ERIA Research Project Report 2012, No. 23

STUDY ON EFFECTIVE INVESTMENT OF POWER INFRASTRUCTURE IN EAST ASIA THROUGH POWER GRID INTERCONNECTION

Edited by
ICHIRO KUTANI

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DISCLAIMER

This report was prepared by the Working Group for the "Study on Effective Investment of Power Infrastructure in East Asia through Power Grid Interconnection" under the Economic Research Institute for ASEAN and East Asia (ERIA) Energy Project. Members of the Working Group, who represent the participating EAS region countries, discussed and agreed to utilize certain data and methodologies proposed by the Institute of Energy Economics, Japan (IEEJ) to assess the optimal power supply infrastructure for this study. These data and methodologies may differ from those normally used in each country. Therefore, the calculated result presented here should not be viewed as official national analyses of the participating countries.

ACKNOWLEDGEMENTS

This analysis has been implemented by a working group under ERIA. It was a joint effort of Working Group members from the EAS Countries and the IEEJ (The Institute of Energy Economics, Japan). We would like to acknowledge the support provided by everyone involved. We would especially like to express our gratitude to the members of the Working Group, Economic Research Institute for ASEAN and East Asia (ERIA) and IEEJ's study project team.

Mr. Ichiro Kutani

Leader of the Working Group

June 2013

FOREWORD

In East Asian countries where there electricity demand has rapidly increasing, are facing necessity to construct new power plants in a timely manner to serve electricity demand. At the same time, cheaper electricity will be required when considering impact on general public and economy, and needs for cleaner electricity will become stronger when considering impact on pollution and climate issue.

On the other hand in East Asian countries, there are remaining of undeveloped (potential) resources like coal, natural gas and river to fuel power plant. If the region can utilize these resources, it would benefit to cheaper supply and cleaner electricity generation, and also contribute to enhance energy security through reducing regional import dependency of energy supply.

One possible option to maximize the use of undeveloped (potential) resources in the region is international grid interconnection. The region can optimize power supply mix through cross-border power transaction.

Against this backdrop, ERIA organized a working group to carry out a new study aims to analyze a possible optimum power generation mix of the region, and to provide policy recommendations for the improvement of that situation. Experts from EAS countries were gathered to discuss their existing power development plan and possibility for regional optimization.

It is my hope that the outcomes of this study will serve as the point of reference for policymakers in East Asian countries and contribute to the improvement of energy security in the region as a whole.

Ichiro Kutani

Leader of the Working Group

June 2013

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LIST OF ABBREVIATIONS AND ACRONYMS

ACE = ASEAN Center for Energy

ADB = Asia Development Bank

AEC = ASEAN Economic Community

AFTA = ASEAN Free Trade Area

AIMS = ASEAN Interconnection Master Plan

AMEM = ASEAN Ministers on Energy Meeting

APAEC = ASEAN Plan of Action on Energy Cooperation

ASEAN = Association of Southeast Asian Nations

CCGT = Combined cycle gas turbine

CDM = Clean Development Mechanism

CO_2 = Carbon dioxide

EAS = East Asia Summit

ECTF = Energy Cooperation Task Force

ERIA = Economic Research Institute for ASEAN and East Asia

GDP = Gross Domestic Product

GMS = Greater Mekong Sub-region

GW = Giga Watt

GWh = Giga Watt hour

HAPUA= The Heads of ASEAN Power Utilities / Authorities

IEEJ = The Institute for Energy Economics, Japan

MOU = Memorandum of Understanding

MW = Mega Watt

MWh = Mega Watt hour

ODA = Official Development Assistance

PDP = Power Development Plan

TW = Tera Watt hour

TWh = Tera Watt hour

WG = Working group

EXECUTIVE SUMMARY

CHAPTER 1

For the EAS (East Asia Summit) countries, steady large-scale power source development in an economically efficient way is an urgent task. It may be possible to optimize or improve the efficiency of power infrastructure investments in terms of not only an economic efficiency but also a stability of electricity supply and reduction of the environmental burden if we consider ways of developing power infrastructures (power plant and grids) on a pan-regional basis.

This study will analyze the possibility and benefits of the pan-regional optimization of power infrastructure investments in the EAS region. By doing so, the study is intended to accelerate or support the existing initiatives such as the Asian Development Bank (ADB) and HAPUA (the Heads of ASEAN power Utilities/Authorities).

CHAPTER 2

This chapter presents an overview of power sector and their power infrastructure development plan toward the time frame of 2030 in 13 countries in East Asia region, namely Bangladesh, Brunei Darussalam, Cambodia, China [Yunnan & Guangxi], India [North-East], Indonesia, Lao PDR, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Vietnam. The information shown in this chapter will utilized as input data for a simulation analysis in Chapter 4.

CHAPTER 3

This chapter summarizes existing initiatives by ADB and HAPUA for the power infrastructure development in the East Asia region.

The GMS (Greater Mekong Sub-region) program is an international development plan with the ADB as its secretariat. It was launched in October 1992 through a ministerial meeting of six countries of the Mekong River basin, Thailand, Lao PDR, Cambodia, Myanmar, Vietnam, and China. Some goals of the GMS countries are to establish international power trading in order to increase mutual economic and technical benefits, and to have well-balanced power plants through regional energy sources that enable power transport spanning countries throughout the region.

On the other hand, the ASEAN Power Grid concept in the electric power sector was adopted at the ASEAN summit held in Kuala Lumpur, Malaysia, in December 1997. The secretariat of the ASEAN Power Grid is HAPUA. It was confirmed that regional power interconnection can be promoted through information exchange and technology introduction for the planning, construction, and operation of power grids and through basic research on power interchange.

CHAPTER 4

This chapter presents a result of quantitative analysis of power supply mix in 13 countries in East Asia.

A linear programming (LP) model was developed in order to examine the possibility to optimize power supply mix in the East Asia region. The preconditions (input data) for this LP model are each country's power demand, the cross-border trading capacity of grid, power supply capacity by fuel, generating costs by power source, and CO_2 emission factor by power source. The objective function is cost minimization under a certain limitation of CO_2 emission.

Analysis said that if the HAPUA's grid plan achieved, region can save USD 12,142 million in 2020 at the maximum. In addition, if the cross-border trading capacity will expanded to double, region can save USD 17,410 in 2030 at the maximum. These calculated saving will be differ depends on CO_2 emission allowance. If an allowance is large enough to permit cheap but dirty coal fired power plant in high operating rate, economical benefit will be maximized. However, if an allowance is smaller, much high cost natural gas fired power plant will alternate coal to reduce economical benefit, while environmental benefit will gained.

CHAPTER 5

The following things have become clear through this study.

- Not all power demand can be met through a single form of energy. Therefore, a mix that appropriately combines multiple power sources is essential.
- Power interchange through international interconnected lines will bring changes to the entire power source mixes of the countries and region.
- Total investment in power sources can be reduced for the entire region through power interchange via international interconnected grid networks. The total investment reduction effect will be largest under lax regulations for co_2 emissions.
- Through power interchange, countries can alleviate discrepancies between power demand and energy resources for power generation. This contributes to greater energy security throughout the region.
- In countries and regions where domestic power grids themselves are insufficient, international interconnected grid networks can be expected to supplement them. On the other hand, it is conceivable that in some cases, upgrading the domestic power grid is necessary in order to maximize utilization of energy resources that

exist in a region.

In light of the above outcomes, the following points should be borne in mind for future power source development.

- Development of potential resources for power generation shall be quick. In a development, it is necessary to consider the roles of each power source for the base, middle, and peak load purpose and to combine them appropriately.
  - Develop hydropower, which is economical and environmentally-friendly (except during construction), and for which there is still much untapped resources in the region.
  - Develop coal-fired power plant, which is outstanding in terms of economy and amount of resources, especially in China, Indonesia and Vietnam.
  - Develop renewable energy that is relatively economical, such as geothermal and biomass, except solar power.

- Energy utilization that ignores environmental impact is impossible. For power generation as well, initiatives that move towards cleaner energy utilization should be strengthened.
  - Promote higher efficiency in coal-fired power generation. Reducing the emission in flue gas through higher efficiency will alleviate the sole disadvantage of coal utilization.
  - Expanded use of natural gas with its outstanding environmental performances is desirable from the perspective of reducing environmental impact, but natural-gas-fired power plant is less economical than coal-fired.

It is, therefore, necessary to mitigate the economic disadvantage of natural-gas-fired power plant by working to lower the procurement cost as well as price of natural gas.

CHAPTER 1
Introduction

In the EAS (East Asia Summit) countries, power demand is steadily expanding due to a population increase and economic growth. Moreover, as improving the electrification rate is an important policy task in many countries, power demand appears certain to increase in the future in line with a rise in living standards. Meanwhile, as income is relatively low except for a small group of wealthy people, it is necessary to supply electricity at minimal possible cost. Therefore, for the EAS countries, steadily implementing large-scale power source development in an economically efficient way is an urgent task.

Basically, a country implements power source development on the premise of self-sufficiency. That is natural from the perspective of energy security of a country, and it is a rational approach when demand growth is moderate and the country can implement economically efficient power source development on its own so as to meet the demand. However, when demand growth outstrips the capacity to supply necessary domestic resources (manufacturing, human and financial resources) or when economically efficient power source development is difficult due to some constraints, such as high fuel transportation costs and power loss during transmission, importing electricity from neighboring countries should be considered as an option. In light of the above, it may be possible to optimize or to improve the efficiency of power infrastructure investments in terms of supply stability, economic efficiency and reduction of the environmental burden if we consider ways of developing power infrastructures (power sources and grids) on a pan-regional basis.

In the ASEAN region, HAPUA (The Heads of ASEAN Power Utilities / Authorities） and the Asian Development Bank are implementing initiatives related to intra-region power grid interconnections, and bilateral power imports and exports are ongoing. However, individual countries are still placing priority on optimization of investments at the domestic level. Besides, power imports and exports are not brisk enough to contribute to "power grid interconnection," and moves toward pan-regional optimization have been slow.

1. Rationale

The rationale of this study is derived from the 17th ECTF[1] meeting held in Phnom Penh of Cambodia on 5 July 2012. In this meeting, the ERIA explained and proposed new ideas and initiatives for EAS energy cooperation, including the following:

- Strategic Usage of Coal
- Optimum Electric Power Infrastructure
- Nuclear Power Safety management, and
- Smart Urban Traffic

The participants of the ECTF Meeting exchanged views on the above proposals and agreed that it was time to consider new areas in addition to the current work streams to reflect the dynamics of energy demand and supply in the East Asian region. As such, the ECTF Meeting endorsed the proposed new areas and initiatives.

As a result, The Economic Research Institute for ASEAN and East Asia (ERIA) has formulated the Working Group for the "Study on Effective Investment of Power Infrastructure in East Asia through Power Grid Interconnection". Members from 9

[1] Energy Cooperation Task Force under the Energy Minister Meeting of EAS countries.

EAS countries are represented in the WG with Mr. Ichiro Kutani of the Institute of Energy Economics, Japan (IEEJ) as the leader of the group.

2. Objective

This study will quantify the possibility and benefits of the pan-regional optimization of power infrastructure investments in the EAS region. By doing so, the study will provide clues for policy decisions toward the development of optimal power infrastructures and investment decisions. In short, the study is intended to promote power infrastructure investments or support existing initiatives including GMS[2] and APG[3].

3. Work Stream

The study consisted of four work streams for fiscal year 2012.

(A) Collection and compilation of information relating to power infrastructures

Information relating to power infrastructures in East Asia will be collected and examined from the following perspectives:

- Forecast of power demand
- Power source development plans
- Power grid investments and interconnection plans
- Power generation and transmission costs
- Common systems and technical standards, etc. relating to power grid

[2] Greater Mekong sub-region program leaded by Asia Development Bank.

[3] ASEAN Power Grid program leaded by HAPUA.

interconnection

When collecting information, we will pay as much attention as possible to the results of existing initiatives relating to power grid interconnection in East Asia, such as the initiatives of HAPUA (ASEAN Power Grid) and the ADB (Greater Mekong Sub-region Program).

Although information will be collected through document research in principle, a field survey may be conducted as needed.

(B) Identification of challenges and points of debate

Based on information collected as described in (A), challenges and points of debate relating to broad-area infrastructure development in East Asia will be identified. The following are examples of viewpoints of our analysis.

- Entities in charge of developing power grid interconnection infrastructures
- Costs of and financing for the development of power grid interconnection infrastructures
- Legal frameworks and technical standards relating to multilateral power trade
- Incentives for power grid interconnection and the political and administrative implementing capabilities, etc.

(C) Development of a broad-area power infrastructure simulation model and evaluation of the simulation results

Based on information obtained as described in (A), we will develop a broad-area power infrastructure simulation model for the EAS region. Using the developed power grid interconnection model, we will simulate combinations of power sources and power grid interconnections that would achieve the goals of minimizing the total investment amount and the CO_2 emission amount.

In addition, based on the simulation results, we will conduct a comparative analysis of the simulations and existing power infrastructure development plans drawn up by individual countries. The comparative analysis will be conducted from the following viewpoints:

- Whether it is possible to reduce the investment amount compared with existing plans.
- Whether it is possible to reduce the CO_2 emission amount compared with existing plans.

(D) Draw out policy recommendation

Based on study outcome from above mentioned (A), (B) and (C), we will draw out policy recommendation to enhance effective investment of power infrastructure in EAS region.

4. Working Group Activities in 2012

In 2012, the WG was held for 2 times in November 2012 in Jakarta, Indonesia and April 2013 in Tokyo, Japan.

At the first meeting, information sharing and discussion regarding each country's power source development plan took place. Additionally, issues related to existing initiatives such as the ASEAN Power Grid and GMS were discussed.

At the second meeting, the validity of data input for simulations of optimal energy mixes was examined, and calculation results were evaluated and discussed.

CHAPTER 2

Power Infrastructure Development Plan in Each Country

This chapter presents an overview of power infrastructure development plans in 13 countries in East Asia (Bangladesh, Brunei Darussalam, Cambodia, China [Yunnan & Guangxi], India [North-East], Indonesia, Lao PDR, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Vietnam) and projections for their installed generation capacities and power source mixes in 2020 and 2030.

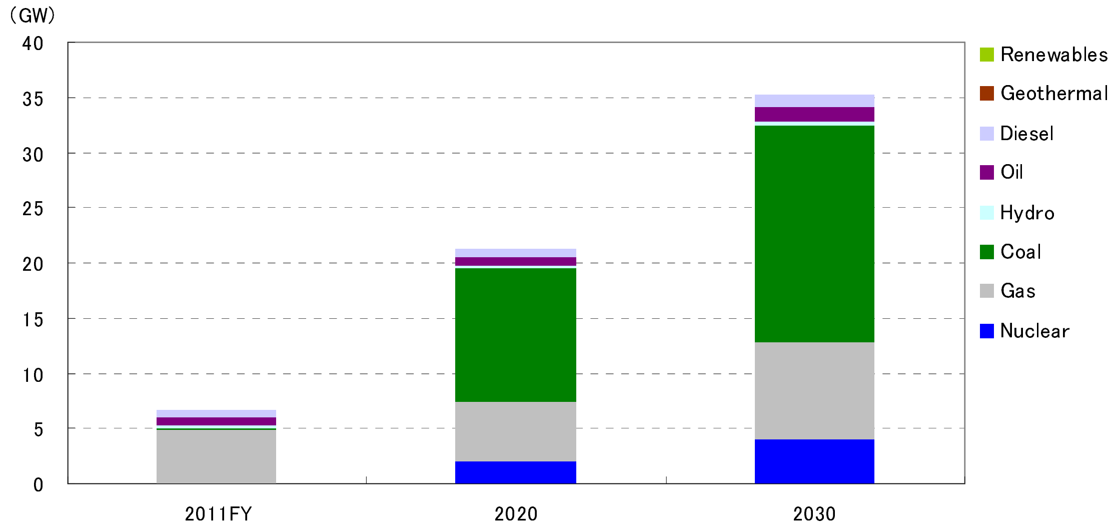
1. Bangladesh's Power Development Plan

In Bangladesh, the Bangladesh Power Development Board (BPDB) and IPPs generate electricity. The BPDB has been in unified charge of planning, construction, and operation of national power generation, transmission, and distribution since the nation gained independence in 1972. Electricity sector reform began in the 1990s with the aim of introducing private capital into the sector. Conversion of existing BPDB power plants into internal divisions and separate companies and the participation of IPPs have progressed.

Even today, however, improvement of power plants and other power transmission and distribution facilities in Bangladesh is notably lagging. Although potential power demand is extremely high, the nation has been forced into chronic power supply shortages and constant restrictions on demand. As of June 2010, the rate of access to electricity remained at a low level, 47 percent.[4] This forms an impediment to economic growth and direct investment of foreign capital. With the objective of raising national living standards, the Bangladeshi government aims to increase the amount of power supplied.

[4] Board of Investment, http://boi.gov.bd/key-sectors/power-industry

Figure 2-1: Power Development Plan toward 2020 and 2030 (Bangladesh)



Bangladesh (GW)

	2011FY	2020	2030
Nuclear	0.000	2.000	4.000
Gas	4.863	5.427	8.850
Coal	0.220	12.050	19.650
Hydro	0.230	0.330	0.330
Oil	0.671	0.735	1.199
Diesel	0.655	0.718	1.171
Geothermal	0.000	0.000	0.000
Renewables	0.000	0.000	0.000
Total Supply Capacity	6.639	21.260	35.200

Source: Power System Master Plan 2010.

In FY 2011, Bangladesh's generation capacity was 6,639 MW. The power source mix was hydropower 230 MW (3.46 percent), coal-fired power 220 MW (3.31 percent), oil-fired power 671 MW (10.11 percent), diesel power 655 MW (9.87 percent), and gas-fired power 4,863 MW (73.25 percent). The power source mix leans heavily on domestic natural gas resources.

On the other hand, development of new gas fields is lagging in Bangladesh, and the transmission network is inadequate. Due to soaring demand accompanying economic development, the supply and demand gap for domestic natural gas is expanding, and already gas supply impediments are causing restrictions on power plant operation. Diversification of the power mix is an urgent issue.

In response to this situation, the Bangladeshi government is considering development of coal-fired power plants that use domestic and imported coal, electricity imports from neighboring countries (India, Nepal, Bhutan, and Myanmar), expanded use of renewable energy, and research on and adoption of nuclear power.

Coal, which is expected to be used as an alternative to gas, is present in the country's northwest. There are estimated deposits of about 1.5 billion tons.[5] Bangladeshi coal is generally bituminous coal, low in sulfur and ash, and well-suited for power generation. Coal production began in Barapukuria in the north in 1994. In 2005, the Barapukuria Power Plant, Bangladesh's first coal-fired power plant, began operation.

However, there are many issues associated with coal mining. Because most of Bangladesh's land is a delta area on the Indian subcontinent along the Bay of Bengal, in many places there are aquifers on top of the coal beds. When the coal is mined, therefore, advanced technologies regarding ground subsidence and water removal are necessary. Moreover, Bangladesh has a very high population density, and most of the land is level, so most potential coalfields have already been developed as agricultural or residential land. Thus, demonstrations against the displacement of residents and the environmental impact of mining have broken out. Consensus forming in local communities is thus a major issue.

As for the adoption of nuclear power, study and research on it has progressed on it in terms of a power source as part of the electricity supply and in terms of diversification of energy resources. In November 2011, Bangladesh signed an agreement with the Russian Nuclear Energy State Corporation, ROSATOM, on construction of a nuclear power plant with two 1,000 MW reactors. Construction is to begin in 2013, with completion in 2018. The planned construction site is in Rooppur, northwest of Dhaka. In addition, in September 2012, Prime Minister Sheikh Hasina announced that in addition to the Rooppur Nuclear Power Plant on which construction planning was advancing, another new nuclear power plant would be built in the nation's south.[6]

Bangladesh's potential for hydropower generation is low. Although the nation is crisscrossed by the Ganges, Brahmaputra River, and Meghna Rivers and their

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[5] Japan Electric Power Information Center, "Electric utilities in other countries, vol. 2, 2010"

[6] Prime Minister’s Office, press releases, 2012.9.6

tributaries and branches, most of its land, except for the hilly country in the east, is flat. There are extremely few places with the sharp changes in elevation needed for hydropower generation. Only one hydropower plant, the Karnafuli Power Plant (five units, total output 230 MW) in the Chittagong Hill Tracts, has been developed to date. According to the United States Agency for International Development (USAID), Bangladesh's hydropower generation potential is 1,897 MW. The Matamuhari and Sangu hydropower projects are under study in the Chittagong Hill Tracts, but it is unclear how realistic they are.

Finally, an overview of the transmission grid in Bangladesh will be presented. The Bangladeshi power grid is divided into east and west regions along the Brahmaputra River, which bisects the center of the country. The eastern region is blessed with natural gas resources and hydropower that utilizes the Chittagong Hill Tracts. Large gas-fired, combined cycle, and hydropower generation are the backbones of the power supply. The western region, however, is poor in resources. Oil- and diesel-fired power generation using imported fuel carries most of the supply load. In order to correct such regional disparities, starting with fuel costs, major substations around urban areas and two 230 kV transmission lines interconnecting the eastern and western region are being constructed.

The country's most advanced international interconnection line is a grid interconnection project with India's West Bengal State. A 400 kV, 125 km long transmission line between Bheramara, Bangladesh and Baharampur, India, is under construction. The Bangladeshi government has signed a contract to import 500 MW of power from India via the line. In the future, it will also be possible for Bangladesh to export power to India. Additionally, large gas fields have been discovered in Tripura State in India's northeast. Construction of an interconnection line to import power from gas-fired power plants in Tripura is now at the planning stage. Furthermore, in Bangladesh's neighbors, hydropower potential is projected at 148,701 MW in India, 42,130 MW in Nepal, and 30,000 MW in Bhutan. Study of international interconnection plans with those nations is also expected.[7]

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[7] South Asia Regional Initiative for Energy, USAID

2. Brunei Darussalam's Power Development Plan

Brunei Darussalam ("Brunei") achieved its independence from the UK in 1984. It is a wealthy country, extremely stable politically and economically, with no personal income tax, and well-developed social welfare programs including free medical care. Supporting this stability and wealth are petroleum and natural gas. In the past, those industries accounted for 70 percent of GDP, and today they still account for about 50 percent. Development of petroleum and natural gas began long ago, with production starting in 1929. Ever since, they have driven the economy. Brunei's reserves as of the end of 2011 were estimated at 1.1 billion bbl for oil, with an R/P of 18.2, and 300 billion m^3 for natural gas, with an R/P of 22.5.[8]

In order to maintain stable oil and gas production and exports over the long term, energy policy centers on a "preservation plan." Barring special circumstances, rapid increases in oil and gas production will be avoided, reserves will be added through the discovery of new resources, and proven reserves will not be reduced. In recent years, therefore, Brunei has emphasized development of its deep sea area, which will contribute to stable long-term production. In March 2009, a six-year dispute with Malaysia over territorial waters was resolved. The two countries' maritime borders were finally set. A commercial agreement zone for oil and gas was arranged. Mutually beneficial exploration and development of oil and gas resources is expected. Exploration of mining areas in very deep waters is projected.[9]

Additionally, the government will proceed with joint development of new oil and gas fields together with foreign oil companies. As for domestic energy use, the government promotes energy conservation and diversification of energy sources. It is developing renewable energy, installing combined cycle gas turbine (CCGT) power plants, and campaigning for energy conservation.

Next, an overview of power supply and demand in Brunei will be presented. Electricity supply in Brunei began with the installation in various areas of small-scale diesel generators for home and agricultural use. After the completion of gas supply facilities in the Seria region in 1955, in 1967 the Seria GT Power Plant,

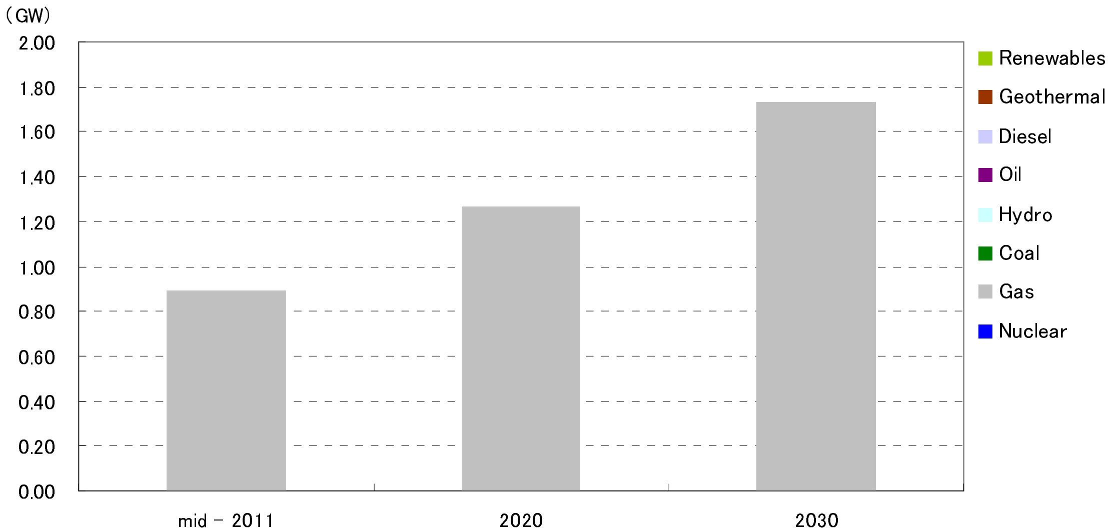
[8] BP Statistical Review of World Energy, June 2012

[9] Japan-Brunei Friendship Association, Brunei News, March 18, 2009

Brunei's first gas turbine power plant, was installed. In conjunction with that, a 66 kV transmission line between Seria and the capital area was completed. Subsequently, as natural gas production increased, it was decided to convert all power plants to gas turbines. With the exception of the Temburong region[10] in the southeast, all power plants were indeed upgraded to gas turbines. All new power plants also had gas turbines installed.

There are two electric utilities in Brunei, the Department of Electrical Services (DES), which is an internal organization of the Ministry of Energy (MOE), and Berakas Power Company (BPC),[11] which mainly provides the power supply to royal palaces, the royal family, and the military. In addition, the oil and natural gas companies Brunei Shell Petroleum (BSP), Brunei Liquefied Natural Gas (BLNG), and Brunei Methanol Co. (BMC) also generate private power and sell their surpluses to the DES.

Figure 2-2: Power Development Plan toward 2020 and 2030 (Brunei)



[10] Temburong power plants are diesel power stations owned by the DES (facility capacity 6.0 MW). They are installed outside the power grid.

[11] The BPC's primary purpose is to supply power to royal facilities, but it also sells excess power to the DES.

Brunei (GW)

	mid – 2011	2020	2030
Nuclear	0.000	0.000	0.000
Gas	0.895	1.266	1.732
Coal	0.000	0.000	0.000
Hydro	0.000	0.000	0.000
Oil	0.000	0.000	0.000
Diesel	0.000	0.000	0.000
Geothermal	0.000	0.000	0.000
Renewables	0.000	0.000	0.000
Total Supply Capacity	0.895	1.266	1.732

Source: IEEJ estimates from ERIA, "ANALYSIS OF ENERGY SAVING POTENTIAL IN EAST ASIA REGION" (2011)

In 2004, the Government of Brunei set a 30-year long-term development plan and established a task force on national vision. Beginning in January 2008, the government launched its long-term plan, which comprises three parts, the 30-year long-term vision "Wawasan Brunei 2035," the 10-year "Outline of Strategies and Policies for Development 2007-2017," and the 5-year "National Development Plan 2007-2012."[12]

However, because there is not enough data to calculate power plant capacity as of 2020 and 2030, estimated electricity outputs from ERIA Research Project Report 2011 "ANALYSIS OF ENERGY SAVING POTENTIAL IN EAST ASIA REGION" were used. According to the report's projections, Brunei's electricity output will increase from its 2009 figure of 3.6 TWh at an annual rate of 1.04 percent to reach 5.5 TWh in 2020, and then increase by 1.03 percent annually from 2020 to 2035 to reach 8.8 TWh.

Based on those figures, power plant capacity as of 2020 and 2030 is estimated to rise from 895 MW in 2011 to 1,266 MW in 2020 and 1,732 MW in 2030. Today, almost all electricity connected to the grid comes from domestically produced natural gas. That is unlikely to change in the future.

Finally, an overview of Brunei's power grid will be presented. With the buildup of power plants in Brunei, transmission line projects are also projected. In concrete terms, extension of a 275 kV transmission line to Kuala Belait in far western Brunei

[12] JPEC Report, August 5, 2011

and interconnection with Sarawak Electricity Supply Corporation (SESCO) in Malaysia is progressing.[13] SESCO's 275 kV transmission line reaches the Tudan substation just outside Brunei. Kuala Belait, Brunei, and Tudan are to be interconnected. This interconnection project has been presented to a HAPUA subcommittee. Future interconnection to Sabah, Malaysia, Kalimantan, Indonesia, and the Philippines is being studied.

3. Cambodia's Power Development Plan

In Cambodia, in the national "Rectangular Strategy" for economic development, development of power infrastructure is a high-priority strategy. Sustainable and steady electricity sector development at accessible prices and economical and environmentally-friendly power facility development are to be carried out.

Today, however, regions with an electricity supply are limited to the capital and major cities. Electrification has yet to reach many areas. Nationally, about 20 percent of households have electricity. In cities, about 80 percent have it, but in rural areas, only about 10 percent do. Even in areas with a nominal electricity supply, many factories, hotels, and so on get their power from their own generators. Thus, potential power demand is likely to be quite large. It is therefore necessary to improve the development situation for generation and distribution facilities to supply inexpensive, stable power.[14]

Cambodia has hydropower, oil, natural gas, lignite, etc., but none of them have been adequately developed. Over 90 percent of the country's electricity output is generated using diesel, which has kept electricity charges high.

The impact of the civil war that started in 1970 and lasted about 20 years kept both technical prowess and financial power low. The hydropower plants now operating are O Chum 2 (1 MW) and Kirirom 1 (12 MW), and Kamchay Power Station (195 MW), which went into operation on December 7, 2011. The Kamchay Power Station, constructed on the Kamchay River in southern Cambodia, was

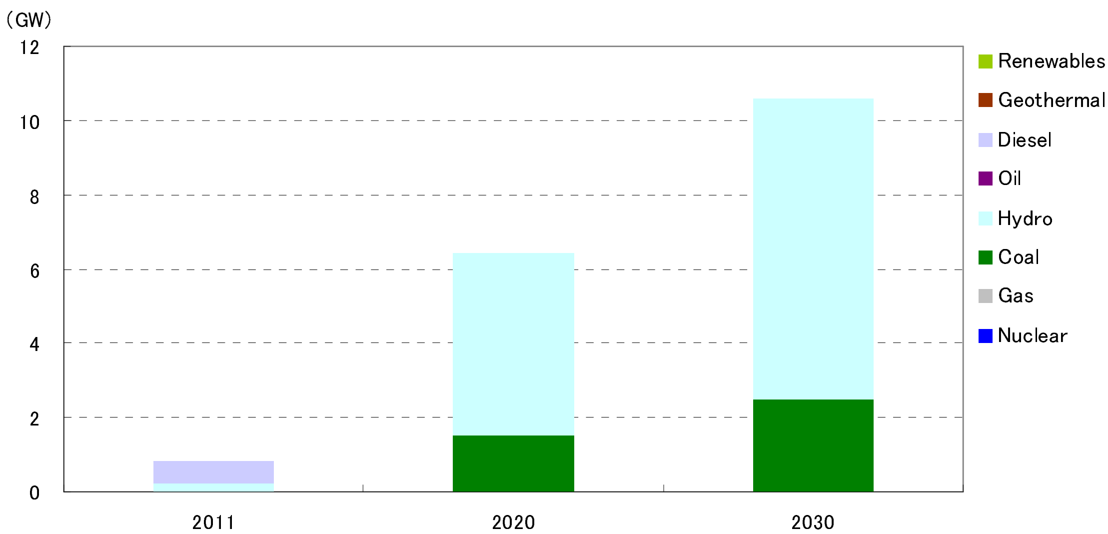
[13] Japan Electric Power Information Center, "Electric utilities in other countries, vol. 2, 2010"

[14] Japan Electric Power Information Center, January 2009

constructed at a total cost of 280 million US$. The Sinohydro Group, which also built the Three Gorges Dam, the world's largest, carried out the construction.[15]

Cambodia is surrounded by highlands and has many rivers, including the Mekong River. It therefore has high expectations for domestic hydropower development, for which the potential is considered high. According to the Asian Development Bank, Cambodian hydropower resources that can be economically developed are approximately 8,600 MW. That includes 6,500 MW on the main Mekong River, 1,100 MW on tributaries, and 1,000 MW not on the Mekong River. The Ministry of Industry, Mines, Energy (MIME), on the other hand, estimates the potential at 10,000 MW (5,000 MW on the main Mekong River, 4,000 MW on tributaries, and 1,000 MW not on the Mekong River). The Electricity Authority of Cambodia estimates the hydropower potential that it is technically possible to develop at 6,700 MW (broken down the same as above at 3,580 MW, 1,770 MW, and 1,340 MW).

