Chapter 2

Major Assumptions for the Study

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Chapter 2

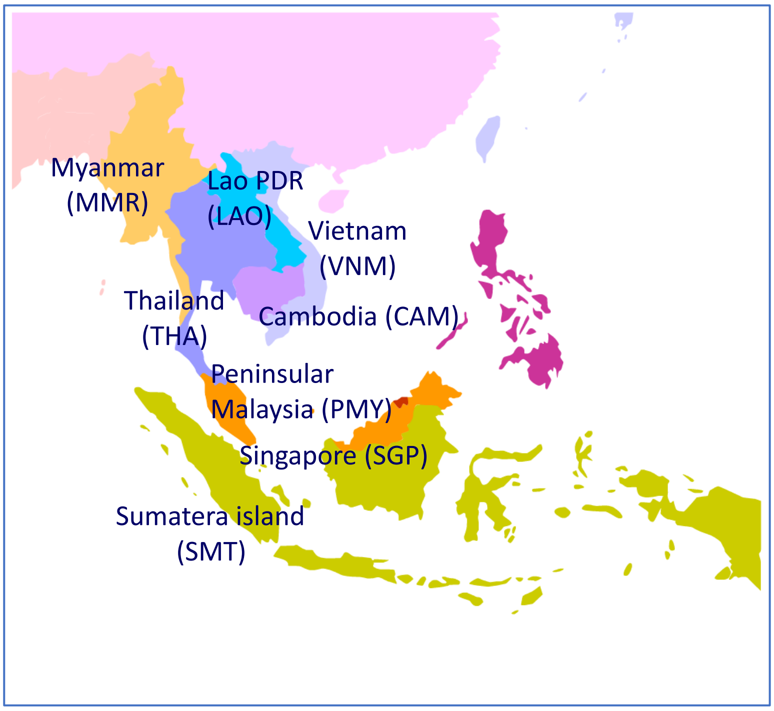
Major Assumptions for the Study

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



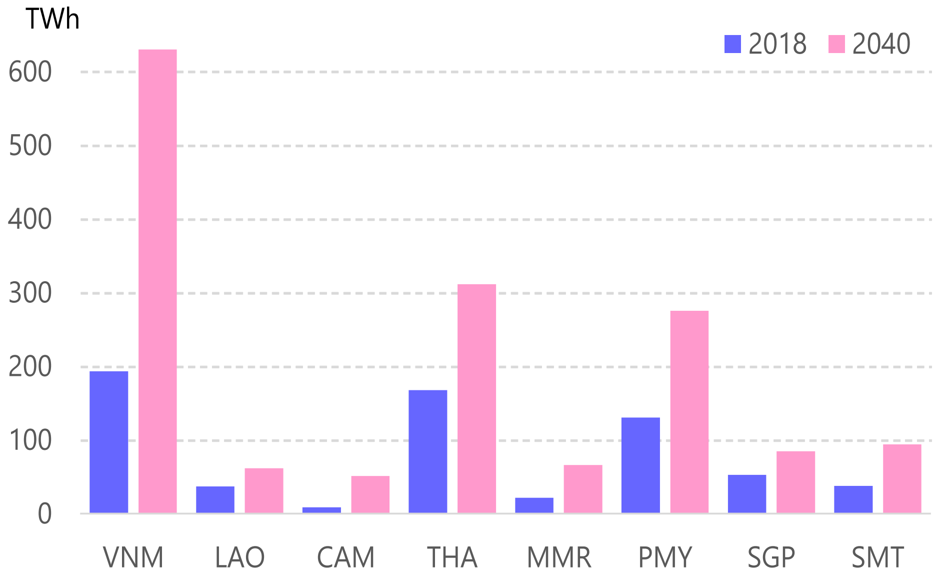
Source: IEEJ.

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.

