POWER SECTOR DEVELOPMENT WITH CARBON AND ENERGY TAXES

AN ASSESSMENT IN SIX ASIAN COUNTRIES

Ram M. Shrestha

RERIC
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Preface

The power sector is a major emitter of the greenhouse gases (GHGs) and local/regional pollutants in Asia. As electricity demand is growing rapidly in most countries in Asia, it is increasingly important to develop the power sector in a climate-friendly and environmentally sustainable manner. Policies that promote the adoption of cleaner and energy-efficient technologies and resources are therefore needed towards that end.

This volume presents a set of studies assessing the effects of two different types of economic instruments, i.e., carbon tax and energy tax, on the development of the power sector of selected countries in Asia. While the carbon tax is primarily focused on reduction of carbon emissions - a global climate change objective, the energy tax is mainly focused on more efficient use of energy, which is a national energy policy objective in many countries. However, each of these policy instruments can also meet global climate change and national energy policy objectives to a large extent. The present set of studies assesses the effects of the two tax policies in terms of mitigation of GHGs and local pollutant emissions as well as energy efficiency improvements.

A part of the research underlying this volume was carried out under the Asian Regional Research Programme in Energy, Environment and Climate (ARRPEEC) funded by the Swedish International Development Cooperation Agency and coordinated by the Asian Institute of Technology (AIT). The ARRPEEC was launched in 1995 and executed in three phases during 1995-2005, with the aim of enhancing national capacity to identify and assess energy-related GHG mitigation options in China, India, Indonesia, the Philippines, Sri Lanka, Thailand and Vietnam. As a major component of ARRPEEC, research activities on energy, environmental and climate issues related to the power sector of six countries in Asia (China, India, Indonesia, Sri Lanka, Thailand and Vietnam) were carried out jointly by researchers of participating research institutes in the countries and AIT. The studies in this volume discuss of the effects of introducing carbon and energy taxes in the power sector of the six countries.

Each country study in this volume analyzes separately the key implications of carbon and energy taxes on technology choice, energy resource mix, total costs and investment requirements in the development of the power sector from a long-term planning perspective. The studies also assess the effects of the taxes on emissions of carbon dioxide and local/regional pollutants from the power sector. The studies were mostly carried out during 2004-2005; however, their publication was delayed. It is thus expected that there will be some differences between the quantitative results reported in the studies and the actual data available since the time the studies were conducted.

Therefore, a discussion on differences between the actual data on some key elements of the power sector development and the corresponding values estimated by a country study has been included at the end of the respective chapters as a post-script. It is believed that the qualitative insights generated by the studies on the effects of carbon and energy taxes on the development of the power sector will be useful to policy makers and researchers in developing countries in general. Furthermore, since there are very few quantitative analyses in the context of developing countries of the kind presented in this volume in the existing literature, climate and energy policy makers and planners involved in the sustainable development of the power sector will find the studies to be of significant interest.

Ram M. Shrestha

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R.M.S.

Abbreviations

AAGR	Annual Average Growth Rate
AIC	Average Incremental Cost
$AIC_{overall}$	Overall Average Incremental Cost
ARRPEEC	Asian Regional Research Project on Energy, Environment and Climate
BIGCC	Biomass Integrated Gasification Combined Cycle
Btu	British Thermal Unit
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCT	Clean Coal Technology
CEB	Ceylon Electricity Board
CEETs	Clean and Energy Efficient Technologies
CF	Capacity Factor
CO_2	Carbon Dioxide
CT	Carbon Tax
DPG	Distributed Power Generation
DSM	Demand-side Management
EETs	Energy Efficient Technologies
EGAT	Electricity Generation Authority of Thailand
EGP	Electricity Generation Planning
EPPO	Energy Planning and Policy Office
ERI	Energy Research Institute
ESP	Electrostatic Precipitators
ET	Energy Tax
FGD	Flue Gas Desulphurization
GBtu	Giga-British Thermal Unit
gC	Gram of Carbon
Gcal	Gigacalorie
GDP	Gross Domestic Product
GEP	Generation Expansion Planning
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt hour
HP	High Parameter
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IRPA	Integrated Resource Planning and Analysis
kcal	Kilocalorie
kWh	Kilowatt hour
LNG	Liquefied Natural Gas

LP	Low Parameter
LRAC	Long Run Average Cost
LRMC	Long Run Marginal Cost
MBtu	Million British Thermal Unit
MJ	Megajoule
$MtCO_2$	Million tonne of CO_2
mth	Month
Mtoe	Million tons of oil equivalent
MW	Megawatt
NGCC	Natural Gas based Combined Cycle
NIDA	National Institute of Development Administration
NO_x	Nitrogen Oxides
NRIs	National Research Institutes
O&M	Operation and Maintenance Cost
OCC	Oil-fired Combined Cycle
OECD	Organization for Economic Co-operation Development
PFBC	Pressurized Fluidized Bed Combustion
RETs	Renewable Energy Technologies
SARI	South Asia Regional Initiative
SCR	Selective Catalytic NOx Removal
SIDA	Swedish International Development Cooperation Agency
SLSEA	Sri Lanka Sustainable Electricity Authority
SO_2	Sulfur Dioxide
SPC	State Power of China
tC	tonne of Carbon
TWh	Terawatt hour
WACF	Weighted Average Capacity Factor
WATGE	Weighted Average Thermal Generation Efficiency

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1. Introduction

It is well known that electricity plays a crucial role in the economic growth and development of countries. With economic growth and industrialization, electricity demand is rapidly growing in most developing countries in Asia. However, power generation in most Asian developing countries is dominated by the use of fossil fuels, and is largely based on coal in major countries like China and India. Furthermore, the power sectors of many Asian countries are characterized by relatively low efficiency of thermal power generation.

The power sector is a major source of emissions of greenhouse gases (GHGs) as well as local/regional pollutants. Power generation and heat production accounted for over half of the total fuel-combustion related CO_2 emissions in China and India in 2012, and they accounted for about one-third of the emissions in several other developing countries in Asia. As electricity demand is growing rapidly, the emissions of CO_2 and other GHGs from the power sector are also expected to increase significantly if the present structure of power generation is to continue. The present patterns of power sector development can also affect the energy security and environmental sustainability of many countries in Asia.

With rising global concerns about climate change, both developed and developing countries are expected to adopt measures to reduce their respective national GHG emissions. Carbon tax is a major policy instrument to reduce CO_2 emissions by introducing climate-friendly technology- and energy-mix in an economy. Besides reducing GHG emissions, a carbon tax policy can generate co-benefits such as improved energy security and reduced emissions of local/regional pollutants. While the carbon tax is a climate policy tool primarily focused on a GHG mitigation (particularly, CO_2 reduction), other policy instruments like emissions permits and trading, energy taxes (based on units of energy used), and renewable portfolio standards can also be considered to achieve similar results in many cases.

The studies in this volume are focused on the analyses of implications of introducing carbon and energy taxes in the power sector of six major developing countries in Asia, namely, China, India, Indonesia, Sri Lanka, Thailand and Vietnam. The six developing countries considered in the studies come from different regions of Asia: China from East Asia; Indonesia, Thailand and Vietnam from Southeast Asia; and India and Sri Lanka from South Asia. The objectives of the studies are to assess separately the effects of carbon and energy taxes on technology-mix and fuel-mix in the power sectors of the countries as well as the associated emissions of CO_2 and local/regional pollutants (i.e. SO_2 and NO_x). The studies' objectives also include an assessment of the role of these taxes in the promotion of renewable energy technologies and improvements in the overall efficiency of electricity generation through the adoption of efficient technology options. The studies additionally assess the implications of these taxes on the total cost of power generation, investment requirements and the average incremental cost of electricity.

Each country study considers six different carbon tax rates (ranging from \$5/tC to \$150/tC) and four energy tax cases (ranging from \$0.5/MBtu to \$5/MBtu) in addition to a reference (or base) case (i.e., a business-as-usual case without any climate or energy policy intervention)[1]. The carbon taxes are applied to all fossil fuel resources used for power generation, whereas the energy taxes are applied to all sources of energy used in power generation except solar, wind, geothermal and small hydropower. It should be noted that the studies in this volume were conducted during 2004-2005 for the planning period of 2006-2025; however, the publication of this volume was delayed. In the meantime, actual data for the period of 2005-2013 (and 2014 in some cases) have become available. Therefore, a discussion on differences between the actual data on some key elements of the power sector development and the corresponding values estimated by a country study has been included at the end of the respective chapters as a post-script.

Fossil fuel and renewable energy resource/technology options for power generation are considered by all the country studies in this volume. However, the studies do not consider the learning effect of renewable energy technologies (RETs) such as solar PV and wind. The studies also do not include the options of additional nuclear power plants and carbon capture and storage (CCS) in thermal power generation. It should also be noted that the studies consider only the supply-side technology and resource options for the power sector. While the effect of carbon and energy taxes on electricity demand are considered using the price elasticity of demand, demand-side technology options are not explicitly considered in the analyses. Recycling of revenue generated by the energy and carbon taxes may also be an interesting issue as it could have economy-wide effects and affect the choice of technologies and energy resources for power generation. However, recycling of tax revenue is not considered in the present studies as they are based on partial equilibrium analyses.

This book is organized as follows:

Chapter 2 describes the methodological framework used in the country studies to assess the implications of carbon tax and energy tax in the power sector.

Chapter 3 presents a comparative analysis of the effects of selected carbon and energy tax rates in the six countries considered in the studies. The analysis is based on the findings of the country case studies.

Chapters 4 to 9 discuss separately the implications of carbon and energy taxes for power sector development in the six countries. They include the effects on power generation capacity requirements, generation technology-mix, energy resource-mix for electricity generation, investment requirements, capacity

[1] In this book “tC” stands for a tonne of carbon and “MBtu” stands for a million British thermal unit. 1 MBtu is equivalent to 1055.06 Megajoules (MJ).

utilization, overall thermal power generation efficiency, emissions of CO_2, SO_2 and NO_x and electricity price (in the form of average incremental cost). Analyses of the contributions of changes in demand- and supply-sides in total reduction in CO_2 emissions with the taxes as well as estimates of carbon and energy tax elasticities of CO_2 emissions are also included in these chapters.

2. Methodology

As is well known, carbon and energy taxes affect the development of the power sector through changes in the demand- and supply-sides of the sector. In the supply-side, there could be changes in the energy resource mix and technology mix (or power generation capacity mix) due to technological and inter-fuel substitutions in power generation with the introduction of the taxes. As a result, there would be changes in the emissions of CO_2 and local/regional level pollutants, the overall efficiency of electricity generation and capacity utilization of the power generation system. The changes in the energy resource mix and technology-wise generation capacity mix would also affect the investment requirements and other costs of the generation system development. In the demand-side, the level of electricity demand would change with both the carbon and energy taxes as a consequence, the electricity generation cost and hence the electricity price would also change. In this chapter, the methodologies of assessing these effects of the carbon and energy taxes are presented. Relevant indicators used to measure some of the effects are also discussed in the chapter.

The carbon tax is a duty levied on fossil fuels proportionate to their carbon content. The purpose of this is to move towards the internalization of the costs associated with the emission of CO_2 from the combustion of fossil fuels while energy tax is a tax imposed on fuel in proportion to the heat (Btu) contents of these fuels. Therefore, imposing taxes (carbon or energy) would increase the fuel cost of utility and would also affect its system cost, generation mix and capacity-mix. Thus, the electricity industry would have to incur higher costs for using coal, oil and gas and as a consequence would choose to burn different fuels according to their relative prices (Barker et al., 1993).

The country case studies in this book also have an objective of assessing the contributions of a carbon tax (similarly an energy tax) in the CO_2 emission reduction from the power sector through a change in the supply-side and demand-side effect. The framework thus also involves the use of an approach for decomposition of these two components of CO_2 reduction.

Levy of a carbon tax (similarly an energy tax) not only affects the electricity generation on the supply-side but also reduces the demand for electricity through the increase in electricity price due to the tax (Bruvoll and Larsen, 2004). Furthermore, carbon and energy taxes could affect CO_2 emission through both supply- and demand-side responses. The supply-side response (hereafter called “supply-side effect”) takes place in the form of inter-fuel and technological substitutions in power generation (Nakata and Lamont, 2001). The demand-side response (hereafter called “demand-side effect”) on the other hand occurs in the form of a reduction in electricity demand due to an increase in electricity price with the introduction of the carbon tax (Shrestha et al., 1998). While the carbon tax is intended to reduce CO_2 emission through the deployment of less carbon-intensive fuels and technologies in power generation (or supply-side), the tax is also expected to contribute to a reduction in CO_2 emission through a reduction in electricity demand. While an energy tax may also reduce CO_2 emission, it is primarily focused on the deployment of more energy efficient fuel- and technology- mixes in power generation. The level and type of clean and energy efficient technologies (CEETs) selected in a country would, however, depend upon the level of these taxes as well as on the candidate resources available and demand pattern in a country.

This chapter is divided into six sections: The next section (i.e., Section 2.1) describes the key elements of the least cost electricity generation system planning, which is at the core of the methodology. It also describes the approaches for calculating the additional cost of using a fossil fuel with the introduction of carbon and energy taxes and incorporating the effect of the taxes on electricity demand. This is followed by a discussion of the procedure to calculate the elasticities of CO_2 emission on carbon and energy taxes in Section 2.2. Sections 2.3 and 2.4 discuss the procedures to calculate the overall electricity generation efficiency of thermal plants and the overall capacity utilization of the power generation system. An approach to calculating the average incremental cost of electricity generation is presented in Section 2.5. In the final section (i.e., Section 2.6), an approach is presented to assess the contributions of the supply- and demand-side effects in the total CO_2 emission reduction due to a carbon tax (similarly an energy tax).

2.1. Least Cost Electricity Generation Planning Framework

To analyze the effects of carbon and energy taxes in the power sector, normally a least cost long-term electricity generation system planning (EGP) model is needed. The EGP determines the optimum schedule for power generation capacity additions to meet the estimated electricity demand during a given planning period at the minimum cost. The EGP model determines the optimum generation capacity expansion plan as well as electricity generation and the amounts of energy (fossil fuels, hydro energy, and other renewable energy sources) used for electricity generation by the existing and new power plants in the system. It also determines the investment requirement and other costs of the generation system development and calculates the emission levels of different pollutants associated with power generation.

The EGP model can be used to obtain the generation and fuel mixes with changes in relative costs of different power generation options due to carbon and energy taxes and corresponding changes in electricity price. The flowchart showing the framework for assessing the electricity planning, environmental and greenhouse gas emission implications of carbon tax (similarly an energy tax) is presented in Figure 2.1 (see Shrestha et al., 1998; Shrestha and Marpaung, 1999). It should be noted here that the present study has used a model called the “Integrated Resource Planning and

Analysis (IRPA)," developed at the Asian Institute of Technology (AIT) Thailand as the EGP model (Shrestha et al., 2001)[1]. IRPA is a mixed-integer programming based long-term EGP model, which can determine the least cost options on the demand- and supply- sides of the power sector.

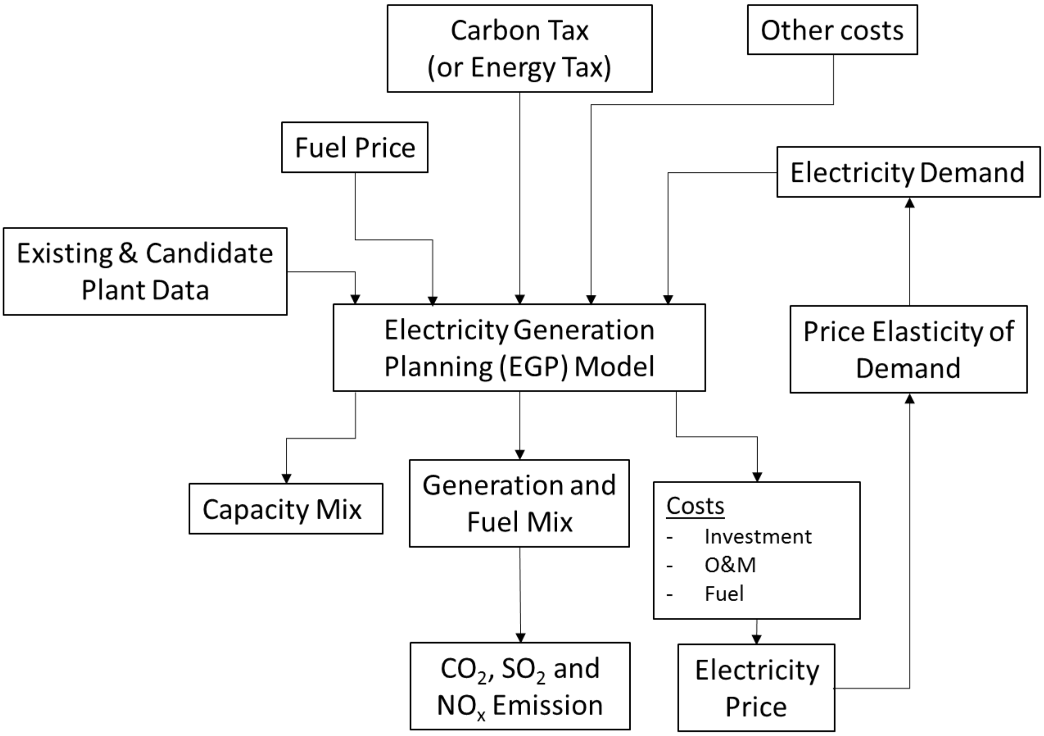

Figure 2.1: Framework for the assessment of utility planning, environmental and GHG emission implications of carbon and energy taxes

The objective function of the EGP model represents the sum of both the supply-side and demand-side costs. The supply-side cost consists of capacity costs of existing and candidate power plants, as well as fuel and operation and maintenance (O&M) cost. The demand-side cost consists of end-use device costs and their O&M costs. However, in the present study, only supply-side costs are considered (this is because the official electricity demand projections, that are used in the study, do not reveal the information on demand-side technologies involved). The typical constraints of the EGP model are as follows:

---

[1] The IRPA model is capable of determining the least cost combination of both supply- and demand-side technology and resource options to meet the projected electricity demand. The model was run using CPLEX (ILOG, 2005) as the solver for the present study.

(a) Power demand constraints: Total power generation from all existing and candidate power plants and power generation avoided by energy efficient end-use appliances/equipment cannot be less than the sum of total power demand and transmission and distribution losses in all periods, seasons and years of the planning period considered.

(b) Plant availability constraints: Power generation from each power plant at any daily period, season and year cannot exceed its available capacity.

(c) Reliability constraints: The sum of installed power generation capacity of all plants and generation capacity avoided by energy efficient end-use options in any year cannot be less than peak power demand plus a reserve margin in that year.

(d) Hydro energy constraints: Total energy generation from a hydropower plant cannot exceed the level of hydro energy available to the plant in each season and year of the planning period.

(e) Annual thermal energy generation constraints: Electrical energy generation from each thermal plant cannot exceed an upper limit that corresponds to the installed capacity and availability of the plant.

(f) Maximum capacity constraints: Total number of generating units of each type in the planning period cannot exceed the maximum permissible (i.e., feasible) number of units. That is, total installed capacity of a type of power plant cannot exceed the maximum allowable capacity of that type of plant.

Note that electricity demand forecasts, which drive the EGP model, are exogenous to the model and, are mostly based on existing studies on future demand. Also, note that the effects of the carbon and energy taxes on the price of electricity and electricity demand are considered explicitly within the framework (see Figure 2.1). The electricity price in the present set of studies is represented by the long run average incremental cost. See Section 2.5 for an approach used to calculate the average incremental cost in the present framework.

The EGP model that provides the least cost power generation system expansion plan, includes information on power generation capacity and investment requirements by type of technology to meet the electricity demand during the planning period. Further, it generates the information on electricity generation as well as fuel consumption by different types of power plants.

