ERIA Research Project Report 2021, No. 13

The Economics and Risks of Power Systems with High Shares of Renewable Energies

Matsuo Yuji

Alloysius Joko Purwanto

The Economics and Risks of Power Systems with High Shares of Renewable Energies

Economic Research Institute for ASEAN and East Asia (ERIA)

Sentral Senayan II 6th Floor

Jalan Asia Afrika no.8, Gelora Bung Karno

Senayan, Jakarta Pusat 12710

Indonesia

ERIA Research Project Report FY2021 No. 13

Published in September 2021

The findings, interpretations, conclusions, and views expressed in their respective chapters are entirely those of the author/s and do not reflect the views and policies of the Economic Research Institute for ASEAN and East Asia, its Governing Board, Academic Advisory Council, or the institutions and governments they represent. Any error in content or citation in the respective chapters is the sole responsibility of the authors.

This report was prepared by the Working Group for the Study on Economics and Risks of Power Systems with High Shares of Renewable Energies under the Economic Research Institute for ASEAN and East Asia (ERIA) Energy Project. Although members of the working group agreed to utilise certain data and methodologies for Cambodia, Indonesia, the Lao PDR, Malaysia, Myanmar, and Viet Nam, these data and methodologies may differ from those normally used in those countries. The calculated results presented here should not, therefore, be viewed as official national analyses.

Acknowledgements

This analysis was jointly implemented by a working group consisting of members from Cambodia, the Lao PDR, Malaysia, Myanmar, the Philippines, Thailand, and The Institute of Energy Economics, Japan (IEEJ), under the Economic Research Institute for ASEAN and East Asia (ERIA). We acknowledge the support provided by everyone involved. We are especially grateful to the working group members and experts who participated in the online working group meetings.

Special thanks go to ERIA's Publication Department – Stefan Wesiak, Fadriani Trianingsih, and their team of editors – for helping to edit the report and prepare it for publication.

Matsuo Yuji

Senior Economist, Manager

The Institute of Energy Economics, Japan

August 2021

Project Members

DR. MATSUO YUJI (LEADER), Senior Economist, Manager of Energy and Economic Analysis Group (EEA), Energy Data and Modelling Center (EDMC), The Institute of Energy Economics, Japan (IEEJ), Japan

MR. SUEHIRO SHIGERU (SUB-LEADER), Senior Economist, Manager of Econometric and Statistical Analysis Group (ESA), EDMC, IEEJ, Japan

MR. KIMURA SHIGERU (ORGANISER), Special Adviser to the President on Energy Affairs, Energy Unit, Research Department, Economic Research Institute for ASEAN and East Asia (ERIA)

DR. ALLOYSIUS JOKO PURWANTO (ORGANISER), Energy Economist, Energy Unit, Research Department, ERIA

MR. CHIPHONG SARASY (WORKING GROUP MEMBER), Deputy Director, Department of New and Renewable Energy, General Department of Energy, Ministry of Mines and Energy, Cambodia

MR. KUTANI ICHIRO (WORKING GROUP MEMBER), Senior Research Fellow, Manager of Global Energy Group 1, Assistant to Senior Managing Director, Strategy Research Unit, IEEJ, Japan

MR. IKARII RYOHEI (WORKING GROUP MEMBER), Senior Economist, EEA, EDMC, IEEJ, Japan

MR. NOGUCHI MASAYOSHI (WORKING GROUP MEMBER), Senior Economist, ESA, EDMC, IEEJ, Japan

MS. AIZAWA NATSUMI (WORKING GROUP MEMBER), Economist, ESA, EDMC, IEEJ, Japan

MS. IINO YUMIKO (WORKING GROUP MEMBER), Researcher, Global Energy Group 1, Strategy Research Unit, IEEJ, Japan

MR. SOMDETH LAKHONVONG (WORKING GROUP MEMBER), Deputy Director, Department of Energy Policy and Planning, Ministry of Energy and Mines, Lao PDR

MR. ASDIRHYME BIN ABDUL RASIB (WORKING GROUP MEMBER), Senior Under Secretary, Sustainable Energy, Ministry of Energy and Natural Resources (KeTSA), Malaysia

MS. ESTHER LEW (WORKING GROUP MEMBER), Principal Assistant Secretary, Renewable Energy Division, Energy Sector, KeTSA, Malaysia

MR. KHAIRUL ANUAR MUKHTAR (WORKING GROUP MEMBER), Assistant Secretary, Policy and Planning of Electricity Supply Division, Energy Sector, KeTSA, Malaysia

MS. SAW SI THU HLAING (WORKING GROUP MEMBER), Director, Department of Electric Power Planning, Ministry of Electricity and Energy, Myanmar

MR. JESUS T. TAMANG (WORKING GROUP MEMBER), Director, Energy Policy and Planning Bureau, Department of Energy, Philippines

Dr. Siti Indati Binti Mustapa (Working Group Member), Director, Institute of Energy Policy and Research, Universiti Tenaga Nasional, Malaysia

Dr. Siripha Junlakarn (Working Group Member), Researcher, Energy Research Institute, Chulalongkorn University, Thailand

Table of Contents

List of Figures

List of Tables

Abbreviations and Acronyms

APG	=	ASEAN Power Grid
ASEAN	=	Association of Southeast Asian Nations
BAU	=	business as usual
CCS	=	carbon capture and storage
CO_2	=	carbon dioxide
ERIA	=	Economic Research Institute for ASEAN and East Asia
Gt	=	gigatonne
GW	=	gigawatt
GDP	=	gross domestic product
HAPUA	=	Heads of ASEAN Power Utilities/Authorities
IEA	=	International Energy Agency
IEEJ	=	The Institute for Energy Economics, Japan
kWh	=	kilowatt hour
LCOE	=	levelised cost of electricity
MMbtu	=	million British thermal unit
Mtoe	=	million tonnes of oil equivalent
MW	=	megawatt
NASA	=	National Aeronautics and Space Administration
NO_x	=	nitrous oxides
PM10	=	particulate matter
PV	=	photovoltaic
SO_x	=	sulphur oxides
t	=	tonne
TWh	=	terawatt hour
VRE	=	variable renewable energies

Executive Summary

This report examines quantitatively the possibility and risks of realising high shares of renewable energies through the planned extension of power grid interconnection, focusing on Southeast Asia, specifically, Cambodia, the Lao PDR, Myanmar, Peninsular Malaysia, Singapore, Sumatra, Thailand, and Viet Nam, using a mathematical model that calculates the cost optimal diffusion of various types of power-generating technologies, setting a long-term target year of 2040.

Main argument

Considering the recent cost declines in solar photovoltaic and wind power generation, the primary aim of this study is to investigate whether variable renewable energies (VRE) and other renewable energies would be diffused in the targeted region without strong policy measures, such as feed-in tariffs, in the cost optimal power generation mix.

Another issue to investigate is whether the international grid interconnection would contribute to higher VRE and renewables diffusion, lower costs in the power sector, and energy security.

The study also sets additional cases with higher fossil fuel prices, with explicit consideration of the health externalities of fossil fuels and with strong policy measures reflecting the different levels of economic development. Moreover, the effects of introducing other low-carbon technologies, such as nuclear power, are investigated.

Through these case studies, this report illustrates the preferable energy mix for each region in 2040, estimating the cost increases related to possible changes in the energy mix, as well as the battery requirements for coping with the risks of supply disruption associated with the intermittency of VRE. This study also investigates the effects of grid interconnection expansion to reduce such costs and risks.

Conclusions

- VRE will be diffused in the Association of Southeast Asian Nations only if people accept strong policy measures to combat climate change, such as feed-in tariff systems, even though the costs of VRE will decline significantly through 2040. Given the challenges associated with the intermittency of VRE, the maximum exploitation of other renewables, such as hydro and geothermal, is also important for achieving low-carbon power systems.
- The currently planned grid interconnection expansion would increase power trade in the region and work as massive regional batteries that can ensure further deployment of VRE. It would also help maximise the use of unevenly distributed hydropower resources, resulting in further carbon dioxide (CO_2) emission reductions and cost minimisation. This can reduce fossil fuel imports and enhance regional energy security.

- The optimal energy mix may change with explicit consideration of higher fossil fuel prices, the health effects of fossil fuels, and economic development levels, which may also be considered when designing future energy policies. In addition, nuclear can also be a viable option as a proven low-carbon technology.

Policy recommendations

- Given the projected low fuel prices, the governments will need strong policy measures to promote renewable energies. Without such measures, high dependence on fossil-fuel fired thermal power generation will remain and may not be changed by and large.
- The governments should promote power grid interconnection expansion at least to the planned scale as this would help in realising CO_2 emissions reductions, cost minimisation, and energy security at the same time.
- Not only strong policy measures but also other factors, including the costs of VRE, international energy prices, externalities, and the utilisation of nuclear may affect the optimal energy mix that governments should seek.
- As achieving very high shares of renewable energies may induce significant cost increases, governments should also consider other decarbonising options, such as the use of fossil fuels with carbon capture and storage, hydrogen, ammonia, and nuclear power.
- 100% decarbonisation of the power sector may be very challenging with considerable cost increases. At the same time, we should also note the inevitable need to decarbonise energy systems, given the growing global concerns about climate change.

Chapter 1
Introduction

In recent years, global environmental problems have come to be regarded as important human problems more than ever before. According to a special report published by the Intergovernmental Panel on Climate Change in 2018, it is necessary to make the artificial carbon dioxide emissions of the entire world net zero by around 2050 or 2075 to restrict the temperature rise from pre-industrial levels to 1.5°C and 2°C. On the other hand, the Nationally Determined Contributions submitted by each country are insufficient for achieving a restriction to that level, and a more ambitious approach is essential.

In light of this situation, a movement aimed at decarbonising energy utilisation has been promoted amongst advanced countries. In Europe, the goal of carbon-neutrality by 2050 has been set. In the United States, since the inauguration of President Joe Biden in the United States, the decarbonisation movement is accelerating. In 2020, the Japanese Government expressed the target to achieve carbon neutrality by 2050. The Chinese Government has also declared its aim to be carbon neutral by 2060. Thus, reducing greenhouse gas emissions is not just a problem in advanced economies but also a problem faced by the entire world, including developing countries.

Introducing and expanding renewable energy are widely expected as a reduction measure, particularly variable renewable energies (VRE), namely wind and solar photovoltaic. The cost of these power sources, which conventionally have been expensive compared to conventional power sources, has been decreasing rapidly in recent years. The levelised costs of electricity of VRE are already lower than those of conventional power sources, depending on the area, and the costs are expected to fall further in the future. The introduction of VRE is already progressing amongst advanced countries, and its share in the power generation mix, which was 0.7% in European Organisation for Economic Co-operation and Development countries in 2000, already reached 16% in 2019 and 28% in Germany in 2019 (International Energy Agency, 2020). Given that the introduction and expansion of hydro and geothermal have been limited and that it may be difficult to expand the capacity of nuclear power generation rapidly enough because of its intrinsic problems, expectations are high for VRE to achieve the decarbonisation of power supplies. However, because VRE is intermittent, it is necessary to note that introducing a large amount of VRE involves specific risks. That is, when a large amount of VRE is installed, there is a risk of insufficient power supply, depending on the weather conditions. Equipment such as batteries will be necessary to reduce the risk, but this will increase the cost of the power system. In view of such a problem, assessing the optimal share of VRE is currently an important problem that many countries are facing when formulating energy policy.

In Association of Southeast Asian Nations (ASEAN) countries, future demand for decarbonisation is expected to increase in order to substantially reduce greenhouse gases at the global level. It should be noted, however, that the energy supply and demand in these countries are different from those of advanced countries, such as those in Europe. That is, in these countries, the energy demand is rapidly increasing along with economic development, and demand is expected to continue its rise. According to forecasts by ERIA (2020), in the business-as-usual scenario, the primary energy consumption of the 10 ASEAN countries is expected to increase from 662 million tonnes of oil equivalent (Mtoe) in 2017 to 1,373 Mtoe in 2040 and 1,823 Mtoe in 2050. In particular, the expected growth in power demand is remarkable, and the total amount of power generation by the 10 countries is expected to increase from 1,041 terawatt hours (TWh) in 2017 to 2,496 TWh in 2040 and 3,439 TWh in 2050. How to stably supply power demand that is rapidly expanding in this way has been a significant policy challenge and will continue to be important in the future.

In addition, because of the difference in energy resource distribution, the energy transition pathways in this region may be different from those in other areas. First, in the ASEAN region, the resource of wind power generation is generally poor. In addition, as hydro and geothermal resources are unevenly distributed, additional investment will be necessary to utilise them effectively. Second, countries in this region have been supplying power using coal-fired and natural gas-fired thermal power generation, which have been relatively cheaper than in other regions. Regarding natural gas, resource depletion and increasing demand have been casting a shadow over supply stability; however, coal is still a cheap and stable energy source for ASEAN members. This highlights the challenges for decarbonising energy utilisation whilst considering economic efficiency in the ASEAN region.

A powerful means for resolving the uneven distribution of energy resources is to construct international transmission interconnection lines. A construction plan for the ASEAN Power Grid has long been developed, and it is expected to contribute to increasing the efficiency of energy utilisation and decarbonisation in the region. In a previous ERIA study by Kutani and Li (2014), model calculations were performed for the 10 ASEAN countries and neighbouring areas to quantitatively evaluate the effect of the international transmission interconnection lines. The study demonstrated the role of grid interconnection for expanding the utilisation of hydroelectric power generation, which would replace mainly thermal power generation, at a time when fossil fuel prices were relatively expensive. However, as of 2021, international energy prices have decreased compared to that time, and the relative economic advantage of hydropower generation is deteriorating. On the other hand, if a large amount of VRE is introduced to ASEAN countries in the future, international transmission lines would be expected to reduce the risk of power-supply shortages due to the intermittency of VRE. From such a point of view, under new circumstances different from the 2014 study, it is important to identify the role of the international transmission interconnection system and to quantitatively evaluate its effect.

For this purpose, in this study, a new power-supply configuration model was constructed for part of the ASEAN region, and the effect of the international transmission interconnection system in the future power-source configuration was quantitatively evaluated. Here, by dividing 1 year into 8,760 time slices, modelling was performed to simulate the power supply and demand under high shares of VRE, taking into account the most recent data, such as primary energy prices and the power generation costs of VRE. By comparing the results obtained here with the previous study by Kutani and Li (2014), it is possible to evaluate whether the recent changes in energy supply and demand situations have altered the significance of the ASEAN transmission interconnection system. In addition, the evaluation in this study involves two types of risks: to what degree the risk of a shortage of fossil fuels, such as natural gas, and the risk of power shortages associated with the introduction of VRE are reduced by the transmission interconnection system; and to what extent VRE can be introduced within the scope of economic rationality, or to what extent cost measures will be necessary to realise the low-carbonisation of the power sector. Thus, this study provides information that contributes to policy formulation for sustainable development.

This report is constructed as follows: Chapter 2 explains the background of the study, the data used, and the assumptions for the calculations. Chapter 3 describes the models used and the case settings. Chapter 4 presents the results of the calculations for each case and contains a discussion on the interpretation of the results. The chapter also illustrates the power supply and demand of each of the target countries and areas to clarify the characteristics of each country/area. Finally, Chapter 5 summarises the calculation results and proposes policy implications.

Chapter 2

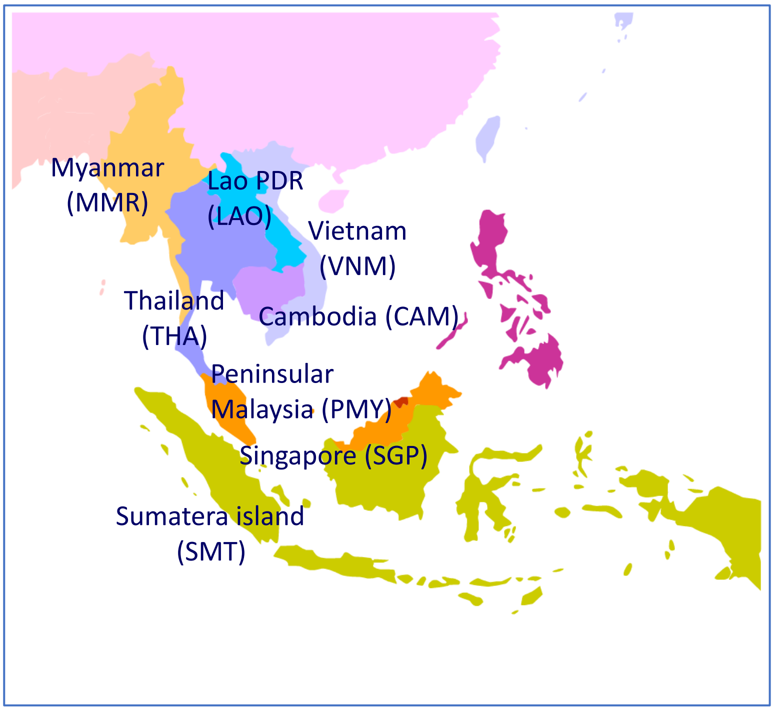
Major Assumptions for the Study

1. Target areas and target years

In the previous study by Kutani and Li (2014), model analysis was performed for 12 regions, including the 10 Association of Southeast Asian Nations (ASEAN) countries, Yunnan Province in China, and the northeast part of India. However, the results of the calculations did not exhibit the economic feasibility of the submarine cables connecting Borneo and the Philippines. In this study, as one country was modelled as one area, Peninsular Malaysia and Borneo were not separated; in reality, as with the Philippine submarine cables, the transmission lines connecting these separated areas would not be economically feasible.

This study analyses interconnection lines with higher feasibility, focusing on the Indochinese Peninsula and the Malay Peninsula. Figure 2.1 shows the regional coverage. Here, in addition to the six countries of Viet Nam, the Lao PDR, Cambodia, Thailand, Myanmar, and Singapore, Peninsular Malaysia and Indonesia's island of Sumatra are modelled, with a long-term perspective targeting 2040.

Figure 2.1. Regional coverage



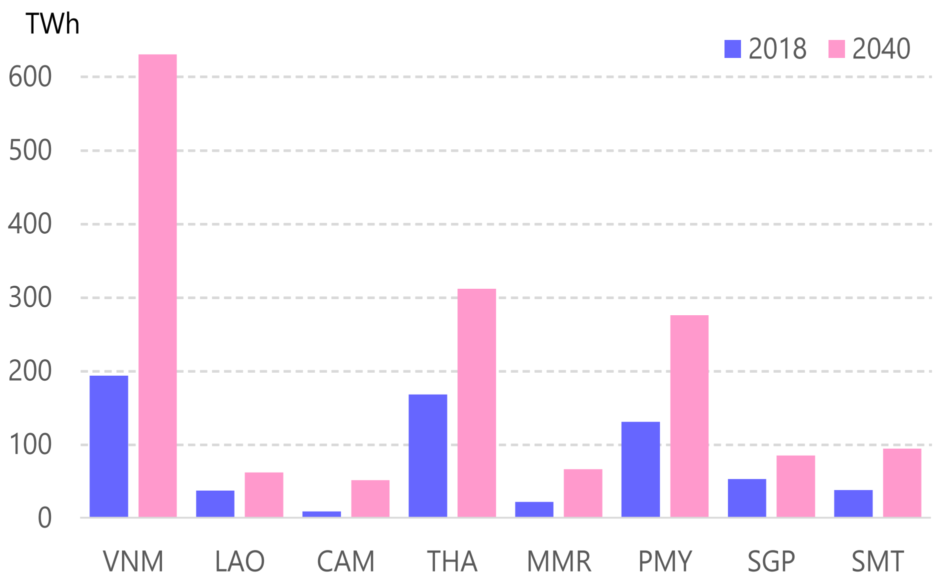
Source: IEEJ.

2. Power demand forecasting and electrical power plant capacity

In this study, the basic assumption is matched with the energy supply and demand forecast by ERIA (2020). The amount of power generation was set according to the business-as-usual (BAU) case. As shown in Figure 2.2, the total power generation for the eight areas is expected to increase from 650 terawatt hours (TWh) in 2018 to 1,570 TWh in 2040. In Viet Nam, power generation is expected to increase by 3.3 times from 193 TWh to 630 TWh. Power demand in Cambodia and Myanmar is expected to increase by 6.0 times and 3.1 times, respectively, by 2040.

In this study, for Peninsular Malaysia and Sumatra, we divided the total power demand for Malaysia and Indonesia proportionally by the ratios of the current power demand.

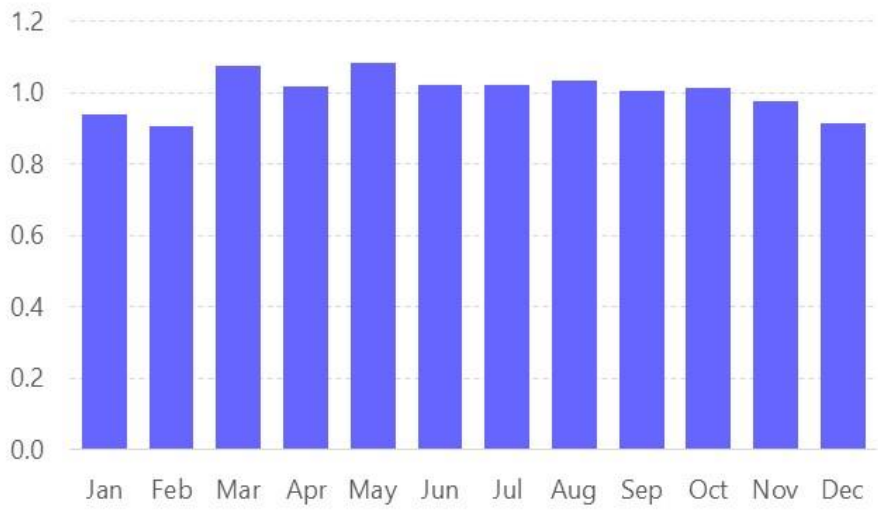
Figure 2.2. Power generation for 2018 and 2040



TWh = terawatt hours.
Source: ERIA (2020) and authors' analysis.