Figure 2-3: Power Development Plan toward 2020 and 2030 (Cambodia)



[15] Morningstar, December 8, 2011

Cambodia			(GW)
	2011	2020	2030
Nuclear	–	–	–
Gas	–	–	–
Coal	0.010	1.518	2.497
Hydro	0.207	4.924	8.101
Oil	–	–	–
Diesel	0.600	–	–
Geothermal	–	–	–
Renewables	0.002	0.002	0.002
Total Supply Capacity	0.819	6.444	10.600

Source: Power Development Plan

Cambodia's power source development plan was set by Electricity Du Cambodia (EDC) in 2008. It is progressing based on the country's long-term power supply strategy through 2022, the "Master Plan on Power Sector Development of Kingdom of Cambodia." The master plan sets forth the following goals.

1. Increase hydropower and coal-fired generation in addition to diesel
2. Develop a power grid interconnecting the nation
3. Electrification of outlying areas
4. Study frameworks for electricity trading with Vietnam, Thailand, Laos, and other ASEAN nations
5. Promote commercialization and participation by private capital, and set up electricity market competition and regulatory policy

The Ministry of Industry, Mines, Energy's (MIME) most recent "Power Development Plan" calls for construction of 4,717 MW of hydropower and 1,508 MW of coal-fired power by 2020. If development proceeds according to plan, as of 2020 power plant capacity will be 4,924 MW hydropower and 1,518 MW coal-fired power. Hydropower is thus projected to account for more than 75 percent of Cambodia's total capacity. With that great improvement from the current power source mix that heavily depends on diesel, the high electricity charges that are now an issue are expected to fall.

On the other hand, because plans beyond 2020 are not clear, the power source mix as of 2030 was estimated using estimated electricity output from the ERIA Research

Project Report 2011 "ANALYSIS OF ENERGY SAVING POTENTIAL IN EAST ASIA REGION." According to the report, Cambodia's electricity output of 1.2 TWh in 2009 is projected to increase to 8.2 TWh in 2020, and then increase at an annual rate of 1.05 percent to reach 17.3 TWh in 2035. Estimation of Cambodia's power plant capacity in 2030 based on this found an increase to 10,600 MW (with hydropower major the main power source at 8,101 MW, and coal at 2,497 MW). Today, Cambodia imports electricity from Thailand and Vietnam, but with the increase in hydropower, it is projected to become an electricity exporting nation.

Finally, an overview of Cambodia's transmission grid will be touched on. Its transmission lines are mainly in two grids only, around Phnom Penh and around Siem Reap. Those grids are independent, unconnected to each other. The grid around Phnom Penh is formed by a 230 kV transmission line from Vietnam via the Takeo Substation and a 115 kV transmission line that brings power to the capital from the Kirirom 1 hydropower plant. In 2007, a 115 kV transmission line from Thailand was connected to the Siem Reap area, which has the nation's second highest power demand. Other cities only have their own independent distribution grids. That is one reason for the low rate of electrification in Cambodia.

As for international interconnection plans, the Ministry of Industry, Mines, Energy (MIME) has set the following goals for electricity trading with neighboring countries.

- Cooperate on Cambodia's domestic generation and transmission plans in order to trade electricity with neighboring countries
- Coordinate electricity trading with neighboring countries in order to improve supply reliability and ensure energy security
- Facilitate power procurement in order to reduce poverty in mountainous and border areas and to improve lives materially and psychologically

Thus, in light of estimated increases in power demand in Cambodia, it is necessary to advance power source development plans for hydropower with its high potential in particular, and at the same time advance plans for transmission line expansion in terms of both domestic and international interconnection.

4. China's Power Development Plan

In Chinese energy policy, the National Energy Commission, which was established in the first session of the 11th National People's Congress in March 2008, is the decision-making body for national energy strategy. The National Energy Administration absorbed the functions of the China Atomic Energy Authority, which had been in charge of nuclear energy policy, and was upgraded to quasi-ministerial status. Under the umbrella of the National Development and Reform Commission, the National Energy Administration is in overall charge of energy administration as the executive office of the National Energy Commission.

China's latest basic policy on energy is laid out in the "Medium- and long-term plan for energy development (2005–2020)" (published June 2004). It is based on the following eight policies.

1. Make energy conservation a highest priority measure and raise energy efficiency.
2. Optimize the energy mix and adhere to an all-out development strategy for coal, electricity, oil, natural gas, and new energy.
3. Rationally allocate energy resources development. Comprehensively consider the rational allocation of energy production, transport, and consumption in accordance with demand in the eastern, central, and western parts of the country and in urban and rural areas.
4. Utilize both domestic and foreign resources.
5. Promote the progress and updating of science and technology and strengthen scientific management.
6. Strengthen environmental protection and bear resource constraints and environmental tolerance in mind.
7. Pay a high degree of attention to energy safety and proceed with the diversification of the energy supply.
8. Set a security policy for energy development.

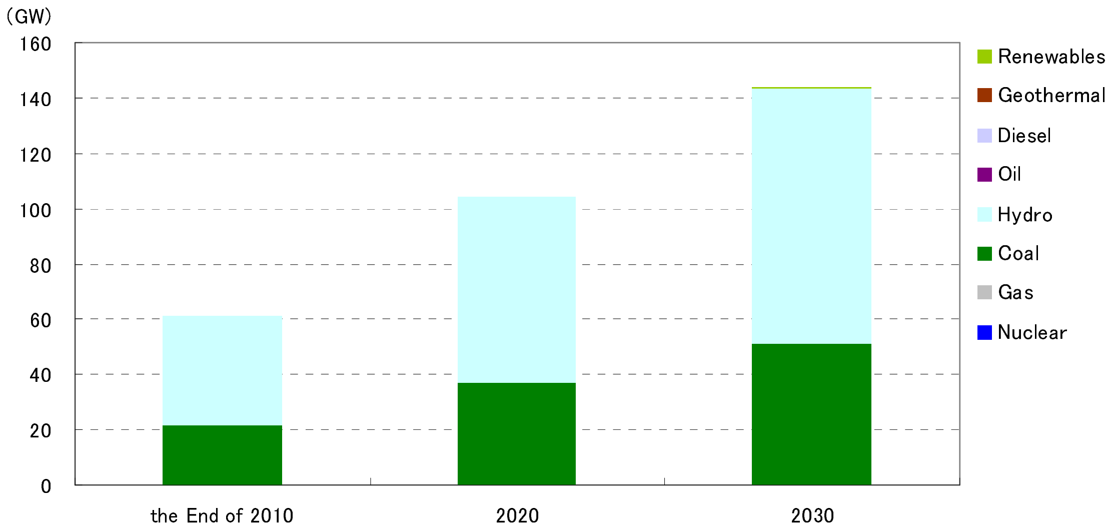
China's short- and medium-term policies are based on five-year plans that are reset every five years. The latest (12th) plan period is 2011–2015.

In the "12th Five-Year Guideline on National Economic and Social Development," announced in March 2011, the economic growth rate for the following five years is set at 7.0 percent. By 2015, non-fossil energy is to account for 11.4 percent of primary consumption, energy consumption per GDP unit is to decrease by 16 percent from the 2010 level, and CO_2 emissions are to decrease by 17 percent from the 2010 level. The "12th Five-Year Plan for Energy Development," set by the Managing Director Board of the State Council in October 2012, lists the following seven items as priority areas.

① Enhancement of the exploration and development of domestic resources
② Promotion of a shift to highly efficient and clean energy
③ Promotion of reform of the means of supplying energy
④ Acceleration of the construction of facilities for energy storage and transport and enhancement of reserves and ability to respond to emergencies
⑤ Implantation of civilian energy projects and promotion of the equalization of urban and rural public energy services
⑥ Rational regulation of total energy consumption
⑦ Rationalization of frameworks for energy price formation in important sectors such as electricity, coal, oil, and natural gas, and adherence to energy security through the encouragement of private sector capital participation in the energy sector and the deepening of international cooperation

As for projected power demand, the "12th Five-Year Plan for Energy Development" projects that electricity consumption will rise at an average annual growth rate of 8 percent from 4,200 TWh in 2010 to 6,150 TWh in 2015.

Figure 2-4: Power Development Plan toward 2020 and 2030
(China [Yunnan & Guangxi])



China (Yunnan & Guangxi) (GW)

	the End of 2010	2020	2030
Nuclear	–	–	–
Gas	–	–	–
Coal	21.720	37.073	51.083
Hydro	39.290	67.063	92.405
Oil	–	–	–
Diesel	–	–	–
Geothermal	–	–	–
Renewables	0.370	0.370	0.370
Total Supply Capacity	61.380	104.506	143.858

Source: IEEJ estimates from China Electricity Almanac

The "12th Five-Year Plan for Energy Development" discusses projections for power source development. It estimates that the 970 GW of installed capacity as of 2010 will increase to 1,490 GW as of 2015. The plan also includes the following projections for installed capacity for each power source.

Table 2-1: Outlook of Power Generation Capacity

	Unit	2010	2015	AAGR
Coal	GW	660	960	7.8%
Hydro	GW	220	290	5.7%
Nuclear	GW	10.82	40	29.9%
Gas	GW	26.42	56	16.2%

Wind	GW	31.00	100	26.4%
Solar	GW	0.86	21	89.5%
Total	GW	970	1,490	9.0%

Source: 12th Five-Year Plan for Energy Development.

China has abundant domestic coal reserves, and generation cost is low, so coal-fired power plants account for most power plant capacity (about 80 percent). Small electric utilities hold about 40 percent of China's power plant capacity. Their thermal power plants are aging and low in energy efficiency. In 2007, the National Development and Reform Commission therefore pursued the closing of small units and issued a "Notice of the promotion of the shutdown of small thermal power generation" and a "Notice of the lowering of wholesale electricity rates for small thermal power generation and the promotion of its shutdown." Additionally, 194 supercritical pressure units (as of the end of 2010) and 39 1-GW ultra-supercritical pressure units (as of the end of 2011), which have greater generating efficiency, have been installed. As a result of those measures, average thermal efficiency improved from 33.3 percent in 2005 to 36.9 percent in 2010.

China has the most domestic hydropower resources of any country in the world, with 541.64 GW technically capable of being developed. China has worked to build small-scale hydropower plants since its founding. Today, it is proceeding with medium- and large-scale plants, such as the Three Gorges Dam, which began operating at its planned installed capacity (22.5 GW, the world's largest generating capacity) in 2012. In addition, there are signs that full-fledged development may begin on the Yarlung Tsangpo River in Tibet Autonomous Region, which has a technically developable capacity of 67.85 GW, but where little work has been done.

China's hydropower resources are skewed towards the southwestern side of the country. In order to transport electricity to the eastern coastal area where demand is high, long-distance transmission lines of 1,000–2,700 km will be needed. Extra-high-tension (800 kV) direct current transmission is therefore planned.

China is also working on the development of nuclear power. As of January 2013, it had 16 reactors in operation and 29 under construction. Using technology from other countries, i.e., Russia (Rosatom VVER light water reactor), the USA, (Westinghouse

AP1000 light water reactor), and France (AREVA EPR light water reactor), China is rapidly proceeding with construction of nuclear facilities.

Following the Fukushima Daiichi nuclear accident in March 2011, new construction permits for nuclear plants were frozen, but as of the end of 2012, permit procedures had returned to normal. The "12th Five-Year Plan for Energy Development" estimates 4,000 MW of installed capacity for nuclear power in 2015. According to the "nuclear power medium- and long-term development plan" announced in November 2007, installed capacity for nuclear power was to be increased to 4,000 MW by 2020. The 12th Five-Year Plan does not address installed capacity in 2020. Reuters and others have reported that there are plans for 58,000 MW of installed capacity as of 2020.

As for renewable energy, China has promoted the adoption of individual types, as with the "Catch the Wind Plan" to nationalize wind power generation and the "Lighting Process" that plans to bring electrification through wind and solar power to non-electrified areas. The Renewable Energy Law passed in 2006 prepared basic frameworks for development, installation, and dissemination. Under the law, 1) all renewable energy power must be purchased, 2) wholesale electricity charges must be approved by the government, and 3) costs are to be shifted to retail electricity charges.

Additionally, China has adopted a renewables portfolio system (RPS) for power producers. For producers with at least 5 GW eligible capacity (installed capacity at wholly-owned power plants + invested power plants × investment ratio), installed capacity of renewable energy (other than hydropower) must account for at least 3 percent of total capacity in 2010 and at least 8 percent in 2020.

The 12th five-year plan concerning the development of renewable energy, published in August 2012, includes the following goals for renewables to be achieved by 2015. 1) They are to account for at least 9.5 percent of primary energy demand, and 2) 160 GW (hydropower 60 GW, wind power 70 GW, solar 20 GW, biomass 7.5 GW, etc.) of new power plant capacity is to be installed. According to the China Wind Energy Association (CWEA), whose record on installing wind power is remarkable, at least 10 GW of wind power generation facilities have been added every year since 2008. At the end of 2012, there had been an increase of 14.049 GW, to reach 76.413 GW. As of the end of 2012, solar power installed capacity was 7,000 MW, an increase of almost 5,000 MW since the end of 2011.

An overview of international collaboration follows below.

In addition to the Chinese territories of Hong Kong and Macao, China carries on electricity trading with neighboring countries such as Russia, North Korea, Mongolia, and Vietnam. However, because the scale was small, the central government was not involved. Instead, each province's power companies carried it out on its own, and often the objective was simply peak exchanges.

China annually imports about 300 GWh of electricity from Russia, but when the planned direct current transmission line between the Amur River and Tianjin is competed, power will be transmittable with small loss from Siberia's rich hydropower resources to Beijing. In 2008, the government therefore approved a construction project that will connect with Russia over a 500 kV transmission line.

Yunnan Province and other areas are connected with Vietnam via 220 kV and 110 kV transmission lines for electricity export. Since power demand in Yunnan is not that high, the amount of electricity exported to Vietnam had been increasing. However, along with the necessity of increasing transmission capacity to Guangdong Province, balance within Yunnan has become an issue. Additionally, as will be discussed in the Vietnam section, the Vietnamese side has been thinking that it would like to curb electricity imports. For those reasons, it is unclear how long stable transmission will continue.

On the other hand, China imports electricity from Myanmar over an international collaboration line constructed between Myanmar's Shweli Hydropower Plant and China's Dehong Substation. Under a September 2009 agreement, the purchase price for electricity from the Shweli power plant is 0.184 yuan/kWh (about 2.9 yen/kWh).

5. India's Power Development Plan

Energy policy in India is set by the Ministry of Power based on energy five-year plans. The Central Electricity Authority (CEA) sets detailed power source development plans during each five-year period. The latest plans, published in January 2012, are the "12th Five-Year Plan (2012-2017)"[16] and the "National Energy Plan."[17]

In the 12th Five Year Plan, during the 12th Period (2012-2017) and the 13th Planning Period (2017-2022), in the base case scenario annual GDP growth is assumed to be 9 percent, with 0.9 and 0.8 values of elasticity. In the final year of the 12th Planning Period, FY 2016 (April 2016 through March 2017, other fiscal years below are the same), estimated total demand is 1,403 TWh. In the final year of the 13th Planning Period, FY 2021, estimated total demand is 1,993 TWh. In the base case scenario, with load factors of 78 percent and 76 percent, peak demand values are estimated at 197,686 MW in 2017 and 289,667 MW in 2022. For sensitivity analysis, with the elasticity value set at 1, total demand in 2017 is estimated at 1,489 TWh, and peak demand value at 209,339 MW. These estimates are based on the 17th Electric Power Survey (EPS), released in March 2007. According to a draft version of the 18th EPS, total demand is 1,354 TWh, and peak demand is 199,540 MW, so the demand estimate is about the same.

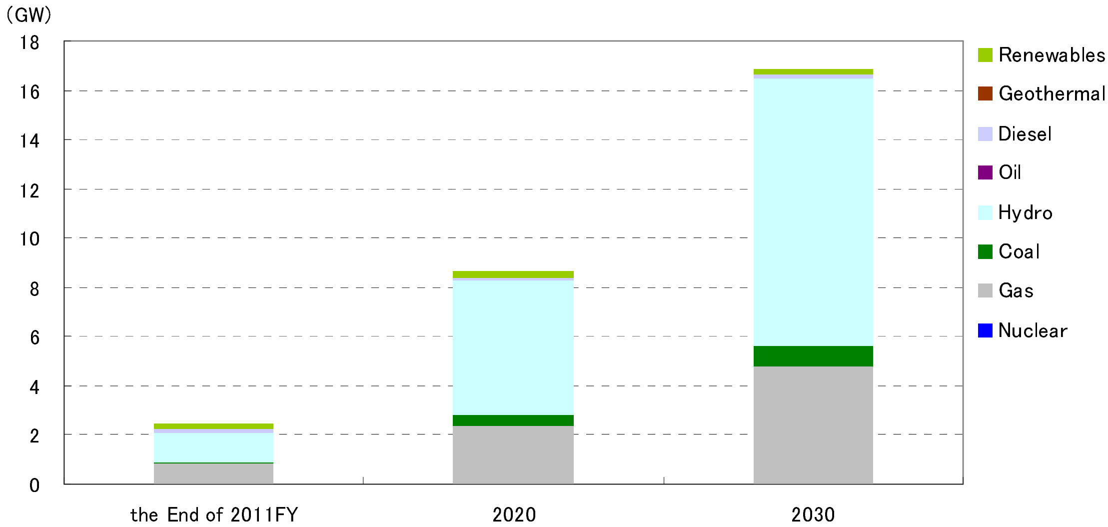
Additionally, according to the 12th Five Year Plan, for more than six years, power demand will exceed generation capacity. In FY 2010, power fell short of total demand by 73.236 TWh (8.5 percent) and of peak power by 12,031 MW (9.8 percent). Along with promotion of power source development, improvement of energy efficiency and enhanced demand side management are noted as major issues.

The changes in power source development shown below are for Northeast India (Assam, Nagaland, Meghalaya, Manipur, Tripura, Mizoram, and Arunachal Pradesh), so the figures differ from those in the CEA plan discussed below.

[16] Report of The Working Group on Power for Twelfth Plan(2012-2017), January 2012, Government of India Ministry of Power

[17] National Energy Plan, January 2012, CEA

Figure 2-5: Power Development Plan toward 2020 and 2030 (N-E India)



India (North East) (GW)

	the End of	2020	2030
Nuclear	–	–	–
Gas	0.824	2.383	4.756
Coal	0.060	0.422	0.842
Hydro	1.200	5.460	10.898
Oil	–	–	–
Diesel	0.143	0.143	0.143
Geothermal	–	–	–
Renewables	0.228	0.228	0.228
Total Supply Capacity	2.455	8.636	16.867

According to the National Energy Plan set by the CEA in January 2012, in order to respond to chronic power shortages during the 11th Planning Period (2007-2012), a large volume of base load power sources was added. However, because demand disparities between day and night and between workdays and holidays are expanding, simply adding base load power sources is considered inadequate. Additionally, based on a low-carbon growth strategy, minimization of carbon dioxide emissions volume is also necessary.

Therefore, in the National Energy Plan, installation of hydropower, nuclear power, and renewable energy is to be promoted. During the 12th Planning Period, in the base case scenario, installation of 79,690 MW of new power sources is planned. Breaking down the base case, that will be hydropower 9,204 MW, nuclear power 2,800 MW, coal-fired 66,600 MW, and gas-fired 1,086 MW. The generation capacity for renewable energy is estimated separately from conventional power sources. In the low installation case, it is 18,000 MW, and in the high installation case, it is 18,500 MW. Separately from that, 1,200 MW of electricity imports is also under consideration, and 4,000 MW of power plant capacity will be shut down during the period.

During the 13th Planning Period, in the base case scenario, 79,200 MW of power sources will be installed. Broken down, that is hydropower 12,000 MW (not including 8,040 MW imported from other countries), nuclear power 18,000 MW, and coal-fired 49,200 MW. At least during the next 10 years, coal-fired power will be the mainstay. Renewable energy in the low installation case will be 30,500 MW, and in the high installation case, it will be 45,000 MW.

India is rich in domestic hydropower resources and is actively developing hydropower plants. According to the CEA, there are 83 candidate sites that could possibly begin operation during the 12th and 13th Planning Periods. Their total development potential as hydropower plants is 22,011 MW. They include some on which construction has already begun, and others where there are geographical or environmental uncertainties. During the 12th Planning Period, 31 sites are projected to begin operating, with an estimated 9,204 MW developed.

With no help from the international community since it carried out nuclear testing, India has developed and installed its own heavy water reactors. Their output, however, remains lower than that of the light water reactors in other countries. In recent years, therefore, India has been proceeding with the construction of nuclear power plants that adopt foreign technology. The CEA projects that four nuclear power reactors, each a heavy water reactor with 700 MW of output and thus totaling 2,800 MW, will go into operation during the 12th Planning Period. They are Rajasthan No. 7 and 8 and Kakrapar No. 3 and 4. No light water reactors are projected to begin operating during the period.

In order to reduce CO_2 emissions volume, the CEA intends to promote the installation of combined cycle gas turbine (CCGT) coal-fired plants, which have a high efficiency of about 55 percent versus the 38–40 percent efficiency of existing coal-fired plants. In light of factors such as transmission efficiency, gas-fired power plants should be built near demand areas.

During the 12th Planning Period, because of concerns over a tight coal supply and in order to cut CO_2 emissions volume, the CEA intends to install 12,000–15,000 MW of gas-fired power plants. However, of gas-fired power plants now under construction, only 1,086 MW of them have a sure gas supply planned. That is the estimate for the base case scenario. Of gas-fired power plants that are under construction or completed, 13,184.5 MW of them do not have a gas supply specified yet.

Regarding India's adoption of renewable energy, the Ministry of New and Renewable Energy (MNRE) puts India's domestic wind power development potential at 45,000 MW. Expectations are high. There are also other unconventional power sources (biomass, small and micro hydropower, wave power, and solar). The MNRE projects renewable energy to expand to a total of 183,000 MW in about 2032. However, the CEA notes that renewable power sources cannot change output in accordance with demand, so it is not responsive to peak power demand. In addition to that problem, costs are higher than with conventional power sources, so (in order to make them economically viable) their use for now should be limited to power transmission to distant areas that would be very expensive to connect to the grid and to the elimination of supply and demand gaps in isolated areas, etc. In order to promote the dissemination of relatively expensive renewable energy, there are an FIT system and subsidies for all renewable energy (wind power, small hydropower of 25 MW or less, solar, biomass, biogas, etc.).

Regarding the installation of renewable energy, the CEA estimates that in the low installation case, during the 12th Planning Period, wind power 11,000 MW, solar 4,000 MW, and other 3,500 MW will be installed for a total of 18,500 MW, while during the 13th Planning Period, wind power 11,000 MW, solar 16,000 MW, and other 3,500 MW will be installed for a total of 30,500 MW. In the high installation case, the estimate for the 12th Planning Period is wind power 15,000 MW, solar 10,000 MW, other 5,000 MW, total 30,000 MW, while for the 13th Planning Period, it is wind power 20,000 MW, solar 20,000 MW, other 5,000 MW, total 45,000 MW.

An overview of international collaboration follows.

India has built good bilateral relations with Bhutan. India has constructed large hydropower plants in Bhutan, which has abundant hydropower resources, and imports electricity from that country. Today, Bhutan has hydropower plants in three places (Chukha, Kurichu, and Tala), with a total output of 1,416 MW. India imports electricity from them via international interconnection lines. Hydropower plants with a total output of 2,940 MW are now under construction in three places (Punatsangchhu Phases 1 and 2 and Mangdechu). The electricity generated by those plants will also be imported by India over newly established international interconnection lines. In addition, detailed project reports (DPRs) for six sites have been approved or submitted, and another is being prepared. For the three competed sites, 60 percent of the construction funds were provided by India, and the remaining 40 percent consisted of loans from India. For the projects now under construction, 60–70 percent of the funding is loans from India, and the remainder is to be provided by India.[18]

Neighboring country Nepal is also projected to have abundant hydropower, and there are plans for India to import electricity over interconnection lines. Construction of a tie line between Dhalkebar, Nepal, and Muzaffarpur, India, is planned. The project will cost 182.3 million dollars, with 99 million dollars to be borrowed from international banks. According to a report from an international bank dated March 2013, a construction contract was to be signed in June 2012, but it still had not been signed, and construction had not begun. With a transmission capacity of 1,000 MW, operation is scheduled to begin in 2016.[19] According to the CEA, in addition to the four sites in Nepal where India is cooperating on hydropower plant construction (Pokhra, Trisuli, Western Gandak, and Devighat), hydropower plant construction through joint funding at four other sites is being considered.[20]

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[18] COOPERATION WITH BHUTAN, 2013/2/28, CEA

[19] Nepal-India Electricity Transmission and Trade Project and South Asia - Nepal-India Electricity Transmission and Trade Project : P115767 - Implementation Status Results Report : Sequence 04 (2013/3/26), The World Bank

[20] Indo- Nepal Cooperation in Hydro Power Sector, CEA, 2013/2/28

6. Indonesia's Power Development Plan

Indonesia's power development plan is the National Power General Plan (RUKN) set by the Ministry of Energy and Mineral Resources (MEMR) for the coming 20 years based on energy policy and environmental policy. Additionally, the Indonesia State Electricity Company (PLN) sets the Electricity Power Supply Business Plan (RUPTL), a detailed 10-year plan for the power supply based on the RUKN.[21]

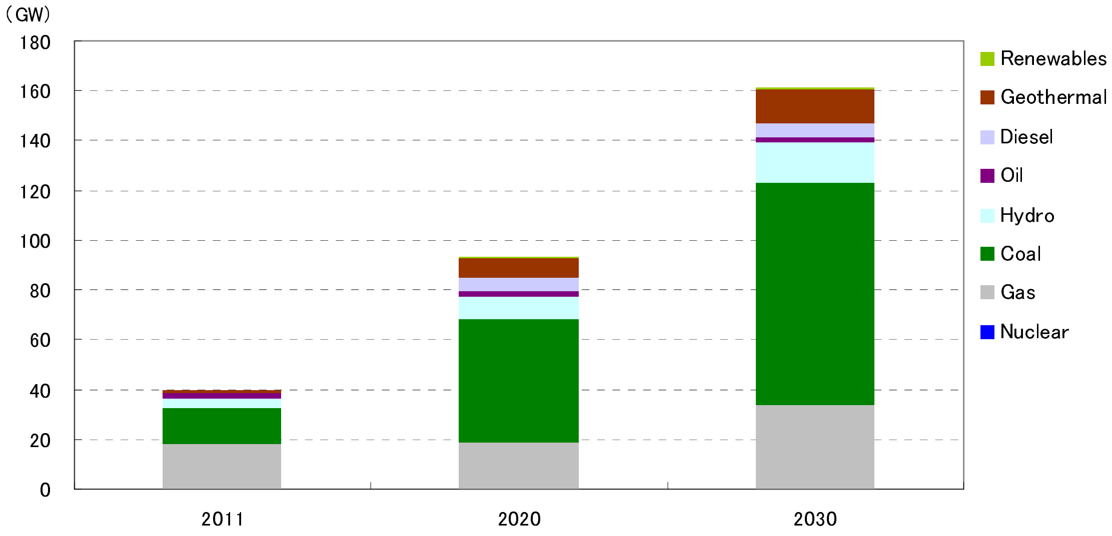
According to the "RUPTL 2011-2020," which is the power development plan for 2011 through 2020, power demand during the period is projected to grow at an average annual rate of 8.5 percent, reaching 328.3 TWh in 2020. Maximum demand as of 2020 is projected to be 55,053 MW, an average annual growth rate of 8.14 percent.

By region, projected demand for Java and Bali is 241.2 TWh in 2020, with an average annual growth rate of 7.8 percent. Eastern and western Indonesia, where the electrification rate has been low, are projected to grow at a faster rate than Java and Bali are. Eastern Indonesia is predicted to grow at an average annual rate of 10.8 percent to 31.7 TWh in 2020. Western Indonesia is predicted to grow at an average annual rate of 10.2 percent to 55.3 TWh in 2020.

In order to meet that demand, expansion and improvement of all facilities for production, transmission, and distribution is essential.

[21] Japan Electric Power Information Center, "FY 2010 Report on survey of electric power in Indonesia"

Figure 2-6: Power development plan toward 2020 and 2030 (Indonesia)



Indonesia (GW)

	2011	2020	2030
Nuclear	–	–	–
Gas	18.399	18.668	33.632
Coal	14.018	49.689	89.521
Hydro	3.881	8.983	16.183
Oil	2.250	2.250	2.250
Diesel	–	5.472	5.472
Geothermal	1.209	7.502	13.516
Renewables	0.129	0.758	0.758
Total Supply Capacity	39.885	93.322	161.332

Source: Power Development Plan (MEMR)

In "RUPTL 2011-2020," a power development plan for 2011 through 2020 is laid out in order to meet the above-mentioned power demand. Development of 53,700 MW of generating facilities by 2020 is projected. By producer, PLN accounts for 31,376 MW (58.4 percent) and IPPs for 22,324 MW (41.6 percent).

Breaking down the power development plan through 2020 by type, coal-fired power plants account for the majority of power plants to be built, with a total capacity of 34,300 MW (not counting coal gasification) accounting for 63.8 percent of the whole. Meanwhile, gas-fired power plants and combined cycle power plants together are 7,400 MW (13.7 percent). As for renewable energy, geothermal has the largest planned share at about 6,100 MW (11.3 percent), followed by hydropower at around 5,700 MW (10.6 percent).

By producer, both PLN and IPPs will carry out development centered on coal-fired power plants. National policy of moving away from oil and effectively utilizing domestically produced coal is obviously reflected.

For changes in power plant capacity towards 2020 and 2030 in this study, estimates were made based on information from the Ministry of Energy and Mineral Resources (MEMR). According to this information, total power plant capacity as of 2020 will be 93,322 MW. Of this, the major power source of coal-fired thermal will account for 49,689 MW. Total power plant capacity as of 2030 is projected at 161,332 MW, with coal-fired thermal increasing to 89,521 MW.

According to a 2010 report by the Ministry of Energy and Mineral Resources (MEMR), Indonesia's coal reserves total 21.1 billion tons (9.9 billion tons in Kalimantan and 11.2 billion in Sumatra). In light of increasing domestic demand and the strength of inquiries from the international market, production capacity is expected to rise. Because high-quality coal is being aggressively exported as a means to acquire foreign currency, low-quality coal such as lignite and subbituminous coal is the heart of the domestic supply. Therefore, if power source development is to proceed according to plan with the focus on coal, ensuring supply and quality are issues that must be addressed.

In terms of ensuring supply, the Indonesian government has developed a domestic market obligation (DMO) policy. Coal producers are required to set aside a portion of production for domestic use. Additionally, the need to improve supply infrastructure so that the coal produced at mines can be transported to power plants nationwide is recognized. In terms of quality, there are many issues. Low-quality coal such as lignite and subbituminous coal has high moisture content and low heat output, so generating efficiency is low, and CO_2 emissions volume is high for the amount of electricity generated. Expectations are therefore high for the establishment and commercialization of clean coal technology for more efficient coal-fired power plants.

Indonesia has abundant natural gas resources, with 164.99 Tscf. Large amounts have been confirmed in the Natuna Islands, South Sumatra, and East Kalimantan. However, most of those large gas fields have been tied up in export-oriented long-term contracts. Moreover, because of booming domestic demand, an adequate supply of natural gas for power plants is not projected. Expectations are therefore high for ensuring supply capacity through steady progress on currently planned gas field development projects and further development of gas pipelines.

