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ENERGY MARKET INTEGRATION IN EAST ASIA: RENEWABLE ENERGY AND ITS DEPLOYMENT INTO THE POWER SYSTEM

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TABLE OF CONTENTS

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EXECUTIVE SUMMARY

1. Background and Objectives

Since the inception in 2005 of the EAS ECTF Workstream on Energy Market Integration, the research has been actively promoted by East Asia Governments to better understand matters impacting on energy trade liberalization and investment, energy infrastructure, pricing reform, and deregulation of domestic energy markets.

For each EMI study, a theme is selected to provide a key focus for the study. Past EMI studies focused on the review on the regional commitment of EAS countries, the benefits from EMI, the electricity market, theories, and subsidies. The EMI 2012-13 study focuses on renewable energy (RE), particularly the deployment of the RE into the electricity grid. The objectives for EMI 2012-13 are to (i) contribute to debate on the role of RE in EMI; (ii) deepen understanding for RE penetration into electricity systems; (iii) investigate the trade barriers for RE Technologies and Commodities (RETCs); and (iv) analyze price mechanisms and impacts of fossil fuel subsidies.

For EMI 2012-13, the following topics were studied:

1. Trends and prospects for the renewable energy sector in the EAS region;
2. The integrated Nordic power market and the deployment of renewable energy technologies: Key lessons and potential implication for future EAS integrated power market;
3. Renewable energy integration in a liberalized electricity market: A New Zealand case study;
4. Toward an integrated renewable energy market in the EAS region: Renewable energy equipment trade, market barriers and drivers;
5. Renewable energy and policy options in an integrated EAS electricity market: Quantitative assessment and policy implications;
6. Facilitating the penetration of renewable energy into the power system;
7. Renewable energy development in Cambodia: Status, prospects and policies;
8. Implications of cash transfers of subsidies in the energy sector in India
9. International oil price, national market distortion and output growth: Theory and evidence from China;

10. Economic growth, regional disparities and energy demand in China: Implication for energy market integration in East Asia.

2. Key Findings

The studies found that future growth in RE in EAS countries will come from wind, solar and biofuel products, which are becoming competitive with fossil fuels due to technological breakthrough and the falling costs of RE production. In the EAS region, there is also potential for growth in geothermal power and hydropower, especially involving the hydro resources in the relatively less-developed economies such as Cambodia, Myanmar and the Laos.

EAS countries will follow a development trajectory where larger shares of variable RE will play greater role in the electricity generation mix. However, the studies found that RE electricity production is variable and uncertain, thus posing a greater challenge for RE penetration. There is a need to improve our understanding of the economics of deployment of RE electricity technologies, particularly the cost and benefits associated with the integration of renewables in the longer term and from a system perspective.

The Nordic/Europe region has, for many years, been developing and integrating their electricity (and gas) market. From the outset, functioning market institutions are a pre-requisite for an electricity market when there is a number of countries and diversity across their generation mix, their renewable energy technologies (RET) policies, and the ownership of production. In the Nordic example, the market institution combines the role of regulation, TSO and spot pool, and, this institution has provided the foundation for a well-functioning power exchange, smooth interaction with the neighbouring European power markets, and adequate levels of information and transparency in the exchange market.

Over the years, many lessons have been learnt by the Nordic market that will have parallels and will provide options that could mesh with the aspirations of the EAS region to integrate its national markets. For the Nordic region in particular, this includes the integration of RE options into their regional electricity market. The Nordic experience found that decisive policy support (in particular to overcome cost barriers) has been essential for the development of RE sources and the deployment of renewable energy technologies (RETs) for power generation. Within this context, Feed-In Tariffs (FiT) have proven to be one of the effective support mechanisms to overcoming cost barriers and reduce financial uncertainty for the wholesale power market. In addition, indirect policy support such as carbon pricing and reduction targets for GHG emissions have also promoted a much better investment climate for RETs. Within this institutional framework and policy support, the studies also found that regional power infrastructure development has laid the foundation for power trade within the Nordic and with European neighbours.

The finding from New Zealand's case study also confirmed that FiT have been effective in supporting RE power generation projects to cope with high set-up costs and high connection costs. Carbon trading has been established under the Climate Change Response (Emissions Trading) Amendment Act 2008 and the Electricity (Renewable Preference) Amendment Act 2008: this legislation enables the RE electricity generators to effectively price the cost of carbon into the price of electricity, and thus attract investment into RE generation.

While progress has been made on increasing RE in the electricity mix in the EAS region, some countries lag behind due to trade and non-trade barriers on the deployment and utilization of the RETs and end-user appliances. One of the studies analyses the prospects of an integrated RE market in the EAS region from the vantage point of trade in Renewable Energy, Technologies and Commodities (RETC) and the, associated market barriers and major drivers. It found that the EAS region has huge potential for RETC trade which will eventually pave the way for enhanced RE use. Despite this potential, factors such as the current high tariff rates inhibit the growth of RETC trade in the region (see Table 1).

Table 1: Import Tariff Rates on RETC in the EAS Countries

Country	Tariff (%)	Country	Tariff (%)
Australia	0.8	Malaysia	4.8
Brunei Darussalam	11.7	Myanmar	1.8
Cambodia	12.5	New Zealand	1.4
China	8.5	Philippines	4.5
India	9.4	Russian Federation	11.4
Indonesia	2.6	Singapore	0.0
Japan	0.7	Thailand	6.2
Republic of Korea	6.8	United States	2.1
Lao PDR	6.7	Vietnam	6.2

Source: WTO Integrated Trade Database 2013.

Targeting the electricity mix with RETs is seen as a clear step toward abatement of GHG emissions and thus contribute to regional ‘green growth’. One of the studies uses economic simulation to test the best options for FiT policy and Renewable Portfolio Standards (RPS). A Renewable Portfolio Standard is a regulation that requires the increased production of energy from renewable energy sources, such as wind, solar, biomass, and geothermal. For RPS, the study tests what percentage of RE in the total electricity supply is most cost-effective. For FIT, it tests the level of the FIT that is the optimum to ensuring RE investment and minimising the consumer burden. See Table 2 for key assumptions/parameters of the scenarios.

Table 2: Key Assumptions/parameters of the Scenarios

Scenario	Description
BAU (No Carbon Costs or EMI)	Business-As-Usual (BAU) with no carbon costs1 or EMI imposed on the power sector
BAUCC (Carbon Costs with No EMI)	This scenario assumes that carbon costs are imposed on power generation but the region has no effective EMI to allow free cross-border power trade
BAUCCEMI (Carbon Costs with EMI)	Both carbon costs and EMI are implemented in the power sector of the region
FIT10	USD 10 / MWh of subsidy provided to electricity generated from renewable energy
FIT20	USD 20 / MWh of subsidy provided to electricity generated from renewable energy
FIT30	USD 30 / MWh of subsidy provided to electricity generated from renewable energy
FIT40	USD 40 / MWh of subsidy provided to electricity generated from renewable energy
FIT50	USD 50 / MWh of subsidy provided to electricity generated from renewable energy
RPS10	The share of renewable energy in total electricity is required to be above 10%
RPS20	The share of renewable energy in total electricity is required to be above 20%
RPS30	The share of renewable energy in total electricity is required to be above 30%
RPS40	The share of renewable energy in total electricity is required to be above 40%
RPS50	The share of renewable energy in total electricity is required to be above 50%
RPS60	The share of renewable energy in total electricity is required to be above 60%
RPS70	The share of renewable energy in total electricity is required to be above 70%
RPS30 by 2030	The share of renewable energy in total electricity is required to be above 30% from 2030 onwards
FIT10 RPS10	A Combination of FIT10 and RPS10

[1] Carbon costs usually come from Cap-and-Trade schemes for carbon emissions from specified sectors. Although ASEAN has no such scheme at the moment, carbon costs from other markets such as the Europe and U.S. could be applied to reflect the environmental cost of carbon emissions from power generation activities. Importantly, as our model is a sector model, it is not possible to endogenize carbon costs which are derived from multi-sector markets.

The results of the simulation show that, under the BAU scenario, RE will make moderate progress in the region, mostly driven by hydropower. The results also suggested that the costs-benefits optimization of implementing RPS30 by 2030 could be a low-hanging fruit to achieve moderate improvements in carbon emissions reduction and RE development while incurring negligible increases in the total cost of electricity.

A similar study has carried out using "trilogy approaches" to analyze the RE penetration into a power system. The first approach analyses the Diversity Index which has often been used by policy makers to understand the energy mix or degree of energy self-reliance. The second approach analyses the historical long term energy mix by employing the Autoregressive Moving Average (ARMA) model. The third approach analyses structure of electricity output by sources by using Markov Model (MM) for policy scenario analysis. The results of this study found that the shares of electricity production in EAS countries from renewable sources are still relatively low, except in the Philippine and New Zealand cases (see Table 3).

Table 3: Electricity Production by Sources (% of total)

No	Country	Oil		Coal		Natural gas		Renewable sources, excluding hydroelectric*	
		1971	2009	1971	2009	1971	2009	1990	2009
1	Brunei Darussalam	1.6	1.0	NA	0.0	98.4	99.0	0.0	0.0
2	Cambodia	NA	95.6	NA	0.0	NA	0.0	NA	0.5
3	Indonesia	56.0	22.8	NA	41.8	0.0	22.1	3.4	6.0
4	Lao PDR	NA	NA	NA	NA	NA	NA	NA	NA
5	Malaysia	72.4	2.0	NA	30.9	0.0	60.7	0.0	0.0
6	Myanmar	23.2	8.9	3.9	0.0	3.9	19.6	0.0	0.0
7	Philippines	99.9	8.7	0.1	26.6	0.0	32.1	22.4	16.8
8	Singapore	100.0	18.8	NA	0.0	0.0	81.0	0.0	0.1
9	Thailand	53.6	0.5	6.1	19.9	0.0	70.7	0.0	4.0
10	Vietnam	0.0	2.5	73.3	18.0	0.0	43.4	0.0	0.0
11	Australia	3.4	1.0	71.0	77.9	3.3	13.7	0.5	2.6
12	China	7.9	0.4	70.5	78.8	0.0	1.4	0.0	0.8
13	India	6.3	2.9	49.1	68.6	0.6	12.4	0.0	2.2
14	Japan	62.6	7.2	11.9	26.8	1.4	27.4	1.4	2.5
15	Korea, Rep.	80.6	4.4	6.9	46.2	0.0	15.6	0.0	0.4
16	New Zealand	2.0	0.0	4.8	7.6	0.3	20.6	8.2	15.9

Note: *includes geothermal, solar, tides, wind, biomass, and biofuels. NA is not available.
Source: World Development Indicators, the World Bank.

Although RE has been promoted among the EAS countries, the diversity index indicates that electricity production from fossil fuel has grown much faster than RE electricity production. The primary energy mix in electricity generation has become less diverse because some EAS countries continue to intensify their use of coal-firing. The ARMA model and Markov model also confirmed that the share of RE (excluding hydropower) will increase marginally and most EAS countries will continue to rely on the fossil fuels for electricity generation. Facilitating the penetration of RE needs to be urgently discussed among EAS members.

To understand the potential for RE in a developing economy in the EAS, a case study of Cambodia was undertaken. Cambodia's RE resource has a substantial potential to contribute to national economic development and environmental sustainability. However, RE is not widely known to Cambodia's policy makers, implementers, and population. In addition, high expectations for developing Cambodia's large-scale hydropower projects and for imports from neighbouring countries may prompt the Cambodia Government to overlook the development of other RE resources. Few of Cambodia's potential RE resources have been developed to meet the immense electricity needs of the country, particularly for off-grid electricity, and to assist with Cambodia's electrification rate. Non-hydro RE resources in Cambodia, essentially biomass and solar, has the potential to expand electricity access for rural and remote areas and to bring down the cost of supplying electricity to these populations. The study also found that a developing economy will need institutional capacity building and a policy framework to disseminate RE technologies and promote such investment.

Throughout the EMI studies, evidence found that energy subsidies are widespread in EAS countries, and they vary greatly in their form and level of support. India's case study on energy subsidies through its Direct Cash Transfer Scheme (DCT) has aided our understanding of the approaches taken by the Government of India (GoI) to ensure that affordable energy commodities and services are available to lower income households. This approach is moving away from general subsidies to an approach more targeted to the economic poor. India provides major subsidies to the household, agriculture, industry, health, education and transportation sectors, and, for the last couple of years, the total subsidy provided by the GoI has been between 2-3 percent of GDP. The target is to contain this below 1.75 percent of the GDP in the next three years. This study suggests that continuation of these subsidies may not be possible due to the limits on domestic production of oil and gas, the rising cost of energy commodities, and the GoI's burgeoning fiscal deficit. Theoretically, any form of fossil-fuel subsidy will undermine RE development. However, the GOI has chosen the DCT Scheme as a step-wise approach to reduce the financial burden on the Government compared to the general subsidies of the past. The actual implementation of the DCT Scheme remains to be seen.

Pricing mechanisms remain a central discussion to EMI. Price regulation in the energy market, such as price caps and subsidies, has been practiced for a long time and is still prevailing in many EAS countries. Many policy makers prefer to have such price regulation on the grounds that these measures can insulate a domestic economy from the negative impacts of high global oil prices. However, many studies have found that the induced distortion may exert negative impacts. Contributing to this debate is the EMI study of oil price shocks, market distortion and output growth in China. This study found that oil price distortion hurts industrial growth in the short run and that this negative impact persists in the long run. Thus, price control is one important barrier to energy market integration and the finding of this study lends support to the energy market integration that many regions, such as East Asia, are advocating.

East Asia is actively promoting energy market integration (EMI), but such integration takes a long time and there is no clear picture as to its future shape. Contributing to this debate, the study on economic growth, regional disparities and energy demand in China attempts to explore a possible shape of an integrated energy market for East Asia by analyzing China's cross-province energy demand under a perfectly integrated energy market. Using the panel data of 30 provinces between 1978 and 2008, the study found that economic development tends to increase demand for energy, while EMI will, in general, reduce the response of price to the increased energy demand through cross-province trade in energy products. In addition, the effects of commodity price increases can be alleviated through reducing transportation costs and improving marketisation levels by privatization and deregulation. The findings of this study have important policy implications that suggest that EMI is beneficial to the EAS region through facilitating diversified energy demand/supply patterns across countries.

3. Policy Recommendations

The findings of the studies of the EMI study 2012-13 provide policy and recommendations for EAS countries and, to some extent, reflects implications for future ASEAN market integration.

Recommendation 1. ***Fostering EAS's RE aspirations and deployment targets*.**

EAS countries are strengthening the sharing of common goals on poverty alleviation, energy security, energy access, investment, and trade, which are substantially covered in bilateral/multilateral ASEAN agreements. These are important elements to fostering energy market integration among neighbouring EAS countries. As an early step towards EMI and RE deployment, EAS members could also develop RE deployment goals for each country within a target period that reflects the reality in each member's economy. EAS could tap the experience of the Nordic/Europe which suggests that RETs do not fit into current electricity market structures without their deliberate and positive support. Therefore, it is suggested that EAS countries should consider and evaluate regionally supported and harmonised policy options such as

- the development of clear but simple institutional framework of RE policy instruments (e.g. Feed-in-Tariff, tradable green certificate scheme) because it has a direct impact on the administrative burden faced by authorities and eligible actors;
- feed-in-tariffs combined with renewable portfolio standards (complemented with GHG pricing);
- tradable green certificates (complemented with GHG pricing);
- tax credits for R&D and production-based (per-kWh tax credits), and soft loans;

- the development of a long-term EAS multilateral finance model/fund(s), which aligns private and public sector investment (including regional development banks) to support low carbon infrastructure investment;
- a legal and enforceable framework that provides investors the assurance to invest in RE power infrastructure, new production, and storage options.

Recommendation 2. ***Establishment of the framework for a regional regulatory and power trading body for integrating a regional power system***. It will be necessary to set up a regional electricity regulatory and trading institution which is exclusively responsible for the promotion, harmonisation, implementation and enforcement of policies and regulations for an integrated power market and for RETs within that market. Key functions of a regulatory and trading institution include administering and enforcing power market regulation, accurate and high-quality information, equal access for all market participants, and guarantee of all trades and their delivery. Importantly, it could also provide a forum for regional coordination and cooperation across EAS governments in RE policies, investment, and technologies. The regional integration of EAS electricity markets, with RE as a key part of the electricity generation mix, may benefit from Nordic experience in their establishment of a regional regulatory and power trading institution.

Given the geographical spread of EAS countries, this recommendation is more immediately pertinent for ASEAN member countries. ASEAN countries should assess whether the current ASEAN Power Grid (APG) initiative and other ASEAN platforms such as the ASEAN Energy Regulators Network, which have the commitment of ASEAN Heads of States/Governments, could be the starting point for a functioning market institution as seen in the Nordic/Europe. Taking into account the relatively early stages of energy market integration in the ASEAN region, continuous and decisive political decisions will be crucial to developing an effective framework for the institution.

Recommendation 3. ***Removal of trade barriers on RE Technologies and Commodities (RETCs) is key to promoting utilisation of RE products and to supporting investment in RE technologies.*** Fostering the implementation of a "free trade" in goods and services of RE Technologies and Commodities (RETC) across EAS countries will reduce costs on RETC by the removal or reduction of import tariffs. This will also help address the problem of asymmetric technological development particularly in the smaller EAS economies. To support investment consideration into RETC in EAS countries, a proper analysis on the cash-flow is required. If the EMM so decides, ERIA is available to undertake a detailed cash-flow analysis on RETC investment.

Recommendation 4. ***Harmonisation and standardisation of RE technologies and products is necessary in an integrated regional market***. The Governments of EAS countries have a window of opportunity under the ASEAN "free trade agreement" and other trade facilities to review RE products and come up with "minimum operating standards". RETs are relatively new products in most EAS members, and EAS members will need to adopt common standards and practices. This is a prerequisite for EMI, and EAS countries may explore the best practices regionally and globally before developing a regional approach. If EMM so decides, ERIA is available to lend support into this further study.

Recommendation 5. ***Cross-border power infrastructure connectivity is necessary for an integrated power market that brings RE into the regional electricity mix***. The Nordic/Europe experience points to the implementation of the ASEAN Power Grid initiatives and interconnection with southern China as the starting point for a regional integrated power market. The Nordic integrated power market has been developed from separate national markets to a cross-border pan-regional trading market that heavily utilises RE power generation. An EAS regional market will develop at a different but gradual pace, initially forming sub-markets (e.g. country-to-country market coupling, followed by sub-regional market coupling), on the road towards wider regional integration. Here, the coordination of the involved EAS Governments and industry is crucial. The Nordic countries' and the European Union's legal developments have provided the guiding regulatory framework that has harmonized the practices across the European electricity markets to enable their interconnection. Similar attention will be required by EAS countries and further analysis and information gathering on the Nordic/European experience would be useful for EAS consideration. ERIA is available to further support this analysis.

Recommendation 6. *Institutional capacity building and development of financing mechanisms in RE are key to reducing the lead time for RE deployment*. Recognising each EAS country's level of development, study findings point to EAS countries requiring institutional capacity building and development of financial mechanisms to make RE deployment a possibility. Consequently, financial cooperation and capacity development amongst EAS countries are policy priorities to support developing member countries to embark on RE development. The New Zealand case study on policy support incentives for RE deployment highlighted similar experiences to the Nordic/Europe region, and these provide lessons and successes that could be replicated or tailored-to the EAS context.

Recommendation 7. *Removal of fossil fuel subsidies is key to initiating green development*. The Governments of EAS countries will need to review their national fossil fuel subsidies. The India case study pointed to a win-win policy reform by removing subsidies that are both economically costly and leading to greater fossil-fuel use. India has moved away from a general subsidy toward one that is more targeted to the economically poor population to ensure their welfare and access to energy.

Recommendation 8. ***EAS countries shall speed up the implementation of the Energy Market Integration as it provides benefits to economies at large*.** EMI studies highlighted the issue that, while economic development tends to increase energy demand, EMI, in general, reduces the response of prices to the increased energy demand. This important finding suggests that EMI would benefit the EAS region through facilitating a diversified energy trade pattern across member countries.

CHAPTER 1

Trends and Prospects of the Renewable Energy Sector in the EAS Region

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The rising prices of fossil fuels and the deteriorating world environment have made renewable energy the brightest business prospect in the energy sector. In fact, as the world's fossil fuel resources are limited and gradually depleting, renewable energy could be the main source of energy in the future. Thus, developments in the renewable energy sector could have important implications for the world. In particular, the East Asia Summit (EAS) countries as a group are net energy importers and hence have a keen interest in renewable energy development. This is not only related to energy consumption in the region but is also linked with the goal of promoting energy market integration within the EAS group. The objectives of this study are twofold, namely, a) to present a review of the trends in the renewable energy sector and b) to shed light on the prospects of development and growth in this sector within the EAS area. Specifically, this project will review the status and trends of renewable energy development among the EAS members. It will provide a comparative perspective in renewable energy policy and business development in the EAS region. It will explore the prospects of future development and growth in renewable energy and the role of renewable energy in energy market integration within the EAS energy sector.

Key words: Renewables, EAS group, energy market integration
JEL classification: Q40, Q42, Q47

1. Introduction

With the rising awareness of environmental degradation and rapid depletion of fossil fuel resources, renewable energies (REs or renewables) have attracted the attention of policy makers as well as energy experts worldwide. The East Asian Summit (EAS) nations as major energy consumers are also keen to develop their RE sectors. Many EAS countries have adopted specific policies to promote their RE sectors.[1] To gain more insight into the RE industry, this paper aims to present an overview of the status and trends of development in the RE sectors among EAS members. It will also discuss the implications of RE development for energy market integration (EMI) policy and business in the EAS region.

The rest of the paper starts with a review of the worldwide RE industry (Section 2). This is followed by discussion of the RE sector in the EAS economies (Section 3). The outlook for REs and the potential drivers for and hindrances to RE growth in the EAS region are then explored (Section 4). The key findings and policy recommendations are presented in Section 5.

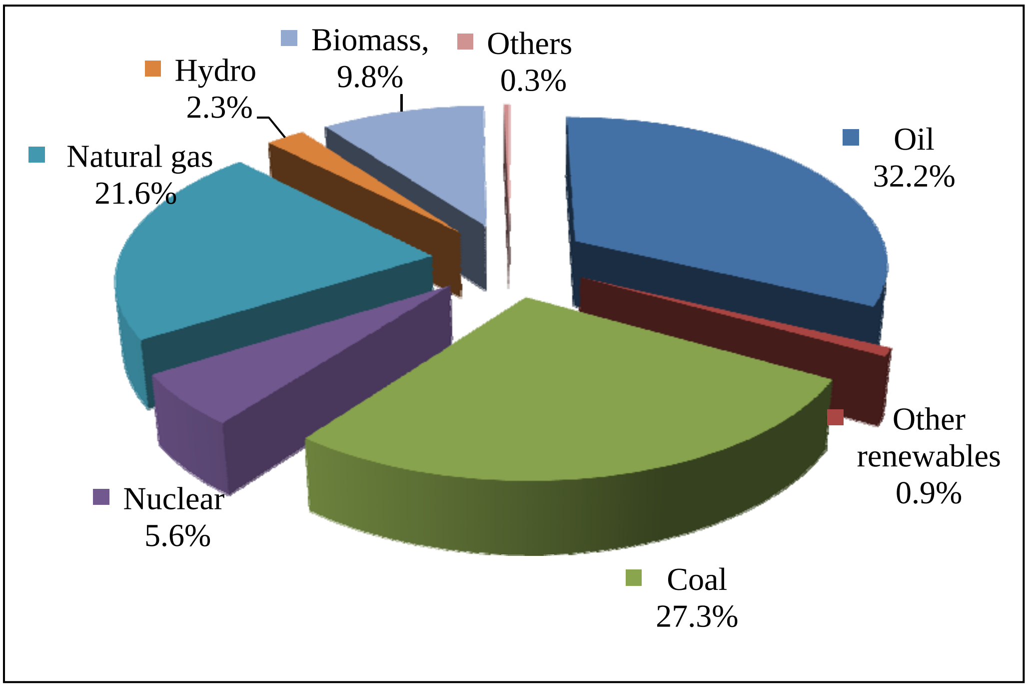
2. The Global RE Industry

REs broadly include energies sourced from sunlight (solar), water (hydro), wind, biomass, marine (wave), tides (tidal) and geothermal heat. In the existing literature the exact coverage of REs is not without controversy. For example, biomass can be divided into traditional and modern biomass. Traditional biomass includes wood, charcoal, crop residues and animal dung mainly used for cooking and heating, while modern biomass refers to biogas and liquid biofuels (such as biodiesel and biogasoline). The use of biomass could be sustainable or unsustainable (Goldemberg and Coelho 2004). Hydropower is generally classified into traditional or large hydroelectric power and small hydropower. The latter is assumed to be more environment-friendly. The measurement of REs by several key organizations also

[1]For detailed discussions of RE policies in the EAS region, see Olz and Beereport (2010), Ipsos (2012) and IRENA (2013b).

varies. A major problem is the measure of non-commercial–energies, which are dominated by traditional biomass. It is argued that about 20-40 per cent of biomass use is not reported in official energy statistics (IPCC 2012). Due to this complication, BP (2012) reports traded or commercial energy statistics only. According to the International Energy Agency (IEA), REs accounted for about 13.0 per cent of the world's total energy production in 2010, including 9.8 per cent from biomass, 2.3 per cent from hydroelectricity and 0.9 per cent from other REs (Figure 1). In recent years (2006-2010), REs globally recorded an average annual rate of growth of 3.05 per cent which is higher than the growth rate (2.31 per cent) of the world's total primary energy supplies (TPES) in the same period.[2]

Figure 1: Composition of Global Energy Production in 2010



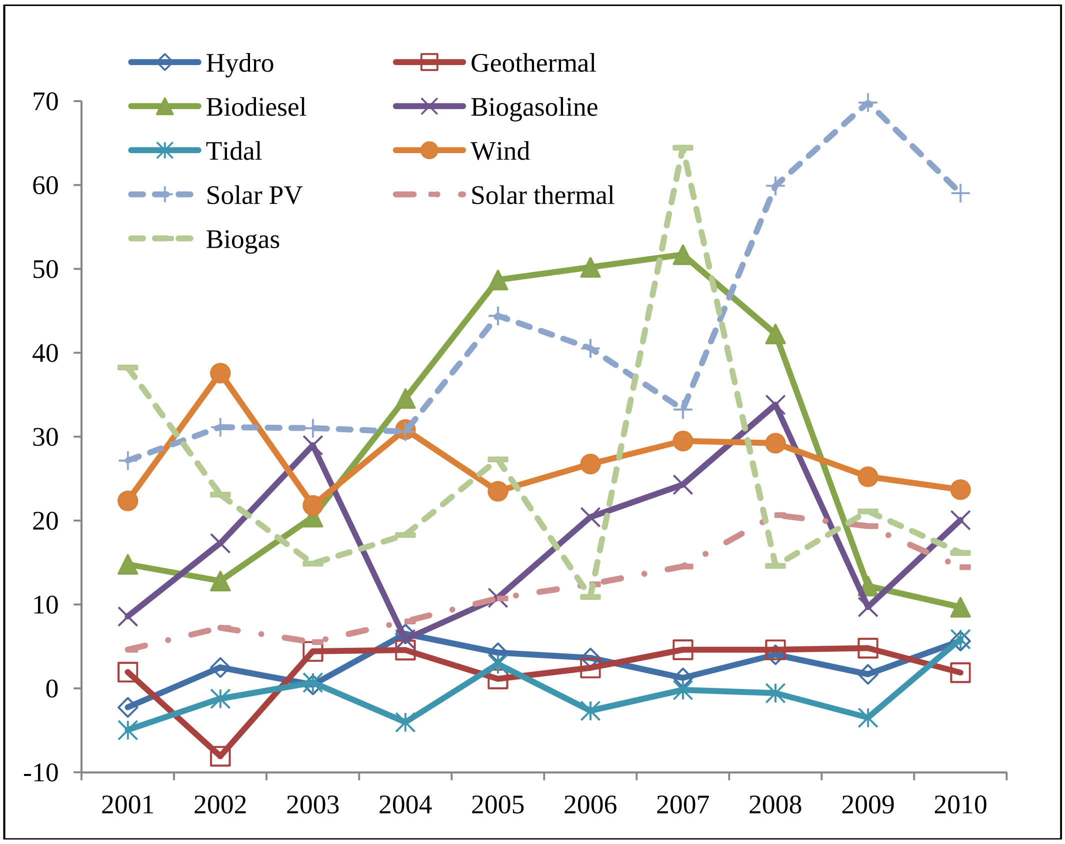
Source: IEA (2012a).

In absolute terms all RE supplies in 2010 totaled about 1657 million tonnes oil equivalent (Mteo) of which three-quarters are generated by biomass and renewable wastes, 18 per cent by hydro and 7 per cent by other REs (IEA 2012a). The latter include geothermal (4.0 per cent), wind (1.8 per cent) and solar and tide (1.2 per cent). Though the "other REs" have the smallest share, some products in this

[2] These growth rates are computed using data from the OECD (2013).

category have recorded high growth in production in recent years. For example, growth has been exceptionally high for solar photovoltaic (PV) and wind (Figure 2). Other products with two-digit growth rates include biofuels (biogases and liquid biofuels) and solar thermal energies, according to the same source. The main driving force for the rapid growth in REs is their declining production cost and hence falling RE prices in recent years.

Figure 2: Annual Growth Rates, 2001-2010



Note: The percentage growth rates are computed using data from the OECD (2013).

Regional shares of TPES and REs are presented in Table 1. As shown in this table, the underperforming regions (where RE shares are lower than their TPES shares) are the Middle East, OECD, and non-OECD Europe and Eurasia. In Africa, Latin America and Asia, REs have relatively high shares largely due to the use of biomass in these regions. In addition, the world's major energy consumers (top-5) accounted for about 52.7 per cent of the world's TPES in 2010 while their RE production share was only 37.5 per cent in the same period according to Table 1. Thus, the world's large energy consumers should boost their efforts to promote RE production and consumption.

Table 1: TPES and RE Shares by Region and in Selected Countries, 2010

Region/countries	TPES (%)	REs(%)
Latin America	5.0	11.1
Middle East	5.1	0.2
Africa	5.5	20.4
Non-OECD Europe and Eurasia	9.0	2.6
Asia	31.9	40.3
OECD	43.5	25.4
World	100.0	100.0
China	19.7	16.9
United States	17.8	7.5
Russian Federation	5.6	1.1
India	5.5	11.0
Japan	4.0	1.0
Sub-total	52.7	37.5

Note: TPES and RE are abbreviations for total primary energy supplies and renewable energy, respectively. The numbers are calculated by the author using raw data from the IEA (2012a).

The share of REs in TPES also varies across the groups. REs have relatively high shares in Africa, Asia and Latin America due to the dominant use of biomass (Table 2). For example, in Africa, biomass amounted to 96.9 per cent of total REs. In these regions, as commercial energies become more affordable, the share of biomass in TPES and REs is expected to decline and thus, the share of REs over TPES is also likely to decline over time. Globally, traditional biomass share over total REs fell from 50 per cent in 2000 to 45 per cent in 2010 (IEA 2012b).

Table 2: RE shares of Total Primary Energy Supplies (TPES) in 2010

Regions/countries	RE/TPES (%)	Biomass/RE (%)	Hydro/RE (%)	Others/RE (%)
Middle East	0.5	14.7	46.4	38.8
OECD	7.8	57.4	27.6	15.0
United States	5.6	67.2	18.0	14.7
Japan	3.3	36.1	42.6	21.3
Non-OECD Europe and Eurasia	3.9	36.4	61.8	1.8
Russian Federation	2.6	16.7	80.9	2.4
Africa	49.4	96.9	2.7	0.5
Latin America	29.8	65.6	32.5	1.9
Asia	37.1	81.0	12.6	6.4
China	11.4	72.1	22.2	5.7
India	26.5	93.5	5.4	1.1
World	13.0	75.2	18.0	6.8

Notes: TPES and RE are abbreviations for total primary energy supplies and renewable energy, respectively. The numbers are calculated by the author using raw data from the IEA (2012a).

There is also considerable variation among individual countries, reflecting the impact of energy policies and differences in resource endowment. As the largest energy consumer, China is also the largest RE producer and consumer (Table 1). In relative terms, REs only have a share of total consumption of less than 10 per cent in the US, Japan and Russia. If biomass is excluded from the REs, RE shares of TPES in 2010 were 3.2, 2.2, 2.1, 1.8 and 1.7 per cent in the world's top five energy consuming economies (China, Russia, Japan, the US and India), respectively. Therefore the role of REs is still small among the world's major energy players.

In absolute terms, China not only tops the list of the world's largest RE producers but is also the largest supplier of biomass and hydropower, and is second to the US in terms of other RE supplies (wind, solar and so on) (Table 3). In 2010, about 19.4 per cent of the world electricity was generated from REs (IEA 2012a). However, REs play the dominant role in power generation in some countries. For example, the percentage shares of electricity production from REs in 2010 were 100 in Iceland, 95.7 in Norway, 73.3 in New Zealand, 66.4 in Austria and 60.9 in Canada (IEA 2012a).

Table 3: Top-10 RE Supplies in the World (MTOE), 2010

Ranking	Total		Biomass		Hydro		Others	
1	China	280.3	China	202.1	China	62.2	United States	18.4
2	United States	124.9	Nigeria	94.8	Brazil	34.7	China	16.0
3	Brazil	116.7	United States	84.0	Canada	30.2	Mexico	5.9
4	Nigeria	95.4	Brazil	81.4	United States	22.5	Italy	5.9
5	Canada	42.9	Ethiopia	31.0	Russia	14.3	Germany	5.2
6	Germany	32.5	Pakistan	28.9	Norway	10.1	Spain	4.8
7	Pakistan	31.6	Germany	25.5	Venezuea	6.6	Iceland	3.3
8	Ethiopia	31.4	Congo	22.2	Sweden	5.7	Turkey	2.6
9	Congo	22.9	Tanzania	17.8	France	5.4	El Salvador	1.3
10	France	21.0	France	14.6	Paraguay	4.7	Kenya	1.2

Source: OECD (2013).

Due to resource and technology constraints there are considerable variations in the role of RE products among countries. For example, wind power generation has a significant share in total electricity generation in Denmark (21%), Portugal (18%), Spain (15%), Ireland (10%)and Germany (6%); geothermal sources account for more than a quarter of total electricity generated in Iceland, and more than a fifth in El Salvador and Kenya.[3]

In terms of consumption, REs are dominantly used in the residential, commercial and public sectors (with a share of 52.5 per cent in 2010). This is largely due to the use of biomass for cooking and heating in developing countries. Only 28.5 per cent of REs were used for electricity and heat production and 3.5 per cent were consumed in the transport sector. However, about a half of RE use in OECD countries is constitutes the production of electricity and heat (IEA 2012a). Overall, the role of REs in world energy has expanded and is still increasing. There are large differences across the country groups and between the RE products. In general, growth in hydro and geothermal energies is modest and that in traditional biomass has shown a declining trend. Further growth in REs will rely on biofuels, wind power and solar energies.

[3]These shares are calculated using the data of electricity production from the World Bank (2012), wind energy supply from IEA (2012a) and geothermal energy supply from the OECD (2013).

3. REs in the EAS Economies

In 2010, EAS economies as a group accounted for 35.7 per cent of the world's TPES (Table 4). In the same year the group also supplied 38.6 per cent of the world's REs.[4] In terms of product mix, EAS economies have done proportionately better in biomass and other REs according to Table 4. Three EAS members, namely China, Japan and India, are among the world's top-5 energy consumers as shown in Table 1. However neither Japan nor India is listed as the world's top-10 RE producers (Table 3). Several relatively low income countries, such as, Myanmar, Cambodia and the Laos still rely largely on biomass as the main source of energy supplies (Table 4).

Overall, about 14 per cent of the EAS group's TPES were drawn from REs in 2010. This figure is compatible with the world average (13 per cent) in the same year. Similar to the world trend, biomass dominates REs in the EAS region as well. In general, the EAS as a group follows the global trend in RE development, although some EAS members such as, Brunei, Singapore, South Korea, Japan, Australia and Malaysia seem to be lagging behind (Table 4). These variations, in terms of country as well as product mix are described in detail below.

[4] This figure is estimated using the numbers in Table 4.

Table 4: RE shares in EAS Economies, 2010

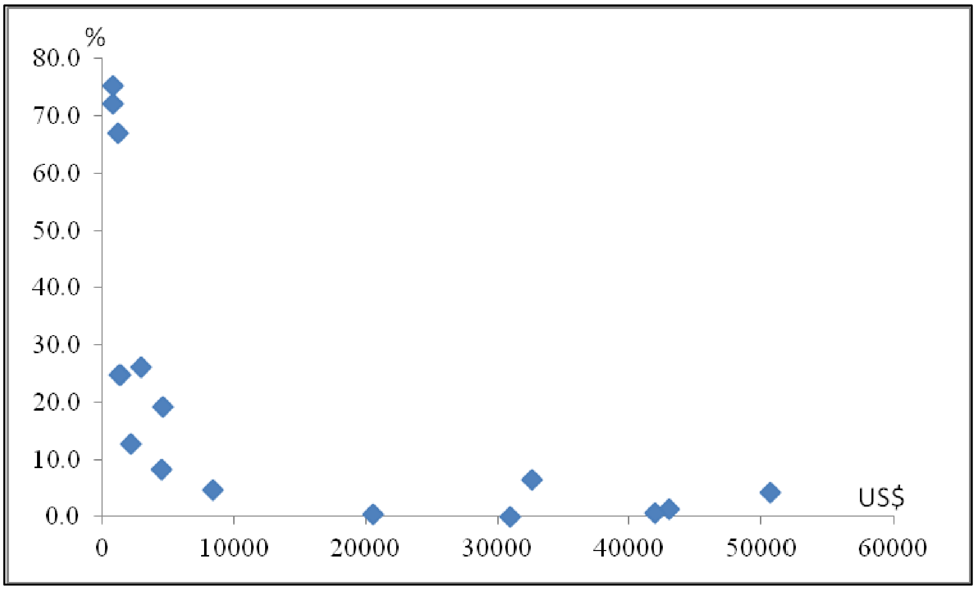
Members	TPES	Shares (%)			
	(MTOE)	Bio	Hydro	Other REs	Non-REs
China	2438	8.3	2.6	0.7	88.5
India	688	24.8	1.4	0.3	73.5
Japan	497	1.2	1.4	0.7	96.7
Korea	250	0.5	0.1	0.1	99.3
Indonesia	208	26.0	0.7	7.8	65.5
Australia	125	4.1	0.9	0.5	94.5
Thailand	117	19.3	0.4	0.0	80.3
Malaysia	73	4.7	0.8	0.0	94.5
Vietnam	59	24.8	4.0	0.0	71.2
Philippines	38	12.6	1.8	22.3	63.4
Singapore	33	0.6	0.0	0.0	99.4
New Zealand	18	6.5	11.7	20.8	61.0
Myanmar	14	75.3	3.1	0.0	21.6
Cambodia	5	72.0	0.1	0.0	27.9
Brunei	3	0.0	0.0	0.0	100.0
Lao PDR	2	67.0	13.0	0.0	20.0
EAS	4568	11.0	1.9	1.1	86.0
World	12782	9.8	2.3	0.9	87.0

Source: Author's own calculations using data from the IEA (2012a) and IRENA (2013a).

3.1. Biomass

Traditionally, biomass has been a popular energy source for cooking and heating in Asia. As energy consumption increases and resources deplete rapidly, biomass as a source of energy will decline. This trend is evident in Figure 3 which clearly shows the declining trend of biomass shares of total energy supplies as per capita income rises among the EAS economies. Thus, it is anticipated that biomass as a share of TPES is likely to fall in countries such as Myanmar, Cambodia and the Lao PDR which currently rely on biomass as the main source of energy for households. The same may also occur in Indonesia, India, Vietnam and Thailand, which currently obtain about one-quarter of their energy supplies from biomass (Table 4).

Figure 3: Biomass shares over TPES and GDP per capita, 2010



Notes: The biomass shares are from Table 4. GDP per capita was drawn from the World Bank (2012).

The decline in the use of traditional biomass is due to its inefficiency and un-sustainability. With an increase in income levels, the consumers tend to use more commercial energies. However, there is potential growth in the production of biofuels in the EAS area. One example is the production of palm biodiesel which could be based on the large palm oil sector in Southeast Asia. In fact, several EAS members have started the production of biodiesel in recent years. In 2010, Thailand was the largest producer with a production output of 454 kilotonnes oil equivalent (ktoe) followed by Indonesia with an output of 356 ktoe (OECD, 2013). In addition, within the EAS group, China is the largest producer of biogasoline with a production output of 1035 ktoe in 2010. In terms of biofuels, their environmental impacts have to be assessed so that their production in relevant areas does not lead to negative impacts on the local ecological system and hence is sustainable in the long run. Thus, environmental consideration is an important factor underlying the development of biofuels. Furthermore, biogas can be produced from organic waste, animal manure and sewage sludge, and is often used for heating and electricity generation in rural communities.

3.2. Hydro

EAS members are well endowed with hydro resources. During the decade 2001-2010, hydro energy production in the EAS group grew at an average annual rate of 8.12 per cent which is well above the world average rate of 2.77 per cent during the same period.[5] Lao PDR and New Zealand obtained 13 and 11.7 per cent of their countries' total energy supplies from hydropower, respectively, which are the highest among the EAS group. Vietnam (4 per cent), Myanmar (3.1 per cent) and China (2.6 per cent) are the other three which achieved relatively good shares. In absolute terms, China is the world's largest producer of hydroelectricity with a share of 21 per cent of the world total in 2010 (see Table 3). The country's hydro power also enjoyed an average annual rate of growth of 12.8 per cent during 2001-2010. There is still potential for growth in the hydro power sector in the EAS area. In particular, as resource endowment varies across countries, cross-border trade in hydro power has appeared and can be further expanded.

3.3. Geothermal

Apart from biomass and hydropower, other forms of RE have also been produced in the EAS area. According to Table 5, EAS as a group accounted for 35.3 per cent of the world's installed wind capacity, 15.1 per cent of solar capacity and 40.4 per cent of geothermal capacity. While EAS has a relatively large share of the world's geothermal capacity, growth of this product is limited due to resource and technology constraints. For example, over the past decade (2002-2011), the average rate of growth in the installed capacity of geothermal energy was modest in both the EAS group (2.2 per cent) and the world (3.1 per cent). The world's growth in installed capacity was very much driven by that in the United States which has been the largest producer of geothermal energy for decades and has been growing at the average rate of 4.0 per cent since 2002 according to BP (2012). Two EAS members, namely, the Philippines and Indonesia, in turn have the world's second and third largest geothermal energy capacity with a joint share of 28.7 per cent over the world

[5] These rates of growth were calculated by the author using the statistics downloaded from the OECD (2013).

total in 2011. However, the installed capacity in the top three countries (US, the Philippines and Indonesia) remains almost unchanged in recent years.

In terms of geothermal energy production, the EAS group is more impressive with a share of 53.4 per cent of the world total in 2010 (Table 6). Indonesia and the Philippines have been the world's largest producers since 2002. Substantial production was also recorded in China, New Zealand and Japan. During the decade 2001-2010, production output in the EAS group grew at an average rate of 3.3 per cent which is higher than the world's average growth rate of 2.2 percent during the same period. In particular, during 2001-2010, China and Indonesia achieved an average annual growth rate of 9.1 per cent and 7.0 per cent, respectively.

Table 5: Installed Capacity (megawatts) in EAS, 2011

Countries	Geothermal	Solar	Wind
Australia	1.1	1344.9	2476.0
China	24.0	3000.0	62412.0
India		427.0	16078.0
Indonesia	1189.0		
Japan	502.0	4914.1	2595.0
Malaysia		12.6	
New Zealand	769.3		603.0
Philippines	1967.0		
South Korea		747.6	370.0
Thailand	0.3		
EAS	4452.7	10446.2	84534.0
World	11013.7	69371.1	239485.0
EAS (%)	40.4	15.1	35.3

Source: BP (2012).

Table 6: World Major Geothermal Energy Producers in 2010

Countries	Ranking	Output (Mtoe)
Indonesia	1	16.09
Philippines	2	8.54
US	3	8.41
Mexico	4	5.69
Italy	5	4.78
China	6	3.71
New Zealand	7	3.64
Iceland	8	3.35
Japan	9	2.47
Turkey	10	1.97
EAS		34.51
World		64.61

Note: The raw data are downloaded from the OECD (2013).

3.4. Wind

Due to technology advance and the resultant fall in production costs, both the world and EAS group have experienced rapid expansion in wind farms. During the past decade (2002-2011), the average annual rate of growth in capacity was 25.5 per cent in the world and 43.6 per cent in the EAS group.[6] China has been growing at an average rate of 70 per cent since 2002 and overtook the United States to have the world's largest capacity for wind energy production in 2010. China's rapid expansion in wind energy capacity sets a good example for other developing countries. The country's growth took off in 2007 when China's first renewable energy law was implemented. The Law provides a legal framework for the operation and development of renewable energy technologies in the country. Grid companies are required to prioritize renewable energies over other sources of power (IRENA 2012). India, with the world's fifth largest capacity also recorded a high rate of growth, at 27.6 per cent annually during 2002-2011. This growth benefited from the RE purchase obligations mandated under the Indian Electricity Act and through the implementation of the so-called renewable purchase specification (RPS). A

[6]The rates of growth cited in this paragraph are derived by the author using the statistics from the BP (2012).

renewable energy law is yet, however, to be enacted in India. In terms of wind energy production, the EAS as a group achieved 22.2 per cent of the world total in 2010, with China and India being the second and fifth largest producers. Given the rapid growth in capacity, production is expected to expand significantly in the coming years.

3.5. Solar

The production of solar energy has also expanded rapidly in the EAS group. During the period 2002-2011, the average annual rate of growth in installed photovoltaic (PV) capacity was 36.0 per cent, though this is lower than the world average rate of growth of 45.4 per cent (BP 2012). A main factor underlying this growth in EAS is the rapid expansion in capacity in China in recent years. While it started at a low base, China's installed capacity expanded from 100 megawatts (MW) in 2007 to 300 MW in 2009. It reached 3000 MW in 2011 according to BP (2012). High growth was also recorded in Australia (with an average annual growth rate of 92.7 per cent during 2007-2011) and India (with an average annual growth rate of 79.8 per cent during 2007-2011).

Due to the increased capacity, the output of solar PV power in the EAS area grew at an average annual rate of 30.5 per cent during 2001-2010 (OECD, 2013). However, this rate is lower than the world's average growth rate of 42.7 per cent in the same period. As a result, the EAS share of the world total solar PV power declined from its peak of 50.3 per cent in 2003 to 18.3 per cent in 2010. During the same period (2001-2010), production in solar thermal energy has also been growing at an average rate of 17.5 per cent. The EAS share of the world total solar thermal power has expanded from 37.7 per cent in 2000 to 62.0 per cent in 2010.

In summary, REs are rapidly expanding in the EAS economies. But the development varies a lot across countries and products. The main products in the EAS economies include biomass, hydro, geothermal, solar and wind energies. There is hardly any development in oceanic energies.[7] In general the share of REs of total energy supplies in the EAS area is similar to the world average. The share of

[7] In 2011, only three countries- France, Canada and Korea- recorded energy output in the category of "tide, wave and ocean" according to the OECD (2013). France dominates this sector.

biomass over of REs is slightly higher in the EAS group than in the world average. However past experience shows that biomass consumption is likely to decline relatively as economies develop. In addition, geothermal energy production has been stable in recent years. Hence the potential for growth in the near future lies in solar and wind energies.

4. RE Outlook and Implications for EMI

4.1. Growth Prospects

In 2012, the world celebrated the International Year of Sustainable Energy for All (SE4ALL) initiated by the United Nations (IRENA, 2013b). One of the SE4ALL objectives is to double the 2010 RE share of the world energy mix by 2030. The realization of this goal would result in an RE share of at least 26 per cent in 2030 according to IEA statistics. To reach this goal, combined with other energy efficiency improvement commitments, RE production in the EAS area would have to grow at an average annual rate of 5-6 per cent according to the forecasts in Table 7. This rate would be much higher than the average rate of 1.9 per cent achieved by the region in the past decade (2001-2010). In recent years, only Korea, New Zealand and Thailand recorded RE growth rates close to this predicted rate. Furthermore, if there is no efficiency improvement (i.e. 'business as usual'), the growth rate would have to be even higher (at 9.0 per cent). During the decade 2001-2010, only Korea achieved such a high growth rate. The main sources of growth will in turn be wind, solar and biofuel products. By 2030, the output of wind energy would probably exceed that of solid biofuel.

Table 7: Average RE Growth Rates (%), 2011-2030

Products	2001-2010		2011-2030		
	World	EAS	I	II	III
Wind	27.1	40.3 (7)	27.1 (784)	27.1 (784)	31.5 (1559)
Solar PV	42.7	30.5 (1)	30.5 (103)	30.5 (103)	42.7 (614)
Biodiesel	29.7	87.9 (2)	22.0 (81)	25.0 (132)	29.7 (279)
Solar thermal	11.8	17.5 (9)	11.8 (87)	17.5 (236)	17.5 (236)
Solid biofuel	1.6	0.6 (490)	0.3 (519)	0.3 (519)	0.6 (549)
Hydro	2.8	8.1 (89)	4.1 (196)	4.1 (196)	5.4 (254)
Geothermal	2.2	3.3 (35)	2.2 (54)	2.2 (54)	3.3 (66)
Sub-total	2.5	1.9 (631)	5.5 (1824)	6.0 (2024)	9.0 (3557)

Notes: The numbers in parentheses are the output values in the final year of each period, namely 2010 and 2030, and expressed in million tons oil equivalent (Mtoe). The raw data for the period 2001-2010 are drawn from the OECD (2013). The three scenarios for the period 2011-2030 are based on three predicted rates of growth in TPES, namely, 2.2% in Asia Pacific by BP (2013), 2.8% in Asia by ADB (2013) and 5.6% in EAS (the 'business as usual' case).

In general EAS countries are well-endowed with RE resources. There is considerable scope for further growth in REs, with the exception of Singapore, which is poorly endowed with RE resources. The RE policy of the government of Singapore is to focus on modest solar projects, production of biofuels using raw material from neighboring countries and most importantly the establishment of the country as a R&D centre for REs. For other EAS members, the stated national RE goals and policies are mixed (Table 8). The stated goals refer to RE shares of electricity production in most countries but some are defined as shares of primary energy supplies, installed capacity, total consumption and so on. The target periods vary too. These inconsistencies make bench-marking analysis and cross-country comparisons very difficult. Whether these predicted or stated goals are achievable depends upon several factors which can be either supportive (driving forces) or obstructive (challenges).

Table 8: Stated RE Policy Goals in the EAS area

Countries	Reserves	RE (2010)	Goals
Australia	H/G/S/W/O		20% electricity by 2020
Brunei	H		10% electricity generation by 2035
Cambodia	H/S		6.5% total electricity supply by 2015
			15% rural electricity supply by 2015
China	H/G/S/W/O		15% primary energy by 2020
India	H/G/S/W/O		20GW solar PV by 2022 (0.4GW in 2011)
			31GW wind by 2022 (16GW in 2011)
Indonesia	H/G/S/O		17% primary energy by 2025
Japan	H/G/S/W/O		20% final consumption by 2020
Korea	H/S/W		6.1% primary energy by 2020
Laos	H/G/S/W		10% transport energy by 2020
Malaysia	H/G/W/O		11% electricity generation by 2030
Myanmar	H/G/S/W		15% installed capacity by 2015
New Zealand	H/G/W/O		90% electricity generation by 2025
Philippines	H/G/S/W/O		Triple 2010 RE capacity by 2030
			40% electricity generation by 2020
Singapore	S		R&D centre for REs
Thailand	W/G/S		25% total energy consumption by 2022
			Triple capacity by 2030
Vietnam	H/S/W		6% electricity generation by 2030 (excluding hydro)

Sources: IRENA (2013a), Khaing (2012), Ipsos (2012), Nelson, *et al*. (2012), Poch (2013) and author's own compilations.

4.2. Driving Forces for RE Growth

Several factors could be the driving forces for further RE growth in the EAS area. First, the increasing awareness of global climate change demands urgent actions by governments to control and reduce carbon emissions. To date, various regulations have been introduced and enforced in the world, particularly within the OECD economies. EAS members are following or will have to follow the global trend. Furthermore, some EAS members have enjoyed high economic growth for decades. However, this is at the cost of a continuously deteriorating local and regional environments. Thus, for their own benefit, the EAS members need to change their energy mix and use more clean energies, and REs are the best choice. So far many EAS members have adopted RE strategies or goals to guide future development. These include large players such as China, India, Japan and Australia (IEA 2012b).

Secondly, technological advance has led to a dramatic decline in the RE cost.[8] For example, it is reported that the selling price of PV cells dropped from US$1.5/watt in 2010 to US$0.60/watt in 2011 (UNEP, 2012). This decline will continue in the future and hence make REs more economically competitive with fossil fuels. Some REs are not luxuries anymore and are affordable by many low and middle income economies. For example, the lowest levelized cost for wind power in China is now close to the ceiling cost of nuclear and hydro power, and is projected to fall by 20-30 per cent from current level by 2030.[9] By then wind power would be nearly competitive with other forms of generation (ADB, 2013). In addition, the affordability of REs is also due to rising energy prices in recent years.

Thirdly, EAS countries, particularly the developing members, can or will increasingly be able to afford the development of RE products because of their robust economic performance and subsequently rising income. According to ADB (2013), developing Asian economies will maintain a growth rate of 6.6 per cent in the coming years. This rate is much higher than the industrial countries' average rate of 1.2 per cent (ADB, 2013). In particular, according to the same source, the relatively poor EAS members such as Cambodia and Laos will enjoy a rate of growth of 7.4 per cent and 7.7 per cent respectively.

Lastly, with rising income, consumers can afford to pay more for electricity. This provides the opportunity for the introduction of feed-in-tariffs (FiT) in several EAS countries. For example, the March 2011 Fukushima nuclear accident in Japan triggered a fundamental shift in the country's energy policy. The most immediate effect is the introduction of a series of clean energy FiTs. These tariffs are far higher than the retail commercial power price which averaged ¥14.59/kWh in the year to March 2012. In the year to March 2013, for example, the biomass tariff is ¥33.60/kWh for 20 years with wind generating ¥23.10/kWh and geothermal up to

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[8]For comprehensive reviews of RE technology costs, see Hearps and McConnell (2011) and Kost, *et al*. (2012).

[9] The levelized cost of energy is defined as the cost of an energy generating system over its life time (IPCC, 2012).

¥42 for 15 years. The solar tariff is amongst the highest in the world, at ¥42 (US$0.53) (METI, 2013). FiTs have also been introduced in other EAS countries (such as Australia, China, India, Indonesia, Malaysia, the Philippines, Thailand and Vietnam). This kind of policy supports will certainly boost the development of REs within the EAS area.

4.3. Challenges for RE Development

While economic growth has increased the affordability of REs by many EAS members, several EAS economies are still at the early stage of development. Their governments are still struggling with the provision of universal access to modern energies for all citizens. Thus investment in REs is limited, not to mention government subsidies for RE initiatives. The latter played a key role in promoting REs in Europe and other parts of the world. According to the IEA (2012b), subsidies provided to RE projects in the world totaled about US$88 billion in 2011 and are expected to reach US$240 billion per year by 2035. The main recipients are producers - from the solar, wind and biofuel sectors. Furthermore, the expanded access to modern energies in some EAS member economies will essentially reduce the use of traditional biomass. As a result, it is even more challenging for those countries to meet the RE4ALL goal by 2030.

In addition, for EAS members who can afford more investment in REs, an important concern is the need for electricity storage and smart grids to support higher RE penetration levels in the electricity sector. Smart grid technologies are already making significant contributions to electricity grids in some countries (such as Puerto Rico, Jamaica, Denmark, and Singapore). However, these technologies are still undergoing continual refinement and improvement and hence are vulnerable to potential technical and non-technical risks. RE growth will thus be constrained by infrastructure development as well as by the evolution of technology. These also include capacities in assessing and predicting the availability of renewable energy sources. These capacities offer additional benefits, notably the promise of higher reliability and overall electricity system efficiency.

5. Key Findings and Recommendations

In the midst of global climate change and the rapid depletion of fossil fuel resources, REs provide a bright prospect for the world's energy sector. EAS countries will have to follow the same trend as the rest of the world and expand their RE industries. Through a review of the global RE industry, this paper helps gain important insight into the development of the RE sector in the world in general and the EAS area in particular. Several interesting findings can be summarized as follows.

5.1. Key findings

First, it is shown that, though REs globally have enjoyed faster growth than total energy production, their share of total output is still small. This share amounted to about 1 percent in 2010 if traditional biomass and hydroelectricity are excluded. The situation is similar in the EAS area. There are however substantial variations across the countries. Growth also varies considerably across the RE products.

Second, it is argued that great growth potential in the future will come from wind, solar and biofuel power which will be competitive with traditional fossil fuels due to technological advance. Among the EAS economies, there is also ample scope for growth in hydroelectricity, particularly in relatively less developed economies such as Cambodia, Myanmar and Lao PDR. In several EAS countries, there is also potential for growth in geothermal energy. However, environmental impacts have to be carefully assessed and hence taken into consideration when new projects, especially hydro and biofuel ones, are initiated.

Third, to reach the UN goal of doubling RE shares of total primary energy supplies by 2030, there are still challenges for many EAS members. These include technological constraints in the short run, the balance between RE investment and spending in providing energy for all (such as electrification), and the complex relation between economic development and environmental control.

5.2. Policy recommendations

For improved promotion of RE development within the EAS area, the following recommendations are made.

Recommendation 1: Strengthening regional institutional facilities

The International Renewable Energy Agency (IRENA) was founded in 2009, and is dedicated to the global promotion of renewable energies. Not all EAS countries have become IRENA members. It is thus necessary to set up a regional body which is exclusively responsible for the promotion of REs within the EAS region. This body can be a sub-unit of an existing regional institution or an independent inter-governmental organisation. Through such an organization, local policymakers and think-tanks can hold regular meetings to discuss regional cooperation in RE policies, investment, and technologies. This institution can also oversee the standardization and harmonization of RE rules and practices within the EAS area. At present, due to the lack of dialogues among members, the region's RE goals are quite diverse and inconsistent between the member economies.

Recommendation 2: Setting potential goals for RE development

It is common practice that potential goals are set for each member within economic blocks such as the EU. Through intergovernmental exchanges and consultations, EAS members could agree to some potential goals for each country within a certain period of time. These goals would reflect the reality in each member's economy. Setting such goals can help promote the awareness of REs in member countries. In addition, through information exchanges and strategic planning, policy makers in member countries can identify priorities in their RE development. The formation of regional goals can also help member countries better respond to the IRENA roadmap or simply to the global campaign for green energy development.

Recommendation 3: Promoting sub-regional coordination in RE development

As RE resources are unevenly distributed, sub-regional coordination could lead to more efficient allocation of resources in some areas such as hydroelectricity. In particular, for large hydro projects near borders, sub-regional or cross-border cooperation could better protect the environment. Through cross-border cooperation, members involved could also benefit from the availability of more capital and potentially better technologies. The greater Mekong sub-regional (GMS) group is a good example.[10] The group held its 18th ministerial conference in December 2012 and has established the GMS Environment Operations Center (EOC) and Regional Power Coordination Center. It is expected to play a key role in developing hydro power and promoting EMI within the region. Similar coordination could be adopted to manage the production of palm oil which is a main input for biofuels and would be a threat to biodiversity in some regions.[11]

Recommendation 4: Boosting EMI through RE development

Policy makers have reached a consensus decision to promote energy market integration (EMI) within the EAS area.[12] As RE is a rapidly growing energy product, it could play an important role in the promotion of EMI. In terms of cross-country interconnectivity, hydroelectricity has been traded across the greater Mekong sub-region for several years. Thus RE is leading sub-regional EMI within the EAS. In addition, as REs are relatively new products in most EAS members, they are less constrained by the existing regulations and policies. It is thus relatively easy for members to reach consensuses and adopt the common standards and practices which are prerequisites for EMI.

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[10]The GMS involves Cambodia, Laos, Myanmar, Thailand, Vietnam and two provinces (Yunnan and Guangxi) of China.

[11] For a background review of the palm oil sector, see Pye and Bhattacharya (2012).

[12]For more detailed discussion of EMI, see Shi and Kimura (2010) and Wu, *et al*. (2012, 2013).

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Chapter 2

The Integrated Nordic Power Market and the Deployment of Renewable Energy Technologies: Key Lessons and Potential Implications for the Future ASEAN Integrated Power Market

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The report examines the integrated Nordic power market and its linkages to renewable energy technology (RET) deployment for power production. It has two purposes. First, it aims to improve the understanding of the expansion of the Nordic power market and integration and deployment of RET. Secondly, it takes lessons from the Nordic experience that could inform the development, deployment and integration of RET in the future ASEAN integrated power market. Whenever possible, historical or co-evolution aspects are addressed.

The study analysed three central building blocks underpinning the development of the Nordic market: i) the Nordic power system and its links to the European (EU) power markets ii) significant policy and regulatory characteristics that have driven both market power integration and RET deployment and iii) the complexities and technicalities of the Nordic power market exchange (the Nord Pool Spot). Different evaluation criteria are used to assess RET deployment in the integrated Nordic power market. These criteria include information asymmetry/transparency, market concentration, barriers to entry, transmission bottlenecks, balancing resource and price volatility/uncertainty. Information was collected from a critical literature review, expert interviews and a key stakeholder survey. Links with European policies and power markets are covered wherever existing knowledge allows. To formulate suitable recommendations, different studies addressing energy market integration in the ASEAN region were reviewed. Recommendations have emerged by contrasting lessons from the Nordic/European region with the situation in the ASEAN region.

Our findings strongly suggest that a decisive mix of RET policy support mechanisms and ambitious RE targets are essential to developing RET power in the ASEAN region. The gradual integration and transformation of electricity markets can further strengthen RET incorporation into the ASEAN market. One key recommendation is to develop international structure(s) or organization(s) to design, support and enforce relevant policies and regulations. Since RET markets need time to develop and mature, aggressive RE policies in the ASEAN region should be introduced as soon as possible. This will ensure that RET is in a very good (national/local) position to be integrated into the future ASEAN power system. For the deployment of RETs, power systems cannot be left to energy integration policy efforts alone. RET support policy mechanisms are indispensable.

[1] The views expressed in the article are purely those of the authors and may not in any circumstance represent those of IRENA. The authors will be solely responsible for the content of this chapter. Corresponding author email address: mundacatoro@gmail.com.

1. Introduction

Electricity markets in the Nordic region have changed significantly since the early 1990s. Nordic countries have opened up power trading and electricity production to market competition. All Nordic countries have liberalized their electricity markets. The region now has the world's most harmonized cross-border power market.

The objective of market liberalization in the region was to improve and encourage efficient utilization of production resources and transmission network operation. Renewable energy (RE) sources have played a critical role, and climate and energy policies encouraging the transition to a low-carbon Nordic society have grown in importance.

Since the liberalization and integration of the Nordic electricity markets, the region has received substantial attention from other regions with similar policy and market objectives. Renewable energy sources and corresponding technologies have always played a critical role in the Nordic power system. This means increasing attention has in recent years been given to climate and energy policy instruments encouraging the transition to a low-carbon Nordic society. This study analyses the liberalization/integration of power markets and its relation with the deployment of renewable energy technologies (RETs).

The International Renewable Energy Agency (IRENA)[2] has commissioned this study to extract key lessons from the Nordic region, which have the potential to support energy market integration within the Association of Southeast Asian Nations (ASEAN)[3]. Given its particular focus on RET, the Nordic region is expected to provide valuable lessons to ASEAN countries aiming to integrate their power markets and ensure regional energy security.

1.1. Objectives and Research Questions

This study has two main objectives: 1) to improve the understanding of the relationship between the expansion of the Nordic power market and grid network and the integration and deployment of RET; 2) to analyse and generate lessons from the

[2] For further information visit www.irena.org
[3] For further information visit http://www.asean.org

development of the Nordic power market and deployment of RET that can support energy market integration in the ASEAN region. It covers two specific issues. Firstly, it includes an assessment of the Nordic power market and market exchange (i.e. the Nord Pool Spot) and its links with the European power markets. This is considered in relation to the integrated market for the utilization of renewable energy resources (particularly small-scale hydro power plants). Key factors and critical elements that may facilitate or restrict the integration of unconventional RET (i.e. excluding large hydro) are identified. Secondly, we draw key lessons from the Nordic region. These in turn yield suitable recommendations for ASEAN Power Grid (APG) expansion. To guide the study, we sought to answer the following research questions:

- What are the characteristics of the Nordic power system and the role of renewable energy?
- What market reforms have been used to deregulate and integrate it? How has RET deployment been encouraged?
- How does the Nord Pool Spot market exchange work? How does price formation take place? What is the level of power trading within and outside the Nordic region?
- How has the Nordic power market performed after integrating and deploying RET?
- What critical lessons from the Nordic region can be extracted from the analysis?
- To what extent can the Nordic experience assist ASEAN countries integrate the energy market integration and increase RET deployment?

1.2. Methodology

To achieve the objectives and answer the research questions, different research methods (i.e. triangulation) were used to approximate objectivity and reduce uncertainty.

Interviews played an important role during the research since there is little or no literature on, for example, the effects of the Nord Pool Spot on renewable energy development. In particular, no empirical information about the co-evolution of the Nordic integrated power market and the development of RET is available. However, experts provided some anecdotal information. Semi-structured interviews were based on interview protocols. In addition, an inspection of peer-reviewed material, statistical databases, books and grey literature (i.e. project reports, workshop/seminar presentations, institutional publications, policy statements, etc.) was conducted. Official information from the Nordic energy authorities was used extensively throughout the research. To support the data, a key stakeholder survey was launched. It focused on critical issues relating to the Nordic power market and RET deployment.

We analysed public policy development associated with RET that could be related to the liberalization and integration of the Nordic power market. In particular, we used different evaluation criteria to guide the analysis. The multi-criteria approach includes:

- **Information asymmetry/transparency**: this refers to the level, quality, degree of uncertainty and timeliness of information market participants get to support decisions associated with transactions (e.g. selling or buying power).
- **Market power/concentration and market liquidity**: market power refers to the amount of influence a firm has on the industry in which it operates. In the neoclassical economic model, companies are assumed to have zero market power (part of the conditions for "perfect competition"). Firms with market power are said to be "price makers" as they can set the price for an item while maintaining market share. Market liquidity is often characterised by a high level of trading activity whereby agents can quickly convert commodities into cash.
- **Barriers to entry**: this relates to the efficiency of the administrative process for concessions, procedures for new generation, and to what extent restricted site availability and environmental regulations prevent market entry or not.
- **Transmission bottlenecks and balance resources**: this relates to the option and related impacts of accessing the transmission grid, management tools to handle bottlenecks, trans-border power trading and capacities, and grid connectivity. It also relates to the Nordic power system's ability to deal with variable and discontinuous production from wind power.
- **Price volatility/uncertainty**: this focuses on the impacts (if any) of price volatility or uncertainty on RE power producers. An understanding of price dynamics is critical for RET investment risk management.

1.3. Scope and limitations

Our study dealt with a broad set of issues relating to the Nordic power market, power system and RET deployment. In addition, the total costs of the project, the time period for its development (35 days approx.) and the defined length of the report created practical limits to its scope. It is important to note that there is no empirical information available on the co-evolution of the Nordic integrated power market and the development of RET. The experts and survey yielded only anecdotal evidence on these issues. Our findings reveal that it is sometimes difficult to distinguish clearly between the impacts of the liberalization/integration of the Nordic power markets and the renewable energy policy instruments. To the best of our knowledge, there is no study in this field.

From a geographical point of view, our focused on Denmark, Finland, Norway and Sweden (i.e. Nordic countries). Wherever feasible (e.g. due to data availability), linkages with European power markets (e.g. Germany) were also addressed.

The Nordic power system is dominated by renewable energy sources, especially large hydro. This study aims to focus mostly on unconventional RET, that is wind energy, bioenergy, solar and small-scale hydro. However, the reader has to note that the bulk of existing knowledge relates to large hydro and to some extent wind energy. This is relatively consistent with the share of these technologies in the Nordic fuel mix. Much less is known about solar photovoltaic (PV), for instance.

RET deployment in the Nordic regions is strongly associated with specific policy instruments, such as feed-in tariffs (FITs) or tradable green certificates. EU climate and energy-related targets and instruments such as the European Emission Trading Scheme (EU ETS) also play a major role. We do pay close attention to specific supportive instruments, but an evaluation of their effectiveness is outside the scope of this study.

2. The Nordic Power System – An Overview

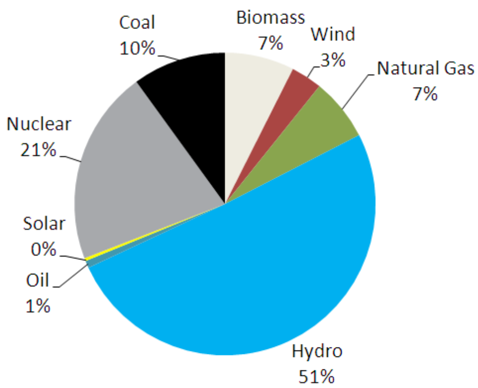
2.1. Supply side

The Nordic region is powered by fossil fuels, hydropower, wind and biomass. Installed generation capacity reached more than 98 000 MW in 2011 and is very diverse (NordREG, 2012a). Hydropower has over half of generation capacity (most Norwegian and nearly half the Swedish capacity). Combined Heat and Power (CHP) is the second largest generation source (31%), mainly using biomass. Thermal power generation, especially in Finland and Denmark, uses swing production. This means it acts as backup production capacity when hydropower generation in Sweden and Norway decreases (NordREG, 2012a). Nuclear power is the third largest source

(Sweden and Finland). It has 12% of total Nordic generation capacity, while wind energy has nearly 7 %.

By 2010, power production reached 389 TWh, and renewables represented 62% (see Figure 1). Hydropower was responsible for more than 50% (197 TWh). Biomass represented 7% (29 TWh) and wind 3% (13 TWh). Nuclear power represented 21% (81 TWh). Solar PV was responsible for nearly 1TWh (Denmark and Sweden). In 2011, total power generation in the region reached 370 TWh. A weaker economy and warm weather, which reduced heating needs, explain the reduction from 2010. Thermal power (Finland and Denmark) accounted for most power production decrease (NordREG, 2012a).

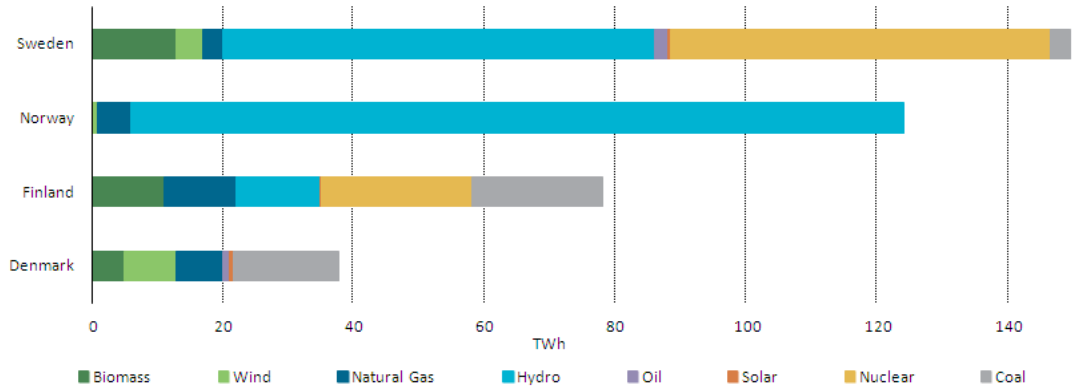
Figure 1: Fuel mix for electricity generation (389TWh) in the Nordic region (2010)



Data Source: NER & IEA (2013)

We observe sharp differences across Nordic countries when it comes to power production (see Figure 2). First, Sweden has the greatest electricity generation (149 TWh in 2010), with hydropower, nuclear and biomass-fired production representing the major share (NER & IEA, 2013). In addition, wind power has become increasingly relevant in Sweden, with power generation reaching 4 TWh. Secondly, hydropower dominates Norway‘s fuel mix (95%), with only minor production from wind (1 TWh) and natural gas (5 TWh). Thirdly, Finland has the most diverse fuel mix (NER & IEA, 2013). Biomass and hydro are 31%, while fossil fuels represent 40% and nuclear 29%. Domestic wind energy has an impressive share of the Danish market. This increased from 12% in 2000 to 21.9% in 2010 bringing total net wind power to nearly 9 TWh (NER & IEA, 2013). Wind power development differences within the Nordic countries can be attributed to particular factors: policy instrument choice, electricity price, domestic fuel availability and energy sources etc. (Pettersson, Ek, Söderholm, & Söderholm, 2010).

Figure 2: Electricity Generation in Nordic Countries (2010)



Data Source: NER & IEA (2013)

Power generation capacity in Sweden grew by 1072 MW, while 329 MW was decommissioned. Wind made the largest contribution to net capacity increase (734 MW). Nearly 736 MW was added to installed capacity, 34 % more than in 2010 (NordREG, 2012a).

2.2. Demand side

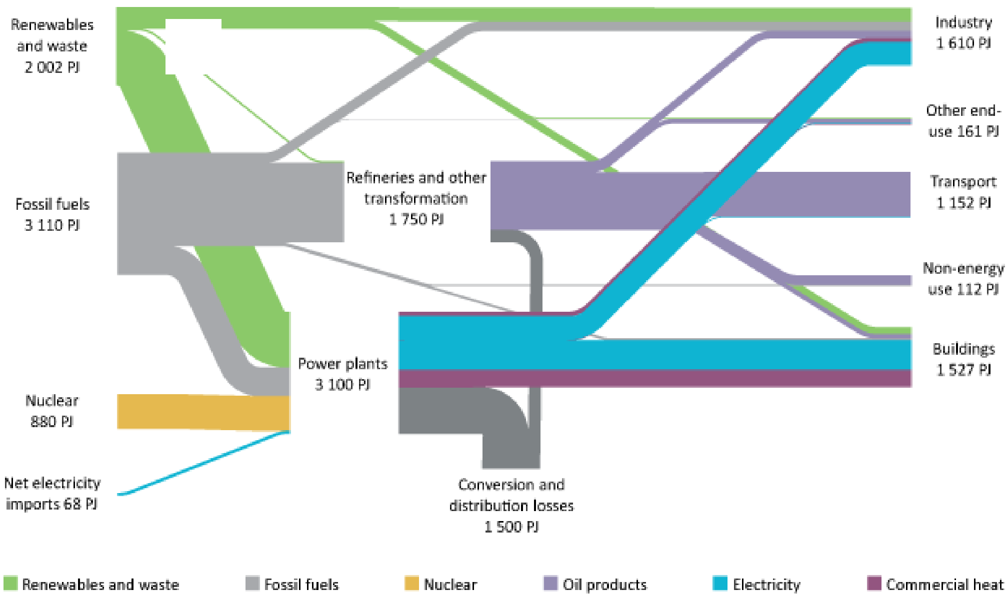
Electricity generation and relatively low electricity prices (see section 4.3) are a critical component of the Nordic energy-economy system and have thus framed the region’s economy by creating an electricity-intensive industry centre.

Electricity consumption in Scandinavia is higher than in other European countries due to cold winters, relatively low prices, electrically heated houses and relatively high industrial demand. Demand in Finland, Sweden and Norway is significantly affected by energy-intensive industries, and is also significant in the household sector. Electricity demand fluctuates more in these three nations than in Denmark. Per capita power consumption in Norway is one of the highest in the world at around 25.000 kWh/per year (2010).

The building and industrial sectors dominate renewable energy demand (including conversion losses – see FFigure 3). Sweden has the largest share of total power consumption followed by Norway, Finland and Denmark. Electricity consumption in the Nordic region varies widely due to specific conditions in each country as well as population and economic structure; however, it is generally affected by temperature variation and economic growth.

Peak loads (mornings and afternoons) often take place during cold spells. In 2011, maximum capacity generation was put into operation by the end of February. Nevertheless, power consumption exceeded aggregate production, necessitating net imports of 3278 MW from Germany and Russia. Finland often requires imports from neighbouring countries (especially Russia). However, this should change when a new nuclear reactor (Olkiluoto 3), with an installed capacity of 1600 MW is ready to run. For details of exports and imports see section 4.4.

Figure 3: Energy Flows in the Nordic Region in 2010

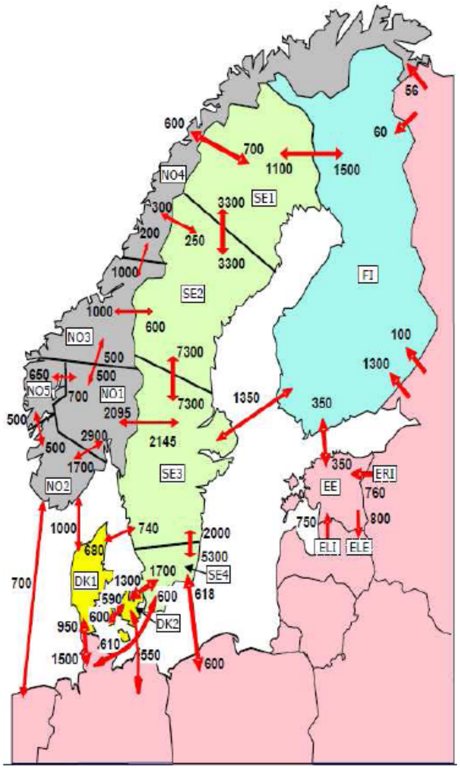


Data source: NER & IEA (2013)

2.3. Transmission Grid

The transmission grid covers all the Nordic countries and combines all the national grids (excluding western Denmark) into one common power system (see Figure 4). The Nordic grid (6 GW in 2010) is decentralized: national transmission companies are responsible for operating and investing in the national network (NordREG, 2007, 2011a). Voluntary cooperation between transmission companies takes place through NORDEL (now replaced by ENTSO-E, see section 3). This body was founded in 1963 for cooperation between transmission system operators in Denmark, Finland, Iceland, Norway and Sweden. The grid is part of the transmission network of North West Europe. Eastern Denmark is synchronous with the Nordic grid while western Denmark is synchronous with the area of continental Europe. A DC transmission cable linking eastern and western Denmark has been running since 2010 (NordREG, 2012a). Transmission interconnectors also link the Nordic market to Estonia, Germany, the Netherlands, Poland and Russia.