Fluctuations in power demand, in addition to variations in variable renewable energies (VRE) as described below, may also affect energy supply and demand. Ideally, the actual hourly power demand data for 2019 should be exploited, as well as the VRE output data. However, due to the constraints of the data, the daily load curve for power described in Kutani and Li (2014) is used here. In addition, monthly fluctuations in power demand are set with reference to the data for Thailand by the Energy Policy and Planning Office (Figure 2.3). Using more accurate power demand curves for each country should be an important future task.

Figure 2.3. Monthly power demand (Thailand): Ratio to annual average



Source: Energy Policy and Planning Office. *Electricity Statistics*. http://www.eppo.go.th/index.php/en/en-energystatistics/electricity-statistic (accessed 14 May 2021).

3. Energy resource potential

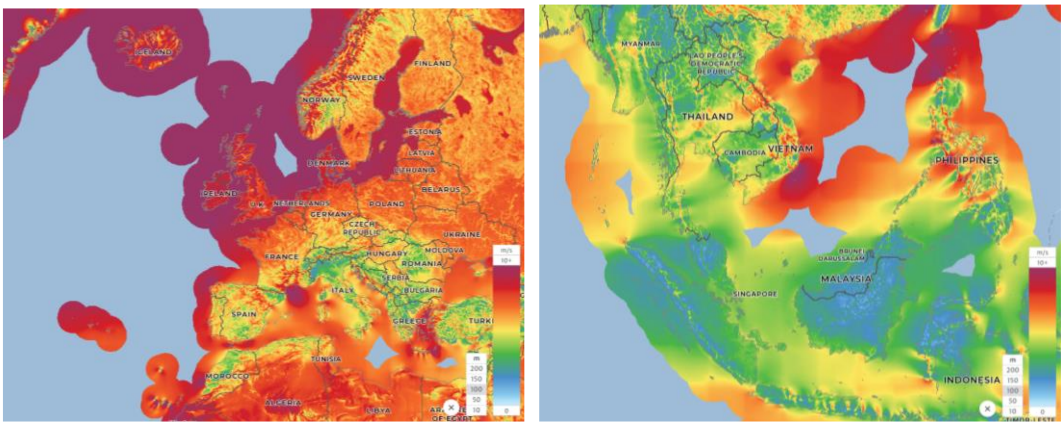
In general, the introduction potential of renewable energy is greatly affected by the natural conditions of the area. In this study, renewable potentials are assumed as follows based on various information. In cases where only potential data at the whole-country level were obtained for Indonesia and Malaysia, the figures are divided in proportion to the land area of the region.

3.1 Variable renewable energies

Solar photovoltaic (PV) and wind are collectively referred to as variable renewable energies (VRE). As many countries around the world are aiming for decarbonisation, they have ambitious targets for the large-scale deployment of VRE. However, the scale of VRE resources differs depending on the country/area, and this has an important meaning for decarbonisation in ASEAN.

Figure 2.4 shows the wind conditions in Europe and ASEAN. In Europe, there are many areas blessed with favourable wind conditions. As a result, a large number of wind power generation facilities have already been established, and further rapid introduction is expected in the future. On the other hand, in the ASEAN region, wind velocity is typically low. Although some areas offshore from Viet Nam and the Philippines have good wind conditions, the wind power resources are limited in other areas.

Figure 2.4. Wind power resources of Europe and ASEAN

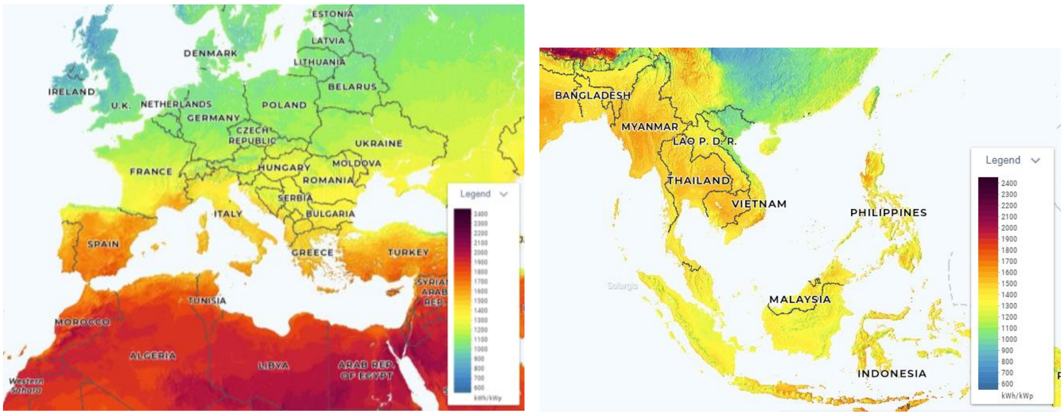


Europe **ASEAN**

Source: Global Wind Atlas 3.0, a free, web-based application developed, owned and operated by the Technical University of Denmark. Global Wind Atlas 3.0 is released in partnership with the World Bank Group, utilising data provided by Vortex, using funding provided by the Energy Sector Management Assistance Program. For additional information, see https://globalwindatlas.info.

Similarly, Figure 2.5 shows the distribution of solar radiation in Europe and ASEAN. As shown here, although the ASEAN area is inferior to Africa, it still has good solar radiation equal to or greater than that of Europe. Therefore, in the ASEAN area, there is the potential to deploy solar power generation widely in the future.

Figure 2.5. Solar resources of Europe and ASEAN



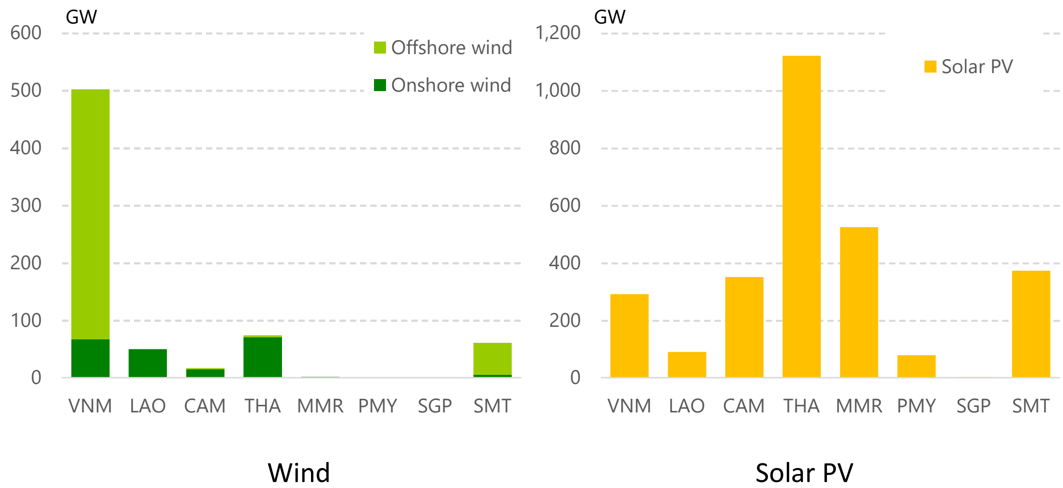
Europe **ASEAN**

Source: Global Solar Atlas 2.0, a free, web-based application is developed and operated by the company Solargis s.r.o. on behalf of the World Bank Group, utilising Solargis data, with funding provided by the Energy Sector Management Assistance Program. For additional information: https://globalsolaratlas.info.

This study used the potential data of wind power/solar power generation for each country, evaluated based on the wind conditions/solar radiation in the *IEEJ Outlook 2021* (IEEJ, 2020). Here, for solar power, the available area is determined considering the slope of the land, and the land-use suitability factor of 0%–5% is determined for each land-use section in accordance with Hoogwijk (2004). Regarding wind power, with reference to Eurek et al. (2017), using a suitability factor of 0%–90% for each land-use section for land that has a wind velocity of 5.5 metres per second (m/s) or more, potential sites are narrowed down based on data such as altitude, inclination, protected area, and distance from the coastline (and water depth in the case of offshore systems).

Figure 2.6 shows the potential of wind power/solar power for each region. As illustrated here, the potential for wind power is low, except for offshore wind power in Viet Nam. On the other hand, solar power has high potential and could be widely used depending on economic efficiency.

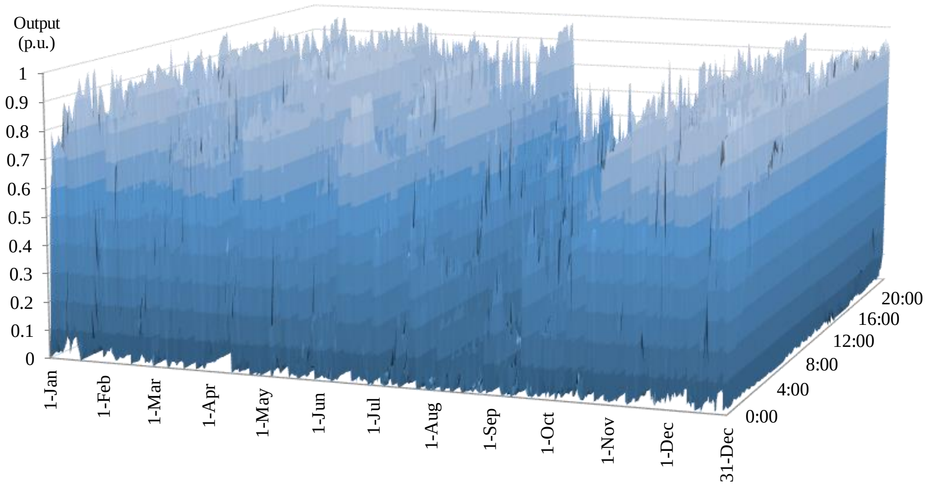
Figure 2.6. Potential for wind power/solar power in each region



GW = gigawatts, PV = photovoltaic.
Source: Authors' estimates.

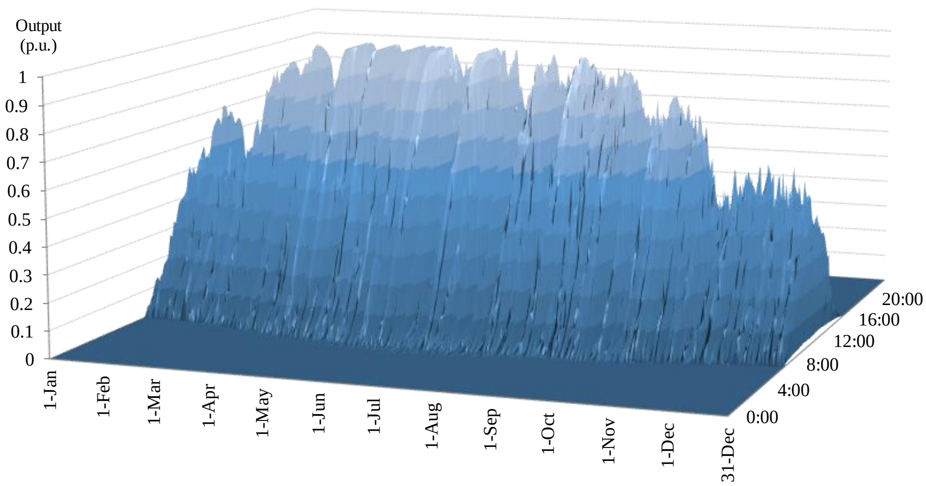
Regarding the output patterns of wind power/solar power generation, the data sets obtained from Renewables.ninja (Staffell and Pfenniger, 2016; Pfenniger and Staffell, 2016) were used. Here, based on the reanalysis data by the National Aeronautics and Space Administration (NASA), the hourly output patterns of wind power/solar power in all regions of the world in 2019 have been estimated. We selected locations near capital cities for solar PV, and locations with good conditions for wind. Figures 2.7 and 2.8 show examples of offshore wind and solar PV, respectively, for Viet Nam.

Figure 2.7. Example of offshore wind power generation output patterns (Viet Nam)



Source: Authors' estimates.

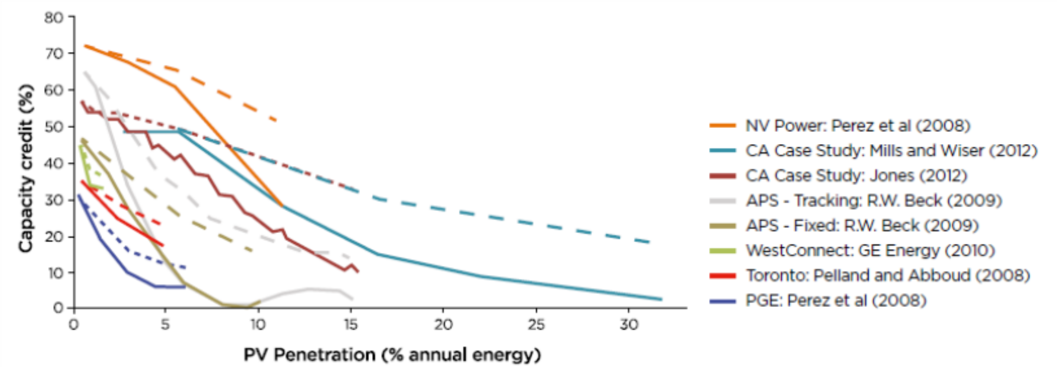
Figure 2.8. Example of solar power generation output patterns (Viet Nam)



Source: Authors' estimates.

Assumptions for the capacity credits may affect the calculation results considerably. The capacity credit is a ratio indicating how much a power facility of one unit can contribute to reducing peak demand. If a thermal power generation facility is operated at 1 gigawatt (GW) at peak time, the peak demand can be reduced by 1 GW, indicating a 100% capacity credit. In the case of VRE, however, the capacity credit is usually smaller than 1. If the peak demand occurs during the daytime, solar PV is expected to operate at a significant probability at peak time; therefore, the capacity credit becomes relatively large. However, in this case, the capacity credit becomes smaller with the expansion of solar PV because the peak load of the residual demand, obtained by subtracting the solar PV output from the power demand, is considered to move to a time zone that is not daytime as the introduced amount of solar power generation increases (Figure 2-9). Obviously, the capacity credit depends on both the VRE power generation profiles and demand profiles. Data for different years indicate different supply and demand situations; therefore, it is necessary to perform the evaluation by statistical analysis using data from multiple years. However, since an accurate power demand curve for each ASEAN country cannot be obtained, in this study, we simply assumed the capacity credits both for wind and solar PV to be 30%.

Figure 2.9. Capacity credit estimates for solar PV (International Renewable Energy Agency)



Source: International Renewable Energy Agency (2017).

3.2 Hydro, geothermal, and biomass

There is hydro power potential in almost all of the target areas, except Singapore. Myanmar, Viet Nam, and the Lao PDR, in particular, have abundant hydro resources. Here, we assumed that large-scale resource development may take place by 2040, setting the potential of the hydro power in each area based on published data.[1] However, it should be noted that in some countries, sufficient development may not proceed due to movements opposing it, armed conflicts, and government resource shortages, etc. In particular, although the hydro power potential in Myanmar is estimated at 100 GW (Aye, 2018), a more conservative evaluation of 27 GW has been adopted (IFC, 2018) for this study.

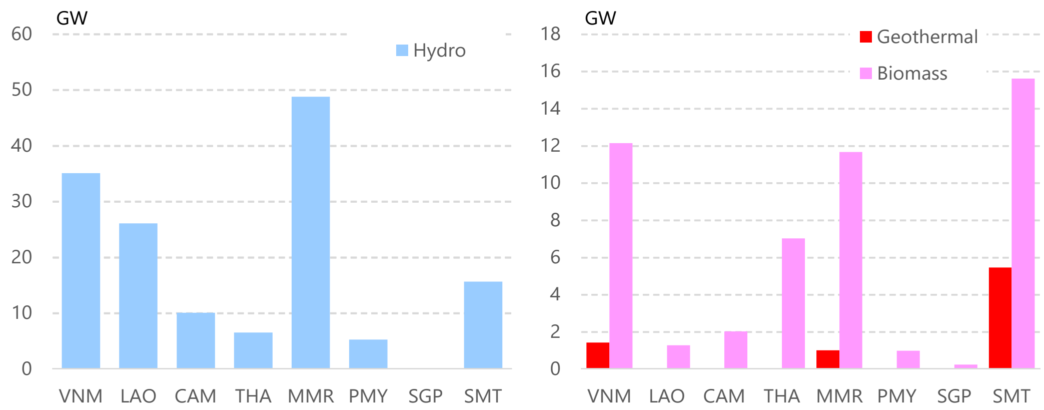
Regarding geothermal power, Indonesia, including Sumatra, has the largest potential. Viet Nam and Myanmar also hold geothermal potential, although it is not as great as Indonesia's. Geothermal potential is classified by the likelihood of availability, and classification such as Hypothetical Resources and Speculative Resources may be included in the figures in public sources (MEMR, 2019). If the Hypothetical Resources and

[1] See, for example, Asian Development Bank (2018, 2019), Vietnam Electricity website (2019), PwC, (2018), and Huber et al. (2015).

Speculative Resources are included in the assumed potential, it may overestimate realistic future deployment. Therefore, this study adopts 50% of the values obtained from public sources as the upper limit for deployment in 2040.

Figure 2.10 shows the hydro, geothermal, and biomass power potential in each area assumed in this study.

Figure 2.10. Hydro, geothermal, and biomass potential



GW = gigawatt.
Source: ADB (2018, 2019).

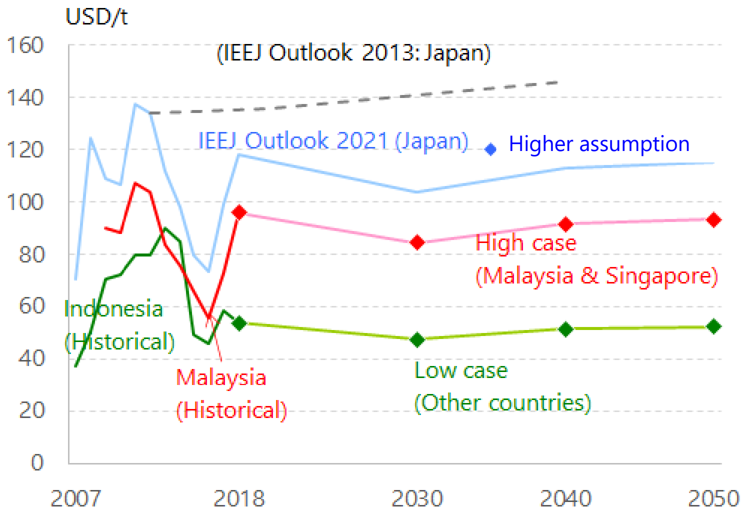
4. Primary energy prices

Primary energy prices are one of the most important assumptions determining the economy of a power sector. In Kutani and Li (2014), based on the actual value for 2010 and with reference to various forecasts, it was assumed that the coal price will reach US$120 per tonne (t) even in a low-cost country by 2035 and that the current price difference will converge for the natural gas price, reaching US$12/million British thermal units (MMBtu) in 2035. However, as energy prices have fallen after 2014, price forecasts have also declined significantly, considering the future possible development of climate change countermeasures.

Figure 2.11 shows the forecast for coal prices. Here, as a reference, the price assumptions for the Reference Scenario in *IEEJ Outlook 2013* and *IEEJ Outlook 2021* are shown as a dotted line and a solid blue line, respectively. The 'higher assumption' shown by a blue dot indicates the assumption for 2035 in Kutani and Li (2014).

The actual coal prices in 2018 were US$54/t (PLN, 2019) in Malaysia and US$96/t (Tenaga Nasional, 2019) in Indonesia. Here, we assume that the difference between the actual values will continue in the future in accordance with *IEEJ Outlook 2021*, with the price reaching US$91.6/t$CO_2$ in high-priced countries (Malaysia and Singapore) in 2040 and US$51.5/t$CO_2$ in other countries. Note that all prices in this report are shown in 2016 US dollars.

Figure 2.11. Assumptions for coal prices

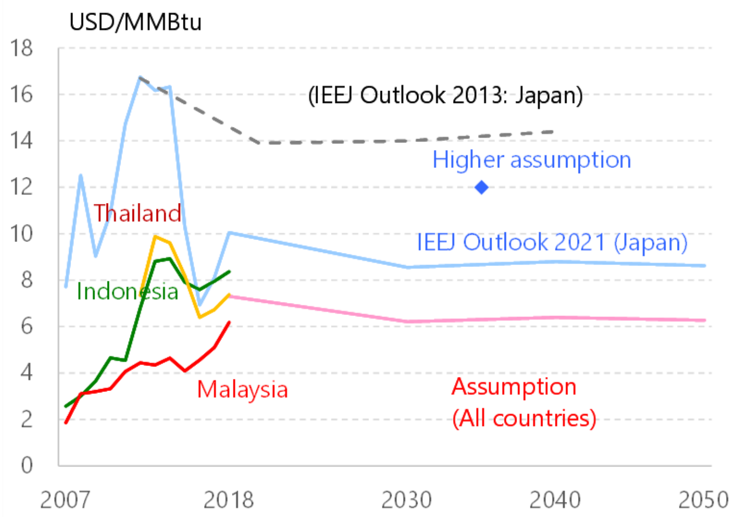


Source: Statistics of each country, IEEJ (2020) and authors' analysis.

