Quantitative Analysis of Effects of International Power Grid Interconnection in ASEAN Region[1]

Yuhji Matsuo*, Kazutaka Fukasawa*, Yu Nagatomi**,
Wataru Fujisaki*, Ichiro Kutani*, Noboru Seki*** and Yoichiro Kubota****

Summary

This study used the optimal power generation planning model and the supply reliability evaluation model to quantitatively assess the effects of future international power grid interconnection in the ASEAN region where electricity demand is expected to rapidly grow over a long time. Enhancing power grid interconnection can first be expected to improve the reliability of electricity supply. This effect eliminates the need for maintaining excessive reserve power generation capacity, allowing the investments for constructing additional power generation facilities to be saved. Second, power grid interconnection between countries with great power generation potential including hydro and those having no choice but to depend on energy resource imports will enable them to make effective use of regional resources. A quantitative analysis of these effects indicates that regional power grid interconnection could cut cumulative costs through 2035 by $10 billion and those through 2050 by $15 billion.

Benefits from international grid interconnection differ depending on routes. A line linking a region with electricity surpluses and one with shortages more efficiently can produce more benefits. This study conducted a route-by-route analysis and found that a route linking Vietnam, Laos and Thailand would produce a particularly great benefit. For the future, it is desirable to further examine potential and costs for each resource to assess the economic efficiency and the feasibility of a grid interconnection project for each line under an in-depth analysis.

1. Introduction

Global energy consumption has continued rapid growth. Particularly, Southeast Asian countries have posted remarkable energy consumption growth attributable to their population and economic expansion. According to the Energy Balance Tables by the International Energy Agency[1)], eight ASEAN countries (excluding Laos and Cambodia) expanded primary energy consumption 1.6-fold from 233 million tons of oil equivalent (Mtoe) in 1990 to 380 Mtoe in 2000 and 1.5-fold from the 2000 level to 573 Mtoe in 2012. Their electricity demand growth has been faster than primary energy consumption growth. The eight countries' electricity generation grew 2.4-fold from 1990 to 2000 and 2.0-fold from 2000 to 2012.

In Southeast Asian countries, there are many households that have yet to be electrified. The electrification of such households is a key policy challenge in many of these countries. Therefore, future electricity demand is expected to increase far more rapidly. At the same time, electricity supply costs are required to be lowered as much as possible since income levels for ordinary people in these countries are still

1 This study was funded by the Economic Research Institute for ASEAN and East Asia, or ERIA. This paper is released under approval by ERIA.
* Strategy Research Unit , the Institute of Energy Economics, Japan (IEEJ)
** Fossil Fuels & Electric Power Industry Unit, the Institute of Energy Economics, Japan (IEEJ)
*** Power Grid Company, Tokyo Electric Power Company, Inc (TEPCO)
**** International Affairs Department, Tokyo Electric Power Company, Inc (TEPCO)

low. In this way, Southeast Asian countries are urgently required to steadily develop massive electricity sources with economic efficiency taken into account.

Basically, a country develops domestic electricity sources to achieve higher self-sufficiency. But Southeast Asia is unevenly endowed with power generation resources such as coal, natural gas and hydro. While some countries in the region have more resources than required to meet domestic demand, others fail to develop sufficient electricity sources on their own due to resources shortages. International power grid interconnection is a solution to this problem. The measure resolves differences in degrees of electricity source development difficulty and in resources endowment and allows a region to develop electricity infrastructure more efficiently than individual countries.

Already, ASEAN has implemented power grid interconnection initiatives[2) 3)] through HAPUA (the Heads of ASEAN Power Utilities/Authorities) and other forums and seen bilateral electricity trade. But ASEAN countries still give priority to their respective domestic optimization of electrification, with electricity trade falling short of developing into any large-scale grid interconnection. Efforts to optimize electrification for the whole of the ASEAN region have been limited to moderate ones.

Given the situation, this study quantitatively analyzed the potential and advantages of international power grid interconnection for the purpose of providing data to back up policy and investment decisions for optimal electricity infrastructure development in Southeast Asia. This study also selected some promising grid interconnection routes, assessed relevant costs and benefits and analyzed grid interconnection measures and challenges for these routes.

2. 2. Estimation Methods and Assumptions

2-1 Overview of Models

This study used the optimal power generation planning model and the supply reliability evaluation model to assess international power grid interconnection. Their overview follows:

(1) Optimal Power Generation Planning Model

The model is designed to determine an optimal electricity mix to satisfy a given electricity demand level in a country or region at a minimal cost. In order to assess the effects of international power grid interconnection, the model can set specific grid interconnection capacities between countries and regions and design electricity supply to meet the demand at any time.

(2) Supply Reliability Evaluation Model

International power grid connection can be expected to improve the reliability of electricity supply by allowing a country to receive electricity supply from other countries to avoid a blackout when its domestic supply is short. This means that international power grid interconnection can allow any country participating in the interconnection to achieve the same loss of load expectation (LOLE) even at a lower supply reserve margin than in the case without such interconnection and save reserve power generation capacity. To assess this effect, this study developed a supply reliability evaluation model using the Monte Carlo method.

Details of these models are indicated in Annex A.

2-2 Major Assumptions

This study covers a total of 12 East Asian countries, namely Brunei Darussalam, Cambodia, China (Yunnan Province), India (northeast region), Indonesia, Lao People's Democratic Republic (PDR), Malaysia, Myanmar, the Philippines, Singapore, Thailand and Vietnam. The following abbreviations are used to represent the names of these countries and regions.

Table 2-1 Country Codes

Country name	3-letter code	Country name	3-letter code
Brunei Darussalam	BRN	Philippines	PHL
Cambodia	KHM	Singapore	SGP
Indonesia	IDN	Thailand	THA
Lao PDR	LAO	Vietnam	VNM
Malaysia	MYS	Yunnan province, China	YNN
Myanmar	MYA	Northeast India	NEI

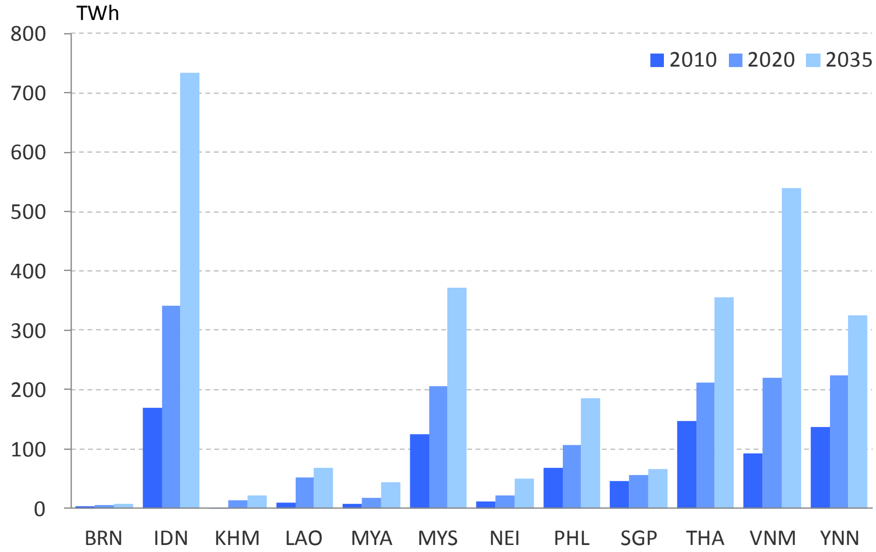
(1) Electricity Demand

The demand for energy in the East Asian region has risen steadily to date, and is expected to increase continuously going forward due to the expansion of the power supply region, the industrialization in line with economic growth, rising income levels, and urbanization. Increases in demand during the period up to 2020 are expected to be particularly substantial in Cambodia and Lao PDR.

Much of Cambodia is still without electricity, with the country's electricity supply currently confined largely to the capital region and major cities. As of June 2012, the household electrification rate for the country as a whole stood at approximately 35%, with the rate for urban areas at almost 100%; whereas that for rural areas was only around 25%. Moreover, latent power demand is believed to be considerable even in regions where power is already supplied, because the power demand of from many of the production plants and hotels found in these regions is are covered supplied by private power generators. Against this backdrop, the Government of Cambodia has set out targets of achieving 100% village electrification by 2020, and over 70% household electrification by 2030; and aims to improve the state of Cambodia's power generation and distribution facilities and ensure an affordable and stable supply of power.

It is expected that in Lao PDR, power demand will increase going forward as its manufacturing and commercial industries develop as a result of foreign investment and as progress is made in policies aiming to increase the country's electrification rate. The Government of Lao PDR has set out a target of raising the household electrification rate in Lao PDR to 90% by 2020.

The projected power demand for each country was assumed based on the power generation output (TWh) for each country in the business as usual (BAU) scenario discussed in the Economic Research Institute for ASEAN and East Asia (ERIA) Research Project[4)]. The projected power demand figures for India (northeast region) and China (Yunnan Province) were calculated by taking the power generation output (TWh) of the entire country to which each of the regions belongs, and calculating a share of this output proportional to the region's actual performance in the regional breakdown of the country's generation output.



Source: ERIA[4)]

Figure 2-1 Outlook for Electricity Demand

Table 2-2 Outlook for Electricity Demand

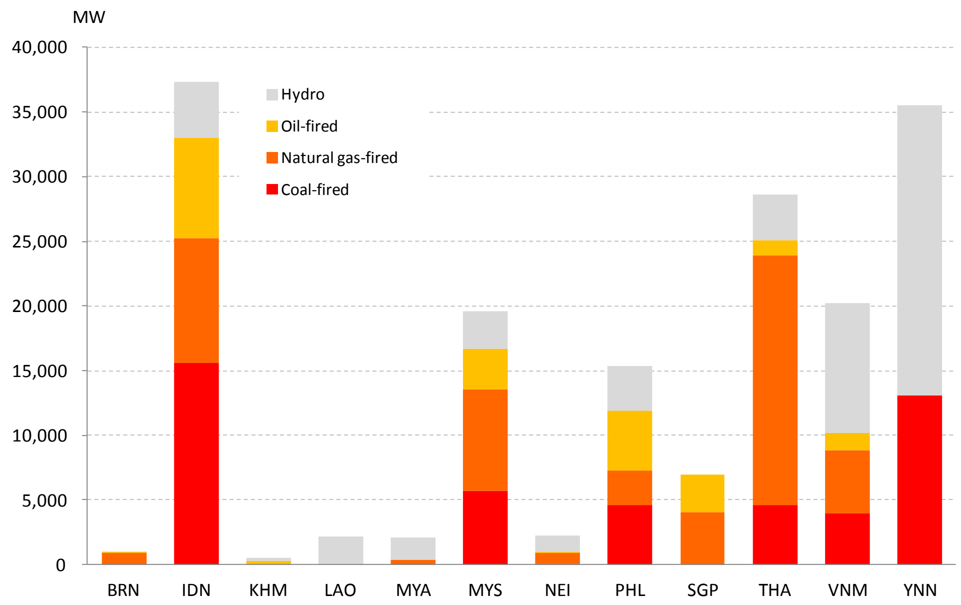
Unit：TWh

	2010	2015	2020	2025	2030	2035
BRN	4	4	5	6	7	8
IDN	170	252	342	448	576	733
KHM	1	6	12	18	20	22
LAO	8	23	51	65	67	69
MYA	8	11	16	23	32	45
MYS	124	161	205	254	309	372
NEI	11	16	22	30	38	49
PHL	68	85	107	131	156	186
SGP	45	51	56	59	62	66
THA	147	180	211	258	310	355
VNM	92	148	220	295	399	539
YNN	137	189	224	260	297	325

(2) Power Generating Capacities

When assuming the power generation capacity for each country, the authors made use of the dataset published by Platts[5)]. This data were segregated by country, type and installed capacity. For some countries figures are set based on information obtained by interviews with experts. The results are set out in Figure 2-2 and Table 2-3.

The projected future installed capacity was then estimated, assuming that peak demand in each country would rise proportionally with the total demand (TWh) for the country, and that new power plants would be constructed to meet the estimated peak demand. The assumptions for operational life time of each type of power generation are as follows: 40 years for coal-fired, oil-fired and nuclear power plants, 30 years for natural gas-fired power plants and no retirement until 2035 for hydropower plants.



Note: The data for NEI are as of Jan. 2013

Source: Platts[5], etc.

Figure 2-2 Existing Power Generating Capacities as of 2012

Table 2-3 Existing Power Generating Capacities as of 2012

Unit: MW

	Coal-fired	Natural gas-fired	Oil-fired	Nuclear	Hydro
BRN	0	885	32	0	0
IDN	15,603	9,680	7,705	0	4,343
KHM	10	0	286	0	207
LAO	0	0	8	0	2,125
MYA	0	347	29	0	1,678
MYS	5,685	7,875	3,136	0	2,897
NEI	60	824	143	0	1,200
PHL	4,598	2,656	4,653	0	3,441
SGP	0	4,077	2,850	0	0
THA	4,568	19,366	1,133	0	3,517
VNM	3,964	4,884	1,328	0	10,051
YNN	13,047	0	0	0	22,495

(3) Hydropower generation potential

Figure 2-3 shows the potential of the various energy sources among the ASEAN countries. The mismatch between high electricity demand areas and the ones rich in resources for power generation areas are evident which is the main motivation to expand international interconnected grid network in this region. In addition, the reserves-to-production ratios of fossil fuels are declining in most of the ASEAN countries. This means that countries such as Indonesia, Malaysia, Thailand, and Vietnam in particular, where power demand is expected to increase substantially, now increasingly need to import energy resources, resulting in rising power costs in these areas.

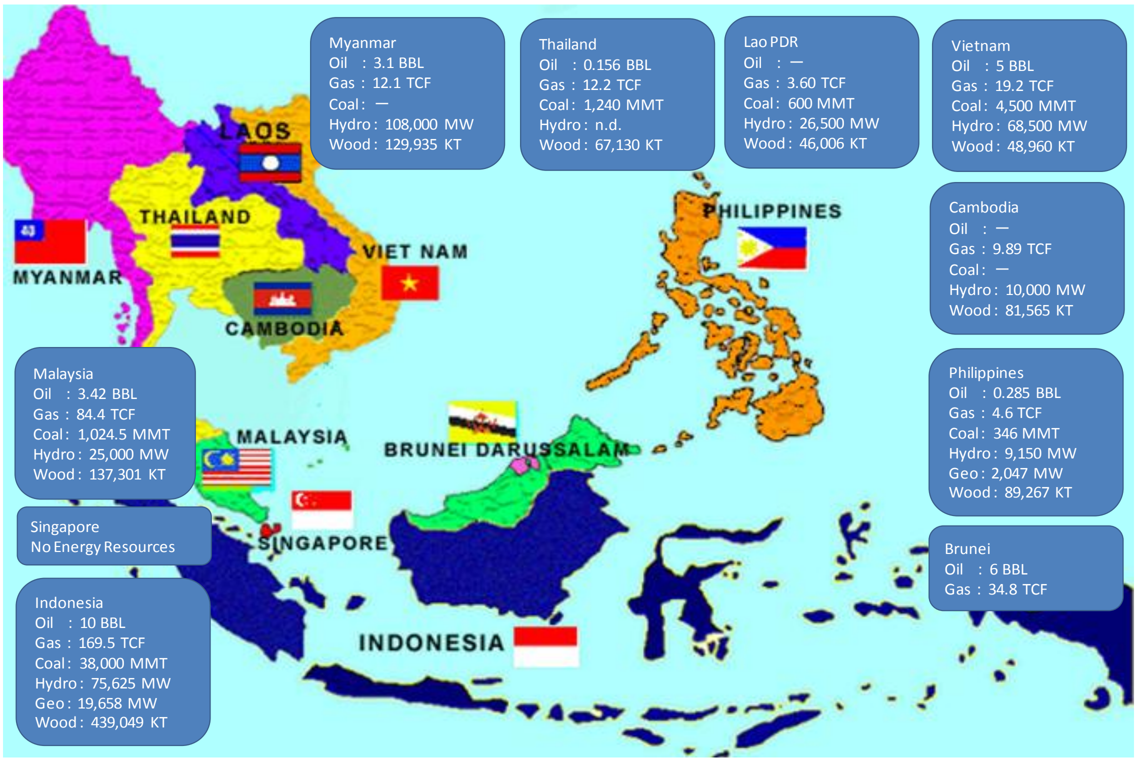
On the other hand, while domestic demand for electric power is lower in countries in the Mekong Basin, such as Lao PDR, Cambodia, or Myanmar, compared to their neighbors, these countries also possess rich hydropower resources and have massive potential for future development.