Figure 4: Transmission Capacities between Different Nordic Pricing Areas (2011)



Source: NordREG (2012a)

The Nordic power system uses two models to handle transmission grid congestion. These are the area price model (also called market splitting), leading to different area prices calculated by the Nord Pool Spot, and the countertrade model (Flatabo, Farahmand, Grande, Randen, & Wangensteen, 2003; NordREG, 2007). In the former, the Nordic area is divided into different price bidding regions (see section 3). This means congestion in the Nordic spot market results in market splitting. At present, there are 12 price bidding areas: five in Norway, four in Sweden, one in Finland and two in Denmark (see Figure 4). Sweden was split into four bidding areas in November 2011. It is argued that this change took place to improve market efficiency and lay the groundwork for financing future network improvements (NordREG, 2012a).

Once divided, internal congestion - transmission bottlenecks within the Transmission System Operator (TSO) control area - is handled via countertrade or by reducing interconnector transmission capacity at bidding area borders (NordREG, 2007). Countertrade here means the TSOs correct the electricity flow using market-based redispatch to assure that it does not exceed grid security limits (i.e. down or upregulation. See details in section 4.2). TSOs have to pay for this service, and this is covered by the grid tariff (NordREG, 2007). Countertrade is often used after gate closure in the ELSPOT or day-ahead market (see section 4).

In 2011, market splitting in the Nordic electricity market was forced 74 % of the time. This means all Nordic countries shared a common system price 26% of the time (NordREG, 2012a). These figures were nearly the same in 2010.

According to NER & IEA (2013), Nordic transmission capacity needs to increase to around 15 GW by 2050 (from around 6 GW at present). This is obviously required to facilitate the effective use of the entire power system in relation to growing demand, increase security of supply and support trading among Nordic countries and with the rest of Europe. Substantial reinforcements have been made and/or are planned in the transmission system, most notably (NordREG, 2012a):

- Finland: the Fenno-Skan 2, a submarine 500kV DC-link with 800 MW transmission capacity started up in November 2011. This link between Finland and the SE3 Swedish price areas was built by the Finnish and Swedish TSOs

(Fingrid and Svenska Kraftnät). Since then, these two have shared the same price 92% of the time. A new transmission link, the EstLink 2- a submarine HVDC cable of 650 MW between Finland and Estonia, is due to start up in early 2014.[4]

- Denmark: a transmission link to improve connectivity between eastern and western parts of the country was commissioned in 2010. Since then, prices in both areas have been much more uniform. This link is critical to channelling wind generation, which dominates the western region, to other parts of the Nordic market. Grid companies are also reinforcing transmission and distribution according to the national 2008 Danish Cable Action Plan. This includes improvements between central and southern Sweden and Norway and Denmark.[5]

- Norway: several projects in the country will improve and strengthen transmission capacity. For instance, a 92 km link (420 kV OH) between Sima and Samnanger is due to be commissioned in 2014. The line will also integrate new hydropower in the region. The Skagerrak IV is a new 140 km DC cable between Norway and Denmark with a 700 MW capacity. It is expected to start up in 2014. A 285 km (420 kV) OH line from Sogndal to Ørskog also aims to improve security of supply in Mid-Norway. This link, due in 2015, is intended to improve RES integration and net transfer capacity. Likewise, a 360 km (420 OH) line from Balsfjord to Hammerfest will improve security of supply in North Norway. This link, due in 2018, will benefit RES integration and growth load. Finally, the Norwegian TSO (Statnett) and UK National Grid signed a cooperation agreement to commission a new DC cable between Norway and UK with a capacity of 1400 MW by 2020.[6]

- Sweden: various projects will increase the capacity and operational reliability of the Nordic power system. For instance, the South West Link will reduce existing transmission restrictions in southern Sweden and between southern Norway and Sweden. This will be ready by 2016. The Swedish TSO (Svenska Kraftnät) is also planning the NordBalt, a link between Sweden and Klaipeda in Lithuania. More projects are under way to strengthen the grid in major urban regions.[7]

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[4] For further information visit www.fingrid.fi/

[5] For further information visit www.energinet.dk/

[6] For further information visit www.statnett.no

[7] For further information visit http://www.svk.se/

3. Policy and Regulatory Framework

3.1. Electricity Market Liberalization in the European Union

Liberalization in the EU has followed a top-down process driven by legislation. It came in force in 1996 through Directive 96/92/EC on common internal electricity market rules. However, it faced fierce opposition and took over a decade to get approval in the European Council (Fouquet and Johansson, 2008a). It was replaced by Directive 2003/54/EC, elaborating rules on new capacity authorization procedures, third party access and the tasks of TSOs. Unbundling was required of TSOs and Distribution System Operators (DSO). This Directive was in turn replaced by the present Directive 2009/72/EC. This states that national regulatory authorities are to cooperate within the Agency for the Cooperation of Energy Regulators to guarantee compatible interregional regulatory frameworks. Member states must designate a national independent regulatory authority and exercise its powers impartially. It is mainly responsible for setting transmission or distribution tariffs; cooperating on cross-border issues; monitoring transmission system operator investment plans and ensuring access to customer consumption data. Directive 2009/72/EC is also part of the Third Energy Package, containing the most critical rules for electricity markets. The most important rules in the context of this report are:

- Regulation (EC) No 714/2009 on conditions for access to the network for cross-border electricity exchanges, which establishes the European Network of Transmission System Operators for Electricity (ENTSO-E) and its main tasks.[8] It also sets rules on developing network codes, how TSOs are compensated when hosting cross-border flows of electricity, regional TSO cooperation etc. In addition, it lays out principles for information sharing and congestion management.
- Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT), which aims to prevent abuse in the wholesale energy

[8] For further information see The European Network of Transmission System Operators for Electricity (2013).

markets, including rules on market surveillance and penalties and disclosure of information

Functioning markets require other types of institutional cooperation. These include forums for legal harmonization, development of network codes and standards and technical assessment and well-functioning forums for exchange of best practice. Besides treaties and directives, the following are key to the liberalization process:

- The Directorate-Generals (DGs) of the European Commission[9] are responsible for developing and implementing European policies in their overlapping fields: DG Energy and Transport (DG TREN), DG Competition and DG Environment;
- The ENTSO-E represents all electric TSOs in the EU and others connected to their networks. Important assignments include the development of network codes and secure power system operations.
- The Agency for the Cooperation of Energy Regulators (ACER)[10] ensures market integration and harmonization of regulatory frameworks respects EU energy policy objectives.
- The Council of European Energy Regulators (CEER)[11] is the voice of Europe's national regulators of electricity and gas at EU and international level.
- The Electricity Regulatory Forum (Florence Forum)[12] and the electricity cross-border committee[13] was set up to discuss the creation of the internal electricity market, including cross-border electricity trade, cross-border electricity exchange tariffs and the management of scarce interconnection capacity.

The internal market rules for electricity require regulated third party access for all transmission and distribution infrastructures. Directive 2009/72/EC states: “Member states shall ensure the implementation of a system of third party access to the transmission and distribution systems based on published tariffs, applicable to all eligible customers and applied objectively and without discrimination between system users.” Infrastructure operators must grant third parties non-discriminatory access and earn a regulated return on their investment for such assets. From March

[9] For further information see European Commission (2013a).
[10] For further information see The Agency for the Cooperation of Energy Regulators (2013).
[11] For further information see The Council of European Energy Regulators (2013).
[12] For further information see European Commission (2013b).
[13] For further information see European Commission (2013b).

2012, member states must unbundle transmission systems and TSOs. An undertaking must be certified before being officially designated as TSO.

The Directive also lists TSO and DSO tasks. It requires the accounts of electricity undertakings to be available to member states and competent authorities, providing confidentiality of certain information is preserved. Electricity undertakings must keep separate accounts for transmission and distribution; member states must arrange third party access to transmission and distribution systems. A regulatory authority must approve and publish tariffs. Member states must also lay down criteria for granting authorization to construct direct lines in their territory. The Directive also requires owners of natural monopoly infrastructure facilities to grant access to parties other than their own customers, usually competitors, on commercial terms.

Member states may choose between three types of unbundling: ownership unbundling, independent system operator (ISO) and independent transmission operators (ITO). Ownership unbundling splits generation (electricity production) from transmission (electricity from electrical generating station to a distribution system operator or to the consumer). The ISO option also gives member states the opportunity to let transmission networks remain under the ownership of energy groups, but transfers operation and control of their day-to-day business to an independent system operator. Under the ITO model energy companies retain ownership of their transmission networks. However, transmission subsidiaries are legally independent joint stock companies operating under their own brand under a strictly autonomous management and stringent regulatory control. However, investment decisions are made jointly by the parent company and regulatory authority.

3.2. Electricity Market Liberalization in Nordic Countries

Norway was the first country to liberalize its electricity market, starting with a new Energy Act in 1990. The reform was driven by poor resource utilization in the system, which led to major overcapacity.[14]Hydro was the main Norwegian power source. Its dependence on the climate was causing frequent supply and demand

[14] For a full historical account on deregulation in Norway see Bye and Hope (2005).

shocks that needed to be prevented using other power sources (Amundsen, *et al.*, 1999). In 1972, the Norwegian power market was officially organized as a spot market in a power exchange, known as Samkjøringen. Norwegian electricity market reform in the 1990s established a spot market for power trade. This was a separate legal entity within the TSO, Statnett. There were also rules on access to the network system on a transparent and non-discriminatory basis.

The dominant, state-owned and vertically integrated company Statkraft was split into two legal entities: the generating company, Statkraft, and the transmission company, Statnett. The other vertically integrated power companies were separated into generating or trading divisions and network divisions for accounting purposes. The network companies were subject to natural monopoly regulations. The regulatory regime was administered and enforced by the Norwegian Water Resources and Energy Directorate (NVE), on the basis of rate-of-return regulation. Market liberalization took place without ownership changes, as power sector privatization was politically unacceptable. The creation of a financial forward market and introduction of standardized financial futures contracts followed. New rules aimed to stimulate the consumer's active retailer choice.

In 1992, the Swedish State Power Board was split into two separate entities, a grid operator and a power producer. The 1996 Electricity Act introduced market deregulation. Swedish investment laws are more open to foreign and private investors than Norwegian laws. Sweden and Norway established the Nord Pool Spot in 1996. Like Sweden, Finland liberalized its market in 1996. Integrating Finnish power with the Nordic market has been complicated, as Finland has a large share of industrially produced thermal power. Finland had its own power exchange before joining the Nord Pool Spot. Denmark also faced integration problems, and did not introduce third party access to the grid until 1998. While early reforms aimed to develop national and Nordic markets, national rules in the 2000s were often introduced to comply with the EU Electricity Directives of 2003 and 2009 (replacing the EU Directive (96/92/EC)). Nordic countries had already established NORDEL in 1963. This was formed by TSOs from Denmark, Finland, Norway, Sweden and Iceland, who aimed to create the foundations for developing an effective and harmonized Nordic electricity market. NORDEL provided advice and recommendations, taking into account conditions in each Nordic country. It was abolished by Nordic TSOs in 2009 and replaced by the European Network of Transmission System Operators (ENTSO-E). Regional cooperation within ENTSO-E is now the official platform for developing transmission grids and an integrated electricity market.

Energy regulators from Denmark, Finland, Norway and Sweden cooperate through NordREG.[15] The cooperation was formalized in a Memorandum of Understanding in 2002. NordREG has a rotating presidency lasting one year. Its main task is to "actively promote the legal and institutional framework and conditions necessary for developing the Nordic and European electricity markets".[16] The cooperation means exchanging views and experiences, mapping and analysing electricity markets and preparing common reports and position papers. NordREG cooperation is based on 1) initiatives from the Nordic Council of Ministers, and 2) initiatives from Nordic regulators. Work is organized through working groups addressing electricity wholesale and end-user markets. NordREG regularly produces work programmes, roadmaps and updates on harmonizing Nordic markets and coordinating grid expansion.

Different Nordic TSOs vary somewhat in terms of tasks and regulatory frameworks (see Table). When national TSOs decide independently on grid investments, their priorities affect the Nordic electricity market (e.g. national investments remediating grid bottlenecks have a positive effect on the whole Nordic market). National parliaments and governments should therefore actively engage with grid development and not leave all decisions to the national TSO (Swedish National Audit Office, 2013).

Nordic countries are all subject to EU rules on supply competition, unbundling and net access and related market surveillance and reporting to the European Commission. They have all chosen the ownership unbundling model. The 2009 EU Electricity Directive sets different deadlines for when all unbundling rules must be in place. A recent report evaluated EU countries excluding Norway, which is not an member (CEER, 2012). It stated that Denmark and Sweden were complying with EU

[15] For further information see Nordic Energy Regulators (2013a).
[16] For further information see Nordic Energy Regulators (2013b).

unbundling rules. Finland gets a good grade though some EU rules still have to be transposed into Finnish law. All countries have opted for the regulated TPA (rTPA) for accessing the transmission and distribution network. This means access prices are published and not subject to negotiation. However, the rules differ somewhat in terms of obligations to connect and costs.

The existence of national rules for costs does not necessarily lead to equal or objective cost allocations. Guidelines are in place but different calculation methods mean grid operators charge different fees for connection and use. Sometimes this leads to lengthy legal disputes. According to some interviewees, some grid operators charge more because their owners demand higher profit margins rather than for any objective reason. There are indications that private and state-owned companies charge higher fees than companies owned by municipalities. These are usually viewed as service providers for local citizens and therefore have less strict profit requirements. Companies whose owners demand high profits may underinvest in grid capacity to meet short--term goals; too much profit is distributed to shareholders and too little put aside for grid investment.[17] If a grid owner is a large player, it is in a better position to handle lengthy legal disputes than small players, and small electricity plants may therefore have difficulties upholding their legal rights on fees.

Table1: Key Regulatory Framework for TSOs in Nordic Countries

Element	Denmark	Finland	Norway	Sweden
The legal basis	EU level and Energy Act and law on Energinet	EU level and Electricity Market Act	EU level and Energy Act	EU level and Energy Act, Governmental decree
Who appoints the TSO?	Government – the Act	EMV (Energy Market Authority)	NVE (NO Water Resources and Energy Directorate)	Government – regulation 1994: 1806
Who gives licences to build network components?	Government	EMV	NVE	Government
Where is the system operation	Energy Act and law	In the Licence given by the EMV. Details	Regulation decided by NVE- Reg. no.	Energy Act, Governmental decree on the

[17] There is currently a media debate in Sweden about the incentives of various market players and the need for more control over grid operator fees.

responsibility specified?		(SO) in the Licence are unchanged since 1998	448 of 7 May 2002	system operator for electricity
Where is the method of economic regulation specified?	Executive order nr. 965 of 2006 on economic regulation of Energinet	EMV methodology decision. Dnro 831/430/2011, 23.11.2011	Regulation decided by NVE – Reg. No. 959 of 7 December 1990	Governmental decree (2010:304) establishing the revenue cap under the Electricity Act
Main objectives of the regulation	Promote and ensure security of supply, efficiency, consumer protection and reasonable consumer prices.	Ensure preconditions for an efficiently functioning electricity market; secure the sufficient supply of high standard electricity at reasonable prices.	Ensure that generation, conversion, transmission, trading, distribution and use of energy are conducted in a way that efficiently promotes the interests of society.	Ensure preconditions for an efficiently functioning electricity market so as to secure the sufficient supply of high-standard electricity at reasonable prices.
Main system operation tasks	Upholding security of supply; extending infrastructure in electricity area; creating objective and transparent conditions for competition in energy markets; implementing cohesive planning including further needs for transmission capacity and the long term security of supply.	Technical functioning and system security; maintain frequency using production reserves needed by virtue of an agreement between the Nordic TSOs; take care of duties pertaining to system responsibility in an equal and neutral manner.	Operate the transmission grid; national power system planning of the grid; manage congestion and establish bidding zones; set transmission capacity limits between and within bidding zones; ensure sufficient frequency reserves at all times.	Overall responsibility for power installations; establish objective and non-discriminatory targets for operational security in the national grid and in interconnections to other countries; ensure grid is being expanded to increase its reliability and availability.
Economic regulation of network model	Cost-plus regulation	Ex-ante revenue cap model	Ex-ante revenue cap model	Ex-ante revenue cap model

Sources: NordREG (2011a, 2012b)

Table 2: Legal and Financial Aspects of Transmission Grid Access

	Denmark	Finland	Norway	Sweden
Obligations of grid operator	Plant operators are entitled against the grid operator to the connection of their plants to the grid. No deadlines are specified for the connection procedure.	Plant operators are entitled to connect. The grid operator must enter into an agreement if the plant in question meets the grid operator's criteria. Detailed provisions are specified in a connection agreement.	Obliged to connect new plant, but exemptions may be granted. Obliged to provide schedule for grid connection.	Obliged to connect unless special reasons (e.g. insufficient grid capacity). Obliged to deal with application within reasonable period and provide a roadmap.
Legislation	Act on Electricity Supply Order 1063/2010	Electricity Market Act	Energy Act and Energy Regulation	Electricity Act
Cost allocation	The plant operator bears the cost of connecting a plant to the grid. The plant owner and TSO bear the cost of connecting a wind energy plant.	The plant operator pays the grid operator a reasonable cost for connecting its plant to the grid. It may request a detailed list of costs from the grid operator.	Plant operator.	Plant operator through network tariff.

3.3. Direct RET Policies

Some key EU legislation has acted as umbrella policy for all EU countries. The Directive 2001/77/EC aimed to support the promotion of electricity from RE sources. It covered all RE sources and sets specific indicative targets for each member state. However, this was revoked (from January 2012) by the EU Renewables Directive 2009/28/EC. This requires EU member states to ensure an agreed proportion of energy consumption derives from renewable sources, setting national RET targets.[18] These are in line with the EU 20-20-20 targets by 2020.[19] This Directive is in a portfolio of EU energy and climate change legislation that includes energy efficiency and greenhouse gas (GHG) emissions. EU member states must produce action plans

[18] For further information see RES Legal Europe (2013).
[19] A 20 % share of renewables in EU energy consumption, a 20% of energy efficiency improvements and a 20 % reduction of GHG emissions compared to 1990.

to meet their targets.[20] The Directive also establishes a common framework for the production and promotion of energy from renewable sources. Each member state must be able to guarantee the origin of electricity, heating and cooling produced from renewable energy sources. The information contained in the guarantees of origin is standardized and may be used to inform consumers on the composition of different electricity sources. EU member states must comply with the Directive through appropriate changes in national law and provide progress reports.[21]

Member states, including Nordic countries, have used a number of direct RET policy instruments, including regulatory approaches, informative schemes and market-based instruments. The most common of these are as follows, according to the European Renewable Energy Council, 2013:

- **Tradable Green Certificate (TGC) schemes**: the RE target under the TGC scheme is determined by the authorities and the certificate price by the market. A given electricity supply chain agent (e.g. generator, supplier or consumer) must meet an individual quota and show a fixed minimum quantity of green certificates, often on an annual basis. Green certificates are originated per MWh of RE electricity (RES-E) generated. Obligated parties can thus generate or buy certificates on the market; the certificate price represents the premium for the renewable energy production. Section 6.2 includes some lessons from the TGC schemes in Norway and Sweden.
- **Feed-in-tariffs (FITs)**: This is a specific guaranteed price, often set for a period of years. It must be paid by electricity companies (often retailers), to domestic producers of green electricity. Section 6.2 includes some lessons from the FIT scheme in Denmark
- **Tendering systems**: member states issue a series of invitations to tender for the supply of RES-E, which will be sold at market price. The additional cost is passed on to the final consumer in the form of a special tax.

The EU Renewable Directive targets are binding, but Nordic countries also have individual political targets.[22] For instance, Norway's target is to be carbon neutral in 2030 if emissions cuts are made by other countries or by 2050 regardless of international emission cuts. Denmark has also adopted a 100% RE supply target by

[20] The EU has a number of additional legal acts related to various aspects of RET, including rules on fuel trade and classification, cogeneration of heat and electricity, and rules on state support and competition.
[21] For more information about this process see European Renewable Energy Council (2013).
[22] These targets can be found in the Nordic Council of Ministers (2013).

2050. These national targets stress the role of RET in Nordic countries. From 2012 there is a common Swedish-Norwegian market for electricity certificates. This means certificates issued in Norway can be used to fulfil the Swedish quota obligation and vice versa. The common market target is to increase electricity production from renewable energy sources in Sweden and Norway by 26.4 TWh in 2012-2020. This means new renewable electricity production is split evenly between the two countries regardless of where production is located.

3.4. Indirect RET Policies in EU and Nordic Countries

Many EU policies provide indirect RET incentives. The EU ETS Cap-and-Trade scheme for CO_2 is the most well-known.[23] The EU also sets minimum energy taxation rules.[24] In addition, EU legislation affects grid investments and lead times for new energy production and new grid infrastructure projects. Environmental impact assessment and public participation rules for new infrastructure projects are the most fundamental examples. Denmark, Finland, Norway and Sweden all use carbon and energy taxes, though with different rates and different exemptions. National rules on environmental impact assessments and public participation vary. This affects the time it takes to undertake new projects to strengthen grid capacity and build new power plants.

Table 3: Direct RET Support Policy Instruments and Related Institutional Aspects

	Denmark	Finland	Norway[25]	Sweden
EU Renewable Directive target 2020 (% gross final energy consumption)[26]	30 % (35% national decision)	38 % (20% renewables in road transport)	67.5%	49 % (50% national decision)
Main RET policies	1) Feed-in and premium tariffs for electricity	1) FIT for electricity from RET 2) A heat	1) TGC scheme (joint system with Sweden) 2)	1) TGC scheme (joint system with Norway) 2) Real

[23] For further information see European Commission (2013c).
[24] For further information see European Commission (2013d).
[25] Norway is not a member of the EU. It is however a member of the European Free Trade Area (EFTA). The EFTA and EU together constitute the European Economic Area (EEA). EFTA countries have agreed to implement a number of EU directives.
[26] Set in Directive 2009/28/EC of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

	from RET 2) Loan guarantees for wind planning 3) Subsidies for small-scale RET	bonus allocated to CHP plants using biogas and wood as fuels	funding scheme for renewable heat and electricity	estate tax reductions for wind 3) PV subsidies
RET & grid access	Non-discrimination[27]	Non-discrimination	Non-discrimination	Non-discrimination
RET & grid use	RET has priority	Non-discrimination	Non-discrimination	Non-discrimination
Key actors	1) Danish Energy Agency 2) Danish Ministry of taxation 3) Danish Ministry for Climate and Energy 4) Energinet (TSO) 5) Danish Energy Regulatory Authority	1) Fingrid (TSO), 2) Energy Market Authority 3) Ministry of Employment and the Economy 4) Ministry of Agriculture and Forestry 5) Ministry of Finance	1) Stanett (TSO) 2) Norwegian Water Resource and Energy Directorate 3) Ministry of Petroleum and Energy	1) Swedish Energy Agency 2) Energy Markets Inspectorate 3) Svenska Kraftnät (TSO) 4) Ministry of Enterprise, Energy and Communications, 5) Ministry of the Environment 6) Swedish Tax Authority
Main legal acts	1) Act on Electricity Supply, 2) Law on the Promotion of Renewable Energy	1) Electricity Market Act, 2) Act on Production Subsidy for Electricity Produced from Renewable Energy Sources	1) Energy Act, 2) Electricity Certificates Act	1) Electricity Act 2) Electricity Certificates Act 3) Energy Tax Act

4. Nordic Power Market Exchange

Taking into account the objective of our study, this section briefly unravels the technicalities of Nordic power market trading.[28]

4.1. Nord Pool Spot Market

The common Nordic power market started with the deregulation of the Norwegian power system in 1991 (see section 3.2). Within this policy-driven liberalization market process, the Norwegian TSO established a power market exchange (originally known as Statnett Marked). This was named the Nord Pool Spot when the Swedish power market was also liberalized and joined its Norwegian

[27] Non-discrimination means that all types of energy sources have equal access.
[28] This section relies extensively on information provided by the Nord Pool Spot. For further information visit http://www.nordpoolspot.com/

counterpart in 1996. The Nord Pool Spot is the world's first and largest international power trading market. It acts as the financial focal point in the Nordic power market and is the largest in Europe. It is dedicated to the wholesale electricity market. Electricity producers and buyers, intermediaries and traders participate in the market as do major end-users.

The Nord Pool Spot supplies accurate and transparent information to market agents; provides liquidity and security; offers equal access and guarantees contract settlement and power delivery. It is 100% owned by the Nordic and Baltic TSOs - the organizations responsible for keeping their respective geographical areas electrically stable (e.g. Statnett in Norway, Svenska Kraftnät in Sweden, Fingrid in Finland, and Energinet in Denmark). A TSO regulates and controls the electricity systems in its own country.

The Nord Pool Spot organizes and operates a power marketplace which has to contribute to effective price formation and an adequate flow of power. It is obliged (through the ELSPOT market, see below) to ensure the exchange of power with neighbouring countries is as effective as possible. Power exchange must be based on relevant area prices. The concessions oblige the Nord Pool Spot to undertake certain tasks, such as market supervision, to identify price manipulation. Trading on the Nord Pool Spot is governed and regulated through a detailed rulebook. This is a set of private legal agreements applying to all parties involved in trading and related activities.[29] Rule updates and clarifications are provided regularly, [30]often to comply with EU Directives.

4.2. Markets in the Nordic Power Market Exchange

The Nord Pool Spot covers four wholesale markets that work together. These are essential for the power market exchange to function. The wholesale power market is a common integrated Nordic market, in which electricity is traded on the Nordic power market exchange, i.e. the Nord Pool Spot. Trading on the Nord Pool Spot is voluntary; however, all day-ahead cross-border trading must be done on the Nord Pool Spot, which consists of two sub-markets, the ELSPOT market (day-ahead)

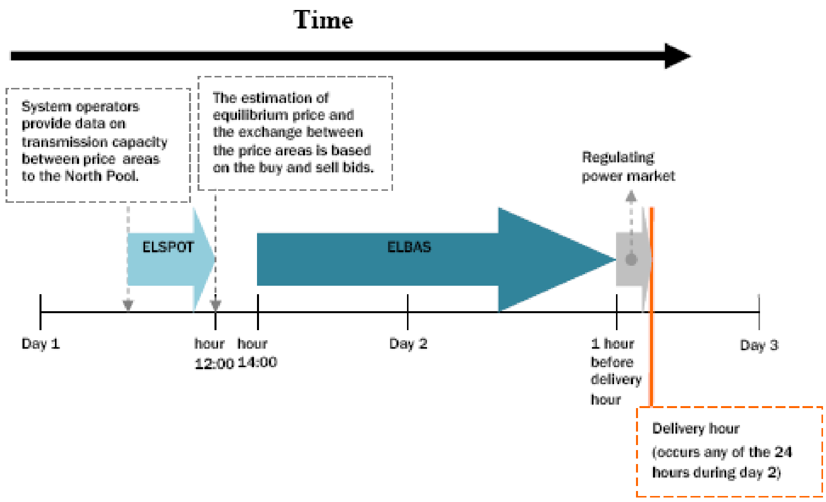
[29] For further information visit http://www.nordpoolspot.com/TAS/Rulebook-for-the-Physical-Markets/
[30] For further information visit http://www.nordpoolspot.com/Download-Centre/

and the ELBAS markets (intra-day). These markets are described below (Nord Pool Spot, 2013):

- **ELSPOT market**: in this day-ahead market, electricity is auctioned for delivery in the next 24 hours. TSOs report transmission capacities before 10.00 a.m for each Nordic bidding area. All market players must send in supply and demand bids (via the internet) by noon every day at the latest for each hour in the day before power is delivered. Prices are based on the intersection of supply and demand. Prices are calculated for each hour of the day based on orders and transmission capacities. This is the system price, i.e. the price that would be realized if there were no congestion between bidding areas (see next section). Prices for each hour of the day are announced and trade is invoiced between sellers and buyers. Approximately 75% of Nordic power consumption is bought on the ELSPOT market. Transmission congestion occurs when large volumes are needed to meet demand. Different area prices avoid bottlenecks. When transmission capacity is constrained, the price rises to reduce demand.
- **ELBAS market**: this is a continuous market in which trading for a specific hour takes place until 30 minutes before electricity is actually delivered. It is critical to adjust power supply or demand plans. Trading is on a first-come first-served basis. If transmission capacity in the Nordic power system remains, neighbouring countries can also trade on the ELBAS market. In the intra-day market, participants in Norway, Finland, Sweden, Denmark, Germany and Estonia can trade for the next day once the day-ahead spot market has closed.
- **Financial market**: this is a future or forward-contract market in which legally binding trading agreements are arranged for up to six years. The financial market is often used for managing risks. Market agents secure prices for future purchases or sales of electricity, with contracts made for up to six years. The ELSPOT System Price is used as a reference price. Given the critical role of hydro in the Nordic system, forward prices or futures represent the value of hydro resources and are needed for optimal use of hydropower during different time periods.
- **Regulating power market**: this market has its own specific regulation and is run by the TSOs aiming to provide a stable transmission grid frequency. If a supply/demand imbalance arises within the operational hour, the TSO uses bids to balance the power system. On the one hand, if consumption exceeds power generation (i.e. frequency of alternating current falls below 50Hz), the TSO buys more electrical power from suppliers that claim to have excess generation capacity. This is known as up-regulation. If power generation on the other hand exceeds consumption, the TSO sells electrical power back to suppliers, encouraging them to reduce power generation. This is known as down-regulation. The balancing power market is also used for congestion management. Settlement

works as follows (Nord Pool Spot, 2013): when the TSO buys regulating power, the price is set the same way as when the TSO sells regulating power. If there is down-regulation, the TSO invoices the down-regulating price (normally lower than the market price). Conversely, if there is up-regulation during a given hour, the TSO invoices the up-regulating price (normally higher than the market price). In 2011, the Nordic balancing power market represented 4.3 TWh; nearly 1% of total electricity production. The balancing market set-up differs slightly between European countries; an overview is provided by Heden and Doorman (2009).[31] In Sweden, the Electricity Act outlines the main balancing rules, with some rules in other ordinances. This states that an electricity producer can only supply the grid if a market player is responsible for balancing at the feed-in point. The producer can enter into an agreement with a balancing player, who must in turn have a contract with the Swedish TSO Svenska Kraftnät.[32] In Norway and Denmark, Balancing Power Option Markets allow buyers and sellers to bid available capacity for balancing power on a weekly or seasonal basis.

Figure 5: Graphic Representation of the Different Markets in the Nord Pool Spot



Source: Nord Pool Spot (2013b)

The Balancing Power Market (BPM) settlement plays a critical role in settling imbalances as a result of power delivery the Nordic power market. TSOs arrange two types of settlements (NordREG, 2012):

[31] At the EU level, Directive 2009/72/EC (see section 3.1) states that national balancing rules must be objective, transparent and non-discriminatory. It sets some general principles for balancing services, but does not provide detailed regulations. Nordic countries in 2008 agreed some common balancing principles. There are, however, still national differences in rules.

[32] Svenska Kraftnät regularly publishes on its website information and standard contracts (and other relevant material) related to the Balancing Power Market.

- A settlement *between* countries: balancing power between two countries is priced and settled in the BPM. This is known as a TSO-TSO market.
- Balancing settlement *within* a particular country: this is a settlement between the respective TSO and the parties responsible for balancing. It is governed by national balance agreements. TSOs are trying to find common procedures for balance settlements between the TSO and the parties responsible for balancing (i.e. a Nordic Balance Settlement). Nordic countries have become more harmonized due to the 2008 NORDEL agreement. Nevertheless, the regulatory frameworks are quite complex. For an examination of the systems of different countries see Heden and Doorman (2009). In Sweden, for example, specific regulation addresses the BPM, where the TSO makes the sales/purchases required to maintain the balance. The TSO requests bids from balancing partners ranked every hour. They are accepted in ranked order until there is no more grid capacity. The balancing partners are paid either by the most expensive up-regulation bid accepted or the least expensive down-regulation bid accepted. There are some deviations to this rule. The economic responsibility for imbalance among balancing partners is calculated with a user balance (applicable to all partners) and a production balance (applicable for partners with responsibility for production balancing). The pricing of imbalance is rather complicated and depends on the spot price and the price area (see Heden & Doorman, 2009) Balance power is calculated per hour. Balance calculations consist of several steps, the most important ones being *a*) balancing partners report production plans and trade a day in advance *b*) the grid operators report electricity use (based on metering) the morning after *c*) the TSO makes the first balance estimate at 12:15 the day after the relevant hour *d*) the TSO reports calculations to the balancing partners *e*) balancing is updated once grid operators have provided the latest electricity use data *f*) billing is calculated twice a month and corrections provided through recalculations within a 45-day period.

4.3. Price Formation in the Wholesale Market

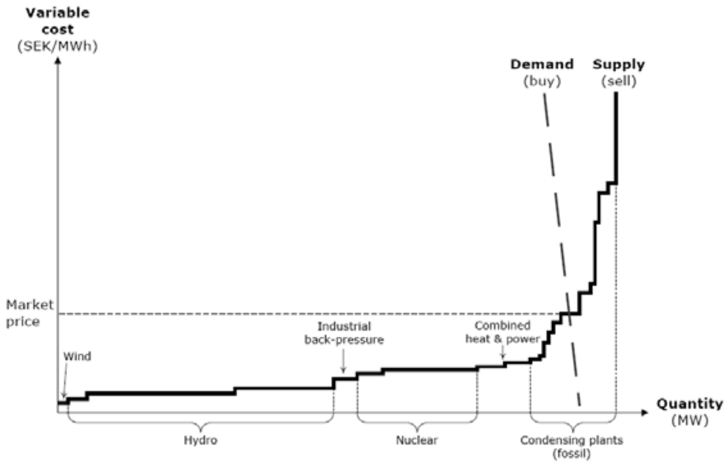
Prices in the Nord Pool Spot are based on supply, demand and transmission capacity. Once the noon deadline for market agents to submit bids is passed, all buying and sales orders are aggregated into two curves for each delivery hour: an aggregate demand curve and an aggregate supply curve. There are three different types of prices (Nord Pool Spot, 2013a; NordREG, 2007):

System price. The system price for each hour of the day is estimated by intersecting the aggregate supply and demand curves that represent all bids and offers for the entire Nordic region. It is a clearing price in which transmission bottlenecks between bidding areas are eliminated. Most standard financial contracts in the Nordic region use the system price as reference price. Some standard financial contracts refer to specific area prices.

Area price. Available transmission capacity is set by the TSOs on an area-by-area basis and thus fluctuates from the available grid transmission capacity. When electricity flows between bidding areas exceed the maximum amount of electrical power (trading capacity) that can flow from one bidding area to another, area prices are calculated and price differences across different areas emerge. The purpose of the area price calculation is to reduce transmission congestion. The area price exercise is repeated so that capacity between the high and low price area is maximized. A price area refers to a section of the ELSPOT market using a similar price. This may encompass a single bid area or two or more bid areas. At times of grid congestion, the Nordic area is divided into 12 different price areas. Bids in the bidding areas on each side of the congestion are aggregated into supply and demand curves in the same fashion as in the system price calculation. Transmission congestion within a price zone can either be handled via capacity setting in the ELSPOT Market and/or through the BPM.

Equilibrium price. All generators that produce and all consumers that consume power in a specific hour use the equilibrium price. This defines the market price in the wholesale market. Depending on the conditions outlined above, especially transmission congestion, the system price or area price represents the equilibrium price. It corresponds to the variable (marginal) production cost for the most expensive production plant needed to meet demand. The equilibrium in the market reflects the costs of producing the last needed unit of electricity to meet demand. This means the price of electricity is defined at the margin (i.e. the cost of increasing total production by one additional unit). This is defined by the marginal production costs of the most expensive technologies, e.g. combined heat and power plants or condensing coal plants in the Nordic region (see Figure6). This means producers with the lowest marginal cost (e.g. wind and hydro) often earn a margin equal to the market price minus the marginal production costs.

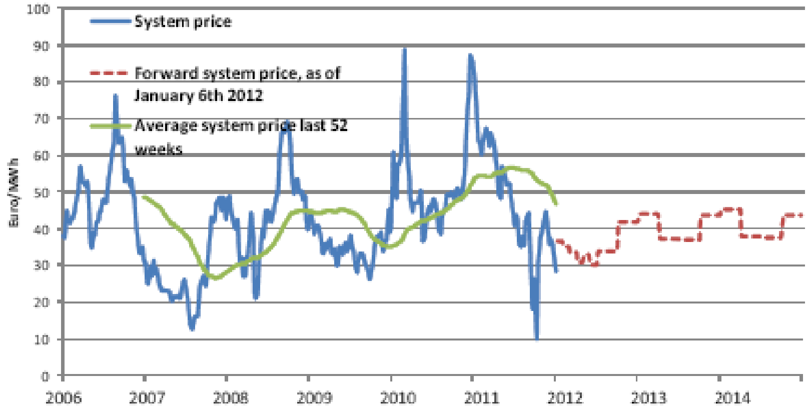
Figure 6: Graphic Representation of Price Formation in the Nord Pool Spot Market



On the Nord Pool Spot, all agents who submit purchase bids at prices equal to or exceeding the equilibrium price may buy that quantity of electricity at the equilibrium price. Players who submit purchase bids below the equilibrium price may not buy any electricity (EMIR, 2006). Likewise, all market agents who submit sales bids at a price equal to or lower than the equilibrium price may then sell the offered quantity at the market clearing price. Thus market agents who submit sales bids above the market clearing price may not succeed. Hence all available electricity production competes at the same level.

Price formation in the Nord Pool Spot is complex due to a variety of other factors. Historical prices can be explained by fundamental factors, such as weather patterns, capacity developments, the EU ETS, economic activity and fuel prices. For instance, there is a strong correlation between annual rainfall levels and electricity prices. Sharp price increases correlate well with dry seasons and thus lower hydropower production in Norway and/or Sweden. Likewise, very cold winters can also raise demand and thus prices. Technical problems (e.g. in nuclear reactors) can take place in cold or dry seasons and also trigger high prices. Conversely, low electricity prices correlate well with high rainfall levels and also lower economic activity during the global financial crisis and the Euro crisis. Figure 7 shows the development and fluctuations of the Nordic wholesale electricity system price in recent years.

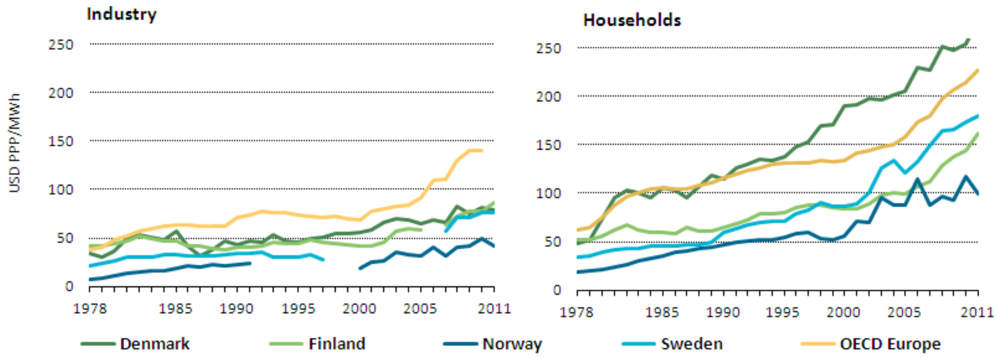
Figure 7: Development of the Weekly System Price and Forward Price at Nord Pool Spot (2006-2014)



Source: NordREG (2012a).

There was a common Nordic price (i.e. system price) for 26.2 % of hours in 2011 (i.e. a situation with no transmission congestion) and 18.6 % of the time in 2010. Sweden and Finland faced a common system price for 74% of the hours in 2011. Although retail electricity prices vary among Nordic countries (e.g. due to energy taxes or VAT), prices in the Nordic region (with the exception of Denmark) have been historically below OECD averages for both residential and industrial consumers.

Figure 8: Electricity Prices in the Nordic Region (1978 - 2011)



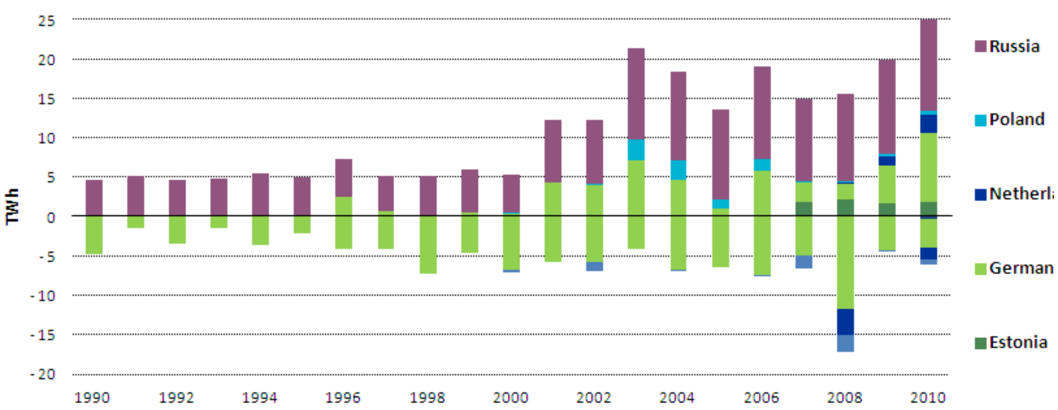
Data source: NER & IEA (2013).

4.4. Electricity Trading among Nordic Countries and European Power Markets

The liberalization and integration of national Nordic power markets, including the abolition of border tariffs, has increased cross-border trading since 1990. Whether the country is a net exporter or importer of power depends heavily on hydro inflows in Norway and Sweden and also on other climate conditions, especially temperatures (NER & IEA, 2013). Whereas Norway, Sweden and Denmark are sometimes net importers in a given year, they can also be net exporters in the next (Nord Pool Spot, 2013a). Conversely, Finland has been a net importer most years, buying electrical power mainly from Russia.

Average export from Denmark has been 1.75 TWh and from Norway 3.85 TWh (NER & IEA, 2013; Nord Pool Spot, 2013a) since 2000. Over the same period, Finland imported 10.89 TWh and Sweden 1.66 TWh. Russia and Germany are now much more integrated with Nordic countries (see Figure 9). The Nord Pool Spot trades with Central and Eastern Europe, including Germany, Russia and the Netherlands (NER & IEA, 2013; Nord Pool Spot, 2013a). Figure 9 shows the volume of trade has grown gradually since 2000. 2010 was a particularly dry for hydropower in Norway and Sweden, and three Nordic countries were net electricity importers: Denmark from Germany; Finland from Estonia and Russia and finally Norway from Russia (Nord Pool Spot, 2013a). Sweden was a net exporter to Poland but it also required power from Germany (Nord Pool Spot, 2013a).

Figure 39: Power Trading Outside the Nordic Region 1990 – 2010 (in TWh)



Data source: NER & IEA (2013) and Nord Pool Spot (2013a). Note that positive numbers depict imports and negative numbers exports.

The expansion of transmission capacity between the Nordic region and Central Europe will play a crucial role (see section 2.2.). Nordic energy organizations in the region agree that several European countries are using flexible generation from the Nordic region to complement variable renewable electricity capacity deployment (see e.g. NER & IEA, 2013; NordREG, 2012a). See section 6.

5. Nordic Power Market and Renewable Energy Development

This section provides a brief analysis of the deployment of RET in relation to the integrated Nordic power market. We had a lack of empirical evidence and could only collect anecdotal information on this issue.

5.1. Information Asymmetries, Transparency

The Nord Pool Spot power exchange plays a dual role as trading platform and information database for market agents. Nordic market agents and renewable energy producers have a good opinion of the role of the Nord Pool Spot in this respect. Interviewees agree that the Nord Pool Spot serves a very important function by providing price information. In addition, rules and procedures in the integrated power system ensure that both expected and unexpected situations affecting the market are properly and immediately reported online by the Nord Pool Spot (Bye, 2007). Quality information flows have been critical to assuring a well-functioning power exchange market (Srivastava, Kamalasadan, Patel, Sankar, & Al-Olimat, 2011). Renewable and non-renewable producers, sellers, traders and brokers are evenly informed of market developments to ensure fair access to information. This also includes transmission capacity considerations such as availability and constraints (Svenska Kraftnät, 2012).

There is strong consensus that high quality information and market data resolution influences the integration of RET. This is supported by Amundsen and Bergman (2006), who found that the Nord Pool Spot market rules maximise transparency because they are rigorous on the provision of information to all market agents. Thus data on the operation of nuclear power plants or levels of hydro stocks must not be withheld (Amundsen and Bergman, 2006). This is consistent with Srivastava, *et al.* (2011). Transparency applies to everyone regardless of their size or generation capacity, and this is critical for unconventional RET players to avoid bad contracts due to limited price information.

In the last couple of years, RET owners have become better informed, not least because of green certificates, but also the low costs of electricity. In the integrated power market, RET producers do not need a customer base since they can sell electricity directly on the Nord Pool Spot. Its data are mostly used by electricity traders on behalf of small-scale RET owners, as they cannot act alone in the market for different reasons (see next section). Information on bilateral contracts (common among unconventional RET producers and power buyers) is not publicly available. However, ELSPOT (the system price) is commonly used as a benchmark for such contracts.

We found that RET investors are more interested in getting a very clear understanding of the rules and regulatory framework associated with RET policies than with power trading. They want a simple, clear operational and regulatory RET policy framework. They find the level of information on how transmission grids are economically regulated at the macro level easy to follow. For instance, Nordic countries regulate network companies by setting revenue caps. In addition, the goals of the regulatory framework are very similar (see section 3.2). However, RE producers have difficulties understanding Nordic economic regulations for transmission grids e.g. decisions and assessments about rate-of-return when setting revenue caps (cf. NordREG, 2011a).

Nordic authorities with links to the power market (e.g. regulators, TSO, competition bodies, financial inspectorates) have agreements to share confidential information and best practice about their respective energy markets. This information exchange also increases transparency and competition on the market (Flatabo *et al*, 2003; Nordic Competition Authorities, 2007). For instance, NordREG includes all Nordic energy regulators. Its mission is to promote legal and institutional conditions needed for the Nordic electricity market development and integration with the rest of Europe. NordREG works and cooperates in four areas: dialogue on competition regulation, analysis of energy markets, development of technical information, and decisions on common action and policy measures. Public consultations are also carried out by NordREG.[33]

The level of high quality information and related exchange in the Nordic region aims to overcome one of the key challenges of economic regulation: that the regulator does not know in advance the true level of (efficient) production, costs and price formation on the market (NordREG, 2011a).

5.2. Market Power/Concentration and Liquidity

There is consensus that the Nordic power market has promoted a competitive market structure (Srivastava *et al.*, 2011). Despite medium-to-high market concentration (Bye, 2007; EMIR, 2006; Flatabo *et al.*, 2003), levels shown by the Nordic power market have not been distressing (Bye, 2007; Hjalmarsson, 2000). We found that the degree of market concentration/power depends on the level of integration of the four national power markets. This heavily depends on transmission capacities and institutional barriers to trade (cf. Amundsen and Bergman, 2006; Tennbakk, 2000). The potential for exercising market power therefore increases due to transmission bottlenecks in the Nordic region (Bye, 2007; Purjasoki, 2006; Srivastava *et al*, 2011).

Before market liberalization, one could easily identify a dominant agent with a market share of 50% or more, such as Vattenfall in Sweden. Market liberalization and integration was therefore one key strategy to overcome this market concentration (Skytte, 1999). For instance, the abolition of border tariffs and adoption of a transmission pricing system independent of distance considerably expanded the overall market. Market power exercised by national champions (one per Nordic country) was reduced automatically (Amundsen & Bergman, 2006). In addition to this, market liberalization also helped unbundle the production and transmission of vertically integrated companies. This in turn reduced their potential for exercising market power. Interviews with officers from the Norwegian and Swedish competition authorities (Konkurransetilsynet and Konkurrensverket respectively) reveal that when the Nordic electricity market is actually integrated by minimising or abolishing transmission constraints, market concentration is low.

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[33] For further information visit https://www.nordicenergyregulators.org/

Now liberalization and integration are in place, several indicators can be used to resolve the level of market power. First, price equalization (i.e. system price) is used as a proxy for the existence of any company exercising market power. The higher the market integration, the less companies can influence the wholesale price. In 2001, the Nordic market was fully integrated 52% of the time (Bye & Hope, 2005). Statistics from 2011 show there has been complete price equalization 25-74% of the time (on an annual basis), and only marginal price differences appear the rest of the time (NordREG, 2012a). These figures can be compared to 2005, in which price equalization occurred 30-60% of the time and minor price differences the rest of the time (Amundsen & Bergman, 2006). The Swedish and Finnish markets have been completely integrated most of the time since 2003. When looking at the interaction with EU power markets, prices have been gradually brought in line since 2000, especially between Germany and the Nord Pool Spot area (NER & IEA, 2013).

Secondly, market share in terms of generation capacity can be used to approximate levels of market concentration. In 2003, the four main Nordic power producers had high market shares nationally - 19-47% (see

Table 44). However, from an integrated market perspective, their market shares were lower: 8-17%. The combined Nordic market share of these companies was below 50% in 2003. The figures reveal that when the Nordic power market is taken as a single market, the combined market share of the main power producers decreases - from 48% in 2003 to nearly 40% in 2011. Analysts conclude that neither Vattenfall nor other major power companies together dominate the Nordic market (Bye, 2007; NordREG, 2012a).

Table 4: Market Shares of Nordic Power Producers

Power producer (country)	**National market share (2003)[2]**	**Nordic market share (2003)[2]**	**Nordic market share (2011)[3]**
Fortum (Finland)	29%	14%	5.2%
Statkraft (Norway)	27%	9%	11.3%
Vattenfall (Sweden)	47%	17%	16.9%
E.On Sweden[1] (Sweden)	19%	8%	6.7%
	TOTAL	48%	40.1%

Note: [1] former Sydkraft
[2] Data source: Swedish Energy Agency
[3] Data source: NordREG (2012a)

The Herfindahl–Hirschman Index (HHI), indicates market concentration and is often used in economic regulation assessments (Rhoades, 1993). Figures for the Nordic market for 2012 reveal high-to-medium concentrated wholesale markets. Only Norway shows low market concentration (HHI index < 1000) but Denmark, Finland and Sweden show relatively high market concentration (HHI index = 2000 approx - NordREG, 2012a). However, these figures take into account transmission bottlenecks, which mean the time the Nordic power market has to be split in different bidding areas. Nordic energy regulators stress that high market concentration can damage market competition, but power generation is a very capital-intensive business which naturally leads to concentrated markets (NordREG, 2012a). Again, Nordic authorities stress that transmission constraints are critical to a fully integrated Nordic market and reduce market concentration (Purjasoki, 2006). For instance, before a transmission link started up between western and eastern Denmark, market concentration in western Denmark was considered a problem (Bye, 2007). This is no longer the case (see also section 2.2.)

Further unbundling of production and transmission can also reduce existing levels of market power (Bye, 2007). The risks of market concentration should never be overlooked (cf. EMIR, 2006). In addition, more transmission capacity reduces the risk of market power from transmission congestion (Srivastava *et al.*, 2011). Finally, it is argued that authorities should reject mergers and/or acquisitions that increase corporate market share (e.g. Bye, 2007).

There is agreement that the market has performed well in terms of liquidity, notwithstanding market concentration considerations (cf. Bye & Hope, 2005). The Nord Pool Spot has played a large part in this.

To increase liquidity, we found that small-scale RES-E producers tend to use traders (e.g. ENEAS, BIXIA) to sell their electricity (including green certificates and to some extent certificates of origin). Interviewees agree that minor players often cannot act on their own in the market and tend to operate through larger organizations. This is explained by their relatively insufficient market knowledge (compared to large producers), high balancing responsibility costs and insufficient volumes for portfolio management. Indeed increasing power production volumes and achieving economies of scale when selling (by reducing transaction costs) was a common trading strategy for unconventional RE producers. This was also stressed by the RET organizations (SREA, SWPA) and traders interviewed. It was further confirmed when interviewing a small-scale hydro investor. To that end, small-scale Swedish RET organizations have negotiated a general agreement on price-setting clarity for their members. Members greatly appreciate this, according to the SREA. Swedish interviewees note that similar contracts are common in other Nordic countries.

5.3. Barriers to Entry

Regardless of generation technology, concerns have been expressed about complexity and fairness in transmission capacity management and down-regulation by TSOs (see section 4.2). This relates to trans-border transmission capacities used to solve domestic capacity constraints (Bye, 2007). Some producers feel limiting trans-border trading because of domestic capacity constraints and different price areas is unfair (see details in next section).

Nordic countries have all opted for the rTPA to access the transmission and distribution network. This is acknowledged as a better option to encourage a competitive power market than a regulatory approach in which third-party access is negotiated (Amundsen and Bergman, 2006; NordREG, 2011a). Since border tariffs were abolished to encourage market integration, experts agree that the only barrier in this respect is the actual transmission capacity of the interconnected grid for trading among Nordic countries (Amundsen and Bergman, 2006; NordREG, 2012a; Srivastava *et al*, 2011). Transmission tariffs all are all similar across the Nordic area and independent of geographical distances between trading partners (Amundsen and Bergman, 2006). However, different tariff values can emerge depending on specific calculations used at the national level. The threshold effect is often a major problem for small-scale RET plants. This means any power plant requiring access to a grid with no capacity has to pay the whole cost of capacity investment (to strengthen grid capacity) as well as extra capacity not used by the plant. The Swedish TSO has proposed solutions for this, including cost calculation changes and TSO risk acceptance (Svenska Kraftnät, 2009). The Swedish wind energy associations have lobbied to change the rules. The Swedish National Audit Office recently found that different lead times and practices in Swedish regions create major differences in the time it takes to undertake grid investments (Swedish National Audit Office, 2013).

Our sources strongly indicated that FITs are the most effective policy instruments for overcoming financial barriers and uncertainties. They agree that RET is capital-intensive and requires support mechanisms and long-term policy goals. Our interviewees credit the role of FITs (as opposed to green certificates) in providing greater financial certainty over time. Cost barrier reduction and guaranteed grid access are key benefits recognized in the Nordic region and Germany for making RET financially viable.

The literature often cites restricted site availability and environmental regulations (e.g. environmental impact assessments) as local barriers, especially for unconventional RE producers (Söderholm, *et al.*, 2007). Our survey found that restricted site availability and environmental regulations can prevent small-scale RET investments, especially in wind and hydro. Interviewees and survey results reveal that small-scale hydro is more difficult than wind energy because it is subject to the same kinds of demands as large-scale hydro. This came through in our interview with the small-scale hydro investor, especially in terms of inefficient administrative processes for environmental permits, but much less for the concession process. Planning and permitting are also considered potential barriers to entry in Sweden, where municipalities must agree to the configuration of wind farms at a certain location in order to give the go-ahead (Pettersson *et al.*, 2010). Small-scale wind energy producers have complained that local planning processes often give high priority to local impacts (e.g. visual interference) and much less to wind conditions and low grid connection costs (Pettersson *et al.*, 2010; Söderholm *et al.*, 2007). While they have local planning power in the area, they should recognize that some places have been identified by the Energy Agency as areas of national interest for wind power production. Swedish municipalities have a high level of independence and this sometimes creates conflicts with national land planning guidelines. A recent Swedish evaluation revealed significant variations in planning permission lead times in different Swedish regions (Swedish National Audit Office, 2013).

Sweden is not like Denmark or Norway, where the planning system is much more vertically integrated and gives greater scope for the local adoption of national wind power policy (Pettersson *et al.*, 2010). However, social acceptability is sometimes also mentioned as a barrier to entry. Local acceptance is critical to both offshore and onshore wind energy (NER & IEA, 2013). We found that getting social acceptance can be difficult and that municipalities have the right to veto installations (EMIR, 2006). However local government and energy companies can provide information and consult regularly with communities on potential environmental impacts reducing the risk of community rejection (McCormick and Kåberger, 2005).

5.4. Transmission Bottlenecks and Balance Resources

RE power producers, especially small-scale and also independent power producers, do not welcome transmission bottlenecks. Interviewees remarked that the market concentration rises when transmission capacity constraints prevent integration. If transmission capacity is adequate, the system price prevails in all Nordic countries and full market integration is met. When there is lack of transmission capacity, cross-border trade is blocked and area prices arise (the system price disappears). Countertrade then emerges and costs are covered by a grid tariff increase.

When transmission constraints split the market, price areas are viewed as an efficient means for regulating it (NordREG, 2011a). In our case, RE power producers can confront two situations depending on their geographical location or spatial markets. On the one hand, RE power producers benefit financially by raising the sales price in the deficit area. On the other, RE power producers in the surplus area sell at a lower price. Each country has different views of transmission access. For instance the Swedish and Norwegian electricity systems have been evolving more hierarchically, especially in relation to wind power. It is claimed that national power boards (Vattenfall and Statkraft) have exercised important control over the transmission grid. These are lesser concerns in Norway because hydropower dams are more widely distributed (Pettersson, *et al.*, 2010). Conversely, Danish electricity has been organized bottom-up with cooperative organizations (wind farm owners) and municipalities owning distribution utilities and power stations (Pettersson, *et al*, 2010). Simplified grid connection administrative measures have played a very positive role (NER and IEA, 2013).

Connection to the main grid from the point of source seems much more important to RE producers than the expansion of the transmission network in itself. For instance, the distinctive grid connection of Nordic offshore wind farms (where technical potential is very large) at present consists of turbines connected along radial feeders brought together at an offshore substation. This is followed by offshore and onshore voltage transformation. However, it is argued that this solution is no longer suitable for large and distant offshore wind farms due to excessive power loss and need for expensive reactive power-compensating equipment (NER & IEA, 2013). Beyond a certain power and distance, it is agreed that high-voltage direct current technology is the most suitable option (NER & IEA, 2013). Certainly, there is always a need for onshore transmission capacity to convey power to demand hubs let alone transmission capacity from offshore wind farm to land.

EU countries diverge significantly when it comes to strengthening grid infrastructure or building and connecting RET plants, especially in relation to national RET policies, grid features and national environmental protection and biodiversity rules. Practices for conducting stakeholder dialogue and environmental impact assessments and lead times for obtaining permits also differ. There may also be national and regional differences (e.g. on grid fees). Often, grid owners and power producers have legal disputes over appropriate and fair fees for a) connecting new power plants to the grid and b) regular fees paid to the grid owner.

The high concentration of wind energy and small-scale CHP plants in western Denmark has created problems in the grid. For instance, surplus power production combined with transmission bottlenecks in neighbouring countries have often distorted market prices (Lund and Münster, 2006; NEPP, 2011a). Since 2010, however, variable wind energy production has been better balanced with hydropower mostly from Norway. A new transmission link between eastern and western Denmark has improved the situation. This has added a technical facility for also balancing wind with Swedish hydropower (see below). In addition, there are ongoing efforts to find more reliable and cost-effective flexible regulation (e.g. including CHP units in balance regulation, investment in heat pumps and heat storage capacity) in order to avoid production surplus losses and to better exploit international power trade (Lund and Münster, 2006; NEPP, 2011a).

Our research reveals that the availability of balancing power from hydro within the energy system is very important for integrating RET into the power market. The literature also stresses that the Nordic power system does not lack balancing resources (NEPP, 2011a). Nonetheless, there are certain limitations to using hydropower as a balancing resource. These include court decisions setting limits for lower and upper reservoir levels, and unpredictable conditions like hydro inflow and wind (NEPP, 2011a). Intermittent power source development and the potential phase-out of some nuclear capacity mean the integrated market can also serve important functions for regulating net flows in the future.

Interviewees indicated that an efficient and flexible transmission grid is of prime importance for hydropower to facilitate the effective decarbonisation of the European power system (cf. NER and IEA, 2013). Nordic hydropower is likely to be progressively more valuable for regulating the North European power system. Another 11 transmission projects (double the number of transmission lines available at present) are required to enable grid interconnections with central Europe and Russia and among Nordic countries (NER and IEA, 2013; NordREG, 2012a).

One of the interviewees argued that mainland Europe is more affected by increased wind power on the grid than Scandinavia (e.g. Germany with its large production fluctuations is much more vulnerable than Sweden and Norway who have limited wind and solar and major hydro capacity). This means more backup power than usual is required when more wind power is installed but the wind is not blowing. With present low electricity prices, there is a clear risk that producers will scrap balancing power capacity or not invest in new backup power. In order to avoid this, preliminary discussions are under way within the Nord Pool Spot and among other market players to set up a new, complementary market for balancing power. This would also create incentives for investing in backup power.

5.5. Price Volatility/Uncertainty

Deregulation opens up a more competitive market, which can benefit end-users with lower prices. Price risks and uncertainty in the wholesale market may slow

RET investment. High returns are often needed to make RET investments profitable, but higher profits may be heavily associated with higher risks. When price fluctuations became large and unexpected (e.g. with seasonal variations, as observed in the Nordic region), they can create uncertain or negative long-term financial conditions for RET (e.g. affecting balance of payments).

Our interviews and survey reveal that price volatility is sometimes considered a problem for RE power producers, especially in Sweden and Norway. They rely on TGC schemes to support RET, with certificates also subject to market fluctuations. However, interviewees also stressed that increased electricity prices after market integration positively affected RET deployment. Interviewees agree that RET deployment has much more to do with: *i*) supportive policy instruments *ii*) RET price development and *iii*) capital costs affecting investments than with the integrated power market.

According to market regulators and energy authorities, price creation in the Nord Pool Spot is efficient (EMIR, 2006). Even when the power system is exposed to dry/cold seasons, the power market exchange works well in terms of economic efficiency and market functionality (cf. Bye and Hope, 2005; Proietti, 2012). However, this does not mean that price volatility is not a challenge for RE power producers. The literature presents different views on this problem:

- Bask and Widerberg (2009) found that electricity prices became less volatile over time. This was the case when the Nordic power market was enlarged (due to further integration) and thus the level of competition improved. This suggests that the gradual integration of the Nordic power market is less sensitive to price shocks than before. Further Nordic power market integration has been beneficial to reduce price volatility and provide more confidence to RE power producers.

- The relationship between spot and future prices has also been analysed. Even with price volatility, Botterud, *et al.* (2010) found future prices tend to be higher than spot prices. This is important for two reasons. Firstly, some small-scale RE power producers do also trade in futures (e.g. via bilateral contracts). Secondly, the relationship between spot and future prices is partially explained by the hydro inflow. Thirdly, balancing capacity from hydro is critical for market performance and system operation. Bach (2009) also found weak correlations between wind power and (volatile) spot prices. It is thought that variable production from wind power (negatively) influences spot prices, which in turn deters wind power integration. The author finds this not to be the case for Denmark and Germany. One of our interviewees agreed, saying: “The more wind we have on the trading market, the less volatility”. However due consideration must be given to transmission capacity and balancing power. Whereas price volatility is not a problem, it can hinder confidence among wind energy market players (Bach, 2009).

- Price peaks in the Nordic wholesale power market did take place during the winter of 2009-2010 (see fFigure 7). According to Nordic Energy Regulators (2011b) various drivers behind price peaks were identified. Firstly, it was a very cold winter. Secondly, the availability of Swedish nuclear power was low. Third, the methodology for allocating transmission capacity lacked flexibility. The resulting low transmission capacity availability towards areas with scarce production resources also contributed to the price peaks. The authorities concluded that the tools, conditions and network utilization needed improvement (NordREG, 2011b).

- Hellström *et al.* (2012) also analyse possible electricity price peak drivers. The authors found that market structure plays a significant role in whether price shocks in demand and supply translate into price peaks. The market structure in terms of capacity constraints is fundamental. For instance, after Finland joined the Nord Pool Spot, the intersection of supply and demand was closer to the capacity constraint in the market. Price jumps were more likely to take place. The situation changed when Denmark joined the Nord Pool Spot, as the intersection between demand and supply moved away from the aggregated capacity constraints (Hellström *et al.*, 2012).

Our survey and interviews strongly suggest that FITs are powerful financial mechanisms to counteract price volatility. They provide the financial certainty that spot markets cannot always provide (Fouquet and Johansson, 2008b; Lipp, 2007). Interviewees also agreed that long term contracts (with futures) are greatly preferable for small scale RET. Futures are less volatile and, according to Botterud *et al* (2010), tend to be higher than spot prices. Stakeholders also perceive that climate policies have had a positive effect on RET investments, rather the Nord Pool Spot or green certificate market. Fluctuation in certificate prices is problematic (Oikonomou and Mundaca, 2008). The Swedish-Norwegian TGC market works largely towards 31st March, the annual clearing date. Assigning a value for green certificates is very complex when there is no continuous market during the year. Permanent price signals are lacking (see section 6).

The literature, interviews and survey strongly suggest that RE policy instruments have had a much stronger influence over RET development than the Nord Pool Spot and especially as far as price volatility is concerned.

6. Key Lessons from the Integrated Nordic Power Market and RET Development

This section briefly elaborates some key lessons from the Nordic experience that may inform the ASEAN region in its first steps towards market integration. It uses new material and builds on findings from the previous section. Lessons are drawn from institutions, regulatory and policy schemes, the power market exchange and infrastructure.

6.1. Political and Institutional Considerations

Strong political support was critical in kick starting electricity market liberalization and integration (Amundsen & Bergman, 2006). Norway took the lead and others followed. Commitment towards market transformation has been very relevant. In addition, energy market integration and the deployment of RET in Nordic countries has been seen as a long-term political commitment and objective (NCM, 2009; NER & IEA, 2013). The Nordic Council of Minister has the vision of "a free and open market with efficient trade with neighbouring markets".

Nordic power market integration closely replicated or assembled steps set out in EU directives (especially in 1996 and 2003). It contained four building blocks for electricity reform: restructuring (e.g. vertical unbundling), competition and markets (e.g. wholesale market and retail competition), regulation (e.g. establishing an independent regulatory body) and ownership (e.g. allowing new/private investors). These building blocks initially aimed for better market competition and efficient production resource utilization and transmission network operation. Integrating power markets and reducing supply and demand shocks arguably showed that energy security was also a major implicit policy objective.

The Nordic experience strongly suggests that building international partnerships and organizations was crucial. For instance, the establishment of NORDEL in the early 1960s created significant conditions for the further development of an effective and harmonized Nordic power market. NORDEL was the foundation for international cooperation and information exchange in the power system and renewable electricity market. It was a significant supranational platform for advice and recommendations promoting an efficient power system in the region, taking into account the conditions in each country. The development of NordREG (Nordic Energy Regulators) has been another milestone for the region. NordREG promotes legal and institutional frameworks and conditions necessary for developing the Nordic and European electricity markets. Another example is the Nordic Working Group on Renewables within the Nordic Council of Ministers and ongoing efforts to establish a Nordic TSO. Collaboration and common purpose in engineering an integrated power market is also evident in the region (e.g. abolition of cross-border tariffs). The common TGC scheme between Norway and Sweden is another example.

Cooperation among countries is another lesson of interest for the ASEAN region. The creation and further development of the Nord Pool Spot market is a remarkable example. Dialogue in the Nordic region takes place through different channels e.g. the Policy of Regional Cooperation on Energy R&D (since 1985), or through Nordic Energy Ministers and the Action Plan for Nordic Energy Cooperation. The latter is considered to be the cornerstone of the vision for Nordic energy cooperation as adopted by Nordic energy ministers in 2004 (NER, 2005). This Action Plan was created to solve the most important and politically most relevant energy policy challenges faced by the Nordic region. The latest efforts within the Action Plan emphasise five critical issues related to the particular case of the Nordic integrated power market: *i*) support national grid investment processes *ii*) strengthen national TSOs for better grid planning *iii*) start dividing the market into additional bidding and/or price areas *iv*) harmonize balancing power rules and *v*) improve congestion and balance management practices.

Policy and research dialogue among Nordic countries on a carbon neutral energy future is increasingly channelled via NORDEN.[34] A high-level group of Nordic ministers (e.g. employment, energy, enterprise) forms the Electricity Market Group

[34] For further information see the Nordic Energy research http://www.nordicenergy.org/

(EMG), which is responsible for following up and implementing the resolutions of the Nordic Council of Ministers in this area. It is argued that each Nordic country has its own specific approach towards energy policy and related issues, but that there are various common elements of close cooperation. These include a strong focus on research and development (R&D) and carbon/energy taxation (NER & IEA, 2013).

6.2. Policy and Regulatory Issues

Early liberalization efforts in the Nordic countries were driven by domestic agendas and efforts to develop a Nordic electricity market, but later developments have been driven to a larger extent by EU policies and regulations. These aim to create an integrated EU electricity market. Despite the complexities involved, it has been possible to simultaneously develop national, regional and supraregional electricity markets once (EU and/or national) regulations and institutional cooperation (e.g. at the international level) are in place.

National electricity market reforms are often introduced to obtain a better balance between power generation capacity and demand, increase efficiency within the power industry and reduce regional differences in electricity prices. EU efforts to create an integrated electricity market have greatly stimulated competition and cut prices, and contribute to energy security. Experience from the Nordic region suggests the deregulation of the power market works well if *i*) no price regulation and constraints are imposed on financial market development and *ii*) there is continuous political support for market-based power even if electricity is in short supply and prices are high (Amundsen and Bergman, 2006). EU member states must report market surveillance practices and prices regularly to the European Commission, and this is also a strength of the EU system.

However, European electricity markets are becoming increasingly complex, as are policies affecting RET development. Not only are the rules complex, but policy-making takes place on five levels. The EU level is fundamental, as the EU has comprehensive legislation that regulates the electricity market set-up. EU rules on fair competition as well as on electricity are both relevant here.[35] At the Nordic

[35] Sweden added a fourth price area because the previous system was considered to breach EU fair competition rules. Danish players claimed the previous system breached EU treaties, as the TSO Svenska Kraftnät used its dominant position in a way that affected Danish electricity

level, individual countries have taken significant steps to harmonize electricity market developments. Plans to move towards a customer-oriented Nordic power market will require further regulatory framework harmonization. There are also ongoing efforts to harmonize Nordic RET markets and increase the cost-effectiveness of policies. One example is the joint Sweden-Norway market for green certificates. At the national level, differences in national rules may exist as long as they do not breach EU rules or cause problems in the joint electricity markets. The regional level is important too as many grid infrastructure projects require permits from regional authorities. Finally, the municipal level is important because municipalities are often local grid operators and energy company owners. In some countries municipalities can veto wind power projects.[36]

Findings and developments in the Nordic region strongly suggest that policy support mechanisms have been essential for RET deployment (NER & IEA, 2013). Power integration has further supported RET integration. The literature shows that the performance of supportive policy instruments for RET is rather case-and context-specific (EC, 2013) — see below for national experiences.

Mandatory renewable energy targets, sometimes aiming higher than EU targets, are an essential precondition for RET deployment. Nordic/European countries have used a variety of support mechanisms to deploy RET and mobilize needed finance (Fouquet and Johansson, 2008a). The internalization of negative social and environmental externalities from fossil fuels has been high on the policy agenda in recent decades (NER and IEA, 2013). In addition, strong political commitment has been necessary to minimize regulatory risk so that stakeholders can effectively plan, develop and/or adjust their investment and compliance strategies.

The experience in Denmark and Germany shows policy makers must give special attention to six key elements in the FIT regime. First, impose a priority purchase obligation. This means grid operators must be obliged to connect RE producers to the grid and transmit the power. Secondly, determine which technologies will be covered by the law. Obviously, a FIT has to be crystal clear

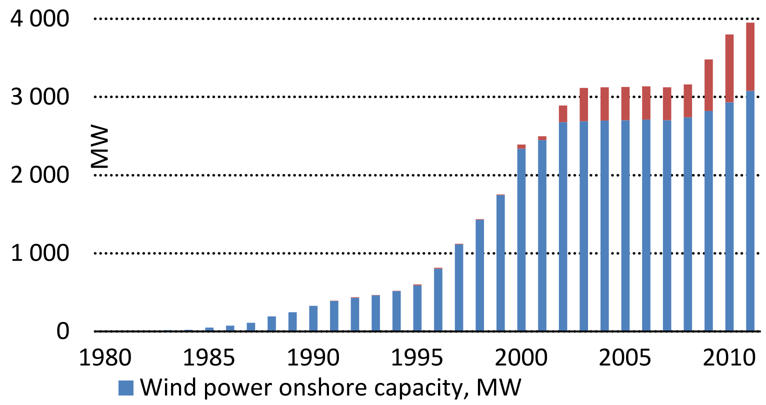
consumers unfairly. Svenska Kraftnät then proposed to introduce a new price area approved by the European Commission. The rule is current and found in Article 102 in the Treaty of the Functioning of the European Union.

[36] This is the case in Sweden; the municipal veto is stated in chapter 16 of the Environmental Code.

about this. Thirdly, set an attractive tariff rate that guarantees financial feasibility/profitability for RE generation. It must reflect the costs related to electricity production from the specific RET source/plant. Fourthly, guarantee the tariff over a specific period of time once qualified RE power producers are connected to the transmission grid. Policy makers must also establish an effective way to finance the FIT scheme[37]and also reduce the tariff rate over time. This is critical to encouraging innovation and cost reduction among RE participants.

The Danish experience of wind power generation is successful but also complex. Wind power has grown rapidly since the 1990s (see Figure). However, the FIT programme contained two distinct stages of decreased deployment rates in wind capacity. This was when the feed-in law came into force in 1992 and after the 2002 reform.

Figure 10: Installed Wind Power Capacity in Denmark (1980 – 2011)



Source: Danish Energy Agency (2012a).

The 1992 FIT law for wind power had a fixed (although not constant) price premium averaging 0.0336 – 0.0524 EUR/kWh. It was accompanied by a subsidy programme where wind power would receive a carbon tax refund of 0.013 EUR/kWh and a production incentive 0.023 EUR/kWh (Agnolucci, 2007). However, in 1991 - 1994, wind power technology deployment decreased (Danish Energy Agency, 2012a). It is argued that this investment delay was rooted in regulatory risk rather

[37] Experience shows that two options are used at present. Firstly, costs are covered by a sharing mechanism covering all electricity end-users. In Germany this option roughly equates to €1.5 per month per household. A second option is via a dedicated fund which receives financial flows, for instance, from carbon or fossil fuel taxes or a reallocation of fossil fuel subsidies

than planning constraints and tariffs (Agnolucci, 2007). It has also been attributed to increased public opposition to wind power (Danielsen, 1995) and low oil and coal prices (Valentine, 2013). But the pace of technology deployment recovered, backed up by government funded R&D and a new investment subsidy in 1994 (Valentine, 2013). This resulted in a 2086 MW rise in wind power capacity in 1995 – 2002 (Danish Energy Agency, 2012a). Critics of the FIT scheme were arguing the feed-in law was over-subsidizing and that there were problems of substandard grid interconnectivity (Valentine, 2013). The government decided to reform the FIT scheme in 2002. Instead of the previous fixed price FIT, wind generators were paid the market price (set at the Nord Pool Spot) and an environmental premium price of around 0.013 EUR/kWh. In subsequent years (2002 – 2008) the deployment of wind turbines stagnated at 271 MW of installed wind capacity (Danish Energy Agency, 2012b). In 2008 the Danish government revamped the FIT scheme yet again, introducing a balancing cost subsidy of 0.03 EUR/kWh on top of the 2002 premium price FIT of 0.013 EUR/kWh and the Nord Pool Spot price. The statistics indicate the change reinvigorated wind power investment. Another 789 MW of wind capacity was added, roughly tripling capacity increases of 2002 – 2008 in just three years (Danish Energy Agency, 2012b).

Wind power in Denmark is often associated only with the FIT scheme, but it is actually the result of a portfolio of policies. These include simplified grid connection procedures, interconnection with hydro-dominated power systems and government supported R&D connected to a strong local industry (NER & IEA, 2013).

The main expectations when the TGC scheme was introduced in Sweden were as follows: *i*) it would substantially increase the share of renewable electricity[38] *ii*) it would increase the renewables share in a cost efficient manner with low social and consumer costs, and generate an equitable distribution of costs and benefits and *iii*) it would increase the competitiveness of renewable electricity through technical change.

We found that the TGC scheme underwent significant changes in 2007. These included an increased target and time frame: to 17 TWh by 2016 (later amended to

[38] . The initial goal was to add 10 TWh of green power to the power balance by 2010. The goal was amended in two later stages, and the current objective is to add 25 TWh from 2002 to 2020. An additional objective of 26 TWh is set in relation to the joint Swedish-Norwegian scheme.

25 TWh to 2020); a shift in parties subject to quota obligation (from end-users to suppliers); new allocation periods for certificates (a maximum period of 15 years and cut-off dates were introduced for plants commissioned at the start of the scheme). The fact that the scheme was given a longer time horizon and received political backing as the main RET policy instrument had a substantial effect on market confidence. It led to an increased willingness to invest in new RET capacity (Bergek and Jacobsson, 2010; Oikonomou and Mundaca, 2008). Before the scheme was extended, some utilities postponed investments due to uncertainty. The Swedish scheme has been cost-effective (Bergek and Jacobsson, 2010; Oikonomou and Mundaca, 2008). It has successfully contributed to new wind and bioenergy installed capacity in particular, with developers given very high importance in the TGC scheme when investing in increased electricity production capacity (see Svebio, 2011).[39] Evaluations of cost-effectiveness are positive (with due consideration to transaction costs —see below), but consumer costs are higher than expected. Large rents are generated by both existing and new RET facilities i.e. windfall profits as a result of free-riding (Bergek and Jacobsson, 2010; Kåberger, *et al.*, 2004; Nilsson and Sundqvist, 2007). Transaction costs are the administrative costs electricity producers and retailers bear in handling the renewable energy quota obligation on behalf of end-users (Bergek and Jacobsson, 2010; Kåberger, *et al.*, 2004). The initial design of the Swedish TGC scheme, however, allowed electricity retailers to charge customers for the certificate-handling service they provided. A significant amount of money paid by end-users to retailers did not in fact reach RE electricity producers (Kåberger *et al.* 2004; Nilsson & Sundqvist 2007). Transaction costs associated with bilateral contracts outside the Nord Pool Spot are unknown (cf. Srivastava *et al*, 2011). It is argued that the scheme's contribution to technological innovation is poor, as it only promotes mature cost-effective RET (Bergek and Jacobsson, 2010; Kåberger *et al.*, 2004; Oikonomou and Mundaca, 2008). From 2007, investment has been directed at bioenergy and wind. The effect on solar is marginal at best. It is commonly accepted that the TGC scheme will not be a driver for new radical technologies, which require other policies.

