INVESTING IN POWER GRID INTERCONNECTION IN EAST ASIA

INVESTING IN POWER GRID INTERCONNECTION IN EAST ASIA

Edited by
ICHIRO KUTANI AND YANFEI LI

Economic Research Institute for ASEAN and East Asia

Copyright ©2014 by Economic Research Institute for ASEAN and East Asia

All rights reserved. No part of this publication may be reproduced, stored in a retrieval system, or transmitted, in any form or by any means, electronic, mechanical photocopying, recording or otherwise, without prior notice to or permission from the Publisher.

Book design by Fadriani Trianingsih.

ERIA Research Project Report 2013, No.26

Published October 2014

DISCLAIMER

This report was prepared by the Working Group for the Sustainable Development of the Natural Gas Market in the East Asia Summit (EAS) Region 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 analyse market trends. These data and methodologies may differ from those normally used in each country. Therefore, the calculated result presented here should not be viewed as the official national analyses of the participating countries.

The views in this publication do not necessarily reflect the views and policies of the Economic Research Institute for ASEAN and East Asia (ERIA), its Academic Advisory Council, and the Management.

CONTENTS

List of Figures *vi*

List of Tables *ix*

Foreword *x*

Acknowledgements *xi*

List of Project Members *xii*

List of Abbreviations and Acronyms *xiv*

Executive Summary *xvi*

Chapter 1 Introduction 1

Chapter 2 Electric Power Supply in EAS Countries 5

Chapter 3 Optimising Power Infrastructure Development 27

Chapter 4 Preliminary Assessment of Possible Interconnection 51

Chapter 5 Key Findings and Next Step 63

Appendix 1 Power Generation Mix in Each Case (2035) 71

Appendix 2 Power Trade in Each Case (2025, 2030, 2035) 73

Appendix 3 Cumulative Cost Up to 2035 (differences compared to Case 0) 79

LIST OF FIGURES

Figure 1.1	Study flow	4
Figure 2.1	Projected electric power demand (TWh)	6
Figure 2.2	Breakdown of existing power generation capacity as of 2012 (MW)	8
Figure 2.3	Potential of the various energy resources in the countries of ASEAN	11
Figure 2.4	Projected hydropower development potential in 2035 (TWh)	12
Figure 2.5	Daily load curve (average for 2006) and load duration curve for BRN	13
Figure 2.6	Daily load curve (dry season, 2013) and load duration curve for IDN	14
Figure 2.7	Daily load curve (average for 2007) and load duration curve for KHM	14
Figure 2.8	Daily load curve (dry season, 2012) and load duration curve for LAO	14
Figure 2.9	Daily load curve (rainy season, 2007) and load duration curve for MYA	15
Figure 2.10	Daily load curve (June 2012) and load duration curve for MYS	15
Figure 2.11	Daily load curve (July 2013) and load duration curve for NEI	15
Figure 2.12	Daily load curve (September 2011) and load duration curve for PHL	16

Figure 2.13	Daily load curve (May 2010) and load duration curve for SPG	16
Figure 2.14	Daily load curve (April 2012) and load duration curve for THA	16
Figure 2.15	Daily load curve (August 2011) and load duration curve for VNM	17
Figure 2.16	Projected future construction costs (by energy source)	18
Figure 2.17	Projected future variable O&M costs (by energy source)	19
Figure 2.18	Projected thermal efficiency (by energy source)	19
Figure 2.19	Projected future coal prices (Steam coal)	20
Figure 2.20	Projected future natural gas prices	21
Figure 2.21	ASEAN Power Grid (APG)	23
Figure 2.22	Greater Mekong Sub-region (GMS)	24
Figure 3.1	Preconditions and outputs of the optimal power generation planning model	27
Figure 3.2	Power source choices in the optimal calculations	28
Figure 3.3	Supply reliability evaluation model	31
Figure 3.4	Comparison between the calculation results for each country's power generation mix and the ERIA Outlook	33
Figure 3.5	Required reserve margin to gain the same LOLE	36
Figure 3.6	Power supply mix in 2035 (Case 0)	36
Figure 3.7	Power supply mix in 2035 (Case 1)	37
Figure 3.8	Power supply mix in 2035 (Case 2a)	38
Figure 3.9	Power supply mix in 2035 (Case 2b)	39
Figure 3.10	Power supply mix in 2035 (Case 3)	39
Figure 3.11	Power supply mix in 2035 (total of all regions)	40
Figure 3.12	CO_2 emissions in 2035	41
Figure 3.13	Power trade flows in 2035 (Case 1)	42

Figure 3.14	Power trade flows in 2035 (Case 2a)	43
Figure 3.15	Power trade flows in 2035 (Case 2b)	44
Figure 3.16	Power trade flows in 2035 (Case 3)	45
Figure 3.17	Changes in power trade in Case 2b (1)	46
Figure 3.18	Changes in power trade in Case 2b (2)	47
Figure 3.19	Changes in power trade in Case 2b (3)	47
Figure 3.20	Changes in power trade in Case 2b (4)	48
Figure 3.21	Cumulative costs in each case	49
Figure 4.1	How routes are considered in each case	52
Figure 4.2	Actual transmission line construction costs in neighbouring countries (500kV overhead lines)	55
Figure 4.3	Actual transmission line construction costs in neighbouring countries (500kV undersea cable)	55

LIST OF TABLES

Table 2.1	List of country names and abbreviations	5
Table 2.2	Projected international interconnection transmission capacity in 2020 and later (GW)	22
Table 4.1	Route length calculation results (Route 1)	53
Table 4.2	Route length calculation results (Route 2)	53
Table 4.3	Transmission line construction costs (Route 1)	59
Table 4.4	Transmission line construction costs (Route 2)	60
Table 4.5	Estimated cost benefit of new transmission line	61
Table 5.1	Possible interconnection and cumulative cost benefit	64
Table 5.2	Cost benefit and equivalent investment	65
Table 5.3	Possible interconnection line and their priority	66
Table 5.4	HAPUA lead plan	67

FOREWORD

In East Asian countries where electricity demand is rapidly increasing, there is a necessity for planting up more generating capacities to meet the growing demand. At the same time, cheaper electricity will be required when considering the impact on the general public and economy, and the need~~s~~ for cleaner electricity will become stronger when considering impact on pollution and climate issue.

On the other hand, in East Asian countries, (potential) resources like coal, natural gas and river to fuel power plants remain underdeveloped. If this region can utilise these resources, it might be possible to supply sufficient amount of electricity at cheaper price. Furthermore, energy security is enhanced through reducing regional import dependency of energy supply.
One possible option to maximise the use of undeveloped resources in the region is international/regional grid interconnection. The region can optimise power supply mix through cross-border power transaction.

Against this backdrop, ERIA organised a working group to carry out a study which aims to analyse 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 plans and possibility for regional optimisation. The result of their work is this volume titled *Investing in Power Grid Interconnection in East Asia*.

It is our hope that the outcome from this work will serve as a reference for policymakers in East Asian countries and contribute to the improvement of energy security in the region as a whole.

Prof. Hidetoshi Nishimura
ERIA Executive Director
September 2014

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, the Economic Research Institute for ASEAN and East Asia (ERIA) and IEEJ's study project team.

In addition, I would like to acknowledge Mr. Shaiful Bakhri Ibrahim, HAPUA Secretary in Charge, for his contribution in providing insights on the issue that was subject of the study.

Special mention and recognition should also be given to the authors of one of the chapters of this report:

Chapter 4 by Mr. Yoichiro Kubota and Mr. Noboru Seki of
Tokyo Electric Power Company.

Mr. Ichiro Kutani
Leader of the Working Group
September 2014

LIST OF PROJECT MEMBERS

Working Group Members

MR. ICHIRO KUTANI (LEADER): Senior Economist, Manager, Global Energy Group 1 , Assistant to Managing Director, Strategy Research Unit, The Institute of Energy Economics, Japan (IEEJ)

MR. SHIMPEI YAMAMOTO (ORGANIZER): Managing Director for Research Affairs, Economic Research Institute for ASEAN and East Asia (ERIA)

MR. SHIGERU KIMURA (ORGANIZER): Special Advisor to Executive Director on Energy Affairs, Economic Research Institute for ASEAN and East Asia (ERIA)

DR. HAN PHOUMIN (ORGANIZER): Energy Economist, Energy Unit, Research Department, Economic Research Institute for ASEAN and East Asia (ERIA)

DR. ANBUMOZHI VENKATACHALAM (ORGANIZER): Energy Economist, Energy Unit, Research Department, Economic Research Institute for ASEAN and East Asia (ERIA)

DR. YANFEI LI (ORGANIZER): Energy Economist, Energy Unit, Research Department, Economic Research Institute for ASEAN and East Asia (ERIA)

MR. PISETH SOUEM: Officer, General Department of Energy, Ministry of Mines and Energy (MME), Cambodia

MR. Wong Yuk-sum: Consultant, Automotive and Electronics Division, Hong Kong Productivity Council (HKPC), China

MR. AWDHESH KUMAR YADAV: Deputy Director, System Planning and

Project Appraisal Power System, Central Electricity Authority (CEA), India

MR. PRAMUDYA: Electricity Inspector, Directorate of Electricity Program Supervision, Directorate General of Electricity, Ministry of Energy and Mineral Resources (MEMR), Indonesia

MR. WATARU FUJISAKI: Senior Coordinator, Global Energy Group 1, Strategy Research Unit, The Institute of Energy Economics, Japan (IEEJ)

MR. YUHJI MATSUO: Senior Economist, Nuclear Energy Group, Strategy Research Unit, The Institute of Energy Economics, Japan (IEEJ)

MR. KAZUTAKA FUKASAWA: Senior Researcher, Global Energy Group 1, Strategy Research Unit, The Institute of Energy Economics, Japan (IEEJ)

MR. BOUNGNONG BOUTTAVONG: Deputy Director, Technical Department, Electricite Du Laos (EDL), Lao PDR

MR. JOON BIN IBRAHIM: General Manager (Technical Advisory & Industry Development), Single Buyer Department, Tenaga Nasional Berhad (TNB), Malaysia

DR. JIRAPORN SIRIKUM: Assistant Director of System Planning Division - Generation, Electricity Generating Authority of Thailand (EGAT), Thailand

MR. TANG THE HUNG: Deputy Director, Planning Department, General Directorate of Energy, Ministry of Industry and Trade (MOIT), Viet Nam

List of Abbreviations and Acronyms

AAGR	= Average Annual Growth Rate
AC	= Alternating Current
ADB	= Asian Development Bank
APG	= ASEAN Power Grid
ASEAN	= Association of Southeast Asian Nations
BAU	= Business as Usual
CO_2	= Carbon dioxide
DC	= Direct Current
EAS	= East Asia Summit
EC	= European Commission
ECTF	= Energy Cooperation Task Force
EIA	= Energy Information Administration
ERIA	= Economic Research Institute for ASEAN and East Asia
ETP	= Energy Technology Perspectives
GDP	= Gross Domestic Product
GMS	= Greater Mekong Sub-region
GW	= Giga Watt
HAPUA	= The Heads of ASEAN Power Utilities/Authorities
IEA	= International Energy Agency
IEEJ	= The Institute for Energy Economics, Japan
LOLE	= Loss of Load Expectation
MOU	= Memorandum of Understanding
MW	= Mega Watt
O&M	= Operation & Maintenance

OECD/NEA = Organisation for Economic Co-operation and Development - Nuclear Energy Agency

TWh = Tera Watt hour

USD = United States Dollar

WG = Working Group

EXECUTIVE SUMMARY

This report examines the possibility of improving investment efficiency of power infrastructures through enhancing interconnection of power grids in the region, mainly focused on South East Asia.

MAIN ARGUMENT

In general, power infrastructure development is made under the premise of self-sufficiency within each country. While there remain much resources to fuel power stations in some countries, other countries are facing difficulties in their own power development. Power grid interconnections are a possible option to overcome these challenges. Regional planning of power infrastructure development is anticipated to provide benefits of total investment cost reductions, improve electricity supply stability and move towards decarbonisation.

The study first developed simulation models that enable the analysis of least-cost mix of power generation and grid interconnection. A second part of the study estimated the cost of possible interconnection lines which is derived from the above mentioned simulation analysis. By comparing these two outcomes, namely, benefit and cost of enhanced grid interconnection, the report has selected priority projects that seem to provide greater benefit for the region and at the same time are perceived to be economically viable.

KEY FINDINGS

- Possible interconnection line, its estimated cost and net economic benefits, which imply feasibility and priority of the proposed new transmission capacities, are estimated.
- A positive net economic benefit indicates economic feasibility of the project and thus should be prioritised. Among the listed projects, the Viet Nam - Lao - Thailand – Malaysia – Singapore interconnection route could be the most beneficial, and the Cambodia - Thailand linkage could be the

second beneficial interconnection.

Case		Possible cumulative cost benefit range [mil.USD]	Estimated cost of trasmission line [mil USD]	
A	THA-KHM	4,560 -- 5,470	162 -- 1,009	second priority
B	THA-LAO	19,282 -- 20,604	728 -- 1,957	first priority
C	THA-MYA	(4,607) -- (2,766)	2,244 -- 3,956	need careful assess.
D	MYA-THA-MYS-SGP	(1,118) -- 3,064	2,384 -- 6,272	need careful assess.
E	VNM-LAO-THA	21,604 -- 23,715	922 -- 2,885	first priority
F	MYS-IDN	3,968 -- 4,087	1,790 -- 1,901	second priority
G	LAO-THA-MYS-SGP	23,217-- 26,557	868 -- 4,273	first priority

IDN: Indonesia, KHM: Cambodia, LAO: Laos, MYA: Myanmar, MYS: Malaysia, SGP: Singapore, THA: Thailand, VNM: Viet Nam
* Numbers in brackets are negative.

POLICY IMPLICATIONS

- If grid interconnections within the region are to be enhanced, investment efficiency for power infrastructure could be improved. Interconnections also bring other benefits such as electricity supply stability and reduction of greenhouse gas emissions.
- The following are some key challenges that need to be resolved for the advancement of grid interconnection:
    - Each power grid is unique and governed by its own policies and codes. There needs to be a comprehensive guideline encompassing all the member countries. At the moment, there has yet to be sufficient bilateral or multilateral discussion and coordination in order to promote construction.
    - The investment environment is not always attractive to private companies and foreign capital. Accordingly, there has not been a sufficient provision of capital.

CHAPTER 1

INTRODUCTION

In the EAS (East Asia Summit) countries, power demand is steadily expanding due to population increase and economic growth. As improving the electrification rate is an important policy task in some countries, power demand appears most certain to increase in the future in line with rising living standards. Meanwhile, as GDP is relatively low in this region, it is necessary to supply electricity at the minimum 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 or 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, importing electricity from neighbouring countries should be considered as an option. In light of the above, it may be possible to optimise or to improve the efficiency of power infrastructure development in terms of supply stability, economic efficiency and reduction of the environmental burden if ways of developing power infrastructures (power sources and grids) on a pan-regional basis are considered.

This idea may be supported by creating an ASEAN Economic Community (AEC) by 2015. The initiative is aimed at strengthening regional ties by enhancing inter-regional trade, including energy commodity.

Meanwhile in the ASEAN region, HAPUA (The Heads of ASEAN Power Utilities/Authorities） and the Asian Development Bank (ADB) are implementing initiatives related to intra-regional power grid interconnections and, at the same time, bilateral power imports/exports are ongoing. However, some countries are still placing priority on the optimisation of investments at the domestic level. Besides, power imports and exports are not brisk enough to contribute to "power grid interconnection," and progress towards pan-regional optimisation has been slow.

1.1. Rationale

The rationale of this study is derived from the 17th ECTF[1] (Energy Cooperation Task Force) meeting held in Phnom Penh, Cambodia on 5 July 2012. During this meeting, the Economic Research Institute for ASEAN and East Asia (ERIA) explained and proposed new ideas and initiatives for 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 to endorse the proposed new areas and initiatives.

As a result, ERIA has formulated the Working Group for the "Study on Effective Investment of Power Infrastructure in East Asia through Power Grid Interconnection". Members from 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.

1.2. Objective

The Working Group's study, which is packaged in this volume titled *Investing in Power Grid Interconnection in East Asia*, quantifies the benefits of the pan-regional optimisation of power infrastructure development in the EAS region. By doing so, the study provides clues for improving efficiency of investment for power station and cross-border grid interconnection. It should be noted that the background of this study has been developed by making reference to the Greater Mekong Sub-region (GMS) program of ADB

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

and ASEAN Power Grid (APG) program of HAPUA, thus making the study consistent with these existing initiatives.

1.3. Work stream and working group activity

1.3.1. Fiscal year 2012

In the first year of the study, the following describes the work streams that were conducted.

(A) Collecting power infrastructure data and information
(B) Identifying challenges and discussion points
(C) Developing a simplified power infrastructure simulation model
(D) Drawing out policy recommendations (preliminary analysis)

In 2012, the WG held two meetings; one in November 2012 in Jakarta, Indonesia and another in April 2013 in Tokyo, Japan.

In 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.

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

1.3.2. Fiscal year 2013

In the second year of the study, the following work streams were conducted.

(E) Detailed analysis of optimal power infrastructures

Here, a more detailed simulation model, and exercise analysis to figure out optimal mix (cost minimum) of power generation and beneficial interconnection lines were developed. This part of the study provides possible benefit for each candidate through interconnection.

- Annual / daily load curb of demand
- Cost of power generation (construction, O&M, fuel)
- Interconnection line (connecting point, length, capacity, loss rate)
- Cost of interconnection line (construction, O&M)

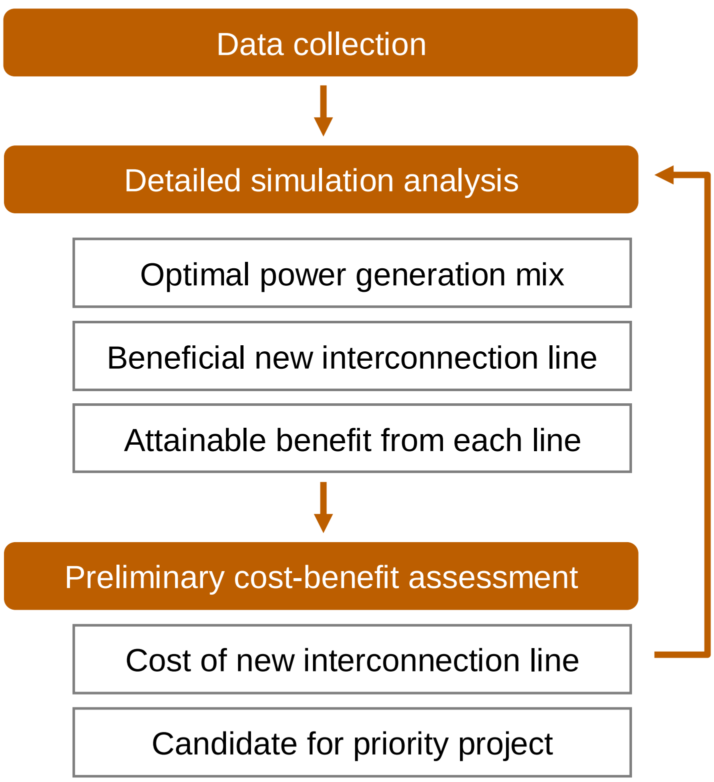
(F) Preliminary assessment of possible new interconnection

In this part, the cost of possible interconnection lines was estimated. This cost was then fed back to the simulation analysis in the previous part (E). By having an attainable utility of each interconnection line from previous step (E), preliminary cost-benefit assessment was executed. Based on this assessment, some candidates that will be prioritised were then selected.

(G) Draw out policy recommendation

Based on the study outcome from the abovementioned (E) and (F), policy recommendations were drawn out to enhance the effective investment of power infrastructure in the EAS region.

Figure 1.1: Study flow



CHAPTER 2

ELECTRIC POWER SUPPLY IN EAS COUNTRIES

This chapter sets out the data for each individual country used in the simulation model (in Chapter 3).

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

Table 2.1: List of country names and abbreviations

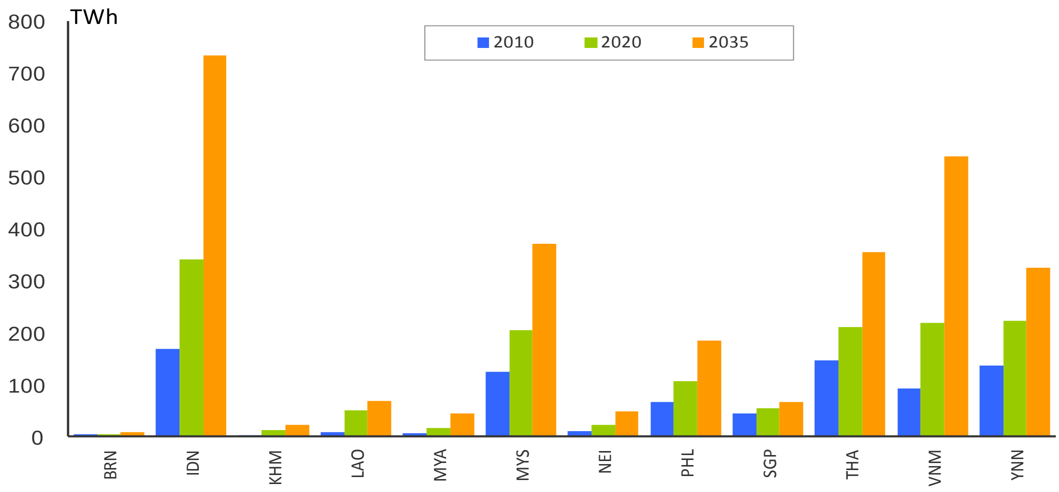
Country	3-letter codes	Country	3-letter codes
Brunei Darussalam	BRN	Malaysia	MYS
Cambodia	KHM	Myanmar	MYA
China (Yunnan province)	YNN	Philippines	PHL
India (North-East region)	NEI	Singapore	SGP
Indonesia	IDN	Thailand	THA
Lao PDR	LAO	Vietnam	VNM

2.1. Projected electric power demand

The projected power demand for each country was assumed on the basis of the power generation output (TWh) for each country in the business as usual (BAU) scenario discussed in the ERIA Research Project Report 2012, No. 19 titled "Analysis on Energy Saving Potential in East Asia".

However, the projected power demand figures for India (northeast region) and China (Yunnan Province) were calculated by taking the power generation output (TWh) of the entire country to which each of the regions belongs, and calculating a share of this output proportional to the region's actual performance in the regional breakdown of the country's generation output.