For a given power demand, a carbon tax (similarly an energy tax) would result in an increase in electricity price and hence a reduction in electricity demand. With the reduction in electricity demand due to the tax, the EGP model is rerun to obtain the new least cost power development plan. After the new least cost plan is obtained, the corresponding price of electricity is estimated and the value of electricity demand is revised accordingly. The EGP model is rerun to revise the power generation system expansion plan. This procedure is repeated until the equilibrium combination of electricity price and output is obtained. The EGP model also calculates the emissions of CO_2, SO_2 and NO_x from power generation. The information on consumption of different types of fuels used in power generation and their respective emission factors are used by the model to estimate the emissions of CO_2 and SO_2. The emission of NO_x is estimated based on the information on the electricity generation by different thermal power generation technologies and their corresponding NO_x emission factors.

Note that the EGP model requires information on the additional costs imposed by a carbon tax (similarly an energy tax) for electricity generation. Further, it should be noted that the demand for electricity is expected to be different with the introduction of the carbon tax (similarly an energy tax) as the electricity generation cost, and hence, the electricity price would change with these taxes. The methods for calculating the additional costs imposed by the taxes on the use of fuels and incorporating the change in electricity demand with the introduction of the carbon and energy taxes are discussed in the following sections.

2.1.1. Calculating additional costs of using fuels (or energy inputs) under carbon and energy taxes in the EGP model

Additional cost of a fossil fuel under carbon tax:

Carbon taxes are applicable on fossil fuel-based power generation. The additional cost of using a fossil fuel in the face of a carbon tax depends on the carbon content of the fuel. As the EGP model considers the fuel cost per unit of heat input used for power generation; the calculation of the additional cost due to the carbon tax has to also consider the heat content of the fuel.

Let,

CV_i = Calorific value of fuel type i (kcal/unit of fuel);

CC_i = Carbon content of fuel type i (kg/unit of fuel); and

CT = Carbon tax in $/ton of carbon.

Then, the additional cost of using fuel type i in the presence of carbon tax is calculated as

$$= \frac{CT}{CV_i} \times CC_i \times 1000 \ (\$ \ / \ \text{Gcal})$$

Note that the carbon tax is not applicable to nuclear, hydro and other renewable power generation sources (such as the wind and solar power). Power generation based on biomass is also exempt from a carbon tax as it is assumed that biomass used for power generation is produced on a sustainable basis in the present study.

<u>Additional cost of using a fuel (or energy input) under energy tax</u>:

The energy tax is applied on power generation based on fossil fuels, large-scale hydropower, and nuclear energy. Large hydropower based power generation are taxed because of the environmental and ecological damages caused whereas the nuclear power generation is taxed because of the safety risks involved with that electricity generation option. The energy tax is also applied to biomass-based power generation due to the emission of local air pollutants associated with biomass combustion. Following Hoerner and Muller (1993), energy tax, in the case of electricity produced by hydropower and nuclear fission, is calculated by considering the energy input per kilowatt-hour (kWh) of electricity produced by these plants to be equivalent to the average heat energy used per unit electricity generation by fossil fuel based power plants. Renewable energy sources (i.e., solar, wind, geothermal and small hydro) used for power generation are exempted from the energy tax due to their relatively low environmental impacts.

As a result of an energy tax, the fuel (or energy input) cost of power generation (except in the cases of renewable energy sources mentioned earlier) would increase. The procedure to calculate the energy tax cost (i.e., the additional cost per unit of electricity generation due to the energy tax) in the case of a thermal power generation plant is straightforward and is given by the product of the heat rate[2] of the power plant and the energy tax rate. In the case of large hydropower and nuclear plants, the procedure to estimate the energy tax cost per unit of electricity generation involves the following steps:

Step1: From the information generated by a least-cost power generation system plan in the base case (i.e., without energy tax), find the plant capacity factor of the power plants and then categorize the power plants as base load, intermediate load- and peak-load- plants for all the existing plants as well as candidate plants that are added in the system.

Step 2: Calculate the weighted average heat rates for each category of power plants. Let HR_b, HR_i and HR_p denote the weighted average heat rates of the base load-, intermediate load- and peak-load- plants respectively.

Step 3: Additional cost per unit of electricity generation from plant j due to energy tax (ΔEC_j) can be expressed as

$$\Delta EC_j = HR_j \times ET; \; j = \text{base-load, intermediate-load and peak-load},$$

where,

$ET = \text{Energy tax in } \$/\text{Btu}$; and

$HR = \text{Heat rate (Btu/MWh)}$.

---

[2] Heat rate is defined as the amount of thermal energy input used per unit of electricity generation by a thermal power plant.

Thus, in the case of run-of-the-river hydro and nuclear power plants, which are base load plants, the additional cost due to the tax is given by:

$\Delta EC_j = HR_b \times ET$.

2.1.2. Incorporating the effect of carbon tax (similarly an energy tax) on electricity demand in the EGP model:

For a given power demand, a carbon tax would result in an increase in electricity price leading to a reduction in the demand for electricity. The corresponding change in the demand (lower level) due to electricity price increase can be derived using the price elasticity of demand. Accordingly, a new least cost power development plan is obtained using the generation planning model. An iterative process is followed to determine the equilibrium level of electricity price generation and GHG emission for a given carbon tax and energy tax. The steps of finding the equilibrium level of electricity price and electricity demand with the introduction of carbon or energy tax are as follows:

Step 1: Run the EGP model to find electricity price (P_1) at the level of demand (Q_1) forecasted without the imposition of carbon or energy tax.

Step 2: Rerun the EGP model with a carbon/energy tax. The carbon or energy tax will cause electricity price to increase to a new electricity price (P_2).

Step 3: Find the new level of demand (Q_2) at the new electricity price (P_2) through price elasticity of electricity demand.

Step 4: At this level of demand (Q_2), rerun the EGP model to find a new electricity price (P_3).

Step 5: The above process is repeated until the demand and electricity price converges to a single equilibrium electricity price (P_{eq}) and electricity demand (Q_{eq}).

2.2. Calculation of Elasticities of CO_2 Emission on Carbon and Energy Taxes

The carbon tax elasticity of CO_2 emission measures how the CO_2 emission would change with a change in the carbon tax rate. The carbon tax elasticity is defined as the percentage change in CO_2 emission associated with the percentage change in carbon tax rates. The elasticity calculation in this study is based on the arc elasticity concept.

The energy tax elasticity of CO_2 emission measures how the CO_2 emission would change with a change in energy tax rate.

Algebraically, the carbon tax elasticity of CO_2 emission is in this study is calculated as follows:

$$\text{Carbon tax elasticity of } CO_2 \text{ emission} = \frac{(\epsilon_2 - \epsilon_1)/[(\epsilon_2 + \epsilon_1)/2]}{(T_2 - T_1)/[(T_2 + T_1)/2]} \qquad (2.1)$$

where:

ϵ_1 and ϵ_2 are CO_2 emissions with the carbon tax rates T_1 and T_2 respectively (with $T_2 > T_1$).

The energy tax elasticity of CO_2 emission is calculated similarly.

2.3. Calculation of Overall Efficiency of Thermal Power Generation

The overall thermal power generation efficiency of the power system in a year is expressed as the weighted average thermal generation efficiency (WATGE) of thermal power plants with the respective shares of different types of thermal power plants in the total annual thermal electricity generation being the weights.

The study also compares the overall efficiency of thermal power generation under the base and different tax cases during the entire generation planning period. For this purpose, again an overall WATGE during the planning period in each case is calculated as the weighted average of overall annual thermal power generation efficiencies in different years with the annual shares in total thermal electricity generation during the entire planning period being the weights.

Algebraically, the overall thermal power generation efficiency of the power system in a year t (denoted as $WATGE_t$) is expressed as:

$$WATGE_t = \sum_i \left(\frac{e_{it}}{E_t} * \eta_i \right) \qquad (2.2)$$

where:

η_i = Efficiency of thermal power plant type i;

e_{it} = Electricity generation by thermal power plant type i in year t; and

E_t = Total electricity generation by all thermal power plants in year t (= $\sum_i e_{it}$).

The overall efficiency of thermal power generation during the entire planning period of T years (denoted as $WATGE_{overall}$) is expressed as:

$$WATGE_{overall} = \sum_t \frac{E_t}{E_{total}} * WATGE_t \qquad (2.3)$$

where, $E_{total} = \sum_t E_t$; for t = 1, …, T.

2.4. Calculation of Overall Capacity Utilization of the Power Generation System

The overall capacity factor of the power system in a year is expressed as the weighted average of the capacity factors (CFs) of the power plants in the power system with the respective shares of different types of power plants in total annual electricity generation being the weights.[3]

The overall capacity factor of the generation system is measured as the weighted average capacity factor (WACF) of all the power plants and is algebraically expressed as:

$$\mathrm{WACF} = \sum_i \left(\frac{E_i}{E_{total}}\right) * CF_i \qquad (2.4)$$

Where,

E_i = Electricity generation by plant i in a year;

E_{total} = Total electricity generation of the system in the year; and

$$CF_i \text{ (i.e., Capacity Factor) of Plant i} = \frac{E_i}{8760 \times C_i} \qquad (2.5)$$

with C_i = Power generation capacity of plant i.

2.5. Calculation of Average Incremental Cost (AIC) of Electricity Generation

Average incremental cost (AIC) is used in the present set of country studies as a proxy for the long-run marginal cost (LRMC) of electricity generation. In the present study, AIC is calculated using the following steps:

Step 1: Find the discounted total minimum cost (TC_1) of the electricity generation system with constant electricity demand (E_0) throughout the planning period (with the energy demand being equal to that at the beginning of the first year of the planning period) (see Figure 2.2).

Step 2: Find the discounted total minimum cost (TC_2) of the electricity generation system with the projected electricity demand (E_0, E_1, …,E_T) during the planning period (see Figure 2.2).

Step 3: Find the total incremental "discounted" energy generation (E_C) during the planning period.

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[3] Capacity factor (CF) of a power plant is the ratio of the total electricity generation from the plant in a year to the maximum potential electricity generation in the year when the plant is operated at its installed capacity.

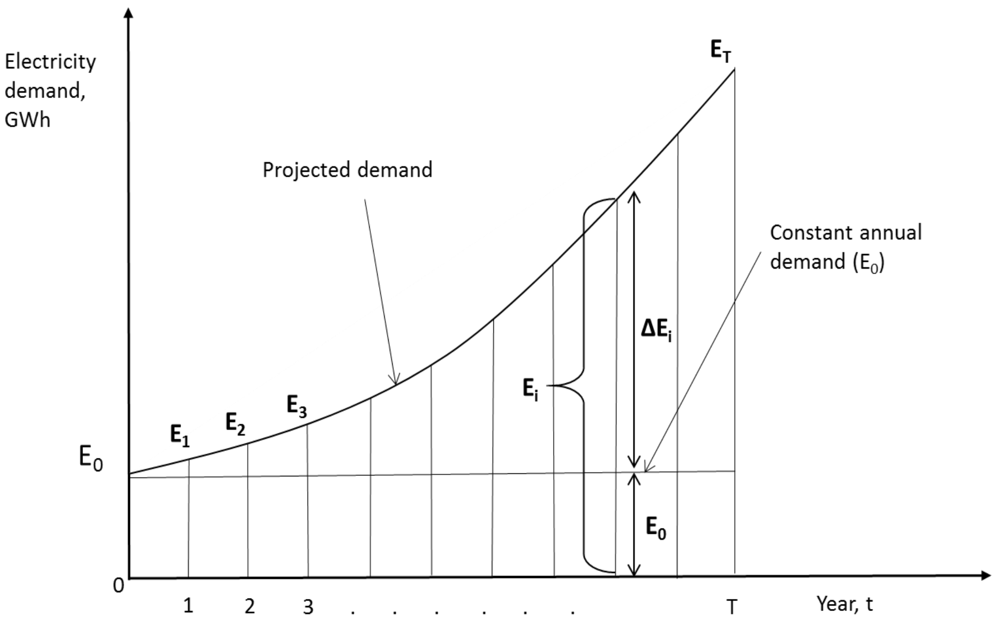

Figure 2.2: Future Electricity Demand Profiles for Calculation of AIC of generation

Step 4: The overall Average Incremental Cost (AIC) is the levelized cost per unit of electricity generated during the planning period and is calculated using equation 2.6.

$$\mathrm{AIC} = \frac{\mathrm{TC_2 - TC_1}}{\mathrm{E_c}} \tag{2.6}$$

where,

$E_c = \sum \frac{\Delta E_i}{(1+r)^i} = \sum \frac{(E_i - E_0)}{(1+r)^i}$ for i =1, 2, 3,…., T (T being the length of the planning period)

E_i : Electricity generation in year i;

E_0 : Electricity generation at the beginning of year 1;

T : Length of planning period; and

r : Discount rate.

2.6. Decomposition of Total CO_2 Emission Reduction: Estimating the Contributions of Demand- and Supply- side Effects of Carbon and Energy Taxes

A reduction in CO_2 emission is expected to take place under a carbon tax policy. In most cases, an energy tax is also expected to cause a reduction in CO_2 emission. The total reduction in the emission results from two kinds of effects: First, there would be a reduction in electricity demand with an increase in electricity price under each of these taxes; this type of reduction is hereafter called the "demand-side effect" of the tax. Second, there can also be a reduction in CO_2 emission due to the substitution of carbon-intensive power generation options with low-carbon and/or zero-carbon options under each of these taxes; such a phenomenon is hereafter called as the "supply-side effect".

This section explains the methodology used in the present study to determine the supply-side and demand-side effects on the total reduction in CO_2 emission from the power sector in the case of the carbon tax.

The supply-side effect on the reduction of CO_2 emission ($\Delta\epsilon_s$) is calculated in terms of the mitigation of CO_2 emission associated with the fuel and technological substitutions in power generation due to the tax. It is expressed as:

$$\Delta\epsilon_s = \epsilon_0 - \epsilon_s \qquad (2.7)$$

where,

ϵ_0 = CO_2 emission corresponding to the least cost fuel mix in the base case (i.e., without a carbon tax) for meeting the projected levels of power demand during the planning horizon; and

ϵ_s = CO_2 emission corresponding to the least cost fuel mix for meeting the projected levels of power demand during the planning horizon under a carbon tax, all other things remaining the same as in the base case.

The demand-side effect or CO_2 mitigation associated with the demand-side response ($\Delta\epsilon_p$) due to an increase in electricity price with the carbon tax, is expressed as:

$$\Delta\epsilon_p = \epsilon_s - \epsilon_p \qquad (2.8)$$

where,

ϵ_p = CO_2 emission associated with the least cost fuel mix for meeting the reduced levels of electricity demand during the planning horizon with an increase in the electricity price resulting from a carbon tax, all other things remaining the same as in the case of ϵ_s.

Total CO_2 mitigation effect of a carbon tax ($\Delta\epsilon$) is then:

$$\Delta\epsilon = \epsilon_0 - \epsilon_p \tag{2.9}$$

$$= (\epsilon_0 - \epsilon_s) + (\epsilon_s - \epsilon_p)$$

$$= \Delta\epsilon_s + \Delta\epsilon_p$$

= (Supply-side Effect) + (Demand-side Effect)

Here, Demand-side effect (%) = $\Delta\epsilon_p / \Delta\epsilon$; and

Supply-side effect (%) = $\Delta\epsilon_s / \Delta\epsilon$

CO_2 emissions were calculated using information on optimal (i.e., least cost) fuel requirements and relevant emission factors.

A similar approach is used to determine the supply- and demand-side effects of an energy tax.

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3. Comparative Analysis

This chapter presents comparative analyses of the effects of carbon and energy taxes on power sector development of the six countries under the present study, i.e., China, India, Indonesia, Sri Lanka, Thailand and Vietnam. The comparative analysis is based on the results of the individual country studies presented in Chapters 4 to 9. All country studies consider a base case (i.e., without any climate and energy policy interventions), six carbon tax cases (with the carbon tax varying from $5/tC to $150/tC) and four energy tax cases (with the energy tax considered varying from 0.5 $/MBtu to 5 $/MBtu). The effects of carbon and energy taxes considered are in terms of power generation capacity requirements, electricity generation-mix, thermal efficiency of power plants, CO_2 emission, CO_2 emission intensity and local/regional pollutant emissions in the countries. The effect of the taxes on the total cost, investment requirement and the overall average incremental cost across the countries under the study are also discussed in this chapter. Furthermore, the chapter compares the roles of the demand- and supply-sides on CO_2 emission across the countries.

3.1. Resource and Technology Options

In the present set of country studies, coal and oil are considered as an option in all the countries. Gas has been considered as an option in all countries except in Sri Lanka. Conventional coal-fired power plants as well as cleaner and energy efficient technologies (CEETs) such as pulverized fluidized bed combustion (PFBC), Biomass Integrated Gasification Combined Cycle (BIGCC) and Super Critical (SC) power plants have been considered as candidate plants in all countries under the study. Integrated Gasification Combined Cycle (IGCC) power plants using coal are considered as a candidate in all countries except in India.

The Natural Gas Combined Cycle plant (NGCC) has been considered in Thailand and China. Wind, solar and biomass power options are considered in all countries; however, the wind power plant options considered in the case of China were limited only to their potential in the northern and southeastern provinces of the country due to limited the data available at the time of the study. Geothermal options have been considered in Vietnam and Indonesia only.

It is important to note here that additional nuclear power generation capacity and thermal power generation with carbon capture and storage technologies are not considered in the present set of studies. Note also that the demand-side technology options (i.e., end-use device options) and learning effect on technologies like solar PV have not been considered in these studies.

3.2. Electricity demand growth

The annual growth in electricity demand considered during the study period (2006-2025) varied across the countries from 4.8% in China to 8.3% in Vietnam. In the present studies, the effects of carbon and energy taxes on electricity demand are estimated through the change in electricity price (represented in the studies by the average incremental cost of electricity supply) and price elasticities of electricity demand. The price elasticity of demand used in the studies, however, vary widely across the countries; i.e., -0.05 in the case of Thailand, -0.20 in the case of India and as high as -0.35 in the case of Indonesia. Some of these elasticity figures are based on country specific study (i.e., in the case of Thailand), while others were mostly borrowed from the estimates available in the literature on other developing countries due to lack of the country specific figures at the time the country studies were carried out.

3.3. Effects of Carbon Tax

This section discusses the significant commonalities and differences in the results that are observed in the country studies in terms of the effects of carbon tax on generation-mix, capacity-mix and emissions of CO_2, SO_2 and NO_x in the power sector during 2006-2025. Also discussed are the effects of the taxes on power generation cost including the investment or capacity cost. Furthermore, it discusses the contributions of the supply- and demand-sides on the total CO_2 reduction from the power sector due to the taxes. It should be noted here that as the studies in this volume are based on partial equilibrium analyses using the least cost electricity generation system planning model, the recycling of the carbon tax revenue has not been considered in assessing the effects of the tax in these studies.[1] Note also that carbon tax is applied to fossil fuels only; biomass energy is exempt from carbon tax as biomass is assumed to be produced on a sustainable basis.

3.3.1. Effect on electricity generation capacity mix

The estimated total generation capacity requirements of the countries under the study in the base case in 2006 and 2025 are shown in Table 3.1. The range of the increase in the total generation capacity during 2006-2025 in

[1] Recycling of revenue generated by carbon tax means to use the carbon tax revenue in different ways. For example, the tax revenue adds to government receipt to decrease government deficit (Gupta and Hall, 1997), or it is invested in carbon-abating or energy efficient technologies (Gupta and Hall, 1997; Goto, 1995), or the revenue from the carbon tax is used to cut distortionary taxes such as income tax or corporate tax (Bovenberg and de Mooij, 1994; Pearce, 1991) or it is recycled to the household sector as additions to personal income (Vanden et al., 1997). If these issues are considered, carbon tax may yield a “double dividend”, i.e., not only a cleaner environment but also a less distortionary tax system (Bovenberg and de Mooij, 1994; Pearce, 1991).

the base case is estimated to be 103% in China to 294% in Sri Lanka.[2] With the carbon tax of $10/tC, the reduction in total power generation capacity is estimated to vary in the range of 0.56% in Thailand to 2.03% in Vietnam, whereas with the tax of $150/tC, the reduction in the capacity would vary in the range of 1.5% in Vietnam to 24.3 % in India.

