected revenues of each utility at the end of the AEDP,[18] DPV has an associated negative impact on utility revenues in 2025 of about 0.33% for MEA, 0.14% for PEA and 0.48% for EGAT, relative to expected utility revenues in that year. These economic impacts are relatively small for the utilities because DPV adoption is low.

Table 6.3 • Projected revenue impacts in 2025 under AEDP scenario

	AEDP 2015 scenario in 2025	
	Yearly impacts on revenue (Million THB)	% Yearly impacts to overall revenues (%)
MEA	-978	-0.33
PEA	-1 076	-0.14
EGAT	-3 854	-0.48

Note: THB = Thai baht.

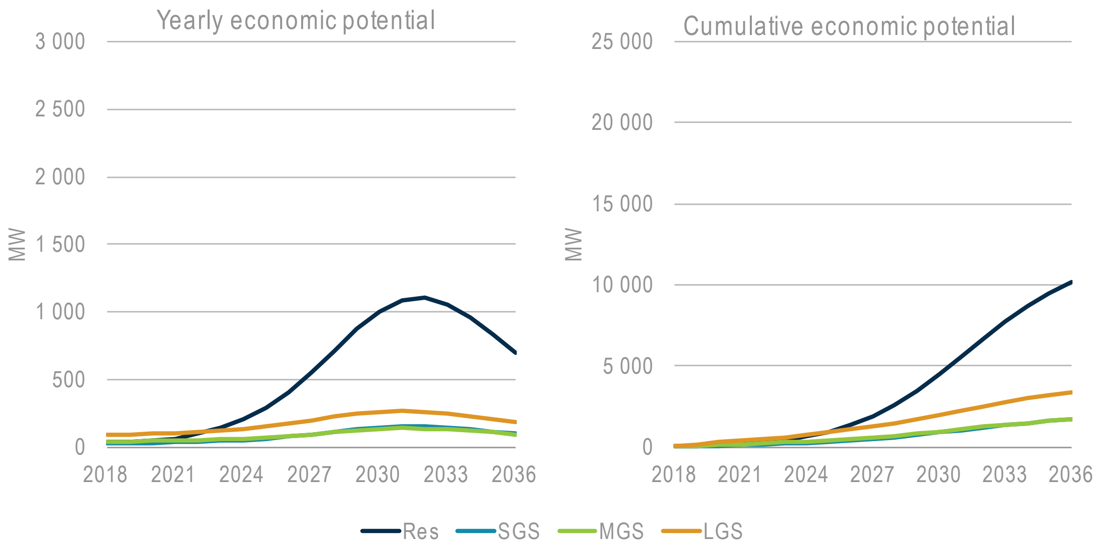
DPV adoption and economic impact under RE2 scenario

For assessing the RE2 scenario, 17 000 MW of DPV deployment is assumed by 2036. The development path for DPV was selected based on a combination of buy-back and cost reduction analyses, as outlined in chapter 4. The target level of 17 000 MW was found to be closest to the scenario with the most conservative economic assumptions, i.e. 0.00 THB/kWh and minimum cost reduction. The deployment trajectory was then scaled to meet 17 000 MW.

Figure 6.5 shows the pattern of deployment assuming the RE2 DPV level as a maximum cumulative market potential. As will be seen in the subsequent scenarios, RES and LGS consumers accounted for the greatest share of economic potential.

[17] This is based on the assumption that 3 200 MW installed capacity for both ground-mounted and DPV that was expected to be achieved in 2036 therefore there would be around 2 800 MW remaining the AEDP's 2036 target (ERC, 2017). For the AEDP scenario, the annual PV adoption was based on the minimum cost reduction scenario (2%). Using these parameters it was found that, assuming deployment along the technologies' maximum economic potential, the AEDP's target could be reached by 2025.

Figure 6.5 • Yearly and cumulative economic potential by customer group under RE2 scenario



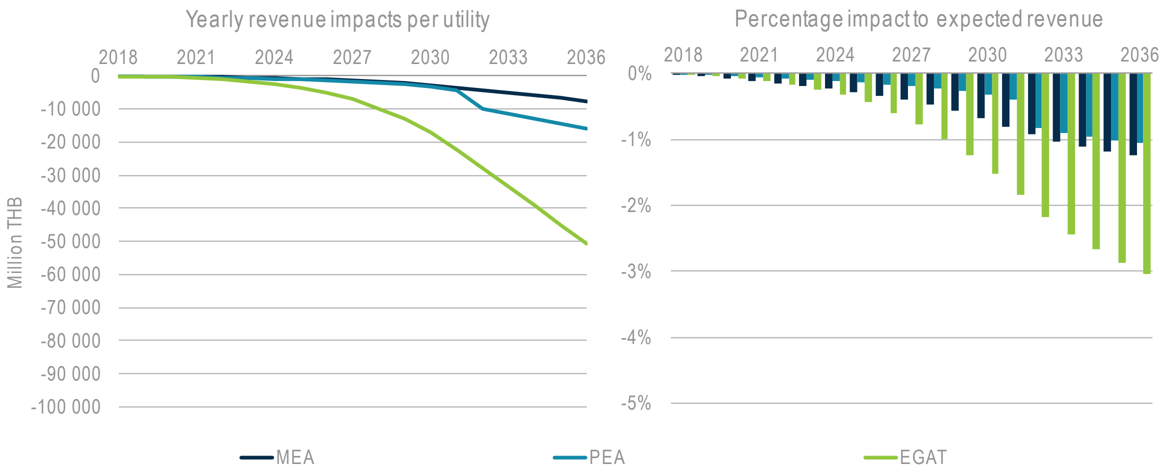
Key message • Residential customers have the highest economic potential to meet DPV deployment level under the RE2 scenario.

In this scenario, the greatest number of PV installations take place in PEA's area (Table 6.4) due to the combined effect of a large number of customers and the very high share of self-use of electricity they achieve based on the averaged load profile approach. As for the distribution of costs and benefits, EGAT sees an annual gross reduction of around THB 50 000 million relative to expected 2036 revenues, while the annual revenue reductions of PEA and MEA are around THB 16 000 million and THB 8 000 million, respectively (Figure 6.6). These revenue reductions account for around 3% for EGAT and 1% for both MEA and PEA, relative to their projected revenues without DPV deployment. Note that ultimately customers would absorb these losses via the base tariff component impact. However, even without this adjustment mechanism, the impact on utilities would remain very small.

Table 6.4 • Maximum economic potential for DPV deployment by utility and customer class

	Total economic potential for PV (MW)	
	MEA	PEA
RES	2 346	7 854
SGS	391	1 309
MGS	391	1 309
LGS	782	2 618
Total	3 910	13 090

Figure 6.6 • Associated revenue impacts per utility in RE2 scenario



Key message • Residential customers have the highest economic potential to meet the RE2 target.

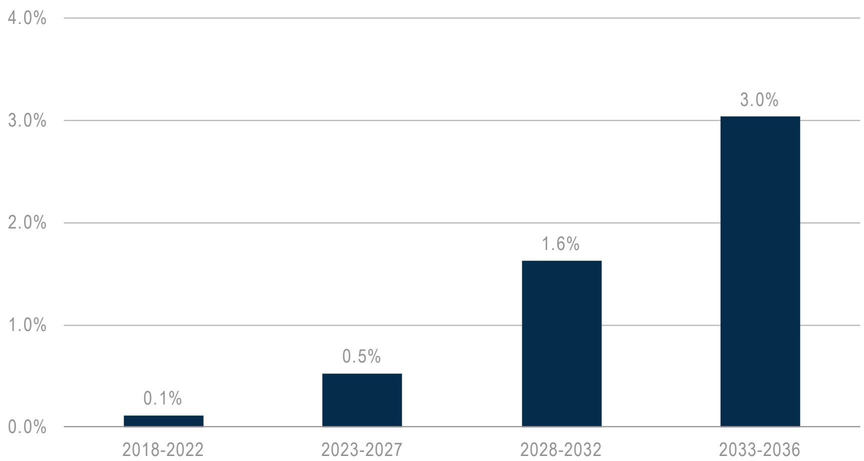
Impact on retail rates

For the end-use consumer, these impacts to utilities translate into retail rate impacts of up to approximately 3% during the period 2032-36, relative to rates during that period without DPV (Figure 6.7). This is due to the increase in the base rate, which in turn is driven by revenue losses incurred by MEA, PEA and EGAT.

In summary, the economic impact of DPV remains very low under this scenario. It should be noted that there are a number of important assumptions linked to this analysis. The annual deployment of DPV peaks around 2032, when the cost of solar PV systems is assumed to have already declined substantially. In addition, the peak annual market deployment is at just above 1 000 MW. Actual deployment may outpace this level even in the coming years.

As long as revenue losses to MEA, PEA and EGAT remain marginal, the adjustment via the base rate tariff increase is an appropriate approach to make DPV deployment cost neutral to utilities. However, at too-rapid deployment levels, this adjustment mechanism can generate a positive feedback, leading to faster market deployment. Thus, a close monitoring of deployment levels is advisable.

Figure 6.7 • Retail rate impacts in RE2 scenario



Key message • Retail rate impacts increase over time as PV adoption reduces utility revenue base.

Summary and implications of analysis

The above scenarios describe possible evolutions of DPV deployment in the context of Thailand. Note again that these scenarios are not intended as recommended target levels for DPV, nor as a desirable market size for DPV installations. Rather, they serve to understand the dynamics underpinning DPV adoption in Thailand and the resulting impacts for EGAT, PEA/MEA and electricity ratepayers in general.

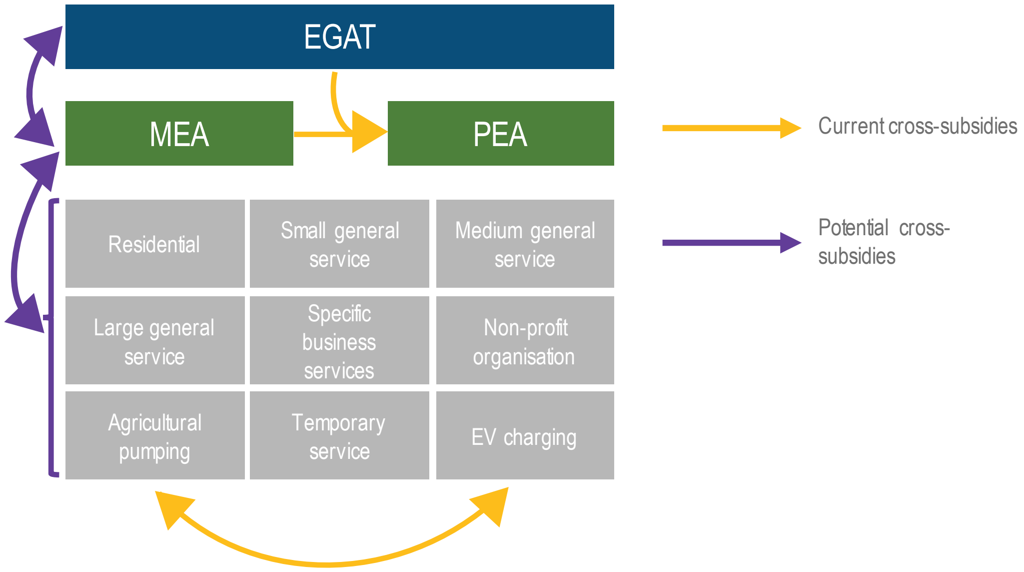
It should be noted that the exact market dynamics, i.e. how many systems are installed each year, is subject to considerable uncertainty. However, a number of robust, general trends can be observed through this analysis.

First, due the sheer number of customers combined with the high self-use levels assumed in this analysis, the RES customer segment in PEA has the largest overall economic potential for DPV deployment under the assumed system sizes. While this segment currently shows longer payback periods for DPV systems than other customer groups, it is a very relevant segment for the long-term evolution of Thailand's DPV market. Understanding the possible adoption dynamics of this customer group is thus particularly important for long-term system planning.

Second, the buy-back rate for electricity fed back into the distribution grid does not appear to be a significant factor in determining economic potential of DPV in Thailand. Under the average load profiles assumed in this analysis, all customer groups were able to use relatively high proportions of the electricity from DPV systems to offset directly their demand, which has an economic impact that is independent of the buy-back rate. In addition, the cost of DPV systems may undercut retail electricity prices so much in the long run that the economics of avoiding grid consumption alone may make a DPV investment sufficiently attractive. This, of course, depends significantly on the future cost of DPV systems. The maximum cost-reduction case demonstrates this very clearly. Because self-consumption of DPV energy is a significant economic driver for deployment, the design of residential tariffs is quite important to guide the uptake of DPV on a sustainable path. For example, it may become preferable to provide low-income customers with direct subsidies towards their electricity bill, rather than relying on the inclining block tariff designs to subsidise their use. In addition, moving towards a more differentiated time-dependent electricity price, with pricing structures taking into account DPV, can help to provide accurate economic incentives.

Third, there is a mismatch between the revenues impacts of PEA, MEA and EGAT prior to retail rate readjustments. As already mentioned, the structural driver behind this is that PEA and MEA may be able to offset purchases from EGAT with grid-injected DPV electricity in the presence time-invariant wholesale price. This is problematic, considering the potential for higher shares of DPV in Thailand. At present, EGAT offers MEA and PEA off- and on-peak wholesale rates based on the voltage level. According to the analysis, the bulk of DPV grid injections across the customer classes takes place during peak hours. In the cases studied above, electricity is bought at a maximum of 2.73 THB/kWh, which is the average of both the off- and on-peak prices, and results in savings for MEA and PEA. In this case, EGAT may be able to reduce their costs of procuring on-peak energy, assuming they have visibility over the amount of DPV to be injected and can adjust dispatch accordingly. In contrast, during the evening periods where DPV cannot produce, EGAT is most likely to cover a relatively high electricity demand compared to the daytime, resulting in higher costs. An approach to reducing the mismatch between wholesale price and cost of generation is to increase the granularity of wholesale prices to accurately reflect the cost of generating electricity. As a first step, the marginal generation cost of the system needs to be tracked and made available for each 15-minute period in order to assess options (Figure 6.8). In a second step, the wholesale price can be made time-dependent with increasing granularity.

Figure 6.8 • Conceptual representation of potential cross-subsidies in Thailand's power sector



Key message • The directions and dynamics of cross-subsidies will depend on the remuneration scheme in place and the distribution of costs across customer groups.

Fourth, the impact on customer bills would be relatively large if the full economic potential of DPV is ever achieved, though achievement of the DPV deployment goals set forth in the AEDP and even the levels assessed for the RE2 scenario are estimated to result in a relatively insignificant rate increase. In general, DPV deployment can have a feedback effect that makes DPV even more economically attractive due to rising retail tariffs. An option to avoid such feedback effects would be to restructure retail tariffs, as well as the compensation mechanism for DPV. Many innovative retail tariff options for DPV customers, including time-of-use structures and minimum bills, can be used to ensure utility cost recovery while providing a fair compensation for DPV generation.

A number of limitations in these findings need to be discussed. First, assuming average customer load profiles ignores the distribution in income and electricity consumption levels and patterns across the Thai population. While performing payback period analysis for average customers with average load profiles under net billing schemes gives an indication of customer economics in the future, it fails to capture the full reality of the market, where customers with higher consumption levels may ultimately be the first to adopt. Such dynamics are not yet captured in this analysis and would require greater detail in terms of appliance ownership information and household occupancy patterns.