Figure 2.1: Projected electric power demand (TWh)



	TWh						AAGR		
	2010	2015	2020	2025	2030	2035	2010-2020	2020-2035	2010-2035
BRN	3.87	4.47	5.22	5.96	6.77	7.67	3.0%	2.6%	2.8%
IDN	169.79	252.38	341.64	448.07	576.05	733.09	7.2%	5.2%	6.0%
KHM	0.99	6.15	12.33	17.67	19.58	22.15	28.6%	4.0%	13.2%
LAO	8.45	22.54	51.35	65.44	67.13	68.82	19.8%	2.0%	8.8%
MYA	7.54	11.42	16.44	23.15	32.24	44.59	8.1%	6.9%	7.4%
MYS	124.10	161.20	205.10	254.00	309.10	371.80	5.2%	4.0%	4.5%
NEI	11.44	15.68	22.18	29.52	38.34	49.28	6.8%	5.5%	6.0%
PHL	67.74	84.63	106.79	130.51	156.00	185.93	4.7%	3.8%	4.1%
SGP	45.38	51.19	55.60	59.40	61.85	65.76	2.1%	1.1%	1.5%
THA	147.01	180.37	210.86	257.53	309.56	355.03	3.7%	3.5%	3.6%
VNM	92.17	148.35	219.59	295.41	398.83	538.70	9.1%	6.2%	7.3%
YNN	136.50	188.88	223.71	260.19	296.66	324.67	5.1%	2.5%	3.5%

Source: ERIA Research Project Report 2012,
"Analysis on Energy Saving Potential in East Asia"

The demand for energy in the East Asian region has risen steadily to date, and is expected to increase continuously forward due to the expansion of the power supply region, the industrialisation in line with economic growth, rising income levels, and urbanisation.

With Indonesia, Malaysia, Thailand, Viet Nam and China (Yunnan Province) showing particularly dramatic increases in demand, it will be essential to expand and augment all power-related facilities including power generation, transmission and distribution facilities in all of these countries.

From 2010 to 2035, Indonesia's power demand is projected to rise from 169.8TWh to 733.1TWh, Malaysia's from 124.1TWh to 371.8TWh, Thailand's from 147.0TWh to 355.0TWh, Viet Nam's from 92.2TWh to

538.7TWh, and Yunnan Province's from 249.4TWh to 593.2TWh.

Increases in demand during the period up to 2020 are expected to be particularly substantial in Cambodia and Lao PDR.

Power demand in Cambodia is forecast to increase by 13.2 percent a year over the 25-year period from 2010 to 2035, soaring by 28.6 percent a year over the 10-year period leading up to 2020. Much of Cambodia is still without electricity, with the country's electricity supply currently confined largely to the capital region and major cities. As of June 2012, the household electrification rate for the country as a whole stood at approximately 35 percent, with the rate for urban areas at almost 100 percent; whereas that for rural areas was only around 25 percent. Moreover, latent power demand is believed to be considerable even in regions where power is already supplied, because the power demand from many of the production plants and hotels found in these regions are supplied by private power generators. Against this backdrop, the Government of Cambodia has set out targets of achieving 100 percent village electrification by 2020, and over 70 percent household electrification by 2030; and aims to improve the state of Cambodia's power generation and distribution facilities and ensure an affordable and stable supply of power.

It is expected that in Lao PDR, power demand will increase as its manufacturing and commercial industries develop as a result of foreign investment and as progress is made in policies aiming to increase the country's electrification rate. Power demand in Lao PDR is forecast to increase by 8.8 percent a year over the 25-year period from 2010 to 2035, soaring by 19.8 percent a year over the 10-year period leading up to 2020. The Government of Lao PDR has set out a target of raising the household electrification rate in Lao PDR to 90 percent by 2020.

2.2. Projected power generation capacity

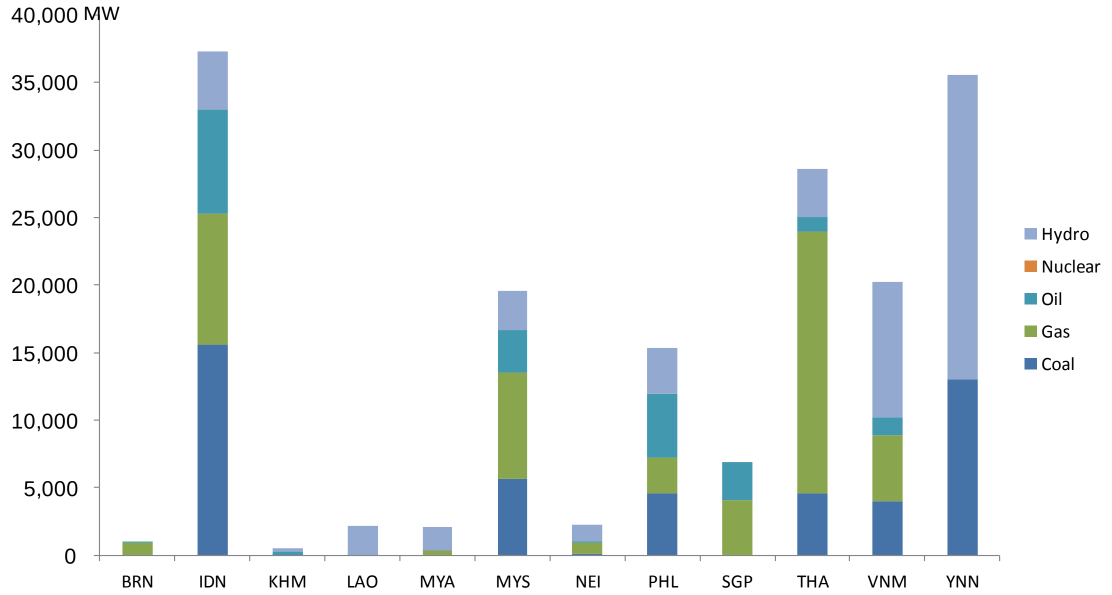
When assuming the power generation capacity for each country, the study utilised the dataset published by Platts; "World Electric Power Plants Database (as of 2012)". This dataset was segregated by country, type and installed capacity. For some countries, figures are based on information obtained by the working group (WG) of this study. The results are set out in Figure 2.2.

The projected future installed capacity was then estimated, assuming that peak demand in each country would rise proportionally with the total demand (TWh) for the country, and that new power plants would be constructed to meet the estimated peak demand.

The following conditions were established for the operational life time of each type of power generation.

Coal-fired power plants: Expected to be retired after 40 years of use
Gas-fired power plants : Expected to be retired after 30 years of use
Oil-fired power plants : Expected to be retired after 40 years of use
Nuclear power plants : Expected to be retired after 40 years of use
Hydropower plants : All expected to continue operation into the future

Figure 2.2: Breakdown of existing power generation capacity as of 2012 (MW)



(MW)

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

Source: Drafted by IEEJ based on Platts World Electric Power Plants Database and the information obtained by the WG of this study

2.3. Hydropower generation potential

Figure 2.3 shows the potential of the various energy sources among the ASEAN countries. The mismatch between high electricity demand areas and the ones rich in resources for power generation areas is evident, thereby becoming the main motivation to expand international interconnected grid network in this region.

In addition, the reserves-to-production ratios of fossil fuels are declining in most of the ASEAN countries. First reason is their expansion of domestic demand in line with their economic growth. Second reason is the maintenance of export volumes in order to obtain foreign currencies. And the third reason is the need to adhere to long-term export agreements that are already in place.

This means that countries such as Indonesia, Malaysia, Thailand, and Viet Nam in particular, where power demand is expected to increase substantially, now increasingly need to import energy resources, resulting in rising power costs in these areas.

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

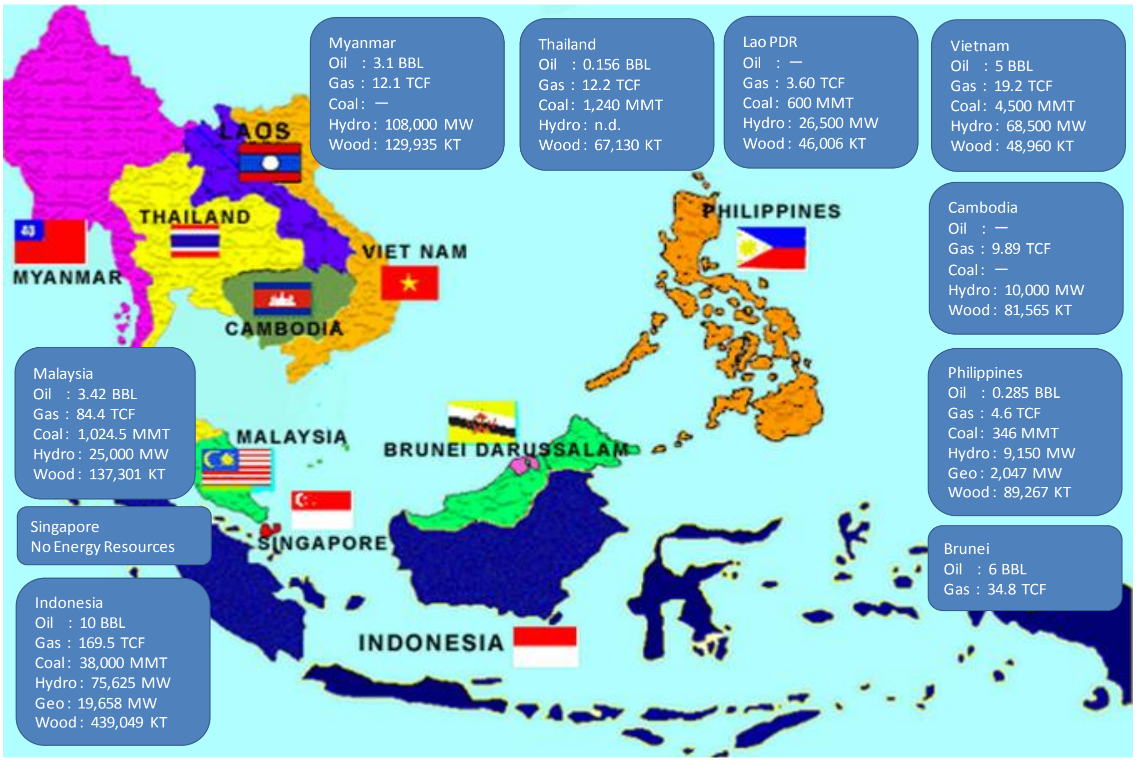
As a country whose terrain is characterised by the Mekong River which cuts through approximately 1,500km of the country’s length, and by the multiple tributary rivers which flow into the Mekong River from high-elevation areas such as the Annamite Range, Lao PDR's hydropower development potential could theoretically be as high as 26,000 to 30,000MW. It is estimated that no more than around one-tenth of this potential is currently developed.

In addition, calculations by the Ministry of Industry, Mines, Energy (MIME) of Cambodia estimate that the hydropower resources with development potential in Cambodia could provide 10,000MW of power (5,000MW from the main stream of the Mekong River itself, 4,000MW from the subsidiary basin, and 1,000MW from other parts of the Mekong River); and that no more than around 3 percent of this potential is currently developed.

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

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

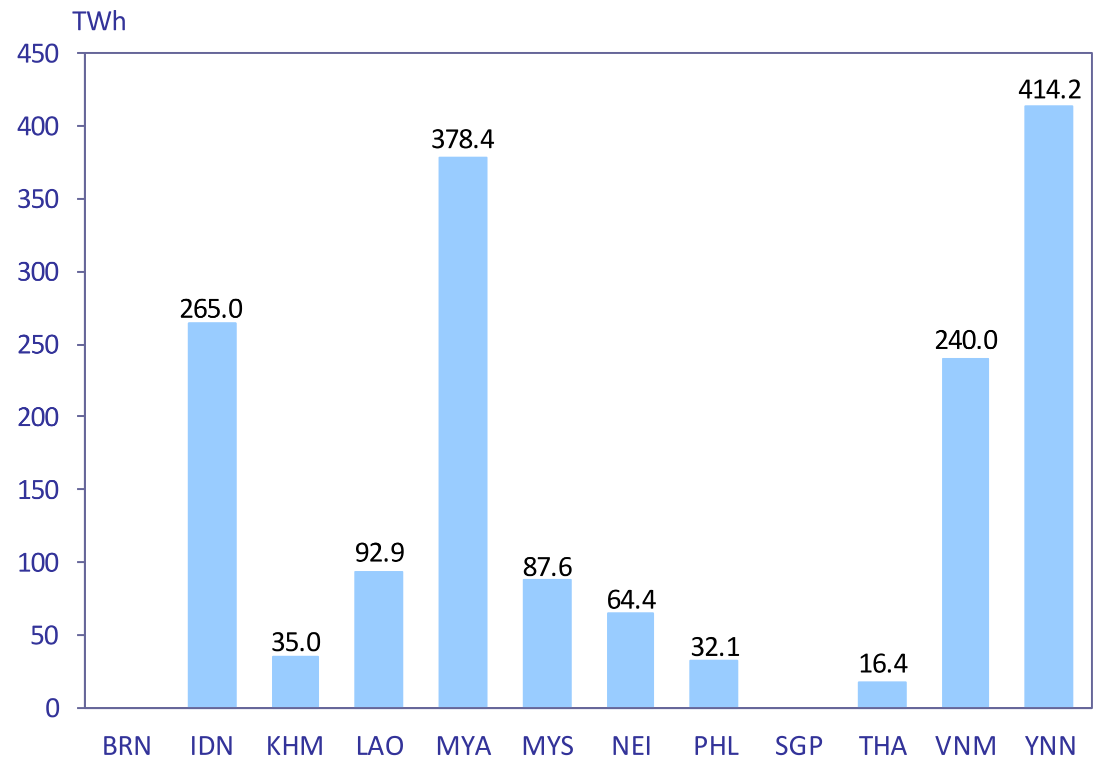
Figure 2.3: Potential of the various energy resources in the countries of ASEAN



Source: "ASEAN Interconnection Briefing on ASEAN Power Grid" (EAGT) - 14th March 2013

Figure 2.4 shows the potential of the hydropower resources of the various countries in the simulation model developed in this study. The figures were developed by taking the power generation capacity figures (MW) shown in Figure 2.3 as a baseline, and provisionally assuming a uniform utilisation rate of 40 percent. However, given the data constraints, the projected figures for Thailand, India (northeast region), and China (Yunnan Province) have been calculated based on their power infrastructure development plans, information obtained by the working group of this study, and other sources.

Figure 2.4: Projected hydropower development potential in 2035 (TWh)



Source: IEEJ projections

2.4. Projected load curve

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

As early as the mid-1990s, power consumption patterns in Thailand, the Philippines, Indonesia (Java-Bali Transmission Line), and Viet Nam (southern region) were beginning to display a load curve which peaked during the daytime when industrial demand is high since these countries are relatively mature markets.

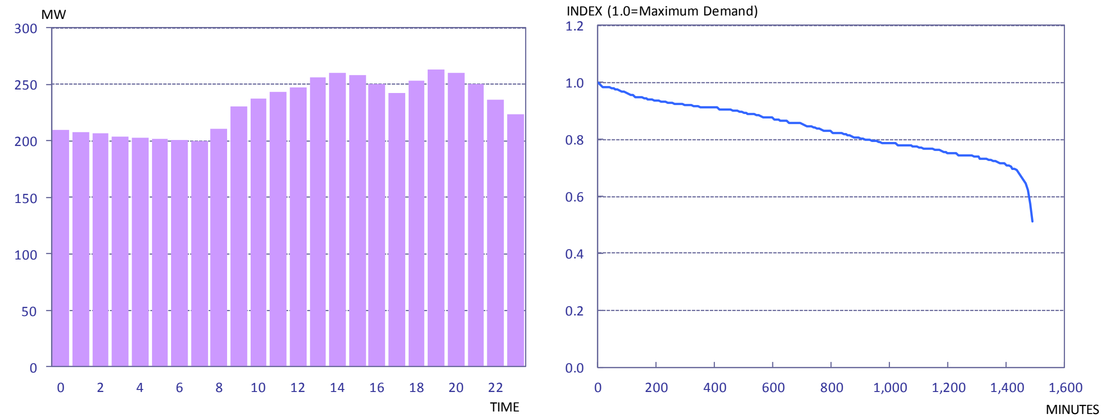
Meanwhile, the power consumption patterns of other East Asian countries have, until recent years, retained the traditional electric lighting-centered demand mode, where the daily peak occurs from early evening through nighttime. However, with the growing power demand for industrial purposes in recent years due to economic development, there are now signs that the rate of increase in the daytime peak is starting to exceed the rate of interest in the nighttime peak. This means that the extent of the gap between the daytime and nighttime peaks in power demand is decreasing year on year.

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

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

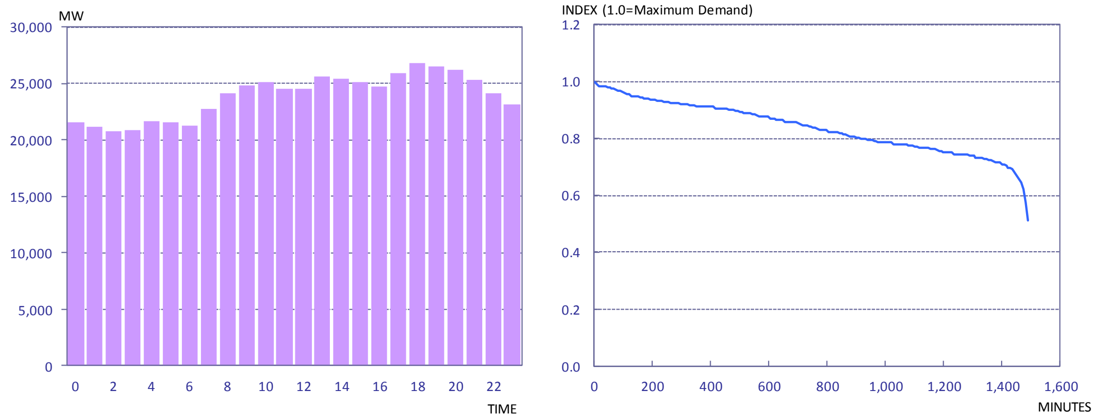
The following figures show the daily load curve and load duration curve projected for each country in the simulation model of this study. However, given the data constraints, the projected curves for Yunnan province in China have been assumed to be similar to Viet Nam's data.

Figure 2.5: Daily load curve (average for 2006) and load duration curve for BRN



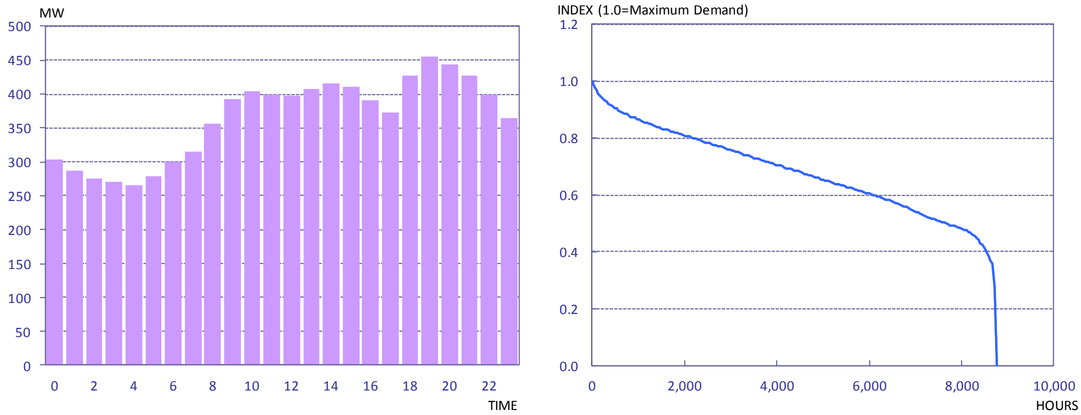
Source: by IEEJ based on Japan Electric Power Information Center (JEPIC) materials

Figure 2.6: Daily load curve (dry season, 2013) and load duration curve for IDN



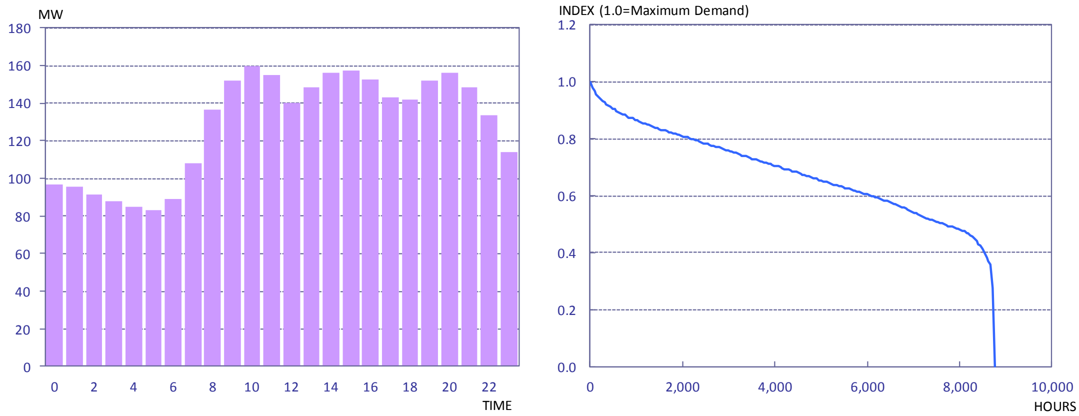
Source: by IEEJ based on 1st WG presentation materials (Nov. 2013)

Figure 2.7: Daily load curve (average for 2007) and load duration curve for KHM



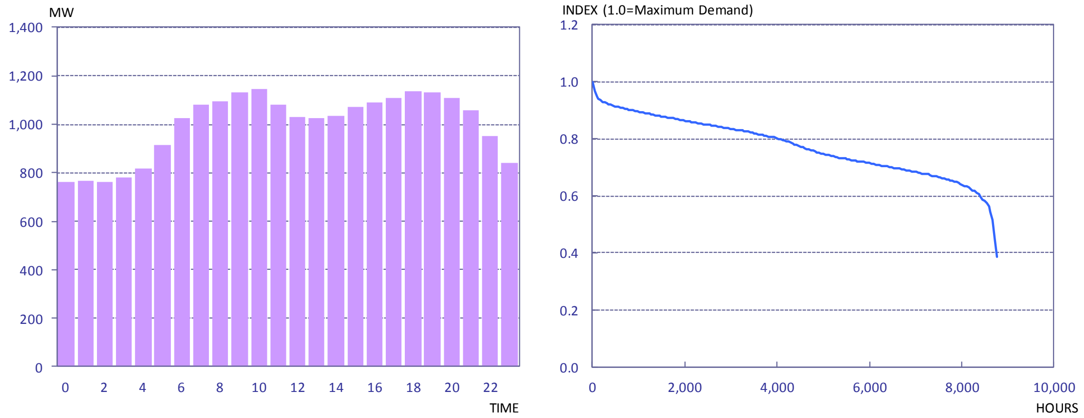
Source: by IEEJ based on Cambodia's Profile in Power Sector by Tonn Kunthel