[39] For statistics and up-to-date figures visit
http://www.ekonomifakta.se/sv/Fakta/Energi/Styrmedel/Elcertifikat/

A draft law for introducing certificates was presented in Norway in 2004, but it was heavily debated and shelved (Tudor, 2011). Norway and Sweden entered into an understanding of the development of a joint market for certificates in 2008. This was later updated and formalized through several rounds of negotiations until a common scheme was created in 2012.[40- 41] Tudor (2012) argues that a joint TGC market can provide better stability through the diversified energy mix. The author also claims the system requires limited state involvement as corporations provide many of the tasks imposed by the regulatory framework. According to our interviews, the fact that clearing only takes place once a year means there is no continuous market. In addition, interviewees stressed that different circumstances may lead to suboptimal outcomes (e.g. best wind conditions are found in Norway but wind investment may still take place in Sweden because of better conditions for obtaining permits and grid access). These kinds of trade-offs (cost-effectiveness versus national policy interests) could challenge the joint scheme.

The literature suggests that national FIT schemes are preferable to TGC schemes as far as policy objectives are concerned (i.e. a stable RET investment climate, more RET deployment, better energy security, GHG emission reductions, etc.) (Fouquet and Johansson, 2008a; Kåberger *et al.*, 2004; Lipp, 2007). The fact that countries such Denmark and Germany have FIT schemes and are world leaders in RET deployment (including related job creation and industrial development) is no coincidence (Lipp, 2007).

Finally, even if Nordic countries have made progress in integrating the power market and deploying RET for power production, energy efficiency has been a key priority to transform the energy system (NER and IEA, 2013). It complements the policy efforts devoted to energy market integration and RET development.

6.3. Power Market Exchange

The Nordic experience shows that the process of market integration (or market coupling) and the development of the Nord Pool Spot have been gradual and smooth.

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[40] The target for the joint scheme between Norway and Sweden is to increase RET with 26.4 TWh between 2012 and 2020 (13.2 TWh of quota obligations in Sweden and Norway respectively), representing approximately 10 % of electricity production in the two countries.

[41] For more information about the joint scheme in English visit http://www.nve.no/en/Electricity-market/Electricity-certificates/

Norway started restructuring its power market and developed the original power market exchange platform in 1993. Sweden joined in 1996, followed by Finland in 1998 and Denmark in 2000. Power trading growth has been incremental. Market surveillance is a critical component and was established as an independent function nearly ten years after its creation. Also following an incremental EU path in power market integration, the Nord Pool Spot engaged very recently in the North West European Price Coupling (NWE) project, alongside 13 TSOs and four power market exchanges. This EU initiative will provide a new price coupling system for day-ahead power markets. It has been labelled a cornerstone for the pan-European power market, covering 75% of the EU power market.[42]

It is agreed that the Nord Pool Spot has provided a well-functioning power exchange (Amundsen and Bergman, 2006; NER and IEA, 2013; Srivastava *et al.*, 2011). As indicated in section 5, findings and interviewees revealed important and positive features, such as clear trading rules, an adequate level of transparency and efficient market-based mechanisms for handling transmission congestion. Eliminating border tariffs and putting in place a system with transmission prices independent of distance has significantly enlarged the Nordic power market. The market power of dominant generators has in turn been diluted (Amundsen and Bergman, 2006). However, market power emerging from transmission congestion, high transaction costs (in particular for small-scale RES-E producers) and tough market entry needs further improvements. The unbundling of dominant (publicly-owned) firms (Srivastava *et al*, 2011) is one contentious political area (Bye, 2007).

Nordic countries have learnt that correct price signals must be visible to market agents (Bye, 2007). Despite high wholesale prices due to, for instance, dry or very cold seasons, Bask and Widerberg (2009) show that prices have increased in stability over time. This process correlates well with the expansion of and more intense competition in the Nordic power market. Price stability and a very efficient power market are primarily dependent on hydro reservoirs (also used to balance capacity resources) across Norway and Sweden (Botterud *et al*, 2010; Proietti, 2012).

[42] For further information visit http://www.elia.be/en/projects/market-integration/nw-eur-day-ahead-marktkoppeling

It is agreed that the Nordic region has good potential to provide flexible and low-carbon power as the rest of Europe seeks to further decarbonise its electricity fuel mix (cf. Lund, 2005; Pettersson *et al.*, 2010; Srivastava *et al.*, 2011).

The Nordic experience also reveals that the wholesale market has low demand-side flexibility (NordREG, 2011b). This can in turn intensify problems due high market concentration. Arguably, real-time pricing (combined with emissions allowances) can positively promote RET market access (Kopsakangas and Svento, 2012) to correct this problem. This is consistent with claims that market efficiency improves when end-users respond to hourly price variations in markets with a great deal of wind power (Grohnheit, *et al.*, 2011). Energy regulators have also suggested that publishing area bidding curves to all market agents can promote demand flexibility (NordREG, 2011b).

There is some agreement on the importance of transmission tariff transparency, which has an impact on power trading (NordREG, 2007, 2011a; Srivastava, *et al*, 2011). Tariffs are independent of the geographical distance between trading parties. This approach adds transparency and fairness to the system. This is appreciated by unconventional RE producers according to our interviews and survey. However, different tariff values can emerge, depending on specific calculations used at the national level. The Swedish Energy Markets Inspectorate has recently proposed rules to remedy some problems associated with high tariffs. These include stricter guidelines for fee calculations, changing accounting practices and allowing national agencies to intervene more often on unfair fees and contracts (Energimarknadsinspektionen, 2013).

Another lesson from the power market exchange is the increasing cooperation and coordination across energy and competition authorities. For instance, the Nord Pool Spot established the Cross-border Regulatory Council Dialogue in 2011 to improve regulatory aspects concerning the power market exchange. This involves all the Nordic energy regulators and market surveillance authorities including Estonia. The Council was greatly needed to facilitate dialogue and information exchange on market surveillance among national regulators. In addition, there was also a need to establish this cooperation platform to support EU electricity market regulation (e.g. monitoring, transparency).

6.4. Infrastructure and Transmission

The Nordic experience suggests that legal reforms in electricity infrastructure were critical to improving transmission infrastructure and thus raising RET involvement. A high share of variable electricity generation from wind and solar has required extensive system integration in the Nordic/EU region. Nordic hydropower has become the centrepiece of the balancing resource to all nations with renewable electricity production. However, interviews revealed that grid expansion brings a number of technical, financial and social acceptance challenges. On the one hand, falling low-carbon electricity generation costs, coupled with transmission grid reinforcements, can make the Nordic countries major net exporters of electricity and increase economic efficiency (cf. Bye and Hope, 2005). This may lead to positive reactions among renewable producers as electricity prices increase. On the other hand, increased Nordic export will raise electricity prices in a region with traditionally low prices. This may trigger negative reactions among Nordic power consumers (NER and IEA, 2013).

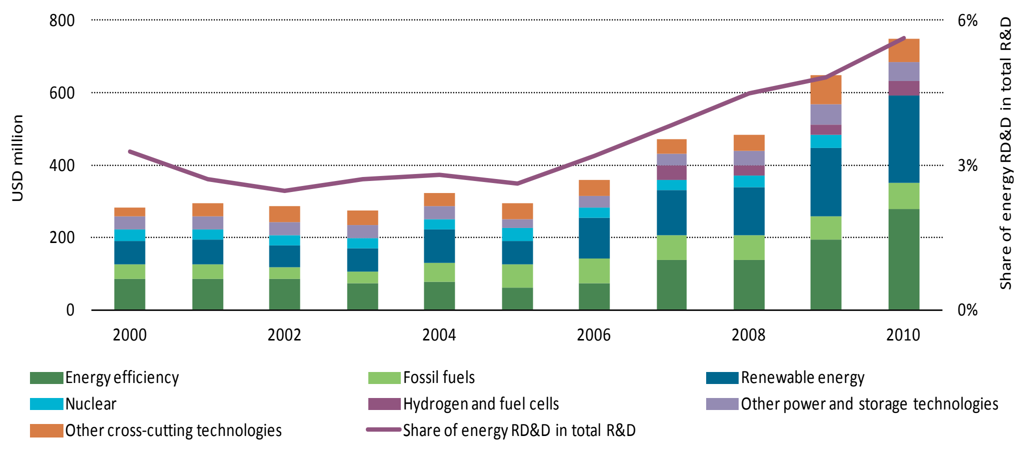
Price differences between zones incentivize the construction of new transmission capacity and avoid transmission congestion. By raising the price in the deficit area, market agents will sell more and purchase less, while in the surplus area a lower price will lead to more purchase and fewer sales (Flatabo, *et al.*, 2003; NordREG, 2007). Nevertheless, it is argued that short periods with limited capacity and very high electricity prices (e.g. caused by an unexpected nuclear reactor shutdown in winter) do not provide enough incentives to expand transmission capacity in the Nordic region (Norden and IEA, 2013). When a market is split due to transmission constraints, it is claimed price areas are an efficient means to regulate it (NordREG, 2011a). At the same time, free trade is a priority. Nonetheless, capacities are sometimes limited in the international transmission grid to secure domestic balances with equal prices between regions. This is not consistent with free trade (Bye, 2007). We found some TSOs have sometimes limited cross-border transmission capacities to secure domestic reserves. This means that a given country moves some of the costs of domestic capacity constraints to other countries by restricting international connection capacities (Bye, 2007).

Assuming that Nordic power generation is carbon neutral by 2050, wind energy generation will increase substantially from 3% in 2010 to 25% in 2050 (NER and IEA, 2013). Once again, this will increase the need for flexible generation capacity and grid interconnections, in particular to accommodate variable and discontinuous wind power production (NEPP, 2011b). Raising and strengthening transmission capacity will be critical to improve the security of RE supply.

Experience shows that a lack of balancing resources has never been a problem due to major hydro resources. However, there are increasing efforts to analyse more cost-effective and flexible regulation systems. These include CHP units in balancing wind powerfluctuations, heat pump investments and more heat storage capacity. These options could allow wind power to double its installed capacity in Denmark (Lund and Münster, 2006).

Capacity building and R&D in the Nordic/European region have been essential for new technologies. To support RET development and its integration into the power market, Nordic countries have had a policy of regional cooperation in energy R&D since 1985. National funding agencies contribute to a common fund administered by Nordic Energy Research. This supports projects involving research partners from three or more Nordic countries. Public R&D spending for RET and energy efficiency has increased substantially in the past decade (see Figure1).

Figure 11: Nordic Public R&D Spending per Energy Source (2000-2010)



Source: NER and IEA (2013)

Given the high share of renewable energy, Nordic countries are in a very good position to make the transition from fossil fuels to low carbon and support the rest of the Europe in doing so (NER and IEA, 2013). As an exporter of low-carbon power supply, transmission capacity needs to be strengthened to facilitate this role. One wind power representative stressed that this is critical for Norway, where transmission capacity is relatively poor compared to other Nordic countries but wind conditions much better. Respondents consider it very important to raise cross-border capacity investments. These alleviate bottlenecks between the physical market areas and help incorporate renewable energy sources in an integrated power market.

Nordic hydropower has become vital as a balance resource to accommodate variable and discontinuous wind power. As shown in section 2.1, the Nordic power system deals with large amounts of wind power (especially from western Denmark). This means it is often necessary to change production to maintain the second-to-second balance between production and consumption (Lund and Münster, 2006). The capacity of hydropower to go from maximum production to zero (or vice versa) quickly and predictably makes it suitable for reducing variation and maintaining electricity supply and demand balance. Hydropower can easily be controlled with a high ramp rate. North European Power Perspectives states the Nordic experience is positive: during normal conditions, hydrological constraints and court decisions allow hydropower to be used for balancing hourly variations even for large amounts of wind power.

The Nordic experience suggests there has been progress in harmonizing transmission regulation. This includes system planning and investment, congestion management and transparency. Nevertheless, there are growing calls for a common Nordic TSO (or a jointly owned and operated TSO) that will benefit and solve many harmonization challenges. Optimal grid investment is a key task for a Nordic TSO (Bye, 2007; NordREG, 2011a, 2012b).

7. Recommendations to the ASEAN Region

This section aims to provide plausible recommendations for the ASEAN initiative. Recommendations have emerged by contrasting findings and lessons from the Nordic region with the situation in the ASEAN region. Recommendations focus on market integration, policy and regulatory issues. The Economic Research Institute for ASEAN (ERIA) and experts from the region have provided critical information about energy market integration in ASEAN.

7.1. Power Market Integration

Support and develop international structures/organizations

ASEAN should consider developing an international body to design, support, implement and enforce policies and regulations to develop an integrated power market and deploy RET. It should assess whether the ASEAN Power Grid (APG) initiative, backed by ASEAN heads of state/governments, could play the role of NORDEL or NordREG, for instance. Continuous and effective political decisions are crucial for further development at this early stage of energy market integration. The need and opportunity for a regional solution should persuade ASEAN countries to find a common political agenda. A number of ASEAN initiatives could sustain long-term political dialogue. For instance (descending in order of importance): ASEAN summit meetings, ASEAN Ministers of Energy Meeting (AMEM), ASEAN Energy Regulatory Network (AERN), ASEAN Power Utilities and Authority Meetings (HAPUA), and the ASEAN Centre for Energy Initiative (ACE).

Coordinate national, regional and supraregional institutional developments

It should be possible for ASEAN countries to develop at different but gradual rates, forming submarkets (e.g. country-to-country market coupling), leading to eventual integration. This may not be the preferred path, but the Nordic/European experience shows it is possible. Coordination is essential. EU legal developments have provided a guiding regulatory framework that has harmonized the practices in various electricity markets. Attempts to create an international electricity market exchange should therefore pay considerable attention to overarching institutional frameworks.

ASEAN countries could develop an Action Plan on Energy Cooperation to encourage collaboration (see section 6.1 and NCM 2005), as in the Nordic region. The 6^{th} ASEAN Energy Ministerial Meeting has laid foundations in this area. The plan could initially target the electricity and renewable energy market. The Economic Research Institute for ASEAN (ERIA) is in an excellent position to further support ASEAN collaboration.

Facilitate cross-border and free movement of green electricity

The Nordic experience suggests ASEAN countries may benefit from improving electricity market competition so the right incentives for renewable investments are set up. A legal framework must be developed and enforced to provide investors the assurance to invest in new renewable energy production and storage. Since the renewables market has developed from local to cross-border supply in the EU, requirements for a pan-Nordic/European trade in renewable energy is being defined on the basis of best practice. Grid infrastructure is critical to developing renewable energy technology and competitiveness with conventional technologies. Transparency, fair terms and reciprocal conditions (e.g. price mechanisms) are important to establish cross-border trade.

Ensure long-term harmonized investment plans for energy market integration

Energy security in the grid is an important building block for a combined energy market. With an increasing RET balancing resource, power availability is of major importance. As a combined energy market develops, it should be accompanied by strategic transnational investments in transmission capacity from key regulating production units to key consumption areas based on location. Authorities should ensure investment decisions allow for a time lag for construction permits. Investment costs should be shared between TSOs according to the benefit to market player.

Build strong international partnerships with neighbouring countries

Since the ASEAN region is much more diverse than the Nordic area, finding neighbouring partners will be easier during the early stage of market integration.

Existing cross-border interconnection projects between Thailand-Malaysia (Sadao-Bukit Keteri) and Thailand-Lao PDR (Roi Et2-Nam Theun 2) support this hypothesis. Common goals on poverty alleviation, energy security, energy access, investment, trade (substantially covered in bilateral/multilateral ASEAN agreements) and economic growth will significantly help ASEAN energy market integration.

Stay the course politically, provide safeguards

In 2002-2003 – when prices were very high due to lack of hydro - the political support for the market was severely tested. While the public demanded price intervention, no action was taken, especially in Norway. In some countries it may be difficult to maintain the system in the face of strong public pressure. It is probably unwise to regulate market prices in such a situation, so other safeguards can be put in place. A fund of electricity subsidies using designated revenue streams for vulnerable consumer groups is a possible solution. The mixed character of the ASEAN market means it is worth planning for such eventualities using instruments like this fund.

Gradually develop and test a trading platform

Power market integration in the ASEAN region will depend on a core power exchange market. This is a critical component in Nordic power market integration. The growing number of neighbouring ASEAN interconnection projects (more than 15 as at January 2013) provides the potential to develop and test small-scale trading platform(s) as a building block (e.g. for power market coupling). In the long run, interconnection projects across Thailand, Vietnam, Lao PDR and Cambodia (some of them to be completed in 2025) represent a great opportunity to further develop and assess an ASEAN power market exchange.

Guarantee and monitor a well functioning power market exchange

For ASEAN countries, key functions of a power market exchange should include: providing liquidity and security, accurate and high-quality information, equal access to market participants and guaranteeing all trade and delivery. A distinction also needs to be made between the physical trade in electricity and the green value of the electricity. Electricity from RET is subject to the same restrictions as conventional electricity in the Nordic/EU region; including mandatory disclosure. ASEAN regulators need the power to collect and exchange relevant information to enforce the law and enhance market performance. Market surveillance plays a critical role in giving confidence in and integrity to the market, especially to small-scale RE producers.

Harmonization across transmission power markets takes time

Transmission networks are natural monopolies, and regulation is often used to control existing market power. The regulation and management of network companies and network constraints differs, so harmonization is critical. Likewise, a clear mandate and understanding of responsibilities becomes essential. Congestion constraint management demands good coordination between system operators using common rules. Well-defined and transparent investment decision criteria need to be established that take the impact on transmission pricing and charges into account. For a supranational TSO, political agreement and ownership issues are major challenges.

Improve and adapt transmission infrastructure

RET cannot simply slot into existing market structures. Wind and solar, for instance, are fundamentally different from conventional technology sources in terms of cost structure, dispatchability and size. The ASEAN region should expect to improve electricity grid operation transmission and distribution to cope with RET integration. Adapting the electricity grid and system operation with storage capacity improvements, better system controls and forecasting techniques greatly improves the efficiency of the power infrastructure. In operation and grid development, rules for grid access, congestion management tools and cost-sharing approaches should be considered. In some European countries, renewable energy enjoys certain support in terms of grid access and use (e.g. the national TSO may pay part of the costs of grid connection or renewable energy may have primary access). In other countries, renewable energy is treated like other types of energy production in all matters relating to the grid. Each country should evaluate the pros and cons of these options.

They should consider creating a long-term ASEAN multilateral finance model/fund that aligns private and public sector investment (including regional development banks) with low-carbon infrastructure investment.

Pay attention to all relevant policy areas in order to support grid development and investment in RET

A number of policies affect the investment climate for renewable electricity production. While RET support policies are crucial, other developments, less often discussed, can be very important. There are major differences between countries and regions in the time it takes to obtain concessions and relevant permits for grid investment. This strongly influences the time it takes to resolve bottlenecks and can also influence the willingness to invest in RET in certain regions. In some countries, the threshold effect is a major barrier to RET investment. This is when a power plant that wants access to a grid with no capacity has to pay the whole cost of capacity investment (to strengthen grid capacity) and also the extra grid capacity not used by the plant. We recommend that these issues are dealt with as early as possible.

Give extensive consideration and analysis of balancing resource mechanisms

This is important already in the short-term harmonization of the integrated power markets and increased deployment of RET. More RET with intermittent energy production will affect the primary electricity system needs to regulate power on the market. This results from the complex interactions of several parameters, including the rate of RET deployment, fuel prices, transmission capacity investments, new technologies and the success of smart grid solutions. With increasing intermittency, incentives engaging market players in balance power capacity exchange are required. If market regulation does not promote energy balance, there is a risk of repeatedly underestimating production forecasts. This endangers grid security, adversely affects the hydro reservoir needed for energy-intensive seasons and affects trust between market players. In the Nordic region, limiting factors affect the balancing capacity of hydropower, such as hydrological coupling, court decisions, transmission constraints and weather uncertainty. Hydropower producers want to maximize profits rather than balance capacity, which they will only do if it is profitable.

7.2. Policy and RET Aspects

Design and implement a mix of policy mechanisms to support RET financing and deployment

Our findings strongly suggest that the development of internal electricity cannot be separated from the policy instruments supporting RET (and vice versa). ASEAN countries need to implement a mix of policy instruments to foster RET. Power market integration is not sufficient for that purpose. Options include FITs combined with a renewable portfolio standard (RPS) and complemented with GHG pricing, R&D and per-kWh tax credits, R&D and demonstration programmes, green electricity labelling and soft loans. There should be thorough evaluations. ERIA is in an excellent position to support ASEAN in this area. A multi-criteria evaluation (e.g. cost-effectiveness, economic efficiency, environmental effectiveness, distributional equity) should be applied accordingly. RE policy instruments should eliminate or correct market failures and not create or maintain market distortions. ASEAN countries should also ensure consumers are informed about the way RE policy instruments affect them. Continuous assessments are recommended once instruments are in place in order to improve their performance.

Set ambitious renewable energy targets

Mandatory RE targets are an essential precondition for RET deployment. RE targets automatically become the benchmark for evaluating the effectiveness of policy instruments. As RE electricity is a moving target addressed by multiple policy instruments, the reference scenario(s) must be periodically updated. If targets are ambitious, support policy mechanisms, non-compliance rules and effective enforcement become increasingly important. Events in the ASEAN countries suggest the region is on the right track: in 2004-2009, ASEAN met its 10% target to increase renewable electricity installed capacity. Following this policy path, the ASEAN Plan of Action for Energy Cooperation 2010-2015 - Programme Area N^{o}5 on Renewable Energy - includes a collective 15% target for renewable energy in installed power capacity by 2015. It is worth raising the bar even further. Continuous evaluation is a must.

Ensure long-term policy objectives to provide confidence in emerging RET markets

RE policy scheme design and implementation must be a long-term policy objective rather than a single dash. A secure long-term policy horizon will help market players factor the costs and benefits of RE policy instruments into their investment and commercial plans. It will also help them develop adequate marketing strategies compatible with other policy instruments and encourage technological change capable of meeting higher RE target levels. The Nordic experience shows that in the long term, the high added value of RET (including its public good) will positively affect growth and employment in ASEAN.

Develop clear but simple RE institutional frameworks

The development of the institutional framework for RE policy instruments has a direct impact on red tape. Simple but clearly defined operational and regulatory frameworks are necessary to ensure effective implementation and learning among stakeholders. A simplified, robust enforcement system can ease the burden for the authorities without compromising the integrity of any given support scheme. Additionality must prevent eligible parties from free-riding, thus only encouraging RET that would not have developed in a business-as-usual scenario. Authorities should design streamlined procedures that can counteract approval delays and help eligible parties reduce related transaction costs (e.g. fast-track or simplified modalities for small-scale RET). Standardized contracts (or at least key contractual provisions) can reduce transaction costs for legal services and perceived liability. Developing and enforcing fair and transparent investment cost-recovery mechanisms is critical.

Market surveillance, smooth legal processes and transparency are crucial

The regulators' role as market watchdog is increasingly important. Their supervision of grid operator tariffs and grid investment practices is paramount; tariffs vary greatly not just within countries but also smaller regions. Great efforts are needed to find good mechanisms for solving legal disputes over grid costs. Major players can often afford lengthy legal processes, unlike their smaller counterparts. These are at a disadvantage. Mechanisms that provide transparency will help create a fair market. Grid operators must be forced to publish tariffs and other types of information to increase transparency. The institutionalized cooperation between EU national energy regulators could also be relevant to ASEAN nations. Activism, staffing, funding and rights to intervene may differ greatly between energy regulators in different countries. This can lead to an uneven playing field, even in situations where the rules *per se* are harmonized.

Provide legal and policy flexibility

While harmonizing certain practices, the legal framework can also allow for flexibility when appropriate. The EU often allows member states to choose the means for reaching targets. Flexibility means member states can make options that suit their existing regulatory and organizational structures. Furthermore, exemptions should be possible. EU rules on unbundling through DSOs, for instance, allow the exemption of integrated electricity undertakings serving less than 100 000 connected customers or serving small isolated systems. Exemptions make sense when comparing costs and benefits. For ASEAN countries, this means a proper balance between harmonization and flexibility. Too much flexibility and too many exceptions can be a problem, but we should also avoid too much harmonization, leading to higher costs etc. A clearing house can keep market players updated on the dynamics of policy instruments and regulatory frameworks.

Develop clear and enforceable non-compliance regulatory frameworks

The Nordic/EU experience strongly suggests that RE policy instruments rely on non-compliance rules and effective enforcement. For instance, penalties for non-compliance in the form of ceiling prices act as penalties for non-compliance in tradable green certificates. The logic is that they must be high enough to act as a deterrent to non-compliance with individual RE quotas. RE target-hitting relies on enforcement mechanisms alongside specific penalties for non-compliance, legal regulations and effective M&V approaches. Non-compliance must not pay.

Price mechanisms must send correct signals to market actors

Electricity prices in Nordic countries fully reflect the true social and private costs of power production and consumption. Without efficient price signals, policy objectives and targets will be more costly to meet. In a well-functioning competitive power market, the price must give efficient signals to any market player for generation, investment and consumption decisions. This guarantees competitive prices for the benefit of the end-user. With due consideration for energy poverty, ASEAN countries should consider eliminating fossil fuel subsidies or grant justified equivalent subsidies to renewable energy. Price signals caused by transmission system bottlenecks should contribute to incentives for efficient investment both in the production and transmission grid.

Develop local/national capacity for RET transitions

Any policy and political effort will depend on local human knowledge and expertise. ASEAN development of local/national capacity will require feedback, flexibility and the support of RE strategies and policy instruments. At micro level, capacity development should be an integrated process of change in knowledge, practices, norms and skills across institutions. It is necessary to create and/or strengthen local capacities for the design, manufacture, distribution, maintenance and repair of RET. RE resource assessments should be the starting point for countries that have not evaluated their potential. National or regional RE data collection programmes should be put in place, identifying appropriate sites for private investment (e.g. wind, small-scale hydro). Demonstration projects indicate the feasibility of renewable electricity projects, especially in areas where they have not been implemented. They could be directly linked to a concrete RE financing project, allowing developers and local host entities to learn directly from them. Careful technical planning, baseline and monitoring methodologies are essential. Nordic cooperation and technology transfer could play an important role in supporting local/national capacity development in ASEAN countries.

8. Conclusions

The Nordic/Europe experience demonstrates that decisive policy support mechanisms, especially to overcome cost barriers, have been an essential platform for renewable energy development. The gradual integration and transformation of electricity markets has further strengthened RET incorporation into the Nordic power market.

The objective of Nordic market liberalization was to lay better foundations for competition and encourage the most efficient use of production resources and operation of transmission networks. It was quickly followed by Nordic power market integration. The establishment of the Nord Pool Spot, the Nordic electricity exchange, was a significant milestone in market integration. The liberalization and integration of the Nordic power market was in many ways ahead of Europe.

National electricity market reforms have aimed to obtain a better balance between power generation capacity and power demand, increase efficiency within the power industry and reduce regional differences in electricity prices. Early liberalization efforts in Nordic countries were driven by domestic agendas and the efforts to develop a Nordic electricity market. Later, EU policies and regulations to integrate the electricity market predominated. The system is complex. However, European countries have been able to develop at a different pace. This was possible due to a regulatory framework that lays foundations for integrated markets yet allows some flexibility for national regulators and the emergence of regional markets. This is exemplified by the Nord Pool Spot.

The Nord Pool Spot shows it is also possible to set up a functioning electricity market when participating countries have a good energy mix, diverse RET policies and different kinds of ownership of production. It has laid the foundations for a well-functioning power exchange, smooth interaction with other European power markets and an adequate level of information and transparency.

There have been robust efforts to create an integrated, interconnected and competitive Nordic power market, the heart of which is RET and green electricity. Nordic countries have put in place aggressive renewable energy policies as well as transposing EU power market integration legislation to support RET for power and heat production. Ambitious targets, long-term policy objectives and strong political commitment have also played a significant role. There is limited knowledge of the historical interplay between power market integration and Nordic RET deployment. However, findings suggest FITs combined with a quota system (RPS) are the most effective support mechanisms for RET deployment. They have to be supported by R&D, simplified grid connection and major hydro balance resources. This has greatly helped overcome cost barriers, reduce power system disturbance and increase the economic and technical feasibility of deploying RET. Carbon pricing (as an indirect policy mechanism) and GHG emissions reduction targets also improve the RET policy framework and investment climate.

We have identified many lessons from the Nordic/European experience that can further help integrate RET into the power market in the ASEAN region. The Nordic experience suggests ASEAN countries need strong political commitment, policy cooperation, international partnerships and a supranational or interregional organization. To develop a fully integrated, effective cross-border power market with a large share of renewable electricity production, policy making must be directed at five distinct levels: supranational, regional, national, provincial and local. Regulatory frameworks and institutions for cross-national cooperation are only one part of the story. Quite often, long lead times, red tape and unfair tariffs at the provincial and local level raise major barriers to investment and grid strengthening. Market surveillance and transparency rules are therefore key elements of a successful regulated energy market.

The Nordic experience strongly suggests the design, evaluation and implementation of aggressive renewable energy policies is very significant for deploying and integrating RET. Long-term policy objectives and targets have provided confidence and certainty in (emerging) RET markets. Ex-ante and ex-post policy evaluations have also supported the process and informed policy. ASEAN countries should also note the importance of market surveillance, smooth legal processes and transparency. Eliminating border tariffs and introducing transmission prices independent of distance significantly helped enlarge the Nordic power market. Policy makers should also prioritize energy efficiency.

Integrating and coupling different national power markets was a gradual and incremental process. There is good cause to believe that ASEAN energy market integration will follow a similar path. Power market integration and the ensuing market exchange have promoted competitive market structures and market-based management tools for handling transmission congestion. Market surveillance is a critical component and functions independently. It is possible to simultaneously develop national, regional and supraregional electricity markets despite the complexities involved if the regulations are well thought through and institutional cooperation in place. The price must give efficient signals to any market player for generation, investment and consumption decisions if the market is to function successfully. These guarantee competitive prices for the end-user.

The Nordic experience suggests legal electricity infrastructure reforms are needed to improve transmission infrastructure for RET involvement. Wind and solar, for instance, have intrinsically different characteristics from conventional technology in terms of cost structure, dispatchability and size. RET cannot merely slot into existing unadjusted market structures. RET grid access is fundamental. A priority purchase obligation via FIT schemes can greatly ensure this process. Adapting the electricity grid and system operation, including storage capacity improvements, better system controls and forecasting techniques (e.g. wind, hydro) greatly improve the efficiency of the present power infrastructure. While Nordic hydropower has become a core balancing resource to any countries deploying RE electricity production, different options in the ASEAN region should be continuously analysed. The development of local/national capacity to support RET market transformation is essential.

Finally, the process of power market integration in the Nordic/European region has been gradual. However, that is no reason to delay the design, evaluation and implementation of aggressive policy instruments to promote RETs in the ASEAN region. RET markets need time to develop and mature and the sooner the process starts, the better. Energy integration policy efforts in themselves are not enough to drive and effectively support the deployment of RETs.

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CHAPTER 3

Renewable Energy Integration in a Liberalised Electricity Markets: A New Zealand Case Study

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In ASEAN and East Asian countries, renewable energy has become a mainstream option, driven by a tremendous growth in energy demand arising from rapid economic growth, concerns about energy security, abundance of renewable energy resources, improvements in renewable technologies, and efforts to limit pollution. This has presented both opportunities for economic growth and challenges to it. One challenge the ASEAN and East Asian countries face is the integration of renewable energy into national or regional electricity networks.

With the bulk (70%) of its current electricity generation from renewable resources, and targeting 90% by 2025, New Zealand's experience with renewable energy development may have some implications for the renewable energy development in ASEAN and East Asian countries.

While renewable energy accounts for the bulk of electricity generation, the variability and unpredictability of some renewable energy sources, together with the asymmetry of electricity generation and demand, mean that system integration is a significant issue. With the current expectations of high fuel prices and carbon emission charges, the use of renewable energy for electricity generation is likely to increase in the future, especially the contribution from wind energy.

To achieve the target of generating 90% of its electricity from renewable sources by 2025, and to ensure environmentally sustainable energy generation and ensure the stability and security of the electricity system. New Zealand has taken the following steps to promote the development of renewable energy, which may provide implications for ASEAN countries in their renewable energy development:

First, to encourage the development of renewable energy and to ensure environmentally friendly and sustainable economic development, the New Zealand government has published a long term energy development strategy, with a focus on renewable energy development and the adoption of environmentally sustainable energy technologies.

Secondly, recognizing the barriers to the deployment of Renewable Energy Sources (RES), the New Zealand Government has passed several regulations and laws to facilitate the development of renewable energy. For example, in 2008 parliament, passed the Climate Change Response (Emissions Trading) Amendment Act 2008, and the Electricity (Renewable Preference) Amendment Act 2008. To support the RES, the Emissions Trading Scheme has been passed into law and put

into effect since 2010, requiring electricity generators to take into account the carbon price in electricity pricing. This will allow renewable generators to gain competitive advantages over fossil-fuelled generators.

In 2011, the New Zealand government released its National Policy Statement (NPS) on Renewable Electricity Generation under Section 32 of the Resource Management Act 1991 (MFE, 2011). This NPS has lifted the status of renewable electricity generation to that of national importance. This encourages local governments to incorporate renewable energy development into their policy statements and plans, and streamlines the consenting process for renewable energy projects.

The Energy Efficiency and Conservation Authority (EECA) has also provided small financial assistance for new renewable energy projects under its Energy Efficiency program. EEC also works with and provides support to renewable energy industries in New Zealand, such as providing seed funding for industry associations, supporting and encouraging the development of industrial standards, etc.

Thirdly, in New Zealand renewable energy development and integration have been mainly achieved through the functioning of a liberalised and vertically separated electricity market. Electricity is traded in the wholesale electricity market. An independent transmission grid gives the new renewable energy generators an access that is equal to that of incumbent generators. A competitive electricity wholesale market enables new renewable energy generators to compete with incumbent generators on a level playing field.

Due to the variable and unpredictable nature of some renewable energy, especially wind energy, New Zealand has also made a few operational adjustments in electricity market operation in order to facilitate renewable energy integration, and to ensure the stability of the electricity system at the same time. These operational adjustments include initiatives to improve forecasting methodology, establish back up mechanisms, more flexible "gate closure" time for wind generators, etc.

Fourthly, to deal with the timing difference between transmission investment and generation investment, in order to accommodate further renewable energy investment, the governing body of the electricity market, the Electricity Authority, and its predecessor the Electricity Commission, together with the system operator, have also taken proactive initiatives to facilitate transmission investment for further renewable energy investment and integration, such as identifying potential renewable energy resources and their location, the costs associated with each potential renewable project, and the transmission investment to support the development of renewable energy generation, which are then fed into the Electricity Authority and system operator's transmission investment planning and scheduling process, which then send signals to potential renewable generation investment.

Introduction

Renewable energy has experienced major global growth over the recent years, driven by factors including emission reduction, energy security, and economic growth (employment). In ASEAN and East Asian countries, renewable energy has become a mainstream option, driven by a tremendous growth in energy demand arising from rapid economic growth, concerns about energy security, an abundance of renewable energy resources, improvements in renewable technologies, and efforts to limit pollution. This has presented both opportunities for economic growth and challenges to it.

In New Zealand (NZ), renewable energy accounts for the bulk of electricity generation (77% in 2011). However, the variability and unpredictability of some renewable energy sources, together with the asymmetry of electricity generation and demand, mean that system integration is a significant issue.

With the current expectations of high fuel prices and carbon emission charges, the use of renewable energy for electricity generation is likely to increase in the future, especially the contribution from wind energy. The New Zealand Energy Strategy 2011-2021 (MED, 2011) set the target of generating 90% of electricity from renewable sources by 2025.

To achieve this target, the New Zealand government has taken steps to promote the development of renewable energy generation. In 2011, it released a National Policy Statement for Renewable Electricity Generation (MFE, 2011), lifting the status of renewable energy generation to that of national importance, with the objectives of encouraging investment in wind, geothermal, hydro, and tidal power, and accelerating the resource consenting process required for renewable energy development. It has also listed renewable energy development as a priority in its energy strategy.

With a large volume of renewable energy, especially wind energy, added to the system in the future, issues with system integration will become even more significant. These issues may require the adjustment of operational, market, and regulation mechanisms and policies, and new transmission investment to ensure the stable and efficient operation of the electricity market.

To ensure better integration of renewable energy into the electricity market, the previous Electricity Commission (replaced by the Electricity Authority in 2010) initiated the Transmission to Enable Renewables project to improve the understanding of the operational, market design, and regulatory issues associated with integrating renewable energy into the electricity market. The current Electricity Authority has also taken steps to better facilitate renewable energy integration.

There are some special characteristics inherent in New Zealand's electricity market. It has been liberalised and vertically separated as a result of market oriented economic reforms since the 1990s. The effective integration of renewable energy into the electricity system has been accomplished mainly through market mechanisms with only limited intervention from the government. The objectives of this study are to review New Zealand's experience with renewable energy integration, to examine policy challenges for renewable energy integration in New Zealand's liberalised electricity market, and to explore what East Asia Summit (EAS) countries can learn from New Zealand's experience.

This study will examine New Zealand's experience of promoting renewable energy generation and facilitating renewable energy integration, the current issues associated with renewable energy integration, and the way forward. We will draw some policy implications from New Zealand's experience for EAS countries to consider.

This report will be organised as follows: section 2 reviews the current electricity market in New Zealand and the New Zealand government's Energy Strategy; section 3 reviews renewable energy development in New Zealand and its challenges; section 4 reviews policy options, market design and operational adjustment in New Zealand to facilitate renewable energy integration; section 5 explores policy implications for ASEAN and East Asian countries.

1. The Current Electricity Market in New Zealand

1.1. History of Electricity Market in New Zealand

New Zealand consists primarily of two similar sized main islands: the North Island (NI) and the South Island (SI). The North Island has over 75% of the population and accounts for 73% of national gross domestic product (GDP), while the South Island has less than 25% of the population, and accounts for around for 27% of national GDP.

New Zealand's history of electrification began in the late 19th century, when local authorities and private entrepreneurs started to construct small generation facilities to serve local markets. The first substantial use of electricity was for lighting. Various shops and small factories generated their own electricity for this purpose, city councils either built their own small generation plants or purchased electricity from private generators to provide street lighting, lighting for public buildings, etc. The first major hydro electricity generation project, and one of the major electricity generation initiatives, came in 1886 at a gold mine in South Island.

In the early 1900s, the development of high voltage transmission provided the opportunity to develop large scale hydro electricity generation and electricity transmission over long distance. Increasingly, the central government was seen as the only entity with the necessary financial resources to enable the development of large electricity generation and transmission projects, and was granted the exclusive right to generate electricity using water power in 1903.

In the 1920s and 1930s, the Government started with the construction of a set of large state-owned hydroelectric plants on major rivers. These plants were linked by a transmission grid from which power was taken off by local government distribution and retail companies, the so called ESAs (Electrical Supply Authorities). After World War II, more power stations were built, including hydro powered, coal fired, gas fired, oil powered, and geothermal powered stations. Since the later 1980s and early 1990s, market oriented economic reform has significantly changed the electricity market in New Zealand.

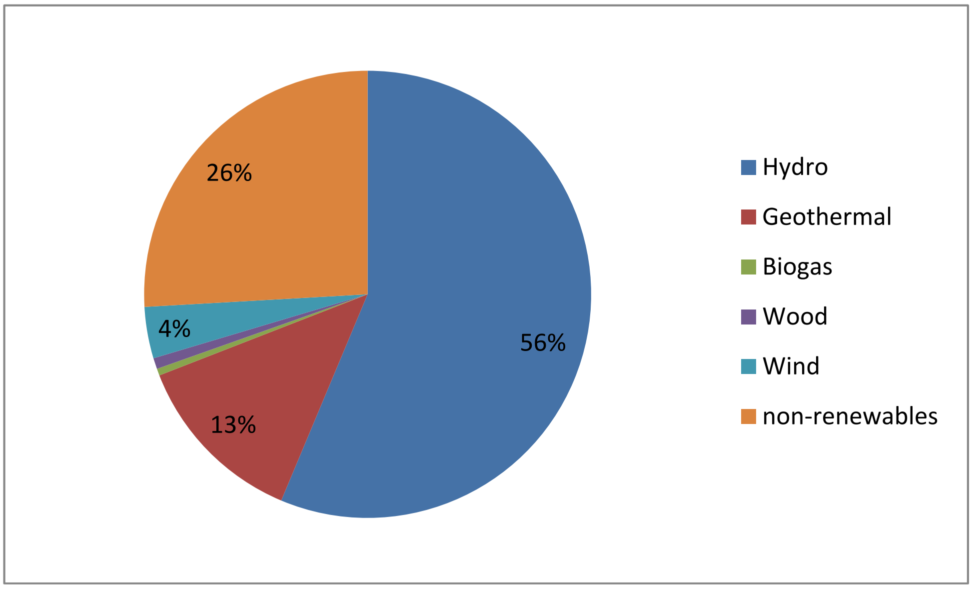
The majority of transmission lines, which established the national grid, were built by the government in the 1950s and 1960s. By 1965, the North and South Islands were linked by undersea High Voltage Direct Current (HVDC) cables across the Cook Strait.

1.2. Electricity Supply and Demand in New Zealand

In 2011, the installed capacity for electricity generation was 9751 megawatts (MW), generating 43,110 gigawatt hours (GWH) of electricity. Renewable energy sources have provided the bulk of electricity, making New Zealand one of the lowest carbon dioxide emitting countries in terms of electricity generation. In 2010, a total of 74% of electricity generation came from renewable resources (see

Figure 1), with 56% from hydro, 13% from geothermal, 4% from wind, and another 1% from other forms of renewable energy sources, such as biogas, wood, etc.

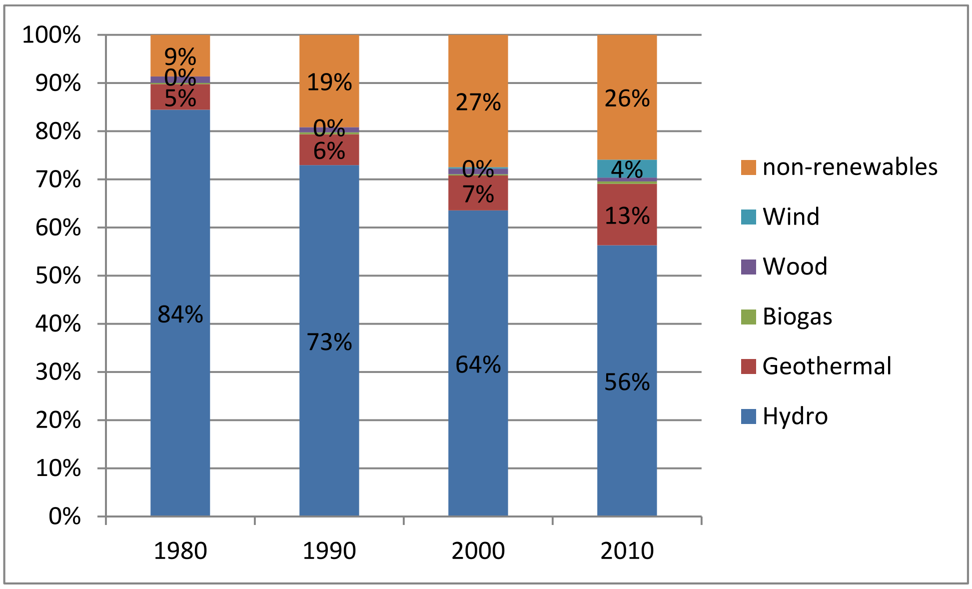
Figure 1: Share of Electricity Generation by Fuel Types in 2010



Source: NZIER calculation based on New Zealand Data File 2012 (MBIE, 2012).

However, the share of electricity generated from renewable sources has trended down over time, dropping from over 90% in 1980 (see Figure 2). The share of electricity generated from hydro sources has decreased from around 85% in 1980 to 56% in 2010. Contrasting to this, the shares of electricity generated from geothermal and wind sources have increased. The share of electricity generated from geothermal resources has increased from 5.3% in 1980 to 12.8% in 2010. While in 2000, the share of electricity generated from wind energy was still negligible (0.3%), by 2010, this share had increased to around 4%.

Figure 2: Share of Electricity Generation by Fuel Types in 1980, 1990, 2000, and 2010



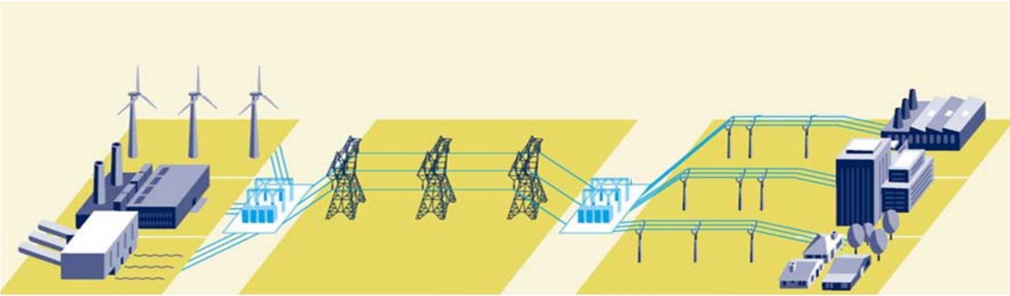
Source: NZIER calculation based on MED's New Zealand Energy Data File 2012 (MBIE, 2012).

During the period between 1976 and 2010, electricity generation grew at an average of 2.1% per annum. This was largely fuelled by the growth in generation from non-renewable sources, with an average growth rate of 2.9% annually, and renewable sources other than hydro, such as geothermal, with an annual growth rate of 4.3%. The growth of generation from wind energy is even more significant. In 1990, there was no electricity generated from wind; by 2011, electricity generated from wind had reached nearly 2000GWH.

1.3. The Electricity Market in New Zealand

Traditionally, the electricity sector in New Zealand was organised as a vertically integrated state monopoly. Since the 1990s, the sector in New Zealand has experienced significant changes due to market oriented reform and restructuring initiated in the 1990s. The reform is still going on with the recent partial privatisation of a state owned electricity generation company, and another planned in the near future. As a result of this reform and restructuring, the current New Zealand electricity market is split into the following areas: regulation, generation, wholesale, retail, transmission, and distribution.

Figure 3: The Four Main Components of the Electricity Industry in New Zealand



Generation **Transmission** **Distribution** **Retailing**

Source: Ministry of Business, Innovation & Employment.

1.3.1. Generation

Electricity in New Zealand is largely generated from hydro, gas, coal, and geothermal resources, of which hydro accounts for more than 50% of the electricity generated. Electricity is produced at generation stations and supplied at high voltage to the national grid at grid injection points (GIPs). There are around 40 major electricity generation stations connected to the grid.

There are currently five major generation companies: Contact Energy, Genesis, Meridian, Mighty River Power and TrustPower. These five companies generate more than 93% of New Zealand's electricity; the biggest three supply 74%. These five generators are also electricity retailers; they are the so called "gentailers".

1.3.2. Retail Market

Electricity is supplied to residential and small commercial and industrial customers through electricity retailers. Retailers purchase electricity from the electricity wholesale market. The electricity purchased may come from a retailer's own generation arm (gentailer) or another generator that has supplied into the wholesale market.

Currently, there are five major retailers. All of them are vertically integrated gentailers, and they are all major generators too. These five companies account for 96% of the electricity purchased from the wholesale market, while the remaining 4%

is purchased by a number of small retailers. Electricity retailers pay distribution companies for distribution and transmission services.

1.3.3. Wholesale Market

The wholesale market is the place where the electricity supplied by generators meets the demand from retailers. All electricity generated is traded through the central pool, with the exception of small generating stations of less than 10MW. Bilateral and other hedge arrangements are possible, but function as separate financial contracts.

The market operation is managed by several service providers under agreements with the Electricity Authority. The physical operation of the market is managed by Transpower in its role as System Operator. NZX is contracted as Reconciliation Manager, reconciling all metered quantities, Pricing Manager, determining the final prices at each node, and Clearing and Settlement Manager, paying generators for their generation at the market clearing price and invoicing all retailers for their off-take. The wholesale market operates every day on a continuous basis in 30-minute trading periods; there are thus 48 trading periods per day. Generators submit generation offers to the system operator, indicating for each period how much electricity the generator is willing to supply, and at what price. Likewise, electricity purchasers must submit bids to the system operator, indicating the amount of electricity they intend to purchase.

Once all offers and bids have been received and finalised for a particular trading period, the system operator issues actual dispatch instructions to each generator on how much electricity it is required to generate and/or other required actions.

For each trading period, the pricing manager determines the single price to be paid to the generators for all electricity supplied. This price is determined by the price of the marginal generation required to meet demand for a given trading period.

1.3.4. Transmission

The electricity transmission system connects generators to the local distribution networks, who transmit high voltage electricity from GIPs at generation stations to grid exit points (GXPs). At GXPs, transformer substations reduce the electricity voltage for distribution through local distribution networks to end-users.

The New Zealand transmission network consists of two subsystems, one in the North Island and one in the South Island. The two subsystems are connected by a high voltage direct current (HVDC) link. This makes possible the export of electricity from the South Island, where 60% of the electricity is generated, to the North Island, where the demands for electricity are predominantly located.

Transpower, a state-owned enterprise (SOE), owns, operates and maintains the transmission network. As owner it provides the infrastructure for electric power transmission that allows consumers to have access to generation from a wide range of sources, and enables competition in the wholesale electricity market. As system operator, under contract with the Electricity Authority, it manages the real-time operation of the network and the physical operation of the New Zealand electricity market.

1.3.5. Distribution

The electricity distribution network distributes electricity from the transmission system to the end-users. There are 28 electricity lines businesses in New Zealand. They range in size from around 5,000 electrical connections to nearly 500,000 connections. Other entities also provide electricity distribution services as part of their normal activities. Included among these are airports, ports, and large shopping mall operators. The electricity distribution networks are considered to be natural monopolies, and are subjected to performance based incentive regulation.

1.3.6. Regulatory Framework

The electricity industry is covered by a set of generic and specific legislation (including regulations), including

- Electricity Industry Act 2010 (the Act)
- Commerce Act 1986;
- Electricity Industry Participation Code 2010
- Electricity Industry (Enforcement) Regulations 2010 (Regulations)
- National Policy Statement on renewable electricity generation.

The regulatory bodies include the Electricity Authority (previously the Electricity Commission), the Ministry of Business, Innovation, and Employment (MBIE), and the Commerce Commission.

MBIE is responsible for developing and implementing policies and legislation for the electricity sector, and for monitoring the performance of the Electricity Authority and the Commerce Commission. The Commerce Commission implements and monitors the price and quality regulation of distribution and transmission businesses.

The Electricity Authority is responsible for giving effect to government policies, and is required to make and administer the electricity industry participation code, and to monitor compliance with the electricity industry act, electricity industry regulations, and the industry participation code. It is also responsible for the operation of the electricity market. It contracts Transpower as system operator for the day-to-day operation of the electricity system. It also contracts NZX as reconciliation manager, pricing manager, and clearing and settlement manager.

1.4. Issues in the Electricity Market

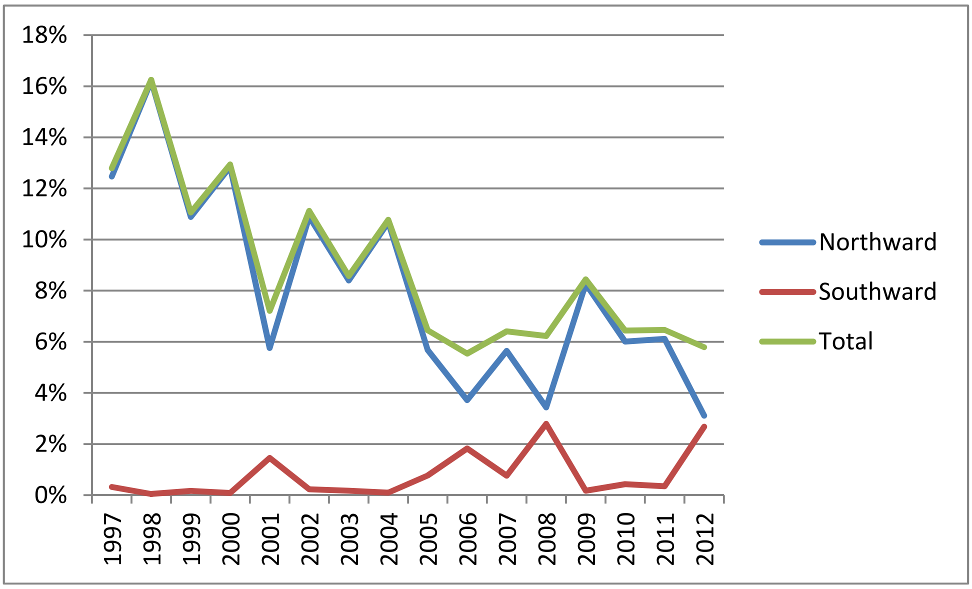
The issues in the electricity market revolve around the two main challenges facing New Zealand: security of electricity supply and climate change.

The first issue is the geographical asymmetry of electricity generation and demand between New Zealand's South Island and North Island. The North Island has over three times the population of the South Island (3.39 million vs 1.04 million). Consequently, the North Island has a substantially larger energy demand. In 2011, around 37.1% of the total electricity generated was consumed in the South Island, while 62.9% was consumed in the North Island. Before the 1980s the South Island used to account for 60% of the electricity generated in New Zealand, while the North Island accounted for 40%. This imbalance has been shifting due to investments in geothermal and gas-fuelled electricity generation. However, this imbalance still exists three decades later although to a lesser degree. In 2011 generation from South Island has reduced to 40.9% of national electricity generation, while the contribution from the North Island has increased to 59.1% from a mixture of mainly hydroelectric, natural gas and geothermal generation, plus smaller amounts of coal and wind generation.

The imbalance has been managed through the wholesale electricity market and with substantial transmission between the two islands through an undersea high voltage direct current (HVDC) cable. This transfer is typically from the South Island to the North Island. While in the late 1990s, electricity transmitted from the South Island to the North Island accounted for more than 10% of the total electricity demanded, this figure has dropped to around 5 or 6% since 2005 (see Figure 4).

This results in the HVDC system being a critical facility for electricity security and availability. For example, on 16 June 2006 the HVDC experienced an unplanned outage just before the evening peak period on one of the coldest days of the year. With four North Island power stations out for service and an outage of another power station's (Tauranga's) ripple load control equipment, even with a reserve (Whirinaki) power station being called upon, the North Island experienced electricity shortages and Transpower subsequently declared a nationwide Grid Emergency.

Figure 4: Electricity Transmission between the North Island and the South Island (% of Total Electricity Demanded)

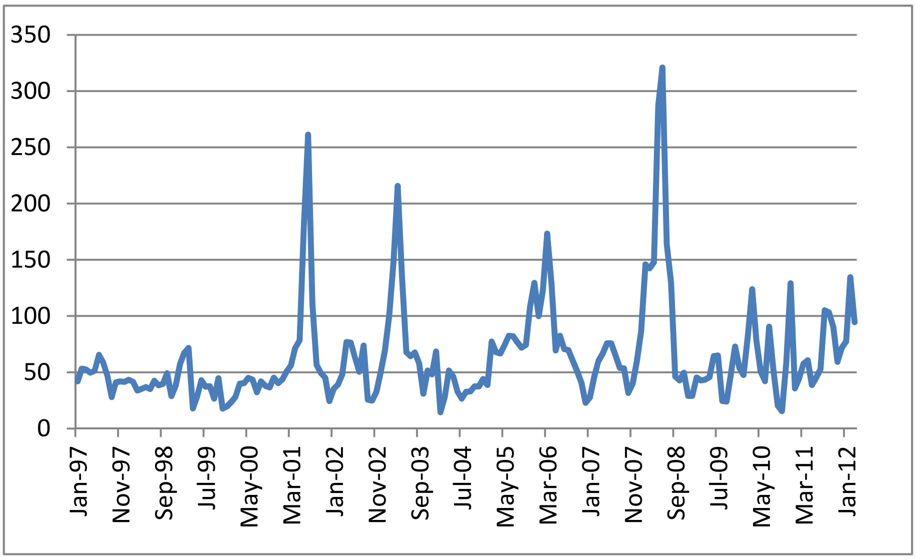


Source: NZIER Calculation based on Electricity Authority's Centralised Dataset.

The second issue is the low volume storage system in New Zealand, which makes the electricity market subject to supply shortfalls in the event of dry seasons. The storage system only has a storage capacity of 34 days' supply at peak winter demand. Therefore, the system is prone to supply shortfalls in the event of dry seasons. In a dry season the shortfalls have to be met by high cost fossil-fuelled reserve electricity generators. This can lead to high wholesale electricity prices which we saw in 1992, 2001, 2003, 2006, and 2008 (See Figure 5).

In the event of supply shortfall, generators also have incentives to hold back generation to raise the wholesale price even higher. In 2008, following the high price spike, there were indeed allegations of generators abusing market power and complaints about high wholesale and retail prices, which led to the Commerce Commission's investigation into the ability of and incentives for the four largest electricity suppliers in New Zealand to exercise unilateral market power and to quantify the market power rents in the wholesale market that have resulted from the exercise of such unilateral market power.

Figure 5: Consumption Weighted Average Wholesale price ($/MWH), Jan 1997-Mar 2012



Source: NZIER calculation based on Electricity Authority's Centralised Dataset.

The third issue concerns ensuring that New Zealand has sufficient generation capacity to meet growth in energy demand in the future, another aspect of the security of electricity supply. It arises from the increasing demand for electricity, high forecasted fossil fuel prices, and New Zealand's commitment to reduce greenhouse gas emissions.

The recent Energy Outlook 2011 (MBIE, 2012) projects that electricity demand will grow by an average of 1% to 1.5% per annum over the period to 2030. There is some evidence to suggest that, in the shorter term, increases in demand may be higher than these figures. Analysis of grid exit point data from 1999 to 2005 indicates that electricity demand is currently increasing in the range of 2 to 2.5% per annum on average.

In order to meet increasing demand for electricity, according to MBIE's New Zealand Energy Outlook's projection, electricity generation needs to grow at 1.5% annually until 2025. This would mean that 10800GWH of additional generation will be needed by 2025. If the demand for electricity continues to grow at 1.5%, an extra 35000GWH of electricity would be needed by 2050.

For the period up to 2025, it is projected that prices for gas and coal will increase significantly (30% and 90%). As demand for electricity generation grows, together with the adoption of the Emissions Trading Scheme (ETS), forecast rises in the price of fossil fuels, the decline of gas supply from the Maui gas field, and a possible international cap and trade agreement on carbon, the costs of continuing reliance on fossil-fuel-fired generation to meet peak demand will escalate. New Zealand has also made commitments to reduce greenhouse gas emissions and for environmentally sustainable development.

All these factors mean that New Zealand needs to put more emphasis on renewable energy generation and to undertake the transition to renewable energy sources to ensure that it has the capacity to accommodate the growth in demand and to compensate for the likely decline in the availability of natural gas from local gas fields.

1.5. The New Zealand Energy Strategy

To meet these challenges, in 2007 the then Labour Government put forward the New Zealand Energy Strategy (NZES) to 2050 (MED, 2007). Through NZES, New Zealand has put renewable and environmentally friendly energy development at the centre of its long term energy development strategy. It has also declared that New Zealand should achieve the target of having 90% of its electricity generated from renewable sources by 2025.

The vision of the 2007 NZES was for New Zealand to have "A reliable and resilient system delivering New Zealand sustainable, low emissions energy services, through:

- Providing clear direction on the future of New Zealand's energy system

- Utilising markets and focused regulation to securely deliver energy services at competitive prices
- Reducing greenhouse gas emissions, including through an Emissions Trading Scheme
- Maximising the contribution of cost-effective energy efficiency and conservation of energy
- Maximising the contribution of cost-effective renewable energy resources while safeguarding our environment
- Promoting early adoption of environmentally sustainable energy technologies
- Supporting consumers through the transition (MED, 2007, p.15).

In the 2007 NZES, the government also declared that 90% of New Zealand's electricity should be generated from renewable sources by 2025. This strategy was however put on hold in 2008 after the new National-led Government took office.

In 2011, the National-led Government put forward another energy strategy, New Zealand Energy Strategy -Developing Our Energy Potential for the period between 2011 and 2021 (MBIE, 2011), replacing the New Zealand Energy Strategy to 2050 (MBIE, 2007) released in 2007. The new strategy has however retained the renewable energy target for electricity generation proposed in the 2007 NZES that 90% of electricity generation be from renewable sources by 2025.

As described in the new strategy document, the goal of the government is "for New Zealand to make the most of its abundant energy potential, for the benefit of all New Zealanders" (MBIE, 2011, p.4), and the Government proposed to achieve this goal through the "environmentally responsible development and efficient use of the country's diverse energy resources, so that:

- The economy grows, powered by secure, competitively priced energy and increasing energy exports
- The environment is recognised for its importance to our New Zealand way of life." (MBIE, 2011, p. 4)

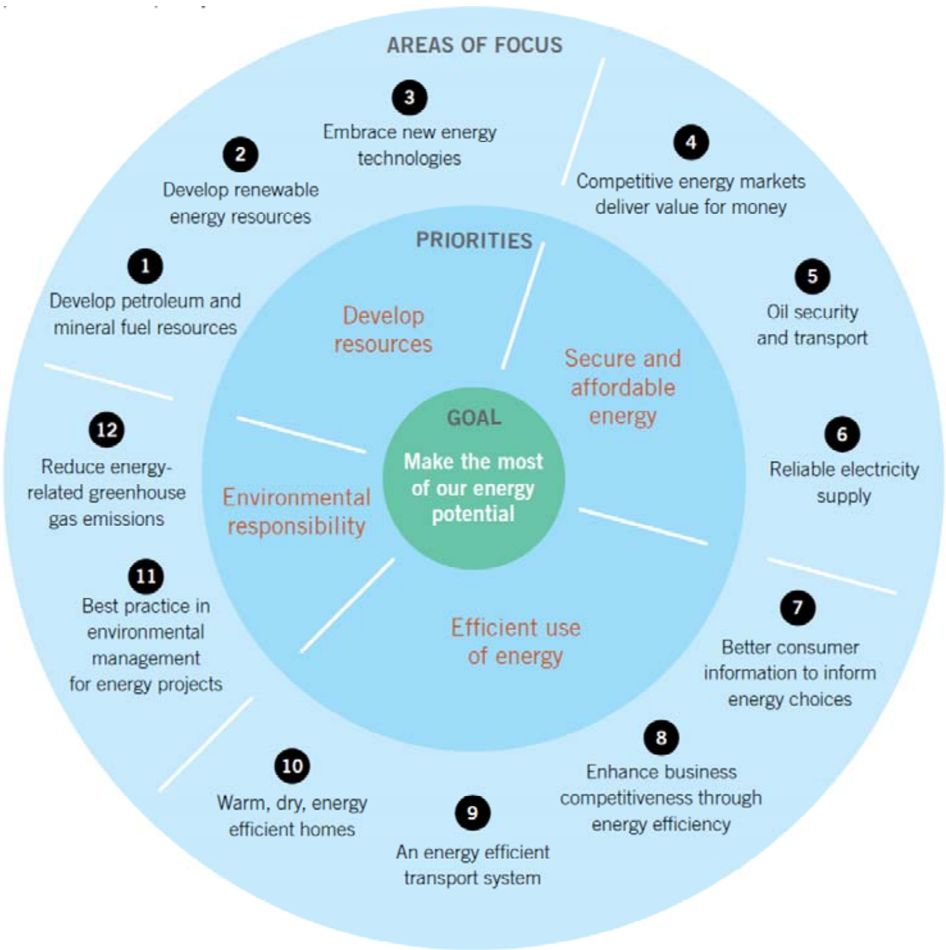
To put the goals into action, the 2011 NZES has further identified four strategy priorities to achieve this goal, including:

- Diverse resource development
- secure and affordable energy

- efficient use of energy
- environmental responsibility.

For each strategy priority, the government has identified a few areas of focus (see details in Figure 6).

Figure 6: New Zealand Energy Strategy, 2011-2021.



Source: New Zealand Energy Strategy, Developing our Energy Potential, 2011-2021.

One noticeable difference between the two versions of the NZES is that the 2007 NZES focused on building a “reliable and resilient energy system” (MED, 2007, p.15) , while the 2011 NZES focused on the benefits of building such a system: “the economy grows” and the “environment is recognised for its importance to our New Zealand way of life” (MBIE, 2011, p. 4). However, there are some common themes underlying the two versions of NZES; developing renewable energy for the security of energy supply is one of them.

2. Renewable Energy Development

This section focuses on the current use of renewable energy in New Zealand and its capacity for future development. While hydro power already accounts for more than half of electricity generation, its capacity to grow in the future is limited. The growth of renewable energy will mainly come from wind energy. However, because of its inherent characteristics, there are several barriers to its development.

2.1. Renewable Energy Capacity and Potential

Renewable energy already provides 75% of electricity generated in New Zealand, but there is still potential for further growth, especially in wind energy (see Table 1).

Table 1: Renewable Energy Capacity and Potential (MW)

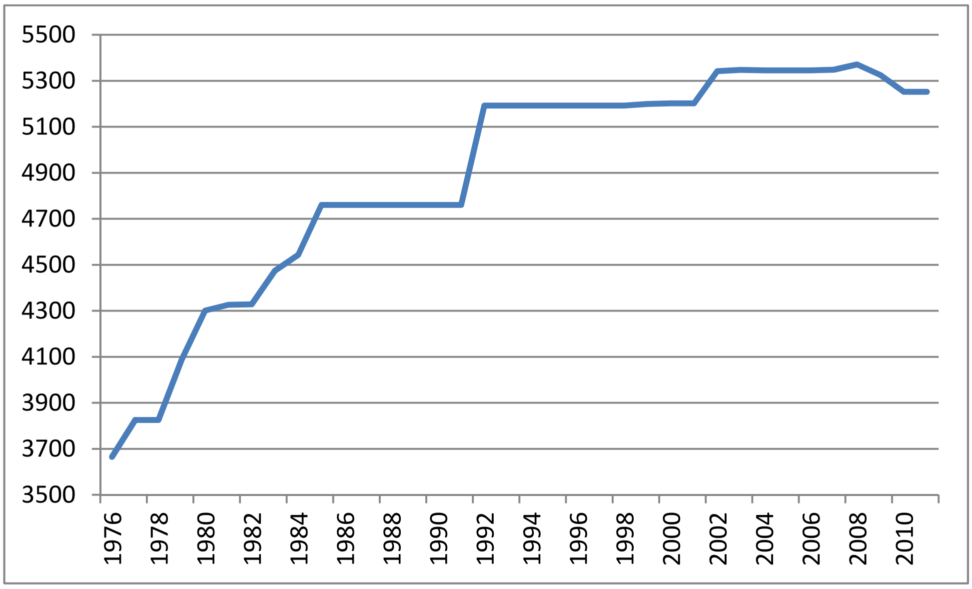
	Hydro	Geothermal	Wind
Operational generation capacity	5252	730	610
Potential capacity	1295	1100	4100
2025 capacity	6500	1500	2000

Source: Draft report on transmission to enable renewables (Energy Authority, 2008).

Hydro power is the main source of renewable energy in New Zealand, accounting for 56% of total electricity generated in 2010. Although its contribution to total electricity dropped from nearly 90% in 1980, the actual generation capacity has increased nearly 1,000MW over the 30 year period. However, capacity has remained static since 1990 (See Figure 7). According to the most recent study commissioned by the previous Electricity Commission (reference), there is still 1295MW of hydro capacity to exploit.

But this capacity will be significantly constrained by physical, environmental, and cost factors. Most of the potential hydro capacity identified is located in the South Island, but the increased demand is mainly located in the North Island. The development of this capacity would subject the security of the system more to the reliability of the undersea HVDC cable.

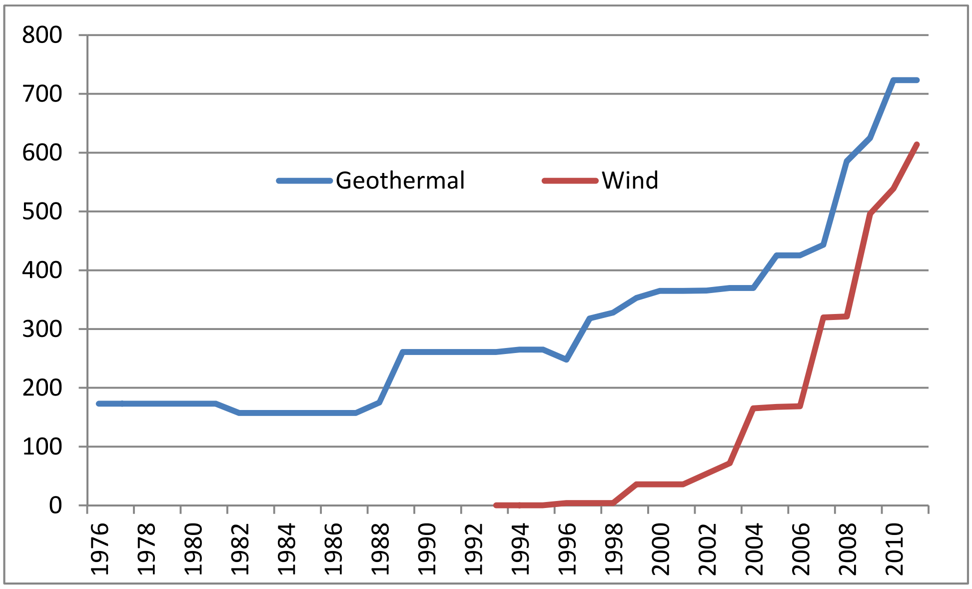
Figure 7: Operational Hydro Electricity Generation Capacity (MW)



Source: New Zealand Energy Data File 2012 (MBIE, 2012).

Geothermal and wind energy together currently account for 17% of electricity generated, with operational capacities of 700MW and 600MW installed in 2010 respectively. Both have increased significantly over the past two decades (see Figure 8).

Figure 8: Operational Geothermal and Wind Electricity Generation Capacity (MW)



Source: New Zealand Energy Data File 2012 (MBIE, 2012).

Both geothermal and wind energy still have big growth potential. A recent assessment of geothermal capacity suggested that a net increase of 1100MW could be added to the system, taking into account various constraints; by 2025, the capacity of geothermal could reach up to 1500MW, a net increase of 770MW. Wind energy could have an even bigger potential. Research for the Electricity Commission has suggested that more than 4000MW electricity generation capacity from wind energy could be added to the system in the future. By 2025, the installed wind energy capacity could reach up to 2000MW, contributing around 20% of the total electricity generated without causing major problems to the system.

As we have seen from Table 1, only around 12% of potential wind energy capacity is utilised currently; even by 2025, there will still be more than 50% of wind energy capacity available for exploitation. To meet the increasing demand for electricity, wind energy has actually been identified as a priority source of new energy.

2.2. Issues with Renewable Energy Development

Most of the renewable energy sources are normally located in remote and (often) conservation areas, away from the existing transmission grid and away from demand.

Consequently, new renewable generation projects tend to have high set up costs and high connection costs, and face a higher uncertainty of the availability of sufficient transmission capacity.

Renewable energy production, especially wind energy, solar energy, and tidal energy, has high variability and cannot be predicted with great accuracy. This requires improving forecasting methodology, establishing back up mechanisms, and changes in market design and operational practices to ensure the security of supply and stability of the system.

There are a few issues associated with furthering renewable energy development. **First, environmental considerations** have been a major issue. In New Zealand, energy project proposals are managed in consent terms through the Resource Management Act 1991 (RMA). Under the RMA, the consenting authority must have regard to the follows:

- The effects (actual or potential) on the environment
- The provisions of any relevant national coastal or regional policy statement and plan, proposed or operative
- Any other matter the consenting authority considered relevant.
-

While for a proposed renewable energy project the effects on the environment are mainly local, the benefits are generally national. It is a difficult task for a local consenting authority to balance the local effects with the national benefits. Environmental concerns have led to the process of seeking resource consent being long and expensive. Typical environmental concerns include: the visual impacts of renewable energy projects on the landscape, the impacts of road and other infrastructure construction on site ecology, the noise from wind turbines, disruption to the local economy, etc.

Recently these environmental concerns led to the withdrawal of the Project Hayes wind farm proposal in the South Island, with projected capacity up to 630MW making it potentially the largest wind energy project to date planned for New Zealand. Project Hayes was developed by Meridian Energy from 2006 to 2012. Meridian lodged applications for resource consents with the Central Otago District Council and with the Otago Regional Council between July and October 2006. Resource consents were granted in 2007. However, the project was opposed by a group of prominent individuals, and the decision was appealed to the Environment Court. In November 2009, the Environment Court declined the consents. Meridian appealed the Environment Court's decision to the High Court, which allowed Meridian's appeal, and sent the case back to the Environment Court. The High Court's decision was appealed to the Court of Appeal in August 2010. As of February 2011, no dates had been set for the next round of court hearings. In January 2012, Meridian announced it had withdrawn the applications for resource consent. The whole process cost Meridian Energy around $8.9million.

Second, system integration cost issues. Most renewable energy generation is located away from demand and away from the existing transmission grid. Consequently, the costs of setting up the generation capacity and connecting to the existing transmission grid are high. Compared to gas fuelled electricity generation, the main form of fossil-fuelled electricity generation, the capital cost per MW capacity for wind, hydro and geothermal generation are at least two times higher. While the connection costs for fossil-fuelled electricity generation are typically NZ$ 1 million, the average connection costs for wind energy projects are NZ$76.85 million per project.

Table 2: Average Costs for New Generation Projects by Energy Yypes (NZ$/MW)

	Variable O&M $/MWh	**Fixed O&M, $/kW**	**LRMC $/MWh (exclude CO2 price)**	**Capital cost (Million $/MW)**	**Connection cost (Million $)**
Coal	12.96	67.19	164.41	5.27	1.00
Diesel	10.59	15.30	664.31	1.91	1.00
Gas	6.24	22.57	175.47	1.53	1.00
Geo	0.00	100.43	91.20	5.89	5.90
Hydro	0.72	7.13	132.54	4.98	19.40
Wind	2.87	58.23	128.29	3.52	76.85 (?)

Source: Variable Fixed O&M, LRMC, and Capital cost are based on MBIE's electricity generation cost model 2011, see http://www.med.govt.nz/sectors-industries/energy/energy-modelling/modelling/new-zealands-energy-outlook/interactive-electricity-generation-cost-model-2010; Connection cost is based on "Transmission to Enable Renewables Project: Transmission Network Reinforcement Inputs for GEM" (System Study Groups, 2008)

Renewable energies are volatile and cannot be predicted with great accuracy. This is particularly true of wind energy. With a target of having 20% of electricity generated from wind by 2030, the high volatility and unpredictability of wind energy will create potential errors in the scheduling and dispatch process, and consequently have impacts on the stability and security of the security of this system. This in turn increases the levels of capacity margins and operating reserves that are required to be available to system operators in order to ensure the demand and supply of electricity are constantly balanced. As a result, there are costs associated with a higher level of capacity margin and higher operating reserves. A study commissioned by Meridian (Meridian, 2008) has estimated the additional costs under the scenarios of having 5%, 10%, and 20% wind penetration in 2010, 2020, and 2030. The estimated additional costs are listed in Table 3. As the wind penetration increases, the addition costs increase.

Table 3: Additional System Costs (NZ$/MWh) in Wind Generation Integration

	2010 (5% of wind penetration)	**2020 (10% of wind penetration)**	**2030 (20% of wind penetration)**
Installed wind capacity (MW)	634	2066	3412
Capacity cost	2.4-3.6	3.6-5.5	6.3-9.5
Reserve cost	0.19	0.76	2.42

Source: The system impacts and costs of integrating wind power in New Zealand (Meridian, 2008).

The high variability and unpredictability of wind energy also requires operational and market design changes, such as investment in forecasting, to have more accurate forecasts and to have more reserve and curtail mechanisms, etc. All these entail costs, which raises the question of who should pay for the costs associated.

Third, incentives to invest. Another key issue concerning renewable generation investment is the incentives to investment. There are several factors that discourage investments in renewable generation, especially investment by smaller investors.

There are big differences in timing between generation investment and transmission capacity development. Transpower needs to have a lead time of eight years for the provision of a new transmission line, while wind generation investment can be developed rather quickly, taking as little as 12 months from the granting of consents to full operation. It is unlikely that new small entrants would be able to endure eight years of negotiation and waiting.

New Zealand is characterised by vertical integration between generation and retail. Five major electricity generators are also major retailers ("gentailers"). Both the generation and retailing markets are highly concentrated. These five gentailers have 91% of electricity generation capacity and cater for 97% of the total demand. One consequence of this is that existing gentailers are hedged on both generation and retail sides against the high volatility in the electricity market. Small non-vertically integrated generators, who find it hard to get such hedging contracts, have to face the full consequences of wholesale price volatility.

All these factors create barriers to entry for small non-vertically integrated generators, reflected in the fact that 99% of all existing wind capacity is owned by only three gentailers.

Fourth, New Zealand also lacks policy instruments to induce investments. In many countries a variety of policy instruments have been applied to encourage investment in renewable energy generation. The two main forms of such policy instruments are: the feed-in tariff, and the renewable portfolio standard.

A feed-in tariff requires energy generators to be paid a specified price for their output from renewable energy. The goal of feed-in tariffs is to offer cost-based compensation to renewable energy producers, providing the price certainty and long-term contracts that help finance renewable energy investments.

A renewable portfolio standard (RPS) requires electricity supply companies to produce a specified fraction of their electricity from renewable energy sources. Certified renewable energy generators earn certificates for every unit of electricity they produce and can sell these along with their electricity to supply companies. There are also other forms of policy instruments, such as capital subsidies and tax credits, etc.

In New Zealand there are no direct policy instruments to encourage renewable energy developments. However, there are indeed small financial grants available under the energy efficiency programs of the Energy Efficiency and Conservation

Authority (EECA). Furthermore, the Emissions Trading Scheme (ETS) when put in place may create incentives for investment in renewable energy.

3. Government Policies and Market Designs to Facilitate Renewable Energy Integration

The issues around renewable energy development have been attended to in New Zealand through government policy initiatives, market design improvements, and special operational arrangements in the electricity market. These policies are still at their early stage of implementation, and it is still too early to assess their impacts, given the long term nature of electricity generation. However, they do provide incentives for and facilitate the development of renewable energy.

3.1. Government Policy Initiatives to Encourage the Development of Renewable Energy Sources

To encourage renewable energy development, to ensure future energy supply security, to reduce greenhouse gas emissions and to maintain environmentally sustainable development, the government has listed developing renewable energy resource as one of its strategic priorities under the New Zealand Energy Strategy (NZES).