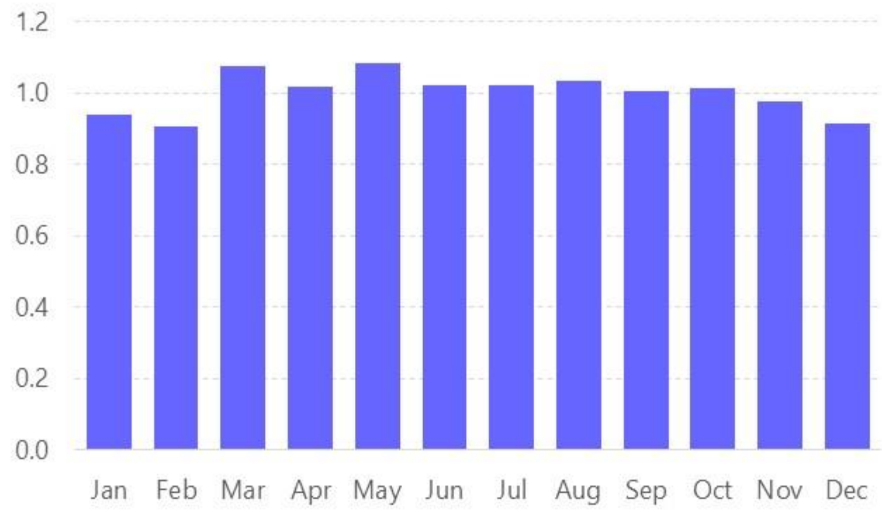
Figure 2.2. Power generation for 2018 and 2040



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

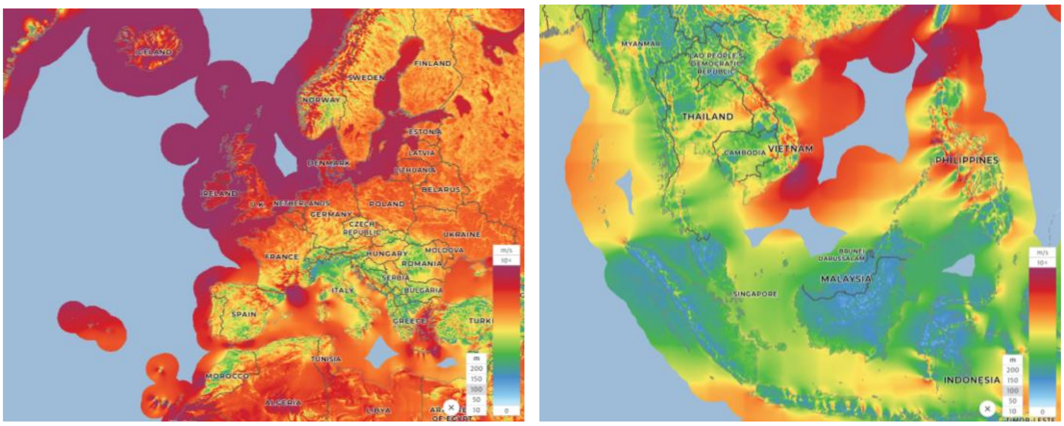
In general, the introduction potential of renewable energy is greatly affected by the natural conditions of the area. In this study, renewable potentials are assumed as follows based on various information. In cases where only potential data at the whole-country level were obtained for Indonesia and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