Figure 2.8: Daily load curve (dry season, 2012) and load duration curve for LAO



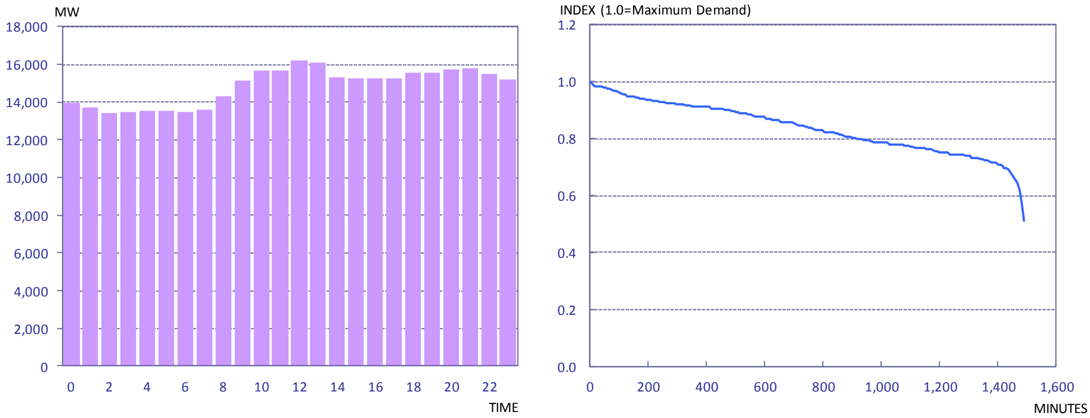
Source: by IEEJ based on 1st WG presentation materials (Nov. 2013)

Figure 2.9: Daily load curve (rainy season, 2007) and load duration curve for MYA



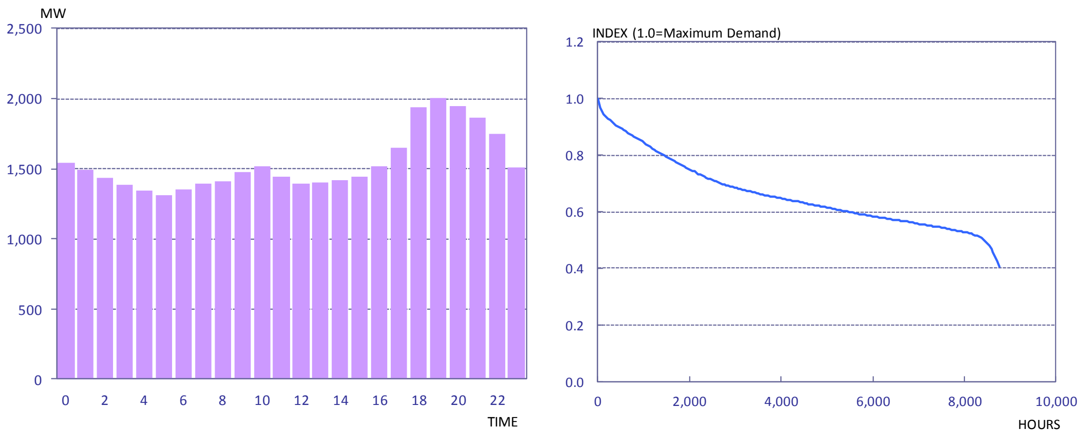
Source: by IEEJ based on JEPIC materials

Figure 2.10: Daily load curve (June 2012) and load duration curve for MYS



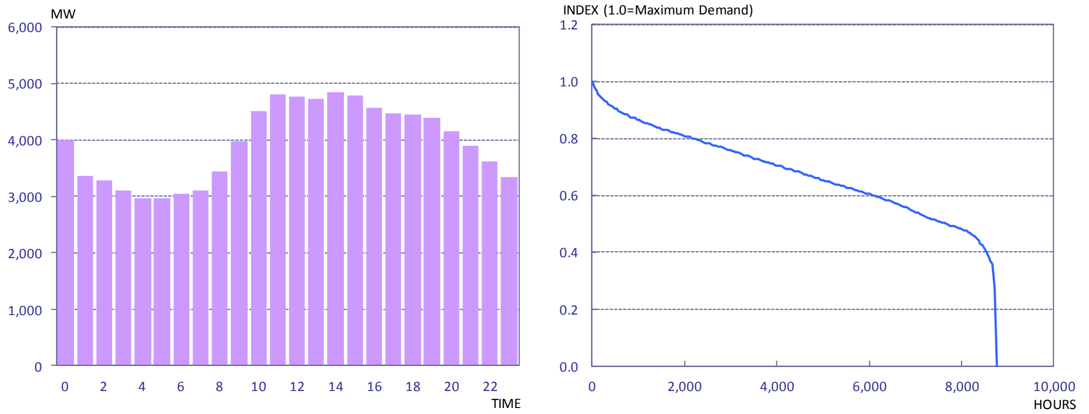
Source: Energy Commission, Grid System Operation and Performance Report 1st Half 2012

Figure 2.11: Daily load curve (July 2013) and load duration curve for NEI



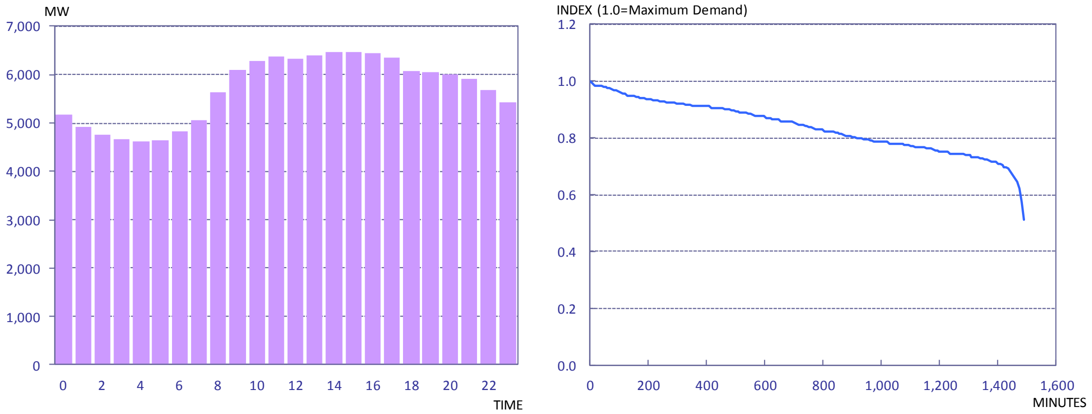
Source: by IEEJ based on 1st WG presentation materials (Nov. 2013)

Figure 2.12: Daily load curve (September 2011) and load duration curve for PHL



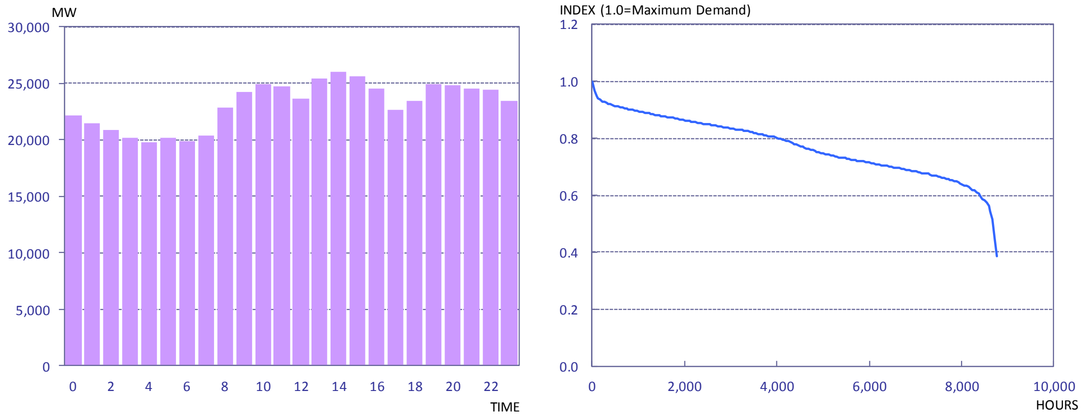
Source: Manila Electric Company (MERALCO), Investors' Briefing & Teleconference 2011

Figure 2.13: Daily load curve (May 2010) and load duration curve for SPG



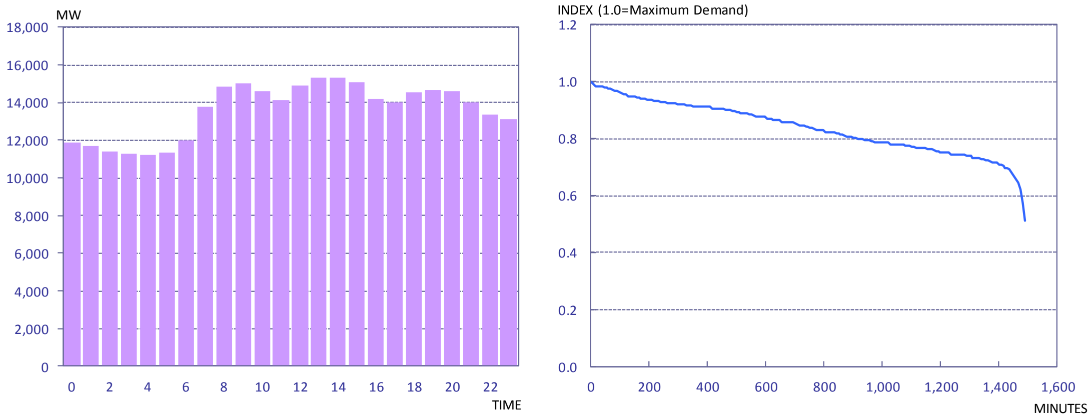
Source: Energy Market Authority, Statement of Opportunities for the Singapore Energy Industry 2011

Figure 2.14: Daily load curve (April 2012) and load duration curve for THA



Source: by IEEJ based on 1st WG presentation materials (Nov. 2013)

Figure 2.15: Daily load curve (August 2011) and load duration curve for VNM



Source: Created by IEEJ based on 1st WG presentation materials (Nov. 2013)

2.5. Projected power costs (Construction costs and O&M costs)

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

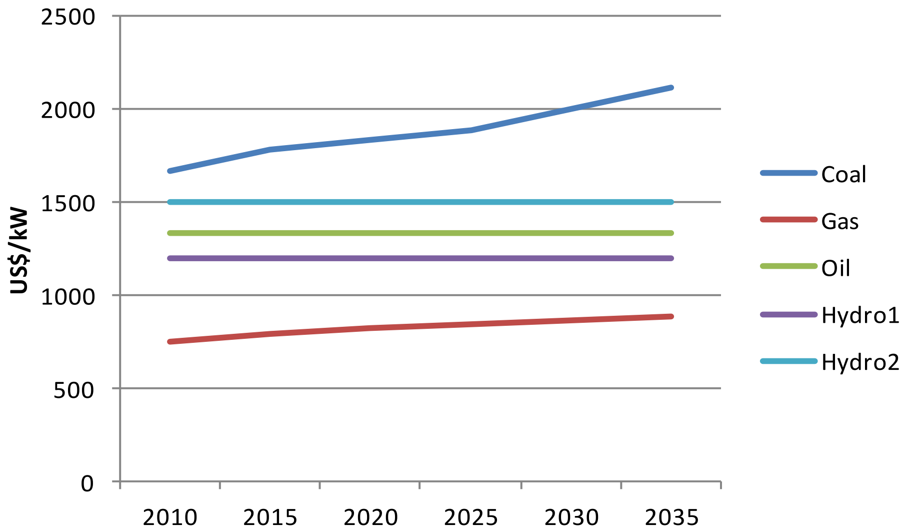
Projected construction costs were calculated using various materials as references, including the costs projected by;

OECD/NEA, IEA "Energy Technology Perspectives 2012" (ETP2012) EIA "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants"

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

With regards to thermal power generation, it is assumed that increasingly advanced power generation technologies will gradually be adopted in coal-fired and gas-fired power generation, and that power generation costs will therefore tend to rise in line with the adoption of new technology. More precisely, it is assumed that there will be a shift towards combined cycle technology in gas-fired power generation; while in coal-fired power generation, there will be a move away from the traditional subcritical pressure boilers as supercritical and ultra-supercritical pressure boilers are introduced. The same cost is assumed for oil-fired power generation throughout the period, on the grounds that there is believed to be little room for technological development with this mode of power generation.[2]

Figure 2.16: Projected future construction costs (by energy source)



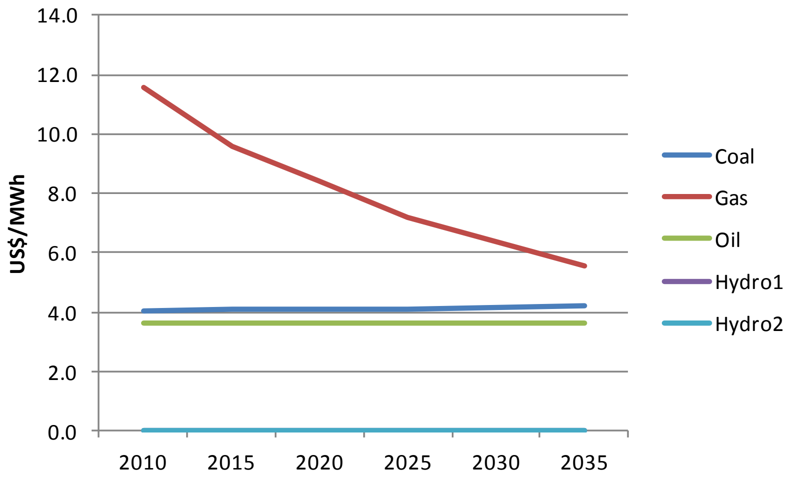
Source: Calculated by IEEJ based on costs projected by OECD/NEA, IEA's "ETP2012" and EIA's "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants"

Fixed costs are assumed to make up 10 percent of construction costs for coal-fired power generation, Hydropower 1 and Hydropower 2,5 percent of construction costs for gas-fired power generation, and a uniform rate of USD94/kW for oil-fired power generation.

Variable costs other than fuel costs are envisaged as follows, using costs projected by OECD/NEA, IEA's "ETP2012" and EIA's "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants" as references. There is a dramatic decrease in the projected costs for gas-fired power generation because it is projected that there will be a progressive shift away from traditional single cycle generation towards combined cycle generation, for which variable costs are relatively low.

[2]The cost for nuclear, biomass and geothermal power generation is abbreviated because these types of power generation are exogenous to the design of the model calculations.

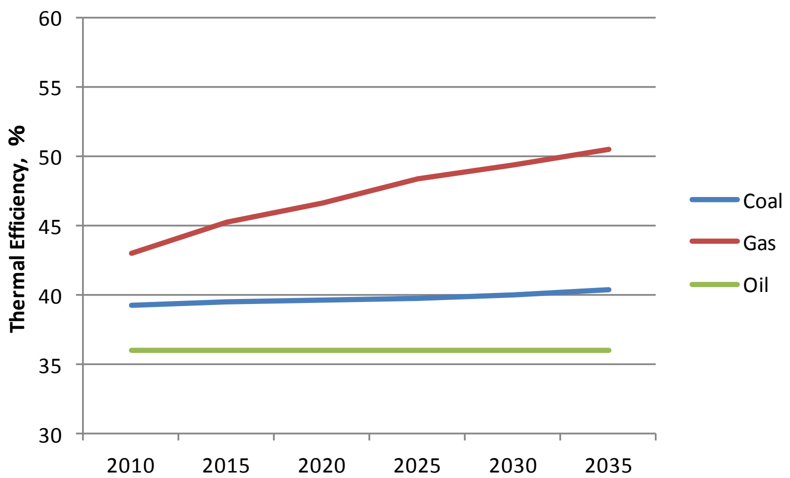
Figure 2.17: Projected future variable O&M costs (by energy source)



Source: Calculated by IEEJ based on costs projected by OECD/NEA, IEA's "ETP2012" and EIA's "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants"

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

Figure 2.18: Projected thermal efficiency (by energy source)



Source: IEEJ projections

2.6. Projected annual discount rate

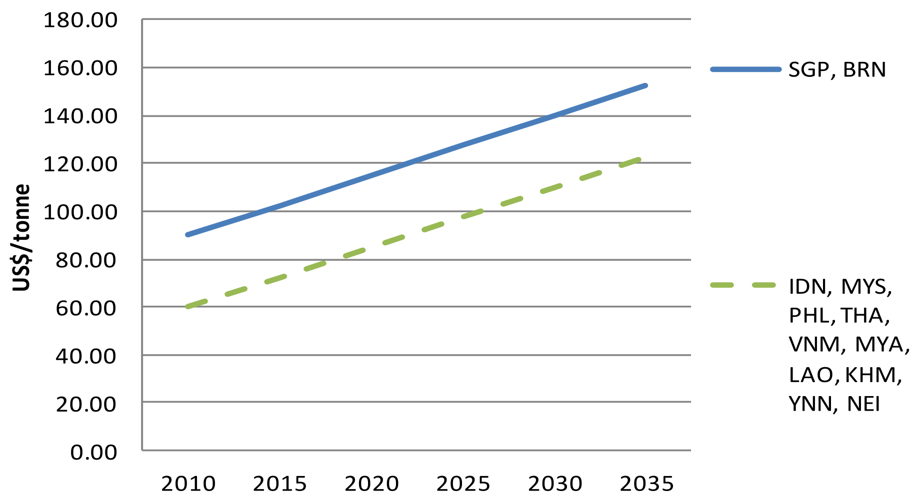
The discount rate can differ according to the investment risk and economic climate for each country and scenario, and on what the objective of the evaluation is. However, the simulation model in this report provisionally assumes a uniform rate of 10 percent by bringing together available sources of information and opinions from several experts.

2.7. Projected fuel costs

Future costs for coal and natural gas were projected as follows.

Projected coal prices were divided into two levels: prices for coal-producing countries and prices for coal-importing countries. Indonesia, Malaysia, the Philippines, Thailand, Viet Nam, Myanmar, Lao PDR, Cambodia, China and India are coal-producing countries. Two other countries—Singapore and Brunei—are coal-importing countries. Coal prices for 2010 are set at USD60/ton for coal-producing countries and USD90/ton for coal-importing countries. The price of USD60/ton for coal-producing countries was determined based on the extraction costs plus costs of transportation to ports. Prices are expected to rise by USD2.5/ton per year from 2010 onwards, taking inflation and the rising costs of coal production into consideration. This rate of increase was determined based on the estimated average rate of increase in Asian costs, insurance, and freight (CIF) calculated for the period between 1991 and 2013 in IEA Coal Information 2013.

Figure 2.19: Projected future coal prices (Steam coal)

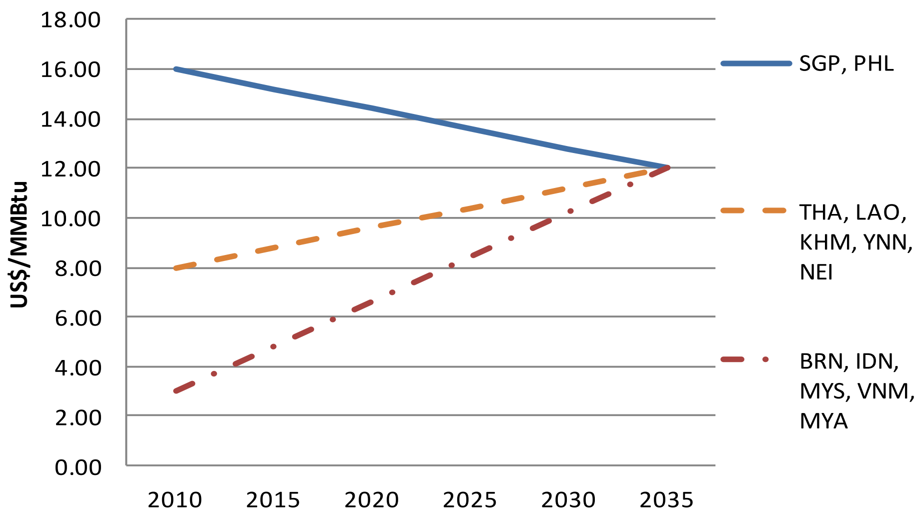


Source: IEEJ projections

Projected prices for natural gas are divided into three levels: countries which import natural gas and do not produce any domestically (Singapore and the Philippines); countries which currently possess some domestic gas fields but where the price of gas used domestically is relatively high

(Thailand, Lao PDR, Cambodia, China and India); and countries which currently possess natural gas fields and where the price of gas used domestically is relatively low (Brunei, Indonesia, Malaysia, Viet Nam and Myanmar). As of 2010, these prices stood at USD16/MMBtu, USD8/MMBtu and USD3/MMBtu respectively. These figures are converging into a provisional figure of USD12/MMBtu up to the year 2035, based on the prospect that increasing trade liquidity is expected in the natural gas market as the natural gas/LNG import increases over time in most Asian countries, and as short-term trading is expected to increase.

Figure 2.20: Projected future natural gas prices



Source: IEEJ projections

2.8. Projected cross-border trading capacity of grid

Two initiatives are currently underway for developing power grid interconnection in the East Asian region: the ASEAN Power Grid (APG) which will cover 10 ASEAN countries; and the Greater Mekong Sub-region (GMS) grid which will cover six countries/regions in the Mekong Basin, including Yunnan Province in China.

The maximum power grid capacity projected in the simulation model of this project, based on the APG and GMS plans, is set out in Table 2.2. However, the power grid capacity between Myanmar and India (northeast region) is based on the joint hydropower development projects of 2,080MW capacity in that nation, because neither the APG nor the GMS contains its line.

Table 2.2: Projected international interconnection transmission capacity in 2020 and later (GW)

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

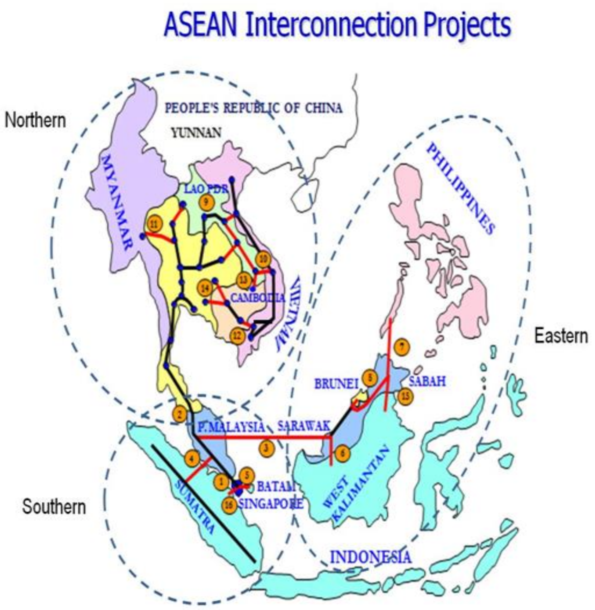
Source: Established by IEEJ based on the ASEAN Power Grid and Greater Mekong Subregion

An outline of the APG and GMS grids is described below as a reference.