Figure 2.12 shows the forecast for natural gas prices. The natural gas price also significantly decreased from *IEEJ Outlook 2013* to *IEEJ Outlook 2021* and is lower than the assumption (US$12/MMBtu in 2035) by Kutani and Li (2014).

Regarding the actual values in 2018, the average value for Indonesia (PLN, 2019), Thailand (EGAT, 2019), and Malaysia (Energy Commission, 2021) is US$7.3/MMBtu. It was assumed that the difference between this and the import price in Japan will continue in the future. Consequently, the natural gas price will be US$6.4/MMBtu (common in all areas) in 2040.

Figure 2.12. Assumptions for natural gas prices



Source: Statistics of each country, IEEJ (2020) and authors' analysis.

In addition to the calculations based on these assumptions, this study also sets a 'high-price case', in which primary energy prices are assumed in accordance with the price assumption for 2035 in Kutani and Li (2014), to evaluate how the energy supply and demand change when the fossil fuel price increases for some reason in the future.

5. Assumption of the power generation cost

5.1. Data sources and assumptions for the study

The assumptions for power generation costs have been taken from three documents: In the assumptions for 2040, since sufficient data for each country cannot be obtained, the data for Indonesia by Dewan Energi Nasional (DEN) and the Danish Energy Agency (DEN, 2017) were applied to all the regions.

For carbon capture and storage (CCS) and nuclear, for which this document contains no data, the costs assumed by the International Energy Agency (IEA, 2020b) have been used. In this case, the average value for China and India was adopted for coal-fired power with CCS, gas-fired power with CCS, and nuclear. Based on these data sources, the assumptions for the cost of each power generation type are set as shown in Table 2.1.

Table 2.1. Assumptions for power generation cost

		Coal	Coal (CCS)	Natural Gas	Natural Gas (CCS)	Hydro	Geo -thermal	Biomass	Nuclear	Solar PV	Wind Onshore	Wind Offshore
Construction Cost	US$/kW	1,455	3,075	685	1,875	2,200	3,050	1,500	2,650	530	1,210	2,820
O&M Ratio		3.8%	4.0%	3.3%	3.5%	1.9%	0.6%	3.6%	4.9%	2.2%	4.0%	2.8%
Electricity Efficiency	%	43.5	43.5	59.5	59.5			31.0	33.0			

CCS = carbon capture and storage, O&M = operation and maintenance, PV = photovoltaic.
Source: DEN (2017), IEA (2020b), and IEA and NEA (2020).

5.2. Levelised cost of electricity of each power source

In the following, based on the above power generation cost assumptions and the fuel cost assumptions used in this study, the levelised cost of electricity (LCOE) is estimated and compared. The LCOE is a value obtained by dividing the cost over the life cycle of each power source by the amount of power generated, and shows the average cost required for the power source to generate 1 kilowatt hour (kWh) of power. Specifically, the following formulas are used.

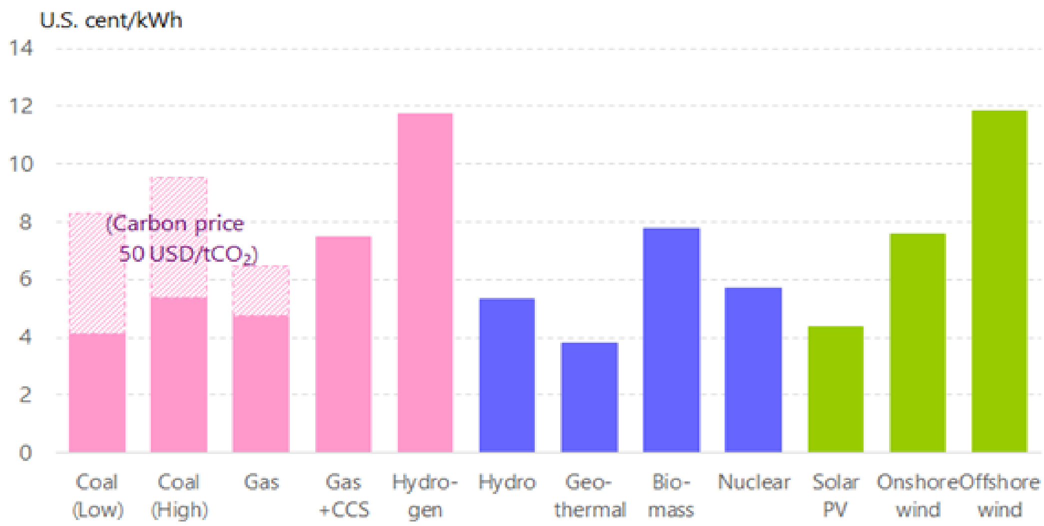
$$LCOE = \sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t} \Bigg/ \sum_{t=1}^{n} \frac{E_t}{(1+r)^t} \tag{1}$$

LCOE = the average lifetime levelised cost of electricity generation
I_t = investment costs in the year t (including financing)
M_t = operations and maintenance costs in the year *t*
F_t = fuel expenditures in the year *t*
E_t = electricity generation in the year *t*
r = discount rate
n = economic life of the system.

Note, in Eq. (1), only the cost of plant operation is calculated; however, in practice, there may also be construction costs from years before the plant begins operating or waste disposal costs when plant operation ends. In such cases, *t* ranges from a negative value to a value greater than *n*.

Figure 2.13 shows the LCOE of each power source. Amongst the renewable energy sources, the LCOE of geothermal and solar PV in 2040 indicates that they will be power sources having a price competitiveness at around 4 cents/kWh, which is comparable to the LCOE of coal-fired thermal power with low fuel prices. Conversely, other renewable energy types, such as hydro, have higher LCOE than thermal power generation as long as there is no carbon price. Coal-fired power remains a cheap option, at 4 cents/kWh; however, the price becomes 8 cents/kWh and is relatively expensive when a carbon price of US$50/$tCO_2$ is added.

Figure 2.13. LCOE of power sources



CCS = carbon capture and storage, PV = photovoltaic.
Source: Authors' estimates.

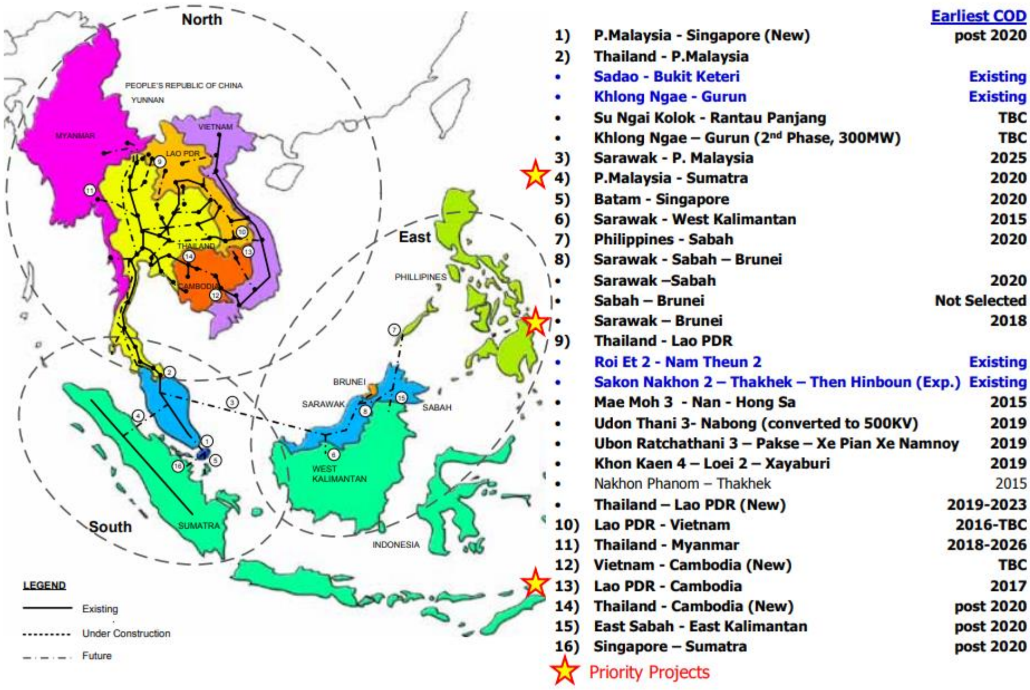
5.3. Grid interconnection

5.3.1. The ASEAN Power Grid

The ASEAN Power Grid (APG) was established in 1997 to enhance cross-border electricity trade in the ASEAN region. Regarding the promotion of the APG, Heads of ASEAN Power Utilities/Authorities (HAPUA), an organisation comprising the electric utilities or power-related authorities of the relevant countries, plays an important role. Through the ASEAN Power Grid Consultative Committee, HAPUA aims to develop a common ASEAN policy on power interconnection and trade.

Thus far, the interconnection projects are on a cross-border bilateral basis. However, APG aims to move beyond bilateral exchanges of power towards multilateral power interconnections. As shown in Figure 2.14, sixteen interconnection projects have been identified. In particular, the project connecting the Lao PDR, Thailand, Malaysia, and Singapore (the Lao PDR–Thailand–Malaysia–Singapore Power Integration Project: LTMS PIP) is addressed as a priority project, and further expansion of the existing interconnection is being planned.

Figure 2.14. Interconnection projects of the ASEAN Power Grid



Source: ACE (2015).

As of January 2019, the total capacity of the interconnection lines, including that connecting Thailand and the Lao PDR, was 5,502 megawatts (MW). Development of interconnection lines of 26,680–30,150 MW in total is being considered for the future (IEA, 2019).

In this study, we performed analysis for the region with a relatively high possibility of realising an interconnection system focused on the Indochinese Peninsula and the Malay Peninsula shown in Figure 2.1. The existing and future interconnection lines, including plans for the target region, are as shown in Tables 2.2 and 2.3. These figures are based on the APG plan and interviews on the latest situations with relevant people from each country.

Table 2.2. Existing interconnection for the target area (gigawatts)

	CAM	LAO	MMR	PMY	SGP	SMT	THA	VNM
CAM		0.0					0.1	0.2
LAO	0.0						3.6	0.9
MMR							0.0	
PMY					0.5	0.0	0.4	
SGP				0.5				
SMT				0.0				
THA	0.1	3.6	0.0	0.4				
VNM	0.2	0.9						

Source: IEA (2019).

Table 2.3. Future interconnection, including plans, for the target area (gigawatts)

	CAM	LAO	MMR	PMY	SGP	SMT	THA	VNM
CAM		3.0					2.3	0.2
LAO	3.0						9.0	5.0
MMR							14.9	
PMY					1.1	0.6	0.8	
SGP				1.1				
SMT				0.6				
THA	2.3	9.0	14.9	0.8				
VNM	0.2	5.0						

Source: IEA (2019).

5.3.2. Cost and transmission-loss rate of interconnection

The cost and transmission-loss rate of the interconnection were set in accordance with Kutani and Li (2014).

First, the cost associated with transmission must include the construction cost of the transmission facility itself, as well as the costs required for maintenance and management. Regarding the construction of the interconnection system in the ASEAN region, in addition to the construction of general overhead transmission lines, it is necessary to consider a route using shore-to-shore submarine cables to supply power to remote islands across bodies of water.

For the transmission cost, the cost of the electric wires constituting the transmission lines, the steel towers, and the substations must be included. In this study, however, the unit price per distance (km) was set for the cost required for the entire transmission line part except the substations, and the cost corresponding to the transmission distance was calculated. Further, the total cost was obtained by adding the construction cost corresponding to the number of substations (switching stations) necessary for the route. Specifically, the construction unit price of the transmission line part was US$0.9 million/km per 2 circuits when the overhead lines were used and US$5 million/km per 2 circuits when the submarine cables were used, based on past construction results from the neighbouring countries. Further, the construction cost of the substations (switching stations) was US$20 million per station as the fixed cost[2] and US$10 million per line as the additional cost.[3]

The operation/maintenance management cost was assumed to be about 0.3% per year of the total construction cost.

In theory, the transmission loss rate is proportional to the transmission distance if the transmission conditions (the type, diameter, number of lines, current value, etc. of the transmission line) are the same. However, in practice, transmission conditions are not the same because power generated at other power plants also flows along the same transmission line, the electric current value changes from moment to moment according to power usage, and the electric wires to be used are of different types and diameters. Therefore, the longer the transmission distance, the greater the transmission loss rate; however, it is not actually proportional to the distance and cannot be converted uniformly into numbers.

In this study, because of a lack of exact data, we assumed a transmission loss of 1% per 100 km, which is proportional to the transmission distance in the case of AC transmission. In the case of DC transmission, 2% was added as the loss due to AC–DC conversion in addition to the transmission loss equivalent to AC transmission.

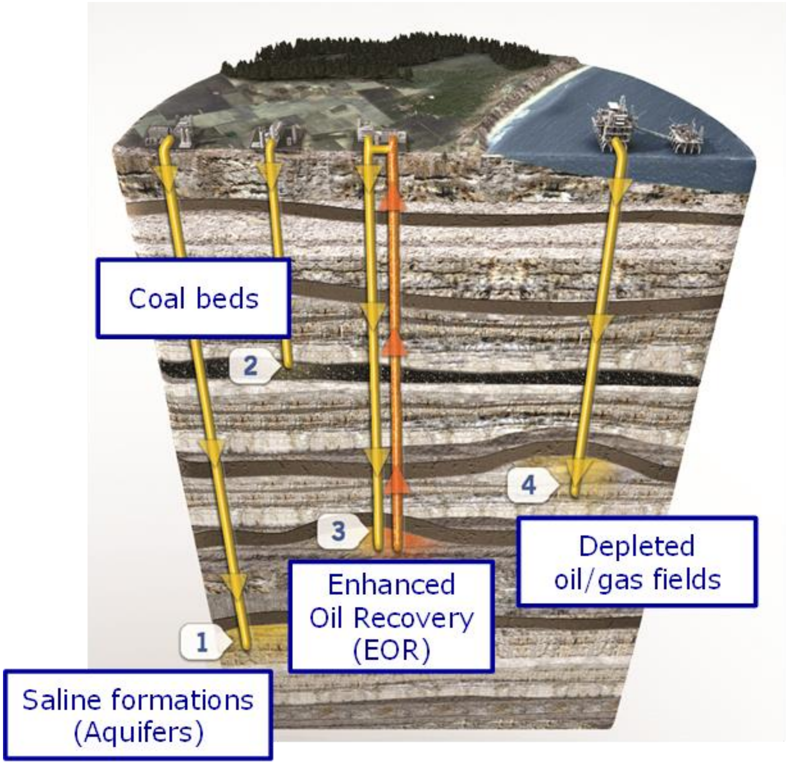
[2] A common cost necessary for setting one switching station, such as securing land and installing common facilities.

[3] A cost for installing devices according to the number of lines.

5.4. Carbon capture and storage

Carbon capture and storage (CCS) is an essential technique for decarbonising the power sector. However, in order to introduce CCS, a stratum structure suitable for storing CO_2 is necessary. For this reason, CCS cannot be introduced without limitations, and there is an upper limit to the introduction potential depending on the natural conditions of each country. As shown in Figure 2.15, aquifers are expected to be used to store CO_2 in addition to depleted oil and gas fields and coal beds.

Figure 2.15. Illustration of carbon capture and storage



Source: Global CCS Institute. https://www.globalccsinstitute.com/resources/ccs-image-library/ (accessed 14 May 2021).

Although many countries have been attempting to evaluate the potential of CCS, it is difficult to evaluate it for all countries on an equal basis because the assumed conditions are different. Table 2.4 shows the CCS potential evaluation results in ASEAN countries (Global CCS Institute, 2016). Although accurate estimation is difficult, within ASEAN there is a total storage potential of 85 $GtCO_2$ or more.

In this study, the annual CO_2 storable upper limit in the target area is assumed to be 50 $MtCO_2$/year. This is equivalent to around 150 TWh of thermal power generation with CCS, and corresponds to about 9% of the power demand in the area.

Table 2.4. CCS potential evaluation results in ASEAN countries

($GtCO_2$)

	Depleted oil/gas fields, enhanced oil recovery, etc.	**Aquifers**
Indonesia	1.4–2	10 ?
Malaysia	28	?
Philippines	0.3	22.7
Thailand	1.4	8.9
Viet Nam	1.4	10.4

Note: Question marks signify that the data are uncertain or that there are no data.
Source: Global CCS Institute (2016).

Chapter 3

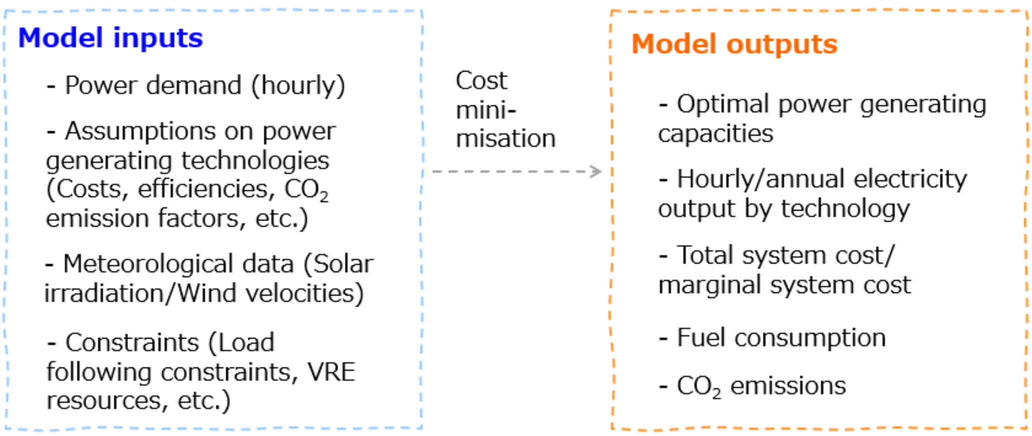
Methodology and Case Settings

1. Optimal power generation mix model

Under the above conditions, in this study, we performed analysis by using an optimal power generation mix model that adopts a linear planning method developed by the University of Tokyo and the Institute of Energy Economics, Japan (IEEJ). Figure 3.1 shows an outline of the model.

The model simulates the optimal facility configuration and operation to minimise the total cost of the power system based on a time step of 8,760 hours per year for the eight targets areas. In this case, the cost includes the capital cost, converted to annual expenses, the operating cost of each power generation technology, the capital cost and operating cost of the power storage systems, and the capital cost of the transmission lines. In addition, if the amount of generated power exceeds the power demand when the solar photovoltaic (PV) and wind power generation is large, it is assumed to be possible to use any of the power-storage options, then use the stored power later or curtail output. Since the power-storage system is expensive, output curtailment is often selected. See previous studies (Komiyama and Fujii, 2017; Matsuo et al., 2020) for more details on the model, as well as Appendix A.

Figure 3.1. Overview of the optimal power generation mix model



VRE = variable renewable energy.

Source: Authors.

1.1. Case settings

In this study, model analysis of several cases was performed under various condition settings in order to estimate the optimal power generation mix in the target regions for 2040 and capture how trade flows change with different conditions, such as grid interconnection and changes in environmental policies. Table 3.1 shows the analysed cases (white boxes) in this study and the condition settings (grey boxes) for each case.

Table 3.1. Case settings list

Inter-connection capacity	Solar PV price	Externality	Nuclear Capacity	Carbon prices (USD/CO2-t)				High fuel prices	Differentia-ted Carbon price
				0	50	100	200		
Only existing	Base (2040)	Not included	Only in IDN	Base Case					
Existing + Planned expansion	Base (2040)	Not included	Only in IDN						
	2050								
Limitless	Base (2040)								
Existing + Planned expansion			Limitless						
		Included	Only in IDN						

IDN = Indonesia, PV = photovoltaic.
Source: Authors.

Regarding the interconnections, we assume two cases: one in which the only existing interconnections are utilised, and another in which future interconnection expansion plans are assumed as shown in Table 2-3. Cases in which the upper-limit restriction on interconnection capacity is relaxed is also implemented for reference.

In some cases, calculations have been performed with different carbon prices, ranging from US$0/t$CO_2$ to US$200/t$CO_2$. The carbon price literally increases the cost of the fuel unit price in proportion to the amount of CO_2 emitted through coal-fired thermal power generation and natural-gas thermal power generation; however, in terms of policy, the carbon price may be considered as an index that assumes not only a direct carbon tax but also indicates the strength of various measures for promoting low-carbon power sources or suppressing increases in thermal power generation.

In addition, the following five types of case analysis were also performed, setting special conditions.

- Thermal power lower limit case
- Low solar PV cost case
- High fuel price case
- Externality case
- Differentiated carbon price case
- Limitless nuclear case

In the thermal power lower limit case, lower limits are set for thermal power generation in some countries with large hydropower potentials. In the case of setting carbon prices, most of the electricity supply would be hydropower in some countries with high hydropower potential; however, this is not realistic given the current policies of each country and their energy security. Therefore, the lower limits of thermal power are set in some countries to get closer to a more realistic power generation mix.