To achieve a 90% renewable energy target, Parliament passed in 2008 the Climate Change Response (Emissions Trading) Amendment Act 2008, and the Electricity (Renewable Preference) Amendment Act 2008. While the former requires the electricity generators to effectively price the cost of carbon into the price of electricity from July 2010, the latter effectively imposes a 10 year ban on the construction of new baseload fossil-fuelled electricity generation with capacity over 10MW except where an exemption is appropriate (for example, to ensure security of supply) from 2010.

To deal with the environmental barriers to renewable energy development, in 2011 the New Zealand government released its National Policy Statement (NPS) on Renewable Electricity Generation under the Section 32 of the Resource Management Act 1991 (Ministry of Environment, 2011). This NPS has lifted the status of renewable electricity generation to that of national importance. The objectives of the NPS are to recognise the significance of renewable electricity generation to the wellbeing of New Zealand, to incorporate provisions for renewable energy generation activities into regional policy statements and regional and district plans, to drive a consistent and streamlined consenting process for renewable energy generation projects, and to encourage investment in wind, geothermal, hydro, and tidal power so as to achieve New Zealand's renewable energy target. The NPS has proposed eight policies to achieve these objectives.

In regard to policy instruments, the Emissions Trading Scheme has been passed into law and put into effect since 2010, requiring electricity generators to take into account the carbon price in electricity pricing. This will allow renewable generators to gain competitive advantages over fossil-fuelled generators. The Energy Efficiency and Conservation Authority (EECA) has also provided small financial assistance for new renewable energy projects under its Energy Efficiency program. EEC also works with and provides support for renewable energy industries in New Zealand, such as providing seed funding for industry associations, supporting and encouraging the development of industrial standards, etc.

3.2. The Current Market Design to Facilitate the Integration of Renewables

The integration of renewable generation into the system is through the functioning of the market, with electricity governance rules and related arrangements neither penalising nor favouring wind generation relative to its true system costs.

Under the current regulatory framework, transmission services are provided independently. As a result, new renewable energy generators have equal access to the transmission network as do incumbent generators. On the other hand, Transpower, as system operator, is obliged to make transmission assets accessible to grid users, giving no preferential rights to existing grid users.

Electricity is traded in the wholesale electricity market. Electricity from new renewable energy generators is traded the same way as electricity generated from incumbent generators, and is dispatched on the basis of the prices they bid into the wholesale market at the relevant point of injection.

The connection of generation to the grid is either through the so called "connection" or "deep connection" assets, lines that are solely used to connect generators to the grid, or through transmission assets, lines that are part of the interconnected grid. Connection and deep connection assets are commissioned as a result of bilateral negotiation between Transpower and the generator requiring the relevant assets. While the generators pay for the services of "deep connection" assets, grid off-take customers pay for the service of transmission assets. The charge for the services of transmission assets are governed by transmission pricing methodology.

Due to its high volatility and unpredictability, the connecting of renewable energy, especially wind energy, to the grid would increase the systems' demand for additional capacity and additional reserve capacity to ensure electricity supply security and the stability of the electricity system. Consequent high prices for such capacity would send a strong signal for investment.

Introducing new or potential generation investment could reach the limits of the connecting transmission grid and increase the demand for upgrades of, or new investment in, transmission capacity to relieve the constraint. A constrained transmission grid would also make additional new generation investment less attractive. Similarly, transmission investment and potential future transmission investment will also have significant impacts on the economic analysis of generation investments.

Upgrades of, and new investment in, transmission capacity are typically conducted by Transpower with the approval of the Electricity Authority. The Electricity Authority uses the Grid Investment Test (GIT) to establish whether investment in additional transmission capacity is necessary. If a generator saw a significant benefit in a transmission investment that did not pass GIT, it could negotiate with Transpower and contract them to make the investment with costs met by the generator.

3.3. Transmission Investment to Accommodate further Renewable Energy Integration

To deal with the timing difference between transmission investment and generation investment, the previous Electricity Commission initiated the 'Transmission to Enable Renewables Project, (TERP) in order to facilitate the coordination of renewable energy generation and transmission investment.

This project has investigated the potential renewable energy resources in New Zealand, including hydro, geothermal, wind, and marine energy, and has provided an up-to-date "map" of renewable resources location and potential scale, which are then factored into Transpower's planning process.

As a result, substantial renewable energy resources have been identified. It is estimated that geothermal capacity could be 3600MW, and that wind capacity could be even more significant, reaching up to 41000MW.

In addition to identifying potential renewable resources, TERP has also investigated the costs associated with each potential renewable project, including capital costs, operating costs, system costs, (such as connection costs), and the additional capacity and reserve costs.

To investigate the possible transmission investments, for which Transpower could apply for approval to support the development of renewable energy generation, the previous Electricity Commission in 2007 commissioned research to look into different options for the transmission investment required to support the integration of renewable generation, and the costs (grid connection cost and cost of upgrade) associated with each option.

These options were then fed into the Generation Expansion Model (GEM). The GEM helps to define how much of the identified renewable resource is economically rational to develop, how much transmission investment is justified and where the investment should be located, and the form of investment (deep connection or inter-connection). It also helps determine the optimal transmission and generation investment sequence.

The results from these exercises are then fed into the Electricity Authority and Transpower's transmission investment planning and scheduling process, which then send signals to potential renewable generation investment.

3.4. Operational Arrangements

To facilitate renewable energy integration and to ensure the stability of the electricity system at the same time, New Zealand has also made some operational adjustments in electricity market operation.

While New Zealand is adept at managing hydro and geothermal generation, managing wind energy is still a challenge. The previous Electricity Commission had actually initiated a Wind Integration Project (WIP) to look into the different operational options to facilitate wind energy integration. The operational arrangements mentioned below only apply to wind energy.

The variable and unpredictable nature of wind energy requires improvements in forecasting methodology in order to improve forecast accuracy. Currently, New Zealand has a decentralised wind forecast system. Each wind generator is responsible for its own wind generation forecast over the schedule period, which is then required to feed into market schedules. At the same time, non-wind generators and big consumers may also have incentives to forecast more accurate wind generation, especially when wind energy penetration increases. The system operator, Transpower, can prepare its own forecasts of wind generation. The Electricity Authority further provides incentives for wind generators to provide more accurate wind generation forecasts by publishing a quarterly wind forecast accuracy monitoring report.

Wind generators are allowed a more flexible gate closure time. All generators are required to submit an offer 71 trading periods before the relevant trading period. All generators can revise or cancel offers at least 2 hours before the trading period in respect of which the offer is made. However, for wind generators, while they can only revise the offer price at least 2 hours before the trading period, they can revise the offer quantity within the 2 hour period immediately before the trading period. Wind generators can also cancel offers in writing 30 minutes before the trading period. Having a more flexible gate closure time could help wind generators better manage wind uncertainty. To deal with the flexibility of gate closure time for wind generators, the system needs to have sufficient reserve and curtail capacity to respond to the subsequent variations in energy supplied.

Wind energy is also treated as "must run" in the wholesale spot market, and can only bid at $0.00/WW and $0.01/MW. This ensures that wind generation could be dispatched if the market price is higher than $0.01/MW. However, this does not guarantee that the wind generation will be dispatched, especially during the time when the dispatch price could be negative at some nodes. Even when the dispatch price is high, it is not guaranteed that wind generation will be profitable, because the dispatch price might be lower than the wind generator's marginal cost.

Currently, wind generation only accounts for around 4% of total electricity generation, so these operational arrangements in regard to wind generation are still special cases. With the increase of wind penetration in the next 10 to 20 years, operational arrangements for wind generators would still need to be adjusted.

4. Policy Implications for ASEAN and East Asian Countries

We understand that, in ASEAN and East Asian countries, renewable energy has become a mainstream option, driven by a tremendous growth in energy demand arising from rapid economic growth, concerns about energy security, abundance of renewable energy resources, improvements in renewable technologies, and efforts to limit pollution. This has presented both opportunities for economic growth and challenges to it. One challenge the ASEAN and East Asian countries face is the integration of renewable energy into national or regional electricity networks.

With the bulk (70%) of its current electricity generation from renewable resources, and targeting 90% by 2025, New Zealand's experience with renewable energy development may have some implications for the renewable energy development in ASEAN and East Asian countries.

The main lessons from New Zealand include the following:

First, to encourage the development of renewable energy development and to ensure environmental friendly and sustainable economic development, the New Zealand government has put out a long term energy development strategy, with a focus on renewable energy development and adoption of environmentally sustainable energy technologies.

Second, Recognising the barriers of the deployment of RES, the New Zealand has passed several to facilitate the development of renewable energy development. For example, the parliament, in 2008, passed the Climate Change Response (Emissions Trading) Amendment Act 2008, and the Electricity (Renewable Preference) Amendment Act 2008. To support the RES, the Emissions Trading Scheme has been passed into law and put into effect since 2010, requiring electricity generators to take into account the carbon price in electricity pricing. This will allow renewable generators to gain competitive advantages over fossil-fuelled generators.

In 2011, the New Zealand government released its National Policy Statement (NPS) on Renewable Electricity Generation under the Section 32 of the Resource Management Act 1991 (Ministry for Environment, 2011). This NPS has lifted the status of renewable electricity generation to that of national importance. This encourages the local governments to incorporate renewable energy development into their policy statements and plans, and streamlines the consenting process for renewable energy projects.

The Energy Efficiency and Conservation Authority (EECA) has also provided small financial assistance for new renewable energy projects under its Energy Efficiency program. EEC also works with and provides support to renewable energy industries in New Zealand, such as providing seed funding for industry associations, supporting and encouraging the development of industrial standards, etc.

Third, in New Zealand renewable energy development and integration have been mainly through the functioning of a liberalised and vertically separated electricity market. Electricity is traded in the wholesale electricity market. An independent transmission grid gives the new renewable energy generators an access that is equal to that of incumbent generators. A competitive electricity wholesale market enables new renewable energy generators to compete with incumbent generators on a level playing ground.

Due to the variable and unpredictable nature of the renewable energy, especially wind energy, New Zealand has also made a few operational adjustments in electricity market operation in order to facilitate renewable energy integration and to ensure the stability of the electricity system at the same time. These operational adjustment include initiatives to improve forecasting methodology, establishing back up mechanisms, more flexible "gate closure" time for wind generator, etc.

Fourth, to deal with the timing difference between transmission investment and generation investment in order to accommodate further renewable energy investment. The governing body of the electricity market, the Electricity Authority and its predecessor the Electricity Commission, together with the system operator, have also made proactive initiatives to facilitate transmission investment for further renewable energy investment and integration, such as identifying potential renewable energy resources and their location, the costs associated with each potential renewable project, and the transmission investment to support the development of renewable energy generation, which are then fed into Electricity Authority and system operator's transmission investment planning and scheduling process, which then send signals to potential renewable generation invest

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CHAPTER 4

Towards an Integrated Renewable Energy Market in the EAS Region: Renewable Energy Equipment Trade, Market Barriers and Drivers

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The East Asia Summit (EAS) region has huge untapped renewable energy (RE) potential. Using indigenous renewable energy sources to meet the growing energy demand in the region will therefore enhance its energy security, reduce its dependence on imports of primary energy, and diffuse the pressure on domestically available conventional energy resources. Promoting RE will also facilitate the EAS countries' greenhouse gas (GHG) emission mitigation efforts. It seems clear that the region's scattered renewable energy resources can promote balanced utilization, provided that a regional cooperation arrangement in the energy sector is established. Many EAS countries lack appropriate technologies to utilize their RE resources. Several factors—such as high tariff rates and low levels of inventions among the developing countries—inhibit the growth of renewable energy in this region. Intraregional trade in machinery and equipment for the physical production of renewable energy is one of the key means of improving usage and promoting access to green energy in the region. In this study we investigate the relationship between trade in the machinery and equipment required for renewable energy production and other technical, economic and policy factors that are in place for promoting renewable energy. Our underlying key assumption is that promotion of RE equipment trade can lead to increased use of renewable energy and subsequently to regional energy market integration.

1. Introduction

Rapid economic growth over the last five decades has made East Asia the most dynamic and flourishing region of the world. Sustained growth led the region toward improved standards of living, reduced poverty, and a more prominent role in the global economy. This impressive growth, on the other hand, has caused a huge increase in the energy demand of the region as a whole as well as for individual countries. Catering to the needs of the “factory Asia”, energy consumption in this region since 1980 has persistently been much higher than the consumption in other regions of the world. The East Asia Summit (EAS)[1] region’s total energy consumption in 2010 was more than 60% of the global consumption (EIA 2013). The energy-intensive growth of EAS has put tremendous pressure on the conventional energy resources of the region, which also led to the accumulation of greenhouse gases (GHG) in the atmosphere. The cumulative energy demand of the region is likely to reach between 7 and 8 billion tonnes of oil equivalent (Btoe) by 2030 (IEA 2008). To ensure sustained growth, these are some of the priority issues that the region must address. Scholars and policymakers alike suggest that an integrated renewable energy (RE) market may resolve many of the region’s energy-related problems.

This study uses an empirical model to examine the bilateral RE equipment trade and its determinants among the EAS countries. It attempts to examine RE production through analysing the RE equipment trade within this region. Section 2 of the paper explains why the EAS should promote RE and why RE is important for the region’s energy market integration. It also discusses the problems and difficulties in promoting RE in the region. Section 3 puts forward the rationale and objective of the study, while section 4 describes the methodology as well as the specification and the structure of the econometric model used in the empirical analysis of the study. Section 5 explains the variables used in the model and related descriptive statistics.

[1] The East Asia Summit, or EAS, is a regional leaders' forum for dialogue and cooperation on major issues and challenges facing the East Asian region. The inaugural EAS took place in Kuala Lumpur in December 2005. As of 2013, the EAS has 18 member countries: Australia, Brunei Darussalam, Cambodia, China, India, Indonesia, Japan, Republic of Korea, Lao People’s Democratic Republic, Malaysia, Myanmar, New Zealand, the Philippines, the Russian Federation, Singapore, Thailand, the United States, and Vietnam.

Section 6 provides the estimation results with associated discussion. Section 7 concludes the paper with a discussion on regional policy implications based on the results of the study.

2. Significance of RE for the EAS Region

2.1. Why should EAS Promote RE?

The rationale behind promoting the use of RE in this region is manifold. The EAS countries are struggling to constrain the growth in their GHG emissions; in 2011, the region accounted for more than 21 billion metric tons of CO_2 emissions, which is about 65% of total global carbon emissions (EIA 2013). Increasing the share of RE in the supply mix will enhance these countries' emission mitigation efforts. Also, energy self-sufficiency is quite low among most of the EAS countries (Table 1), and the region as a whole is a net energy importer. But the EAS countries have huge potential for RE (Table 1), which has largely remained untapped. Increased use of RE in the region, utilizing this potential, will help reduce the import of primary energy on the one hand, and diffuse the pressure on domestically available conventional energy resources on the other.

Table 1: Energy Production, Import, Export, Supply and Consumption in the EAS countries, 2010

Country	Production (Ktoe)	Import (Ktoe)	Export (Ktoe)	TPES (Ktoe)	TFC (Ktoe)	Energy self-sufficiency ratio	RE potential (GWh)
Australia	310,620	42,990	228,620	124,730	75,280	2.5	100,000,000
Brunei	18,559	157	15,459	3,314	1,701	5.6	154
Cambodia	3,621	1,437	N/A	5,024	4,262	0.7	60,000
China	2,208,962	386,242	50,499	2,417,126	1,512,218	0.9	529,373
India	518,671	244,143	62,699	692,689	457,491	0.7	1,44,000
Indonesia	381,446	42,119	214,725	207,849	156,449	1.8	421,684

Japan	96,790	427,270	18,040	496,850	324,580	0.2	1,132,265
Republic of Korea	44,920	266,840	45,800	250,010	157,440	0.2	18,718
Lao PDR	N/A	N/A	N/A	N/A	N/A	N/A	24,960
Malaysia	85,878	39,468	50,580	72,645	43,329	1.2	58,094
Myanmar	22,530	239	8,879	13,997	12,887	1.6	52,000,000
New Zealand	16,860	7,140	4,280	18,200	12,770	0.9	80,000
Philippines	23,417	22,374	3,851	40,477	23,818	0.6	327,996
Russian Federation	1,293,049	22,887	601,986	701,523	445,764	1.8	7,602,000
Singapore	404	134,521	56,754	32,774	23,724	0.0	0
Thailand	70,559	64,432	12,982	117,429	84,582	0.6	34,312
United States	1,724,510	725,640	192,060	2,216,320	1,500,180	0.8	481,800,000
Vietnam	65,874	13,572	20,848	59,230	48,515	1.1	165,946

Notes: Ktoe = Thousand tonnes of oil equivalent; Lao PDR = Lao People's Democratic Republic; TPES = Total primary energy supply; TFC = Total final consumption; N/A = Not available; Energy self-sufficiency = Ratio of energy production to supply (Production/TPES).

Source: Romero, *et al.* 2010; IEA 2012a; IEA Steenblik; Sargsyan, *et al*. 2011.

2.2. Why RE is Important for EAS Energy Market Integration

The EAS member countries are quite heterogeneous in terms of their levels of economic development and distribution of energy resource (both conventional and RE) availability. As such, it is unlikely that individual countries will be able to cater to their growing energy needs all by themselves. Indeed, the region needs a robust energy system which can ensure reliable, affordable and timely supply of energy for undeterred sustained growth and development. At present, with the exception of a few bilateral or multilateral schemes, there is hardly any collective initiative for ensuring energy security for the EAS region. This study argues that special arrangements for RE market integration can promote balanced utilization of abundant RE resources scattered among the member countries. Since the EAS region as a whole is a net importer of energy, efficient and effective utilization of indigenous resources is crucial for long term sustainability and economic integration.

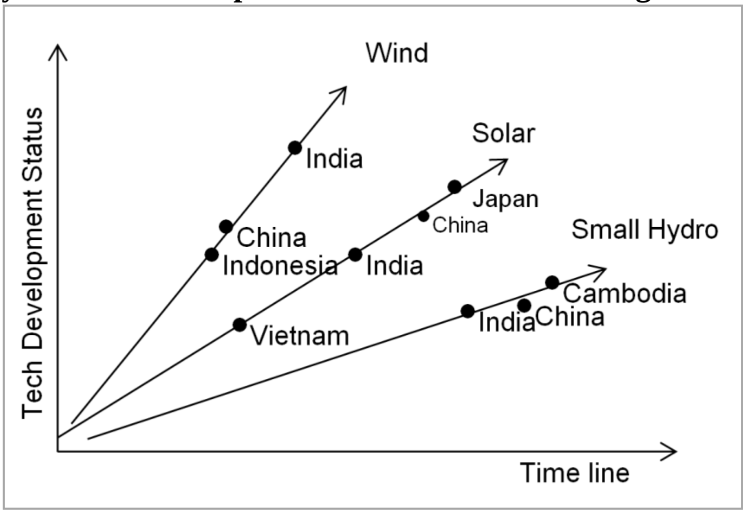
We emphasise the importance of inclusive growth for the entire region by promoting collective action in spheres of economy including energy. We argue that untapped renewable energy resources are a critical factor in this region's effort to achieve sustainable development.

2.3. Difficulties in Promoting Renewable Energy in the Region

The large scale deployment of renewable energy in the region faces problems despite having huge potential. Besides the various drawbacks which have already been discussed extensively in various academic as well as political forums, we focus on certain specific issues which have the potential to guide the decision making processes to promote renewable energy in the region.

- *Inconsistency in RE financing:* Like any other infrastructure project, financing in RE schemes is often quite large, with lengthy periods required before gaining returns on investment. There was a significant surge in RE investment on the global scale from 2004-2008, but as credit dried up during the global financial crisis of 2008, investment dropped sharply (IEA, 2010). On a global scale, about four-fifths of total RE investment comes from Europe and two EAS member countries—China and the United States. In 2011, the total capital investment in the renewable energy sector in India exceeded total investment in the fossil fuel sector in the year 2010. However, it is thought that this change in the investment pattern has more connection to the on-going natural gas supply problem in the Indian energy market than to any 'green' motivation.
- *Certain RE technologies are relatively new and are still in the early stages of development:* Although interest in RE has spurred significant R&D activities, the technologies and equipment for generating energy from renewable sources are still at their early stage. Several such technologies are already commercially available, but many others are at various stages of development.
- *Asymmetric development status of RE technologies across the region:* Enhancing the use of RE in the EAS region requires that the member countries have access to state-of-the-art RE generation technologies and equipment. Within this region, significant asymmetries exist in terms of the development status of RE technologies. For example, solar PV is very advanced in China while India is very advanced in wind technology, but Vietnam is still lagging far behind in developing of its own solar and wind technology (Figure 1). Collaboration among nations for increasing trade in the RE equipment area is therefore necessary.

Figure 1: Asymmetric Development Status of RE Technologies in EAS



Source: Authors.

- *Low trade in RE technologies/components/equipment:* As of 2005, most of the trade in renewable technologies/equipment took place among the OECD countries (Steenblik 2005). Several factors are inhibiting RE equipment trade in the EAS region. One such trade-retarding factor is the existence of various forms of tariff and non-tariff barriers. In India, for example, RE components face an import tariff exceeding 9%, while in China the figure is more than 8% (Table 3). Meanwhile, the United States, a new member of the EAS, is likely to impose tariffs ranging from 24% to 36% on solar panels imported from China (Cardwell and Bradsher 2012). China may face similar anti-dumping duties in other developed countries, particularly the European Union. However, many developing countries cannot afford to maintain feed-in-tariffs and other subsidies. These countries often depend on import tariffs to protect their own RE equipment industry. Consequently, they are likely to face unfair competition if they are required to lower their tariffs while developed countries continue to provide subsidies to their RE equipment producers (Jha 2009).

3. Rationale and Objectives of This Study

It appears that larger deployment of renewable energy in the region is not only handicapped by its high initial investment cost but also by the non-uniform availability of technical knowledge and engineering support related to building renewable energy power plants. As a matter of fact, a gap has been noticed between good policy to promote renewable energy at a regional scale and on-the-ground implementation. In this study we therefore would like to address the issues which can narrow such gaps and can increase the real deployment of renewable energy.

This study follows the thesis that trade in technologies/equipment used in harnessing renewable energy is one of the most important means of integrating the renewable energy market in the EAS region. This study is essentially concerned with mitigating the asymmetric development status of RE technologies across the region by enhancing trade in RE equipment in the region. We assume that if cross-border RE equipment trade increases, so will the use of RE in the national energy supply mix and subsequently in the regional mix as well.

4. Methodology

The study primarily employs an econometric analysis to investigate the interrelationship among selected indicators to prove the hypothesis of the study. This is that in order to have more renewable energy equipment trade, countries need to have certain domestic market conditions fulfilled. Such enabling conditions can therefore promote regional energy market integration. These conditions include the share of export/import tariff of RE equipment, the existing share of renewable energy supply in the total electricity supply mix, research and development budget spending, domestic share of renewable energy technology patent and other enabling policy conditions in the domestic market. Based on the findings of the analysis, the study will outline the way forward for integrating the RE technology/equipment market in this region and for general energy market integration.

4.1. Econometric Model Specification

While the renewable energy sector has received significant attention in recent years, only limited studies have so far addressed to the dynamics of trade in renewable energy equipment/components (RETC). In particular, for the EAS region there is hardly any literature covering the prospects and challenges of intra-regional RETC trade.

A 2009 study by Veena Jha attempted to analyze the trade in major climate mitigation technologies and components for 34 selected countries/regions. The study provides important insights into the factors that affect RETC trade, particularly how trade is affected by tariffs, subsidies, the share of renewables in the energy grid, and the share of patents. The study stresses the challenges relating to identification of single-use RETC goods, and highlights the idea that producers in developing countries are likely to be in disadvantageous position as these countries in general do not enjoy the same incentives, such as high feed-in-tariff, as the producers in the developed countries. This study, however, does not take into consideration all the EAS member countries. Additionally, as most RETC trade is highly concentrated among the developed countries, particularly in the EU, it is difficult to obtain a clear idea about the RETC trade and the special situations among the EAS countries. The empirical analysis of the study also does not consider some important factors such as RETC research and development spending, the potential of the individual countries for RE, or RE-promoting regulatory frameworks.

Algieri, *et al.* (2011) used the Balassa index to investigate the international specialization patterns of the world's major solar photovoltaic (PV) industry. They identified the role of several market and trade drivers such as subsidies. However, the study did not cover any other RETC. Similarly, a recent study by Cardwell and Groba (2013) developed a gravity model for 43 countries to analyze the development of solar PV and wind energy technologies exports from China, to demonstrate the country's competitive position against the world. However, none of these studies covered any other RETC such as those relating to bioenergy, hydro or geothermal (the next subsection of this paper discusses the major RETCs included in the current study).

The current study has been conducted more in line with the work of Jha (2009) as discussed above. The multivariate regression under the current study has been further enhanced by including other important determinants of trade flows among the EAS countries. In order to isolate the trade effects and market integration potential of the selected determinants without being biased by the major RETC traders such as the European Union countries, the geographical coverage of this study has been kept limited to the 18 EAS countries only. The next subsections of the paper discuss the

RETC taken into consideration in this analysis, and the selection of variables as well as the logic of their inclusion. The basic premise of this study is that an economy is likely to export renewable energy equipment/components (hereinafter RETC) with supporting policies such as feed-in-tariff and other subsidies, and an enabling regulatory framework. This study develops an econometric model to analyze the effects of various relevant trade barriers, market drivers, and policies such as price support mechanisms (e.g. feed-in-tariff and other subsidies) and regulatory frameworks that can affect the trade in RE technology, equipment and associated goods and eventually the RE market integration in the EAS region. A multivariate cross-country regression has been used for assessing how the export of RETC is affected by the chosen independent variables. The geographical scope of the study is the 18 EAS countries.

4.2. Model Structure

In this study, we will use cross-section data for the year 2011 to estimate the effects of the factors and determinants of RETC export in the EAS region. The model has been specified with the following regression equation:

$$EXP\_RETC_{ijt} = \beta_0 + \beta_1 SGDP_{jt} + \beta_2 TAR_{ijt} + \beta_3 RGD_{it} + \beta_4 PAT_{it} + \beta_5 RND_{it} + \beta_6 CWP_{it} + \beta_7 FIT_{it} + \beta_8 SUB_{it} + \beta_9 POL_{it} + u_{ijt}$$

where,

EXP_RETC_{ijt}	=	Export of renewable energy technology and components from exporting country *i* to importing country *j* at time *t;*
$SGDP_{jt}$	=	Country *j*'s share in the whole region's GDP at time *t*;
TAR_{ijt}	=	Import tariff on RETC by both importing country *j* and the exporting country *i* at time *t*;
RGD_{it}	=	% of renewables in the energy grid in the exporting country *i* at time *t*;
PAT_{it}	=	% of inventions (represented by the share of a country in global registered patents) of the exporting country *i* at time *t*;
RND_{it}	=	Research and development budget of the exporting country *i* at time *t*;
CWP_{it}	=	Country-wide potential for renewable energy generation in the exporting country *i* at time *t*;
FIT_{it}	=	Dummy on feed-in-tariff provided to renewables in the exporting country *i* at time *t*;
SUB_{it}	=	Dummy for other subsidies (capital subsidy, grant, or rebate)

POL_{it} = Other renewable energy promoting policies focusing on regulatory framework in the exporting country *i* at time *t*;

u_{ijt} = Error term.

The study conducted a coefficient diagnostics test for checking the presence of collinearity among the independent variables. The issue will be discussed in the later part of this paper.

5. Description of the Variables

In the following section we describe the variables that we have selected to conduct this analysis.

5.1. Identification of RE Technologies/Components/Equipment

A major issue for this study is to identify which commodities should be categorized as RETC. As some of these commodities can have multiple uses, isolating them as RE-related is often not a straightforward task. Underscoring the role of RE sources in providing energy services in a sustainable manner, particularly in addressing climate change, the Special Report on Renewable Energy Sources and Climate Change Mitigation of the Intergovernmental Panel on Climate Change (IPCC) has identified six types of RE technologies: bioenergy; direct solar energy; geothermal energy; hydropower; ocean energy; and wind energy (IPCC, 2011). This study has attempted to cover the RETCs that are related to all these six broad categories.

A study conducted by Paul Lako (2008) focused on RETCs within the energy supply sector. Instituted by the International Centre for Trade and Sustainable Development (ICTSD), this mapping study identified the key RETCs. The study was peer-reviewed by the IPCC. Izaak Wind, the former Deputy Director (Harmonized System) of the World Customs Organisation later continued this mapping study, which classified the major RETC under 85 different 6-digit Harmonized System (HS) codes, divided into 42 headings (Wind, 2009). Yet another study by Veena Jha further refined the RETC listing to better reflect the predominantly single-use commodities that are assumed to be directly RE supply, exports and imports (Jha, 2009). The current study and its econometric analysis will be based on these 69 identified 6-digit HS codes.[2]

5.2. Bilateral Export Flows of RETC among the EAS Countries

The dependent variable of the multivariate regression is the cross-border export flows of RETC among the EAS countries. Data for each of the 69 6-digit HS lines with 2011 as the base year have been collected for each country. The United Nations (UN) COMTRADE Database (2013) is the main source of this data. China and Japan are by far the largest exporters of RETC in the EAS region, followed by the Republic of Korea and the United States (Table 2). Smaller economies of the region such as Cambodia, Myanmar and Brunei Darussalam export negligible amounts.

Table 2: Individual Country's Total Export of RETC in the EAS region, 2011 (US$ million)

Country	RETC Export	Country	RETC Export
Australia	434.5	**Malaysia**	3099.5
Brunei Darussalam	6.5	**Myanmar**	0.7
Cambodia	0.3	**New Zealand**	177.3
China	26032.2	**Philippines**	1190.7
India	945.7	**Russian Federation**	315.3
Indonesia	1065.7	**Singapore**	4735.0
Japan	20079.6	**Thailand**	2142.6
Republic of Korea	8236.2	**United States**	8087.1

Source: UN COMTRADE Database 2013.

5.3. Importing Country's Share in Regional Gross Domestic Product (GDP)

The economic size of a country, measured in terms of its GDP, plays an important role in international trade. Empirical analyses of trade, for example those applying the gravity model, hold that bilateral trade between two countries is positively related to their economic sizes, and such analyses often include the GDP of both the importer and the exporter as proxies to their respective economic sizes.

[2] Complete list of these RETC is available in Annex 1 of this document.

While the current study does not apply a gravity model, it underscores the importance of the EAS countries' relative economic size as an important factor in the import of RETC. Additionally, we assume that a variable on the relative economic size of the importing country will scale the data for a more consistent analysis. It is expected that the coefficient on this variable will bear a positive sign, to indicate that countries with larger relative economic sizes tend to import more RETC. Data on the importing countries' GDP relative to the total GDP of the whole region has been collected from the World Bank's *World Development Indicators 2013* (Myanmar data has been taken from *The World Factbook 2013 – 14* of the Central Intelligence Agency (CIA)). As can be seen from Table 3, the United States accounts for an overwhelming share (41%) of the total EAS region GDP, followed by China (20%) and Japan (16%). Among the ASEAN countries, Indonesia (2.3%), Thailand (1%), and Malaysia (0.8%) have the highest shares, whereas Brunei Darussalam, Cambodia and Lao PDR account for negligible shares.

Table 3: Individual Country's Share in Total GDP of the EAS region

Country	Share in regional GDP (%)	Country	Share in regional GDP (%)
Australia	3.76	Malaysia	0.78
Brunei Darussalam	0.04	Myanmar	0.15
Cambodia	0.03	New Zealand	0.44
China	19.94	Philippines	0.61
India	5.04	Russian Federation	5.06
Indonesia	2.31	Singapore	0.65
Japan	15.99	Thailand	0.94
Republic of Korea	3.04	United States	40.85
Lao PDR	0.02	Vietnam	0.34

Source: World Development Indicators 2013; and CIA World Factbook 2013 -2014.

5.4. Import Tariff Affect on RE Technology/Components/Equipment in the Importing Country

As with any other commodity, export of RETC is adversely affected by the presence of tariff barriers in the importing country. Data on the EAS countries' import tariffs on the identified 69 6-digit HS line RETC products have been collected from the World Trade Organization's Integrated Trade Database. Table X presents individual countries' simple average ad valorem tariff on RETC products. As can be seen from the table, tariff rates vary from country to country. Those maintaining high tariffs include Cambodia, Brunei, the Russian Federation, India and China, whereas Singapore, Japan and Australia maintain 0% - 1% tariff (Table 4). The coefficient on this variable is expected to bear a negative sign, indicating that lowering or removal of tariffs is likely to lead to higher levels of RETC trade and eventually greater integration of the energy market in this region.

Table 4: Import Tariff Rates on RETC in the EAS Countries

Country	Simple Average AV Tariff (%)	Country	Simple Average AV Tariff (%)
Australia	0.8	**Malaysia**	4.8
Brunei Darussalam	11.7	**Myanmar**	1.8
Cambodia	12.5	**New Zealand**	1.4
China	8.5	**Philippines**	4.5
India	9.4	**Russian Federation**	11.4
Indonesia	2.6	**Singapore**	0.0
Japan	0.7	**Thailand**	6.2
Republic of Korea	6.8	**United States**	2.1
Lao PDR	6.7	**Vietnam**	6.2

Source: WTO Integrated Trade Database 2013.

5.5. Share of RE in the Electricity Grid of the Exporting Country

The percentage of renewables in the exporting country's electricity generation is an important factor demonstrating the technological advancement and know-how of the country. Consequently, a higher share of RE in the electricity grid implies that the exporting country has more potential to transfer RE technologies to other countries. The regression analysis of this study has included this factor as an explanatory variable in the model, and the coefficient is expected to bear a positive sign. Table 5 below shows the difference among the EAS countries in terms of electricity generated from renewable sources. Larger economies such as China, United States, Russian Federation, India, and Japan generate higher volumes of electricity in absolute terms. However, as electricity consumption in these economies is very high, they also depend heavily on fossil fuels. Consequently, the percentage of electricity generated from renewables may not be very high in all cases. Nonetheless, the percentage for these economies is more than 10%, indicating their strong technological capacity in RE. It is important to note that some smaller countries such as Lao PDR and Myanmar have very high shares of electricity produced from renewables, although the absolute amount is much lower compared to more advanced economies. The model of this study uses the percentages as an independent variable and the expected sign is positive.

Table 5: Share of RE in Electricity Generation in the EAS countries 2011 (or latest year)

Amount in Billion KWh (percentages in parentheses)

Country	Amount and % of electricity generated from RE	Country	Volume and Share of RE in electricity generation
Australia	24.86 (11.0%)	**Malaysia**	7.69 (6.5%)
Brunei Darussalam	0.00 (0.0%)	**Myanmar**	5.05 (68.8%)
Cambodia	0.05 (5.2%)	**New Zealand**	33.50 (76.9%)
China	770.92 (19.7%)	**Philippines**	17.72 (27.4%)
India	162.00 (16.4%)	**Russian Federation**	166.59 (16.7%)
Indonesia	26.95 (16.7%)	**Singapore**	1.17 (2.7%)
Japan	116.44 (11.1%)	**Thailand**	8.68 (6.0%)
Republic of Korea	7.55 (1.6%)	**United States**	520.07 (12.7%)
Lao PDR	3.23 (89.0%)	**Vietnam**	27.38 (30.2%)

Source: EIA 2013.

5.6. Research and Development (R&D) Budget in the RE Sector of the Exporting Country

Accelerating the development of RETC is imperative in promoting the use of renewable energy. Technology is undoubtedly at the core of this discussion as we discussed earlier that asymmetric development of technology among the EAS countries is one of the major deterring issues for regional renewable energy development. Continued support and investment in RETC R&D is required. Like elsewhere in the world, the promotion of RE over conventional energy is a relatively new phenomenon in the EAS region. Although the interest in RE spurred significant research and development activities, technologies and equipment for generating energy from renewable sources are still at their early stage. Several such technologies are already commercially available, and many others are at different stages of development. However, RETC R&D is quite expensive and there are considerable asymmetries among the EAS countries in terms of their budget for such R&D. The hypothesis of this study is that higher R&D budget leads to improved technological achievement both quantitatively and qualitatively, which eventually provides greater scope for RETC exports. Based on this, an explanatory variable on RETC research budget has been added to the model, with the assumption that the coefficient will be positive. Obtaining data on RETC R&D budget, however, has not been an easy task. Bloomberg New Energy Finance and UNEP have been the primary sources, from which RETC R&D data for the world and the major EAS economies such as the United States, India and China has been collected. For the other countries, data has been calculated by weighing their gross domestic product (GDP) against the global RETC R&D budget and cross-checking with the Asia-Oceania region's R&D budget as provided from Bloomberg. Even if the data is not perfect, these indicative values serve the purpose of the current study. Significant variation is observed across the region. The United States spends the highest amount for RETC R&D, distantly followed by China and Japan (Table 6). On the other hand, the smaller countries such as Brunei Darussalam, Cambodia and Lao PDR spend negligible amounts. The trend in RETC R&D expenditure corresponds to the export of RETC; countries with higher budget tend to export more RETC commodities.

Table 6: RETC R&D Budget of the EAS Countries, 2011

Country	RETC R&D Budget, US$ million	Country	RETC R&D Budget, US$ million
Australia	160.9	**Malaysia**	33.6
Brunei Darussalam	1.9	**Myanmar**	-
Cambodia	1.5	**New Zealand**	18.6
China	853.7	**Philippines**	26.2
India	215.6	**Russian Federation**	216.7
Indonesia	98.8	**Singapore**	28.0
Japan	684.4	**Thailand**	40.3
Republic of Korea	130.2	**United States**	1748.7
Lao PDR	1.0	**Vietnam**	14.4

Source: Compiled from UNEP and Bloomberg New Energy Finance 2012, and World Development Indicators 2013.

5.7. Share of RE Technology Inventions of the Exporting Country

Along with R&D budget, access to and diffusion of RETC is affected by the presence of various forms of intellectual property rights, particularly by patents.[3] Jha (2009) observes that the "number of patents that have been registered in the renewable sector in different countries could provide an indication of the dissemination of renewables across borders." It is extremely difficult to find specific data on registered patents of the identified 69 RETC technologies. To address this issue, we used the study conducted by Dechezleprêtre, *et al*. (2008). Using data from EPO/OECD World Patent Statistical Database (PATSTAT), Dechezleprêtre considered 13 different classes of technologies which include seven RE technologies (wind, solar, geothermal, ocean energy, biomass, waste-to-energy, and hydropower), methane destruction, climate-friendly cement, energy conservation in buildings, motor vehicle fuel injection, energy-efficient lighting, and carbon capture & storage. We assume that the data generated in this study can reasonably be used in the regression analysis of the current study. The EAS countries' innovation data (as

[3] However, other forms of intellectual property rights, such as trade secrets, may also protect technologies and innovations. This study only takes into consideration patent protection, assuming that patent counts likely to be positively correlated to the quantity of non-patented innovations and transfers (Dechezleprêtre, *et al*. 2008).

percentage of global registered patents) is presented in Table 7. The geographical distribution of RETC inventions varies within the EAS region and a serious gap can be seen among the developed and developing country members of the EAS. Japan leads the world with an overwhelming 37%of RETC inventions. The nearest EAS countries are the United States (12%), China (8%) and the Republic of Korea (over 6%). All these countries are also the major exporters of RETC in the region. Most of the smaller developing countries do not hold any significant share in the RETC global innovation.

Table 7: Percentage of Global RETC Inventions of the EAS Countries

Country	% of global RETC Inventions	Country	% of global RETC Inventions
Australia	2.5	**Malaysia**	0
Brunei Darussalam	0	**Myanmar**	0
Cambodia	0	**New Zealand**	0
China	8.1	**Philippines**	0
India	0.2	**Russia**	2.8
Indonesia	0	**Singapore**	0
Japan	37.1	**Thailand**	0
Republic of Korea	6.4	**United States**	11.8
Lao PDR	0	**Vietnam**	0

Source: Dechezleprêtre, *et al*. 2008

Country-wide potential for RE generation in the exporting country: This study has added an explanatory variable on country-wide RE potential of the EAS countries in the regression analysis. RE potential is expected to boost a country's efforts in specializing in certain technologies related to RE-abundant resources, which will yield higher export of these RETC. On a general level, the region has huge untapped RE potential, albeit at different levels across the region (Table 8). In particular, the United States, Australia, Myanmar, and the Russian Federation possess tremendously high RE potential. Only Cambodia and Singapore have low potential. The hypothesis of the study is that the coefficient on this variable may take a positive or negative sign, but it will depend on the extent to which the potential has been utilized. A negative sign may indicate underutilized potential and inverse correlation with the exports.

Table 8: Renewables Potential in the EAS countries

Country	RE potential (GWh)	Country	RE potential (GWh)
Australia	100,000,000	**Malaysia**	58,094
Brunei Darussalam	154	**Myanmar**	52,000,000
Cambodia	60,000	**New Zealand**	80,000
China	529,373	**Philippines**	327,996
India	1,44,000	**Russian Federation**	7,602,000
Indonesia	421,684	**Singapore**	0
Japan	1,132,265	**Thailand**	34,312
Republic of Korea	18,718	**United States**	481,800,000
Lao PDR	24,960	**Vietnam**	165,946

Source: Romero, *et al.* 2010; World Bank, 2011.

5.8. RE Promoting Policies

Considering the importance of RE in ensuring energy security, many of the EAS countries have adopted policies that promote the use of RE. As these policies may guide the production of RE or deployment of RETC (Jha, 2009), they drive the RE market in general and may also positively affect trade in RETC. These RE-promoting policies may fall under three broad categories: financial incentives, public financing, and regulatory policies (REN21, 2013). Financial incentives may include policies such as capital subsidy, grant or rebate; tax incentives; and energy production payment. Public financing relates to policies on public investment, loans, or financing and public competitive bidding. Regulatory policies may vary widely and include feed-in-tariff, utility quota obligation, net metering, obligation and mandate, and tradable renewable energy certificate. Among these, feed-in-tariff is one of the most important drivers of RE in many countries. In the EAS region, nearly half of the member countries maintain some form of feed-in-tariff.

The econometric analysis of this study considers three dummy variables reflecting RE-promoting policies in the exporting country. Although based on the policies identified by REN21, the categorization of these policies has been slightly modified to serve the purpose of this study. The variables included in the regression are: feed-in-tariff, other subsidies, and other regulatory policies. In the case of other regulatory policies, this study considers four subcategories (utility quota obligation, net metering, obligation and mandate, and tradable renewable energy certificate), and the dummy is unity when any of the four subcategories is present (zero otherwise). The absence or presence of these policies is presented in Table 9.

Table 9: Renewables Energy Policies in the EAS Countries

	Capital subsidy, grant, rebate	Feed-in tariff	Regulatory Policies			
			Utility quota obligation	Net metering	Obligation and mandate	Tradable RE Certificates
Australia	√	√	√	-	√	√
Brunei	-	-	-	-	-	-
Cambodia	-	-	-	-	-	-
China	√	√	-	-	√	-
India	√	√	√	-	√	√
Indonesia	-	√	-	-	√	-
Japan	-	√	-	-	-	-
Republic of	√	-	√	-	√	√
Lao PDR	-	-	-	-	-	-
Malaysia	-	√	√	-	√	-
Myanmar	-	-	-	-	-	-
New Zealand	√	-	-	-	-	-
Philippines	√	√	√	√	√	-
Russian	√	-	-	-	-	-
Singapore	-	-	-	√	-	√
Thailand	-	√	-	-	√	-
United States	-	-	-	-	-	-
Vietnam	-	-	-	-	-	-

Source: Compiled from REN21 Renewables Interactive Map Country Profiles 2013

6. Model Estimates and Discussion

This study conducted a least square regression with all the variables, including the three dummies. The econometric analysis of the study commenced with a hypothesis test for checking multicollinearity among the variables. For this we identified the correlation coefficients of the explanatory variables. The correlation matrix below (Table 10) shows that R&D budget and counry-wide RE potential have a moderately strong and positive linear relationship, with the coefficient value as high as 0.76. The other coefficients, most of which are >0.5, in general show weak or negligible correlation (we ignore the signs of the coefficients) among the explanatory variables. Additionally, auto-correlation was not an issue as the study used cross-sectional data. ,

Table 10: Correlation Coefficients of the Explanatory Variables

VARIABLES	Importers share in regional GDP	Import tariff on RETC	Share of RE in electricity generation	Share of inventions	R&D budget in RETC	Country-wide RE potential	Feed-in-tariff	Other subsidies	RE promoting policies
Importers share in regional GDP	1								
Import tariff on RETC	-0.17023	1							
Share of RE in electricity generation	0.01571	0.032812	1						
Share of inventions	-0.05148	0.027917	-0.12241	1					
R&D budget in RETC	-0.08061	0.01774	-0.04446	0.448499	1				
Country-wide RE potential	-0.06231	0.024368	-0.05695	0.181736	0.764338	1			

Feed-in-tariff	-0.02078	0.033416	-0.1098	0.138452	-0.06866	-0.27019	1		
Other subsidies	-0.0121	0.007696	0.391415	-0.20425	-0.08903	-0.21186	0.032368	1	
RE promoting policies	-0.01035	0.035297	-0.3009	-0.40761	-0.27256	-0.3307	0.561357	0.185311	1

Source: Authors' calculations.

Next, the study conducted White's general test for heteroskedasticity in the error distribution. In this test, the squared residuals are regressed on all the distinct regressors, cross-products and squares of regressors. The results are presented in Table 11.

Table 11: White's General Test of Heteroskedasticity

Dependent variable: RESID^2
Method: Least Squares
Included observations: 237

F-statistic	1.810946	Prob. F(34,202)	0.006553
Obs*R-squared	55.364741	Prob. Chi-Square(34)	0.0117472
Scaled explained SS	111.935986	Prob. Chi-Square(34)	0.000000

Source: Authors' calculations.

The calculated scalar is 11.0704976935. Since the nR^2 value of 55.36474 is greater than the 5% critical χ^2 value of 11.0704976935, we can reject the null hypothesis of no heteroskedasticity.

The results of the model estimates are presented in Table 12, followed by the analytical discussion on the effects of the factors on RETC export among the EAS countries.

Table 12: Regression Results

Dependent Variable: Bilateral exports of RETC from country *i* to country *j* Method: Least Squares Included observations: 237		
Variable	**Coefficient**	**t-Statistic**
Importer's share in regional GDP	0.801535	11.30526**
Import tariff on RETC	-0.297445	-3.378478**
Share of RE in electricity generation	0.917617	8.790657**
Share of Inventions	0.636375	8.908713**
R&D budget in RETC	0.265317	3.756623**
Country-wide RE potential	-0.167356	-4.123828**
Feed-in-tariff	-0.222000	-0.493205
Other Subsidies	-3.145050	-8.796140**
RE promoting policies	4.174112	8.760244**
R-squared	0.691603	
Adjusted R-squared	0.679375	
F-statistic	56.56258	

Notes:1. * and ** denote significant at 5% and 1% levels respectively
Source: Authors' calculations based on the results of the model.

The importing country's share in the EAS region's total GDP has been found to be highly correlated to the import of RETC from the exporting countries, suggesting that countries with higher shares of regional GDP tend to import more RETC. As expected, the coefficient bears a positive sign, and demonstrates very high statistical significance at the 1% level. As can be seen from Table 11, 1% increase in the importer's share in regional GDP is likely to increase the import from other EAS countries by 0.8%. We can therefore assume that as the economies of many of the EAS countries continue to grow, these countries will import more RETC.

On the other hand, import tariff has a negative correlation with RETC trade. The coefficient thus conforms to the assumption of the study and shows high statistical significance at 1% level. The estimations show that the presence of tariff hinders the trade in RETC; a 1% increase in tariffs is expected to decrease RETC export to the importing country by about 0.30%. In other words, removal or reduction of tariffs by the importing countries will facilitate increased RETC exports from their trading partners, and will lead to higher RETC trade among the EAS countries.

The positive and nearly proportional coefficient for the share of RE in electricity generation indicate that countries which already possess advanced technologies for generating electricity from renewables are likely to export more RETC. The coefficient is statistically significant at the 1% level. Similarly, share of global RETC inventions and RETC R&D budget have been found to have high to moderate impact on RETC export, indicating that EAS renewable energy market integration will be beefed up once the countries invest more on RETC R&D, and once they start holding more registered patents for RETC commodities.

Somewhat different and unexpected results have been found for the coefficient on country-wide RE potential. The value of the coefficient is low, and it bears the opposite sign. The negative sign on RE potential suggest that this variable is adversely affecting RETC trade. This study argues that given the current state of RETC trade in the region, the result is not so unexpected. As discussed elsewhere in this study, the region has huge potential for RE, but this potential has largely remained untapped. Put differently, the region's RE potential has so far been remained underutilized and consequently has not had any positive effect on RETC exports in the region.

The dummy variables generate mixed results. The coefficient on feed-in-tariff has a relative low value and it bears the opposite sign than the assumption. However, it has been found to be statistically insignificant. The results therefore suggest that at least within the EAS region the feed-in-tariffs may be less effective. Similarly, the dummy on other subsidies, although expected to have a positive correlation, was found to be negative with high significance. In other words, financial incentives in the form of capital subsidy, grant or rebates provided by the exporting countries may not have a positive affect on RETC trade within the region. The variable on regulatory policies, on the other hand, bears the expected positive sign and has extremely high value with 1% statistical significance. We can therefore argue that introducing policies such as utility quota obligation, or tradable RE certificates is likely to promote RETC trade among the EAS countries.

7. Regional Policy Implication

The EAS region has an explicit policy goal of integrating the regional energy market. The EAS Energy Ministers “reaffirmed the importance of establishing efficient, transparent, reliable, competitive and flexible energy markets as a means to provide affordable, secure and clean energy supplies for the region” (EMM5, Brunei, 2011). The current study analyses the prospects of an integrated renewable energy market in the EAS region from the vantage point of RETC trade, associated market barriers and major drivers. The study finds that the region has huge potential for RETC trade which will eventually pave the way for enhanced RE use in the region. Despite this potential, certain factors such as high tariff rates, low level of inventions among the developing countries, and underutilized potential inhibit the growth of RETC trade in the region. This study also demonstrates that domestic individual policy to promote renewable energy investment, like feed-in-tariff, may not induce regional cooperation. Based on the findings of the analysis, this study makes the following policy recommendations:

- The EAS member countries should remove or reduce import tariffs on RETC to spur trade in these commodities. This will help address the problem of asymmetric technological development particularly in the smaller economies, and eventually lead to higher use of RE in the region. The overall RE market will also be more integrated.
- Investing in RETC R&D and fostering inventions will enable these economies to acquire more advanced RE technologies. Subsidies in RETC R&D can generate significant impact on the demand structure and markets for the RE industries.
- Untapped RE potential in the region may be addressed through efforts toward increased RETC trade so as to increase the access to advanced technologies for the countries which are in need. Once these countries have the appropriate technologies, they will be able to tap their respective RE potential.
- RE promoting policies, particularly an adequate regulatory framework (such as utility quota obligation, net metering, and tradable RE certificates) with the support of feed-in-tariff and other forms of subsidies, are likely to promote use of RE within the country but may not promote regional cooperation in terms of promoting renewable energy at a regional scale. Due to the limited scope of this study, and data constraints, a detailed analysis of these factors has not been done, but further research and in-depth analysis is necessary to

capture the effects of these factors in promoting the energy market integration in the EAS region.

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ANNEX 1

HS codes for RE technologies and components

6-Digit HS Code	Product Description (for 6-Digit HS Code)	RES Products and/or Components (Assumed to be) Included Under 6-Digit HS Code	Remarks
220710	Undenatured ethyl alcohol	Bio-ethanol	It is not possible to know from trade statistics at the 6-digit HS level how much is used for fuel. From July 2008, the HTSUS includes a new 10-digit code (2207106010) for US imports of undenatured ethyl alcohol for fuel use. US Imports under the provisions of this item accounted for more than 90 percent (in value terms) of total US imports under the provisions of HS 20710 in the period July 2008-May 2009
220720	Ethyl alcohol and other spirits	Bio-ethanol	It is not possible to know from trade statistics at the 6-digit HS level how much is used for fuel. From July 2008, the HTSUS includes a new 10-digit code (2207200010) for US imports of denatured ethanol for fuel use. US Imports under the provisions of this item accounted for more than 80 percent (in value terms) of total US imports under the provisions of HS 220720 in the period July 2008-May 2009
380210	Activated carbon	Biomass (Activated carbon that includes carbon molecular sieve used for process of purification of bio-ethanol).	
382450	Non-refractory mortars and concretes	Hydro	
382490	Other chemical products and preparations of the chemical or allied industries (including those consisting of mixtures of natural products), not elsewhere specified or included: other	Biodiesel (This category could include chemicals used in purification of biofuel as well as biodiesel itself)	It is not possible to know from trade statistics at the 6-digit HS level how much trade is used for fuel. In the United States, the 10-digit HTSUS code for biodiesel is 3824904020. US biodiesel imports have increased in recent years and in 2008 accounted for almost half of the value of all US imports under the provisions of HS 382490. In the EU a separate code for biodiesel (CN 38249091) was introduced in January 2008. This code covers fatty-acid monoalkyl esters

			(FAMAE), although other forms of biodiesel could still enter the EU under other codes depending on the chemical composition. EU-27 imports under the provisions of this CN code accounted for 28 percent of total EU-27 imports (43 percent if intra-EU trade is excluded) under the provision of HS 382490 in 2008.
681091	Prefabricated structural components	Hydro	
700991	Glass mirrors, unframed	Solar	
700992	Glass mirrors, framed	Solar	
711590	Other articles of precious metal or of metal clad with precious metals, other	Solar	
730431	Pipes and tubes	Solar, geothermal	
730441	Pipes and tubes	Solar, geothermal	
730451	Pipes and tubes	Solar, geothermal	
730820	Towers and lattice masts	Wind	
732290	Other structures	Solar	
741121	Tubes and pipes, of copper-zinc base alloys (brass)	Biomass, geothermal	
741122	Tubes and pipes, of copper-nickel or copper-nickel-zinc base alloys	Biomass, geothermal	
741129	Other tubes and pipes	Biomass, geothermal	
830630	Photograph, picture or similar frames, mirrors; and parts thereof	Solar	
840681	Steam turbines and other vapour turbines, of an output exceeding 40 MW	Biomass	
840682	Steam turbines and other vapour turbines, of an output exceeding 40 MW	Biomass	
841011	Hydraulic turbines of a power not exceeding 1,000 kW	Used in hydro energy	

841012	Hydraulic turbines of a power exceeding 1,000 kW but not exceeding 10,000 kW	Used in hydro energy	
841013	Hydraulic turbines of a power exceeding 10,000 kW	Used in hydro energy	
841090	Hydraulic turbines: parts, including regulators	Used in hydro energy	
841182	Other gas turbines, of a power exceeding 5,000 kW	Biomass	The 10-digit HTSUS distinguishes gas turbines for aircraft and other use. Gas turbines imported into the US under HS 841182 are largely for “other” use, which may include the biomass sector.
841280	Other engines and motors	Solar	
841290	Other engines and motors; parts	Blades for wind turbines	
841620	Other furnace burners, including combination burners	Biomass	
841861	Heat pumps other than air conditioning machines of heading 8415	Geothermal heat pump	
841919	Instantaneous or storage water heaters, nonelectric	Solar water heaters. Listed in several studies on renewable energy products, although strictly speaking not a renewable energy supply product	The HTSUS distinguishes 3 sub-items: instantaneous water heaters (HTSUS 8419.19.00.20), solar water heaters (HTSUS 8419.19.00.40); and “other” (HTSUS 8419.19.00.60). US imports of solar water heaters accounted for less than 5 percent of water heaters imported under the provisions of 841919, in value terms, on average, in the period 2006-2008. Most imports came from China. Imports under HTSUS 8419.19.00.60 (“other”), mostly from Mexico, were far more important.
841931	Dryers: for agricultural products	Biomass	
841940	Distilling or rectifying plant	Biomass	
841950	Heat exchange units	Geothermal	
841989	Other machines and mechanical appliances for the treatment of materials by a process involving a change of	Biomass	

	temperature: other	
841990	Other machines and mechanical appliances for the treatment of materials by a process involving a change of temperature: parts	Solar
847920	Machinery for the extraction or preparation of animal or fixed vegetable fats or oils	Biomass
848210	Ball bearings	Wind turbine components
848220	Tapered roller bearings	Wind turbine components
848230	Spherical roller bearings	Wind turbine components
848240	Needle roller bearings	Wind turbine components
848250	Other cylindrical roller bearings	Wind turbine components
848280	Other ball or roller bearings	Wind turbine components
848340	Gears and gearing, other than tooth	Wind turbine components
850161	AC generators (alternators): of an output not exceeding 75kVA (kilovolt ampere)	Wind, hydro and biomass
850162	AC generators (alternators): of an output exceeding 75kVA but not exceeding 375 kVA	Wind, hydro and biomass
850163	AC generators (alternators): of an output exceeding 375kVA but not exceeding 750 kVA	Wind, hydro and biomass
850164	AC generators (alternators): of an output exceeding 750kVA	Wind, hydro and biomass
850231	Other generating sets: wind-powered	Wind turbines
850239	Other generating sets:	Solar, ocean energy

	other		
850300	Parts suitable for use solely or principally with the machines of heading 8501 or 8502	Used for wind turbines	
850421	Liquid dielectric transformers: having a power handling capacity not exceeding 650 kVA	Hydro, wind and ocean energy	
850422	Liquid dielectric transformers: having a power handling capacity of 650 kVA – 10,000 kVA	Hydro, wind and ocean energy	
850423	Liquid dielectric transformers: having a power handling capacity exceeding 10,000 kVA	Hydro, wind and ocean energy	
850431	Electric transformers, having a power handling capacity less than 1kVA	Hydro, wind and ocean energy	
850432	Electric transformers, having a power handling capacity of 1 kVA – 16 kVA	Hydro, wind and ocean energy	
850433	Electric transformers, having a power handling capacity of 16 kVA – 500 kVA	Hydro, wind and ocean energy	
850434	Electric transformers, having a power handling capacity exceeding 500 kVA	Hydro, wind and ocean energy	
850440	Static converters	Solar	
854140	Photosensitive semiconductor devices, including photovoltaic cells whether or not assembled in modules or made up into panels: light-emitting diodes	PV panels	PV modules fall under HS 854140. This 6-digit code also includes unrelated light-emitting diodes. The EU 8-digit CN classification includes separate sub-heading for light-emitting diodes and “other”. The latter sub-heading (CN 85414090) represented more than 90 percent of EU imports under HS 854140 in 2008. HS code 854140 would thus seem to be a reliable indicator of trade in PV modules.The HTSUS breaks HS 854140 down into 8 national subheadings, two of which explicitly

			cover solar cells. These two items together represented 45 percent of total US imports under the provisions of HS 854140. The 6-digit code would appear to be a reasonable indicator of trade in PV modules.
854449	Other electric conductors, for a voltage not exceeding 80 V	Ocean	
854460	Other electric conductors, for a voltage exceeding 1,000 V	Ocean	
890790	Other	Wind	
900190	Other (including lenses and mirrors)	Solar	
900290	Other optical elements (including mirrors)	Solar	
900580	Other instruments	Solar	
902830	Electricity meters	Wind	
903020	Cathode-ray oscilloscopes	Wind	
903031	Multi-meters	Wind	
903039	Other instruments and apparatus for measuring or checking voltage, current or resistance, with a recording device	Wind	

Source: Jha, 2009.

CHAPTER 5

Renewable Energy and Policy Options in an Integrated ASEAN Electricity Market: Quantitative Assessment and Policy Implications

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Energy market integration (EMI) in the ASEAN region is a promising solution to relieve the current immobilization of these resources and would serve the fast increasing demand for electricity in the region. EMI could be further extended with coordinated policies in carbon pricing, renewable energy portfolio standards (RPS), and feed-in-tariffs (FIT) in the ASEAN countries. Using a linear dynamic programming model, this study quantitatively assesses the impacts of EMI and the above-mentioned policies on the development of renewable energy in the power generation sector of the region, and the carbon emissions reduction achievable with these policies. EMI is expected to 'harvest the low-hanging fruit' and could significantly promote the adoption of renewable energy. Along with EMI, FIT appears to be more cost-effective than RPS and is recommended, albeit the administration costs for implementation might be a practical concern. In addition, an RPS of 30% electricity from renewable sources by 2030 is in reality considered a reasonable option by many policy makers and it would achieve moderate improvements in carbon emissions reductions and renewable energy development, while incurring negligible increases in the total cost of electricity.

Keywords: Energy Market Integration (EMI); Renewable Energy Portfolio Standards (RPS); Feed-in-Tariff (FIT); Carbon pricing; Renewable energy resources

1. Introduction

Strong economic growth of the ASEAN countries in the recent decade has been coupled with far stronger growth in electricity consumption (see Table 1). The growth rate of electricity consumption in ASEAN countries is more than double the world average, which could reflect the fact that the region is undergoing rapid urbanisation and industrialisation.

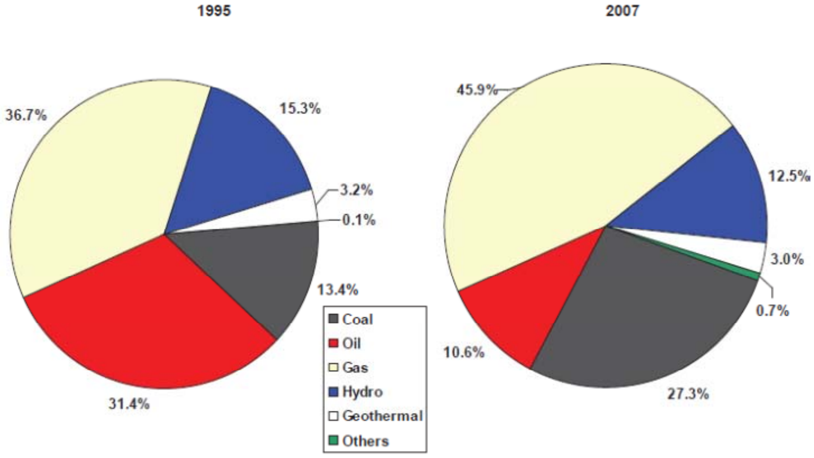
Table 1: Growth in GDP, Energy Consumption and Electricity Consumption - ASEAN and World Average 2000-2009

	GDP	Energy Consumption	Electricity Consumption
ASEAN	5.2%	4.8%	6.6%
World Average	3.5%	2.2%	3.1%

Source: Authors' estimation based on World Bank and Energy Information Administration (EIA) data

Like the rest of the world, fossil fuels dominate in the electricity generation of the ASEAN countries. The share of oil is decreasing while the shares of natural gas and coal are increasing. The share of renewable energy such as hydro and geothermal has been going down but the total rate of utilisation has increased. It was 18.6% in 1995 but 16.2% in 2007. These observations indicate that electricity generation from renewable energy sources has been developing slower than that from fossil fuels and that most of the increase in electricity demand has been met by electricity generated from fossil fuels (see Figure 1).

Figure 1: ASEAN Electricity Generation by Source, 1995 and 2007



Source: The Third ASEAN Energy Outlook, Institute of Energy Economics Japan, ASEAN Centre for Energy, National ESSPA Project Team, Feb 2011

According to various energy statistics, ASEAN countries have abundant renewable resources in the form of hydro, geothermal, biomass, solar, and wind. However, these resources are unevenly distributed among the member countries. It is estimated that ASEAN has 254 GW of hydro resources, excluding Vietnam. Hydro resources are concentrated in Myanmar, Indonesia, Lao PDR, and Malaysia. About 20,000 MWe or 40% of the world's geothermal energy resources are found in Indonesia, and the country is the second largest geothermal energy producer in the world. The Philippines also has abundant geothermal resources and is ranked fourth in the world. Indonesia, Malaysia, and Thailand have 50 GW, 29 GW, and 7 GW of biomass potential respectively. Malaysia has 41% of world palm oil production and it has the potential to be one of the major contributors of renewable energy in the world via palm oil biomass. Vietnam, the Philippines, and Lao PDR have the greatest theoretical wind power potential in the region (Abdullah, 2005; Do and Sharma, 2011, Lidula, *et al*., 2007; Thavasi and Ramakrishna, 2009; Ong, *et al*., 2011)

Despite its strong potential in renewable energy, the utilization of renewable energy for power generation is very low in the region. In the rural areas of many ASEAN countries, most of the biomass energy is still being used in traditional burning. The share of biomass used in this way has been as high as 73.8% in Cambodia, followed by Myanmar (64%), Vietnam (60%), and Lao PDR (54.2%) in their total energy mix (Thavasi and Ramakrishna, 2009).

There are a few major barriers for ASEAN countries to overcome in adopting modern technologies to harvest renewable energy and turn it into the cleaner form, which is electricity, for consumption. While the high upfront investment costs of the advanced renewable energy technologies are the key barrier to adoption, the lack of financial means and technology / knowledge transfer are the other critical barriers (Das and Ahlgren, 2010).

There are some solutions available to tackle such barriers of finance, technology and knowledge transfer. The Clean Development Mechanism (CDM) is one of the potential solutions. However, the methodology used by the CDM in determining the amount of emissions-reduction prevents the least-developed countries from certifying their renewable energy projects (Lim and Lee, 2011). Countries like Myanmar, Cambodia, Vietnam, and Lao PDR already have a high share of renewable energy in terms of traditional biomass such as wood in their energy mix, and using modern renewable energy technologies to replace traditional renewable energy cannot qualify for CDM credits unless there is a significant improvement in efficiency.

Energy market integration (EMI) in ASEAN is a promising means of relieving the immobilization of potential renewable energy development caused to a large extent by the above barriers. First, EMI brings an integrated regional power market, which would enable poorer countries that have abundant renewable energy to export their clean energy to richer countries by means of cross-border power trade. Second, EMI allows financial resources to move from richer countries to poorer countries. It thus relieves the financial constraint on renewable energy investment. Third, an integrated regional energy market also makes technology and knowledge transfer easier between the two groups of countries in the region (Lim and Lee, 2011). This study quantitatively assesses how the market integration brought by EMI could promote the development of renewable energy for power generation.

Importantly, EMI could go further towards implementing three sets of coordinated policy regimes to promote renewable energy development in the power sector of the region. First, ASEAN countries could coordinate and impose renewable energy standards (RPS) to a certain extent in the power sector of each member country, as Thailand and the Philippines have already been attempting. (Lidula, *et* *al*., 2007). Second, it could seek the establishment of a common carbon emissions rights market in this region, and the common prices of carbon emissions rights could serve as an additional incentive to investments in power generation using renewable energy. Third, ASEAN countries could also seek to coordinate provision of feed-in-tariffs (FIT) to renewable energy development in the power sector. This study thus further delves into how these three policy regimes can help the development of renewable energy in the power sector of the region.

The remainder of this paper is organised as follows; section 2 presents the methodology of the study, which is linear dynamic programming modelling for quantitative simulation of the impacts of the above-mentioned policy scenarios. Section 3 describes key data inputs for the scenarios. Section 4 presents scenario simulation results and analysis of the results. Section 5 concludes.

2. Methodology and Model

This study adopts a linear dynamic programming model developed by Chang and Li (2012). In this model, taking a long time-horizon, a planner's objective is to choose power plant capacities and output levels across the countries covered in the research scope, so as to minimize the present value of total costs while meeting the growing demand for power over the modelling period. The model assumes that the ASEAN Power Grid (APG) is in place so that countries in the region are allowed to trade power. Levelized costs of generating electricity are embedded in this model. Depending on the modelled policies on cross-border power trade, the amounts of power to be traded between countries in each year of the period are also optimized. The model is solved using GAMS. Technical details of the original model can be found in Appendix A.

In addition, for the purpose of this study, two major modifications are applied to the original model. One modification models the implementation of uniform RPS policy in all countries of the region. The other models the implementation of uniform FIT policy in all countries of the region.

To model the RPS policy, an RPS constraint is imposed to the original model. The constraint says that the share of electricity generated from renewable sources should not be lower than a specified level in the total electricity generated in a certain year. The equation below represents this constraint.

$$\sum_{i=1}^{I}\sum_{j}^{J}\sum_{v=-V}^{t}\sum_{p=1}^{P}\sum_{RES=1}^{RES}u_{RES,ijtvp}\cdot\theta_{jp}\geq\sum_{i=1}^{I}\sum_{j}^{J}\sum_{v=-V}^{t}\sum_{p=1}^{P}\sum_{m=1}^{M}u_{mijtvp}\cdot\theta_{jp}\qquad(1)$$

Here, u_{mijtvp} is power output of plant type *m* (power generation technology), vintage *v*, in year *t*, country i, block p on the load, and exported to country j. θ_{jp} be the time interval of load block p within each year in the destination country. *RES* represents the subset technologies which are categorized as renewable energy technologies.

Importantly, to create realistic RPS scenarios, it is assumed that the policy is effective from 2020 onwards.

FIT is a policy to provide a certain favourable price to purchase the power generated from specified types of renewable energy sources. The implicit implication of FIT is that it provides per unit subsidy on renewable energy. Since our model deals with minimization of costs of power generation instead of maximization of revenue from power generation, only the implicit implication of FIT could be modelled. However, this interpretation of FIT in our model does not skew its impact on decision-making related to power generation capacity development and utilization. Therefore, in the FIT policy scenarios, an FIT subsidy for each unit of electricity generated from renewable sources is added into the objective function.

The following equation represents total FIT subsidy on renewable energy in each year and the value is subsequently inserted into the objective function of the model.

$$subsidy(t)=\left(\sum_{i=1}^{I}\sum_{j}^{J}\sum_{v=-V}^{t}\sum_{p=1}^{P}\sum_{RES=1}^{RES}u_{RES,ijtvp}\cdot\theta_{jp}\right)\cdot fit(t)\qquad(2)$$

Here, $subsidy(t)$ is the total subsidy for all renewable energy in year t. $fit(t)$ is the per unit implicit subsidy from FIT policy on renewable energy.

In addition, to reflect the potential of small hydro and Carbon Capture and Storage (CCS) technologies in the region, these technologies are now added into the model. To reflect the concern that the prices of carbon emission rights in future may still go through cyclical developments, our assumptions about the prices of carbon emissions follows a similar pattern to publically available U.S. carbon trading data.

3. Data Inputs and Scenarios

This study covers the ten member countries of ASEAN, which are Brunei, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, the Philippines, Singapore, Thailand, and Vietnam. Technologies for power generation covered in this study include coal, coal CCS, diesel, natural gas, natural gas CCS, hydro, small hydro, geothermal, wind, solar PV, and biomass. The period covered by this study is 2012 to 2035.

The main items of data required for this study include existing capacities of the types of power generation mentioned above, the CAPEX and OPEX of these types of power generation, the load factor and life expectancy of each vintage of each type of power generation, the energy resources available for power generation in each country, the peak and non-peak power demand and duration of power demand of each country, projected growth rate of power demand, and transmission cost and transmission losses of cross-border power trade. Detailed data and sources of data are presented in Appendix B.

The purpose of this study has two layers. One is to assess how policies such as EMI, carbon prices, RPS and FIT impact the pattern of power generation capacity development and utilization, as well as that of cross-border power trade in the region, with special focus on renewable energy applications in the region. The other is to assess what level of policy intervention is most effective for each policy regime, in terms of the additional costs incurred and the additional capacity development in renewable energy achieved.

Specially, we focus on testing various RPS and FIT policies. For RPS, we test what percentage of renewable energy in the total electricity supply is most effective in promoting renewable energy capacity development. For FIT, we test how much subsidy is most effective in promoting renewable energy capacity development. The following table lists the key assumptions or parameters of the scenarios.

Table 2: Key Assumptions/Parameters of the Scenarios

Scenario	Description
BAU (No Carbon Costs or EMI)	Business-As-Usual (BAU) with no carbon costs[1] or EMI imposed on the power sector
BAUCC (Carbon Costs with No EMI	This scenario assumes that carbon costs are) imposed to the power sector but the region has no effective EMI to allow free cross-border power trade
BAUCCEMI (Carbon Costs with EMI)	Both carbon costs and EMI are implemented in the power sector of the region
FIT10	USD 10 / MWh of subsidy provided to electricity generated from renewable energy
FIT20	USD 20 / MWh of subsidy provided to electricity generated from renewable energy
FIT30	USD 30 / MWh of subsidy provided to electricity generated from renewable energy
FIT40	USD 40 / MWh of subsidy provided to electricity generated from renewable energy
FIT50	USD 50 / MWh of subsidy provided to electricity generated from renewable energy
RPS10	The share of renewable energy in total electricity is required to be above 10%
RPS20	The share of renewable energy in total

[1] Carbon costs usually come from Cap-and-Trade schemes for carbon emissions from specified sectors. Although ASEAN has no such scheme at the moment, carbon costs from other markets such as the Europe and U.S. could be applied to reflect the environmental cost of carbon emissions from power generation activities. Importantly, as our model is a sector model, it is not possible to endogenise carbon costs which are derived from multi-sector markets.

	electricity is required to be above 20%
RPS30	The share of renewable energy in total electricity is required to be above 30%
RPS40	The share of renewable energy in total electricity is required to be above 40%
RPS50	The share of renewable energy in total electricity is required to be above 50%
RPS60	The share of renewable energy in total electricity is required to be above 60%
RPS70	The share of renewable energy in total electricity is required to be above 70%
RPS30 by 2030	The share of renewable energy in total electricity is required to be above 30% from 2030 onwards
FIT10 RPS10	A Combination of FIT10 and RPS10

The BAU scenario assumes that in the studied period no coordinated policies such as carbon costs, EMI, RPS or FIT are adopted to promote renewable energy in the power sector of the region.

The BAUCC scenario assumes that carbon costs are imposed on power generation in all countries in the region, but no EMI is implemented. This scenario, when compared with the previous BAU scenario, reflects the impact of carbon costs.

The BAUCCEMI scenario assumes that both carbon costs and EMI are introduced. This scenario, when compared with the previous carbon costs only scenario, reflects the impact of EMI.

FIT10 to FIT50 is a series of scenarios which test the impacts of various levels of FIT subsidies. RPS10 to RPS70 is another series of scenarios which test the impacts of various levels of RPS requirements on the share of renewable energy in total power generation to be met from 2020 onwards. Our model is solvable at up to RPS of 70% level, meaning that the region has ample renewable resources, especially hydro, to enable the scenario. Both FIT and RPS scenarios assume the implementation of both carbon costs and EMI.

RPS30 by 2030 is an additional scenario that says 30% of the power generated is supplied from renewable sources from 2030 onwards. This scenario is currently perceived by policy practitioners in the region as reasonable. The model thus helps assess the effectiveness of such a policy. FIT10 RPS10 is another additional scenario that says that FIT10 and RPS10 will be combined and implemented simultaneously. The scenario represents popular thinking from the U.S. policy makers. This model will also help assess if this policy would be favourable in ASEAN context.

4. Results and Analysis

Key results from the simulation of the scenarios in Table 2 are listed in the following table. The second column of Table 3 reports the objective value that is the variable portion of the total cost of electricity generated – CAPEX of newly added capacities and OPEX of both vintage and newly added capacities. Subsidies to OPEX incurred under the FIT scenarios of power generation are reported in the third column. These subsidies are also part of the social costs in producing the electricity. In addition, the historical vintage capacities incur a fixed amount of amortised CAPEX and this is reported in the fourth column. The adjusted actual total costs are therefore a summation of the objective value of the model, the total subsidies, and the amortised CAPEX of vintage capacities. They are reported in the fifth column. The sixth column reports total CO_2 emissions in the corresponding scenario. The penultimate column reports total newly added renewable energy power generation capacities achieved in the period in the corresponding scenario. The last column is a subset of penultimate column showing the newly added renewable energy capacities excluding hydro.

Table 3. Key Results of All Scenarios

Scenarios	Objective (Million USD)	Total Subsidy (Million USD)	CAPEX of Existing Capacity (Million USD)	Actual Total Cost (Million USD)	Total CO_2 Emissions (Million Tonnes)	Renewable Energy Capacity Added (MW)	Renewable Energy Capacity Added w/o hydro (MW)
BAU	470,982	0	2,525,266	2,996,247	17,158	61,419	13,125
BAUCC	489,908	0	2,525,266	3,015,174	16,580	79,355	24,155
BAUCCEMI	473,896	0	2,525,266	2,999,162	15,177	117,041	20,819
FIT10	436,244	43,984	2,525,266	3,005,494	12,475	160,399	38,445
FIT20	387,555	109,749	2,525,266	3,022,570	10,293	181,922	51,253
FIT30	322,592	233,162	2,525,266	3,081,020	7,408	197,425	74,970
FIT40	236,146	387,996	2,525,266	3,149,407	5,634	213,709	83,004
FIT50	130,619	583,638	2,525,266	3,239,522	4,257	250,859	93,702
RPS10	474,084	0	2,525,266	2,999,349	15,067	117,871	21,648
RPS20	476,963	0	2,525,266	3,002,229	14,460	123,725	27,487
RPS30	482,347	0	2,525,266	3,007,613	13,578	128,127	30,512
RPS40	496,085	0	2,525,266	3,021,351	12,351	139,903	40,325
RPS50	515,496	0	2,525,266	3,040,762	11,109	149,598	48,210
RPS60	544,266	0	2,525,266	3,069,532	9,646	178,033	57,849
RPS70	598,918	0	2,525,266	3,124,184	8,324	249,456	86,335
RPS30 by 2030	474,670	0	2,525,266	2,999,936	14,681	125,407	28,753
FIT10 RPS10	436,257	44,006	2,525,266	3,005,529	12,471	160,399	38,445

Source: Simulation results.

Some general observations may be drawn from results reported in Table 3.

- First, without any policy intervention and following the current track as in the BAU scenario, renewable energy will make moderate progress in the region, mostly driven by hydro. Renewable energy other than hydro sees minimum progress.
- Second, imposing carbon costs without EMI would greatly help the development of non-hydro renewables but only give moderate help to hydro.
- Third, EMI which enables cross-border power trade in the region would significantly boost the development of hydro, but cannot help non-hydro as compared to the carbon costs only scenario.
- Fourth, in terms of additional costs to achieve more renewable energy development, the BAUCCEMI scenario incurs less cost but adds much more renewable energy capacity than the carbon costs only scenario (BAUCC). The beneficial impact of EMI is evident.