In the APG concept, 16 international power grid projects are specified, with the HAPUA office (comprising electric power utilities and authorities connected with electric power) playing a central role in promoting the individual projects.

The current progress as of August 2013 as reported by HAPUA, indicates the following: six power grid projects (Projects 1, 2, 9, 10, 12 and 14) are defined as “partially existing” and four more power grid projects (Projects 4, 6, 8 and 13) are defined as “under construction,” with memoranda of understanding (MOUs) having been signed for the projects. Work is expected to start soon on the remaining six power grid projects (Projects 3, 5, 7, 11, 15 and 16).

Figure 2.21: ASEAN Power Grid (APG)



		Earliest COD
1)	P.Malaysia - Singapore (New)	2018
2)	Thailand - P.Malaysia	
•	Sadao - Bukit Keteri	Existing
•	Khlong Ngae - Gurun	Existing
•	Su Ngai Kolok - Rantau Panjang	2015
•	Khlong Ngae – Gurun (2nd Phase, 300MW)	2016
3)	Sarawak - P. Malaysia	2015-2021
4)	P.Malaysia - Sumatra	2017
5)	Batam - Singapore	2015-2017
6)	Sarawak - West Kalimantan	2015
7)	Philippines - Sabah	2020
8)	Sarawak - Sabah – Brunei	
•	Sarawak –Sabah	2020
•	Sabah – Brunei	Not Selected
•	Sarawak – Brunei	2012, 2016
9)	Thailand - Lao PDR	
•	Roi Et 2 - Nam Theun 2	Existing
•	Sakon Nakhon 2 – Thakhek – Then Hinboun (Exp.)	Existing
•	Mae Moh 3 - Nan - Hong Sa	2015
•	Udon Thani 3- Nabong (converted to 500KV)	2018
•	Ubon Ratchathani 3 – Pakse – Xe Pian Xe Namnoy	2018
•	Khon Kaen 4 – Loei 2 – Xayaburi	2019
•	Thailand – Lao PDR (New)	2015-2023
10)	Lao PDR - Vietnam	2011-2016
11)	Thailand - Myanmar	2016-2025
12)	Vietnam - Cambodia (New)	2017
13)	Lao PDR - Cambodia	2016
14)	Thailand - Cambodia (New)	2015-2020
15)	East Sabah - East Kalimantan	2020
16)	Singapore – Sumatra	2020

STATUS OF ASEAN INTERCONNECTION PROJECT
AUGUST 2013 DATA

(MW)

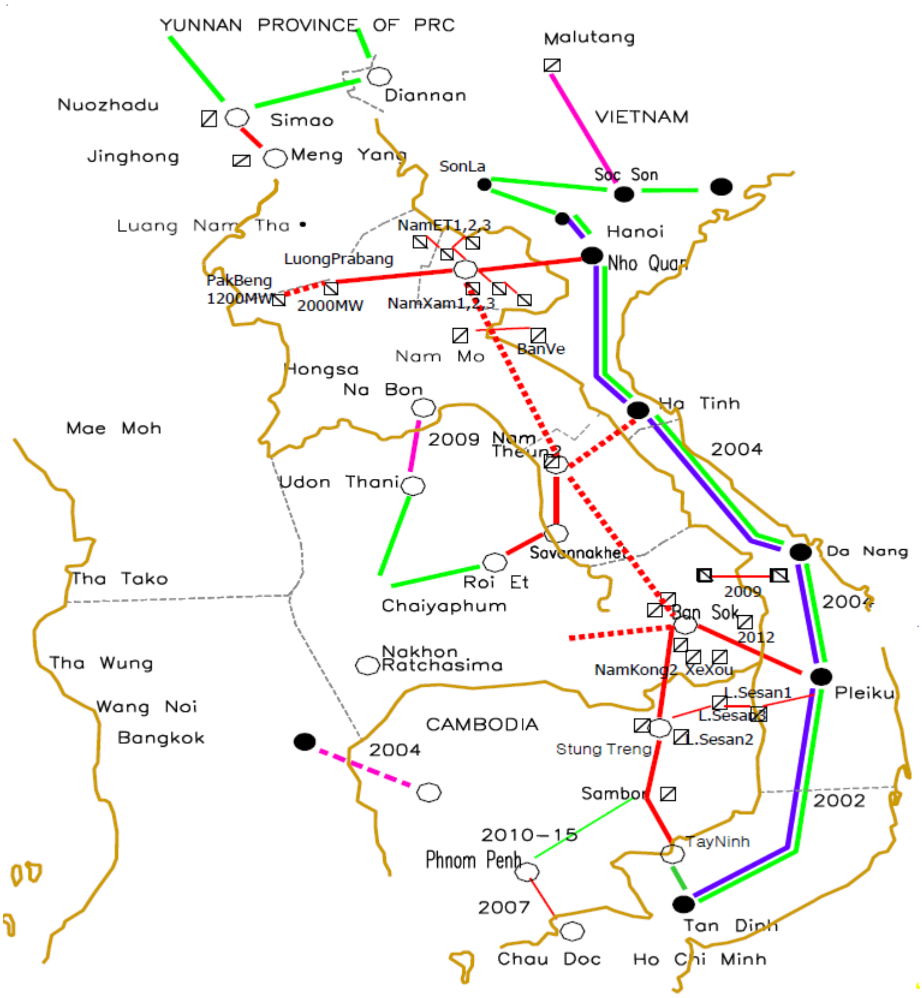
SYSTEM REGION	EXISTING	ON-GOING	FUTURE	TOTAL
NORTHERN REGION	2,659	6,062	16,374	25,095
9. Thailand - Lao PDR	2,111	3,352	2,465	7,928
10. Lao PDR-Vietnam	248	2,410		2,658
11.Thailand- Myanmar			11,709	11,709
12.Vietnam-Cambodia	200			200
13.Lao PDR - Cambodia		300		300
14.Thailand - Cambodia	100		2,200	2,300
SOUTHERN SYSTEM	450	600	1,800	2,850
1. P. Malaysia - Singapore	450		600	1,050
4. P Malaysia - Sumatra		600		600
5. Batam - Singapore			600	600
16. Singapore - Sumatra			600	600
EASTERN SYSTEM		400	800	1,200
6. Sarawak - W. Kalimantan		200		200
7. Philliines - Sabah			500	500
8. Sarawak - Sabah - Brunei		200	100	300
15. E.Sabah - E. Kalimantan			200	200
NORTHERN - SOUTHERN SYSTEM	380	100	300	780
2. Thailand - P.Malaysia	380	100	300	780
SOUTHERN - EASTERN SYSTEM			3,200	3,200
3. Sarawak - P. Malaysia			3,200	3,200
GRAND TOTAL	3,489	7,162	22,474	33,125

Source: HAPUA Secretariat, "APG Interconnection Status"-Revised by August 2013

The GMS program is an inter-regional development program led by the ADB in which multisectoral partnerships are being developed in the Mekong Basin region in infrastructure domains, including transportation, energy and communication, among six countries/regions consisting of Cambodia, Lao PDR, Myanmar, Thailand, Viet Nam and China (Yunnan Province, with the Guangxi Zhuang Autonomous Region also participating since 2004).

Initiatives in the energy sector are underway, centering primarily on upgrading international power grids, and the MoU on the Roadmap of Regional Power Trade was signed in 2008. Figure 2.22 gives the specific details of the power grid projects that are underway.

Figure 2.22: Greater Mekong Sub-region (GMS)



Interconnection		Voltage	Capacity	Distance
Cambodia—Lao PDR	Stung Treng—Ban Hat	115kV	80MW	56km
Cambodia—Thailand	North West Cambodia—East Thailand	250kV	300MW	290km
Cambodia—Vietnam	HPPs e.g. Sambor, Sre Pok, Sre San—Tan Dinh	230kV	–	90km
	Kampong Cham—Tai Ninh	115kV	80MW	64km
	Phnom Penh—Chau Doc	230kV	300MW	110km
China—Lao PDR	China—North Lao PDR	500kV	3,000MW	600km
	China border—HPPs in North Lao PDR	115kV	–	33km
China—Myanmar	Yunnan—Ta Pein and Shweli HPPs	500kV	2,000MW	880km
China—Thailand	Yunnan (Jinghong and Nuozhadu HPPs) —Tha Wung	500kV	3,000MW	1,300km
China—Vietnam	Hong He HPP—North Vietnam	500kV	1,500MW	450km
	Wenshan, Yunnan—North Vietnam	500kV	1,500MW	400km
	Malutang HPP, Yunnan—Soc Son	500kV	460MW	270km
	Guangxi or Yunnan—Quang Ninh	500kV	5,000MW	600km
Lao PDR—Thailand	Hong Sa TPP—Mae Moh	500kV	1,400MW	200km
	Na Bong—Udon Thani	500kV	1,000MW	220km
	Nam Theun 2 HPP—Roi Et 2	500kV	1,000MW	220km
Lao PDR—Vietnam	Luang Prabang HPP—Nho Quan	500kV	–	400km
	Nam Mo HPP—Ban Ma HPP or Ban Mai	230kV	100MW	90km
	Nam Theun 2 HPP—Ha Tinh	500kV	–	190km
	Xe Kaman 3 HPP—Da Nang	220kV	150MW	115km
	Savannakhet—Pleiku	500kV	1,000MW	165km
Myanmar—Thailand	Ta Sang HPP—Mae Moh and Tha Tako	500kV	1,500MW	600km
	HPP in Thanlwin basin—Phitsanulok	500kV	1,500MW	300km
Thailand—Vietnam	Pleiku (Vietnam) —Ban Sok (Lao PDR) — Savannakhet (Lao PDR) —Roi Et (Thailand)	–	–	–
	Ha Tinh (Vietnam) —Nam Theun 2 (Lao PDR) — Savannakhet (Lao PDR) —Roi Et (Thailand)	–	–	–

Source: ADB, "Roadmap for Energy and Power Integration in the GMS" - 29th September 2009

2.9. Transmission loss rate

Theoretically, assuming identical transmission conditions (type and diameter of transmission line, number of lines, current values etc.), the transmission loss rate could be said to be proportional to the distance over which power is transmitted. In practice, however, transmission conditions are never identical because electricity from other power plants flows through the same transmission lines, the current value changes continually in response to the power usage conditions, and various types and diameters of transmission lines are in use. For these reasons, it is generally considered that although transmission losses grow as the transmission distance increases, in practice, the extent of such losses is not perfectly proportional to the distance and cannot therefore be quantified in a uniform manner.

Given the constraints on the data and other factors, the following simplified conditions are used in the simulation model in this study.

AC transmission	1% loss per 100km
DC transmission	1% loss per 100km + 2% loss for AC-DC converter facilities

2.10. Transmission costs

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

The conditions for calculating such transmission costs in the simulation model of this report are as follows.

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

In a precise sense, the unit construction costs for the transmission line stands at USD0.9 million/km/2 circuits for overhead lines and USD5 million/km/2 circuits for submarine cables, based on the most recent actual performance figures for construction in neighbouring countries. The estimated sum of construction costs of transformer stations (switching stations) was obtained by assuming fixed costs[3] of USD20 million per station, and adding additional costs[4] of USD10 million per line.

Turning to O&M costs, ideally, the personnel costs, raw material costs and others should be estimated separately. However, given the data constraints, total construction costs of approximately 0.3 percent/year were assumed in this simulation model.

[3]Shared costs required to install a single switching station such as the cost of securing land and installing shared facilities.
[4]Costs required for installing the number of devices in accordance with the number of lines.

CHAPTER 3

OPTIMISING POWER INFRASTRUCTURE DEVELOPMENT

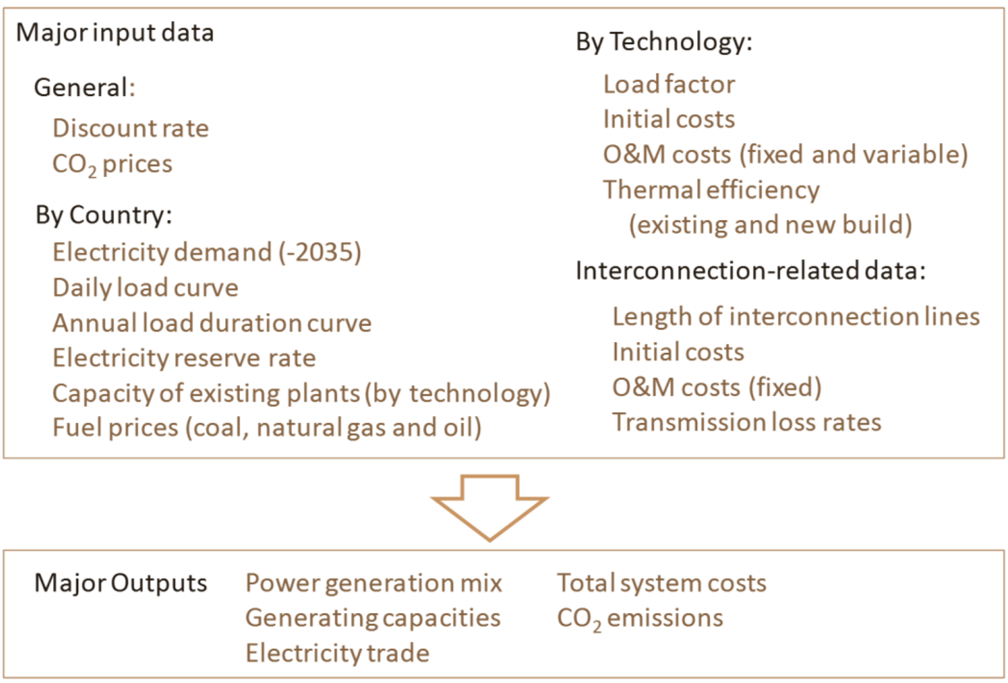
Optimising calculations were carried out according to the conditions set in the previous chapter, using an optimal power generation planning model and a supply reliability evaluation model employing the Monte Carlo method. An overview is displayed below.

3.1. Model overview

3.1.1. Optimal power generation planning model

In this study, an optimal power generation planning model using linear programming method was employed to estimate future power demand and supply. The model's main preconditions and output results are shown in Figure 3.1.

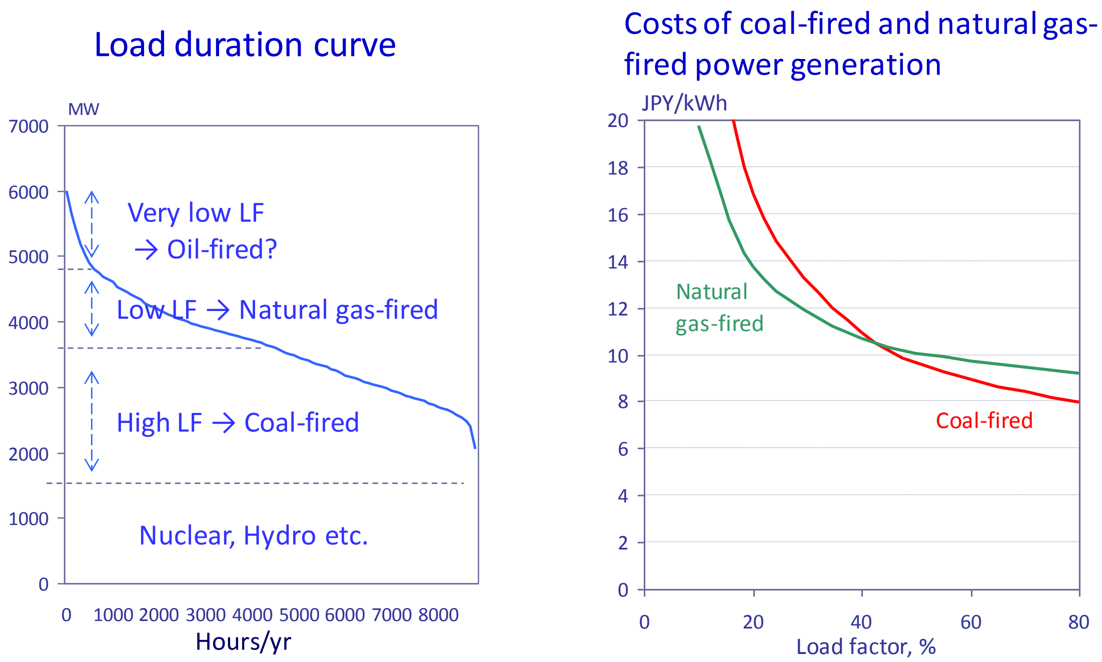
Figure 3.1: Preconditions and outputs of the optimal power generation planning model



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

When comparing coal-fired power generation and natural gas-fired power generation, the former has higher initial investments and lower fuel costs. Thus, as shown on the right in Figure 3.2, coal-fired generation is cost-advantageous when the load factor is high, and natural gas-fired is cost-advantageous when the load factor is low. Consequently, according to cost minimisation calculations in the annual load duration curve shown on the left in Figure 3.2, in the domain where the annual operating volume is large (the middle and lower part of the figure) coal-fired is chosen; and in the domain where the annual operating volume is small, (middle and upper part of the figure) natural gas-fired or oil-fired is chosen.

Figure 3.2: Power source choices in the optimal calculations



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

The objective function and main constraint equations are shown below. It should be noted, however, that although the power generation facility operation, the power trade, and the power consumption are variables dependent upon day *d* and time *t*, for simplicity, these subscripts are omitted.

(Objective function)

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

$$+ \sum_{r,T',d,t} \left\{ \sum_{i} Yn_{r,i,T'} \left(I_{r,i} + \sum_{T>T'} Cf_{r,i} (1-dr)^{T-T'} \right) I_{r,i} \right.$$

$$\left. + \sum_{r'} W_{r,r',T'} \left(II_{r,r'} + \sum_{T>T'} Cif_{r,r'} (1-dr)^{T-T'} \right) \right\} (1-dr)^{T'}$$

Where:

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

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

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

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

Z: power trade: *lr*: transmission loss rate

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

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

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

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

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

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

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

(Supply reserve margin)

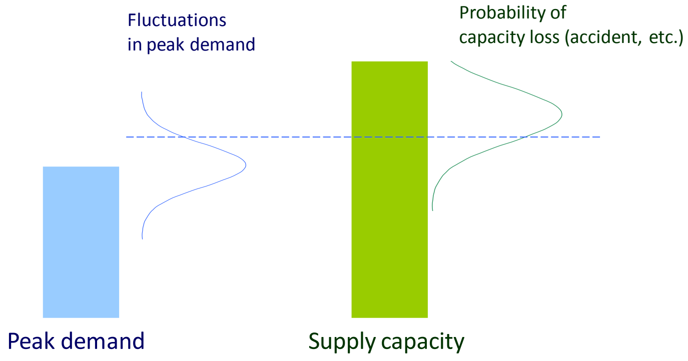
$$PD_{r,T}(1 + s_r) < \sum_{i} F_{r,i} \left(Ye_{r,i,T} + \sum_{T'<T} Yn_{r,i,T'} \right)$$

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

3.1.2. Supply reliability evaluation model

In these calculations, a supply reliability evaluation model employing the Monte Carlo method was used in combination with the abovementioned optimal power generation planning model. A conceptual diagram of this model is shown in Figure 3.3.

Figure 3.3: Supply reliability evaluation model



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

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

3.2. Major assumptions and case settings

3.2.1. Major assumptions

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

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

3.2.2. Case settings

The calculation cases were set as follows:

(1) Calculations covering the total system

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

Case 0 : Reference case (no additional grid connection)

Case 1 : Additional grid connection, no additional hydro-potential

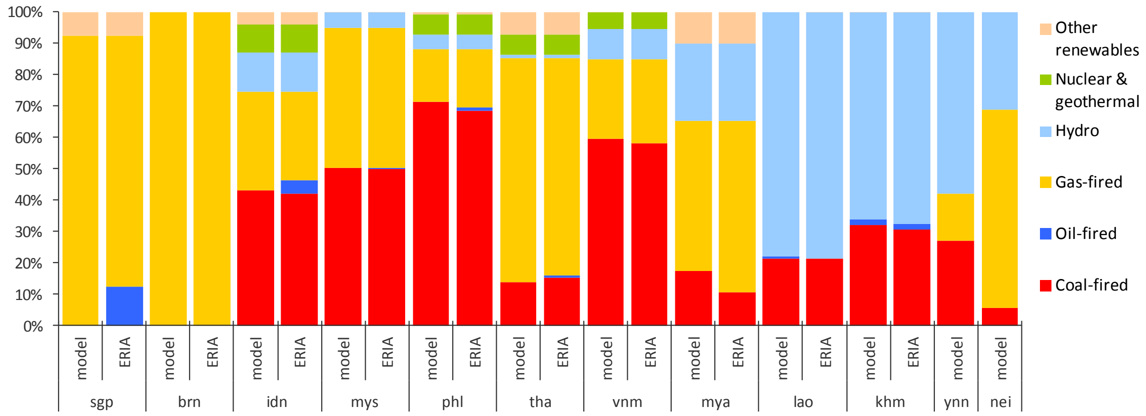
Case 2a : Additional grid connection, additional hydro-potential

Case 2b : Additional grid connection, additional hydro-potential for export purpose only

Case 3 : Same as Case 2b, with no upper limit set on the grid connection capacity

Case 0 does not take grid connection into account, and is a scenario in which a power generation mix is attained that resembles the ERIA Outlook through the utilisation of the domestic power generation facilities of each country only. Figure 3.4 presents a comparison between results of each country's 2035 mix (model output for Case 0) and the ERIA Outlook.

Figure 3.4: Comparison between the calculation results for each country's power generation mix and the ERIA Outlook



Generally, with low discount rates (for example, 3-5%), coal-fired power generation is more cost-advantageous than natural gas-fired. In this study, however, a relatively high real discount rate (10%) is envisioned, and so selections are made with a certain ratio of both coal-fired and natural gas-fired, according to each country's load curve and load duration curve. For the most part, those results do not show significant variance with ERIA's forecasts, but they do differ on several points.

First, in ERIA's forecasts, oil-fired power generation is utilised in countries such as Singapore and Indonesia, but in the results for the optimal model, oil-fired is not selected due to its high cost. Conceivably, oil-fired would actually be utilised based on contributing factors other than just cost such as supply capability. That said, even in ERIA's forecasts, the share accounted by oil-fired is not high, and consequently in this study, no adjustment was made to the model.

Second, in the ERIA Outlook, coal-fired is not utilised in Singapore or Brunei. This is conceivable based on realistic supply capability. In this study, an upper limit of zero was set for coal-fired in both of these countries.