As a country whose terrain is characterized by the Mekong River which cuts through approximately 1,500km of the country's length, and by the multiple tributary rivers which flow into the Mekong River from high-elevation areas such as the Annamite Range, Lao PDR's hydropower development potential could theoretically be as high as 26,000 to 30,000MW of which only one-tenth has been developed.

Calculations by the Ministry of Industry, Mines, Energy (MIME) of Cambodia estimate that the hydropower resources with development potential in Cambodia could provide 10,000MW of power[6], of which only one-tenth has been developed as in the case of Lao PDR.

It is estimated that the hydropower potential of Myanmar could theoretically reach 108,000MW, and development works making use of economic cooperation and direct investment from China, Thailand and India has gone into full swing in recent years.

Development of international grid networks in the EAS region is expected to help optimize the power supply as a whole. In addition, power export through interconnection becomes an important sector for economic growth in these countries. Also, neighboring countries will benefit in diversification of their energy supplies and lower power costs through importing power.



Source: EGAT[7]

Figure 2-3 Potential Energy Resources in ASEAN Countries

Figure 2-4 and Table 2-4 shows the potential of the hydropower resources of the various countries in the simulation model developed in this study. The figures were developed by taking the power generation capacity figures (MW) shown in Figure 2-3 as a baseline, and provisionally assuming a uniform load factor of 40%. Given the data constraints, the projected figures for Thailand, India (northeast region), and China (Yunnan Province) have been calculated based on their power infrastructure development plans[8)9)10)], information obtained by interviews with experts.

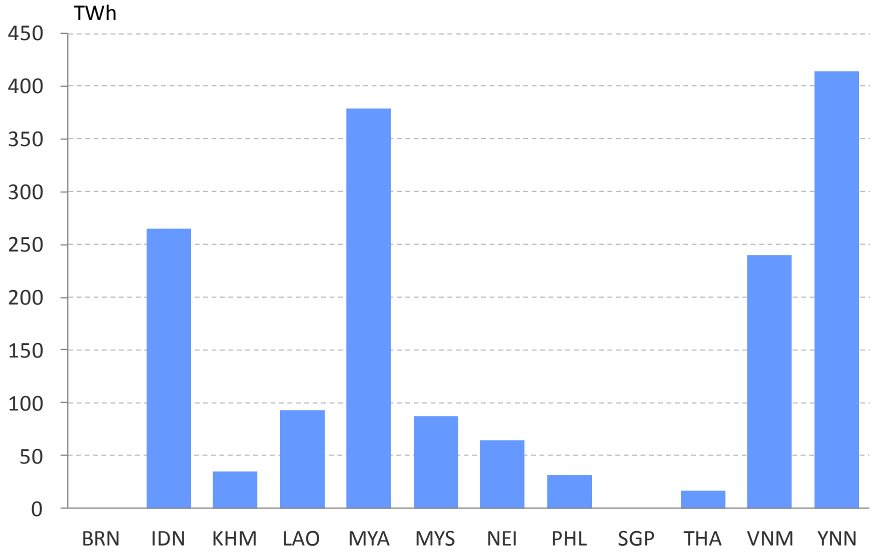


Figure 2-4 Assumptions on Hydropower Potential

Table 2-4 Assumptions on Hydropower Potential

Unit: TWh

	2010	2015	2020	2025	2030	2035
BRN	0	0	0	0	0	0
IDN	18	67	117	166	216	265
KHM	0	7	14	21	28	35
LAO	8	25	42	59	76	93
MYA	5	80	154	229	304	378
MYS	7	23	39	55	71	88
NEI	0	11	22	21	43	64
PHL	8	13	18	22	27	32
SGP	0	0	0	0	0	0
THA	3	10	16	16	16	16
VNM	28	70	113	155	198	240
YNN	129	197	264	314	364	414

(4) Load Curves and Load Duration Curves

The development of power resources is dictated by the power demand during peak times rather than by the annual power demand for the country in question. In recent years there have been changes in the load curve in much of the East Asian region due to changes in the industrial structure and living environments in the region.

As early as the mid-1990s, power consumption patterns in Thailand, the Philippines, Indonesia (Java-Bali Transmission Line), and Vietnam (southern region) were beginning to display a daily load curve which peaked during the daytime when industrial demand is high, due to these countries being relatively mature markets. Meanwhile, the power consumption patterns of other East Asian countries have, until recent years, retained the traditional lighting-centered demand mode, where the daily peak occurs from the evening into nighttime. With the growing power demand for industrial purposes in recent years due to economic development, however, there are now signs that the rate of increase in the daytime peak is starting to exceed the rate of interest in the nighttime peak. This means that the extent of the gap between the daytime and nighttime peaks in power demand is decreasing year on year.

Although future long-term trends in the load curve are difficult to predict with any accuracy because they are intricately connected with a range of factors including culture and climate, as well as the economic circumstances of the country or region, the simulation model created by this report has been established as follows.

As a general rule, peak power for each country was established using the daily load curve and load duration curve on the days of maximum power demand taken from the most recent data that could be obtained for each country. However, for countries where such data was difficult to obtain, the peak power was established using data from neighboring countries where the pace of economic development was similar.

Figure 2-5 show the daily load curve and load duration curve for Thailand. Daily load curves for other countries are shown in Appendix B.

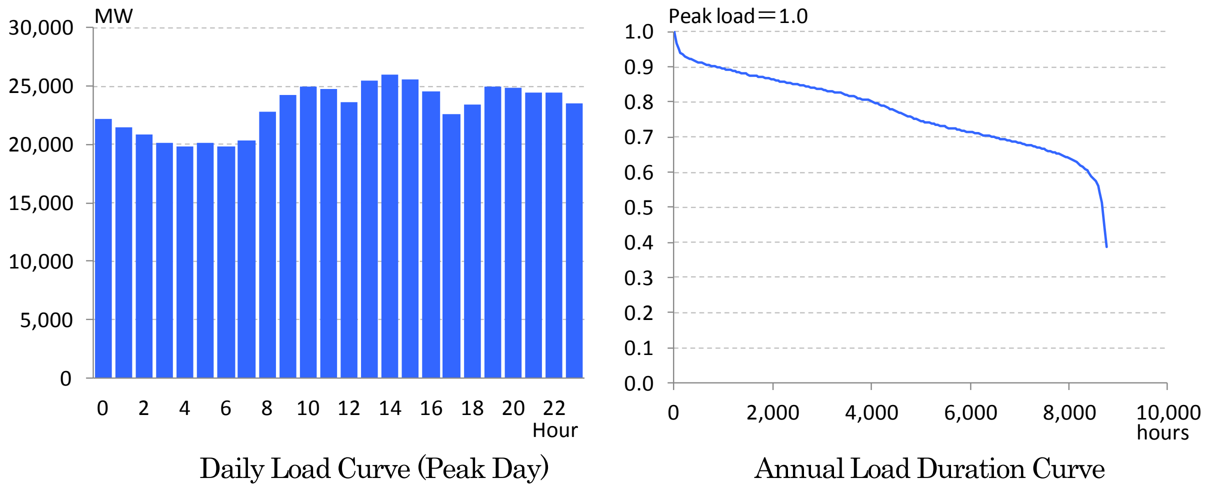


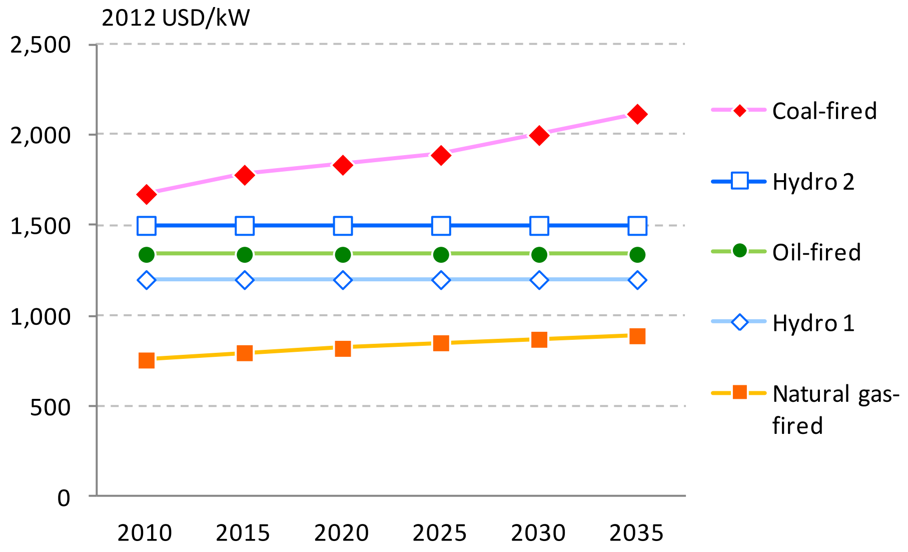
Figure 2-5 Examples of Load and Load Duration Curves

(5) Costs for Power Generationf

The cost of power generation consists of construction costs, fuel costs, variable costs other than fuel costs, and fixed costs. Future power generation costs were projected based on the assumption that countries will adopt similar type of technologies for the new construction and that the costs of these will be similar; country-wise differences are not considered, exept for the fuel costs.

Cnstruction costs were assumed following Reference 11) and other documents. Although ASEAN countries possess hydropower resources of tremendous potential, the level of difficulty of developing the hydro resources varies by country, and developing such resources is expected to become increasingly difficult as development progresses. In this analysis, therefore, hydropower plants are divided into "Hydropower 1" (where development is believed to be relatively easy) and "Hydropower 2" (where development is believed to be relatively difficult), and two different of costs are assumed respectively.

With regard to thermal power generation, it is assumed that increasingly advanced power generation technologies will gradually be adopted in coal-fired and gas-fired power generation, and that power generation costs will therefore tend to rise in line with the adoption of new technology. More precisely, it is assumed that there will be a shift towards combined cycle technology in gas-fired power generation; while in coal-fired power generation, there will be a move away from the traditional subcritical pressure boilers as supercritical and ultra-supercritical pressure boilers are introduced. The same cost is assumed for oil-fired power generation throughout the period, on the grounds that there is believed to be little room for technological development with this mode of power generation.



Source: OECD[11], etc.

Figure 2-6 Assumptions on Construction Costs

The thermal efficiency of newly constructed thermal power generation plants is set out as follows.

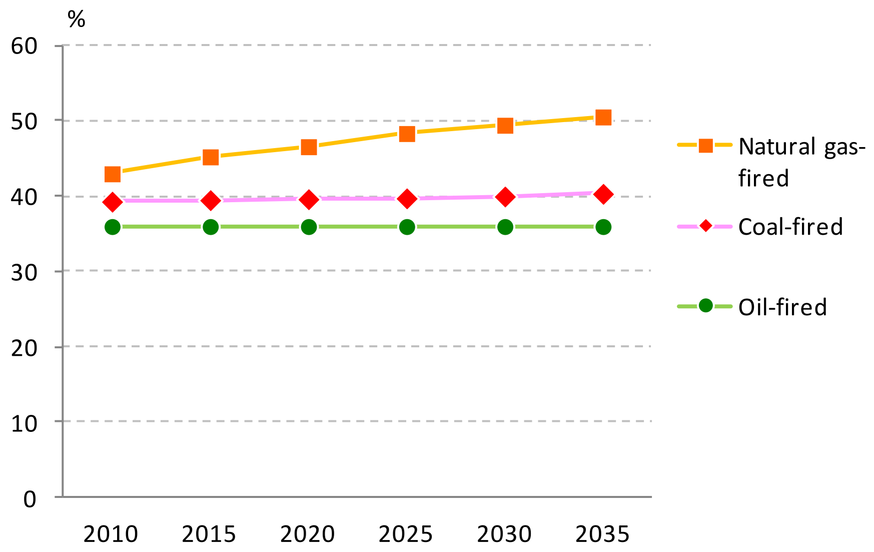
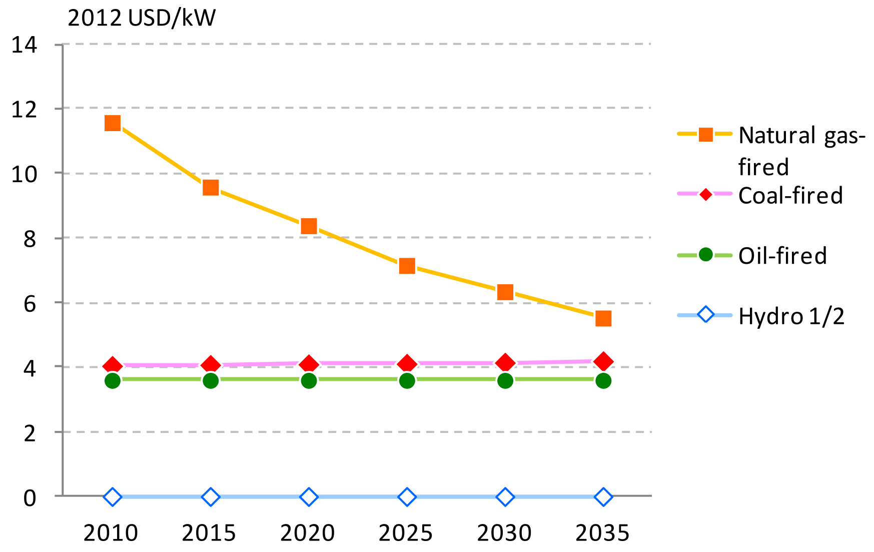


Figure 2-7 Assumptions on Thermal Efficiencies

Fixed costs are assumed to make up 10% of construction costs for coal-fired power generation, Hydropower 1 and Hydropower 2, 5% of construction costs for gas-fired power generation, and a uniform rate of USD 94/kW for oil-fired power generation.

Variable costs other than fuel costs are envisaged using costs projected by OECD/NEA[11], IEA[12] and EIA[13] as references. There is a dramatic decrease in the projected costs for gas-fired power generation because it is projected that there will be a progressive shift away from traditional single cycle generation towards combined cycle generation, for which variable costs are relatively low.



Sources: OECD[11], IEA[12], U.S. EIA[13], etc.

Figure 2-8 Assumptions on Variable Costs

(6) Fuel Costs

Projected coal prices are divided into two levels: prices for coal-producing countries and prices for coal-importing countries. Indonesia, Malaysia, the Philippines, Thailand, Vietnam, Myanmar, Lao PDR, Cambodia, China and India are coal-producing countries. Two other countries—Singapore and Brunei—are coal-importing countries. Coal prices for 2010 are set at USD 60/ton for coal-producing countries and USD 90/ton for coal-importing countries. The price of USD 60/ton for coal-producing countries was determined based on the extraction costs plus costs of transportation to ports. Prices are expected to rise by USD 2.5/ton per year from 2010 onwards, taking the rising costs of coal production based on Reference 14), etc. into consideration.