Further limitations include the remuneration mechanism design used for the analysis, along with issues of retail rate design. Within the remuneration mechanism, one aspect is that the maximum buy-back rate is effectively lower than any applicable wholesale rate during peak hours of consumption. Further analysis could examine the economic impact of buy-back rates, which are higher than the average wholesale rate and/or buy-back rates that reflect the actual cost of generation with some level of time granularity. In reality, implementation of such a mechanism would require the deployment of advanced metering infrastructure. Furthermore, this analysis assumes DPV buy-back through a net billing scheme. Detailed discussions of alternative remuneration mechanisms and their implications can be found in Tongsopit et al. (2017). With respect to retail rate design, the present study recovers the net effect on utility revenues on expected consumption in the following regulatory period. Further studies could look into the effect of introducing capacity-based rather than volumetric charges to recover costs, particularly from customers with DPV installations as well as minimum bills or time-of-use retail tariff structures.

Lastly, the present study is based on uniform allocation of the net impacts to utilities across the four selected customer groups. In reality policy makers and regulators may decide to shift the burden of foregone revenues customers with different affluence levels within one customer group, or to shift costs across customer groups (e.g. from household to industry) due to specific energy and industrial policy strategies. Based on this, further studies could look into the effect of DPV deployment on the current mechanism for cross-subsidies from MEA to PEA or the provision of subsidies from, for example, commercial electricity consumption to residential electricity consumption.

Recommendations and action priorities

Following the results of the analysis, it is recommended that Thailand officials take action steps in three areas:

- implement an enhanced time- and location-specific wholesale electricity pricing scheme
- modify retail electricity tariffs with more differentiated time-of-use rates
- modify buy-back rate to a value-based remuneration scheme for DPV.

Establishing a time- and location-specific wholesale electricity price

The current wholesale energy pricing structure between EGAT and PEA/MEA does not adequately capture differences in the cost of electricity generation that may vary by time and location. Prices do vary by voltage level, but they are the same throughout the country and during the entire year. This could lead to a number of misalignments of incentives.

A first step towards creating a more sophisticated pricing structure is to obtain more information on the cost of electricity generation for EGAT at any given point in time. This could be calculated as part of the system operation process. Such a price signal could also address a number of other issues, including the design of power purchase agreement (PPA) for large VRE generators to provide incentives for generating electricity when it is most needed for the system. A second step could be to account for systematic differences in the cost of electricity provision in different locations. This would provide an incentive for PEA and MEA to promote distributed generation options, especially in those locations where EGAT's cost for electricity supply is rather high. The introduction of a more sophisticated wholesale pricing scheme could also be a useful stepping stone in further reforming the overall electricity market structure.

Modification of retail electricity tariffs

The analysis in this chapter highlighted how important retail electricity tariffs are for DPV adoption rates because they directly influence the value of self-consumption of DPV. Following the introduction of time- and location-specific wholesale energy rates, it may be possible to incentivise DPV deployment while preventing negative net impacts on utilities by introducing time-of-use retail electricity rates that somewhat reflect MEA and PEA's new time-dependent costs for procuring electricity for their customers. This can help to minimise revenue impacts to MEA and PEA and thus minimise retail electricity rate impacts more broadly.

One key aspect for successfully implementing tariff reform is the deployment of modern equipment for metering and control. With modern IT systems and emerging valuation methodologies, it is increasingly becoming possible to calculate in greater detail the actual value of a given kWh of electricity production or consumption at a specific time and place. The deployment of smart or intelligent meters makes it possible to communicate this value to end users and use data measurements at more regular intervals in order to apply them in the billing process. Price signals that accurately capture the impact on overall system cost give a stronger incentive for demand, shaping when and where this is most valuable to the power system.

In practical terms, this can have a number of benefits. Improved visibility over electricity consumption may assist MEA and PEA to monitor and identify problems such as unregistered DPV installations by validating consumption patterns against the expected consumption of the contracted user base.

As for small consumers, the deployment of advanced metering can be used to measure not only overall energy consumption in kWh, but also maximum demand in a given period or maximum network during times of local or system-wide peak demand. It provides more detailed information on energy used which could enable consumers to adjust their usage to lower electricity bills. Being able to measure such patterns in consumption and network use is a useful first step in the development of retail tariffs that may encourage DPV deployment, while clearly allocating cost for network capacity use and grid-energy consumption. This could allow Thai DPV customers to sell their electricity back to the grid, while still covering their share of the cost of the underlying transmission and distribution infrastructure. At the same time, retail rates would likely need to be more simplified and less granular than the time-dependent wholesale rates that they are based upon, given that simplicity of rate structures for end users is a core value of ratemaking processes.

Based on emerging international experiences, it should be pointed out that the design of new retail tariffs is as important as the way in which the tariffs themselves are rolled out. One alternative to avoid widespread opposition to tariff reform is to introduce these gradually, or on a voluntary basis, or only to select customers (e.g. customers who adopt DPV). Policy makers may face the trade-off that voluntary programmes may result in greater individual engagement but lower overall tariff membership, while generalised programmes with voluntary opt-out may result in lower levels of individual participation but greater overall membership (DOE, 2016). A detailed theoretical description of retail tariff design options involves three dimensions, including the time granularity of energy charges, the time granularity of demand charges, and the locational granularity of retail tariffs (Figure 6.9).

Figure 6.9 • Options for retail pricing at different levels of granularity

	−		Granularity		+
Time - Energy	Flat tariff	Seasonal time-of-use (summer/winter)	Daily time-of-use (weekday/weekend)	Intra-daily time-of-use (peak/off-peak hours)	Real-time pricing
Time - Demand	No demand charge	Customer peak	Expected system coincident peak, annual	Expected system coincident peak, monthly	Real-time coincident peak
Location	Single price	Zonal disaggregation	Nodal disaggregation	Locational marginal price (LMP)+Txlosses	LMP +Tx/Dx losses

Notes: Tx = transmission; Dx = distribution; LMP = locational marginal price.

Source: IEA (2017), *Status of Power System Transformation 2017: System Integration and Local Grids*

Key message • Retail electricity prices can be refined along three main dimensions.

Modify buy-back rate to value-based remuneration scheme for DPV

One key aspect of the announced net billing scheme for DPV in Thailand is that the tariff for electricity fed back into the grid is between 2.3-2.5 THB/kWh, which is below the wholesale electricity rate, particularly during peak hours. Such remuneration designs fail to recognise the potential benefits of DPV to the system, both in terms of avoided cost of generation and grid reinforcements. One alternative to such approach is the introduction of value-based remuneration scheme.

Value-based approaches have become increasingly relevant with rising VRE deployment and decreasing costs. The main idea of value-based approaches is to determine the remuneration for distributed energy resources such as DPV based on the range of costs and benefits that DPV brings to the power system, including avoided generation costs, deferred infrastructure investments, and changes to power system operations.

Value-based policies are useful in that they capture both the positive and negative system impacts of additional VRE output. The system value of generation also depends on location and timing. A pure value-based system would imply that not all DPV receives the same remuneration, thus providing a locational signal to encourage positive system contributions.

Table 6.5 • Value-based considerations for distributed energy resource remuneration

Grid Services
Energy • Avoided energy by way of displaced variable costs (e.g., fuel costs) from thermal generation • Avoided energy losses from generation directly at the distribution level • Lost margins on retail sales for MEA and PEA • Lost fixed cost recovery on thermal generators owned by EGAT
Infrastructure • Cost of avoided or deferred investment in new generation • Increase or decrease in transmission and distribution investment due to DPV deployment • Increased network management costs
Grid support • Reactive supply and voltage control • Frequency regulation • Operating reserves
Financial value
Avoided or increased requirement for fuel price hedging mechanisms • Cost incurred by a utility to guarantee that a portion of electricity supply costs are fixed
Market price response • Potential decrease in wholesale electricity market as well as commodity price due to decrease in residual demand.
Security value
• Outage reduction through congestion alleviation • Increased diversity and reducing large scale outages • Back-up power: VRE, inverters and storage
Environmental value
• Carbon emissions • Air pollutants • Reduced water use • Land use
Social value
• Net social value • Additional job creation or associated job displacement

The scope of value-based compensation varies greatly in terms of the system services that valuation analyses take into account. At the most basic level, DPV output can be valued at the marginal cost of generation in real time, although this may impose high requirements in terms of recording data in real time and settling payments *ex post*. Utilities may choose to further remunerate distributed energy resources locally, in case grid injections are beneficial for alleviating local system peaks or for matching demand locally. However, defining the exact system value of VRE generation depends on a number of assumptions and complex calculations. Some approaches undertaken recently by the New York Public Service Commission and UK Power Networks include determining remuneration for distributed energy resources based on the avoided cost of local network reinforcement Investments.

Shifting to a value-based buy-back rate is recommended for Thailand. Theoretically, the buy-back level of solar could vary, not only in terms of its exact level but in terms of the period that excess balances can be carried forward. Determining monthly or yearly rolling credits is a very important question and relates directly to the government's choice of prosumer strategy: restricting, enabling, or encouraging prosumers.

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7. Power Development Plan (PDP) assessment and variable renewable energy (VRE) system costs

HIGHLIGHTS

- Integrated and co-ordinated planning frameworks which include consideration generation, transmission and distribution networks, as well as demand side and electrifications of other sectors, can help identify appropriate options for the future power system.
- The current planning process in Thailand could limit the potential of renewable energy (RE) targets since possible transmission expansion for the locations with high RE resources are not integrated in detail.
- The existing reliability and reserve margin approaches used in Thailand's power sector planning are largely based on deterministic criteria. This can be improved which would result in lower costs while still maintaining system reliability.
- The approach used to determine dependable capacity (i.e. capacity credit) of solar and wind is concentrated on two typical peak demand periods, which could lead to underestimation or overestimation.
- Capacity credit analysis, which takes into account the top 2% of load periods, shows that the VRE contribution to capacity requirements is strongly dependent on both the underlying load pattern and VRE generation. Therefore, it is most accurate to consider capacity credit in a scenario-specific manner rather than use a single number.
- A system cost analysis shows that the levelised cost of electricity (LCOE) of VRE, including system effects, increases with increasing VRE shares, but remains lower than the reference combined cycle gas turbine (CCGT) LCOE.
- In the short term, the cost of VRE generation would need to fall below approximately 2 250 THB/MWh (Thai baht per megawatt-hour) in order to reduce overall costs to consumers. This figure considers short-term system costs of VRE integration.
- The cost-benefit approach compares the LCOE of VRE with CCGT and supercritical coal for a high and low VRE investment cost case. In both cost cases, VRE is shown to be lower cost than CCGT, but more expensive than coal. The low investment cost case offers much larger net savings relative to CCGT and only a small net cost savings relative to coal.
- The total system cost approach finds that with low investment costs, VRE reduces the cost of the overall system in all scenarios due to fuel savings, even without considering any capacity contribution from VRE. This reflects the high level of gas generation in the Thai system, and that the large LCOE benefits of VRE relative to CCGT found in the system cost and cost-benefit analyses demonstrate a net savings. Inclusion of capacity credit for VRE

This chapter assesses the current planning process for the power sector in Thailand, identifying areas for improvement, particularly with regard to increasing shares of renewable energy (RE). In addition to exploring the overall planning framework, the processes to set RE targets and reserve margin criteria are also examined. Finally, system costs are analysed under different future power system scenarios, as indicated in Chapter 4 and 5.

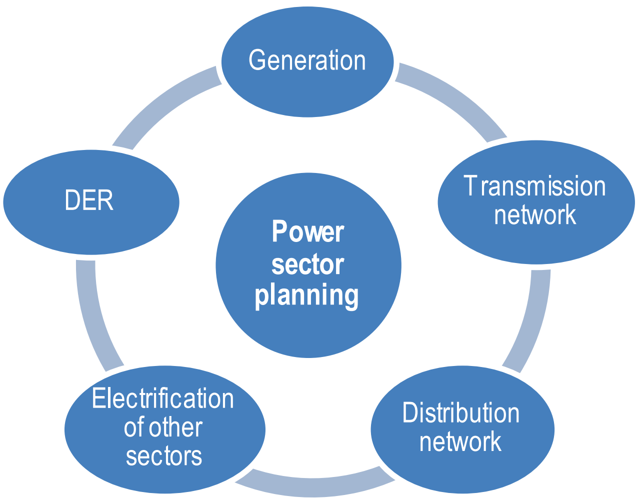
Assessment of power sector planning in Thailand

This section summarises the findings from an analysis of the methods used to construct Thailand's PDP, the process and methods used in long-term generation planning, and the formulation of the Alternative Energy Development Plan (AEDP), which sets the long-term RE targets. This covers power sector reliability and reserve margin criteria, and the framework and tools used for power system planning. It also provides recommendations based on this analysis. In addition, the approach for setting the RE target as briefly discussed in Chapter 2 is assessed in more detail.

Improvements in power sector planning to accommodate higher VRE

As discussed in Chapter 2, power sector planning has traditionally focused on developing supply-side resources and infrastructure to meet demand. However, the landscape of the power sector is changing. This is largely due to increases in the uptake of VRE and distributed energy resources (DERs), demand-side participation, and the electrification of transport and heat. Thus, the implications of such developments for the power sector can be taken into consideration together with generation, transmission and distribution network planning (Figure 7.1). A well-integrated and co-ordinated planning that considers these factors will help identify pertinent options for future power systems. More importantly, it will encourage appropriate investment decisions on flexible resources as the share of VRE increases.

Figure 7.1 • Primary aspects of power sector planning



Key point • Effective power sector planning must consider a range of factors and drivers.

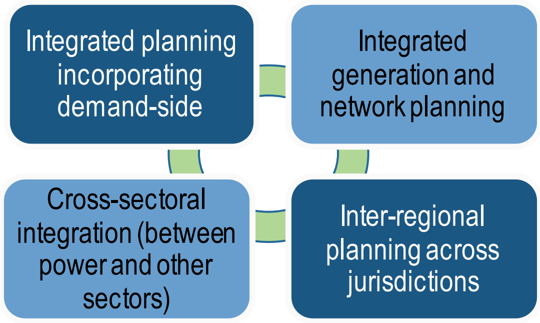
Power sector planning is an inherently complex process because the planning horizon is long and the drivers behind each aspect (shown in Figure 7.1) are highly uncertain. Compounding this complexity is a frequent lack of co-ordination on a number of activities across multiple stakeholders and jurisdictions, particularly transmission system operators (TSOs) and distribution system operators (DSOs). This is particularly the case in Thailand, as previously described in Chapter 2 and 3.

Better-integrated and co-ordinated planning frameworks can help identify appropriate options for the power system going forward as the share of VRE increases. The process should consider system flexibility, reliability and security in addition to looking at how different supply- and demand-side resources can play a role in integrating VRE successfully. Co-ordinated and integrated planning can be broadly considered in the following categories (Figure 7.2) (IEA, 2017):

- integrated planning incorporating demand resources
- integrated generation, transmission and distribution planning
- cross-sectoral planning between electricity sectors and other sectors
- planning across different regions, jurisdictions and balancing areas.