In the low solar PV cost case, calculations were performed using a lower cost for solar PV in order to see the effect of more rapid cost declines.

In the high fuel price case, fossil fuel prices are assumed to be higher, following the assumptions by Kutani and Li (2014) as described in Chapter 2. In this case, renewable energy utilisation will be expanded without any carbon prices, and the interconnection lines between the areas will be utilised. The share of the gas-fired power portion in the total power generation mix of the regions will be reduced as gas-fired power generation will be less cost-competitive.

The externality case is a case in which the external costs of power generation – in particular, the effects of health damage due to thermal power generation – are internalised and included as part of the cost of generating power.

In the case of differentiated carbon pricing, carbon prices are not uniform across all countries; rather, high carbon prices are set in high-income countries and low carbon prices are set in low-income countries. In fact, considering the current situation in which high carbon prices have already been set in some advanced countries, higher carbon prices may also be imposed in ASEAN Member States in the future. In addition, the carbon price in the model can be considered as a proxy for indicating the strength of the CO_2 reduction measure; therefore, it can be considered as a case that simulates the case in which a stronger CO_2 reduction measure is taken in higher-income countries.

The unlimited nuclear case is that in which nuclear power generation can be introduced to an economical maximum by eliminating the construction constraints on nuclear power plants. In practice, building a nuclear power plant takes a long time and requires various procedures, such as local agreement. Therefore, this case should be considered as a hypothetical case that only takes economic efficiency into consideration.

Chapter 4

Results and Discussion

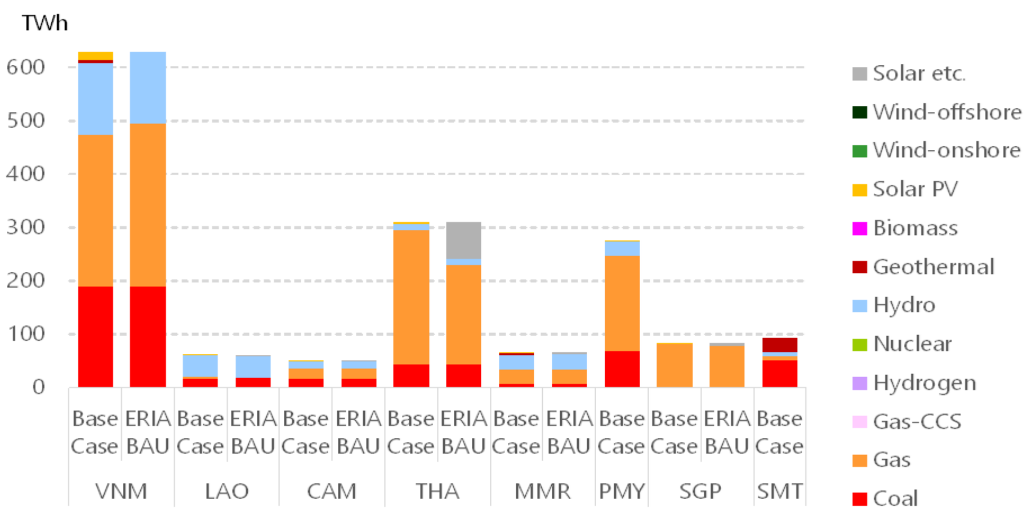
1. Base case

1.1 Base case (existing interconnection case)

The base case refers to a case in which, basically, individual countries maintain a balance between supply and demand based on their domestic power generation, although only the existing interconnection is considered. Neither the external cost nor the carbon price is set for thermal power generation. The conditions have been set to roughly match the business-as-usual (BAU) scenario of the ERIA Outlook.

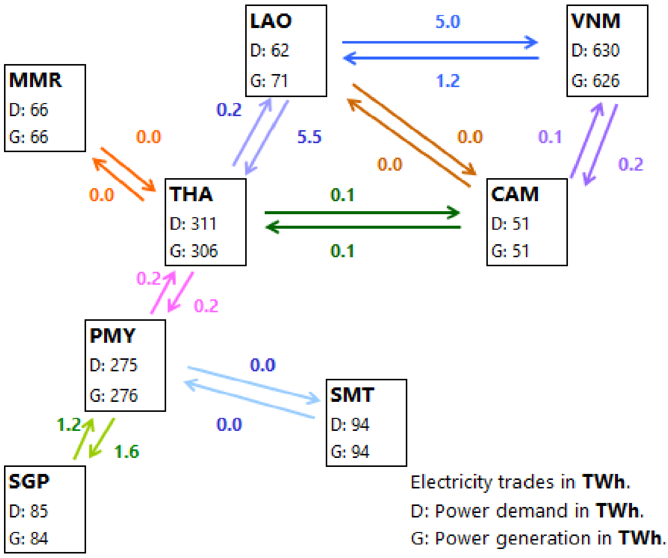
Figure 4.1 shows that thermal power is the main power source in 2040, accounting for around 80% of the power generation mix for all the target regions. On the other hand, hydropower is adopted in countries such as Viet Nam, the Lao PDR, and Myanmar, which have high potential for hydropower generation. The introduction of variable renewable energies (VRE), such as solar photovoltaic (PV) and wind power, has progressed little. Figure 4.2 shows the electricity trade flows in the base case.

Figure 4.1. Comparison of the base case with the ERIA Outlook (power generation mix in 2040)



BAU = business as usual, CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

Figure 4.2. The base case (trade flows)



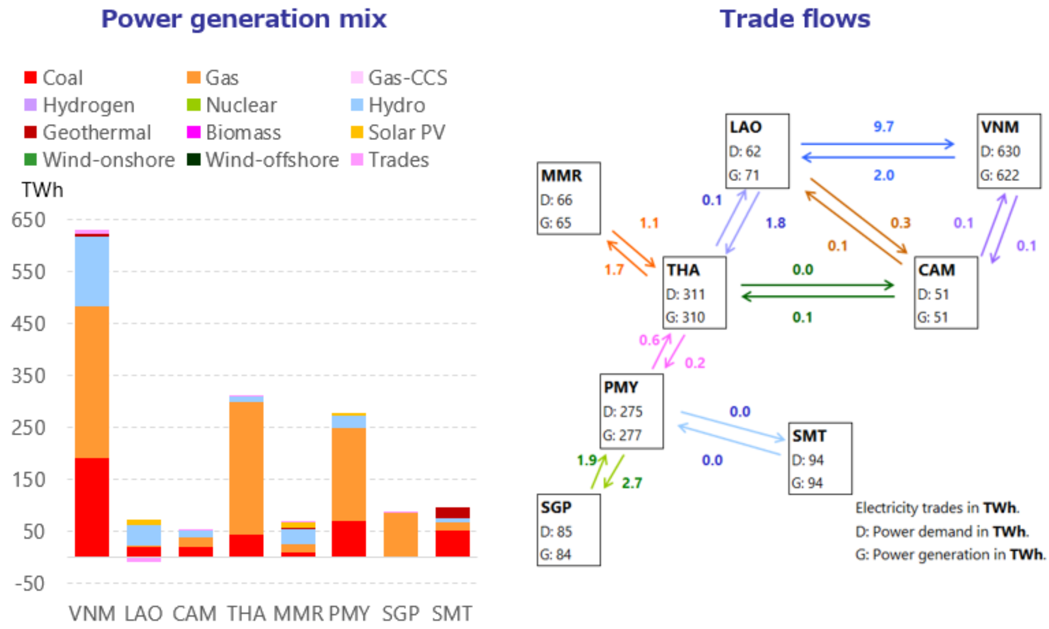
TWh = terawatt hour.
Source: Authors' analysis.

1.1.1. Planned interconnection case

The planned interconnection case has made electric power trade possible up to a planned interconnection capacity, as shown in Table 2.3. Neither the external cost nor the carbon price is set for thermal power generation.

Figure 4.3 shows the power generation mix and the electricity trade flows in the planned interconnection case. The trade flows are not much different from the existing interconnection case, even considering the planned interconnection expansion as long as the external cost and carbon price for thermal power are zero. The primary reason is that the utilisation of domestic coal-fired power is prioritised over using the potential for hydropower by other countries from the perspective of economic efficiency because the levelised cost of electricity (LCOE) of hydropower is higher than that of coal-fired power. In countries with high capacity factors of solar PV, such as Myanmar and the Lao PDR, a small amount of solar PV is introduced due to the low LCOE of solar PV.

Figure 4.3. The planned interconnection case



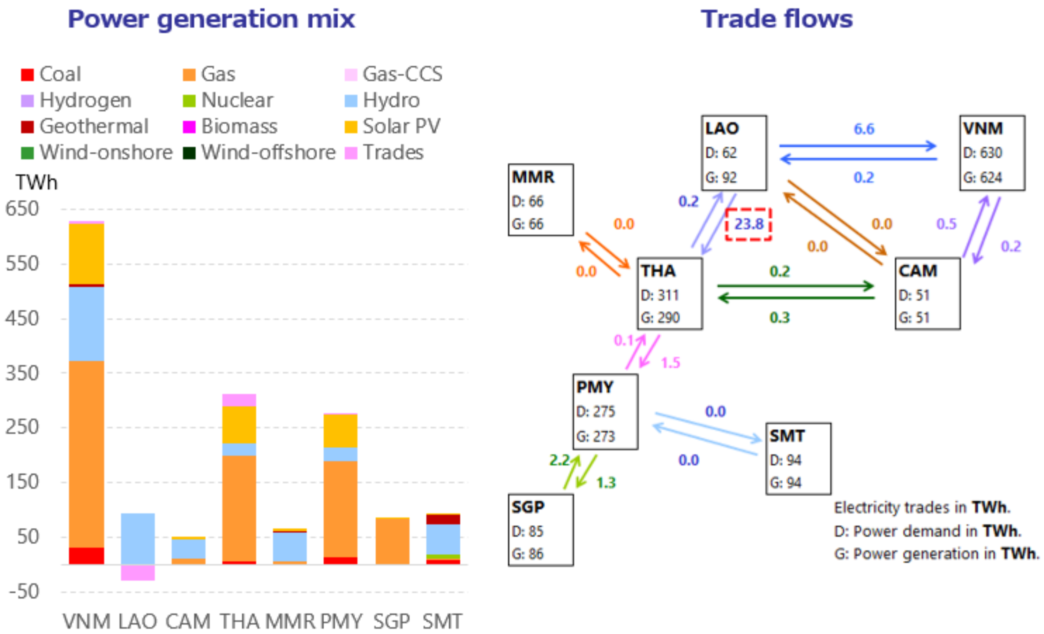
CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

1.1.2. The US$50/t$CO_2$ carbon price case

In the case of setting the carbon price at US$50/t$CO_2$, which indicates strong policies towards decarbonisation, the LCOE of coal-fired power is within the range of 8.3–9.5 US cents/kWh, resulting in a deterioration in price competitiveness. As a result, it is expected that coal-fired power would almost go out of use in any country regardless of the presence of interconnections.

Figure 4.4 shows the power generation mix and the electricity trade flows in the US$50/t$CO_2$ carbon price case with existing interconnection. Most electricity is supplied by hydropower in countries such as the Lao PDR, Cambodia, and Myanmar, which have a high potential for hydropower. In other countries, gas-fired power is adopted as a major power source, and the introduction of solar PV is expected to progress. Regarding trade flows, trade from the Lao PDR to Thailand increases, and hydropower in Lao PDR is expected to replace part of thermal power in Thailand.

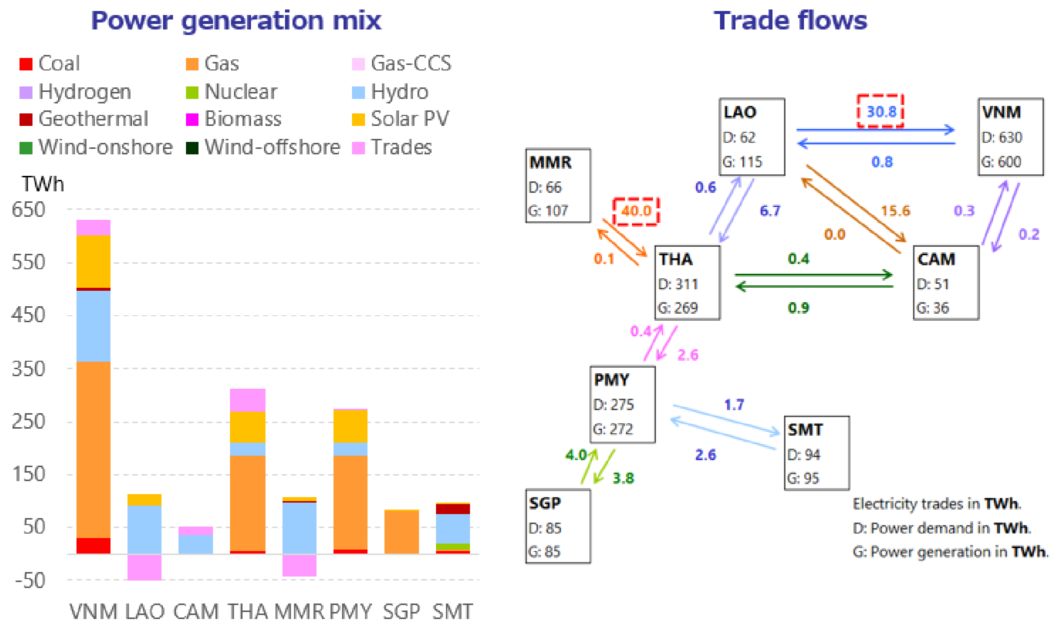
Figure 4.4. The US$50/tCO$_2$ carbon price case with existing interconnection



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

On the other hand, hydropower in Myanmar is used effectively in the planned interconnection case. Currently, there is no interconnection between Myanmar and Thailand, however, there are plans to expand the interconnection with a large capacity of 14.9 gigawatts (GW) in the future. Figure 4.5 shows that exports from Myanmar to Thailand increase significantly, and in turn, Lao PDR increases exports to Viet Nam, reducing exports to Thailand. As a result, thermal power generation in Thailand and Viet Nam are curtailed.

Figure 4.5. The US\$50/tCO₂ carbon price case with planned interconnection



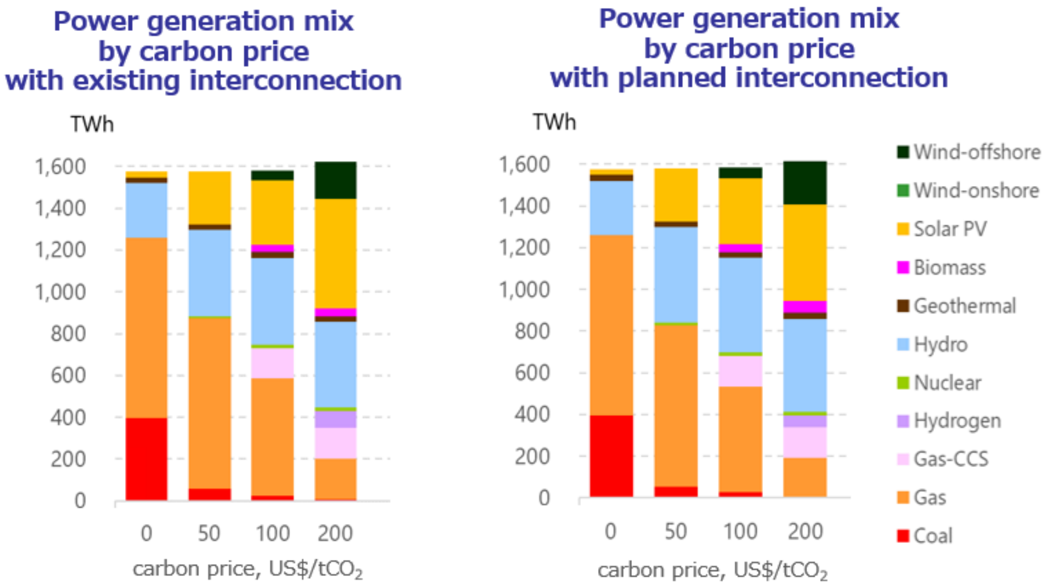
CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

1.1.3. Power generation mix: Total for the eight regions

As mentioned above, when the carbon price is zero, about 80% of the power generation mix depends on thermal power regardless of the presence of an interconnection. Coal-fired power would almost go out of use when the carbon price reaches US\$50/tCO₂, and the utilisation of hydropower and solar PV would rise along with a further carbon price rise or strong policy measures towards decarbonisation.

Comparing the power generation mix of the existing interconnection case and the expanded interconnection case, there is no significant difference in the entire region.

Figure 4.6. Power generation mix by carbon price



CCS = carbon capture and storage, PV = photovoltaic.
Source: Authors' analysis.

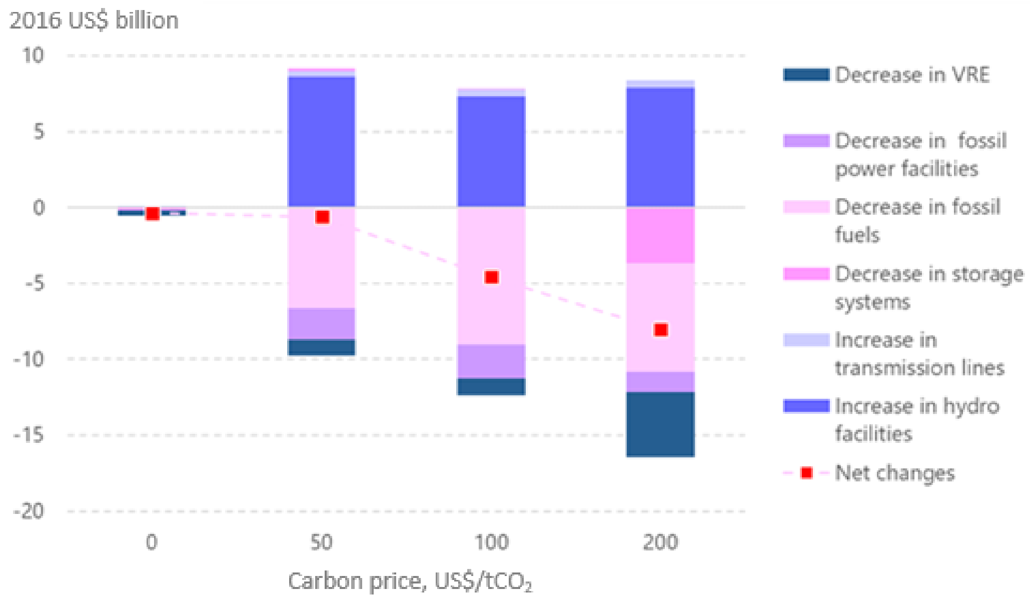
However, considering individual countries, the power generation mix is different depending on the interconnection capacity along with a further carbon price rise or strong policy measures towards decarbonisation.

Under a high carbon price or strong policy measures towards decarbonisation, in the existing interconnection case, the hydropower potential in Myanmar and the Lao PDR is mainly used in their own countries. The capacity to export electricity generated in Myanmar and the Lao PDR is limited so that the countries with poor hydropower potential need to introduce a large amount of VRE to replace thermal power generation. On the other hand, in the planned interconnection case, the hydropower potential is effectively utilised in the entire region. In countries with abundant hydropower potential, such as Myanmar and the Lao PDR, hydropower can be exported to earn foreign currency, whilst the domestic power supply can be supplemented by solar PV. Countries with poor hydropower potential can get closer to a well-balanced power generation mix by utilising imported hydropower and their own VRE.

A massive introduction of VRE, including solar PV and wind, leads to additional costs related to intermittency. Also, hydropower alone cannot meet the electricity demand in the dry season because the amount of electricity generation decreases during the dry season. The expansion of the interconnection can be expected to adjust the output fluctuation of renewable energy in the entire region and enable more efficient utilisation of regional renewable energy resources.

Figure 4.6 shows the changes in the total annual system cost for carbon prices ranging from US$0/tCO$_2$ to US$4200/tCO$_2$ in cases with planned interconnection lines compared to those without interconnection lines. The presence of interconnection lines means that there will be transmission line costs and expansion of hydro power generation as well. On the other hand, the decrease in thermal power generation and VRE cost makes them a net benefit. In particular, in the case where the carbon price is very high at US$200/t$CO_2$, although the expansion of VRE would require a large amount of storage batteries, the presence of interconnection lines would greatly reduce the actual quantity of batteries needed. Thus, cross-border interconnection lines throughout the region have the potential to generate great benefits when strong policy measures are implemented.