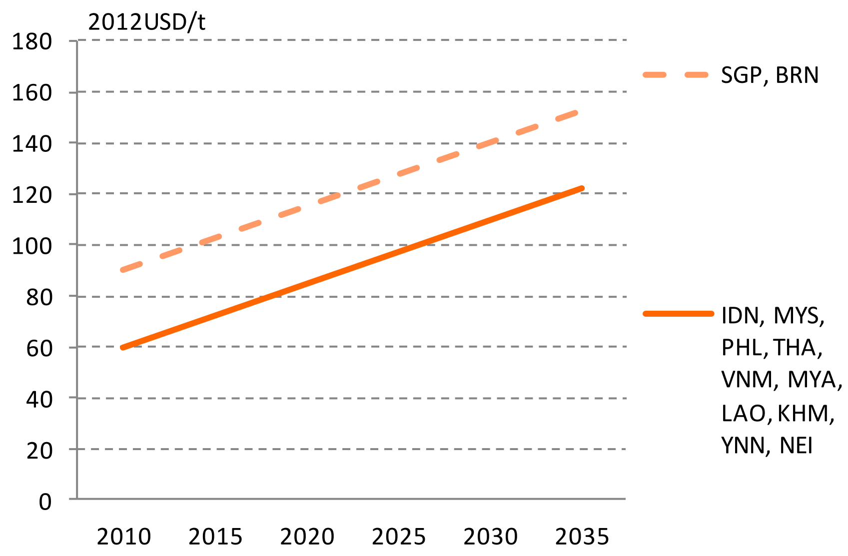


Figure 2-9 Assumptions on Coal Prices

Projected prices for natural gas are divided into three levels: countries which import natural gas and do not produce any domestically (Singapore and the Philippines); countries which currently possess some domestic gas fields but where the price of gas used domestically is relatively high (Thailand, Lao PDR, Cambodia, China and India); and countries which currently possess natural gas fields and where the price of gas used domestically is relatively low (Brunei, Indonesia, Malaysia, Vietnam and Myanmar). As of 2010, these prices stood at USD 16/MMBtu, USD 8/MMBtu and USD 3/MMBtu respectively. These figures are projected to converge into a provisional figure of USD 12/MMBtu up to the year 2035, based on the prospect that increasing trade liquidity is expected in the natural gas market as the natural gas/LNG import increases over time in most Asian countries, and as short-term trading is expected to increase.

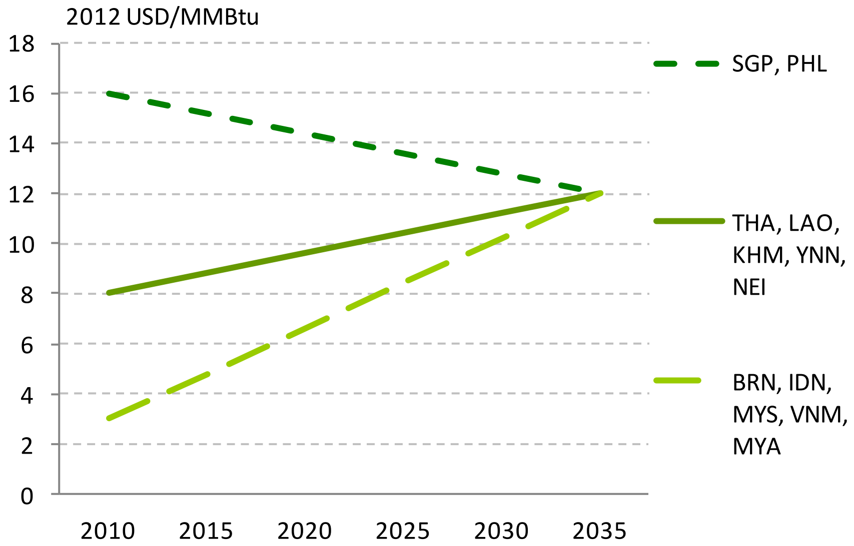


Figure 2-10 Assumptions on Natural Gas Prices

(7) Grid Interconnection Capacities

Two initiatives are currently underway for developing power grid interconnection in the East Asian region: the ASEAN Power Grid (APG)[15] which will cover 10 ASEAN countries; and the Greater Mekong Subregion (GMS)[16] grid which will cover six countries/regions in the Mekong Basin, including Yunnan Province in China. The maximum power grid capacities assumed for this study, based on the APG and GMS plans, are set out in Table 2-5.

Table 2-5 Projected international interconnection transmission capacity in 2020 and later (GW)

Unit: GW

	BRN	IDN	KHM	LAO	MYA	MYS	NEI	PHL	SGP	THA	VNM	YNN
BRN						0.3						
IDN						2.2						
KHM				0.3						2.3	0.4	
LAO			0.3							7.9	2.7	3.0
MYA							2.1			11.7		2.0
MYS	0.3	2.2						0.5	1.1	0.8		
NEI					2.1							
PHL						0.5						
SGP						1.1						
THA			2.3	7.9	11.7	0.8						
VNM			0.4	2.7								8.5
YNN				3.0	2.0						8.5	

(8) Transmission Losses

Theoretically, assuming identical transmission conditions (type and diameter of transmission line, number of lines, current values etc.), the transmission loss rate could be assumed to be proportional to the distance over which power is transmitted. In practice, however, transmission conditions are never identical, because electricity from other power plants flows through the same transmission lines, because the current value changes continually in response to the power usage conditions, and because various different types and diameters of transmission lines are in use.

In this study, however, the transmission loss rates are assumed in a simplified manner: 1% per 100 km for AD transmission, and additional 2% loss for DC transmission due to the AC-DC converter facilities.

(9) Transmission Costs

When calculating costs associated with power transmission, the actual construction costs of the transmission plants and the costs of repairing, maintaining and managing these facilities must be considered. In addition, when constructing power grids within the East Asian region, the need for submarine cables for supplying power to opposite sides of channels and to islands must be taken into consideration, as well as the construction of the usual overhead transmission lines.

Principally, the individual costs of all facilities including power lines, pylons and transformer stations should be massed in order to estimate the transmission line construction costs. However, given the data constraints, in this study, unit costs per unit of distance (km) are assumed for the whole transmission lines excluding transformer stations, and the costs calculated according to the transmission distance. By adding this figure to the construction costs according to the number of transformer stations (switching stations) that are likely to be needed for the route in question, an estimate is obtained for the total costs required.

More precisely, the unit construction costs for the transmission line stands at USD 0.9 million/km/2 circuits for overhead lines and USD 5 million/km/2 circuits for submarine cables, based on the most recent actual performance figures for construction in neighboring countries. The estimated sum of construction costs of transformer stations (switching stations) was obtained by assuming fixed costs of USD 20 million per station, and adding additional costs of USD 10 million per line. For the O&M costs, 0.3%/year were assumed.

2-3 Case Setting

In this study, the optimal power generation planning model and the supply reliability evaluation model mentioned earlier were utilized to estimate the optimal power generation mix and power trade up to 2035, by making use of the data described above. Because the introduction of renewable energy (other than hydro) and nuclear power are chiefly swayed by policy, they were set in line with the forecasted figures in the ERIA Outlook[4)], and only thermal power generation (coal, natural gas and oil) and hydropower generation were calculated by the model. Of those energies, the introduction of hydropower generation was as in the ERIA Outlook in Cases 0a, 0b and 1 discussed in the following section, while in the other cases the figures discussed in Section 2-2 were utilized to show additional hydro-potential.

In employing the optimal power generation planning model, the time interval was assumed at five years. That is to say, 2010 is the latest actual value, and the figures from 2015 onward are forecasted figures. In the supply reliability evaluation model the number of trials with the Monte Carlo method was approximately 140,000 times.

(1) Calculations covering the total system

Calculations were made based on the following case configurations, covering all the 12 countries and regions:

Case 0 : Reference case (no additional grid connection)
Case 1 : Additional grid connection, no additional hydro-potential
Case 2a: Additional grid connection, additional hydro-potential
Case 2b: Additional grid connection, additional hydro-potential for export purpose only
Case 3 : Same as Case 2b, with no upper limit set on the grid connection capacity

Case 0, regarded as the Business as Usual case, does not take grid connection into account. It is a scenario in which a power generation mix is attained that resembles the ERIA Outlook through the utilization of the domestic power generation facilities of each country only. Case 1 was configured so that interconnection up to the upper limit set on the grid connection capacity indicated in Table 2-5 is possible, but the additional hydro-potential is not taken into account. In this case, as a result of interconnection, the supply reserve margin is trimmed down, and the thermal power-generation mix (the ratio of coal-fired and natural gas-fired) changes slightly.

In Case 2a, grid connection is made possible as with Case 1, and additional hydropower generation is possible with the hydropower generation potential presented in Table 2-4 as the upper limit. In this case, as will be explained later, additional hydropower generation is made to satisfy the domestic power demands of the country concerned. In reality, in Indonesia for example, due to its characteristic features as an archipelago country the domestic power system itself is not connected as one. Thus, even if significant hydropower generation potential existed on some islands, unless additional grid connection was carried out it would not be possible to fully utilize that potential. Similar circumstances are present in other countries to some degree, and consequently the ERIA Outlook does not assume that it will be possible to fully exploit hydropower generation potential in order to meet domestic demand at least over the period up to 2035. In this perspective, Case 2b was configured as a case in which additional power generation can only be used for export and cannot be exploited as supply to cover domestic demand.

Case 3 is similar to Case 2B, in which additional hydropower generation can only be allocated to exports, but no cap is set on grid connection capacities. Consequently, hydropower generation potential can be utilized fully, and in particular large amounts of power are exported from Myanmar, which is envisioned to have the largest potential. Again, this is not necessarily realistic, and Case 3 could be described as assessing what kind of situation lies ahead, should interconnection on a scale exceeding HAPUA's upper limits on interconnection become possible.

(2) Evaluation for Specific Lines

In addition to the calculations applicable to the total system as mentioned above, in order to make it possible to assess the economics of the individual interconnection lines, calculations were made for cases that permitted grid connections between specific regions only, and were compared against the case without grid connections. The assumed connections are as follows:

Case A: Thailand (THA) – Cambodia (KHM)
Case B: Thailand (THA) – Laos (LAO)
Case C: Thailand (THA) – Myanmar (MYA)
Case D: Myanmar (MYA) – Thailand (THA) – Malaysia (MYS) – Singapore (SGP)
Case E: Vietnam (VNM) – Laos (LAO) – Thailand (THA)
Case F: Malaysia (MYS) – Indonesia (IDN)
Case G: Laos (LAO) – Thailand (THA) – Malaysia (MYS) – Singapore (SGP)

When considering a transmission system interconnection between two countries, it is necessary to confirm the condition of the transmission systems of each country in detail, and then decide the optimal connection points and detailed interconnection routes. As the goal of this study is a preliminary assessment of the relationship between the effects of interconnection and the cost, however, we adopted a more simplified approach, estimating the range of the distances: Route 1 shall be a comparatively long-distance route linking capital cities, and Route 2 shall be linking short distance points with existing substations wherever possible. As it is difficult to establish detailed routes in this study, the transmission route length shall be set as 1.2 times the linear distance between two points.

3. Results and Discussion

3-1 Supply Reserve Margin Savings Due to Grid Interconnection

Figure 3-1 shows the supply reserve margin in each country and region. In Case 0, which does not envisage a grid connection, the reserve margin is 7-8% for most countries, and around 11-12% for Singapore and Brunei, where the grid systems are small relative to the scale of the power generation facilities. In the cases where grid connections are assumed, the supply reserve margin to achieve the same 24-hour/yr LOLE decline substantially. The degree by which the reserve margin declines differs depending on the country. In the Philippines, where interconnection does not take place due to the high interconnection costs, the supply reserve rate is not reduced; and in Indonesia, which has a relatively large power system and is directly interconnected only with Malaysia, a net power importer in 2035, the supply reserve margin saving is small.

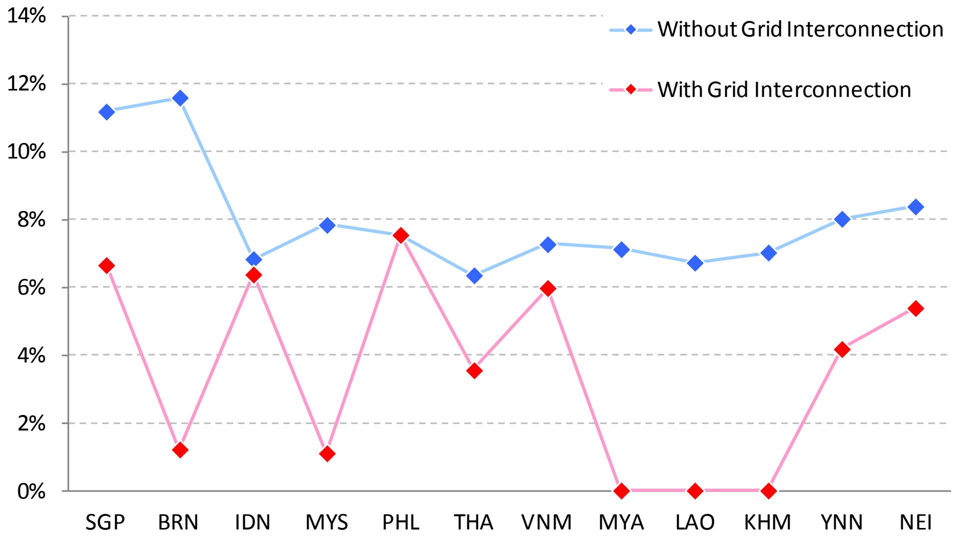


Figure 3-1 Required Supply Reserve Margin to Gain the Same LOLE

3-2 Power Supply Mix in 2035

Figures 3-2 to 3-6 show the power supply in 2035 for each case. In these figures, the areas designated with purple sloping lines show net imports, representing net imports if they are positive, and net exports if they are negative.

Figure 3-2 represents the power supply mix in Case 0, where a grid connection is not envisioned. As mentioned above, apart from oil-fired generation, these results basically conform to the ERIA Outlook[4].