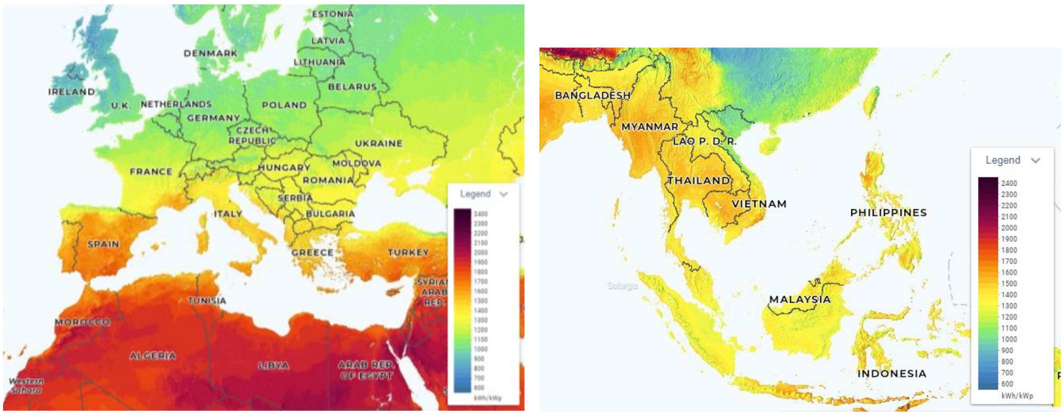


Europe **ASEAN**

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



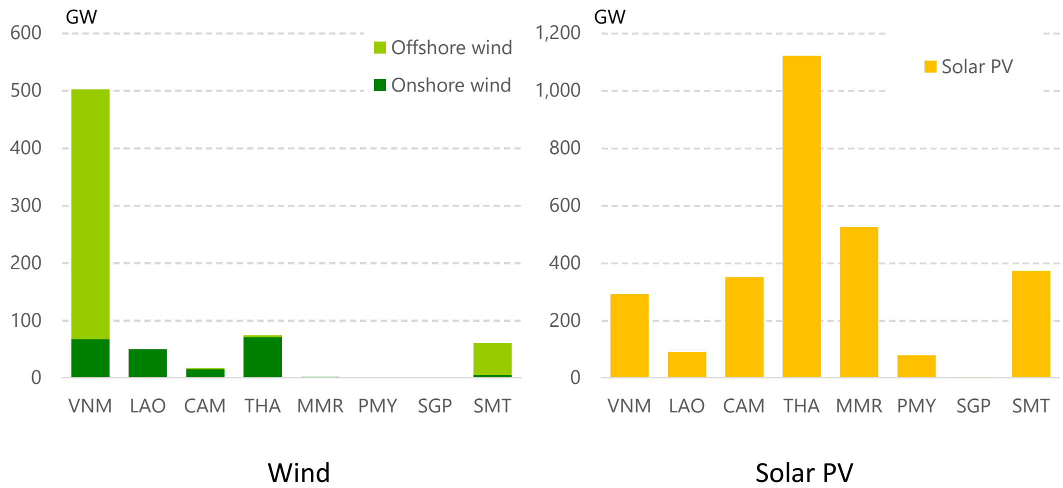
Europe **ASEAN**

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.

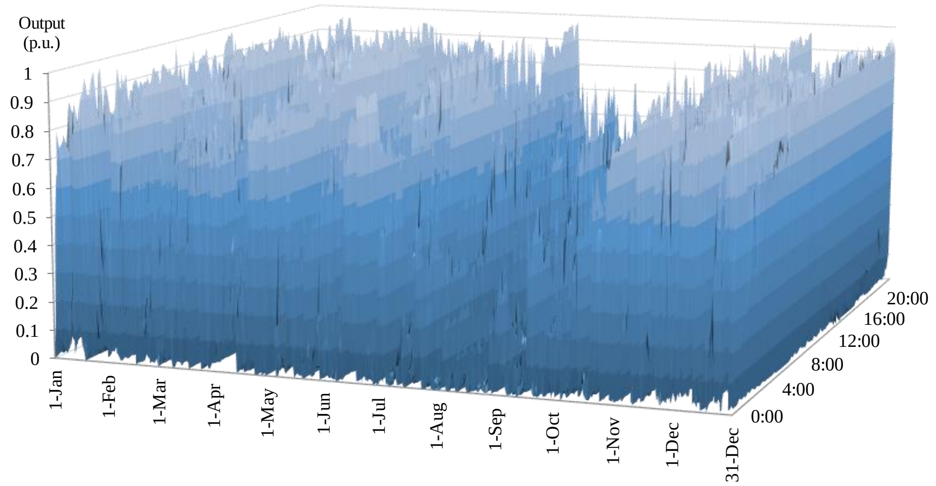
Figure 2.6. Potential for wind power/solar power in each region



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

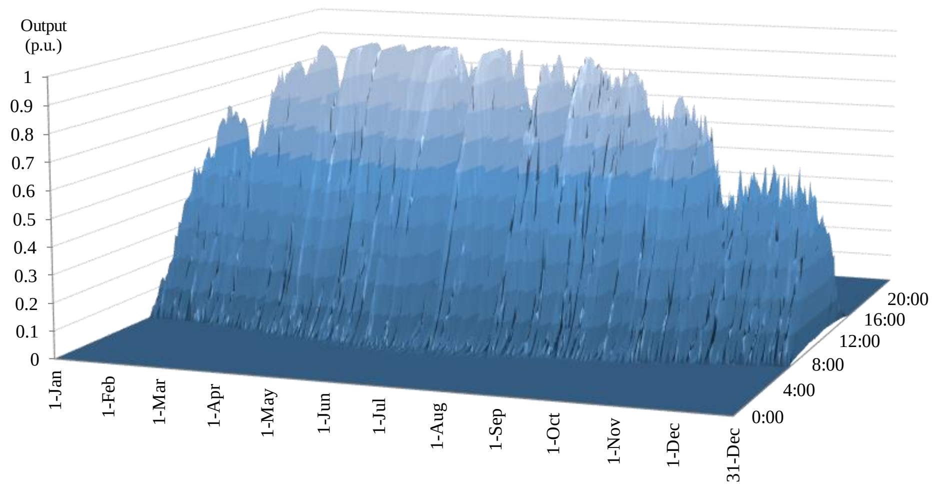
Regarding the output patterns of wind power/solar power generation, the data sets obtained from Renewables.ninja (Staffell and Pfenniger, 2016; Pfenniger and Staffell, 2016) were used. Here, based on the reanalysis data by the National Aeronautics and Space Administration (NASA), the hourly output patterns 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.