Table 3.1: Total generation capacity in the base case (MW)

Country	2006	2025
China	505,615	1,027,734
India	165,168	519,570
Indonesia	22,056	86,036
Sri Lanka	2,135	8,407
Thailand	27,872	74,311
Vietnam	14,113	49,559

Table 3.2 shows the share of renewable energy technologies (RETs) in the total power generation capacity in the base case. The shares of RETs in total power generation capacity during the study period are found to vary significantly across the countries reflecting the availability of renewable and fossil energy resources in the countries as well as the level of the power demand. In the base case, the share of RETs (including hydro) in the total generation capacity is estimated to vary from 6% in Indonesia to 35% in Vietnam by 2025. As shown in Table 3.3, at the carbon tax of $10/tC, the share of RETs would be the lowest in China (i.e., 2.7%) and highest in Vietnam (i.e., 28.0%). At the carbon tax of $150/tC, the share of RETs would be the lowest in Thailand (i.e., 8.0%) and highest in Indonesia (i.e., 82.7%). The high share of RETs at $150/tC in Indonesia is due to the replacement of coal-fired plants with BIGCC plants.

[2] The relatively low growth in the power generation capacity in China is due to the low growth rate of the future electricity demand considered at the time this study was carried out. The future electricity demand growth considered by the present study happened to be significantly lower than the actual growth in demand during 2006-2013 in China. As a result, the available data on the power sector of China shows that the actual generation capacity and electricity generation during 2006-2013 are both significantly higher than the corresponding estimates of this study.

Table 3.2: Share of RETs in total power generation capacity in the base case (%)

Country	2006	2025
China	21	11
India	27	18
Indonesia	12	6
Sri Lanka	61	22
Thailand	24	14
Vietnam	37	35

Table 3.3: Share of renewables in total power generation capacity added during 2025 (%)

Carbon tax ($/tC)	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0 (Base)	2.8	10.6	3.4	4.7	6.1	26.2
5	2.7	10.7	6.5	3.9	6.1	27.5
10	2.7	10.7	27.5	3.9	7.6	28.0
25	9.3	10.1	65.0	4.9	7.8	27.2
50	9.5	13.4	78.0	6.1	7.8	35.1
100	14.2	17.3	80.0	7.5	8.0	55.5
150	14.9	16.6	82.7	66.8	8.0	58.2

3.3.2. Effects on electricity generation mix

As the carbon tax increases, the demand for electricity is expected to decrease and so is the total electricity generation.[3] The levels of electricity generation in the base case in 2006 and 2025 are shown in Table 3.4. As can be seen from the table, during 2006-2025 the total electricity generation in the base case would increase by 1.4 times in China, 2.2 times in India, 3.0 times in Indonesia, 3.1 times in Sri Lanka, 1.9 times in Thailand and 3.2 times in Vietnam.

Table 3.4: Cumulative electricity generation in the base case (TWh).

Country	2006	2025
China	2,706	6,559
India	791	2,500
Indonesia	121	478
Sri Lanka	10	41
Thailand	151	437
Vietnam	73	309

[3] In the present set of studies, the equilibrium levels of electricity demand and the corresponding electricity generation with a carbon tax are derived iteratively by using the average incremental cost (AIC) of electricity supply (as a proxy of the electricity price) and price elasticity of electricity demand. The change in the electricity price with the carbon tax is measured as the difference between AICs with and without the carbon tax (see Section 2.5 in Chapter 2).

The share of RETs in cumulative electricity generation during 2006-2025 in the base case is estimated to be 8.8% in China, 16.6% in India, 4% in Indonesia, 26.9% in Sri Lanka, 13.3% in Thailand and 29.6% in Vietnam.

At the low tax of $5/tC, the decrease in the electricity generation compared to the base case is lowest in Thailand (i.e., decrease by 0.02%) and highest in Indonesia (i.e., decrease by 1.0%), whereas at the highest tax of $150/tC, the electricity generation would decrease in the range of 2.3% in Thailand to 12.0% in China.

As shown in Table 3.5, at the carbon tax of $10/tC, the share of RETs in electricity generation is estimated to be highest in Vietnam (i.e., 30.6%) and lowest in China (i.e., 8.9%). At the carbon tax of $150/tC, the share of RETs is estimated to be highest in Indonesia (i.e., 84.4%) and lowest in Thailand (i.e., 15.4%). The high share of RETs in electricity generation in Indonesia, Sri Lanka and Vietnam is due to the large addition of the BIGCC capacity in the case of Indonesia and Sri Lanka and wind power plants in the case of Vietnam at a high carbon tax.

Table 3.5: Share of RETs in cumulative electricity generation during 2006-2025 (%).

Carbon tax ($/tC)	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0 (Base)	8.8	16.6	4.3	26.9	13.3	29.6
5	8.9	16.8	7.1	26.7	13.4	29.9
10	8.9	16.8	29.6	26.8	14.4	30.6
25	14.3	17.2	70.0	27.5	14.3	32.2
50	14.7	17.7	85.4	28.6	15.0	36.9
100	17.1	23.2	84.2	30.5	15.2	41.6
150	17.7	25.3	84.4	82.3	15.4	43.4

3.3.3. Effects on CO_2 emission

In the base case, the cumulative emissions of CO_2 from the power sector during 2006-2025 in the countries under the study are 91,095 Mt in China, 24,142 Mt in India, 4,678 Mt in Indonesia, 250 Mt in Sri Lanka, 2,384 Mt in Thailand and 2,207 Mt in Vietnam. In the base case the annual CO_2 emission from the power sector during 2006-2025 is estimated to increase from 2,672 Mt to 6,549 Mt in China, 590 Mt to 2,097 Mt in India, 103 Mt to 428 Mt in Indonesia, 3 Mt to 28 Mt in Sri Lanka, 78 Mt to 164 Mt in Thailand and 35 Mt to 183 Mt in Vietnam. Table 3.6 shows that with the introduction of $10/tC carbon tax, the cumulative reduction in CO_2 emission during 2006-2025 would vary in the range of 0.8% in Sri Lanka to 36.7% in Indonesia. At the carbon tax of $150/tC, the cumulative reduction in CO_2 emissions would vary in the range of 13.3% in Thailand to 82.9% in Sri Lanka. At $150/tC the reduction in CO_2 emission is significantly higher in Sri Lanka due to the replacement of conventional coal-fired power plants by BIGCC. In the case of Thailand, there is a smaller reduction in the emissions as there is very little fuel shifting as compared to that in the other countries; this is because the power system in Thailand relies mainly on

CCGT and conventional biomass power plants for electricity generation in the base case as well as the carbon tax cases.

The CO_2 intensity of the power sector (defined as carbon dioxide emission per unit of electricity generation) is found to decrease at the carbon tax of $150/tC in all countries. The decline in the CO_2 intensity is due to a switch from fossil fuels to biomass in power generation. Although CO_2 emission would decrease with the increase in carbon tax, it is found that the CO_2 intensities would not necessarily decrease in each tax case: For example, in the case of Thailand, the CO_2 intensity would hardly change with the increase in carbon tax, as biomass resource in this country is very limited.

Table 3.6: Cumulative reduction in the CO_2 emission during 2006-2025* (%)

Carbon tax ($/tC)	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
5	0.6	0.6	4.5	0.2	6.7	1.1
10	1.3	1.3	36.7	0.8	7.6	2.6
25	15.2	3.2	59.1	2.9	7.8	7.7
50	17.5	16.0	67.7	6.4	8.7	44.6
100	23.3	23.6	79.6	12.6	10.4	55.2
150	47.3	27.8	81.5	82.9	13.3	66.3

*The figures represent the reduction as a percentage of the cumulative CO_2 emission during the period in the base case.

3.3.4. Role of demand- and supply-side effects on CO_2 emission reduction

The demand-side effect here is defined as the change in CO_2 emission brought about by the change in electricity demand as the electricity price changes with the introduction of carbon tax. The supply-side effect, on the other hand, is the change in CO_2 emissions resulting from a change in electricity generation technology-mix and fuel-mix due to the tax; for example, switch from a coal intensive technology to a more efficient and less carbon intensive electricity generation technology.[4] At the carbon tax of $5/tC, the demand-side effect is dominant in China, India and Sri Lanka (see Table 3.7). In the case of Thailand, the supply-side effect is found to be significantly higher in all the carbon tax cases except at $100 and $150/tC. The smaller contribution of the supply-side effect at higher taxes in Thailand is due to the predominant use of gas-based power plants in the country as the price of gas is significantly lower than the price of competing resources. In the case of Indonesia, the supply-side effect is observed to be dominant because the share of biomass in the capacity-mix increases by 25% at $10/tC and by 79% at $150/tC when compared to that in the base case. The

[4] The demand- and supply-side effects in the case of an energy tax are defined similarly.

supply-side effect becomes dominant above the carbon tax of $10/tC in China, $25/tC in India and $100/tC in Sri Lanka. In the case of Vietnam, the demand-side effect is only dominant at $25/tC.

Table 3.7: Demand-side effect on cumulative CO_2 emission reduction in the selected countries during 2006-2025

Carbon tax $/tC	Share of demand-side effect in total CO_2 emission reduction (%)					
	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
5	98	84.2	42.5	90.2	1.0	45.8
10	97.2	83.1	2.4	94.9	1.8	48.3
25	17.3	80.5	0.2	90.7	12.1	55.9
50	27.2	19.7	1.2	90.6	37.6	9.7
100	34.5	18.9	1.2	82.2	54.8	11.0
150	8.9	27.7	1.3	2.4	61.2	10.6

3.3.5. Carbon tax elasticity of CO_2 emission

The carbon tax elasticity of CO_2 emission has been calculated using the arc elasticity concept (see Section 2.2 in Chapter 2 for more explanation). Based on the country studies, the CO_2 emission is found to be mostly inelastic and it would be increasingly elastic with an increase in the carbon tax. The carbon tax elasticity of CO_2 emission is found to vary from almost zero in China and India to -0.35 in Thailand in the range of carbon tax from $0/tC to $5/tC across the countries. At the higher range of the tax (i.e., $100 to $150/tC), the elasticity is found to vary from -0.08 in Thailand to -0.93 in China. At the same tax range, the carbon tax elasticity of CO_2 emission is found to be elastic (i.e., -3.99) only in the case of Sri Lanka.

3.3.6. Effects on thermal generation system efficiency

Table 3.8 displays the change in the overall efficiency of thermal power generation during 2006-2025 (expressed as the weighted average of annual thermal generation efficiencies (WATGE)) as an effect of the carbon tax in the power generation system (see Section 2.3 in Chapter 2 for more explanation on WATGE). In the base case, the overall efficiency would be lowest (i.e., 34.2%) in India and highest (i.e., 38.9%) in Thailand. The imposition of carbon tax is found to increase the efficiency in all countries except in Sri Lanka. At the carbon tax of $10/tC, the overall efficiency would remain the same as in the base case (i.e., 34.2%) in India; in Indonesia it would increase to 39.5% from 38.8% in the base case. At the tax of $150/tC, the overall efficiency is found to decrease significantly in Sri Lanka (i.e., from 37.6% in the base case to 28.9%) due to the replacement of conventional coal power plants by BIGCC plants, whereas the overall efficiency would increase most in the case of Vietnam (i.e., from 36.8% in the base case to 42.4%) due to the decrease in coal use by 70% (as compared to the base case) and increase in electricity generation from cleaner fuels. The studies show that the overall thermal power generation efficiency does not necessarily improve with the introduction of carbon tax as is illustrated by the case of Sri Lanka, where the efficiency is found to decrease at the tax of $150/tC.

Table 3.8: The effect of carbon tax on the overall WATGE during 2006-2025.

Carbon Tax ($/tC)	WATGE in the base case and carbon tax cases (%)					
	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0 (Base)	37.6	34.2	38.8	37.6	38.9	36.8
5	37.6	34.2	38.9	37.6	39.3	36.9
10	37.7	34.2	39.5	37.6	39.1	36.8
25	38.0	34.2	39.4	37.6	39.1	37.0
50	38.1	35.3	39.4	37.5	38.9	40.9
100	38.2	34.8	39.1	37.5	39.0	41.2
150	40.3	34.8	39.3	28.9	39.1	42.4

3.3.7. Co-benefits of carbon tax

The present set of country studies has estimated the effects of the selected carbon tax rates on the emissions of two local/regional level pollutants, i.e., SO_2 and NO_x. The changes in cumulative emissions of SO_2 and NO_x during 2006-2025 as a result of carbon taxes are shown in Table 3.9. As shown in the table, at the carbon tax of $10/tC, the reduction in SO_2 emission as a percentage of cumulative SO_2 emission during 2006-2025 in the base case would vary in the range of 1% in Thailand to 43% in Indonesia. The significant reduction in the case of Indonesia is due to the replacement of conventional coal-fired power plants by BIGCC plants at the carbon tax. At the carbon tax of $150/tC, the SO_2 emission reduction would vary in the range of 18% in Thailand to 82% in Indonesia.

Table 3.9: Reduction in SO_2 and NO_x emissions at selected carbon tax rates during 2006-2025

Carbon tax ($/tC)	Reduction in SO_2 emission (%)						Reduction in NO_x emission (%)					
	China	India	Indonesia	Sri Lanka	Thailand	Vietnam	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
5	0.4	0.6	5.0	1.0	1.0	0.6	0.5	0.6	5.0	15.0	57.0	1.2
10	1.4	1.3	43.0	2.0	1.0	1.3	1.5	1.3	42.0	16.0	58.0	2.8
25	50	3.5	67.0	4.0	1.0	4.5	48.5	3.2	66.0	19.0	58.0	7.9
50	50.9	31.6	72.0	5.0	1.0	35.5	49.7	24.6	71.0	22.0	59.0	39.8
100	53.8	36.6	80.0	13.0	5.0	43.4	52.8	28.4	79.0	26.0	61.0	51.7
150	55.0	40.4	82.0	81.0	18.0	78.0	53.7	31.5	80.0	81.0	62.0	59.4

As shown in Table 3.9, at $10/tC, the reduction in the emission of NO_x would vary in the range of 1.3% in India to 58% in Thailand, whereas at $150/tC, the reduction would be in the range of 31.5% in India to 81.0% in Sri Lanka. Significant reductions in the emissions of SO_2 and NO_x are estimated in the case of Indonesia, due to fuel switching from coal to cleaner fuels (mainly biomass and wind). In Thailand, there would be a reduction in SO_2 emission of only 18% at the carbon tax of $150/tC, whereas the NO_x reductions would vary from 57% to 62% at the tax rates considered; this is mainly due to the dominant share of gas-fired generation (based on CCGT) in power generation, which is maintained in all the carbon tax cases considered.

3.3.8. Cost implications of carbon tax

The percentage increases in the total cost of electricity generation (inclusive of the carbon tax revenue) in the carbon tax cases are presented in Table 3.10. At the carbon tax of $10/tC, the total cost would increase in the range of 1% in Indonesia, Sri Lanka and Thailand to 5% in China. With the carbon tax of $150/tC, the total cost would increase in the range of 18% in Indonesia to 107% in China.

In the base case, the estimated investment requirements (i.e., cumulative cost of capacity addition) during 2006-2025 in the study countries are 553,675 million USD in China, 212,458 million USD in India, 45,716 million USD in Indonesia, 4,535 million USD in Sri Lanka, 55,208 million USD in Thailand and 16,854 million USD in Vietnam. With the imposition of carbon tax, the power generation investment requirements in most countries (i.e., China, India, Sri Lanka, Thailand and Vietnam) are estimated to decrease, whereas in Indonesia, it is estimated to increase.

At the carbon tax of $10/tC, the investment requirement would decrease by about 1% in Sri Lanka and Vietnam to 16% in Thailand, whereas at the tax of $150/tC, the range of decrease in the investment requirements would vary from 3% in India to 25% in China and its range of increase would vary from 2% in Vietnam to 35% in Indonesia. With the carbon tax of $150/tC, the investment requirement would decrease by 25% in China and increase by 64% in Indonesia. At carbon taxes above $10/tC, the investment requirements would increase in Indonesia mainly due to the replacement of the conventional coal-fired power plant by BIGCC and wind power plants.

Table 3.10: Increase in the total cost due to carbon tax (%) during 2006-2025.

Carbon tax ($/tC)	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
5	5	3	1	1	1	2
10	9	5	2	2	2	5
25	21	12	4	5	6	11
50	40	23	8	9	11	20
100	75	45	13	17	23	33
150	107	65	18	21	33	44

3.3.9. Effect on the average incremental cost of electricity generation

The average incremental cost (AIC) of electricity generation measured in US cents per kWh in the base case during 2006-2025 are 3.2 in China, 3.3 in India, 4.2 in Indonesia, 4.9 in Sri Lanka and Thailand and 2.9 in Vietnam.

With the carbon tax of $10/tC, the percentage increase in AIC of electricity generation would be in the range of 1.2% in Thailand to 8.7% in China. With $150/tC, the percentage increase in AIC would vary from 23.8% in Indonesia to 96.9% in India and 121.4% in China (see Table 3.11). This shows that carbon tax would have widely varying effects on the electricity price across the selected countries.

Table 3.11: AIC of electricity generation as an effect of the carbon taxes during 2006-2025

Carbon tax ($/tC)	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0 (Base)	3.2	3.3	4.2	4.9	4.9	2.9
5	3.4	3.4	4.3	5.0	5.0	2.9
10	3.5	3.5	4.3	5.0	5.0	3.0
25	3.9	3.8	4.4	5.2	5.2	3.3
50	4.7	4.4	4.7	5.7	5.5	3.6
100	5.9	5.4	5.0	5.0	5.9	4.0
150	7.2	6.4	5.2	5.2	6.5	4.3

3.3.10. Effect on electricity generation capacity utilization

The studies show that the weighted average capacity factor (WACF) of the power generation system (WACF) during 2006-2025 would be decreasing with the increase in carbon tax (see Section 2.1.6 in Chapter 2 for an explanation of WACF). In the case of Vietnam, the WACF would decrease from 55.0% in the base case to about 51.0% at the carbon tax of $150/tC due to the increasing share of hydropower and wind capacity with the carbon tax. In Thailand the WACF would decrease from 64.0% in the base case to 63.3% at the carbon tax of $150/tC. In Sri Lanka the WACF would decrease from 54.0% in the base case to 52.0% at the carbon tax of $150/tC, whereas in the case of Indonesia, the WACF would decrease from 62.2% in the base case to 58.9% at the carbon tax of $150/tC.

3.4. Effects of Energy Tax

As in the case of carbon tax, this section compares the effects of energy tax among the six countries in the study, on electricity generation-mix, capacity-mix as well as emissions of CO_2, SO_2 and NO_x in the power sector during 2006-2025. The effects of energy tax on the investment requirements and other costs are also discussed. In addition, it discusses the roles of the demand- and supply-sides in CO_2 emission reduction from the power sector. It should be noted here that in the present set of studies energy tax is not applied on certain energy sources, i.e., solar, wind, geothermal and small hydropower.

3.4.1. Effects on electric capacity mix

Note that the cross-country comparisons of total capacity additions from 2006 to 2025 in the base case have been presented in Tables 3.1 and 3.2 in Section 3.3.1.

With the introduction of the $1/MBtu energy tax, the reduction in power generation capacity requirement as a percentage of the total capacity addition in the base case during 2006-2025 is estimated to vary from 1% in Thailand to 8% in Indonesia. At $5/MBtu, total addition in power generation capacity is estimated to decrease in all the countries: the reductions are in the range of 8% in Vietnam to 17% in China.

Table 3.12 shows that at the energy tax of $1/MBtu, the share of RETs was found to be lowest in China (i.e., 3.7%) and highest in Vietnam (i.e., 32.2%). At the tax of $5/MBtu, the share of RETs is found to be the lowest in Thailand (i.e., 0.5%) and highest in Vietnam (i.e., 63.9%). The high share of RETs in Vietnam is due to the additions of hydro and wind-power plants.