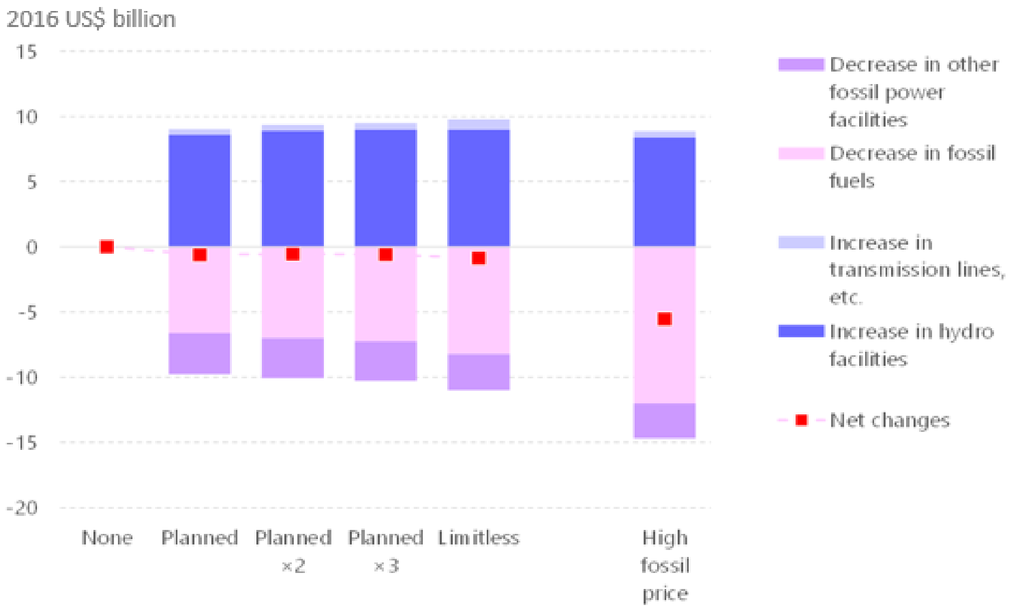
Figure 4.6. Changes in the total annual system cost (eight areas in total): Impact of carbon pricing



VRE = variable renewable energies.
Source: Authors' analysis.

Figure 4.8 shows cases where the capacities of interconnection lines are doubled or tripled compared to the planned levels and when there are no constraints, as well as changes in the total system cost when carbon prices are high. Even though the net benefit grows slightly as the capacity of the interconnection lines increases, the change is smaller than that caused by differences in carbon prices. In the case of high fuel prices, the benefit would be almost as great as when the carbon price is at around US$100/tCO2. It is understood from these results that the economic effect of transmission lines depends strongly on how much fossil fuel prices increase, whilst it can be seen that interconnections between areas are generally possible with transmission lines at the existing planned level.

Figure 4.8. Changes in the total annual system cost (eight areas in total): Capacity of interconnection lines and impact of the fuel price



Source: Authors' analysis.

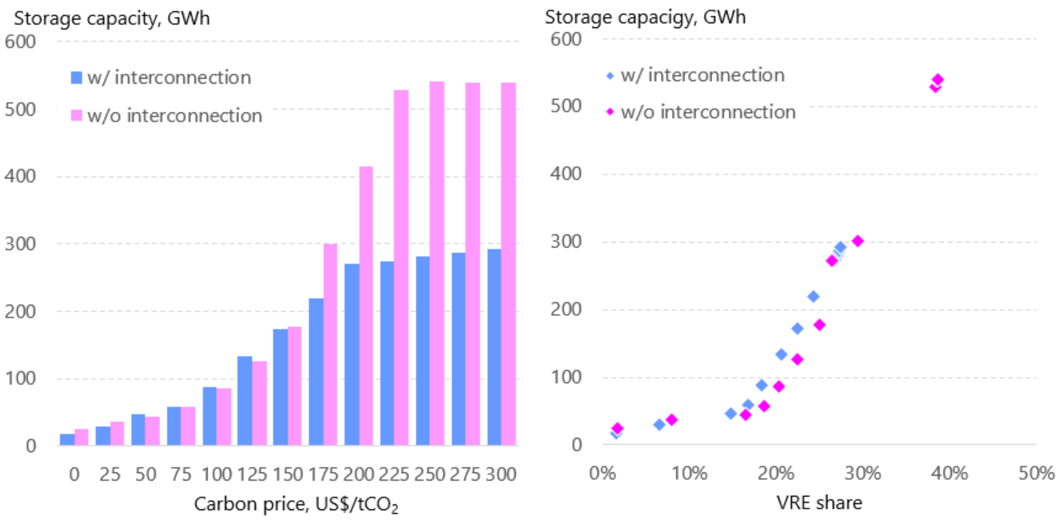
As mentioned above, regardless of whether interconnection lines are in place, the ratio of VRE, led by solar power, rises together with increases in carbon prices. As the VRE ratio increases, the power system needs to become more flexible, and this is where batteries play an important role.

Batteries are considered to play the role of mitigating the risk of power supply disruptions caused by the natural variability of VRE. In other words, it is considered that the required battery capacity, obtained using an optimised model, is calculated as the sufficient energy storage to compensate for the power supply deficit caused by consecutive days with weak sunlight in the case of the solar power generation ratio (Matsuo et al., 2020). Therefore, the required amount of batteries not only indicates the cost of the stabilisation measures necessary for achieving the energy mix but also provides a benchmark for indicating the instability of the energy supply.

The graph on the left-hand side of Figure 4-9 shows the required battery capacity by carbon price. As described previously, the VRE ratio increases along with rises in the carbon price, causing the required amount of batteries to rise as well. In the case of planned transmission interconnection, however, the increase in the required batteries is curbed at the level around which the carbon price exceeds US$200/t$CO_2$. This suggests that a cross-border interconnection line has the effect of decreasing the risk of energy supply breakdown and reduce the energy system cost, especially when achieving high VRE ratios.

The chart on the right-hand side of Figure 4-9 plots battery capacity against the VRE share based on the same estimate results, indicating that the capacity rapidly increases when the VRE share exceeds 15%. In other words, it is possible to integrate a VRE system relatively easily as long as the VRE share falls within a range up to around 15%, whereas the need to secure adjusting capability for batteries rapidly increases when the share exceeds this range because VRE output fluctuations have a great impact on the balance of supply and demand. Therefore, it is important to consider not only the power generation cost but also the costs required for system integration when introducing VRE on a large scale.

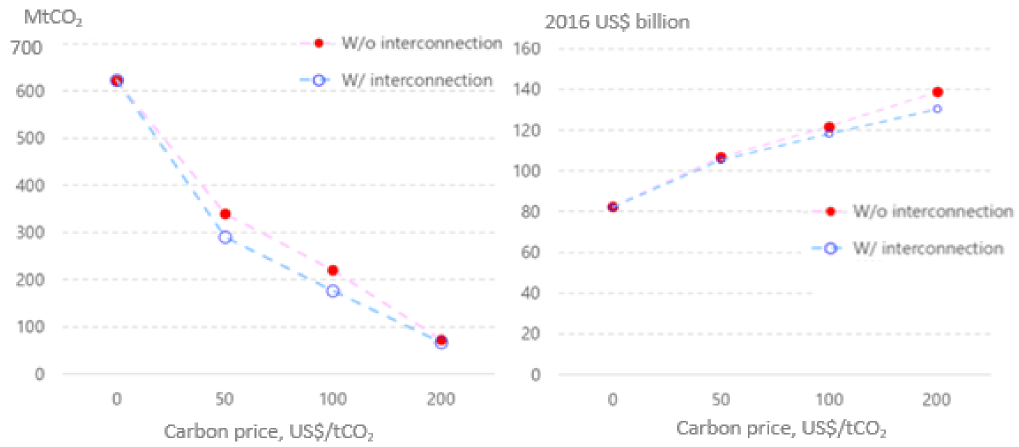
Figure 4.9. Quantity of batteries introduced (eight areas in total)



GWh = gigawatt hour, VRE = variable renewable energies.
Source: Authors' analysis.

Finally, CO_2 emissions depending on the presence of planned interconnection lines were compared with the total annual cost. Figure 4.10 shows a reduction in CO_2 emissions, as well as an increase in the total annual cost along with carbon price rises regardless of whether interconnection lines are present. However, it is understood that utilising interconnection lines contributes to reducing not only CO_2 emissions but also the total annual cost by comparing between cases with and without interconnection lines.

Figure 4.10. Comparison of differences in results depending on the presence of interconnection lines



CO_2 emissions Total annual cost

Source: Authors' analysis.

1.2. Analysis of other cases

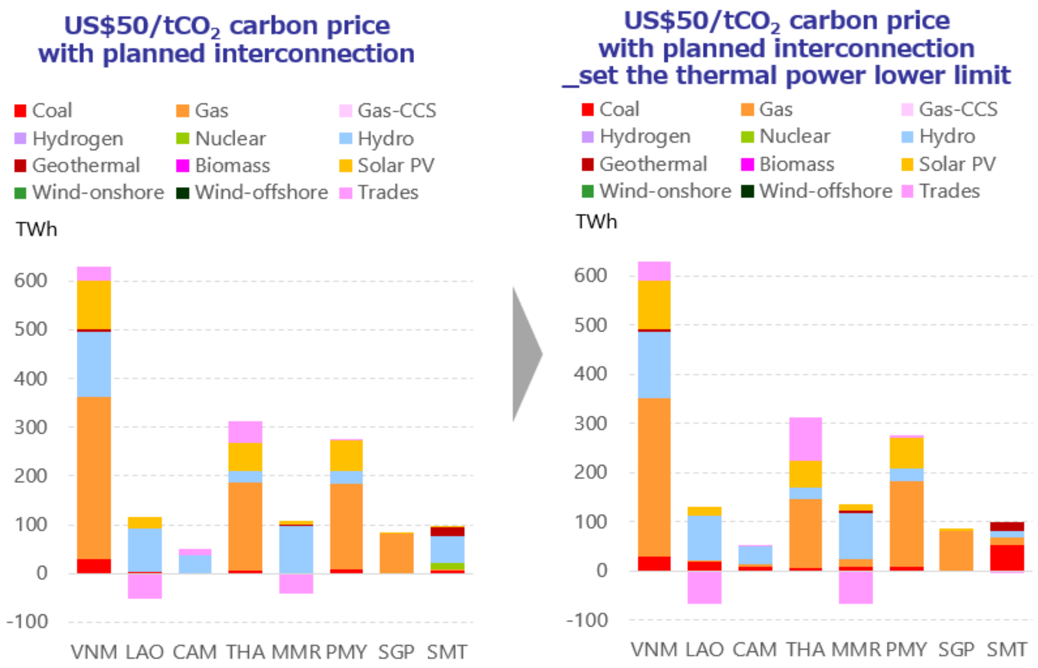
1.2.1. Thermal power lower limit case

In Section 1.3 of this chapter, we showed the power generation mix of each country in the case of a US$50/t$CO_2$ carbon price with planned interconnection (see Figure 4.5). In this case, most electricity is supplied by hydropower in regions such as the Lao PDR, Cambodia, Myanmar, and Sumatra, which have high hydro potentials.

However, this result is not realistic given the current policies of each country and energy security. Each country expects to utilise a certain amount of thermal power as an economical power source in the future to respond to the rapid increase in electricity demand and to utilise hydropower for exporting to earn foreign currency. In addition, hydropower alone cannot meet the electricity demand in the dry season because of the reduction in power generation. Therefore, in this case, the lower limits of thermal power are set in some countries to get closer to a more realistic power generation mix. The lower limits of thermal power are set in the Lao PDR, Cambodia, Myanmar, and Sumatra. The lower limits are based on the amount of thermal power generation in each country without carbon prices.

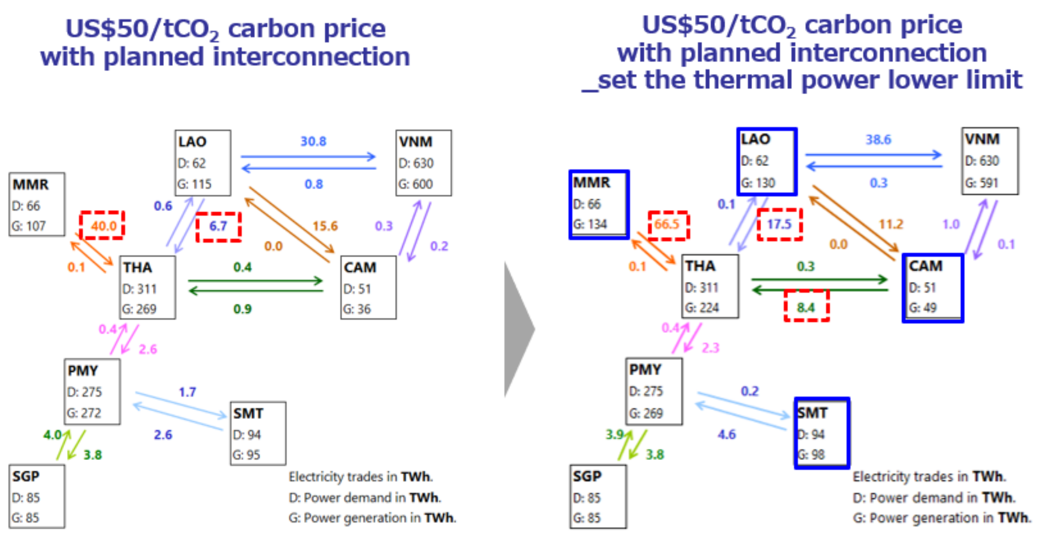
Comparing the power generation mix and trade flows with and without the thermal power lower limits, the exports from Myanmar, the Lao PDR and Cambodia to Thailand mainly increase and replace gas-fired power in Thailand. On the other hand, the exports from Sumatra to the Malay Peninsula increase only slightly. This is because the cost of the submarine interconnection is high, and it is not economical.

Figure 4.11. Power generation mix with and without thermal power lower limits



CCS = carbon capture and storage, PV = photovoltaic.
Source: Authors' analysis.

Figure 4.12. Trade flows with and without thermal power lower limits



TWh = terawatt hour.
Source: Authors' analysis.

Since thermal power generation would increase in the thermal power lower limit case, CO_2 emissions would also increase from 314 Mt-CO_2 to 369 Mt-CO_2. However, the costs would change little across the entire region. This is considered to bring about an income redistribution effect, since electricity exports would increase from relatively poor nations to relatively rich ones, although CO_2 emissions would increase.

1.2.2. Low solar PV cost case

The levelised cost of electricity (LCOE) of solar power PV is declining sharply worldwide, and further cost reductions are expected in ASEAN. The low solar PV cost case is implemented in order to identify the impact of a cost reduction in solar PV on the power generation mix.

Table 4.1 shows the LCOE of solar PV in each country. For the power generation costs of solar PV in 2050, the Indonesian data from Dewan Energi Nasional (DEN) and the Danish Energy Agency (DEN, 2017) shown in Section 5.1 of Chapter 5 are also applied to all regions, as in 2040. In 2050, the LCOE of solar PV is expected to decrease by 0.6–0.8 cents compared to 2040.

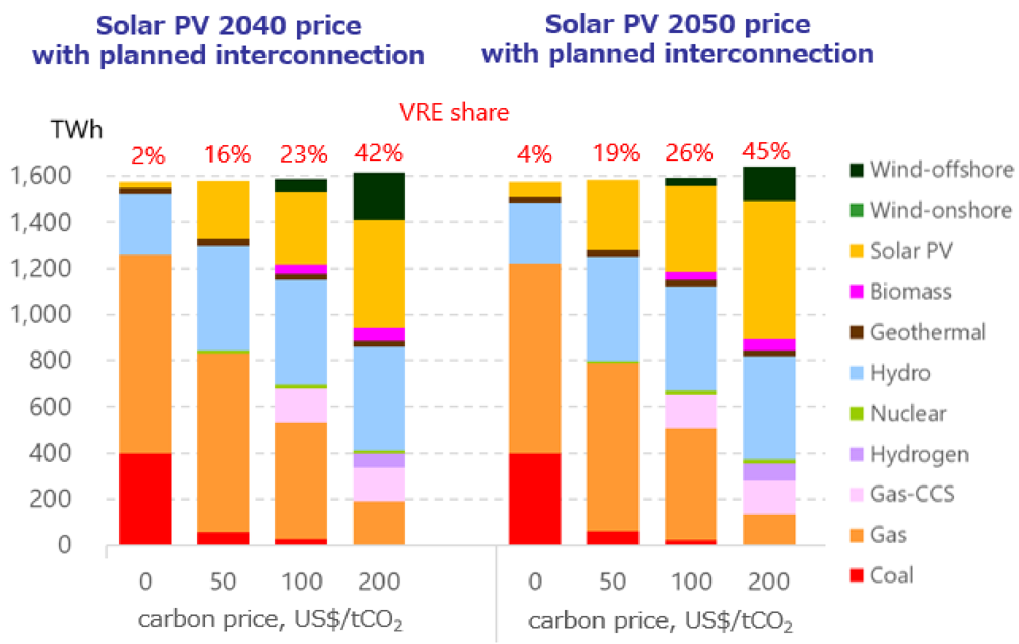
Table 4.1. Assumed LCOE of solar PV (cents/kWh)

Country	CAM	SMT	LAO	PMY	MMR	SGP	THA	VNM
2040	4.4	5.3	4.2	4.6	3.7	4.9	4.4	4.7
2050	3.8	4.5	3.5	3.9	3.1	4.2	3.7	4.0

Source: Authors.

Figure 4.13 shows a comparison of the power generation mix with default (2040) and low (2050) solar PV costs. The VRE share increases slightly with the low assumptions. The reason why the power generation mix does not change largely is that solar PV cannot replace thermal power and hydropower easily because of its low capacity credit.

Figure 4.13. Power generation mix of the 2040 and 2050 solar PV price cases



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

1.2.3. High fuel prices case

Increases in coal and gas prices may put additional upward pressure on the costs of coal- and gas-fired power generation plants. As seen in Section 1.2 of this chapter , coal- and gas-fired thermal power accounts for a large share of the power generation mix in target regions, where fuel is at the base price assumptions used in this study and a carbon price has not been introduced. Therefore, a power generation mix and trade flows that are different from those in the base price case could be economically optimal when assuming a future environment in which coal and gas prices fluctuate at a level exceeding the base prices. The high fuel prices case is implemented in order to quantitatively examine the changes.

Table 4.2 shows a comparison of the coal and gas prices in 2040 in the base price assumptions in this study and the high fuel prices case.

Table 4.2. Base price assumptions (left) and high fuel prices (right)

	Malaysia, Singapore	Other regions
Coal (2016 US$/t)	87.8	49.3
Gas (2016 US$/MMbtu)	6.1	

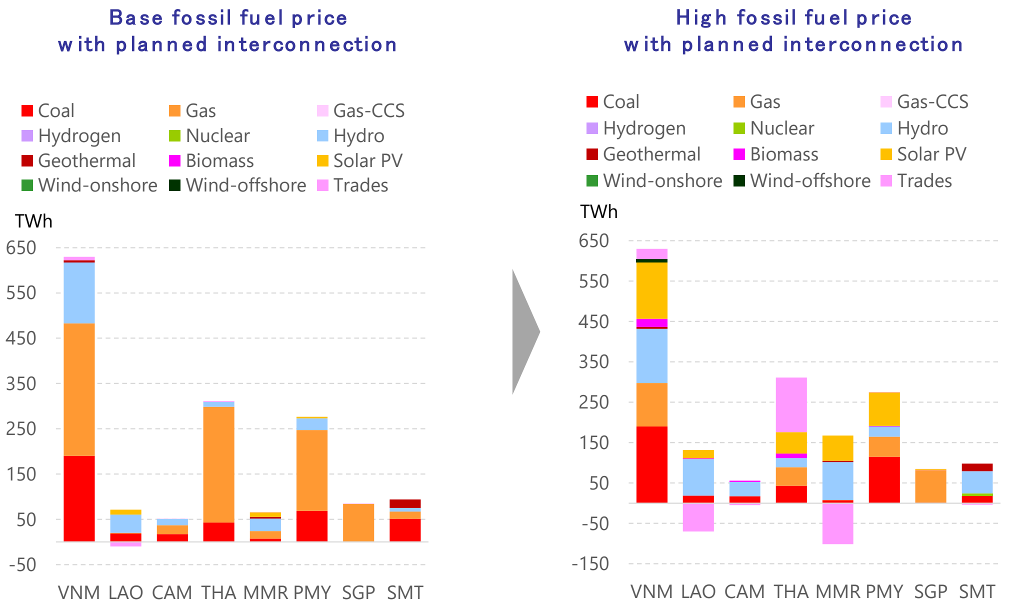
	All regions
Coal (2016 US$/t)	127.1
Gas (2016 US$/MMbtu)	12.7

Source: Authors.

In addition, it is assumed in these cases that a carbon price will not be imposed and that the interconnection capacity will be expanded as planned.

Figure 4.14 shows a comparison of the power generation mix for the base prices (i.e., the case shown in Section 1-2 of this chapter and the high prices.

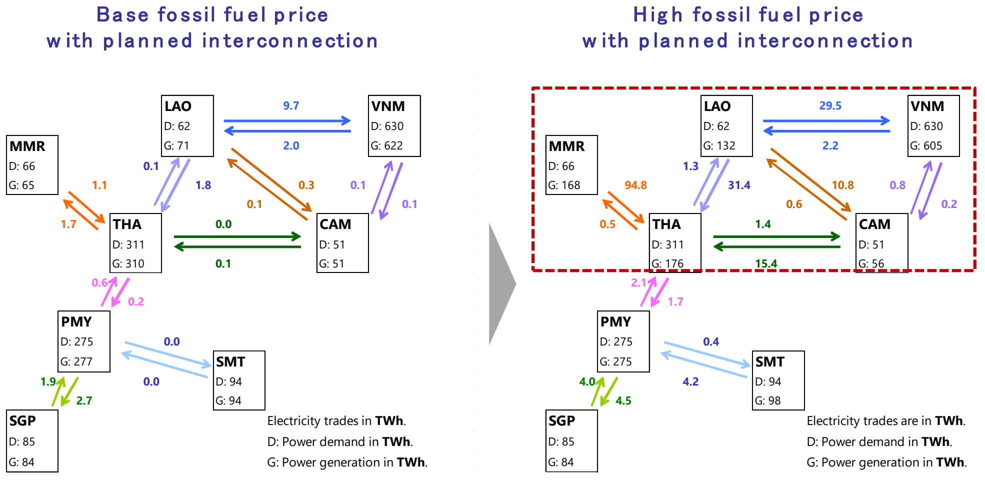
Figure 4.14. Power generation mix in the cases of the base prices and the high fuel prices



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

The figure indicates that in this case, whilst the utilisation of renewables will be expanded, the proportion of gas-fired thermal power will decrease due to its increased power generation cost. Figure 4.15 shows a comparison of the trade flows between both cases.