- Fifth, for the FIT and RPS scenarios that are in addition to the implementation of carbon costs and EMI, the stronger the policy is, the more progress in renewable energy development would be made.[2]
- Sixth, the RPS30 by 2030 scenario does not seem to be better than the original RPS30 scenario that assumes the implementation of RPS requirement from 2020 onwards. It incurs less additional costs but achieves less carbon emissions reduction as well as newly added renewable energy capacities. The scenario is a marginal improvement compared to BAUCCEMI scenario.
- Seventh, the combined policy scenario, FIT10 RPS10, looks not much different than FIT10. RPS10 seems not to have much impact on the results but adds administrative complexity to the policy.

The comparison of effectiveness of FIT and RPS presents noticeable implications. Since FIT and RPS are two policies of very different nature – one is a subsidy and the other is a regulation standard, it is difficult to draw such implications from Table 3 directly. However, the resulting impacts of the two types of policies could be compared. It is especially interesting and useful to look at the incurred additional costs and the additional capacity development for renewable energy. The following table and figures are developed to facilitate the comparison.

Table 4 estimates percentage change of each FIT and RPS scenario in total costs and newly added renewable energy capacities, as compared to the baseline scenario with carbon costs and EMI only (BAUCCEMI). According to this table, for similar increases in total costs, FIT policies are more effective in reducing carbon emissions and promoting the development of renewable energy. Such is more obvious in Figure 2 to Figure 4.

[2] RPS policy imposes restrictions on the share of electricity generated from renewable sources (in MWh terms) rather than the share of renewable power generation capacities (in MW terms). A stricter RPS not only encourages the development of more renewable power generation capacities, but also encourages higher utilization of the renewable power generation capacities built.

Table 4: Percentage Changes in Costs and Newly Added Renewable Energy Capacities under FIT and RPS

Scenarios	% Decrease in Carbon Emissions	% Increase in RE Capacity Added	% Increase in RE Capacity Added w/o hydro (MW)	% Increase in Cost
FIT10	18%	37%	85%	0.21%
FIT20	32%	55%	146%	0.78%
FIT30	51%	69%	260%	2.73%
FIT40	63%	83%	299%	5.01%
FIT50	72%	114%	350%	8.01%
RPS10	1%	1%	4%	0.01%
RPS20	5%	6%	32%	0.10%
RPS30	11%	9%	47%	0.28%
RPS40	19%	20%	94%	0.74%
RPS50	27%	28%	132%	1.39%
RPS60	36%	52%	178%	2.35%
RPS70	45%	113%	315%	4.17%
RPS30 by 2030	3%	7%	38%	0.03%
FIT10 RPS10	18%	37%	85%	0.21%

Source: Estimations based on Table 3.

Figure 2: FIT vs. RPS in Carbon Emissions Reduction

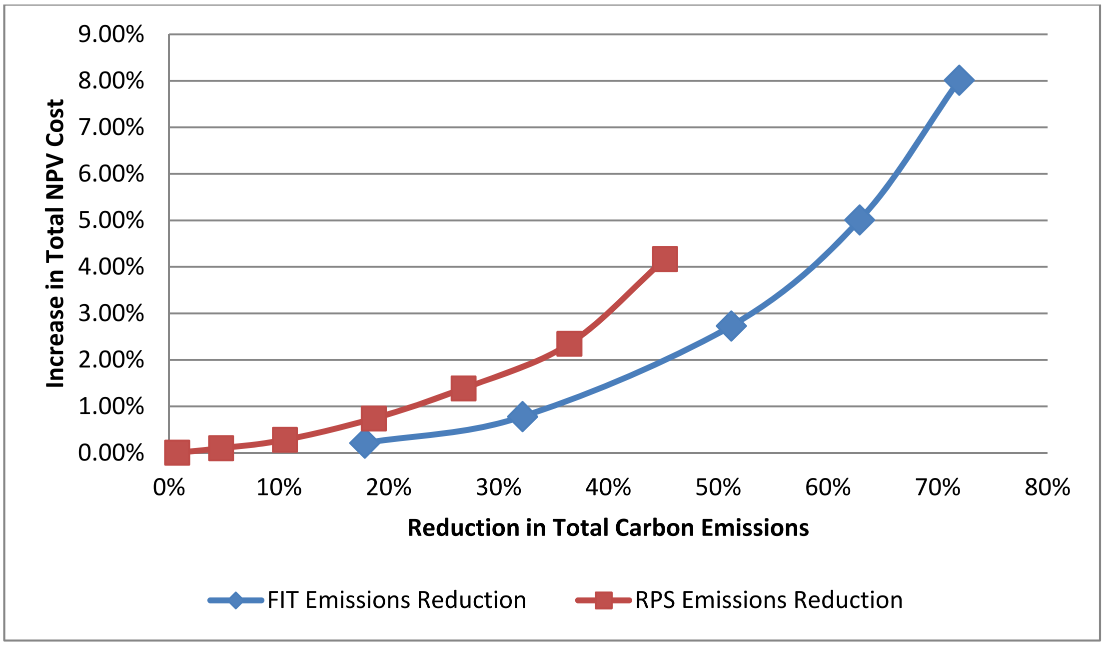


Figure 3: FIT vs. RPS in Increasing Renewable Energy (RE) Capacities

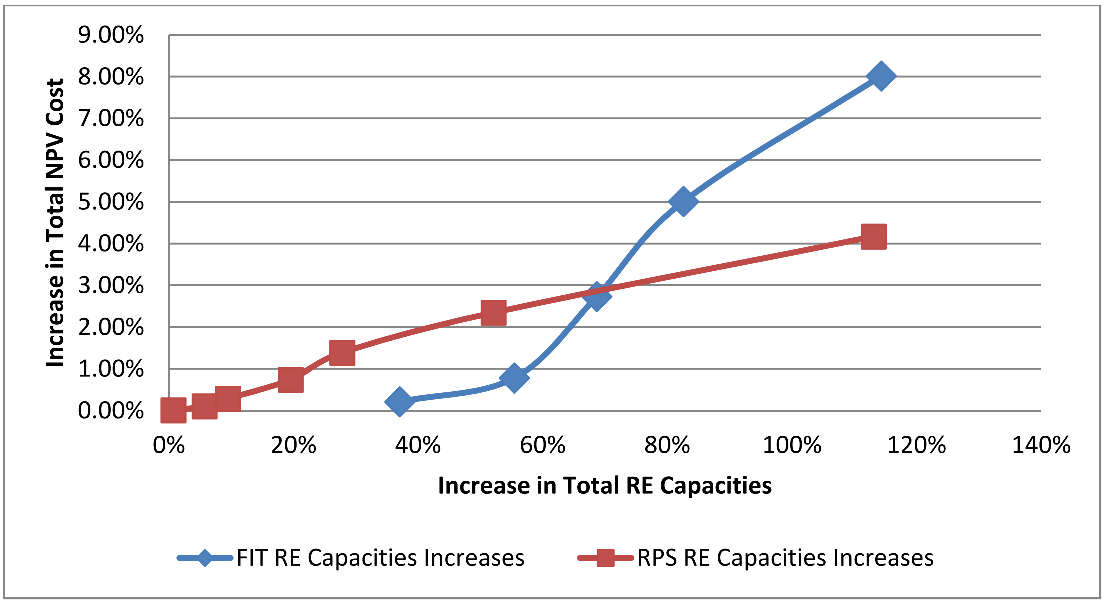


Figure 4: FIT vs. RPS in Increasing Renewable Energy (RE) Capacities (Excluding Large Hydro)

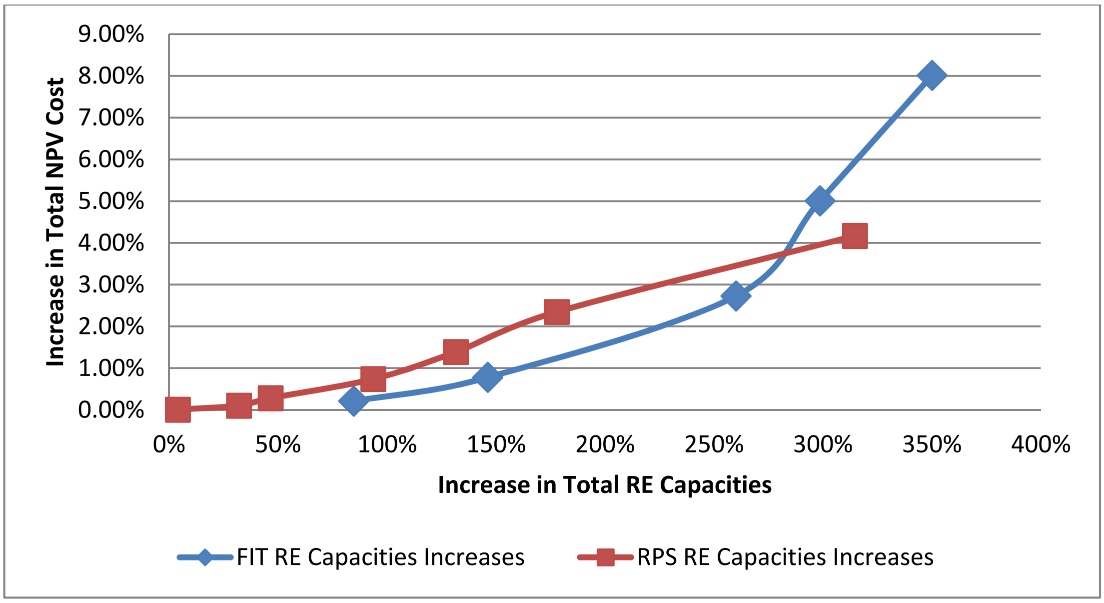


Table 4 and Figures 2 to 4 lead to the following important observations.

- First, in all simulated scenarios FIT performs better than RPS, as the curves of FIT in Figure 2 to Figure 4 constantly stay above those of RPS, except when RPS is raised to an unrealistic level of 70%. This means that for the same percentage of additional costs incurred, FIT achieves both more carbon emissions reduction and more additional capacity of renewable energy.

- Second, with up to 20% of increase in total costs in FIT scenarios, which is most likely acceptable in reality to policy makers and to the public, all curves appear to present diminishing marginal return to additional costs. (Diminishing marginal return means the rate of change in the target measurement is lower than the rate of change in costs.) Namely, as additional costs increase, the speed of increase in carbon emissions reduction and the capacity for renewable energy decrease.
- Third, within the above mentioned range, there exists a point at which the curve is tangent to a 45 degree straight line. Before this point, 1 percent increase in total costs incurs more than 1 percent increase in carbon emissions reduction or capacity of renewable energy. After this point, it incurs less than 1 percent increase in carbon emissions reduction or capacity of renewable energy. Theoretically, this point represents the optimal (or efficient) amount of additional cost for the society to invest and subsequently achieve carbon emissions reduction or renewable energy development.
- Perceived as practical and favourable policies under the current situation, RPS30 by 2030 seems to be a low-hanging fruit to achieve certain carbon emissions reduction and the development of renewable energy capacities. More stringent policies are needed subsequently to achieve meaningful impacts.
- The combined policy of FIT10 RPS10 appears to have the same impact as FIT10.

Unit Cost of Carbon Emissions Reduction and Additional Renewable Energy Capacity

It is also interesting to look at the unit cost of additional reduction in carbon emissions and additional renewable energy capacity for each of the FIT and RPS scenarios. Table 5 presents the calculations derived from Table 3 for this purpose.

Table 5: Unit Cost of Carbon Emissions Reduction and Additional Renewable Energy Capacity for FIT and RPS Scenarios

Scenarios	Unit Cost of Carbon Emissions Reduction (USD/Ton)	Unit Cost of Increases in RE Capacity (Million USD/MW)	Unit Cost of Increases in RE Capacity w/o Hydro (Million USD/MW)
FIT10	2.34	0.15	0.36
FIT20	4.79	0.36	0.77
FIT30	10.54	1.02	1.51
FIT40	15.74	1.55	2.42
FIT50	22.01	1.80	3.30
RPS10	1.71	0.23	0.23
RPS20	4.28	0.46	0.46
RPS30	5.29	0.76	0.87
RPS40	7.85	0.97	1.14
RPS50	10.23	1.28	1.52
RPS60	12.72	1.15	1.90
RPS70	18.24	0.94	1.91

Figure 5 to Figure 7 compare the results for FIT and RPS in Table 5 in pairs.

Figure 5: Unit Cost of Carbon Emissions Reduction

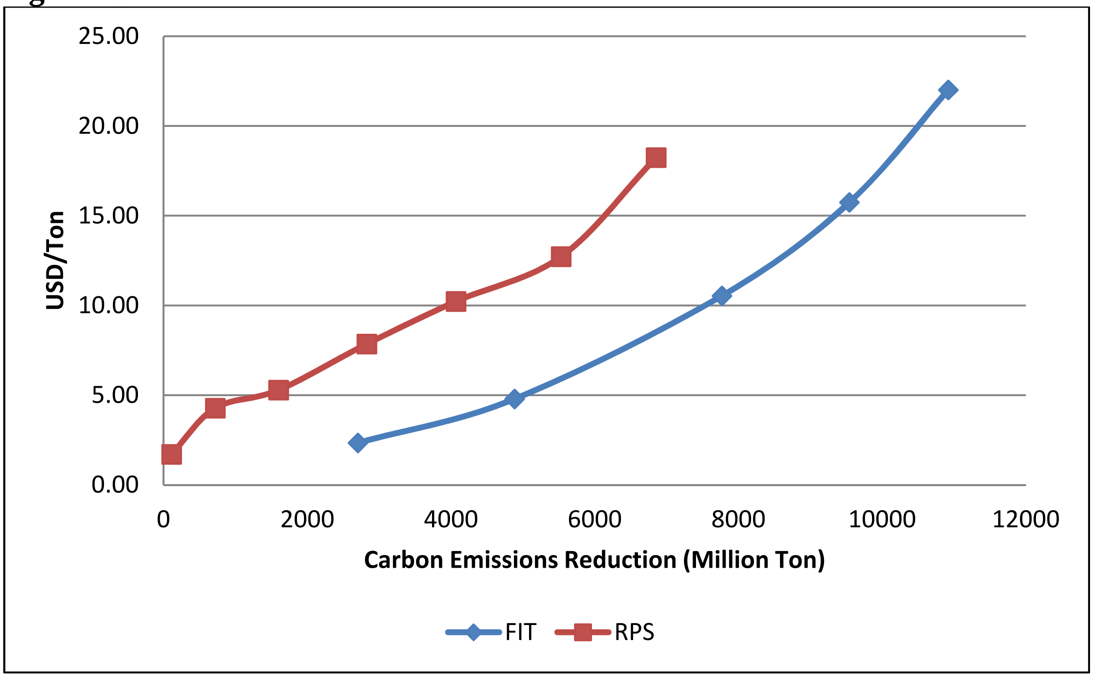


Figure 6: Unit Cost of Additional Renewable Energy Capacity

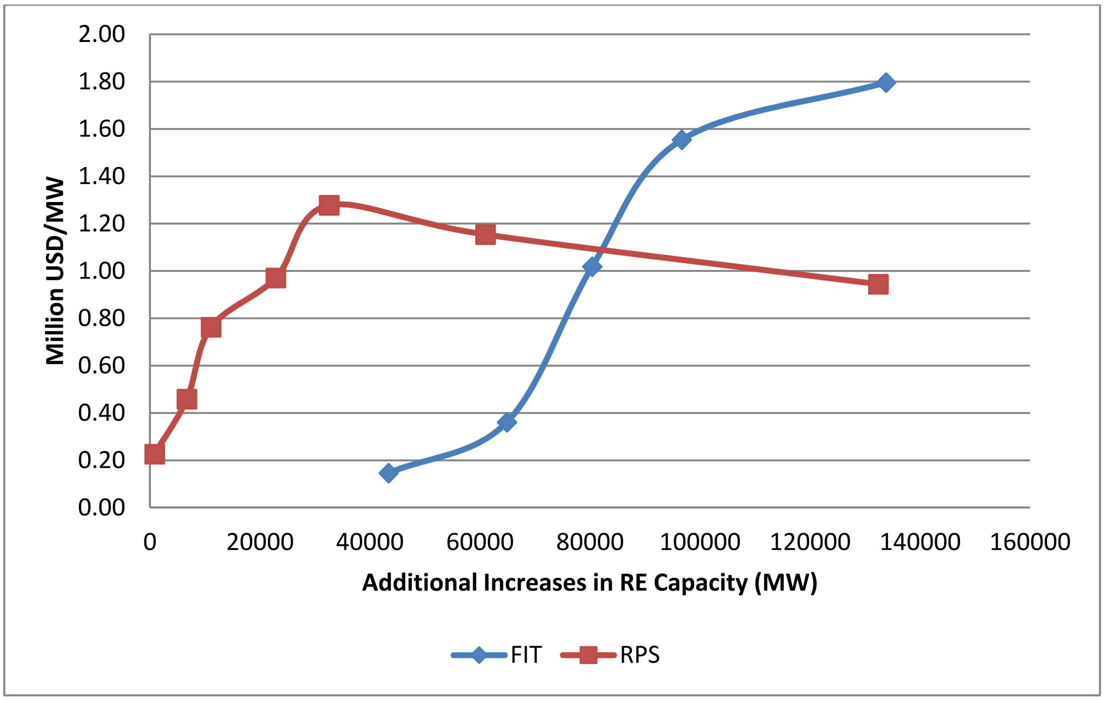
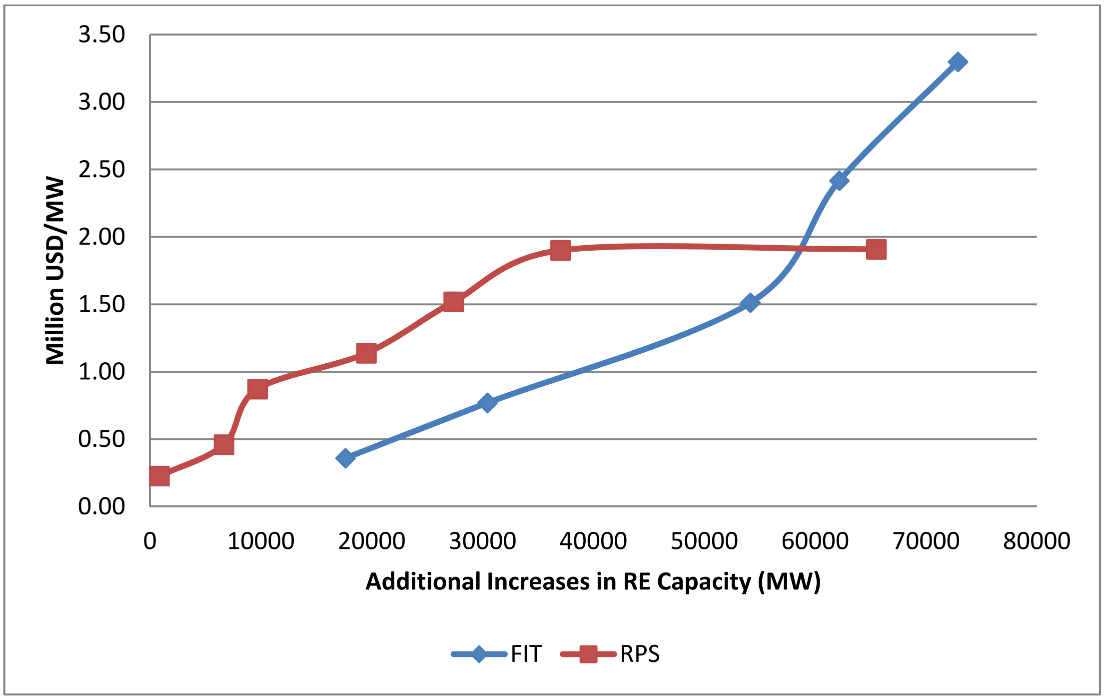


Figure 7: Unit Cost of Additional Renewable Energy Capacity (Excluding Large Hydro)



Two important implications can be derived. First, figure 5 shows that FIT is more cost effective in reducing carbon emissions at any level of total reduction. Second, in terms of cost effectiveness in promoting renewable energy capacities, FIT does better than RPS for most of the time, except when the targeted increase in percentage is exceptionally high.

In general, the above observations echo the empirical findings about the effectiveness of FIT and RPS in the literature. Dong (2012) shows that FIT is more effective in increasing renewable energy capacity than RPS, using multi-country panel data, and that such is consistent with many previous studies. The U.S. National Renewable Energy Laboratory (NREL) reported that properly designed FITs could also be more cost effective than RPS according to European evidence (NREL, 2009).

5. Sensitivity Analysis

Before concluding discussion of the observations drawn in Section 4, we are curious if the exclusion of large hydro would deliver significantly different patterns and observations when the above simulations are repeated. This is an important issue as many parts of the world do exclude large-scale hydro when devising renewable energy policies.

In exploring this possibility as a sensitivity analysis, it is noted that as the region has a limited total amount of renewable resources when large hydro is excluded, and the highest share renewable energy could contribute to total electricity supply from 2020 onwards could only be 14.5%. Therefore, in our sensitivity analysis, RPS scenarios run with requirements from 10% to 14.5%. FIT scenarios remain the same. In all simulations for sensitivity analysis, large hydro is not considered as renewable energy targeted by FIT or RPS. Figure 8 to 10 presents the findings in sensitivity analysis form.

Figure 8: Unit Cost of Carbon Emissions Reduction in Sensitivity Analysis

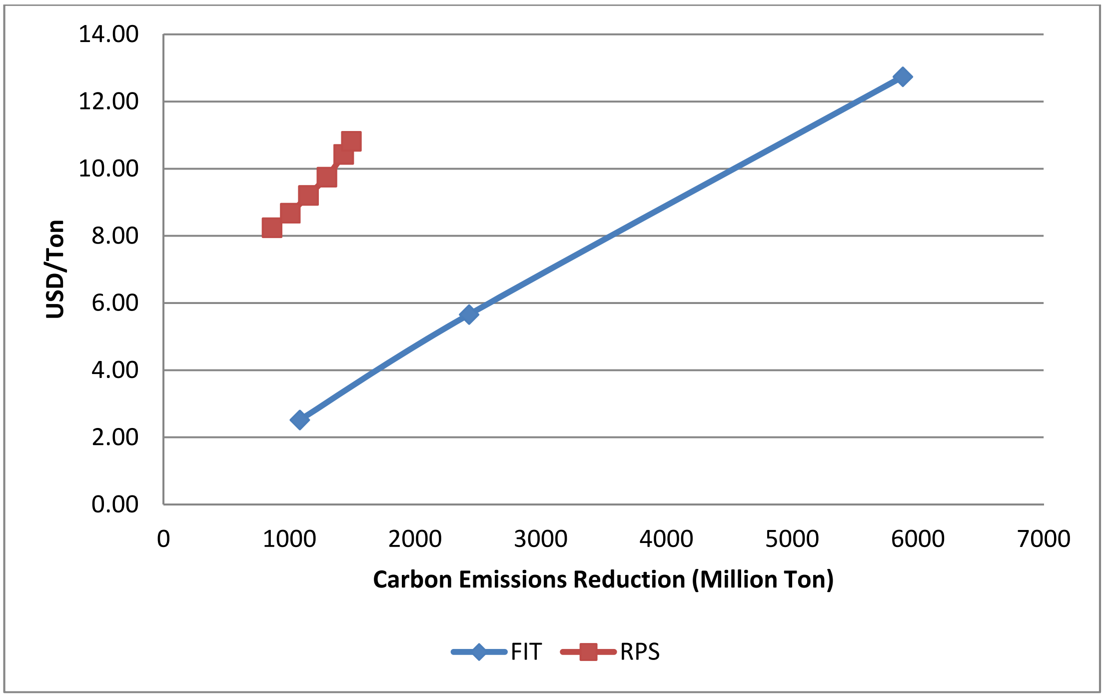


Figure 9: Unit Cost of Additional Renewable Energy Capacity in Sensitivity Analysis

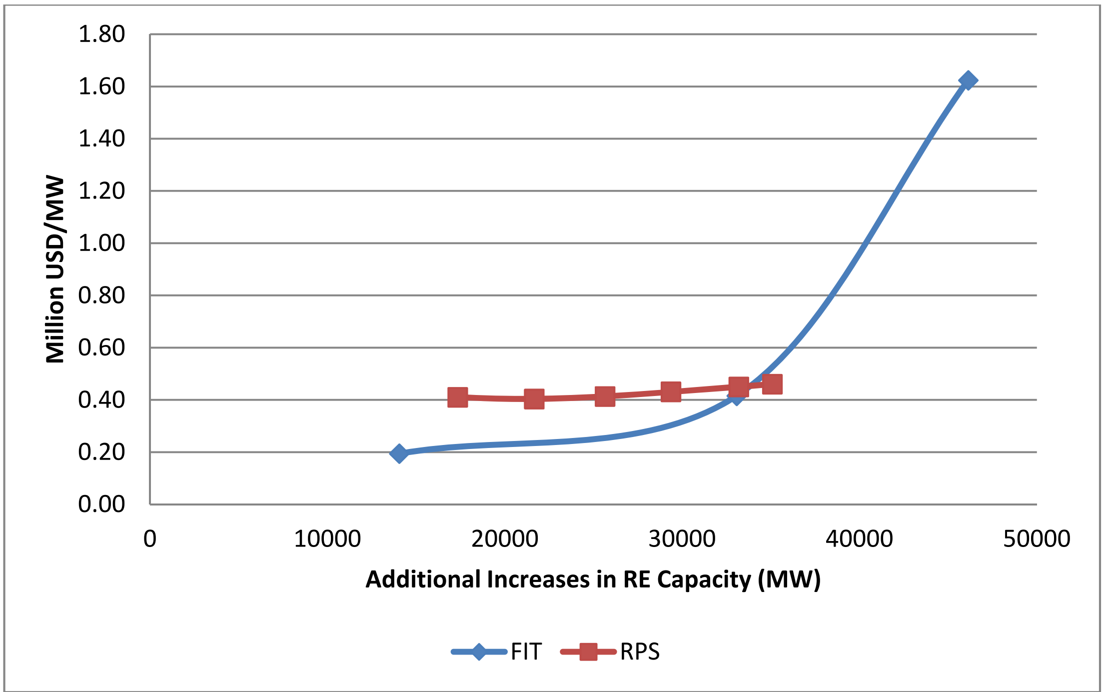
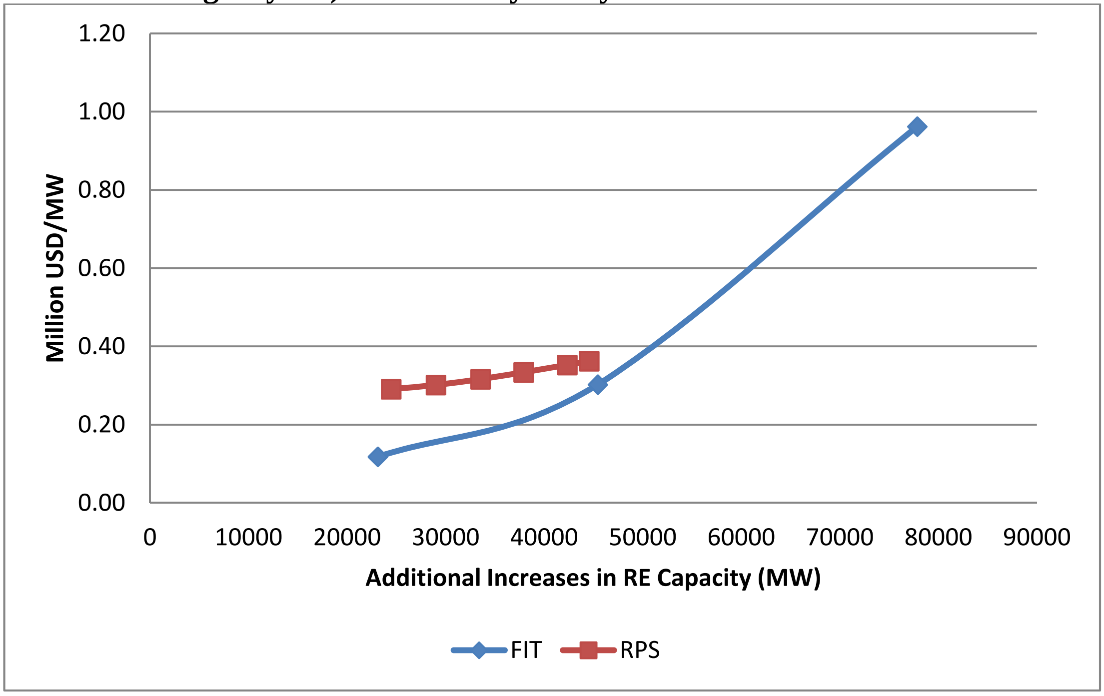


Figure 10: Unit Cost of Additional Renewable Energy Capacity (Excluding Large Hydro) in Sensitivity Analysis



Comparing the three figures (8, 9 and 10) with Figure 5 to 7, no significant pattern shift is observed. Therefore, the effectiveness of FIT and RPS does not seem to be affected by the scope of targeted renewable energy, namely the inclusion or exclusion of large hydro.

6. Conclusions and Policy Implications

This study investigates the impacts of various policy regimes on the development of renewable energy in the power sector of the region. These policy regimes include carbon pricing, EMI, FIT and RPS. A linear dynamic programming model is applied to quantitatively simulate and assess these policy scenarios.

Results from simulations deliver several important implications on these policy options, which are summarized as follows.

- With no changes in the current policies of countries in the region, in the business-as-usual (BAU) scenario, renewable energy will make moderate progress in the region, mostly driven by hydro.

- Imposing carbon costs without EMI would greatly help the development of renewable energy but only give a moderate help to that of hydro. This is because many countries in the region that need more electricity in the future do not have enough potential of hydro as a low-carbon energy source so that they will be forced to choose non-hydro renewable energy.
- EMI is the low-hanging fruit by implementing which the region not only achieves lower total costs in meeting the growing demand for electricity in the next two decades, but also significantly promotes the adoption of renewable energy.
- EMI enabled cross-border power trade in the region will significantly boost the development of hydro, but will not provide so powerful a boost for non-hydro renewable energy. This is because hydro is the cheapest energy for power generation.
- Moving ahead, FIT is theoretically a better choice than RPS according to our model. In reality, the administration costs for implementing FIT may be a concern. As FIT or RPS scales up to higher subsidy or proportion levels, additional effects on the promotion of renewable energy and reduction of carbon emissions decline. Our results suggest that a policy that increases total costs up to 10% is more efficient for the purposes discussed above, as within this range a 1% increase in total cost incurs more than 1% additional achievement in the targeted effects.
- Implementing RPS30 by 2030 is a reasonable choice as the low-hanging fruit if policy makers perceive it as more practically implementable. It achieves moderate improvements in carbon emissions reduction and renewable energy development while incurring negligible increases in total cost of electricity.
- Sensitivity analysis shows that the above conclusions are not affected by the inclusion or exclusion of large hydro as targeted renewable energy by FIT or RPS.

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Appendix A. The Original Model

CAPEX

The following models the capital expenditure (CAPEX) of a certain type of power generation capacity at a certain point of time. Let x_{miv} be the capacity of plant type *m*, vintage *v*,[3] in country *i*.[4] And c_{miv} is the corresponding capital cost per unit of capacity of the power plant. So the total capital cost during the period of this study would be $\sum_{i=1}^{I}\sum_{v=1}^{T}\sum_{m=1}^{M} c_{miv} * x_{miv}$. (In GAMS code, for consistency in presentation with the other cost terms, we add a time dimension to the equation besides the vintage dimension. By doing that, we amortize capital cost using a capital recovery factor).

OPEX

The following models the operational expenditure (OPEX) of a certain type of power generation capacity at a certain point of time. Let u_{mijtvp} be power output of plant *m*, vintage *v*, in year *t*, country *i*, block *p* on the load, and exported to country *j*. Let F_{mitv} be the corresponding operating cost which varies with *v*, and θ_{jp} be the time interval of load block *p* within each year in the destination country. *Opex*(*t*) in year t is expressed as $\sum_{i=1}^{I}\sum_{j}^{J}\sum_{v=-V}^{t}\sum_{p=1}^{P}\sum_{m=1}^{M} F_{mitv} * u_{mijtvp} * \theta_{jp}$.

Carbon Emissions

The model considers carbon emissions of different types/technologies of power generation capacity and takes the cost of carbon emissions into consideration. Let ce_m be the carbon emissions per unit of power plant capacity of type *j* plant, and cp_t be the carbon price per unit of carbon emissions in year *t*. The amount of carbon emissions produced are expressed as $\sum_{m=1}^{M}\sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{v=-V}^{T} u_{mijtvp} * \theta_{jp} * ce_m$, and carbon cost in year *t* is $CC(t) = cp_t * (\sum_{m=1}^{M}\sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{v=-V}^{T} u_{mijtvp} * \theta_{jp} * ce_m)$.

[3] Vintage indicates the time a certain type of capacity is built and put into use.
[4] This variable represents investment in new power generation capacity. Investment is considered done once the power generation facility has been constructed and not at the moment when investment decision is made and construction commences

Cross-border Transmission Cost

The costs of cross-border transmission come in two forms. One is the tariff paid to recover the capital investment and operational cost of the grid line. The other is the transmission loss, which could be significant if the distance of transmission is long. To model the tariff of transmission, let $tp_{i,j}$ be the unit MWh transmission cost of power output from country *i* to country *j*. Let *TC*(*t*) be the total cost of cross-border power transmission in year *t*, we have $TC(t) = \sum_{i=1}^{I} \sum_{j=1}^{J} \sum_{v=-V}^{T} \sum_{p=1}^{P} u_{mijtvp} * \theta_{jp} * tp_{i,j}$.

Objective Function

As discussed earlier in the methodology section, our objective is to minimize the total cost of electricity during the period of this study. The objective function is written as:

$$obj = \sum_{i=1}^{I} \sum_{v=1}^{T} \sum_{m=1}^{M} c_{miv} * x_{miv} + \sum_{t=1}^{T} \{Opex(t) + CC(t) + TC(t)\} \quad (1)$$

Constraint Conditions

Optimizing the above objective function is subject to the following constraints. Equation (2) shows a first set of constraints, which require total power capacity to meet total power demand in the region. Let Q_{itp} be the power demand of country *i* in year t for load block *p*.

$$\sum_{i=1}^{I} \sum_{j=1}^{J} \sum_{m=1}^{M} \sum_{v=-V}^{t} u_{mijtvp} \geq \sum_{i=1}^{I} Q_{itp} \quad (2)$$

The second one, shown in equation (3), states the constraint of load factor lf_{mi} of each installed capacity of power generation. Let kit_{mi} be the initial vintage capacity of type *m* power plant in country *i*.

$$u_{mijtvp} \leq lf_{mi} * (kit_{mi} + x_{miv}) \quad (3)$$

The third constraint, shown in equation (4), says that power supply of all countries to a certain country must be greater than the country's power demand. Let $tl_{i,j}$ be the ratio of transmission loss in cross-border electricity trade between country *i* and country *j*.

$$\sum_{j=1}^{J}\sum_{m=1}^{M}\sum_{v=-V}^{t} u_{mijtvp} \cdot tl_{ij} \geq Q_{itp} \tag{4}$$

Equation (5) states that total supply of power of one country to all countries (including itself) must be smaller than the summation of the country's available power capacity at the time.

$$\sum_{j=1}^{J} u_{mijtvp} \leq \sum_{m=1}^{M}\sum_{v=-V}^{t} lf_{mi} * (kit_{mi} + x_{miv}) \tag{5}$$

The fifth constraint, shown in equation (6), is capacity reserve constraint. Let pr be the rate of reserve capacity as required by regulation. And let $p = 1$ represent the peak load block.

$$\sum_{i}^{I}\sum_{m=1}^{M}\sum_{v=-V}^{t} lf_{mi} * (kit_{mi} + x_{miv}) \geq (1 + pr) * \sum_{i}^{I} Q_{it,p=1} \tag{6}$$

Specially, hydro-facilities have the so-called energy factor constraint as shown in equation (7). Let ef_{mi} be the energy factor of plant type *m* in country *i*. Other facilities will have *ef*=1.

$$\sum_{p=1}^{P}\sum_{j=1}^{J} u_{mijtvp} \leq ef_{mi} * (kit_{mi} + x_{miv}) \tag{7}$$

Lastly, development of power generation capacity faces resource availability constraint, which is shown in equation (8). Let $XMAX_{mi}$ be the type of resource constraint of plant type *m* in country *i*.

$$\sum_{v=1}^{T} x_{miv} \leq XMAX_{mi} \tag{8}$$

Appendix B. The Data Inputs

Table B1: Existing Power Generation Capacity of ASEAN Countries (Base year 2009, Unit: MW)

	Brunei	Cambodia	Indonesia	Lao PDR	Malaysia	Myanmar	Philippines	Singapore	Thailand	Vietnam
Coal	0	0	12203	0	9068.4	0	5584.4	0	10719.2	3301.7
Coal CCS	0	0	0	0	0	0	0	0	0	0
Diesel	5.8	372	3328	50	685.4	279.08	1330.4	2511.2	269.3	580.5
Natural Gas	753	0	10929	0	13380.2	980.92	3387.2	7934.8	32088.6	5795.9
Natural Gas CCS	0	0	0	0	0	0	0	0	0	0
Hydro	0	13	4872	1805	2107	1460	3291	0	3488	5500
Small Hydro	0	1.87	21	7.8	0.1	39.7	151.3	0	128	75
Geothermal	0	0	1189	0	0	0	1953	0	0.3	0
Wind	0	0	1	0	0	0	33	0	0.4	8
Solar PV	0	0	0	0	0	0	1	0	10	0
Biomass	0	5.78	0	0	0	0	0	20	800	0

Sources: EIA website, IEA website, and Energy Studies Institute (2012)

Table B2: CAPEX, OPEX, Life, and Availability of Power Generation Assets

	Coal*	Coal CCS	Diesel	Natural Gas	Natural Gas CCS	Hydro**	Small Hydro	Geothermal	Wind	Solar PV	Biomass
CAPEX (Million USD/MW)	2.079	4.925	1.139	1.054	2.27	4.933	2.3	6.18	2.187	5.013	4.027
OPEX (USD/MWh)	31.86	37.6	229.75	43	46.87	4.32	4.68	14.23	20.58	19.52	28.87
Life (Years)	40	40	30	30	30	80	50	30	25	25	25
Load Factor (Percentage of A Year)	0.85	0.85	0.85	0.85	0.85	0.9	0.9	0.95	0.3	0.11	0.85

Sources: IEA (2010) and EU SEC (2008)

* Due to the consideration of abundance in coal resources, countries including Indonesia, Malaysia, Thailand, and Vietnam are assumed to have 30% lower CAPEX and OPEX in coal-fired power generation.

** Due to the consideration of abundance in hydropower resources, countries including Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, and Philippines are assumed to have 30% lower CAPEX and OPEX in hydropower generation.

Table B3: Energy Resources for Power Generation in ASEAN Countries (Unit: MW)

	Brunei	Cambodia	Indonesia	Lao PDR	Malaysia	Myanmar	Philippines	Singapore	Thailand	Vietnam
Coal	15000	15000	50000	15000	50000	30000	30000	15000	50000	50000
Diesel	15000	15000	15000	15000	15000	15000	15000	15000	15000	15000
Natural Gas	15000	15000	50000	15000	50000	30000	30000	30000	50000	50000
Hydro	0	10300	75459	18000	29000	0	13097	0	700	2170
Small Hydro	0	300	493	48.8	20.4	231	1287	0	556	1800
Geothermal	0	0	27000	0	67	930	2379	0	5.3	270
Wind	0	452	7404	1600	452	1600	7404	0	1600	452
Solar PV	115	3771	37800	4538	6192	12967	6336	130.7	300	10321
Biomass	0	700	49810	0	29000	4098	200	50	7000	400

Sources: Lidula, *et al*. (2007) and WEC Survey of Energy Resources 2010.

Table B4: Power Demand and Duration of the Demand in ASEAN Countries

	Brunei	Cambodia	Indonesia	Lao PDR	Malaysia	Myanmar	Philippines	Singapore	Thailand	Vietnam
Peak Demand (MW)	454.7	291	23438	350	12990	1140	8766	5711	22586	11605
Peak Duration (Hours)	4681.7	4925.2	4681.7	4745	4681.7	2428	4015	5840	4015	2428
Non-peak Demand (MW)	257	85	5338	60	8388	162	3394	1324	8692	6862
Non-Peak Duration (Hours)	4078.3	3834.8	4078.3	4015	4078.3	6332	4745	2920	4745	6332

Sources: HAPUA website; Center for Data and Information on Energy and Mineral Resources, Handbook of Energy & Economic Statistics of Indonesia 2011; Electricite du Laos, Annual Report 2010; and Zhai (2008, 2009).

Table B5: Transmission Loss and Cost among ASEAN Countries

		Transmission Loss (%)	Transmission Cost ($/MWh)
Distance*	0-1600 km	0.01	3
	>1600 km	0.087	5
	>3200 km	0.174	7.5

Sources: Claverton Energy Research Group http://www.claverton-energy.com/

* Distance is estimated as the distance between Capital cities of countries.

Table B6: Carbon Emissions Coefficient for Different Power Generation Technologies

	Coal	Coal CCS	Diesel	Natural Gas	Natural Gas CCS	Hydro	Small Hydro	Geothermal	Wind	Solar PV	Biomass
Carbon Emissions (Ton per MWh)	1.0	0.1	0.8	0.5	0.038	0.001	0.001	0.05	0.01	0.05	0.05

Source: Authors's estimation based on Varun, *et al*. (2009) and EU SEC (2008)

Table B7: Projected Cost of Carbon Emissions Right in ASEAN

Year	Cost of Carbon Emissions Right (USD/Ton)	Year	Cost of Carbon Emissions Right (USD/Ton)
2012	0.97	2025	3.51
2013	1.07	2026	4.12
2014	1.82	2027	1.03
2015	3.56	2028	0.10
2016	3.19	2029	0.06
2017	3.74	2030	1.18
2018	0.93	2031	1.29
2019	0.09	2032	2.20
2020	0.05	2033	4.31
2021	1.07	2034	3.86
2022	1.18	2035	4.53
2023	2.00		
2024	3.92		

Source: Authors' assumptions by referring to the patterns of the U.S. Chicago Climate Exchange historical prices of carbon emissions right, which is available at https://www.theice.com/ccx.jhtml.

Appendix C. List of Key Findings of This Study

- Without any policy intervention and following the current track as in the BAU scenario, renewable energy will make moderate progress in the region mostly driven by hydro. Renewable energy other than hydro sees minimum progress.
- EMI that enables cross-border power trade in the region significantly boosts the development of hydro. The BAUCCEMI scenario incurs less cost but adds much more renewable energy capacity than the carbon costs only scenario (BAUCC). The beneficial impact of EMI is evident.
- For the FIT and RPS scenarios that are built in addition to the implementation of carbon costs and EMI, the stronger the policy is, the more progress in renewable energy development would be made.
- In all simulated scenarios, FIT performs better than RPS. This means that for the same percentage of additional costs incurred, FIT achieves both more carbon emissions reduction and more additional capacity of renewable energy.
- With up to 20% of increase in total costs in FIT scenarios, which is most likely acceptable in reality to policy makers and to the public, both carbon emissions reduction and increases in additional renewable energy capacities present diminishing marginal returns to additional costs. Namely, as additional costs increase, the speed of increases in carbon emissions reduction and capacity of renewable energy decreases. Therefore, there exists a point that represents the optimal amount of additional costs for the society to invest and subsequently achieve carbon emissions reduction or renewable energy development.

CHAPTER 6

Facilitating the Penetration of Renewable Energy into the Power System

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The ASEAN Vision 2020, four pillars of energy cooperation, was defined in 1997 as including the ASEAN Power grid (APG), the Trans ASEAN gas pipeline, energy efficiency and conservation, and development of new and renewable energy sources. We have developed analyses into the four sections: (i) to examine renewable energy policy in both developed and developing countries; (ii) to measure the diversity index of the power generating systems of the East Asia Summit (EAS) area and individual countries; (iii) to investigate the future path of renewable energy utilization in power generation; (iv) to make policy recommendations on how to optimize the penetration of renewable energy sources in the context of energy market integration. There are three main findings from this study. First, European countries can provide lessons on how to promote renewable energy using a feed in tariff policy and a renewable portfolio standard. Second, experiences from Indonesia and Malaysia show both similarities and differences in policies promoting renewables, such as in terms of incentives, criteria, regulations, and institutional arrangements. Third, historical data indicates that since the mid-1980s, East Asia Summit (EAS) countries have shown reduced diversity in their primary energy power supply mix, and their share of renewable energy has tended to decrease. In future, the share of electricity production from renewable energy is expected to decrease further, especially the share of hydropower, while the share of renewable energy other than hydropower will increase marginally. Finally we suggest that it is necessary to enhance the trilogy dialogue among the EAS members in addressing the issues of: (1) improving the diversification ratio; (2) increasing the share of renewable energy; and (3) reducing emissions intensity. The trilogy dialogue aims to develop: (1) renewable energy targeting; (2) intensity targeting (kgCO2/kWh); and (3) renewable energy consumption per capita (kWh/capita).

1. Background

The ASEAN Vision 2020 with its four pillars of energy cooperation was stated in 1997 as the four pillars are the ASEAN Power grid (APG), the Trans ASEAN gas pipeline, energy efficiency and conservation, and the development of new and renewable energy sources. In 1999 HAPUA, an ASEAN inter-governmental energy organisation was asked by the ASEAN Senior Official Meeting on Energy to prepare an ASEAN interconnection Master plan Study (AIMS). The AIMS was divided into three regions: (i) Greater Mekong Sub Region (GMS) (Thailand, Viet Nam, Lao PDR, Cambodia and Myanmar); (ii) Indonesia – Malaysia – Singapore (IMS); and (iii) Trans Borneo Power Grid (East Malaysia, Brunei and Kalimantan).

Promoting energy market integration (EMI) in East Asia has become a challenging development goal. Following the Energy Ministers' Meeting (EMM) and Energy Cooperation Task Force (ECTF), Shi and Kimura (2010) discussed four key issues with regard to the promotion of EMI. These were removal of trade and investment barriers, enhancing linkage in energy infrastructure, energy pricing reform, and liberalisation of domestic energy markets.

Within the energy market integration framework, one of the sectors needing to be studied deeply is the electricity sector. Wu (2012) argues that an integrated electricity market can improve efficiency, reduce the cost of production, and raise standards of service. However, Wu (2012) also points out that developing interconnectivity in grid systems and trade among the EAS's members will be a task requiring many years. Furthermore, Chang and Li (2012) mentioned that geographical location is the main obstacle because this determines the transmission losses and costs. Chang & Li (2012) believe that market integration in ASEAN countries can encourage development of power generation from renewable energy such as geothermal, hydro, and wind.

Current rising demand for electricity has been mainly supplied by fossil fuel. Table 1 shows that fossil fuel remains the major source of electricity production. It can be seen that over the last four decades, electricity production from oil has decreased rapidly. At the same time, the share of coal and natural gas has tended to increase. Cambodia's power system remains highly dependent on oil, while in

Indonesia and Singapore the share of electricity production from oil has decreased to 23% and 18.8% respectively. Table 1also shows that the average share of gas in the ASEAN-10 countries is higher than the six partner countries.[1] Natural gas has become the backbone of power supply in Brunei, Malaysia, Singapore and Thailand. Natural gas has low emission intensity (ton CO2/TJ)[2]; in view of this, developing natural gas infrastructure and deepening gas utilization will have a positive impact on the environment. On the other hand, in Australia, China and India the share of coal is still relatively high (above 60%), while in Indonesia, Korea, and the US, the share of coal for electricity production is about 40%. Due to the wide variety in fossil fuel utilization and the inflexibility of plants and systems, there is a possibility that power systems may face "double traps", i.e. a "carbon lock" and rising generating cost, if decision makers fail to consider diversification in energy use, energy efficiency and conservation.

For the 16 member countries of the EAS, the shares of electricity production from renewable sources are still relatively low, except in the Philippines and New Zealand. As seen from Table 1, between 1990 and 2009, for some countries such as Brunei, Malaysia, Myanmar, and Vietnam, the share of renewable sources is still zero, and in Singapore, the share has increased only marginally.

Table 1 Electricity production by sources (% of total)

No	Country	Oil		Coal		Natural gas		Renewable sources, excluding hydroelectric*	
		1971	2009	1971	2009	1971	2009	1990	2009
1	Brunei Darussalam	1.6	1.0	NA	0.0	98.4	99.0	0.0	0.0
2	Cambodia	NA	95.6	NA	0.0	NA	0.0	NA	0.5
3	Indonesia	56.0	22.8	NA	41.8	0.0	22.1	3.4	6.0
4	Lao PDR	NA	NA	NA	NA	NA	NA	NA	NA
5	Malaysia	72.4	2.0	NA	30.9	0.0	60.7	0.0	0.0
6	Myanmar	23.2	8.9	3.9	0.0	3.9	19.6	0.0	0.0

[1] Partner countries consist of Australia, China, India, Japan, Korea, and New Zealand.
[2] Emissions intensity for oil, coal and gas is 74.1 tonCO2/TJ, 101.2 tonCO2/TJ, and 56.1 tonCO2/TJ respectively (IPCC, 2006).

7	Philippines	99.9	8.7	0.1	26.6	0.0	32.1	22.4	16.8
8	Singapore	100.0	18.8	NA	0.0	0.0	81.0	0.0	0.1
9	Thailand	53.6	0.5	6.1	19.9	0.0	70.7	0.0	4.0
10	Vietnam	0.0	2.5	73.3	18.0	0.0	43.4	0.0	0.0
11	Australia	3.4	1.0	71.0	77.9	3.3	13.7	0.5	2.6
12	China	7.9	0.4	70.5	78.8	0.0	1.4	0.0	0.8
13	India	6.3	2.9	49.1	68.6	0.6	12.4	0.0	2.2
14	Japan	62.6	7.2	11.9	26.8	1.4	27.4	1.4	2.5
15	Korea, Rep.	80.6	4.4	6.9	46.2	0.0	15.6	0.0	0.4
16	New Zealand	2.0	0.0	4.8	7.6	0.3	20.6	8.2	15.9

Note: *includes geothermal, solar, tides, wind, biomass, and biofuels. NA is not available.
Source: World Development Indicators, World Bank, 2012

In this study, we argue that there is a need for a more in-depth study of the potential of renewable energy in the power sector in the context of EMI. We investigate four elements: (i) renewable energy policies in developed and developing countries; (ii) the diversity index of the power generating systems of EAS countries and its individual members (iii) the future path of renewable energy utilization in power; (iv) policy recommendations on how to optimise the penetration of renewable energy sources in the context of energy market integration.

2. Data and Methodology

We conduct two main analytical studies. First, a qualitative analysis focuses on policy relating to renewable source utilization in the power sector. Second, a quantitative analysis is designed to address the second and third objectives (see above). It focuses on the diversity index and energy composition forecasting by applying a time series (ARMA) analysis and the Markov model.

2.1. Diversity Index

Power generation diversity is one of the key development indicators used by energy policymakers. According to Costello (2007), diversity is a concept that has different interpretations and dimensions. There are several ways to measure diversity, such as the entropy index, the Herfindahl-Hirschman index (HHI), the Shannon-Weiner index (S-WI) and the integrated multi-criteria diversity index. Costello (2007) and Hickey, *et al*. (2010) used the S-WI index to measure diversity. The index is expressed as follows (Costello, 2007 and Hickey, *et al*. 2010).

$$DI = \sum - S_i \ln(S_i) \tag{1}$$

where the diversity index (DI) directly relates to the share of generation by the i-th type of generation (i.e. Si). This index measures the changes in installed capacity composition among all power plant energy sources. The higher the index, the more desirable, because this shows more types of generation technologies and fuel sources in the system, and also shows more balance and diversity in input use.

2.2. ARMA Model

We developed an autoregressive moving average (ARMA) for the 'business as usual' scenario analysis. A business as usual scenario means that the long term energy mix depends on past information. We applied a Box-Jenkins approach to modelling the stochastic process (Greene, 2003).

2.3. Markov Model

We developed a Markov model (MM) for policy scenario analysis. MM is a stochastic or probabilistic model. A Markov model assume the future phenomenon depends upon only the recent past data. The model is very useful in addressing three basic issues: (i) forecasting the structure of electricity output by sources; (ii) showing the stability of structural change; and (iii) showing how fast the system can reach the steady state.

3. Renewable Energy Policy in the Electricity Sector: Commitments and Challenges

3.1. Developed Countries Perspective

European countries have shown strong commitment to promoting renewable energy. In 1990, the UK introduced a Non-Fossil Fuel Obligation (NFFO). Base on NFFO, the Public Electricity Suppliers (PESs) need to secure the specific amount of electricity production from renewable energy sources. As a consequence, the PESs need to enter into contracts with the Non-Fossil Purchasing Agency Ltd. The target of this policy was to achieve 10% of UK electricity production from renewable energy by 2010. Kettle (1999) said that NFFO had created a competitive environment among the contractors, and that it had driven prices down.

In 2002 renewable obligations (ROs) were started and now the UK also has Renewable Obligation Certificates (ROCs). ROCs require the electricity suppliers to increase the share of electricity production from renewable energy. ROCs can be traded and when the suppliers do not have sufficient ROCs to meet their obligations, they must pay for the equivalent amount. This scheme is called a 'buy-out' fund. Kannan (2009) argued that in the medium term the decarbonisation of power plants depends on two technologies, namely carbon capture and storage (CCS) and renewable energy. The wind generating capacity in UK is expected to reach 20% of the total capacity in the European Union, but it will still be less than that installed in Spain or Germany (Kannan, 2009). The critical challenge for the UK is on investment in transmission capacity from Scotland to England (Kannan, 2009). In the case of the UK, Kannan (2009) proposed two main policies that need to be in place; first, preparing long term policy instruments to achieve the emissions reduction target, such as carbon price signals, accelerated demonstration of CCS, and financial incentives for capital intensive low carbon technology and secondly, promoting demand-side energy efficiency improvement.

Germany introduced a feed-in law in 1991. Further, the Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz / EEG) is believed to be one of the most successful instruments in promoting renewable energies (Lehmann, 2011). The act requires that in 2020, the share of renewable energy sources in electricity supply reaches at least 35% and their share in the total gross final consumption of energy at least 18%. Huenteler, *et al*. (2012) argued that designing renewables policy is subject to a continuous learning and adaptation process. Even now, in Germany, there are three main political challenges that need to be addressed (Huenteler, *et al*., 2012): mounting costs, low R&D intensity (R&D per sales unit), and rising net imports. These problems have resulted in conflicting policy objectives.

In Germany, the feed in tariff / FIT aims to integrate three area of policy (Huenteler, *et al*., 2012): environmental policy, economic policy, and technology policy. Although industrial policy was not explicitly mentioned, according to the Minister of the Environment, FIT provides protection to the local solar industry (Photon, 2012, as cited in Huenteler, *et al*., 2012). Hoppmann, *et al*. in 2011 (as cited in Huenteler, *et al*., 2012) argued that the generous FIT incentivised firms to reallocate resources to new production capacity and, in relative terms, away from R&D. Schroer (2010) and Wetzel (2011), (as cited in Huenteler, *et al*., 2012) said that the FIT was termed a 'failed' industry and technology policy. Huenteler, *et al*. (2012) also argued that market subsidies on renewable energy rather than research funding in Germany appears to have created incentives to favour deadweight effects over long term research.

In 2002, the Japanese government adopted its Basic Act on Energy Policy, with three goals (EIA, 2008, as cited in Duffeld and Woodall, 2011): securing a stable supply of energy, ensuring environmental sustainability, and utilising market mechanisms. In promoting clean energy, the Japanese energy industry has faced challenges from other countries. For example, Japan's solar cell industry, one of the largest in the world, was surpassed in 2008 by those of Germany and China (Duffeld and Woodall, 2011). Further, in late 2009, a Korean consortium out-bid a Japanese nuclear power plant manufacturer to build four nuclear reactors in the UAE (Duffeld and Woodall, 2011).

Since 2003, Japan has implemented a Renewable Portfolio Standard (RPS) and this has become its main renewable energy policy instrument. The power utility companies need to supply a certain amount of power from renewable energy. However, the target was set at a very low level (1.63% of electricity output by 2014) (IEA, 2008 as cited by Moe, 2012). Japan has prioritized its feed-in tariff (FIT) as its main policy. The FIT was introduced in 2009, but as Moe (2008) pointed out it was implemented belatedly and half-heartedly by an institution that does not believe in its usefulness'. Initially, the FIT applied to solar. Bhattacharya and Kojima (2012) argued that the Japanese government needs to pursue a more proactive role in reducing the cost related to the development of renewable energy. Fiscal support and risk analysis for renewable energy needs to be promoted.

According to the Japanese Basic Energy Plan 2010, there is to be a "zero-emission power supply ratio" in 2030. Nuclear power and renewable energy such as wind, solar, and biomass are expected to increase substantially. However, the supply of hydroelectric power will not much change because its potential has already been largely exploited (IEA, 2008, as cited in Duffeld and Woodall, 2011). In addition, the situation has been changed by the Fukushima disaster. According to a recent poll, 85% of respondents are currently in favour of the phasing-out or immediate cessation of nuclear power generation (Moe, 2012). Thomas (2012) said that post the Fukushima disaster, a blend of energy efficiency and renewable energy, will be the key factor in reducing Japan's dependency on nuclear. In June 2011 Prime Minister Naoto Kan planned to increase the share of renewable energy in the power supply to about 20% by 2020, and on August 2011 he also extended the feed-in tariff (FIT)[3] (Huenteler, *et al*. 2012). The new FIT has started in July 2012 and it covered solar photovoltaics (PV), wind power, small hydro, geothermal and biomass (Huenteler, *et al*. 2012).

In June 2011, the Japanese government announced a goal of putting PV systems on 10 million roofs by 2030. There are two reasons why PV has taken on an important role. First, "PV is partly on the inside of the vested interest structure, while wind power is the ultimate outsider and decidedly on the outside" (Moe, 2012). Second, "PV plants are quick to install and they are suitable to fill the current gap between electricity capacity and peak demand around noon" (Huenteler, *et al*., 2012). Following the lessons learned in promoting renewable energy in Germany, Huenteler, *et al*. (2012) provided three main conclusions in respect of by Japan. First, the government needs to minimize the industry interest in the regulatory

[3] According to Huenteler, *et al*. (2012: p7) 'A feed-in tariff guarantees the power producer a fixed electricity purchase tariff for a specified period (often 10–20 years), typically in combination with preferential grid access for the electricity produced.'

process. This is important in order to obtain more effective policy on renewables. Second, the effectiveness of policy learning and refinement is possible if there is a balance of powers and objectives under a political framework. Third, it is important to keep a transparent process in determining FIT. Huenteler, *et al*. (2012) also said that an integrated policy framework that aims to balance energy security, environmental policy, climate policy, and economic and industrial policy needs to be enhanced by government in the long run.

3.2. Developing Country Perspectives

At the 29th ASEAN Ministers for Energy Meeting in September 2011, there was a consensus among the ASEAN member states that a collective target of 15% of renewable energy's share in the region's total installed power capacity by 2015 should be adopted(Suryadi, 2012). However, it seems that there is no mandatory obligation involved. For example in the case of Indonesia, according to Presidential Regulation Republic of Indonesia No 5/2006, the share of fossil fuel, especially natural gas and coal, in the total primary energy mix in 2025 will still dominate.

Accelerating renewable energy utilisation, for instance hydropower, has faced difficult problems especially in the Greater Mekong Sub-region. Hebertson (2012) pointed out that developing the Lower Mekong dams would bring significant social, economic and environmental cost. Development of the Xayaburi Dam, for example, has polarised opinion. Lao PDR and Thailand support the Dam and Cambodia and Vietnam oppose it. Further, Hebertson (2012) pointed out three lessons from the Xayaburi dam. First, energy planning should not take place behind close doors. Second, strategic environmental assessments should become a regular part of energy planning. Third, when advocates say that hydropower is "renewable", more questions are needed about the overall impact of a scheme, for example on downstream water users.

According to the National Energy Blueprint 2005 – 2025, Indonsia had determined 12 milestones of alternative energy, seven of which are renewable energy sources such as geothermal, biodiesel, bioethanol, solar cell, micro-hydro, biomass/waste, and wind. Following the Minister of Economic and Mineral Resources (MEMR) regulation No 02/2010 jo MEMR regulation No 15/2010, and jo

MEMR regulation No 01/2012, PT.PLN (a State Owned Company in the Electricity Sector) focuses on geothermal and hydropower. Currently, the government is attempting to promote pumped storage and hydropower reservoirs to serve peak power demands. Similarly, to enhance rural electrification, several sources of renewable energy can be used such as hybrid PV, hybrid wind, microhydro, and biomass. Government has also developed a research and development programme on thermal solar power, OTEC (ocean thermal energy conversion) and fuel cells.

The Malaysian government has shown strong commitment to the promotion of renewable energy. McNish, *et al*., (2010) said that in 2001, the Malaysian government launched the Small Renewable Energy Production (SREP) Programme. The SREP aimed to achieve 500 MW of renewable energy capacity nationwide by 2005. However in July 2009, there was still only about 43.5 MW of grid-connected renewable power in Malaysia. In 2005, Malaysia and the United Nations Development Programme developed the Building Integrated Photo-Voltaic (BIPV) project (McNish, *et al*., 2010). The goal of this program is to achieve 1.5 MW of distributed solar capacity by 2010 (McNish, *et al*., 2010). Malaysia has implemented several policies to reduce dependency on oil such as (McNish, *et al*., 2010): the Green Technology Financing Scheme (GTFS), the Energy Efficiency Master Plan, the Renewable Energy Policy and Action Plan, and the National Green Technology Action Plan.

According to the 9th Malaysia Plan 2006-2010, the targeted power generation mix in 2010 was: 51% natural gas, 26% coal, 9% hydro, 8% oil, 5% diesel, and 1% biomass[4]. Thus in 2010, the share of renewable energy was to reach about 10%. The Malaysian Sustainable Energy Development Authority (SEDA) has seven functions: (i) to implement, manage, monitor and review the Feed in Tariff system; (ii) to advise the Minister and government entities on all matters relating to sustainable energy; (iii) to promote and implement national policy objectives for renewable energy; (iv) to implement sustainable energy laws, including the renewable energy act, and to recommend reforms; (v) to promote private sector investment in the sustainable energy sector; (vi) to promote measures to improve public awareness;

[4] SEDA was established on 1 September 2011 under the SEDA act 2011.

and (vii) to act as a focal point on matters relating to sustainable energy and climate change matters relating to energy. There are five strategic thrusts of national renewable energy policy: (i) introduction of legal and regulatory frameworks; (ii) provision of a conducive business environment for renewable energy; (iii) intensification of human capital development; (iv) enhancement of renewable energy research and development; and (v) create public awareness and renewable policy advocacy programmes.

According to Indonesian Energy Law No 30/2007, Indonesia also has a similar organisation to SEDA, namely the Dewan Energi Nasional (National Energy Council). The National Energy Council has four main tasks. First, designing national energy policy that can be guided for government before it is approved by the parliament. Second, stating the general plan of national energy policy. Third, determining steps to measure the energy crisis. Fourth, monitoring and evaluating the implementation of energy policy across the sector.

In terms of renewable energy law, Malaysia is one step ahead of Indonesia. On April, 27th 2011, a renewable energy act was passed in Parliament. The act consist of 9 main elements, namely: (i) preliminary; (ii) FIT system; (iii) connection, purchase, and distribution of renewable energy; (iv) Feed in Tariff; (v) renewable energy fund; (vi) information gathering powers; (vii) enforcement; (viii) general; and (ix) saving and transitional. To follow up the act, the government produced 11 subsidiary regulations in the same year.

Both Indonesia and Malaysia have issued a feed in tariff policy. The Indonesian government has determined the feed in tariff for renewable energy based on the Ministry of Energy and Mineral Resources Regulation (MEMR) No 4/2012. There are two main elements of feed in tariff. First, PT. PLN must buy electricity and excess capacity from renewable energy producers. Second, the price is fixed without negotiation and approval from the Ministry of Energy and Mineral Resources. PT. PLN can buy the electricity above the feed in tariff, based on its own evaluation, but it has to obtain approval from the Ministry.

This regulation applies to renewable energy projects with capacity below 10 MW. There are four main areas of renewable energy, namely renewable energy in general, biomass and biogas, city waste (zero waste) and city waste (sanitary landfill). The feed in tariff not only depends on type of renewable energy but also type of connection and region. Outside Java such as in Maluku and Papua, government provides increased incentive by increasing the F- value.

In December 2011, the Malaysian government applied a feed in tariff to four types of renewable energy (biogas, biomass, small hydro, and solar PV) [5]. There are two types of FIT, known as basic and bonus. In the case of biogas, the basic FIT depends on capacity. The FIT rate increases when the capacity decreases. The capacity ranges between 4 MW and 30 MW. The bonus is added to the basic rate if the renewable energy installation fulfills one of the following conditions: gas engine technology with electrical efficiency of above 40%; use of locally manufactured or assembled gas engine technology; and use of landfill or sewage gas as fuel source. In the case of biomass, the feed in tariff is provided for capacity between 10 MW and 30 MW. The bonus rate is provided when at least one of the following conditions exists; use of gasification technology, use of steam based electricity generating systems with overall efficiency above 14%, use of locally manufactured or assembled gasification technology, and use of municipal solid waste as fuel source.

In the case of small hydropower, there is no bonus rate and an FIT applies when the installed capacity is between 10 MW and 30 MW. Finally in the case of solar PV, a basic renewable energy installation is between 4 kilowatts and 30 MW. Bonus on FIT will be provided when one or more of the following criteria is met: used as installations in buildings or building structures; used as building materials; use of locally manufactured or assembled solar photovoltaic modules; use of locally manufactured or assembled solar inverters. The effective period (commencing from the FIT commencement date) is also different among the type of renewable energy. For example the effective periods for biogas, biomass, hydropower, and solar PV are 16 years, 16 years, 21 years, and 21 years respectively. Up to 31 October 2012, according to the chairman of SEDA, in 2012, SEDA allocated 2,000 solar rooftop programmes and in 2013, SEDA will increase the allocation to about 10,000. This programme aims to boost public investment in solar power systems. The programme

[5] To finance the FIT policy, the Malaysian government provided US$ 60.4 million to its renewable energy fund, but the fund needs to pay this back (Green Prospect Asia, 2012). Because there is no subsidy for FIT and no additional cost to tax payers, the government adds 1% additional tariff for consumers who consume 300kWh or above (Green Prospect Asia, 2012).

runs as follows: maximum 12 kWper application, each individual maximum submit 2 applications, and application send thorugh e-FiT application online system. Green Prospect Asia (2012) mentioned four key challenges that need to be addressed by the Malaysian government: (i) sustaining funds to support FIT; (2) managing the mix of new and mature RE technologies; and (iii) providing adequate infrastructural and other support for continued renewable energy growth.

The Indonesian Renewable Society (METI) suggested that the Indonesian government provide not only FIT in to promote photovoltaic generation (PV), but also fiscal incentives. Generally speaking the proposed FIT for PV is generous. For example, FIT for PV for all capacities is about 35 US cents /kWh for the first 10 years and about 13 cents /kWh for the next 10 years. Further, if the PV module uses at least 40% of local content, the FIT rises to 40 US cents /kWh. METI urges four actions from government, namely: a free tax for PV that produces locally, duty free and free tax for PV components (e.g. EVA and glass), free tax for independent power producers (IPP) that can develop PV, and fiscal incentives for consumers substituting PV in place of fossil fuel.

Thus, comparing the criteria for FIT in Indonesia and Malaysia, it seems that both countries attempt to enhance their supply chains by promoting domestic labour absorption, creating backward and forward linkage to local industries. However, setting the level of FIT is still a big issue. Failure to take account of externalities such as environmental and social cost can lead to wrong directions in the future path of renewable energy.

In Indonesia, there are three major sources of funds for new power investment. These are the State's official funds, PT.PLN's self financing and foreign funds. Foreign funds result from issuing obligations (bonds), multilateral loans such as IBRD and ADB and bilateral loans from JICA, AFD, and China. PT.PLN has utilized "green funds" from the Clean Development Mechanism and voluntary carbon mechanism. Because the financial condition of PT.PLN depends on the margin of public service obligation (PSO), it has a limited capacity to obtain loans. The margin of PSO depends on government subsidy for the electricity tariff. We also argue that lack of investment may affect the Indonesian government's capacity to develop infrastructure such as a grid connection between Indonesia and Malaysia (see Box 1) and there is also uncertainty in the stability of power purchase.

BOX 1

According to PT.PLN's business plan 2009-2018, in the area of Kalimantan PT.PLN plans to buy (import) electricity from SESCo. An interconnection between Sarawak and West Kalimantan will be constructed with transmission at 275 kV. The transmission is designed to supply electricity at 200 MW capacity. SESCo is connected with Benkayan's system in Indonesia and Mambong in Sarawak-Malaysia. Indonesia has responsibility for construction of a 180 km transmission line between Benkayan and Malaysia's cross border and inter bus transformer (IBT) at 250 MVA. A power trading or energy exchange will be started in 2015. From the Indonesian perspective, there are two benefits of power trading. First, it can support the steam coal (peat steam) project– Pontianak 1, if the project is delayed due to environmental constraints. Second, power trading can increase the power reserve that is necessary to improve system security. Furthermore, Indonesia can also sell electricity to SESCo. Electricity trading will be promoted under the independent power producer (IPP) scheme. The document indicates that power trading will be started in 2015 with capacity of 50 MW until 2018. As seen from the table, in 2015 West Kalimantan will buy about 34% of its total electricity balance from SESCo. However, the share will tend to decrease and will be below 10% between 2019 and 2021.

Energy Balance in West Kalimantan (GWh)

Year	PT.PLN	SESCo	Total	Share of SESCO to total (%)
2012	1,374	0	1,374	0
2013	1,725	0	1,725	0
2014	1,993	0	1,993	0
2015	1,443	733	2,176	34
2016	1,798	727	2,525	29
2017	1,970	737	2,707	27
2018	2,141	738	2,879	26
2019	2,833	227	3,060	7

2020	3,162	142	3,304	4
2021	3,250	317	3,567	9

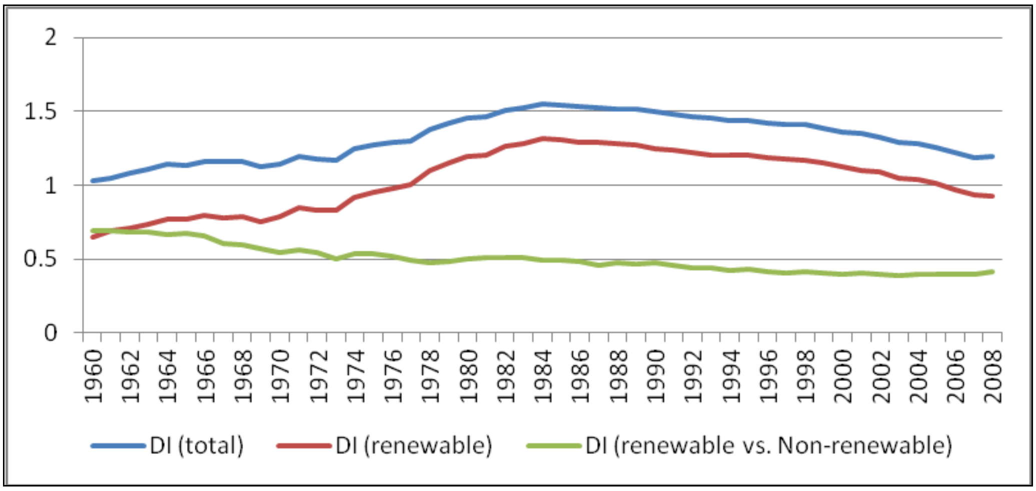
Source: PT.PLN's Business Plan 2012-2021

4. Diversity of Power Generation and Future Path of Renewable Power Generation

4.1. Diversity Index

As seen from Fig. 1, between 1960 and the mid 1980s the diversity index (DI) in the group of countries listed below the figure tended to increase, but after that it decreased gradually. This indicates that electricity production concentrated only on certain types of fossil fuel. The renewable vs. non renewable DIs show that electricity production from renewable energy tends to decrease.

Figure 1: Diversity Index



Note: Countries - Brunei Darussalam, Cambodia, Indonesia, Malaysia, Myanmar, the Philippines, Singapore, Thailand, Vietnam, Australia, China, India, Japan, Korea Rep., New Zealand.

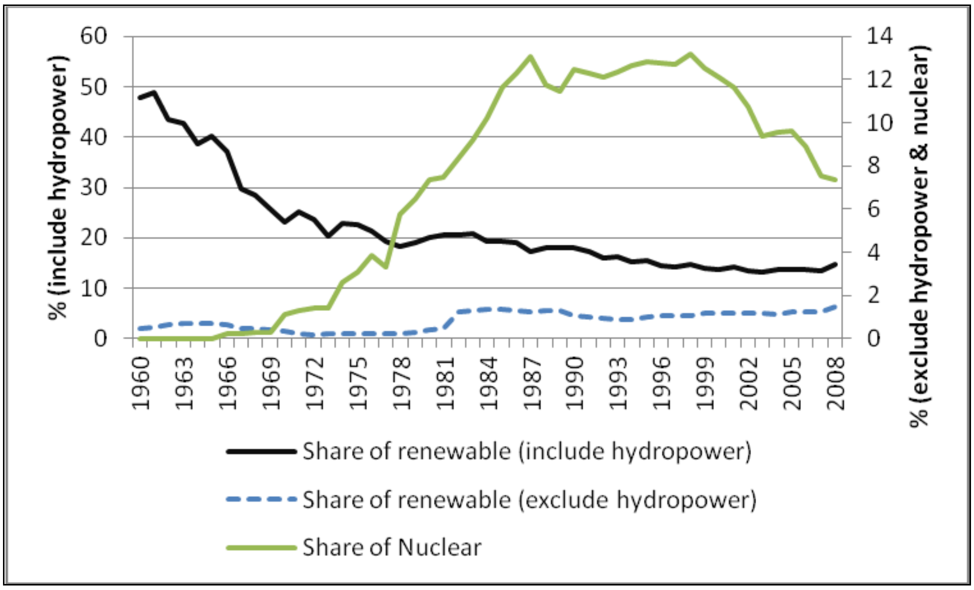
Table 2 indicates that the diversity index between 1990 and 2008, in seven countries, decreased substantially. These were Thailand, Malaysia, China, Japan, Myamar, Australia, and Korea. In Vietnam, New Zealand, Cambodia, Singapore, Indonesia, India, Brunei Darussalam and the Philippines an increasing trend can be seen. Thus we can conclude that because most EAS countries tend to become less diverse in their power systems, the diversity index in the EAS region tends to decrease.

Table 2: Diversity Index by Country

Year	**Brunei Darussalam**	**Cambodia**	**Malaysia**	**Myanmar**	**Singapore**
1980	0.064	NA	0.731	1.325	0.000
1990	0.053	NA	1.469	1.324	0.000
2000	0.052	0.000	1.003	1.303	0.495
2008	0.054	0.305	1.105	1.213	0.510
Year	**Thailand**	**Japan**	**Australia**	**China**	**Korea, Rep.**
1980	0.841	1.638	1.137	1.291	0.909
1990	1.496	1.799	0.974	1.111	1.483
2000	1.270	1.724	0.846	1.005	1.340
2008	1.106	1.734	0.938	0.988	1.251
Year	**Indonesia**	**Vietnam**	**Philippines**	**India**	**New Zealand**
1980	0.825	1.341	1.217	1.316	1.012
1990	1.471	1.237	1.459	1.247	1.148
2000	1.641	1.412	1.553	1.241	1.254
2008	1.580	1.448	1.700	1.284	1.410

We investigated the share of renewable source from the 16 member countries of the East Asia Summit region. (EAS). As seen from Figure 2, the share of renewable energy (including hydropower) decreased substantially between 1960 and 2008 from about 50% to about 15%. We also see that the share of renewable energy increased marginally from about 0.5% in the 1960s to about 1.5% in 2008. This indicates that development of renewable energy in the EAS countries has lagged behind the situation in the 1960s. We also see that that the share of nuclear power increased rapidly, peaking at about 13% in 1987. Then it decreased to about 7.4% in 2008.

Figure 2: Share of Electricity Production from Renewable Energy and Nuclear



Although the share of renewables has decreased substantially, the average CO2 emissions per kWh from electricity generation decreased (Table 3). Between 1990 and 2010, the average emissions from the 9 ASEAN countries (except Lao PDR) decreased from 652 grams of CO2 per kWh to about 581 grams or by about 11%. However, some countries have not been able to reduce their emissions intensity, such as Indonesia, Malaysia, and the Philippines. Between 1990 and 2000, the average emissions intensity in China and India increased by 4.7%, but between 2000 and 2010, it decreased by about 6%. In the case of developed countries, the emissions intensity increased between 1990 and 2010, but it slightly decreased between 2000 and 2010. We can see that in the case of Indonesia, Malaysia and the Philippines, although the diversity index tended to increase between 1990 and 2008, the emissions intensity tended to increase between 1990 and 2010 (see Table 3 and Table 4). Thus more diverse electricity output does not necessary lower emissions intensity. This is because, despite the increasing diversity in power supply, there is still a substantial bias towards fossil fuel such as coal and natural gas.

Table 3: CO2 Emissions per kWh from Electricity Generation

No	Country	1990	2000	2010
1	Australia	817	853	841
2	Japan	435	402	416
3	Korea	520	529	533
4	New Zealand	109	165	150
5	Brunei Darussalam	924	795	798
6	Cambodia	NA	834	804
7	India	812	920	912
8	Indonesia	679	654	709
9	Malaysia	677	495	727
10	Myanmar	510	457	262
11	Philippines	341	493	481
12	Singapore	908	762	499
13	Thailand	626	567	513
14	Vietnam	552	427	432
15	China	894	865	766
	Average (15 countries)	629	615	590
	Average (9 ASEAN countries)	652	609	581
	Average (8 ASEAN countries, exclude Singapore)	615	590	591
	Average China & India	853	893	839
	Australia, Japan, Korea, and New Zealand	470	487	485

Source: Calculated from IEA database, 2012.