Third, in ERIA's forecasts, Thailand's coal-fired ratio in 2035 is 15 percent, which is relatively low. This is because in Thailand, until now, abundant natural gas resources are being utilised. The construction of new coal-fired power generation plants, however, is currently restricted mainly for political reasons. Consequently, in this study, the 2035 coal-fired power generation capacity was set at the same level as that of the ERIA Outlook by imposing an upper limit constraint on new coal-fired power plant construction in Thailand.

In the case of other countries, the model results are also made to basically match ERIA's forecasts by placing upper limit constraints on new facility construction for either coal-fired or natural gas-fired. The reason why upper limits were set here but not lower limits was in order to make it possible to estimate how much the power generation capacity of coal- and natural gas-fired, respectively, would decline according to the model, in the event that supply from hydropower generation increases and supply from thermal power decreases in Cases 2a, 2b and 3.

Case 1 was configured so that interconnection up to the upper limit set on the grid connection capacity indicated in Table 2.2 is possible, but the additional hydro-potential is not taken into account. In this case, as a result of interconnection, the supply reserve margin is trimmed down, and the thermal power-generation mix (the ratio of coal-fired and natural gas-fired) changes slightly.

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

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

(2) Calculations covering specific interconnection lines

In addition to the calculations applicable to the total system as mentioned above, in order to make it possible to assess the economics of the individual interconnection lines discussed in Chapter 4, calculations were made for cases that permitted grid connections between specific regions only, and were compared against the case without grid connections. The assumed connections are as follows:

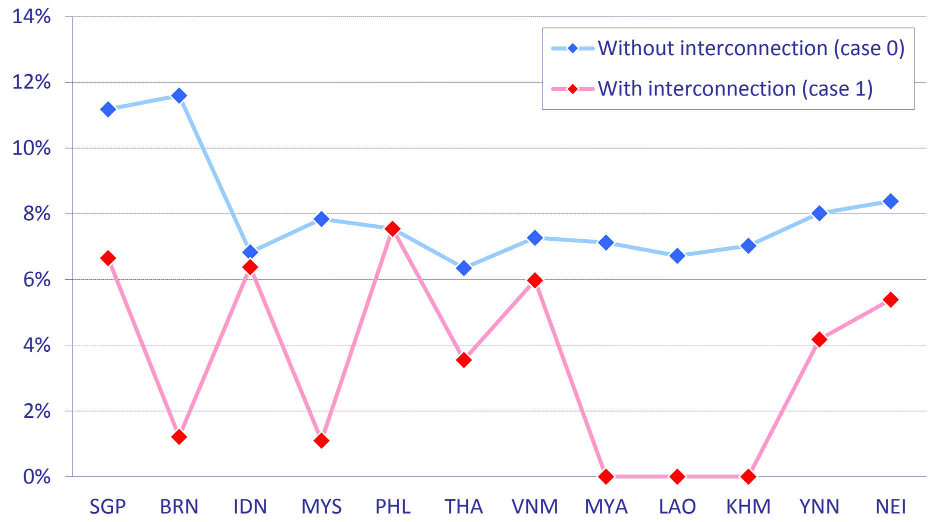
a. Cambodia – Thailand (2.3GW)
b. Lao PDR – Thailand (7.9GW)
c. Myanmar – Thailand (11.7GW)
d. Myanmar – Thailand – Malaysia – Singapore (11.7GW/0.8GW/1.1GW)
e. Viet Nam – Lao PDR – Thailand (2.7GW/7.9GW)
f. Indonesia – Malaysia (2.2GW)
g. Lao PDR – Thailand – Malaysia – Singapore (7.9GW/0.8GW/1.1GW)

3.3. Results and discussions

3.3.1. Supply reserve margin savings arising from grid connections

Figure 3.5 shows the supply reserve margin in each country and region. In Case 0, which does not envisage a grid connection, the reserve margin is 7-8 percent for most countries, and around 11-12 percent for Singapore and Brunei where the systems are small relative to the scale of the power generation facilities. In the cases where grid connections are assumed, the supply reserve margin to achieve the same 24-hour LOLE declines substantially. The degree by which the reserve margin declines differs, however, depending on the country. In the Philippines, where interconnection does not take place due to the high interconnection costs, the supply reserve rate is not reduced; and in Indonesia, which has a relatively large power system and is directly interconnected only with Malaysia, a net power importer in 2035, the supply reserve margin saving is small.

Figure 3.5: Required reserve margin to gain the same LOLE



3.3.2. Power generation mix in 2035

Figure 3.6 to Figure 3.10 show the power supply in 2035 for each case. In these figures, the areas designated with purple sloping lines show net imports (representing net imports if they are positive and net exports if they are negative).

Figure 3.6 represents the power supply mix in Case 0, where a grid connection is not envisioned. As mentioned above, apart from oil-fired generation, these results basically conform to the ERIA Outlook study.

Figure 3.6: Power supply mix in 2035 (Case 0)

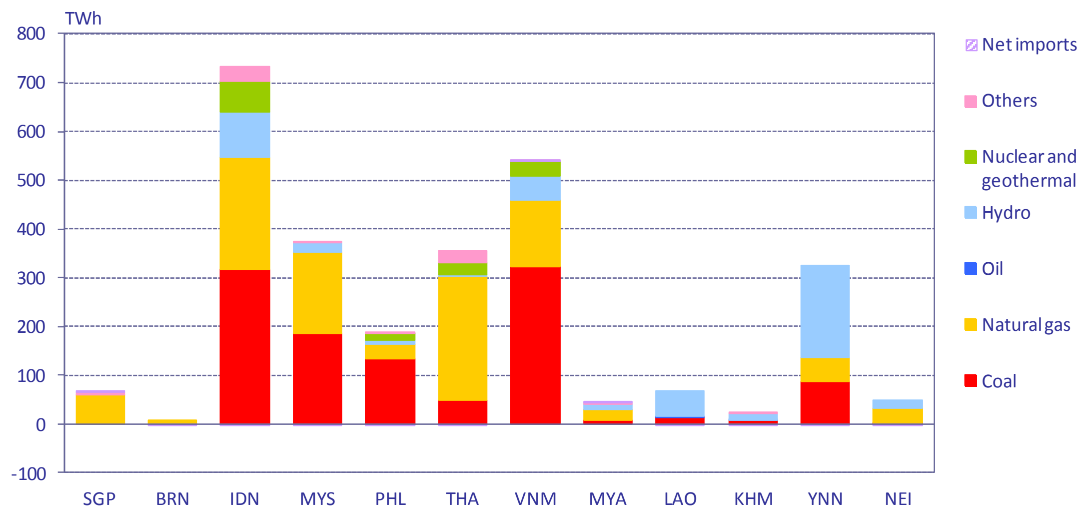


Figure 3.7 shows the power supply mix in Case 1. For this case, hydropower generation is the same as for Case 0, but changes can be detected in the thermal power generation. In Thailand the natural gas ratio is high in Case 0 compared to the cost-optimised. Its natural gas-fired power generation is reduced in Case 1 and is covered by coal-fired power generation from neighbouring countries (in this instance Lao PDR). In this way, there is a possibility that a more cost-optimal power generation mix could be achieved through the utilisation of international interconnection lines, taking into account each country's particular restraints (in this case, restraints on new coal-fired power plant construction in Thailand).

Figure 3.7: Power supply mix in 2035 (Case 1)

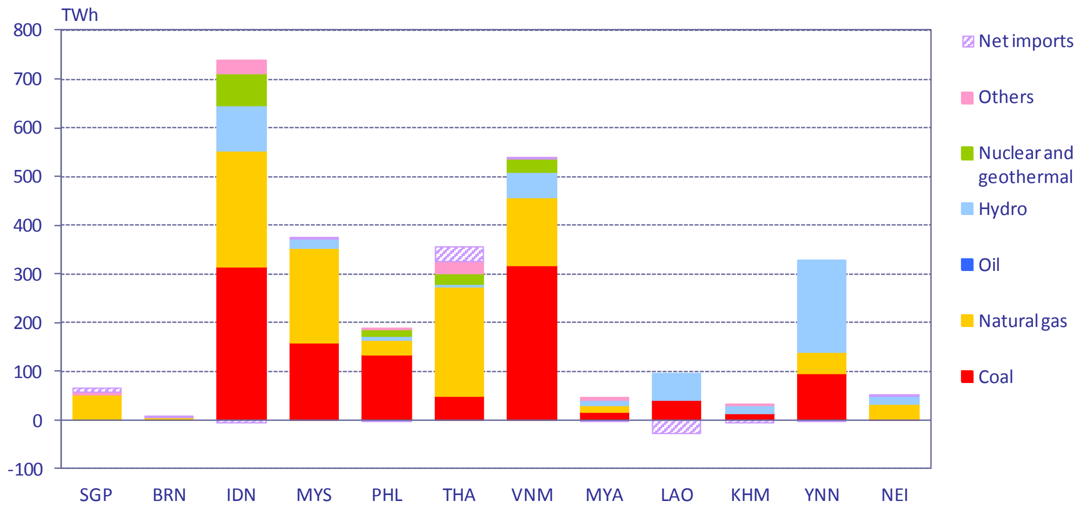


Figure 3.8 shows the power supply mix in Case 2a. In this case, utilisation of additional hydropower potential in each country takes place and exports occur from countries and areas possessing significant potential such as Myanmar, Lao PDR, Cambodia, southern China and Northeast India to Thailand, Viet Nam, Singapore and Brunei.

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

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

Figure 3.8: Power supply mix in 2035 (Case 2a)

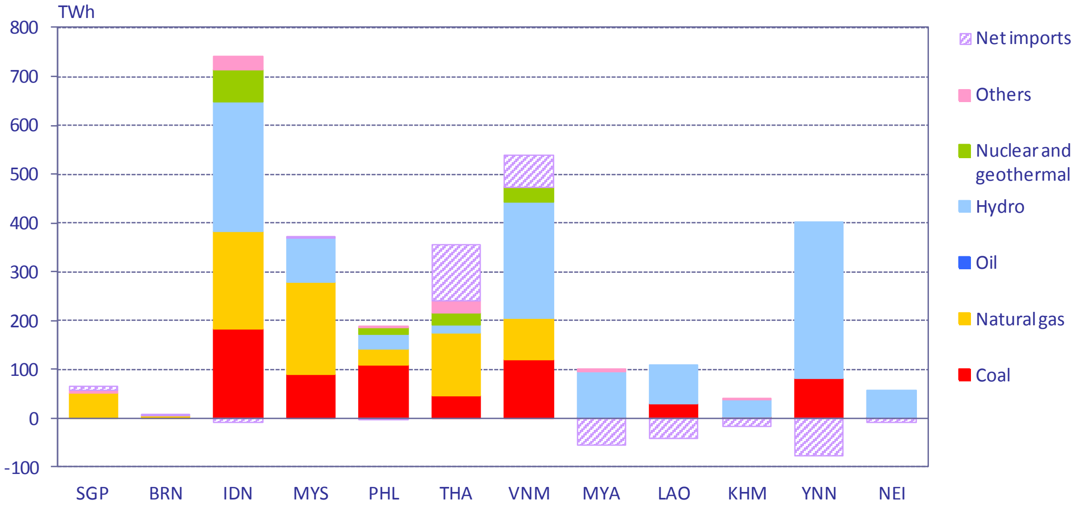


Figure 3.9 represents the power supply mix in Case 2b. Case 2b envisions that additional hydropower generation capacity will only be used for exports. For that reason, the hydropower generation in Indonesia and Viet Nam is smaller than in Case 2a. In terms of domestic power supplies in Myanmar and Cambodia, a certain amount of thermal power generation is used alongside hydro; thus, the surplus hydropower generation portion is exported. Compared to Case 2a, Case 2b therefore presents a more realistic picture.

Figure 3.9: Power supply mix in 2035 (Case 2b)

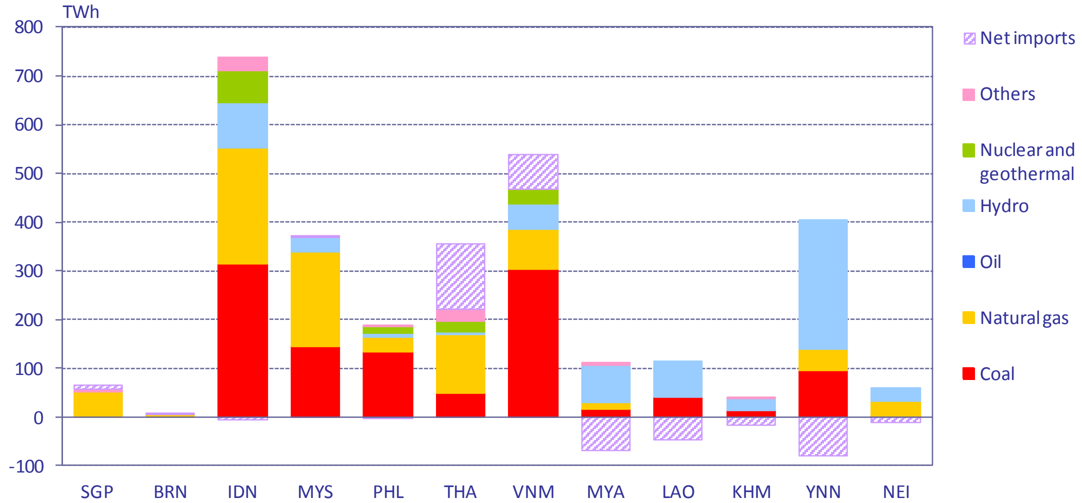


Figure 3.10 represents the power supply mix in Case 3. In this case, hydropower generation in Myanmar in particular is extremely large, with the country exporting 250TWh of electricity per year. At the same time, power is also exported from Lao PDR, Cambodia, southern China and Northeast India which contributes to the supply in Thailand, Viet Nam, Malaysia, Indonesia, Singapore and Brunei. In reality, even if there were no upper limit constraints on interconnection lines, the issue is whether or not the hydropower generation potential in Myanmar could be economically developed on this scale. This will therefore need to be studied further.

Figure 3.10: Power supply mix in 2035 (Case 3)

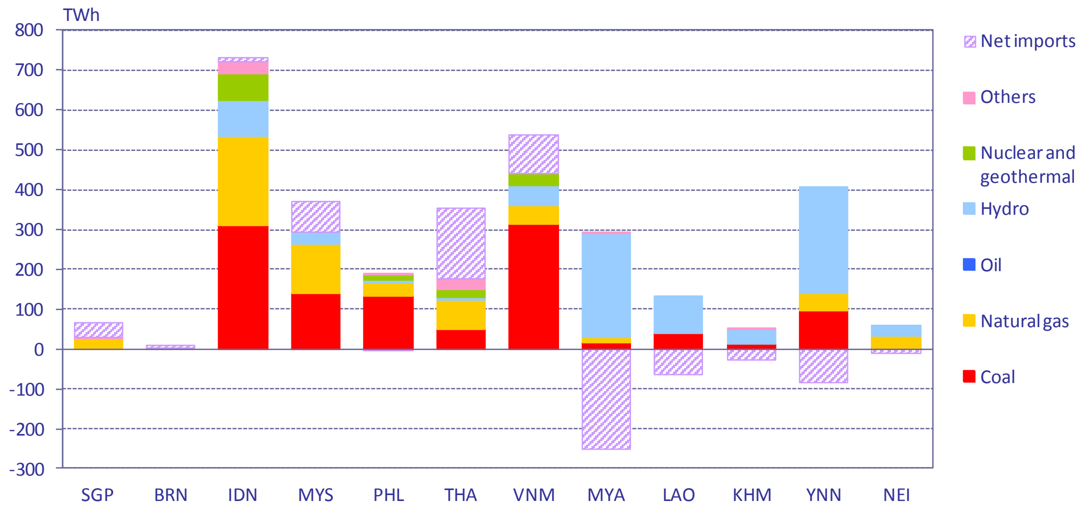
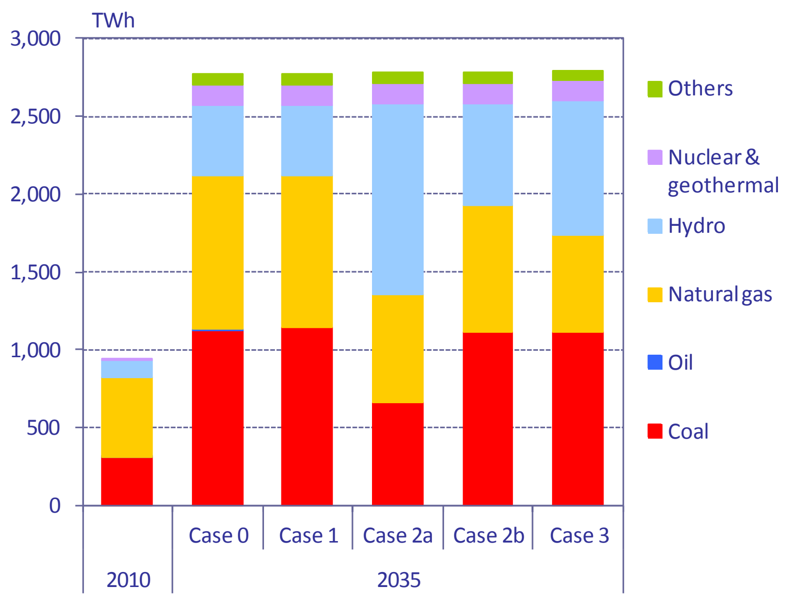


Figure 3.11 shows the power supply mix for all 12 countries and regions combined.

The area's total power generation capacity will expand from 940TWh in 2010 to roughly 2,800TWh in 2035. In Case 0, which does not envisage grid connection, the power generation mix in 2035 consists of coal-fired (40%), natural gas-fired (36%), hydro (16%), and others such as nuclear and renewables (7%). By comparison, in Case 1, the coal-fired thermal ratio increases slightly to 41 percent.

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

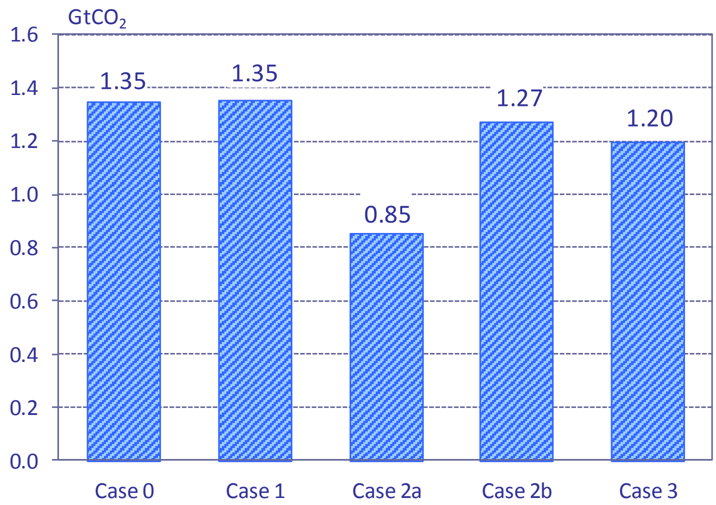
Figure 3.11: Power supply mix by case in 2035 (total of the regions)



3.3.3. CO_2 emissions in 2035

Figure 3.12 shows CO_2 emissions in 2035 (the total for the 12 countries and regions). Compared to Case 0, Case 1 does not have additional hydropower generation and at the same time, the ratio of coal-fired power generation increases slightly as a result of cost optimisation across the entire system based on grid connection. ,. In view of this, CO_2 emissions increase by a small amount, from 1.346Gt in Case 0 to 1.354Gt in Case 1. By comparison, in Cases 2a, 2b and 3, which make use of grid connection along with additional hydropower generation, there are striking declines in CO_2 emissions. This is especially true in Case 2a where the utilisation of domestic hydro-potential in Indonesia and Viet Nam progresses, reducing CO_2 emissions significantly to 0.85Gt. However, as mentioned above, this cannot be described as a realistic case, The CO_2 emission reductions compared to Case 0 are around 0.07Gt in Case 2b, where a grid connection limit corresponding to HAPUA's limit is set; and around 0.15Gt in Case 3, which does not set a limit to interconnection capacity.

Figure 3.12: CO_2 emissions in 2035

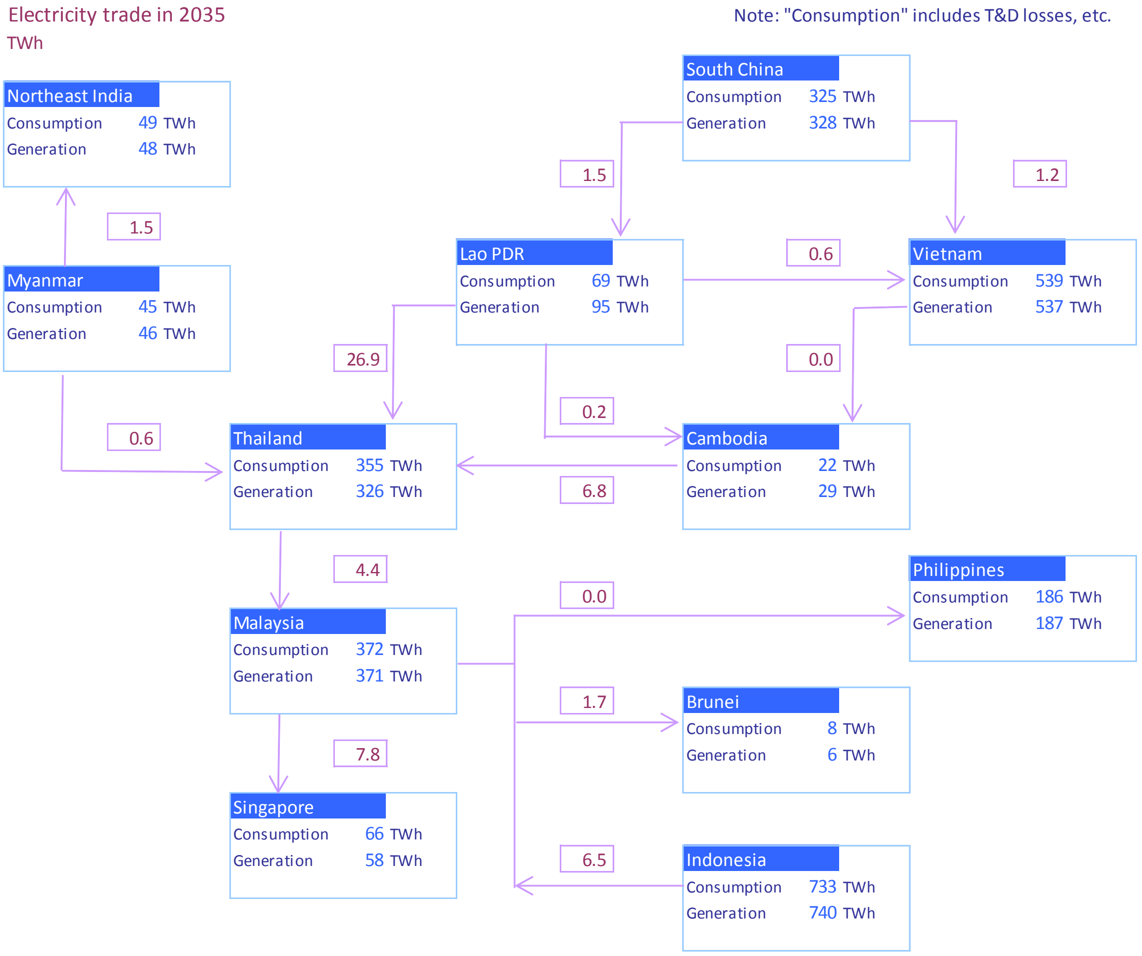


3.3.4. Power trade flows in 2035

Figure 3.13 to Figure 3.16 show power trade flows in 2035.