Figure 4.15. Trade flows in the cases of the base prices and high fuel prices



TWh = terawatt hour.
Source: Authors' analysis.

The figure shows that trade flows between some regions have increased in the high prices case. In particular, exports from Myanmar and the Lao PDR have risen remarkably.

Considering the results described above, the high fuel prices case suggests that the securing capacities of interconnections may surely become important from the perspective of economic optimisation in preparation for an increase in trade volume under future price hikes of coal and gas.

1.2.4. Externality case

In general, hazardous substances such as nitrogen oxides (NO_x), sulphur dioxide (SO_x), and particulate material (PM10), which may have adverse impacts on the human body, are generated when burning fossil fuels, such as coal and natural gas. External costs refer to the quantified impacts of such substances on human health. The externality case has been conducted to analyse how the power generation mix would change in the target regions if the external costs were included in the power generation cost.

Even though no uniform method has been established to quantify external costs, values that had been used in a preceding study on external costs for the Indonesian power sector have been referred to (Wijaya and Limmeechokchai, 2010). Table 4.3 shows the assumed external costs in coal- and gas-fired power plants. The costs have been converted to 2016 real prices. In addition, this case assumes that interconnection capacities are equal to planned expansion and that a carbon price is not introduced.

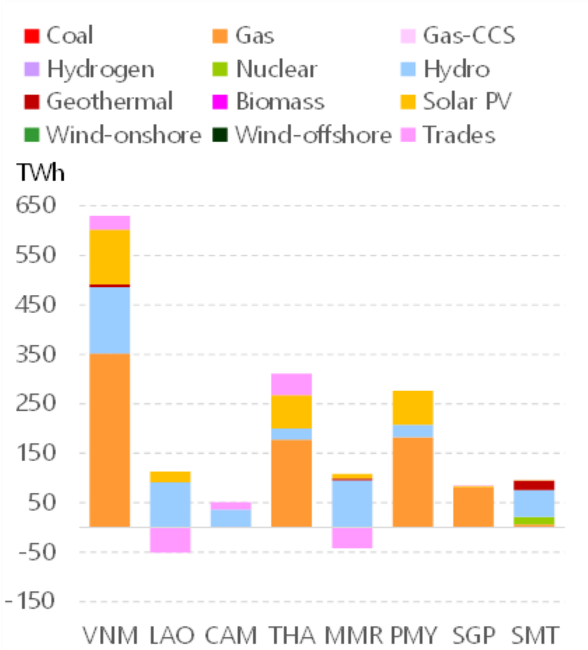
Table 4.3. Assumed external costs

Power plant	SO_x Damage (Cents/kWh)	NO_x Damage (Cents/kWh)	PM_{10} Damage (Cents/kWh)	Total Damage (Cents/kWh)
Coal-fired	6.45	4.67	4.55	15.67
Natural Gas CCGT	negligible	1.90	negligible	1.90

CCGT = combined cycle gas turbine, kWh = kilowatt hour.
Source: Wijaya and Limmeechokchai (2010).

Figure 4.16 shows the power generation mix for the externality case.

Figure 4.16. Power generation mix (externality case)



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

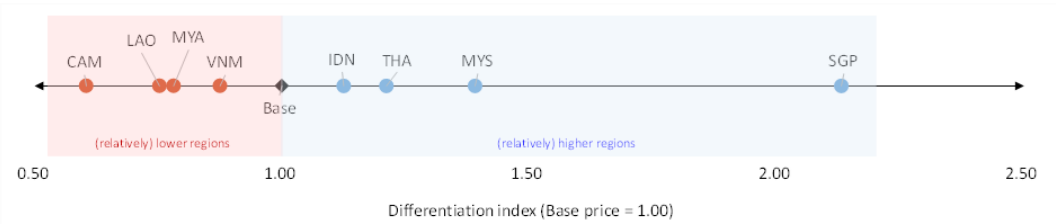
As the figure shows, even under an environment where a carbon price is not introduced, coal-fired power was almost out of the power generation mix due to the increased cost of coal-fired power generation.

1.2.5. Differentiated carbon prices case

In the normal cases where a carbon price is introduced, one price is assumed to be introduced to all target regions. However, there are differences in the levels of actual economic development from region to region, and the impact of carbon pricing on individual regional economies may differ even if the carbon price is the same. In this regard, a case with differentiated carbon prices has been introduced in order to capture the effects when decarbonisation policy measures are introduced at differentiated levels according to the degree of each region's economic development.

In this case, GDP per capita has been adopted as the benchmark for the degree of economic development. Assuming US\$50/tCO_2 as the base carbon price, higher carbon prices are adopted in regions with relatively higher economic development as of 2040, whilst lower carbon prices are adopted for those with relatively lower GDP per capita. Specifically, taking the natural log of the assumed GDP per capita of each region as of 2040 based on the ERIA Outlook, the assumed carbon prices were differentiated for each region by multiplying the base price by the 'differentiation index', i.e., the ratio of the natural log of GDP per capita of each region with respect to the median value of all regions (Figure 4.17).

Figure 4.17. Differentiation index

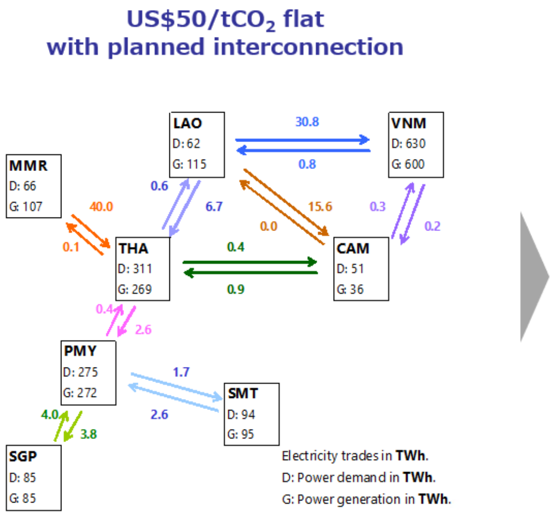


Source: Authors.

In addition, the interconnection capacity is assumed to be equal to the planned expansion in this case.

Figure 4.18 shows a comparison of the trade flows between the case with a uniform carbon price at US\$50/tCO_2 in all regions (the case in Figure 4.5) and the case with differentiated carbon pricing.

Figure 4.18. Trade flows in the cases of uniform and differentiated carbon prices

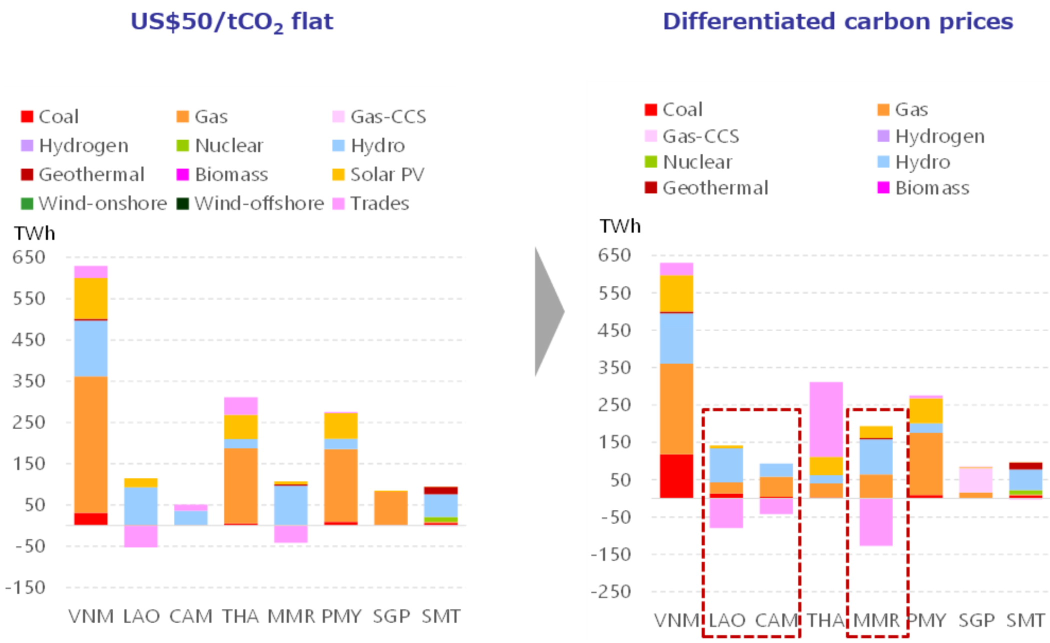


TWh = terawatt hour.
Source: Authors' analysis.

These results show that the exports from the Lao PDR and Cambodia, where relatively lower carbon pricing is adopted, to regions with relatively higher carbon prices would be greater in the case with differentiated carbon pricing.

Figure 4.19 shows a comparison of the power generation mix for both cases. It indicates a result in which Myanmar, the Lao PDR, and Cambodia mainly increase their respective quantities of gas-fired thermal power generation case in order to increase their exports.

Figure 4.19. Power generation mix for the cases with uniform and differentiated carbon prices



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

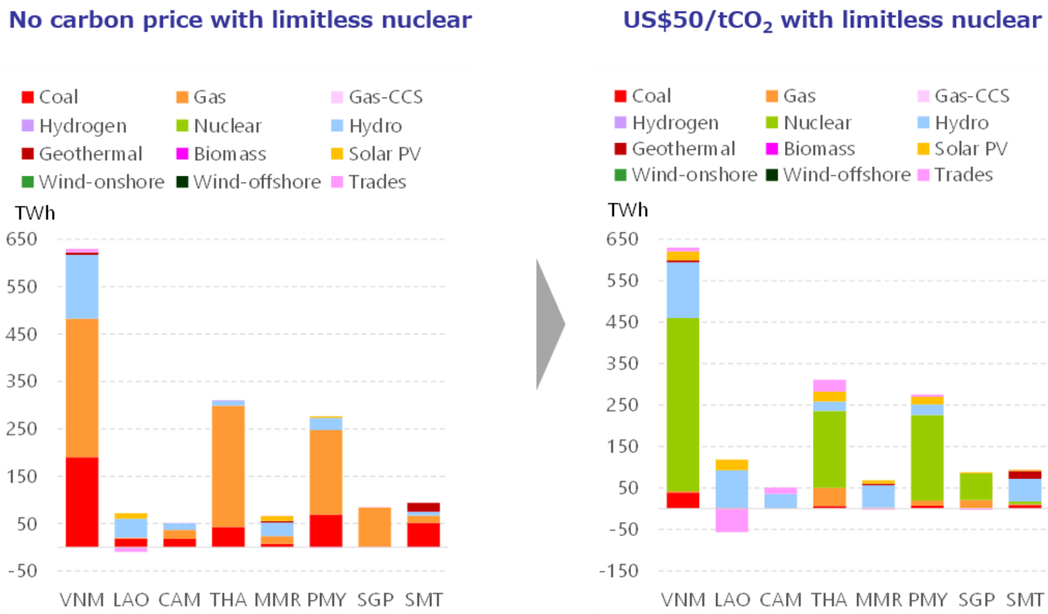
There are two points to consider suggested by the results described above. First, if the intensity of environmental policies differ by region, at least from the perspective of cost optimisation, securing the capacities of interconnection would become important for coping with some of the increase in the trade volume. Second, income redistribution would be enhanced within these regions in that more economically developed regions will import electricity from less economically developed regions and pay the price to them. At the same time, it should be noted that less economically developed regions increase non-CCS gas-fired power generation in order to increase their export amounts, resulting in an increase in CO_2 emissions.

1.2.6. Nuclear capacity limitless case

Nuclear power plants present social and technical problems in their construction and safe operation, even though their environmental load is low. In reality, such shortcomings have led to significant constraints for nuclear power plant construction, and based on the assumptions of this study, the utilisation of nuclear power generation will remain limited.

As such, an analysis has been conducted with an extreme assumption that unlimited nuclear capacities could be built, in order to make it easier to capture the impacts of the additional construction of nuclear power plants on the power generation mix, CO_2 emissions, and electricity costs in the target regions. The carbon price is assumed at US$0/$tCO_2$ and US$50/$tCO_2$. Figure 4-20 shows the power generation mix for these cases.

Figure 4-1. Power generation mix with carbon prices of US$0/tCO$_2$ and US$50/tCO$_2$

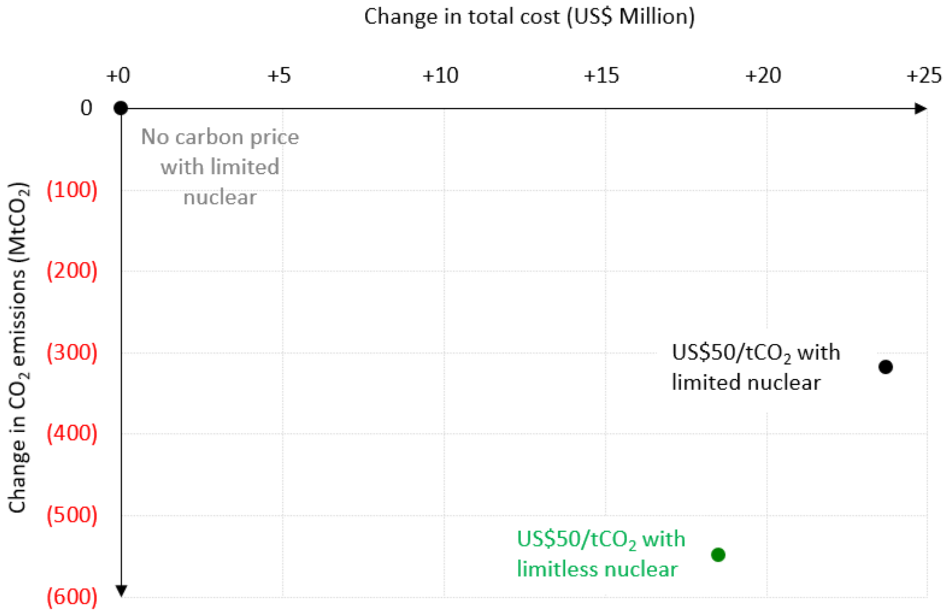


CCS = carbon capture and storage, PV = photovoltaic.
Source: Authors' analysis.

It is understood from the figure that nuclear power does not appear in the power generation mix with a carbon price of US$0/tCO$_2$ because of its higher LCOE than those of coal, gas, and hydro power generation. With a carbon price of US$50/tCO$_2$, however, the LCOE of nuclear power generation becomes lower than that of coal- and gas-fired power generation. Therefore, nuclear power is introduced to reach a share of 56% in the power mix. It should be also noted that the construction of nuclear power plants is not necessarily a feasible option in all regions. In particular, the result shows that the economic feasibility of nuclear power is reduced in regions that are rich in hydro and geothermal resources, such as the Lao PDR, Cambodia, Myanmar, and Sumatra.

The next point to consider is how the electricity cost and CO$_2$ emissions change in this case, compared with the case of limits on the additional construction of nuclear power plants as per the assumptions of this study (the case in Figure 4-5 above). Figure 4.21 plots how the electricity cost and CO$_2$ emissions vary in both cases with a carbon price of US$50/tCO$_2$, compared with the case with limited construction without a carbon price (see Section 1.2 of this chapter).

Figure 4.21. Change in total cost and CO_2 emissions



Source: Authors' analysis.

The figure indicates that both the electricity cost and CO_2 emissions are lower in the case without restrictions on the construction of additional nuclear power plants compared with the case with such a restriction.

There are two points to consider that are suggested by the results described above. First, the penetration of nuclear power could be enhanced in the target regions from the perspective of optimising economics as the carbon price increases, based on the assumptions in this study. Second, the electricity cost and CO_2 emissions could be reduced by incorporating much more nuclear power generation into the power generation mix in cases with strong decarbonising policy measures. As mentioned above, it is difficult in reality to build a very large number of nuclear power plants due to various intrinsic problems. In future energy and environmental policies, however, nuclear power may be a feasible option to reduce costs and CO_2 emissions.

1.3. Analysis of individual areas and realistic cases

This subsection proposes calculation results for individual regions with different diffusions of solar PV. Here, we develop several cases for existing and planned grid interconnection. The 'base' cases are those without a carbon price, as shown in Section 1.1 and 1.2 of this chapter. Starting from these cases, we raised the share of solar PV to 10%–40%, and calculated the energy mix and the total annual cost. Additionally, we showed the results of 'advanced' policy cases, which are equivalent to cases with a carbon price of US$50/$tCO_2$ and with lower limits of thermal power generation, shown in Section 2.1 of this chapter.

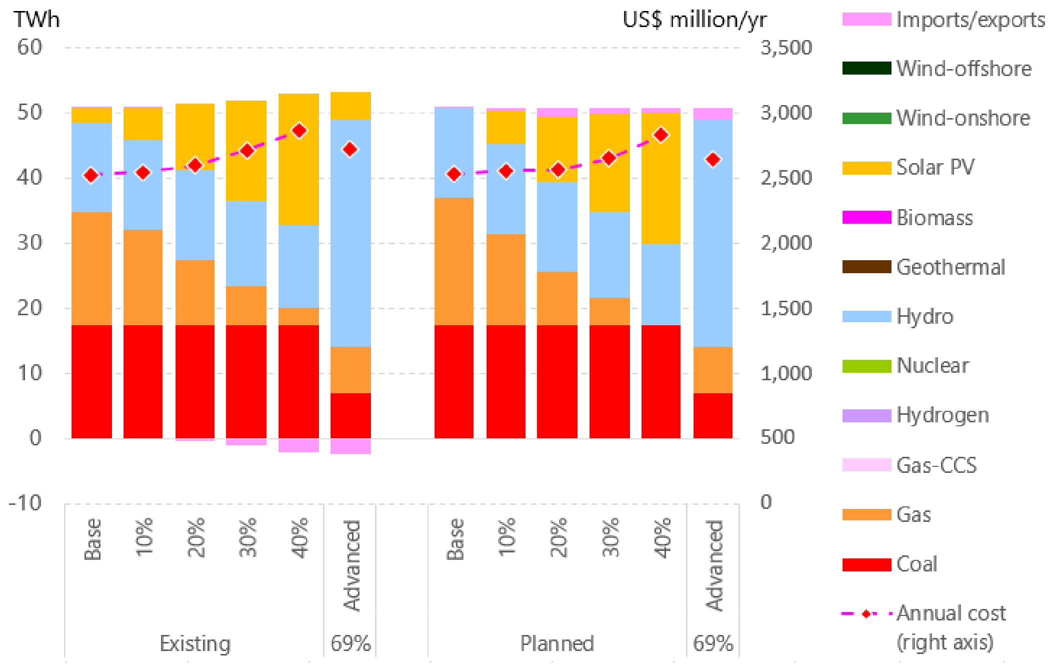
1.3.1. Cambodia

As Figure 4.22 shows, in Cambodia, natural gas- and coal-fired power accounts for about 70% of the total power generation in the base cases. With planned grid interconnection, annual net electricity imports increase almost two times from 54 GWh to 102 TWh. Because of the induced declines in electricity prices, the share of thermal power (coal and natural gas) increases slightly from 69% to 73%, and the optimal share of solar PV declines from 4% to lower than 1%.

With increasing shares of solar PV, the total annual cost increases. With existing interconnection capacities, it increases from US$2,522 million/year in the base case to US$2,863 million/year with a 40% solar PV share.

With advanced policies, the share of renewables expands, whilst the share of thermal power declines to 27%. With existing interconnection capacities, the share of solar PV rises to 9%, whilst that of hydro rises to 69%. With planned grid interconnection, however, the share of solar PV remains less than 1% because of increasing electricity imports from other regions.

Figure 4.22. Power generation mix and the total annual cost in Cambodia



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.
Source: Authors' analysis.