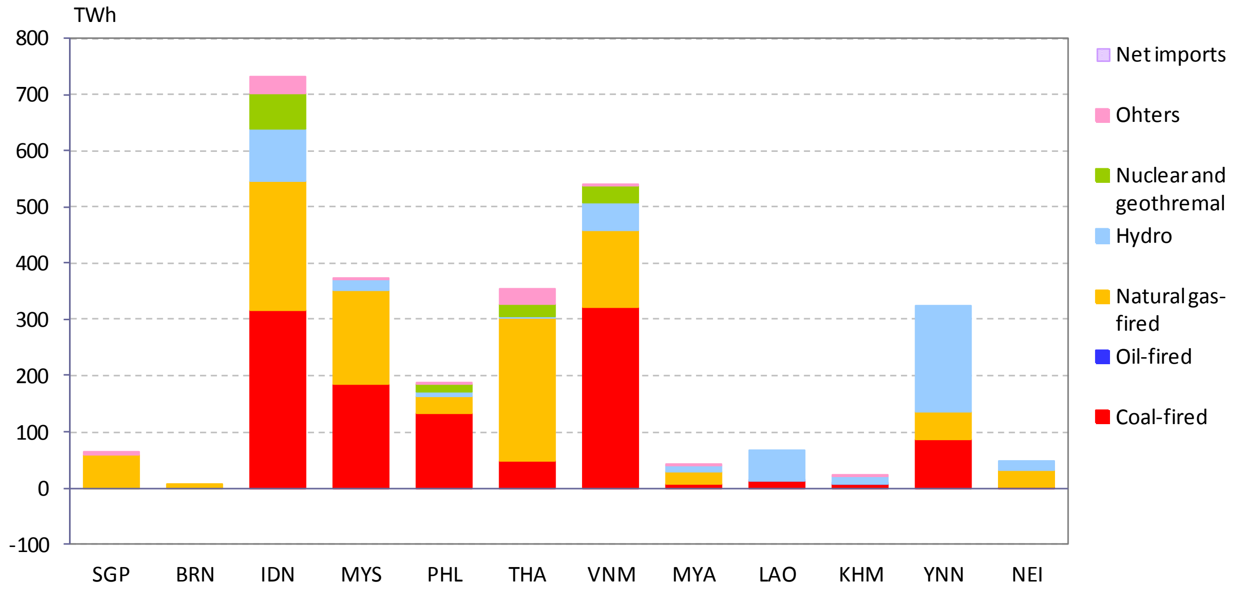


Figure 3-2 Electricity Supply in 2035 (Case 0)

Figure 3-3 shows the power supply mix in Case 1. With this case, because utilization of additional potential is not envisioned, hydropower generation is the same as for Case 0, but changes can be detected in the thermal power generation. In Thailand, where the natural gas ratio is high in Case 0, natural gas-fired power generation is reduced in Case 1 and is covered by coal-fired power generation in neighboring countries (in this instance Lao PDR). In this way, there is a possibility that a more cost-optimal power generation mix could be achieved through the utilization of international interconnection lines, taking into account each country's particular restraints (in this case, restraints on new coal-fired power plant construction in Thailand).

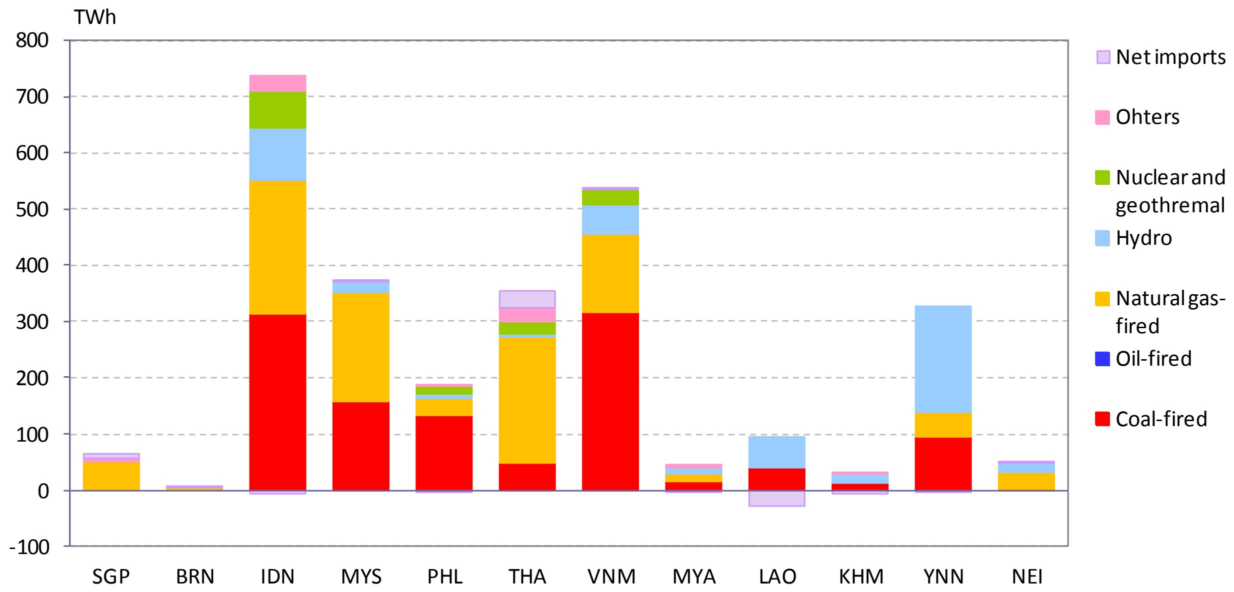


Figure 3-3 Electricity Supply in 2035 (Case 1)

Figure 3-4 shows the power supply mix in Case 2a. In this case, utilization of additional hydropower potential in each country takes place and exports occur from countries and areas possessing significant potential such as Myanmar, Lao PDR, Cambodia, southern China and Northeast India, to Thailand, Vietnam, Singapore and Brunei.

Additional hydropower generation potential also exists in countries such as Indonesia, the Philippines and Vietnam. In Case 2a, growth in hydropower generation in these countries will be utilized to meet their domestic power demands. Consequently, hydropower generation accounts to 36% of total electricity supply in Indonesia and 45% in Vietnam in 2035. In reality, despite the hydropower generation potential that physically exists in these countries, most are not utilizable due to geographical and economic factors, for example. In view of this, as is shown in the ERIA Outlook, a situation in which hydropower generation covers nearly 40% of the power supply cannot be anticipated in these regions.

In Case 2a, hydropower generation accounts for 95% of Myanmar's power supply and 93% of Cambodia's power supply. From the viewpoint of power system operation, it is not realistic to assume hydropower generation percentages as high as this. From that perspective, although Case 2a shows some potential in terms of approaches to utilize international interconnection lines, it should not be regarded as a realistic picture in 2035.

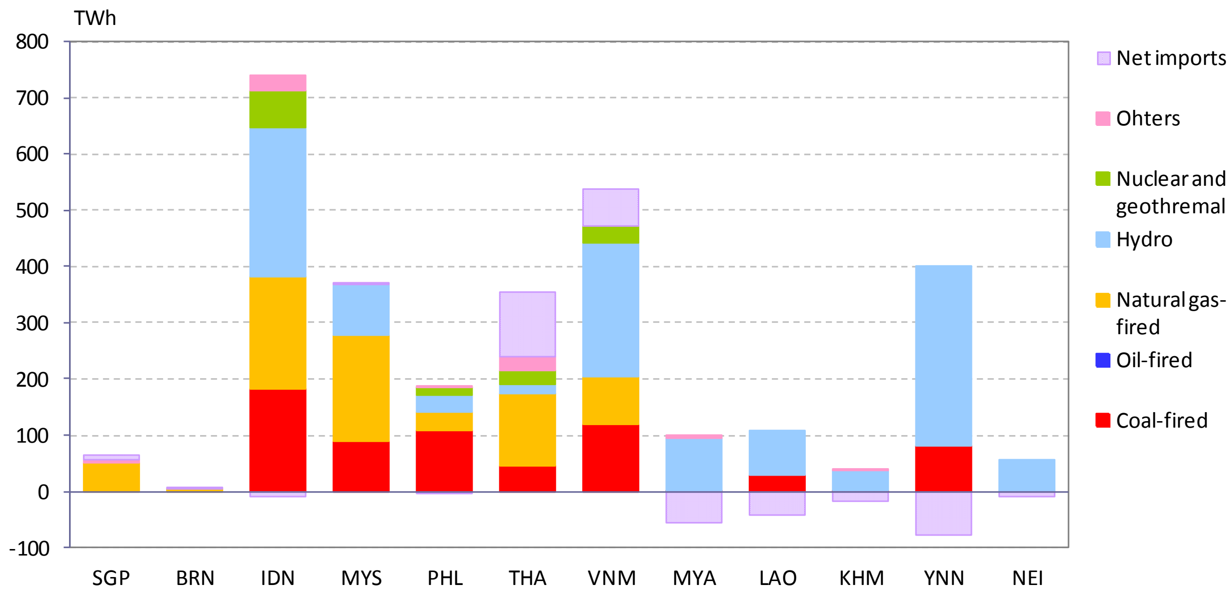


Figure 3-4 Electricity Supply in 2035 (Case 2a)

Figure 3-5 represents the power supply mix in Case 2b. Case 2b envisions that additional hydropower generation capacity will only be used for exports. For that reason, the hydropower generation in Indonesia and Vietnam is smaller than in Case 2a. In terms of domestic power supplies in Myanmar and Cambodia, a certain amount of thermal power generation is used alongside hydro, and so surplus hydropower generation portion is exported. Based on the perspective mentioned earlier, compared to Case 2a, Case 2b presents a more realistic picture.

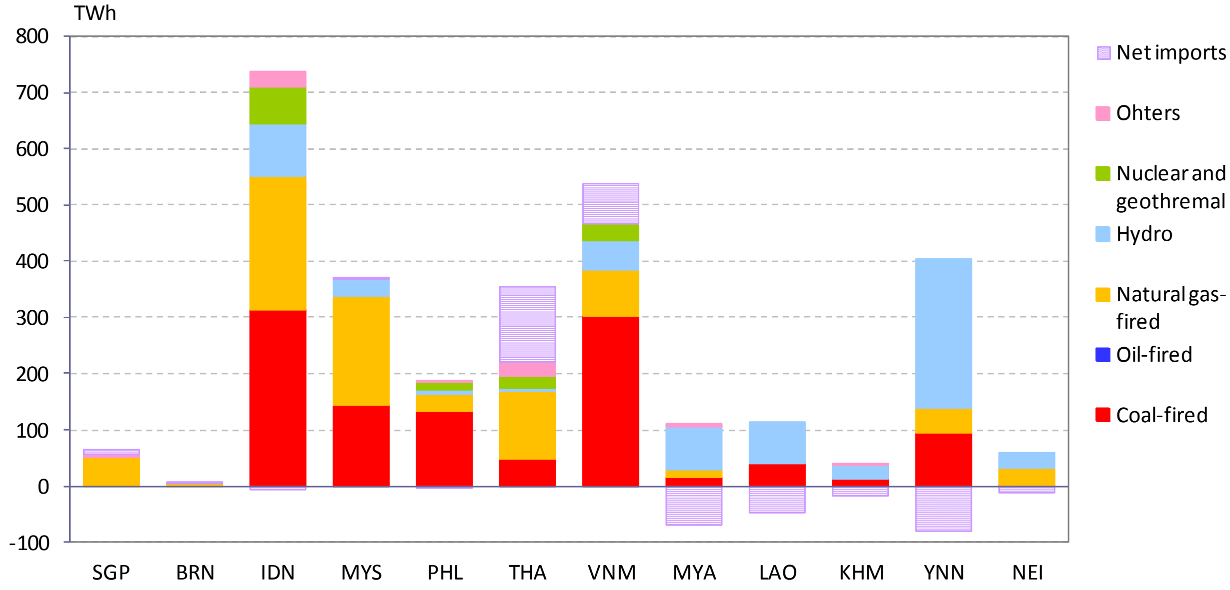


Figure 3-5 Electricity Supply in 2035 (Case 2b)

Figure 3-6 represents the power supply mix in Case 3. In this case, hydropower generation in Myanmar in particular is extremely large, and it exports 250 TWh of electricity per year. At the same time, power is also exported from Lao PDR, Cambodia, southern China and Northeast India, and that power is contributing to the supply in Thailand, Vietnam, Malaysia, Indonesia, Singapore and Brunei. In reality, even if there were no upper limit constraints on interconnection lines, whether or not the hydropower generation potential in Myanmar could be economically developed on this scale is an issue that will need to be studied further.

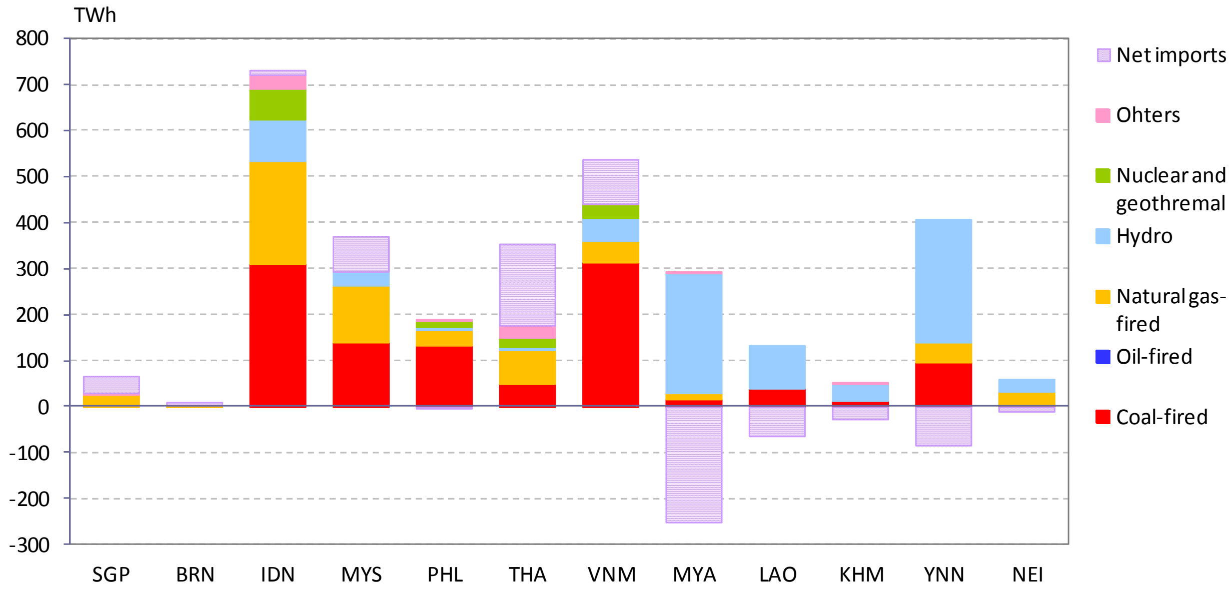


Figure 3-6 Electricity Supply in 2035 (Case 3)

Figure 3-7 shows the power supply mix for all 12 countries and regions combined.

The area's total power generation capacity will expand from 940 TWh in 2010 to 2,800 TWh in 2035. In Case 0, which does not envisage grid connection, the power generation mix in 2035 consists of coal-fired (40%), natural gas-fired (36%), hydro (16%), and other (nuclear and renewable etc.) (7%). By comparison, in

Case 1 the coal-fired thermal ratio increases slightly, to 41%.

In Case 2a, as a result of utilizing additional hydropower generation potential, the hydropower generation ratio rises to 44%, and accordingly, the shares covered by both coal-fired and natural gas-fired decline. By comparison, in the more realistic scenario of Case 2b, the hydropower generation ratio rises to 23%, and in Case 3, which does not take grid connection constraints into account, the ratio rises to 31%. In Cases 2b and 3, the hydropower generation increases compared to Case 1, and so the dominance of natural gas-fired power generation decline accordingly.