Some of these frameworks have been adopted in the Association of Southeast Asian Nations (ASEAN) countries, such as the Lao People's Democratic (PDR), Thailand and Malaysia Power Integration Project (LTM-PIP), which allows cross-border electricity trading between Lao PDR and Malaysia, through Thailand. This multilateral power exchange project had to overcome a range of regulatory, technical and operational challenges (EGAT, 2016).

Figure 7.2 • Integrated planning with increasing deployment of VRE



Key point • More integrated and co-ordinated planning can help identify appropriate options for future power systems.

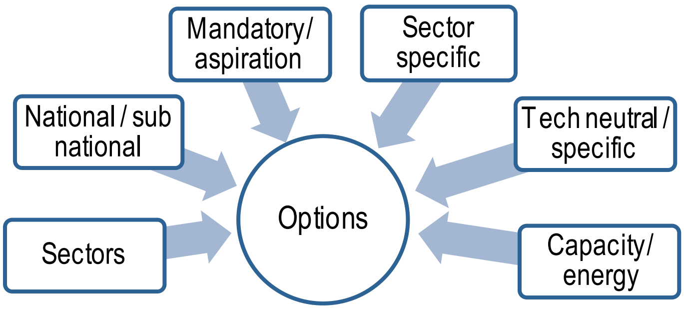
Renewable energy target setting and system planning

A RE target is an official commitment or goal set by a government (local, state, or national level) to achieve a certain amount of RE deployment by a certain year. Targets can be set by regulatory agencies or ministries. The main objectives of RE target are to:

- provide a policy and/or economic signal to drive uptake and investment in RE
- provide confidence to stakeholders on the government's commitment to RE
- create a framework for monitoring and evaluation of policies
- provide a clear definition of the RE target and the approach used to establish it that is consistent with other energy and economic plans.

There should be a consensus from the stakeholders and the target would be continuously updated (IRENA, 2015). RE targets can be set in a number of formats, such as a contribution to total primary energy for the entire economy, or a specific sector of the economy. For power sector targets, they are frequently specified in terms of power generation capacity (i.e. GW), units of generated electricity (i.e. GWh), or a percentage of total capacity or generated electricity. These targets can be technology-specific or set for RE more broadly. Figure 7.3 describes several options for RE target setting.

Figure 7.3 • Options for RE target setting



Key message • There are a variety of format and options for setting RE targets.

Other important considerations are how many years into the future RE targets are set and whether or not there are interim targets. Well-designed targets tend to consist of a combination of short, medium and long-term goals. A number of countries/jurisdictions, such as the European Union, Australia, India, China, Japan and Mexico, have set ambitious RE targets in both the short- and medium-term (i.e. 2020-30 (See Annex D). For Thailand, a primary RE target was set for 2036, while annual deployment targets from 2017-36 were fixed to allow for a constant increase in order to meet the 2036 target.

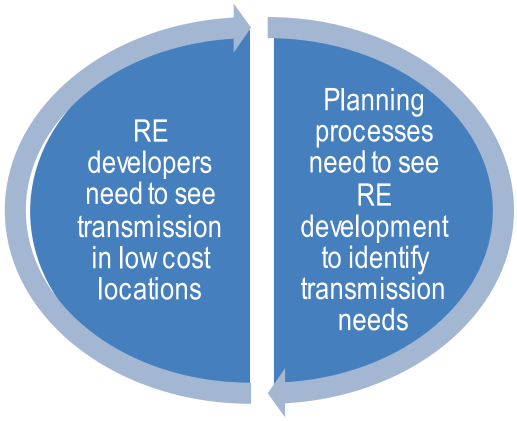
As mentioned in Chapter 2, the establishment of RE targets in Thailand was mainly conducted by Department of Alternative Energy Development and Efficiency (DEDE) as part of the Thailand Integrated Energy Blueprint (TIEB). Although some of the key factors have been taken into account, there are a number of areas that could be improved particularly, co-ordination and integration with the PDP, which covers generation and transmission expansion in detail. With increasing level of RE, integrated planning becomes very important in order to achieve cost-effectiveness and reliability of the system.

Transmission planning in particular is growing more complex, as accessing high quality VRE resources may necessitate new transmission infrastructure to be built in order to access them (or to reduce congestion on existing lines) since good VRE resources are typically in remote locations. Transmission planning would face a causality dilemma (i.e. a co-investment conundrum) since planning processes need to examine RE potential to identify transmission needs, and RE developers need certainty of transmission access to secure financing (Figure 7.4).

For Thailand, although the RE targets for each type of RE technology have been distributed for each region, the planning of transmission infrastructure in the PDP does not take into account potential RE development in any specific locations. This could potentially result in transmission congestion. In addition, it does not give project developers confidence that suitable transmission access will be available for their future projects in the medium to long term. While the current planning process takes into consideration certain limitations and restrictions on transmission potential, it does not take into account the transmission expansion options that might help to access high-quality RE resources.

Thus, more sophisticated approaches are required to reach optimal outcomes. As a start, planners can consider the potential for transmission development to locations with suitable RE resources because high-capacity factor projects attract investors and project developers and result in a higher utilisation of transmission assets. In the future, and with more advanced renewable resource data sets, it may also be possible to shift from promoting high-capacity factor locations to high *system value* locations (e.g. a set of locations that experience high wind speeds or solar insolation when the system needs additional generation the most, such as during system peaks).

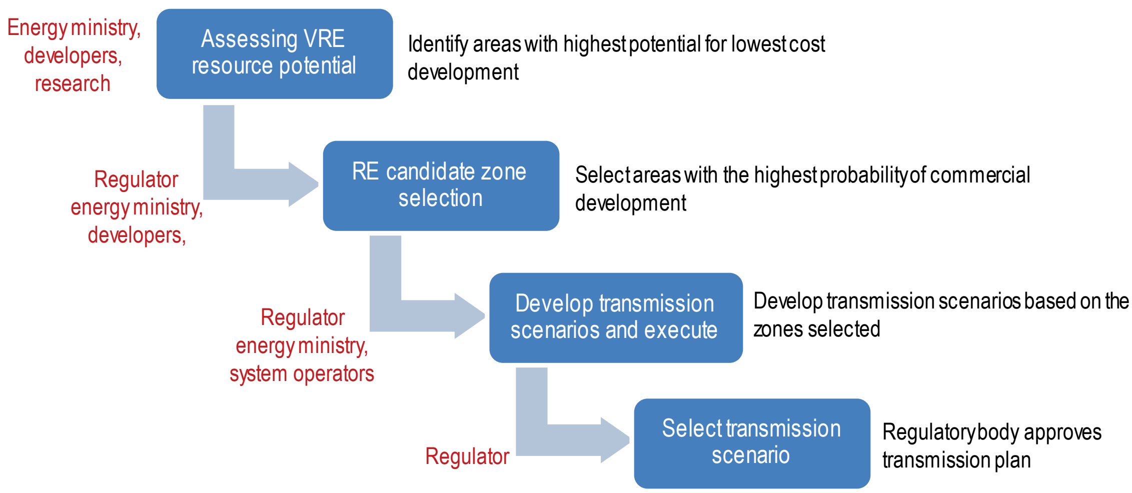
Figure 7.4 • Causality dilemma between traditional transmission planning and VRE project development



Key message • Traditional transmission planning processes do not suitably consider VRE potential.

A renewable-energy-zone (REZ) approach has been adopted in many countries, which customises transmission planning and the development of RE projects. REZ are geographical areas that are characterised by high-quality RE resources, suitable topology, and strong developer interest. The process to establish REZs consists of assessing the VRE resource potential, selecting candidate zones, developing transmission modelling scenarios once the zones have been selected to assess the value of various options, and ultimately, selecting transmission scenarios (i.e. projects) to be developed (Figure 7.5). These steps involve a number of stakeholders in the energy sector, including the regulator, utilities, and potential RE developers.

Figure 7.5 • Process in establishing REZ



Source: Adapted from NREL (2017), *Renewable Energy Zone (REZ) Transmission Planning Process: A Guidebook for Practitioners*.

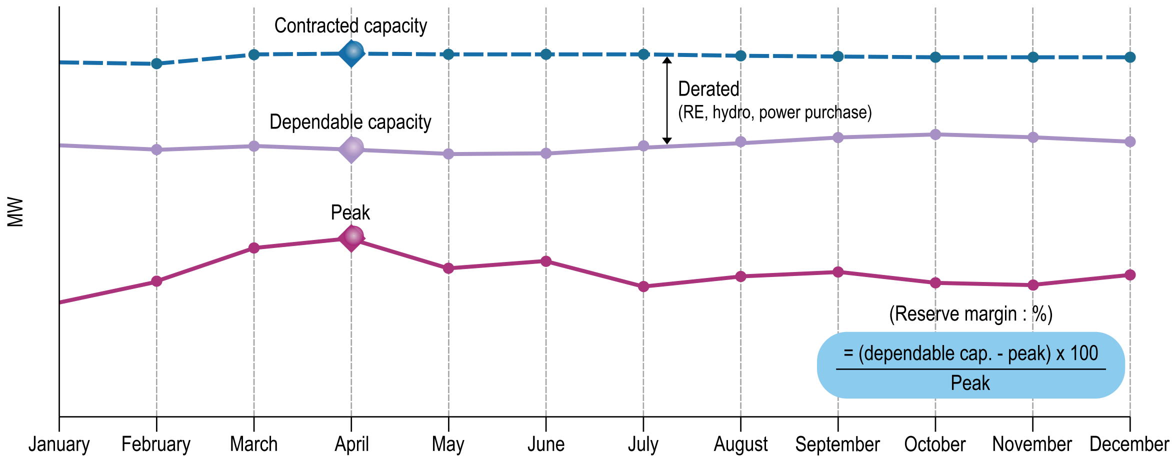
Key message • The establishment of REZ is an effective approach to concurrently develop transmission infrastructure and VRE projects while promoting system integration.

Countries and jurisdictions that have adopted the REZ approach include South Africa and the Electric Reliability Council of Texas (ERCOT). South Africa is an interesting and relevant example given that its electricity sector structure is still vertically integrated, which is somewhat similar to Thailand. The South Africa Renewable Energy Development Zone (REDZ) process was established and approved in 2016, and the state-owned utility Eskom now considers RE resources holistically in their transmission planning exercises. The example of South Africa is described in additional detail in Annex D.

Power sector reliability and reserve margin criteria

There has been significant discussion about the present reserve margin criteria used for planning purposes in Thailand, and whether or not they are suitable in terms of promoting cost-effectiveness. Currently, the reserve margin is calculated based on the difference between the dependable generating capacity (or commonly known as capacity credit) and the annual peak demand (Figure 7.6).

Figure 7.6 • Electricity Generating Authority of Thailand (EGAT)'s approach for determining dependable capacity and reserve margin



Source: Adapted from EGAT.

Key message • Reserve margin is determined by comparing dependable capacity and peak demand.

The reserve margin criteria is currently set at 15%, with reliability based on loss of load expectation (LOLE), which is at 24 hours per year or 99.726%. In this respect, the reserve margin criteria used are consistent with international standards and with the North American Electric Reliability Corporation (NERC) for power systems based on fossil fuels. Although the probabilistic technique of LOLE is employed, the existing approach is still largely based on deterministic criteria. This approach can be further improved, which would result in lower system costs while maintaining adequate system reliability.

Existing methodology used to determine capacity value of wind and solar power plants in Thailand power system

The capacity value (or capacity credit)[19] of wind and solar power plants in Thailand is referred to as "Dependable Capacity", which is the per unit capacity that each type of power plant can be depended upon. Based on EGAT's current approach to determine the capacity credit of wind and solar, it is based on the probabilistic evaluation method, which concentrates on two typical peak demand periods (Sangpetch, 2014). The dependable capacity is used by EGAT to estimate the

[19] Capacity value (or capacity credit) can be considered as the contribution of a power plant to meet demand in a reliable manner, It is typically determined as the percentage of installed generation capacity.

amount of renewable capacity that the system can rely on. It is also used in the calculation of the reserve margin. The capacity value is currently assessed by:

- Identifying critical hours; this is currently set to 14h00-15h00 and 19h00-20h00 during March, April and May, which are usually when the peak demand occurs
- Obtaining real VRE generation profiles from the past three years during these hours for all plants
- Normalising output profiles to installed capacity of each power plant and grouping of plants per technology
- For each technology group, taking the 80th percentile output level during the peak hours (so only 20% of observations are higher); this metric is the capacity credit.

This methodology is accurate as long as the following conditions hold:

- The last three years of weather data are representative
- The selected set of VRE generation plants is adequate and spread across Thailand
- The periods of system stress being evaluated remain unchanged over time.

This approach resulted in relatively low capacity credit for wind in both afternoon and evening peak, while the capacity credit for solar is relatively high since only the afternoon period was considered (Table 7.1). These capacity credits have been used for long-term capacity expansion planning.

Table 7.1 • Capacity credit (i.e. dependable capacity) of wind and solar generation determined for power system planning in Thailand

Technologies	EGAT's capacity credit (Dependable capacity)	
	Time: 14.00-15.00	Time: 19.00-20.00
Solar	35%	0%
Wind	2%	4%

Source: provided by EGAT.

Going forward, this approach is problematic for two reasons. First, looking at only these two time intervals does not capture all relevant system needs. Time windows should thus be revised in light of system needs continuously. Second, the 80th percentile criterion may need to be reviewed to make sure the resulting firm capacity estimate is in line with the desired reliability level.

For example, a longer period of VRE generation observations and a more representative set of VRE time series can be obtained from the actual data of all of the existing VRE plants rather than using observations. In addition, calculating future expected net load can help to identify future expected periods of system stress, as opposed to using a static quantity. Relatedly, the deployment of VRE plants over time across different geographical locations must be taken into account.

At higher shares of solar PV, it can be expected that there will be no capacity shortage mid-day, and the current method may ultimately overestimate capacity credit. On the other hand, if the assessment is based only on a few plants, this could underestimate capacity credit. If time and resources allow, a full Effective Load Carrying Capability (ELCC) calculation could be carried out (see Keane et al. 2011). Capacity credit analysis is provided in the next section.

Potential ways to improve Thailand's reserve margin criteria

Regarding possible ways to improve the deterministic criteria currently used, it is likely that the shift towards a reserve margin criteria derived from a fully probabilistic method could provide a reserve margin adapted to Thailand's power sector characteristics and thus improve the reliability of the system.

Two examples of this methodology were provided to EGAT by the International Energy Agency (IEA) during the preliminary meeting. First, the Mexican case, where the 13% deterministic margin was substituted by a 15.9%, resulting from a probabilistic exercise taking into account observed availability from generators.

The second example was the joint exercise to define the generation adequacy assessment for Germany, the Benelux, Switzerland and Austria in the framework of the Pentalateral Energy Forum (PLEF). This exercise shows how properly accounting for statistical interactions between different sources allows for a definition of an expected number of hours of load loss, which would not be as accurate if the same assessment was done separately for each country (PLEF, 2015).

An example demonstrating the aggregate value of this type of exercise for the PLEF is provided (Figure 7.7). A scenario where each country relies only on the resources within its boundaries in order to satisfy its peak demand is shown in the left side, with the number of hours of expected loss of load per country. The right side of the table shows a scenario where stochastic behaviour of weather and availability of resources in each country are taken into account in order to derive the expected number of hours where load will not be served. This highlights the benefit of ensuring adequacy over larger regions, whether across national borders or within a country.