Table 3.12: Share of renewables in total power generation capacity added during 2025 (%).

Energy tax ($/MBtu	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0 (Base)	1.5	10.7	3.4	4.7	6.1	26.2
0.5	1.5	11.0	4.4	3.2	5.0	27.9
1	3.7	10.1	4.7	5.0	5.4	32.2
2	3.8	10.9	4.9	7.5	3.6	53.0
5	14.3	11.8	5.6	11.3	0.5	63.9

3.4.2. Effect on electricity generation mix

Total cumulative electricity generation during 2006-2025 in the countries studied is expected to decrease with an increase in the energy tax as a result of installation of more efficient electricity generation technologies.

Across the countries, the reduction in total electricity generation at the energy tax of $1/MBtu would vary in the range of 3% in China to 5% in both Indonesia and Vietnam, whereas at the tax of $5/MBtu, the reduction in the electricity generation would vary in the range of 5% in Thailand to 17% in both China and Sri Lanka. Energy tax is found to be most effective in the case of Indonesia due to addition of CCGT and wind power plants and least effective in the case of Thailand. In the case of China and Sri Lanka, energy tax would become more effective (i.e., with the highest decrease in electricity generation of 17% in both the countries) at the tax of $2/MBtu and higher.

Table 3.13 shows the share of RETs in electricity generation across the countries at energy tax of $1/MBtu would be the highest in Vietnam (i.e., 34.1%) and lowest in Indonesia (i.e., 4.4%). At the energy tax of $5/MBtu, the share of RETs in electricity generation would increase by only 0.6% (i.e., increases from 42% in the base case to 4.8%) in Indonesia when compared to a 17.4% increase in Vietnam (i.e., increase from 29.6% in the base case to 47.0%).

Table 3.13: Share of RETs in cumulative electricity generation during 2006-2025 (%).

Energy tax ($/MBtu)	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0 (Base)	8.8	16.6	4.2	26.9	13.3	29.6
0.5	8.9	16.9	4.3	26.7	11.1	31.7
1	9.5	17.4	4.4	28.2	10.9	34.1
2	9.7	17.9	4.3	30.2	8.8	41.6
5	13.1	19.6	4.8	35.2	6.3	47.0

3.4.3. Effects on CO_2 emission

A brief description on the cumulative CO_2 emission in the base case (i.e., from 2006 to 2025) has already been presented in Section 3.3.3.

Table 3.14 shows that at the energy tax of $1/MBtu, the cumulative reduction in CO_2 emission as a percentage of the emission in the base case during 2006-2025 would vary in the range of 4.3% in India to 11.2% in China, whereas at the tax of $5/MBtu, the CO_2 emission would decrease in the range of 5.1% in Thailand to 61.9% in Vietnam. The relatively high reduction of CO_2 emission in Indonesia (i.e., decrease by 43.9%) and Vietnam at the tax of $5/MBtu is due to the fuel shift from coal to gas in power generation. The CO_2 emission in Thailand would not change significantly because of the relatively high share of natural gas in the country in the base case.

Table 3.14: Reduction in CO_2 emissions during 2006-2025 (%)

Energy tax ($/MBtu)	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0.5	6.0	2.2	2.8	1.9	5.2	5.3
1	11.2	4.3	5.6	6.1	5.5	10.8
2	13.4	17.8	11.2	12.3	4.6	31.9
5	26.5	31.2	43.9	31.2	5.1	61.9

The CO_2 intensity tends to decrease with energy tax in all countries. In Indonesia and Vietnam, at $5/MBtu, the CO_2 intensity would decrease because the share of gas in the total fuel consumption in power generation would increase. In Thailand, the change in CO_2 intensity is estimated to be insignificant as gas-based power generation is predominant in all the energy tax cases. In the case of China, it is found that the rate of improvement in CO_2 intensity would be much smaller at the energy tax above $1/MBtu.

3.4.4. Role of demand- and supply-side effects in CO_2 emission reduction

Like in the case of carbon tax, the demand-side effect on CO_2 emissions is caused by a change in electricity price due to an energy tax. The supply-side effect, on the other hand, is the effect of the energy tax on technological and fuel switch; for example, a switch from conventional coal-fired power plants to more efficient and cleaner coal-based electricity generation technologies. A switch to an efficient generation technology and cleaner fuel system in the supply-side would result in a reduction of CO_2 emissions.

Table 3.15 shows that at the energy tax of $0.5/MBtu, the demand-side effect is significant in all the countries except in China and Thailand. The demand-side effect would be more dominant in the case of China and Thailand only at the energy tax of $5/MBtu. As in the case of carbon tax, there is very high supply-side effect in Thailand at the lower energy tax rates; this is because gas-based power plants are predominant in all the tax cases as the gas is relatively cheaper than other competing resources. In the case of Sri Lanka, the demand-side effect is dominant in all the energy tax scenarios whereas in Indonesia, the supply-side effect is more dominant only at the energy tax rate of $5/MBtu. In the case of Vietnam, on the other hand, the supply-side effect is only dominant at the tax rate of $1/MBtu. In Vietnam, the effect of demand-side decreases with the increase in the tax from $0.5/MBtu to of $1/MBtu; however, it would increase with the increase in the energy tax above $1/MBtu. The supply-side effect would be more dominant in India at the tax rate of $2/MBtu and higher.

Table 3.15: Demand-side effect on cumulative CO_2 emission reduction in selected countries during 2006-2025.

Energy tax	Share of demand-side effect in total CO_2 emission reduction (%)					
$/MBtu	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0.5	26.5	82.5	97.7	86.1	1.5	50.0
1	25.0	79.9	96.6	90.7	22.7	45.2
2	37.2	24.1	94.6	86.0	40.6	58.3
5	58.2	28.0	20.1	75.2	80.7	82.9

3.4.5. Energy tax elasticity of CO_2 emission

CO_2 emission elasticity has been estimated to be inelastic with respect to energy tax in all countries. Furthermore, the emission is found to be increasingly elastic at the higher taxes. The energy tax elasticity of CO_2 emission is found to vary from almost zero in China and India to -0.28 in Thailand and Vietnam in the energy tax range of 0 to $0.5/MBtu across the countries. At the higher tax range (i.e., $2 to $5/MBtu), the elasticity is found to vary from -0.006 in Thailand to -0.66 in Vietnam.

3.4.6. Effects on thermal generation system efficiency

An energy tax is expected to improve the overall efficiency of thermal power generation. As shown in Table 3.16, at $1/MBtu, the efficiency would have the highest increase in China (i.e., from 37.6% in the base case to 40.8%). At the energy tax of $5/MBtu, it is estimated that the highest increase in the efficiency would take place in Indonesia (i.e., from 38.3% in the base case to 46.0%) and lowest increase would be take place in Sri Lanka (i.e., 37.6% in the base case to 39.9%).

The studies estimate a significant increase in the efficiency in all the countries at $5/MBtu. This is because the less efficient conventional coal-fired plants would be replaced by efficient and cleaner power generating options such as wind and IGCC in China, supercritical coal-fired plants in India, CCGT in Indonesia, IGCC in Sri Lanka, CCGT in Thailand and combined cycle plants in Vietnam. Interestingly, the overall efficiency of thermal power generation is reported to decrease in the case of Vietnam at the tax of $1/MBtu (i.e., from 34.9% to 34.0%); this is because of the increase in the share of RETs as well as coal-based power generation and reduced share of gas-based power generation in the country with the energy tax.

Table 3.16: The effect of energy tax on the overall WATGE during 2006-2025 (%).

Energy Tax ($/MBtu)	Change in WATGE compared to the base case (%)					
	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0 (Base)	37.6	34.7	38.3	37.6	38.9	34.9
0.5	39.2	34.7	38.3	37.6	39.8	34.9
1	40.8	34.7	38.3	37.6	39.8	34.0
2	40.7	35.8	38.9	37.6	40.5	35.5
5	40.4	36.9	46.0	39.9	41.5	41.2

3.4.7. Co-benefits of energy tax

Table 3.17 shows that at the energy tax of $1/MBtu, reduction in SO_2 emission as a percentage of the cumulative SO_2 emissions during 2006-2025 would vary in the range of 1.6% in Thailand to 51.5% in China. Similarly, at the tax of $5/MBtu, the SO_2 reduction would vary in the range of 4.6% in Thailand to 70.0% in Indonesia.

At $1/MBtu, the emission of NO_x would increase by 3.6% in Thailand and decrease by 49.8% in China, whereas at $5/MBtu, the emissions would increase by 2.0% in Thailand and decrease by 62% in Indonesia. The reduction in the local pollutants in Indonesia is significant at the energy tax of $5/MBtu due to the replacement of conventional coal power plants by CCGT. Significant reduction in SO_2 emission is also estimated in the case of China with the imposition of energy tax of $5/MBtu; this would happen due to an increase in the capacity of pumped storage hydropower and wind power plants. Thailand, however, presents a completely different picture with a very small reduction of SO_2 and a slight increase in NOx emissions at $5/MBtu (mainly due to an increase in the addition of CCGT generation). In China, there would be a relatively small reduction in the cumulative emissions of both SO_2 and NO_x, when the tax is increased further to $5/MBtu. Thus, it is shown that an energy tax above $1/MBtu may not bring much additional co-benefit in terms of SO_2 and NO_x emission reductions from the power sector of China.

Table 3.17: Reductions in SO_2 and NO_x emissions at selected energy tax rates during 2006-2025.

Energy ($/MBtu)	Reduction in SO_2 emission (%)						Reduction in NO_x emission (%)					
	China	India	Indonesia	Sri Lanka	Thailand	Vietnam	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0.5	28.6	2.4	3.0	2.9	1.6	2.6	27.6	2.2	3.0	4.5	-4.3	5.6
1	51.5	4.6	6.0	3.8	1.6	5.4	49.8	4.3	6.0	7.9	-3.6	11.4
2	51.5	33	12.0	12.0	2.5	17.6	50.2	26.2	11.0	15.7	-3.5	33.0
5	55.1	61.7	70.0	61.5	4.6	42.1	55	38.7	62.0	55.1	-2.0	60.8

3.4.8. Cost implications of energy tax

The total cost of electricity generation in the base case has been presented in Table 3.10 (in Section 3.3.8). Table 3.18 presents the change in the total cost with the selected energy taxes. At the energy tax of $1/MBtu, the increase in the total cost (inclusive of the carbon tax revenue) would vary in the range of 3% in Sri Lanka to 12% in China. At the tax of $5/MBtu, the increase in the total cost would lie in the range of 24% in Sri Lanka to 92% in China.

At the energy tax of $0.5/MBtu, the range of decrease in the investment requirements would be 0.5% in Vietnam to 21% in Thailand, whereas at the energy tax of $5/MBtu, the range of decrease would vary from 2% in India and Vietnam to 26% in Indonesia and Thailand. The investment requirements would increase in the case of China from 13% at the tax of $0.5/MBtu to 2% at $5/MBtu. The decrease in the investment in Thailand is due to a significant decrease in IGCC, BIGCC and conventional biomass plant capacity in Thailand.

Table 3.18: Increase in the total cost due to energy taxduring 2006-2025 (%).

Energy tax ($/Mbtu)	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0.5	12	8	6	3	7	9
1	24	17	11	6	15	8
2	46	34	23	12	29	12
5	92	82	55	24	69	25

3.4.9. Effect on average incremental cost of electricity generation

As can be expected, an energy tax affects the unit cost of electricity generation. At $1/MBtu, the increase in AIC of electricity generation as a percentage of the AIC in the base case is estimated to vary from 10% in Thailand to 24% in China, whereas at $5/MBtu the increase in AIC is estimated to vary from 45% in Vietnam to 114%% in China (see Table 3.19).

Table 3.19: The average incremental cost of electricity at different energy tax rates

Energy tax ($/MBtu)	China	India	Indonesia	Sri Lanka	Thailand	Vietnam
0 (Base)	3.2	4.3	4.1	4.9	5.0	2.9
0.5	3.7	4.7	4.5	5.2	5.4	3.2
1	4.0	5.1	5.0	5.5	5.5	3.5
2	4.7	5.9	5.9	6.2	6.2	4.1
5	6.9	8.0	8.0	8.4	8.0	5.3

3.5. Summary of Key Findings and Final Remarks

In this study, cross-country variations in the effects of carbon and energy taxes in the power generation systems of China, India, Indonesia, Sri Lanka, Thailand and Vietnam are assessed in terms of changes in the electricity generation-mix, capacity-mix, technology selection, investment requirements along with the changes in CO_2, SO_2 and NO_x emissions.

The country studies find that the share of RETs in the total additional power generation capacity during 2006-2025 with the carbon tax of $50/tC and above would be higher than that in the base case in all countries under the study. With the carbon tax of $25/tC and above, the share of RETs in cumulative electricity generation during the period would be higher than that in the base case in all countries. With the energy tax of $2/MBtu and above, the share of RETs in the total additional power generation capacity during the period would be higher than that in the base case in all of the countries except Thailand, where the share is found to be lower than that in the base case in all energy tax cases. Similarly, the share of RETs in cumulative electricity generation would be higher than that in the base case in all the countries except Thailand with the energy tax of $1/MBtu and above. In the case of Thailand the share of RETs is found to be decreasing in both the power generation capacity addition and cumulative electricity generation during 2006-2025 due to the decrease in the share of BIGCC and conventional biomass and increase in the share of gas-based power generation.

With the carbon tax of $10/tC, the cumulative emission of CO_2 would be reduced by 0.8% in Sri Lanka and by as high as 37% in Indonesia. At the higher tax rate of $150/tC, the cumulative reduction in CO_2 emission would vary from 13% in Thailand to 83% in Sri Lanka. In the case of energy tax, all the country studies show that CO_2 emission would decrease with the tax. The decrease in the emission would be in the range of about 2% in India and

Sri Lanka to 6% in China at the tax of $0.5/MBtu, whereas it would vary from 5% in Thailand to 62% in Vietnam at $5/MBtu.

The carbon tax has been found to decrease SO_2 and NO_x emission in all the countries under the study. At the carbon tax of $10/tC, the reduction in SO_2 emission would be in the range of 1% in Thailand to 43% in Indonesia, whereas the reduction in NO_x would be in the range of 1.3% in India to 58% in Thailand. At the high carbon tax of $150/tC, the percentage reduction in SO_2 would be in the range of 18% in Thailand and 82% in Indonesia and the range of the percentage reduction in NO_x would vary from 32% in India to 81% in Indonesia. In the case of energy tax, the SO_2 emission is found to be decreasing in all the countries and the NO_x emission is found to be decreasing in all the countries except in Thailand. The percentage reduction in SO_2 emission at the energy tax of $0.5/MBtu would be in the range of 2% in Thailand and 29% in China, whereas at $5/MBtu, the reduction would vary in the range of 5% in Thailand to 70% in China. The NO_x emission, however, would increase in Thailand by 4% and decrease in China by 28% at $0.5/MBtu, whereas it would increase in Thailand by 2% and decrease in Indonesia by 62% at the tax of $5/MBtu.

Normally, the energy tax is expected to increase the overall efficiency of thermal power generation. This has also been reported by the country studies except in the case of Vietnam, where at the energy tax of $1/MBtu, the weighted average thermal power generation efficiency during 2006-2025 is estimated to decrease due to increased shares of in the RETs and coal-based power plants in electricity generation and a decrease in the share of gas-based power generation. In the case of carbon tax, the studies have found that the weighted average efficiency of thermal power generation during 2006-2025 would be increasing with the tax in all the countries except Sri Lanka, where the efficiency is estimated to decrease from 37.6% in the base case to 28.9% with the tax of $150/tC; this is due to a large increase in the share of BIGCC in cumulative electricity generation during the period in that country.

The studies have reported that the CO_2 emission would be mostly inelastic with respect to changes in carbon tax. The carbon tax elasticity is estimated to vary from almost zero in China and India (in the tax range of $0/tC to$5/tC) to -0.93 in China (in the tax range of $100/tC to $150/tC). However, in the case of Sri Lanka, the elasticity is estimated to be as high as -3.99 at the high range of carbon tax (i.e., from $100/tC to $150/tC). Similarly, the CO_2 emission is reported to be inelastic with respect to changes in energy tax. The estimated energy tax elasticity of CO_2 emission is found to vary from close to zero in China and India in the low energy tax range of (i.e., from 0 to $0.5/MBtu) to -0.66 in Vietnam in the higher tax range (i.e., $2 to $5/MBtu).

The studies have estimated that the discounted values of investment requirements for power generation during 2006-2025 would decrease with carbon tax in most cases as compared to the corresponding values in the base case. At the tax of $10/tC, the investment requirement would decrease in the range of about 1% in Sri Lanka and Vietnam to16% in the case of

Thailand. At the higher tax of \$150/tC, the requirement would decrease by 3% in India to 25% in China, whereas it would increase by 2% in Vietnam and 64% in Indonesia. The increase in the case of Indonesia is primarily due to replacement of the conventional coal-fired plants by BIGCC and wind power plants.

In the case of energy tax, the discounted investment requirements would decrease in all countries except China. At the energy tax of \$0.5/MBtu, the range of decrease in investment required would be 0.5% in Vietnam to 21% in Thailand. At \$5/MBtu, the reduction in the investment requirement would vary from 2% in India and Vietnam to 26% in Indonesia and Thailand. In the case of China, the investment requirement would increase by 13% at the tax of \$0.5/MBtu to 2% at \$5/MBtu.

It should be noted that this study has not considered the options of additional nuclear power generation and thermal power generation with carbon capture and storage. In addition, it does not consider the role of demand-side technology options in determining the least cost options for electricity generation system. Furthermore, the learning effect on the costs of RETs such as solar PV and wind has not been considered in the studies. Thus the present set of studies is likely to underestimate both the total CO_2 emissions and the shares of RETs in electricity generation under the carbon and energy taxes.

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4. Power Sector Development in China: Effects of Carbon and Energy Taxes[1]

4.1. Introduction

China has been the world's largest producer of electricity since 2011, with its global share increasing from 21% in 2011 to 24% in 2014 (IEA, 2014; BP, 2015). Coal is the dominant fuel used for power generation in the country (IEA, 2014). Thermal power plants accounted for nearly 69% of the total installed power generation capacity (1258 GW) in 2013 (NBSC, 2014). The growth of the power sector in the country has serious implications on both GHG as well as local and regional level pollutant emissions. Thus, the subject of reduction of GHG emissions and other harmful emissions in China's power sector has gained significant attention. Economic instruments such as carbon and energy taxes are among the options widely discussed for reducing emissions from the power sector. The effects of these taxes on the structure of electricity generation, capacity addition and costs would, however, vary across countries depending on the power demand growth, resources and technology options available and their potential. As electricity generation is growing rapidly and is consuming substantial energy as well as emitting GHG and local pollutants in China, it is of interest to study the effects of carbon and energy taxes in the power sector of the country.

The analysis presented in the following sections of this chapter was conducted in 2004-2005 to assess the utility planning, environmental and economic implications of introducing carbon and energy taxes in the power sector of China for the planning period of 2006-2025. Electricity demand forecast and other relevant data available at that time (i.e., 2004-2005) were used for the study. Six carbon tax rates (i.e., \$5/tC, \$10/tC, \$25/tC, \$50/tC, \$100/tC and \$150/tC) and four energy tax rates (i.e., \$0.5/MBtu, \$1/MBtu, \$2/MBtu and \$5/MBtu) were considered in the study. The findings of the study are outlined in Sections 4.2 to 4.5 of this chapter. The results of the least cost generation planning (without carbon and energy taxes) (i.e., in the "Base Case") are presented in Section 4.2. That is followed by a discussion of the results on the effects of carbon and energy taxes in Sections 4.3 and 4.4, respectively. A summary of key findings is presented in Section 4.5. Since this study was conducted in 2004-2005, the chapter contains a post-script at the end of the chapter to discuss the differences between the results from the base case of this study and the actual data in

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terms of the growth in electricity generation, generation-mix and capacity additions and energy policies related to the power sector in recent years after the study was carried out. As a post script, it is particularly important to note here that the actual electricity demand during the last 8 years (i.e., 2005-2013) has been found to grow at a much higher rate than the electricity demand growth rate projected for the same period at the time this study was carried out. As a result, one can find major differences between the results of the study and actual evolutions in the power sector in recent years (i.e., during 2006-2013 and in some cases till 2014) after the study. Nevertheless, there are several interesting qualitative insights generated by the study on the effects of the carbon and energy taxes, which would mostly remain valid irrespective of changes in demand projections.