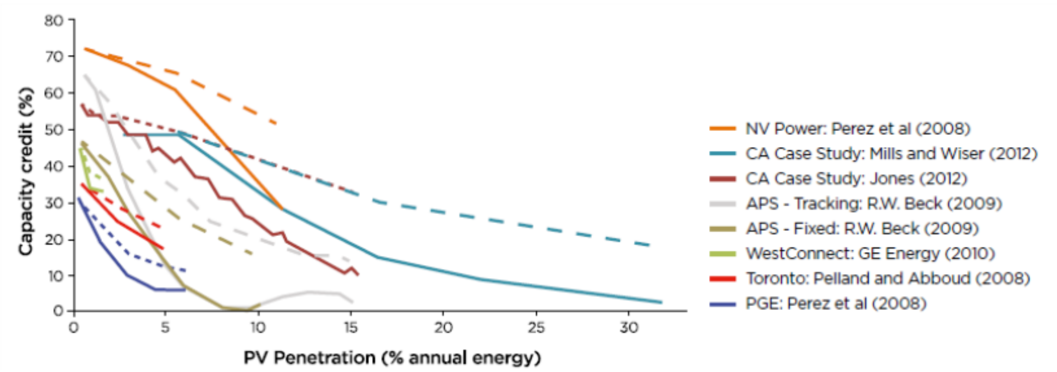
Figure 2.8. Example of solar power generation output patterns (Viet Nam)



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.

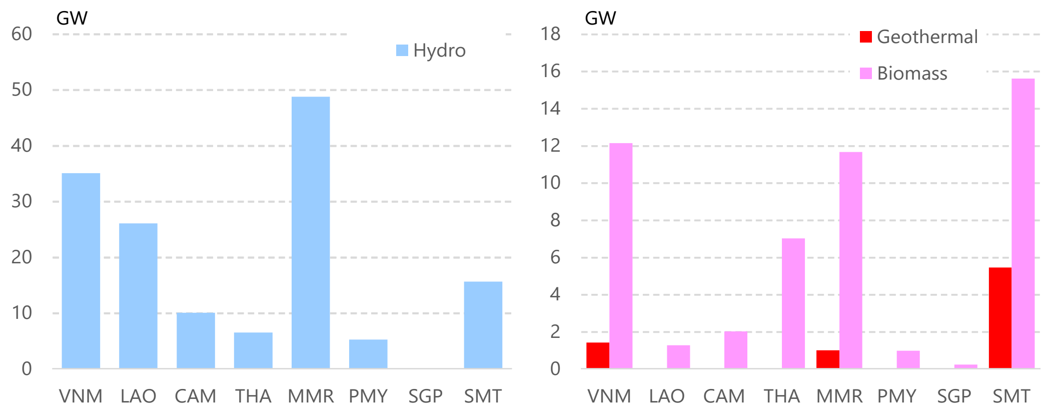
Regarding geothermal power, Indonesia, including Sumatra, has the largest potential. Viet Nam and Myanmar also hold geothermal potential, although it is not as great as Indonesia's. Geothermal potential is classified by the likelihood of availability, and classification such as Hypothetical Resources 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).