Figure 7.7 • Comparing national and cross-border adequacy results

Isolated adequacy analysis

Isolated case for winter 2020-2021

	LOLE (h)		ENS (GWh)	
	Average	**P95**	**Average**	**P95**
Belgium	308	448	277	455
France	151	398	782	2423
Austria	3	20	1	10
Switzerland	1086	1822	1046	2298
Germany	0	3	0	1
Netherlands	32	64	13	33
Luxembourg	8760	8760	4800	4900

Interconnected adequacy analysis

Interconnected case for winter 2020-2021

	LOLE (h)		ENS (GWh)	
	Average	**P95**	**Average**	**P95**
Belgium	0	0	0	0
France	6	27	15	65
Austria	0	0	0	0
Switzerland	0	0	0	0
Germany	0	0	0	0
Netherlands	0	0	0	0
Luxembourg	0	0	0	0

Note: ENS = energy not served.

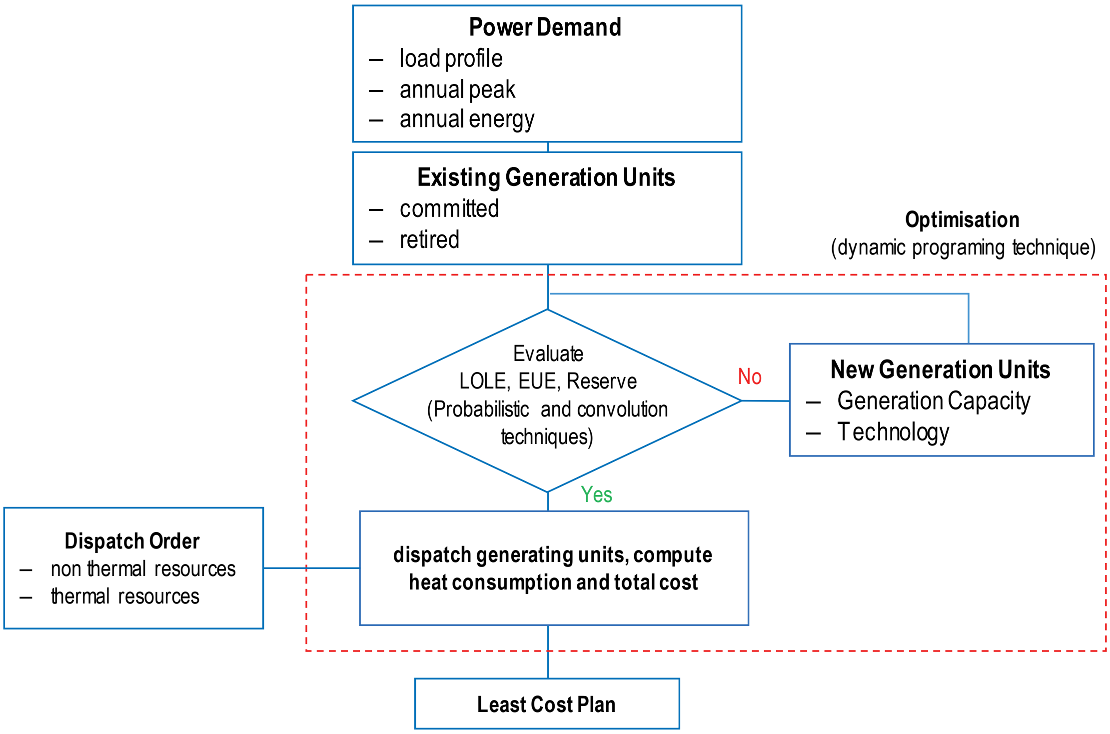
Source: PLEF (2015), *Pentalateral Energy Forum Support Group 2 - Generation Adequacy Assessment*.

Key message • National and cross-border adequacy results are significantly different.

Frameworks and tools used for power system planning

Regarding the tools used for the planning process, the Thai officials responded that the ABB STRATEGIST software was the tool being used for planning purposes. This model applies probabilistic techniques for forced outages of generating units. The dynamic programming approach is applied to determine the least cost generation plan based on the key factors including capacity costs, fixed operation and maintenance (O&M) and outage costs (Figure 7.8).

Figure 7.8 • Flowchart of generation expansion model, as used by EGAT



Note: EUE = expected unserved energy.

Source: Provided by EGAT.

Key message • EGAT is applying a software tool named "Strategist" to determine the new generation capacity requirements of the system.

Although this tool is a power system planning model, the description of the tool from the vendor clarifies that it is not suited for performing:

- short-term analyses
- studies requiring high levels of operational detail (which is important as the share of VRE increases)
- studies requiring the modelling of the primary power plant operational characteristics, such as ramp rates or start-up costs.

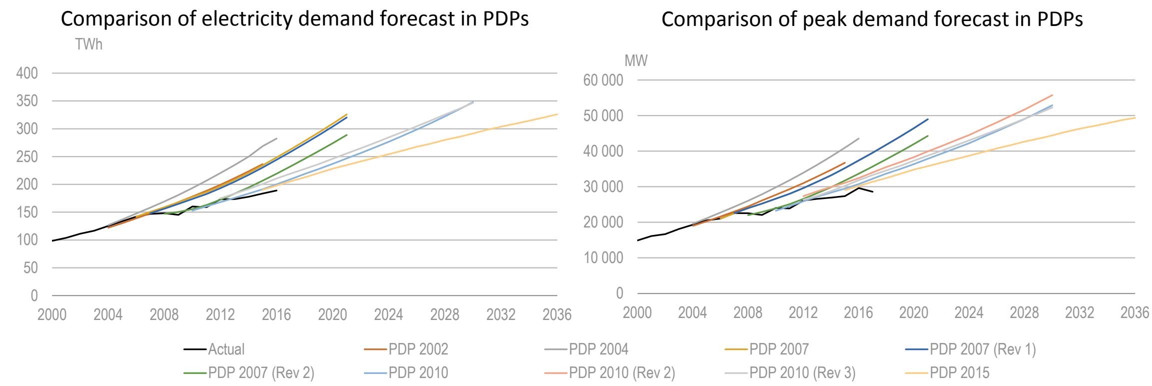
Given that integrating large shares of renewables into the system requires planners to take into account a range of operational power plant characteristics (e.g. ramp rates) and associated costs (e.g. start-up costs), supplementing the planning process with a different or additional type of tool is recommended in order to make assessments more suited for variable generation. In addition, the software should be consistent in short-, medium- and long-term planning.

As the Thai power system is approaching Phase 2 of VRE deployment, more sophisticated planning tools may be required which are also able to integrate across various power system timescales.

Comparison of demand forecast from past PDPs with real demand data

IEA performed a simple comparison of the energy consumption and the peak demand forecast with the observed values as shown in Figure 7.9. As can be seen, both the electricity consumption and the peak demand forecast tend to be systematically higher than actual values.

Figure 7.9 • Demand and peak demand forecast from previous PDPs



Source: EGAT (2002; 2004; 2007a; 2007b; 2007c; 2010; 2016); EPPO (2010; 2015).

Key message • Recent electricity demand forecasts in Thailand's PDP have been consistently higher than actual demand.

This is very common bias among centrally planned electric systems. Nonetheless, EGAT expressed concerns about the demand growth patterns in recent years, which differ from forecasts considerably. In order to understand the over-estimation of demand, a brief analysis of the variables taken into account during the formulation of demand forecasts was undertaken for different sectors, including EGAT's direct customers, residential, business, industrial and other sectors using different inputs and variables (Table 7.2). The estimation was performed using either an end-use model or econometric model. Peak demand is estimated by using aforementioned forecasted energy demand and surveyed power consumption pattern of each sector.

Table 7.2 • Input and variable for load forecasts in the current PDP

Sector	Survey data	Drivers	Assumptions
residential sector (end-use model)	income/household, % share of each household type, Watt/appliance, hours of use/day of appliance, lifetime of appliance, etc.	gross domestic product (GDP), population	% efficiency growth, % temperature growth
business sector (end-use model)	average area/each business sector, power consumption per area, opening hours/day of each business type, average age of business	GDP of each industrial sector	% efficiency growth, % temperature growth
industrial sector (end-use model)	capacity/factory, production/capacity, no. process/production, power consumption/process, lifetime of factory	GDP of each industrial sector	% efficiency growth, % temperature growth.
other sectors (small general service, non-profit organisations, agricultural pumping, etc.) (econometric model)	no. users from MEA/PEA, energy consumption by user from MEA/PEA, gross regional product (GRP), population	GRP, population	% efficiency growth, % temperature growth
EGAT's direct customer	Estimated by surveying customers' power demand and business plan and reviewing every three years.		

Note: MEA = Metropolitan Electricity Authority; PEA = Provincial Electricity Authority.

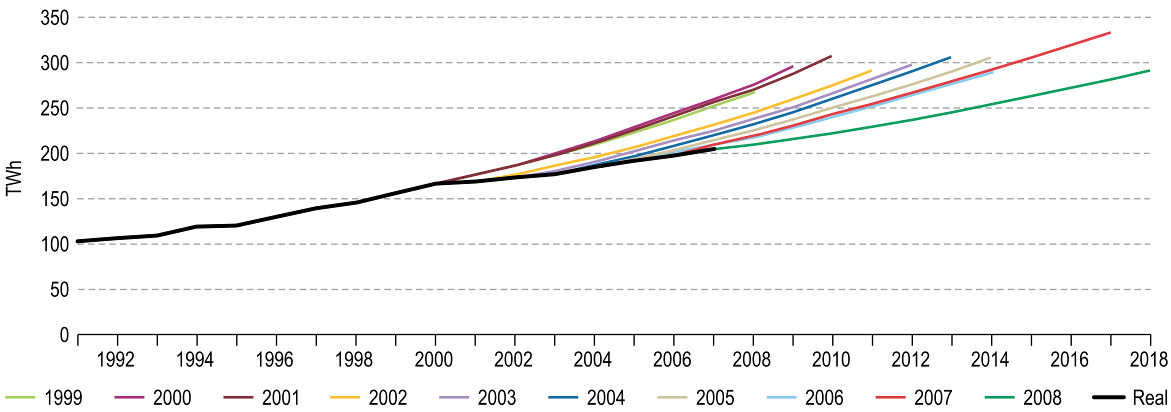
The conclusions are that the set of variables that EGAT uses to forecast demand does not appear to have missed any relevant information and the method appears to be analytically sound. Given that assessment, the IEA recommendation to EGAT is to focus efforts on assessing the quality of the inputs to their demand models.

International experiences on power sector planning

Similar experiences of consistently overestimating peak demand and energy consumption have also happened in many other countries, such as Mexico (Figure 7.10). The main reasons were due to the former state planning exercise (known as POISE, its initials in Spanish), which was a "policy statement" following official economic growth expectations.

The legal reforms from 2013 ordering the opening of the sector to competition allocated the responsibility of the planning process to the Energy Ministry, in order to guarantee impartiality of the planning process. The output of this process is the National Power Sector Development Program (known as PRODESEN, its initials in Spanish), an annual planning exercise conducted for the power sector. This shift from POISE to PRODESEN was an opportunity to review a variety of planning procedures, including how demand forecasting was being conducted. This new long-term planning exercise is explained in Annex C.

Figure 7.10 • Comparison of electricity demand forecasts in Mexico



Source: Programa de Obras e Inversiones del Sector Eléctrico (POISE) 2009-18.

Key message • Over-forecasting of electricity demand also occurred in Mexico before the reform.

Although power systems around the world face different national circumstances and possess distinct portfolios of resources, many lessons can be learned from examining other countries' practices on the various stages of power system planning. From the way information is gathered, to the forecast methods utilised for relevant variables (e.g. peak demand, energy demand, fuel prices), to the process of soliciting and integrating stakeholder input, all these aspects alter the outcome of planning exercises. By examining experiences from various countries with very different legal frameworks, one can learn about innovative methods that led to smart solutions and about problems shared by most planners; examples from various countries with very different legal frameworks were taken to highlight the range of problems faced and solutions found by most planners. Examples of the planning process were taken from the following (with the details in Annex D):

- Mexico's National Power Sector Development Program (PRODESEN)
- South Africa's Integrated Resource Plan (IRP)
- France's Ten-Year Network Development Plan (TYNDP)

System cost and cost-benefit analysis

Results of capacity credit analysis

An average capacity credit analysis was first formulated using six years of load data (2011-16), based on simulated VRE profiles and an assumed 3 000 MW solar, 600 MW wind – this corresponds with the estimated historical VRE capacity in 2016. The multi-year approach demonstrates how different underlying load curves and generation profiles produce different results inter-annually (see Table 7.3).

Table 7.3 • Estimated capacity credit for 3 000 MW solar and 600 MW wind for different years

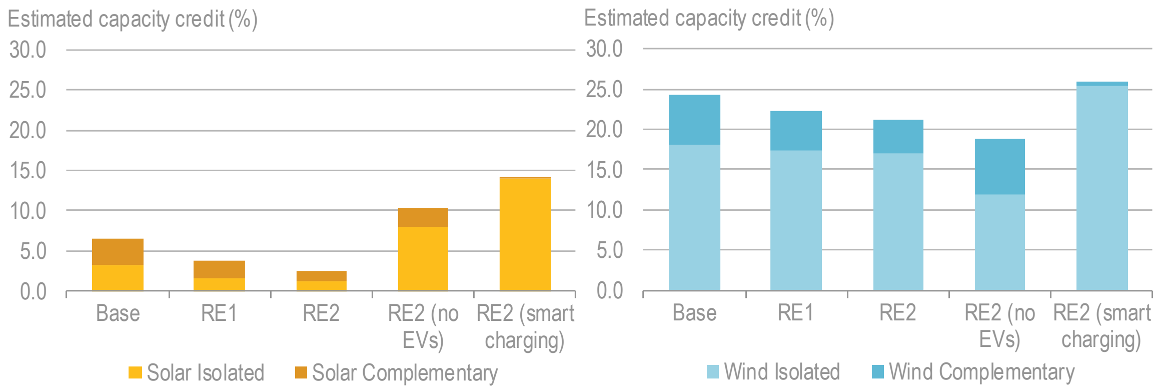
	Estimated capacity credit	
Load curve year	**Solar**	**Wind**
2011	13.3	18.3
2012	17.9	22.8
2013	24.9	13.6
2014	17.4	16.3
2015	15.7	15.4
2016	18.2	15.7

Based on the assumption of an estimated 18.2% capacity credit for solar PV in 2016, this would result in an estimated firm capacity value of 550 MW for the approximately 3 GW of solar present in the Thai system in 2016. It is important to note, however, that a more accurate estimate would need to use the detailed generation profiles for all solar PV generation in 2016, which is not available because much of the solar PV fleet is not metered. The analysis also suggests that this estimate would vary quite significantly year to year.

The average capacity-credit analysis for future scenarios illustrates some interesting differences from the analysis of historical data and results in a much lower estimated capacity credit for solar (Figure 7.11). While the higher solar penetration in the future scenarios has some effect on the capacity credit, the primary driver of the reduction is changes in the underlying load curve. The 2036 load curve assumes an unmanaged electric vehicle (EV) charging profile, which shifts the system peak from the afternoon into the evening. This can be clearly seen by the results of analysing the load curve with EVs excluded, which increases the capacity credit estimate for solar from around 3% to 10%. Smart EV charging – which enables EVs to respond to time-of-use pricing schemes, shift peak load, and promote system flexibility – further increases this to a value of 14%.