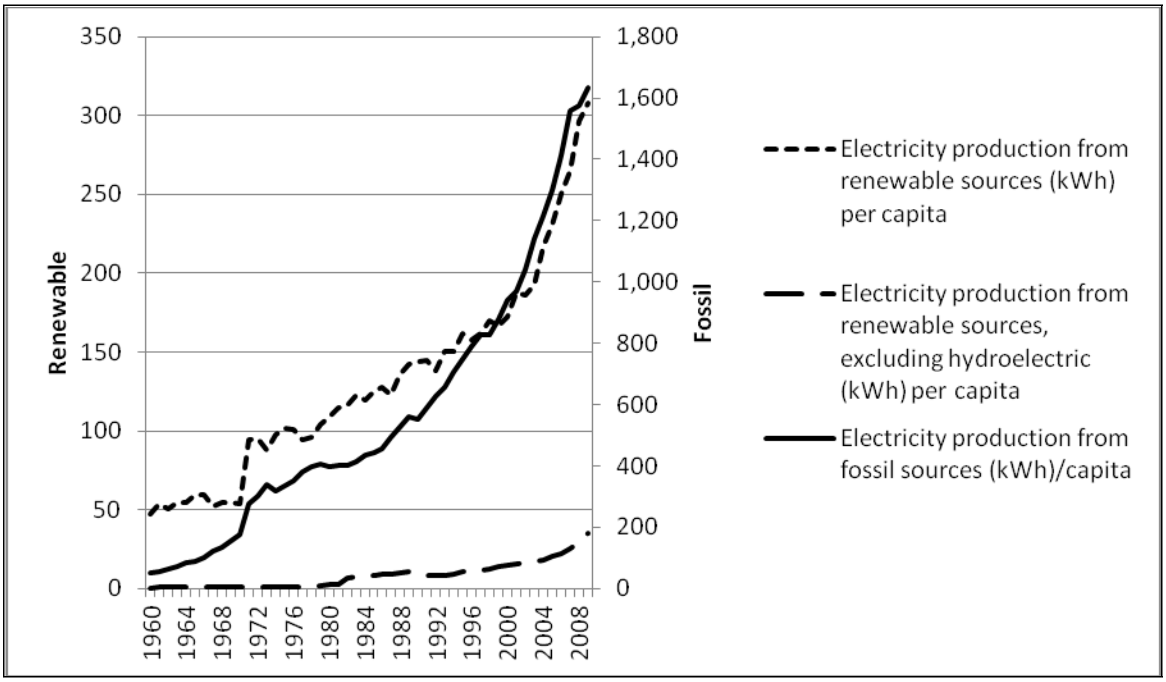
4.2. ARMA and Markov Models

We developed the ARMA and Markov models to analyze two patterns of diversity index. We selected Malaysia and Japan for their decreasing trend; New Zealand, the Philippines, and Indonesia to represent increasing trends.

Historical data leads to two main findings: (i) decreasing trends in energy diversity; and (ii) decreasing shares of renewable energy. Even in the future, the ARMA and Markov models confirm that the share of electricity production from hydropower will tend to decrease while the share of renewable energy (excluding hydropower) will increase marginally except in New Zealand (for detailed information please refer to the Appendix). This implies that there is risk of lack of energy diversity and a carbon lock situation among the 16 member countries of the EAS. The models also indicate that clean fossil fuel such as natural gas and oil will become less important. In some countries, such Indonesia, Malaysia and the Philippines, the share of oil will even fall to zero. However, due to lack of natural gas infrastructure and the relatively high cost of LNG, coal is the best substitute for oil. Thus, carbon intensity (tonCO2/MWh) will become difficult to control.

As seen from Figure 3, the historical data indicate that electricity consumption per capita from renewable energy increased from about 47 kWh/capita to about 308 kWh/capita about 6.5 times. However, electricity consumption from fossil fuel increased much faster than from renewable sources, from about 51 kWh/capita to about 1,635 kWh/capita. This indicates development of renewable energy was lagging far behind the growth in use of fossil fuel.

Figure 3: Electricity consumption per capita (1960 – 2009)



Source: Calculated from World Development Indicators

Although the Markov model is very sensitive to the assumptions of transitions among the energy sources, we highlighted three main findings. First, the share of renewable energy can increase significantly in the future if there is a consistent policy for promoting it. Thus, it is important to increase gradually share of renewable energy. Second, the share of renewables can increase if there is a commitment to reduce the share of fossil fuel and provide more opportunity for renewable energy to substitute oil, for example. Third, because the share of coal will tend to increase in the future, it is necessary to determine a minimum standard of permissible steam coal technology, such as ultra-supercritical.

5. Conclusion

Renewable energy must be part of any sustainable energy mix. Promoting renewable energy needs to enhance value added and reduce greenhouse gases emissions. European countries can provide lessons on how to promote renewable energy. Germany is a pioneer of climate protection and is urging a 30 per cent reduction in EU GHG emissions. Germany has implemented both command-and-control and market-based policies to promote the share of renewable energy in its power system. Formulating policy on renewable energy is a continuous learning and adaptation process. This is because an energy policy has multidimensional impacts on environmental, economic, technological, and industrial policy. Thus in formulating renewable energy policy, there can be no “one size fits all” policy. Germany also realizes that a too-generous FIT policy, rather than investment in research and development has a negative impact on long term research incentives. The objective of FIT needs to be clearly addressed, especially how to encorporate FIT policy in promoting industrial and technology policy. The general conclusion indicates that FIT should be close enough to the market price.

The effective implementation of a Renewable Portfolio Standard (RPS) needs strong political will from government. Setting up a reasonable target for renewable energy is important. Too low a target can reduce programme credibility while too ambitious a target indicates too many unsolved national energy problems. It is thus important to increase the share of renewable energy gradually (by very small amounts), instead of taking a “big bang” approach. This approach will provide a more realistic way of increasing capacity in areas such as such as human resources and institutional arrangements.

The comparisons between Indonesia and Malaysia indicate similarities with developed countries in certain policy areas, such as FIT. Both Indonesia and Malaysia have done their best to promote renewable energy in their power systems. Both Indonesia and Malaysia have published indicative targets on the shares of renewable energy in their future primary energy mixes. They have also both implemented FITs, but have different schemes. We indentify three major differences between the two countries. First, Malaysia has a higher upper bound of renewable energy capacity limit, at 30 MW, while in Indonesia the limit is about 10 MW. Second, incentive formulation is different, such as in bonus formulation in the case of Malaysia and regional incentives in the case of Indonesia. Third, Malaysia has implemented its renewable energy act and therefore has a mandatory obligation to increase the usage of renewable energy, while Indonesia does not have such an act. Further, SEDA has the highest authority to execute the regulations in Malaysia, and to promote development of renewable energy. In Indonesia, the National Energy Council shares similar functions with SEDA.

Although renewable energy has been promoted among the member countries of the East Asia Summit (EAS), the diversity index indicates that growth of electricity production from fossil fuel has grown much more than renewable energy. According to historical data, the primary energy mix in power supply has become less diversified and the share of renewable energy has tended to decrease. Some countries, such as Indonesia, the Philippines and Japan, have used coal more intensively rather than grow renewable energy.

Both the ARMA and Markov models indicate that, in the future, the share of electricity production from renewable energy will tend to decrease, especially the share of hydropower, while the share of renewable energy (excluding hydropower) will increase marginally. The two models confirm that fossil fuel will remain the backbone of power systems (except in New Zealand). Thus facilitating the penetration of renewable energy into the power system needs to be further discussed among EAS members.

6. Policy Recommendations

This study shows that encouraging the penetration of renewable energy into the power system depends on five main components. First, it is important to enhance the renewable energy policy dialogue between developed and developing countries. Because most developing countries are in the early stages of implementing a renewable portfolio standard and feed in tariff, it is important to frame the multidimensional aspects of energy policy in the context, for example, of industry, trade, research and development policy. Developing countries can benefit from the prior experience of their developed neighbours.

Second, financing of new power generation will become a major obstacle. Most new power investment depends on non state funds or unsustainable sources. Thus renewable energy investment needs to be economically sound. Further, it is also important to share the best practices in sharing the FIT in the region. However, failure to consider externalities and providing fossil fuel subsidies have eroded the competitiveness of renewable energy. Further, macroeconomic instability has driven interest rates up and led to shorter loan tenors and higher equity requirements. Next, government interventions in state electricity companies, such as in pricing policy, lead to a lack of investment funds from the companies' own resources. As a result, it becomes difficult for developing countries to diversify their energy mixes toward renewable energy. Thus there is a renewable energy "trap" in many developing countries. Cooperation in research and development needs to be enhanced in order to reduce the investment cost of renewable energy. Revolution on information-communication-technology (ICT) can be of the models in developing renewable energy in the future.

Third, every country has a different capability in the area of renewable energy. This depends on endowment factors and energy policy. For example, in the case of Indonesia and Malaysia, it may be possible to reach a 30% target in the 2040s while in the Philippines the same taget can be attained in 2020. However, there are still many risks and uncertainties in reaching this target.

Fourth, demand-side management can reduce pressure on new power investment that will be supplied mostly by steam coal power plant. Further, demand-side management will also provide more time for renewable energy to be more competitive. Thus it is important to increase the level of knowledge of how to use energy effectively.

Finally, we suggest that the trilogy of green power system dialogue among the EAS members be enhanced in addressing the issues of: (1) improving the diversification ratio; (2) increasing the share of renewable energy; and (3) reducing emissions intensity. The trilogy dialogue aims to set three kinds of targets: (1) renewable energy targeting; (2) intensity targeting (kgCO2/kWh); and (3) renewable energy consumption per capita (kWh/capita).

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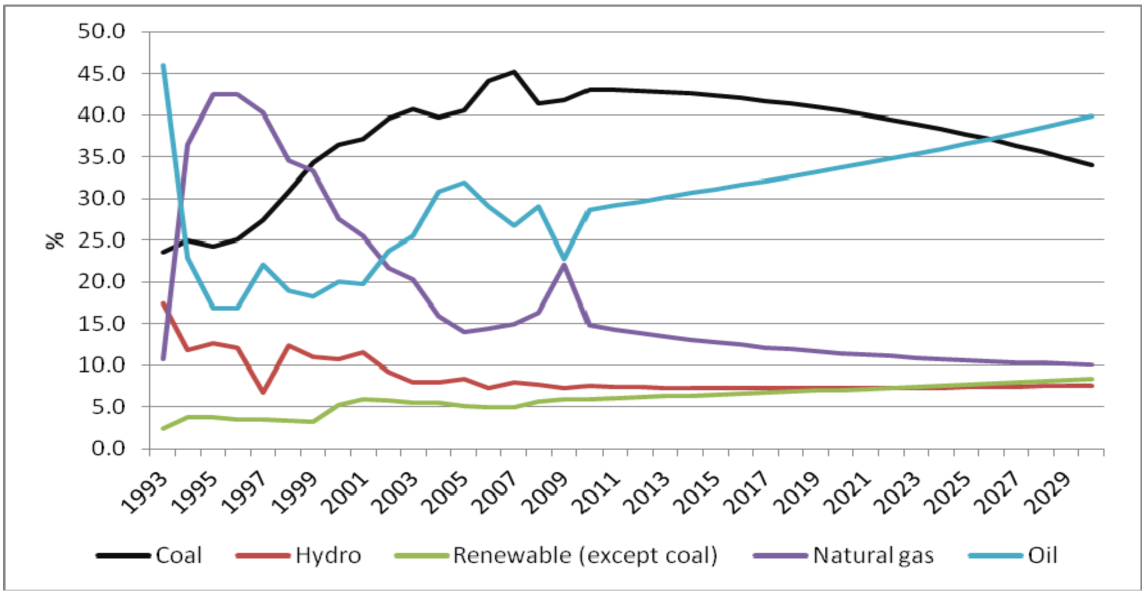
Appendix

1. Indonesia

Figure A1: Share of Electricity Production by sources (1993 – 2030) in Indonesia



Note: Results from ARMA model

Table A1: Change in Share between 1998 and 2009

	Share (%)		
Electricity production	1998	2009	Author's assumption
Hydroelectric	12	7	8
Renewable	3	6	7
Coal	31	42	46
Natural gas	34	22	21
Oil	19	23	18

Note: Author's assumption indicates the situation that is possible to achieve in the medium term

Table A2: Share of Electricity Production by Sources

Year	Hydroelectric	Renewable	Coal	Natural gas	Oil
2009	0.073	0.060	0.418	0.221	0.228
2010	0.083	0.070	0.458	0.211	0.179
2011	0.093	0.077	0.489	0.202	0.140
2012	0.102	0.084	0.513	0.192	0.109
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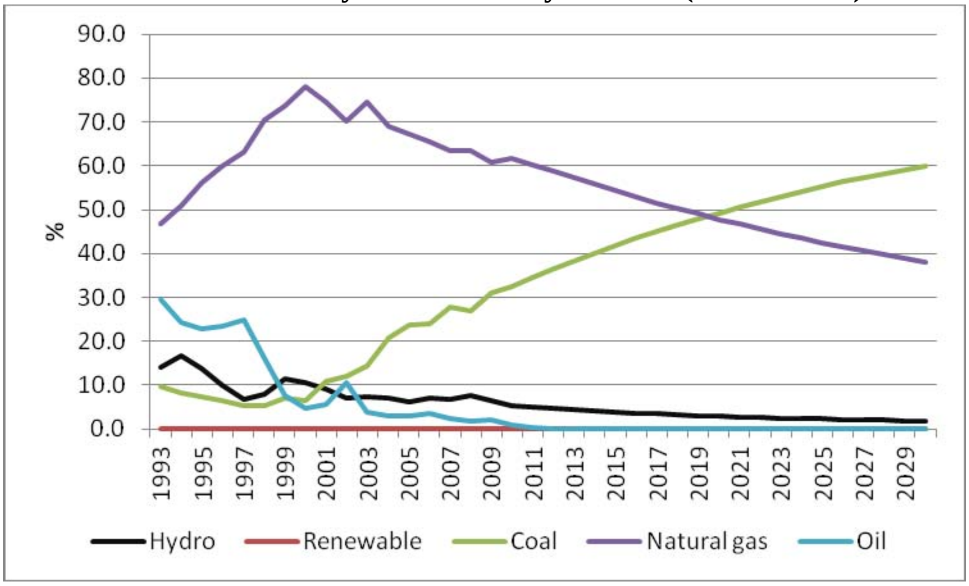
2037	0.233	0.105	0.600	0.061	0.000
2038	0.236	0.105	0.600	0.058	0.000
2039	0.239	0.105	0.600	0.056	0.000
2040	0.241	0.105	0.600	0.053	0.000

Source: Author's calculation from Markov model

2. Malaysia

Figure A2: Share of Electricity Production by Sources (1993 – 2030) in Malaysia



Note: Results from ARMA model.

Table A3: Change in share between 1998 and 2009

Electricity production	Share (%) 1998	2009	Author's assumption
Hydroelectric	10.71	6.35	8
Renewable	0.00	0.00	1
Coal	6.59	30.92	35
Natural gas	77.93	60.73	55
Oil	4.78	2.00	1

Note: Author's assumption indicates the situation that is possible to achieve in the medium term

Table A4: Share of Electricity Production by Sources

Year	Hydroelectric	Renewable	Coal	Natural gas	Oil
2010	0.083	0.010	0.349	0.548	0.010
2011	0.101	0.015	0.385	0.494	0.005
2012	0.118	0.018	0.417	0.445	0.003
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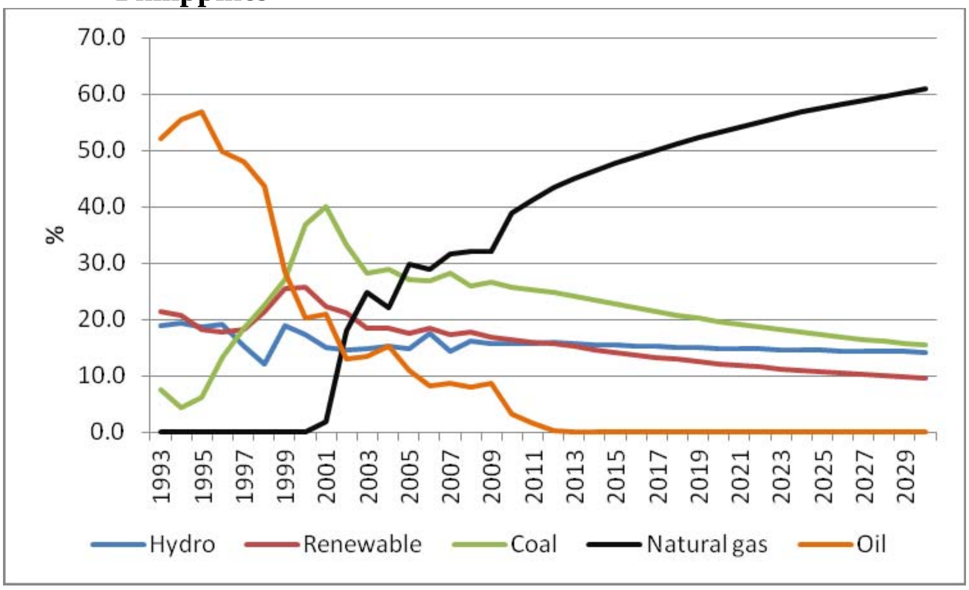
2042	0.259	0.020	0.701	0.020	0.000
2043	0.260	0.020	0.702	0.018	0.000
2044	0.261	0.020	0.703	0.016	0.000
2045	0.261	0.020	0.704	0.015	0.000

Source: Author's calculation from Markov model

3. The Philippines

Figure A3: Share of Electricity Production by Sources (1993 – 2030) in the Philippines



Note: Results from ARMA model

Table A5: Change in share between 2002 and 2009

Electricity production	Share (%) 2002	2009	Author's assumption
Hydroelectric	15	16	17
Renewable	21	17	18
Coal	33	27	30
Natural gas	18	32	33
Oil	13	9	3

Note: author's assumption indicates the situation that is possible to achieve in the medium term

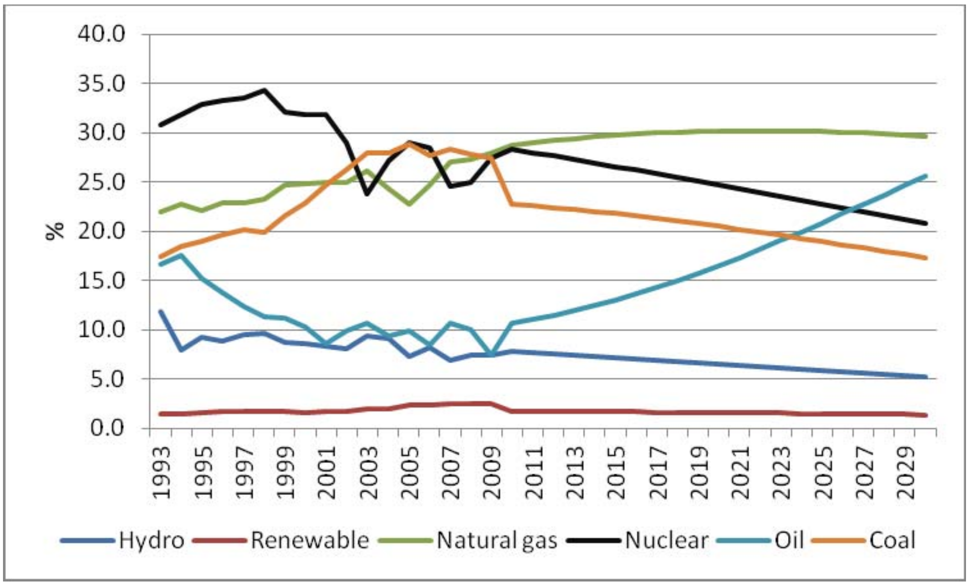
Table A6: Share of Electricity Production by Sources (%)

	Hydroelectric	Renewable sources, excluding hydroelectric	Coal	Natural gas	Oil
2009	15.8072	16.7778	26.6081	32.1167	8.6901
2010	16.7728	17.7434	29.5048	33.0823	2.8967
2011	17.0947	18.0653	30.4704	33.4042	0.9656
2012	17.2019	18.1725	30.7922	33.5114	0.3219
2013	17.2377	18.2083	30.8995	33.5472	0.1073
2014	17.2496	18.2202	30.9353	33.5591	0.0358
2015	17.2536	18.2242	30.9472	33.5631	0.0119
2016	17.2549	18.2255	30.9512	33.5644	0.0040
2017	17.2554	18.2260	30.9525	33.5649	0.0013
2018	17.2555	18.2261	30.9529	33.5650	0.0004
2019	17.2556	18.2262	30.9531	33.5651	0.0001

Source: Author's calculation from Markov model

4. Japan

Figure A4: Share of Electricity Production by sources (1993 – 2030) in Japan



Note: Results from ARMA model

Table A7: Change in share between 2002 and 2010

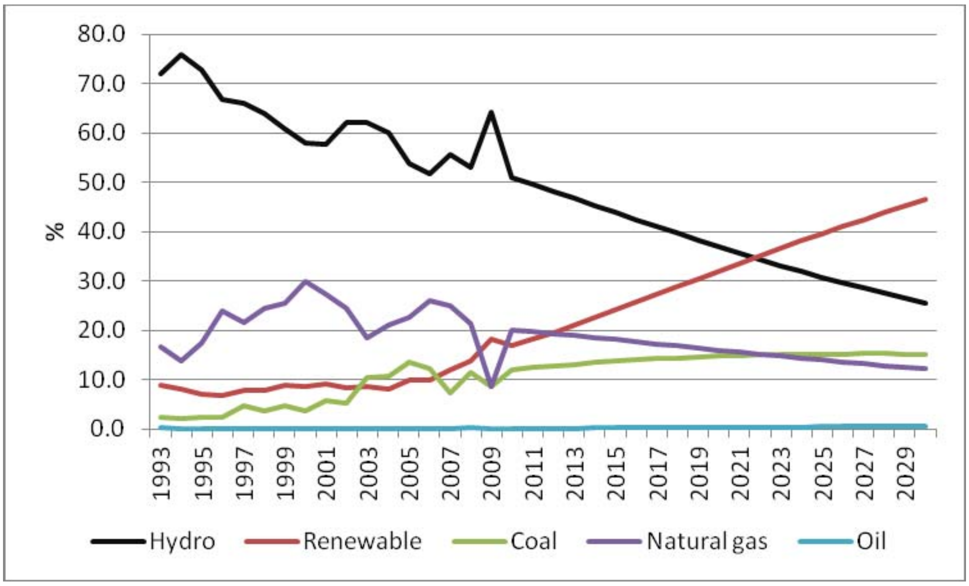
Electricity production	Share (%) 2000	2010
Hydroelectric	9	7
Renewable	2	3
Coal	23	28
Natural gas	25	28
Nuclear	32	28
Oil	10	7

Table A8: Share of Electricity Production by Sources (%)

	Hydroelectric	Renewable, excluding hydroelectric	Coal	Natural gas	Nuclear	Oil
2011	5.506	3.355	31.770	30.255	24.071	5.043
2012	4.283	3.967	35.390	31.768	21.062	3.530
. . . 2043	0.002	6.107	58.257	35.298	0.336	0.000
2044	0.001	6.107	58.299	35.298	0.294	0.000
2045	0.001	6.107	58.336	35.299	0.257	0.000

5. New Zealand

Figure A5: Share of Electricity Production by Sources (1993 – 2030) in New Zaeland



Note: Results from ARMA model.

Table A9: Change in Share between 2002 and 2010

	Share (%)	
Electricity production	2000	2010
Hydroelectric	58	55
Renewable	8	18
Coal	10	5
Natural gas	24	22
Oil	0	0

Table A10: Share of Electricity Production by Sources (%)

	Hydroelectric	Renewable	Coal sources	Natural gas	Oil
2010	55.210544	18.163744	4.619680554	22.0015637	0.00446778
2011	52.3548262	25.162766	2.309840277	20.1681001	0.00446778
2012	49.6468179	30.706369	1.154920139	18.4874251	0.00446778
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2042	10.0909556	88.545576	1.0756E-09	1.35900045	0.00446778
2043	9.56900963	89.180772	5.37802E-10	1.24575041	0.00446778
2044	9.07406086	89.779533	2.68901E-10	1.14193788	0.00446778
2045	8.60471288	90.344043	1.3445E-10	1.04677639	0.00446778

CHAPTER 7

Renewable Energy Development in Cambodia: Status, Prospects and Policies

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The central question of this study is how to accelerate renewable energy (RE) development in Cambodia in a sustainable manner. Based on international experience, setting a national target for RE's share is an essential part in guiding and inducing RE development. The supporting mechanisms of both financial and non-financial policies should be in place to achieve the national target effectively. Currently, the scale of RE deployment in Cambodia remains low, although there has been steady progress. Rather than focusing predominantly on hydropower and coal, the government should increase its efforts on the development of other REs (e.g., biomass and solar), as the vast potential has been under-utilised. The government should systematically expand RE promotion and information to the general public; especially those potential consumers who live in areas where publicly provided electricity is not available. Public financing is needed to aid the private sector to pioneer RE projects, because of the high upfront investment costs and the public bidding process ensures fair competition. Enhancing the data management of the RE industry, adopting a pricing policy, and relevant regulations are also required to build trust in the private sector to invest in RE projects and to integrate renewables based electricity into the national grid.

1. Introduction

Cambodia, officially known as the Kingdom of Cambodia, is located on the mainland of Southeast Asia and is bordered by Lao PDR, Thailand, and Vietnam. With a total population of approximately 15 million, of which approximately 80 per cent live in rural areas, the country is one of the poorest in terms of economic development and electricity accessibility throughout the region.

Cambodia's electricity demand has grown faster than what was projected. The demand has averaged 19.0 per cent per annum (p.a.), which is higher than the previous estimate of 12.1 per cent p.a. (REEEP, 2012). The consumption of electricity per capita has grown roughly seven per cent p.a. over the past five years (Prime Minister, 2013). Nonetheless, this growth rate is not sufficient for such a fast growing economy. Excluding the year 2009, when the economy was affected by the global economic downturn, the average economic growth rate during 2003-12 was 9.0 per cent p.a., according to the data received from the National Institute of Statistics (NIS).

The majority of the people, especially those living in rural and remote areas, still have no access to electricity. By 2011, while almost all the households in Phnom Penh (98.9 per cent) had access to on-grid electricity, only 23.5 per cent of total households in rural areas had access to publicly provided electricity (Prime Minister, 2013).

The diversification of power sources is a critical issue for Cambodia for expanding the rate of electrification and increasing the electricity supply. At present, the supply is constrained in terms of quantity and quality. Power is produced mainly by generators that use costly Heavy Fuel Oil (HFO), diesel, hydropower, and coal, the last two being the minor sources. Instability and inefficiency continue to be concerns for power distribution. These two factors create difficulties for households and businesses in addition to expensive electricity bills.

Cambodia is blessed with an abundance of renewable resources, which have great potential for power production. Situated in the middle of the Greater Mekong Sub-region (GMS), Cambodia contains major rivers and waterways, which are suitable for hydropower development. Given its geographical location, the country is also endowed with wind and solar resources that have not been exploited to generate electricity for industry or household consumption. Moreover, the agricultural sector has annually produced an abundance of residues that are suitable for electricity generation.

The development of Renewable Energy (RE) is a significant solution to accelerate power sector development. The crucial question–how to promote RE development–is vital and needs to be explored. In the context of regionalism, how Cambodia can develop the potential of its renewable resources and contribute to the domestic and regional Energy Market Integration (EMI) is an intriguing question.

Many studies on RE in Cambodia have been conducted, but studies on RE development in the context of regional integration are lacking. This study intends to bridge that gap in the current literature and more importantly; it aims to develop the policy implications for Cambodia's RE development. This study has three main objectives , which include:

- examining the current condition of the RE sector in Cambodia to identify the barriers, challenges, and possibility for RE development;
- examining international experience and using the lessons learnt to develop Cambodia's RE sustainably; and
- deriving policy implications to accelerate RE development in Cambodia and to enhance EMI in the region.

Reviewing the literature on RE development is carried out to create a foundation and to gather the essential data for analysis. Consultation with key informants is conducted to collect primary data, verify secondary data, and to acquire industry insiders' insights. A SWOT (strength, weakness, opportunity, threat) analysis is employed in the study as well.

This study is undertaken with the perspective of accelerating power sector development. RE development is essential for other sectors such as heating, cooking, and transportation. This study, however, focuses primarily on enhancing RE development in order to resolve concerns in the electricity sector.

2. Renewable Energy Development – International Experience

2.1. RE deployment

RE is considered the best alternative for power supply in terms of environmental friendliness and sustainability. RE is essentially produced from such resources as hydropower, wind and solar energy, biomass, biogas, biofuel, solid wastes, and geothermal energy. These resources have their own potential and require different extractive technologies, but they are fundamental in promoting the sustainability of power sector development.

Energy security, environmental concerns, and sustained economic growth are the essential drivers for RE deployment. The International Energy Agency (IEA, 2011a) indicated that RE deployment is driven predominately by energy security, the reduction of CO_2 emissions and environmental impacts, economic development, and innovation and industrial development.

RE development is increasing. Over the last five years, the IEA (2011b) found that the deployment of RE technologies has increased significantly around the world. It is no longer an interest typical of the countries in the Organisation for Economic Co-operation and Development (OECD) but of many other countries as well. China has become a leader in RE deployment.

RE development, however, faces critical barriers. According to the IEA (2011a), obstacles to RE deployment can be classified as techno-economic and non-economic barriers. The non-economic barriers include:

- regulatory and policy uncertainty;
- institutional and administrative issues.;
- the markets;
- finance;
- infrastructure.;
- the lack of knowledgeable and skilled personnel.;
- public acceptance; and
- environmental concerns.

Deployment difficulties are dynamic and vary from country to country. The dynamics relate to the maturity of a particular energy technology, the condition of domestic markets for that technology, and the status of global markets for that technology (Muller, *et al.* 2011).

RE production also requires different kinds of technologies and different levels of technological application, due to the distinctive types of renewable resources and diverse areas. In this regard, RE promotion policy plays an essential role in accelerating renewable technologies (Zhang and Cooke, 2009).

A conducive investment environment plays a crucial role in stimulating RE production. The European Renewable Energy Council (EREC, 2008) found that easing administration and regulation created a favourable environment for businesses and was beneficial to RE advancement.

The government supports RE market businesses through production subsidies that promote electricity generation from renewable resources. These subsidies contribute to the cost of electricity production from renewable resources, through either Production Tax Credit (PTC) or by subsidising the initial capital investment. This has a positive effect on RE production (Doner, 2007).

2.2. RE Policy

Regulators and policy makers have an essential role in promoting and accelerating RE deployment. One of their tasks is to enact policies or regulations that are conducive to RE deployment across the country. The IEA's *Renewable Energy Technology Deployment* (2012) stated that, "policy-makers play a key role in accelerating deployment of RE technologies by influencing near-and long-term planning and investment decisions through government policy."

Favourable policies and a regulatory framework are the underlying basis for diffusing RE deployment effectively. It also creates suitable conditions for the RE market. The IEA (2012a) found that supportive policies and a market framework in OECD countries stimulated a maturing portfolio of RE technologies, which led to an unprecedented expansion of global RE capacity.

Transitioning from a fossil fuel based economy to a renewables based economy requires an inclusive policy that commits the government to certain policy targets and close collaboration with the relevant stakeholders, especially the private sector.

Strong cooperation between policy makers and businesspeople can make the crucial change in the power system both timely and successfully (IEA-RETD, 2012).

Setting the national target for an RE share of total energy consumption is understood as a common policy agenda (EREC, 2008). As of 2009, RE policy targets exist in at least 73 countries worldwide, including all 27 European Union countries, the U.S., Japan, and developing countries such as China and India (Zhang and Cooke, 2009). There are also at least 64 other countries implementing specific support schemes (Pegels, 2009).

Policy action is a necessary instrument for RE deployment, as it is a guide to set the direction and drive the implementation. To accelerate RE deployment successfully, The IEA-Renewable Energy Technology Deployment (2012) proposed six policy acts called ACTION:

- *Alliance building*: Build alliances and reach agreements among policy makers and relevant stakeholders; including industry members, consumers, investors, and others
- *Communicating*: Communicate knowledge about renewable energy resources, technologies and issues to create awareness on all levels, address the concerns of stakeholders, and build up the needed work force
- *Target setting*: Clarify the goals, set ambitious targets on all levels of government, and enact policies to achieve those goals
- *Integrating*: Integrate renewables into policymaking and take advantage of synergies with energy efficiency
- *Optimizing*: Optimize policy frameworks by building on own policies or other proven policy mechanisms and adapting them to specific circumstances
- *Neutralizing*: Neutralize the disadvantages in the marketplace, such as misconceptions of costs and the lack of a level playing field

According to the Renewable Energy Policy Network for the 21st Century (2012), three types of policy devices are available for the government to promote RE development including financial incentives, public financing, and regulatory policies. Financial incentives are comprised of capital subsidies, grants or rebates, tax incentives, and energy production payments. The two financing strategies of public investment are loans or financing and public competitive bidding. Regulatory policies include Feed-in-Tariff (FIT), utility quota obligation, net metering, obligation and mandate, and tradable RE Certificate (REC).

2.3. Incentives for RE Development

Government granted incentives are imperative to promote private sector participation in the RE market because there are high costs and numerous risks associated with initial RE projects. Zhang and Cooke (2009) stressed that successful RE development was derived from the incentives set by central and regional governments. Many such incentives go directly to the developers of renewable energy projects, such as capital investment subsidies, tax incentives, and low-interest loans.

The appropriate arrangement of incentives for developing a functional RE market is an essential prerequisite to foster RE development. The IEA (2012b) emphasized that, "incentives are justified to compensate for market failure." In its sustainability survey of 2011, which interviewed 551 qualified sustainability experts, GlobeScan (2011) found that four out of five experts thought governments should subsidize solar and energy efficiency initiatives to accomplish low-carbon energy.

Incentives for the government to support businesses are justified because there are exorbitant costs for businesses to initiate RE projects. It should, however, be reduced over time once the market has matured. It is also worth noting that different stimuli are required as there are a wide range of renewables at different stages of technological and market development (IEA, 2012b).

To attract financial investments from the private sector for RE development, the government must formulate policies that are beneficial for businesses by incentives and the market environment. Doner (2007) found that to maintain RE growth, government policies should be designed in a way that investors are given incentives to channel their finances into the development of RE technologies.

2.4. Case studies

2.4.1. China

Over the past three decades, China's economy has averaged a growth of more than 10.0 per cent annually. During this strong economic performance, China's energy demand has surged 13.0 per cent p.a., since 2001 and it accounted for 10.0 per cent of the global energy demand. Its share of global energy consumption has continued to rise to over 15.0 per cent, making China the second largest energy consumer in the world (Wang, Yuan, Li & Jiao, 2011).

Renewable energy development is a priority for China to satisfy its ever-expanding energy demands, mitigate CO_2 emission and pollution, and maintain a sustained economic development. Schuman and Lin (2012) pointed out that to further its low-carbon economic development strategy, China needed to enlarge the share of renewable energy in its energy mix. Wang, *et al*. (2011) agreed that expanding the RE share in the energy mix was a way to sustain economic development and reduce the negative effects on the environment and realise the target of reducing GHG emission by 40-45 per cent from 2005.

China aims to achieve a target of 10 per cent of RE of total energy consumption by 2010 and 15 per cent by 2020 (Schuman and Lin, 2012). The mid-term and long-term RE Development Plan 2007-2020 (REDP) also set specific targets of installed capacity for various RE technologies in 2010 and 2020 (Table 1).

Table 1: Installed capacity targets for China's renewable energies

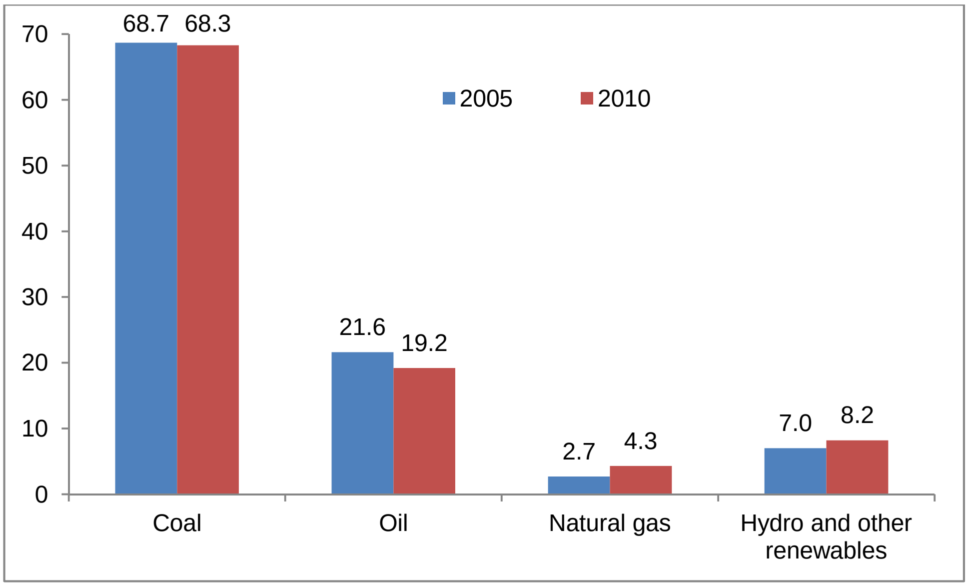
Type	2010	2020
Hydropower	190 GW (50 GW from small hydro)	300 GW (75 GW from small hydro)
Wind power	10 GW	200 GW
Solar PV	0.3 GW	30 GW
Solar water heating (SWH)	150 million m^2	300 million m^2
Biomass power	5.5 GW	30 GW
Bioethanol	3 million tons	10 million tons
Biodiesel	0.2 million tons	2 million tons
Biogas	19 billion m^3	44 billion m^3

Source: Compiled from Fourmeau (2009), APCO (2010), and Schuman and Lin (2012)

The ambitious target of RE's share of total energy consumption was almost met. The RE share in the total energy consumption rose significantly from 7.0 per cent in 2005 to 8.2 per cent in 2010, expanding 1.2 percentage points (Figure 1). The RE industry has developed quickly in recent years as well as the scale of equipment manufacturing for renewable energy. The research and development of industrialisation technology has also experienced a swift expansion (Zhang and Ding, 2012). Given this rapid expansion in RE share of total energy composition since

2006, China is placed among the leading countries in deploying renewable energy (Schuman and Lin, 2012).

Figure 1: China's Energy Consumption in 2010 by Sources (%)



Source: Li (2011).

The Renewable Energy Law (REL) and its associated regulations had a substantial impact on the growth of RE (Schuman and Lin, 2012). China's REL, which came into effect in 2006 and was amended in 2009, is the guiding policy directing RE development. The REL set out specific RE targets; a mandatory connection and purchase policy, on-grid electricity price for renewables, and a cost-sharing mechanism. The defined targets provided the consent to industry (including generators) grid companies, equipment manufacturers, and indicated to government officials at all levels that the central government supported RE development (Schuman and Lin, 2012).

A stimulus program of US $68,724 million was devoted to sustainable energy and released in late 2008 (Fourmeau, 2009). In addition to the feed-in-tariff (FIT) to incentivise investments in REs subsidies (e.g., Golden Sun program and the Building Integrated PV Installation program for solar energy), special funds for project developments are provided for various types of renewable technologies. Given the FIT measure that was announced in late 2009, wind energy has accelerated faster than the government anticipated and has more than doubled each year since 2005 (Schuman and Lin, 2012).

Policy and regulatory framework plays a vital role in promoting the RE industry and in expanding the RE share of total energy consumption. Financial incentives were also crucial to stimulate investments in RE including production, distribution, equipment manufacturing, and technology research and development.

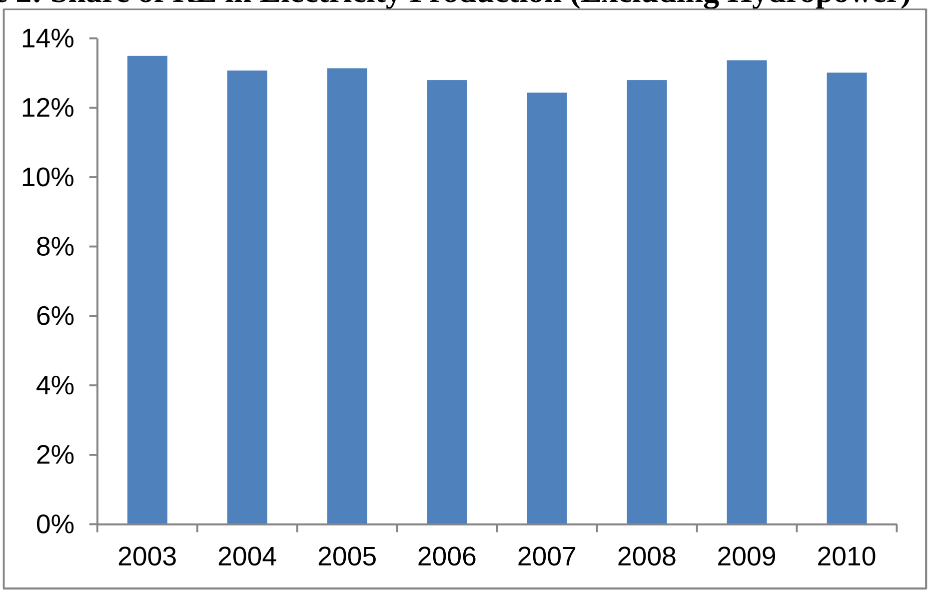
2.4.2. South Africa

South Africa is an emerging economy and a member of the BRICS group (Brazil, Russia, India, China, and South Africa). The economy gained a moderate growth of 2.8 per cent p.a. during 2010-12 after the economy had contracted by 1.5 per cent in 2009 due to the global economic downturn.

With a per capita GDP of US $3,825, electricity consumption per capita was 4,802.5 kWh in 2010 (WDI database, 2013). Although it is a middle-income country, a quarter of the total population remains without access to electricity according to the World Development Indicator (WDI) database.

In response to the global concern of greenhouse gas emission and energy security, the government of South Africa adopted the *White Paper on Renewable Energy* in 2003 to guide its RE development. The target of the policy was to produce 10,000 GWh of electricity from renewables including biomass, wind, solar, and small-scale hydropower by 2013.

Figure 2: Share of RE in Electricity Production (Excluding Hydropower)



Source: World Development Indicator Database (2013)

Winkler (2006) argued that financial support for renewables in the form of subsidies and tax incentives should be considered, but for a limited period.

In 2009, the Renewable Energy Feed-in-Tariff (REFIT) was introduced. With a guarantee of tariff payments for a period of 20 years (Pegels, 2009), the REFIT is, "a mechanism to promote the deployment of renewable energy that places an obligation on specific entities to purchase the output from qualifying renewable energy generators at pre-determined prices."

Edkins, *et al.* (2010) pointed out that, "the REFIT has resulted in a great interest by independent power producers to develop renewable energy projects." The impact of the REFIT program is clearly demonstrated by the instalment of more than 1,100 MW of wind energy, which is under firm development, as well as 500–600 MW of Concentrated Solar Power (CSP) and 0.5 MW from solar PV (Edkins, *et al*., 2010).

Within ten years of implementation, the target of 10,000 GWh by 2013 seemed unrealistic. However, since the announcement of the REFIT, it is conceivable that the renewable energy market in South Africa is set to go. Edkins, *et al*. (2010) projected that South Africa could achieve the set target by 2011 if the REFIT had been introduced into practice earlier than its current phase.

The projection showed that 4,700 GWh could have been supplied from biomass, 1,400 GWh from landfill gas, nearly 2,000 GWh from wind, 2,300 GWh from CSP, and about 100 GWh each from solar PV and small hydropower in 2011 (Edkins, *et al*., 2010).

Though the REFIT seems to be a productive mechanism, it has a crucial flaw. The state owned utilities Eskom is the unchallenged purchaser of electricity from all types of RE projects and responsible for distributing it to consumers. RE investments, however, are not secured because Eskom is not oblighed to buy the electricity produced from those projects (Pegels, 2009).

Consequently, the achievements remain far short of the policy target. Accelerating the implementation of the REFIT is a priority and reforming the existing electricity infrastructure as a means to encourage further investments in RE is required.

3. Cambodia's Electricity Sector Overview

As stated in the National Strategic Development Plan Update 2009-2013 (NSDP), the electricity sector is one of the Cambodian government's development priorities. The government aims to accomplish two policy targets: (1) by 2020, all villages in the country should have access to electricity; and (2) by 2030, at least 70 per cent of total households in the country should have access to quality grid electricity. Achieving these two main targets depends on the utilisation of all types of electricity sources and the participation from relevant stakeholders.

Electricity consumption has expanded significantly during the last decade. Per capita consumption of electricity reached 190 kWh in 2011, increasing almost four-fold from 54 kWh in 2005 (MIME, 2012). Practically all people in urban areas can access electricity from different sources, although price and quality remain crucial concerns. However, only a small fraction of the rural population has been electrified.

Electricity coverage remains low despite the progress that has been made. More than half of the total villages in the country have not been connected to transmission lines. Out of 13,935 villages, only 43.6 per cent have transmission lines in their villages (EAC, 2012b). The electrification rate grew to 34.1 per cent in 2011, which is up from 20.3 per cent in 2007 (MIME, 2012). Yet, more than 60 per cent of the entire population is still has no access to electricity.

Table 2: Electricity Sector in Cambodia at a Glance

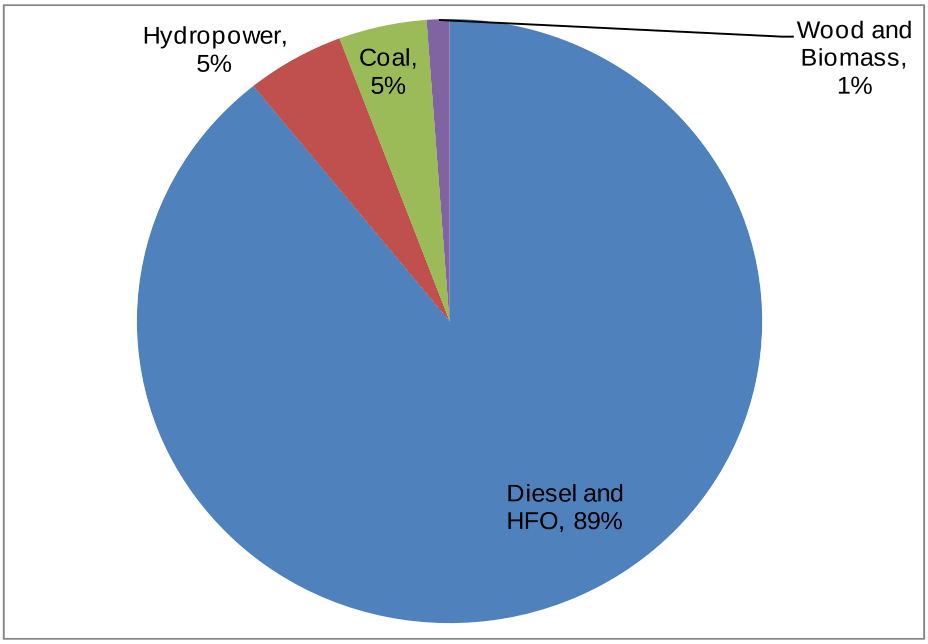
Description	Unit	2010	2011	% Change
Electricity generated	Million kWh	968.364	1,018.540	5.18
Electricity imported from Thailand	Million kWh	385.278	430.790	11.81
Electricity imported from Vietnam	Million kWh	1,155.409	1,392.396	20.51
Electricity imported from Lao PDR	Million kWh	5.749	6.599	14.79
Total electricity import	Million kWh	1,546.436	1,829.786	18.32
Total electricity available	Million kWh	2,514.800	2,848.326	13.26
Generation Capacity	kW	360,078	569,041	58.03
Number of consumers	#	672,709	810,984	20.55
Electricity sold to consumers	Million kWh	2,254.039	2,572.737	14.14
Overall loss	%	10.37	9.68	

Source: EAC (2012a).

Electricity transmission in 2011 was diffused by fragmented grids. A national grid incorporating 68.0 per cent of the total energy input would serve only 48.7 per cent of total consumers. This grid covers only a few areas of the country including Phnom Penh, Kandal, Kampong Speu, Takeo, and Kampong Chnang province. Other grids inputted by local electricity generators and imported from neighbouring countries supplied electricity to other parts of the country.

The installed electricity capacity in 2011 was 569 MW, expanding by more than half of the previous year's capacity due to newly introduced hydropower plants and other power plants. The installed capacity could generate electricity of 1,018.5 GWh. In 2011, electricity was generated from four types of facilities: (1) hydropower plants; (2) diesel power plants; (3) coal-using thermal power plants; and (4) wood/biomass power plants.

Figure 3: Electricity Generation by Types of Sources in 2011



Source: EAC (2012a).

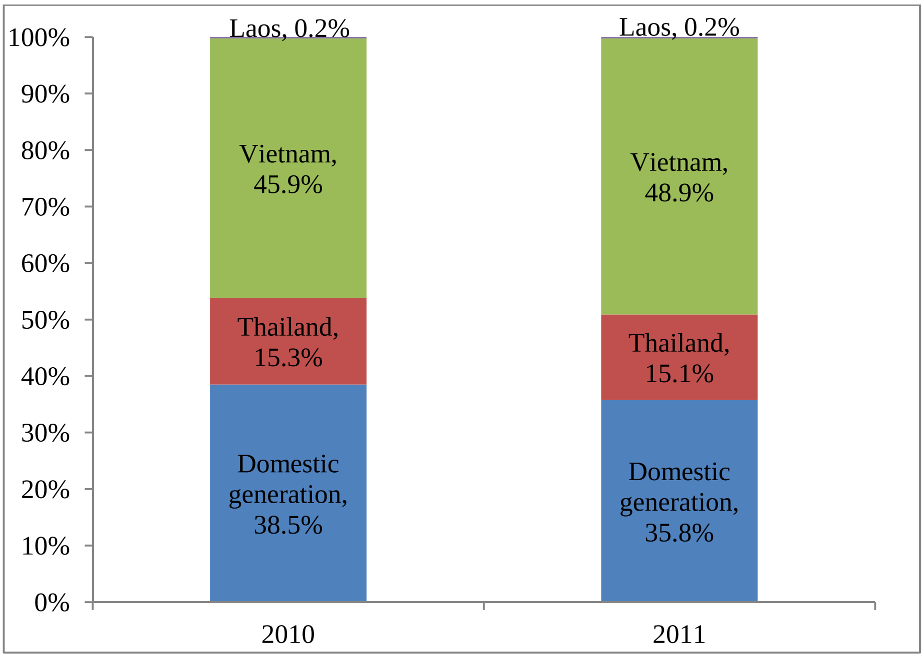
Nevertheless, domestic electricity generation remained substantially below electricity needs. Annual demand within the country grew at an average rate of 19.0 per cent. The demand, however, in Phnom Penh was 25.0 per cent (Jona, 2011). Electricity consumption in 2011 was 2,848.3 GWh, expanding 13.3 per cent from the previous year's 2,514.8 GWh. Given the limited domestic production, electricity is imported from three neighbouring countries, Lao PDR, Thailand, and Vietnam to satisfy the rising demand.

Cambodia is unduly dependent on electricity imports for domestic consumption. Total electricity imports represented more than half of the entire electricity consumption within the country. Based on the data from the Electricity Advisory Committee (EAC), Cambodia is highly reliant on electricity imports from Vietnam and Thailand, which have low electricity consumption in their own territories.

In 2011, Cambodia's total electricity imports expanded by 18.3 per cent, reaching 1,829.8 GWh. This accounted for 64.2 per cent of the total electricity supply within the country. Imports from Vietnam were 1,392.4 GWh and accounted for 76.1 per cent of total imports, while another 430.8 GWh and 6.6 GWh were from Thailand and Lao PDR with 23.5 and 0.4 per cent of the total imports, respectively.

In other words, while the domestic production of electricity was only 35.8 per cent of the total supply in 2011, imports from Vietnam accounted for 48.9 per cent, followed by 15.1 per cent from Thailand, and 0.2 per cent from Lao PDR.

Figure 4: Electricity Supply in the Country in 2010-2011



Source: EAC (2012a).

Cambodia's electricity tariffs are the highest in the region and in the world. The tariffs for industrial consumers range from US ¢11.71-14.63 per kWh and is the most expensive in ASEAN. The high rates of electricity tariffs make Cambodia less competitive in global and regional trade and investments.

The high tariff is because Cambodia’s domestic electricity generation is highly dependent on oil and Cambodia is a net oil importer. Diesel and Heavy Fuel Oil (HFO) remain the main source for power generation, though power sources are quite mixed. Diesel and HFO comprise 89.0 per cent of the total power sources used to produce electricity in 2011 (EAC, 2012a).

Electricity tariffs vary considerably across the country due to the diverse sources of electricity supply. While only a small number of rural households are accessible to electricity, they pay higher tariffs than their urban counterparts. For the EdC grid, which is generally available in urban areas, consumers pay US ¢9-25 per kWh, while consumers in rural areas pay US ¢40-80 per kWh (Lieng, 2010). The differences in tariffs between the urban and rural areas are due to several factors; including different capacities of electricity suppliers, economy of scale, load factor, fuel transportation cost, cost of capital and financing, power supply losses, and high risk premium for rural consumers (Poch and Tuy, 2012).

4. Why Renewable Energy for Cambodia

The lack of electricity is unmistakable and almost two thirds of the total population is without access to electricity. Even the capital Phnom Penh suffers from electricity shortages due to higher than forecasted demand and the slow progress of investment in electricity generation. Electricity outages are quite frequent because the electricity needs to be cut off for a period in some areas to supply other areas. Phnom Penh’s electricity demand in 2012 was 456 MW, while the supply could serve only 412 M, resulting in a deficiency of 44 MW.

Beside expensive tariff rates, electricity provision is not reliable. Diesel and HFO, the only main source of power generation, are imported from foreign countries. This makes electricity tariffs very high and exceedingly volatile, as they fluctuate with the price of imported oils. Due to the unstable supply from diesel and HFO based power plants, old facilities and voltage fluctuations the reliability of electricity supply remains a daunting challenge for the country.

Despite the fact that Cambodia is a low-income country, getting electricity is costly and only a fifth of the total population living in rural areas has electrical access. In addition, rural households spend on average 10.0 per cent of their income on fuel and electricity and have to spend roughly 3-4 hours per day on energy related activities such as collecting fuel wood, boiling water, and cooking (World Bank, 2009).

Electricity security is significantly at risk. Electricity supplies across the country rely predominately on imports from neighbouring countries. Moreover, domestic production, which is generated almost exclusively from diesel and HFO, is exposed to oil price shocks. Therefore, the country's economic activities are particularly vulnerable. More importantly, this situation has a considerable effect on political and social stability. Protests relating to electricity disconnection and tariff increases have been significant.

It is evident that Cambodia's power sector is narrowly based and the diversification of power sources is essential. Various renewable resources can play a key role in tackling the rising electricity demand and extend electricity coverage across the whole country. Furthermore, if they are able to push down the electricity tariffs, more households and businesses would have access to low-cost electricity.

The reduction of fossil fuel imports is critical, at least in the mid-term as long as domestic oil production has yet to materialise. This would lessen the country's vulnerability to oil price crises and maintain a macro-economic stability and sustained growth. Cambodia experienced an extremely high inflation rate of 25 per cent in 2008 due to the global oil price crisis. Moreover, reducing the use of fossil fuel is beneficial for mitigating pollution and the negative environmental impacts.

Climate change is a grave concern for the country's power sector development. The growing consumption of fossil fuels and the higher demand for sufficient energy supplies are a major cause of climate change (Abbaspour and Ghazi, 2013). To address such energy challenges as climate change, the growing demand for energy, and energy security renewable energy requires effective technologies (Zhang and Cooke, 2009). Renewable energy has the potential to mitigate the negative impacts of climate change and CO_2 emissions. It can also lead to a reduction in global warming (Toch, 2012).

Restructuring the power sector is indispensable if a greener growth is to be realised. The Cambodia Green Growth Roadmap and The National Policy and Strategic Plan for Green Growth 2013-2030 were enacted in 2010 and 2013. In order to achieve the envisaged green growth objectives, focusing on the utilisation of renewable resources for electricity generation is required. Furthermore, renewable resource development will help create green investments, jobs, and technologies that are correlated with green growth and environmental sustainability.

5. Analysis on Renewable Energy Development

5.1. Overview

Although Cambodia is endowed with huge potential, the RE share of total electricity production is at present minimal. According to the data compiled by the Electricity Authority of Cambodia (2012a), even including both large and small-scale hydropower and biomass the RE share could reach only 6.0 per cent of the total electricity generation in 2011. If large-scale hydropower (larger than 10 MW) was excluded, the RE share would fall to around 1.0 per cent.

Based on the Rural Electrification Master Plan (REMP), the government is intending to expand the electrification of rural areas through RE in addition to other options. There is, however, no specific target of how much renewable energy will share in the total energy mix by a particular deadline. This unspecified plan might be attributed to a greater focus on hydropower and coal power development.

The deployment of RE technologies remains at a low level and various RE projects are still in the pilot or demonstration stage (Toch, 2012). The people’s acceptance of RE technologies is quite slow due to limited knowledge and inadequate information dissemination.

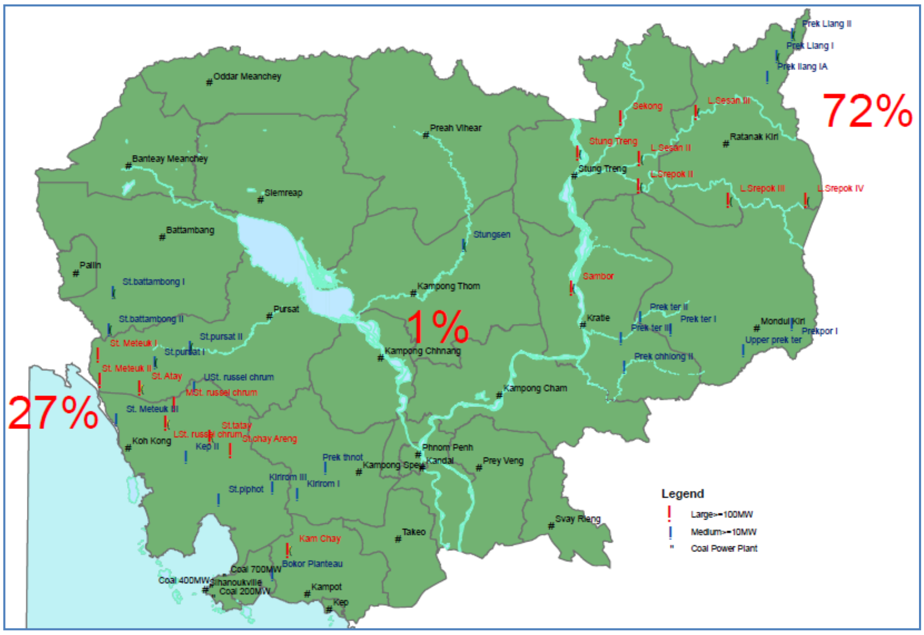
5.2. Renewable Energy Potential and Development

Cambodia has a variety of viable RE resources including hydropower, biomass, biogas, biofuel, solar and wind energy, to address the rising energy demand in the country. The Japan Development Institute (JDI, 2007) projected that if 10.0 per cent of alternative sources replaced imported fossil fuels in power generation, Cambodia would be able to save up to US $30 million by 2020. Nonetheless, these resources are presently underutilised, though hydropower has been progressively utilised.

1) Hydropower

The potential of hydropower is estimated at 8,600-15,000 MW of installed capacity, of which 90.0 per cent is located in the Mekong River basin and its tributaries. The remaining 10.0 per cent is in the southwestern coastal areas (CRCD, 2006b). However, according to the government (Figure 5), prospective hydropower is roughly 10,000 MW, of which 72.0 per cent is located in the northeastern region of the country, 27.0 per cent in the southwestern region, and another one per cent in other regions (Eav, 2011).

Figure 5: Hydropower Development Sites



Source: Eav (2011).

As of now, approximately 220 MW capacities have been installed, while 1,104 MW are under construction according to the data compiled by The Ministry of Industry, Mine and Energy (MIME) and EdC. Therefore, about 10.3 per cent of the total 10,000 MW has been exploited and many other projects are under feasibility studies. Most hydropower projects have been carried out under the Build Operate Transfer (BOT) modelled by Chinese companies.

Electricity demand by 2020 is estimated to grow to around 4,000 MW (Jona, 2011). Seventeen (17) hydropower projects have been proposed for development and they might meet at least half of the total estimated demand. The total capacity of the proposed projects is 4,048 MW, but this capacity is unlikely to deliver its maximum potential.

Hydropower plants' electricity supply is significantly vulnerable to seasonal variations in hydrology, weather pattern, and climate phenomena (e.g., droughts). Cambodia has two seasons, rainy and dry. The former is generally able to provide enough water to run hydropower plants. During the dry season, however, the country is very likely to run short of water for hydropower plants' operations.

The development of large-scale hydropower is indeed risky, not only for the electricity supply itself but also for socio-economic development and environmental sustainability. The alteration of the water flow is anticipated and fisheries production is expected to decline. As a result, the livelihoods of people will be affected. The extinction of species is anticipated due to accumulative impacts of proposed large-scale hydroelectric dams, particularly on the mainstream of the Mekong River (Worrell and Seangly, 2013).

According to the EdC in March 2013, the Kamchay hydroelectric dam, the country's largest hydropower station, was reportedly operating at 10.0 per cent of its total 190 MW capacity due to a water shortage. Because the station served almost half of the electricity supply to Phnom Penh via the national grid, electricity shortages and outages were a recurring problem. This has prompted the EdC to urge big businesses to use their own generators, which are very costly in terms of production and maintenance, to ease the electricity demand from the grid.

2) Biomass

Traditional biomass is composed of wood and charcoal and accounts for about 80.0 per cent of the total energy consumption in the country. It is primarily used for cooking in rural areas and by a small segment of households in urban areas. This has put considerable pressure on forests in Cambodia. Though the dependence on firewood has declined from 90.4 per cent in 1998 to 79.5 per cent in 2010, it remains far behind the national target of 52.0 per cent by 2015 (UNCSD, 2012). Encouraging people to use alternative energy sources (e.g., electricity and liquefied petroleum gas) for cooking is particularly challenging given the fact that almost one-third of the total population remains in poverty and live in rural and remote areas. Other energy sources are expensive and the electrification rate remains extremely low. Wood is also used in biomass combusting gasifiers for electricity generation, but it is not encouraged because it is not a renewable energy.

Rubber trees are also a wood based biomass that can be used for electricity generation. Proper planning is required to use this type of biomass material for power generation sustainably. Jona (2011) revealed that more than 25,000 tons of old rubber trees are available every year and rubber production is on the rise. As of 2011, the total number of rubber plantation regions reached 213,104 ha in which 45,163 ha, or 21.2 per cent, have been tapped (MAFF, 2012). The Ministry of Agriculture, Forestry and Fisheries (MAFF) expects that rubber plantation regions will increase to 300,433 ha in 2020 (MAFF, 2011).

An abundant amount of agricultural residue and the rapid growth of the agro-industry has resulted in growing biomass resources (modern biomass) available for power generation. As an agrarian economy, Cambodia grows many crops–the most important being rice–which produces a considerable amount of biomass materials. Other types of agricultural residues such as corncobs, peanut and coconut shells, and other kinds of plant husks are potentially usable for biomass combusting electricity production.

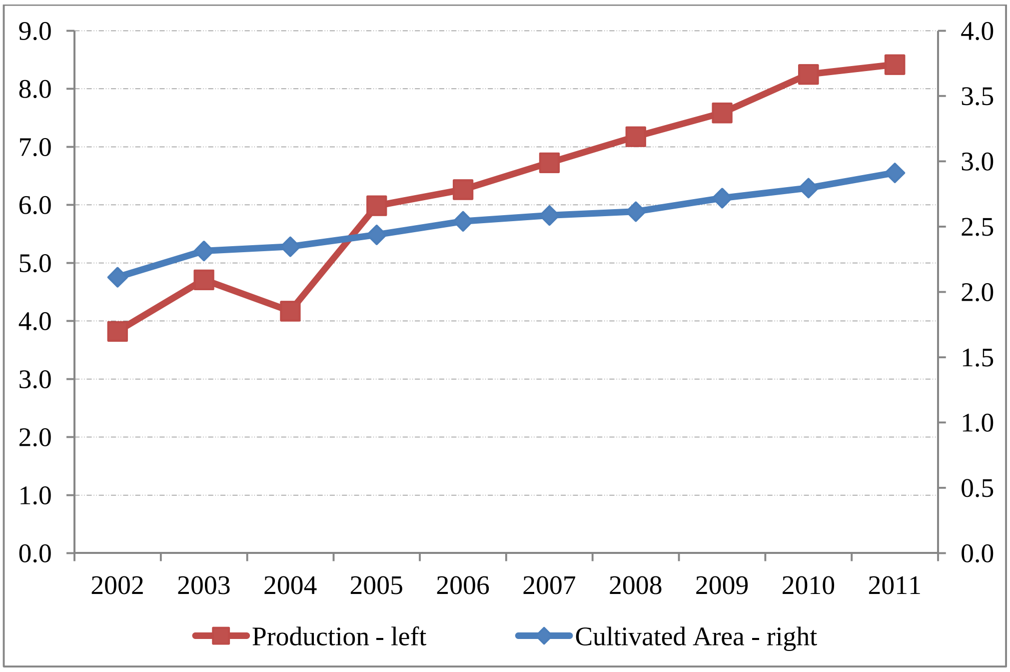
With 8.4 million tons of rice produced in 2011 (Figure 6), roughly 1.8 million tons of rice husks, or about 22 per cent of total rice milled in the country is available for power generation. Approximately 2 kilograms (kgs) of rice husks can generate nearly a kilowatt-hour. The total estimate of rice husks can generate around 924 million kWh of electricity, which is 32.4 per cent of the total electricity supply in 2011.

Although roughly two million tons of rice is exported from the country every year there remains more than one million tons of rice husk usable for electricity generation. Currently, the country exports about 0.2 million tons of milled rice. The government plans to expand milled rice exports to one million tons by 2015; this would require at least 1.6 million tons of rice surpluses after domestic consumption. Consequently, rice husk available for power generation will have to be expanded.

Given the significant potential of reduced production costs and increased savings, biomass combusting gasifiers have powered many industries; including rice milling factories, brick kilns, ice-making enterprises, garment factories, rural electricity enterprises (REEs), and electricity retailers in rural areas. Many rice-milling factories located in Battambang, Kampong Cham, Kampong Thom, Kampong Speu, Kandal, and Takeo province, have started using gasifiers to produce electricity for their own consumption and selling the surplus to households in their communities. The exact number of gasifiers being operated in the country is not available at present. By June 2009, with six suppliers of gasifiers, 126 gasifiers had been installed.

No formal arrangement has been agreed upon as to how the electricity surpluses from these producers are to be sold to the state owned utilities or other electricity wholesale distributors. Producers sell their surpluses through their own small grids or households contribute to the grid extension for electricity connection.

Figure 6: Rice Production (million tons) and Cultivated Area (million ha)



Source: Ministry of agriculture, forestry and fisheries (MAFF).

3) Biofuel

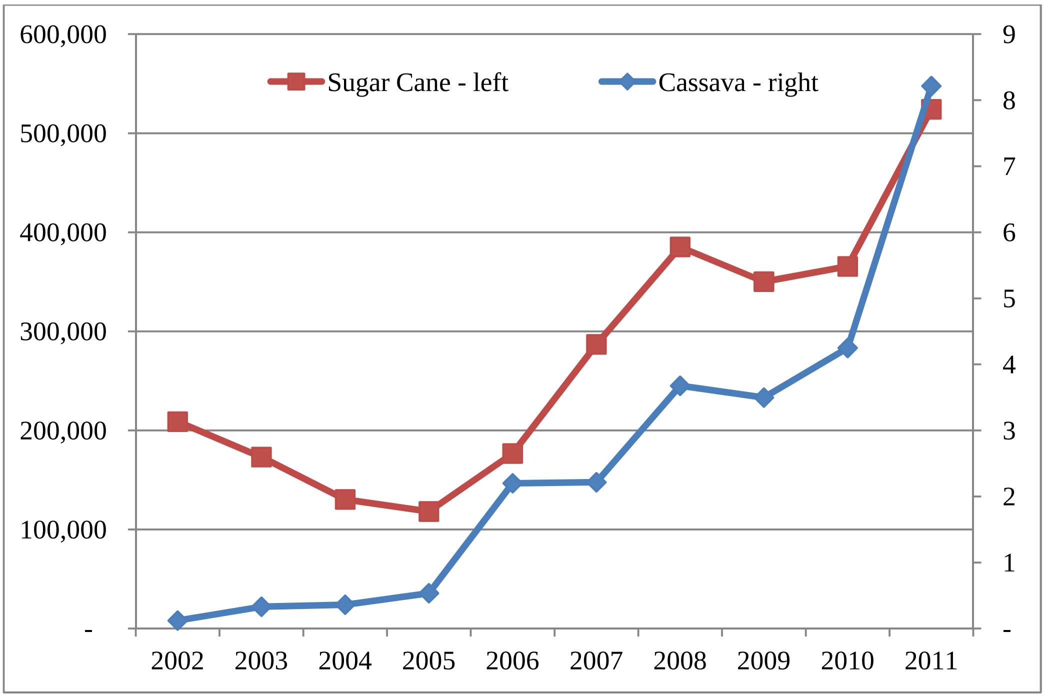
Cambodia has great potential for biofuels to replace fossil fuels and as long as the country prioritises the use of biofuels to meet internal demand over export, economic sectors would be less vulnerable to fluctuations in oil prices (ADB, 2012). A range of agricultural materials such as cassava and sugar cane provide substantial potential for biofuel production.

The JDI (2007) recommended that given its good soil and weather, Cambodia should plant cassava, as it holds considerable potential for biofuel extraction. Total cassava cultivated areas and production has increased rapidly over the last decade. These cultivated areas increased twenty-fold, from 19,563 ha in 2002 to 387,952 ha in 2011 and production expanded to 8.2 million tons, up from 0.1 million tons in 2002.

Cambodia's first ethanol shipment was sent to the European market in late 2008 by a Korean company, the first company to produce ethanol from cassava. Cambodia could export 9,600 tons of ethanol to Europe in 2009 (May, 2009). Ethanol production in Cambodia is primarily for export, because domestic consumption is not considered. Recently, production was not stable because the price of cassava fluctuates significantly, causing difficulties for a company's operation. Ineffective management of the company is largely responsible for this issue. At present, few companies are setting up their ethanol producing operations in the country.

Sugar cane production has also increased rapidly. While sugar cane can be processed into products such as sugar and ethanol, its bagasse is extremely useful for electricity generation. Cultivated areas expanded to 24,103 ha in 2011 and production was 524,126 tons. The total amount of bagasse was approximately 157,238 tons with 30 per cent from sugar cane processing, which can generate roughly 70,757 MW of electricity and was nearly 2.5 per cent of the total electricity supply in 2011. Sugar cane production is dispersed across the country but there is a concentration of production (e.g., sugar cane plantations via land concessions). More importantly, rural areas are more likely to get electrical access because they are located near the sugar plantations. Two plantations have already used sugar cane bagasse to generate electricity for their factories' operations and supply surpluses, although a small amount of power, to local communities. However, there is no policy in place on how the electricity surpluses are to be sold and fed into the national grid.

Figure 7: Sugar Cane (tons) and Cassava (million tons)



Source: Ministry of agriculture, forestry and fisheries (MAFF).

Biofuel production can also be extracted from around 1,000 ha of jatropha and 4,000-10,000 ha of palm oil (So, 2011). These two crops have significant potential for electricity generation using biodiesel in the country. As the price of fuel is on the rise and the current tariff of electricity is expensive, interest in cultivating biofuel or biodiesel to generate electricity is increasing. This is possible over the next 5-10 years, when an adequate electricity supply and a sharp drop of the tariff are not anticipated. A feasibility study was conducted to establish a power plant using biodiesel from jatropha seeds to supply electricity to Cambodia's Phnom Penh Special Economic Zone. How these resources can be extracted for biofuel production and thus electricity generation is not indicative.

4) Biogas

A number of projects have been effective with small-scaled biogas, though they are still in the pilot and demonstration stage. The conversion of waste material (e.g., animal and human waste) into high quality gas for cooking and electricity for lighting can deliver remarkable socio-economic, heath, and environmental benefits for poor and rural households.

A joint development program between Cambodia's Ministry of Agriculture, Forestry and Fisheries (MAFF) and the Netherlands Development Organization (SNV), with the financial support of the Dutch Ministry of Foreign Affairs National Bio-digester Program (NBP), is aimed at establishing a market oriented biogas sector in Cambodia. More than 15,000 bio-digester plants have been installed since 2005 and an additional 23,000 units are anticipated by 2016.

The NBP provides a fixed subsidy of US $150 per unit for all plant sizes. Moreover, farmers who have the technical potential and credit worthiness can get a loan of up to US $1,000 from participating microfinance institutions. This program has exhibited a significant effectiveness that is due to several key factors. Farmers are convinced that their animal waste can be converted into gas for cooking and electricity for lighting and subsidies share a significant portion of the farmers' financial burdens. The subsidies range from 37.5 per cent of the investment cost of small sized bio-digester ($4m^3$) to 16.7 per cent for the largest ones ($15m^3$). The quality of biodigester construction, training for farmer usage, and after-sale services also play a crucial role.

Though the government plans to disperse electricity transmission lines across the country by 2020, but not all villages will be able to connect to the grids due to economic inefficiency. Given the current pace of electricity generation and transmission development, biogas is expected to satisfy the growing demand for scarce products such as electricity and gas in poor and rural areas, where grid connection remains out of reach.

Adopting biogas over the grid is dependent on the cost of running biogas and the tariff of grid electricity, which is not expected to be reduced. A bio-digester has a lifespan of 10 years, which gives a household the ability to save up to US $1,400 and around 2,600 hours in collecting firewood (GreenSeat, 2013). Although a specific policy for the biogas sector has not been spelled out, the government plays a crucial role for alternative energies, including biogas in expanding electrification and reducing the forest dependency ratio.

5) Solar energy

Average sunshine duration in Cambodia is 6-9 hours per day and solar radiation is estimated at 5 kWh/ m^2 per day. This creates a huge potential for Solar Home Systems (SHS), solar Photovoltaic (PV), and Concentrated Solar Power (CSP). The total technical potential of solar power is 65 GWh per year (CRCD, 2004) but only about 2 MW of solar power has been installed so far (Toch, 2012).

The country's solar power is driven mainly by donor projects extending from pilot stages. With the assistance of the World Bank, the Bulk Purchase, and the SHS Installation project implemented by the government's REF, the goal is to install 30W and 50W SHS for 12,000 households in rural areas where mini or the national grid is not anticipated for the next 5-10 years. This subsidized project allows beneficiary households to repay the cost of system installation to the REF in instalments of up to four years. As of March 2012, the project has installed 11,975 units throughout eight provinces. Alongside this project, other solar powered solutions projects have been carried out by other donors; such as the Japan International Cooperation Agency (JICO), the Korean International Cooperation Agency (KOICA), the United Nations Industrial Development Organization (UNIDO), the Agence Française de Développement (AFD), and other NGOs.

A solar energy market is emerging. About 20 companies have been importing and selling solar products (e.g., solar panel, lantern, and lamp) in the country. Though these companies are typically targeting households living in areas where grid connection is not available, only a number of companies are active in rural areas.

The solar energy systems face a crucial challenge for acceptance by rural households. The upfront costs of solar powered solutions are significantly expensive and rural households are low-income or poor. Rural and poor people possess a limited knowledge while solar technologies are rather complicated and public financial support is not available to promote this fledgling sector. Poorly designed systems or poor quality solar products damage the reputation of solar technologies and the market.

The solar systems are not financially competitive with battery charging, which costs a household about US $2 per month for lighting. Though the import tax on solar components has been reduced from 30.0 per cent to 7.0 per cent since 2009, solar technologies remain costly for rural households. A SHS of 40Wp costs US $298 and can only generate 45 kWh per year and the 80Wp unit costing US $450 produces just 130 kWh per year (Picosol, 2011).

With a lifespan of approximately 20-25 years, the cost of electricity generated from the 40Wp SHS for lighting is roughly US $1 per month or US $0.26-0.33 per kWh excluding other maintenance costs. Moreover, the lifespan of a battery used with a solar system is about 3-4 years, so maintenance cost increases.

The uptake of solar power will expand as long as the cost of solar technologies decline to a level that is competitive with the current cost of the electricity tariff or battery charging in rural areas.

6) Wind energy

Wind speeds of at least 5 meters per second are available for electricity generation in the southern parts of the Tonle Sap River and coastal regions such as Preah Sihanouk, Kampot, Kep, and Koh Kong province. The Cambodian Research Centre for Development (CRCD, 2004) pointed out that wind energy could deliver a total electrical capacity of 3,665 GWh per year.

The development of this renewable resource is in the early stages. A few projects have been piloted in the northeastern and southwestern provinces. The first wind turbine, costing roughly US 1.74 million, is located in Preah Sihanouk province. It is co-funded by Cambodia's Sihanoukville port authority (48%), Belgium (28%), the EU (24%), and was inaugurated in January 2010. The pilot project was to demonstrate that wind power could be an effective energy source in Cambodia as well as in the region. The generated electricity is to supply the Sihanoukville port.

Since the resources remain untapped, investments in this sector are scarce. The private sector has not indicated that there is opportunity for investments. This can be attributed to a range of factors. First, the upfront investment is extremely costly. Second, policy direction and incentive schemes for development of the sector are not in place. Third, while electricity demand in Phnom Penh and other provincial towns is substantial, the areas to generate electricity from wind power are in the southern coastal areas and the national grid is not available yet.