The "Master plan survey on Indonesia's geothermal development" carried out by West JEC in 2007 is a survey report on Indonesia's geothermal resources and stockpile. According to the report, 50 sites with 9,000 MW can be developed in Indonesia. The potential is at least 12,000 MW. In "RUPTL 2011-2020," many geothermal power projects are included in Sumatra, Java, North Sulawesi, Nusa Tenggara, and Maluku in particular. In Indonesia's remote areas, especially its outlying islands, diesel generation is the most common power source. Because of fuels costs and CO_2 emissions as well, it is therefore planned to effectively utilize what is said to be the world's greatest geothermal potential and develop geothermal power plants as an alternative power source. For the power source plan to progress steadily, it is expected that the government will contribute funds for development and that CDM will be commercialized.

Indonesia also has high hydropower development potential. Nippon Koei's 2011 "Master plan survey for the development of hydropower in Indonesia" reported finding a potential of 26,321 MW. On the so-called outer islands other than Java, although development of large hydropower plants is possible, power demand is low because of the population density distribution, and the cost of transmission to demand areas is very high. Site selection for development is therefore very important.

Nuclear power is not included in the "RUPTL 2011-2020." Although nuclear power plants are under consideration as a very promising power source to meet Indonesia's power demand, lack of clarity on capital costs, spent fuel disposal and storage costs, and reactor decommissioning costs is an issue. Detailed construction plans that address multiple factors such as political issues, safety, and community acceptance in addition to economic and energy issues have not been made clear.

Finally, an overview of international interconnection will be presented. At this time, Indonesia has no record of electricity import/export with any neighboring country. However, international interconnection plans with Malaysia and Singapore are under study. As discussed above, Indonesia has a shortage of gas for domestic consumption because of the need to maintain its gas exports to other countries.

Effective utilization of coal, for which abundant reserves have been confirmed, is planned. On the other hand, most thermal power plants in Singapore burn gas supplied by pipeline from Malaysia and Indonesia. Improvement of that skewing towards gas firing has been raised as an issue in terms of energy security and fuel costs. Indonesia exporting coal-fired power to Singapore is expected to optimize power in the region. It would help Indonesia solve its domestic gas shortage because of the export gas supply, and allow Singapore to diversify its energy sources and lower electricity rates.

7. Laos's Power Development Plan

Laos's power development plan focuses on hydropower, except for small-scale things not connected to the grid. Flowing out of China's Yunnan Province, the Mekong River flows from north to south through Laos for 1,500 km. a number of rivers flow into the Mekong from highlands such as the Annamite Range. Its development potential is very high. It has been theoretically put at 26,000 MW or 30,000 MW, so there is enormous room left for development. As of the end of 2011, installed capacity was 2,570 MW.

The Laotian government therefore considers hydropower projects to be an important sector that contributes to economic growth and fighting poverty. It names the objectives of such power source development as "ensuring a stable and adequate power supply in the nation" and "acquisition of foreign currency through promotion of the export of electricity from hydropower."

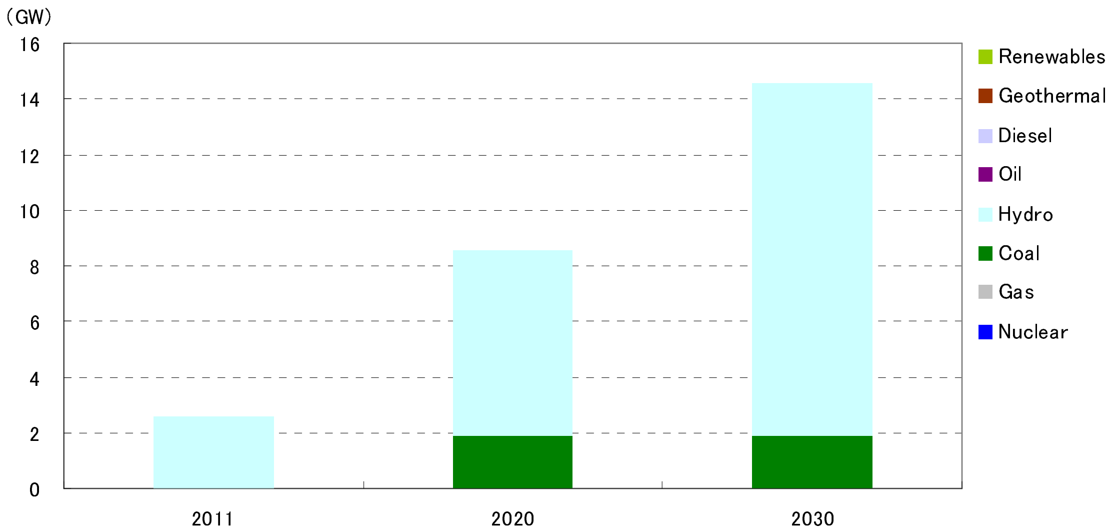
It is planning and attempting a basic policy of promoting IPP power source development through the BOOT (Build, Own, Operate and Transfer) method[22] is an example of that.

As for the domestic electricity supply, in contrast, power demand areas are scattered through mountainous land, and despite being surrounded by those abundant water resources, many areas are geographically difficult to connect to the grid for

[22] The method in which private-sector corporations undertake construction, including procurement of funds, and, after completion, own the project for a fixed period of time, receiving the profit from operation, and then transfer ownership.

electrification. Therefore, renewable energy such as solar, biomass, and small-scale hydropower has an important role to play. Currently operating power sources are small-scale hydropower at 6.2 MW, solar at 2.2 MW, and the only thermal power, diesel at 1.7 MW.

Figure 2-7: Power Development Plan toward 2020 and 2030 (Laos)



Lao (GW)

	2011	2020	2030
Nuclear	–	–	–
Gas	–	–	–
Coal	–	1.878	1.878
Hydro	2.570	6.646	12.689
Oil	–	–	–
Diesel	0.002	0.002	0.002
Geothermal	–	–	–
Renewables	0.008	0.008	0.008
Total Supply Capacity	2.580	8.534	14.577

Source: Powering Progress.

Regarding Laos's power development plan, the Department of Energy Promotion and Development (DEPD) publishes on its website "Powering Progress" (http://www.poweringprogress.com) detailed data on projects in the construction, planning, and feasibility study phases.

First, projects under construction will be discussed. Laos is currently constructing power plants at 12 sites. The relatively small projects are planned for domestic use, while the large ones are planned for electricity export. Hydropower projects account for the majority, but the only project scheduled to be in operation in 2015 is the Hongsa Lignite power plant (1,878 MW), which will use lignite as its energy source and become the nation's first large coal-fired power plant.

Against the background of the abundant water resources of the Mekong River system, Laos has built hydropower generation. However, hydropower is characterized by sharp fluctuations in output between rainy and dry seasons, so the annual average operating rate is only 40–60 percent. If there is a dry season supply and demand gap, Laos will have to import electricity from Thailand. Expectations are therefore rising for the adoption of thermal-fired power as a stable base power source. However, the Electricity Generating Authority of Thailand (EGAT) has a contract to purchase up to 95 percent of the power plant's electricity output, so it will not be a dramatic solution. The number one candidate for a base power source is coal-fired thermal power using domestically produced lignite.

Regarding the Xayabouri hydropower plant (1,285 MW) under construction in northern Laos, a ministerial-level meeting of the Mekong River Commission (comprising Thailand, Vietnam, Cambodia, and Laos) held on December 8, 2011, decided to postpone the construction plan and carry out environmental impact assessment. It is now uncertain when the plant will go into operation.[23]

Power plant projects in the planning phase in Laos are all hydropower plants. Twenty-five of them are listed. Construction of power plants at five sites (combined output of 970–1,270 MW) as power sources for export to Vietnam and Thailand is in the planning phase.

All the power plants currently in the feasibility study phase are also hydropower plants. Including large power sources, over the medium- and long-term (from 2020 on), they will meet increases in domestic demand. At the same time, they are expected to become an important means of foreign currency acquisition for Laos. There are currently 35 power plant sites totaling about 7,750 MW undergoing feasibility studies.

[23] Asahi Shimbun, December 9, 2011

Finally, an overview of the transmission grid in Laos will be presented. Laos's transmission lines to Thailand for electricity export include 500 kV transmission lines from the Nam Ngum 3 and Nam Theun 2 hydropower plants, and 230 kV transmission lines from the Thenm Hinboun and Houay Ho hydropower plants. There are also transmission lines under 115 kV with Cambodia, China, Vietnam, and Thailand, but none of these are interconnected to the domestic grid.

The domestic grid currently comprises only 115 kV transmission lines in the vicinities of the capital, Vientiane, and cities in the south. According to the Ministry of Energy and Mineral Resources (MEM), only 30–40 percent is interconnected, so some areas have surplus electricity, while others rely on imports to supply their power. A mix that can effectively utilize existing facilities has not been achieved.[24]

Laos has signed memoranda (MOUs) to sell electricity to Thailand (7,000 MW), Cambodia (300–500 MW), and Vietnam (5,000 MW). In the future as well, against the background of abundant water resources, electricity exports will be a pillar of industrial policy. Export-oriented resources development through IPPs will be promoted to acquire foreign currency. From the perspective of energy security, on the other hand, facilitation of transmission line construction projects that can quickly enable economical and efficient interconnection is necessary.

8. Malaysia's Power Development Plan

The energy division of the Economic Planning Unit (EPU), an organization under the Prime Minister's Department, the highest decision-making body, is in charge of Malaysian energy policy. The latest energy policy is the 10th Malaysia Plan 2011-2015, announced in June 2010.[25]

The 10th Malaysia Plan emphasizes energy security and economic efficiency along with environmental and social considerations. It has five strategic priorities on energy: "Initiatives to Secure and Manage Reliable Energy Supply," "Measures to

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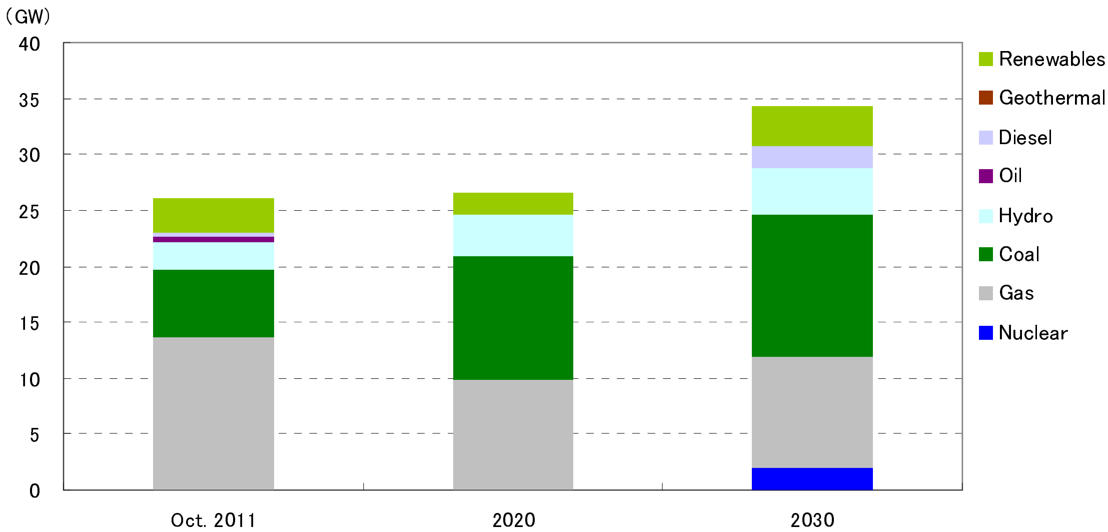
[24] Japan Electric Power Information Center, February 2009

[25] The Tenth Malaysia Plan 2011-2015, Economic Planning Unit Prime Minister’s Department, June 2011

Encourage Efficient Use of Energy," "Adoption of Market-based Energy Pricing," "Stronger Governance," and "Managing Change."

In the 9th Plan period (2006-2010), economic growth was sluggish, but that was because of the global slump. Without economic reforms that can meet changes in the outside environment, long-term growth cannot be expected. Improving domestic competitiveness and raising productivity during the 10th Plan period are considered necessary for economic growth. If that is achieved, an average annual GDP growth rate of 6 percent during the 10th Plan period is estimated. However, the plan does not include any estimates for power demand.

Figure 2-8: Power Development Plan toward 2020 and 2030 (Malaysia)



Malaysia (GW)

	Oct. 2011	2020	2030
Nuclear	–	–	2.000
Gas	13.627	9.900	10.000
Coal	6.070	11.000	12.600
Hydro	2.406	3.700	4.224
Oil	0.516	–	–
Diesel	0.352	–	2.000
Geothermal	–	–	–
Renewables	3.060	2.000	3.500
Total Supply Capacity	26.031	26.600	34.324

Source: IEEJ estimates from IHS Global Insight.

Regarding the development of generating facilities, the 10th Plan discusses facilitating expanded use of existing coal and LNG-fired power plants as well as hydropower. It also discusses construction of supercritical pressure coal-fired power plants and beginning consideration of nuclear power. The detailed power source development plan during the 10th Plan period is as follows.

As for hydropower, construction is progressing at Ulu Jelai and Hulu Terengganu. Their combined output will be 662 MW. Tenaga Nasional Berhad (TNB), the electric utility in charge of Peninsular Malaysia is carrying out the construction. Construction of a 2,400 total MW hydropower plant at Bakun is also progressing. Although the project was originally approved for construction in 1986, it was temporarily halted in 1990, restarted in 1993, and then suspended again in 1997 during the Asian currency crisis. In 2002, construction restarted with Malaysia-China Hydro (MCH) as the main construction contractor. In 2011, the generators first began producing electricity. There has been much criticism of the project because many residents were displaced and because of the claim that capacity is excessive in comparison to power demand. (Power demand in Sarawak is currently about 1,000 MW.) It is reportedly planned to expand the generators to 2,400 MW in 2014.[26]

As for coal-fired power, TNB subsidiary TNB Janamanjung is constructing a supercritical pressure coal-fired power plant in Janamanjung. With an electricity output of 1,000 MW, it is scheduled to begin operating in 2015. Once it goes into operation, it will become Southeast Asia's first 1 GW class supercritical pressure coal-fired power plant. The main contractor is France's Alstom. According to that company. Total project costs will be about 1 billion euros.[27]

As for gas-fired power, a subsidiary of the national oil company, Petronas, is constructing the Kimanis power plant (300 MW, scheduled to begin operating in 2013), Malaysia SPR Energy is constructing the SPR power plant (100 MW, scheduled to begin operating in 2013), and TNB is constructing the Lahad Datu power plant (300 MW, scheduled to begin operating in 2016). All of those gas-fired power plants are located in Sabah State.

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[26] Malaysia's Bakun dam online but criticisms persist, AFP, 2011/10/27

[27] South East Asia’s first 1000 MW supercritical coal-fired power plant at Malaysia’s Manjung for €1 billion, Alstom, 2011/4/4/

As for nuclear power, the 10th Plan clearly states it is to be considered a long-term option. Development of nuclear power is assigned an important place in energy security. The Malaysian government has announced that nuclear plants of 1,000 MW each are scheduled to go online in December 2010, 2021, and 2022. In January 2013, after the Fukushima Daiichi nuclear accident, Malaysia Nuclear Power Corporation CEO Mohd Zamzam Jaafar stated that feasibility studies for power plant construction would be six months late, and that construction of the first nuclear power plant in Malaysia is expected to begin in 2021. It is unclear what effect the accident has had on the plans.

Renewable energy is positioned as a "fifth fuel" to supplement conventional energy resources (oil, natural gas, hydropower, and coal) and its use is promoted. During the 9th Plan period, however, installation of renewable energy power plant capacity fell well below targets. As of 2009, installed capacity was only 41.5 MW (<1%). The 10th Plan therefore sets out a plan to bring renewable energy power plant capacity up to 985 MW (5.5 percent). An FIT system has been operating since December 2011. The government agency in charge of the FIT system, the Sustainable Energy Development Authority (SEDA), has established a "renewable energy fund" for the operation of the system and the collection of surcharges. The fund is used to pay power companies the difference from their average generating costs. The source of the fund is a 1 percent surcharge on the electric bills of consumers who use more than 300 kWh in a month. The goals for renewable energy adoption are 985 MW/5.4 GWh in 2015, 2,080 MW/11.3 GWh in 2020, 4,000 MW/17.2 GWh in 2030, and 21.4 GW/44.2 GWh in 2050.

An overview of international collaboration is as follows.

Malaysia has power tie lines with Thailand and Singapore. According to Suruhanjaya Tenaga (Malaysian Energy Commission), the amount of power exported in 2010 was 88 GWh, and the amount imported was 0.03 GWh. Compared with exports in 2007 (2,477 GWh), the amount has been trending down year by year.[28] This is probably because, with the opening of gas pipelines from Malaysia and

[28] Industri Pembekalan Elektrik di Malaysia 2010, Suruhanjaya Tenaga

Indonesia to Singapore, that country has shifted to gas-fired power plants utilizing that gas.

As discussed in the Indonesia section, there are plans to construct an international tie line between Malaysia and Indonesia. Singapore relies on gas imported through pipelines. The need to improve that skewing towards gas-fired power has been indicated from the perspectives of security and fuel costs. Diversification of power sources and lowering of electric charges through imported electricity is projected. However, in Indonesia, control of gas for export has led to domestic shortage, which could also be improved.

Additionally, the concept of constructing a 275 kV transmission line with a transmission capacity of 50–100 MW between Sarawak and Indonesia's West Kalimantan and beginning electricity trading in 2014 has been announced.[29]

9. Myanmar's Power Development Plan

Myanmar's energy policy is set by the Energy Planning Department (EPD) under the Ministry of Energy (MOE). The EPD set an energy plan during the 1990s, but it still has not been updated. The following five areas have been taken up as issues in power policy.

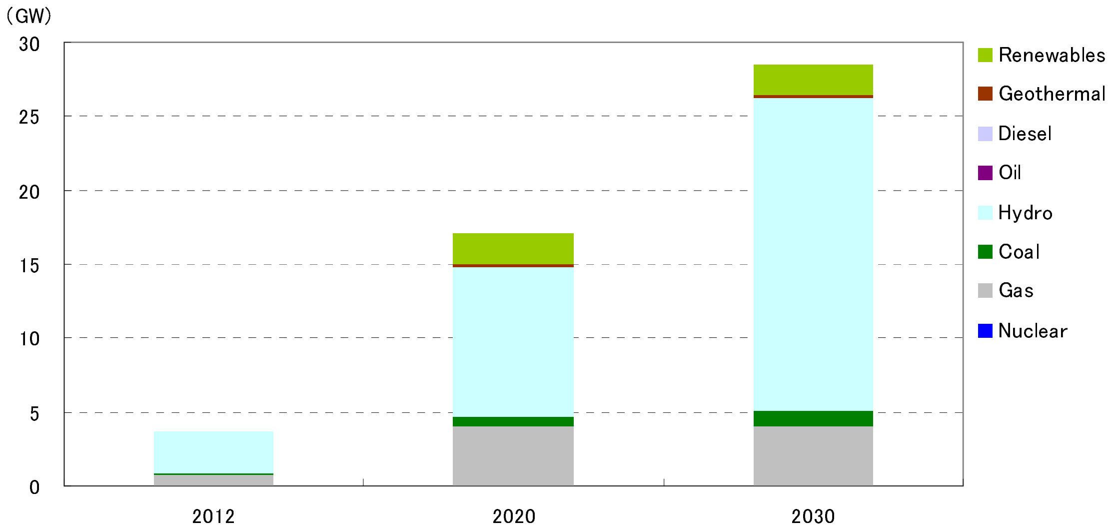
1. As a short-term plan, expansion of gas turbines in order to alleviate planned power outages
2. As a medium- and long-term plan, promotion of hydropower development and electricity exports
3. Upgrading of power transmission and distribution equipment
4. Reduction of transmission and distribution loss and promotion of energy conservation
5. Promotion of renewable energy development

Myanmar's power demand grew by an annual average of 3.8 percent from 1987 through 2008. Electricity output has been increasing rapidly since 2008. FY 2008

[29] Malaysia, Indonesia to begin power trade in 2014, New Straits Times, 2012/2/28

electricity output was 6,622 kWh. In FY 2011, it was 10,000 kWh, for a high average annual growth rate of 14.7 percent. As for projected future power demand, materials[30] published by the (Ministry of Electric Power 2 (MOEP2) in 2008 estimate high peak demand, with the annual rate through 2021 expected to be 9–10 percent, and the annual rate after that expected to be 7–7.5%. Projections are 3,575.9 MW as of the end of 2020, and 7,334.82 MW as of the end of 2030.

Figure 2-9: Power Development Plan toward 2020 and 2030 (Myanmar)



Myanmar (GW)

	2012	2020	2030
Nuclear	–	–	–
Gas	0.715	4.042	4.042
Coal	0.120	0.690	0.990
Hydro	2.780	10.088	21.247
Oil	–	–	–
Diesel	–	–	–
Geothermal	–	0.200	0.200
Renewables	–	2.066	2.066
Total Supply Capacity	3.615	17.086	28.544

Source: IEEJ estimates from 1st WG, Nov. 2012 Presentation

After a military government took over Myanmar in 1988, economic assistance (ODA, etc.) from other countries was cut off. That led to electricity shortages and

[30] Country Report on Progress of Power Development Plans and Transmission Interconnection Projects, 25th–27th November 2008

ongoing supply restrictions. Efficient power source development is therefore important. Since large gas fields were discovered in 1992, gas turbine power plants, which require only short construction periods, have been built and subsequently converted to combined cycle in an effort to shorten power outages. During that time, development of hydropower plants was promoted with the aim of ending electricity shortages. Today, natural gas exports are seen as an important means of foreign currency acquisition, and effort is being put into hydropower development.

Myanmar's domestic hydropower resources are vast. Theoretical hydropower plant development potential is estimated at 10.8 GW. Of that, economically developable capacity is estimated to be about 43.45 GW., Development is promising for the Thanlwin River, the Ayeyarwady River, the Chindwin River basin, the Shan Highlands, the Arakan Mountains, and thee southern peninsula area.

With ODA cut off, development of hydropower resources stagnated. In recent years, however, development has shifted into high gear through economic cooperation and direct investment from China and Thailand. Including those based on bilateral cooperation, development of hydropower plants is planned for 18 sites (total output 31,059 MW). The largest plan, a joint venture with China Power Investment Corp, is a project to put seven generators with a total output of 16,500 MW on the upper Ayeyarwady River. The first generator is expected to go into operation around 2015. Additionally, joint development with China of hydropower plants in Shweli and Dapein is planned. With a Thailand’s corporation and the Ministry of Electric Power 1 (MOEP1) have formed a joint venture company that is developing hydropower plants in Ta Sang and Taninthayi. In Hutgyi, a joint feasibility study with Thailand was completed in 2007. With India, a memorandum of understanding (MOU) on development of a hydropower plant in Tamanthi was signed with the National Hydroelectric Power Corporation (NHPC) in 2008. The plan calls for development of six 200 MW hydropower plants for a total of 1,200 MW. The objectives of constructing the Tamanthi power plants include flood prevention and control. In addition, domestic IPPs have signed MOUs for development of hydropower plants in Thaukyegat, Baluchaung, Saidin, and Upper Baluchaung.

Inside Myanmar, exploration for oil fields on land began during the 1960s. No major fields were discovered, however, and production volume from land-based oil and gas fields is trending downwards. Exploration of offshore oil fields beginning in the 1970s, however, led to the 1992 discovery of vast gas fields. Full-fledged gas production began at the Yadana gas field in 1998 and at the Yetagun gas field in 2000. The gas produced at those gas fields, in addition to being piped into the domestic supply (Yadana gas field), is also exported to Thailand (Yadana/Yetagun gas fields). It has become a means for Myanmar to acquire foreign currency. As discussed above, in order to meet power demand, construction of gas-fired power plants has been underway since 1992, but because gas exports are given priority, operation must be coordinated depending on availability of fuel. No more power plants using natural gas can be constructed.

The state of international collaboration on power lines is as follows.

There is a 188 km international tie line between Myanmar's Shweli power plant and China's Dehong substation. Under a September 2009 agreement, the purchase price for electricity from the Shweli power plant is 0.184 yuan/kWh (about 2.9 yen/kWh). In addition, there are small-scale electricity import lines from China and Thailand. Electricity imported from China costs about 1.2–1.5 yuan/kWh (19–24 yen/kWh), and that from Thailand costs about 4.5–6.25 baht/kWh (15–21 yen/kWh).

Electricity exports to India re also planned. Electricity produced at the Tamanthi power plant that is a joint venture with the NHPC, is to be exported to India via international tie line. Construction of new transmission lines is therefore planned.

10. Philippines' Power Development Plan

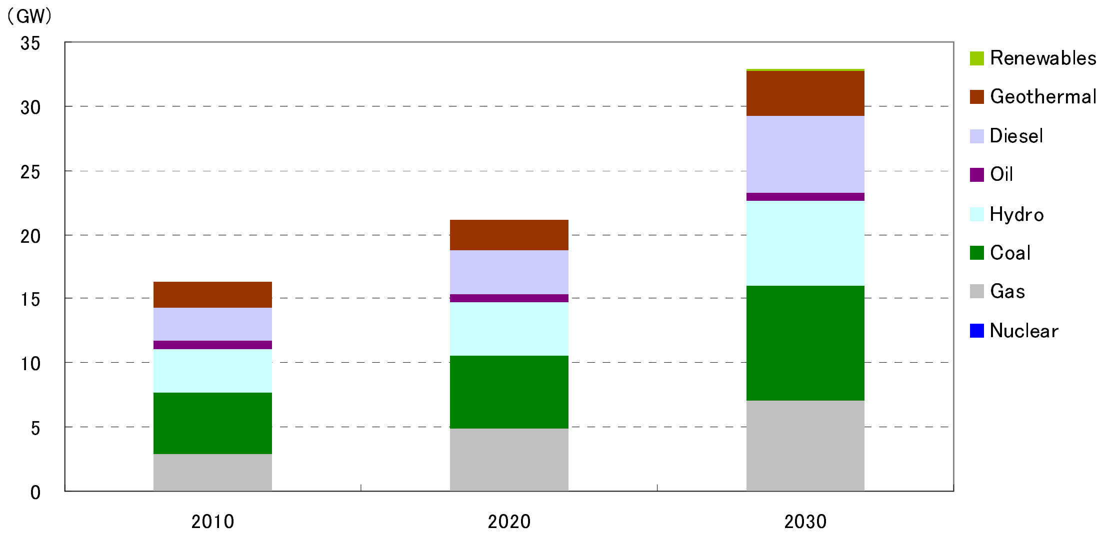
In the Philippines, the Department of Energy (DOE) has overall jurisdiction over energy policy. It is responsible for setting, implementing, and managing all plans in the energy sector. It promotes exploration, development, and use of energy resources and encourages energy conservation. The latest energy plan is the (2012-2030 Philippine Energy Plan (PEP 2012-2030). The latest power development plan is Power Development Plan 2009-2030[31] (PDP 2009-2030).

[31] Although it has not been published on the DOE website, a draft version of PDP 2010-2030 (Power Development Plan 2010-2030) was referred to as appropriate.

Major measures in the PEP 2012-2030 include "securing energy security" through expanded use of renewable energy and development of oil and coal resources, "expansion of energy supply access" through technology, and "promotion of a low-carbon society" through efficient energy utilization and clean fuel technology.

As for projected power demand, according to the PDP 2009-2030, the DOE estimates electricity output at 55,417 GWh as of 2008, 86,809 GWh as of 2018, and 149,067 GWh as of 2030. By region, the DOE predicts power demand in the Luzon islands (region) will grow at 4.53% annually to reach 109,477 GWh in 2030, demand in the Visayas islands will have a slightly faster average annual growth rate of 5% to reach 19,121 GWh in 2030, and demand in the Mindanao islands will grow at an average of 4.62% annually to reach 20,470 GWh in 2030.

Figure 2-10: Power development plan toward 2020 and 2030 (Philippines)



Philippines (GW)

	2010	2020	2030
Nuclear	–	–	–
Gas	2.861	4.961	7.061
Coal	4.867	5.627	8.972
Hydro	3.400	4.112	6.605
Oil	0.650	0.650	0.650
Diesel	2.543	3.443	5.943
Geothermal	1.966	2.295	3.559
Renewables	0.073	0.072	0.072
Total Supply Capacity	16.360	21.160	32.862

Source: IEEJ estimates from Draft PDP 2010-2030.

According to the PDP 2009-2030, by running simulations based on the above demand forecasts, the DOE calculates that 17 GW of power source development will be necessary by 2030. However, the only power plants development plans to which commitments have been made are two in the Luzon islands (600 MW), one in the Visayas islands (100 MW), and three in the Mindanao islands (258 MW), for a total of 958 MW. New plans are needed to make up the difference. The DOE calculates that the capacity that must be installed is 11,900 MW in the Luzon islands, 2,150 MW in the Visayas islands, and 2,500 MW in the Mindanao islands.

In the past, the National Power Corporation (NPC) carried out power plant development in the Philippines on an exclusive basis. Participation by independent power producers (IPPs) has been permitted since 1993, and the NPC has been selling off assets, so the NPC's share of electricity output has fallen sharply from 68.1% in 2001 to 14.5 percent in 2010. IPPs now handle most power source development as well.

The DOE estimates hydropower potential in the Philippines at 13,100 MW. However, a total of only 3,400 MW has been developed so far, so there is still much development left. The government's policy is to develop hydropower as part of its renewable energy development. It plans to increase hydropower to 7,530 MW by 2030. There are many issues in hydropower development. In the Luzon islands, the division between the summer season and the rainy season makes it easy for droughts to occur. In the Mindanao islands, which depend on hydropower for over 50 percent of their power, abnormal weather in early 2010 forced daily power outages of 5–8 hours.

As of 2000, there were about 5,000 MW of oil-fired power plants (including diesel). Through the closing of aging facilities and so on, that fell to about 2,000 MW as of 2010.

For the sake of energy self-sufficiency, the government promotes the opening of gas fields. Production volume as of 2009 was 35 billion cf; the plan is to increase that to 2.694 trillion cf by 2030. Natural gas from the Malampaya gas fields has since 2001 been supplied via pipeline to gas-fired power plants in the Luzon islands and Batangas State. Currently, 2,861 MW of gas-fired power plants are in operation. First Gen Corp. plans to build a 500 MW (ultimately, 1,300 MW) gas-fired power plant in

San Gabriel.[32] Additionally, Energy World Corp. plans to build an LNG terminal in Pagbliao, along with a 300 MW gas-fired power plant.[33]

The Philippine government is pushing the development of coal resources as an alternative to oil. It intends to increase annual production volume to 2.5 times as much (about 1.2 million tons) by 2030. The installed capacity of coal-fired power plants as of the end of 2000 was 3,963 MW. As of 2010, it had gradually increased to 4,867 MW. Development of coal-fired power plants continues. In 2012, GN Power Ltd. began operating a 600 MW coal-fired plant in Bataan on Luzon.

The Philippines has an estimated 4,790 MW of geothermal resources. Generating cost is the least expensive after hydropower, and utilization ratio is high, so it is utilized an important base power source. As of 2010, there were geothermal power plants at 10 locations in the Philippines, with total installed capacity of 1,996 MW, the second most in the world. The Philippine government plans to continue developing geothermal power, to raise installed capacity to 3,450 MW by 2030.

The Philippines decided to build a nuclear plant in Bataan. Construction began in 1976 and was completed in 1984. However, numerous defects were found, and in light of the Chernobyl disaster, it was mothballed rather than going into operation. In 2010, however, although nuclear power itself was not abandoned, a final decision was made to never use the Bataan nuclear power plant. How to use it, including possible sale, is under consideration.

As for renewable energy, in 2008, the government set out the National Renewable Energy Program (NREP) and passed the Renewable Energy Law. According to NREP, installed capacity of renewable energy is to be doubled from its 5,300 MW in 2008 by 2030. Therefore, a corporate income tax exemption (7 years), an exemption on duties on imported equipment (10 years), and a reduction of property taxes have been adopted along with a feed-in tariff (FIT) system beginning in 2010.

As for international collaboration, the Philippines is an island nation far from its neighbors, so at this time it has no electric tie lines with any of them.

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[32] First Gen unveils $2.3-b expansion, Manila Standard Today, 2013/3/4

[33] Under Development – Philippines, Energy World HP, http://www.energyworldcorp.com/ud-phil.html

11. Singapore's Power Development Plan

Singapore separated from Malaysia and gained its independence in August 1965. It is an urban nation with a land area of about 700 km^2 and a population of more than 5 million. Singapore has no hydropower resources. Constrained by a small land area and high population density, it is unclear if nuclear power can be a realistic option for Singapore. All the nation's power plants are thermal generation. Capacity as of October 2010 was 12,330 MW. The power source mix by fuel type was natural gas about 70 percent and oil about 30 percent, and some refuse incineration power generation also in operation. As for coal-fired power, its installation is also considered problematic because of land constraints.