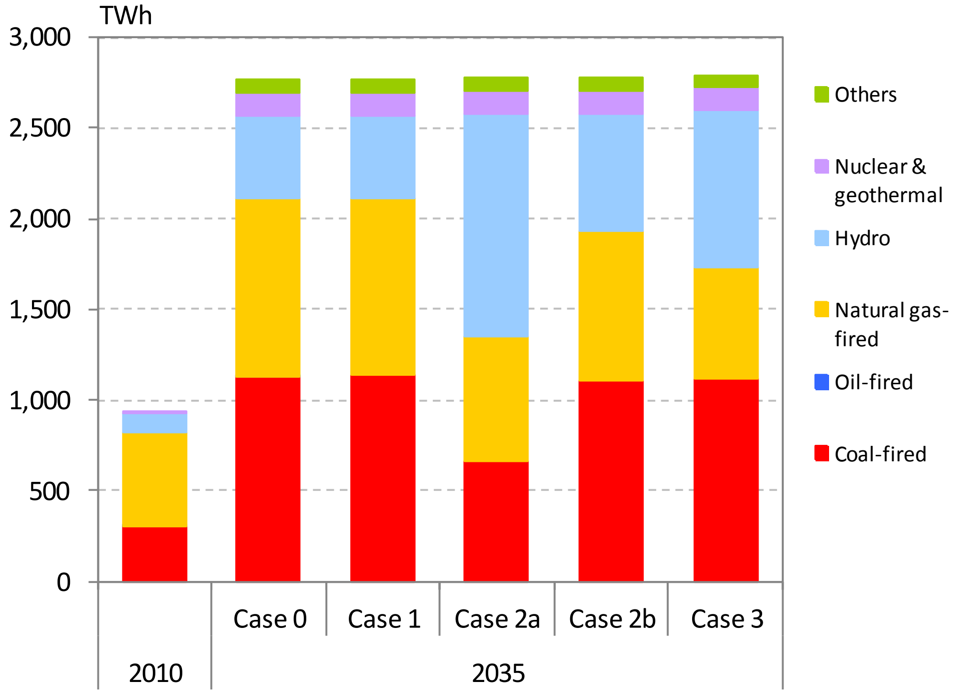


Figure 3-7 Electricity Supply in 2035 (Total of All Regions)

3-3 CO_2 Emissions in 2035

Figure 3-8 shows CO_2 emissions in 2035 (the total for the 12 countries and regions). Compared to Case 0, in Case 1 additional hydropower generation does not take place, and at the same time, as a result of cost optimization across the entire system based on grid connection, the ratio of coal-fired power generation increases slightly. Therefore, CO_2 emissions increase by a small amount, from 1.35 Gt in Case 0 to 1.36 Gt in Case 1. By comparison, in Cases 2a, 2b and 3, which make use of grid connection along with additional hydropower generation, there are striking declines in CO_2 emissions. Particularly in Case 2a, where the utilization of domestic hydro-potential in Indonesia and Vietnam progresses, there is an extremely significant reduction in CO_2 emissions, to 0.86 Gt. As mentioned above, however, this cannot be described as a realistic case, The CO_2 emissions reductions compared to Case 0 are around 0.07 Gt in Case 2b, where a grid connection limit corresponding to HAPUA's limit is set; and around 0.31 Gt in Case 3, which does not set a limit on interconnection capacity.

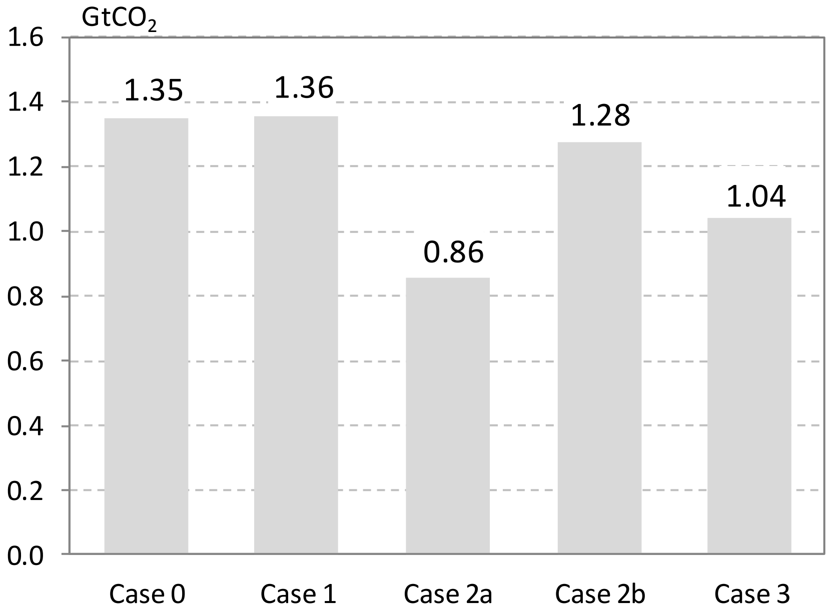


Figure 3-8 CO_2 Emissions in 2035 (Total of All Regions)

3-4 Power Trade Flows in 2035

Figures 3-9 to 3-12 show power trade flows in 2035. In Case 1 (Figure 3-9), because the utilization of additional hydro-potential is not envisioned, the quantity of power trade is small compared to Cases 2a, 2b and 3. However, even in this case, accompanying changes chiefly in thermal power generation, power trade takes place, with Thailand the biggest importer of power, followed by Singapore. The biggest power exporter is Lao PDR, which supplies electricity to Thailand.

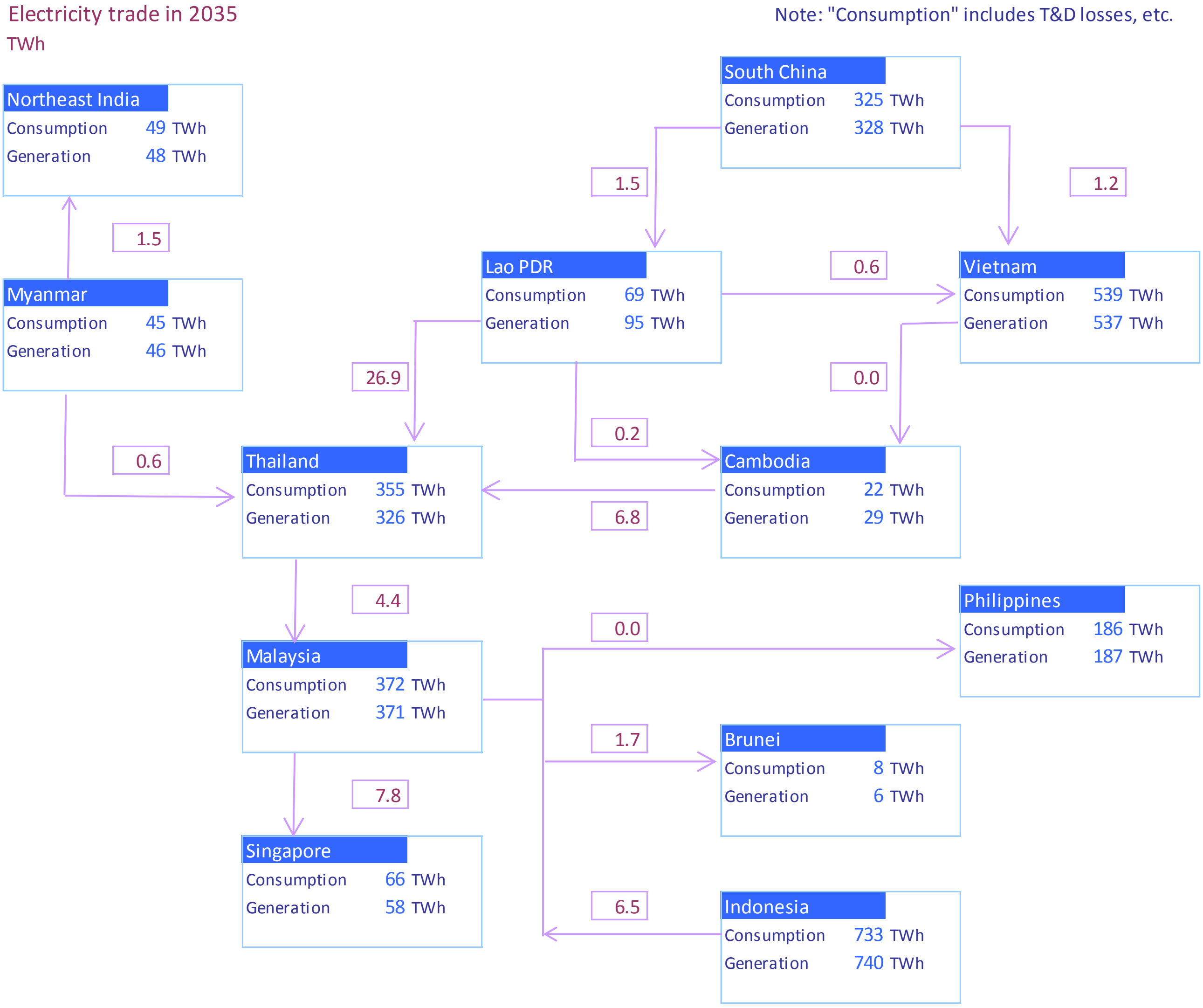


Figure 3-9 Electricity Trade in 2035 (Case 1)

In Case 2a, which envisions the utilization of additional hydro-potential, power is exported to Thailand from three neighboring countries of Myanmar, Lao PDR and Cambodia. Substantial volumes are advanced from Lao PDR and Myanmar in particular, countries which have large additional hydro-potential. Additionally, in this scenario power is also supplied to Thailand from northeastern India, via Myanmar. Southern China also supplies power to Thailand via Lao PDR, but it supplies more power to Vietnam.

Meanwhile, power flows to Malaysia from Thailand. Some is utilized as Malaysian power supply, and along with that, power advanced from Indonesia is utilized to satisfy power demand in Singapore.

The Philippines is a latent power importer, but in the model analysis results it does not import power. This is because the distance covered by a seafloor cable from Malaysia (Borneo) to the Philippines would be extremely long, and the construction cost would exceed the advantages arising from the supply.

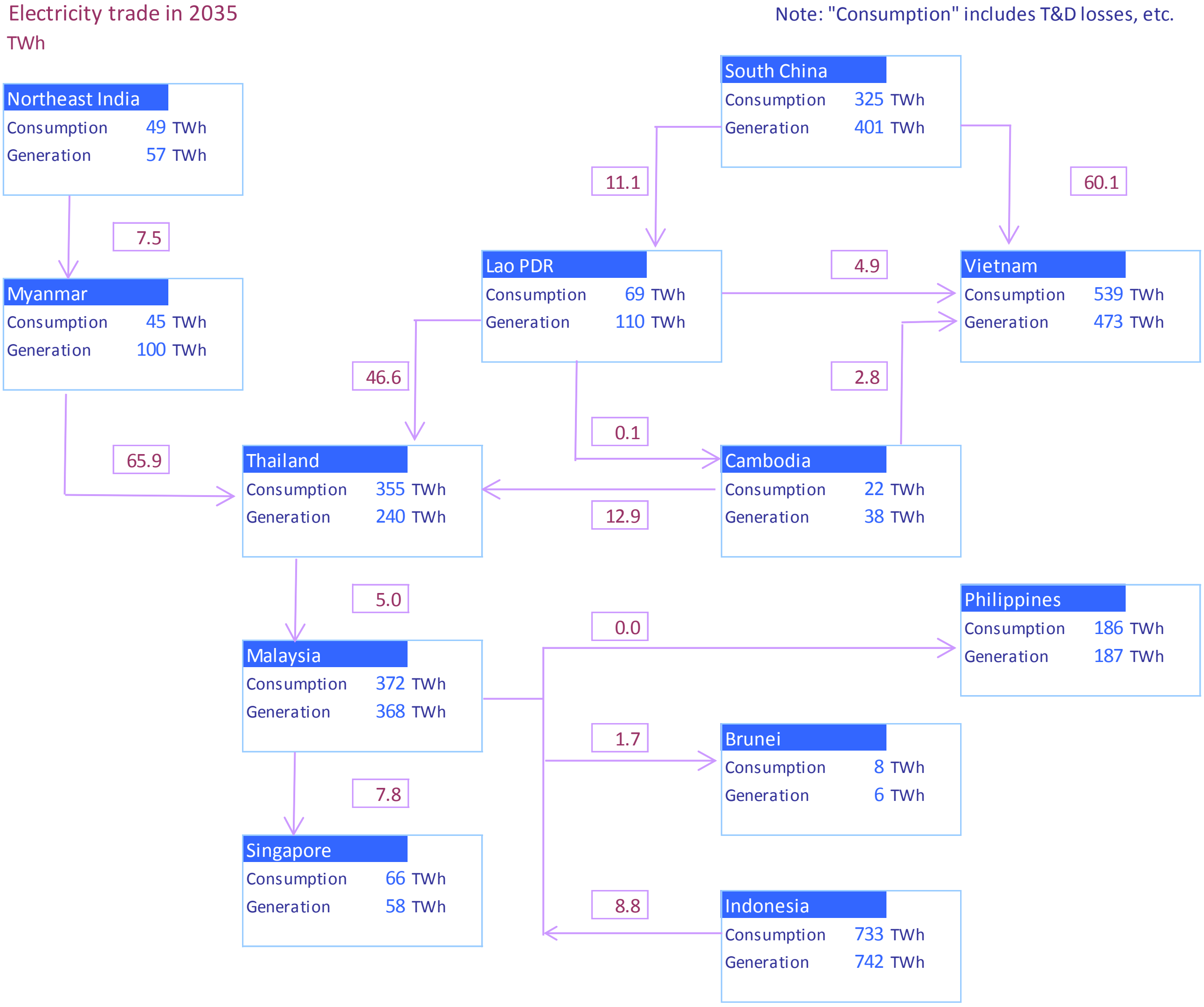


Figure 3-10 Electricity Trade in 2035 (Case 2a)

Case 2b envisions a scenario in which additional hydropower generation potential is not used to satisfy domestic demand in the country concerned, and is only used for exporting. As mentioned above, this case is more realistic. From the standpoint of the quantity of power trade, the outcomes in this case basically resemble those in Case 2a.