The overall picture for wind is quite different, with the capacity credit remaining much more stable with increasing penetrations. While the capacity credit of wind can be lower than PV at very low shares, it is much more robust at high shares. This is because wind generation follows a more stochastic pattern, without daylight hours limiting times of non-zero output. In contrast to solar, wind capacity credit is higher in an evening peaking system as seen by the drop from 21% to 19% when EV load is excluded. The average wind capacity credit – based on the 90th percentile benchmark for wind in the different scenarios – is 24% for the Base scenario, 22% for the RE1, and 21% for the RE2 scenario.

Figure 7.11 • Estimated capacity credit for wind and solar across various scenarios



Key message • The average capacity credit for wind is higher and more stable than solar in the modelled 2036 scenarios, with solar dropping off rapidly with increasing penetration. Implementation of measures to promote system flexibility can boost the capacity credit of VRE resources.

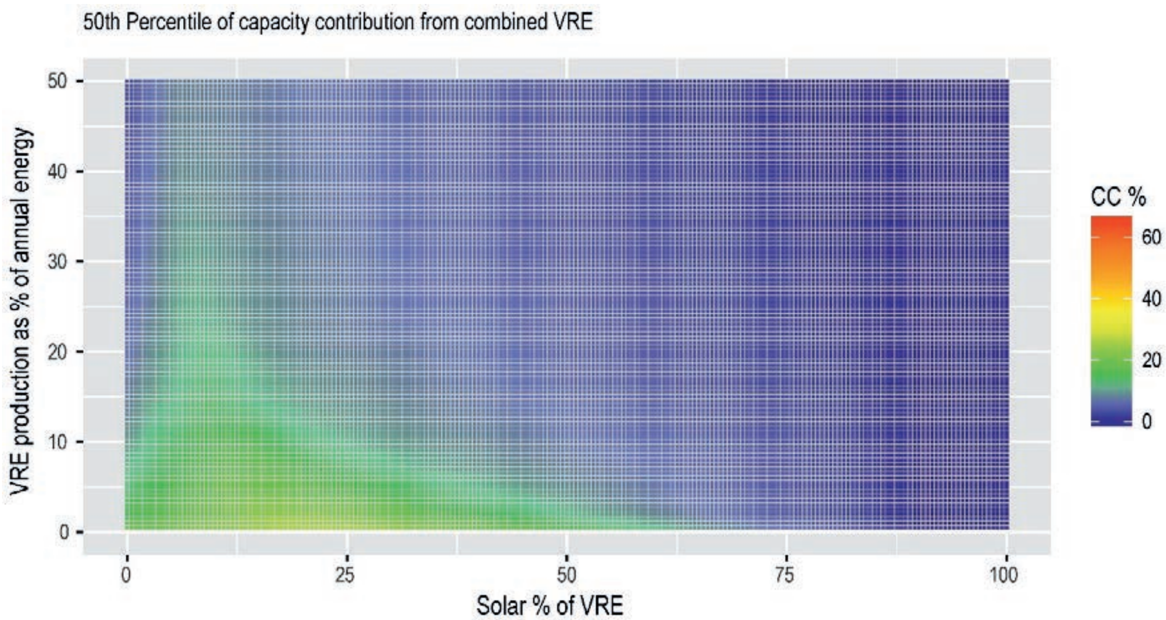
To see the interaction between wind and solar PV, the individual capacity credits for each technology are compared with their combined effect (Figure 7.11, see the darker upper portion of bars). This demonstrates a clear synergy between wind and solar, with all estimates being higher when considering their complementary effects. In other words, deploying a mix of wind and solar PV results in a capacity credit for the combined fleet that is higher than the sum of the individual technologies when deployed alone. This somewhat counterintuitive result can be understood in the following way: solar PV shifts the peak net load to times when it is generally more windy, compared to the usual peak demand times in the absence of solar PV. Conversely, when the system peak normally occurs in the evening, wind may help shift it earlier in the day, increasing the contribution of solar.

A more detailed understanding of the change in capacity credit with increasing penetration can be obtained by examining the *marginal* capacity credit at different shares of VRE and with different shares of wind and solar (Figure 7.12).[20] Here we can see that the highest marginal capacity credits are provided by a mix of wind and solar at moderate VRE penetrations (see the yellow-green zone in the lower left of the graph) and the decline in capacity credit at higher VRE shares increases. Almost no capacity contribution is seen from very high solar shares (see the blue area at the right of the graph), which is consistent with the results from the average capacity-credit analysis using the 2036 unmanaged load curve.

This marginal capacity credit approach can also illustrate strikingly how the underlying load curve influences the capacity contribution of VRE. Exactly the same methodology applied instead to the 2036 load curve with smart EV charging yields much higher capacity credits for solar in particular (Figure 7.13). The analysis demonstrates how the capacity credit of solar can actually be much higher than wind in an afternoon peaking system (orange-red area in the lower right of the graph), but this value reduces very sharply as solar penetration increases (blue zone in the upper right). The complementarity of the two technologies is again underlined, with the highest capacity contributions at high VRE shares offered by a mix of wind and solar.

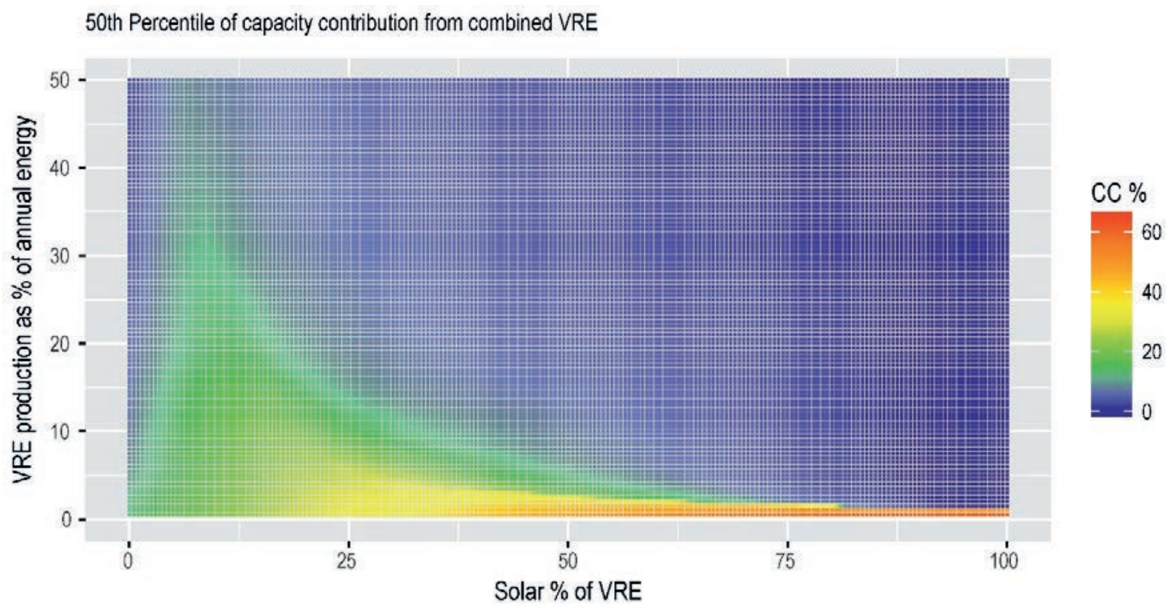
[20] Marginal capacity credit can be defined as the capacity credit of the next individual generator added to the fleet, rather than the fleet-wide average metric.

Figure 7.12 • Marginal capacity credit for different wind and solar portfolios with unmanaged EV charging in 2036



Key message • The appropriate mix of wind and solar PV can provide an optimal contribution to capacity credit.

Figure 7.13 • Capacity credit for different wind and solar portfolios with smart EV charging in 2036



Key message • Smart EV charging can enhance the capacity credit of VRE.

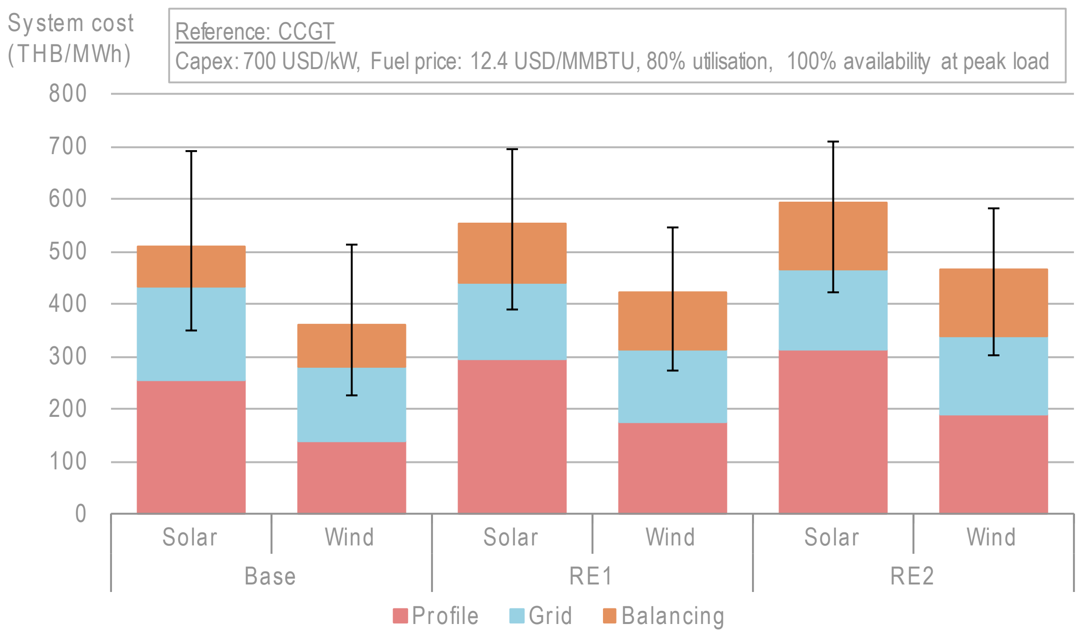
In summary, the results confirm that in Thailand, solar PV can be considered primarily as an energy resource and not a capacity resource as shares increase. It can, however, have a higher capacity credit at lower shares in an afternoon peaking system, and this positive effect is already visible in the current situation in Thailand. Wind power provides a modest, but more stable contribution to firm capacity that should be considered in long-term planning. To estimate accurately the capacity contribution of new wind and solar resources, the load curve and the existing wind and solar penetration all need to be taken into account.

Results of system cost analysis

This analysis compares the levelised system costs of wind and solar PV to a set of CCGTs with an 80% capacity factor and 100% availability at peak demand. As discussed in the methodology chapter, this approach does not answer the question of whether it is beneficial to add additional generation to the system; rather, it compares the relative costs of different technologies while taking into account the cost of certain system effects. A comparison between CCGT and wind/solar technologies is made for the different scenarios considered in the analysis (Base, RE1 and RE2).

For the modelled scenarios and the chosen reference technology (CCGT), system costs are estimated to range from 500 to 600 THB/MWh for solar and from 350 to 450 THB/MWh for wind (Figure 7.14). Importantly, these estimates may deviate by ±32% on average when applying different assumptions for fuel price, grid connection cost, and other factors.

Figure 7.14 • System cost estimates for VRE in the Base, RE1 and RE2 scenarios in 2036



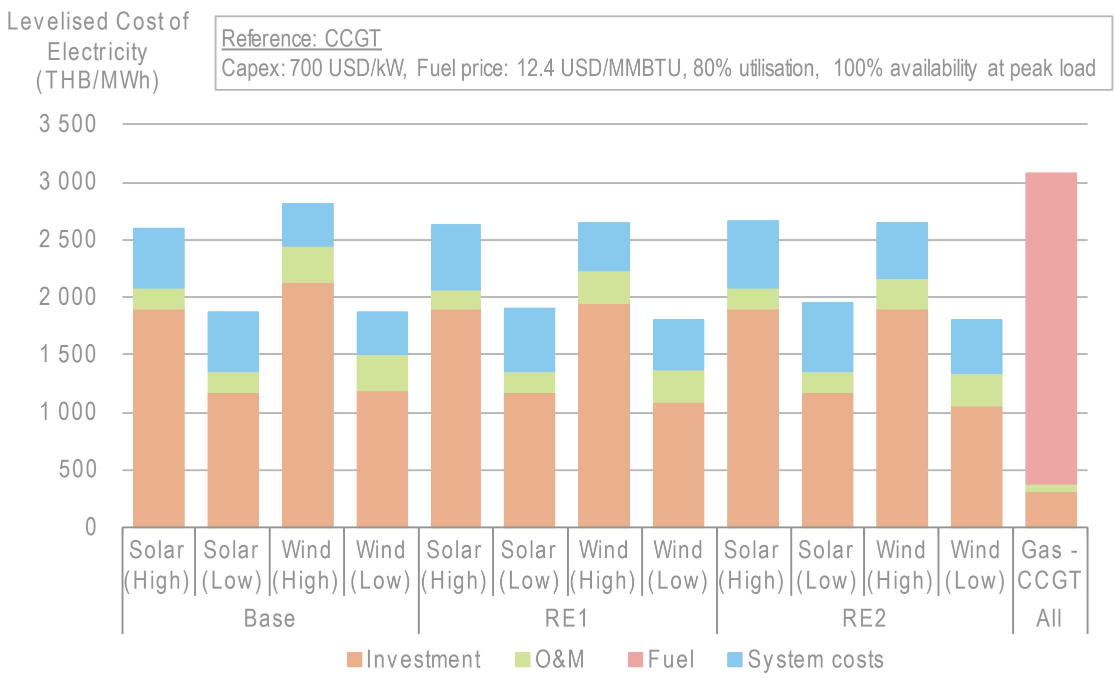
Key message • VRE system costs increase with higher VRE penetration.

Profile costs are mainly driven by the costs for capacity adequacy. While wind and solar PV do contribute to capacity requirements, this is relatively low and declines with increasing share. For wind, it falls from 24% estimated capacity credit in the base scenario to 21% in the RE2 scenario, and for solar PV from 7% in base to 3% in RE2. The result of this lower capacity credit is that other generation needs to be deployed to ensure reliable electricity supply at all times. The need for backup generation can be reduced by utilising innovative flexibility options such as storage and demand-side response. Profile costs are calculated against the aforementioned reference CCGT, unless stated otherwise.

Grid costs are the cost of VRE plant connection to the transmission grid as well as transmission grid upgrades, which are estimated to be in the range of 140-180 THB/MWh across the different scenarios, with an uncertainty of 31% on average. Grid costs do not necessarily increase with VRE penetration since the connection cost per electricity output decreases depending on plant location and capacity factor of additional VRE plants, while the cost for transmission and distribution grid upgrades increases in the higher penetration VRE scenarios. Note that technologies other than VRE may have grid costs as well; however, we assume grid connection costs of 0 THB/kW for reference CCGT plants in order to provide a conservative assessment.

Balancing costs are mainly driven by the need to balance forecast errors and, to a lesser degree, reduced part-load efficiencies of plants and the additional costs of starting plants more frequently. By adding these combined components to the LCOE of each technology, we derive a “system LCOE” which can then be compared with the reference technology (CCGT) (Figure 7.15).