There is zero domestic production of the two main power sources, gas and oil, so all of it must be imported. This makes energy security an extremely important issue for Singapore.

As for oil, Singapore holds to a policy of fostering industry in free markets and free trade with minimal government interference. It has built itself into a global oil hub with oil companies from around the world, including the majors.

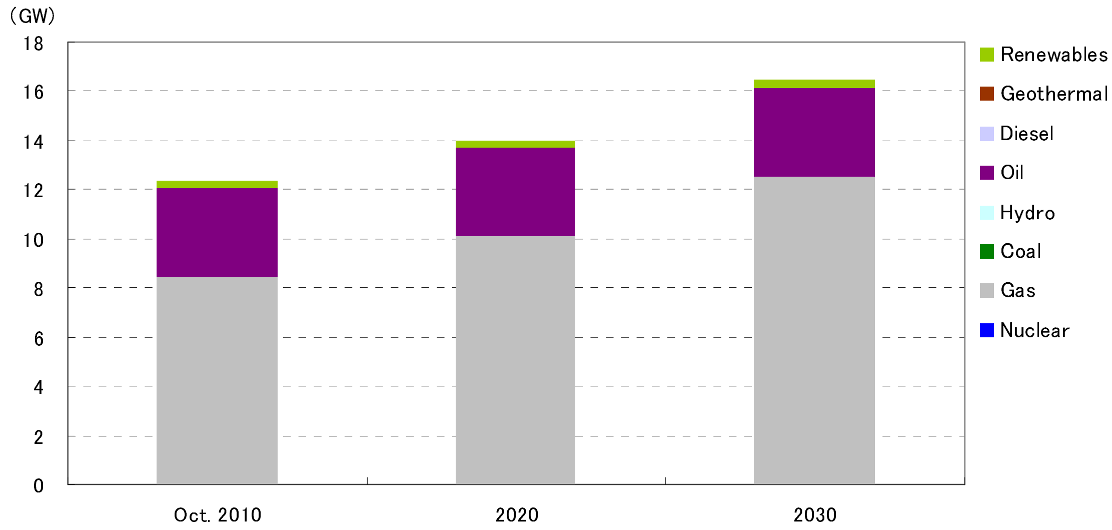
As for natural gas, Singapore began importing it from Malaysia via pipeline in 1992. It also began importing gas via undersea pipeline from West Natuna and southern Sumatra in Indonesia in 2001 and 2003, respectively. Today, therefore, it is supplied from three locations. In addition, Singapore is moving forward with plans to import LNG in order to secure stable supply through source diversification and to prepare to meet soaring gas demand. It will also build its first LNG receiving terminal on Jurong Island, the import site for pipeline gas from Indonesia. Initial site capacity is projected at 3.5 million tons per year in two LNG tanks. Preparation is underway to begin operations during the second quarter of 2013. A third tank is to begin operating during the fourth quarter. A plan has been conceived to eventually add a fourth tank, expanding capacity to 9 million tons per year.[34]

Electricity in Singapore has been liberalized, and the competitive sectors of generation and retail sale and the non-competitive sectors of transmission and distribution are separated at the ownership level. Since January 2003, Singapore's

[34] Singapore Government, SG Press Centre 2012/10/24

electricity wholesale market has been operated through the National Electricity Market of Singapore (NEMS) by Energy Market Company (EMC), an affiliate of the Energy Market Authority (EMA), which is the regulatory agency for the electricity and gas industries. Power producers sell electricity to the wholesale market in units of 30 minutes. All electricity buying and selling in the wholesale market takes place via EMC. As of October 2010, the power producers participating in NEMS were Senoko Energy (production capacity: 3,300 MW), Power Seraya (3,100 MW), Tuas Power Generation (2,670 MW), SembCorp Cogen (785 MW), Island Power Company (800 MW), Keppel Merlimau Cogen (1,400 MW), ExxonMobil Asia Pacific (220 MW), National Environment Agency (179.8 MW), Shell Eastern Petroleum (60 MW), Senoko Waste-to-Energy (55.4 MW), and Keppel Seghers Tuas Waste-to-Energy plant (24 MW).

Figure 2-11: Power Development Plan toward 2020 and 2030 (Singapore)



Singapore (GW)

	Oct. 2010	2020	2030
Nuclear	0.000	0.000	0.000
Gas	8.457	10.079	12.499
Coal	0.000	0.000	0.000
Hydro	0.000	0.000	0.000
Oil	3.625	3.625	3.625
Diesel	0.000	0.000	0.000
Geothermal	0.000	0.000	0.000
Renewables	0.248	0.296	0.367
Total Supply Capacity	12.330	14.000	16.491

Source: Statement of Opportunities.

According to "Statement of Opportunities for the Singapore Energy Industry 2011," published by the Energy Market Authority (EMA), Singapore's total power plant capacity as of 2020 is planned to be about 14,000 MW. Although installed capacity by fuel type is not clear, judging from the shift in generating fuel from diesel oil to natural gas in recent years, development is likely to continue to focus on combined cycle generation using pipeline gas and LNG, which will start being received in 2013.

Because plans beyond 2020 are unclear, the power source mix as of 2030 was extrapolated using the estimated electricity output in ERIA Study Project Report 2011 "ANALYSIS OF ENERGY SAVING POTENTIAL IN EAST ASIA REGION." According to the report, electricity output in Singapore will increase from 41.8 TWh in 2009 to 60.7 TWh in 2020. From 2020 to 2035, it is projected to increase at an average annual rate of 1.02 percent to 77.6 TWh. Based on that, estimation of Singapore's power plant capacity in 2030 indicates an increase to 16,491 MW (with gas-fired power the major source at 12,499 MW).

Since February 2011, EMA has been working on the creation of the "Regulatory Framework for Electricity Imports." Promotion of electricity imports in Singapore is of course expected to diversify the nation's energy and fuel mix in terms of expanding both the mix by type of fuel and the sources of the supply. It is also expected to enhance power interconnection, trade, cooperation, etc., with neighboring countries in mutually beneficial ways. An overview of electricity imports presented in a consultation paper in December 2011 is as follows.[35]

- The estimated electricity import framework for power supplies from overseas is a maximum of 600 MW per country.
- Bidding and selection of winning businesses for electricity import will proceed with the aim of completion in 2013.
- Electricity importers will begin selling electricity in Singapore around 2017–2018.

[35] Ministry of Economy, Trade and Industry, "Survey of ASEAN power optimization business through Indonesian electricity exports," February 2012

- EMA will ask each bidder to bid on a contract-for-differences (CfD) price. Imported electricity will be paid at the lower of the CfD Strike Price and the general Pool Price.
- The winning electricity importers will receive an electricity import license permitting 600 MW of electricity import for 20 years.

The consultation paper expired March 30, 2012, and was made public in order to gather comments and feedback. Preparation for bidding on electricity imports is likely underway at this time.

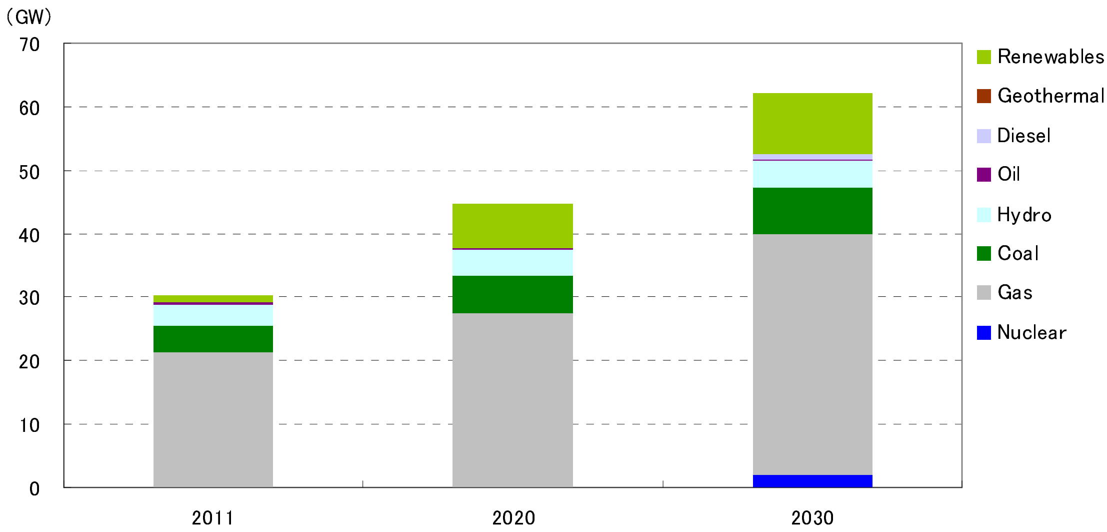
12. Thailand's Power Development Plan

Against a background of steady economic growth, power demand in Thailand has been growing at an annual average of around 5 percent. Peak demand in 2012 was about 26,000 MW, almost 10,000 MW higher than 10 years earlier. With this growth expected to continue, ensuring supply capacity for the future is an urgent issue. Furthermore, because of past air pollution problems, Thailand has a strong aversion to coal-fired power. A power supply mix that is over-reliant on natural gas is another concern. As of 2011, of Thailand's domestic power plant capacity of 30,246 MW, natural gas-fired power accounted for 21,474 MW, about 70 percent.

The Electricity Generating Authority of Thailand (EGAT) is in charge of creating the nation's power source development plan. In April 2010, a new power source development plan, the "SUMMARY OF THAILAND POWER DEVELOPMENT PLAN 2010-2030 (PDP2010)," was released. Subsequently, in light of an opposition movement by local residents, plans for development of coal-fired power were scaled back. After the accident at Fukushima Daiichi nuclear power plant, the timing and scale of the adoption of nuclear power were trimmed as well. Those changes were reflected in the "SUMMARY OF THAILAND POWER DEVELOPMENT PLAN 2012-2030 (PDP2010: REVISION 3)" released in June 2012, which is now Thailand's latest official power source development plan.

In power source development, in consideration of ensuring energy security and clean power supply as well as addressing high fuel prices, adoption of nuclear power as a new power source, fuel diversification, and increasing the volume of electricity imports from neighboring countries are planned.

Figure 2-12: Power Development Plan toward 2020 and 2030 (Thailand)



Thailand (GW)

	2011	2020	2030
Nuclear	–	–	2.000
Gas	21.474	27.442	37.912
Coal	3.955	5.886	7.387
Hydro	3.436	4.086	4.130
Oil	0.319	0.315	0.315
Diesel	0.004	0.004	0.754
Geothermal	–	–	–
Renewables	1.058	6.898	9.558
Total Supply Capacity	30.246	44.631	62.056

Source: PDP2010 Revision 3

According to "PDP2010: REVISION 3," Thailand's domestic power plant capacity exclusive of electricity imports, was 30,246 MW as of 2011. By 2020, it will expand to 44,631 MW. The major power source mix will be natural gas 61.5 percent (vs. 71.0 percent in 2011), coal 13.2 percent (vs. 13.1 percent), hydropower 9.2 percent (vs. 11.4 percent), and renewable energy 15.5 percent (vs. 3.5 percent). The plan is to attempt to use increased generation by renewable energy to reduce dependence on natural gas. In 2030, total output exclusive of electricity imports will be an estimated 62,056 MW. The major power source mix will be natural gas 61.1 percent, coal 11.9 percent, hydropower 6.7 percent, renewable energy 15.4 percent, and nuclear power 3.2 percent. Plans for the construction of nuclear power plants are incorporated.

By power source, a vision is sketched of natural gas power plant capacity rising from 21,474 MW in 2011 to 27,442 MW in 2020 and 37,912 MW in 2030. In order to avoid overdependence on natural gas, gas-fired facilities will not increase, but expansion of combined cycle plants with high thermal efficiency is planned. EGAT and IPPs expect to add new combined cycle plants. Installed capacity is projected to expand to 18,495 MW (41.4 percent of the capacity mix) as of 2020 and to 31,119 MW (50.1 percent of the capacity mix) as of 2030. For the natural gas supply, in order to diversify sources, in addition to domestically produced gas, and pipeline gas from the neighboring country of Myanmar, the Map Ta Phut LNG Receiving Terminal was operational in September 2011 and began receiving LNG.

As for coal-fired power plant, installed capacity of 3,955 MW as of 2011 is projected to reach 5,886 MW in 2020 and 7,387 in MW 2030. In "PDP2010: REVISION 3", domestically-produced lignite-fired 600 MW is planned to construct in 2018. On the other hand, EGAT intends to construct new thermal power plants that use imported coal as fuel. After bringing 800 MW coal-fired power plant online in 2019, it is projected to gradually build up to 3,200 MW in 2030.

As for hydropower, there is a plan to build a 500 MW pumped-storage power plant in 2017, but there are no other large-scale hydropower development plans. As noted above, therefore, hydropower's share of total power plant capacity is projected to fall from 11.4 percent in 2011 to 6.7 percent in 2030.

As for nuclear power, in the first version of PDP2010, the plan was to begin operating the first plant (1,000 MW) in 2020, and then install more reactors for a total of five reactors (5,000 MW in total) by 2028. However, after the accident at Fukushima Daiichi nuclear power plant caused by the Great East Japan Earthquake, the installation date was extended and the scale was reduced. According to "PDP2010: REVISION 3," installation of one 1,000 MW reactor in 2026 and another 1,000 MW reactor in 2027 is planned.

Lacking abundant fossil fuels such as oil and natural gas or hydropower resources, and highly dependent on energy imports, in recent years Thailand has been aggressively adopting renewable energy.[36] Thailand has abundant renewable energy resources, particularly biomass and solar power. In biomass, Thailand aims to utilize agricultural residual and industrial waste products such as rice, sugar cane, palm oil, and wood offcuts (residual). The northern and central parts of the country have good sites for solar power. For wind power, there are suitable locations in the eastern coastal area, on the Gulf of Thailand in the south, and in the mountains of the south and west. Expectations for future use are high. Thus, to promoted renewable energy usage in Thailand, the Ministry of Energy has planned for the Alternative Energy Development Plan 2012-2021 (AEDP2012-2021); and that plan has already approved by the Cabinet. Against this background, according to "PDP2010: REVISION 3," power plant capacity from renewable energy will expand from 1,058 MW in 2011 to 6,898 MW in 2020 to 9,558 MW in 2030, inaccordance with the AEDP2012-2021, surpassing coal-fired capacity. It is an ambitious plan.

Finally, an overview of international interconnections between Thailand and its neighbors will be presented. International interconnection lines are 500 kV and 230 kV transmission lines to Laos and 132 kV and direct current ±300 kV transmission lines to Malaysia. Electricity import capacity in 2011 was 2,184 MW (1,884 MW from Laotian hydropower and 300 MW from Malaysia's Tenaga Nasional Berhad).

As for future electricity trading, power plant construction projects for electricity exports to Thailand are planned in adjacent countries. Construction of associated international interconnection lines is also planned. The following memoranda have been signed by Thailand and adjacent countries. With Thailand's domestic power demand increasing, the importance of electricity imports from neighbors will probably also increase.

[36] Japan Electric Power Information Center, "Electric utilities in other countries, vol. 1 supplement 2, energy and electricity in major Asian nations," 2011

Table 2-2: MOU for electricity trade with neighboring countries

Partner country	Date of MOU	Amount of power
China	1998.11.12	3,000 MW
Lao PDR	2007.12.22	7,000 MW
Myanmar	1997.07.04	1,500 MW
Cambodia	2000.02.03	Unspecified

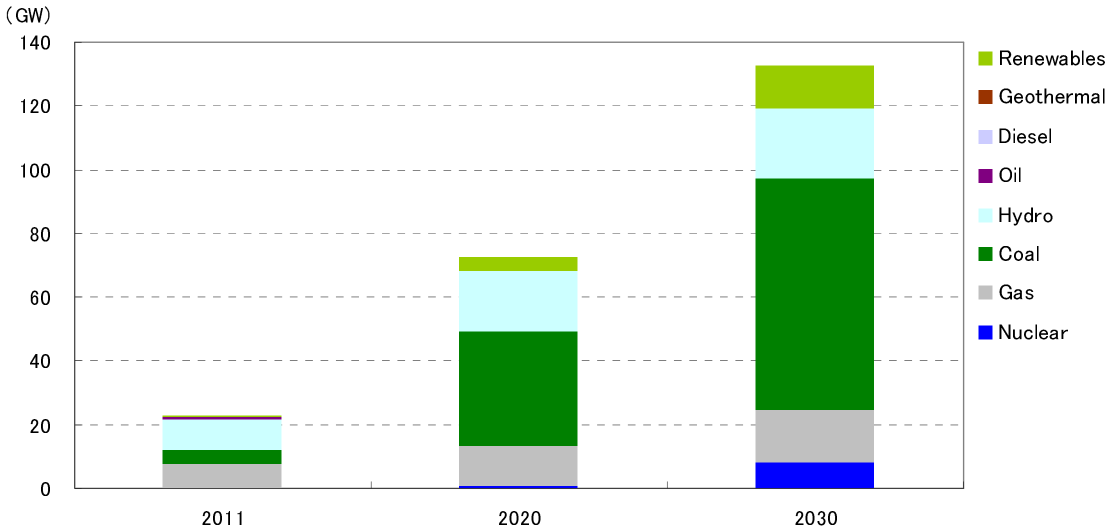
Source: Created from various materials and interviews.

13. Vietnam's power development plan

In Vietnam, domestic energy demand accompanying economic growth in recent years has grown steadily. Peak power grew at an annual rate of 12.3 percent from 2001 to 2010 increasing to 2.8 times as large over 10 years. In order to respond to this booming power consumption, the "7th National Electricity Master Plan" was created in July 2011. Vietnam's power development plan proceeds based on it.

According to the master plan, Vietnam's domestic power plant capacity exclusive of electricity imports will expand from 22,785 MW as of October 2011 to 72,675 MW in 2020. The power source mix will be hydropower (including pumped-storage) 26.3 percent, coal-fired power 49.5 percent, gas-fired power 17.0 percent, nuclear power 1.4 percent, and renewable energy 5.8 percent. A policy of advancing energy source diversification is presented. In 2030, total output exclusive of electricity imports will be 132,608 MW. The projected power source mix is hydropower (including pumped-storage) 16.7 percent, coal-fired power 54.8 percent, gas-fired power 12.5 percent, nuclear power 6.0 percent, and renewable energy 10.0 percent.

Figure 2-13: Power Development Plan toward 2020 and 2030 (Vietnam)



Vietnam (GW)

	2011	2020	2030
Nuclear	–	1.000	8.000
Gas	7.673	12.375	16.614
Coal	4.390	36.000	72.653
Hydro	9.647	19.100	22.106
Oil	0.575	–	–
Diesel	–	–	–
Geothermal	–	–	–
Renewables	0.500	4.200	13.235
Total Supply Capacity	22.785	72.675	132.608

Source: Vietnam's Power Development Master Plan VII.

The power source development plan in the 7th Electricity Master Plan is following these four visions as it proceeds.[37]

1. Electricity production in the north, central, and south areas shall be coordinated for balance. Transmission loss shall be mitigated by supplying stable power to each region. By sharing reserve power sources hydropower plants can be operated efficiently in any season.
2. By rationally developing local power companies nationwide and ensuring the stability of local power supplies, loss from transmission on the national power

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[37] JETRO "National power development plan vision through 2030 and decision on ratification in the 2011–2020 national power development plan, " July 21, 2011

grid can be alleviated, ensuring the economy of power-related projects and contributing to national and local socioeconomic development.

3. While developing new power sources, upgrade the technology of operating power plants, and apply modern technology in new power plants to meet environmental protection standards.
4. Diversify forms of investment in power development in accordance with improvements in competitiveness and economy.

Next, future plans by power source type are presented.

For hydropower, the plan is to prioritize development as comprehensive projects of power plants that have the objectives of flood control and irrigation. There is also development of large-scale hydropower, but because such development is limited to locations with good geographical conditions, small- and medium-scale hydropower development is also scheduled in various areas. Under the plan, the installed capacity of 9,647 MW in October 2011 shall be raised to 19,100 MW in 2020 and 22,106 MW in 2030. Within this, pumped-storage power generation shall be researched and developed from the perspective of efficient power grid operation. The plan shall increase installed capacity to 1,800 MW in 2020 and 5,700 MW in 2030.

For thermal power generation, the plan is to carry out development in rational ratios according to fuel supply locations, means, and capacities. A vision is sketched of increasing installed capacity of gas-fired power from 7,673 MW in October 2011 to 12,375 MW in 2020 and 16,614 MW in 2030. Within this, development of power plants that use LNG is planned. Installed capacity is to be 2,000 MW in 2020 and 6,000 MW in 2030. Securing LNG is one strategy for diversifying the sources of fuel needed for electricity production.

For coal-fired power, the plan is to take installed capacity from 4,390 MW in October 2011 to 36,000 MW in 2020 and 72,653 MW in 2030. Coal consumption in those years is projected at 67.3 million tons and 107.1 million tons. The estimated consumption amounts cannot be covered by domestic coal alone, so construction and operation of power plants that use imported coal beginning in 2015 is considered. By region, in power plants in the northern area, use of domestic coal is to be maximized and prioritized to meet thee base load. In the south, on the other hand, much development with thermal power from imported coal is planned. Coal could be imported from Indonesia and Australia, but the south has many shoals, and there are no large ports where large ships can dock, o tankers cannot be received. Development of a coal center is therefore a major issue.[38]

With future depletion of domestic energy sources assumed, development of nuclear power in order to ensure the stable supply of electricity is planned. In June 2008, the Nuclear Power Basic Law was passed. It set up the legal basis for the promotion of nuclear power in Vietnam. Announcement of a master plan on nuclear power in 2010 indicated the direction of nuclear power development planning through 2030. Under the plan, the aim is for Vietnam's first nuclear power unit (1,000 MW) to go into operation in 2020. Installed capacity in 2030 is to be 10,700 MW, with electricity output of 10.5 billion kWh (10.1 percent of total electricity output). Even after the Fukushima Daiichi nuclear disaster, Vietnam showed no signs of rethinking its nuclear power policy. Temporarily suspended talks between Japan and Vietnam on cooperation on provision of nuclear technology and capital procurement reopened in September 2011.[39] However, as Ministry of Science and Technology Vice-Minister Le Dinh Tien stated, if safety cannot be ensured, the dates of construction and first operation of nuclear power could be delayed.[40]

As for renewable energy, wind power, solar, biomass, etc., are being quickly developed on a priority basis, and the ratio of renewable energy in the power source mix is being gradually increased. Generation through renewable energy is one method of rural electrification in areas that are especially far from a power grid. That role and its developmental potential are recognized. Although wind power currently accounts for only a small percentage of the power source mix, coastal areas, especially islands, have high potential, and foreign investment is increasing. In the 7th Electricity Master Plan, it is therefore planned to increase wind power to 1,000 MW in 2020 and 6,200 MW in 2030, and its share of electricity output to 0.7 percent in 2020 and 2.4 percent in 2030. Biomass at this time is high-cost and difficult to

[38] Japan Electric Power Information Center, "FY 2011 Report on survey of electric power in Vietnam," March 2012

[39] Jiji Press, September 9, 2011

[40] NNA Asia Keizai Joho, August 17, 2011

make a commercial profit from, so it has not attracted attention from investors. However, the Vietnamese government has indicated a policy of favorable treatment of renewable energy development. The 7th Electricity Master Plan, in addition to sugar factories that use sugarcane as a raw material for biomass power generation, aims to develop other materials for biomass power and bring it to 500 MW in 2020 and 2,000 MW in 2030. That would be 0.6 percent of electricity output in 2020 and 1.1 percent in 2030.

Finally, an overview of international interconnections between Vietnam and neighboring countries will be presented. Neighboring countries involved with electricity trading and transmission line construction with Vietnam are China, Laos, and Cambodia.

Currently, Vietnam imports electricity from China via a 220 kV transmission line. However, Vietnam wants to curb it for two reasons, "an increase in the import price in the latest contract renewal" and "security concerns regarding dependence on China."

The political environment in Laos is extremely good. Vietnam wants electricity, and Laos wants to acquire foreign currency through electricity exports. (With no industry, next to resources export, electricity is Laos's best source of foreign currency.). The two countries' interests match well, so they aim to improve relations.

Electricity rates are high in Cambodia, so Vietnam exports electricity to it. Relations between the countries are stable.

In light of this background, the 7th Electricity Master Plan states, "carry out efficient electricity import/export with countries in the region, ensure benefit to both sides, exchange information with Laos, Cambodia, China, and other countries good at hydropower, ensure a stable transmission grid, and enhance imports." Implementation of cooperation on electricity trading and grid interconnection programs with Southeast Asian (ASEAN) and Mekong sub-region (GMS) nations can be expected.

CHAPTER 3

Existing Initiatives

This chapter will summarize existing initiatives by the Asian Development Bank (ADB) and HAPUA (the Heads of ASEAN Power Utilities/Authorities) for the stabilization of electricity supply in the East Asia region.

1. Initiatives in the GMS (Greater Mekong Sub-region)

1-1 GMS program

The GMS program is an international development plan with the ADB as its secretariat. It was launched in October 1992 through a ministerial meeting of six countries of the Mekong River basin, Thailand, Laos, Cambodia, Myanmar, Vietnam, and China, at the ADB's Manila headquarters. Rather than seeking political and security cooperation, it specializes in economic ties. As its secretariat, the ADB facilitates dialog among the members and, when necessary, provides technical and financial assistance.

In the program's operation, there are summit meetings held every three years, annual ministerial meetings, annual meetings of senior officials, and annual working group meetings. Institutions in each country coordinate development plans based on the GMS program, with development items carried out individually by the countries.

A comprehensive framework for the program, the 10-Year Strategic Framework, was formulated at the first GMS Summit Meeting, held in Phnom Penh in November 2002.[41] With a vision of greater economic integration, prosperity, and fairness in the Mekong region, the framework lays out four goals. They are 1) achieving accelerated and sustained economic growth, 2) eradicating poverty and correcting income disparities, 3) improving quality of life, and 4) protecting and conserving natural resources and the environment. More concretely, it sets direction for intra-regional

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[41] ADB, Midterm Review of the Greater Mekong Sub-region Strategic Framework 2002 – 2012
http://beta.adb.org/sites/default/files/gms-sf-midterm-review.pdf

cooperation on development in terms of infrastructure improvement, enhancement and promotion of border trade, investment, and tourism, promotion of private sector participation and enhancement of its competitiveness, human resources development and improvement of technical levels, and environmental conservation and sustainable utilization of natural resources. Nine priority areas are listed: 1) the transport sector, 2) the telecommunications sector, 3) the energy sector (see Chapter 7 below), 4) the environmental sector, 5) tourism, 6) trade systems, 7) the investment environment, 8) human resources development, and 9) the agricultural sector.

Of the above nine sectors, the one that has seen the most active advancement has been improvement of transport infrastructure. Development of transport infrastructure, especially road improvement, is utilized not only to promote and improve the movement of goods, but also for routes for the movement of people and the flow of information and energy. Along with energizing economic activity, it is expected to raise the incomes of regional residents, improve living environments, and promote technology exchanges. A master plan was therefore created in 1995. At the GMS program ministerial-level meeting in 1998, a priority program was set for three "corridors," the North-South Economic Corridor, the East-West Economic Corridor, and the Southern Economic Corridor.

The North-South Economic Corridor comprises a route from Bangkok, Thailand, through Laos and Myanmar to Kunming in China's Yunnan Province, a route from Kunming to Hanoi, Vietnam, and a route from Hanoi to Nanning in China's Guangxi Zhuang Autonomous Region. The Hanoi-Nanning route in particular is expected to form an important connection between the South China region including Hong Kong, Shenzhen, Guangzhou, and the Pearl River and the industrial zone of northern Vietnam. For the route from Bangkok through Laos to Kunming, the ADB and the Chinese and Thai governments each provided one-third of the funding. With the implementation of road improvement in Laos, the entire route was opened in March 2008. The Kunming-Hanoi-Nanning route is planned to be developed with funding from the Chinese and Vietnamese governments.

The East-West Economic Corridor crosses Indochina from west to east, from Myanmar through northeastern Thailand and southern Laos to Da Nang, Vietnam. With the December 2006 completion through yen loans from Japan of the Second

Mekong International Bridge, spanning the Mekong River on the Thailand-Laos border, the corridor was fully opened. It is expected to contribute to establishment of international division of labor between Thailand and Vietnam, which produce auto parts and electrical and mechanical products.

Development of the Southern Economic Corridor, the route linking Bangkok, Phnom Penh, and Ho Chi Minh City, is lagging behind that of the other two economic corridors described above. However, it is expected to establish optimal international specialization as a major shipping base for the apparel manufacturing industry, with textiles and fibers being manufactured in Thailand, sewing taking place in Cambodia, and exporting from Hanoi.

Initiatives in the electric power sector within the GMS program have helped to promote opportunities for each country's economic cooperation in the sector, facilitate the implementation of major electric power projects, and clarify technical, economic, financial, and institutional issues regarding the development of electric power in the region. However, these have mainly been generalized unofficial efforts focusing on principles and systems. Although they are just getting underway in multiple concerned nations (China-Vietnam, Laos-Cambodia, Laos-Thailand, Thailand-Cambodia, Vietnam-Cambodia, Vietnam-Laos), these power flows at present are almost all one-way. Because they mainly comprise the buying and selling of electricity from fixed power plants, they are considered power lines from specific projects rather than interconnected grids. In the future, some goals of the GMS countries are to establish international power trading in order to increase mutual economic and technical benefits, and to have well-balanced power plants through regional energy sources that enable power transport spanning countries throughout the region. There are various initiatives and international agreements towards those ends. The GMS Electric Power Forum (EPF) was established in 1995, and the Experts' Group on Power Interconnection and Trade (EGP) in 1998.

Major developments in power trade in the GMS are as follows.

Figure 3-1: Economic Corridor of GMS Program

Source: ADB website

1-2 Policy Statement on Regional Power Trade in the GMS (Jan 2000)

In light of the above developments in the GMS program, at the ninth ministerial meeting in Manila in January 2000, representatives from Cambodia, China, Laos, Myanmar, Thailand, and Vietnam signed a policy statement on regional power trade in the Greater Mekong Sub-region. Its objectives were the following categories.

(a) Promotion of economic growth and efficient development of the electricity sector in the GMS

(b) Promotion of opportunities to expand each country's economic cooperation in the energy sector

(c) Promotion of prioritized implementation of power projects

(d) Clarification of technical, economic, financial, and institutional issues in the development of electric power in the region

(e) Promotion of economic transactions in electricity

(f) Protection and improvement of the environment through the adoption of appropriate technology and plans

1-3 Inter-governmental Agreement on Regional Power Trade in the GMS (3 Nov 2002)

The intergovernmental agreement on regional power trade in the Greater Mekong Sub-region is an agreement to implement the above-mentioned "policy statement on regional power trade in the Greater Mekong Sub-region." It was signed by national representatives in November 2002 at the first GMS summit meeting, in Phnom Penh, Cambodia. The intergovernmental agreement covers the establishment of the Regional Power Trade Coordination Committee (RPTCC), which is an institution that coordinates each country's power trade and each country's initiatives in response.

As its first step, the RPTCC is required to complete the final draft of the Regional Power Trade Operating Agreement (RPTOA) and determine the first stage of its implementation.

1-4 MOU on the Guidelines for the Implementation of the Regional Power Trade Operating Sgreement Stage 1 (MOU-1) (5 Jul 2005)

MOU-1 is a memorandum of understanding intended to set out guidelines for power trade during Stage 1 (when only bilateral power trade is possible). It covers the institutional arrangements that each country and the RPTCC should follow in relation to power trade during Stage 1.

1-5 MOU on the Road Map for Implementing the GMS Cross Border Power Trading (MOU-2) (31 Mar 2008)

MOU-1 set forth institutional and other arrangements for Stage 1 power trade, including the perspectives of transactions and operations related to international interconnection and flow. This was linked to the establishment of i) the RPTCC Focal Group (FG) to take charge of coordinating most RPTCC activities in each country and ii) the Planning Working Group (PWG) to take charge of planning and system research in order for the GMS countries to shift to everyday power trade guidelines. However, the fact that the GMS countries had no clear schedule for evaluating "promotion of power development programs," "coordination in power trade development related to the goals of intergovernmental agreements," and so on became an issue. Therefore, a schedule that would serve as benchmarks for the completion of Stage 1 of regional international power trade during 2008–2012 and a roadmap of methods of preparing for Stage 2 while Stage 1 was being implemented were established.