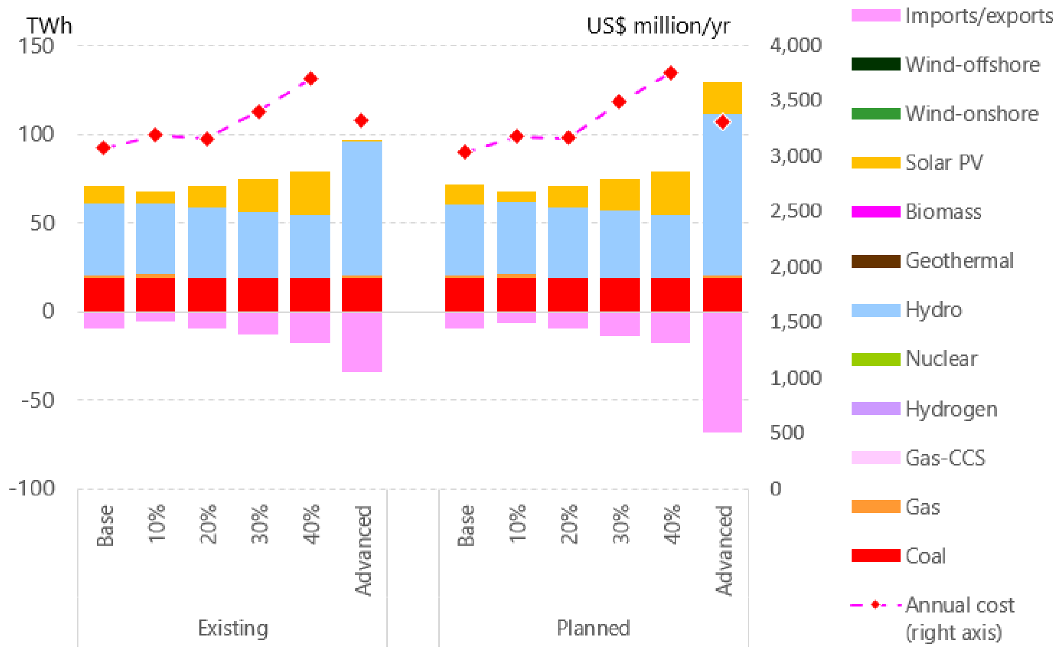
1.3.2. Lao PDR

As Figure 4-23 shows, in the Lao PDR, in the base case with existing grid interconnection, hydropower accounts for 65% of total power generation, whilst thermal power accounts for 34%. With planned grid interconnection, the share of solar PV increases slightly from 16% to 18%, with net electricity exports increasing from 9,165 GWh to 9,671 GWh.

As the optimal shares of solar PV in the base cases are relatively high at 16%–18%, the total annual cost is higher with a solar PV share of 10% (US$3,192 million/year), than with that of 20% (US$3,158 million/year). However, with an even higher solar PV share, the total cost soars: it reaches US$3,700 million/year with a 40% solar PV share with existing grids.

With advanced policies, the share of renewables expands from 81% to 123% with existing grids. As hydropower generation increases to be exported to other regions, the share of solar PV declines to almost zero. However, with planned grid interconnection, the shares of hydro and solar PV rise to 147% and 30%, respectively, and net annual exports amount to 68 TWh.

Figure 4.23. Power generation mix and the total annual cost in the Lao PDR



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.
Source: Authors' analysis.

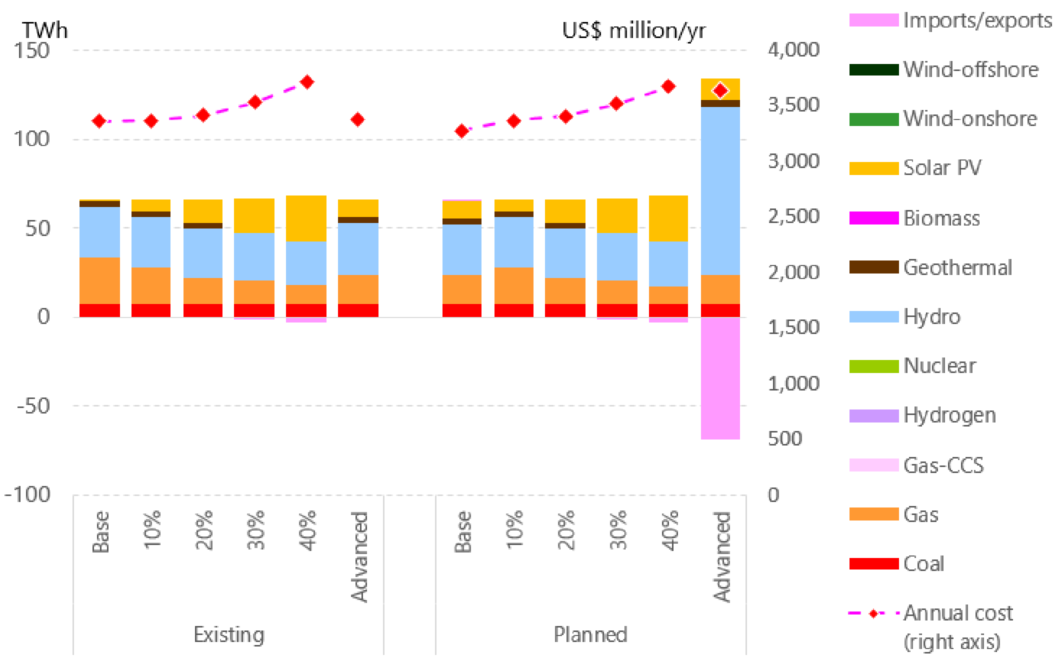
1.3.3. Myanmar

As Figure 4.24 shows, in Myanmar, with the existing grid interconnection, hydropower accounts for 42% of total power generation, whilst thermal, solar PV, and geothermal account for 51%, 1%, and 5%, respectively. However, as electricity prices are lower than in other regions, because of the assumed coal prices, the share of thermal power declines to 36% with the planned grid interconnection because of higher electricity prices.

With increasing shares of solar PV, the total annual cost increases from US$3,362 million/year in the base case to US$3,710 million/year with a 40% share of solar PV with existing grids.

With advanced policies and the existing grids, the share of thermal power declines to 36%, whilst that of solar PV and hydro rise to 15% and 44%, respectively. With the planned grid interconnection, the maximum hydropotential is utilised; the share of hydropower rises to 143%, and annual net exports expand to 69 TWh. However, we should note that this is the case only with affordable costs of grid interconnection lines, under the assumption that large hydro potential is exploited at reasonable costs.

Figure 4.24. Power generation mix and the total annual cost in Myanmar



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.
Source: Authors' analysis.

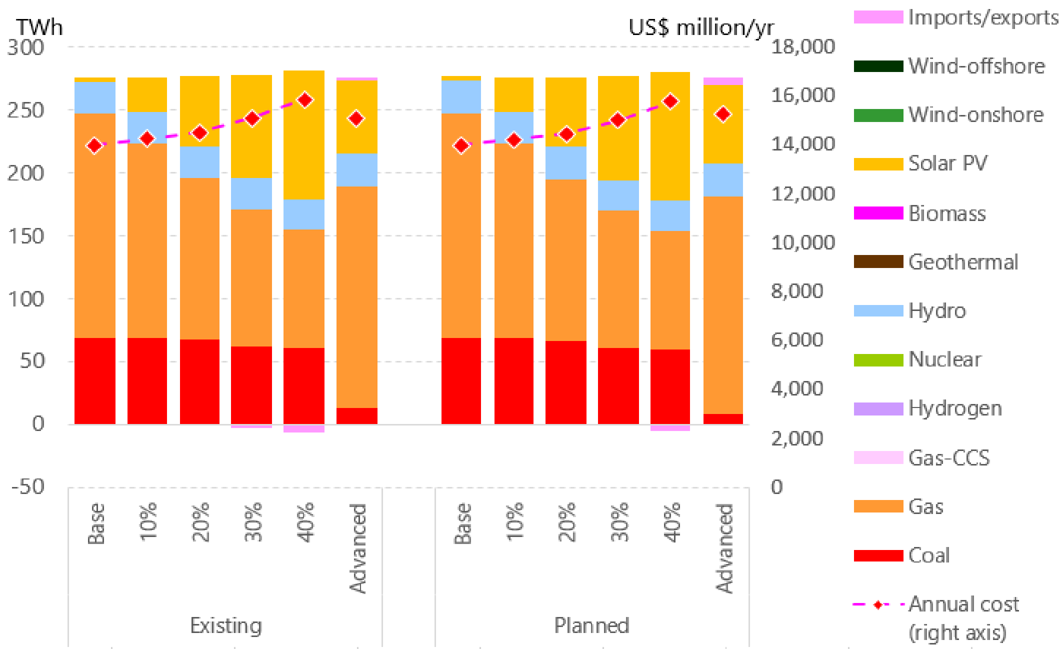
1.3.4. Peninsular Malaysia

As Figure 4.25 shows, in Peninsular Malaysia, in the base case, thermal power accounts for 90%, and the rest is mainly supplied with hydropower, with the share of solar PV at 1%. The results are hardly different for the existing and planned grid interconnection capacities.

The total annual cost increases with the increasing share of solar PV. It rises from US$30,585 million/year in the base case to US$36,323 million/year in the 40% case. With higher solar shares, net annual exports slightly increase and reach 5 TWh in the 40% case.

With advanced policies, the share of solar PV rises to 21% and 23% with the existing and planned grid interconnection capacities, respectively, and the share of coal power generation declines to 9% in both cases.

Figure 4.25. Power generation mix and the total annual cost in Peninsular Malaysia



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.

Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.

Source: Authors' analysis.

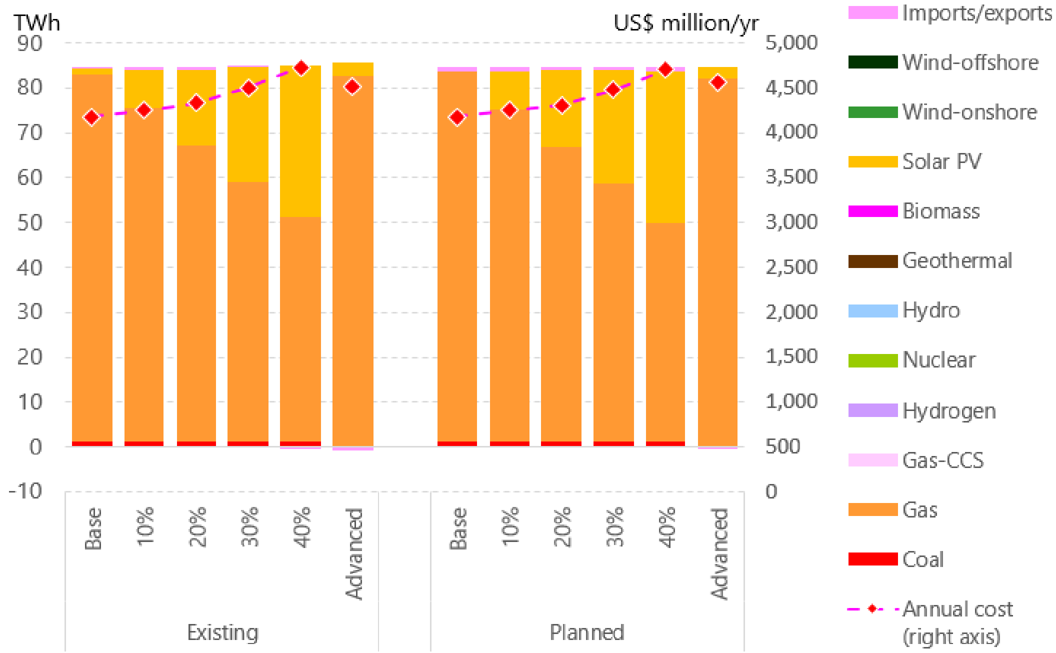
1.3.5. Singapore

As Figure 4.26 shows, in Singapore, natural gas-fired power generation accounts for 97%–98% in the base cases. With existing grids, the share of solar PV is 1%, which declines to nearly 0% with the planned grid interconnection, induced by net imports from Peninsular Malaysia. With increasing shares of solar PV, the total annual cost increases from

US$4,175 million in the base case to US$4,732 million in the 40% solar case. Net annual exports also rise to 400 GWh.

With advanced policies, the share of coal declines from 1% in the base case to 0%, and the share of solar PV rises to 3%, both with the existing and planned grids. Although net exports in the advanced policies case with existing grids expand to 928 GWh, they are much smaller, at 108 GWh, with the planned grid interconnection because the neighbouring region, Peninsular Malaysia, is supplied more with imports from Thailand.

Figure 4.26. Power generation mix and the total annual cost in Singapore



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.

Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.

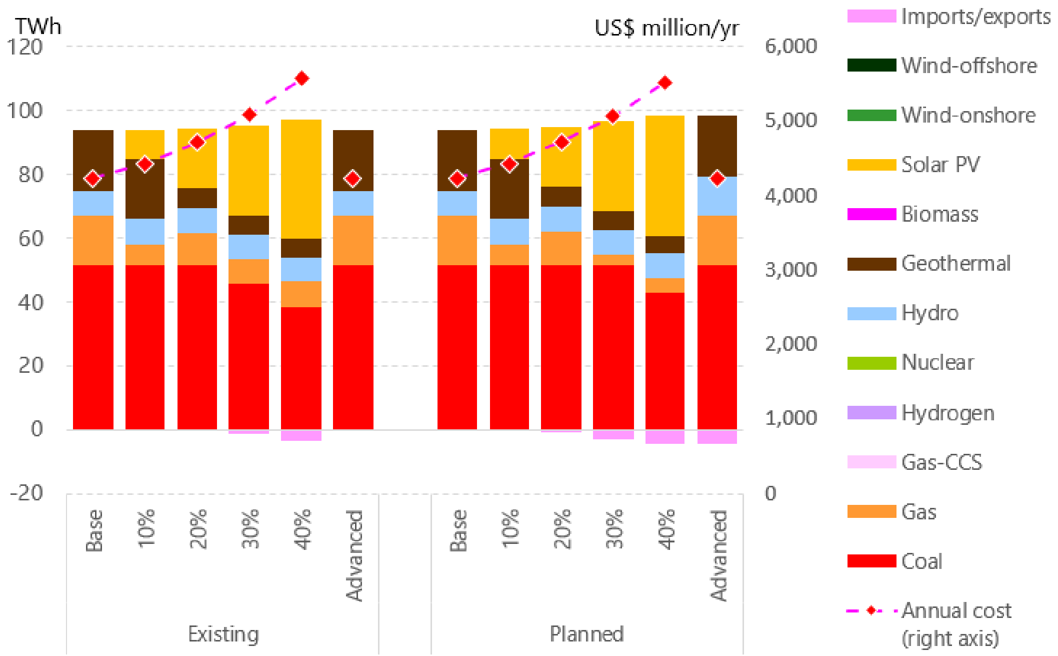
Source: Authors' analysis.

1.3.6. Indonesia (Sumatra)

As Figure 4.27 shows, in Sumatra, in the base cases, thermal power generation accounts for 71% of total power generation, whilst geothermal and hydro account for 20% and 9%, respectively. With an increasing share of solar PV, the shares of thermal and geothermal decline significantly. In the 40% solar PV case with the existing grids, the thermal share declines to 50%, and the geothermal share declines to only 6%. With the planned grid interconnection, the share of thermal power rises to 51%, with a larger share of coal at 46%, and larger net exports of 4,392 GWh in the 40% solar PV case.

With advanced policies, the power generation mix does not change much with the existing grids because a large amount of electricity is already supplied by renewable energies (hydro and geothermal) in the base case. With the planned grid interconnection, the share of hydropower rises to 13%, with large net annual exports of 4,483 GWh.

Figure 4.27. Power generation mix and the total annual cost in Sumatra



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.

Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.

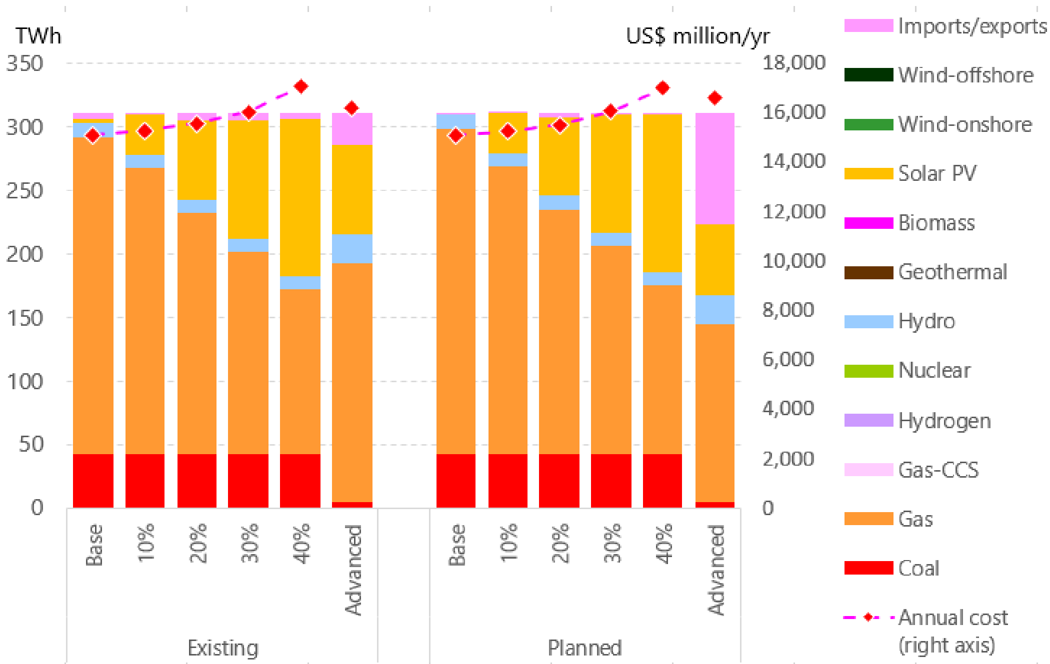
Source: Authors' analysis.

1.3.7. Thailand

As Figure 4.28 shows, in Thailand, natural gas and coal power generation account for 80% and 14%, respectively, in the base case with the existing grids; hydro and solar PV account for only 3% and 1%, respectively. The picture does not change significantly with the planned grid interconnection. The total annual cost increases with a rising share of solar PV, from US$15,111 million/year in the base case to US$17,063 million/year in the 40% solar PV case.

With advanced policies, the share of solar PV remarkably expands to 23% with the grid interconnection, associated with net annual imports of 25 TWh. In this case, the share of thermal power declines to 62%. With the planned grid interconnection, net imports reach 88 TWh, with smaller shares of solar PV and thermal power at 18% and 47%, respectively.

Figure 4.28. Power generation mix and the total annual cost in Thailand



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.

Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.

Source: Authors' analysis.

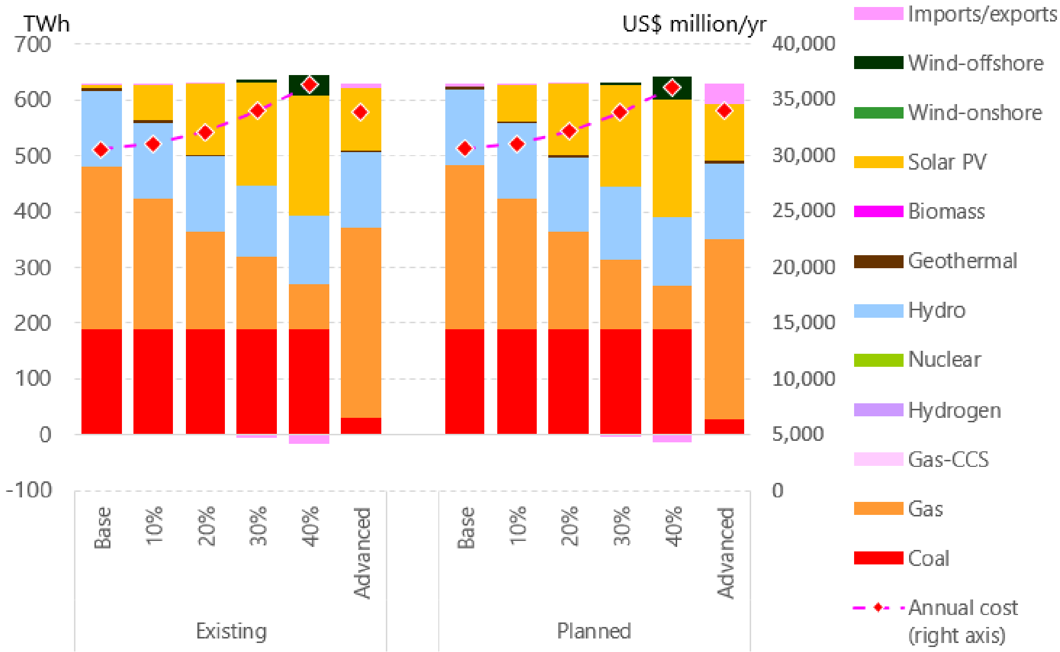
1.3.8. Viet Nam

As Figure 4.29 shows, in Viet Nam, thermal power and hydro account for 76% and 21%, respectively, in the base case with the existing grids. This energy mix does not change much with the planned grid interconnection, with the thermal share only slightly increasing to 77%. The share of solar PV is 1% and 0% with the existing and planned grid interconnection, respectively.

With the existing grid interconnection, the total annual cost increases from US$30,585 million/year in the base case to US$36,323 million/year in the 40% solar PV case. The results imply that offshore wind power will be introduced with high shares of solar PV because the two technologies are complementary, generating electricity at different times.

With advanced policies, the thermal share declines to 59%, whilst the solar PV share increases to 18% if we assume only the existing grids. Net annual imports are relatively small at 8 TWh in this case. With the planned grid interconnection, net imports expand to 39 TWh, with lower shares of thermal power and solar PV at 56% and 16%, respectively.

Figure 4.29. Power generation mix and the total annual cost in Viet Nam



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.

Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.

Source: Authors' analysis.