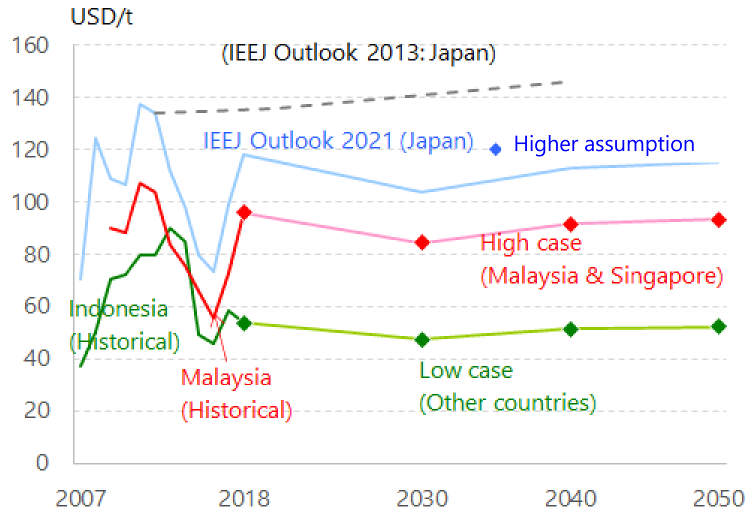
4. Primary energy prices

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

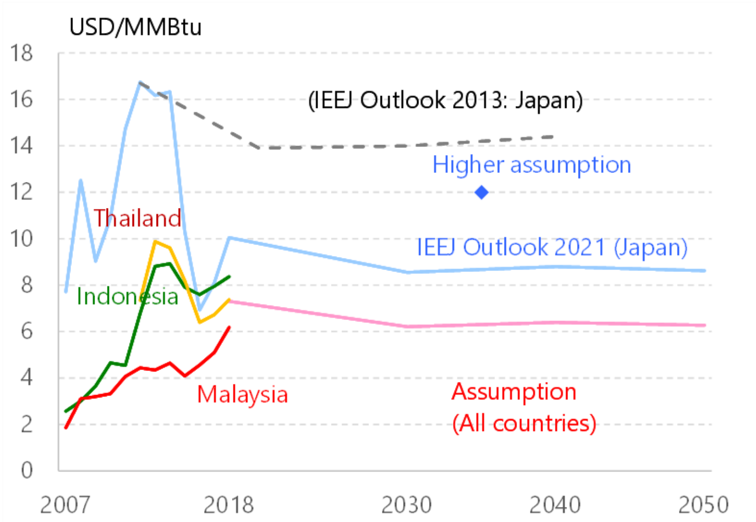


Source: Statistics of each country, IEEJ (2020) and authors' analysis.

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.

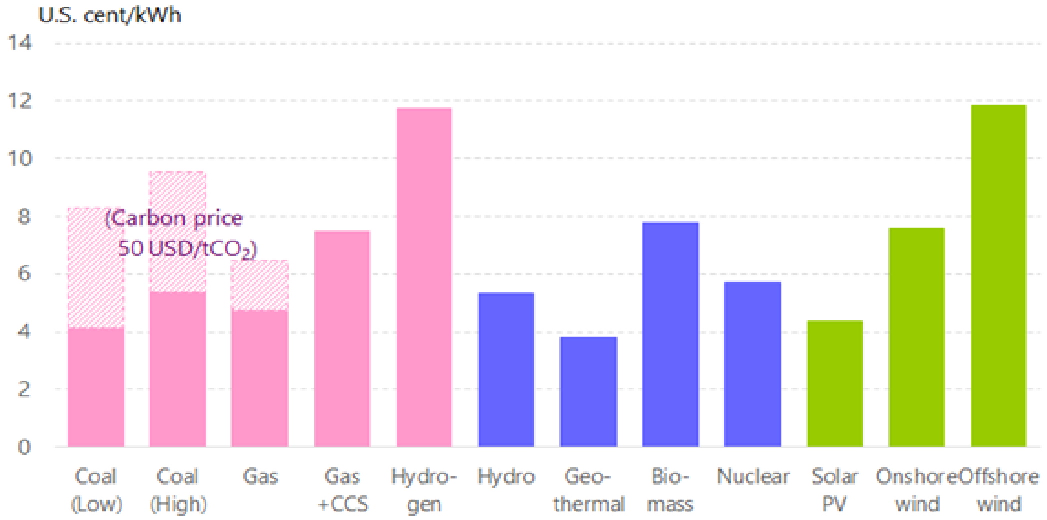
$$LCOE = \sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t} \Bigg/ \sum_{t=1}^{n} \frac{E_t}{(1+r)^t} \quad (1)$$

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$50/t$CO_2$ is added.