Table 3: Summary of Potential Energy Generation and Saving

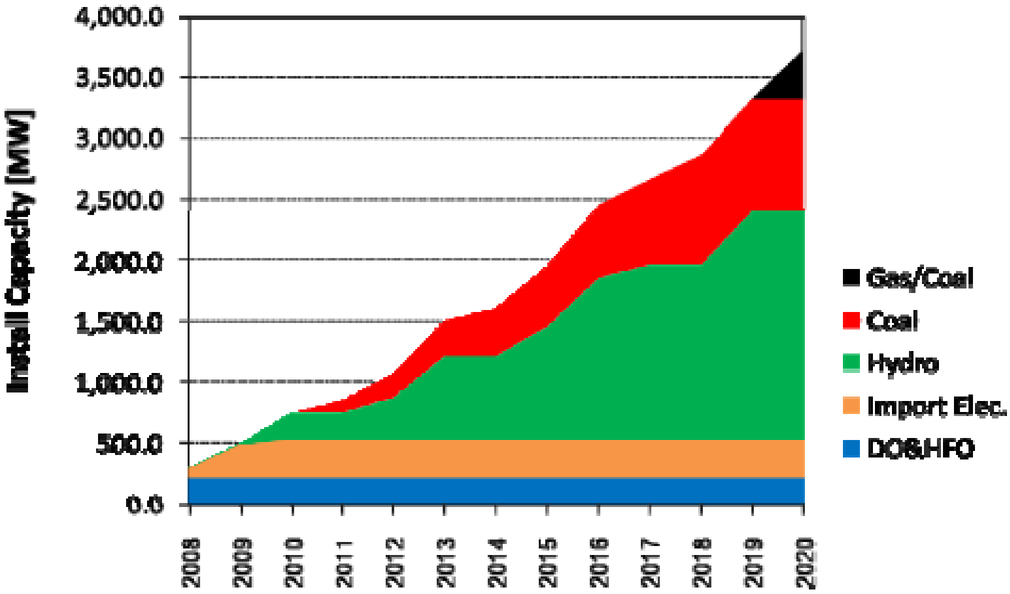
Energy Sources	Technical Potential (GWh/year)	Currently Installed Projects (GWh/year)	Theoretical Remaining Potential (GWh/year)	Potential Annual GHG Abatement (kton CO_2 equiv.)
Solar	65	1	64	44
Wind	3,665	-	3,665	2,556
Industrial energy efficiency	547	-	547	381
Residential energy efficiency	6,591	29	6,562	4,576
Total	**10,868**	**30**	**10,838**	**46,931**

Source: CRCD (2004).

5.3. Power Development Plan and RE Analysis

According to government projections, electricity demand in the country will reach almost 4,000 MW by 2020 (Figure 8). The Power Development Plan 2008-2020 indicated that hydropower would account for more than half of the total installed capacity by 2020, followed by coal, gas, imports, diesel and HFO. Electricity imports will be kept at roughly 250 MW per year and applies to electricity generated from diesel and HFO.

Figure 8: Power Development Plan 2008-2020



Source: Jona (2011).

If electricity demand increases to around 4,000 MW by 2020 as projected, the Power Generation Plan (PGP) over the period of 2011-20 is very likely to meet the estimated demand. Total installed capacity of the planned 29 projects in the Power Generation Plan 2011-2020 is estimated at 5,137 MW. As long as the planned projects are commissioned by 2020, combined with the existing capacity of 585 MW, the total electricity supply will reach 5,722 MW. The PGP is essentially focused on large-scale hydropower to meet the electricity demand by 2020. Out of the total 5,137 MW estimated capacity, hydropower will account for 4,261 MW (82.9 per cent), followed by coal (15.6 per cent), imports (1.4 per cent), and diesel (0.1 per cent).

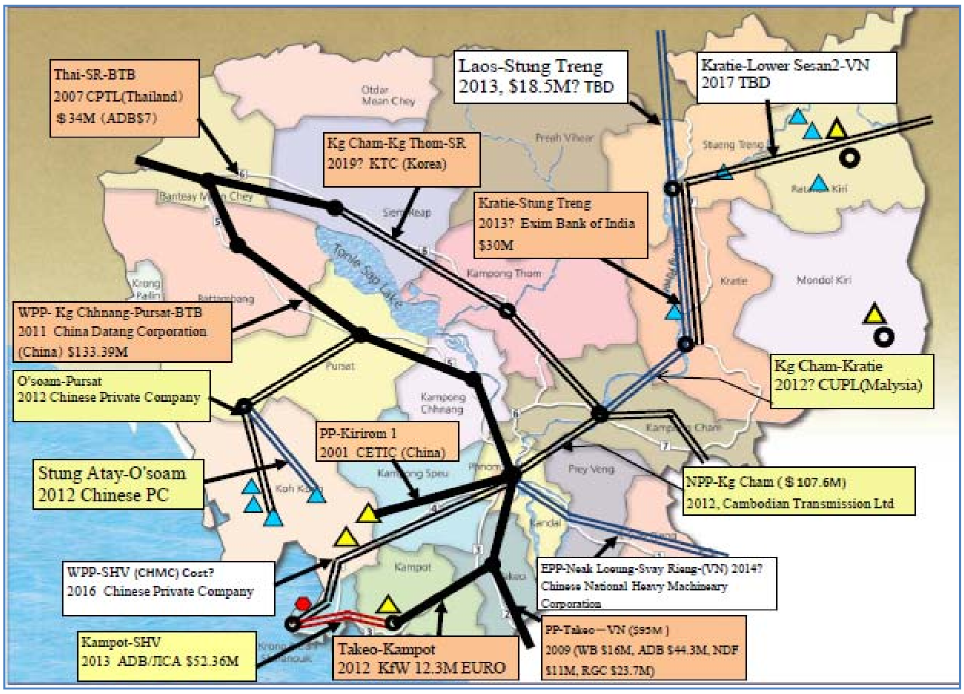
However, there remain risks. First, the feasibility of planned hydroelectric dams remains in doubts as hydropower projects on the Mekong River are subject to agreement by the other three Mekong River countries, Lao PDR, Thailand, and Vietnam. Second, due to the number of large hydroelectric stations on the upper Mekong River, the planned projects in Cambodia are not likely to produce at maximum capacity. Third, as explained in the hydropower section, the relentless concentration on hydropower is undeniably precarious for the country, especially in the current context of climate change. More importantly, when hydropower is the primary focus, the government abandons opportunities to develop alternative resources to achieve electricity development goals in a sustainable and equitable manner.

Cambodia can rely on power imports from neighbouring countries, but it should not depend completely on imports to power its fast growing economy while it holds considerable potential of energy resources. It can, however, import electricity to supply areas where domestic supply is inefficient (e.g., areas along its borders). Dependence on power imports is highly insecure for the country. On 22 May 2013, a wide spread power outage affected Phnom Penh for a few hours due to an electricity interruption in Vietnam (Chan and Henderson, 2013). Rather than being a power importer, Cambodia should utilise its potential energy resources to become not only power self-sufficient but also a power exporter in the region.

There is a role for RE to expand power generation and consumption. It can support power development given the deficiencies of large-scale hydropower projects. The government also needs to achieve the regional target of RE share by 15.0 per cent of total energy consumption by 2015.

Figure 9 illustrates the transmission development plan to create a national grid by 2020. The dark lines are current transmission lines and additional lines are in the planning stage. According to this scheme, some parts of the country are still left without connection to the national grid.

Figure 9: Transmission Development Plan 2020



Source: Hirata (2012).

By 2020, the total number of transmission lines will increase to approximately 2,106 kilometres (Jona, 2011). The transmission development plan consists of 17 projects for transmission lines to be built. This will expand the grid to cover the main parts of the country, particularly in areas of high population density, which are in the areas along the Mekong and Tonle Sap Rivers. Electricity distribution, however, to areas of low density remains a critical challenge because of the economy of scale and efficiency issues. For these reasons, electricity generated from renewable resources is the solution.

5.4. Barriers

The slow progress of RE development can be explained by the lack of accurate data. Another factor is that the accuracy and reliability of the data on RE resources is questionable due to the lack of scientific studies, systematic storage, and the update of data. The distrust of government among private businesses, related to potentially sensitive business data that could be used to extract higher taxes and fees or assist competitors, results in incomplete RE data (Williamson, 2006). Though some data are accessible, they need to be verified and updated in order to reflect the changes that occurred from the time the studies were conducted to the current situation so that real conditions are reflected.

Institutional capacity is undoubtedly a crucial barrier. The concept of RE has yet to be widespread among government agencies and relevant stakeholders. Well-trained professionals in RE technologies and development skills are not readily available in government agencies or the private sector. According to Toch (2012), the government has little experience in the development of RE resources. Moreover, relevant government agencies are deficient in resources and the technical capacity to collect data (Williamson, 2006).

Policy makers are not encouraged to implement renewable energy policies since there is an expectation that current electricity problems will be resolved by imports from neighbouring countries and by investments in large-scale hydropower and coal power plants. Oil and gas deposit are also anticipated to provide cheaper fossil fuels for electricity production in the country. This is termed the "high hope" barrier (Williamson, 2006).

An important barrier is technology stigma (Williamson, 2006). RE technologies are costly so as they are not prevalent in the country, while there are cheaper sources of energy available.

The lack of financial support is a barrier to RE development and public financing is not available. The government's national budget, which about half is financed by foreign aid and loans, doesn't allocate a particular amount for the promotion of RE production and deployment. Consequently, on-going RE projects are primarily financed by donors.

The lack of maintenance and management skills in RE equipment (e.g., solar PV products) is decisive barriers. The population in rural areas does not have a sufficient knowledge to maintain or repair RE products. Therefore they are reluctant to adopt the use of these products, which are now available through imports.

5.5. Policy and Regulatory Climate

The *Renewable Energy Action Plan* (REAP) and the *Rural Electrification Master Plan* (REMP) are the main policy papers that have been introduced since 2003 to promote RE development and utilization. The REMP emphasises the use of renewable energy to increase the supply of modern electricity services to the rural population.

To implement the Rural Electrification Policy, the government has established a Rural Electrification Funds (REF), which is an institution to promote the equity of access to electricity supplies. It also encourages the private sector to invest in a rural electricity supply in a sustainable manner and to encourage the use of renewable energy.

Since it was created in 2004, the REF has played a role in carrying out pilot renewable energy projects that are jointly supported by the government and development partners. Minimal progress has been made as this institution is short of human and technical resources and financial support from the government. Implementing projects to expand electrification and use renewable energy is mainly dependent on the funding from development partners.

Tax incentives are provided to encourage the private sector to engage in RE development. Since 2009, import taxes on solar PV components, biomass, and solar water heating components have been reduced from 30 per cent to seven per cent and from 15 per cent to zero per cent, respectively (Bun, 2012).

Referring to the power sector development plan, if both large and small-scale hydropower is considered renewable energy, the RE will account for more than half of the total energy production by 2020. The adopted policies, however, do not set out a specific target within a particular timeframe for the other types of renewable resources, such as biomass and solar power in the total energy mix.

Given the fact that large-scale power projects, hydroelectric and coal fired plants, are the main focuses until 2020, the government's incentive schemes are disproportionately directed towards these two types of power projects. The government provides guaranteed payments to hydroelectric and coal fired plant developers for generated electricity during the concession periods. As of early 2013, the government has provided guaranteed payments to 13 power projects in the country (Naren and Chen, 2013).

Incentive schemes are not available for other types of RE such as biomass and solar power. The solar power market has been predominantly driven by the electricity needs of people who are unable to access on-grid electricity. Increased solar PV installation is also stimulated by the two programs implemented by the REF and the MIME, which are funded by the World Bank and AFD, respectively.

6. Key Findings

RE deployment is on the rise. Energy security, environmental concerns, and sustained economic growth are the driving forces. Enabling the regulatory and business environment is fundamentally important to promote RE development. Supporting mechanisms via financial and non-financial policies are always a part of the national target setting, which is a common policy tool.

The experience of China and South Africa shows that a national target is beneficial in spearheading RE development. At the same time, other supporting policies are required to achieve the target by the prescribed deadline.

The scale of RE deployment in Cambodia remains low. To expand the electricity supply, substantial investments in hydropower are anticipated over the next decade and coal is another priority. The electricity generated from biomass combusting gasifiers is gradually growing among Small and Medium Enterprises (SMEs), especially in rural areas.

While the limited biofuel production has been primarily for export, biogas based electricity has been adopted for cooking and lighting by a small percentage of households in areas where publicly provided electricity is not available. The solar energy market has been emerging because a small portion of the total households in the country has access to electricity. Wind energy is in its early stages.

Though the demand for energy in the future is expected to be fulfilled by hydropower and coal power by 2020, there remains a role for RE. RE helps diversify power sources, reinforces hydropower, increases the power supply, hastens the electrification rate, and lessens power import dependency.

Feeding the power surplus from RE using producers (e.g., biomass) into the national grid is not available and the regulatory framework for the sale of electricity surpluses to communities or national grid is not defined.

RE development is obstructed by many barriers, such as the lack of accurate data, institutional capacity, government commitment and financial supports, and the people's awareness and acceptance.

The national target is not defined and the supporting policies are extremely limited. Though there is an emerging market, the lack of public effort and financing has resulted in slow progress for RE deployment.

7. Conclusion

The national target for RE's share of total energy consumption, or energy mix, is the primary instrument in guiding RE development. It is employed worldwide not only in advanced countries, but also developing countries such as China and South Africa. RE development requires the government's political will and actions in establishing a favourable business environment, effective institutions, and providing financial support.

RE is typically utilised for the electricity supply in Cambodia's rural areas, where power grids are not available, so electricity access cannot be expanded. A considerable amount of RE potential remains untapped, so there are ample opportunities for advancing RE development in response to the growing electricity needs and ultimately to achieve continued economic development and environmental sustainability.

Hydropower, together with coal power, will be major power sources in satisfying the power needs of Cambodia by 2020. The role of RE, however, will be significant because of the deficiencies of the major power sources, the increasing availability of RE resources such as biomass and biofuel, and the growing demand for power. Moreover, nearly two-thirds of the total population remains non-electrified.

Although there are many decisive barriers, the RE market is slowly emerging. An appetite for power, where the electricity grid is not available, prompts an increasing demand for RE technologies (e.g., solar PV, bio-digesters, and gasifiers). People's awareness, however, and the acceptance of RE technologies is a formidable barrier. Another critical barrier is the lack of government commitment and support.

The policy and regulatory framework is inadequate to promote RE development. The national target for RE's share in the energy mix is not specified by a particular timeline and the supporting mechanism is not enough to energise the RE market.

Integrating the power surpluses generated from renewable based producers is a decisive challenge. Pricing policies and regulations need to be adopted to promote RE development, to expand electricity access, and to reduce tariff rates.

8. Policy Implications

Implications for Cambodia:

Setting the national target for RE's share in the total energy mix is vital to spearhead government resources and efforts to mobilise the private sector's participation in RE development.

Financial incentives (e.g., subsidies and tax incentives) are essential to attract investments and encourage consumer usage. At the same time, public financing is needed to assist the private sector to pioneer RE projects, because of the high upfront investment costs and to ensure fair competition. Incentives, however, should be balanced and reduced over time as market conditions change.

FIT is proven to be a useful application in various countries including China and South Africa. It should be defined to promote renewable based electricity generation and to integrate that electricity into the national grid.

The business environment needs to be improved in order to attract investments in the RE industry. Enhancing the data management of the RE industry, adopting pricing policy, and relevant regulations are required to build the trust of the private sector so it will invest in RE projects.

The government, or the REF, should systematically increase RE promotion and information dissemination to the general public, especially those potential consumers who live in areas where the power grids are not available.

Rather than focusing exclusively on hydropower, the government should increase its efforts on the development of other REs, as the vast potential has been under-utilised.

The government should provide financial incentives to promote electricity production using biomass, such as rice husk and other plants husks. A policy to integrate the electricity surpluses generated from biomass into the national grid should be enacted.

Public financing and tax incentives should be channelled into the biofuel industry to promote production for either export or domestic consumption. A policy on how to use ethanol with diesel should be introduced to increase electricity generation from this renewable resource.

The government should augment its effort to increase public awareness and acceptance of biogas in daily cooking and lighting, particularly in the areas where the national grid has not reached.

The government needs to create a mechanism to control the trade and distribution of solar products in Cambodia to prevent the inflow of poor quality products that can ruin the reputation of solar energy technologies and thus the solar market.

The government should engage the private sector to participate in wind energy production through public financing, financial incentives, and regulatory policies, such as FIT.

<u>Implications for EMI in East Asian Summit (EAS) countries:</u>

To accelerate the role of RE in EMI, setting the target for the RE share in the energy mix in EAS countries is fundamental. Each country needs to commit to a specific target of RE share in the energy mix by a particular timeframe.

For the purpose of bridging the developmental gap, countries in the region should set up a mechanism for the technical transfer, cooperation, and the best practices for sharing to promote RE deployment in the region.

Capacity building should be at the centre of cooperation in the region. Less developed member countries are desirous of knowledge and the know-how to use RE technologies that are available in the market.

Given the fact that financing is the most crucial challenge, financial cooperation is a policy priority to help poorer member countries to embark upon RE development. This can be carried out through multilateral financing mechanisms.

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CHAPTER 8

Implications of Cash Transfers of Subsidies in the Energy Sector in India

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Recently, India has introduced a subsidy reform plan which involves a gradual removal of all subsidised items, including energy commodities, provided through public distribution systems (PDS). Broadly, the aim is to replace the PDS subsidies by direct cash transfers to the beneficiaries. However, there are several concerns associated with this reform plan, namely, the manner in which it is designed and implemented, and its impact on energy sector reforms.

This study is specifically focused on the plans, existing status and feasibility of direct cash transfer schemes (DCTS) for energy commodities such as PDS kerosene and liquefied petroleum gas. The study investigates the existing problems in the provision of energy subsidies through PDS; the impact of removal of these subsidies; effectiveness and sustainability of the cash transfers to the needy people; possibility of tackling leakages and corruption with DCTS which were associated with subsidisation through PDS; and the economic, environmental and social implications of cash transfers in India.

It is expected that the energy subsidy reforms may eventually lead to a gradual phasing out and ultimately a complete removal of energy subsidies. In such a case, the availability of energy commodities at market price across India could facilitate trading opportunities and contribute to energy market integration (EMI) within various states in the country and possibility with other countries in the East Asia Summit (EAS) region.

1. Introduction

The energy sector is one of the most important and heavily subsidised sectors in many countries across the globe. In petroleum-importing countries, the high cost of products such as diesel, petrol, kerosene and liquefied petroleum gas (LPG) need to be subsidised so as to make them affordable to masses. The factors that determine the provision of subsidies are their total cost, fiscal burden on the economy, the social benefits and impact on the welfare of the beneficiaries. The International Energy Agency (IEA) defines energy subsidy as any government action that lowers the cost of energy production, raises the price paid to energy producers or lowers the price paid by energy consumers. Many countries across the world subsidise fossil fuels in order to provide financial support for the users and compensate for steep increases in international energy prices. The IEA estimates that fossil-fuel subsidies worldwide amounted to $523 billion for the year 2011. However, these subsidies prove to be very costly in economic terms, creating a huge burden on government budgets and distorting national and international markets.

In India, energy subsidies aimed at protecting consumers are provided for electricity and four major petroleum products: petrol, diesel, kerosene and LPG. Petrol subsidies have been removed and those on diesel are being gradually phased out. Energy commodities such as kerosene and LPG are still subsidised to reduce the cost of energy, particularly for economically weaker households. Subsidies impose tremendous pressure on the government's fiscal budget and yet their benefits often fail to reach the targeted population. For example, while the government of India (GoI) provides huge LPG subsidies, the majority of Indians who use LPG as a cooking fuel live in urban areas and are economically well-off. On the other hand, most of India's roughly 1.2 billion people who are below the poverty line (BPL) dwell in rural areas and continue to use traditional fuels such as coal, wood or dung for cooking and heating. Also, both subsidised kerosene and LPG, which were available to the poor through the public distribution system (PDS) earlier, was wrongly diverted for commercial usage.

Recently, the government of India (GoI) has initiated energy subsidy reforms to stop leakages and corruption in the PDS and benefit the targeted population.

Consequently, subsidies on LPG and kerosene are being replaced by direct cash transfers (DCTs), also termed as direct beneficiary transfers (DBTs). Under this Direct Cash Transfer Scheme (DCTS), money is directly deposited in the beneficiaries' bank accounts to enable them to buy energy commodities at the market price. These DCTs are not conditional, therefore there is a possibility that the subsidy amount maybe misspent by the beneficiaries on items other than LPG and kerosene.

The objective of this study is to review the state of provision of energy subsidies (kerosene and LPG) through DCTs in India and their economic, environmental and social implications. Based on some examples of good practices, the study endeavours to seek country-specific solutions to associated problems and suggest appropriate remedial measures.

The main research questions addressed in the study are as follows:

- What are the existing problems associated with the provision of subsidies in the energy sector and what would be the impact of removing these subsidies?
- Would the cash transfers (CTs) to the needy people be effective and sustainable?
- Would the CT mechanism tackle the problems such as leakages and possible corruption which were associated with traditional forms of subsidisation (PDS)?
- What would be the economic, environmental and social implications of CTs in India?
-

It is expected that the energy subsidy reform may eventually lead to a gradual phase-out and, ultimately, a complete removal of energy subsidies. Such a scenario, when energy commodities are available at market price across India, could facilitate trading opportunities and contribute to energy market integration (EMI) with other countries in the East Asia Summit (EAS) region.

2. Overview of Energy Subsidies

The main reasons for providing the energy subsidies to consumers are increasing access to energy for those who cannot afford it at market price; reducing pollution to fulfil international obligations; and Employment and social benefits (EEA, 2004). However, energy subsidies often have several adverse effects, such as higher levels of consumption and wasteful use of valuable resources; possibility of diversion of subsidised commodities into the black market; weakening the prospects of economic growth; and not reaching the targeted people who need them most (UNEP, 2002; Pershing and Mackenzie, 2004).

In 1997 the World Bank estimated the amount of annual fossil-fuel subsidies at $10 billion in the OECD and $48 billion in twenty of the largest non-OECD countries. By 2007, these subsidies had increased to $310 billion per year in the same twenty non-OECD countries (WEO, 2008). It is estimated that more than 90 per cent of the direct subsidies from European governments during the period from 1990 to 1995 went to fossil fuels and nuclear power, while only 9 per cent of it was directed towards other forms of renewable energy. The majority of these subsidies were consumption subsidies meant for end-users (Morgan, 2007). The IEA estimated that fossil fuel subsidies provided to consumers in 37 countries, representing 95 per cent of global subsidised fossil fuel consumption, reached $557 billion in 2008. It was found that subsidies provided to producers of fossil fuels were around $100 billion per year. The total volume of subsidies to producers and consumers, almost $700 billion a year, was roughly equivalent to one per cent of the world GDP (WB, 2009; OECD, 2008).

Many types of subsidies, especially those that encourage the production and use of fossil fuels and other non-renewable forms of energy, can have high economic and social costs. In developing countries they also compete for limited resources; widen the scope for rent seeking and commercial malpractice; discourage both supply-side and demand-side efficiency improvement; promote wasteful consumption of energy; can make new forms of renewable energy uncompetitive; and, can be detrimental to the environment.

Reforming the environmentally harmful energy subsidies plays an important role in the global objective of moving towards a more sustainable development path. Some countries are already reassessing their subsidy policies in terms of their environmental, social and economic impacts. Globally, all countries need to make much more concerted efforts to reduce the subsidies that promote the use of fossil fuels.

Reforms in subsidies such as their restructuring, reduction and removal may prove to be helpful for the economy as well as the environment. It has been demonstrated that subsidy reforms have the potential to provide significant gains in economic efficiency and reductions in CO_2 emissions (Anderson and McKibbin, 1997). For energy-producing countries, the removal of energy subsidies would increase energy prices immediately, which would result in a fall in energy consumption and rise in energy exports (Saunders and Schneider, 2000). It is estimated that, if consumer subsidies for fossil fuels and electricity in 20 non-OECD countries were phased out gradually, by 2050 world CO_2 emissions would be reduced by 13 per cent and Greenhouse Gas (GHG) emissions would be reduced by 10 per cent (Burniaux, *et al*., 2009).

According to an estimate by IEA, fossil-fuel subsidies worldwide amounted to $523 billion for the year 2011, up from $412 billion in 2010, with subsidies to oil products representing over half of the total (WEO, 2012). Variations in international fuel prices are chiefly responsible for differences in year-to-year subsidy costs. The increase in the total global amount of subsidies in 2011 closely tracked the sharp rise in international fuel prices. The total global amount of fossil fuel subsidies provided in 2012 was around $775 billion. Among developed nations, Australia paid $8.4 billion in subsidies while Germany and the UK paid $6.6 billion each. Japan provided $5 billion (OCI, 2012).

3. Energy Subsidies in India

Energy prices are heavily subsidised in India with the objective of protecting the consumers from international price fluctuations and allowing energy access to them on a sustainable basis. International oil prices are very important in the domestic pricing of sensitive petroleum products in India as the country imports about 80% of its crude oil requirement. In India, crude prices have been steadily increasing since 2008, largely due to the global economic recovery and increasing demand from emerging economies. Major share of subsidies in India, for food, fertiliser and petroleum, has increased significantly over the years, from 1.39 per cent of GDP in 2000-01 to around 2.3 per cent of GDP in the year 2011-12 and 1.78 per cent of GDP in the year 2012-13

(ET, 2013). In the Union Budget 2012-13, the target was to keep all subsidies (energy and non-energy) under 2 per cent of GDP and under 1.75 per cent of GDP in the next 3 years. According to GoI estimates, if the traditional PDS is replaced by the DCTS, it could potentially reduce the under-recoveries on kerosene by INR.75 billion and on LPG by INR 72 billion (IIFL, 2013). In the recent Budget, presented in February, 2013, major subsidies bill has been estimated at INR 2.48 trillion. Petroleum subsidy for 2013-14 is seen at INR. 650 billion while that for 2012-13 has been revised to INR. 968.8 billion (TOI, 2013).

In India, the sale price of subsidised kerosene and domestic LPG is lower than international market prices. Although the GoI provided a fiscal subsidy on LPG and kerosene, it covers only a part of the difference between the cost price (including marketing costs) and the selling price of these three petroleum products, thereby resulting in "under-recoveries" for government-owned oil marketing companies (OMCs) such as Indian Oil Corporation Limited (IOCL), Bharat Petroleum Corporation Limited (BPCL) and Hindustan Petroleum Corporation Limited (HPCL). The under-recoveries are calculated as the difference between the cost price and the regulated price at which petroleum products are finally sold by the OMCs to the retailers, after accounting for the subsidy paid by the government.

Along with the steady increase in international oil prices, the OMCs' under-recoveries have also been rising proportionately. The details of the under-recoveries incurred by OMCs on the sale of sensitive petroleum products from the year 2005-06 to 2012-13 are given in Table 1. Figure 1 summarises the under-recoveries and fiscal subsidies for the past five years. It can be seen in Table1 that the fiscal subsidy has increased only marginally, while the under-recoveries have almost doubled between 2009–2010 and 2010-11.

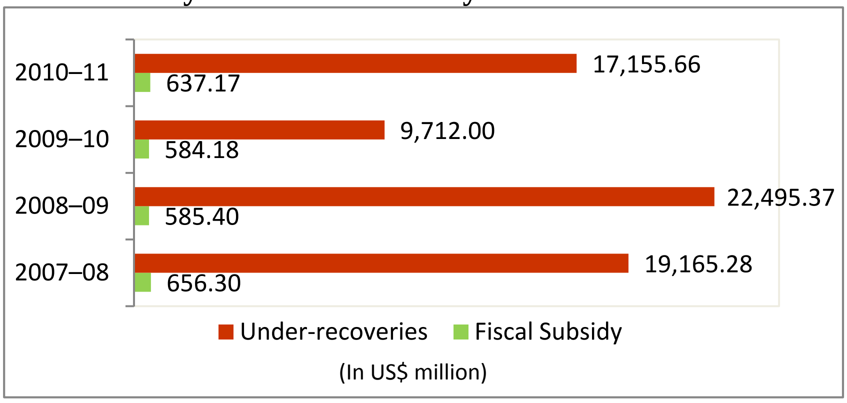
Table 1: Under-recovery to OMCs on Sale of Petroleum Products (in crore, INR)

Sensitive Petroleum Products	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13
Petrol *	2,723	2,027	7,332	5,181	5,151	2,227	-	-
Diesel	12,647	18,776	35,166	52,286	9,279	34,706	81,192	92,061
Domestic LPG**	10,246	10,701	15,523	17,600	1,457	21,772	29,997	39,558
PDS Kerosene	14,384	17,883	19,102	28,225	1,764	19,484	27,352	29,410
Total	**40,000**	**49,387**	**77,123**	**103,292**	**46,051**	**78,190**	**138,541**	**161,029**

Source: PPAC, (2013a)

Note: * Under-recovery on petrol is only up to 25th June 2010 after which it has been deregulated.
** Effective 18.01.2013, the GoI will sell Diesel to all consumers taking bulk supplies directly from the installations of OMCs at the non-subsidised market-determined price.
***Effective 18.01.2013, the GoI will provide 9 subsidised LPG cylinders to each consumer annually.

Figure 1: Fiscal Subsidy and Under-recovery on Petroleum Products



Source: PPAC, (2013b).

Until 2010, the Indian government controlled the prices of petrol, diesel, kerosene and LPG. In June 2010, the Indian government deregulated the price of petrol and in 2013 also announced a gradual phasing out of subsidies on diesel. In its budget for 2011-12, the Indian government proposed substitution of subsidies for specific budget items, namely kerosene, LPG and fertilisers, by CTs. There are several factors responsible for this decision, such as India's growing fiscal deficit; distortions resulting from the existing subsidy policies/schemes; lessons learned from other countries exemplifying the success of cash transfers as a means of reducing poverty levels and improving the social welfare of lower-income households; and ambitious projects like the "Aadhaar" biomarker-based Unique Identity (UID) program wherein each citizen is provided a unique identity number using their biometric information and "Swa-bhiman" under which every Indian will have access to a bank account.

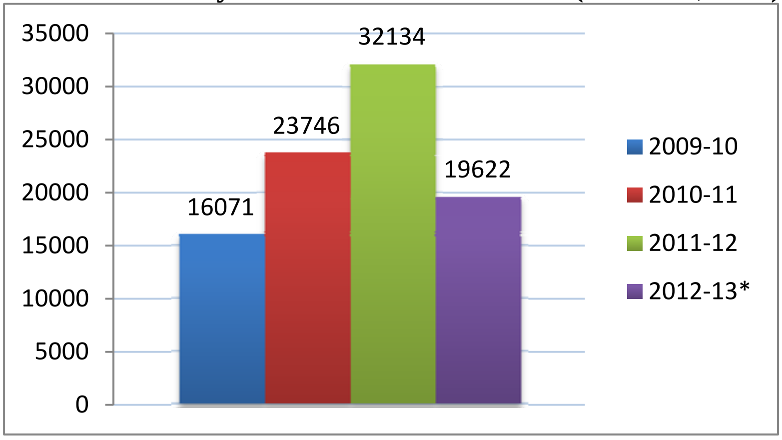
Liquefied petroleum gas (LPG)

LPG is supplied to the consumers through distribution networks of the OMCs, mainly in urban areas and some rural areas. An estimated 76 percent of LPG subsidy is allocated to urban areas, which contain only one quarter of the Indian population. Of this urban subsidy, over half is enjoyed by approximately one quarter of households. This means that almost 40 percent of the LPG subsidy benefits a mere 7 percent of the population. Moreover, the subsidy represents less than 5 percent of expenditure for this segment of the population. This is a far lower share than what Indians living BPL spend on kerosene (UNEP, 2008).

In terms of consumption, LPG for household use accounts for nearly 89% of the total off-take in India. Total LPG consumption for the year 2011-12 was more than 16.5 MT (Million Tons) and it is expected to grow at 8-9% according to official estimates provided by the Ministry of Petroleum and Natural Gas. LPG for domestic cooking is heavily subsidised and thus, to restrict any diversion, every household is permitted to have only one registered LPG connection. LPG subsidies mainly benefit higher-income households that generally give preference to LPG for cooking and water heating. The state-owned LPG wholesale suppliers have been forced to ration the supply of subsidised LPG to limit their financial losses given rising demand and international prices.

Figure 2 shows the total subsidy provided to LPG consumers between years 2009-10 and 2012-13, which increased from INR 160.71 billion in 2009-10 to INR 321.34 billion in 2011-12. The provisional figure for April to September 2013 is INR 196.22 billion, which is more than half of last year's subsidy value. In 'per unit' terms, LPG subsidy increased from INR 200.71 per cylinder in 2009-10 to INR 342.88 per cylinder in 2011-12 and INR 405.67 per cylinder for the first half (April to September) of 2012-13.

Figure 2: Total LPG Subsidy from 2009-10 to 2012-13 (in Crore, INR)



Note: *: Provisional Figures for the first half (Apr. to Sept.) of 2012-2013.
Source: PIB, (2013)

Kerosene

Since 2002-03 the kerosene subsidy has increased more or less uniformly from INR 4.14 per litre in 2002-03 to INR 27.26 per litre in 2011-12. According to a conservation estimate by the Union Oil Ministry, in 2012 as much as 40 per cent of the kerosene supplied was siphoned off and sold on the black market. It is then used as furnace oil in industries and even used for adulteration of diesel and lubricants. In India, it's the affluent who generally consume larger quantities of petroleum products and electricity. Thus, the energy subsidies benefit higher-income households rather than the economically weaker sections of society, thereby defeating the very purpose of the subsidies (IHT, 2005; TOI, 2012). Table 3 gives the details of the total subsidy on PDS Kerosene and Domestic LPG to customers over the last decade.

Table 3: Total Subsidy on PDS Kerosene and Domestic LPG to Consumers (in INR)

Year	**PDS Kerosene per litre**			**Domestic LPG per cylinder**		
	From Government Budget	By Public Sector Oil Companies	**Total Subsidy**	From Government Budget	By Public Sector Oil Companies	**Total Subsidy**
2002-03	2.45	1.69	**4.14**	67.75	62.27	**130.02**
2003-04	1.65	3.12	**4.77**	45.18	89.54	**134.72**
2004-05	0.82	7.96	**8.78**	22.58	124.89	**147.47**
2005-06	0.82	12.10	**12.92**	22.58	152.46	**175.04**

2006-07	0.82	15.17	**15.99**	22.58	156.08	**178.66**
2007-08	0.82	16.23	**17.05**	22.58	214.05	**236.63**
2008-09	0.82	24.06	**24.88**	22.58	234.88	**257.46**
2009-10	0.82	14.85	**15.67**	22.58	178.13	**200.71**
2010-11	0.82	17.39	**18.21**	22.58	249.94	**272.52**
2011-12	0.82	26.44	**27.26**	22.58	320.30	**342.88**
2012-13	0.82	31.16	**22.58**	22.58	427.14	**449.72**

Source: PPAC, (2013a).

India has made a commitment to the Group of 20 (G-20) to phase out inefficient energy subsidies that encourage wasteful consumption and are a fiscal burden on the government budget and also the OMCs which price retail petroleum products below their cost. This is also likely to provide the framework for a discussion within the national government on rationalizing petroleum subsidies. This in turn will help link the domestic retail prices of petroleum products to international crude prices. Such a parallel relationship will reduce the subsidies and thereby ease the burden on the OMCs.

In January 2013 the GoI decided to restrict the number of subsidised LPG cylinders to nine per household per year. A government committee also took the decision to partially deregulate the diesel prices and empowered OMCs to increase diesel prices gradually (INR 0.5 per month). However, the price of public distribution system (PDS) kerosene is still regulated and, if continued, may create problems with possible substitution or adulteration of diesel by subsidised kerosene.

4. Subsidy on Renewable Energy

India is working on increasing the share of renewable energy (RE) in its total energy mix and, in order to enhance the use of clean energy, the GoI provide subsidies and some regulatory incentives to attract investors. Recently, in April 2013, the GoI announced its plans for green growth at the fourth Clean Energy Ministerial (CEM4). India's 12th Five Year Plan is believed to be a key strategy for sustainable growth. A national target has been set towards increasing the efficiency of energy use to bring about a 20 to 25% reduction in the energy intensity of the country's GDP by 2020. Plans to achieve this target would include exploiting solar, wind and biomass energies. The GoI has also announced a target of doubling the RE capacity from 25,000 megawatts in 2012 to 55,000 megawatts by the year 2017. The GoI launched the Jawaharlal Nehru National (JNN) Solar Mission in January 2010, with an ambitious target of deploying 20,000 MW of grid-connected solar power by 2022. The Government strongly encourages global manufacturers to set up production facilities in the country.

In 2010, the Ministry of New and Renewable Energy (MNRE) in India introduced a subsidy-linked credit scheme for solar off-grid (photo-voltaic and thermal) and decentralised applications to promote commercial marketing of solar energy systems and devices by extending financial incentives in the form of capital and interest subsidy on loans availed from financial institutions by the target clientele. The National Bank for Agriculture and Rural Development (NABARD) is the authorised route for transferring these subsidies on bank loans (MNRE, 2013b).

With an installed capacity of 19 GW of wind energy as of March 2013, renewable energy sources (excluding small Hydro) currently account for 12.5% (i.e. 27.5 GW) of India's overall installed power capacity. Wind energy holds the major portion of 70% among renewable sources and continued as the largest supplier of clean energy. In its 12th Five Year Plan (2012-2017), the GoI has set a target of adding 18.5 GW of renewable energy sources to the generation mix, out of which 11 GW is estimated for wind energy; 4 GW for solar energy and 3.5 GW for others (MoP, 2013).

The GoI reintroduced a subsidy for wind farms and announced low-interest loans for clean energy generators in its budget for 2013-14. The government will allocate INR 8 billion ($147 million) to the renewable energy ministry for the subsidy. Annual installations in India, the world's third biggest wind market, more than doubled from 2009 to 2011 helped by the subsidy. The withdrawal of the incentive in March 2012 contributed to a 50 per cent drop in capacity additions this fiscal year. Reinstatement of the generation-based incentive is expected to add at least 400 megawatts of wind capacity in India within a year. The GoI will also provide companies that generate renewable energy with low-interest loans for the next five years from the National Clean Energy Fund (Bloomberg, 2013).

Currently, in addition to the Central Financial Assistance, fiscal incentives such as 80% accelerated depreciation, concessional import duty, excise duty, and 10-year tax holidays are available for biomass power projects. The benefit of concessional custom duty and excise duty exemption are available on equipments required for initial setting up of biomass projects based on certification by the Ministry. State Electricity Regulatory Commissions have determined preferential tariffs and Renewable Purchase Standards (RPS). The Indian Renewable Energy Development Agency (IREDA) provides loans for setting up biomass power and bagasse cogeneration projects (MNRE, 2013a).

5. Subsidies through Direct Cash Transfers

The recent expansion of cash transfer programs throughout emerging and low-income economies, with eligibility for benefits linked to certain criteria, has greatly increased the capacity of these economies to protect poor households from price and other shocks while simultaneously addressing the root causes of persistent poverty. (Fiszbein and Schady, 2009; Garcia and Moore, 2012). Many countries have implemented DCTS as an energy subsidy reform measure. The best examples are the Latin American countries, such as Mexico, Nicaragua, Brazil, Honduras, Jamaica, and Chile (Nigenda and González-Robledo, 2005). In addition to addressing the problems of leakages and poverty, the CTs could also contribute directly or indirectly to a greater range of development outcomes. The additional income from the CTs could help households develop human capital, own productive assets and gain access to credit on better terms.

In *Indonesia* the government has allocated 274.7 trillion Rupiah (about 29 billion US dollars) for energy subsidies in 2013, which is equivalent to 18 per cent of the budgeted spending. The energy subsidy reached 306 trillion Rupiah in 2012, more than the 202 trillion Rupiah allocated in the revised state budget (XN, 2012). Indonesia's unconditional cash transfer program, which covered 35 per cent of the population, was an important component of its successful strategy in overcoming social and political opposition to fuel subsidy reforms. *Armenia* successfully introduced a targeted cash transfer program during its electricity reform and was able to gradually reduce the coverage of households from 25 per cent in 1999 to 18 per cent in 2010.

Iran is one of the largest gasoline consumers in the world and was the largest provider of fuel subsidy until 2009. A fuel subsidy reform plan was introduced in 2010 after careful planning based on an extensive public relations campaign which stressed the importance of replacing energy subsidies with CTs to reduce wasteful energy consumption and leakages. The subsidy amount was deposited in the bank accounts (opened well in advance, prior to the introduction the scheme) of the intended beneficiaries before the price hike of the energy product (IMF, 2013). According to their government estimates, almost $100 billion is spent on energy subsidies per year, of which $45 billion is on subsidising fuel prices alone. It is believed that implementation of the targeted subsidy system will eradicate unemployment and poverty in Iran within three years (Wikipedia, 2013).

In *India*, the PDS for energy subsidies have not been successful mainly because the subsidies have not reached the targeted beneficiaries. In fact, the benefits received by the non-poor households have been far greater than those for the poor. Under the current circumstances of increasing fiscal deficits the country has implemented the DCTS. However, the scheme (discussed in the next section) is still in its initial stage and due to several operational deficiencies the benefits of such a transition from in-kind to cash transfers are yet to be seen.

6. DCTS in India

The Direct Cash Transfer Scheme (DCTS) for provision of energy subsidies has been recently introduced in India (in 2013) and it is expected to reduce leakages that were inherent in the PDS. DCTS is preferred due to several other reasons, such as lower operational costs; greater purchasing power; larger consumption choice-set for the beneficiaries; progressive impact of the program on income distribution of the poor; and, less scope for corruption. The role of DCTS in the Indian context is summarised in Table 4.

Table 4: The role of DCTS in the Indian context

Role	Focus*	Objective
Protection	vulnerable (poor and near-poor); chronic poor; transitory poor	Alleviate chronic poverty by improving the living standards to an acceptable level; prevent market price fluctuations from causing irreversible damage to the productive capacities and human capital of vulnerable section.
Promotion	economically active poor; near-poor	Improve capabilities and provide opportunities to the poor and vulnerable households; enable households to avoid low-risk, low productivity traps.
Empowerment	socially marginal or excluded groups; women and girl-child	Empowerment of women, Dalits and other marginalised ethnic groups and provide economic opportunities and access to public services.

Source: DFID, 2011.

Definitions:

i) *Poor*: Identified as those whose incomes or financial resources fall below the poverty line (According to India's Planning Commission Report, 2012, the Poverty Line in India is defined at INR 672.8 in rural area and INR 859.6 in urban areas).

ii) *Chronic poor:* An individual whose permanent income is insufficient to meet basic needs.

iii) *Economically active poor:* Those who fall under the definition of poor but have the capacity to repay back loans.

iv) *Near Poor:* Identified as those whose incomes or financial resources exceed the current definition of poverty but who have very limited economic resources.

v) *Transitory poor:* An individual whose permanent income exceeds a given minimum standard but annual income falls below that standard in some years.

7. Pilot studies on DCTS

In December 2011 a pilot DCTS project was initiated in Kotkasim, a village in Alwar, Rajasthan that has over 25,000 households. It was intended primarily to replace the state subsidy of INR 14 per litre on kerosene. Under this project, in all fair price shops kerosene was sold at Rs 44.50 per litre, which was the open market price set by oil companies in this region. For this project, the central government gave the subsidy amount to the district administration, which then transferred it to eligible ration card holders. Preliminary results indicated that the scheme was not successful for several reasons. The main problem was the inefficiency in the implementation process. Although the ration shops were stocked up with months of kerosene supply, the villagers could not buy it either due to delay in transfers or due to the fact that the villagers who did receive the cash were not regular buyers and were using it for other purposes. With the withdrawal of the subsidy, prices increased while the cash transfer was delayed or did not take place at all. The government did not have in place an efficient system to replace subsidy by cash delivery. Based on the lessons learnt from this pilot project the GoI decided to use Aadhaar-linked direct cash transfers to the beneficiaries.

With effect from January 1 2013, the GoI has introduced DCTS at an all-India level, which is based on a UID number called "Aadhaar." The two main eligibility criteria for the scheme are bank/post office accounts and a UID number. Under this scheme, beneficiaries in 20 districts across the country will receive the subsidy amount in cash into their bank accounts/post office accounts and use that to purchase kerosene from the Fair Price Shops at the regular market price. The purpose of these cash transfers is to ensure that benefits go to individuals' bank accounts electronically, minimizing the number of tiers involved in fund-flow thereby reducing delays in payment, ensuring accurate targeting of the beneficiary and curbing pilferage and duplication.

The DCTS scheme covers a total of 121 districts and is divided into Phase I (43 districts) and Phase II (78 districts). The second phase of DBT (including the LPG subsidy) was introduced from 1 June 2013 to cover 20 districts, and then will be extended nation-wide along with the expansion of Aadhaar enrolment. In this phase, 78 more districts are to be covered in addition to the 43 districts already under DCTS in Phase I. Conceptually, DCTS involves four simple steps, which are: 1) digitizing data; (2) enrolling in Aadhaar numbers; (3) opening bank accounts; and (4) linking these accounts. Practically, one needs to resolve the operational issues related to the manner in which these steps are taken.

8. Shortcomings in DCTS

Despite its efforts, the GoI has failed to fast-track the DCTS. This scheme was to be introduced in all 655 Indian districts by mid-2013. However, this is far from the real situation as the scheme is now suffering from drawbacks and is facing several complexities due to unsatisfactory tracking and monitoring systems in various departments. Some limitations of this scheme are given below:

Inefficiencies in UID system: In the DCTS, the subsidy amount is directly deposited into the bank account of the beneficiaries, which are linked to their UID numbers. Presently, only about 21 crore of the 120 crore people of India have these cards. This is less than a third of the number of people targeted under this scheme. This implies that the current UID registration and distribution system is quite inefficient and incapable of developing a robust structure to identify the targeted beneficiary.

Inadequate Banking Infrastructure: Another drawback is that only 40 percent of India's population has bank accounts; most BPL families don't have bank accounts and several villages don't have any bank at all. Also, the current banking infrastructure does not have the capacity to handle more accounts on a larger scale. Moreover, the banks have been unenthusiastic to come to rural areas as these are merely utilitarian accounts that are not profitable for banks.

Inaccurate Identification: In India, a major problem is definition of poverty line and identification of BPL families based on this definition. The National Sampling Survey (NSS) data show that about 50% of poor rural households do not have a BPL card. These families are deprived of the subsidy benefits and such incorrect identification of the BPL families could hamper the DCTS.

No Safeguard against Inflation: In the DCTS, the amount of cash transferred to each beneficiary is fixed and does not vary with the market prices. Hence it will offer no protection for poor families against inflation in kerosene and LPG prices. This is a critical point in the present scenario of high inflation rates.

Leakages and Possible Corruption: One of the main benefits of introducing the DCTS is reduction in leakages and corruption. However, since a proper monitoring mechanism is still not in place, it will encourage the retailers to continue to indulge in malpractices by diverting the quota provided by the government for the beneficiaries to the black market. The poor, who are the targeted beneficiaries, are often unaware of their rightful quota and days of availability of the energy item (e.g. kerosene) in the fair price shops. Although the official price of kerosene in the fair price shops is around INR 14-15 per litre, the black market price is between INR 70- 80 per litre (ET, 2013). Such a false projection of acute shortage and high black market price is a deterrent and compels the poor to opt for cheaper cooking fuels instead of kerosene.

Diversion of Energy Cash Subsidies: The BPL families are so poor that they may prefer not to buy energy commodities from the open market. Instead, these families may use the cash transfers to buy food and other basic items. For meeting their energy needs, they may use traditional (polluting) fuels, which will have a negative impact on the health of the household and the environment.

9. Impact of DCTS

Introduction of DCTS in India may have several economic, environmental and social impacts, some of which are outlined as follows.

Various forms of subsidies, including energy subsidies, account for a significant part of the Indian government's expenditure. According to the GoI estimates, the DCTS could reduce gross under-recoveries on kerosene by INR75 billion and on LPG byINR72 billion (IIFL, 2013). However, an important consideration is that when money is directly deposited on a monthly basis into the bank accounts of the beneficiaries, a higher number of people could avail this benefit. Unlike the PDS system where all the beneficiaries may not avail the in-kind subsidy, in the DCTS the number of people availing the cash-subsidy could be higher. This may increase the fiscal burden and government expenditure. On the other hand, diversion of subsidised items, provided through PDS, into the black market could be curtailed in DCTS, thus reducing the economic burden on the government.

The environmental impacts of the DCTS could be positive as well as negative. While providing energy commodities at a subsidised price through PDS encourages the consumer to use clean forms of energy, cash transfers, if not conditional, may not be as effective. Under normal cash transfers, a consumer may not buy the kerosene or LPG, preferring to use traditional fuels which cause both ambient and indoor air pollution. This may have detrimental effect on the health of household members and society as a whole. On the other hand, if subsidies are removed, free market and higher price may reduce overall consumption of energy commodities, resulting in less ambient air pollution and associated health hazards. Thus, from an environmental point of view, it is necessary to estimate the net effect of both schemes.

In developing countries like India, in order to estimate the social benefits of DCTS of energy items one needs to understand two main effects, namely a) the impact of changes in energy prices on the targeted beneficiaries, and b) the effect on people's access to, and use of, different types of energy and resulting impact on their health and well-being. For example, reducing subsidies on commercial fuels (kerosene and LPG) makes them expensive and poorer households are thereby forced to resort to non-commercial fuels, such as wood, which in turn may be responsible for deforestation and environmental pollution. These impacts, especially those related to health, are clearly important and have major social implications, especially in developing countries. Therefore, any plan to remove or reduce energy subsidies must include actions that compensate the negative social consequences.

10. Conclusions

This study reviews and analyses the provision of subsidies and assesses the implications of energy subsidy cash transfers in India. Provision of subsidies and their objectives are country-specific, for example developing nations like India provide subsidies to reduce poverty and improve people's standards. However, the benefits can be maximised only when the subsidies are transparent, well targeted, and effectively implemented without any leakages. Any subsidy program must ensure that its benefits reach the poorest section of the population and avoid errors of inclusion or exclusion. In general, the GoI provides major subsidies in the household, agriculture, industry and transportation sectors. For the last couple of years, the total subsidy provided by the government has been between 2 and 3 per cent of GDP, and the target is to contain this amount at less than 1.75 per cent of GDP in the next three years.

Energy subsidies in India are means of ensuring affordable energy commodities and services for lower income households, and protecting them from international price volatility. However, continuation of these subsidies may not be possible due to the limited domestic production of oil and gas, the rising cost of energy supply, and the government's burgeoning fiscal deficit.

Energy subsidies generally benefit the affluent, and often do not reach the poor who should be the real targeted beneficiaries. Also, the subsidies provided through PDS may not reach the targeted beneficiary as subsidised fuel items are illegally diverted to the open market and often lead to inefficiency and other related problems.

To reduce the problems associated with market distortion, leakages and corruption the GoI introduced a subsidy reform plan in January 2013, wherein subsidies will be provided in cash to the beneficiaries. The plan is known as DCTS and aims to link a unique identification number (UID), called "Aadhaar," to the bank account of the beneficiary. This scheme is expected to lower operational costs, create greater purchasing power, provide a larger consumption choice-set for the beneficiaries, and have a progressive impact distribution of income to the poor. The CTs may prove to be more efficient as they save time and reduce the cost of transport, storage and distribution of the subsidised energy goods required in the PDS.

Cash transfers for LPG and kerosene have been included under the DCTS scheme from June 2013. The Public Sector OMCs have launched LPG transparency portals to improve customer service and reduce leakages. Thus, the GoI has made an earnest effort to address issues such as leakages, possible corruption and fraud. There is a plan to extend the DCTS to the whole country within a year and complete the linking of beneficiaries' bank accounts with their UID number. However, given the existing condition of banking and UID enrolment infrastructure, this may prove to be very difficult task.

It is not clear if the CTs for LPG and kerosene, provided through DCTS, will be conditional or not. If they are not conditional, it may have several negative socio-economic and environmental effects as the additional income support may not be used for energy items. For example, instead of buying clean fuels for cooking, the consumers may spend the subsidy money on food items or on consumption of tobacco or alcohol, and switch over to using traditional fuels. Both of these activities would adversely affect the health of consumers and the environment. Initially, the DCTS may look attractive to consumers but, if not linked to inflation, they may not be sustainable as the purchasing power of the beneficiaries will be reduced in the long run. This is of particularly concern given the often-changing political scene in India in which new governments often change the social welfare schemes of the previous government.

An important prerequisite for success of DCTS is the accurate identification of beneficiaries and a reliable institutional structure to monitor the progress of DCTS and simultaneously rectify problems as soon as they are detected. However, at present this is not being addressed in these schemes.

Energy subsidy reform in India could be an important step for EMI in the EAS region. When energy items are provided at market price, it encourages price parity and trading among countries. In order to promote foreign investment and a competitive energy market, it is essential to work towards the removal of import barriers and cross-subsidies in energy price. Further, transparent dealings, robust infrastructure, efficient procedures and, most importantly, political goodwill among trading partners will go a long way towards promoting EMI in East Asia.

11. Recommendations

The DCTS for provision of subsidies, recently introduced in India, are aimed at being effective and reduce the burden of the Government's saving compared to the subsidies through PDS. However, as of now only a few districts are covered and the success of the scheme can be seen only after it is implemented in many districts. Given various problems with the earlier PDS, any reform in subsidy provision, such as that through DCTS, should address issues related to efficiency, equity and fiscal impacts. Current reforms in subsidies may pose a challenge on socio-economic, political, and environmental fronts. To ensure a positive impact of DCTS, some recommendations are as follows:

- Energy subsidy reforms should be based on two basic norms, namely, proper identification of beneficiaries and delivery of subsidies to them, as well as their implementation, should be reviewed periodically. This necessitates a speedy issuance of "Aadhaar" numbers to intended beneficiaries, facilitating the opening of their bank accounts, and linking Aadhaar to these bank accounts.
- DCTS will have some 'transaction costs' and it is important to take into account all such costs while reviewing these schemes. These costs could be analysed in terms of the main sources of these costs, and the extent to which these are borne by the government, OMCs and the consumers. Based on the lessons learned from the experience of earlier implementation, some complementary policy instruments and remedial measures can be introduced to minimise transaction costs in future implementations.
- Operational and transactional costs could be reduced substantially if the cash transfers are made through mobile phone accounts. Mobile phones have much higher subscription levels than bank accounts, particularly in rural areas of India. Thus, linking "Aadhaar" numbers to mobile phone accounts could be faster and less expensive than widening the usage of bank accounts.
- It is necessary to estimate total fiscal burden on public authorities subsequent to implementation of the DCTS, which includes the cost of the UID procedures, linking of bank accounts to the UID of beneficiaries and expenses incurred in upgrading the infrastructure to handle the DCTS on a large scale.
- DBTS should be economically efficient and result in maximum net social benefits, i.e. the difference between total social benefits and economic costs should be maximum. Thus, the total costs incurred by the DCTS scheme during the initial phase could be estimated and weighed against the benefits of energy cost savings and increased energy efficiency. All stakeholders need to focus more on fulfilment of the objectives of the DCTS, such as benefiting the poor, and social and environmental welfare rather than the economic expenditure. For achieving maximum socio-economic and environmental benefits and being effective in helping the poor, the DCTS for energy commodities should be "conditional" so that the cash transferred to the beneficiaries is specifically used for buying only energy commodities such as LPG and kerosene. Conditional energy subsidy cash transfers will not only provide additional income support to the poor but will also modify household behaviour (i.e. they use the cash to buy clean fuel only), thereby achieving the larger social and environmental objectives.
- The Government could establish a special purpose working group which collects feedback from, and disseminates information to, the public about the benefits of the DCTS. It could establish a network of people from the media, civil society, local communities, government representatives etc., to educate the masses and also reform the scheme based on any shortcomings, if detected.

Thus, the advantages of the DCTS can be promoted while the problems can be reduced or eliminated in the long run.

- The DCTS must ensure that the subsidy amount is transferred on time as delays in release of these funds to the beneficiaries' bank accounts will defeat the very purpose of the cash transfers. Also, the amount of subsidy money should not be fixed as there must be some provision for adjusting this amount in line with the market price of the energy product.

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CHAPTER 9

International Oil Price, National Market Distortion, and Output Growth: Theory and Evidence from China

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Energy prices are often distorted by government control. This is justified on the grounds that it will help mitigate the negative impacts of price volatility from oil imports and will have a positive effect on the domestic economy. In this paper, we establish, in a two-sector growth model, that such price distortions do affect the economy and then based on that model we empirically estimate its impact on the output growth in China, using monthly time series data. In contrast to the arguments for price control, we find that price distortion negatively affects the output growth in China in both the short run and long run, which is robust to different measures of output and price distortion. Price control is a significant barrier to energy market integration. Since the induced distortion dampens the domestic economy, the grounds to maintain price control are seriously undermined. Therefore, the finding of this paper lends support to the energy market integration that many regions, such as East Asia, are advocating.

Keywords: price regulation; macroeconomy; price distortion; energy market integration; China

JEL Classification: C02, E23, Q43

1. Introduction

The relationship between oil price and macroeconomy has been debated since the early 1980s (Hamilton, 1983) with the first oil crisis and the global recessions that followed (Jones, *et al.*, 2004; Segal, 2007). These studies were initially instigated by the stagnation of the US economy in the 1970s as oil price shocks were thought to be the only promising hypothesis to explain the stagflation (Barsky and Kilian, 2004). Many early studies, such as Darby (1982) and Hamilton (Hamilton, 1983, 1985), demonstrated that changes in the oil price have substantial impacts on output, employment, inflation, and economic growth. However, others argue that the induced monetary policy, rather than oil price shock itself is the key driver for recessions after oil price shocks (Clark and Terry, 2009; Chen, 2009; Bernanke, *et al.*, 1997). These issues were revitalised in the 2000s when oil prices rose more than 600 per cent between 2001 and 2008, while the average quarterly core inflation in the US was about 2 per cent over the same period (Clark and Terry, 2009). A more recent study finds that a relationship may exist in some cases of oil shocks but not in others (Kilian, 2008).

In China, the focus of this paper, the literature on the impact of international oil price shock on economic growth also yields inconclusive findings. Zaouali (2007), using a Computable General Equilibrium (CGE) model, revealed that an oil price hike will have a negative impact on the GDP and the impacts on the petroleum sector are more serious than on the non-petroleum sector. Tang, *et al.* (2010) also found that an oil price increase will lead to an output decrease. Using a structural dynamic factor model approach, Ou, *et al.* (2012) found that oil price shock will make China's industrial output increase initially but subsequently decrease in the long term. Lescaroux and Suez (2009) showed that an oil price shock leads to a delayed negative impact on the GDP as well. In contrast, Du, *et al.* (Du, *et al.*, 2010; Wu, *et al.*, forthcoming) found that China's GDP is related positively to oil price increase.

Despite the empirical results being inconclusive, it appears that policy makers generally believe that oil price shocks exert a negative impact on the domestic economy and due to this belief price regulations in the energy market, such as price caps and subsidies, have been practiced for a long time and still prevail in many countries (IEA, 2012). Many policy makers prefer to have such price regulations on the grounds that these measures will insulate the domestic economy from the negative impacts of high oil prices in the world market. For example, Indonesia and Malaysia fixed their petroleum prices at a very low level (Wu, *et al*., 2012).

Nevertheless, price regulation will inevitably lead to price distortion in the energy market and it is a significant barrier to the energy market integration that many regions, such as East Asia, are advocating (Shi and Kimura, 2010). Although policy makers hope such price regulations will benefit the domestic economy, the induced distortion may actually exert negative impacts. If the distortion dampens the domestic economy, the justification to maintain price regulation will be seriously undermined.

Therefore, examining the impact of price distortion will present important implications for policy makers and will lead to a better understanding of energy market integration. However, even with its policy significance, there is no previous study that explores the impact of energy price distortion on the domestic economy. To fill this gap, this paper intends to explore the impact of energy price distortion, both theoretically by using a two-sector growth model and empirically by a time-series analysis of China's situation.

This paper focuses on China, a large developing economy. On the one hand, China's fast economic growth creates a huge demand for resources such as oil. On the other hand it also maintains a number of intervention measures, such as price control in the domestic energy market. Since 2009, imported oil has accounted for more than half of the total oil consumption in China and the oil price has become more volatile. Investigating the impact of price distortion, which occurs due to these intervention measures, will lead to significant implications for policy makers not only in China but also in other developing economies. Later, our empirical exercise will reveal that such distortion does harm to the industrial output.

The contribution of this paper is four-fold. First, we explicitly introduce the role of energy market distortion into the thoroughly examined oil price shock-macroeconomy nexus. We further argue that market distortion, including energy price distortion, will have a significant negative impact on the relationship. Second, we illustrate the impact of the price distortion in a two-sector growth model. Third, our empirical exercise focuses on China, a large and fast developing economy with a high dependence on imported oil and price control. This will lead to significant implications for policy makers in China and other developing countries. We also propose several measures on the price distortion in China. Fourth, our study also sheds light on a better understanding of energy market integration, which is often hindered by subsides and other price control measures in the domestic markets.

The remainder of this paper is as follows. Following the introduction, Section 2 presents a discussion on oil consumption and the energy pricing mechanism in China, which gives background information for the subsequent exercise and measures the energy price distortion in China. Section 3 presents a two-sector growth model where we demonstrate that oil price distortion affects the domestic economy. Using these implications from the theoretical model in Section 3, we then propose the empirical specification and discuss the data in Section 4 and in Section 5 we report empirical results. Section 6 concludes the paper.

2. Oil Pricing Mechanism and Price Distortion in China

Due to its escalating volume of oil consumption, increasing dependence on oil imports, and the gradual liberalising of the domestic oil pricing mechanism, researchers have expected a more active interaction between the world oil price and China's macroeconomy (Du, *et al*., 2010; Wu, *et al*., forthcoming). Therefore, China is a suitable case study for the role of market distortion and oil price shocks. In this section, we will discuss the pricing mechanisms in the energy market and measure the associated price distortion.

2.1. The Oil Consumption and Pricing Mechanisms

China's energy consumption, as well as its dependence on imported oil, has been increasing dramatically over the past two decades and is expected to grow in the future (IEA, 2012). During 1990-2008, China's GDP grew at an annual rate of 10 per cent on average and is expected to grow at an annual average rate of 5.7 per cent during 2008-2035 (IEA, 2010). Such a fast economic growth leads to strong demand for energy. In 2009, China became the world's largest energy consumer.

Meanwhile, China's domestic oil price has also experienced significant changes and before 1998, it was heavily regulated. In the 1980s and 1990s, China adopted a dual-track pricing system, under which the prices for most oil products were tightly regulated, while the rest were traded in the market more or less freely. A market-based petroleum pricing mechanism was adopted in 1998 and in October 2001 oil product prices were linked to major international futures markets (Du, *et al*., 2010). They were benchmarked against the Singapore futures markets and later in 2001 the benchmark was extended to Singapore, Rotterdam, and New York futures markets, where an unpublished weight was used to set the domestic prices (Du, *et al*., 2010). In 2006, this price benchmark was changed from refinery product prices to the Brent, Dubai, and Minas crude oil prices. Although this price benchmarking enables the domestic markets to follow the international markets, it is also intended to insulate the domestic markets from the volatility of petroleum prices in the global markets (IEA, 2010). Due to this intention, even with the liberalizing reforms implemented in the early 2000, the pricing regime was besotted with ad hoc subsidies and the non-transparent, inconsistent enforcement of pricing behaviour.

In 2009, China introduced a formula-based pricing mechanism for oil products. According to this formula, domestic fuel prices may be adjusted when international crude oil prices, measured as a weighted average of the Brent, Dubai and Cinta crude oil prices, change more than 4 per cent over a period of 22 working days (Government of China, 2008).

This pricing mechanism tends to alleviate price volatility in the fuel markets and subsequently the shocks in China will be less severe. When the average crude oil price is below US$ 80 a barrel, domestic gasoline prices move relatively freely. Between US$ 80 and US$ 130 a barrel, domestic prices are responsive but cannot be in case as much as the crude oil prices does and above US$ 130, fuel tax breaks will be used to keep domestic prices low. Furthermore, fuel price adjustments have lagged behind the world price movement (Kojima, 2012). This flaw was taken advantage of by distributors and consumers who profited from hoarding oil products when international oil prices registered large rises and selling them after government price adjustments (China.org.cn, 2013).

With the increasing demand for the full marketisation of domestic oil product prices, China changed its oil pricing mechanism in March 2013. It can adjust domestic oil prices every 10 working days regardless of how much international oil prices change. Domestic prices will be changed if price changes in the international oil markets are not more than 50 Yuan per tone. However, the government retains the authority to suspend, postpone or downsize the price adjustment in special cases, such as sharp rises in domestic inflation, emergencies or dramatic swings in global oil prices. Nevertheless, there are no pre-defined conditions under which the government will intervene and thus the government may surprise the market. The National Development and Reform Commission (NDRC) claims that the new mechanism is more responsive to global oil market changes and will help the country to better utilise overseas resources to ensure domestic oil supplies (China.org.cn, 2013).

2.2. Measurement of Oil Price Distortions

The on-going adjustment of oil product pricing regimes provides a good case study for the impact of price distortion. Even though China is gradually liberalising the pricing mechanism of domestic oil products, there still exists significant price control in the energy market, as discussed above. Such price control creates distortions in the energy market and we measured the price distortion in the following way.

First, we calculated the average monthly gasoline price (Chinese Yuan per ton) in China for three types of gasoline without lead (gasoline no. 90, 93, and 97), the prices for these types are sourced from the CEIC database. Second, we extracted the average end user price of all grade motor gasoline in the US, which was sourced from the US Energy Information Administration (EIA). The unit for this price is US dollar per gallon, which we then converted into US dollar per ton by using the formula of 1 gallon gasoline = 2.7974 kg gasoline. This price is further converted into Chinese currency (Yuan) by using the average period of official nominal exchange rate sourced from the IMF.

Third, after we obtained the Chinese and US gasoline prices with the same unit (Chinese Yuan per ton), we calculated three measures of domestic oil price distortion.

The first measure is the ratio of Chinese price against US price, namely $\sigma_1 = P_{China} / P_{US}$, where P denotes price and σ denotes price distortion.[1] The second measure is the percentage difference between Chinese and US prices, namely $\sigma_2 = (P_{China} - P_{US}) / P_{US}$. For σ_2. It is also possible that the direction of percentage difference does not matter in affecting the economy and the impact is symmetric. Considering this point, we also calculated the third measure as $\sigma_3 = |P_{China} - P_{US}| / P_{US}$.

In measuring the price distortion, as in Lin and Jiang (2011), we used the US gasoline price as a reference. We assumed that the US price would be close to the perfectly competitive market price. Although the US gasoline price cannot be a perfectly competitive market price, it is possibly the best available proxy to the perfectly competitive market price for the following two reasons. First, the US enforces a 13% tax, which is lower than that in all European countries (Thompson, 2011), and compared to European countries the distortion from the government intervention is minor. Second, the US maintains strict control on anticompetitive conduct in the petroleum industry, including the gasoline market (The US Federal Trade Commission, 2007) and so the distortion from market power is minor. In addition, as long as the US gasoline price is not systematically correlated to market distortion in the Chinese gasoline market the benchmark price, although not a perfect competitive price, is acceptable to be used to measure the gaps.

Figure 1 represents the constructed price distortion. We can observe that there exist significant price distortions in China. On average China's price is around 26 per cent higher than that of the US. In addition, even though China is attempting to liberalise its oil product pricing mechanism, the distortion does not appear to be reducing. In addition, there appears to be a structural break in 2009m1. After 2009m1, the average price distortion is clearly higher than before 2009m1. One reason for the sudden increase in gasoline price is that the fuel tax was increased from 0.2 CNY (US 3 cent) per litter to 1 CNY (US 15 cent) per litter since 2009. For the continuous high level of oil price, it is argued that the gasoline was under-priced (Xin Jing Bao, 2011).

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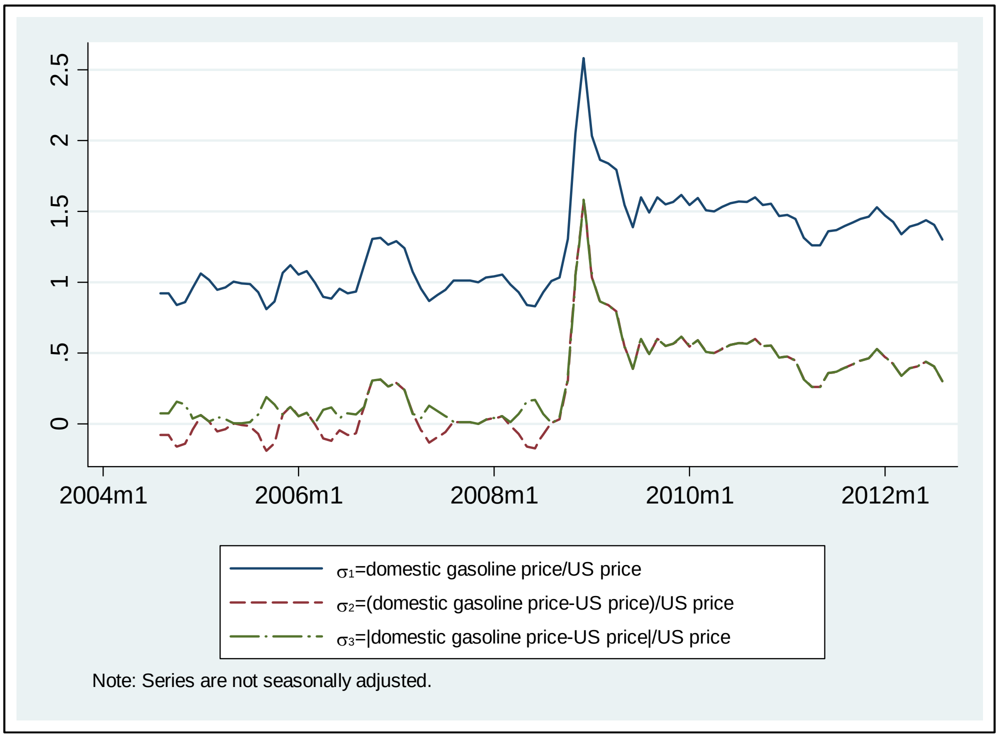
[1] Later we use this measure in the theoretical model.

Figure 1: The Price Distortion in China



Source: The authors' calculation with data sourced from the CEIC database, EIA, and IMF

3. The Model

Price controls are the main reason for the price distortion in the energy market. Nevertheless, they are often justified because they can shield the domestic economy from undesired oil price shocks in the world market. Such oil price shocks can lead to inflation and recession in the domestic economy (Barsky and Kilian, 2004; Darby, 1982). This negative impact, however, is questioned in later studies (Bernanke, *et al.*, 1997), and a number of recent studies suggest that the negative impact does not derive from the oil price shocks themselves but from the policy response to the oil price shocks (Kilian, 2008).

In addition, price controls such as subsidies negatively affect the domestic economy. A number of studies show that price distortion hurts economic growth (Wu, *et al.*, 2012; Tang, *et al.*, 2010). Theoretically, the regulated energy prices can affect the domestic economy in the following three ways. First, the subsidies, or the surrendering of profits from state owned oil companies, essentially transfer government revenue to consumers in a way that is not necessarily efficient. Consequentially, we can expect welfare loss from such subsidies.

Second, price distortion leads to the inefficient allocation of energy among industrial users. A price lower than the perfectly competitive market price induces firms to substitute away from other factors into energy and in turn this leads to low energy productivity and efficiency loss. In addition, given a low energy price, firms have little incentive to upgrade their energy technology. Third, for retail consumers, the low energy price can lead to inefficient consumption and the waste of energy (GSI, 2011). For example, when presented with cheaper fuel prices consumers are more likely to use vehicles intensively and have less incentive to switch to more energy efficient vehicles.

Therefore, we expect price distortion to affect the domestic economy in a negative manner. Below we explore the impacts of oil price distortion, measured as the price deviation between domestic and world markets, on the domestic economy in a two-sector growth model.

3.1. A Two Sector Growth Model

With an endowment of labour L, the economy consists of two sectors, specifically the oil sector and final goods sector. A representative consumer chooses a sequence of consumption of final goods to maximise their lifetime utility, as follows:

$$\max_{\{c_t\}} U = \sum_{t=0}^{\infty} \rho^t ln(c_t)$$

where t denotes time, ρ is the discount rate and c denotes quantity of consumption. At each period the consumer is presented with the following budget constraint:

$$c_t + k_{t+1} = w_t + r_t k_t + (1-\delta)k_t$$

where k denotes capital they own, w is their wage income, and r and δ are rental and depreciation rates of capital respectively. Solving the utility maximisation problem, we obtain an Euler equation as follows:

$$\frac{c_{t+1}}{\rho c_t} = r_{t+1} + 1 - \delta \qquad (1)$$

In the final goods sector, capital, labour, and oil are used to produce final goods in a constant return to scale Cobb-Douglas function:

$$Y_t = AL_t^{1-\alpha-\beta}K_{yt}^{\alpha}O_t^{\beta}$$

(2)

where Y, A, L, K_y, and O denote the output, technology, labour, capital used in the final goods sector, and oil inputs respectively and α and β are two parameters where $\alpha \in (0,1)$, $\beta \in (0,1)$, $\alpha + \beta \in (0,1)$. The oil inputs are sourced from either the domestic or world markets. Let p_t denote the oil price in the world market and $\sigma_t p_t$ denote domestic oil price. Thus, σ_t measures the distortion in the domestic oil price.

Firms in the final goods sector choose employment of labour, capital, and oil to maximise their profits:

$$\max_{\{L_t, K_{yt}, O_t\}} Y_t - w_t L_t - r_t K_{yt} - \gamma_t O_t \sigma_t p_t - (1-\gamma_t) O_t p_t$$

where 1-γ denotes oil dependence, specifically the share of oil consumption that is sourced from the world market. The profit maximisation yields the following first order conditions:

$$w_t = (1-\alpha-\beta)AL_t^{-\alpha-\beta}K_{yt}^{\alpha}O_t^{\beta} \tag{3}$$

$$r_t = \alpha AL_t^{1-\alpha-\beta}K_{yt}^{\alpha-1}O_t^{\beta} \tag{4}$$

$$\beta AL_t^{1-\alpha-\beta}K_{yt}^{\alpha}O_t^{\beta-1} - (\gamma_t\sigma_t + 1 - \gamma_t)p_t = 0 \tag{5}$$

Equation (5) defines the demand for oil from which we can derive the corresponding demand for domestic oil as:

$$\gamma_t O_t = \gamma_t \left[\frac{\beta AL_t^{1-\alpha-\beta}K_{yt}^{\alpha}}{(\gamma_t\sigma_t+1-\gamma_t)p_t}\right]^{1/(1-\beta)} \tag{6}$$

In the oil sector, the production function is also Cobb-Douglas, as follows:

$$X_t = S_t K_{xt}^{\eta} \tag{7}$$

where X, S, and K_x denote the oil output, oil reserve, and capital used in the oil sector ($K_{xt} \in [0,1]$), and η is the parameter that takes a value between zero and one. The economy is initially endowed with an oil reserve of S_0, and subsequently the oil reserve evolves in the following manner:

$$S_{t+1} = S_t\left(1 - K_{xt}^{\eta}\right) \tag{8}$$

Subject to the transition of state variable S (Equation 8), firms in the oil sector choose the level of capital to maximise their life time profits with the Bellman equation as follows:

$$V(S_t) = \max_{\{K_{xt}\}}\{X_t\sigma_t p_t - r_t K_{xt} + \rho V(S_{t+1})\} = \max_{\{K_{xt}\}}\left\{M_t S_t^{\beta} K_{xt}^{\beta\eta} - r_t K_{xt} + \rho V(S_{t+1})\right\}$$

where $V()$ denotes the value function and $M_t \equiv \frac{\beta A L_t^{1-\alpha-\beta} K_{yt}^{\alpha} \gamma_t^{1-\beta} \sigma_t}{\gamma_t \sigma_t + 1 - \gamma_t}$. The second equality is obtained by plugging in the demand for domestic oil (Equation 6) and oil production function (Equation 7) into the first equality.

Differentiate the value function with respect to K_{xt}, we obtain the first order condition as $\beta\eta M_t S_t^{\beta} K_{xt}^{\beta\eta-1} - r_t - \rho\eta S_t K_{xt}^{\eta-1} \frac{\partial V}{\partial S_{t+1}} = 0$. Using the Envelope Theorem, we can obtain $\frac{\partial V}{\partial S_t} = \beta M_t S_t^{\beta-1} K_{xt}^{(\beta-1)\eta} - \frac{r_t(1-K_{xt}^{\eta})}{\eta S_t K_{xt}^{\eta-1}}$, which is then shifted one period forward ($\frac{\partial V}{\partial S_{t+1}} = \beta M_{t+1} S_{t+1}^{\beta-1} K_{xt+1}^{(\beta-1)\eta} - \frac{r_{t+1}(1-K_{xt+1}^{\eta})}{\eta S_{t+1} K_{xt+1}^{\eta-1}}$) and plugged into the above first order condition to obtain the following equation:

$$\beta\eta M_t S_t^{\beta} K_{xt}^{\beta\eta-1} = r_t + \rho\eta S_t K_{xt}^{\eta-1}\left[\beta M_{t+1} S_{t+1}^{\beta-1} K_{xt+1}^{(\beta-1)\eta} - \frac{r_{t+1}(1-K_{xt+1}^{\eta})}{\eta S_{t+1} K_{xt+1}^{\eta-1}}\right] \tag{9}$$

which characterises the optimal level of capital in the oil sector. Equation (9) indicates that the optimal level of capital in the oil sector shall be such that its marginal revenue (the right hand side of Equation 9) is equal to the marginal cost (the left hand side of Equation 9). Since current oil extraction affects future oil extraction by the reduction of oil reserves, the marginal cost is the rental rate plus a term that accounts for the cost of reduction in oil reserve.

The resource constraint in the economy (final goods market clears) implies that:

$$C_t + K_{yt+1} - (1-\delta)K_{yt} + K_{xt+1} - (1-\delta)K_{xt} + (1-\gamma_t)O_t p_t = Y_t \tag{10}$$

where $C_t = Lc_t$ and $K_{xt} + K_{yt} = Lk_t$. An equilibrium in the economy is then characterised by $\{C_t, K_{yt}, K_{xt}, w_t, r_t, \gamma_t\}_{t=0}^{\infty}$ such that Equations (1), (3), (4), (5), (8), (9), and (10) are satisfied.

3.2. Impacts of Price Distortion (σ) at Steady State

We now focus on a steady state where consumption, output in the final goods sector, and domestic oil price distortion are constant, specifically $C_t = C$, $Y_t = Y$, and $\sigma_t = \sigma$. Since $C_t = C$, the equilibrium interest rate in the steady state is constant,

$r = \frac{1}{\rho} + \delta - 1$. From Equations (2) and (4), we can rewrite the interest rate as $r_t = \alpha Y_t / K_{yt}$. Therefore constant Y and r imply that K_{yt} is constant as well, namely $K_{yt} = K_y$. Similarly, from Equation 2, we find that the oil demand is constant as well ($O_t = O$). At the steady state, the resource constraint is transformed into:

$$C + \delta K_y + K_{xt+1} - (1 - \delta)K_{xt} + (1 - \gamma_t)Op = Y \tag{11}$$

where we assume the world oil price (p) is constant in the steady state. Allowing p to change across time will not affect the subsequent results, since p is exogenous to the model. From the production function in the oil sector (Equation 7), we obtain the following relationship among γ, S, and K_x:

$$\gamma_t = \frac{S_t K_{xt}^{\eta}}{O} \tag{12}$$

Then at steady state the economy is characterised by Equations (8), (9), and (11), together with Equation (12).