4.2. Base Case Analysis

4.2.1. Definition of Base Case

In the base case, electricity demand and supply are assumed to grow in the business as usual manner (i.e., without considering any climate and energy policy).

Input data and assumptions

Most data used for electricity generation system planning (e.g., existing, committed, and candidate power plant data) in this study are based on ERI (2004). In this study, the planning period is 2006-2025. All prices used in the study were economic prices in constant 2000 US dollars. In the base case (i.e., without considering any climate and energy policy), the data on projected peak power demand up to the year 2025 are based on SPC (2003). A discount rate of 10% is considered in the study. The price elasticity of electricity demand used in this case study is -0.21. It should be noted that demand-side management (DSM) options are not considered in this study.

Existing and committed power generation capacity considered in the electricity generation system planning (EGP) model at the time of this study (i.e., 2004) consisted of 345,607 MW of thermal power plants (77%) and 104,834 MW of hydro power plants (23%). Thermal generation capacity consisted of 309,107 MW of coal power plants (i.e., 89% of thermal power capacity), 2,893 MW of oil-based steam plants, 13,794 MW of diesel plants, including 2,956 MW of oil-based combined cycle plants, 5,264 MW of oil-based gas turbines, 2,893 MW of gas-based gas turbine plants and 8,700 MW of nuclear plants. The conventional coal plants were categorized into two types: (a) low parameter (LP) coal plants, which include coal plants of installed capacity of 300 MW and less, (b) high parameter (HP) coal plants, which include coal plants of installed capacity higher than 300 MW. The heat rates of existing LP coal plants varied from 3,160-2,520 kCal/kWh, while heat rate of HP coal was 2,310 kCal/kWh. The heat rate of existing supercritical plants was 2,170 kCal/kWh. The heat rates of oil-fired steam plants, diesel plants, gas-based gas turbines, oil-based gas turbines, oil-based combined cycle plants and nuclear plants were 3,264, 1,833, 2,985, 2,748, 1,832, and 2,606 kCal/kWh, respectively.

Existing and candidate power plants

Candidate hydro plants with a total capacity of 9,500 MW, pump storage hydro with a total capacity of 26,100 MW and eight types of candidate thermal plants were considered. The candidate thermal plants included conventional coal-fired steam plants, oil-fired combined cycle plants (OCC), natural gas-based combined cycle plants (NGCC), three types of clean coal technologies (i.e., supercritical, integrated gasification combined cycle (IGCC) and pressurized fluidized bed combustion (PFBC)), in addition to conventional biomass-fired steam turbine plants and biomass integrated gasification combined cycle (BIGCC) plants. We considered that biomass is used at a sustainable rate (thus, the net CO_2 emission from electricity generation from biomass-based plants would be zero). Furthermore, solar PV and wind power plant options with capacity unit sizes of 1 MW and 10 MW respectively were considered. The maximum potential of biomass power generation capacity considered is 30,000 MW. In the case of wind, maximum potential of 30,000 MW (15,000 MW of each in northern and southeastern provinces) were considered. Since the detailed wind energy data required for the IRP model was available only for the northern and southeastern provinces, we considered only wind power potential in these provinces. It should be noted here that the study does not consider the full potential of all the renewable energy-based power generation options due to limited availability of data on their potential when the study was carried out in year 2004. The technical, economic and environmental characteristics of the candidate power plants considered in the study are shown in Table 4.1. It should be noted here that nuclear power plants were not considered as candidate plants in this study as one of the objectives of the study was to assess CO_2 emission reduction potential of the power sector without the nuclear power generation option.

Table 4.1: Characteristics of candidate power plants in 2004+.

Candidate Plants	Unit Capacity (MW)	Capacity Cost ($/kW)	Fuel Cost ($/Gcal)	Heat rate (kcal/kWh)	Emission factor (g/kWh)		
					CO_2	SO_2	NO_x
HP-coal Conventional coal	300	602	7.28	2310.0	1139.5	9.1	2.8
LP-coal Conventional coal	100	615	7.28	2520.0	1243.1	9.9	3.0
OCC	100	482	61.27	1942.2	584.9	7.6	1.2
NGCC	300	482	29.36	1562.0	365.6	0.1	0.4
IGCC	300	843	7.28	1869.6	922.2	0.8	1.0
PFBC	200	843	7.28	2047.6	1010	0.9	1.2
Supercritical	600	663	7.28	2170.0	1070.4	6.7	2.6
BIGCC	10	1626	3.03	2390.0	-	0.9	0.6
Conventional biomass	10	482	3.03	5064.2	-	1.0	0.7
Solar	1	3133	-	-	-	-	-
Wind	10	964	-	-	-	-	-

+ A '-' sign means either zero or a negligible quantity.

4.2.2. Power sector development during 2006-2025

This section presents the generation expansion plan during 2006-2025 in the base case. The least cost generation planning analysis shows that supercritical coal (SC) power plants would be cost-effective even in the base case, besides some new hydropower capacity. In the base case, it would be desirable to have capacity additions of 704,400 MW of supercritical coal-fired plants, 10,500 MW of pump storage hydropower plants and 9,500 MW of other types of hydropower plants during 2006-2025. A total of 724,400 MW generating capacity would be added during the period in the base case. The conventional coal-fired plants, IGCC, PFBC, OCC, NGCC, conventional biomass, BIGCC, wind and solar plants would not be cost-effective in the base case (see Tables 4.4 and 4.13).

4.2.3. Generation technology capacity mix

Table 4.2 presents the capacity mix by fuel types at selected years in the base case. As can be seen from the table, the coal-based plants would be the main contributor to the power generation capacity expansion for meeting the increased power demand during 2006-2025. The installed capacity of coal-based plants in 2025 would be 141% higher than that in 2006, while the increase in hydro-based capacity from year 2006 to 2025 would be only 7%. None of the existing oil, nuclear and gas plants would get retired during the planning period. The installed capacity of oil, gas and nuclear power plants would not change during the period.

Table 4.2: Generation capacity mix by fuel types at selected years in the base case (MW).

Fuel type	Year				
	2006	2010	2015	2020	2025
Coal	364,277	461,715	598,027	735,435	878,927
Gas	2,893	2,893	2,893	2,893	2,893
Oil	24,907	24,907	24,907	24,907	24,907
Nuclear	8,700	8,700	8,700	8,700	8,700
Hydro	104,838	105,794	107,215	109,200	112,307
Total	505,615	604,009	741,742	881,135	1,027,734

Table 4.3 presents the generation mix at selected years in the base case. The compound annual growth rate (CAGR) of total electricity generation during the period 2006-2025 would be 4.52%. The CAGR of coal-based electricity generation (4.50%) would be almost equal to the CAGR of total electricity generation, as coal is the main contributor to capacity expansion during the period. The share of fossil fuel-based electricity generation would increase from 85.4% in 2006 to 93.1% in 2025[2]. As can be seen in Table 4.3, an increase in the share of electricity generation based on fossil fuels during 2006-2025 is due to the increase in coal-based electricity generation. It should be noted that in the base case, electricity generation based on oil, gas and nuclear energy would remain unchanged during the period.

Table 4.3: Electricity generation mix by fuel types at selected years in the base case (TWh).

Fuel type	Year				
	2006	2010	2015	2020	2025
Coal	2,185.9	2,886.7	3,86.9	4,900.2	5,984.8
Gas	12.7	12.7	12.7	12.7	12.7
Oil	51.2	51.2	51.2	51.2	51.2
Nuclear	61.1	61.7	61.1	61.1	61.1
Hydro	395.4	423.2	428.9	436.8	449.2
Total	2,706.3	3,434.8	4,420.7	5,461.9	6,558.9

Generation system efficiency

Figure 4.1 shows the annual weighted average thermal generation efficiency (WATGE) during 2006-2025 (see Section 2.3 in Chapter 2 for explanation on WATGE). The annual WATGE is calculated by averaging of efficiencies of different thermal power plant categories weighted by their respective shares in total annual thermal power generation. As can be seen from the figure, the WATGE would increase from about 35% in 2006 to nearly 39% in 2025. This is mainly due to addition of more efficient supercritical power plants to the system.

[2] This result needs to be taken with some caution as it does not reflect the growing share of renewable power generation at present. This is partly due to the limited availability of data on renewable power generation options when the study was carried out in 2004.

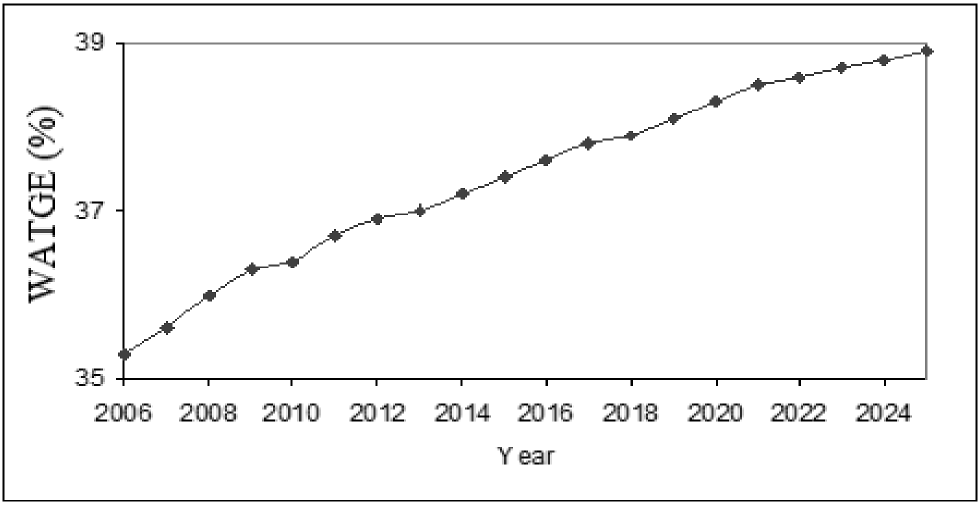

Figure 4.1: Weighted average thermal generation efficiency (WATGE) during 2005-2006 in the base case.

4.2.4. Environmental implications

The total cumulative CO_2 emission during 2006-2025 in the base case would be about 91,095 million tons. Figure 4.2 shows the annual CO_2 emission in the base case. The CO_2 emission would increase from 2,672 million tons in 2006 to 6,549 million tons in 2025. The CAGR of the CO_2 emission during 2006-2025 was found to be 4.6%.

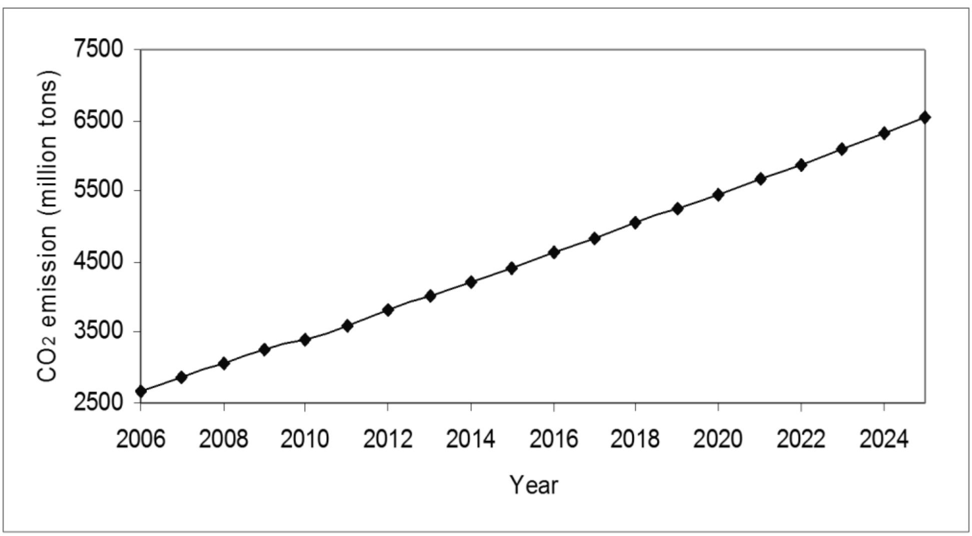

Figure 4.2: Annual CO_2 emission in the base case

Figure 4.3 shows the annual CO_2 intensity during 2006-2025 in the base case. As shown in the figure, the CO_2 intensity was found to be almost constant during the planning period after 2012.

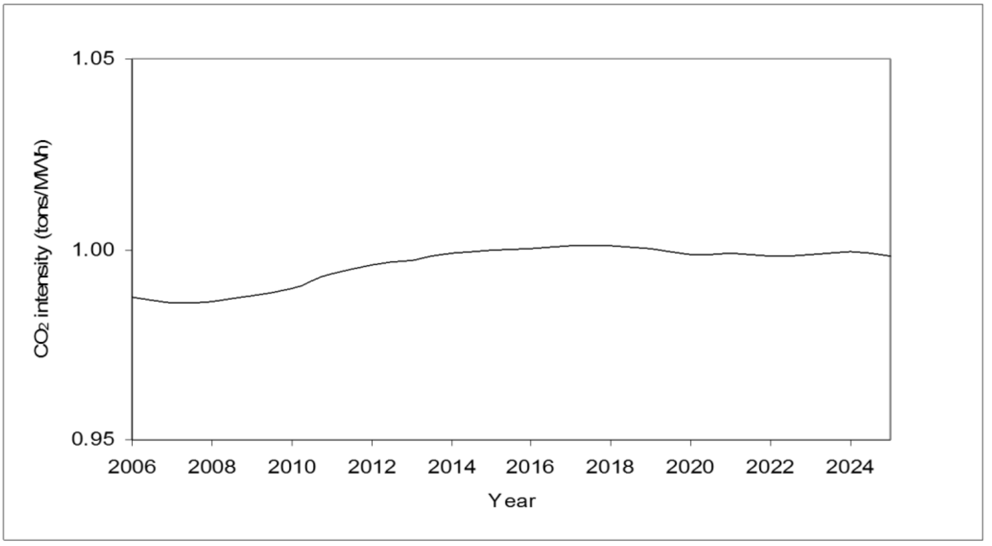

Figure 4.3: Annual CO_2 intensity in the base case.

Figure 4.4 shows the annual SO_2 emission in the base case during 2006-2025, which would increase at the CAGR of 3.8%. The SO_2 emission in 2025 would be 43.1 million tons; which is about twice the SO_2 emission in 2006. During 2006-2025, the cumulative SO_2 emission would be about 636 million tons.

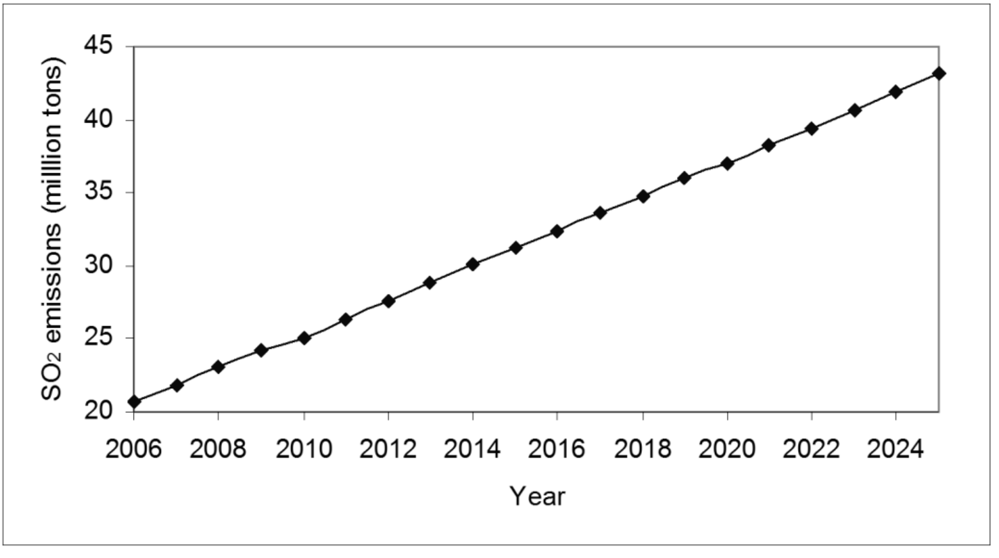

Figure 4.4: Annual SO_2 emission in the base case

Figure 4.5 shows the annual NO_x emission in the base case during 2006-2025. NO_x emissions would increase at the CAGR of 4.6% in the base case during 2006-2025. The NO_x emission would increase from 6.5 million tons in 2006 to 15.9 million tons in 2025 with the cumulative total NO_x emission during 2006-2025 being about 221 million tons.

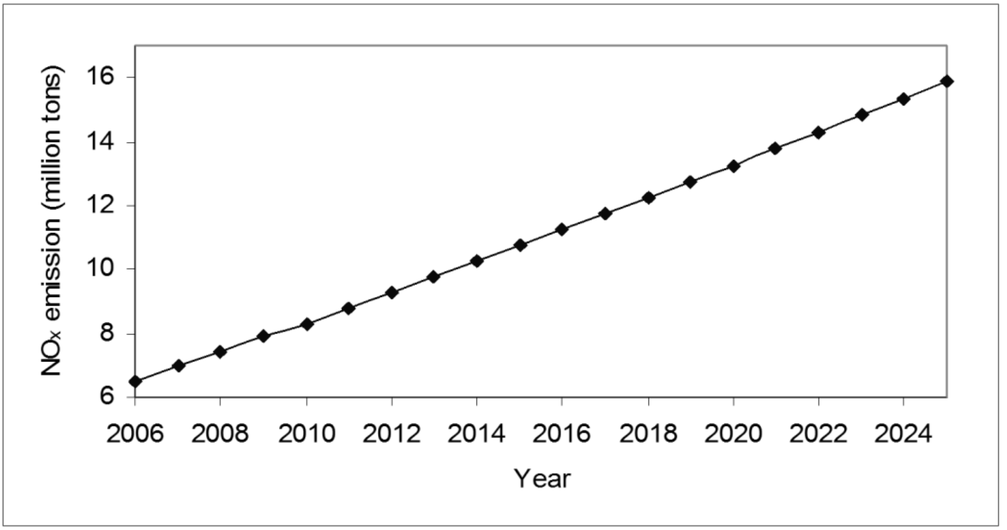

Figure 4.5: Annual NO_x emission in the base case

4.2.5. Economic Implications

The total discounted cost during 2006-2025 was found to be about $553.7 billion. About 65% of the total cost was fuel and variable O&M cost. The total undiscounted cost of the base case was found to be about $2,233 billion. The overall average incremental cost ($AIC_{overall}$) of electricity generation would be ¢3.2/kWh, while the long run average cost (LRAC) of electricity generation would be ¢2.7/kWh.

4.3. Effects of Carbon Tax

In this section, the various implications of carbon tax in the power sector of China are analyzed. In particular, the section focuses on the discussion of utility planning implications, the effects on CO_2 and local pollutant emissions as well as economic implications of the carbon tax.

4.3.1. Utility planning implications

Generation technology capacity mix

Table 4.4 presents capacity additions by type of power generation technology during 2006-2025 at selected carbon tax rates. As can be seen from the table, the total capacity additions would decrease with an increase in the tax rate. It is interesting to note that in the case of China, supercritical coal power plants would be economical even in the base case (i.e., without carbon tax) and that no conventional coal plants would be cost-effective. At the carbon tax of $5/tC, there would be marginal decrease in the addition of the supercritical and pumped storage power plant capacity due to the demand-side effect and no substitution of supercritical coal by efficient or cleaner technologies. At the carbon tax of $100/tC, the supercritical plants would be completely replaced by IGCC and renewable plants (i.e., biomass-based steam plant, wind plants and pump storage hydro plants). At higher carbon tax rate of $150/tC, coal-based IGCC plants would be completely replaced by NGCC, which would, however, not be conducive to energy security concerns of the country, as China does not have a significant domestic reserve of natural gas.