Figure 2.13. LCOE of power sources



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

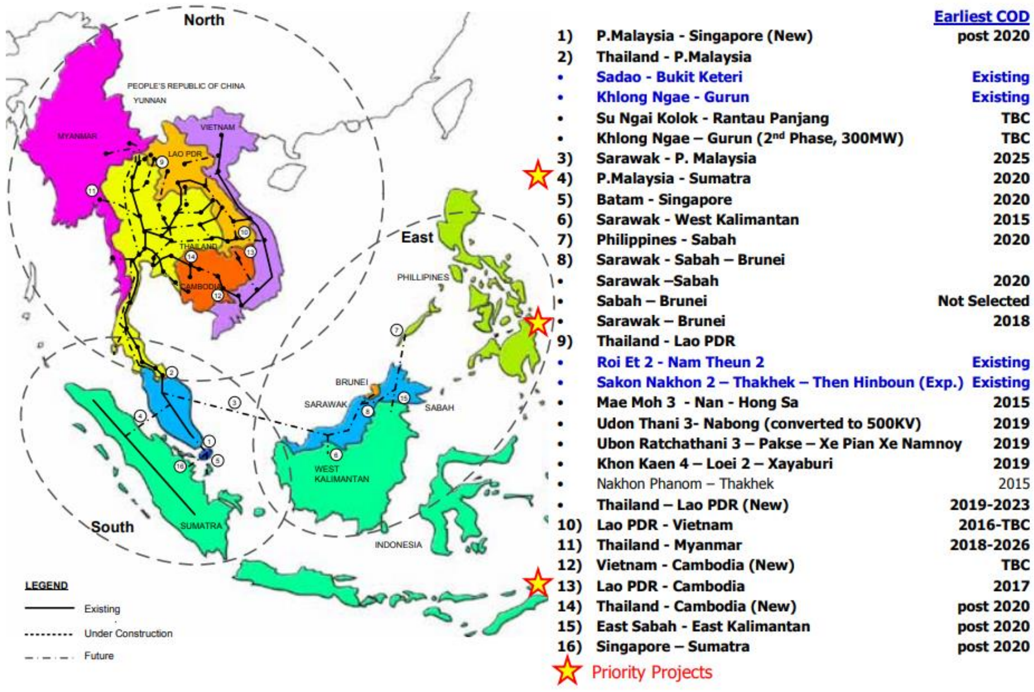
5.3. Grid interconnection

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.

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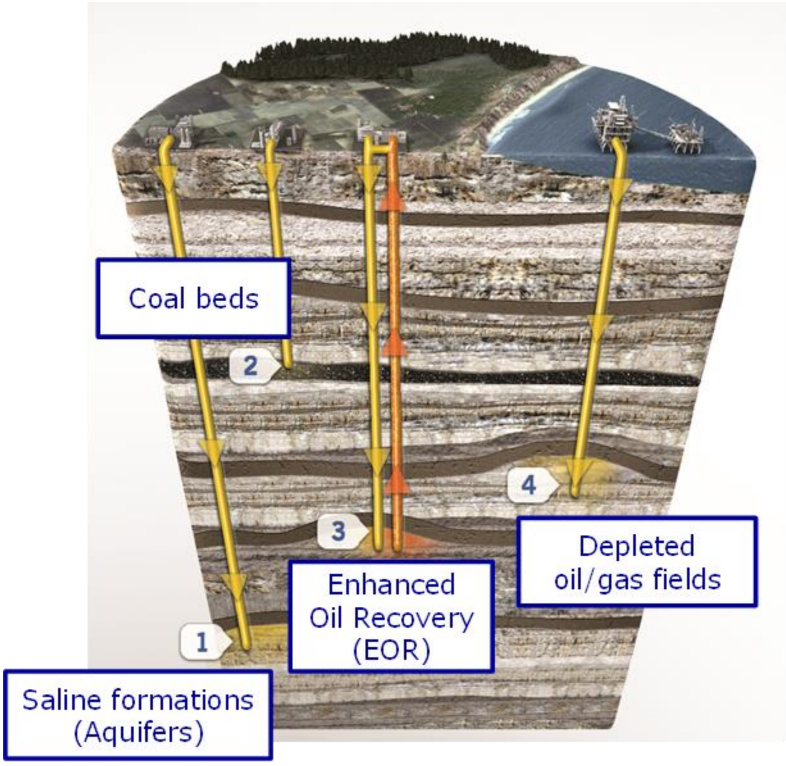
[2] A common cost necessary for setting one switching station, such as securing land and installing common facilities.

[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).