Figure 7.15 • Comparison of system LCOE in the Base, RE1 and RE2 scenarios in 2036



Key message • Even when accounting for integration effects, the cost of new wind and solar plants is lower than the cost of the reference CCGT, mainly driven by the high fuel costs of the reference CCGT.

It is useful to put these figures into real-life perspective. One useful comparison is the possible cost increase as a result of gas price variability for a fleet of natural gas plants providing the same amount of energy as wind and solar. The identified system costs for VRE are comparable to gas price fluctuations of ±2% (base), ±4% (RE1) and ±6% (RE2), which is less than price fluctuations of average annual gas prices in Thailand for the past five years (around ±10%). It is also important to note that other dispatchable technologies can also incur system costs relative to the reference technology (e.g. a large nuclear plant needs contingency reserves).

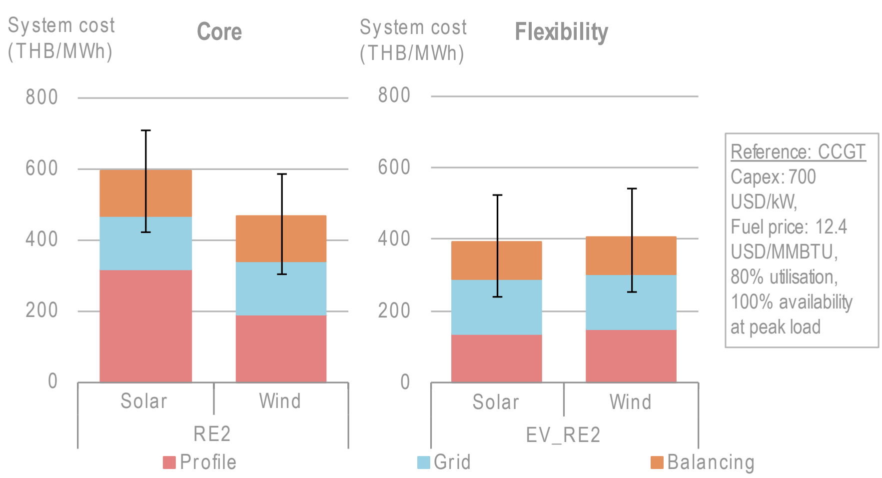
Advanced options for minimising system effects

Electricity storage is one flexibility option that could reduce future system cost of VRE. Storage systems with 3.5-hours discharge duration (e.g. a 1 MW/3.5 MWh-storage system) could provide firm generation capacity during the highest demand periods per year in Thailand. Based on current investment cost for lithium-ion battery systems meeting those criteria (USD 2 070 to USD 2 920/kW [Pacificorp, 2016]) and projected cost reductions by 2036 (50% to 80% [Schmidt et al., 2017]), the total investment costs for lithium-ion battery storage systems could reduce to between 390 and 1 430 USD/kW in 2036. Compared to the assumed reference technology (CCGT at 700 USD/kW), this means profile cost could reduce by using batteries instead of CCGTs if the low cost projection for lithium-ion battery systems occurs.

While these cost reductions for lithium-ion batteries are uncertain, there are other electricity storage technologies, like redox-flow or high-temperature batteries, that could ultimately be more suitable for long-duration storage, should significant cost-reductions for these technologies occur. In addition, utilisation for the battery in the described peak capacity application is 4% because it is only assumed to provide peaking capacity. During the remaining time, this capacity could be used to provide other services that also reduce balancing and grid costs like deferring transmission network upgrades and reducing part-load operation of dispatchable generators.

There are multiple options to increase flexibility of the power system (see Chapter 3). For this analysis, the scenario RE2 with EVs of 1.2 million units (scenario 4.3 in Table 4.1.) is compared with the core RE2 scenario to explore the impact of smart charging. This has a positive impact on the integration of VRE, with system costs for VRE reduced by 34% for solar and 13% for wind (Figure 7.16).

Figure 7.16 • System costs in the RE2 scenario without (left) and with the smart EV charging (right)



Key message • Smart EV charging could reduce system costs up to 34% for solar PV.

VRE system costs reduce from 600 (solar PV) and 450 THB/MWh (wind) in the RE2 scenario to approximately 400 THB/MWh for both technologies when system flexibility is increased. These cost reductions are mainly due to reductions in:

- profile cost – increased capacity adequacy of VRE: 84%
- balancing cost – reduced start-ups & shut-downs: 9%
- balancing cost – reduced part load operation: 6%

The significant impact on capacity adequacy cost is the result of utilising flexible-charging electric vehicles to support the reduction of peak net load, which results in an increasing alignment between the peak load and VRE output. This improved alignment with the peak load increases the estimated capacity credits for solar and wind, which change from 3% and 21% for solar and wind, respectively (RE2, core model), to 14% and 26% (RE2, EV model). The number of hours that coal and gas power stations operate at part-load to provide spinning reserve for VRE plants reduces by 28%, which helps to reduce the balancing cost. On the other hand, the grid cost is unchanged.

In summary, the system cost-analysis has shown that taking the system effects of VRE into account does increase the estimated total system LCOE of solar and wind generation. These costs are system-specific, and tend to increase with increasing VRE penetration, but they can also be mitigated with the inclusion of flexibility options. In all the scenarios studied, VRE technologies remain cheaper than the reference CCGT in the long term.

Results of cost-benefit analysis

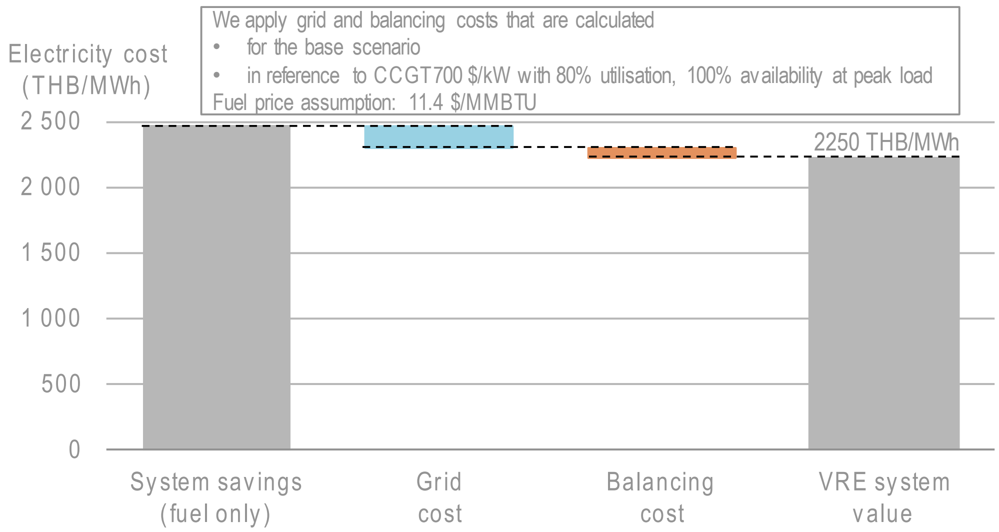
The cost-benefit analysis compares the net benefit of supplying a fixed increment of electricity to the power system with either VRE, CCGT, or coal-fired power plants. The results are expressed per unit of electricity.

The analysis is carried out adopting both a short-term analytical perspective, where VRE can only offset fuel consumption, and a longer-term perspective, where VRE can also reduce the need for adding new capacity, depending on the firm capacity contribution from VRE. The results largely depend on the LCOE of wind and solar PV itself, highlighting the importance of procurement frameworks that reduce the cost of VRE compared to current levels in Thailand.

Short-term cost-benefit analysis results

In the short term, the economic benefit of adding VRE to the power system would be limited to fuel savings. By using a simplified model that assumes VRE does not replace existing power plants but incurs additional costs (i.e. grid and balancing costs), the short-term benefit of VRE can be understood as follows. If the LCOE of VRE is higher than a certain benchmark, the fuel savings provided by VRE are negated by the other costs and do not result in a net benefit. Conversely, if the LCOE is below that same benchmark, adding VRE will reduce the electricity cost of the power system (Figure 7.17).

Figure 7.17 • Benchmark cost at which adding VRE can help reduce total electricity cost in the short-term (2016 costs)



Note: Fuel savings based on 2018 liquefied natural gas (LNG) spot prices. Grid and balancing costs are taken from the Base scenario.

Key message • The cost of VRE needs to fall below 2 250 THB/MWh to be cost-effective purely as a fuel saver in the short term.

Long-term cost-benefit analysis results

The cost-benefit analysis addresses the question of whether or not it is more costly to build VRE generation in 2036 compared with generating the same amount of electricity from CCGTs or coal plants. We calculate the cost and benefit of VRE deployment by 2036 subject to the three VRE deployment scenarios with high and low VRE-investment costs and two reference technologies (CCGT and supercritical coal; Figures 7.18 and 7.19, respectively). Results are shown for VRE deployment overall, which accounts for the combined generation of wind and solar resources in each scenario.

System savings include the avoided fuel cost, the portion of capacity addition, and the portion of O&M costs of the reference technologies that can be avoided by VRE deployment. They are higher when calculated in reference to CCGTs than for supercritical coal, due to the higher CCGT fuel costs assumed for their lifetime per MWh electricity produced. The system savings for the scenarios studied reduce with increasing VRE deployment, due to the decreasing capacity credits of VRE.

Grid and balancing costs reflect the additional costs incurred in the power system and are equal to the grid and balancing costs determined in the system cost analysis. Accordingly, these costs increase with each VRE deployment scenario, and net benefits decrease as VRE penetrations increase. The difference between the overall system value of VRE and the VRE LCOE determines net benefit or cost to the system.

The long-term CBA analysis found that the net benefit per unit of VRE reduces with increasing deployment, due to the reduced per MWh savings (mostly due to reducing capacity credit) and increased per MWh additional costs (i.e. rising system costs). Whether VRE is initially cost effective depends on both the system and the reference technology, and whether it remains cost effective at higher penetrations depends on this per-unit decline in net benefit.

Using CCGT as the reference technology, VRE deployment led to net savings in all scenarios (Base, RE1 and RE2). On the other hand, VRE deployment led to net costs compared with providing the same electricity from supercritical coal plants. While the per-unit saving would be expected to decline with increasing VRE share, the RE1 performs very similarly to the Base scenario as a result of higher capacity factors for the larger utility-scale wind plants[21] included in the higher VRE scenarios. In addition, considering the improved capacity credit of VRE provided by smart charging shifts the net benefit in the RE2 case to be higher than Base case with unmanaged charging. This highlights the importance of flexibility measures in systems with higher VRE shares.

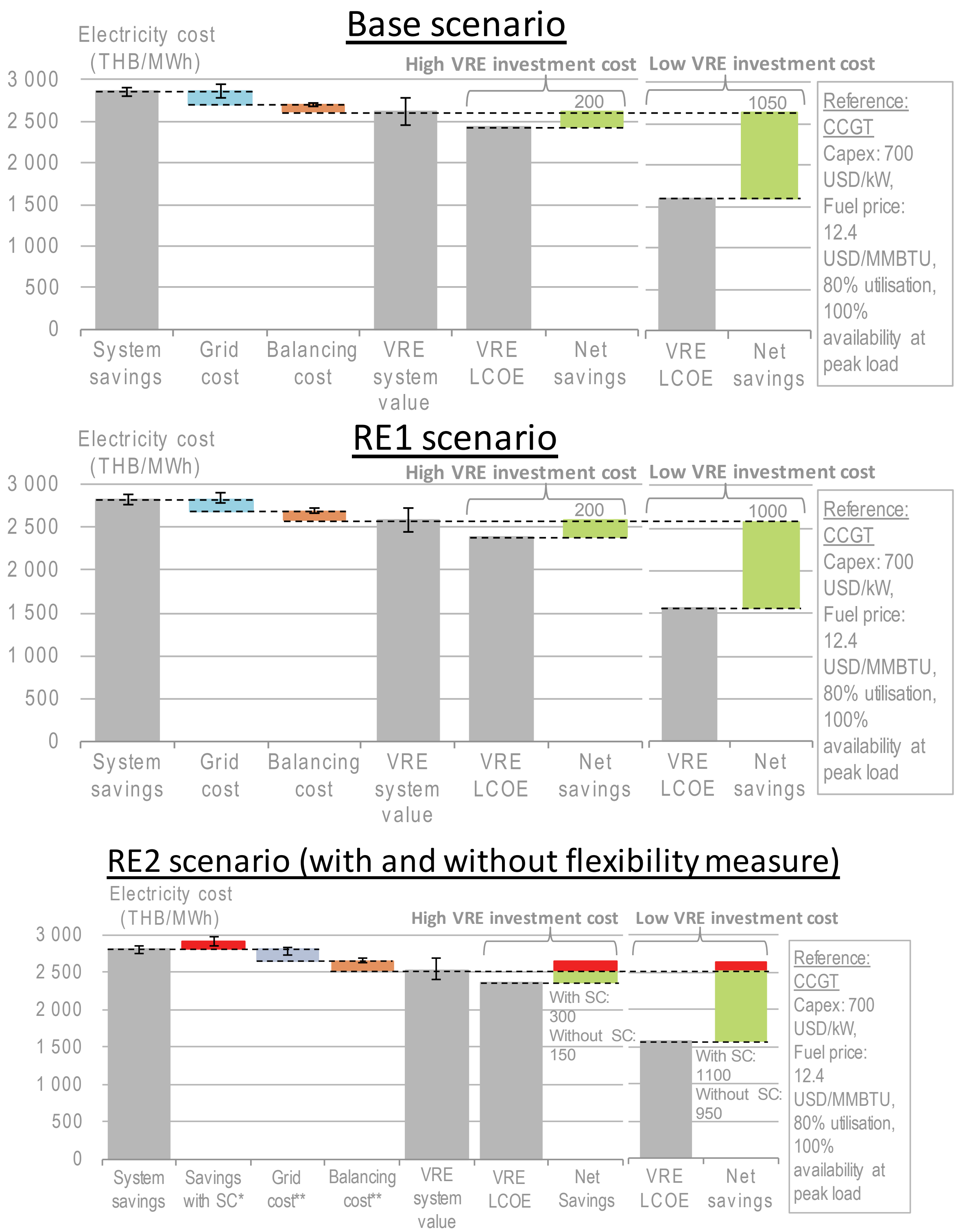
Comparison between the low and high investment cost cases for VRE demonstrates the critical impact of technology costs on the overall cost impact of VRE deployment. Relative to the CCGT reference, VRE provides a large net benefit in all scenarios with low VRE investment costs. For the coal reference case, VRE still results in a net cost in all scenarios but this is only in the range of 100 to 200 THB/MWh compared with around 1 000 THB/MWh for the high investment cost case.

In summary, adding VRE can bring a net benefit to the power system in the long term when compared to deployment of CCGT, and the size of this benefit is highly dependent on the reduction in the capital cost of VRE. While per-unit benefits of VRE decline with increasing share, this can be mitigated with flexibility options such as EV smart charging. Note that these results are based on a number of assumptions; the implications differ according to the assumptions made. For example, we did not assume CO_2 reduction cost in this analysis since there is no

[21] In this analysis, the wind generation profiles were produced at 150-metre hub heights with large turbine size. Details of wind resources and generation profiles are provided in Annex B.

planned pricing scheme in Thailand, however, benefits of VRE for CO_2 mitigation would increase with a higher share of VRE.