Table 4.4: Generation capacity additions by plant types during 2006-2025 at selected carbon tax rates (GW).

Plant type	Carbon tax ($ /tC)+						
	0 (Base case)	5	10	25	50	100	150
Super-critical	704.4	700.2	690.6	79.8	-	-	-
Hydro	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Pumped storage	10.5	9.9	9.9	26.1	26.1	26.1	26.1
IGCC	-	-	3.0	563.7	621.6	576.3	-
Wind	-	-	-	-	-	30.0	30.0
NGCC	-	-	-	-	-	-	548.1
Biomass steam	-	-	0.06	30.0	30.0	30.0	30.0
Total	724.4	719.6	713.1	709.1	687.2	671.9	643.7

+ A '-' sign means either zero or a negligible quantity.

Electricity generation mix

Introduction of carbon tax would change the relative prices of fuels. As a result, the generation mix is likely to change towards less carbon intensive fuels and technologies. Furthermore, with the introduction of carbon tax, the electricity price would increase; this would reduce the demand for electricity and consequently there would be a decrease in electricity generation. Table 4.5 presents the total electricity generation and percentage shares of big hydro, thermal and renewable generation during the planning period at different carbon tax rates. It shows that there would be no significant change in the generation mix with carbon tax of up to $10/tC. As expected, the share of coal-based generation is found to decrease consistently with the carbon tax; the decrease would be drastic at the carbon tax of $150/tC. The share of gas-based generation without the tax would be negligible and the share of gas would not be higher than 0.31% at the tax rate of up to $100/tC. However, the share would jump drastically to 44% at tax rate of $150/tC due to a massive switch from coal- to gas-based generation at this tax rate. Furthermore, the share of renewable-based generation increases from zero in the absence of carbon tax to 7.3% at the carbon tax of $150/tC. The share of hydro generation also increases from 9% in the absence of carbon tax to 10.4% at tax rate of $150/tC. Table 4.5 also shows that there would be a 11.5% decrease in the total electricity generation at the tax rate of $150/tC as compared to that in the base case.

Table 4.5: Cumulative electricity generation mix during 2006-2025 at selected carbon tax rates (%).

Carbon tax ($/tC)	Hydro	Coal	Oil	Gas	Renewable	Nuclear	Total generation (TWh)
0 (Base case)	8.8	88.4	1.1	0.3	0.0	1.3	90,818
5	8.9	88.4	1.1	0.3	0.0	1.4	90,340
10	8.9	88.3	1.1	0.3	0.0	1.4	89,742
25	9.5	82.9	1.2	0.3	4.8	1.4	88,241
50	9.7	82.4	1.2	0.3	5.0	1.4	86,108
100	10.1	79.8	1.2	0.3	7.0	1.5	82,734
150	10.4	35.6	1.3	43.9	7.3	1.5	80,316

Fossil fuel consumption for power generation

Table 4.6 presents the total fossil fuel use by fuel type during 2006-2025 at selected carbon tax rates considering both the supply-side (i.e., technological substitution effect) and demand-side effects (i.e., price effect) of the selected carbon tax rates. Note that the total fossil fuel consumption would be decreasing with the carbon tax as can be expected. As can be seen from the table, at the carbon tax of up to $100/tC there would be a reduction in coal use without significant changes in the use of other fuels. At the tax rate of $150/tC, there would be significant fuel switching in electricity generation and the level of coal use would fall while that of natural gas would increase. The reduction in coal consumption at tax rates of $5/tC, $10/tC, $25/tC, $50/tC, $100/tC and $150/tC would be 0.6%, 1.3%, 15.4%, 17.7%, 23.6% and 62.1%, respectively. The gas consumption at $150/tC would be more than 72 times (i.e., 7,227%) the corresponding base case value. This is because the gas consumption in the base case is very small (i.e., 0.4% of the total fossil fuel consumption) and there is a huge increase in the gas-based generation capacity replacing coal-based capacity at tax rates of $150/tC. The percentage reduction of total fossil fuel consumption during the planning period would be 0.5%, 1.3%, 15.1%, 17.4%, 23.1% and 31.5% at tax rates per ton of carbon of $5, $10, $25, $50, $100 and $150, respectively.

Table 4.6: Cumulative fossil fuel use, by fuel type, during 2006-2025 at selected carbon tax rates (Mtoe).

Carbon tax ($/tC)	Coal	Oil	Gas	Total
0 (Base case)	18278.66	241.36	75.79	18595.79
5	18176.17	241.74	75.79	18493.69
10	18036.95	241.51	75.79	18354.25
25	15472.11	241.31	75.79	15789.23
50	15047.44	242.42	75.79	15365.65
100	13971.83	241.69	75.79	14289.31
150	6935.59	241.21	5553.09	12729.89

Generation system efficiency

Although the purpose of carbon tax is to reduce CO_2 emission, the tax would also affect the overall efficiency of thermal power generation. As shown in Figure 4.6, the overall WATGE would increase with the introduction of carbon tax (see Section 2.3 in Chapter 2 for explanation on WATGE). The WATGE is significantly higher at the tax rate of $150/tC due to a large switch from coal to gas-based generation.

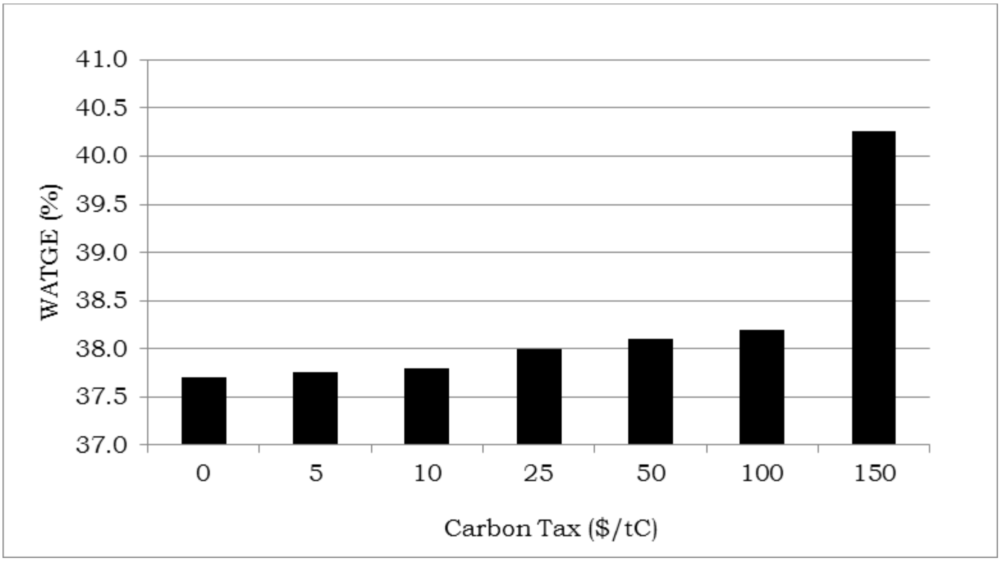

Figure 4.6: Weighted average thermal generation efficiency (WATGE) during 2006-2025 at selected carbon tax rates

4.3.2. Environmental implications

Figure 4.7 shows the total cumulative CO_2 emission from the power sector during 2006-2025 at the selected carbon tax rates. At a relatively low carbon tax of up to $10/tC, the CO_2 emission during 2006-2025 would be reduced by only up to 1.3%. However, the CO_2 mitigation during the period would increase considerably at a carbon tax above $10/tC. At the carbon tax rates of $25/tC, $50/tC, $100/tC and $150/tC, the cumulative CO_2 emission during 2006-2025 would decrease by about 15.2%, 17.5%, 23.3%, and 47.3%, respectively as compared with the emission level in the base case (i.e., without carbon tax). The reduction of CO_2 emission at tax rate of $25/tC is due to the replacement of supercritical plant by IGCC, and the use of pump storage hydro and biomass plants, while the large reduction in emission at the tax rate of $150 is due to replacement of IGCC plants by natural gas-based combined cycle plants.

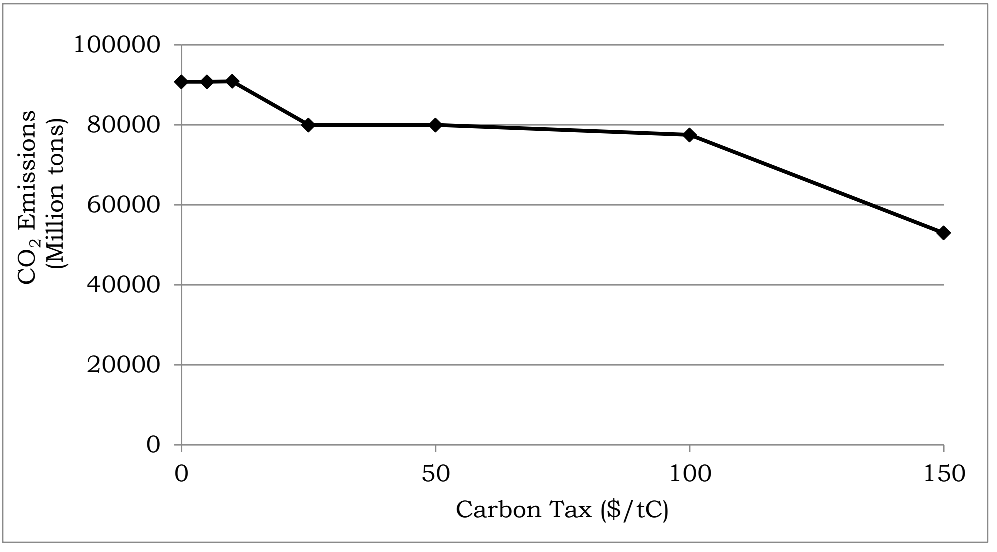

Figure 4.7: Total cumulative CO_2 emission during 2006-2025 at selected carbon tax rates

Decomposition of CO_2 emission reduction: The role of supply- and demand-side effects

The change in total CO_2 emissions with the introduction of carbon tax can be decomposed into supply-side and demand-side effects. Table 4.7 presents the decomposition of total CO_2 emission mitigation at various levels of carbon tax into the percentage reductions due to supply-side effect and demand-side effects (see Section 2.6 in Chapter 2 for calculation of decomposition of CO_2 emission reduction). The table shows that at carbon tax of up to $10/tC, the demand-side effect plays a predominant role in CO_2 reduction. This is because carbon taxes of up to $10/tC would not be able to achieve a significant change in the capacity and generation mix in the power sector in China. At higher tax rates, i.e., $25/tC and above, the supply-side effect of carbon tax is found to be the dominant factor in CO_2 reduction.

Table 4.7: Contributions of demand- and supply-side effects to the Power sector cumulative CO_2 reductions during 2006-2025.

Carbon tax ($ /tC)	CO_2 emission reduction (10^6t)	Demand-side effect (%)	Supply-side effect (%)
5	504	98.0	2.0
10	1,191	97.2	2.8
25	13,846	17.3	82.7
50	15,935	27.2	72.8
100	21,245	34.5	65.5
150	43,119	8.9	91.1

Implications on CO_2 emission intensity

Figure 4.8 presents the overall CO_2 emission intensity during 2006-2025 (measured in tons of CO_2 per MWh) at the selected carbon tax rates. As shown in the figure, the CO_2 emission intensity would not always decrease with the carbon tax. The overall CO_2 emission intensity would slightly increase at relatively low tax rates of up to $10/tC. This is because the CO_2 reduction up to the tax rate of $10/tC is mainly due to the demand-side effect (see Table 4.7). There would be a significant decrease in CO_2 emission intensity at the tax rate of $25/tC due to higher supply-side effect. When the tax is further increased up to $100/tC, the CO_2 emission intensity increases thereafter again due to a weaker supply-side effect (see Table 4.7). Interestingly, there would be a steep decline in the overall CO_2 emission intensity from the tax rate of $100/tC to $150/tC due to significant increase in supply-side effect with addition of less carbon intensive gas-fired plants.

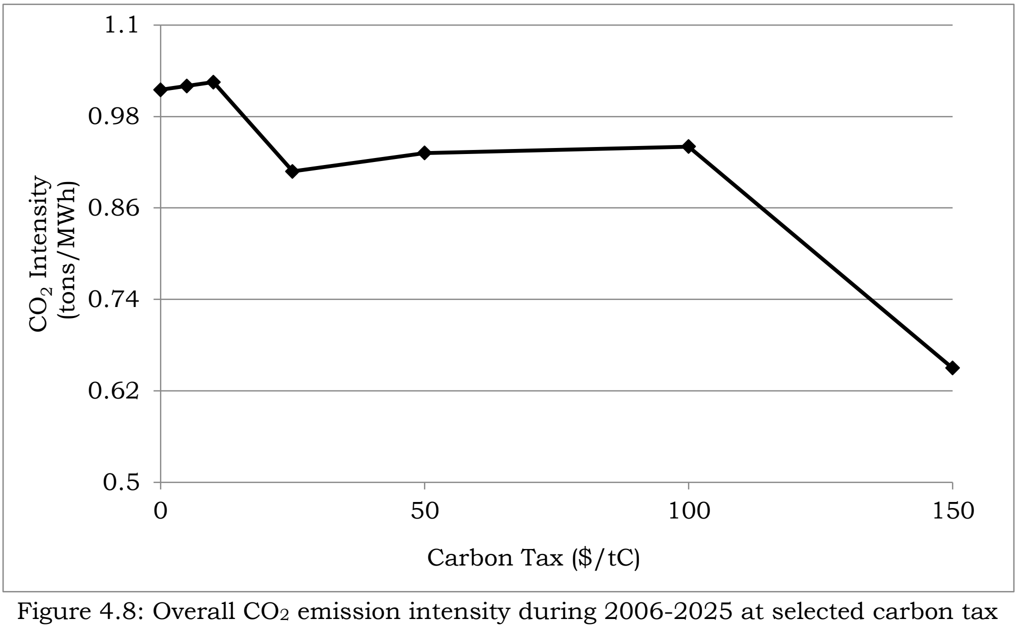

Figure 4.8: Overall CO_2 emission intensity during 2006-2025 at selected carbon tax rates

Carbon tax elasticity of CO_2 emission

As the carbon tax is expected to result in the reduction of CO_2 emission from the electricity sector, it is of interest to know the carbon tax elasticity of CO_2 emission reduction (i.e., the percentage change in CO_2 emission associated with a percentage change in carbon tax) (see Section 2.2 in Chapter 2 for calculation of carbon tax elasticity of CO_2 emission). The results in Table 4.8 show that the CO_2 emission reduction in China is inelastic with respect to the carbon tax studied.

Table 4.8: Carbon tax elasticities of CO_2 emission from the power sector at the selected tax rates.

Carbon tax ($ /tC)	Elasticity
0 – 5	0.00
5 – 10	-0.01
10 – 25	-0.18
25 – 50	-0.04
50 – 100	-0.11
100 – 150	-0.93

Local/regional pollutant emissions

The changes in emissions of SO_2 and NO_x from the power sector of China at different carbon tax rates are presented in Table 4.9. The cumulative SO_2 emission during 2006-2025 would be reduced by 0.4% at $5/tC as compared to the emission in the base case, whereas it would be reduced by 55.0% at $150/tC. Similarly, the cumulative NO_x emission would be reduced by 0.5% at $5/tC and by 53.7% at $150/tC.

Table 4.9: Cumulative emissions of SO_2 and NO_x during 2006-2025 at selected carbon tax rates+.

Carbon tax ($ /tC)	SO_2 pollutant		NO_x pollutant	
	Emission (10^3t)	Reduction (%)	Emission (10^3t)	Reduction (%)
0 (Base case)	636,106	-	221,306	-
5	633,491	0.4	220,263	0.5
10	627,389	1.4	218,014	1.5
25	318,063	50.0	114,079	48.5
50	312,496	50.9	111,428	49.7
100	293,785	53.8	104,517	52.8
150	286,084	55.0	102,494	53.7

+ A '-' sign means either zero or a negligible quantity.

The CAGR of both SO_2 and NO_x emissions would remain almost unchanged up to the tax rate of $10/tC, i.e., 3.9% and 4.6%, respectively. However, if the carbon tax rate of $25/tC were introduced, the CAGR of SO_2 emission would be -1.0%, while in the case of NO_x pollutants, the CAGR would be 0.4%. At carbon tax rates of $25 to $150/tC, the CAGRs of SO_2 emission would be in the range of -2% to -3%, while in the case of NO_x, the CAGR would be in the range of 0% to -1%.

4.3.3. Economic implications

Electricity generation system cost

How would carbon tax affect the total cost of electricity generation, capacity cost, electricity price and tax revenue? As shown in Table 4.10, at the carbon tax of $10/tC, the discounted capacity cost during 2006-2025 would be reduced by $2.2 billion from the base case figure of $95.8 billion due to a reduction in electricity demand with the imposition of carbon tax. However, the discounted capacity cost would increase to $108.9 billion at tax rate of $25/tC due to replacement of supercritical coal-fired plants by IGCC, pumped hydro and biomass power plants. At carbon tax of $50/tC, total capacity cost would be reduced to $103.1 billion due to demand reduction whereas it would increase to $111.1 billion at the carbon tax of $100/tC due to addition of wind power plants. At the tax rate of $150/tC, the capacity cost would decrease significantly to $71.6 billion due to replacement of IGCC with the less expensive gas-fired combined cycle plants.

Table 4.10: Contribution of capacity, fixed O&M and variable O&M costs to the total cost at selected carbon tax rates during 2006-2025+.

Carbon tax ($ /tC)	Capacity cost (10^9 $)	Fixed O&M cost (10^9 $)	Variable O&M and fuel cost including tax (10^9 $)	Total cost (10^9 $)	Total cost increment (%)
0 (Base case)	95.8	97.7	360.0	553.7	-
5	94.7	97.2	387.2	579.2	4.61
10	93.6	96.6	413.6	603.8	9.05
25	108.9	100.4	460.9	670.3	21.07
50	103.1	98.3	571.6	772.9	39.61
100	111.1	101.4	756.4	968.9	75.00
150	71.7	90.3	984.2	1,146.2	107.02

+ A '-' sign means either zero or a negligible quantity.

Carbon tax revenue

As shown in Table 4.11, the undiscounted tax revenue would increase from $132.4 billion (which is 5.6% of total undiscounted cost) to $2,076 billion (which is 41.3% of total undiscounted cost) when the carbon tax is increased from $5/tC to $150/tC. The total undiscounted cost of electricity generation net of carbon tax (i.e., total non-tax cost) would decrease from about $2,233 billion in the base case (i.e., without carbon tax) to $2,016 billion at the carbon tax of $100/tC. When tax is increased to $150/tC, the total non-tax cost would increase to $2,954 billion. The large increase in the total non-tax cost of electricity generation at $150/tC is mainly due to the replacement of IGCC plants by gas-fired combined cycle plants, as IGCC plants have low operating cost, while the gas-fired combined cycle plants have a higher operating cost. The non-tax cost of electricity generation as a percentage of the total cost would be 94.4% at the carbon tax of $5/tC; the corresponding figure at $150/tC would be 58.7%.

Table 4.11: Carbon tax revenue and total undiscounted total cost (gross and net of tax) during 2006-2025 at selected carbon tax rates *.

Carbon tax ($/tC)	Total cost (gross) + (Billion $)	Tax revenue (Billion $)	Total cost, net of tax (Billion $)
0 (Base case)	2,233	-	2,233
5	2,353	132	2,221
10	2,469	265	2,205
25	2,703	571	2,132
50	3,185	1,106	2,080
100	4,071	2,055	2,016
150	5,031	2,076	2,954

+ Total cost including carbon tax revenue

* A '-' sign means either zero or a negligible quantity.