At the steady state, K_{xt} cannot be constant. If not, then equation (8) implies that the oil reserve is depleting at a constant rate. From Equation (12), γ_t is decreasing at a constant rate. A constantly decreasing γ_t and a constant K_{xt} violate the resource constraint (Equation 11). Similarly, γ_t cannot be constant as well. If γ_t is instead constant (i.e. $\gamma_t = \gamma$), Equation (12) indicates that to maintain a constant level of oil production, K_{xt} must be increasing as the oil reserve (S_t) depletes. Equation (12) also implies $S_t K_{xt}^{\eta} = S_{t+1} K_{xt+1}^{\eta}$, which together with Equation (8) leads to $K_{xt+1} = \frac{K_{xt}}{(1+K_{xt}^{\eta})^{1/\eta}}$. Plug this equation into the resource constraint (Equation 11), we obtain:

$$\frac{K_{xt}}{\left(1 + K_{xt}^{\eta}\right)^{1/\eta}} - (1 - \delta)K_{xt} = Y - C - \delta K_y - (1 - \gamma)Op$$

which suggests that K_{xt} is constant and thus contradicts the requirement that K_{xt} must be increasing across time so that the level of oil production is constant.

Therefore, we explore the dynamics of K_{xt} and γ_t at the steady state where the consumption and output are constant and in particular focus on the impacts of domestic oil price distortion (σ) on the dynamics of the national economy. Plug Equation (12) into Equation (11), we obtain:

$$K_{xt+1} = (1 - S_t p - \delta)K_{xt} + S_t p + N \quad (13)$$

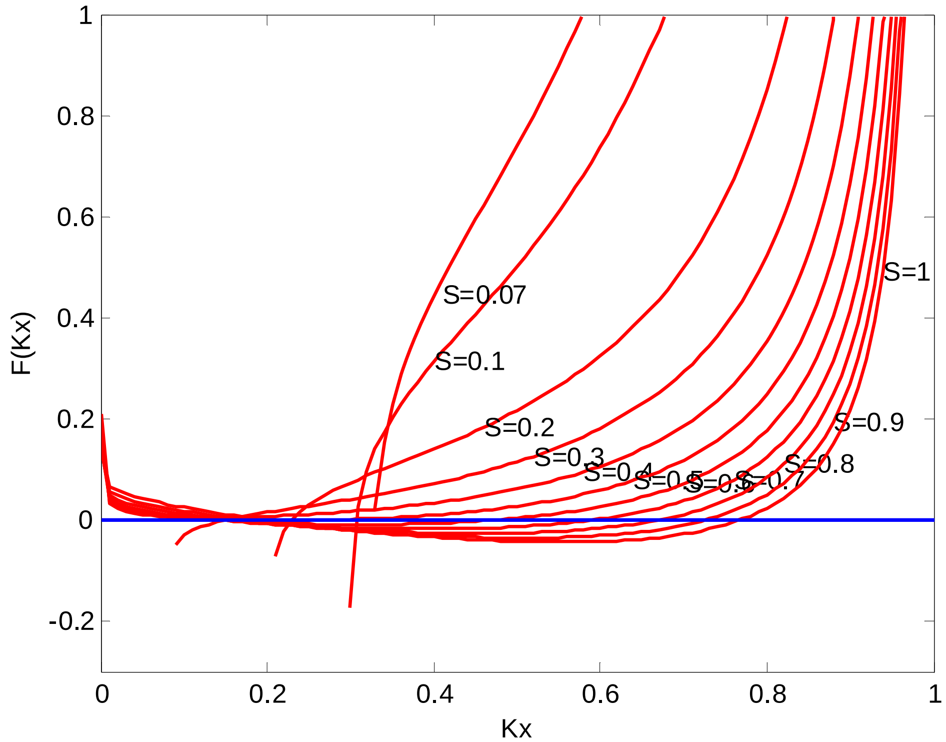
where $N \equiv Y - C - \delta K_y - Op$. Plug Equations (12) and (13) and the steady state values, such as $Y_t = Y$, into Equation (9), and after a series of algebraic manipulations we obtain the following equation:

$$F(K_{xt}, S_t, \sigma) \equiv \frac{\beta Z O^{\beta}\sigma}{S_t K_{xt}^{\eta}(\sigma-1)+O} - \frac{\rho\beta Z O^{\beta}\sigma}{S_t\left(1-K_{xt}^{\eta}\right)[(1-S_t p-\delta)K_{xt}+S_t p+N]^{\eta}(\sigma-1)+O} - \frac{r\left(K_{xt}^{\eta}-K_{xt}\right)}{\eta S_t\left(1-K_{xt}^{\eta}\right)} - \frac{\rho r\left\{[(1-S_t p-\delta)K_{xt}+S_t p+N]^{1-\eta}-[(1-S_t p-\delta)K_{xt}+S_t p+N]\right\}}{\eta S_t\left(1-K_{xt}^{\eta}\right)} = 0 \quad (14)$$

where $Z \equiv \beta A L^{1-\alpha-\beta} K_y^{\alpha}$. Equation (14) defines K_{xt} as a function of S_t and σ, namely $K_{xt} = f(S_t, \sigma)$. Given the initial endowment of oil reserve (S_0), Equations (14), (8), and (12) describe the dynamics of K_{xt} and γ_t recursively.

To further illustrate the impacts of domestic oil price distortion, we carry out a numerical exercise where we set $\alpha = 0.1$, $\beta = 0.5$, $\eta = 0.9$, $\delta = 0.05$, $\rho = 0.95$, $S_0 = 1$, $L = 1$, $A = 1$, $Y = 1$, $C = 0.3$, $p = 1$, and $\sigma \in \{0.5, 0.8, 1.5, 2\}$. Note that given S_t, the equation $F(K_{xt}, S_t, \sigma) = 0$ may have no real solution, one real solution, or more than one real solution. If the equation has no real solution it suggests that the domestic oil sector has been shut down and the economy relies completely on oil imports (i.e. $\gamma = 0$). If the equation has more than one solution then K_{xt} has multiple dynamics. Figure 2 depicts the graphs of $F(K_{xt}, S_t, \sigma)$ at 11 levels of oil reserve where $\sigma = 1.5$. It can be observed that if $S = 0.07$, the equation $F(K_{xt}, S_t, \sigma) = 0$ does not have any real solution.

Figure 2: Graph of F(S(t), K_x(t), other parameters) σ=1.5



Figures 3, 4, and 5 reveal the possible dynamics of K_{xt}, S_t, and 1-γ_t (i.e. oil dependency) respectively. The dynamics are calculated in the following way: (1) first plug S_0 = 1 into Equation (14) to solve for K_{x0}, which we randomly picked one solution if multiple solutions exist; and (2) then given S_0 and K_{x0}, we solve for γ_0 from Equation (12) and S_1 from Equation (9). These two steps are repeated to compute the values of next period K_x, S, and γ.

Not surprisingly, Figure 4 indicates that the oil reserves depletes across time. Even though capital stock in the domestic oil sector appears to increase (Figure 3), in the end the oil reserve is so low that the domestic economy increasingly has to rely on oil imports. When the oil dependency rate approaches 1 (Figure 5), it suggests that the economy will eventually shut down the domestic oil sector.

Regarding the impacts of domestic oil price distortion (σ), Figures 3, 4, and 5 indicate that there exist impacts from the oil price distortion on the dynamics of oil sector capital stock (K_{xt}), oil reserve (S_t), and the oil dependency rate (1- γ_t). Nevertheless, there appears no systematic pattern of such impacts in the three figures.

Figure 3: Dynamics of K_x

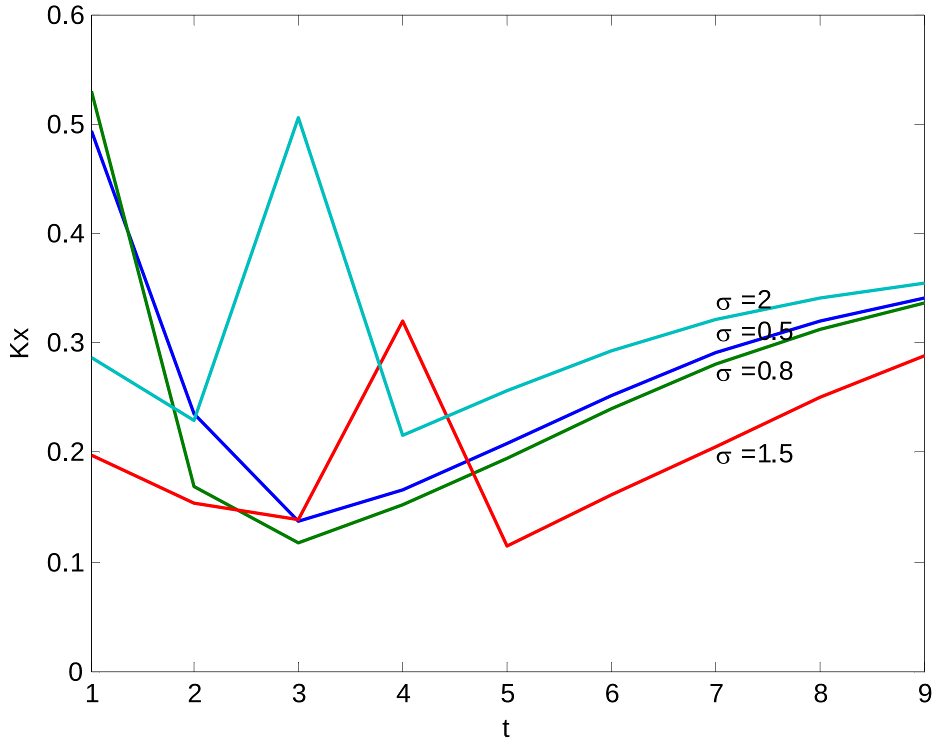


Figure 4: Dynamics of Oil Reserve (S)

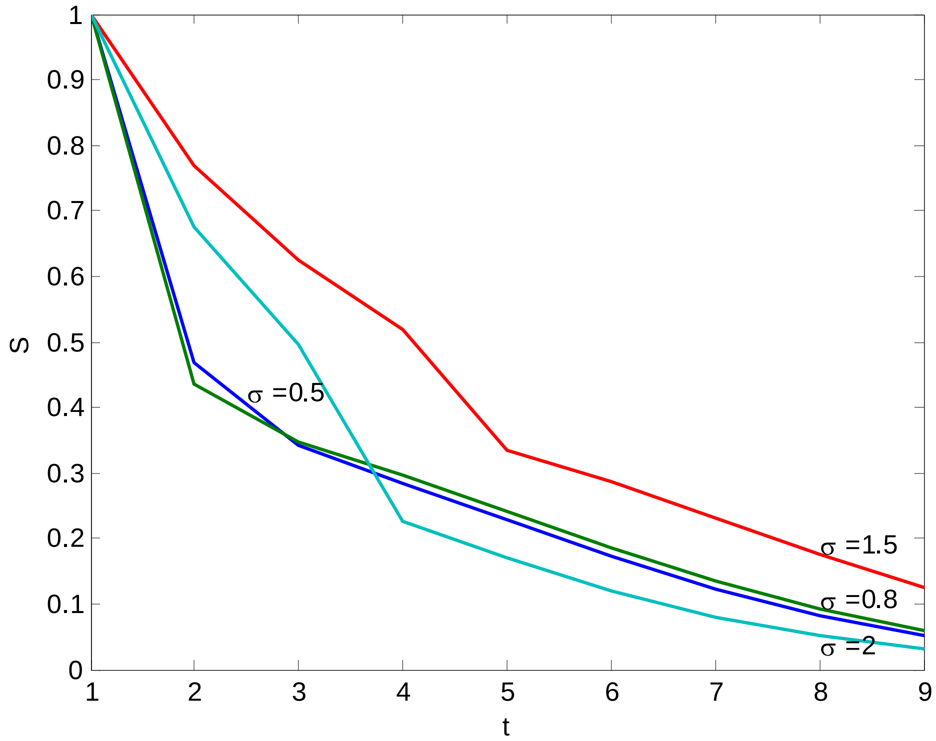
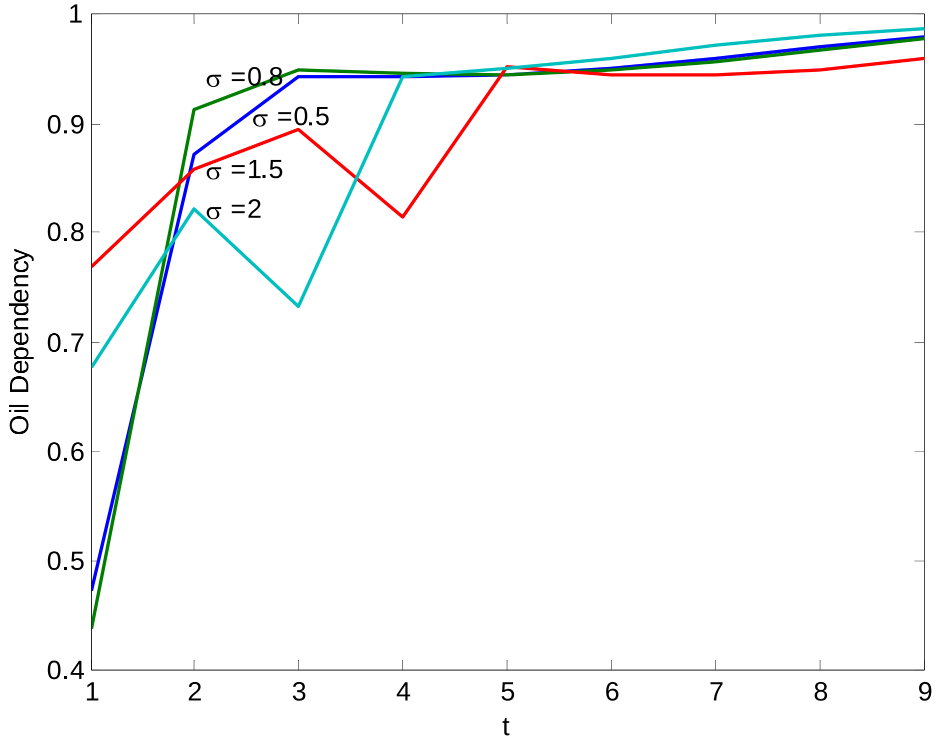


Figure 5: Dynamics of Oil Dependecy (1γ)



4. Empirical Estimations

In Section 3, we investigated the impact of oil price distortion in a two-sector growth model. We now turn to an empirical exercise using time series data from China.

4.1. Empirical Specification

Equations (8) and (9) define the optimal level of capital stock in the oil sector as a function of its one period lag, labour, capital stock in the final goods sector, real interest rate, oil reserve, and oil dependency as follows:

$$K_{xt} = g\left(K_{xt-1}, S_t, L_t, K_{yt}, \gamma_t, \sigma_t, r_t, L_{t-1}, K_{yt-1}, \gamma_{t-1}, \sigma_{t-1}, r_{t-1}\right) \quad (15)$$

where $g()$ denotes the associated functional form derived from Equations (8) and (9). Plug Equation (15) into Equation (7) and use the fact that domestic production of oil must be equal to domestic demand minus oil imports we can obtain the following equation:

$$O_t = \frac{1}{\gamma_t} S_t g\left(K_{xt-1}, S_t, L_t, K_{yt}, \gamma_t, \sigma_t, r_t, L_{t-1}, K_{yt-1}, \gamma_{t-1}, \sigma_{t-1}, r_{t-1}\right)^{\eta}$$

(16)

which can be plugged into Equation (2) to obtain the following equation:

$$Y_t = AL_t^{1-\alpha-\beta} K_{yt}^{\alpha} \frac{1}{\gamma_t^{\beta}} S_t^{\beta} g\left(K_{xt-1}, S_t, L_t, K_{yt}, \gamma_t, \sigma_t, r_t, L_{t-1}, K_{yt-1}, \gamma_{t-1}, \sigma_{t-1}, r_{t-1}\right)^{\beta\eta}$$

(17)

We then use the following logarithm linear specification to approximate Equation (17):

$$ln(Y_t) = \phi ln(Y_{t-1}) + \lambda_0 + \lambda_1 t + \boldsymbol{\theta}' \boldsymbol{Z}_t + u_t$$

(18)

where λ_0, λ_1, □, and $\boldsymbol{\theta}$ are short-run parameters with the long-run parameters being $\lambda_0/(1 -$ □$)$, $\lambda_1/(1 -$ □$)$, and $\boldsymbol{\theta}/(1 -$ □$)$, and $\boldsymbol{Z}_t = (L_t\ K_{yt}\ 1\text{-}\gamma_t\ \sigma_t\ r_t)'$, and u_t is an i.i.d. error term. We used Y_{t-1} to capture the impact of lagged variables such as L_{t-1}, in Equation (17) and $\lambda_0 + \lambda_1 t + u_t$ to capture the rest factors, such as S_t and A. Note that Equation (18) is an autoregressive distributed lag model (ARDL1,0) and we can generalise it by allowing for lags in $\boldsymbol{Z}_t$ and longer lags in Y_t as follows:

$$\phi(L) ln(Y_t) = \lambda_0 + \lambda_1 t + \boldsymbol{\theta}'(L) \boldsymbol{Z}_t + u_t$$

(19)

where $\phi(L) = 1 - \sum_{j=1}^{p} \phi_j L^j$ and $\boldsymbol{\theta}(L) = \sum_{j=1}^{q} \boldsymbol{\theta}_j L^j$ and p and q denote lag length. Since our data are time series, it is not surprising that $\boldsymbol{Z}$s can be non-stationary. Pesaran and Shin (1999) showed that the ordinary least square estimator of the short-run parameters and the corresponding long-run parameters estimates are consistent even if the regressors ($\boldsymbol{Z}_t$) are I(1).

It can also be argued that $\boldsymbol{Z}_t$ can be endogenous, namely $E(u_t|Z_t) \neq 0$. For example, on the one hand oil imports contribute positively to domestic economic growth, while on the other hand, as the economy grows, it may become increasingly dependent on oil imports and specifically a higher level of Y leads to a higher level of γ. This endogeneity can be controlled by including a number of leads and lags of the regressors in differences, which absorb the correlation between regressors and the error term (Stock and Watson, 1993). Therefore, we augment Equation (19) by including the leads and lags of differenced Z and re-write the right hand side variables, as follows:

$$\Delta ln(Y_t) = \lambda_0 + \lambda_1 t + \phi^*(L) ln(Y_t) + \boldsymbol{\theta}' \boldsymbol{Z}_t + \sum_{j=-m}^{m} \Delta \boldsymbol{Z}_{t-j} + u_t \quad (20)$$

where $\phi^*(L) = \sum_{j=1}^{p} \phi_j L^j - L$, Δ denotes the difference operator (i.e. $\Delta = 1 - L$) and m denotes the length of lags. The summation in Equation (20) is made from $-m$ to m and thus leads of differenced $\boldsymbol{Z}$ are included as well.

4.2. Variable Construction and Data

The dataset is a monthly time series from 2004M8 to 2012M8 in China. We obtained the data from the CEIC database, which in turn collects data from different sources. We used two series to measure the output (y). The first one is the industrial production index, which is calculated from a series (percentage change of industrial production index over the corresponding month of previous year) sourced from the International Monetary Fund (IMF), assuming year 1993 is 100. The other is industrial sales in a billion Chinese Yuan sourced from the National Bureau of Statistics (NBS). We used the producer price index for industrial products, which is sourced from the NBS and has a base year of 1997 to deflate the industrial sales. The labour (L) is also sourced from the NBS and is measured as the number of employees in industrial enterprises with the unit being thousand persons. The labour series has missing values, which are replaced by an interpolation.

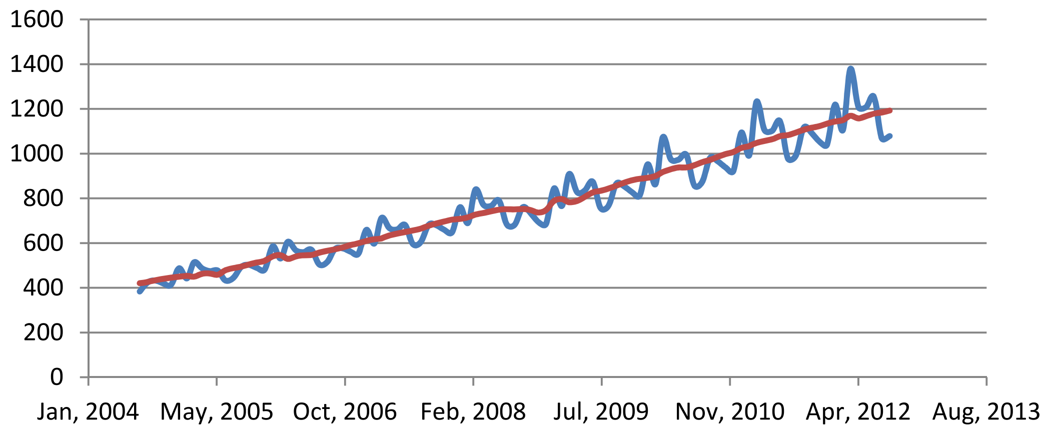
The capital (K_y, in billion Yuan) is constructed from fixed asset investment. First, we calculated the monthly increment of fixed asset investment in secondary industry from year-to-date fixed asset investment data and deflated it using the fixed asset price index with a base year of 2003. Second, we assumed a monthly capital depreciation rate of 0.4 per cent, which translates to a 4.9 per cent per annum depreciate rate, and took 2004M1 fixed asset investment as the initial capital stock. The capital stock in subsequent periods is then calculated as $K_{yt} = I_t + (1 - 0.004) \times K_{yt-1}$, where I_t denotes newly increased fixed asset investment in period t and $K_{y0} = I_0$.

Oil dependency $(1 - \gamma)$ is measured as the share of oil imports in domestic oil consumption and is constructed as follows. First, we extracted the imports and exports of crude oil (million US dollars) and the import and export prices (US dollars per ton), which are sourced from the General Administration of Customs from the CEIC database. From the value and price of imports and exports, we calculated the quantity of exports and imports. Second, we extracted the domestic production of crude oil, which is sourced from the NBS. The oil dependency ratio is then calculated as: $1 - \gamma = Q_{imports} / (Q_{imports} + Q_{production} - Q_{exports})$, where Q denotes quantity.

The real interest rate (r) is calculated as $r = i - \pi$, where i denotes the short-term discount rate sourced from the IMF and π denotes the monthly inflation rate. The monthly inflation rate is calculated from the consumer price index, which is sourced from the International Financial Statistics (IFS) by the IMF and has a base year of 2005. The measures of oil price distortion are constructed as discussed in Section 2.

Since the data are monthly time series, it is not unexpected that they exhibit seasonality. We adjusted the data series by using the X-12-ARIMA Seasonal Adjustment Program to eliminate the influence of seasonal fluctuation[2]. The X-12-ARIMA is a standard approach used by the US Census Bureau for seasonal adjustment of time series data. Figure 6 presents the series of industrial production index before and after de-seasonalisation. The blue curve is the original series and it is evident that it contains seasonality in addition to an upward trending. The de-seasonalised series (red curve) appears to eliminate the seasonality while maintaining the same upward trending.

Figure 6: Industrial Production Index, 1993=100



Source: CEIC Database.

[2] Details of the X-12-ARIMA can be found at http://www.census.gov/srd/www/x12a/.

4.3. Unit Root Tests

We first carried out unit root tests to check the stationarity of the time series. Table 1 reports the results where both the Augmented Dickey-Fuller (ADF) unit root test (Dickey and Fuller, 1979) and Phillips–Perron (PP) unit root test (Phillips and Perron, 1988) are used. It can be observed that some variables are I(1), while the others are I(0). The capital stock, real interest rate, and oil dependency ratio are all I(0) where the null hypothesis of unit root is rejected at the 1 per cent level.

For the three measures of domestic oil price distortion, since Figure 1 suggests that there exists structural break, we carried out the Andrews and Zivot (1992) unit root test that allows for a structural break. Although results in Table 1 indicate that these three measures are I(1), the Andrews and Zivot test suggests that they are I(0) with the test statistic being -5.68, -6.05, and -5.32 for $\ln\sigma_1$, σ_2, σ_3 respectively, which are all significant at the 1 per cent level.

The industrial production index and industrial sales are I(1). For the industrial sales, the ADF test with time trend obtains a test statistic of -3.8 with a *p*-value of 0.016 and the PP test with time trend obtains a test statistic of -3.44 with a *p*-value of 0.046. The test statistics for level variables with no time trend are insignificant and test statistics for differenced variables are all significant at 1 per cent level. Therefore at the 1 per cent significance level, industrial sales are I(1). The labour series is also considered to be I(1) at the 1 per cent level since the test statistics of both ADF and PP with time trend for level variable are only significant at the 10 per cent level and the test statistics for first differenced variable are significant at the 1 per cent level. Given that variables are a mixture of I(1) and I(0), the ARDL modelling is an appropriate approach because that it can be applied when variables are of different order of integration, which is considered to be the main advantage of ARDL modelling (Pesaran and Pesaran, 1997).

Table 1: Unit Root Tests

Variables	Levels ADF Constant	Levels ADF Constant + Trend	Levels PP Constant	Levels PP Constant + Trend	First Difference ADF Constant	First Difference ADF Constant + Trend	First Difference PP Constant	First Difference PP Constant + Trend	Results
Industrial sales (lnY)	-1.37	-3.8**	-1.85	-3.44**	-16.85***	-17.08***	-17.81***	-18.63***	I(1)
Industrial production index (lnY)	-1.51	-2.1	-1.78	-1.9	-9.56***	-9.68***	-9.63***	-9.83***	I(1)
Labour (lnL)	-1.52	-3.41*	-1.62	-3.17*	-12.76***	-12.9***	-13.3***	-13.42***	I(1)
Capital (lnK)	-16.82***	-18.31***	-10.67***	-15.34***	-5.17***	-5.77***	-6.29***	-6.44***	I(0)
Real interest rate (r)	-6.11***	-6.33***	-6.23***	-6.45***	-17.77***	-17.69***	-20.21***	-20.09***	I(0)
Oil dependency (1-γ)	-3.17**	-9.91***	-2.68*	-9.98***	-19.16***	-19.08***	-24.29***	-24.17***	I(0)
Oil price distortion ($\ln\sigma_1$)	-1.81	-2.35	-1.88	-2.54	-7.77***	-7.74***	-7.59***	-7.55***	I(1)
Oil price distortion (σ_2)	-2.03	-2.57	-2.11	-2.76	-7.65***	-7.62***	-7.45***	-7.4***	I(1)
Oil price distortion (σ_3)	-2.28	-2.79	-2.22	-2.79	-8.81***	-8.77***	-8.78***	-8.73***	I(1)

Note: The null hypothesis is that the series contain a unit root. ***, **, and * denote significance at the 1, 5, and 10 per cent respectively

4.4. Regression Results

To estimate Equation (20), we have two measures of industrial output (i.e. industrial sales and industrial production index) and three measures of domestic oil price distortions, which lead to six regressions. In the following, we described the empirical exercise using industrial sales as the measure of industrial output and the ratio of China's gasoline price against US gasoline price ($\ln\sigma_1$) as a measure of oil price distortions and the rest regressions will follow the same specification and serve as sensitivity analysis. The first step in the exercise is to determine the length of lags. We used both the Akaike Information Criteria (AIC) and the Schwartz-Bayesian Criteria (SBC) to determine lag length and chose the length of lags that yielded a minimal AIC and SBC. The maximum length of lags is set to be five[3]. Both AIC and SBC suggest an optimal lag length of one for both the dependent and explanatory variables in Equation (20).

Table 2 reports the regression results where the left panel is the estimated results of short-run coefficients as in Equation (20) and the right panel is the associated long-run coefficients. After the regression, we carried out a set of diagnostic tests. The Breusch-Godfrey test for serial correlation finds no evidence of first, second, third, fourth, or fifth order autocorrelation. A LM test for autoregressive conditional heteroskedasticity (ARCH) also failed to reject the null hypothesis of no ARCH effects at the 1 per cent level. The Breusch-Pagan/Cook-Weisberg test for heteroskedasticity obtains a test statistic of 22.11, which failed to reject the null of homoskedasticity at the 1 per cent level. The Ramsey RESET test obtains a test statistic of 3.63, and failed to reject the null of no omitted variables at the 1 per cent level. We also examined the stationarity of the residual by conducting both ADF and PP tests with both rejecting the null hypothesis of unit root at 1 per cent level. Therefore, the regression is appropriate.

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[3] Longer length leads to estimation problem due to multicollinearity.

Table 2: Regression Results with Industrial Sales and Gasoline Price Ratio

	Short-run coefficients			Long-run coefficients		
	Coef.	Std. Err.	t	Coef.	Std. Err.	t
$\ln y_{t-1}$	-0.8116***	0.1050	-			
t	0.0067***	0.0012	5.79	0.0082***	0.0010	7.89
$\ln l_t$	0.3565**	0.1368	2.61	0.4393**	0.1554	2.83
$\ln k_t$	0.0848**	0.0368	2.31	0.1045**	0.0419	2.50
r_t	-	0.8069	-4.1	-4.081***	0.8842	-
oil dependency (1 –	0.4848**	0.2241	2.16	0.5974**	0.2597	2.30
distortion ($\ln\sigma_{1t}$)	-	0.0241	-	-	0.0233	-
constant	1.3582	1.3785	0.99	1.6735	1.7048	0.98
No. of obs.	94					
F	9.5					
Adjusted R^2	0.67					

Note: the dependent variable is $\Delta\ln(y_t)$; the estimated coefficients of ΔZ_t are not reported to save space; ***, **, and * denote significance at the 1, 5, and 10 per cent respectively.

The long-run (steady state) coefficients in Table 2 are computed as the short-run coefficients divided by the negative of the coefficient of $\ln y_{t-1}$ and the associated standard errors are computed using the delta method. For example, let φ and θ_l (one element of $\boldsymbol{\theta}$ in Equation 20) denote the long-run and short-run coefficients of the labour ($\ln l_t$) respectively and □$_y$ denote the coefficient of lagged industrial output ($\ln y_{t-1}$). Let □$_y$ = □ – 1 in Equation 20, then $\varphi = -\theta_l$ / □$_y$. To obtain the associated standard error, we first linearized φ by the first order Taylor approximation at the point estimates of θ_l and □$_y$, namely $\varphi \cong -\hat{\theta}_l/\hat{\phi}_y - (\theta_l - \hat{\theta}_l)/\hat{\phi}_y + \hat{\theta}_l(\phi_y - \hat{\phi}_y)/\hat{\phi}_y^2$, where the hat denotes point estimate. Then $\widehat{var(\varphi)} = \widehat{var(\theta_l)}/\hat{\phi}_y^2 + \hat{\theta}_l^2\widehat{var(\phi_y)}/\hat{\phi}_y^4 - 2\hat{\theta}_l\widehat{cov(\theta_l, \phi_y)}/\hat{\phi}_y^3$, and $se = \sqrt{\widehat{var(\varphi)}}$, where var, cov and se denote variance, covariance and standard error respectively

In Table 2, the negative coefficient of lagged industrial sales suggests that industrial growth rate decreases as it grows bigger.[4] This regressive development is

[4] Note $\Delta\ln(y_t)$ is approximately growth rate of industrial output.

consistent with the findings of Sheng and Shi (Sheng and Shi, 2013) which states that economic growth across countries converges unconditionally. The growth rate exhibits a significant increasing trend, possibly owing to technological progress and consequently labour and capital contribute positively to industrial growth. The real interest rate exerts a significantly negative impact on the industrial growth rate. A higher real interest rate means a higher investment cost, which decreases investment in the goods and oil sector (*ceteris paribus*) and subsequently impairs industrial growth. This supports arguments in the literature that the actual reason for the slowing of economy growth after oil price shocks is the tightening of the monetary policy (Bernanke, *et al*., 1997). Oil dependency ($1-\gamma_t$) appears to affect positively on industrial growth in the short run, reflecting the importance of oil imports in domestic industrial development.

The coefficient of domestic oil price distortion, measured as the ratio of domestic gasoline price against US gasoline price, is negative and significant at the 1 per cent level. This suggests that the oil price distortion impairs industrial growth. A 10 per cent increase in the distortion leads to a reduction of 0.89 per cent in the industrial growth rate.

In the long run (steady state), the coefficients of all the variables are significant and maintain the same sign as in the short run. The steady state industrial sales exhibit an increasing time trend driven by technological progress. Labour and capital contribute 43.9 and 10.5 per cent to the industrial sales respectively, which adds up to less than one because there are other factors such as oil that contributes to the industrial sales. The real interest rate exerts a significant negative impact on the industrial sales similar to the short run, due to its negative impact on investment. The oil dependency rate also significantly and positively affects industrial sales in the long run same as in the short run. The negative impact from domestic oil price distortion persists to the long run and with a 10 per cent increase in the distortion the steady state industrial output decreases by around 1.1 per cent.

Table 3 reports the results where the dependent variable is the industrial production index. Due to the manner in which the original data was reported, the original series is the percentage change of industrial production index over the corresponding month of previous year, we had to assume that in each month of 1993 the production index is 100 in order to calculate the index from 2004M8 to 2012M8. Owing to this assumption, the results in Table 3 serve only as a comparison to those in Table 2. Compared with Table 2, the negative impacts of oil price distortion continue to hold in the short and long run, even though the magnitude is smaller. The coefficients of lagged industrial production index, time, and capital have the same sign as those of Table 2, while their magnitude is different. Moreover, the coefficients of labour, real interest rate, and oil dependency rate are now insignificant at the 1 per cent level. Therefore, even though we observed some variations in the coefficient estimate between Tables 2 and 3, the negative impact of oil price distortion appears to be robust to different measures of industrial production.

Table 3: Regression Results with Industrial Production Index and Gasoline Price Ratio

	Short-run coefficients			Long-run coefficients		
	Coef.	Std. Err.	t	Coef.	Std. Err.	t
$\ln y_{t-1}$	-0.3880***	0.0848	-4.57			
t	0.0023***	0.0007	3.18	0.0059***	0.0009	6.40
$\ln l_t$	0.0690	0.0520	1.33	0.1779	0.1273	1.40
$\ln k_t$	0.0637***	0.0159	4	0.1641***	0.0366	4.48
r_t	-0.4185	0.2881	-1.45	-1.0787	0.7263	-1.49
$1-\gamma_t$	0.0391	0.0829	0.47	0.1007	0.2125	0.47
$\ln \sigma_{1t}$	-0.0254**	0.0097	-2.61	-0.0654***	0.0188	-3.47
constant	1.0640*	0.5996	1.77	2.7426*	1.3945	1.97
No. of obs.	94					
F	4.47					
Adjusted R^2	0.45					

Note: the dependent variable is $\Delta\ln(y_t)$; the estimated coefficients of ΔZ_t are not reported to save space; ***, **, and * denote significance at the 1, 5, and 10 per cent respectively.

4.5. Robustness

The previous exercise revealed that the oil price distortion exerts a significant and negative impact on industrial production in the short and long run, which is robust to different measures of industrial production. However, is this finding robust to different measures of oil price distortion? In this section, we explore such impacts using alternative measures of oil price distortion.

The alternative two measures we used are described above. We re-estimated Equation (20) using these two measures, where the length of lag is one and Table 4 reports the results. Comparing the estimated coefficient of oil price distortion, the sign is negative in both regressions, consistent with the findings in Table 2, although there exist variations in the magnitude. The coefficients of the other variables are approximately in line with those of Table 2. Therefore, the negative impact of oil price distortion in the short and long run is robust to these two alternative measures of oil price distortion.

Table 4: Regression Results with Alternative Measure of Oil Price Distortion

	[1]						[2]					
	Short-run coefficients			Long-run coefficients			Short-run coefficients			Long-run coefficients		
	Coef.	Std. Err.	t	Coef.	Std. Err.	t	Coef.	Std. Err.	t	Coef.	Std. Err.	t
$\ln y_{t-1}$	-	0.1051	-7.97				-	0.1097	-6.93			
t	0.0067***	0.0011	6.04	0.0080***	0.0010	8.28	0.0058***	0.0012	4.83	0.0076	0.0012***	6.27
$\ln l$	0.4317***	0.1349	3.2	0.5158***	0.1447	3.56	0.3944**	0.1541	2.56	0.5190	0.1820**	2.85
$\ln k$	0.0966***	0.0362	2.67	0.1154**	0.0389	2.96	0.1052***	0.0394	2.67	0.1384	0.0475***	2.92
r	-	0.7830	-3.88	-	0.8160	-4.45	-	0.7625	-4.04	-	0.9285***	-4.37
$1-\gamma$	0.3735*	0.2130	1.75	0.4463*	0.2463	1.81	0.2689	0.2396	1.12	0.3538	0.3038	1.16
$\ln\sigma_I$	-	0.0172	-4.18	-	0.0153	-5.60	-	0.0198	-3.31	-	0.0207***	-4.17
constant	0.6472	1.3292	0.49	0.7733	1.5930	0.49	0.4476	1.5310	0.29	0.5890	2.0219	0.29
Number of obs	94						94					
F	10.79						7.87					
Adjusted R2	0.7						0.62					

Note: the dependent variable is $\Delta\ln(y_t)$, where y is industrial sales; [1] uses the percentage difference of gasoline price between China and US as a measure of oil price distortion; [2] uses the absolute value of such difference as a measure of oil price distortion; the estimated coefficients of ΔZ_t are not reported to save space; ***, **, and * denote significance at the 1, 5, and 10 per cent respectively.

Figure 1 suggests that there exists a structural break for oil price distortion in 2009m1. Therefore, in the above exercise, we also included a dummy variable that takes a value of one in the time after 2009m1 into the regression. The estimation finds that the coefficient of the dummy variable is insignificant at the 1 per cent level and there is little variation in the coefficients of the other variables. Thus, this structural break appears not to significantly affect the regression results.

5. Policy Implications

Since price distortion, which occurs mainly due to price regulation, impairs economic growth this finding contradicts a common argument of energy price regulation; price regulation can shield the domestic economy from negative oil price shocks in the world market. Consequently, this study supports energy price deregulation. It also advocates for the removal of policies and interventions, such as subsidies, that may distort domestic energy prices because they are detrimental to the domestic economy. A market oriented energy price regime may improve the resilience of the domestic economy to global oil price shocks. Although the removal of subsidies is a sensitive issue and difficult, a gradual approach is still possible as China has demonstrated in the past (Lin and Jiang, 2011). This study also implies that a monetary policy, which may be tightened over concerns about inflation resulting from international price shocks, should be finely tuned to avoid impairing economic growth.

This study also leads to a better understanding of energy market integration. Price regulations are the main obstacles to energy market integration. Given that price regulations lead to undesired price distortion, it is worthwhile promoting the integration of the energy market between net energy exporters and importers, which helps to eliminate price distortions. This point is particularly relevant to East Asia, since many East Asian countries still have tight regulations on energy pricing. Brunei, Indonesia, and Malaysia are excellent examples with practically fixed gasoline prices.

6. Concluding Remarks

This paper explores the impact of oil price distortion on the domestic economy, both theoretically in a two-sector growth model and empirically in China. In the theoretical model, we illustrated the impacts of price distortion on the state oil sector capital accumulation and oil dependency. Empirically, using a specification derived from the theoretical model, we applied the ARDL modelling technique to a monthly time series dataset in China from 2004M8 to 2012M8 and found that oil price distortion jeopardises industrial growth in the short run and furthermore this negative impact persists to the long run. The negative impact of oil price distortion appears to be robust to different measures of industrial production and oil price distortion.

Price control is a significant barrier to energy market integration. Since the induced distortion dampens domestic economy, the justifications to maintain price control are seriously undermined. Therefore, the finding of this paper supports energy market integration that many regions, such as East Asia, are advocating.

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CHAPTER 10

Economic Growth, Regional Disparities and Energy Demand in China: Implication for Energy Market Integration in East Asia

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East Asia is actively promoting Energy Market Integration (EMI). The integration process, however, takes a long time and there is no clear picture of its future. This paper attempts to explore a possible scenario for an integrated energy market in East Asia by analysing China's cross-province energy demand, which demonstrates a impeccable integrated energy market. The panel data of 30 provinces from between 1978 and 2008 indicates that economic development tends to increase the energy demand, while EMI will generally reduce the response of energy consumption prices to energy demand and production through cross-province trade of energy products. In addition, the effects can be reduced through reducing transportation costs and improving marketisation levels. This finding has important policy implications since it suggests that EMI is beneficial to the region by facilitating the diversified energy demand pattern across countries.

Keywords: economic growth, regional disparities, energy demand, energy market integration, China
JEL Classification: O13, O53, F15

1. Introduction

There has been rapid economic growth in China over the past three decades driven primarily by two important factors, industrialisation and urbanisation. As one of the major inputs into these twin processes, China's energy demand has been strong during that period, outstripping domestic production and making the country a net importer of crude oil since 1993 and coal since 2009. These changes in energy demand, due to economic growth, is reshaping the pattern of energy trade in the East Asian Summit (EAS) region and throughout the world. This makes understanding the future trends in China's energy demand a matter of both national and global importance (Lee, 2005; Lee and Chang, 2008).

Examining the relationship between economic growth and energy demand in China is a challenging task from an empirical perspective. Although there is evidence regarding to the relationship between economic growth, its drivers, and energy demand for a number of large advanced economies (e.g., the United States and the European Union), it is unclear which of these relationships are relevant to understanding how economic growth and its drivers affect the total energy demand and distribution in China. In particular, it is likely that China's energy demand will be unique, because of significant regional disparities in industrialisation and urbanisation that are not replicated elsewhere.

Using time series and cross-province data, this paper analyses the changes in provincial-level energy demand due to industrialisation and urbanisation, two important drivers behind economic growth. It also examines their impact on the market price of energy products between 1979 and 2008. The purpose is to clarify the role of a unified energy market to deal with the gap between energy demand and supply, which is the result of imbalanced cross-regional economic development. Three questions will be answered in sequence: (1) how to reduce the provincial-level energy demand from total energy consumption given the absence of accurate available data; (2) the impact of energy demand on energy consumption prices at the provincial level in China where there is already an integrated energy market; and (3) other factors such as cross-province disparities in transportation costs and market monopoly, which affect energy prices variation across regions.

The results show that economic growth and its drivers are the most important factors affecting energy demand and its distribution across regions in China in recent years and raising the market price of energy products. Moreover, in an integrated energy market, price effects of the increased energy demand have been significantly reduced. This suggests that market integration helps alleviate the impact of economic growth on energy demand in specific regions. In addition to market integration, some regional specific factors, such as transportation costs and market structure, can also affect energy consumption prices. Consequently, public policies need to be carried out with market integration in order to minimise the negative impact of increased energy demands due to economic growth.

Contributing to the previous literature, this paper explores the empirical relationship between the market price and energy demand by using cross-provincial data in China in an integrated market. This provides insights into the role of international market integration policies in solving the imbalance between energy demand and supply due to the imbalance of economic growth within the EAS region. The results will inform EAS policy makers on the possible scenarios of achieving a fully EMI.

The case study on China is also expected to have important policy implications for Energy Market Integration (EMI) in the EAS region. East Asia is actively promoting EMI but the integration process takes time and there is no clear picture of its future. Using China's case, this paper attempts to provide a possible scenario of an integrated market by analysing the cross-province energy demand in China.

Rapid economic growth has taken place in the major East Asian countries over the past few decades and has significantly increased the energy consumption in those countries. It is, however, still unknown how the increased energy demand is linked to economic growth in the region and whether market integration will help to alleviate the impact. In addition, there are huge disparities among the EAS countries such as difference in income level, which was about 60 times in 2010 (World Bank, 2012). Such similarity encouraged us to study the future of EAS' EMI using China's provincial data. Although the GDP per capita among the provinces is only 5 time more[1] and the average size of the economy of each province is larger than many EAS countries.

The remainder of this paper is arranged as below. Section 2 discusses the relationship between economic growth and energy demand from a theoretical perspective. Urbanisation and industrialisation are identified as the two important factors driving energy demand across regions in China. Section 3 develops the empirical method. In particular, economic development induced energy consumption is split from total energy demand at the provincial level by using information on urbanisation and industrialisation, so that its impact on energy consumption prices in an integrated market can be examined. Sections 4 and 5 analyses the empirical results. As expected, economic growth is a major driver of energy demand and leads to a regional disparity in consumption price, while integrated market arrangement tends to be a remedy. Section 6 extends the discussion to the international market and produces policy implications for energy market integration in the EAS region and section 7 makes the conclusions.

[1] http://news.xinhuanet.com/local/2012-02/07/c_122667889.htm

2. Economic Growth and Energy Consumption: Implications for Regional Analysis

How economic growth can affect energy demand and its distribution across regions is an on-going debate in the literature. Theoretically, stable economic growth was considered a sufficient condition for stable energy consumption growth by its on-going impact on energy-intensive sectors, such as capital equipment, transport, and consumer durables. In practice, however, many developed economies experienced a slowdown in energy consumption growth, despite continued economic growth overall (Crompton and Wu, 2005). This gave rise to the concept of an inverted U-shaped long-term relationship between GDP growth and energy consumption growth, or equivalently between per capita GDP and per capita energy consumption.

The asymmetric relationship between GDP and energy consumption is a consequence of economic growth and development. The two major components of which are industrialisation and urbanisation (Sheng, *et al.*, forthcoming). At low levels of per capita GDP—in the pre-industrialisation stage described above—the national output is concentrated mainly in the primary industry, which is characterised by a relatively low per capita energy consumption. As the per capita GDP rises and the economy enters the industrialisation stage, changing preferences in production and consumption produce a gradual shift towards more energy-intensive products, including infrastructure and housing construction, investment in capital equipment, and the energy intensive manufacturing industry. Urbanisation rates rise significantly during this stage as well, underpinning much of the change in consumer preferences and industrial structure. During this stage, energy consumption growth exceeds GDP growth and per capita energy consumption increases considerably. In the post-industrialisation stage, while per capita income continues to rise, urbanisation rates tend to plateau and this, combined with the on-going shift towards services and high technology products, drives the growth of per capita energy consumption down.

Historical data for the early industrialisers illustrates the idea of a relationship between per capita energy consumption growth and per capita income growth, although it is clear that the relationship varies over time and place. In 1973 the United States reached peak energy consumption per capita of 8.5 tons of oil equivalent with a GDP per capita of $180,000.[2] Energy consumption per capita remained above 8.0 tons of oil equivalent until 1980 and fell as low as 7.1 tons of oil equivalent in 1983, fluctuating between 7.1 to 7.9 tons of oil equivalent since that time. Japan peaked later than the US with a lower per capita energy consumption of 4.1 tons of oil equivalents and a higher GDP per capita of $36,700. In 1970, Britain reached its peak energy consumption at a lower per capita energy consumption than the US with a lower per capita income, while Germany's peak energy consumption was higher and occurred at a lower per capita income level. In contrast, energy consumption per capita in South Korea and Brazil, recent industrialising economies, has not yet revealed any downturn. By 2010, South Korea's energy consumption per capita reached 5.2 tons of oil equivalents, which was around 10 times the level in 1974. During this period per capita income increased five-fold to reach $16,373, close to the turning point for the United States but well below Japan's. By 2010, Singapore's per capita energy consumption of 13.8 tons of oil equivalents was higher than any of the early industrialisers' peak levels, as was its per capita income of $32,538 (BP, 2011; World Bank, 2012).

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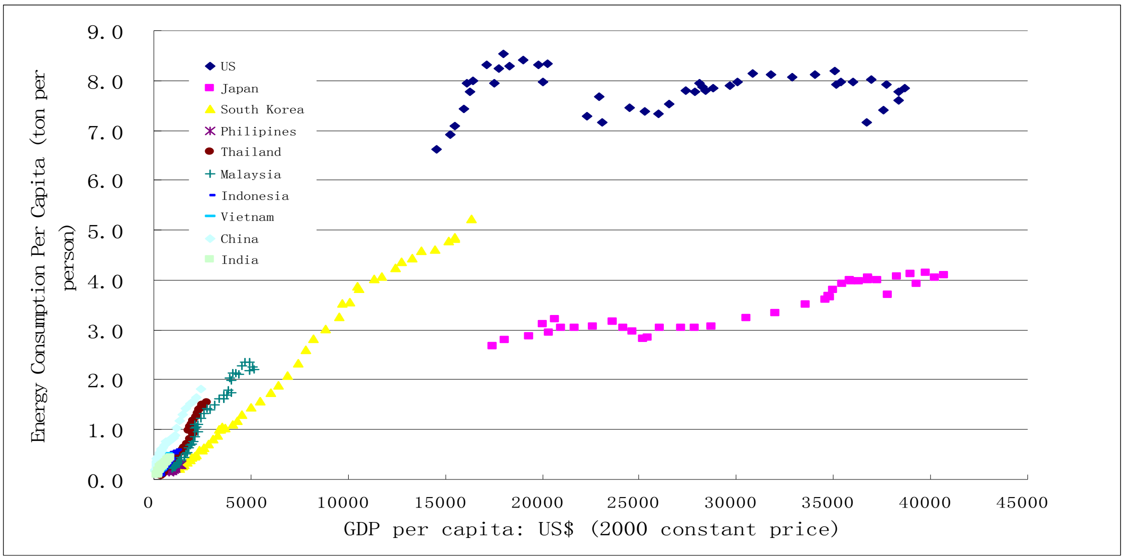
[2] Data used here is drawn from World Bank Development Indicators and BP Energy Statistics 2012. All per capita income reported in 2000 prices.

Figure 1: Relationship between Energy Consumption per capita and GDP per capita: 1965-2010



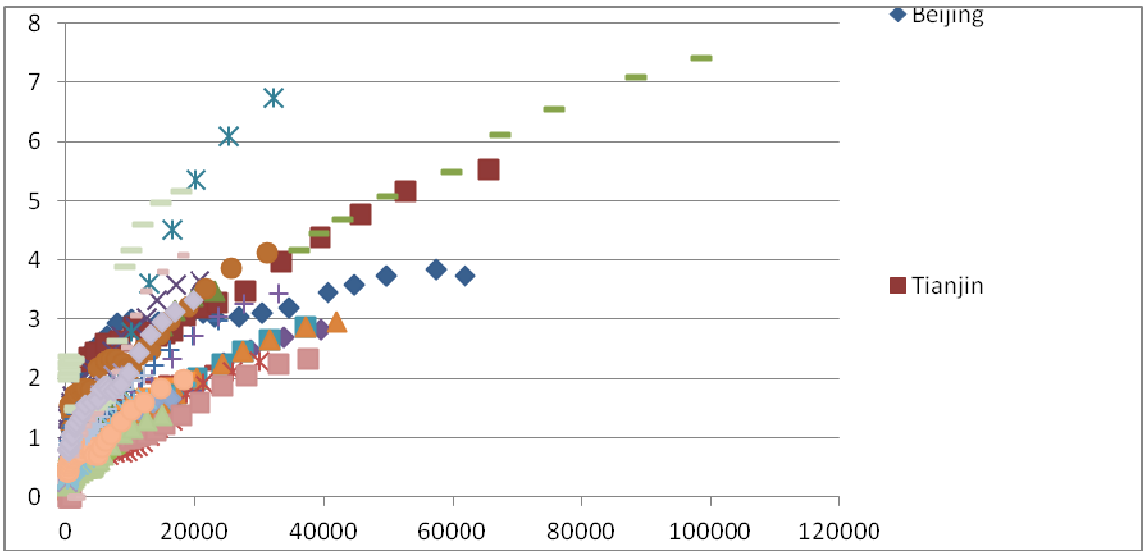
Source: World Development Indicator Database, World Bank (World Bank, 2012).

Although cross-country case studies provide some useful information, it is still unclear whether it is relevant to understanding how economic growth and its drivers may affect the total energy demand and its distribution in China.

As an alternative to using the experiences of other countries to understand the present and future trajectory of China's energy demand, regional-level (particularly provincial level) analysis offers a productive line of research. While there are certainly some regional specific characteristics that are likely to make energy demands differ across provinces, as they do across countries, it seems reasonable to assume that China's less-developed regions are likely to replicate the past trends of its leading provinces than that of other countries (Demurger, 2001). In the case of energy, a catching up period might be expected between poor and rich regions (Crompton and Wu, 2005). This is because all regions within China (under the direction of a unique central government) share the same development strategy and build their energy demand in an integrated energy market. Therefore, the disparity in economic growth can be used to derive the variation in the induced energy demand across regions, such as the role of market integration in reducing the gap between energy demand and supply, and should be thoroughly examined.

In line with the substantial differences in terms of economic development among China's provinces, there are also substantial differences in energy consumption per capita. As illustrated in Figure 1, Shanghai's energy consumption per capita of 7.4 tons of oil equivalents in 2008 was 6.2 times higher than Jiangxi's, which was only 1.2 tons of oil equivalents per capita. Shanghai's GDP per capita is 6.7 times higher than Jiangxi. Although both Shanghai and Jiangxi's energy consumption per capita are still increasing on account of their relative lower income per capita (relative to industrialised countries), the potential for further increase in Shanghai's energy consumption per capita would be less than Jiangxi, since its per capita energy consumption is past the peak of both Britain and Japan. A similar pattern can also been observed for the trans-temporal changes in energy consumption in the same province where energy consumption per capita is increasing with their GDP per capita.

Figure 2: Relationship between Energy Demand and Income per Capita across Regions in China



Source: China Energy Statistical Yearbook, various years.

The above theoretical analysis of the inversed U-shaped relationship between energy consumption and income per capita provides useful insights to explain the interaction between economic development, regional disparity, and energy consumption across regions. Generally, an economy experiencing an industrialisation stage may consume more energy products than their counterparts in the pre and post-industrialisation stages. Since such increased energy demand is a temporary phenomenon, it could be satisfied by re-allocating the resources to more efficient users. As a consequence, the aggregate energy demand would be more stable in an integrated market as long as there is an efficient re-allocation mechanism and all participants could overcome the bottleneck of energy consumption for industrialisation.

Although the logic is coherent, testing it empirically is still a challenge. On the one hand, the statistics for total energy demand contain many regional specific factors beyond economic development, including consumption preference changes and production technology differences among others. On the other hand, although the GDP per capita is a good measurement of economic development, the variable is highly correlated to the energy consumption income effects and thus could not be directly used. To deal with these two problems, the following proposes an instrumental method to reduce the total energy demand into economic development related demand and other energy demand by using the Chinese provincial level data. A further regression of energy consumption price in the integrated energy market on economic development, induced energy demand may provide implications on how market integration can alleviate the demand shocks.

3. Methodology and Data

To identify the energy demand related to economic development, it is essential to identify the factors that characterise economic development stages driving the energy demand. Based on the work of Chenery, *et al*. (1986),we choose three main factors characterising economic development which affect energy demand in China, these include industrialisation, urbanisation, and the fixed asset investments. While other factors, such as consumer preferences and energy saving technology progresses play a role in determining energy demand, the above three factors determine a significant proportion of energy consumption in China at the regional level (Golley, *et al*., 2013). These factors are representative of the demand-side perspective, which is the primary interest here. The importance of the last item stems from the observation that levels of investment will increase as the industrial structure becomes more capital intensive and as the demand for infrastructure associated with urbanisation rises (Kuznets, 1965).

Using the information from province-level industrialisation, urbanisation, and fixed asset investments, a dynamic panel data regression (Arellano and Bond, 1991) can be used to reduce total energy demand to specify the impact of economic growth on energy demand. Specifically, we regressed the total energy consumption on measures of industrialisation, urbanisation and fixed assets investment per capita, and use the coefficients of these three variables to predict energy demand associated with economic development. To make the regression immune to potential endogeneity/simultaneity problems due to the omitted variables, we adopted the General Method of Moment (GMM) for the estimation.[3] The difference between the total energy demand and the predicted energy demand associated with economic

[3] A similar method has been used by Castro, *et al*. (2012) for splitting the firms' sunk costs from total costs.

develop is defined as the energy consumption due to other factors (including regional specific effects).

Equation (1) specifies the regression model that is used for such estimation:

$$\begin{aligned} \ln(Energy_{it}) = \beta_0 + \beta_1 Industrialization_{it} + \beta_2 Urbanization_{it} \\ + \beta_3 \ln(FixedAssetInv_{it}) + u_i + \varepsilon_{it} \end{aligned} \quad (1)$$

Where $\ln(Energy_{it})$ is the apparent energy consumption per capita in province i at time t, $Industrialization_{it}$, $Urbanization_{it}$ and $FixedAssetInv_{it}$ are an industrialisation index (the share of secondary and tertiary industry in total output value), the urban share of the population and the amount of fixed asset investment per capita at 2000 constant prices. u_i represents the time invariant specific effects of each province. It is to be noted that Equation (1) is not a specification based on the demand function. Instead, it is derived from the major components of energy demand at the aggregate level.

Data used for reducing energy demands are drawn from a variety of sources. The data for the consumption of energy products by provinces is available for 30 provinces between 1978 and 2008 in various issues of the China Energy Statistical Yearbook.[4] The industrialisation index, urban population shares, and fixed asset investment ratios are also available for the same 30 provinces and the same time period in China's Comprehensive Data Collection 60 Years: 1949-2008 (NBS, 2010).

After reducing the provincial energy demand per capita, we can further analyse the impact of energy demand per capita on equilibrium prices in market at a steady state. The basic model is an empirical function linking the equilibrium energy consumption price to demand, supply, and other policy instruments. The function is

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[4] Sichuan (because Chongqing start to split since 1995), Fujian, Hainan, Tibet (the latter three have no complete datasets).

derived by equalising a standard energy demand, a standard energy supply function, the detailed derivation and is shown in Appendix A.

In this function, energy consumption prices in equilibrium are determined by energy demand due to different drivers, energy production, and other factors X_{it} (or W_{it} and Z_{it} in Appendix A), as shown in Equation (2). These factors affecting shift of demand and supply curves include preference/technology changes and other policy instruments such as public infrastructure, market arrangements, and so forth.

$$\ln(Price_{it}) = \gamma_0 + \gamma_1 \ln(\hat{Energy}_{it}) + \gamma_2 \ln(Prod_{it}) + \gamma_3 Tra_{it} + \gamma_4 Mkt_{it} + v_i + u_{it} \qquad (2)$$

Where $\ln(Price_{it})$ is the logarithm of energy consumption price, $\ln(\hat{Energy}_{it})$ is the logarithm of various energy demand per capita, which can take the value of total energy demand, energy demand due to economic development, energy demand due to other drivers, and $\ln(Prod_{it})$ the energy production representing the possible impact of factors from energy production perspective.

To identify the potential simultaneity relationship between energy consumption and local production, the local production of energy products determination is introduced, including labour and capital or the production function.

$$\ln(Prod_{it}) = \gamma_0 + \gamma_1 \ln(Labor_{it}) + \gamma_2 \ln(Capital_{it}) + v_i + u_{it} \qquad (3)$$

It is to be noted that in the controlled factors in Equation (2), we have also added two additional variables, Tra_{it} (transportation costs) and Mkt_{it} (marketization levels), in order to account for the cross-province flow of energy products. We can do so because: (1) after accounting for the demand and supply factors, energy prices are mainly determined by the cross-province energy flow, which is not directly observed; and (2) there are no barriers related to institutional arrangements within the same country, since there is an integrated energy market. Thus, the impact of transportation costs due to public infrastructure and market structure on the cross-province energy allocation can be examined.

Based on Equations (2) and (3), the effects of various energy demands on market prices across provinces can be estimated when different energy demands are used. The comparison of coefficients in front of various energy demands can be used to distinguish the effects of different energy demands. In particular, the effects of transportation costs and marketisation indexes can also be specified.

Data used to identify the impact of energy demand on market prices were obtained from the CEIC database. Specifically, the indicator for transportation costs is defined as the within-province freights per capita. The higher the indicator is, the lower the transportation costs are and more energy products can flow in and out of the province. For the indicator of marketisation we used the output value of non state-owned enterprises and non-collective enterprises dividing the total output value of all enterprises. The argument is that in China, the production of state-owned enterprises and collective enterprises are sourcing energy products (as intermediate inputs) from the monopoly market. Thus, it is expected that the higher the marketisation ratio is, the higher the market monopoly power is and the more flexible the market is. As for the capital and labour used for energy production in each province, we aggregated the number of employed workers, the account value of capital stock (derived from fixed asset investment), and the capital services in several sectors including; coal mining, petrol extraction, petrol refining, coal, gas/steam, water/electricity generation, hot water, and gas supply by province for approximation.

Finally, we used the instrumental regression technique to estimate the panel data, which helps to improve the efficiency of the two-step regression procedure. A simultaneous regression using Equations (2) and (3) was also utilised with the control of cross-equation residual correlations for a robustness check.

4. Estimating the Provincial-level Demand for Energy Products, 1979-2008

It is widely believed that there are three main factors affecting energy demand in China, industrialisation, urbanisation, and fixed asset investments that results from the two processes. While other factors such as consumer preferences and energy-saving technology progress play a role in determining energy demand, the above three factors are highly related to economic development and are of primary interest.

Although total energy demand can reflect the impact of economic development on energy consumption at the national level, it cannot be used to capture the effect at the province level. The problems associated with using total energy demand are at least two-fold. First, the official statistics on energy demand are problematic in reflecting economic growth and its impact, as it is the balanced results from both the supply and demand sides. Without accounting for the supply-side factor, total energy consumption at the province level is likely to be biased towards provinces with more energy production. Second, and more crucial is that the total energy demand for each province is not only affected by economic development but it's also heavily influenced by other factors specific to individual regions. These factors typically consist of technology progress, consumption preferences, and historical traditions. For example, the total energy consumption per capita in Shanxi is higher than that in Guangdong due to its abundant resources in coal. Shanxi's economic development, however, is far behind that of Guangdong. Failure to deal with this problem may lead to inaccurate estimations of energy demand, thus making the wrong judgment on changes in energy consumption.

In order to deal with these problems, we used Equation (1) to build the relationship between energy demand and economic development. In particular, economic development is defined by three factor, industrialisation, urbanisation, and fixed asset investment. Moreover, to eliminate provincial and time specific effects, we adopted the system general method of moment technique for the estimations.[5] The estimation results are shown in Table 1. From this table, it is evident that industrialisation, urbanisation, and fixed assets investments play an important role in affecting the demand for energy, since their coefficients are all positive and significant at the one per cent level.

Table 1: Identification of Energy Demand due to Economic Growth: 1979-2008

	Energy Demand: Economic growth identified
Dependent variable: ln_energy_demand	
Industrialisation	0.459***
	(0.061)
Urbanisation	0.070*
	(0.039)
Fixed asset investment	0.208***
	(0.033)
Other control variables	Yes
	Significant
Year	0.009
	(0.007)
Constant	-21.017*
	(12.967)
Number of observations	421
R-squared	0.4431
F-statistics	482.13

Note: Authors' estimation.

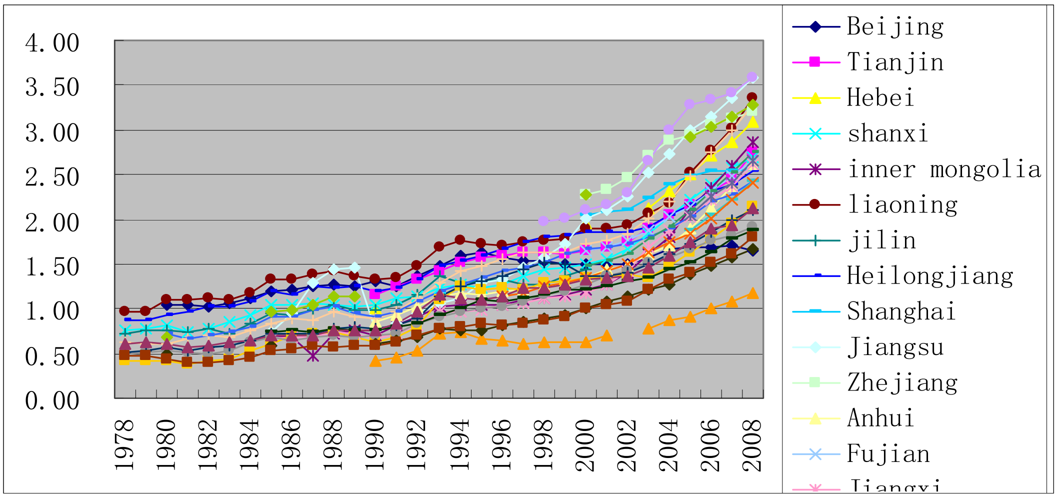
Using the estimated coefficients of industrialisation, urbanisation, and fixed assets investments, we can derive energy demand due to economic development by adding up their effects and the difference between total energy demand and energy demand due to economic development, which is defined as other energy demands.

[5] The choice between the system GMM and the difference GMM method is based on the Arellano-Bond test (Arellano and Bond, 1991).

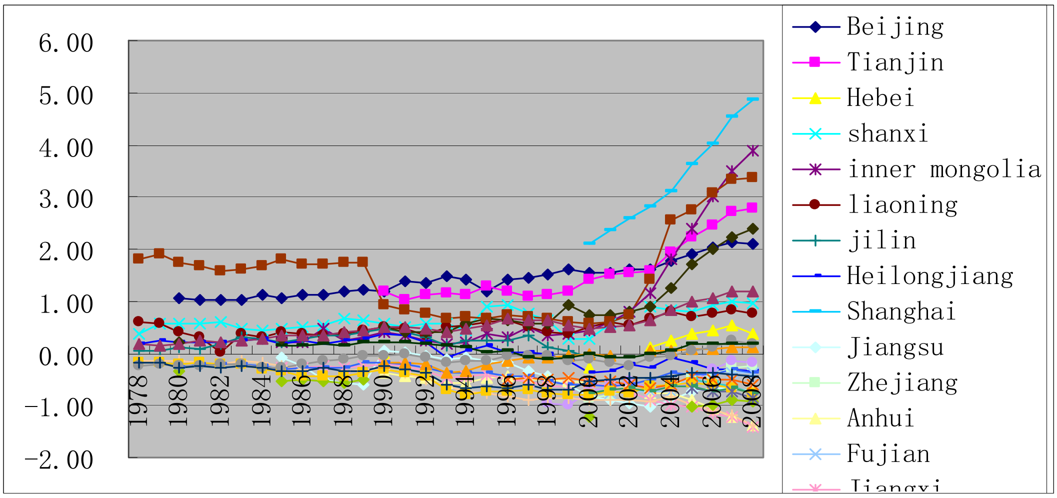
In Figures 3, we compared the estimated energy demand due to economic development and other energy demands between 1979 and 2008. As the two figures show, the two data series are quite different. There are numerous reasons for this divergence.

Figure 3: Comparison of Energy Demand due to Economic Development and other factors: 1978-2008

(a) Energy demand due to economic development



(b) Energy demand due to other factors



Note: Authors' estimation.

First, the estimated energy demand due to economic development has on average been increasing significantly compared to energy demand due to other factors.

Between 1978 and 2008, the average annual growth rate of energy demand due to economic development is 7.7 per cent a year, which is more than energy demand due to other factors at less than 1 per cent a year. Second, the estimated energy demand due to economic development excludes the information from the production perspective, including provincial and time specific supply-side factors captured by u_i, thus, the pattern of energy demand across provinces is likely to reflect the demand-side factors. Third, energy demand due to other factors (captured by the residuals) fluctuated over time, reflecting changes in factors specific to each province over time and macroeconomic shocks.

Critically, however, the difference between the two types of energy demand provides an opportunity to examine how different energy demand may affect market prices or the energy security. Moreover, it is expected that energy demand due to economic development is more likely to affect the equilibrium market price of energy products.

5. Market Price and Various Energy Demands in an Integrated Market

With the reduction of total energy demand by region, a further analysis examines the impact of different energy demands on market prices. In doing so, we needed to repeatedly use Equations (2) and (3) for regressing the market price of energy products on various energy demands with the control of local production and its impact on market prices. In addition, two supplementary variables, transportation costs and marketization index, are incorporated into the regression to examine the role of institutional arrangements. The comparison of the regression results can be used to improve the understanding of the interactive relationship between economic development and energy demand in an integrated market.

Considering that province specific unobservable factors such as provincially specific government policies, history, industrial structures, and production technology will affect energy prices, we adopted the panel data instrumental variable regression with fixed effects. In dealing with the provincial specific effects, the panel data regression with fixed effects is expected to be more appropriate in this case rather than other alternative methods such as first difference, given that demand function for energy products usually takes effect in the long term. In addition, it was also confirmed that this is the case using appropriate statistical tests[6] and therefore opted for the panel data regression with fixed effects.

Table 2: Impact of Energy Demand on Market Prices

	Total Energy Demand ***Model 1***	**Growth Energy Demand** ***Model 2***	**Remained Energy Demand** ***Model 3***
Dependent variable: ln_market_price			
Energy_Demand	0.033***	0.080***	-0.005
	(0.013)	(0.020)	(0.014)
Local_Production	-0.004	-0.032	-0.073*
	(0.045)	(0.036)	(0.041)
Transportation Cost Index	0.070***	0.074***	0.084***
	(0.021)	(0.022)	(0.023)
Marketisation Index	-0.188***	-0.179***	-0.182***
	(0.046)	(0.046)	(0.047)
Year (Technological Progress)	-0.021***	-0.024***	-0.019***
	(0.003)	(0.003)	(0.002)
Constant	45.940***	51.736***	42.284***
	(5.296)	(5.458)	(4.954)
Number of observations	458	392	392
R2	0.221	0.178	0.103

Note: *** p<0.01, ** p<0.05, * p<0.1

[6] In particular, the Hausman test and Breusch-Pagan test.

The estimates for the panel data instrumental variable regression with fixed effects are presented in Table 2. Columns (1), (2), and (3) provide the estimated results for total energy demand, energy demand due to economic development, and other energy demands adjusted for heteroscedasticity and time trends to account for time changing effects. The comparison of the estimation results from the three regressions can be used to provide several useful implications.

Table 3: First-stage Regression to Identify Local Production

	Total Energy Demand *Model 1*	**Growth Energy Demand** *Model 2*	**Remained Energy Demand** *Model 3*
Dependant variable: ln_local_production			
Energy_Demand	0.156***	0.070	0.211***
	(0.024)	(0.056)	(0.024)
Local_Production	0.260***	0.352***	0.309***
	(0.044)	(0.050)	(0.043)
Transportation Cost Index	-0.390***	-0.412***	-0.332***
	(0.117)	(0.128)	(0.116)
Marketisation Index	-0.054***	-0.055***	-0.042***
	(0.008)	(0.009)	(0.008)
Labour Used for Energy Production	0.066***	0.123***	0.122***
	(0.022)	(0.028)	(0.025)
Capital Used for Energy Production	0.202***	0.237***	0.201***
	(0.028)	(0.030)	(0.027)
Constant	104.404***	104.657***	78.799***
	(15.150)	(17.098)	(15.613)
Number of observations	458	392	392
R-squared	0.211	0.180	0.301

Note: the F-statistics for over-identification tests in the first stage regressions are 196.9, 197.9 and 164.7. Also, *** p<0.01, ** p<0.05, * p<0.1

In an integrated market, the equilibrium prices of energy products are not subject to the local energy production in each province when they are identified by using the production function. As shown in Table 2, the coefficients in front of the control variable representing local energy production are all negative, but insignificant at the 5 per cent level. This suggests that an increase in local production at the province level may not change the consumption prices of individual provinces. A possible explanation is that the integrated market will promote the free flow of energy products across provinces so that the equilibrium consumption price of energy products is not sensitive to province specific production. In other words, market integration may help to lessen the impact of supply shocks.

From the demand side, different types of energy demand may impose different impacts on the equilibrium prices of energy products. Although the coefficients in front of both total energy demand and energy demand due to economic growth are positive and significant at the 1 per cent level, the magnitude of coefficient in front of energy demand due to economic development is larger than that in front of total energy demand. In contrast, the coefficient in front of other energy demand, as shown in Column (3), is negative but not significant at a 10 per cent level.[7] This finding implies that energy demand due to economic development differs from other energy demands and will increase energy consumption prices even in an integrated market, though market integration can alleviate the demand shock due to other energy demand. The reason is that rapid economic development may create high marginal productivity of energy and thus influence its price, which may overwhelm the adjustment capacity of an integrated market.

[7] The negative relationship between other energy demands and energy consumption prices deserve some explanation. A possible explanation is that energy demand independent of economic growth (or income) is necessity (or “Giffin good”) such that its demand may decline as the price increases.

In addition to energy demand and production, there are also other factors affecting the market price of energy consumption. Throughout all three regressions, the coefficients in front of transportation costs are negative and significant at the 1 per cent level and the coefficients in front of marketisation index are positive and significant at the 1 per cent level. This implies that a decrease in transportation costs, or increased per capita freights, will tend to lower the market price of energy consumption and furthers the marketisation process or increased non-SOEs share in production. Both of these findings suggest that improving market institutional arrangements may reduce energy consumption prices. A policy implication is that transportation costs can be reduced or marketisation increased to alleviate the negative impact of economic development on local energy price.

In summation, economic development tends to increase energy demand more than other factors and is likely to raise market consumption, even in an integrated market. Market integration will in general reduce the response of energy consumption prices to energy demand and production by the cross-province trade of energy products. Along with market integration, improvement in market institutional arrangement will help to alleviate the negative impact of economic development. In particular, reducing transportation costs and improving the marketisation process will tend to reduce energy consumption prices.

To test the validity of these regression results, we used the simultaneous regression techniques to replicate the above exercises with local energy production to be identified by a simultaneous equation. The results obtained from this exercise are similar to the instrumental variable regressions, suggesting that these findings are not sensitive to the specific regression method.

6. Policy Implications to EMI in the EAS region

Although this study focuses on energy demand, supply, and trade across regions in China, it will have important policy implications for promoting EMI in the EAS region. It is believed that the EMI in the EAS region involves five types of activities: (1) trade liberalization; (2) investment liberalization; (3) development of regional energy infrastructure and associated institutions; (4) liberalisation of domestic energy markets; and (5) energy pricing reform, in particular, the removal of fossil fuel subsidies (Shi and Kimura, 2010; Wu, 2012). This paper will contribute to the provision of policy implications on the EAS EMI in at least three perspectives.

First, the energy trade pattern in the EAS region may be reversed by the involvement of development patterns. It is widely agreed that energy demand and its change over time is determined by country specific characteristics and thus energy market integration policies are always designed to facilitate trade to eliminate country specific disparities. This, however, is not the case in the EAS region. Using China's case study of cross-province energy demand, we demonstrated a direct and positive linkage between energy demand and economic development. It was also pointed out that a better design of energy market integration policies in the EAS region (as in China) is to fuel economic growth in a sequential process, irrespective of where it occurred. From a dynamic perspective, this implies that energy trade in the region can be reversed depending on the relative economic developments across regions, because in the EAS region, the significant change in energy demand and cross-country disparity are mainly derived from their different economic growth patterns.

Second, we examined the impact of market competition on energy consumption prices and split it from the cross-country institutional arrangement differences by using cross-provincial data in China. This helps to quantify the impact of non-policy factors on the imbalance between energy demand and supply and highlights the significant issues that future EMI policies need to focus on when dealing with domestic market distortions, which can be achieved by promoting competition and increasing investment in public infrastructures. These findings lead to the second policy impaction on infrastructure and the third policy implication on domestic market liberalisation.

Third, this study demonstrated that transportation costs (public infrastructure) play an important role in determining the energy prices in each region or country. Lower transportation costs within a region or country will reduce the energy price, given other factors are identical. This implies that EAS member countries may be able to have a favourable energy market by reducing transportation costs through measures such as infrastructure development and trade facilitation.

The results suggesting that a competitive market within a region will reduce prices indicates that it is in a region or country’s own interest to liberalise its domestic market, including the removal of market distortions; such as fuel subsides, trade and non-trade barriers, and limitation of energy investment.

7. Conclusions

Using the panel data from 30 provinces between 1978 and 2008, this paper examined the relationship between economic growth, regional disparity, and energy demand in China. In so doing, we reduced the total energy demand into energy demand due to economic development and other remainders and linked them to the equilibrium energy consumption prices. The results reveal that economic development tends to increase energy demand. Market integration will generally reduce the response of energy consumption prices to energy demand and production through cross-province trade of energy products. In addition, the effects can be alleviated by reducing transportation costs and improving the marketisation level.

The findings from this paper have important policy implications on energy market integration in the EAS region. In particular, it provides further clarification on the possible trade patterns in the EAS region, supports the argument for a more liberalised trade regime, and calls for a more developed energy infrastructure and associate institutional arrangements.

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Appendix A: Mathematical derivation of the basic model

Assuming that the demand function for energy products takes the linear form of:

$$Energy\_Demand_{it} = a * P_{it} + b * Incomc_{it} + c * W_{it} \quad \text{(A1)}$$

Where $Energy\_Demand_{it}$ is energy demand and $Incomc_{it}$ income the related to driver. X_{it} represents other demand-side factors (i.e., preferences).

Similarly, the supply function for energy products takes the linear form of:

$$Energy\_Supply_{it} = m * P_{it} + n * Prodc_{it} + l * Z_{it} \quad \text{(A2)}$$

Where $Energy\_Supply_{it}$ is energy supply and $Prodc_{it}$ the production costs related to driver. Z_{it} represents other supply-side factors (i.e., technological progress).

In equilibrium, the demand and supply of energy products should be equalised so that Equations (A1) and (A2) are combined to derive the determination of equilibrium energy consumption price.

$$P_{it} = \frac{-b}{a-m} * Incomc_{it} + \frac{n}{a-m} * Prodc_{it} - \frac{c}{a-m} * W_{it} + \frac{l}{a-m} * Z_{it} \quad \text{(A3)}$$

Equation (A3) provides a theoretical relationship between equilibrium market price of energy prices and its determinants from consumption and production perspectives, as well as other market mechanisms (incorporated in W_{it} and Z_{it}). This helps to set up the empirical specification that is to be used. It also notes that since the relative magnitude of demand elasticity and supply elasticity are uncertain, the sign of coefficients in front of $Incomc_{it}$ and $Prodc_{it}$ are subject to empirical tests. The above derivation is not constrained by the assumption of linear function form and can be easily extended to a more general case.