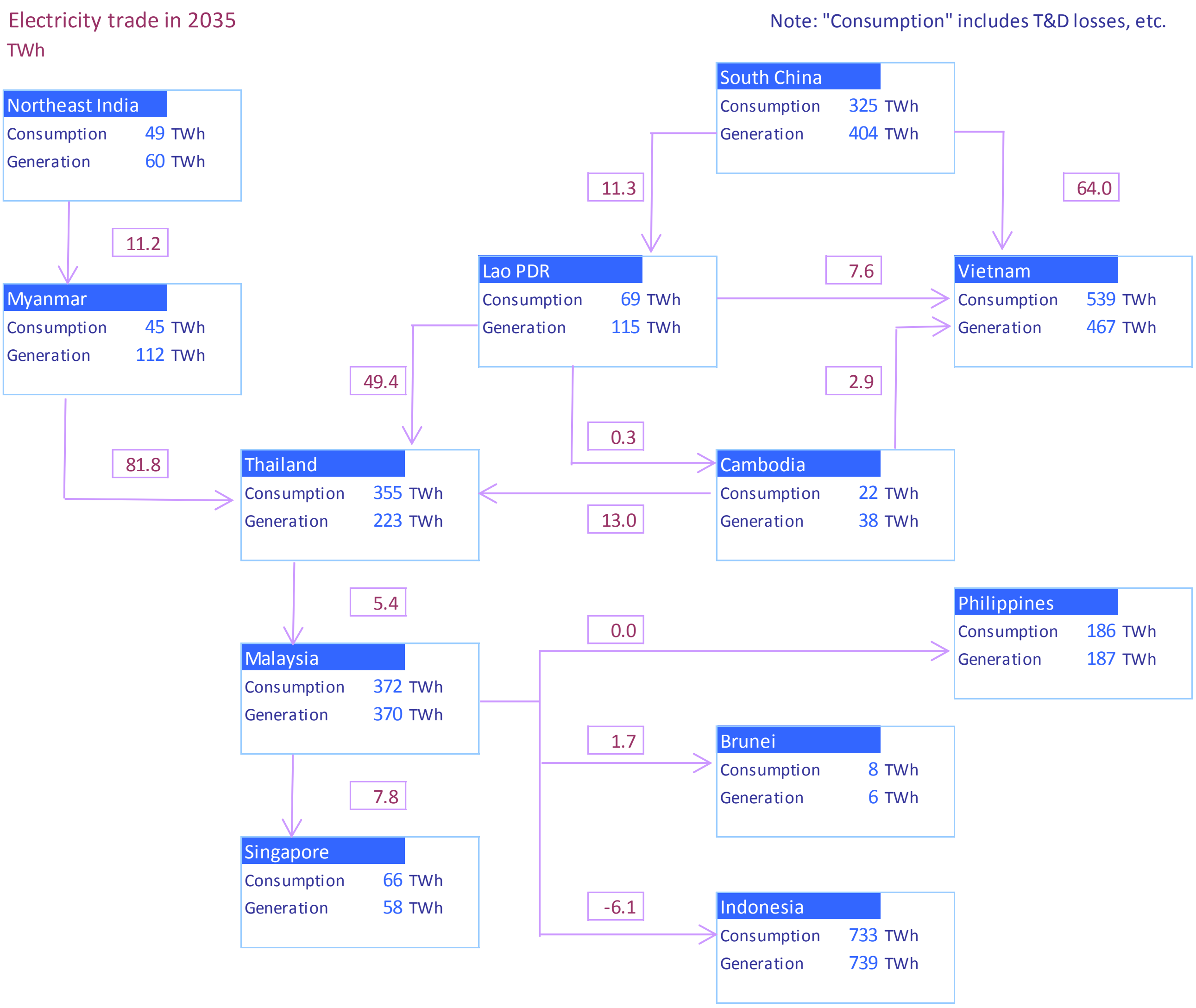


Figure 3-11 Electricity Trade in 2035 (Case 2b)

Case 3 is a case in which no limit is set on grid connection, and additional hydropower generation potential is exercised to the fullest. Myanmar is recognized as having massive potential capacity in particular, and would supply Thailand with 265 TWh of power per year, as well as supplying power to Singapore, Indonesia and Brunei from Thailand via Malaysia. As mentioned above, a more detailed exploration of whether it would be possible to utilize additional hydropower generation to this extent is required. The results of Case 3 can be viewed as suggesting one orientation for looking at a case where power supply on a scale exceeding HAPUA's plans is envisioned, and at what would be a rational form for it to take in terms of power supply and demand.

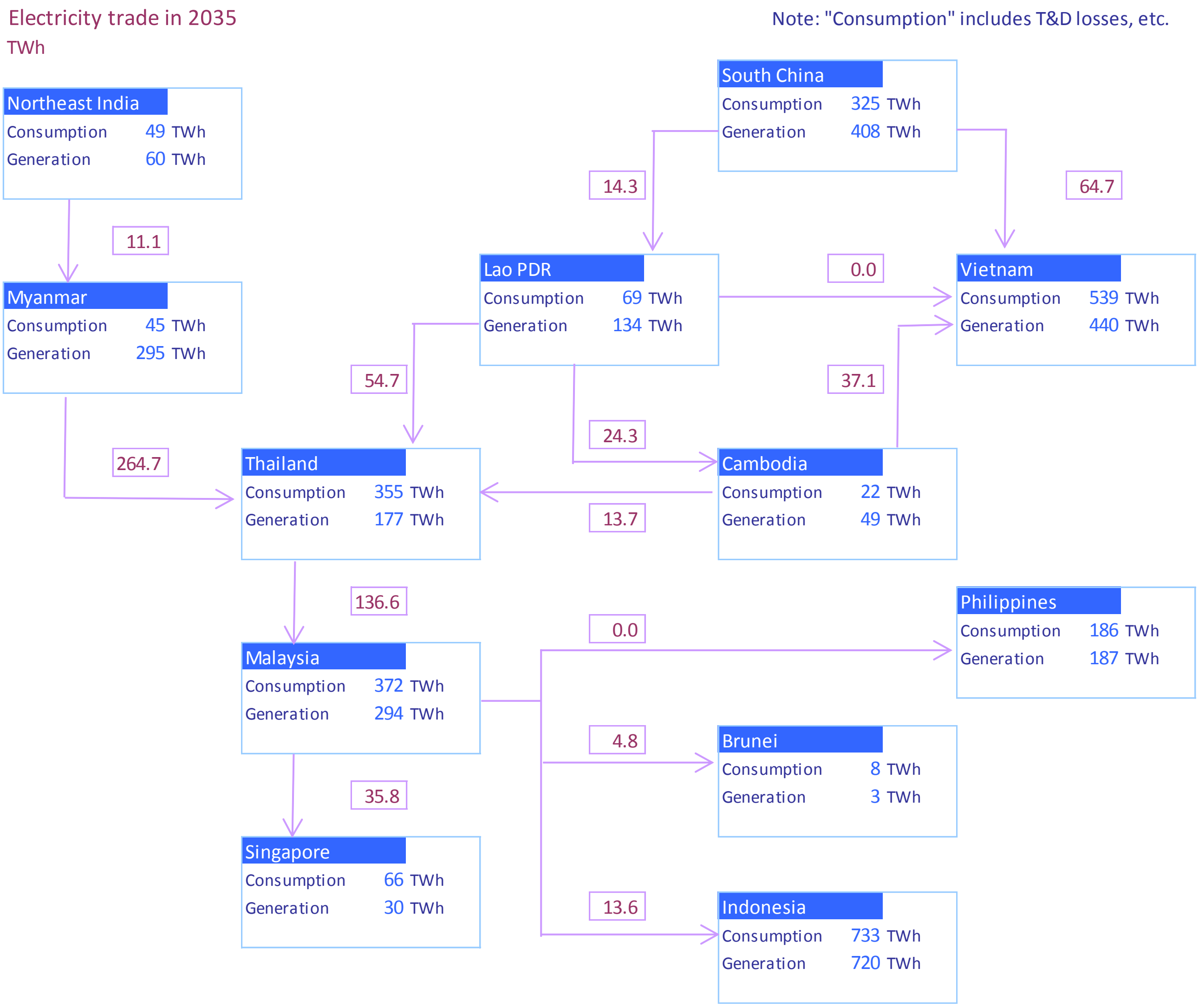


Figure 3-12 Electricity Trade in 2035 (Case 3)

3-5 Changes in Power Trade in Case 2a

Figures 3-13 to 3-16 show changes to power interchange in Case 2b. This case envisions grid connection lines, to be constructed around 2020 and to commence operations from around 2025. In these figures, positive numbers indicate power is being supplied in that direction, and negative numbers indicate power is being supplied in the opposite direction.

Figure 3-13 presents the annual flow via four interconnection lines from southern China to Vietnam and to

Lao PDR, from Cambodia to Vietnam, and from Lao PDR to Vietnam. Power supply from southern China to Vietnam grows continuously. In contrast a flow develops from Vietnam to Cambodia and Lao PDR in 2025, which occurs in order to supply power to Thailand via these countries. The direction of power trade in these interconnection lines is determined as a result of Thailand and Vietnam's demand balance.

The ERIA Outlook sketches a scenario in which Vietnam's power supply and demand grows the most rapidly towards 2035. Consequently, in 2035 the trend reverses, and power is supplied from Cambodia and Lao PDR to Vietnam. Accompanying the expansion in supply from southern China to Vietnam, the exports from southern China to Lao PDR decreases toward 2035.

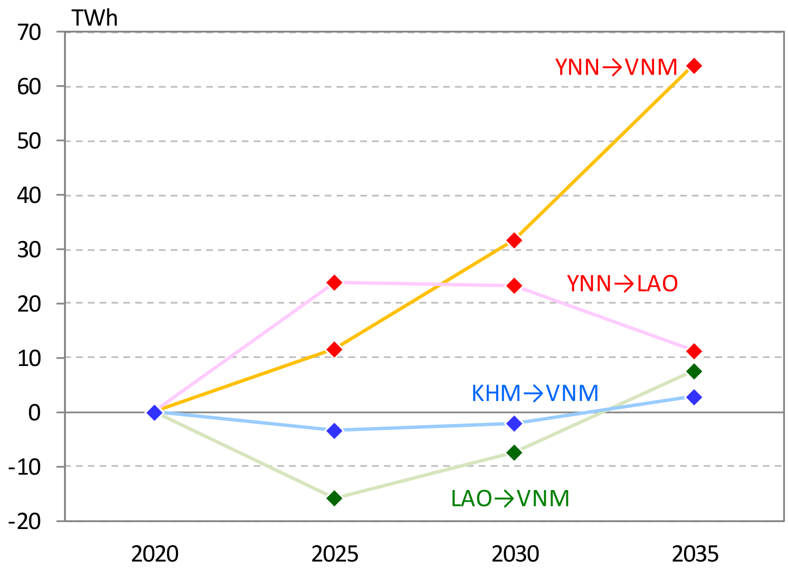


Figure 3-13 Electricity Exports in Case 2b

Figure 3-14 shows the power supply from Myanmar, Lao PDR, Cambodia and Malaysia to Thailand. As of 2025, Lao PDR is the largest supplier of power to Thailand, followed by Myanmar and Cambodia. However, accompanying the rapid expansion in Vietnam's demand, the supply from Lao PDR and Cambodia begins decreasing toward 2035, and Myanmar assumes position as the largest supplier. Meanwhile, despite being in a small net import position with Malaysia in 2025, by 2035 power is conversely being exported from Thailand. As a result, as shown in Figure 3-15, it becomes possible to supply hydro-potential in the northern regions to the southern regions including Singapore. In particular, this influence is strikingly noticeable around 2035, when supply in the south begins to run short accompanying expanding demand in Indonesia.

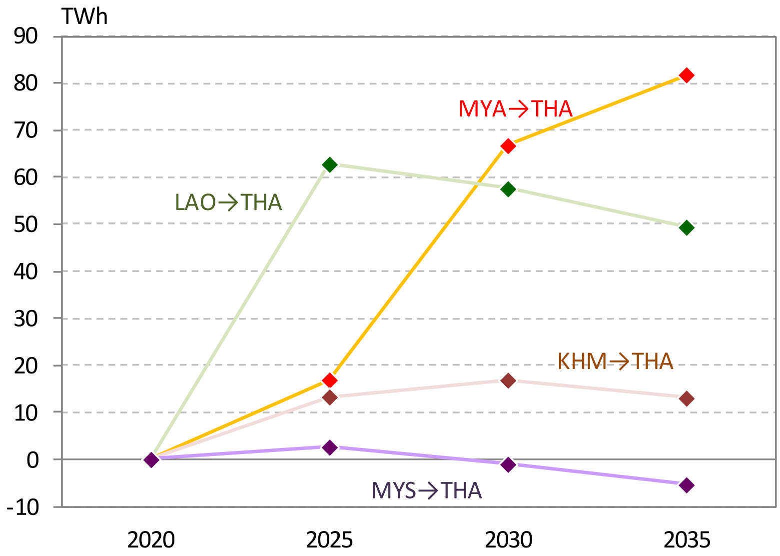


Figure 3-14 Electricity Exports in Case 2b (cont.)

Figure 3-15 presents the export from Malaysia to Singapore, Brunei, Thailand and Indonesia. As this figure shows, Singapore and Brunei enjoy a stable power supply via Malaysia. The countries providing the supply for that are Indonesia and Thailand, but their supply amounts change over time. Namely, supply shrinks in Indonesia accompanying rapid growth in domestic demand, and accordingly, the reliance on northern hydro that passes through Thailand increases. This region's supply capacity itself is around 5-10 TWh, and is small in scale when compared to the supply and demand balance in the northern region shown in Figures 3-13 and 3-14, which centers on Thailand and Vietnam.

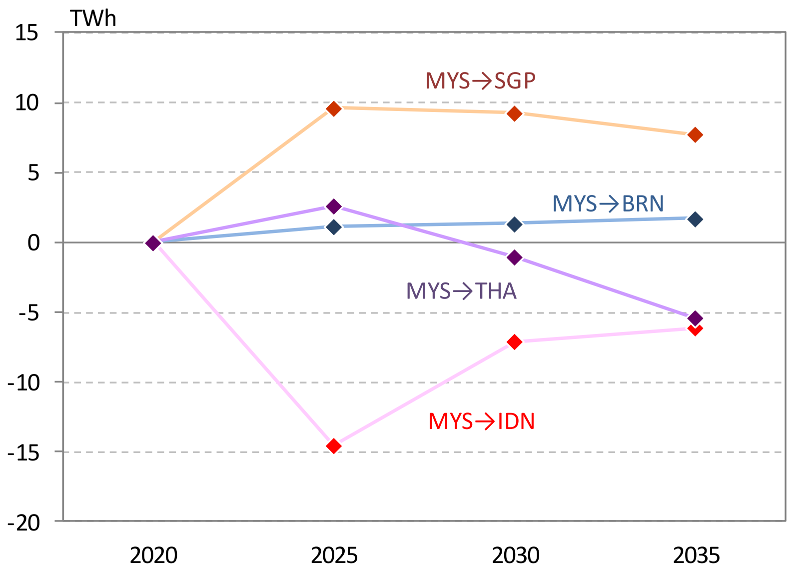


Figure 3-15 Electricity Exports in Case 2b (cont.)

Figure 3-16 shows the export from Northeast India to Myanmar and from Myanmar to Thailand. This interchange continues to grow up to 2035. In other words, amid the ongoing expansion in power demand in Vietnam, Thailand, and Indonesia in the long term, the importance of these regions' power supply capacity will increase more.

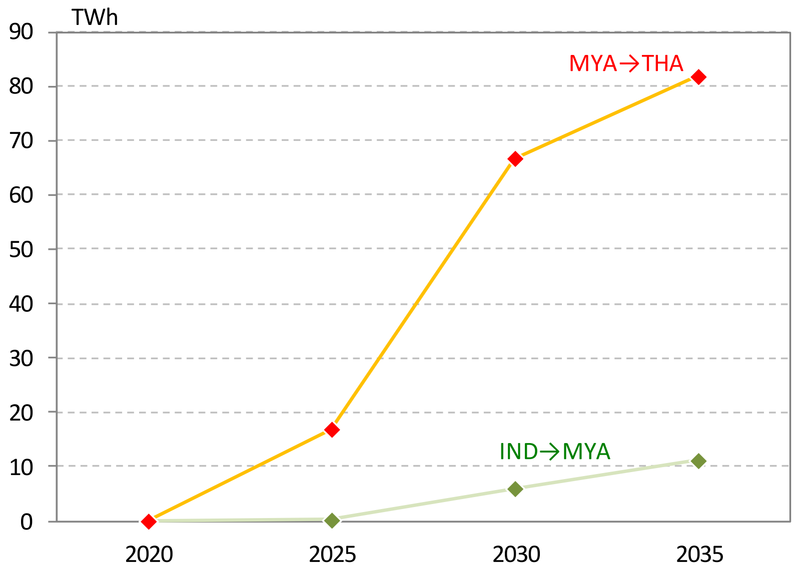


Figure 3-16 Electricity Exports in Case 2b (cont.)

3-5 Cumulative Costs up to 2035 and 2050

Figure 3-17 shows the differences in the cumulative costs up to 2035 and 2050 in Cases 1, 2b and 3, compared to Case 0.

In Case 1, accompanying the decline in the supply reserve rate arising from power interchange compared to Case 0, the required initial investment amount decreases. Accordingly, the O&M costs also fall, and the fossil fuel expenses also decline accompanying the replacement of natural gas-fired with coal-fired thermal. In total, the cumulative costs up to 2035 (the total for the 12 countries and regions) declines by around 9.1 billion USD.