Table 3-1: Regional Power Trade Roadmap 2008-2012 (to accomplish stage 1)

Milestone	Activity	Schedule
Completion of a power interconnection master plan with benchmarks, setting of priorities for new interconnection projects related to feasibility studies already underway	Completion of GMS master plan with benchmarks for power development	2008
	Setting of priorities for interconnection projects shown in the master plan	2009–2010
	Advancement of feasibility studies on projects selected as high priority	From 2009
	Review of the master plan benchmarks	Every 2 or 3 years
Completion of research on GMS standard practices	Completion of research on GMS standard practices, adoption of GMS standard practices for proposed new regional interconnections, and study of synchronized operation of interconnection grid	2010
	Consideration of the adoption of procedures for moving to achievement of proposed GMS standard practices	2010
Completion of research on regulations for interconnection lines	Completion of research on regulations for interconnection lines and consideration of the adoption of research findings on synchronous operation of interconnection grids and coordinating flow control	2010
Completion of research on regional measurement methods in grid interconnection and on rules for power trade	Completion of research on regional measurement methods in grid interconnection for implementation during Stage 1 and on telecommunications system standards, and consideration of the adoption of research findings	2010
	Completion of research on rules for power trade for implementation during Stage 1, including methods for resolving disputes between parties other than existing PPAs, and consideration of the adoption of research findings.	2010

Table 3-2: Regional Power Trade Roadmap 2008-2012 (to prepare for stage 2)

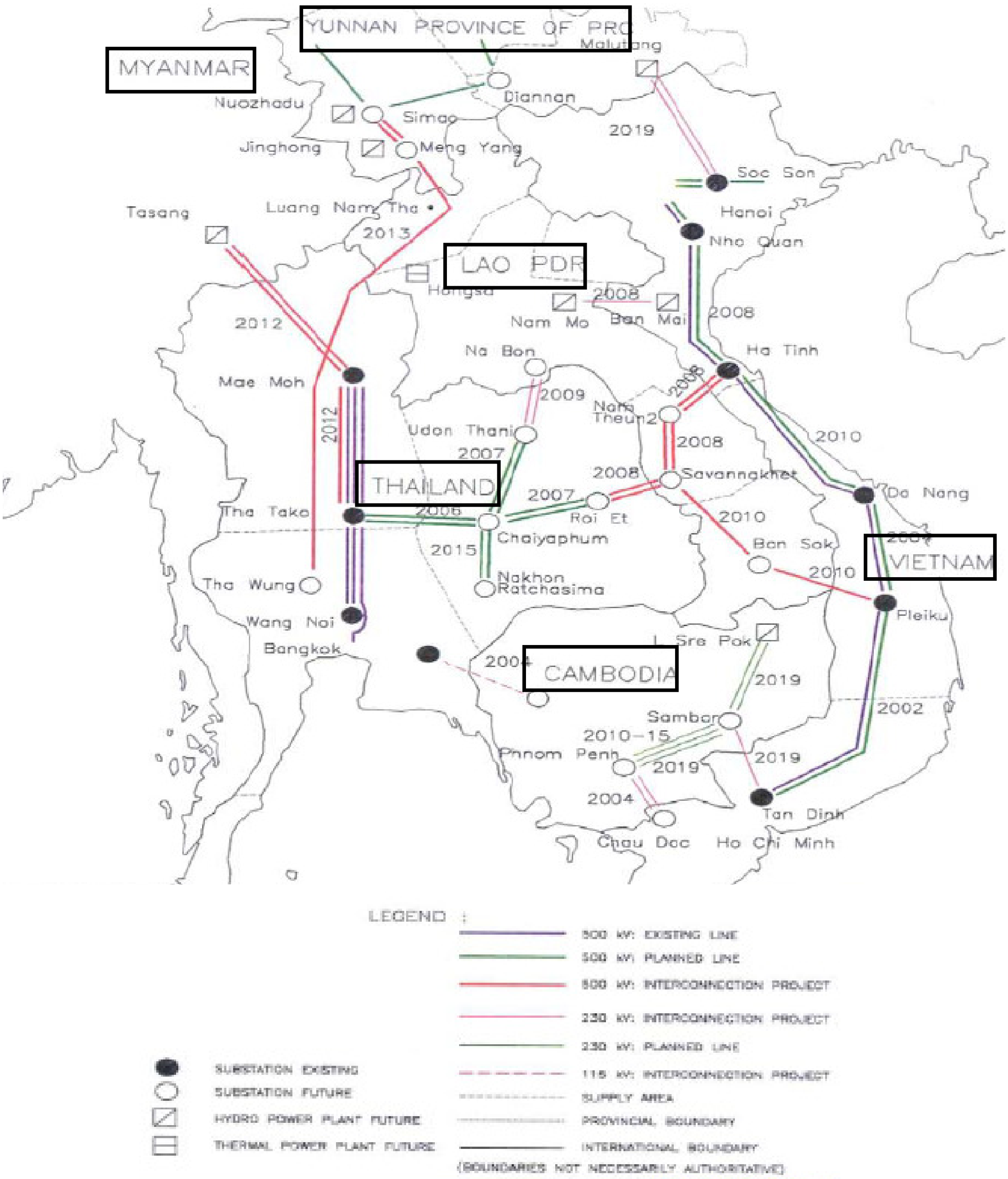
Milestone	Activity	Schedule
Begin research on confirming regulatory barriers against power trade and moving to the next stage	Completion of research on identifying regulatory barriers to the development of power trade and consideration of adoption of institutional arrangements and methods to deal with regulatory barriers	2012
Completion of research on the GMS Grid Code (operational procedures)	Completion of research on the GMS Grid Code and consideration of adoption of the following research findings • GMS standard practices • Procedures for grid operators to coordinate management of deviations from plans and control of interconnection flow • Measurement and communications • Sharing of reserve power and support during emergencies	2010-2012
Completion of research on Stage 2 rules on transmission lines, which allow third-party access to interconnection, including Stage 2 power trade rules that give preference to contracts and PPAs, and dispute resolution procedures	Completion of research on Stage 2 rules on transmission lines and consideration of the adoption of findings to compensate the flows of sponsoring countries related to third-party transactions, including development of payment agreements and duties for third-party use,	From 2012
	Development of power trade rules for short-term international transactions and consideration of their adoption	Through 2012
	Development of power trade rules for paying for deviations from power trade plans on the interconnection grid and consideration of their adoption	Through 2012

1-6 Subsequent Movement

Through support from the ADB, a master plan was created in 2008. It is summarized in Figure 7.1. (The plan was reportedly revised in 2010.)

Additionally, an RPTCC meeting was held in Ho Chi Minh City on November 2011. Two working groups (WG1: Examination of technical standards for power distribution [System performance standards], WG2: Examination of how to eliminate institutional issues [Registration barriers]) were started to facilitate power import-export/grid interconnection. They are to complete their examination of issues by the end of 2012.

Figure 3-2: Master Plan for Grid Interconnection



Source: "The GMS Road Map and Work Plan for Expanded Energy cooperation" (from materials presented at the second Subregional Forum).

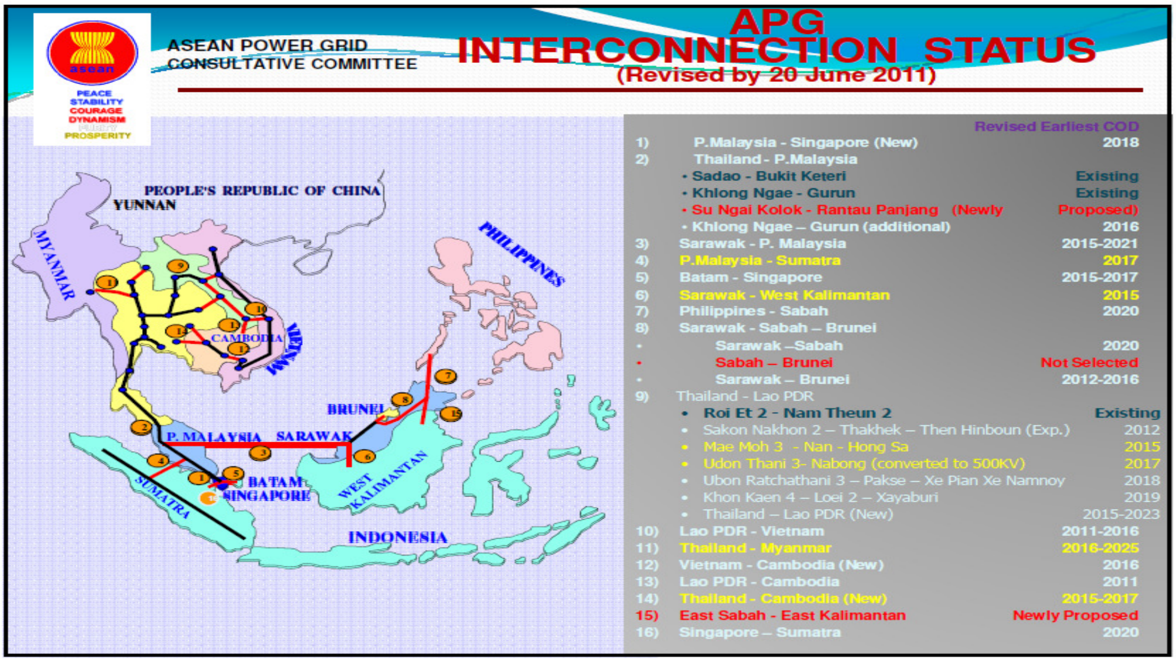
2. ASEAN Power Grid Concept

In ASEAN, the ASEAN Free Trade Area (AFTA), which has been in preparation since the 1990s, aims not only to liberalize regional trade, but also to establish the ASEAN Economic Community (AEC) in 2015. The goal of the AEC is high-quality economic integration with the facilitation of trade, liberalization and facilitation of trade in services, upgrading of infrastructure on a broad scale, movement to common rules and standards, mutual recognition, and reduction of disparities. Against this background, a variety of initiatives regarding improvement of energy infrastructure have also been undertaken with the aim of stimulation and optimization within the ASEAN region.

2-1 ASEAN Vision 2020

At the ASEAN summit held in Kuala Lumpur, Malaysia, in December 1997, "ASEAN Vision 2020" was adopted in order to promote political, economic, security, and cultural cooperation and exchanges in the nations of ASEAN. Against this background, two plans were adopted to mutually connect each country's energy infrastructure: the ASEAN Power Grid concept in the electric power sector and the Trans-ASEAN Gas Pipeline concept in the natural gas sector. It was confirmed that member countries can build and facilitate win-win relationships through international energy deals. The secretariat of the ASEAN Power Grid is the Heads of ASEAN Power Utilities/Authorities (HAPUA). It was confirmed that regional power interconnection can be promoted through information exchange and technology introduction for the planning, construction, and operation of power grids and through basic research on power interchange.

Figure 3-3: Overview of ASEAN Power Grid



Source: The 27th Meeting of HAPUA Council.

2-2 ASEAN Ministers on Energy Meeting process

The ASEAN Ministers on Energy Meeting (AMEM) is hosted annually by member countries on a rotating basis. It is the venue that authorized the ASEAN Plan of Action on Energy Cooperation (APAEC) and checks on the state of its progress. The ASEAN Center for Energy (ACE), which is operated by ASEAN energy ministers and the ASEAN secretariat, handles the setting of the APAEC.

The APAEC for 1999 through 2004 was adopted at the 17th Ministers on Energy Meeting, held in Bangkok in July 1999. The policy framework and means of adoption of interconnection plans were set, and the aim of earlier realization of the ASEAN Power Grid was confirmed. In conjunction with the adoption of the APAEC, the ASEAN Center for Energy (ACE) was established as an intergovernmental organization to focus on energy cooperation and coordinate with the individual countries.

The APAEC for 2004 through 2009 was set at the 22nd Ministers on Energy Meeting, held in Manila in 2004.

In 2007, at the 25th Ministers on Energy Meeting (in Singapore), a memorandum on the ASEAN Power Grid was signed. Member countries agreed to cooperate on research towards the end of a unified grid concept and to facilitate public-private cooperation and capital investment. It was also decided to begin research on harmonization of the differing technical standards, duties on power import/export, contractual frameworks, etc., in the member countries.

At the 27th ASEAN Ministers on Energy Meeting, in Mandalay, Myanmar, on July 29, 2009, APAEC 2010–2015, the latest version, was approved. The plan lays out the following seven categories for regional energy strategy.

1) Development of the ASEAN Power Grid

- Promotion of the development of a unified power grid in ASEAN
- Optimization of power source mixes in accordance with each country's power situation
- Promotion of the utilization of ASEAN's human and economic resources in terms of financing for power generation, transmission, and distribution and of expert advice

2) Development of a Trans-ASEAN Gas Pipeline

- Signing of a memorandum on a Trans-ASEAN gas pipeline network by member countries
- Cooperation on the performance of a feasibility study on the development of the East Natuna gas field by Pertamina and a PSC partner

3) Promotion of clean coal technology

- Design of systems and political frameworks for coal utilization
- Promotion of coal utilization and the adoption of clean coal technology
- Facilitation of coal import/export and development investment in ASEAN
- Enhancement of environmental standards and assessments for coal development and use

4) Promotion of energy conservation and more efficient energy use

- Setting of policies on more efficient use of energy
- Improved dissemination of knowledge and information concerning energy conservation
- Better and more thorough energy management in the industrial and business sectors
- Enhanced financial support for investment in improving energy efficiency

5) Promotion of the adoption of renewable energy

- Set a goal of having 15 percent of the region's generated power come from renewable energy
- Facilitation of and enhanced cooperation on use of renewable resources and services among member countries
- Set up of schemes for financial support
- Promotion of biofuel development and commercial utilization
- etc.

6) Support and information sharing concerning the setting of energy policies and development plans in each country

- Enhancement of Information sharing on energy policy and stable supply
- Support for the development of human resources related to energy and environmental policy
- Implementation in each country of monitoring and assessment of progress on the APAEC
- etc.

7) Development of an environment for the adoption of nuclear power

- Capacity building among ASEAN member countries for the adoption of nuclear power
- Enhancement of information disclosure and education concerning nuclear power
- Development of system designs and legal systems for the adoption of nuclear power, and capacity building among regulatory authorities

Against this background, concrete initiatives on items related to the ASEAN Power Grid concept are the following.

- Improvement of APG advisory committee initiatives on realization of interconnection projects
- Research on issues such as international interconnection grid projects, international power trade, and grid investment, on which study has advanced in HAPUA working groups (on generation, transmission, distribution, power quality, policy, private-sector business development, and human resources development)
- Review and renewal of the ASEAN Interconnection Master Plan (AIMS)

CHAPTER 4

Optimizing Power Infrastructure Development

This chapter will present in quantitative terms the optimal potential and advantages for the entire power infrastructure (power plants and power grids) in 13 countries in East Asia (Bangladesh, Brunei Darussalam, Cambodia, China [Yunnan & Guangxi], India [North-East], Indonesia, Lao PDR, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Vietnam).

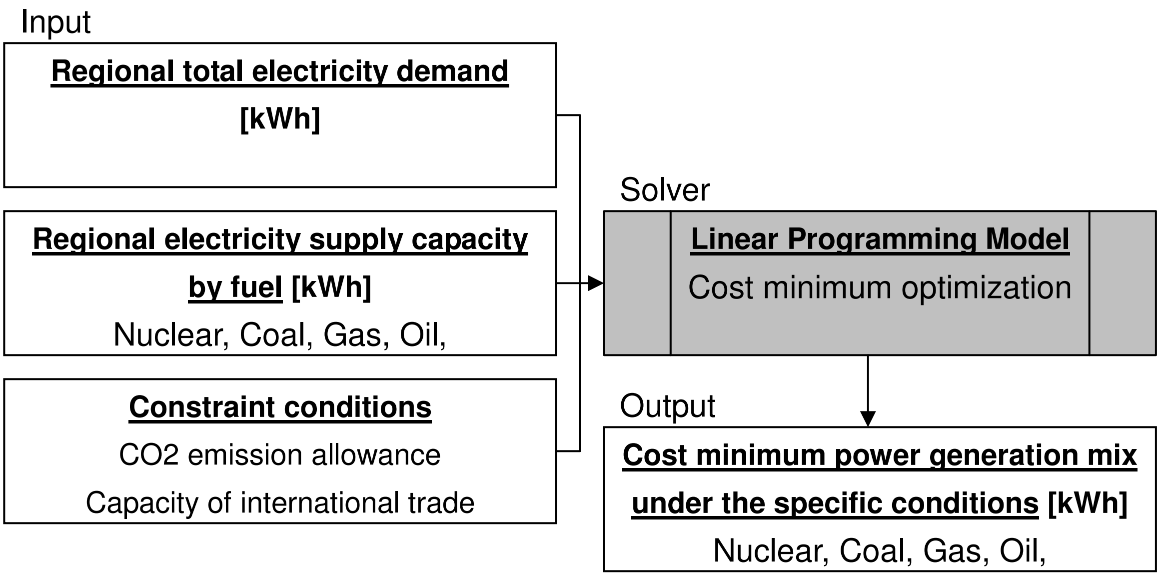
Through this, the ingredients will be provided for East Asian nations in the future to create trade in international power in order to mutually increase economic and technical rewards and to achieve an energy mix for the realization of power transport that spans nations throughout the region.

1. Optimal Inter-state Power Supply Model

A linear programming (LP) model was formulated in order to examine the optimal inter-state power supply system in East Asia.

Power generation capacity and power generation costs by energy source for the East Asian nations were estimated, and overall optimization of the power supply to meet total demand in each country was attempted. The objective function in this case was cost minimization.

Figure 4-1: Overview of LP Model



The following constraints were set in this model.

- Total regional power demand = Total regional power supply volume
- Total regional power supply volume <= Total regional power supply capacity
- Each country's import/export power volume <= Transmission line capacity (each country's interchange capacity)
- Total regional CO_2 emission volume <= Target value for total regional CO_2 emission volume
- Each country's amount of power from renewable energy = Target value for each country's adoption of renewable energy

Ordinarily, when considering optimal power supply, one must consider numerous factors for each country, such as peak demand, wheeling charges, and the construction costs of individual power plants and interconnection lines. In this model, however, because of data limitations, such factors are not reflected.

Moreover, in actual equipment planning, power source mixes and amounts of power import/export are considered based on load curve data. In this model, however, as a simplified method, the advantages of international grid interconnection are analyzed by simulating each country's annual supply capacity and demand balance.

2. The Model's Preconditions

The preconditions in the linear programming (LP) model are each country's power demand, the interchange capacities of international interconnection lines, power supply capacity by source type, generating costs by power source, and CO_2 emission factor by power source.

2-1 Power Demand

First, for each country's power demand in GWh as of 2020 and 2030, for countries in which figures were made clear in power source development plans and so on, those figures were used. For countries in which power source development plans are not clear, estimates were calculated using power generation output figures for BAU (Business as Usual) Cases in "ERIA Research Project Report 2011, No. 18 ANALYSIS ON ENERGY SAVING POTENTIAL IN EAST ASIA REGION." (See Table 4-1.)

2-2 Transmission Capacity and Scenarios

In this model, projections for the interchange capacity (GWh) of international interconnection lines were set in a Base Case and an Accelerated Case and compared with the Status Quo Case (in which interchange capacity remains the same as now, with no new increases or investment in current interchange capacity estimated).

The projected Base Case for each country's interchange capacity was set based on the "AIMS II Report (ASEAN Interconnection Master Plan Study No. 2)," published by the Heads of ASEAN Power Utilities/Authorities (HAPUA). However, for Bangladesh, China (Yunnan Province and Guangxi Zhuang Autonomous Region), and India (North-East), which are not covered by the "AIMS II Report," figures were set based on each country or region's own power import/export plan.

Figures for the Accelerated Cases were set in order to analyze the result if each country's interchange capacity in the Base Case were to be doubled. (See Table 4-2.)

Figure 4-2: Scenario for Interconnection

	2020	2030
Status Quo Case	Same international interchange capacity as today	
Base Case	International interchange capacity as planned in AIMS II	
Accelerated Case	-	International interchange capacity double that of AIMS II

2-3 supply Capacity

In this model, each country's power supply capacity (GWH) by power source as of 2020 and 2030 refers to the maximum supply capacity of the generating equipment in each country. In short, it is calculated based on an operation rate that keeps downtime for periodic inspections and so on to a minimum. It does not necessarily match the operation rates assumed in national power source development plans, etc. This is because, in this model, the objective is to maximize utilization of international interconnection and optimize the energy balance for the entire region, so supply capacity distribution in accordance with peak power demand in each country was minimized to the extent possible.

In concrete terms, each country's generating equipment capacity by power source as discussed in Chapter 2 was multiplied by the following operation rates(= plant factor) to set maximum supply capacity. (See Table 4-3.)

- Base power source: 80 percent
- Middle to peak power source: 60 percent (in light of interchange reduction to ensure reserve power for fluctuations in power demand)
- Nuclear power: 60 percent in 2020 (in light of test operation periods after recent introduction), 80 percent in 2030

- Hydropower: 45 percent (in light of seasonal fluctuations due to rainy and dry seasons)
- Geothermal: 80 percent
- Other renewable energy: biomass 60 percent, wind power 20 percent, small hydropower 40 percent, solar 12 percent

2-4 Generation Cost

For generation cost (US$/kWh) by power source, since data for each country could not be obtained, in this model, the generation price by power source mainly in Thailand and Indonesia was used as a base to set the value for each country.

As for the generation cost for coal-fired thermal power plant, it was set lower for countries such as Indonesia and Vietnam that produce a great deal of coal domestically and use it as fuel than it was for countries that use mainly imported coal.

In the same way, a price difference for the generation cost of gas-fired thermal power plant was set between the gas producing nations of Bangladesh, Brunei, Indonesia, and Myanmar and countries that rely on pipeline gas or LNG imports.

For the generation cost of nuclear, oil-fired, renewables of each country that could not be obtained, in this model, they were set mainly based on the value of Thailand. (See table 4-4.)

2-5 CO_2 Emission Factor

Finally, CO_2 emission factor (kt-CO_2/GWh) by power source is affected by the generating efficiency of each country's power plants. In this model, therefore, figures for the thermal efficiency of thermal power plants found in "ERIA Research Project Report 2011, No. 18 ANALYSIS ON ENERGY SAVING POTENTIAL IN EAST ASIA REGION" were used. Additionally, the following values were used as the CO_2 emission factors[42] by energy source that formed the basis for calculations. (See Table 4-5.)

- Coal (fuel coal): 3.7927 Gg-CO_2/10^{10} kcal (= 0.326 kt-CO_2/GWh)
- Natural gas (LNG): 2.0675 Gg-CO_2/10^{10} kcal (= 0.178 kt-CO_2/GWh)

[42] EDMC, "HANDBOOK OF ENERGY & ECONOMIC STATISTICS in JAPAN 2013"

- Bunker C fuel oil: 2.9992 Gg-CO_2/10^{10} kcal (= 0.258 kt-CO_2/GWh)

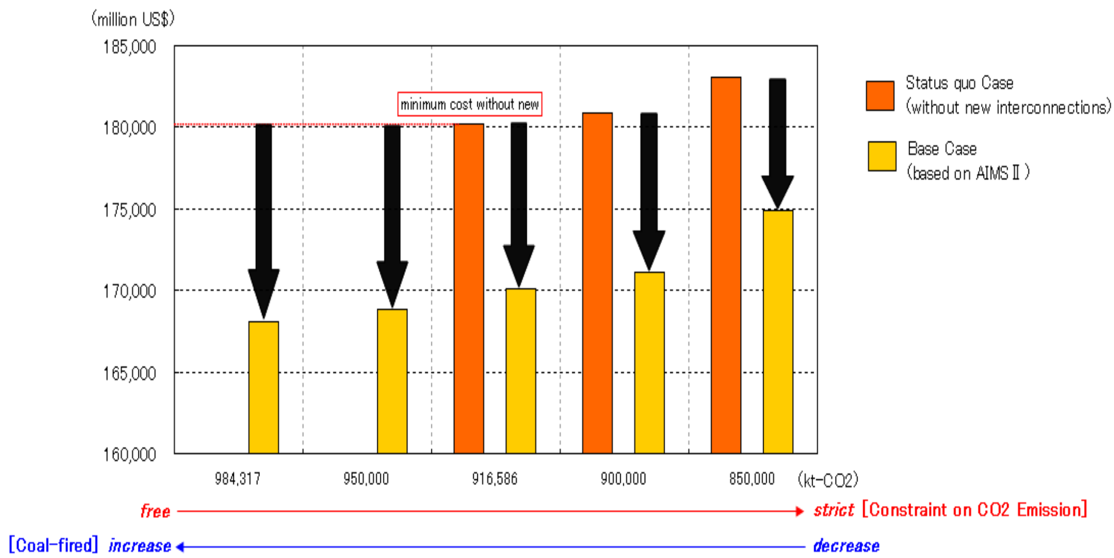
3. Calculation Results

Table 4-6 shows a model in which optimal energy mixes were calculated using each country's power demand and supply capacity by power source as of 2020, with interchange capacity of international interconnection lines as in the Base Case and CO_2 emission volume unrestricted.

Of course, when there are no restrictions on CO_2 emissions, countries will select power sources with the lowest prices first to meet domestic power demand. Furthermore, countries with a power surplus from power sources cheaper than those in other nations will export electricity to the extent enabled by the interchange capacity of international interconnection lines. In other words, the calculation results shown in Table 4-6 are the optimal distribution for cost minimization as of 2020 in the Base Case.

Figure 4-3 shows a comparison of total generation cost for the East Asian nations as a group in the Base Case and the Status Quo Case (in which no new increases and investment in current interchange capacity are estimated) as of 2020, and a cost comparison when restrictions on CO_2 emission volume are made stricter.

Figure 4-3: Comparison of Total Generation Cost in 2020



(million US$)

Target of total CO2 emission	984,317*	950,000	916,586**	900,000	850,000
Status quo Case[①] (without new interconnections)			180,199	180,841	183,077
Base Case[②] (with new interconnections based on AIMS Ⅱ)	168,057	168,830	170,129	171,139	174,921
Savings[=②-①]	▲ 12,142	▲ 11,369	▲ 10,070	▲ 9,702	▲ 8,156

* 984,317kt-CO2 = Maximum CO2 emission in Base Case
** 916,586kt-CO2 = Maximum CO2 emission in Status quo Case

In the Base Case, the calculation results with no restrictions on CO_2 emission volume applied and optimal distribution for cost minimization attempted found a total generation cost of 168,057 million US$ and a total CO_2 emission volume of 984,317 kt. In the Status Quo Case, if restrictions on CO_2 emission volume are not applied, the calculations obtained a total generation cost of 180,199 million US$ and a total CO_2 emission volume of 916,586 kt. Comparing the two cases, if the international power grid is augmented to the degree seen in the Base Case, and if its use is maximized, the East Asian nations as a group could reduce generation cost by 12,142 million US$.

Next, comparisons were carried out of total generation cost when restrictions on CO_2 emission volume were gradually made stricter, going from no limits to 850,000 kt. The calculation results use hydropower and nuclear power, which are clean and have low generation costs, as base power sources. Since no further excess supply exists, power supply from coal-fired thermal power with its high CO_2 emission volume is reduced, while the role of gas-fired thermal in the power supply is increased.

Compared with the case when there are no restrictions on CO_2 emission volume, electricity trade volume decreases by 44,218 GWh, from 181,330 GWh to 137,112 GWh.

As a result, total generation cost in the Base Case increased by 6,864 million US$ to 174,921 million US$. Total generation cost in the Status Quo Case increased by 2,878 million US$ to 183,077 million US$. The cost reduction effect of utilizing the international power grid shrunk to 8,156 million US$. This was because, in order to lower CO_2 emissions, use of coal-fired thermal power was reduced, while use of gas-fired thermal power was increased, raising the average generation cost.

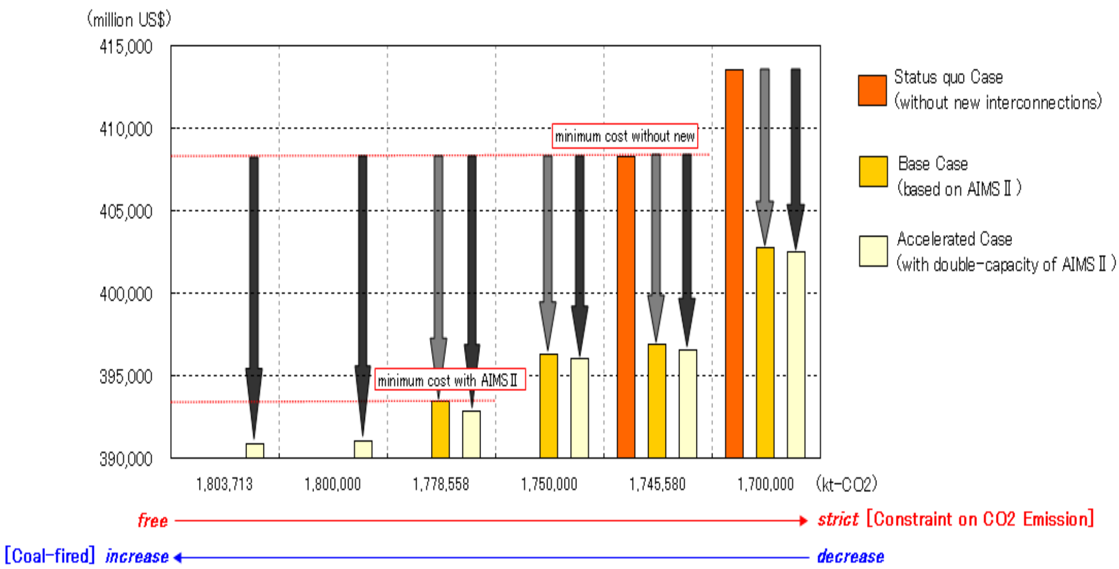
Next, the calculation results for 2030 will be analyzed.

Table 4-7 shows a model in which optimal energy mixes were calculated using each country's power demand and supply capacity by power source as of 2030, with interchange capacity of international interconnection lines as in the Accelerated Case and CO_2 emission volume unrestricted. Table 4-8 shows the result when interchange capacity is kept in the Base Case scenario and all other conditions remain unchanged.

As discussed above, if CO_2 emissions are not restricted, countries will select power sources with the lowest prices first to meet domestic power demand. Furthermore, countries with a power surplus from power sources cheaper than those in other nations will export electricity to the extent enabled by the interchange capacity of international interconnection lines. In other words, the calculation results shown in Table 4-7 and Table 4-8 are the optimal distributions for cost minimization as of 2030 in the different international interconnection scenarios.

Figure 4-4 shows a comparison of total generation cost for the East Asian nations as a group as of 2030 if the interchange capacity of international interconnection lines changes as in the Accelerated, Base, and Status Quo Cases, and a cost comparison when restrictions on CO_2 emission volume are made stricter.

Figure 4-4: Comparison of Total Generation Cost in 2030



(million US$)

Target of total CO2 emission	1,803,713*	1,800,000	1,778,558**	1,750,000	1,745,580***	1,700,000
Status quo Case[①] (without new interconnections)					408,281	413,542
Base Case[②] (with new interconnections based on AIMS Ⅱ)			393,446	396,336	396,894	402,785
Accelerated Case[③] (with double-capacity of AIMS Ⅱ)	390,871	391,025	392,880	395,999	396,575	402,516
Savings[=③-②]	▲ 2,575	▲ 2,421	▲ 566	▲ 337	▲ 319	▲ 269
Savings[=③-①]	▲ 17,410	▲ 17,256	▲ 15,401	▲ 12,282	▲ 11,706	▲ 11,026

* 1,803,713kt-CO2 = Maximum CO2 emission in Accelerated Case
** 1,778,558kt-CO2 = Maximum CO2 emission in Base Case
*** 1,745,580kt-CO2 = Maximum CO2 emission in Status quo Case

In the Accelerated Case, with no restrictions on CO_2 emission volume applied and optimal distribution for cost minimization attempted, the calculation results found a total generation cost of 390,871 million US$ and a total CO_2 emission volume of 1,803,713 kt. In the Base Case, with the same condition and optimal distribution for cost minimization attempted, the calculation results were a total generation cost of 393,446 million US$ and a total CO_2 emission volume of 1,778,558 kt. In other words, if the transmission capacity between states is doubled from the Base Case scenario and its use is maximized, the East Asian nations as a group are projected to reduce generation cost by 2,575 million US$.