Chapter 5

Conclusions and Policy Recommendations

1. Conclusions

(1) High shares of renewable energies can only be achieved with strong policy measures against climate change.

- ✓ Variable renewable energies (VRE), i.e., solar photovoltaic (PV) and wind, would be diffused in the targeted regions if people accept strong policy measures to combat climate change. The reasons why we need strong measures are: (i) solar PV has intermittency, (ii) the capacity credit of solar PV is lower than that of thermal power, (iii) wind power is expected to be more costly than fossil fuels and other renewables, and (iv) fossil fuel prices are not projected to rise considerably in the long term because of anticipated ambitious climate actions worldwide. Even if solar PV costs fall further to the 2050 levels, its diffusion would still require strong policy measures.
- ✓ Hydro and geothermal power are expected to penetrate fully with strong policy measures and grid interconnection expansion. However, it should be noted that hydropower may be affected by seasonal fluctuations that have not been taken into account in this study, and geothermal power would be exploited only in limited countries, such as Indonesia and Viet Nam.
- ✓ Given these limitations and the challenges associated with the expansion of renewables, the maximum exploitation of hydro potentials by grid interconnection expansion is one of the most efficient measures for achieving a high share of renewable energy.
- ✓ If strong policy measures, such as the implementation of feed-in tariff systems, are realised in the targeted nations, VRE capacities would expand more rapidly. In this case, solar PV will be diffused rapidly in such countries/regions as Thailand, Peninsular Malaysia, and Viet Nam, whilst wind power will emerge in Viet Nam. This is partly because these regions are not endowed with large hydropower potential to meet demand, so they have to rely on solar PV and wind power instead.
- ✓ At the same time, if the governments introduce strong policy measures against climate change, both coal- and gas-fired power may be less cost-competitive in the long term, and their outputs would decrease in all the regions, whilst Singapore would utilise gas-fired power with carbon capture and storage (CCS).

(2) Further investment in grid interconnection can also contribute greatly to CO_2 emissions reduction, cost minimisation, and energy security.

- ✓ Grid interconnection enhancement would help to maximise the utilisation of the carbon-free and less expensive hydropower potential, especially in Lao PDR and Myanmar; with larger deployment of hydro facilities, investment in further expansion of grid interconnection would lead to lower CO_2 emissions and total costs at the same time.
- ✓ If the share of VRE exceeds 15%, the required battery capacities would increase rapidly, resulting in considerable cost hikes. This constitutes a major challenge related to high VRE penetration. With larger use of grid interconnection and hydropower, however, the required capacities of solar PV and batteries become smaller.
- ✓ The net benefits of interconnection would increase in line with strong policy measures. They would also rise as the grid capacities expand beyond the planned levels.
- ✓ Interconnection expansion would contribute to achieving higher shares of renewables, reducing the dependence on thermal power with imports of liquefied natural gas and other fuels. This would translate to the enhancement of the energy security of the region.

(3) The optimal energy mix may change with explicit consideration of higher fossil fuel prices, external costs, and economic development levels.

- ✓ Higher fossil fuel prices and the internalisation of external costs on fossil fuels would have similar effects to higher carbon pricing. These would lead to higher renewable ratios because of the higher relative competitiveness of renewables. Internalising health-related external costs on fossil fuels may drastically reduce the optimal thermal power shares.
- ✓ With different intensities of decarbonisation policies, dependent on the degree of economic development, grid interconnection may contribute to the redistribution of income, although with possible increases in CO_2 emissions.

(4) Nuclear can be a viable option as a proven low-carbon technology.

- ✓ In the hypothetical case without nuclear capacity limits, nuclear power would be introduced massively in Singapore, Peninsular Malaysia, Thailand, and Viet Nam if the governments introduce strong policy measures against climate change. However, in the countries/regions endowed with large renewable resources, the introduction of nuclear power may not be a priority.
- ✓ Nuclear can contribute to the further reduction of CO_2 emissions and total costs. Pursuing the cost-optimal mix of low-carbon technologies would involve the promotion of nuclear power. However, intrinsic problems related to accident risks and waste management have to be addressed properly.

1.4. Policy recommendations

- Given the projected low fuel prices, the governments would need strong policy measures, such as feed-in tariff systems, to promote renewable energies, including VRE, even though the LCOE of these technologies will decline significantly in the long term. Without such measures, the high dependence on fossil-fuel fired thermal power generation may not be changed by and large.
- The governments should promote power grid interconnection expansion, at least to the planned scale, as it would help realise CO_2 emissions reductions, cost minimisation, and energy security at the same time. The governments should consider further interconnection, since it would lead to larger net benefits with stronger policy measures towards climate change. In doing so, it should be examined carefully which specific lines are the most beneficial.
- Not only strong policy measures but also other factors including the costs of VRE, international energy prices, externalities, and utilisation of nuclear can exert large impacts on the optimal diffusion of renewable energies. For this reason, the governments should continue revising future VRE diffusion targets, always taking into account the latest situation.
- As achieving very high shares of renewable energies may induce significant cost increases, the governments should also consider other decarbonising options, such as the use of fossil fuels with CCS, hydrogen, ammonia, and nuclear power. Nonetheless, we should seek to maximise VRE diffusion by implementing such measures as introducing batteries and other flexibility technologies.
- Likewise, 100% decarbonisation of the power sector may be very challenging with considerable cost increases and might be viewed as giving too much priority to CO_2 emissions reduction. However, we should also note the inevitable need to decarboni$_z$e energy systems, given the growing global concerns about climate change. The governments should seek for a well-balanced policy mix, considering not only economic effectiveness but also environmental issues and energy security at the same time. With the existing grid interconnection, the total annual cost increases from US$30,585 million/year in the base case to US$36,323 million/year in the 40% solar PV case. The results imply that offshore wind power will be introduced with high shares of solar PV because the two technologies are complementary, generating electricity at different times.

References

ASEAN Centre for Energy (ACE) (2015), *(2016–2025) ASEAN Plan of Action for Energy Cooperation (APAEC)*. ACE. https://aseanenergy.org/2016-2025-asean-plan-of-action-for-energy-cooperation-apaec/

Asian Development Bank (ADB) (2018), *Cambodia: Energy Sector Assessment, Strategy, and Road Map*. Manila: ADB.

ADB (2019), *Lao People's Democratic Republic: Energy Sector Assessment, Strategy, and Road Map*. Manila: ADB.

Aye, K.T. (2018), *The Role of Hydropower in Myanmar*. Nay Pyi Taw: Planning and Statistic Branch, Minister's Office, Ministry of Electricity and Energy. https://www.moee.gov.mm/mm/userfile/role_of_hydropowe_Paper_(11-1-18)2.pdf

Dewan Energi Nasional (DEN) (2017), *Technology Data for the Indonesian Power Sector*. South Jakarta: DEN. https://ens.dk/sites/ens.dk/files/Globalcooperation/Publications_reports_papers/technology_data_indonesian_power_ector_dec2017-2.pdf

Economic Research Institute for ASEAN and East Asia (ERIA) (2020), *Energy Outlook and Energy Saving Potential in East Asia 2020*. Jakarta: ERIA. https://www.eria.org/publications/energy-outlook-and-energy-saving-potential-in-east-asia-2020/

EGAT (2019), *2018 Annual Report*. Nonthaburi: EGAT. https://www.egat.co.th/en/images/annual-report/2018/egat-annual-eng-2018.pdf

Energy Commission (2021), Malaysia Energy Statistics Handbook 2020. Putrajaya: Energy Commission. https://www.st.gov.my/ms/contents/files/download/116/Malaysia_Energy_Statistics_Handbook_2020.pdf

Eurek, K., P. Sullivan, M. Gleason, D. Hettinger, D. Heimiller, and A. Lopez (2017). 'An Improved Global Wind Resource Estimate for Integrated Assessment Models', *Energy Economics*, 64, pp.552–67.

Global CCS Institute (2016), *Global Storage Portfolio: A Global Assessment of the Geological CO_2 Storage Resource Potential*. Global CCS Institute. https://www.globalccsinstitute.com/resources/publications-reports-research/global-storage-portfolio-a-global-assessment-of-the-geological-co2-storage-resource-potential/

Hoogwijk, M.M. (2004), 'On the Global and Regional Potential of Renewable Energy Sources', dissertation, Utrecht University Repository.

Huber, M., A. Roger, and R. Hamacher (2015), 'Optimizing Long-term Investments for a Sustainable Development of the ASEAN Power System', *Energy*, 88, pp.180–93.

Institute of Energy Economics, Japan (IEEJ) (2014), *IEEJ Outlook 2013*. IEEJ. https://eneken.ieej.or.jp/data/5331.pdf

Institute of Energy Economics, Japan (IEEJ) (2020), *IEEJ Outlook 2021*. IEEJ. https://eneken.ieej.or.jp/en/whatsnew/436.html

International Energy Agency (IEA) (2019), *Establishing Multilateral Power Trade in ASEAN*. Paris: IEA. https://www.iea.org/reports/establishing-multilateral-power-trade-in-asean

IEA (2020a), *World Energy Balances 2020*. Paris: IEA.

IEA (2020b), *World Energy Outlook 2020*. Paris: IEA.

International Energy Agency (IEA) and the Nuclear Energy Agency (NEA) (2020), *Projected Costs of Generating Electricity*. IEA and NEA.

International Finance Corporation (IFC) (2018), *Strategic Environmental Assessment of the Myanmar Hydropower*. Yangon: World Bank. https://openknowledge.worldbank.org/handle/10986/31256

International Renewable Energy Agency (IRENA) (2017), *Planning for the Renewable Future: Long-term Modelling and Tools to Expand Variable Renewable Power in Emerging Economies*. IRENA. https://www.irena.org/publications/2017/Jan/Planning-for-the-renewable-future-Long-term-modelling-and-tools-to-expand-variable-renewable-power

Komiyama, R. and Y. Fujii (2017), 'Assessment of Post-Fukushima Renewable Energy Policy in Japan's Nation-wide Power Grid', *Energy Policy*, 101, pp.594–611.

Kutani, I. and Y. Li (2014), *Investing in Power Grid Interconnection in East Asia*. Jakarta: ERIA https://www.eria.org/publications/investing-in-power-grid-interconnection-in-east-asia/

Matsuo, Y., S. Endo, Y. Nagatomi, Y. Shibata, R. Komiyama, and Y. Fujii (2020), 'Investigating the Economics of the Power Sector under High Penetration of Variable Renewable Energies', *Applied Energy*, 267, 113956.

Ministry of Energy and Mineral Resources (MEMR) (2019), *National General Electricity Plan (RENCANA UMUM KETENAGALISTRIKAN NASIONAL) 2019–2038*. Jakarta: MEMR. https://gatrik.esdm.go.id/assets/uploads/download_index/files/0e997-rukn-2019-2038.pdf

Pfenninger, S. and I. Staffell (2016), 'Long-term Patterns of European PV Output Using 30 Years of Validated Hourly Reanalysis and Satellite Data', *Energy*, 114, pp.1251–65.

PLN (2019), *PLN Statistics 2018*. Jakarta: PLN. https://web.pln.co.id/statics/uploads/2019/07/STATISTICS-English-26.7.19.pdf

PwC (2018), *Power in Indonesia - Investment and Taxation Guide*. PwC.

Staffell, I. and S. Pfenninger (2016). 'Using Bias-corrected Reanalysis to Simulate Current and Future Wind Power Output. *Energy*, 114, pp.1224–39.

Tenaga Nasional (2019), *Annual Report for 2018*. Tenaga Nasional. https://www.tnb.com.my/assets/annual_report/TNB_Annual_Report_2018.pdf

Vietnam Electricity (2019), *Overview of Hydropower in Vietnam*. https://en.evn.com.vn/d6/news/Overview-of-hydropower-in-Vietnam-66-163-1514.aspx

Wijaya, M.E. and B. Limmeechokchai (2010), 'The Hidden Costs of Fossil Power Generation in Indonesia: A Reduction Approach through Low Carbon Society', *Songklanakarin Journal of Science and Technology*, 32(1), pp.81–89.

Appendix

Model Structure and Assumptions

Nomenclature for the Appendix

Appendix A

$Ap_{i,d}$: Available capacity, GW

$Cha_{j,d,t}$: Charge to battery, GW

$Dis_{j,d,t}$: Discharge from battery, GW

K_i : Power generating capacity, GW

$KS1_j$: Storage capacity in terms of GW

$KS2_j$: Storage capacity in terms of GWh

$Mk_{m,i}$: Unavailable capacity due maintenance, GW

$SS_{j,d,t}$: Electricity storage, GWh

TC : Total annual cost, 2014 JPY/year

$Tn_{b,d,t}$: Electricity flows (reverse), GW

$Tp_{b,d,t}$: Electricity flows, GW

$X_{H\,i,d,t}$: Power output by hydrogen from tank , GW, $i \in \{0, .. ,8\}$

$X_{i,d,t}$: Power output, GW

where

d: day of the year (1-365), *t*: time of the day (1-24), *n*: node (region) number, *b*: branch (transmission line) number, *i*: power generation plant, *j*: storage facility, and *m*: outage pattern (1–4).

This appendix describes the structure of the Optimal Power Generation Mix (OPGM) model that has been used for this study. The major assumptions are presented in Chapter 2; for other assumptions, we followed Matsuo et al. (2020). Note that the model does not take into account the anticipated future changes in the shape of electric loads, nor the effects of energy-saving technologies or demand side management. Explicit consideration of these effects should be viewed as an important part of future works.

A.1 Objective function

We set the annual total system cost expressed by equation (A.1), which is the sum of the fixed and variable costs of all the related technologies, as the objective function. The model simulates electricity supply and demand for 1 year, annualising all the costs, including initial investments, using a real discount rate of 8% and a technology-specific lifetime.

$$min. TC = \sum_{i}\left(g_i pf_i K_i + \sum_{d,t} pv_i X_{i,d,t}\right) + \sum_{j} CS_j \tag{A.1}$$

$$CS_j = gs1_j pfs1_j KS1_j + gs2_j pfs2_j KS2_j + pfs3_j \frac{TCha_j}{cycle_j} \tag{A.2}$$

$$TCha_j = \sum_{d,t} Cha_{j,d,t} \tag{A.3}$$

where g_i is the annual fixed cost rate, pf_i is the unit initial investment cost, pv_i is the unit variable cost (i.e. fuel cost), $gs1_j$ is the annual fixed cost rate for GW capacity, $gs2_j$ is the annual fixed cost rate for GWh capacity, $pfs1_j$ is the unit battery construction cost in terms of GW, $pfs2_j$ is the unit battery construction cost in terms of GWh, $pfs3_j$ is the expendable costs for batteries, and $cycle_j$ is the maximum charge/discharge number for a storage facility.

A.2 Supply and demand balance constraints

Electricity demand at node *n*, day *d*, and time *t* equals the net total supply from electricity generation, storage systems, and transmission lines, with transmission losses subtracted. For each *n*, *d*, and *t*,

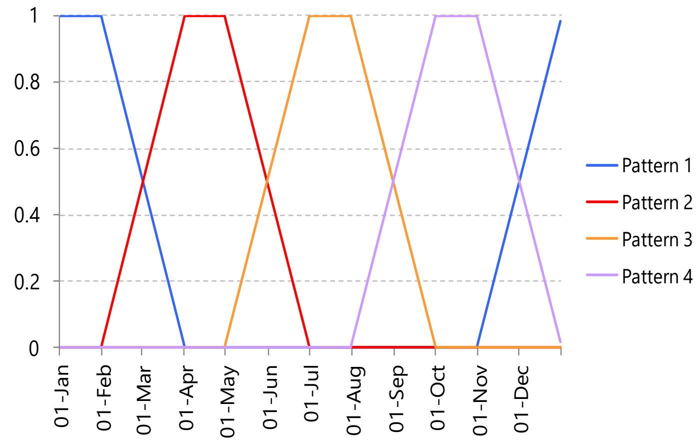
$$\sum_{i \in I_n} X_{i,d,t} + \sum_{i \in I_{H_n}} X_{H\,i,d,t} + \sum_{j \in J'_n} Dis_{j,d,t} - \sum_{j \in J_n} Cha_{j,d,t} + \sum_{b} cc_{n,b}\left(Tp_{b,d,t} - Tn_{b,d,t}\right) - loss_{n,d,t} = load_{n,d,t} \tag{A.4}$$

where I_n is the set of power generating facilities at node *n*, I_{Hn} is the set of hydrogen-fired power generating facilities at node *n*, J_n is the set of storage facilities at node *n*, J'_n is the set of storage facilities at node *n* (other than hydrogen tank), $cc_{n,b}$ is the matrix connecting node *n* and branch *b*, $loss_{n,d,t}$ is the transmission losses, and $load_{n,d,t}$ is the electricity demand plus distribution losses.

A.3 Available capacity constraints

The available capacity $A_{pi,d}$ is calculated via the following equations, subtracting the capacity under maintenance $M_{km,i}$ from the total capacity K_i. The model assumes four types of maintenance schedules, as shown in Figure A.1.

Figure A.1 Assumed rates of plant shutdown



Source: Authors' analysis.

For each *i*,

$$\sum_m urs_m Mk_{m,i} = (1 - upa_i)K_i \tag{A.5}$$

$$urs_m = \frac{1}{365}\sum_d ur_{m,d} \tag{A.6}$$

where $ur_{m,d}$ is the outage ratio due to maintenance, and upa_i is the average annual load factor.

For each *i* and *d*,

$$\sum_m ur_{m,d} Mk_{m,i} \geq (1 - upp_i)K_i \tag{A.7}$$

$$Ap_{i,d} + \sum_m ur_{m,d} Mk_{m,i} = K_i \tag{A.8}$$

where upp_i is maximum daily load factor.

For each d and i representing hydro and geothermal,

$$X_{i,d,t} \leq u_{i,d,t} K_i \tag{A.9}$$

where u_i is the availability factor of hydro and geothermal power plants.
For each d and i representing other technologies,

$$X_{i,d,t} \leq Ap_{i,d} \tag{A.10}$$

For each j, d, and t,

$$Cha_{j,d,t} + Dis_{j,d,t} \leq us1_{j,d} KS1_j \tag{A.11}$$

$$SS_{j,d,t} \leq us2_{j,d} KS2_j \tag{A.12}$$

where $us1_{j,d}$ is the GW availability factor of storage facilities, and $us2_{j,d}$ is the GWh availability factor of storage facilities.

A.4 Capacity constraints

The installed capacity of each technology is subject to upper and lower bounds. For each i,

$$K_{low,i} \leq K_i \leq K_{up,i} \tag{A.13}$$

For each j,

$$KS1_{low,j} \leq KS1_j \leq KS1_{up,j} \tag{A.14}$$

$$KS2_{low,j} \leq KS2_j \leq KS2_{up,j} \tag{A.15}$$

where $K_{low,i}$, $KS1_{low,j}$, $KS2_{low,j}$ are the lower bounds for capacities and $K_{up,i}$, $KS1_{up,j}$, $KS2_{up,j}$ are the upper bounds for capacities.

A.5 Reserve capacity constraints

A certain level of reserve margin must be secured to maintain supply reliability with either thermal power, nuclear power, dispatchable renewables, or storage systems. For each *n* and *d*,

$$\sum_{i \in I_n} Ap_{i,d} + \sum_{j \in J_n} us1_{j,d} KS1_j \leq (1+\delta)\, max\big(load_{n,d,t}\big) \tag{A.16}$$

where δ: reserve margin assumed at 8%.

A.6 Load following constraints

Each type of power plant has its own capability of ramping up and down due to its technological characteristics. Thermal power with high ramping rates is preferred to nuclear with low ramping rates. For each *i*, *d*, and *t*,

$$X_{i,d,t+1} \leq X_{i,d,t+1} + inc_i Ap_{i,d} \tag{A.17}$$

$$X_{i,d,t+1} \geq X_{i,d,t+1} - dec_i Ap_{i,d} \tag{A.18}$$

where inc_i is the maximum increase rate per hour, and dec_i is the maximum increase rate per hour.

A.7 Charge and discharge balance constraints

The charge and discharge balances are expressed as follows, with different efficiencies and different self-discharge rates for different types of batteries.

$$SS_{j,d,t+1} = \big(1 - sd_j\big) SS_{j,d,t} + \sqrt{eff_j}\, Cha_{j,d,t} - \frac{1}{\sqrt{eff_j}} Dis_{j,d,t} \tag{A.19}$$

$$SS_{j,d,t} \leq m_j u_{j,d} SK1_j \tag{A.20}$$

where sd_j is the self-discharge rate, eff_j is the storage efficiency, and m is the energy storage capacity per generation capacity.
The C-rates measure how fast the batteries are charged and discharged.

$$Cha_{j,d,t} \leq crate_j SK2_j \tag{A.21}$$

$$Dis_{j,d,t} \leq crate_j SK2_j \tag{A.22}$$

where $crate_j$ is the C-rate of the batteries.

A.8 Hydrogen balance constraints

Hydrogen tanks are assumed as being one of the storage systems in the model. The 'discharged' hydrogen is used for power generation.
For each *n*, *d*, and *t*,

$$\sum_{i\in J_{H_n}} Dis_{j,d,t} = \frac{1}{eff_H}\sum_{i\in I_{H_n}} X_{H_i,d,t} \tag{A.23}$$

where J_{Hn} is the set of hydrogen tanks at node *n*, and eff_H is the thermal efficiency of hydrogen-fired power generation.