In Case 2b, which takes into account the utilization of additional hydropower potential, fossil fuel expenses decrease substantially on the one hand, while initial investments and O&M costs increase on the other as a result of a shift from natural gas-fired to hydro. When these outcomes are all totaled, the cumulative costs up to 2035 fall by 6.6 billion USD compared to Case 0, and increase by 2.5 billion USD compared to Case 1. In Case 3, where the usage of additional hydropower generation potential is greater, there is a 3.8-billion USD decline in cumulative costs compared to Case 0 and a 5.3-billion USD increase compared to Case 1.

The increase in cumulative costs up to 2035 accompanying the utilization of additional hydro points to the fact that it will not be possible to fully recover the initial investment needed for hydropower generation facilities. If the cumulative costs are evaluated over a longer time-scale, such as until 2050, then because more of the initial investment for hydro will be recovered, the cumulative costs in Case 2b and 3 will decline compared to Case 1. Cumulative cost reduction from Case 1 to Case 2b amounts to 15.8 billion USD. In this way, the economics of constructing international interconnection lines becomes a problem stretching across a long period of time, and requires plans to be drawn up and carried out from a long-term perspective.

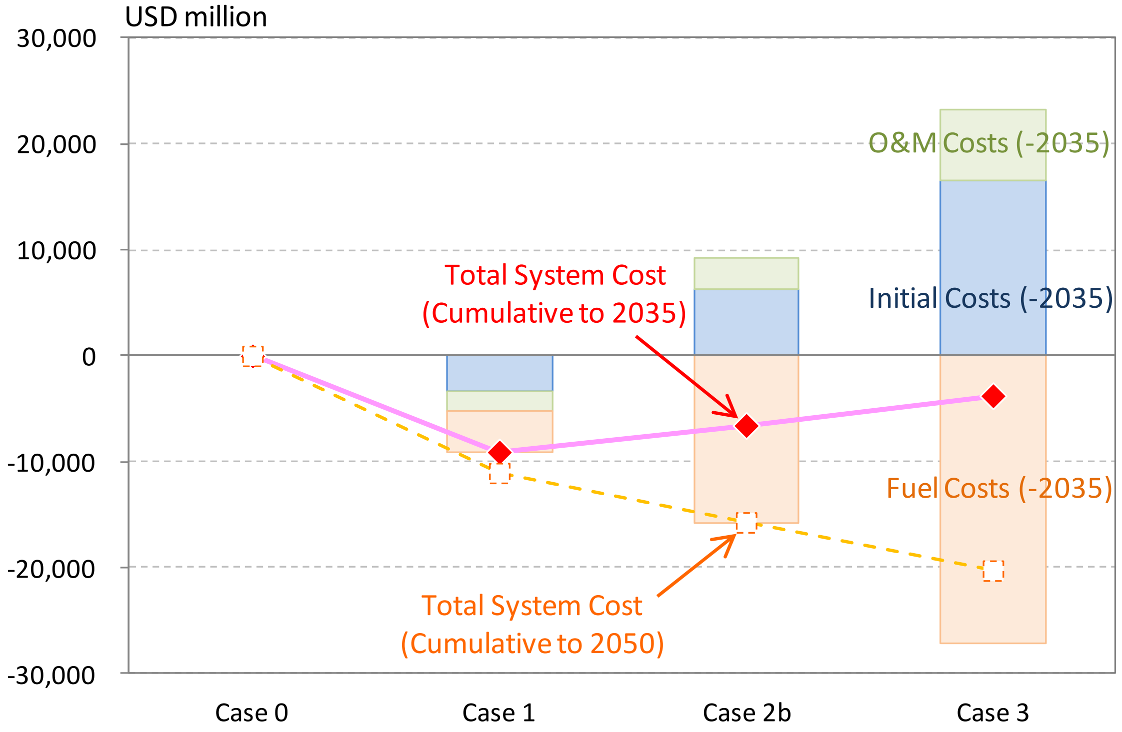


Figure 3-17 Cumulative Costs up to 2035 and 2050

3-6 Costs and Benefits for Individual Interconnection Lines

Table 3-1 shows the costs and benefits (cumulative up to 2035) for individual interconnection lines.

Table 3-1 Possible Interconnection Lines and the Costs/Benefits

Unit 2012 USD million

Case		Costs of Transmission Lines	Net Benefits (Benefits - Costs)
A	THA-KHM	162 — 1,009	4,560 — 5,470
B	THA-LAO	728 — 1,957	19,282 — 20,604
C	THA-MYA	2,244 — 3,956	-4,607 — -2,766
D	MYA-THA-MYS-SGP	2,384 — 6,272	-1,118 — 3,064
E	VNM-LAO-THA	922 — 2,885	21,604 — 23,715
F	MYS-IDN	1,790 — 1,901	3,968 — 4,087
G	LAO-THA-MYS-SGP	868 — 4,273	23,217 — 26,557

In Cases B, E and G, the cost-reduction arising from interconnection appears to be significant. Of the seven cases, the size of the cost benefit is largest in these cases. In Cases A and F, although the overall reduction amount is not as large as in B, E and G, there is a strong possibility of cost reductions even if the interconnection line cost is taken into account. In Cases D and C, immediate benefit from interconnected lines cannot be anticipated, although it is possible to anticipate further increase of benefit in the longer term.

This study is positioned as a preliminary assessment, the cost estimation is not perfectly accurate. Therefore, while a comparative evaluation is possible to a certain extent, a detailed and definitive evaluation is not possible at present. In the future it will be necessary to utilise these cases, and proceed with a more detailed evaluation.

What should be considered here is the size of the investment into interconnected lines. In Case G, for example, the total investments amount to as much as 4,300 million USD. There is of course a need for the provision of capital and manpower. For that reason, if, for instance, the construction of all the candidate routes were to commence at the same time, it can be expected that the project would run into physical difficulties. Accordingly, prioritization should be applied, considering the benefits and feasibility of each route.

4. Conclusions

The most fundamental thing that has been uncovered through this study is, how the entire region could benefit from the strengthening of international grid interconnections. Within this region, there is a trend towards a widespread increase in power demand. On the other hand, the situation related to the presence of fuel resources for power generation differs from country to country. For that reason, while one country may be blessed with abundant resources, another country may have no choice but to rely on imports. Where relationships among neighboring countries are adversarial, each country has no choice but to fulfil its own demand entirely with domestic supply. However, given the trend towards promoting economic integration within this region from an economic perspective it is more logical to find a balance between power supply and demand at a regional level, rather than at an individual country level.

More specifically, in Laos, Cambodia, Myanmar and China's Yunnan Province, in particular, there is great potential for hydropower generation. Although the cost of hydropower varies greatly by location, in many cases, it is competitive with natural gas-fired power generation and coal-fired power generation. Furthermore, in terms of making a response to the problem of climate change, there is demand for the use of energy sources with the smallest possible carbon emissions, and from that perspective as well, hydropower generation is thought to be an appropriate choice. In order to make the greatest possible use of this latent resource, there is a need for a regional interconnected power system.

In addition, utilizing the different power demand pattern of each country, it is possible to reduce the cost of the power supply throughout the entire region. If a country is to meet its power demand on its own, it must maintain a sufficient reserve margin in line with its peak demand levels. If power interchange were possible with neighboring countries with differing peak demand times, it would be possible to reduce the investment needed in order to maintain a reserve margin.

In such a way, regional grid interconnections would give rise to economic benefits for the entire region, although the extent of those benefits would depend on the route. For instance, in cases where neighboring countries also face a lack of sufficient fuel resources for power generation, or cases where peak times occur simultaneously, it would not be possible to achieve the above effects even with grid interconnections. In addition, naturally, the cost of grid interconnections would also affect this issue. If the economic benefits gained from the grid interconnections are less valuable than their investment costs, there is no point in creating grid interconnections in the first place.

This study performed a cost-benefit analysis for each of the many routes thought to be promising for grid interconnections. We found that the Lao-Thailand-Malaysia-Singapore route possesses great potential. The estimated cumulative benefits are enormous, exceeding nominal GDP in 2011 for Lao PDR (USD 8,162 million), Cambodia (USD 12,890 million) and Brunei Darussalam (USD 16,693 million). In light of this, there is sufficiently large economic benefit to be gained from grid interconnection. What should be considered here is the size of the investment into interconnected lines. Prioritization should be applied, considering the benefits and feasibility of each route.

Plans are already in motion to realize a grid interconnection in ASEAN by the Head of ASEAN Power Utilities/Authorities (HAPUA). Each of the routes selected by this study have also been proposed by HAPUA, indicating that the study is roughly consistent with HAPUA's plan. On the other hand, while HAPUA's construction plans generally set a target of 2020, this study considers the accumulated benefit from 2020 to 2035, and is thus regarded as an extension of the HAPUA plans. The reliability of the analysis of this study would be improved by addressing the remaining issues, including more precise estimation of hydropower costs and potentials, existing barriers for the actual realization of grid interconnections, etc. It is hoped that the improvement of the validity of this analysis will create an opportunity for the realization of investment.

Acknowledgement

This study has been partially supported by the Economic Research Institute for ASEAN and East Asia: (ERIA). We would like to offer our deepest appreciation to ERIA.

References

1) International Energy Agency (IEA), "Energy Balances of non-OECD countries", IEA Publications, (2013).
2) Ibrahim, S.B., HAPUA Secretary, "Barriers and Opportunities for Electricity Interconnection the Southeast Asian Experience", (2014).
http://aperc.ieej.or.jp/file/2014/4/4/S2-2-2_IBRAHIM.pdf
3) ASEAN Centre for Energy (ACE), "ASEAN Plan of Action for Energy Cooperation 2010-2015".
http://aseanenergy.org/media/filemanager/2012/10/11/f/i/file_1.pdf
4) Kimura, S. et al., "Analysis on Energy Saving Potential in East Asia Region", ERIA Research Project Report 2011, No.18, (2012).
5) Platts, "World Electric Power Plants Database".
http://www.platts.com/products/world-electric-power-plants-database
6) Poch, K., "Renewable Energy Development in Cambodia: Status, Prospects and Policies", ERIA Research Project Report 2012-26 (2013), pp.227-226.
7) Chimklai, S., Electricity Generating Authority of Thailand (EGAT), "ASEAN Interconnection Briefing on ASEAN Power Grid", (2013).
http://portal.erc.or.th/aern/images/Panel%201-1%20Briefing%20on%20ASEAN%20Power%20Grid.pdf
8) Ministry of Energy (Thailand), "Thailand Power Development Plan 2012-2030 (PDP2010: Revision 3)", (2012).
9) Government of India, Ministry of Power, Central Electricity Authority (CEA), "National Electricity Plan", (2012).
10) Japan Electric Power Information Center (JEPIC), "Overseas electric power industry statistics 2012", (2012). [In Japanese]
11) OECD/NEA, IEA, "Projected Costs of Generating Electricity 2010 Edition", (2010).
12) IEA, "Energy Technology Perspectives 2012", (2012).
13) U.S. Energy Information Administration (U.S.EIA), "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants", (2013).
14) IEA, "Coal Information 2014", IEA Publications, (2014).
15) Bot Sosani, HAPUA Secretariat, "ASEAN Power Grids Interconnection Projects for Energy Efficiency and Security Supply", (2013).
16) Zhai Y., "Energy Sector Integration for Low Carbon Development in Greater Mekong Sub-region: Towards a Model of South-South Cooperation"
http://89.206.150.89/documents/congresspapers/52.pdf

Appendix A　Models Used for the Calculations

(1) Power Generation Planning Model

In this study, an optimal power generation planning model using the linear programming (LP) method was employed to estimate future power demand and supply. The model's main preconditions and output results are shown in Figure A-1.

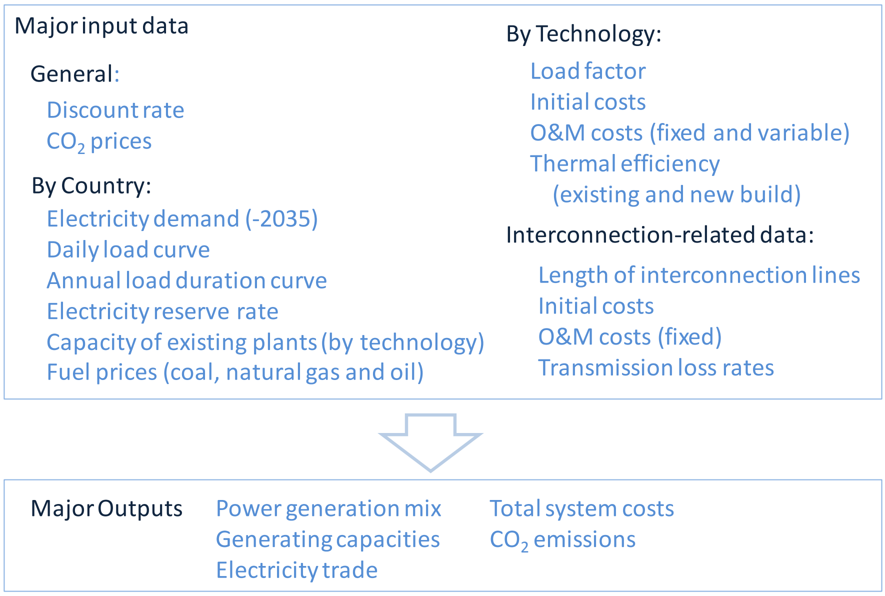


Figure A-1 Input and Output Data for the Power Generation Planning Model

In this model, the cost-optimal (i.e. the minimum total system cost) power generation mix for each country is estimated, with preconditions such as the power demand and load curve of each country and the cost and efficiency of each power generating technology.

When comparing coal-fired power generation and natural gas-fired power generation, the former has higher initial investments and lower fuel costs. Thus, as shown on the right in Fig. 3-2, coal-fired generation is cost-advantageous when the load factor is high, and natural gas-fired is cost-advantageous when the load factor is low. Consequently, according to cost minimization calculations, in the annual load duration curve shown on the left in Figure A-2, in the domain where the annual operating volume is large (the middle and lower part of the figure) coal-fired is chosen; and in the domain where the annual operating volume is small, (middle and upper part of the figure) natural gas-fired or oil-fired is chosen.

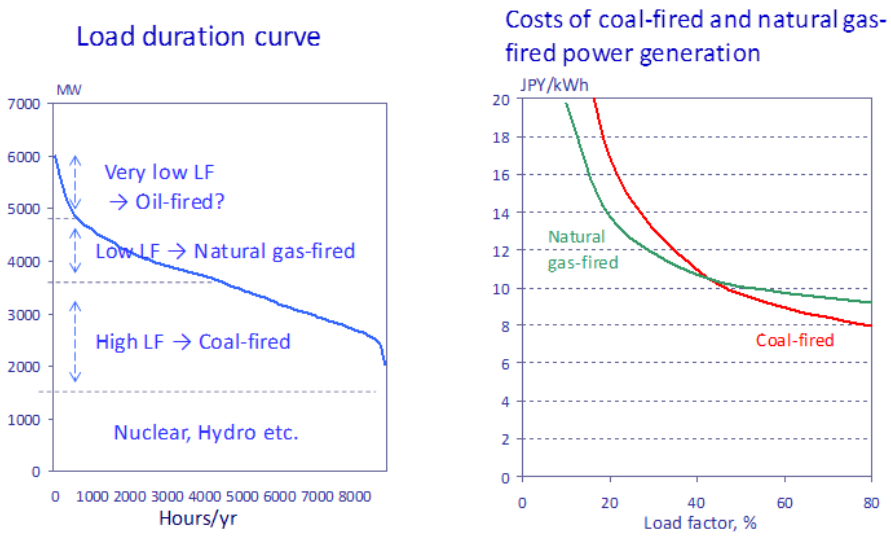


Figure A-2 Concept of the Power Generation Planning Model

Additionally, in this study, it was made possible to simulate electricity trade using international interconnection lines. At a certain time on a certain day, if power export of Z (MW) is carried out from Country A to Country B, the operating capacity of the power generating facilities in Country A must be larger than the power demand by Z, while the operating capacity of the facilities in Country B will be less than the demand by Z × (1 - transmission loss rate). Here, Z cannot exceed the transmission line capacity, and alongside the cost incurred in constructing transmission lines, if an upper limit is set on the transmission line capacity, Z cannot exceed that upper limit.