In the Status Quo Case, with no restrictions on CO_2 emission volume applied, total generation cost was calculated at 408,281 million US$ and total CO_2 emission volume at 1,745,580 kt. If CO_2 emission volume is ignored, and only total generation cost is compared, if international interconnection can be expanded to the Accelerated Case, cost will be reduced by 17,410 million US$. Even if the comparison is the Base Case scenario, a cost reduction of 14,835 million US$ can be expected.

Next, comparisons were carried out of total generation cost when restrictions on CO_2 emission volume were gradually made more strict, going from no limits to 1,700,000 kt. because hydropower and nuclear power, which are clean and have low generation costs, are used as base power sources, no further excess power supply can be projected. Therefore, in an environment in which restrictions on CO_2 emissions are applied, power supply from coal-fired thermal power with its high CO_2 emission volume will be reduced, while the role of gas-fired thermal in the power supply will increase.

At that time, electricity trade volume in the Accelerated Case will shrink by 85,150 GWh, from 247,345 GWh to 162,195 GWh, compared to the case without restrictions on CO_2 emission volume.

An increase in the use of higher-priced gas-fired thermal power had the following results. In the Accelerated Case, total generation cost rose by 11,645 million US$ to 402,516 million US$. In the Base Case, total generation cost rose by 9,339 million US$ to 402,785 million US$. In the Status Quo Case, total generation cost rose by 5,261 million US$ to 413,542 million US$. Thus, in regard to the cost reduction effect of the international interconnection grid, in the comparison with the Accelerated Case and the Base Case it shrank by 269 million US$, and in comparison with the Status Quo Case it shrank by 11,026 million US$.

4. Optimal Energy Mix

As became clear in the previous section, changing the constraints changes the optimal distribution of each country's energy mix. Table 4-9 shows the changes in countries' optimal energy mixes as of 2020 and 2030, with no restrictions on CO_2 emission volume applied, when the interchange capacity of international interconnection lines is increased from the Status Quo Case to the Base Case scenario to the Accelerated Case scenario.

In almost every one of the East Asian nations that were the subject of this research, a steady rise in power demand due to population increase and economic growth is projected. On the other hand, these countries each have their own specific energy resources and environmental constraints. Against this background, in order to achieve the optimal energy mix in terms of factors such as supply stability, economy, and lessening environmental impact, the calculation results in the previous section suggest that considering the balance of the East Asian nations as a group would bring greater benefits than attempting to build up the power grids of individual countries.

As discussed in Chapter 2, Laos and Cambodia have very high hydropower development potential. Clean, high cost performance power exports are projected, but improvement of their domestic transmission grids has been slow. In the coal producing countries Indonesia and Vietnam and the gas producing countries Bangladesh, Brunei, Indonesia, and Myanmar, effective use of domestic resources is expected to produce low-cost, stable power supplies for them and for their neighbors. On the other hand, in Thailand in particular, although it produces coal, oil, and gas, supply capacity cannot keep up with booming domestic demand, so it relies on large fuel imports. At the same time, it has powerful environmental restrictions that make development of coal-fired thermal power and hydropower difficult. Thus, resource availability and demand are mismatched in the East Asian nations. The findings of this research show that it is possible to alleviate this mismatch by improving international interconnection of transmission lines.

Table 4-1: Electricity Demand (GWh)

[2020]

Bangladesh	Brunei	Cambodia	China*	India**	Indonesia	Lao PDR
90,950	5,500	8,200	393,723	21,560	355,862	15,234
Malaysia	Myanmar	Philippines	Singapore	Thailand	Vietnam	
130,000	48,900	94,995	60,700	246,164	330,000	

[2030]

Bangladesh	Brunei	Cambodia	China*	India**	Indonesia	Lao PDR
191,933	7,524	13,489	541,980	41,491	956,929	35,863
Malaysia	Myanmar	Philippines	Singapore	Thailand	Vietnam	
160,000	95,068	149,067	71,500	346,767	675,000	

* For China, Yunnan Province and Guangxi Zhuang Autonomous Region are covered.

** For India, the North-East area is covered.

Table 4-2: International Interconnection Transmission Capacity (GWh)

[Base Case scenario]

Bangladesh	Brunei	Cambodia	China*	India**	Indonesia	Lao PDR
8,760	1,752	35,890	76,825	8,760	33,288	99,198
Malaysia	Myanmar	Philippines	Singapore	Thailand	Vietnam	
41,172	46,682	8,760	31,536	141,036	26,254	

[Accelerated Case scenario]

Bangladesh	Brunei	Cambodia	China*	India**	Indonesia	Lao PDR
17,520	3,504	71,780	153,650	17,520	66,576	198,396
Malaysia	Myanmar	Philippines	Singapore	Thailand	Vietnam	
82,344	93,364	17,520	63,072	282,072	52,508	

* For China, Yunnan Province and Guangxi Zhuang Autonomous Region are covered.

** For India, the North-East area is covered.

Table 4-3: Capability of Electricity Supply (GWh)

Bangladesh (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
10,512	28,524	84,446	1,301	3,863	3,774	-	-

Bangladesh (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
28,032	46,516	137,707	1,301	6,302	6,155	-	-

Brunei (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	8,872	-	-	-	-	-	-

Brunei (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	12,138	-	-	-	-	-	-

Cambodia (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	7,979	19,410	-	-	-	11

Cambodia (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	13,124	31,934	-	-	-	11

China (Yunnan & Guangxi) (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	194,856	264,362	-	-	-	648

China (Yunnan & Guangxi) (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	268,492	364,261	-	-	-	648

India (North-East) (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	12,525	2,218	21,523	-	752	-	799

India (North-East) (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	24,998	4,426	42,960	-	752	-	799

Indonesia (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	98,119	348,221	35,411	11,826	28,761	52,574	2,656

Indonesia (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	176,770	627,363	63,793	11,826	28,761	94,720	2,656

Lao PDR (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	13,161	26,199	-	11	-	28

Lao PDR (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	13,161	50,020	-	11	-	28

Malaysia (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	52,034	77,088	14,585	-	-	-	10,512

Malaysia (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
14,016	52,560	88,301	16,651	-	10,512	-	18,396

Myanmar (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	21,245	3,627	39,767	-	-	1,402	3,620

Myanmar (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	21,245	5,203	83,756	-	-	1,402	3,620

Philippines (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	26,075	39,434	16,210	3,416	18,096	16,083	378

Philippines (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	37,113	62,876	26,037	3,416	31,236	24,941	378

Singapore (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	70,634	-	-	19,053	-	-	1,556

Singapore (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	87,593	-	-	19,053	-	-	1,929

Thailand (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	192,314	41,249	16,107	1,656	21	-	7,251

Thailand (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
14,016	265,687	51,768	16,280	1,656	3,963	-	10,047

Vietnam (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
5,256	65,043	252,288	75,292	-	-	-	4,415

Vietnam (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
56,064	87,323	509,152	87,142	-	-	-	13,913

Table 4-4: Generation Cost by Power Source (US$ / kWh)

Bangladesh (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
0.134	0.100	0.144	0.053	0.334	0.483	-	-

Bangladesh (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
0.146	0.150	0.161	0.064	0.399	0.583	-	-

Brunei (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.100	-	-	-	-	-	-

Brunei (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.150	-	-	-	-	-	-

Cambodia (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	0.144	0.053	-	0.483	-	0.169

Cambodia (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	0.161	0.064	-	0.583	-	0.200

China (Yunnan & Guangxi) (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	0.144	0.053	-	-	-	0.169

China (Yunnan & Guangxi) (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	0.161	0.064	-	-	-	0.200

India (North-East) (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.180	0.144	0.053	-	0.483	-	0.169

India (North-East) (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.216	0.161	0.064	-	0.583	-	0.200

Indonesia (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.100	0.080	0.016	0.334	0.267	0.083	0.169

Indonesia (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.150	0.120	0.016	0.399	0.267	0.083	0.200

Lao PDR (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	0.144	0.059	-	0.483	-	0.169

Lao PDR (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	-	0.161	0.058	-	0.583	-	0.200

Malaysia (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.127	0.100	0.150	-	-	-	0.110

Malaysia (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
0.146	0.127	0.100	0.150	-	0.583	-	0.100

Myanmar (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.100	0.144	0.053	-	-	0.083	0.169

Myanmar (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.150	0.161	0.064	-	-	0.083	0.200

Philippines (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.180	0.144	0.053	0.334	0.483	0.083	0.169

Philippines (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.216	0.161	0.064	0.399	0.583	0.083	0.200

Singapore (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.180	-	-	0.334	-	-	0.169

Singapore (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.216	-	-	0.399	-	-	0.200

Thailand (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
-	0.180	0.144	0.053	0.334	0.483	-	0.169

Thailand (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
0.146	0.216	0.161	0.064	0.399	0.583	-	0.200

Vietnam (2020)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
0.134	0.180	0.080	0.053	-	-	-	0.169

Vietnam (2030)

Nuclear	Gas	Coal	Hydro	Oil	Diesel	Geothermal	Renewable
0.146	0.216	0.120	0.064	-	-	-	0.200

Table 4-5: CO_2 Emission Factor by Power Source (kt-CO_2 / GWh)

Bangladesh

	Gas	Coal	Oil	Diesel
2020	0.415	1.059	0.789	0.789
2030	0.407	0.870	0.733	0.733

Brunei

	Gas	Coal	Oil	Diesel
2020	0.744	-	0.752	0.752
2030	0.744	-	0.752	0.752

Cambodia

	Gas	Coal	Oil	Diesel
2020	-	1.087	1.146	1.146
2030	-	1.087	1.146	1.146

China (Yunnan & Guangxi)

	Gas	Coal	Oil	Diesel
2020	0.423	0.858	0.665	0.665
2030	0.395	0.796	0.629	0.629

India (North-East)

	Gas	Coal	Oil	Diesel
2020	0.415	1.059	0.789	0.789
2030	0.407	0.870	0.733	0.733

Indonesia

	Gas	Coal	Oil	Diesel
2020	0.512	1.029	0.794	0.794
2030	0.512	1.029	0.794	0.794

Lao PDR

	Gas	Coal	Oil	Diesel
2020	-	0.932	-	-
2030	-	0.932	-	-

Malaysia

	Gas	Coal	Oil	Diesel
2020	0.361	0.852	0.772	0.772
2030	0.349	0.834	0.750	0.750

Myanmar

	Gas	Coal	Oil	Diesel
2020	0.642	1.087	-	-
2030	0.642	1.087	-	-

Philippines

	Gas	Coal	Oil	Diesel
2020	0.329	0.932	0.705	0.705
2030	0.329	0.896	0.705	0.705

Singapore

	Gas	Coal	Oil	Diesel
2020	0.379	-	0.727	0.727
2030	0.359	-	0.679	0.679

Thailand

	Gas	Coal	Oil	Diesel
2020	0.386	0.854	0.727	0.727
2030	0.374	0.777	0.727	0.727

Vietnam

	Gas	Coal	Oil	Diesel
2020	0.376	0.849	0.799	0.799
2030	0.362	0.834	0.789	0.789

Table 4-6: Calculation Results (Base Case in 2020)

[CO_2 emission volume not restricted]

	Unit	Bangladesh	Brunei Darussalam	Cambodia	China (Yunnan & Guangxi)	India (North-East)	Indonesia	Lao PDR	Malaysia	Myanmar	Philippines	Singapore	Thailand	Viet Nam	Total
Supply-Demand Balance															
Electricity Demand	GWh	90,950	5,500	8,200	393,723	21,560	355,862	15,234	130,000	48,900	94,995	60,700	246,164	330,000	1,801,788
Grid Capacity (Import:+)	GWh	8,760	1,752	35,890	76,825	8,760	33,288	99,198	41,172	46,682	8,760	31,536	141,036	26,254	
Grid Capacity (Export:-)	GWh	-8,760	-1,752	-35,890	-76,825	-8,760	-33,288	-99,198	-41,172	-46,682	-8,760	-31,536	-141,036	-26,254	
Supply Capacity (Nuclear)	GWh	10,512	0	0	0	0	0	0	0	0	0	0	0	5,256	
Supply Capacity (Gas)	GWh	28,524	8,872	0	0	12,525	98,119	0	52,034	21,245	26,075	70,634	192,314	65,043	
Supply Capacity (Coal)	GWh	84,446	0	7,979	194,856	2,218	348,221	13,161	77,088	3,627	39,434	0	41,249	252,288	
Supply Capacity (Hydro)	GWh	1,301	0	19,410	264,362	21,523	35,411	26,199	14,585	39,767	16,210	0	16,107	75,292	
Supply Capacity (Oil)	GWh	3,863	0	0	0	0	11,826	0	0	0	3,416	19,053	1,656	0	
Supply Capacity (Diesel)	GWh	3,774	0	0	0	752	28,761	11	0	0	18,096	0	21	0	
Supply Capacity (Geothermal)	GWh	0	0	0	0	0	52,574	0	0	1,402	16,083	0	0	0	
Supply Capacity (Renewables)	GWh	0	0	11	648	799	2,656	28	10,512	3,620	378	1,556	7,251	4,415	
Total Supply Capacity	GWh	132,421	8,872	27,400	459,866	37,817	577,567	39,398	154,220	69,660	119,693	91,242	258,597	402,294	2,379,047
Power Supply (Nuclear)	GWh	10,512	0	0	0	0	0	0	0	0	0	0	0	5,256	
Power Supply (Gas)	GWh	28,524	7,252	0	0	0	0	0	52,034	21,245	14,130	27,608	40,521	0	
Power Supply (Coal)	GWh	59,373	0	6,391	191,927	0	298,509	10,233	77,088	698	39,434	0	41,249	252,288	
Power Supply (Hydro)	GWh	1,301	0	19,410	264,362	21,523	35,411	26,199	0	39,767	16,210	0	16,107	75,292	
Power Supply (Oil)	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	
Power Supply (Diesel)	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	
Power Supply (Geothermal)	GWh	0	0	0	0	0	52,574	0	0	1,402	16,083	0	0	0	
Power Supply (Renewables)	GWh	0	0	11	648	799	2,656	28	10,512	3,620	378	1,556	7,251	4,415	
Total Power Supply	GWh	99,710	7,252	25,812	456,938	22,322	389,150	36,459	139,634	66,731	86,235	29,164	105,128	337,251	1,801,788
Power Trade (Import:+/Export:-)	GWh	-8,760	-1,752	-17,612	-63,215	-762	-33,288	-21,225	-9,634	-17,831	8,760	31,536	141,036	-7,251	0
Generation Cost															
Power supply unit Cost (Nuclear)	US$/kWh	0.134												0.134	
Power supply unit Cost (Gas)	US$/kWh	0.100	0.100			0.180	0.100		0.127	0.100	0.180	0.180	0.180	0.180	
Power supply unit Cost (Coal)	US$/kWh	0.144		0.144	0.144	0.144	0.080	0.144	0.100	0.144	0.144		0.144	0.080	
Power supply unit Cost (Hydro)	US$/kWh	0.053		0.053	0.053	0.053	0.016	0.059	0.150	0.053	0.053		0.053	0.053	
Power supply unit Cost (Oil)	US$/kWh	0.334					0.334				0.334	0.334	0.334		
Power supply unit Cost (Diesel)	US$/kWh	0.483				0.483	0.267	0.483			0.483		0.483		
Power supply unit Cost (Geothermal)	US$/kWh						0.083			0.083	0.083				
Power supply unit Cost (Renewables)	US$/kWh			0.169	0.169	0.169	0.169	0.169	0.110	0.169	0.169	0.169	0.169	0.169	
Generation Cost (Nuclear)	million US$	1,409	0	0	0	0	0	0	0	0	0	0	0	704	
Generation Cost (Gas)	million US$	2,852	725	0	0	0	0	0	6,608	2,124	2,543	4,969	7,294	0	
Generation Cost (Coal)	million US$	8,550	0	920	27,638	0	23,881	1,474	7,709	101	5,678	0	5,940	20,183	
Generation Cost (Hydro)	million US$	69	0	1,029	14,011	1,141	567	1,546	0	2,108	859	0	854	3,990	
Generation Cost (Oil)	million US$	0	0	0	0	0	0	0	0	0	0	0	0	0	
Generation Cost (Diesel)	million US$	0	0	0	0	0	0	0	0	0	0	0	0	0	
Generation Cost (Geothermal)	million US$	0	0	0	0	0	4,364	0	0	116	1,335	0	0	0	
Generation Cost (Renewables)	million US$	0	0	2	110	135	449	5	1,156	612	64	263	1,225	746	
Total Generation Cost	million US$	12,880	725	1,951	41,758	1,276	29,260	3,024	15,473	5,061	10,480	5,232	15,313	25,624	168,057
CO2 Emission															
CO2 Emission Coefficient (Nuclear)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission Coefficient (Gas)	kt-CO2/GWh	0.415	0.744		0.423	0.415	0.512		0.361	0.642	0.329	0.379	0.386	0.376	
CO2 Emission Coefficient (Coal)	kt-CO2/GWh	1.059		1.087	0.858	1.059	1.029	0.932	0.852	1.087	0.932		0.854	0.849	
CO2 Emission Coefficient (Hydro)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission Coefficient (Oil)	kt-CO2/GWh	0.789	0.752	1.146	0.665	0.789	0.794		0.772		0.705	0.727	0.727	0.799	
CO2 Emission Coefficient (Diesel)	kt-CO2/GWh	0.789	0.752	1.146	0.665	0.789	0.794		0.772		0.705	0.727	0.727	0.799	
CO2 Emission Coefficient (Geothermal)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission Coefficient (Renewables)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission (Nuclear)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Gas)	kt-CO2	11,850	5,395	0	0	0	0	0	18,767	13,637	4,652	10,467	15,629	0	
CO2 Emission (Coal)	kt-CO2	62,876	0	6,949	164,740	0	307,146	9,536	65,650	759	36,749	0	35,221	214,295	
CO2 Emission (Hydro)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Oil)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Diesel)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Geothermal)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Renewables)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total CO2 Emission	kt-CO2	74,726	5,395	6,949	164,740	0	307,146	9,536	84,417	14,396	41,402	10,467	50,849	214,295	984,317
Target of Total CO2 Emission															9,999,999

Table 4-7: Calculation results (Accelerated Case in 2030)

[CO_2 emission volume not restricted]

	Unit	Bangladesh	Brunei Darussalam	Cambodia	China (Yunnan & Guangxi)	India (North-East)	Indonesia	Lao PDR	Malaysia	Myanmar	Philippines	Singapore	Thailand	Viet Nam	Total
Supply-Demand Balance															
Electricity Demand	GWh	191,933	7,524	13,489	541,980	41,491	956,929	35,863	160,000	95,068	149,067	71,500	346,767	675,000	3,286,611
Grid Capacity (Import:+)	GWh	17,520	3,504	71,780	153,650	17,520	66,576	198,396	82,344	93,364	17,520	63,072	282,072	52,508	
Grid Capacity (Export:-)	GWh	-17,520	-3,504	-71,780	-153,650	-17,520	-66,576	-198,396	-82,344	-93,364	-17,520	-63,072	-282,072	-52,508	
Supply Capacity (Nuclear)	GWh	28,032	0	0	0	0	0	0	14,016	0	0	0	14,016	56,064	
Supply Capacity (Gas)	GWh	46,516	12,138	0	0	24,998	176,770	0	52,560	21,245	37,113	87,593	265,687	87,323	
Supply Capacity (Coal)	GWh	137,707	0	13,124	268,492	4,426	627,363	13,161	88,301	5,203	62,876	0	51,768	509,152	
Supply Capacity (Hydro)	GWh	1,301	0	31,934	364,261	42,960	63,793	50,020	16,651	83,756	26,037	0	16,280	87,142	
Supply Capacity (Oil)	GWh	6,302	0	0	0	0	11,826	0	0	0	3,416	19,053	1,656	0	
Supply Capacity (Diesel)	GWh	6,155	0	0	0	752	28,761	11	10,512	0	31,236	0	3,963	0	
Supply Capacity (Geothermal)	GWh	0	0	0	0	0	94,720	0	0	1,402	24,941	0	0	0	
Supply Capacity (Renewables)	GWh	0	0	11	648	799	2,656	28	18,396	3,620	378	1,929	10,047	13,913	
Total Supply Capacity	GWh	226,012	12,138	45,069	633,401	73,934	1,005,889	63,220	200,436	115,225	185,998	108,575	363,418	753,594	3,786,908
Power Supply (Nuclear)	GWh	28,032	0	0	0	0	0	0	14,016	0	0	0	14,016	56,064	
Power Supply (Gas)	GWh	46,516	11,028	0	0	10,827	176,770	0	52,560	21,245	24,975	38,035	57,434	0	
Power Supply (Coal)	GWh	133,605	0	13,124	268,492	4,426	627,363	13,161	88,301	5,203	62,876	0	51,768	509,152	
Power Supply (Hydro)	GWh	1,301	0	31,934	364,261	42,960	63,793	50,020	16,651	83,756	26,037	0	16,280	87,142	
Power Supply (Oil)	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	
Power Supply (Diesel)	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	
Power Supply (Geothermal)	GWh	0	0	0	0	0	94,720	0	0	1,402	24,941	0	0	0	
Power Supply (Renewables)	GWh	0	0	11	648	799	2,656	28	18,396	3,620	378	1,929	10,047	13,913	
Total Power Supply	GWh	209,453	11,028	45,069	633,401	59,011	965,303	63,209	189,924	115,225	139,208	39,964	149,546	666,271	3,286,611
Power Trade (Import:+/Export:-)	GWh	-17,520	-3,504	-31,580	-91,421	-17,520	-8,374	-27,346	-29,924	-20,157	9,859	31,536	197,221	8,729	0
Generation Cost															
Power supply unit Cost (Nuclear)	US$/kWh	0.146							0.146				0.146	0.146	
Power supply unit Cost (Gas)	US$/kWh	0.150	0.150			0.216	0.150		0.127	0.150	0.216	0.216	0.216	0.216	
Power supply unit Cost (Coal)	US$/kWh	0.161		0.161	0.161	0.161	0.120	0.161	0.100	0.161	0.161		0.161	0.120	
Power supply unit Cost (Hydro)	US$/kWh	0.064		0.064	0.064	0.064	0.016	0.058	0.150	0.064	0.064		0.064	0.064	
Power supply unit Cost (Oil)	US$/kWh	0.399					0.399				0.399	0.399	0.399		
Power supply unit Cost (Diesel)	US$/kWh	0.583		0.583		0.583	0.267	0.583	0.583		0.583		0.583		
Power supply unit Cost (Geothermal)	US$/kWh						0.083			0.083	0.083				
Power supply unit Cost (Renewables)	US$/kWh			0.200	0.200	0.200	0.200	0.200	0.100	0.200	0.200	0.200	0.200	0.200	
Generation Cost (Nuclear)	million US$	4,093	0	0	0	0	0	0	2,046	0	0	0	2,046	8,185	
Generation Cost (Gas)	million US$	6,977	1,654	0	0	2,339	26,515	0	6,675	3,187	5,395	8,216	12,406	0	
Generation Cost (Coal)	million US$	21,510	0	2,113	43,227	713	75,284	2,119	8,830	838	10,123	0	8,335	61,098	
Generation Cost (Hydro)	million US$	83	0	2,044	23,313	2,749	1,021	2,901	2,498	5,360	1,666	0	1,042	5,577	
Generation Cost (Oil)	million US$	0	0	0	0	0	0	0	0	0	0	0	0	0	
Generation Cost (Diesel)	million US$	0	0	0	0	0	0	0	0	0	0	0	0	0	
Generation Cost (Geothermal)	million US$	0	0	0	0	0	7,862	0	0	116	2,070	0	0	0	
Generation Cost (Renewables)	million US$	0	0	2	130	160	531	6	1,840	724	76	386	2,009	2,783	
Total Generation Cost	million US$	32,664	1,654	4,159	66,670	5,960	111,213	5,026	21,889	10,225	19,330	8,601	25,838	77,643	390,871
CO2 Emission															
CO2 Emission Coefficient (Nuclear)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission Coefficient (Gas)	kt-CO2/GWh	0.407	0.744		0.395	0.407	0.512		0.349	0.642	0.329	0.359	0.374	0.362	
CO2 Emission Coefficient (Coal)	kt-CO2/GWh	0.870		1.087	0.796	0.870	1.029	0.932	0.834	1.087	0.896		0.777	0.834	
CO2 Emission Coefficient (Hydro)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission Coefficient (Oil)	kt-CO2/GWh	0.733	0.752	1.146	0.629	0.733	0.794		0.750		0.705	0.679	0.727	0.789	
CO2 Emission Coefficient (Diesel)	kt-CO2/GWh	0.733	0.752	1.146	0.629	0.733	0.794		0.750		0.705	0.679	0.727	0.789	
CO2 Emission Coefficient (Geothermal)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission Coefficient (Renewables)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission (Nuclear)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Gas)	kt-CO2	18,926	8,204	0	0	4,405	90,577	0	18,324	13,637	8,224	13,662	21,454	0	
CO2 Emission (Coal)	kt-CO2	116,208	0	14,269	213,597	3,849	645,515	12,265	73,660	5,657	56,342	0	40,203	424,734	
CO2 Emission (Hydro)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Oil)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Diesel)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Geothermal)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Renewables)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total CO2 Emission	kt-CO2	135,134	8,204	14,269	213,597	8,254	736,092	12,265	91,985	19,294	64,565	13,662	61,657	424,734	1,803,713
Target of Total CO2 Emission															9,999,999

Table 4-8: Calculation Results (Base Case in 2030)

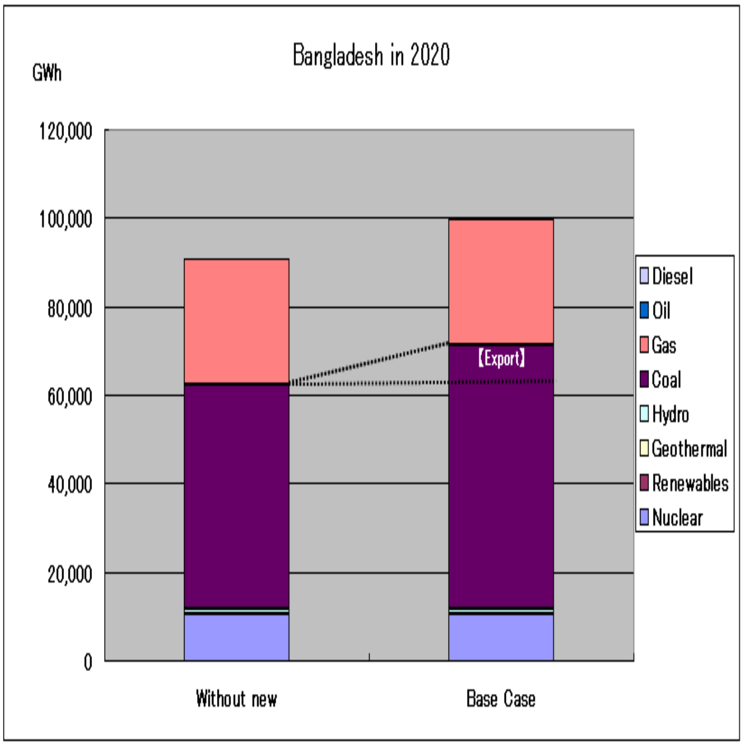
[CO_2 emission volume not restricted]

	Unit	Bangladesh	Brunei Darussalam	Cambodia	China (Yunnan & Guangxi)	India (North-East)	Indonesia	Lao PDR	Malaysia	Myanmar	Philippines	Singapore	Thailand	Viet Nam	Total
Supply-Demand Balance															
Electricity Demand	GWh	191,933	7,524	13,489	541,980	41,491	956,929	35,863	160,000	95,068	149,067	71,500	346,767	675,000	3,286,611
Grid Capacity (Import:+)	GWh	8,760	1,752	35,890	76,825	8,760	33,288	99,198	41,172	46,682	8,760	31,536	141,036	26,254	
Grid Capacity (Export:-)	GWh	-8,760	-1,752	-35,890	-76,825	-8,760	-33,288	-99,198	-41,172	-46,682	-8,760	-31,536	-141,036	-26,254	
Supply Capacity (Nuclear)	GWh	28,032	0	0	0	0	0	0	14,016	0	0	0	14,016	56,064	
Supply Capacity (Gas)	GWh	46,516	12,138	0	0	24,998	176,770	0	52,560	21,245	37,113	87,593	265,687	87,323	
Supply Capacity (Coal)	GWh	137,707	0	13,124	268,492	4,426	627,363	13,161	88,301	5,203	62,876	0	51,768	509,152	
Supply Capacity (Hydro)	GWh	1,301	0	31,934	364,261	42,960	63,793	50,020	16,651	83,756	26,037	0	16,280	87,142	
Supply Capacity (Oil)	GWh	6,302	0	0	0	0	11,826	0	0	0	3,416	19,053	1,656	0	
Supply Capacity (Diesel)	GWh	6,155	0	0	0	752	28,761	11	10,512	0	31,236	0	3,963	0	
Supply Capacity (Geothermal)	GWh	0	0	0	0	0	94,720	0	0	1,402	24,941	0	0	0	
Supply Capacity (Renewables)	GWh	0	0	11	648	799	2,656	28	18,396	3,620	378	1,929	10,047	13,913	
Total Supply Capacity	GWh	226,012	12,138	45,069	633,401	73,934	1,005,889	63,220	200,436	115,225	185,998	108,575	363,418	753,594	3,786,908
Power Supply (Nuclear)	GWh	28,032	0	0	0	0	0	0	14,016	0	0	0	14,016	56,064	
Power Supply (Gas)	GWh	46,516	9,276	0	0	0	176,770	0	52,560	21,245	26,074	38,035	113,619	0	
Power Supply (Coal)	GWh	124,844	0	1,924	253,896	3,280	627,363	4,159	88,301	5,203	62,876	0	51,768	509,152	
Power Supply (Hydro)	GWh	1,301	0	31,934	364,261	42,960	63,793	50,020	16,651	83,756	26,037	0	16,280	87,142	
Power Supply (Oil)	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	
Power Supply (Diesel)	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	
Power Supply (Geothermal)	GWh	0	0	0	0	0	94,720	0	0	1,402	24,941	0	0	0	
Power Supply (Renewables)	GWh	0	0	11	648	799	2,656	28	18,396	3,620	378	1,929	10,047	13,913	
Total Power Supply	GWh	200,693	9,276	33,869	618,805	47,038	965,303	54,207	189,924	115,225	140,307	39,964	205,731	666,271	3,286,611
Power Trade (Import:+/Export:-)	GWh	-8,760	-1,752	-20,380	-76,825	-5,547	-8,374	-18,344	-29,924	-20,157	8,760	31,536	141,036	8,729	0
Generation Cost															
Power supply unit Cost (Nuclear)	US$/kWh	0.146							0.146				0.146	0.146	
Power supply unit Cost (Gas)	US$/kWh	0.150	0.150			0.216	0.150		0.127	0.150	0.216	0.216	0.216	0.216	
Power supply unit Cost (Coal)	US$/kWh	0.161		0.161	0.161	0.161	0.120	0.161	0.100	0.161	0.161		0.161	0.120	
Power supply unit Cost (Hydro)	US$/kWh	0.064		0.064	0.064	0.064	0.016	0.058	0.150	0.064	0.064		0.064	0.064	
Power supply unit Cost (Oil)	US$/kWh	0.399					0.399				0.399	0.399	0.399		
Power supply unit Cost (Diesel)	US$/kWh	0.583		0.583		0.583	0.267	0.583	0.583		0.583		0.583		
Power supply unit Cost (Geothermal)	US$/kWh						0.083			0.083	0.083				
Power supply unit Cost (Renewables)	US$/kWh			0.200	0.200	0.200	0.200	0.200	0.100	0.200	0.200	0.200	0.200	0.200	
Generation Cost (Nuclear)	million US$	4,093	0	0	0	0	0	0	2,046	0	0	0	2,046	8,185	
Generation Cost (Gas)	million US$	6,977	1,391	0	0	0	26,515	0	6,675	3,187	5,632	8,216	24,542	0	
Generation Cost (Coal)	million US$	20,100	0	310	40,877	528	75,284	670	8,830	838	10,123	0	8,335	61,098	
Generation Cost (Hydro)	million US$	83	0	2,044	23,313	2,749	1,021	2,901	2,498	5,360	1,666	0	1,042	5,577	
Generation Cost (Oil)	million US$	0	0	0	0	0	0	0	0	0	0	0	0	0	
Generation Cost (Diesel)	million US$	0	0	0	0	0	0	0	0	0	0	0	0	0	
Generation Cost (Geothermal)	million US$	0	0	0	0	0	7,862	0	0	116	2,070	0	0	0	
Generation Cost (Renewables)	million US$	0	0	2	130	160	531	6	1,840	724	76	386	2,009	2,783	
Total Generation Cost	million US$	31,253	1,391	2,356	64,320	3,437	111,213	3,576	21,889	10,225	19,567	8,601	37,974	77,643	393,446
CO2 Emission															
CO2 Emission Coefficient (Nuclear)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission Coefficient (Gas)	kt-CO2/GWh	0.407	0.744		0.395	0.407	0.512		0.349	0.642	0.329	0.359	0.374	0.362	
CO2 Emission Coefficient (Coal)	kt-CO2/GWh	0.870		1.087	0.796	0.870	1.029	0.932	0.834	1.087	0.896		0.777	0.834	
CO2 Emission Coefficient (Hydro)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission Coefficient (Oil)	kt-CO2/GWh	0.733	0.752	1.146	0.629	0.733	0.794		0.750		0.705	0.679	0.727	0.789	
CO2 Emission Coefficient (Diesel)	kt-CO2/GWh	0.733	0.752	1.146	0.629	0.733	0.794		0.750		0.705	0.679	0.727	0.789	
CO2 Emission Coefficient (Geothermal)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission Coefficient (Renewables)	kt-CO2/GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 Emission (Nuclear)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Gas)	kt-CO2	18,926	6,901	0	0	0	90,577	0	18,324	13,637	8,585	13,662	42,441	0	
CO2 Emission (Coal)	kt-CO2	108,588	0	2,092	201,985	2,853	645,515	3,875	73,660	5,657	56,342	0	40,203	424,734	
CO2 Emission (Hydro)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Oil)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Diesel)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Geothermal)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 Emission (Renewables)	kt-CO2	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total CO2 Emission	kt-CO2	127,514	6,901	2,092	201,985	2,853	736,092	3,875	91,985	19,294	64,927	13,662	82,644	424,734	1,778,558
Target of Total CO2 Emission															9,999,999