Unit cost of electricity generation

Table 4.12 presents the long run average cost (LRAC) of electricity generation and the overall average incremental cost ($AIC_{overall}$) (see Section 2.5 in Chapter 2 for calculation of $AIC_{overall}$) of electricity supply (expressed as the sum of average incremental costs of generation and long run marginal cost (LRMC) of transmission and distribution). The LRMC of transmission and distribution is ¢1.7/kWh. The $AIC_{overall}$ in the base case would be ¢3.23/kWh whereas it would vary from ¢3.39/kWh at $5/tC to ¢7.15/kWh at $150/tC). The LRAC would be ¢2.66/kWh in the base case and it would be in the range of ¢2.76/kWh to ¢6.22/kWh at the selected carbon tax rates.

Table 4.12: LRAC and $AIC_{overall}$ at the selected carbon tax rates.

Carbon tax ($/tC)	LRAC (¢/kWh)	$AIC_{overall}$ (¢/kWh)
0 (Base case)	2.66	3.23
5	2.76	3.39
10	2.93	3.51
25	3.31	3.95
50	3.91	4.66
100	5.10	5.93
150	6.22	7.15

4.4. Effects of Energy Tax

Unlike the carbon tax, the purpose of the energy tax is to improve efficiency of energy supply and utilization. Introducing an energy tax has implications on utility planning, technology and fuel mix for power generation, generation efficiency and expansion. The implications of introducing selected energy tax rates on the power sector development, environment and costs are discussed in this section.

4.4.1. Utility planning implications

Generation technology capacity mix

Table 4.13 presents capacity additions by plant types during 2006-2025 at selected energy tax rates. As can be seen from the table, even at the energy tax rate of $0.5/MBtu, IGCC plants would replace a part of the supercritical capacity additions. The present study shows that at energy tax rates of $1/MBtu and above, the additions of IGCC and pump hydro capacity would be cost-wise more attractive than the supercritical coal-based power plants. At the higher energy tax rate of $5/MBtu, some IGCC plant capacity would be replaced by wind power plants. The level of substitution of thermal power generation capacity with hydro and wind power options is constrained due to the limited size of the new hydro and wind power capacities. Gas and biomass-based power plants would not be economical even at the tax rate of $5/MBtu. As shown in the table, the total additional power generation capacity requirement would decrease from 724.4 GW in the base case to 602.3 GW at the energy tax of $5/MBtu.

Table 4.13: Capacity additions by plant types during 2006-2025 at selected energy tax rates (GW).

Energy tax ($/MBtu)	Coal-based technologies		Hydro	Pumped storage	Wind	Total
	Super-critical	IGCC				
0 (Base case)	704.4	-	9.5	10.5	-	724.4
0.5	474.6	215.1	9.5	10.5	-	708.5
1	-	672.0	9.5	25.8	-	707.3
2	-	649.8	9.5	26.1	-	685.4
5	-	536.7	9.5	26.1	30.0	602.3

+ A '-' sign means either zero or a negligible quantity.

Electricity generation mix

Introduction of an energy tax would change the relative prices of fuels. As a result, the structure of power generation is likely to change to include environmentally friendly and energy efficient technologies (EETs). Table 4.14 presents the cumulative electricity generation and percentage shares of different technologies (i.e., big hydro, coal, oil, gas, nuclear and renewables) in power generation during the study period. The share of coal-based generation is higher than 83% even at a relatively high tax rate of $5/MBtu. While there would be no significant change in the generation mix at the energy tax of $0.5/MBtu, there would be marginal substitution of coal-based generation by hydro-based generation at the tax rates of $1/MBtu and $2/MBtu. At a higher tax rate of $5/MBtu, there would be significant reduction of coal-based generation mainly due to an increase in the share of renewable-based generation to 2.08%. Though the capacity addition of hydro-based capacity remains constant at the tax rate of $2/MBtu and higher, the share of hydro-based generation increases from 9.7% at $2/MBtu to 11.1% at $5/MBtu. This is mainly due to reduction of total electricity generation due to the demand-side effect of the energy tax (i.e., a reduced demand after the tax). As can be seen from Table 4.14, the total electricity generation during 2006-2025 would decrease by about 17% at $5/MBtu as compared to the generation level in the base case due to the demand-side effect.

Table 4.14 Cumulative electricity generation mix during 2006-2025 at selected energy tax rates (%).

Energy tax ($/MBtu)	Hydro	Coal	Oil	Gas	Wind	Nuclear	Total generation (TWh)
0 (Base case)	8.83	88.42	1.13	0.28	0.00	1.34	90818
0.5	8.99	88.20	1.15	0.28	0.00	1.37	89280
1	9.49	87.67	1.17	0.29	0.00	1.39	88037
2	9.73	87.36	1.20	0.30	0.00	1.42	85890
5	11.08	83.52	1.36	0.34	2.08	1.62	75421

Fossil fuel consumption for power generation

Table 4.15 presents the structure of the cumulative fossil fuel use during 2006-2025 at the selected energy tax rates. As can be seen from the table, the introduction of the energy tax would result in the reduction of coal use, while the gas use in power generation would remain unchanged. Coal use would be reduced by 6.1%, 11.3%, 13.5% and 26.8% at tax rates of $0.5/MBtu, $1/MBtu, $2/MBtu and $5/MBtu, respectively. Although there would be a marginal increase in the oil use for power generation of up to the tax rate of $2/MBtu, the level of oil use would slightly decline at higher tax rates of $5/MBtu. It should be noted here that the share of coal in the total fossil fuel use is around 98%, under all the energy tax rates considered, and that there would not be a significant change in oil and gas use with the change in the energy tax. The results show that the introduction of the energy tax in the power sector would not adversely affect the energy security of China.

Table 4.15: Cumulative fossil fuel use by fuel types during 2006-2025 at selected energy tax rates (Mtoe).

Energy tax ($/MBtu)	Coal	Oil	Gas	Total
0 (Base case)	18265	241	76	18582
0.5	17150	241	76	17467
1	16196	241	76	16513
2	15792	242	76	16109
5	13367	241	76	13684

Generation system efficiency

Figure 4.9 shows the values of the WATGE during 2006-2025 at the selected energy tax rates. As shown in the figure, introducing an energy tax in the Chinese power sector would result in a higher WATGE than that in the base case. However, it should be noted that WATGE does not increase consistently with the energy tax rate. As shown in the figure, the WATGE would be decreasing at energy tax rates above $1/MBtu because of the reduced level of electricity demand and a larger share of the existing plants (i.e., with a relatively lower efficiency) in total electricity generation at the higher tax rates.

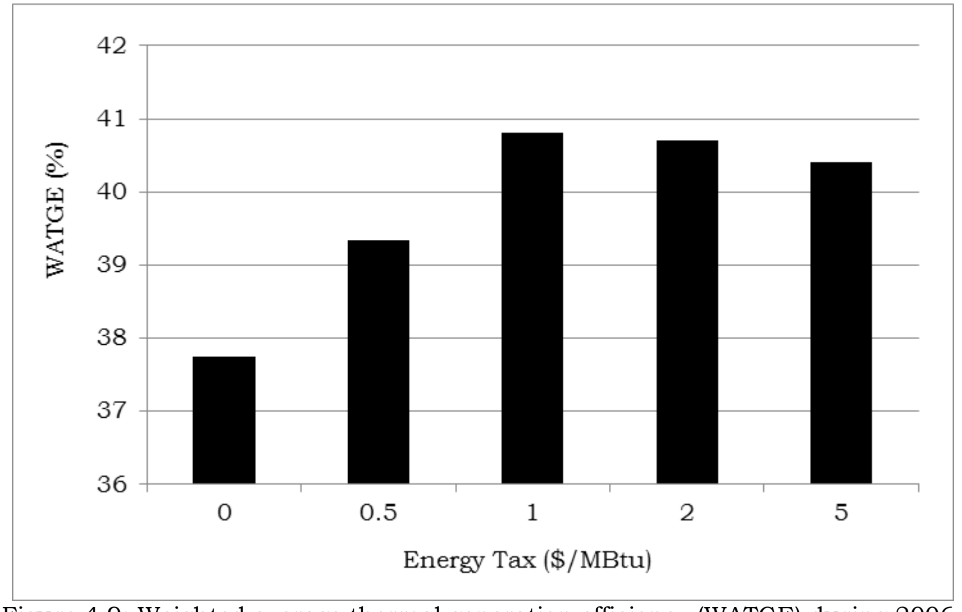

Figure 4.9: Weighted average thermal generation efficiency (WATGE) during 2006-2025 at selected energy tax rates.

4.4.2. Environmental implications

Figure 4.10 shows the power sector's cumulative CO_2 emission during 2006-2025 at the selected energy tax rates. Even at the relatively lower energy taxes of $0.5/MBtu and $1/MBtu, there would be a reduction in CO_2 emission of 6.0% and 11.2%, respectively. The reduction of CO_2 emission during 2006-2025 at $0.5/MBtu is partly due to a partial replacement of supercritical plant capacity by IGCC and partly due to demand-side effects, whereas the reduction at the tax rate of $1/MBtu is due to complete replacement of supercritical capacity additions by IGCC and pumped storage hydropower plants as well as the demand-side effect. The percentage reduction in CO_2 emission at the tax rate of $2/MBtu would be 13.4% and is only slightly higher than that at $1/MBtu. This is because there would be no further major supply-side effect at the tax rate of $2/MBtu as compared to that at $1/MBtu except for an increase in the pumped storage capacity by 300 MW and a reduction in IGCC capacity addition (by 22,200 MW) due to the demand-side effect. At the relatively high tax rate of $5/MBtu, there would be a 26.5% reduction in CO_2 emission due to a further reduction in IGCC capacity additions partly due to the demand-side effect and partly to the addition of 30,000 MW wind power capacity.

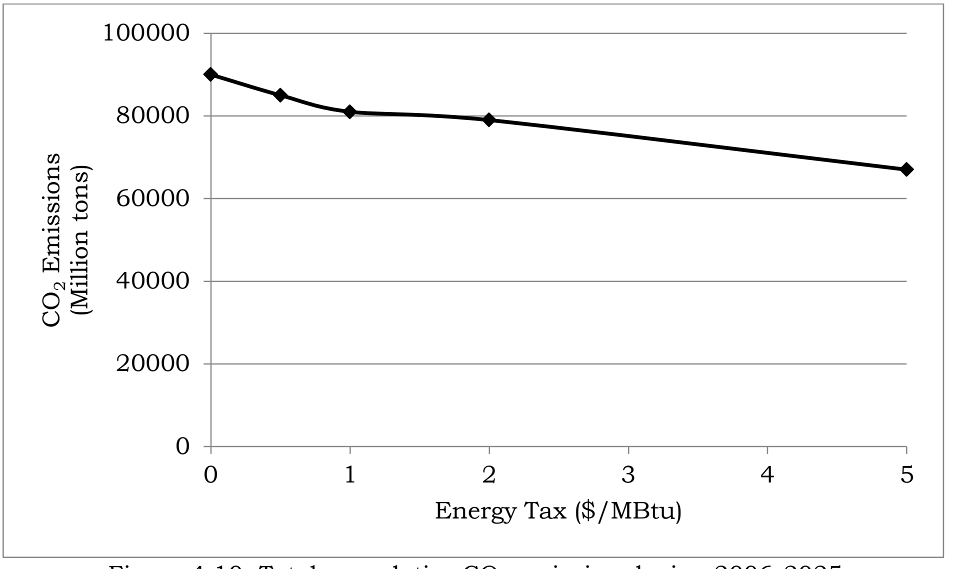

Figure 4.10: Total cumulative CO_2 emission during 2006-2025

Energy tax elasticity of CO_2 emission

How would the CO_2 emission reduction be related with a change in the energy tax rate? For this purpose, an energy tax elasticity of CO_2 emission was calculated. For the changes in energy tax rates the energy tax elasticities of CO_2 emissions are found to be close to or zero (see Table 4.16). This indicates that in the case of the power sector of China, the CO_2 emission reduction would be inelastic with respect to the energy tax.

Table 4.16: Energy tax elasticities of CO_2 emission from the power sector at the selected tax rates.

Energy tax ($ /MBtu)	Elasticity
0 – 0.5	0.00
0.5 – 1	-0.08
1 – 2	-0.04
2 – 5	-0.19

Decomposition of CO_2 emission reduction: The role of supply- and demand-side effects

The change in total CO_2 emissions with the introduction of energy tax could be attributed to the supply- and demand-side effects associated with the tax. Table 4.17 presents the total reductions in CO_2 emission at the selected energy tax rates and contribution of the supply- and demand-side effects in the reductions. The table shows that at energy tax rates of up to $2/MBtu, the CO_2 reduction would mainly occur due to the supply-side effect. This is because the reduction due to the substitution of supercritical plants with the IGCC plants at energy tax rates of up to $2/MBtu is much higher than that due to the demand-side effect. At the tax rate of $5/MBtu, the demand-side effect (i.e., electricity demand reduction) was found to contribute more substantially to reduction in the total CO_2 emission than the supply-side effect.

Table 4.17: Decomposition of cumulative CO_2 emission reduction during 2006-2025 at selected energy tax rates.

Energy tax ($ /MBtu)	Cumulative CO_2 emission reduction (10^6ton)	Demand-side effect (%)	Supply-side effect (%)
0.5	5,504	26.5	73.5
1	10,217	25.0	75.0
2	12,209	37.2	62.8
5	24,185	58.2	41.8

Implication on CO_2 emission intensity

Figure 4.11 presents the overall CO_2 emission intensity (measured in tons of CO_2 emission per MWh) during the planning period at the selected energy tax rates. As shown in the figure, the CO_2 emission intensity would improve significantly up to the tax rate of $1/MBtu and the improvements in the intensity thereafter would not be that significant i.e., the CO_2 emission intensity would decrease from 1.00 tonCO_2/MWh to 0.92 tonCO_2/MWh when the tax is increased from 0 to $1/MBtu, and remain constant between tax rates of $1/MBtu and $2/MBtu. When the tax is increased to $5/MBtu, the CO_2 emission intensity would only slightly improve to 0.89 tCO_2/MWh. Thus, the analysis shows that rate of improvement in the CO_2 intensity is much smaller at the tax rates above $1/MBtu.

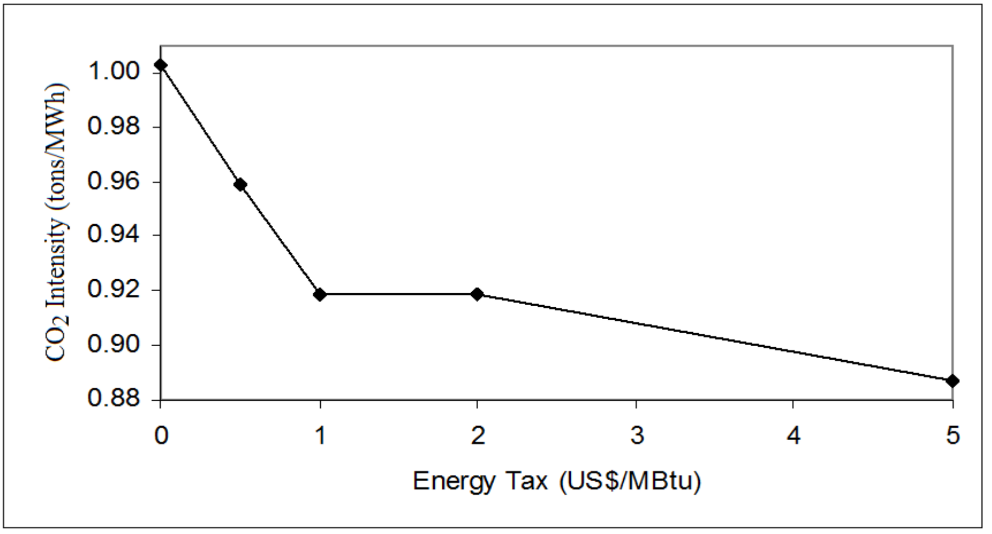

Figure 4.11: Overall CO_2 intensity of power generation at selected energy tax rates during 2006-2025

Local/regional pollutant emissions

An energy tax results not only in the improvement in energy efficiency and reduction in carbon emissions, but it also yields other benefits, such as a reduction in the emission of some local air pollutants (e.g., SO_2 and NO_x). As shown in Table 4.18, at $0.5/MBtu energy tax, the cumulative emissions during 2006-2025 of both SO_2 and NO_x would be reduced by about 28% as compared to the corresponding emission levels in the base case. The cumulative emissions would be reduced by 50% at the energy tax rate of $1/MBtu. Interestingly, there would be no significant reduction in the cumulative emissions of SO_2 and NO_x when the tax is increased from $1/MBtu to $2/MBtu. Similarly, there would be only a relatively minor reduction in the cumulative emissions, when the tax is increased further to $5/MBtu. Thus, the introduction of energy tax above $1/MBtu may not bring much additional co-benefits in terms of SO_2 and NO_x emission reductions from the power sector of China.

Table 4.18: Total cumulative emission of SO_2 and NO_x during 2006-2025 at selected energy tax rates[+].

Energy tax ($/MBtu)	SO_2 pollutant		NO_x pollutant	
	Emission (10^3t)	Reduction (%)	Emission (10^3t)	Reduction (%)
0 (Base case)	636,106	-	221,306	-
0.5	454,465	28.6	160,198	27.6
1	308,763	51.5	111,053	49.8
2	308,409	51.5	110,153	50.2
5	285,871	55.1	99,571	55.0

[+] A '-' sign means either zero or a negligible quantity.

4.4.3. Economic implications

Electricity generation system cost

As shown in Table 4.19, the discounted capacity cost of electricity generation system over the planning period would increase from $95.8 billion in the base case to $114.4 billion at the energy tax of $1/MBtu due to the replacement of supercritical plants by capital-intensive IGCC plants. The total capacity cost would decline at tax rates above $1/MBtu due to the reduction in IGCC capacity additions mainly because of the demand-side effect. Both the variable O&M cost and the total cost are found to increase with the energy tax. At the energy tax of $5/MBtu, the total cost would be 92% higher than that in the base case.

Table 4.19: Break down of total cost of power generation system development cumulative discounted cost during 2006-2025 at selected energy tax rates+.

Energy Tax ($ /tC)	Capacity Cost ($10^9$$)	Fixed O&M Cost ($10^9$$)	Variable O&M and Fuel Cost including tax ($10^9$$)	Total Cost++ ($10^9$$)	Increment in Total Cost (%)
0 (Base case)	95.8	97.7	360.1	553.7	-
0.5	108.2	95.6	417.3	621.2	12.2
1	114.4	94.2	475.7	684.3	23.6
2	108.4	92.1	606.6	807.1	45.8
5	97.1	88.4	876.5	1,061.9	91.8

+ A '-' sign means either zero or a negligible quantity.

++ It also includes the energy tax.

Energy tax revenue

As shown in Table 4.20, the undiscounted energy tax revenue during 2006-2025 is found to increase within the tax rate. The tax revenue would be $345.8 billion (i.e., 13.8% of the total undiscounted cost) at the tax of $0.5/MBtu and would increase to $2,709.2 billion (i.e., 60.0% of total undiscounted cost) at the tax of $5/MBtu.

Table 4.20: Energy tax revenue and total undiscounted cost (gross and net of tax) and tax revenue during 2006-2025 at selected energy tax rates+.

Energy tax ($/MBtu)	Total cost (billion $)	Tax revenue (billion $)	Total cost net of tax (billion $)
0 (Base case)	2232.7	-	2232.7
0.5	2502.4	345.8	2156.6
1	2745.7	653.9	2091.8
2	3316.0	1275.8	2040.2
5	4515.0	2709.2	1805.8

+ A '-' sign means either zero or a negligible quantity.