In Case 1, which is shown in Figure 3.13, the quantity of power trade is small compared to Cases 2a, 2b and 3 because the utilisation of additional hydro-potential is not envisioned. However, even in this case, due to the changes (in thermal power generation) power trade takes place with Thailand being the biggest importer of power, followed by Singapore. The biggest power exporter is Lao PDR, which supplies electricity to Thailand.

Figure 3.13: Power trade flows in 2035 (Case 1)

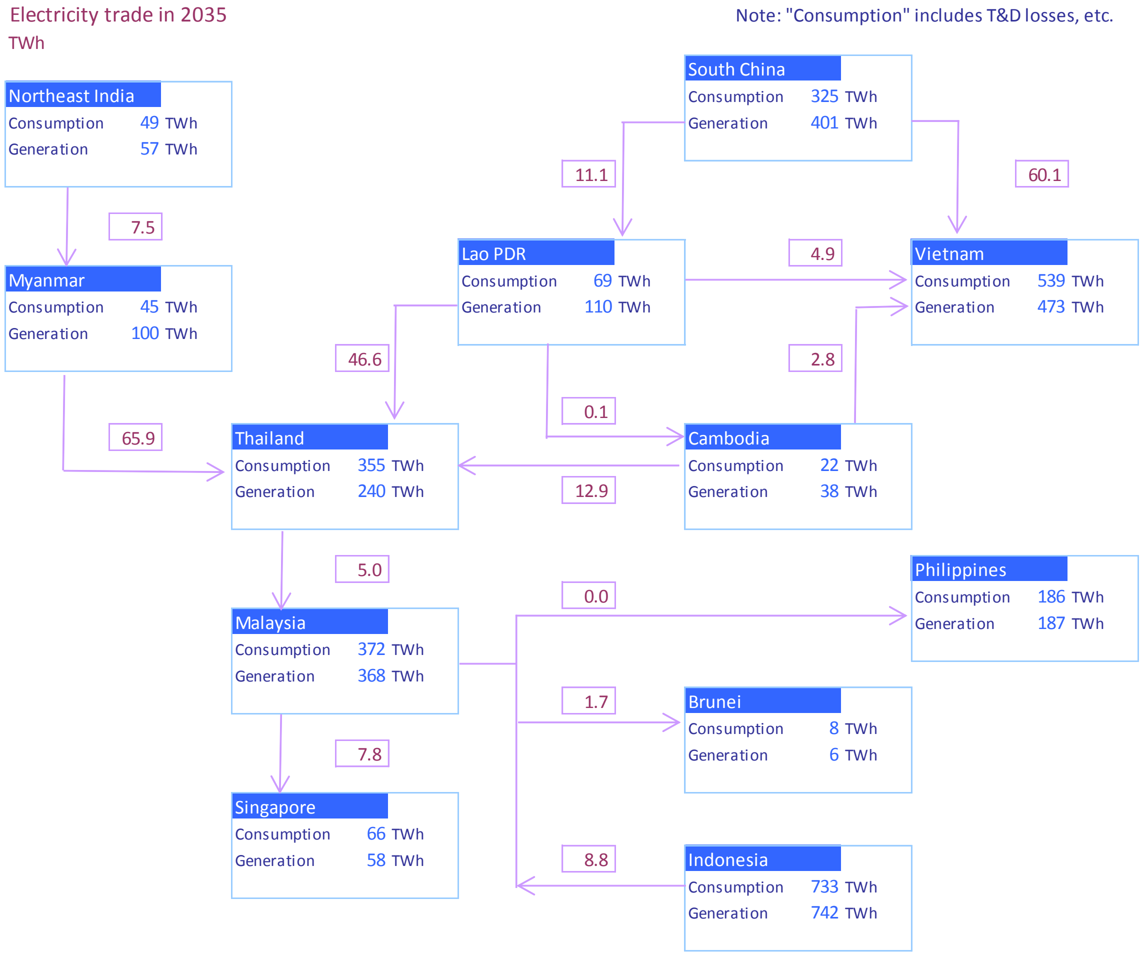


In Case 2a, which envisions the utilisation of additional hydro-potential, power is exported to Thailand from three neighbouring countries, namely, Myanmar, Lao PDR and Cambodia. Substantial volumes are advanced from Lao PDR and Myanmar in particular, countries which have large additional hydro-potential.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

Meanwhile, power flows to Malaysia from Thailand. Part of the power is utilised for power supply to Malaysia and part is used, along with power advanced from Indonesia, to satisfy power demand in Singapore.

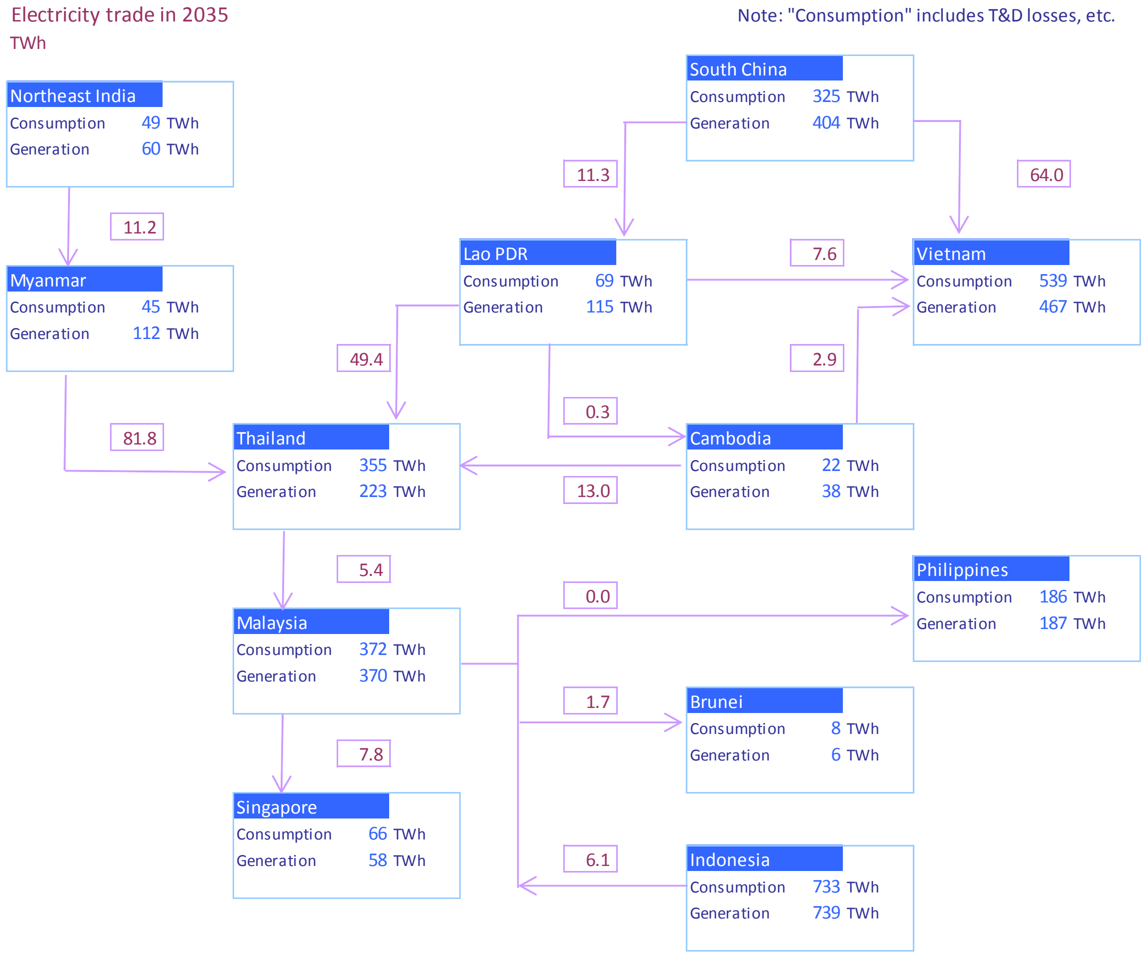
The Philippines is a latent power importer. However, based on the model analysis results, it does not import power. This is because the distance covered by a seafloor cable from Malaysia (Borneo) to the Philippines would be extremely long and the construction cost would exceed the advantages to be reaped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

Figure 3.14: Power trade flows in 2035 (Case 2a)



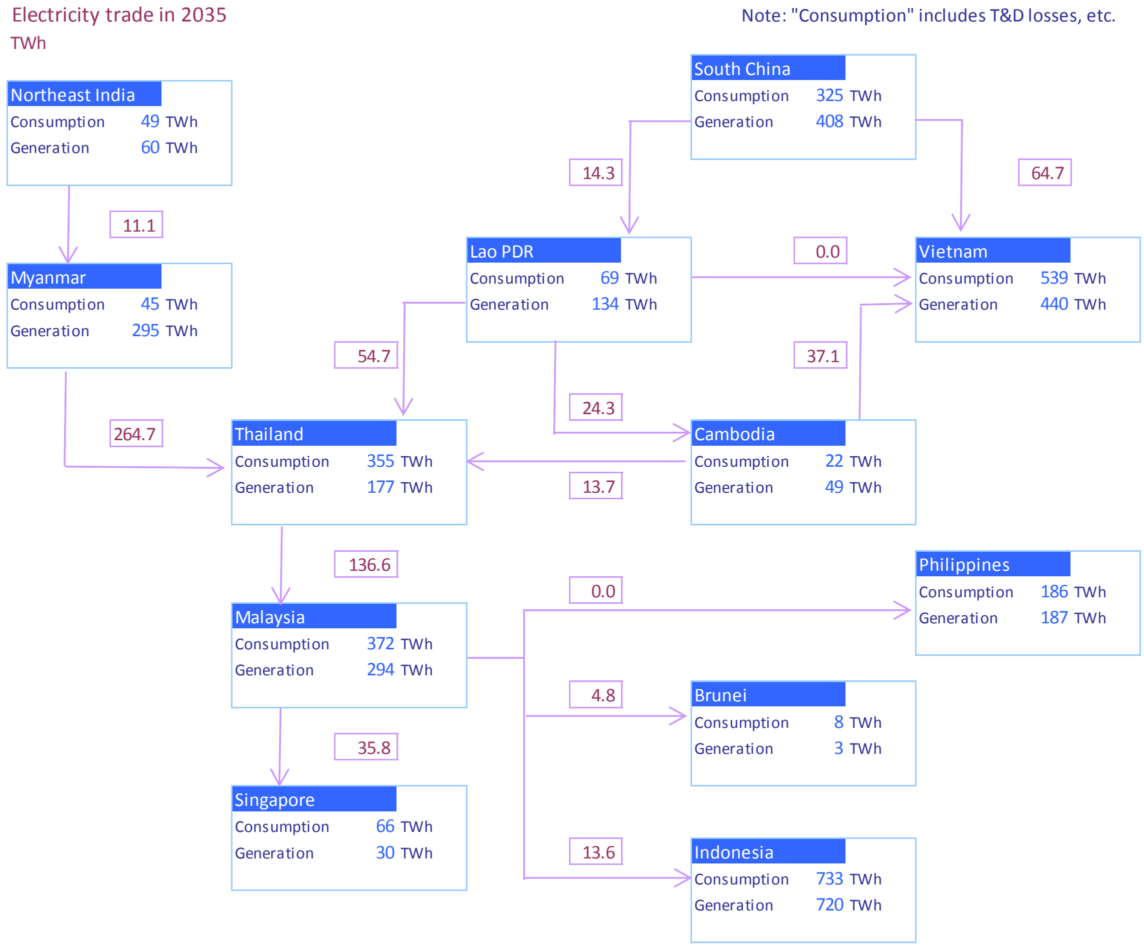
Case 2b envisions a scenario in which additional hydropower generation potential is not used to satisfy domestic demand in the country concerned but only used for exporting. As mentioned above, this case is more realistic. From the standpoint of the quantity of power trade, the outcomes in this case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

Figure 3.15: Power trade flows in 2035 (Case 2b)



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

Figure 3.16: Power trade flows in 2035 (Case 3)



3.3.5. Changes in power trade in Case 2b

Figure 3.17 to Figure 3.20 show changes to power interchange in Case 2b. This case envisions grid connection lines to be constructed around 2020 and to commence operations beginning around 2025. In these figures, positive numbers indicate that power is being supplied towards that direction while negative numbers indicate that power is being supplied in the opposite direction.

Figure 3.17 presents the annual flow via four interconnection lines from southern China to Viet Nam and Lao PDR, from Cambodia to Viet Nam, and from Lao PDR to Viet Nam. Power supply from southern China to Viet Nam continuously grows. In contrast, a flow develops from Viet Nam to Cambodia and Lao PDR in 2025, which occurs in order to supply power to Thailand via these countries. The direction of power trade in these interconnection lines is determined as a result of Thailand’s and Viet Nam’s demand balance.

The ERIA Outlook sketches a scenario in which Viet Nam's power supply and demand grows the most rapidly as time moves towards 2035. Consequently, in 2035, the trend reverses, and power is supplied from Cambodia and Lao PDR to Viet Nam. Accompanying the expansion in supply from southern China to Viet Nam is the decrease in the export of power from southern China to Lao PDR towards 2035.

Figure 3.17: Changes in power trade in Case 2b (1)

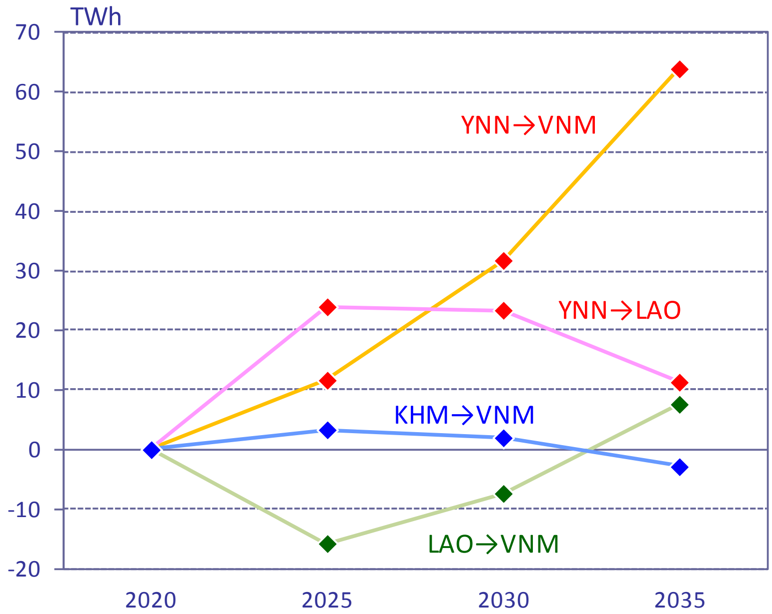


Figure 3.18 shows the power supply from Myanmar, Lao PDR, Cambodia and Malaysia to Thailand. As of 2025, Lao PDR is the largest supplier of power to Thailand, followed by Myanmar and Cambodia. However, accompanying the rapid expansion in Viet Nam's demand, the supply coming from Lao PDR and Cambodia begins to decrease and Myanmar assumes the position of being the largest supplier towards 2035. Meanwhile, despite being in a small net import position with Malaysia in 2025, Thailand will be in a reverse position by 2035 as it begins to export power. As a result, as shown in Figure 3.15, it becomes possible to supply hydro-potential power from the northern regions to the southern regions, including Singapore. This will be particularly noticeable around 2035 when supply in the south begins to run short given the expanding demand in Indonesia.

Figure 3.18: Changes in power trade in Case 2b (2)

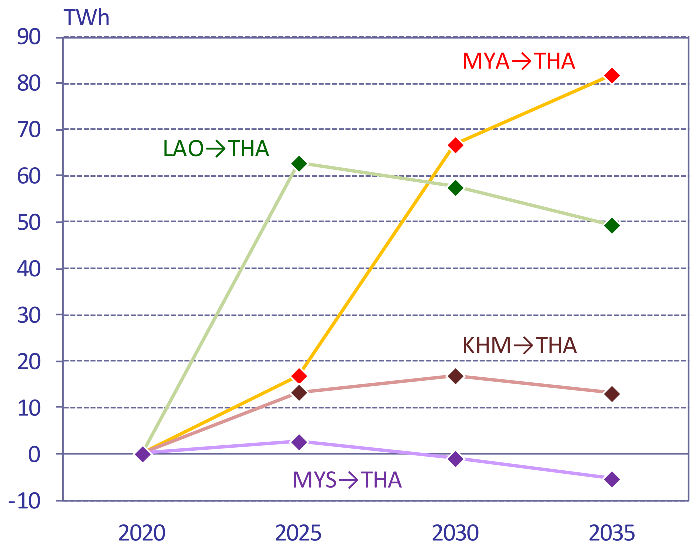


Figure 3.19 presents the export from Malaysia to Singapore, Brunei, Thailand and Indonesia. As this figure shows, Singapore and Brunei enjoy a stable power supply via Malaysia. The countries providing the supply for that are Indonesia and Thailand, but their supply amounts change over time. Supply coming from Indonesia shrinks due to the rapid growth in domestic demand. Accordingly, the reliance on northern hydro that passes through Thailand increases. This region's supply capacity itself is around 5-10TW and is small in scale when compared to the supply and demand balance in the northern region shown in Figure 3.17 and Figure 3.18 which center on Thailand and Viet Nam.

Figure 3.19: Changes in power trade in Case 2b (3)

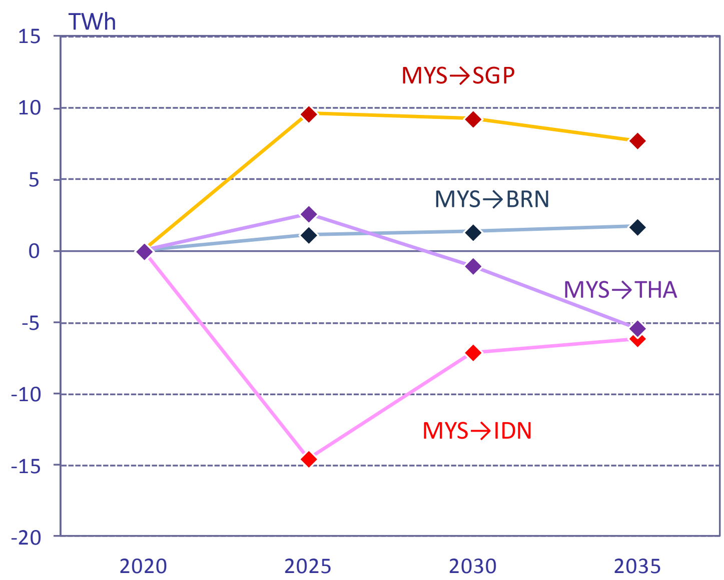
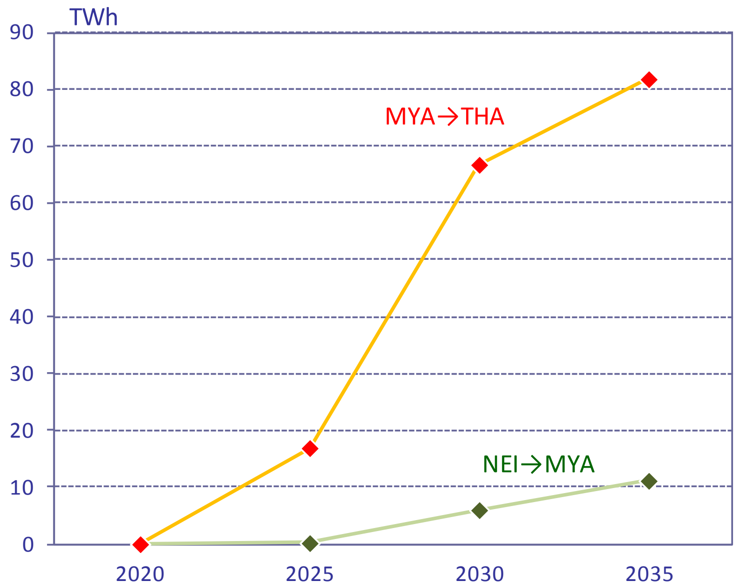


Figure 3.20 shows the export from Northeast India to Myanmar and from Myanmar to Thailand. This interchange continues to grow up to 2035. In other words, amid the ongoing expansion in power demand in Viet Nam, Thailand, and Indonesia in the long term, the importance of these regions' power supply capacity will increase more.

Figure 3.20: Changes in power trade in Case 2b (4)



3.3.6. Cumulative costs up to 2035 and 2050

Figure 3.21 shows the differences in the cumulative costs (up to 2035 and 2050) in Cases 1, 2b and 3, compared to Case 0.

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

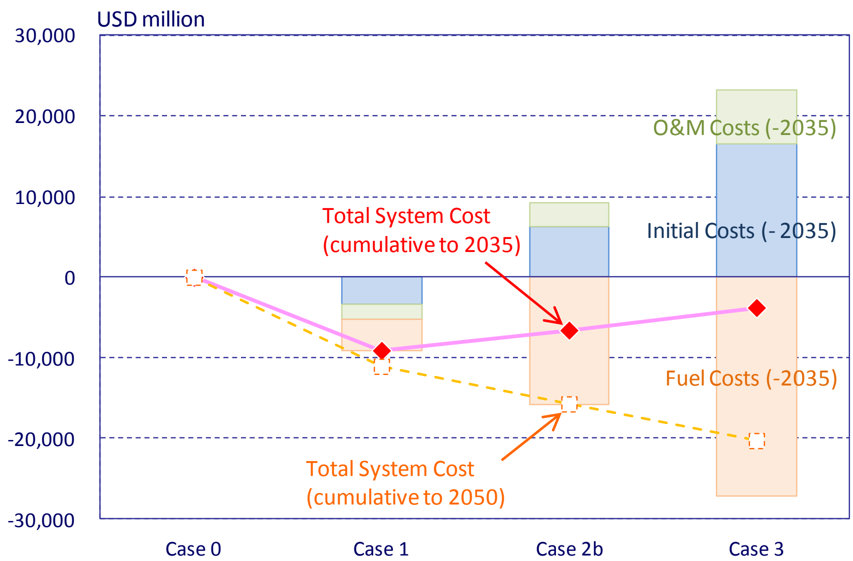
In contrast, in Case 2b, which takes into account the utilisation of additional hydropower potential, fossil fuel expenses decrease substantially, on the one hand, while initial investments and O&M costs increase, on the other, as a result of a shift from natural gas-fired to hydro. When these outcomes are all totaled, the cumulative costs up to 2035 fall by 6.6 billion

USD compared to Case 0, and increase by 2.5 billion USD compared to Case 1. In Case 3, where the usage of additional hydropower generation potential is greater, there is a 3.8-billion USD decline in cumulative costs compared to Case 0 and a 5.3-billion USD increase compared to Case 1.