Table 4-9: Optimal Energy Mixes by Country if International Interconnection Grid is Augmented (Cases in which CO_2 emission volume is not restricted)

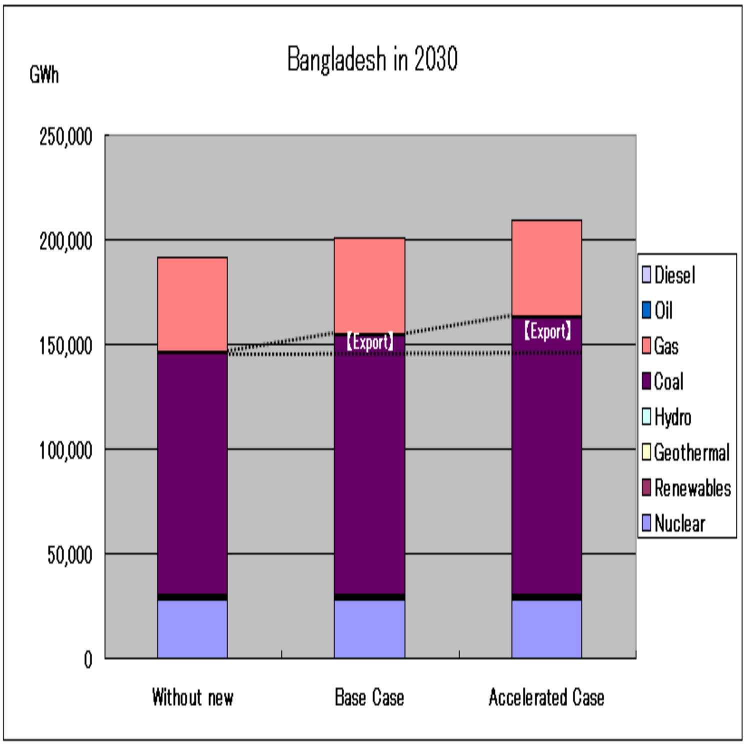
Bangladesh in 2020

	Without new	Base Case	Accelerated Case
Nuclear	10,512	10,512	
Renewables	0	0	
Geothermal	0	0	
Hydro	1,301	1,301	
Coal	50,613	59,373	
Gas	28,524	28,524	
Oil	0	0	
Diesel	0	0	
Total Supply	90,950	99,710	
Power Trade	0	-8,760	



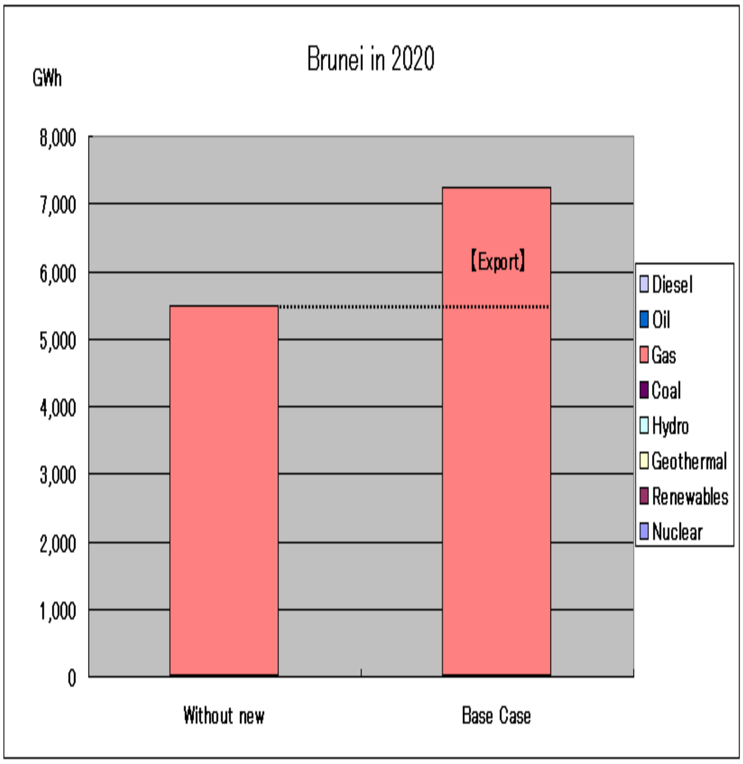
Bangladesh in 2030

	Without new	Base Case	Accelerated Case
Nuclear	28,032	28,032	28,032
Renewables	0	0	0
Geothermal	0	0	0
Hydro	1,301	1,301	1,301
Coal	116,085	124,844	133,605
Gas	46,516	46,516	46,516
Oil	0	0	0
Diesel	0	0	0
Total Supply	191,933	200,693	209,453
Power Trade	0	-8,760	-17,520



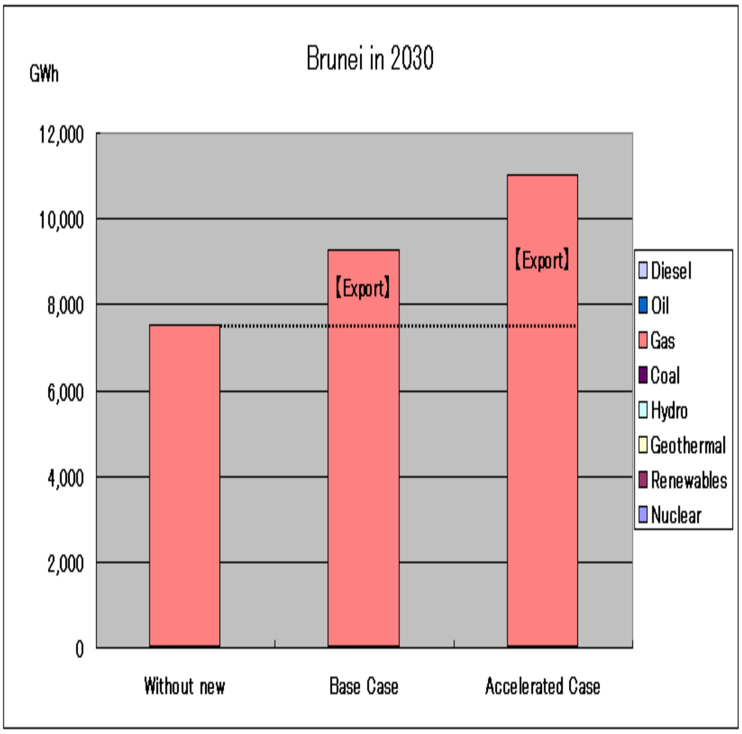
Brunei in 2020

	Without new	Base Case	Accelerated Case
Nuclear	0	0	
Renewables	0	0	
Geothermal	0	0	
Hydro	0	0	
Coal	0	0	
Gas	5,500	7,252	
Oil	0	0	
Diesel	0	0	
Total Supply	5,500	7,252	
Power Trade	0	-1,752	



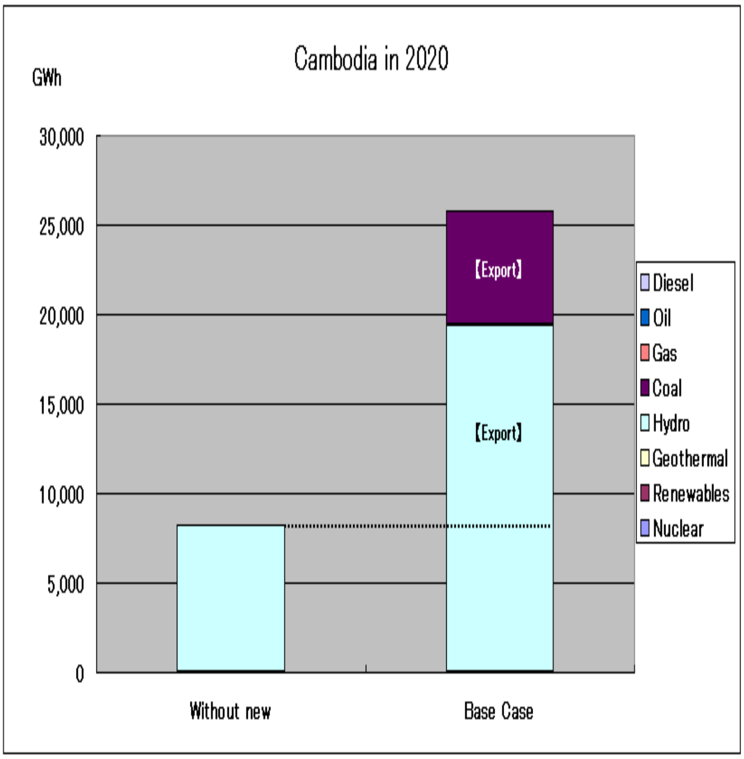
Brunei in 2030

	Without new	Base Case	Accelerated Case
Nuclear	0	0	0
Renewables	0	0	0
Geothermal	0	0	0
Hydro	0	0	0
Coal	0	0	0
Gas	7,524	9,276	11,028
Oil	0	0	0
Diesel	0	0	0
Total Supply	7,524	9,276	11,028
Power Trade	0	-1,752	-3,504



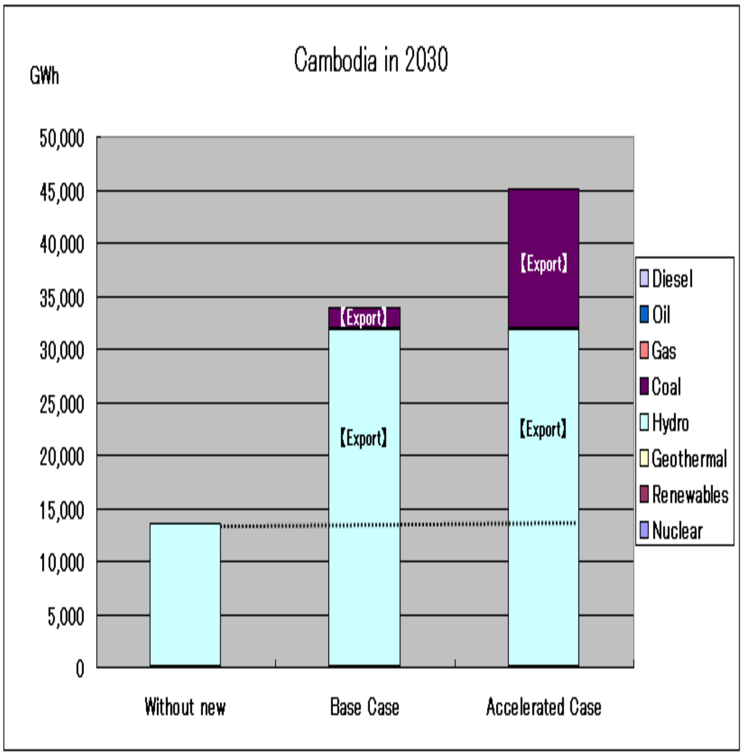
Cambodia in 2020

	Without new	Base Case	Accelerated Case
Nuclear	0	0	
Renewables	11	11	
Geothermal	0	0	
Hydro	8,189	19,410	
Coal	0	6,391	
Gas	0	0	
Oil	0	0	
Diesel	0	0	
Total Supply	8,200	25,812	
Power Trade	0	-17,612	



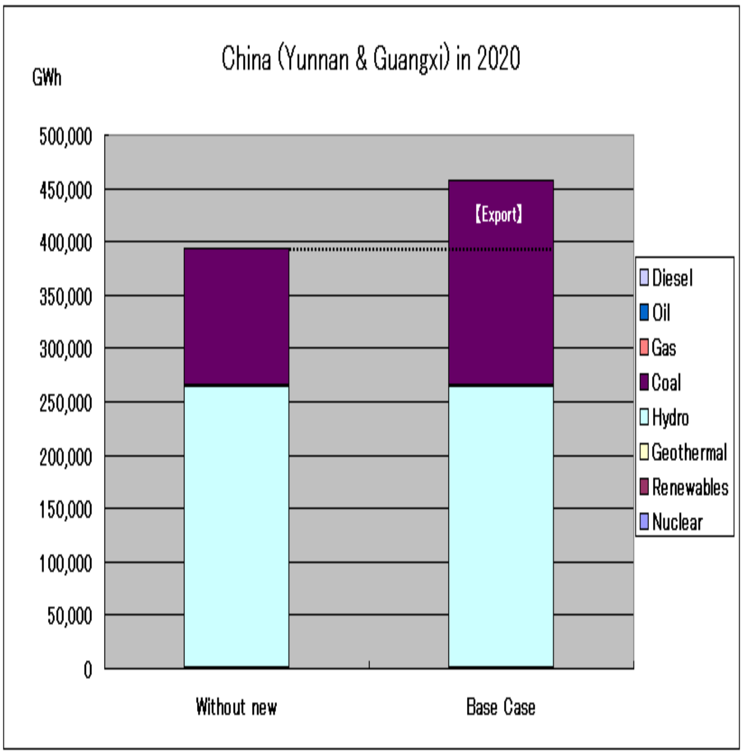
Cambodia in 2030

	Without new	Base Case	Accelerated Case
Nuclear	0	0	0
Renewables	11	11	11
Geothermal	0	0	0
Hydro	13,478	31,934	31,934
Coal	0	1,924	13,124
Gas	0	0	0
Oil	0	0	0
Diesel	0	0	0
Total Supply	13,489	33,869	45,069
Power Trade	0	-20,380	-31,580



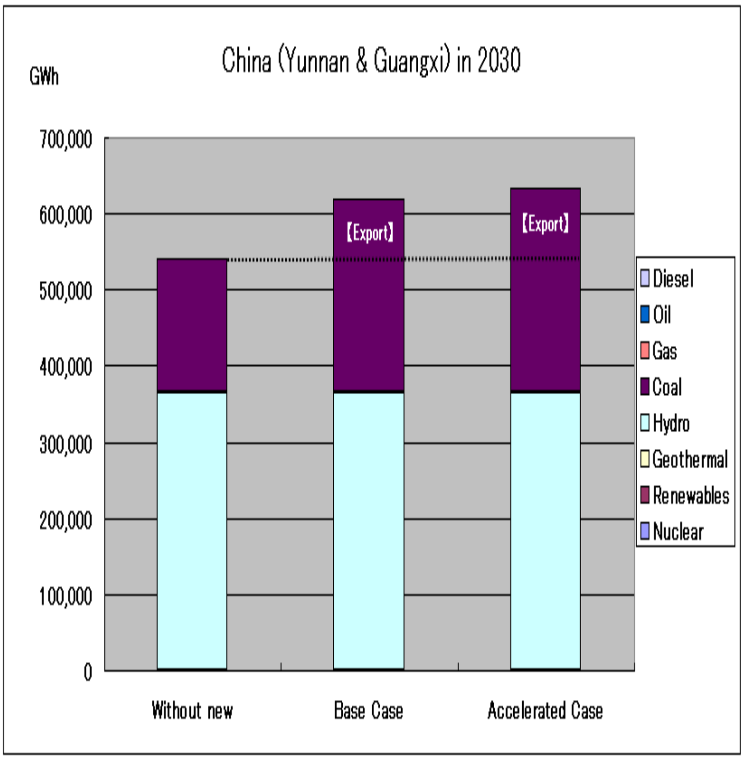
China (Yunnan & Guangxi) in 2020

	Without new	Base Case	Accelerated Case
Nuclear	0	0	
Renewables	648	648	
Geothermal	0	0	
Hydro	264,362	264,362	
Coal	128,712	191,927	
Gas	0	0	
Oil	0	0	
Diesel	0	0	
Total Supply	393,723	456,938	
Power Trade	0	-63,215	



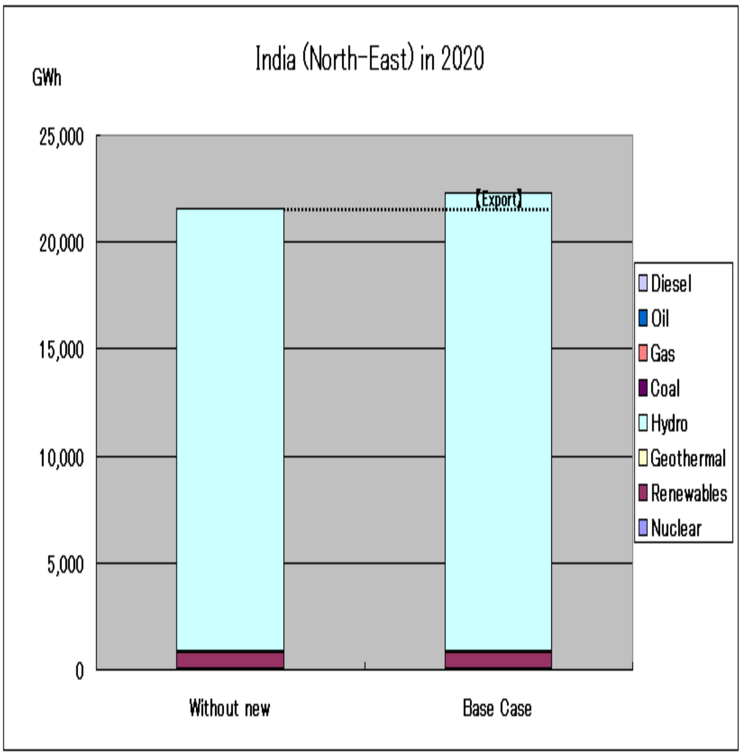
China (Yunnan & Guangxi) in 2030

	Without new	Base Case	Accelerated Case
Nuclear	0	0	0
Renewables	648	648	648
Geothermal	0	0	0
Hydro	364,261	364,261	364,261
Coal	177,071	253,896	268,492
Gas	0	0	0
Oil	0	0	0
Diesel	0	0	0
Total Supply	541,980	618,805	633,401
Power Trade	0	-76,825	-91,421



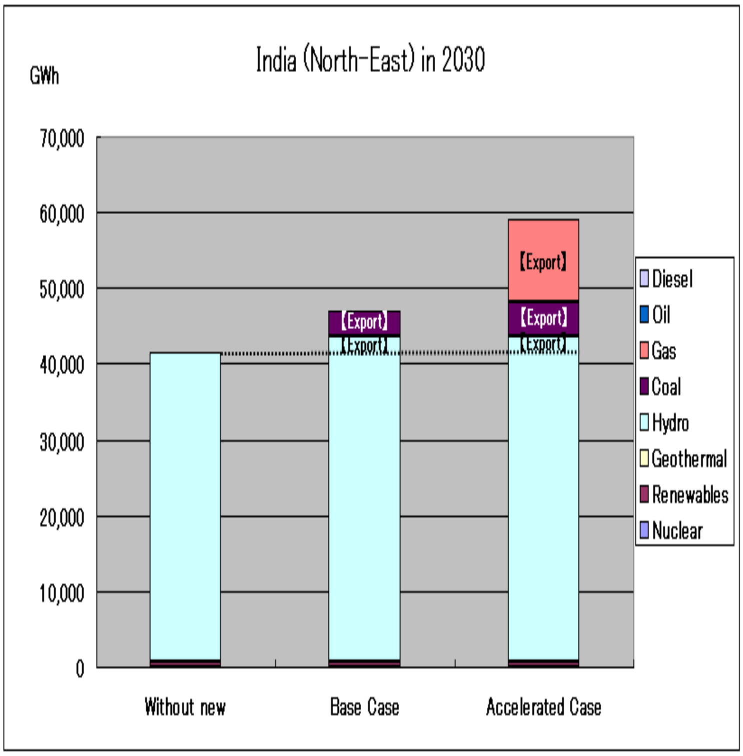
India (North-East) in 2020

	Without new	Base Case	Accelerated Case
Nuclear	0	0	
Renewables	799	799	
Geothermal	0	0	
Hydro	20,761	21,523	
Coal	0	0	
Gas	0	0	
Oil	0	0	
Diesel	0	0	
Total Supply	21,560	22,322	
Power Trade	0	-762	



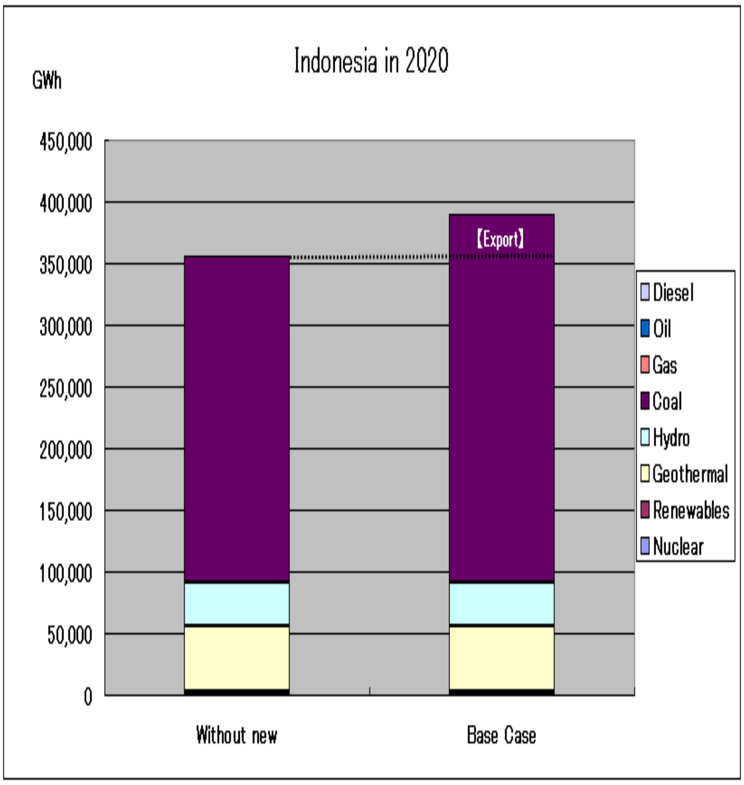
India (North-East) in 2030

	Without new	Base Case	Accelerated Case
Nuclear	0	0	0
Renewables	799	799	799
Geothermal	0	0	0
Hydro	40,692	42,960	42,960
Coal	0	3,280	4,426
Gas	0	0	10,827
Oil	0	0	0
Diesel	0	0	0
Total Supply	41,491	47,038	59,011
Power Trade	0	-5,547	-17,520



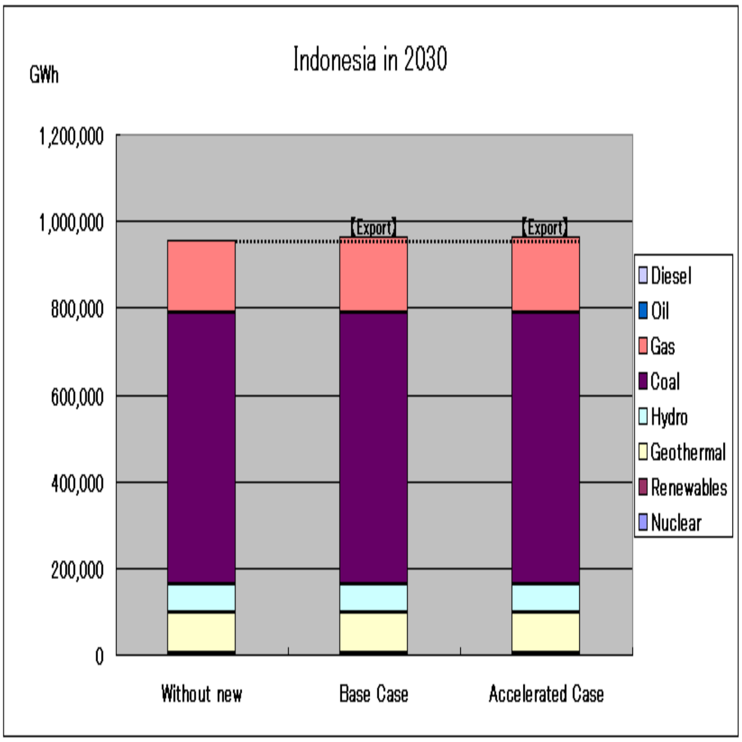
Indonesia in 2020

	Without new	Base Case	Accelerated Case
Nuclear	0	0	
Renewables	2,656	2,656	
Geothermal	52,574	52,574	
Hydro	35,411	35,411	
Coal	265,221	298,509	
Gas	0	0	
Oil	0	0	
Diesel	0	0	
Total Supply	355,862	389,150	
Power Trade	0	-33,288	



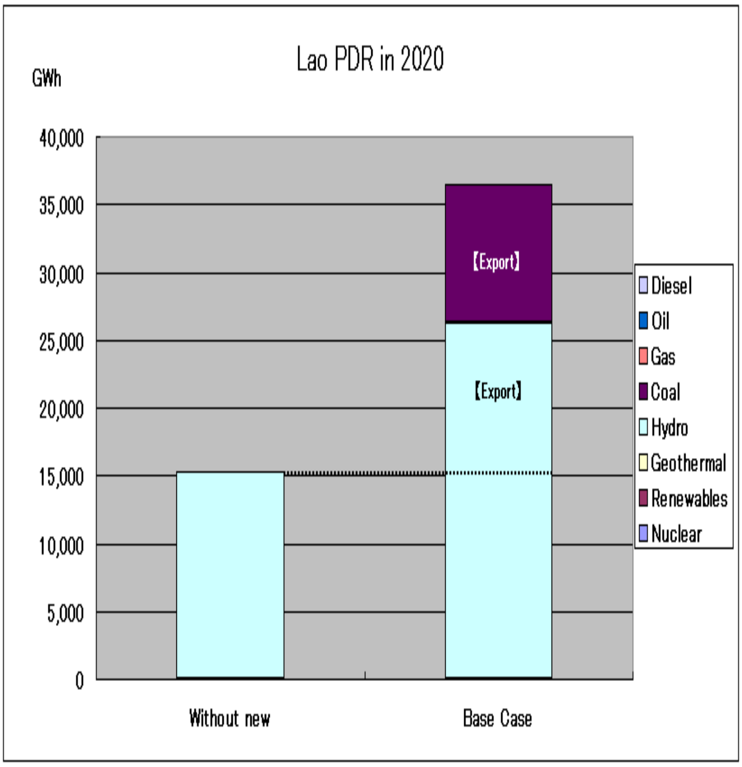
Indonesia in 2030

	Without new	Base Case	Accelerated Case
Nuclear	0	0	0
Renewables	2,656	2,656	2,656
Geothermal	94,720	94,720	94,720
Hydro	63,793	63,793	63,793
Coal	627,363	627,363	627,363
Gas	168,396	176,770	176,770
Oil	0	0	0
Diesel	0	0	0
Total Supply	956,929	965,303	965,303
Power Trade	0	-8,374	-8,374



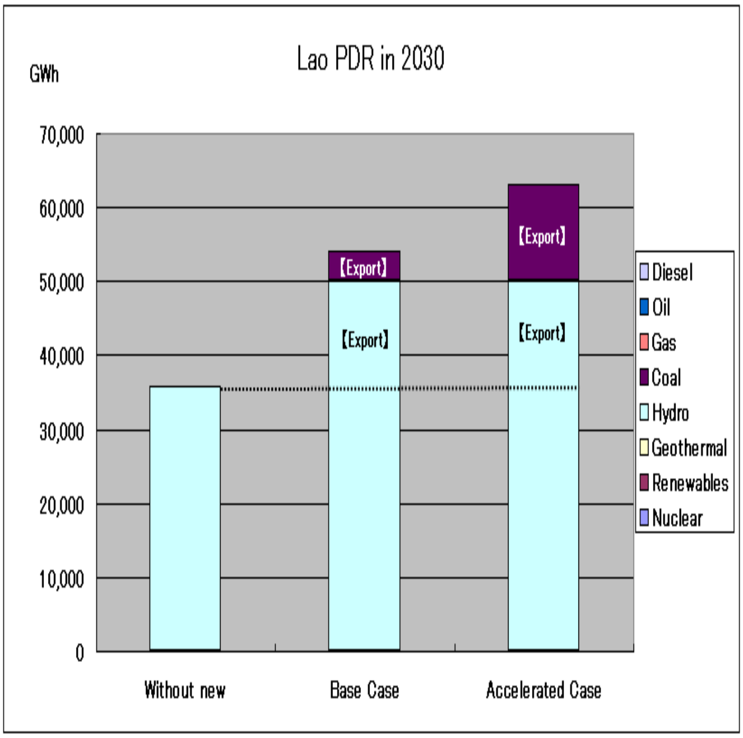
Lao PDR in 2020

	Without new	Base Case	Accelerated Case
Nuclear	0	0	
Renewables	28	28	
Geothermal	0	0	
Hydro	15,206	26,199	
Coal	0	10,233	
Gas	0	0	
Oil	0	0	
Diesel	0	0	
Total Supply	15,234	36,459	
Power Trade	0	-21,225	



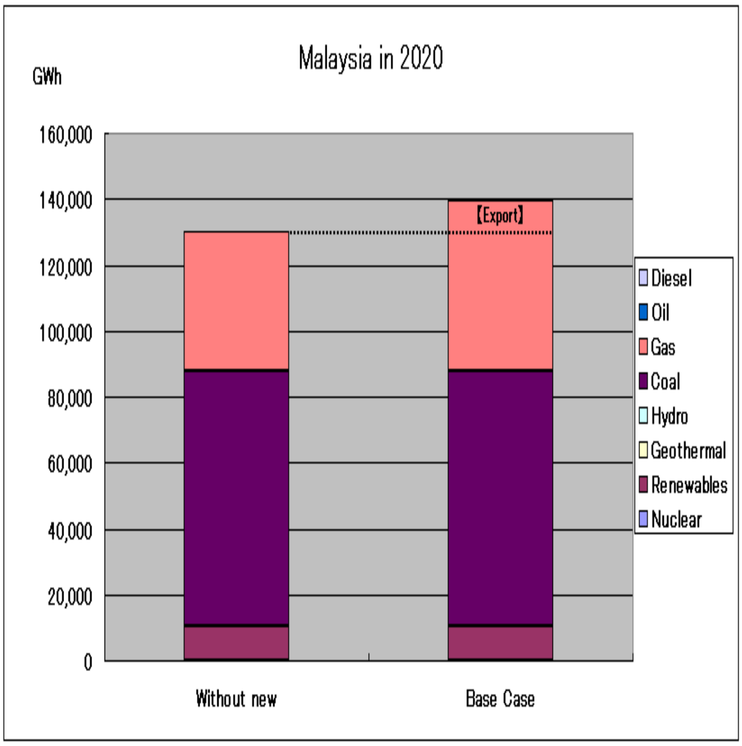
Lao PDR in 2030

	Without new	Base Case	Accelerated Case
Nuclear	0	0	0
Renewables	28	28	28
Geothermal	0	0	0
Hydro	35,835	50,020	50,020
Coal	0	4,159	13,161
Gas	0	0	0
Oil	0	0	0
Diesel	0	0	0
Total Supply	35,863	54,207	63,209
Power Trade	0	-18,344	-27,346