The objective function and main constraint equations are as follows. Incidentally, although the power generation facility operation, the power trade, and the power consumption are variables dependent upon days *d* and time *t*, but for simplicity these subscripts are omitted.

(Objective function)

$$TC = \sum_{r,i,T,d,t} \frac{1}{(1+dr)^{T}} \left\{ Xe_{r,i,T}\left(Cv_{r,i} + \frac{P_{i,T}}{Ee_{r,i}}\right) + \sum_{T'<T} Xn_{r,i,T,T'}\left(Cv_{r,i} + \frac{P_{i,T}}{En_{r,i,T'}}\right)\right\}$$

$$+ \sum_{r,T',d,t} \frac{1}{(1+dr)^{T'}} \left\{ \sum_{i} Yn_{r,i,T'}\left(I_{r,i} + \sum_{T'<T}\frac{Cf_{r,i}}{(1+dr)^{T-T'}}\right) + \sum_{r'} W_{r,r',T'}\left(II_{r,r'} + \sum_{T'<T}\frac{Cif_{r,r'}}{(1+dr)^{T-T'}}\right)\right\}$$

where

T: year of operation, *T'*: year of construction, *r*, *r'*: country number,
i : number indicating power generation technology, *dr*: discount rate,
Xe: operation of existing facilities, *Xn*: operation of new facilities,
Yn: capacity of new facilities, *W*: interconnection line capacity,
Cv: variable operation and maintenance (O&M) costs (power generation facilities),
Cf: fixed O&M costs (power generation facilities),
Cif: variable O&M costs (interconnection lines), P: fuel price,
I: unit construction cost (power generation facilities),
II: unit construction cost (interconnection lines),
Ee: existing power generation facility efficiency,

En: new power generation facility efficiency,
d: day and *t*: time

(Power supply and demand) For all d and t,

$$D_{r,T} < \sum_{i}\left(Xe_{r,i,T} + \sum_{T'} Xn_{r,i,T,T'} \right)(1 - ir_i) + \sum_{r'} \left\{ (1 - lr_{r,r'}) Z_{r',r,T} - Z_{r,r',T} \right\}$$

where
D: power consumption (including transmission loss etc.), *ir*: auxiliary power ratio,
Z: power trade: *lr*: transmission loss rate

(Existing facility power generation capacity constraints) For all d and t,

$$Xe_{r,i,T} < F_{r,i} Ye_{r,i,T}$$

where
Ye: existing facility capacity, *F*: load factor

(New facility power generation capacity constraints) For all d and t,

$$Xn_{r,i,T} < F_{r,i} \sum_{T'<T} Yn_{r,i,T'}$$

(Power trade capacity constraints) For all d and t,

$$Z_{r,r',T} < \sum_{T'<T} W_{r,r',T'}$$

(Supply reserve margin)

$$PD_{r,T}(1 + s_r) < \sum_{i} F_{r,i} \left(Ye_{r,i,T} + \sum_{T'<T} Yn_{r,i,T'} \right)$$

where
PD: maximum demand, *s*: supply reserve rate

(2) Supply Reliability Evaluation Model

In this study a supply reliability evaluation model employing the Monte Carlo method was used in combination with the above-mentioned optimal power generation planning model. A conceptual diagram of this model is shown in Figure A-3.

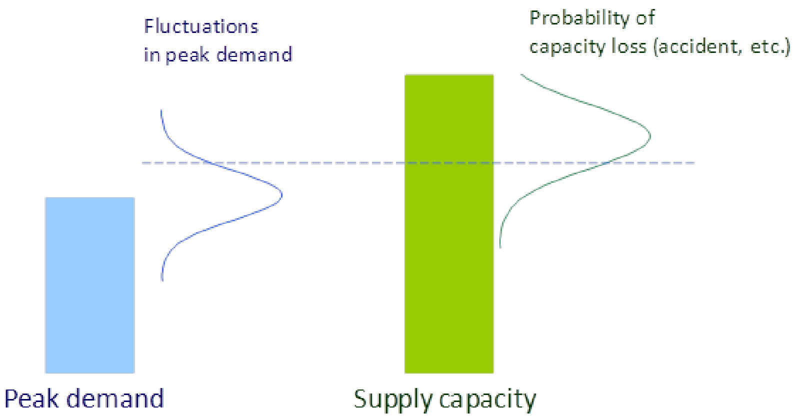


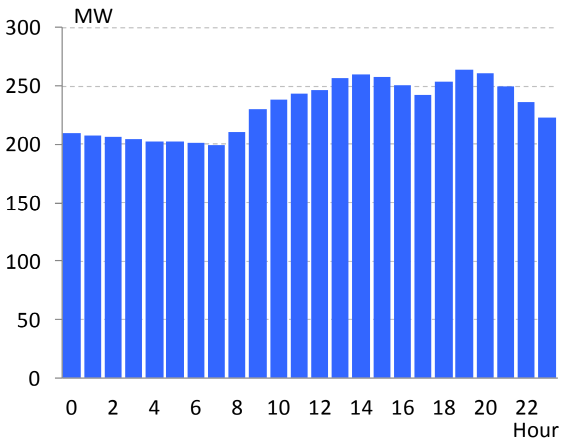
Figure A-3 Concept of the Supply Reliability Evaluation Model

If there are no concerns with the power generation facilities, it is possible to manage the power supply system with some leeway, because a certain reserve capacity is envisaged. In reality, however, power generation facilities suffer breakdowns with a degree of certainty, and so their effective supply capacity drops. Forecasted power demand changes with a certain standard deviation, and when the latter exceeds the former it results in a power outage. In this study, the probability of a trouble occurring at one plant is assumed at 5%, and the standard deviation of power demand changes is assumed to be ±1%. Based on the output results of the optimal power generation planning model, the loss of load expectation (LOLE) is calculated. This is then fed back, and as a result, a supply reserve rate is set for each country and region as a precondition for the power generation planning model, so that the LOLE becomes 24 hours/year.

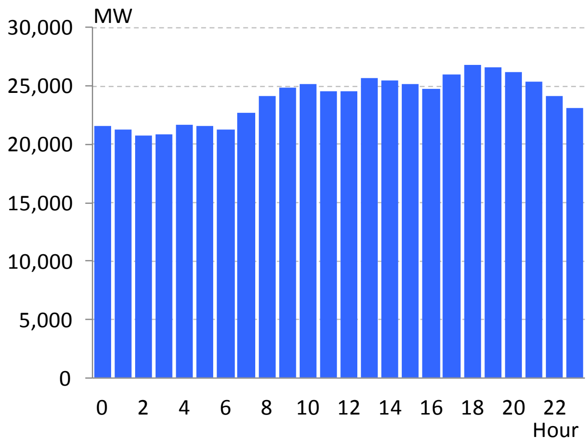
In a case where there is no international grid connection present, because changes in power demand must be handled using only domestic power generation facilities, the LOLE becomes relatively high. By comparison, when an international grid connection is envisioned, the LOLE declines remarkably because even if breakdown occurs at a domestic power generation facility, it will be possible to avert a power outage by importing power. Or, if the LOLE is set at 24 hours, the supply reserve rate for responding to that declines, and it becomes possible to economize on the corresponding initial investment and fixed operating and maintenance costs.

Appendix B Examples of Daily Load Curves

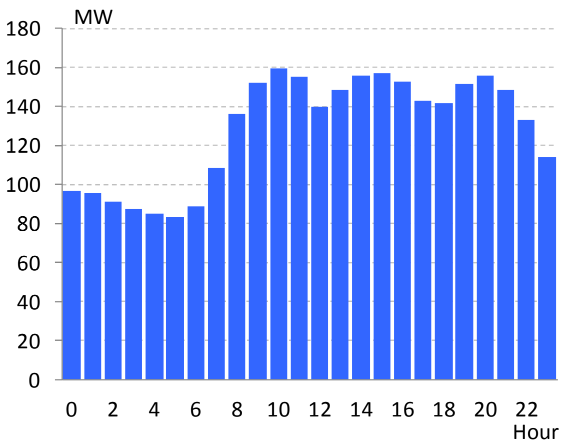
Following are the peak demand day load curves used in this study. For countries for which peak demand day data were not available, we used annual average or other data. The estimation model used only the shapes of these curves with their heights (indicating peak load) normalized appropriately.



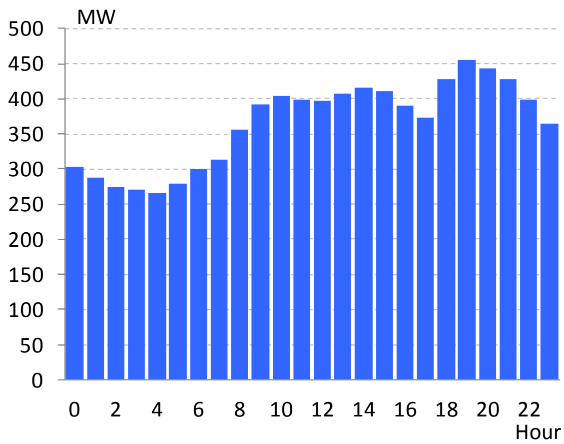
Brunei Darussalam (Weekday, 2006)



Indonesia (Peak day in the dry season, 2013)



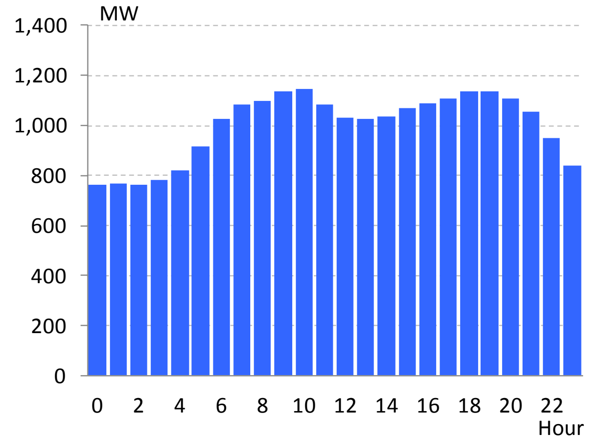
Cambodia (2007 average)



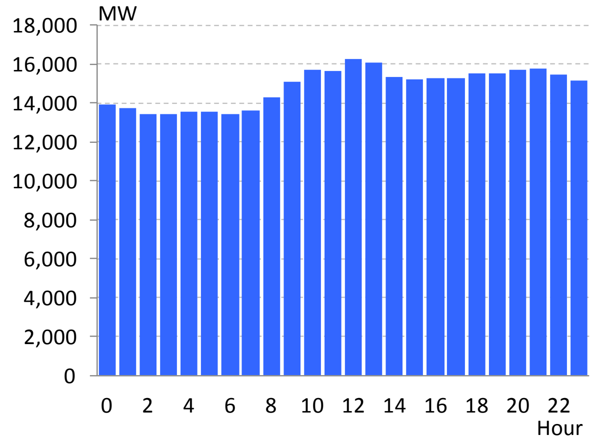
Lao PDR (Peak day in the dry season, 2012)

Source: ERIA Research Project Report 2013-23

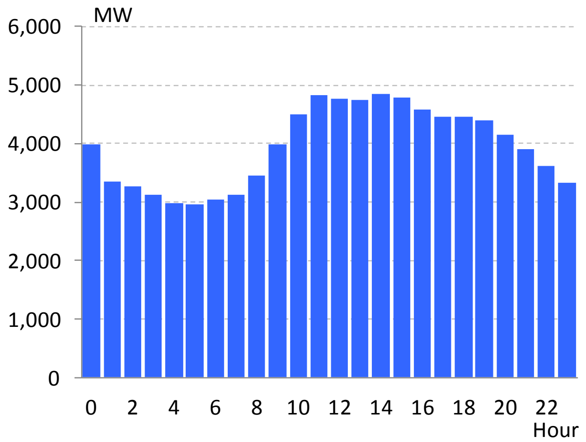
Figure B-1 Daily Load Curves



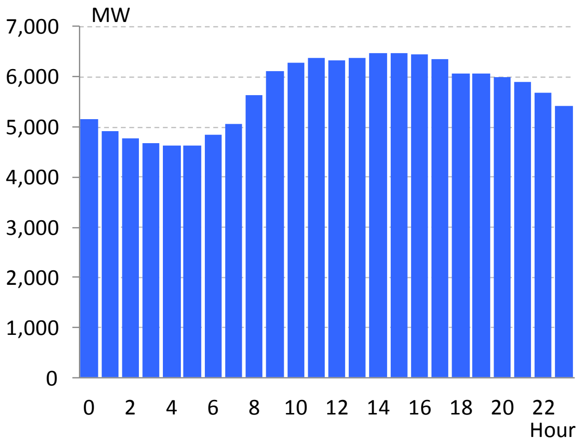
Myanmar (Peak day in the rainy season, 2007)



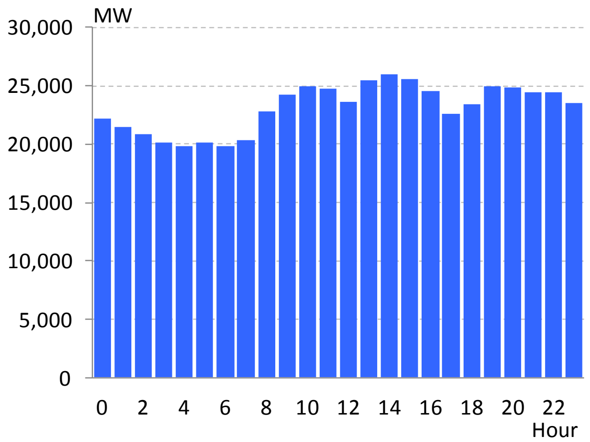
Malaysia (Peak day in June, 2012)



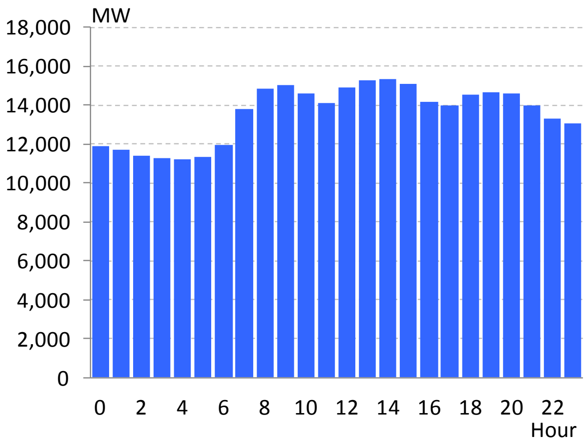
Philippines (Normal day, 2011)



Singapore (Peak day in May, 2010)



Thailand (Peak day in April, 2012)



Vietnam (Peak day in 2010)

Source: ERIA Research Project Report 2013-23

Figure B-2 Daily Load Curves (cont.)

Contact: report@tky.ieej.or.jp