The increase in cumulative costs up to 2035 accompanying the utilisation of additional hydro points to the fact that it will not be possible to fully recover the initial investment needed for hydropower generation facilities. If the cumulative costs are evaluated over a longer time scale such as until 2050, however, then the cumulative costs in Cases 2b and 3 will decline compared to Case 1 because more of the initial investment for hydro will be recovered.

Therefore, the economies of constructing international interconnection lines improves under systematic planning with a long-term perspective.

Figure 3.21: Cumulative costs in each case



3.4. Conclusion

This study uses an optimal power generation planning model that takes into account international interconnection together with a supply reliability model that employs the Monte Carlo method to analyse international grid connection options up to 2035. Grid connections in the ASEAN region would reduce the costs of the overall power system and bring massive benefits to the region through effective utilisation of additional hydropower generation potential and reduction of supply reserve margin. However, when it comes to utilising additional hydro-thermal power potential, it might not be possible to recover the initial investment required due to unavoidable barriers if the time scale is until 2035. Consequently, it is necessary to draw up plans with a longer time scale that looks ahead to, say, 2050.

In this study a constant cost for additional hydro-potential was employed. However, the fact is that the economics of hydropower generation changes depending on location. As a result, there is a possibility that the feasibility of hydro-potential shown in Chapter 2 will also differ. In the future, it will be advantageous if a more realistic evaluation were to be done by assessing, among others, the costs of each kind of power generation, most notably, hydro-generation, and the grid connection costs for each region.

CHAPTER 4

PRELIMINARY ASSESSMENT OF POSSIBLE INTERCONNECTION

This chapter will select candidates for interconnection that would conceivably be effective based on the considerations of the previous chapter, and attempt to calculate the economic effects, including a rough estimation of the cost of constructing interconnected transmission lines. After these considerations, priorities are set for these selected interconnection lines.

4.1. Exploring interconnection cases

Based on the results from the previous chapter, interconnection lines that appear to have significant advantages will be selected, and the economic effects arising from each interconnection will be calculated and compared.

The main criterion for selection is the amount of estimated power flow. Among a number of possible interconnection lines, the lines that are estimated to have larger power flows than the others will be selected.

In this regard, the following cases were explored:

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

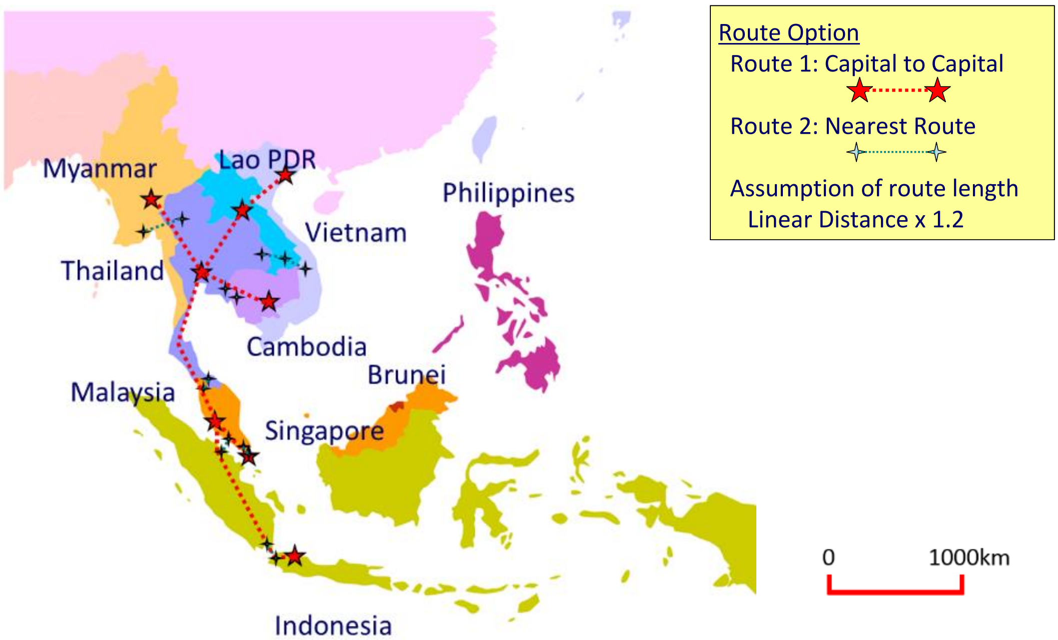
4.2. Route considerations for interconnected transmission lines

When considering ~~a~~ transmission system interconnection between two countries, it is necessary to confirm the condition of the transmission systems of each country in detail, and then decide the optimum connection points and detailed interconnection routes. However, the goal of this study is a preliminary assessment of the relationship between the effects of interconnection and the cost. Hence, issues such as connection points and detailed routes will be the subject of future investigation. Taking that into consideration and given the need to determine routes as a reference for transmission line costs, the most appropriate approach is to configure two routes – a comparatively long-distance route and the shortest possible route – and present the hypothetical costs as a range.

Based on this assumption, Route 1 shall be a comparatively long-distance route linking capital cities, and Route 2 shall be linking short distance points with existing substations wherever possible.

Additionally, because it is not possible to establish detailed routes in this study, the transmission route length shall be set as 1.2 times the linear distance between two points.

Figure 4.1: How routes are considered in each case



The route lengths that were calculated on that basis are as follows:

Table 4.1: Route length calculation results (Route 1)

Case		Point Name	Linear Distance [km]	Route Distance [km]
A	THA-KHM	Bangkok-Phnom Penh	530	636
B	THA-LAO	Bangkok-Vientiane	530	636
C	THA-MYA	Bangkok-Naypyidaw	800	960
D	MYA-THA-MYS-SGP	Naypyidaw-Bangkok	800	960
		Bangkok-Kuala Lumpur	1350	1620
		Kuala Lumpur-Singapore	350	420
E	VNM-LAO-THA	Hanoi-Vientiane	480	576
		Vientiane-Bangkok	530	636
F	MYS-IDN	Kuala Lumpur-(coast of Malay Peninsula)	50	60
		Malay Peninsula - Sumatra Island	90	108
		in Sumatra Island	1200	1440
		Sumatra Island - Java Island	50	60
		(coast of Java Island)-Jakarta	120	144
G	LAO-THA-MYS-SGP	Vientiane-Bangkok	530	636
		Bangkok-Kuala Lumpur	1350	1620
		Kuala Lumpur-Singapore	350	420

Table 4.2: Route length calculation results (Route 2)

Route		Point Name	Linear Distance [km]	Route Distance [km]
A	THA-KHM	Chanthaburi SS - Lower Stug Russey SS	100	120
B	THA-LAO	Ubon 3 SS - Ban Sok SS	200	240
C	THA-MYA	Mae Moh 3 SS - Yangon	450	540
D	MYA-THA-MYS-SGP	Yangon - Mae Moh 3 SS	450	540
		Khlong Ngae SS - Gurun SS	110	132
		Top of Malay Peninsula - Singapore	20	24
E	VNM-LAO-THA	Pleiku SS - Ban Sok SS	120	144
		Ban Sok SS- Ubon 3 SS	200	240
F	MYS-IDN	Malay Peninsula - Sumatra Island	90	108
		Sumatra Island - Java Island	50	60
G	LAO-THA-MYS-SGP	Ban Sok SS- Ubon 3 SS	200	240
		Khlong Ngae SS - Gurun SS	110	132
		Top of Malay Peninsula - Singapore	20	24

4.3. Cost considerations for interconnected transmission lines

4.3.1. Cost components of interconnected transmission lines

When establishing interconnected transmission lines, the necessary costs can be broadly categorised as 1) construction costs; and 2) operating and maintenance (O&M) costs.

The cost of constructing transmission lines would generally be the cost of obtaining (purchasing) the land, the cost of the materials (transmission towers, electric cables, insulators, etc.), the construction labor costs, and so on. However, these costs will change depending on various elements, including the country, location, and environmental condition where the lines are being constructed. For a rigorous cost estimate, it would be necessary to confirm and configure each of those elements in detail. However, because this study only involves a preliminary assessment, the construction costs are simplified.

That being the case, in preliminary assessments, the general approach taken in calculating transmission line construction costs is to establish a unit construction cost per unit length (1 km) and then multiply it with the route length. This is also the approach taken in this study.

It should be pointed out that in all the cases, the interconnected transmission lines to be constructed are assumed to be 500kV transmission lines. The unit construction costs for overhead lines and undersea cables are calculated and set based on actual market prices in recent years.

Where O&M costs are concerned, conceivable costs include the cost of labor for regular patrols, the cost of fuel for traveling, the cost of materials when making repairs, insurance costs when working in high places, and so on. However, due to the difficulty in setting and adding up these costs in detail, generally speaking again, in many cases, a certain annual amount is assumed as the cost, and that amount is established as a fixed ratio of the construction cost. As such, O&M costs in this study are established as an annual cost that is 0.3 percent of the construction costs.

4.3.2. Setting unit construction costs

Unit construction costs (unit cost per km) were calculated as follows:

Figure 4.2 plots the actual contract costs of major transmission line construction projects (500kV) in Southeast Asia in recent years (the past decade) against the transmission line route lengths (two circuits for overhead transmission lines and one circuit for undersea cable).

Figure 4.2: Actual transmission line construction costs in neighbouring countries (500kV overhead lines)

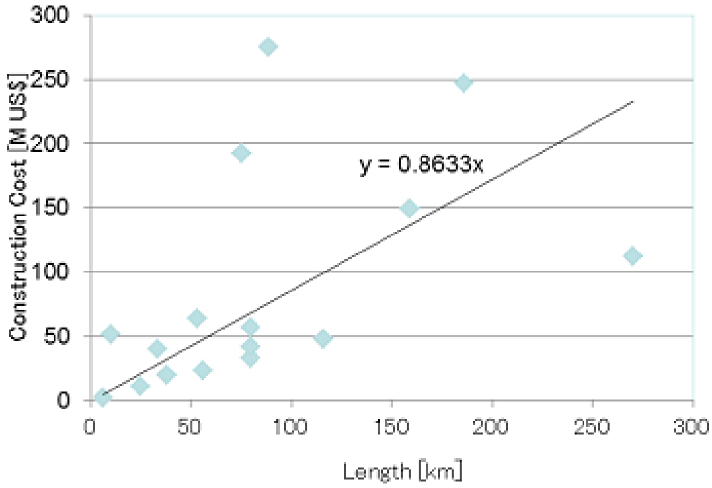
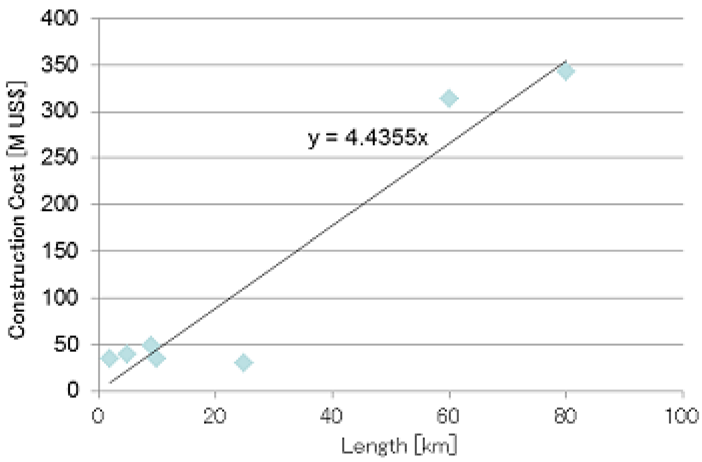


Figure 4.3: Actual transmission line construction costs in neighbouring countries (500kV undersea cable)



Seeking an average value by adding an approximate straight line to each graph based on these data produced the following results:

<Overhead line>

According to the approximate line y=0.8633x, the cost is roughly 0.9 million USD/km/2 circuits overhead lines, so a unit construction cost figure of 0.45 million USD/km/circuit overhead line is established.

<Undersea cable>

According to the approximate line y=4.4355x, the cost is roughly 4.5 million USD/km/1 circuit undersea cable, so a unit construction cost figure of 5 million USD/km/1 circuit undersea cable is established.

4.3.3. Setting conditions for alternative current (AC) transmission lines

Next, the following respective conditions are set as conditions for calculating the construction costs of AC transmission lines. Note that AC overhead lines should be applied to all of Cases A to E.

(1) Voltage

In the region that is subject to this study, 500kV transmission lines are currently widely used as transmission lines for carrying large quantities of power. For the purposes of this study, the interconnected transmission lines shall also be considered as 500kV transmission lines in all cases.

(2) Transmission capacity

A single circuit power line (wire) has a threshold figure for the power it can stably transmit. To carry power in excess of that threshold, it is necessary to increase the number of circuits. As a result, the number of circuits must be set according to the maximum amount of power that may be carried.

This study assumes the use of wires that are commonly utilised in many projects, and sets the transmission capacity per circuit at 1.8GW.

(3) Number of circuits

As stated in (2) above, it is necessary to set the number of circuits according to the maximum power that may be carried. Usually, a spare circuit is allocated to prevent accidental disconnection of electric power flow. Thus, in addition to the number of circuits required to transmit the maximum power, an additional circuit is added as a spare.

(4) Intermediate switching stations (or substations)

In the case of AC transmission lines, intermediate switching stations are generally set up when the route length is long in order to stabilise the voltage and partition circuits during accidents. This study assumes that one switching station (or substation) is set up for every 160km. Switching station construction costs were considered as follows:

(a) Cost components of switching station construction

The costs of constructing switching stations include the cost needed to acquire and develop the land where the switching stations will be located and the facilities and equipment costs (including the installation cost). However, in order to simplify cost estimation, land-related and common equipment costs are consolidated as "fixed costs" and viewed as necessary costs common to a single switching station. Meanwhile, costs associated with the equipment required according to the number of circuits are added to this as "additional costs," with the total amount being a sum of these components. For the additional cost, the unit cost per circuit is multiplied by the number of circuits.

(b) Setting an amount for the fixed cost

The fixed cost will change according to the location of the switching station and the equipment types, but for the purpose of this study, it is necessary to estimate the cost on the safe side. Examining actual cost of new substation construction projects in neighbouring countries show~~s~~ that in many cases, this fixed cost component was around 10 million USD and is consequently assumed here that:

Fixed cost = 20 million USD

(c) Setting an amount for the unit additional cost

Similarly, examining actual cases in neighbouring countries shows that unit additional costs mostly fluctuated around several million US dollars. Consequently, this study assumed that:

Unit additional cost = 10 million USD / line

(d) Switching station construction cost

Based on the above, the cost of constructing a switching station is found using the following formula:

Switching station construction cost = fixed cost + unit additional cost × number of circuits = 20 million USD + 10 million USD × number of circuits.

4.3.4. Setting the conditions for direct current (DC) transmission lines

In Case F, if the power systems of Malaysia and Indonesia were to be interconnected, then connecting the Malay Peninsula and Sumatra, and Sumatra and Java, would be unavoidable. In other words, it would initiate crossing the sea in two places whereby undersea cables would be required.

With undersea cables, the charging current grows too high if AC is used and so equipment is needed at mid-course to compensate. However, when the undersea cable is long (generally 30km or longer), compensation equipment requires land for installation for every around 30km; hence, DC line is used.

If DC is used, the issue of stability does not arise even in cases of long distance transmission. However, equipment for converting the AC and DC (an AC/DC converter) is needed at both ends of the AC system.

(1) Voltage

As with AC, it is assumed that 500kV (±500kV for DC) will be employed.

(2) Transmission capacity

DC transmission can generally carry higher currents than AC transmission. Here, the transmission capacity per line is set as 3.0 GW for overhead lines and undersea cables. Accordingly, in Case F, the transmission capacity is up to 2.2 GW, so only a single circuit is required.

(3) Number of circuits and unit construction costs

With DC transmission systems, in the event of an accident, the impact on the system can be controlled using the AC/DC converters at the connection points. Therefore, in general, backup lines are not set up.

The construction costs concerning the overhead line portion will be lower because the towers are simple compared to AC transmission. Therefore, the unit construction cost for DC overhead transmission lines is assumed to be two-thirds of the unit cost of two circuits AC lines (0.9 million USD/km) and is set at 0.6 million USD/km. With regards to the undersea cable portion, the unit construction cost is set as 5 million USD/km, as found in section 4.3.2.

(4) AC/DC conversion stations

As stated above, DC transmission systems require installations of AC/DC converters at the points of connection with the AC system. Generally, these facilities resemble large substations, and the AC/DC converters are costly. Here, a unit cost per 1 GW is set at 150 million USD/GW. Because the transmission capacity in Case F is 2.2GW, the cost per site will be 330 million USD.

With regards to the necessary number of converters, they will be required at both ends (the Malaysia side and the Indonesia side) or at two sites because with Route 1, DC transmission is to be applied on all lines and with Route 2, they will be needed at both ends of the two sections where crossing the sea takes place. Hence, a total of four sites will be needed.

4.3.5. Cost calculation results

Based on the above assumptions, the construction costs that were calculated for the interconnected transmission lines in the respective cases are shown in Table 4.3.

Table 4.3: Transmission line construction costs (Route 1)

Case		Point Name	No. of Circuit	No. of SS	Cost of 1 SS	Construction Cost [Mil USD]	
A	THA-KHM	Bangkok-Phnom Penh	3	3	50		1,009
B	THA-LAO	Bangkok-Vientiane	6	3	80		1,957
C	THA-MYA	Bangkok-Naypyidaw	8	5	100		3,956
D	MYA-THA-MYS-SGP	Naypyidaw-Bangkok	8	5	100	3,956	6,272
		Bangkok-Kuala Lumpur	2	10	40	1,858	
		Kuala Lumpur-Singapore	2	2	40	458	
E	VNM-LAO-THA	Hanoi-Vientiane	3	3	50	928	2,885
		Vientiane-Bangkok	6	3	80	1,957	
F	MYS-IDN	Kuala Lumpur-(coast of Malay Peninsula)	2	1	330	366	1,901
		Malay Peninsula - Sumatra Island	1	0		302	
		in Sumatra Island	2	8		648	
		Sumatra Island - Java Island	1	0		168	
		(coast of Java Island)-Jakarta	2	1	330	416	
G	LAO-THA-MYS-SGP	Vientiane – Bangkok	6	3	80	1,957	4,273
		Bangkok – Kuala Lumpur	2	10	40	1,858	
		Kuala Lumpur – Singapore	2	2	40	458	

Table 4.4: Transmission line construction costs (Route 2)

Route		Point Name	No. of Circuit	No. of SS	Cost of 1 SS	Construction Cost [Mil USD]	
A	THA-KHM	Chanthaburi SS - Lower Stug Russey SS	3	0	50		162
B	THA-LAO	Ubon 3 SS - Ban Sok SS	6	1	80		728
C	THA-MYA	Mae Moh 3 SS - Yangon	8	3	100		2,244
D	MYA-THA-MYS-SGP	Yangon - Mae Moh 3 SS	8	3	100	2,244	2,384
		Khlong Ngae SS - Gurun SS	2	0	40	119	
			2	0	40	22	
E	VNM-LAO-THA	Pleiku SS - Ban Sok SS	3	0	50	194	922
		Ban Sok SS- Ubon 3 SS	6	1	80	728	
F	MYS-IDN	Malay Peninsula - Sumatra Island	3	0	50	962	1790
		Sumatra Island - Java Island	3	0	50	828	
G	LAO-THA-MYS-SGP	Ban Sok SS- Ubon 3 SS	6	1	80	728	868
		Khlong Ngae SS – Gurun SS	2	0	40	119	
			2	0	40	22	

4.4. Comparative calculation of benefits

Using the results above, the benefits of each case were calculated and compared. In the previous chapter, the change in costs with or without interconnection between the two countries was calculated for each case (development cost increases for hydropower potential, reduced thermal power generation fuel costs result from power interchange, and reduced power plant development costs arise from lower reserve rates). The overall benefit outcomes were calculated by adding the cost of interconnected transmission lines.

Similar to the previous chapter's cost calculations, the method for adding the cost of the interconnected transmission lines was undertaken in the following way:

- The construction of the transmission lines was assumed to take place in 2025, with the full cost to be added that year.
- The O&M cost was assumed to be added annually from the following year of 2026.
- A discount rate of 10 percent was assumed, and net present value at the time of 2025 is calculated.
- The difference compared for both cases -- [without interconnection] minus [with interconnection] -- was calculated on a cumulative basis for the 10-year period from 2025 to 2035.

  * A plus value means gain in benefit.

The results of the above calculations are as follows:

Table 4.5: Estimated cost benefit of new transmission line

Case		Estimated cost benefit [mil.USD]		
		without interconnection line cost	net benefit with Route 1 line cost	net benefit with Route 2 line cost
A	THA-KHM	5,644	4,560	5,470
B	THA-LAO	21,387	19,282	20,604
C	THA-MYA	(352)	(4,607)	(2,766)
D	MYA-THA-MYS-SGP	5,628	(1,118)	3,064
E	VNM-LAO-THA	24,707	21,604	23,715
F	MYS-IDN	6,012	3,968	4,087
G	LAO-THA-MYS-SGP	27,490	23,217	26,557

* Numbers in brackets are negative.

Starting from the left, the table shows the results of calculating what the cost benefit would be in these cases:

- Interconnection line cost not included
- Interconnection line cost included for Route 1
- Interconnection line cost included for Route 2

4.5. Evaluating the calculation results

Based on the above calculation results, the following evaluations can be made:

- In Case G (interconnection between Laos, Thailand, Malaysia and Singapore) or in Cases E and B (interconnection between Thailand, Laos and Viet Nam), the cost-reduction arising from interconnection appears to be significant. Of the seven cases, the size of the cost benefit is largest in these cases.
- In Case A (interconnection between Thailand and Cambodia) and in Case F (between Malaysia and Indonesia), although the overall reduction amount is not as large as in B, E and G, there is a strong possibility of cost reductions even if the interconnection line cost is taken into account.
- In Case D (interconnection between Myanmar, Thailand, Malaysia and Singapore), a detailed assessment and cost reduction in constructing transmission line should be evaluated to uncover any potential benefit.