Figure 7.18 • Costs and benefits of VRE in 2036 in the three deployment scenarios, with high and low VRE investment costs compared to CCGT reference technology

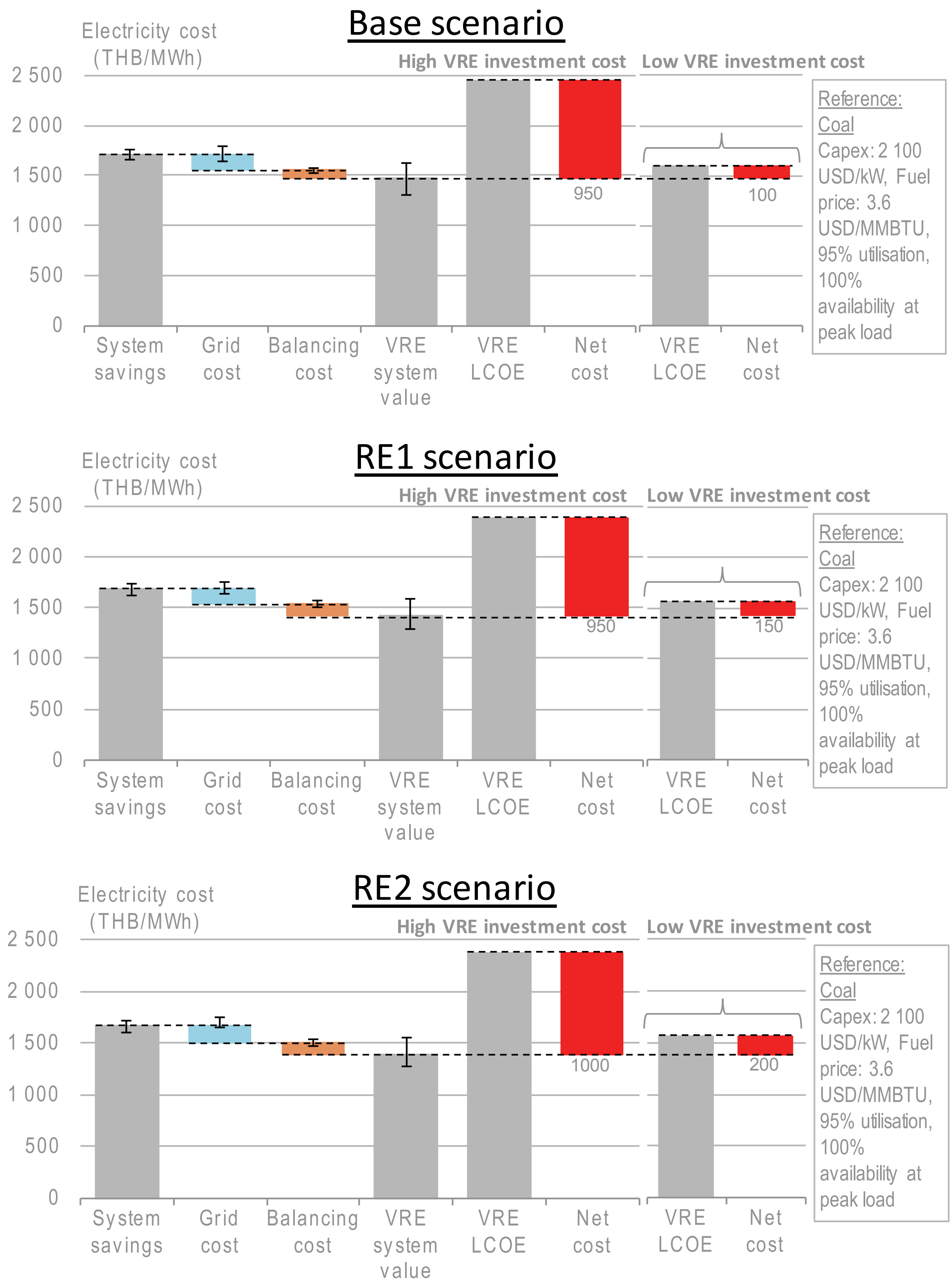


* Smart charging (SC) is well-managed EV charging (explained in *'results of capacity credit analysis' section*)

** This analysis used the grid cost and balancing cost of RE2 scenario (not flexibility scenario), for simplicity

Key message • VRE deployment provides net benefits compared to CCGT deployment in all scenarios.

Figure 7.19 • Costs and benefits for VRE in 2036 in the three deployment scenarios, with high and low VRE investment cost compared to supercritical coal reference technology

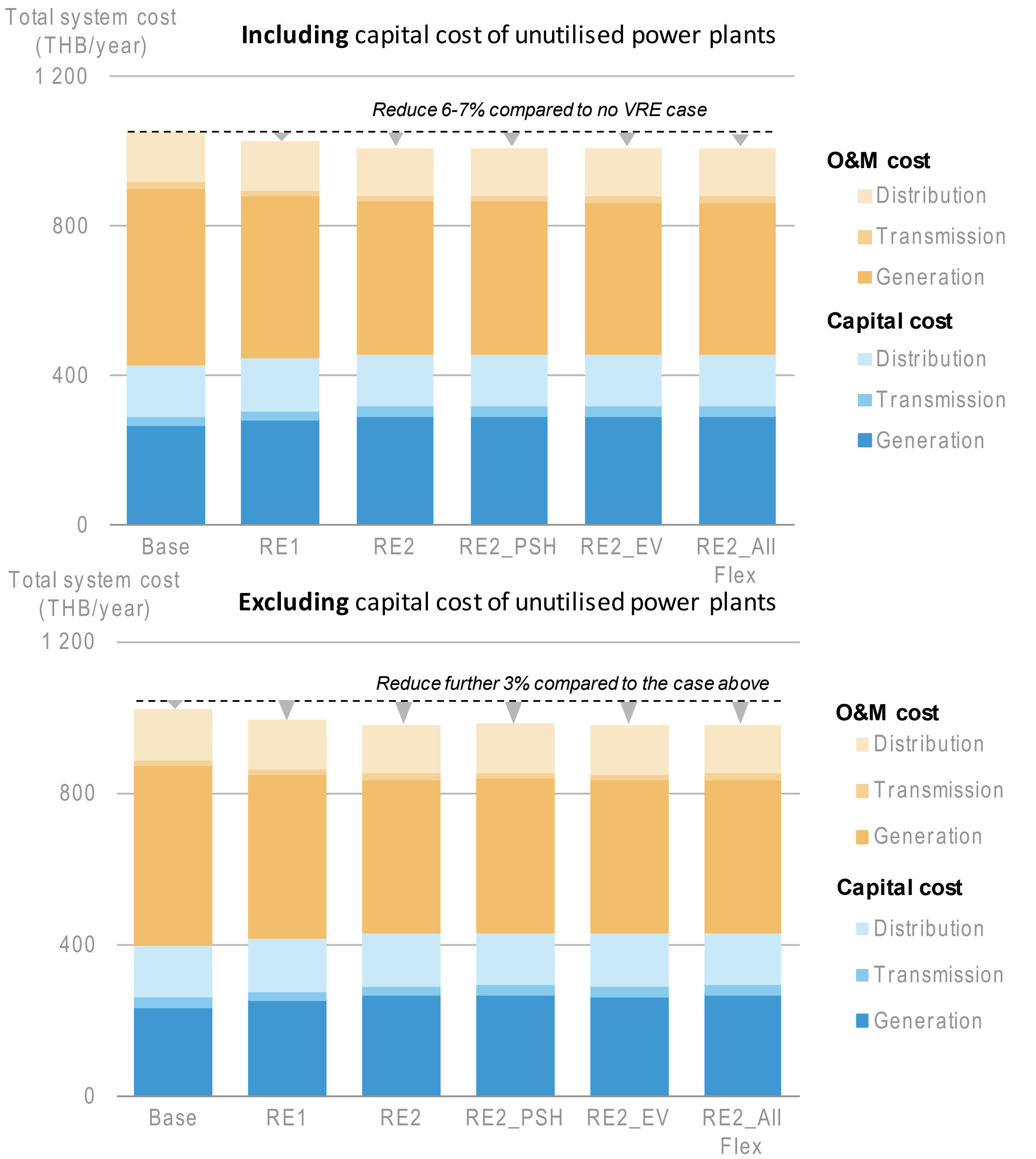


Key message • VRE deployment results in net system costs compared to supercritical coal deployment.

Total power system cost

This analysis calculates the total cost for building the power systems represented in the Base, RE1 and RE2 scenarios "greenfield" in 2036. Capital costs are converted to an annualised annuity payment. Total power system costs for 2036 are estimated at around THB 1 trillion per year, which is equivalent to 8% of Thailand's GDP in 2016. The analysis shows that total power system costs are reduced with increasing penetration of VRE, provided its costs are brought closer to the lowest costs seen internationally today. This positive impact can be further amplified through the introduction of flexibility measures (Figure 7.20).

Figure 7.20 • Total power system cost for modelled 2036 scenarios



Key message • Introduction of VREs and flexibility measures reduces total long-term power system cost by up to 7%.

Increasing penetrations of VRE reduces total power system costs by 6% because the fuel cost savings associated with VRE are higher than the capital expenditure costs. The introduction of flexibility measures reduces other operating expenditures such as start-up and shut-down costs, which further reduces total power system costs between 0.2% and 7.0%. Assuming that the capacity that was not utilised at all in the PLEXOS operational simulations in 2036 is never constructed, total system costs would decrease further by 3%.

Although the cost-benefit analysis shows a negative value for VRE compared with an idealised supercritical coal plant (capacity factor: 95%, capex: 2 100 USD/kW), in this analysis the total system cost nevertheless reduces with increasing VRE penetrations. This is explained by the fact that the 2036 Thailand power system consists of a more diverse power plant portfolio, including a larger amount of gas-fired generation.

Recommendations and action priorities

Recommendations on power sector planning

- Integrated planning approaches should be adopted in order to consider system flexibility, reliability, and security more holistically as well as to consider how different supply- and demand-side resources can play a role in integrating VRE and reducing operational- and investment-related system costs.
- A more sophisticated approach may be required for setting RE targets, which, as a first step, should include direct transmission development to locations with higher-quality VRE resources since high VRE capacity factors can result in increased utilisation of transmission assets. Going beyond this, a more integrated planning process that also looks at other resources such as demand-side resources, battery storage, and the regional integration of power systems should be targeted. A REZ process that intelligently customises transmission planning to consider VRE resources may be an effective approach for the Thai power system.
- The current approaches to determining the capacity credit of VRE resources and system reserve margins should be revised in order to achieve more reliable and cost-efficient outcomes.
- In order to maximise the economic value of the power system, power-sector planning exercises should be conducted with the least of possible restrictions on infrastructure investment options. Goals should include properly assessing the economic value of each of them and accounting for differences across potential plant locations, allowing planning optimisations to define the amount of capacity required from each technology.
- Sophisticated software tools for power system planning should be used in order to take into account short-term operational considerations, flexibility issues, and opportunities that could arise with the deployment of VRE resources. Ideally, the tools and approaches would be analytically consistent for short-, medium- and long-term planning exercises.[22] As a first step, operational models such as the one used in Chapter 5 could be used more regularly as a

[22] Long-term power system planning tools are traditionally used for establishing the generation and transmission investment plan to meet expected future demand. They cover a long time horizon, generally more than 10 years, and are used to facilitate decision making for long-term energy policy goals and integrated resource planning exercises. Traditionally, long-term power system planning tools coarsely cover long periods of time, but do not accurately take into account the chronology and short-term variability of supply and demand. However, with the increasing shares of VRE, power system planning tools need to consider the impact of net demand variability. Modelling tools that have been used by electric utilities and relevant organisations to consider these aspects, at least to some extent, include Balmoral, ETP-TIMES (ESTAP/IEA), PLEXOS, OPTGEN/SDDP, OSeMOSYS, World Energy Model (WEM).

"check" on results yielded from existing longer-term planning tools in order to ensure that the proposed power systems built in capacity expansion models can operate reliably.

- Further co-ordination and perhaps even a formalised feedback process between long-term planning processes, real life system operations, and policy making could be very beneficial. This can be done through developing scenarios that would, in turn, provide more accurate estimates of the costs and consequences of various policies.

Results from capacity credit, VRE system cost, and VRE cost-benefit analyses

- Solar PV and wind have different characteristics in terms of capacity credit although the contribution to firm capacity during peak demands declines with VRE penetration for both technologies. The estimated capacity contribution from solar declines from 18% in the current system to 7%, 4%, and, finally, 3% in the Base, RE1, and RE2 scenarios, respectively. The estimated capacity credit of wind remains more robust at high shares, providing 24%, 22%, and 21% in the Base, RE1, and RE2 scenarios, respectively.
- A mix of wind and solar PV can provide an aggregate capacity credit value that is higher than the sum of its parts due to synergies existing between both technologies. Furthermore, the unmanaged charging of EVs can significantly decrease the capacity credit of solar by shifting peak load into the evening, while smart charging can improve the capacity credit for both PV and wind. In this case, the pursuit of smart EV charging schemes may be a key factor for optimal VRE integration and, more importantly, transforming the Thai power system to be more flexible, reliable, cost-efficient, and environmentally sound.
- VRE system costs are caused by the interactions of VRE with the broader power system and are estimated to range from 574 to 671 THB/MWh for solar and from 395 to 513 THB/MWh for wind. When we add this value to the LCOE of VRE to create a system LCOE, we find that system costs make up 14% to 19% of the total system LCOE of wind, and 22% to 24% for solar, assuming higher investment costs for the technologies. System costs increase with higher VRE penetrations, mainly because of an increasing need for reserve that is required. These costs can be reduced by utilising flexibility options such as storage and demand-side response. In the modelling scenarios, implementing smart EV-charging reduced system costs by 37% for solar and 14% for wind.
- From a short-term perspective, adding VRE to the power system can bring an immediate net benefit, provided the LCOE of VRE falls below approximately 2 250 THB/MWh and assuming fuel savings from avoiding LNG imports are at current spot market prices. This estimate accounts for VRE system costs.
- Over the longer term, when compared with a scenario produce the same amount of electricity when coming from VRE with new CCGTs, VRE brings net benefits in the analysis as a result of both fuel and capacity-cost savings. When compared with a scenario with new coal plants, high shares of VRE are associated with a net cost to the system. Reductions in VRE capital costs and an appropriate policy and procurement framework to realise these cost reductions will be key for promoting cost-effective deployment and integrating VRE in Thailand's power system. In addition, the use of advanced flexibility options, such as smart charging of EVs, can increase the overall net benefits of VRE.
- Based on the generation mix of the modelled future Thai power system, introducing VRE and flexibility measures reduces total power system costs by up to 7%, if the costs of VREs can decrease to the prices experienced in leading jurisdictions today. This is mainly driven by the fact that the fuel cost savings associated with VRE are higher than the

capital expenditures. Conducting a fully integrated analysis, where the generation mix of conventional resources is optimised together with VRE and other relevant assets (integrated resource plan), is strongly recommended.

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8. Key findings and recommendations

This chapter summarises key findings of the analyses conducted under this project, and proposes recommendations on specific steps and practices to support variable renewable energy (VRE) integration in Thailand. It draws on the key analytic highlights and action priorities identified in the study.