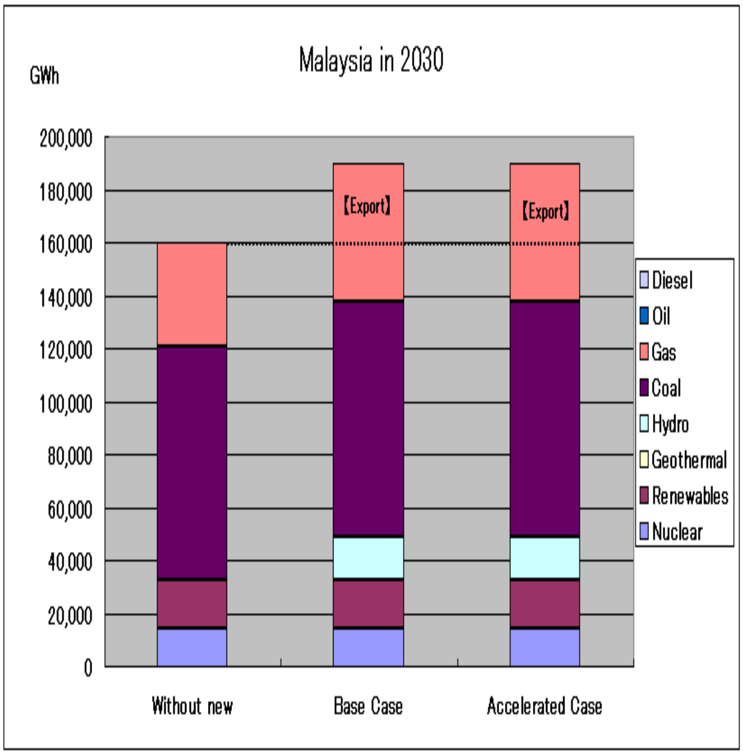
Malaysia in 2020

	Without new	Base Case	Accelerated Case
Nuclear	0	0	
Renewables	10,512	10,512	
Geothermal	0	0	
Hydro	0	0	
Coal	77,088	77,088	
Gas	42,400	52,034	
Oil	0	0	
Diesel	0	0	
Total Supply	130,000	139,634	
Power Trade	0	-9,634	



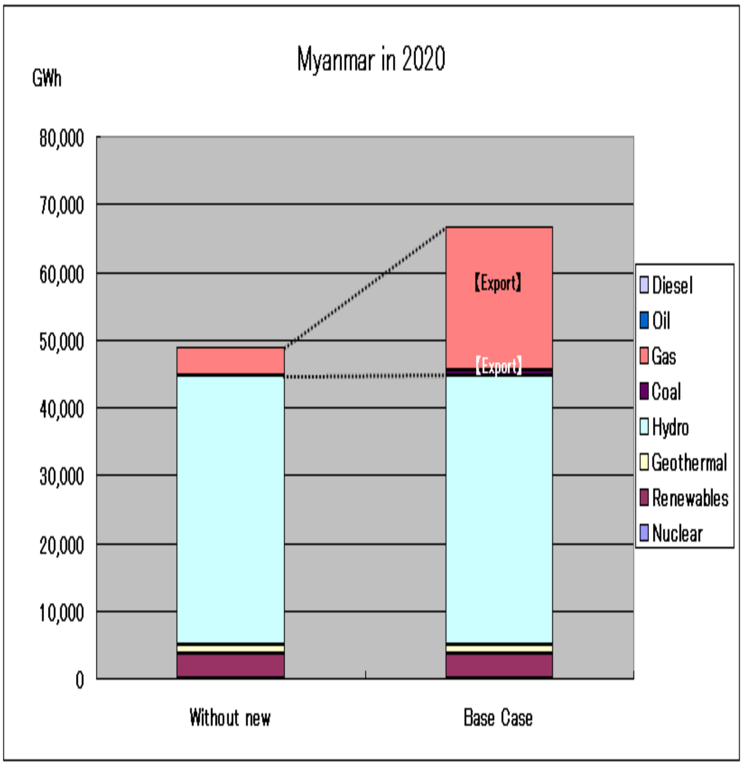
Malaysia in 2030

	Without new	Base Case	Accelerated Case
Nuclear	14,016	14,016	14,016
Renewables	18,396	18,396	18,396
Geothermal	0	0	0
Hydro	0	16,651	16,651
Coal	88,301	88,301	88,301
Gas	39,287	52,560	52,560
Oil	0	0	0
Diesel	0	0	0
Total Supply	160,000	189,924	189,924
Power Trade	0	-29,924	-29,924



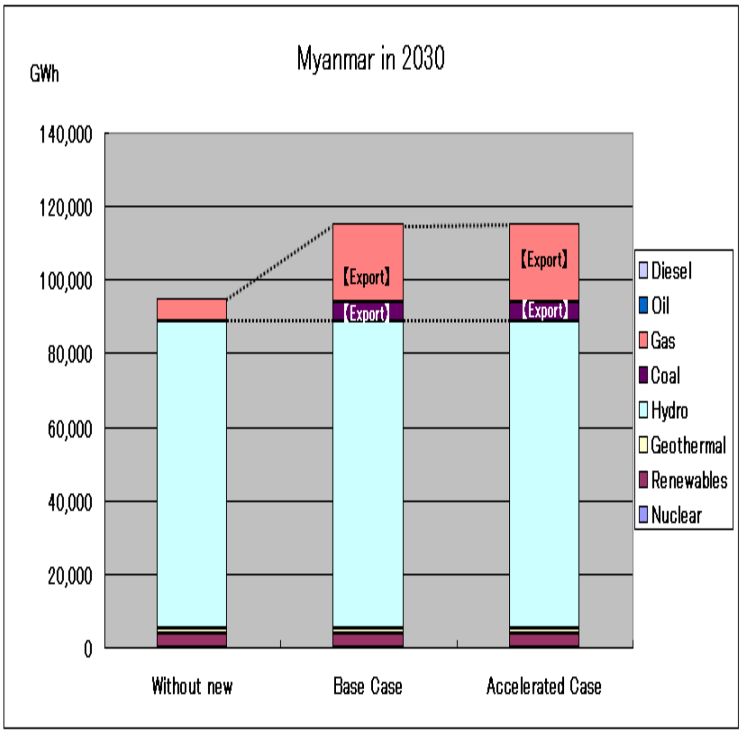
Myanmar in 2020

	Without new	Base Case	Accelerated Case
Nuclear	0	0	
Renewables	3,620	3,620	
Geothermal	1,402	1,402	
Hydro	39,767	39,767	
Coal	0	698	
Gas	4,112	21,245	
Oil	0	0	
Diesel	0	0	
Total Supply	48,900	66,731	
Power Trade	0	-17,831	



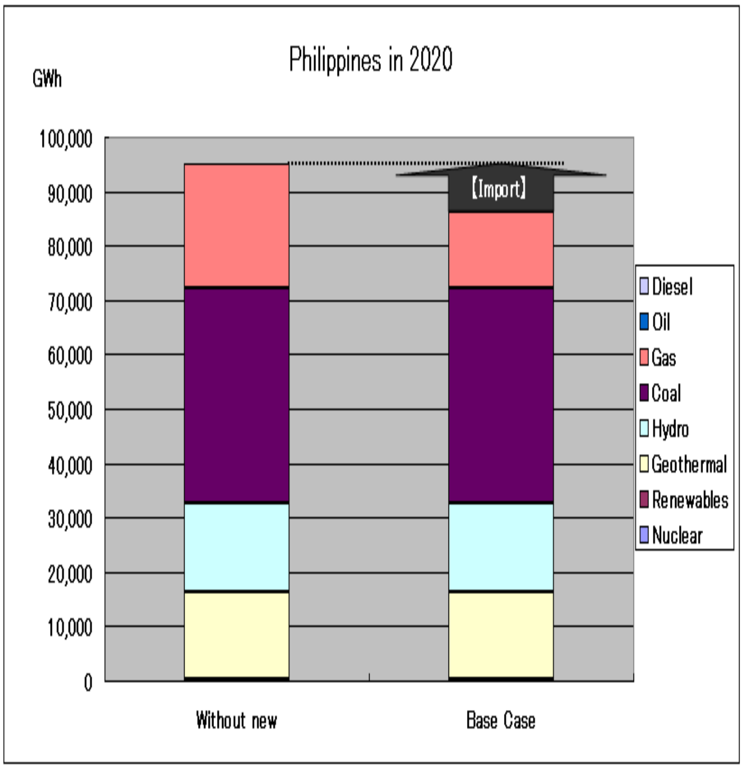
Myanmar in 2030

	Without new	Base Case	Accelerated Case
Nuclear	0	0	0
Renewables	3,620	3,620	3,620
Geothermal	1,402	1,402	1,402
Hydro	83,756	83,756	83,756
Coal	0	5,203	5,203
Gas	6,291	21,245	21,245
Oil	0	0	0
Diesel	0	0	0
Total Supply	95,068	115,225	115,225
Power Trade	0	-20,157	-20,157



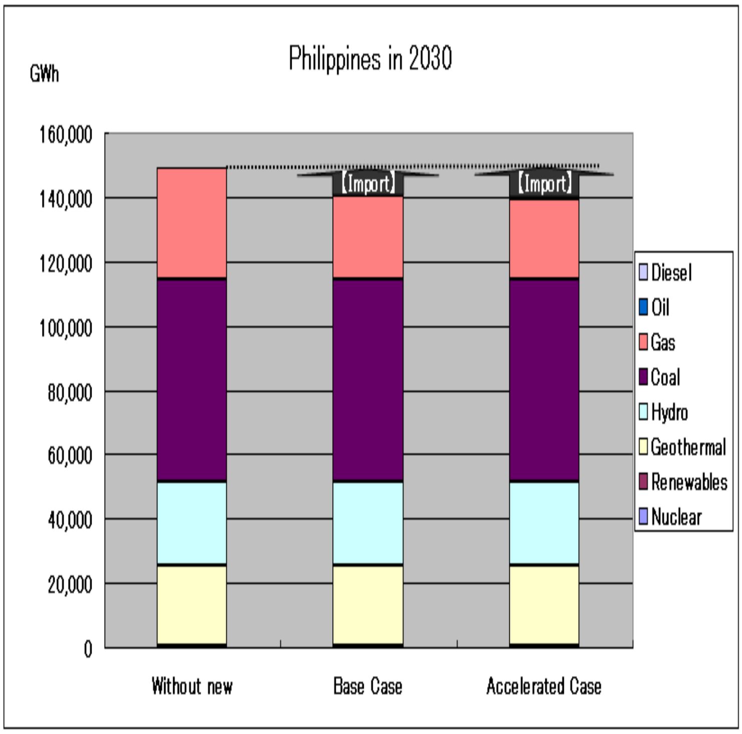
Philippines in 2020

	Without new	Base Case	Accelerated Case
Nuclear	0	0	
Renewables	378	378	
Geothermal	16,083	16,083	
Hydro	16,210	16,210	
Coal	39,434	39,434	
Gas	22,890	14,130	
Oil	0	0	
Diesel	0	0	
Total Supply	94,995	86,235	
Power Trade	0	8,760	



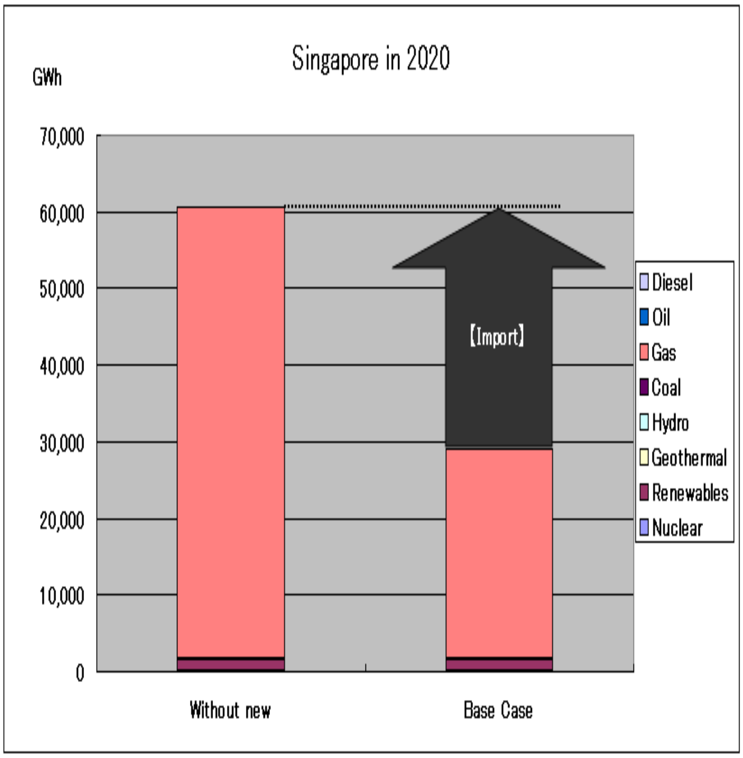
Philippines in 2030

	Without new	Base Case	Accelerated Case
Nuclear	0	0	0
Renewables	378	378	378
Geothermal	24,941	24,941	24,941
Hydro	26,037	26,037	26,037
Coal	62,876	62,876	62,876
Gas	34,834	26,074	24,975
Oil	0	0	0
Diesel	0	0	0
Total Supply	149,067	140,307	139,208
Power Trade	0	8,760	9,859



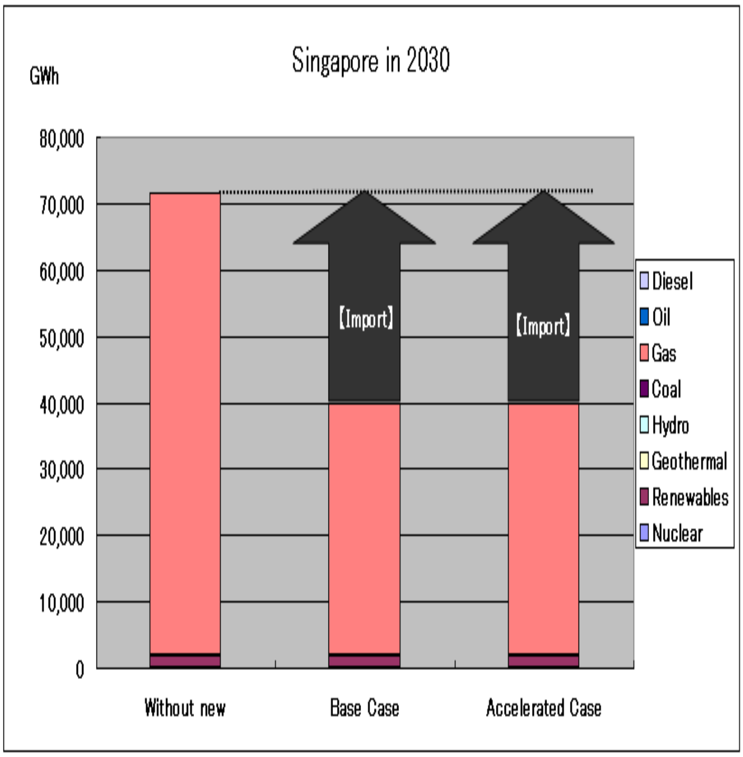
Singapore in 2020

	Without new	Base Case	Accelerated Case
Nuclear	0	0	
Renewables	1,556	1,556	
Geothermal	0	0	
Hydro	0	0	
Coal	0	0	
Gas	59,144	27,608	
Oil	0	0	
Diesel	0	0	
Total Supply	60,700	29,164	
Power Trade	0	31,536	



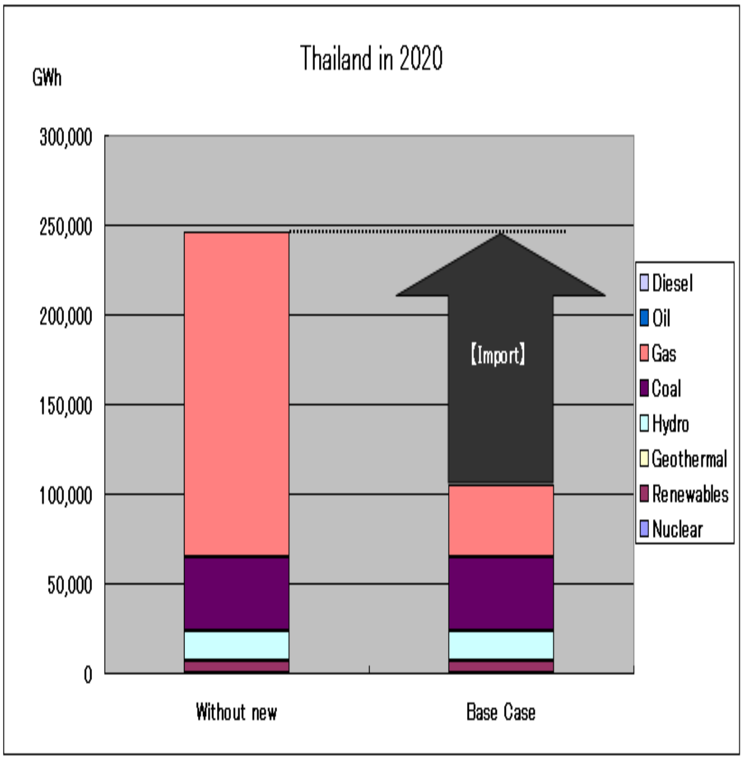
Singapore in 2030

	Without new	Base Case	Accelerated Case
Nuclear	0	0	0
Renewables	1,929	1,929	1,929
Geothermal	0	0	0
Hydro	0	0	0
Coal	0	0	0
Gas	69,571	38,035	38,035
Oil	0	0	0
Diesel	0	0	0
Total Supply	71,500	39,964	39,964
Power Trade	0	31,536	31,536



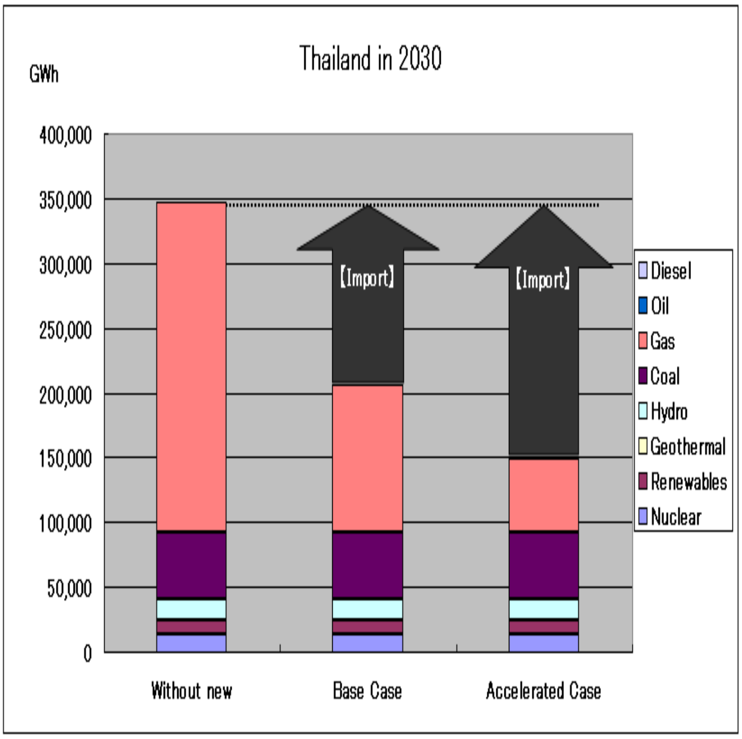
Thailand in 2020

	Without new	Base Case	Accelerated Case
Nuclear	0	0	
Renewables	7,251	7,251	
Geothermal	0	0	
Hydro	16,107	16,107	
Coal	41,249	41,249	
Gas	181,557	40,521	
Oil	0	0	
Diesel	0	0	
Total Supply	246,164	105,128	
Power Trade	0	141,036	



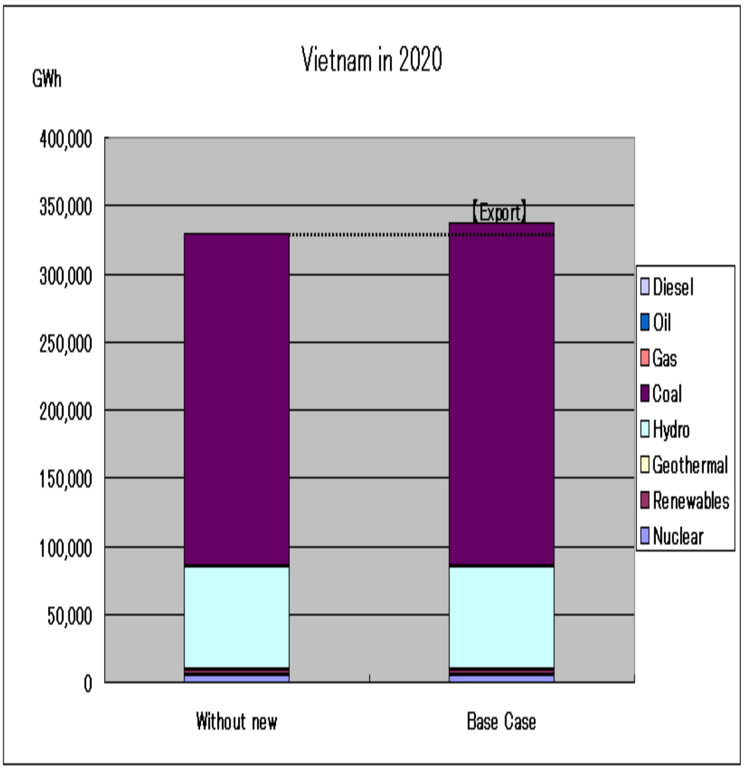
Thailand in 2030

	Without new	Base Case	Accelerated Case
Nuclear	14,016	14,016	14,016
Renewables	10,047	10,047	10,047
Geothermal	0	0	0
Hydro	16,280	16,280	16,280
Coal	51,768	51,768	51,768
Gas	254,655	113,619	57,434
Oil	0	0	0
Diesel	0	0	0
Total Supply	346,767	205,731	149,546
Power Trade	0	141,036	197,221



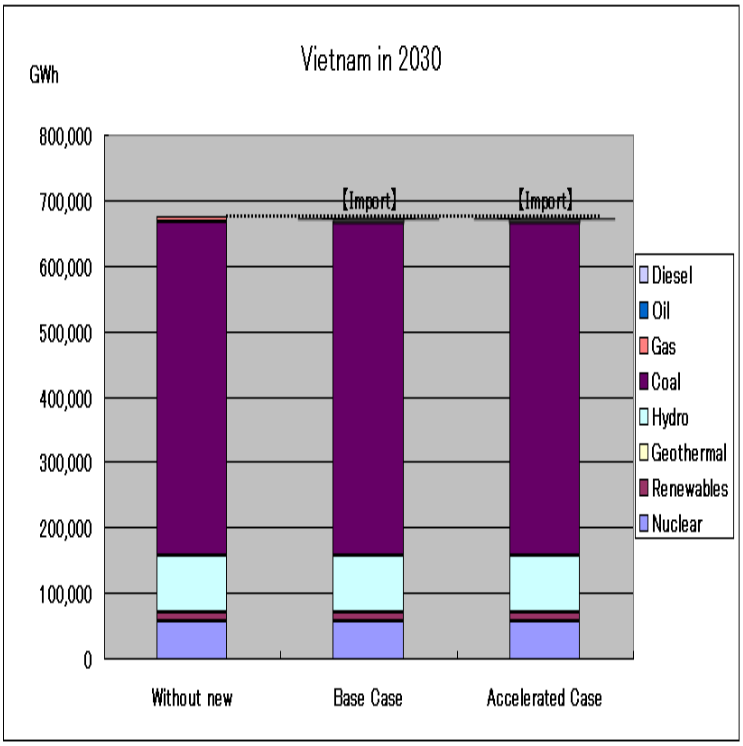
Vietnam in 2020

	Without new	Base Case	Accelerated Case
Nuclear	5,256	5,256	
Renewables	4,415	4,415	
Geothermal	0	0	
Hydro	75,292	75,292	
Coal	245,037	252,288	
Gas	0	0	
Oil	0	0	
Diesel	0	0	
Total Supply	330,000	337,251	
Power Trade	0	-7,251	



Vietnam in 2030

	Without new	Base Case	Accelerated Case
Nuclear	56,064	56,064	56,064
Renewables	13,913	13,913	13,913
Geothermal	0	0	0
Hydro	87,142	87,142	87,142
Coal	509,152	509,152	509,152
Gas	8,729	0	0
Oil	0	0	0
Diesel	0	0	0
Total Supply	675,000	666,271	666,271
Power Trade	0	8,729	8,729



CHAPTER 5

Major Findings and Next Step

1. Key Findings

The following things have become clear through this study.

1. Not all power demand can be met through a single form of energy. Therefore, a mix that appropriately combines multiple power sources is essential. Each power source has its own characteristics, and effort is needed to maximize the advantages and minimize the disadvantages of each of them.

Table 5-1: Comparison of Each Fuel

	Resource availability	Stable electricity output	Generating cost	Environmental friendliness	Necessary action
Coal	Good	Good	Good	Poor	Improve efficiency
Natural gas	Fair	Good	Fair	Fair	Reduce price of natural gas
Hydro	Fair	Good	Good	Good	Develop potential capacity
Biomass Geothermal	Fair	Good	Fair	Good	Financial support for initial stage
Wind Solar	Good	Poor	Poor	Good	R&D for smart grid Support for cost reduction

2. Power interchange through international interconnected lines will bring changes to the entire power source mixes of the countries and region.
   - International power trade can adjust surplus and deficit of annual electricity supply-demand. However, we should be careful on the point that this study does not reflect a necessity for balancing daily peak demand (GW). This study considered only annual energy demand and supply (GWh)..

- Utilization of low-cost power sources available in the region can be maximized. Namely, total power generating cost can be reduced by expanding the interchange capacity of international interconnected lines.
- Emissions of air pollutants including carbon dioxide can be reduced by maximizing utilization of hydropower generation and renewable energy. It is, however, depending on hydropower and renewables potential in the region.

3. Total investment in power sources can be reduced for the entire region through power interchange via international interconnected grid networks. The total investment reduction effect will be largest under lax regulations for carbon dioxide emissions. On the other hand, as regulations on carbon dioxide emissions are tightened, use of relatively inexpensive coal-fired thermal power will fall, while supplying of more expensive but cleaner gas-fired thermal power will increase, diminishing the total investment reduction effect. In short, there is a tradeoff relationship between the reduction effect on total investment in power infrastructure and the strength of carbon dioxide emission regulations. In other words, the strength of environmental regulations has a significant impact on the selection of fuels for power generation.

4. Through power interchange, countries can alleviate discrepancies between power demand and energy resources for power generation. Expanding the interchange capacity of international interconnected grid networks enables stabilization of power supply throughout an entire region and reduction of dependence on imported fuels. This contributes to greater energy security throughout the region.

5. In countries and regions where domestic power grids themselves are insufficient, international interconnected grid networks can be expected to supplement them. On the other hand, it is conceivable that in some cases, upgrading the domestic power grid is necessary in order to maximize utilization of the energy resources that exist in a region. Therefore, domestic power grids should be upgraded at the same time international interconnected grid networks are improved.

In light of the above outcomes, the following points should be borne in mind for future power source development.

- Development of potential resources for power generation shall be quick. In a development, it is necessary to consider the roles of each power source for the base, middle, and peak load purpose and to combine them appropriately.
  - Develop hydropower, which is economical and environmentally-friendly (except during construction), and for which there is still much untapped resources in the region.
  - Develop coal-fired power plant, which is outstanding in terms of economy and amount of resources, especially in China, Indonesia and Vietnam.
  - Develop renewable energy that is relatively economical, such as geothermal and biomass, except solar power.

- Energy utilization that ignores environmental impact is impossible. For power generation as well, initiatives that move towards cleaner energy utilization should be strengthened.
  - Promote higher efficiency in coal-fired power generation. Reducing the emission in flue gas through higher efficiency will alleviate the sole disadvantage of coal utilization.
  - Expanded use of natural gas with its outstanding environmental performances is desirable from the perspective of reducing environmental impact, but natural-gas-fired power plant is less economical than coal-fired. It is, therefore, necessary to mitigate the economic disadvantage of natural-gas-fired power plant by working to lower the procurement cost as well as price of natural gas.

Along with power source development, in order to maximize cross border power trading, improvement and expansion of international grid networks are necessary. As noted above, the ADB's GMS program and HAPUA's ASEAN Power Grid are underway. However, there seem remains some barriers to the realization of those plans. It is necessary to recognize those barriers and steadily undertake measures to eliminate them. Initiatives such as the following are necessary for their elimination.

- First, it is necessary to clarify the degree to which integration of the intra-regional electricity market is ultimately to be carried. If the goal is a single electricity market transcending national boundaries, such as that for which the European Union aims, a highly-independent regulatory body with powerful legal authority must be organized. On the other hand, if integration of the electricity market for the entire region is not a goal, and if national electricity markets are to be the rule, there are options for carrying out power interchange within rational political and economic parameters. Clearly, if the advantages of an international power grid as shown by this study are to be brought out fully, creation of a single electricity market transcending national borders is necessary.

- Although they will vary depending on the degree of market integration that is the goal, in any case, a coordinator that can balance interests in the region and set direction is necessary. The coordinator (organization) should have the following functions. If integration is to be deepened, the coordinating organization will need to concentrate on more functions; and it will need to be given the necessary authority.
  - The ability to establish systems and technical standards for the creation of a regional electricity market
  - The ability to make future plans related to power source development and the international power grid connections
  - Monitoring and guidance of plan implementation in each country
  - The ability to coordinate daily supply and demand

- Integration of systems and technical standards related to power interchange must be advanced. More concretely, that might include the following.
  - Standard connection conditions for transmission equipment (connection methods, measurement methods, division of ownership/management)

- Quality standards for power that is interchanged (voltage, frequency, and acceptable variation)
- Operating rules (load-dispatch instructions, contact methods)
- Rules for handling and responding to emergencies
- Standard contractual conditions for interchange contracts (standard contract)
- Standards for calculating rates for power that is interchanged
- Taxes that apply to power that is interchanged

- Schemes to procure the funds needed for power source development and grid interconnection project investment are required. Whether financing can be provided is an important key to materialize international grid interconnection plan. When considering the possibility of loans and their conditions, it should probably be remembered that the benefits of international grid interconnection will spread to multiple countries and will contribute to improve energy security. However, it would be somewhat unreasonable to ask private-sector financial institutions to evaluate the benefits, which are difficult to quantify. Governments and international financial institutions should undertake some initiatives.
  - Loan guarantees from governments in the countries concerned
  - Creation of a regional fund for power infrastructure improvement, with loan or loan guarantee functions. East Asian governments would finance the fund.
  - Loans from international financial institutions such as the ADB
  - Loans from development banks in developed countries (however, that will be conditioned on benefit to the lending country)

2. Next Step

This year's study obtained the above knowledge and findings, but there are still areas where analysis remains insufficient or deeper inquiry is needed. Those are subjects for study in the coming fiscal year and beyond.

- For the optimal power source mix for the entire region's power supply, if one does not consider carbon dioxide emission volume, resettlement due to hydropower development, or environmental issues such as NOx and SOx from coal-fired power plants, then the answer one obtains is to begin developing the cheapest power sources. However, each country has its own energy policy, which of course affects the choice of power sources. If such policy factors can be incorporated into a model's constraints, then more realistic results can be obtained.

- The analytical model in this study focuses on optimal power supply for the region as a whole. It is constructed from a macro perspective that simulates balanced electricity supply and demand throughout the year. Therefore, elements related to each country's load curve data and state of domestic power grid, transmission loss and transmission costs accompanying international grid interconnection are not incorporated. In addition, in actual equipment planning, it is important to consider the roles of each power source in the base, middle, and peak and to combine them appropriately. If such micro elements can be reflected in the models, more exact results can be obtained.
- The cost effectiveness of international grid interconnection will likely vary by route. Since budget funds that can be devoted to international grid interconnection are limited, development of those routes with higher investment efficiency should be prioritized. If this study is able to identify which routes offer such investment efficiency, then it will contribute to real-world improvements rather than just being a subject for academic debate.
- Interconnection grid network cost should be taken into account in the model for optimal solution of electricity import-export for balancing electricity demand and supply.