- In Case C (interconnection between Thailand and Myanmar), the cost increases following hydropower development; thus, immediate benefit from interconnected lines cannot be anticipated. However, it is possible to anticipate further increase of benefit in the longer term.

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

CHAPTER 5

KEY FINDINGS AND NEXT STEP

5.1. Key findings

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

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

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

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

This study performed a cost-benefit analysis for each of the many routes thought to be promising for grid interconnections. In this regard, the Lao-Thailand-Malaysia-Singapore route was found to possess great potential.

Table 5.1: Possible interconnection and cumulative cost benefit

Case		Estimated cost benefit [mil.USD]		
		without interconnection line cost	net benefit with Route 1 line cost	net benefit with Route 2 line cost
A	THA-KHM	5,644	4,560	5,470
B	THA-LAO	21,387	19,282	20,604
C	THA-MYA	(352)	(4,607)	(2,766)
D	MYA-THA-MYS-SGP	5,628	(1,118)	3,064
E	VNM-LAO-THA	24,707	21,604	23,715
F	MYS-IDN	6,012	3,968	4,087
G	LAO-THA-MYS-SGP	27,490	23,217	26,557

* Numbers in brackets are negative.

Just how significant is the calculated economic benefit? Consider Laos where the GDP in 2011 was USD8,162 million. Similarly, in Cambodia, the nominal GDP that year was USD12,890 million. In Brunei, it was USD16,693 million. The calculated economic benefit is an amount greater than all of these GDP figures.

In addition, if the cost of constructing coal-fired power infrastructure is assumed to be USD2,000/kW, the resulting benefit would be equivalent to approximately 10 or more ~~of~~ coal-fired power plants, each with a capacity of 1,000MW. In light of all these, there is indeed ~~a~~ sufficiently large economic benefit to be gained from grid interconnection.

Table 5.2: Cost benefit and equivalent investment

Case		Possible cumulative cost benefit range [mil.USD]	Equivalent investment cost for 1,000MW CPP [unit]	Equivalent investment cost for 400MW Gas CCGT [unit]
A	THA-KHM	4,560 -- 5,470	2	14 -- 17
B	THA-LAO	19,282 -- 20,604	9 -- 10	60 -- 64
C	THA-MYA	(4,607) -- (2,766)	-	-
D	MYA-THA-MYS-SGP	(1,118) -- 3,064	0 -- 1	0 -- 10
E	VNM-LAO-THA	21,604 -- 23,715	10 -- 11	68 -- 74
F	MYS-IDN	3,968 -- 4,087	1 -- 2	12 -- 13
G	LAO-THA-MYS-SGP	23,217-- 26,557	11 -- 13	73 -- 83

CPP: Coal-fired Power Plant USD2,000/kW

Gas CCGT: Gas-fired Combined Cycle Gas Turbine USD800/kW

* Numbers in brackets are negative.

What should be considered here is the size of the investment in interconnected lines. For instance, for the Laos-Thailand-Malaysia-Singapore route where the greatest benefit can be expected, the cost is estimated to reach USD 4,273 million. This is equivalent to approximately 52 percent of the GDP of Laos, as previously noted. Such big investment requires capital and manpower. In order to avoid a situation where construction of all the candidate routes were to commence at the same time, thereby running into physical difficulties, it would be necessary to set priorities wherein the prioritisation applied should consider the benefits and feasibility of each route.

Based on the potential economic benefits to be gained, routes B, E and G belong to the group of top priority among all the routes evaluated in this study.

Table 5.3: Possible interconnection line and their priority

Case		Possible cumulative cost benefit range [mil.USD]	Estimated cost of trasmission line [mil USD]	
A	THA-KHM	4,560 -- 5,470	162 -- 1,009	second priority
B	THA-LAO	19,282 -- 20,604	728 -- 1,957	first priority
C	THA-MYA	(4,607) -- (2,766)	2,244 -- 3,956	need careful assess.
D	MYA-THA-MYS-SGP	(1,118) -- 3,064	2,384 -- 6,272	need careful assess.
E	VNM-LAO-THA	21,604 -- 23,715	922 -- 2,885	first priority
F	MYS-IDN	3,968 -- 4,087	1,790 -- 1,901	second priority
G	LAO-THA-MYS-SGP	23,217-- 26,557	868 -- 4,273	first priority

* Numbers in brackets are negative.

Plans are already set in motion by the HAPUA to realize a grid interconnection in ASEAN. Thus, there is a need to confirm whether the candidate lines selected by this study conform with the plans that HAPUA is currently advancing.

It should be noted that first and foremost, each of the routes selected by this study has also been proposed by HAPUA. Second, the largest total transmission capacity of any of the lines currently under construction in the HAPUA plans is that of the Viet Nam-Laos-Thailand line, the same priority plan proposed by this study. And third, this study and HAPUA conform in terms of the recognition of a Thailand-Myanmar line as a future interconnection candidate.

Beyond the above, however, there is a need to establish the differences in the methodology employed by this study as compared to that of HAPUA. This study is the result of analysis focused only on economic considerations. On the other hand, HAPUA's assessment took into account another criterion meant to evaluate benefits of new interconnections beyond the economic realm. . For instance, even if a line does not produce as large an economic benefit as other lines, if it contributes to regional economic integration and the power supply, there are instances where that line might receive high prioritisation in the HAPUA plans. Indeed, decisions on selecting the appropriate interconnected lines should be based on a comprehensive set of criteria that considers a variety of aspects in addition to economic reasons.

Despite the slightly different approach, the results of this study can be said to generally conform with the plan being promoted by HAPUA. In addition, while HAPUA's construction plans generally set a target of 2020, this study considers the accumulated benefit from 2020 to 2035, and is thus an extension of the HAPUA plans.

Table 5.4: HAPUA lead plan

		Existing	On-Going	Future	Total
Northern System		2,629	6,550	17,004	26,183
9	Thailand - Lao PDR	2,111	3,352	3,095	8,558
10	Lao PDR - Vietnam	248	2,898	TBD	3,146
11	Thailand - Myanmar	-	-	11,709	11,709
12	Vietnam - Cambodia	170	-	-	170
13	Lao PDR - Cambodia	-	300	-	300
14	Thailand - Cambodia	100	-	2,200	2,300
Southern System		450	600	1,800	2,850
1	P.Malaysia - Singapore	450	-	600	1,050
4	P.Malaysia - Sumatra	-	600	-	600
5	Batam - Singapore	-	-	600	600
16	Singapore - Sumatra	-	-	600	600
Eastern System		-	430	800	1,230
6	Sarawak - W.Kalimantan	-	230	-	230
7	Philippines - Sabah	-	-	500	500
8	Sarawak - Sabah - Brunei	-	200	100	300
15	E.Sabah - E.Kalimantan	-	-	200	200
Northern-Southern Link		380	100	300	780
2	Thailand - P.Malaysia	380	100	300	780
Southern-Eastern Link		-	-	3,200	3,200
3	Sarawak - P.Malaysia	-	-	3,200	3,200
Grand Total		3,459	7,680	23,104	34,243

Source: HAPUA

Based on the above analysis, this study makes the following proposals.

- Accelerate construction of the Viet Nam – Laos – Thailand – Malaysia - Singapore interconnection line.
- Place increased priority on the Thailand-Cambodia line.

Going back to the premise of this study, the economic benefit to be gained from the Viet Nam-Laos-Thailand-Malaysia-Singapore line is huge. There already exists a transmission link connecting these countries and plans are underway to reinforce that line. However, in order to enjoy the benefits that would arise from such an interconnection line to the greatest extent possible, it is desirable to further enhance transmission capacity and accelerate construction.

Although a Thailand-Cambodia line already exists, work has not yet begun on capacity addition. As the benefits that could possibly be gained from line capacity enhancements are quite large, it is desirable to promote the prioritisation of that line.

What must be highlighted here is the extent of progress on power resource development. The benefit to be gained from this grid interconnection will be achieved through the development and use of hydropower generation in Laos and Cambodia. In other words, the strengthening of the grid interconnection must be done alongside the improvement of hydropower generation capacities in both countries. Although both countries have a high hydropower generation potential, there is a need for complex adjustments among the Mekong Basin countries within the development of the main current of the Mekong River in particular. Should the development of power resources be delayed, the investment in the international grid interconnections will be wasted.

In addition, the need to strengthen electricity supply networks in each country and to adjust systems to make the transmission of power possible has to be emphasised. This study has illustrated a route from Myanmar to Singapore but in order to realise the transfer of power along such a route, each country would need to have 500kV main lines and a systematic guarantee of third party access.

As mentioned earlier, the interconnection routes for both HAPUA's and this study are very similar. HAPUA began its activities of strengthening grid interconnections in the region much ahead of this study. But it is unfortunate that progress has not gone well in some parts. It is therefore important for this study to have a sufficient recognition of the reasons behind this inasmuch as the causes of the delay of the APG plan may end up delaying the construction of the priority routes proposed by this study as well.

In this connection, the following points relating to the possible reasons for delays in the HAPUA plans were discussed in the WG meetings for this study:

- Systems and regulations related to the grid interconnections of relevant countries differ. Relatedly, there has not been sufficient bilateral or multilateral discussion and coordination in order to promote construction.

- **The investment environment is not transparent; hence, it does not**

attract sufficient private companies and foreign capital. Accordingly, there has not been ~~a~~ sufficient provision of capital.

Because the framework devised by HAPUA does not pursue economic benefits alone, the plan is unable to gather sufficient investments in the form of private and foreign capital. Therefore, direct and indirect participation by governments, including construction by public power companies, becomes indispensable.

In light of this, there is room for improvement in terms of relations between countries. For instance, in Europe, the European Commission (EC) is constructing unified regulation and market systems with the goal of achieving increasing benefits for all member states. In addition, the EC is also unifying regional power markets as well as selecting routes for which construction should be prioritised in order to improve the stability of supply. It is also offering capital support for this. It is believed that interstate frameworks are functioning effectively for the construction of a region-wide power transmission network running across national borders.

In the EAS region, the creation of a framework with the goal of streamlining the enhancement of benefits for the entire region could be expected to encourage the creation of grid interconnections. Specifically, taking the European experience as a case study, there is a group comprising the regulating bodies of each country, and a group comprising the power transmission companies of each country. These groups set the common regulations they believe should be applied, create common development plans, and set obligations that each country within the region is expected to equally follow. Because each county would have to relinquish part of its own market regulatory functions for this, there would likely be strong resistance to the formulation of such a system. However, this can also be said to be the logical choice, building on the great push towards the creation of the ASEAN Economic Community in 2015.

5.2. Next Step

Based on the results of the quantitative analysis done in this study of the potential economic benefits and costs stemming from international grid interconnections based on certain preconditions, a number of priority routes were selected.

It is hoped that ultimately, actual investments will be made to realise the construction of these routes and to reap the benefits expected to be gained. While the results of the analysis in this research may lead to further discussion and decisions, it has to be acknowledged that a number of issues had been insufficiently addressed in this study. For instance, there has to be a closer examination of the route selection for power transmission lines and of the cost calculations. In addition, certain barriers in terms of policies and, technology, among others, are believed to exist that affect the actual realisation of grid interconnections. These issues need to be addressed because the reliability of the analysis of this research would be improved by addressing these points which have been insufficiently analyzed at the moment. That is therefore the next step. And it is hoped that the improvement of the validity of this analysis will create an opportunity for the realization of investment. That is the direction aimed at by this study.

Appendix 1. Power generation mix in each case (2035)

(Case 0: 2035)

Unit: TWh

	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
Coal	0	0	316	187	133	49	322	8	14	7	88	3	1,126
Oil	0	0	0	0	0	0	0	0	1	0	0	0	1
Natural gas	61	8	231	166	31	254	136	21	0	0	49	31	989
Hydro	0	0	92	18	8	4	51	11	54	15	187	15	457
Nuclear & geothermal	0	0	65	0	12	23	29	0	0	0	0	0	128
Others	5	0	29	0	1	26	0	4	0	0	0	0	66
Net imports	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	66	8	733	372	186	355	539	45	69	22	325	49	2,767

(Case 1: 2035)

Unit: TWh

	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
Coal	0	0	315	157	133	49	316	17	41	14	96	3	1,141
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural gas	53	6	239	195	32	225	141	14	0	0	45	30	978
Hydro	0	0	92	18	8	4	51	11	54	15	187	15	457
Nuclear & geothermal	0	0	65	0	12	23	29	0	0	0	0	0	128
Others	5	0	29	0	1	26	0	4	0	0	0	0	66
Net imports	8	2	-6	1	-1	29	2	-2	-26	-7	-3	1	-2
Total	66	8	733	372	186	355	539	45	69	22	325	49	2,767

(Case 2a: 2035)

Unit: TWh

	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
Coal	0	0	182	91	109	48	119	0	29	3	82	0	662
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural gas	53	6	201	189	33	128	85	0	0	0	0	0	695
Hydro	0	0	265	88	32	16	240	95	81	35	319	56	1,227
Nuclear & geothermal	0	0	65	0	12	23	29	0	0	0	0	0	128
Others	5	0	29	0	1	26	0	4	0	0	0	0	66
Net imports	8	2	-9	4	-1	115	65	-55	-41	-16	-76	-8	-12
Total	66	8	733	372	186	355	539	45	69	22	325	49	2,767

(Case 2b: 2035)

Unit: TWh

	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
Coal	0	0	313	146	133	49	304	17	41	14	96	3	1,115
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural gas	53	6	240	194	32	122	82	14	0	0	45	30	818
Hydro	0	0	92	30	8	4	51	77	74	24	264	28	652
Nuclear & geothermal	0	0	65	0	12	23	29	0	0	0	0	0	128
Others	5	0	29	0	1	26	0	4	0	0	0	0	66
Net imports	8	2	-6	2	-1	132	72	-67	-46	-16	-80	-11	-12
Total	66	8	733	372	186	355	539	45	69	22	325	49	2,767

(Case 3: 2035)

Unit: TWh

	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
Coal	0	0	310	140	133	48	315	17	41	14	96	3	1,117
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural gas	25	3	224	124	32	76	44	14	0	0	45	30	616
Hydro	0	0	92	30	8	4	51	259	93	35	268	28	868
Nuclear & geothermal	0	0	65	0	12	23	29	0	0	0	0	0	128
Others	5	0	29	0	1	26	0	4	0	0	0	0	66
Net imports	36	5	13	78	-1	178	99	-250	-65	-27	-83	-11	-28
Total	66	8	733	372	186	355	539	45	69	22	325	49	2,767

Appendix 2. Power trade in each case (2025, 2030 and 2035)

(Case 1: 2025)

To: Unit: TWh

From:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
SGP													0.0
BRN													0.0
IDN				14.9									14.9
MYS	9.6	1.2	0.2			4.4							15.5
PHL													0.0
THA				1.5									1.5
VNM									17.0	3.4	0.4		20.8
MYA						4.8						10.1	14.9
LAO						62.6				1.4	0.1		64.0
KHM						11.0			0.0				11.0
YNN							1.8	9.4	22.7				33.8
NEI													0.0
Total	9.6	1.2	0.2	16.3	0.0	82.8	1.8	9.4	39.7	4.8	0.5	10.1	176.4

(Case 1: 2030)

To: Unit: TWh

From:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
SGP				0.1									0.1
BRN				0.0									0.0
IDN				9.0									9.0
MYS	9.4	1.3	0.4			2.7							13.9
PHL													0.0
THA				1.0									1.0
VNM									9.3	3.2	0.2		12.7
MYA						2.5						6.9	9.4
LAO						52.2				0.9	0.6		53.6
KHM						11.1	0.1		0.0				11.3
YNN							1.5	2.5	18.8				22.8
NEI													0.0
Total	9.4	1.3	0.4	10.1	0.0	68.5	1.6	2.5	28.1	4.1	0.7	6.9	133.7

(Case 1: 2035)

From: \ To:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
												Unit: TWh	
SGP				0.1									0.1
BRN				0.1									0.1
IDN				6.9									6.9
MYS	7.9	1.8	0.4			0.2							10.2
PHL													0.0
THA				4.5				0.1	0.5				5.1
VNM									0.4	1.1	0.6		2.1
MYA						0.6					0.1	1.5	2.1
LAO						27.4	0.9			0.5	3.7		32.6
KHM						6.8	1.1		0.3				8.2
YNN							1.8	0.3	5.2				7.4
NEI													0.0
Total	7.9	1.8	0.4	11.6	0.0	35.0	3.8	0.4	6.4	1.6	4.4	1.5	74.7

(Case 2a: 2025)

From: \ To:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
												Unit: TWh	
SGP				0.0									0.0
BRN													0.0
IDN				15.4									15.4
MYS	9.5	1.5	0.3			3.3							14.6
PHL													0.0
THA				2.1									2.1
VNM									17.6	3.5	0.5		21.5
MYA						11.6						2.1	13.7
LAO						61.9				1.4	0.0		63.3
KHM						11.0			0.0				11.0
YNN							2.6	6.7	22.8				32.1
NEI								1.8					1.8
Total	9.5	1.5	0.3	17.5	0.0	87.8	2.6	8.6	40.4	4.8	0.5	2.1	175.6

(Case 2a: 2030)

To: Unit: TWh

From:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
SGP				0.2									0.2
BRN				0.0									0.0
IDN				8.9									8.9
MYS	9.4	1.5	0.4			1.1							12.4
PHL													0.0
THA				2.2					0.0				2.3
VNM									4.1	2.5	0.3		6.9
MYA						39.3						1.0	40.3
LAO						53.9	0.2			1.0	0.6		55.6
KHM						14.6	0.2		0.1				14.8
YNN							7.6	2.1	12.8				22.6
NEI								4.3					4.3
Total	9.4	1.5	0.4	11.3	0.0	108.9	8.0	6.4	16.9	3.5	0.9	1.0	168.1

(Case 2a: 2035)

To: Unit: TWh

From:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
SGP				0.2									0.2
BRN				0.1									0.1
IDN				9.2									9.2
MYS	8.0	1.8	0.4			0.6							10.8
PHL													0.0
THA				5.6					0.1				5.7
VNM													0.0
MYA						65.9					0.4	0.5	66.8
LAO						46.7	4.9			0.2	0.7		52.6
KHM						12.9	2.8		0.2				15.9
YNN							60.1	4.4	11.8				76.4
NEI								8.0					8.0
Total	8.0	1.8	0.4	15.0	0.0	126.1	67.8	12.4	12.1	0.2	1.1	0.5	245.4

(Case 2b: 2025)

	To:											Unit: TWh	
From:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
SGP													0.0
BRN													0.0
IDN				14.7									14.7
MYS	9.6	1.2	0.2			4.2							15.2
PHL													0.0
THA				1.6									1.6
VNM									15.8	3.4	0.1		19.3
MYA						16.9						0.1	17.0
LAO						62.8				1.4			64.2
KHM						13.3	0.0		0.0				13.4
YNN							11.8	11.4	24.0				47.2
NEI								0.3					0.3
Total	9.6	1.2	0.2	16.3	0.0	97.2	11.8	11.7	39.8	4.8	0.1	0.1	192.8

(Case 2b: 2030)

	To:											Unit: TWh	
From:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
SGP				0.2									0.2
BRN				0.0									0.0
IDN				7.5									7.5
MYS	9.4	1.4	0.4			1.1							12.2
PHL													0.0
THA				2.1									2.1
VNM									7.8	2.4			10.2
MYA						66.8							66.8
LAO						57.6	0.4			0.5	0.1		58.6
KHM						16.9	0.4		0.2				17.5
YNN							31.8	4.5	23.5				59.8
NEI								6.0					6.0
Total	9.4	1.4	0.4	9.7	0.0	142.3	32.6	10.5	31.5	2.9	0.1	0.0	240.8

(Case 2b: 2035)

To: Unit: TWh

From:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
SGP				0.1									0.1
BRN				0.1									0.1
IDN				6.5									6.5
MYS	7.9	1.8	0.4			0.6							10.6
PHL													0.0
THA				5.9					0.1				6.1
VNM										0.1			0.1
MYA						81.8					0.4		82.2
LAO						49.5	7.6			0.4	0.8		58.4
KHM						13.0	2.9		0.1				16.1
YNN							64.0	4.6	12.2				80.8
NEI								11.2					11.2
Total	7.9	1.8	0.4	12.6	0.0	144.9	74.6	15.7	12.4	0.5	1.2	0.0	272.0

(Case 3: 2025)

To: Unit: TWh

From:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
SGP													0.0
BRN													0.0
IDN				40.0									40.0
MYS	56.1	1.4	0.4			3.1							61.0
PHL													0.0
THA				20.8									20.8
VNM										65.5			65.5
MYA						4.5						2.0	6.4
LAO						58.3							58.3
KHM						80.6							80.6
YNN							25.8	0.0	25.0				50.8
NEI								0.1					0.1
Total	56.1	1.4	0.4	60.8	0.0	146.5	25.8	0.1	25.0	65.5	0.0	2.0	383.6

(Case 3: 2030)

To: Unit: TWh

From:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
SGP													0.0
BRN				0.0									0.0
IDN				16.4									16.4
MYS	58.7	1.7	1.5										61.9
PHL													0.0
THA				46.6									46.6
VNM										46.0			46.0
MYA						77.0							77.0
LAO						74.6				0.0			74.6
KHM						67.3	0.6						67.9
YNN							38.5	1.1	25.3				64.9
NEI								6.0					6.0
Total	58.7	1.7	1.5	63.0	0.0	218.8	39.1	7.1	25.3	46.0	0.0	0.0	461.0

(Case 3: 2035)

To: Unit: TWh

From:	SGP	BRN	IDN	MYS	PHL	THA	VNM	MYA	LAO	KHM	YNN	NEI	Total
SGP													0.0
BRN													0.0
IDN				0.6									0.6
MYS	35.8	4.8	14.2										54.8
PHL													0.0
THA				136.6						0.6			137.2
VNM										5.7			5.7
MYA						264.7							264.7
LAO						54.7				24.3			78.9
KHM						14.3	42.8						57.1
YNN							64.7	4.5	14.3				83.5
NEI								11.1					11.1
Total	35.8	4.8	14.2	137.2	0.0	333.6	107.5	15.6	14.3	30.5	0.0	0.0	693.6

Appendix 3. Cumulative costs up to 2035
(differences compared to Case 0)

Unit: USD million

	Case 0	Case 1	Case 2b	Case 3
Initial cost	0	-3,308	6,276	16,482
Fuel cost	0	-3,882	-15,790	-27,070
O&M cost	0	-1,883	2,952	6,827
Total cost	0	-9,073	-6,562	-3,761