Grid integration context of the existing power system in Thailand

Key findings

- In the Association of Southeast Asian Nations (ASEAN) region, Thailand is the most advanced country in terms of VRE penetration as well as the development of grid infrastructure, advanced operational practices, and the deployment of other flexibility options.
- Previous International Energy Agency (IEA) analysis has identified distinct phases of VRE integration, differentiated by the impact VRE has on the power system (IEA, 2017). Thailand can be considered to be approaching Phase 2 of VRE integration at present. The annual energy penetration of VRE in Thailand is around 4%, and VRE generation is becoming increasingly noticeable to the system operators.
- The current power system in Thailand has a mixture of flexible and inflexible attributes. Thailand's generation fleet appears to be quite technically flexible, given a moderate share of hydropower resources and a high share of combined-cycle gas turbine (CCGT) resources, combined with a large reserve margin overall.
- The operating characteristics of CCGT and coal-fired power plants – particularly minimum generation levels, ramp rates and start-up times – suggest that the current fleet's flexibility could be significantly enhanced. Furthermore, current fossil fuel procurement and power purchase contracts constrain the ability of dispatchable generators in Thailand from operating more flexibly.
- At present, there are several grid codes for the power system in Thailand, which have been established separately by the transmission and distribution utilities (Electricity Generating Authority of Thailand [EGAT], Metropolitan Electricity Authority [MEA] and Provincial Electricity Authority [PEA]). These codes are not consistent, which prevents effective co-ordination among EGAT, MEA and PEA, particularly with the increasing share of distributed energy resources (DERs.
- The visibility and controllability of VRE is essential to ensure the security and stability of the power system. However, Thailand does not currently have a dedicated control centre for renewable energy that collects data on VRE production and produces the short-term production forecasts required to support system integration.

*The following **action priorities** have been identified:*

- **Unlock** existing power plant flexibility by (1) enhancing fossil fuel procurement contracts between PTT and EGAT to promote flexibility, and (2) reviewing options to make contractual arrangements between EGAT and private power producers more flexible.
- **Develop** a harmonised national grid code in a collaborative process between EGAT, PEA and MEA, led by the Office of the Electricity Regulatory Commission (OERC) and informed by external independent experts.

- **Establish** a national renewable energy control centre that has access to state-of-the-art, real-time VRE generation data and short-term production forecasts, and that integrates real-time VRE analysis insights into the operation of the Thai power system.

Grid integration assessment of future Thailand's power system

Key findings

- Higher shares of wind and solar generation reduce overall system operating costs, with the savings primarily being driven by a reduction in fuel costs as natural gas generation is displaced by renewables. These savings can be realised in Thailand's power system by ensuring that fuel supply contracts are sufficiently flexible.
- A scenario in which fuel supply arrangements and power purchase agreements are made more flexible in 2036 exhibits the most notable cost savings across all modelled scenarios. Relaxing contractual constraints allows for greater optimisation of the dispatch of generation and resulting in a significant reduction in both fuel and O&M (operation and maintenance) costs for more expensive generation.
- Wind and solar output are shown to have highly complementary generation profiles in Thailand, allowing a contribution to both midday peak demand and evening peak demand.
- As VRE penetrations increase, so does the expected variability in net demand. This results in increased cycling of conventional generators and the need to use more expensive peaking capacity to meet ramping requirements.
- Net ramping requirements in 30-minute and 3-hour periods increase with higher shares of VRE generation. However, the Thai power system – as currently planned for in 2036 via the Power Development Plan (PDP) 2015 – is technically capable of accommodating such requirements.
- Thermal plants such as coal and CCGT will be required to provide ramping services and will be increasingly cycled with a higher share of renewables. While thermal plants in Thailand are technically capable of meeting increased ramping requirements, their ability to do so may currently be limited because of the nature of the fuel supply arrangements and power purchase agreements with these plants, which constrain operations.
- Enhancing flexibility, either through augmentation of technical (supply-side and demand-side), contractual, or operational characteristics of the power system allows for supply and demand variability to be effectively matched, resulting in a more reliable and cost-efficient operation of the power system.
- Based on the modelling exercises performed, it is evident that the 2036 Thai power system as currently envisioned in the PDP 2015 will be in Phase 3 of VRE integration, where system flexibility becomes an important factor.

*The following **action priorities** have been identified:*

- **Ensure** that future contractual arrangements governing power plant fuel procurement and power purchase agreements do not hinder the optimal dispatch of the power system.
- **Enhance** system operational practices as VRE deployment grows through promoting "faster" dispatch of the power system, with more frequent updates of schedules closer to real time and reduced dispatch intervals for power plants, including small power producer (SPP) plants.
- **Improve** the flexibility of conventional power plants through retrofits and changes to operational practices to improve the key flexibility characteristics including ramp rates,

minimum generation levels and start-up times. In particular, the high minimum generation levels of hydropower plants can be reduced.

- **Facilitate** the deployment of demand-side options, including demand-side management (DSM), smart electric vehicle (EV) charging, and battery and pumped hydropower storage as the level of VRE increases in Thailand because these options can enhance system flexibility in a reliable manner while reducing operational costs.

Distributed solar PV potential and economic impact analysis

Key findings

- Available rooftop area is not a relevant constraint for the uptake of distributed solar photovoltaics (DPV) in Thailand. Even if only 10% of all available estimated rooftop surface in Thailand was used for DPV, this could host a capacity larger than the system's current peak demand. However, other constraints could limit how much DPV can be used in practice.
- In the short term, the small, medium and large general-services customers have the greatest economic potential for DPV deployment in Thailand. Due to the sheer number of customers, the residential customer segment in PEA has the largest overall long-term DPV potential. While this segment currently shows longer payback periods for DPV systems than other customer groups, its economic potential for DPV deployment rises as installation costs decrease.
- The buyback rate for DPV electricity under a net billing scheme has a relatively low impact on DPV deployment in the long term, given that all customer groups are modelled to use relatively high proportions of the electricity from DPV systems to directly offset their demand. Consequently, the design of residential tariffs is important to guide the uptake of DPV on a sustainable path, if the current net billing system is maintained.
- The analysis demonstrates a relevant aspect in the distribution of economic impacts across PEA, MEA and EGAT, which are uneven. This uneven split of costs and benefits points to issues associated with the underlying structure of Thailand's electricity industry and the design of the current wholesale electricity price. Wholesale electricity pricing is not sufficiently differentiated by time and location to ensure that economic incentives for the different stakeholders are well-aligned with overall system needs and to prevent revenue losses that could be incurred by EGAT due to DPV.
- Under the current regulatory structure, both PEA/MEA and EGAT are able to recover any net revenue losses caused by DPV via an automatic adjustment mechanism that adjusts electricity rates to maintain a target rate of return. This means that, ultimately, ratepayers shoulder any possible net revenue losses. However, in the scenarios studied (Alternative Energy Development Plan [AEDP] 2025 and the RE2 scenario), DPV deployment leads to relatively insignificant increases in retail electricity rates compared to a scenario without DPV.

*The following **action priorities** have been identified:*

- **Reform** wholesale electricity tariffs. A first step towards creating a more disaggregated pricing structure is to obtain more information on the cost of electricity generation for EGAT at any given point in time. A second step would be to account for systematic differences in the cost of electricity provision in different locations. The introduction of a more disaggregated wholesale price could also be a useful stepping stone to further reform the overall electricity market structure.

- **Enhance** time-dependent retail pricing. Retail prices should be designed to provide fair and appropriate incentives to both network users and DPV owners. The deployment of smart meters makes it possible to communicate this value to end users and to use data measurements at regular intervals to apply them in billing processes.
- **Determine** appropriate remuneration for DPV grid injections. Understanding the system value of DPV injections is an important first step in fostering system friendly and cost-efficient deployment. Such value calculations could account for reduced operational costs or avoided grid investments associated with DPV, but would require a comprehensive understanding of the network conditions at different times and locations. Analysis of DPV remuneration should also consider alternatives in metering and billing arrangements, including Intelligent Metering and Buy-all, Sell-all schemes

Power system planning process and VRE system cost analysis

Key findings

- Integrated and co-ordinated planning frameworks which include generation, transmission and distribution networks, as well as demand side and electrifications of other sectors can help identify appropriate options for the future power system.
- The current planning process could limit the magnitude of future renewable energy (RE) targets since potential transmission expansion options for locations with high RE resource are not integrated in detail.
- The existing reliability and reserve margin approaches used in Thailand's power sector planning exercises are based largely on deterministic criteria, but this methodology can be improved. This would result in reduced system costs while maintaining system reliability.
- The approach used to determine dependable capacity (or capacity credit) of solar and wind is concentrated on two typical peak demand periods, which could lead to underestimation or overestimation.
- Capacity credit analysis, which accounts for the top 2% of load periods, shows that VRE contributions to capacity requirements are strongly dependent on both the underlying load pattern and existing VRE generation patterns. It is therefore most accurate to consider capacity credit in a scenario specific manner rather than using a single number.
- In the short term, the cost of VRE generation would need to fall below approximately 2 250 THB/MWh (Thai baht per megawatt-hour) (70 USD/MWh) in order to reduce overall cost to consumers. This figure considers relevant system costs of VRE integration.
- The cost-benefit approach compares the LCOE of VRE with CCGT and supercritical coal in all scenarios, considering scenarios with both high- and low-VRE investment costs. VRE was found to be lower cost than CCGT in all scenarios, but more expensive than coal. The low investment cost case offers much larger net savings relative to CCGT and only small net costs relative to coal. Importantly, this analysis does not monetise carbon dioxide savings associated with higher shares of VRE.
- If VRE is deployed with low investment costs, it can reduce the overall cost of the power system due to fuel savings, even without considering any capacity contributions that VRE resources might make.

*The following **action priorities** have been identified:*

- **Adopt** a fully integrated planning process, where VRE capacity expansion is integrated with conventional capacity expansion and transmission grid planning. Feedback loops between different specialised models for each task of the planning analysis is recommended.
- **Update** the methodology, which accounts for VRE capacity credit, to account for the effects of a different future load shape as well as synergies between wind and solar PV deployment.
- **Compare** the cost of VRE in Thailand systematically to international benchmarks, in order to identify the main differences and cost drivers.
- **Reduce** the contracted price of VRE in Thailand by adopting a competitive procurement framework (i.e. VRE auctions with long-term PPAs)**.**

Abbreviations and acronyms

AEDP	Alternative Energy Development Plan
AEMO	Australian Energy Market Operator
AGC	automatic generation control
CAC	Central Area Control Region
CAC-E	Central Area Control Region - East
CAC-N	Central Area Control Region - North
CAC-W	Central Area Control Region - West
CAPEX	capital expenditure
CBA	cost-benefit analysis
CCGT	combined cycle gas turbine
CECRE	Control Centre of Renewable Energies
CHP	combined heat and power
DBC	database connecter
DEDE	Department of Alternative Energy Development and Efficiency
DER	distributed energy resource
DIU	data interface unit
DPV	distributed photovoltaic
DR	demand response
DSM	demand side management
DSO	distribution system operator
E&P	exploration and production
ED	economic dispatch
EEP	Energy Efficiency Plan
EGAT	Electricity Generating Authority of Thailand
ELCC	Effective Load Carrying Capability
EMS	energy management system
ENS	energy not served
EPPO	Energy Policy and Planning Office
ERC	Energy Regulatory Commission
ESS	energy storage system
EUE	expected unserved energy
EV	electric vehicle
FACTS	flexible alternative current transmission system
FLC	frequency limit control
FRT	fault ride through
FSP	forecasting service provider
GDC	generation duration curves
GDP	gross domestic product
GIS	geographic information system
GRP	gross regional product
GT	gas turbine
HVDC	high-voltage direct current
ICT	information and communication technology
ICCP	inter control centre protoco
IPP	independent power producer
IPS	independent power supply
IRP	South Africa's Integrated Resource Planning
JGSEE	Joint Graduate School of Energy and Environment

LCOE	levelised cost of electricity
LDC	load duration curve
LGS	large general service
LNG	liquefied natural gas
LOLE	loss of load expectation
LOLP	loss of load probability
LTM-PIP	Lao PDR, Thailand and Malaysia Power Integration Project
MAC	Metropolitan Area Control Region
MEA	Metropolitan Electricity Authority
MGS	medium general service
MGSA	Master Gas Sale Agreement
MoEN	Thailand's Ministry of Energy
MSW	Municipal Solid Waste
NAC	Northern Area Control Region
NBTC	National Broadcasting and Telecommunications Commission
NEC	North Eastern Area Control Region
NEM	Australian National Electricity Market
NEPC	National Energy Policy Council
NERC	North American Electric Reliability Corporation
NESDP	National Economic and Social Development Plan
O&M	operations and maintenance
OCGT	open cycle gas turbine
OERC	Office of the Energy Regulatory Commission
OLE	object linking and embedding
OPC	OLE for process control
OPEX	operational expenditure
PDP	Power Development Plan
PDR	People's Democratic Republic
PEA	Provincial Electricity Authority
PLEF	Pentalateral Energy Forum
PPA	power purchasing agreement
PRODESEN	Mexico's National Power Sector Development Program
PSH	pumped storage hydropower
PV	photovoltaic
RE	renewable energy
REE	Red Eléctrica de España
REMC	Renewable Energy management Centres
RES	residential customers
REZ	renewable energy zone
ROIC	return on invested capital
RPD	Royal Ploughing Day
SAC	Southern Area Control Region
SAM	System Advisor Model
SCADA	supervisory control and data acquisition
SGS	small general service
SO	system operator
SPm	set point m
SPn	set point n
SPP	small power producer
SPS	special protection scheme

SVC	static VAR compensators
TIEB	Thailand Integrated Energy Blueprint
TSO	transmission system operator
TSM	times series management
UF	under frequency
VRE	variable renewable energy
VSPP	very small power producer
WEM	World Energy Model
WSP	weather service provider

Unit of measures

GW	gigawatt
GWh	gigawatt hour
km	kilometre
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
MW	megawatt
MWh	megawatt hour
MMBTU	million British thermal nit
MJ	megajoule
MJ/m2	megajoule per square meter
MVA	megavolt-amp
THB	Thai Baht

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Thailand Renewable Grid Integration Assessment

Thailand's power sector policy focuses on reducing dependence on natural gas to enhance energy security. With the dramatic reduction in the costs of variable renewable energy (VRE) – solar photovoltaic (PV) and wind power – Thailand is beginning to experience the transformation of its power sector. Conventional power generation is beginning to give way to new alternative sources and generation is moving from centralised to distributed forms.

Thailand has the highest share of VRE in the Association of Southeast Asian Nations (ASEAN) region. Given the unique characteristics of VRE, which are variable and partly unpredictable, there are concerns over the potential operational, economic, and regulatory impacts when integrating VRE into the power sector. Thus, the dynamics shaping the energy policy landscape in Thailand must evolve to accommodate the growth of VRE.

Thailand Renewable Grid Integration Assessment undertakes a comprehensive analysis covering the technical, economic, and policy and regulatory frameworks. The analysis comprises the following important areas: 1) the existing VRE penetration context in Thailand, 2) grid integration of VRE in Thailand's future power system, 3) the technical potential and economic impact of distributed solar PV on stakeholders, and 4) the power sector planning process and system costs. The study provides recommendations to guide decision making in power sector operation and planning, investment, and policy to support the uptake of VRE in a reliable and cost-effective manner in order to achieve the objectives of Thailand's power sector policies.