Unit cost of electricity generation

Table 4.21 presents the long run average cost (LRAC) of electricity generation as well as the overall average incremental cost of generation ($AIC_{overall}$) (see Section 2.5 in Chapter 2 for calculation of $AIC_{overall}$). The LRAC ranges from ¢2.66/kWh in the base case to ¢6.13/kWh at the tax rate of $5/MBtu. $AIC_{overall}$ would be ¢3.23/kWh in the base case. The $AIC_{overall}$ would increase by 13% to 113.6% with the range of the energy tax rates considered.

Table 4.21: LRAC and $AIC_{overall}$ at different energy tax rates.

Energy tax ($/MBtu)	LRAC (¢/ kWh)	$AIC_{overall}$ (¢/kWh)
0 (Base case)	2.66	3.23
0.5	3.03	3.65
1	3.39	4.02
2	4.09	4.72
5	6.13	6.90

4.5. Summary

In the future years (i.e., during 2006-2025), coal-based power plants would still dominate the Chinese power sector as supercritical coal plants account for 85.5% of the capacity mix in the year 2025 in the base case. The generation capacity-mix would shift towards supercritical coal power plants with the addition of about 704,400 MW supercritical power plants by 2025. Hydropower plants would have the second largest share in the total generation capacity in the country. With the addition of about 10,500 MW of the pumped-storage hydro capacity and 9,500 MW of other types of hydro capacity by 2025, hydropower plants would account for 10.9% of the total generation capacity. Supercritical coal power plants, due to their predominant share, would contribute to the improvement in the thermal power generation efficiency in the country. The WATGE would increase from 35% in year 2006 to 39% in the year 2025. As coal-based power plants would continue to dominate the power sector, the CO_2 emission would keep on increasing during the planning period: it would increase from 2,672 million tons in 2006 to 6,549 million tons in 2025. The AAGR of CO_2 emission during this period would be 4.6%.

In this study, two policy options were considered for the mitigation of CO_2 emission, i.e., carbon tax and energy tax. The results of the study show that both the carbon and energy taxes can be effective in introducing clean coal technologies such as IGCC in the Chinese power sector. The study shows that efficient natural gas-based combined cycle technology would not penetrate the power sector of China with the energy tax of up to $5/MBtu. At the carbon tax of $150/tC, there be a shift in fuel use from coal to gas; i.e., the consumption of coal would be reduced by 62%, while that of gas would increase by 72 times due to the replacement of IGCC plant capacity addition by the natural gas-based combined cycle plants.

With the introduction of energy tax of \$0.5/MBtu to \$5/MBtu, coal consumption would decrease in the range of 6% to 27%.

Both the carbon and energy tax would be effective in the promotion of wind energy. Full wind power potential, as is considered in the present study, would be exploited at the carbon tax rates of \$100/tC and above, whereas in case of the energy tax, full wind potential would be used only at the tax rate of \$5/MBtu. It should be noted here that only the maximum wind potential of 30,000 MW (15,000 MW of each in northern area and south east provinces) was considered due to lack of data in other provinces. Biomass-based power plants would be cost-effective at a relatively low carbon tax rate of \$25/tC. The present study shows that biomass-based power generation technologies would not be cost-effective at the energy tax rates considered. Both the carbon and energy taxes would not be effective in the promotion of solar-based power generation due to its high capacity cost.

The total CO_2 emission during the planning period would be reduced by 1.3% to 47.3% at carbon tax rates in the range of \$10/tC to \$150/tC. In the case of energy taxes, the total CO_2 emissions would be reduced by 6.0% to 26.5% at energy tax rates in the range of \$0.5/MBtu to \$5/MBtu. The rate of improvement in the CO_2 intensity is much smaller at the tax rates above \$1/MBtu.

Both carbon and energy taxes would have a beneficial effect in the emission of local/regional pollutants. The emission of SO_2 would be reduced by 29% to 55% at the energy tax in the range of \$0.5/MBtu to \$5/MBtu. Similarly, NO_x emission from the power sector would be reduced by 28% to 55% at the energy tax rates considered. The range of SO_2 and NO_x reduction is greater (i.e., range of SO_2 reduction from 0.4% to 55% and range of NO_x reduction from 0.5% to 54%) when carbon tax rates between \$5/tC to \$150/tC are imposed, compared to reduction due to energy taxes. The introduction of energy tax above \$1/MBtu may not bring much additional co-benefits in terms of SO_2 and NO_x emission reductions from the power sector of China as only minor reductions would be observed between \$1/MBTU to \$5/MBtu.

The share of the tax revenue in the total undiscounted cost would be in the range of 6% to 41% with the introduction of the carbon tax at \$5/tC to \$150/tC, whereas the share would be in the range of 14% to 60% in the case of the energy tax varying from \$0.5/MBtu to \$5/MBtu.

Post-script

As has been mentioned earlier, this study was carried out during 2004-2005 to cover the planning horizon of 2006-2025. Since the actual data on the power sector development are also available for the period of 2006 to 2013 (or 2012 in some cases), comparison of the results of the present study with the actual data for the period of 2006-2013 would help in understanding the differences between them. Several factors could give rise to such differences, e.g., the differences between the power demand projections that were available at the time the present study was carried out and the actual growth in power demand in the country since the study was carried out, as well as the differences between the plant capacity costs, fuel prices and generation efficiency of candidate power plants considered in the study and the corresponding actual values during the period. Also important is the role played by several new energy policy interventions in China after 2005, aimed at increasing the share of renewable energy and energy efficient technologies in the power sector. In this section, an attempt is made to briefly highlight some of the important differences between the actual power sector development data since 2006 and the estimated values of this study and to describe some of the factors in the power development that could help explain the differences.

Considerable differences have been observed between the actual data on installed power generation capacity and electricity generation and the corresponding estimated values of the study. It has been reported that the CAGR of China's actual total installed power generation capacity during 2006-2013 was 10.5%, which is significantly higher than the CAGR estimated in the study (i.e., 4.3%). The estimated electricity generation follows a similar trend as that of the installed capacity and is significantly lower than the actual growth in electricity generation during 2006-2013.

Most importantly, the growths of renewable energy technology capacity and associated electricity generation have been observed to be substantially underestimated by the present study, whereas the growths of capacity and electricity generation based on fossil fuels are over estimated by this study. In the present study, the share of fossil fuel-based generation capacity during 2006-2015 has been estimated to increase from 78% to 84%, and the share of hydropower capacity has been estimated to decrease from 21% to 14%. However, according to NBSC (2014), the share of fossil fuel has actually decreased from 78% in 2006 to 69% in 2013 and the share of renewable energy has increased from 22% in 2006 to 30% in 2013. According to NBSC (2014), in 2012, the actual share of hydro in electricity generation (i.e., 18%) was much higher than that estimated by this study (i.e., 10%) and the actual share (i.e., 79%) of fossil fuels was less than that estimated by this study (i.e., 88%). The increase in the actual shares of renewable energy, in both energy generation and capacity additions during 2006-2013 has been, to a significant extent, a result of the policies introduced in China to promote the use of renewable energy technologies (RETs) such as solar and wind power plants. Another important factor behind higher growth in the adoption of RE technologies is the significant decrease in the cost of solar technology during the period (i.e., from $3,133/kW in 2004 to $1,500/kW in 2014 (IEA, 2014))

Since the present study was carried out, China has set renewable energy development targets in its 12th Five Year Plan (2011-2015) for energy development with the aim to increase the share of renewable sources in the total primary energy consumption by 11.4% in 2020 (KPMG China, 2011). In addition, China has implemented a number of policies to provide financial incentives for the growth of renewable energy, e.g., "Golden Sun Programme (2009)", "Building Integrate Solar PV Programme (2010)", Feed-in Tariff for wind power and solar PV, etc. Furthermore, in 2010 the government introduced a policy to exempt import duties and value added taxes on important renewable energy technologies/equipment. In the 12th Five Year Plan (2012), China has set specific targets for electricity generation from RETs (OECD/IEA, 2015). According to the Plan, the government has set a target to install a total of 200 GW wind power and 100 GW solar PV by 2020 (GWEC, 2014). The annual growth rate of wind and solar capacity installations have been 51% between 2009 and 2013 (NBSC, 2014). The Global Status Report (2014) by REN21 shows that China's renewable energy is leading the world with quite a high share in the newly installed capacity. In 2013, the newly installed capacity for wind and solar power generation in China accounted for around 35% of the global total installed capacity. In addition, China's new renewable power capacity surpassed new fossil fuel and nuclear capacity for the first time in 2013. China has about 21% of the world's renewable power capacity, including an estimated 260 GW of hydropower (REN21, 2014). China is also the country with highest non-hydro RE capacity in the world (REN21, 2014).

It should be noted here that the abovementioned RET policy interventions and targets were not considered at the time the present study was conducted. The aggressive policies of the country to promote renewable energy in the last decade (since the present study was carried out) and the difference in the demand projection and actual demand growth are mainly behind the differences between the results of the present study and actual development in the power sector in terms of the growth in electricity generation, as well as technology- and resource-mix in the power sector.

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5. Power Sector Development in India: Effects of Carbon and Energy Taxes[1]

5.1. Introduction

The Indian power sector has grown massively over the past five decades. From an installed capacity of 1,713 MW in 1950, it has grown to 223,344 MW at the end of March 2013. In spite of such a quantum leap in installed capacity, the energy shortage of 8.7% and the peak load shortage of 9.0% persisted during 2012-2013 (CEA, 2013a).

The power generation during 2010-2011 relied on coal to provide nearly 68% of the country's power, while large hydroelectric plants provided more than 14%. Gas-fired power has grown from almost nothing to more than one tenth (12%) of the total generation in the last decade due to reduced risk associated with low capital requirements, shorter construction periods, diminished environmental impacts and higher efficiencies. Nuclear power contributed to three percent of the total generation (CEA, 2012). Besides being a major source of CO_2 emissions, coal is also the largest source of SO_2, NO_x and other harmful local and regional pollutant emissions. Therefore, the growth of the power sector in India has serious implications for the emissions of greenhouse gases (GHGs) as well as local and regional level pollutants. If the present structure of power generation is to continue, the levels of GHG and other harmful emissions in India will be much higher in the future. Thus, the subject of reduction of GHG emissions and other harmful emissions from the power sector of India has gained immense importance. Environmental and other regulatory policies can influence the process of climate friendly technological adoption and use of cleaner energy resources. Economic instruments such as carbon and energy taxes are among the widely discussed options for reducing CO_2 emissions from the power sector. This study analyzes the effects of carbon and energy taxes as instruments for GHG mitigation from the power sector of India.

This study was carried out in 2004-2005. The main objective of this study was to assess the utility planning, environmental and economic implications of introducing carbon and energy taxes in the power sector of India during planning period of 2006-2025 using the electricity demand forecast and other relevant data available at the time the study was carried out (i.e., 2004-2005). In this study, six different carbon tax rates (i.e., \$5/tC, \$10/tC, \$25/tC, \$50/tC, \$100/tC and \$150/tC) and four energy tax rates (i.e., \$0.5/MBtu, \$1/MBtu, \$2/MBtu and \$5/MBtu) were considered. The findings of this study are presented in Sections 5.2 to 5.5, where the results

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of the least cost generation planning (without carbon and energy taxes) (i.e., “Base Case”) is presented in Section 5.2; followed by a discussion of the results on the effects of carbon and energy taxes in Sections 5.3 and 5.4 respectively. A summary of key findings is presented in Section 5.5, which is followed by a postscript at the end of the chapter to briefly discuss the differences between the base case results of this study and the actual data related to the growth in recent years (i.e., during 2006-2014) after the study in electricity generation, generation-mix, capacity additions and possible underlying factors for the differences, e.g., energy policies related to the power sector in the recent years after the study was carried out.

5.2. Base Case Analysis

5.2.1. Definition of base case

Input data and assumptions

The definition of base case here is the power sector development in terms of capacity expansion and power generation from the least cost planning perspective by considering the existing technological and economic data available at the time the study was conducted. No climate and environmental policy is considered in the development of the power sector in this case. In addition, it should be noted that demand-side management (DSM) options are not considered in this study.

Most data used for electricity generation system planning (EGP) (e.g., data on existing, committed, and candidate power plants) in this study are based on CEA and IITK (2004). The planning period of the study is the period of 2006 to 2025 (hereafter also called “the study period”). All prices used in the study were related to the prices in 2000 in US dollars. In the base case, the peak power demands, up to year 2017 by CEA (2000), were considered. For the remaining years of the study, i.e., from 2017 to 2025, peak demand was extrapolated by taking average percentage growth of 6.3%. The price elasticity of electricity demand used in this case study is -0.2.

Fifty candidate hydro plants of total installed capacity of 34,889 MW and six types of candidate thermal plants are considered in the study. The candidate thermal plants include conventional coal-fired steam turbine plants (for two types of coal and lignite), gas-based combined cycle plants (i.e., CCGT), two types of clean coal technologies (i.e., supercritical coal plants and pressurized fluidized bed combustion (PFBC)), conventional biomass-fired steam turbine plants and biomass integrated gasification combined cycle (BIGCC) plants. Coal-fired integrated gasification combined cycle (IGCC) was not considered as a candidate plant as Indian coal is not suitable for IGCC plants. This study considers that biomass resource is used at a sustainable rate (thus, net CO_2 emission from electricity generation from biomass-based plants would be zero). Furthermore, solar PV plants of 2 MW and wind power plants of 10 MW each are also considered. The technical, economic and environmental characteristics of the candidate plants are shown in Table 5.1. The economic potential of wind and biomass options considered in the study is 10,000 MW and 16,000 MW, respectively. Nuclear power plants were not considered as candidate plants as the study was focused only on the non-nuclear-based power generation options.

Table 5.1: Characteristics of candidate power plants+

Candidate Plants	Unit Capacity (MW)	Capacity Cost ($/kW)	Fuel Cost ($/Gcal)	Heat rate (kcal/ kWh)	Emission factor (g/kWh)		
					CO_2	SO_2	NO_x
Coal 1	500	1000	6.5	2300	943.9	5.5	2.3
Coal 2	500	1000	7.5	2300	811.2	4.7	2.3
Lignite	250	1000	3.8	2438	1180.7	15.4	1.8
CCGT	250	700	29.4	1800	480.1	0.4	1.4
PFBC	500	1440	6.5	2091	593.0	0.3	0.6
Supercritical	400	1430	6.5	2054	561.0	0.3	0.6
BIGCC	22	1789	7.7	2400	-	0.9	0.6
Conventional biomass	25	1510	7.7	2743	-	1.0	0.7
Solar	2	6660	-	-	-	-	-
Wind	10	1110	-	-	-	-	-

Source: CEA and IITK (2004)

+ A '-' sign means either zero or a negligible quantity.

5.2.2. Power sector development during 2006-2025

This section presents the electricity generation system plan in the base case during 2006-2025. The least cost generation planning exercise for the base case shows that a total of 314,221 MW of generating capacity would be added during the period in this case. This includes addition of 23,481 MW of the hydropower capacity, with the rest being thermal generation capacity. Among the thermal power plants, 252,000 MW of conventional coal-fired plants (including 25,000 MW of lignite-fired plants) and 28,750 MW of gas-based CCGT would be cost-effective during the period. It should be noted here that 28,750 MW of CCGT plant additions are forced plant additions for security requirements of the system which will provide ancillary services for voltage and frequency regulation. An installation of the entire candidate wind power plant capacity considered (i.e., 10,000 MW) is also found to be cost-effective. PFBC, supercritical, conventional biomass, BIGCC and solar plants would not be cost-effective mainly due to their high capacity cost. It should be noted here that although new nuclear plants were not considered as a generation option in this study, because of the already committed plants, there would be an increase in the installed capacity of nuclear plants during 2010-2015.

5.2.3. Generation technology capacity mix

Table 5.2 presents the power generation capacity mix by fuel type at selected years in the base case. As can be seen from the table, coal-based plants would have the major share in the total power generation capacity during 2006-2025. The installed capacity of coal-based plants in year 2025 would be 370% higher than that in year 2006, while the hydro-, wind-, nuclear-, gas- and oil-based capacities would increase by 116%, 100%, 70%, 36% and 4%, respectively during the period.

Table 5.2: Generation capacity mix by fuel type at selected years in the base case (MW)

Fuel type	Year				
	2006	2010	2015	2020	2025
Coal	77,667	120,291	169,053	250,553	365,553
Gas	37,142	42,174	42,621	42,621	50,371
Oil	2,685	2,803	2,803	2,803	2,803
Nuclear	3,800	5,955	6,495	6,495	6,495
Hydro	38,874	52,872	66,513	72,948	84,348
Wind	5,000	5,000	10,000	10,000	10,000
Total	165,168	229,095	297,485	385,420	519,570

Table 5.3 presents the electricity generation mix at selected years in the base case. The compound average growth rate (CAGR) of total electricity generation during 2006-2025 would be 5.9%. The coal-based electricity generation would grow at a much faster rate, i.e., at the CAGR of 8.0%. As a result, the share of fossil fuel-based electricity generation would increase from 78.9% in 2006 to 86.5% in 2025. The CAGR of hydro-, wind-, nuclear-, oil- and gas- based electricity generation would be 3.7%, 3.5%, 2.7%, 0.3% and -1.3%, respectively.

Table 5.3: Electricity generation mix by fuel types at selected years in the base case (TWh)

Fuel type	Year				
	2006	2010	2015	2020	2025
Coal	433.8	658.3	937.5	1,400.2	2,014.9
Gas	182.5	112.1	115.4	118.3	139.9
Oil	7.3	7.4	7.4	7.4	7.7
Nuclear	17.4	27.3	29.7	29.7	29.7
Hydro	128.2	175.4	227.9	246.0	264.8
Wind	21.3	21.3	42.7	42.7	42.7
Total	790.5	1,001.9	1,360.5	1,844.5	2,499.7

Generation system efficiency

Figure 5.1 shows the weighted average thermal generation efficiency (WATGE) of the electricity generation system during the study period (see Section 2.3 in Chapter 2 for explanation on WATGE). As can be seen from the figure, although the WATGE decreases in the initial year (i.e., 2007), it is found to increase significantly in the later part of the period. The WATGE would increase from about 32.5% in 2006 to 36.0% in 2025. This is mainly due to the addition of CCGT and conventional coal-fired plants, which are more efficient than the existing coal-fired plants.

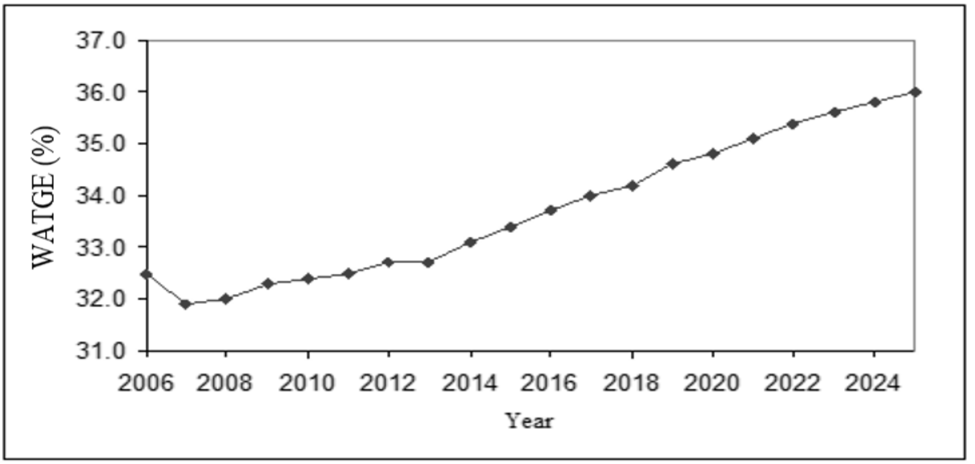

Figure 5.1: Weighted average thermal generation efficiency (WATGE) in the base case for the period 2006-2025

5.2.4. Environmental implications

The total cumulative CO_2 emission from power generation in India during the study period would be about 24,142 million tons in the base case. Figure 5.2 shows the annual CO_2 emission in the base case. The CO_2 emission would increase from 590 million tons in the year 2006 to 2,097 million tons in the year 2025 at the CAGR of 6.5%.

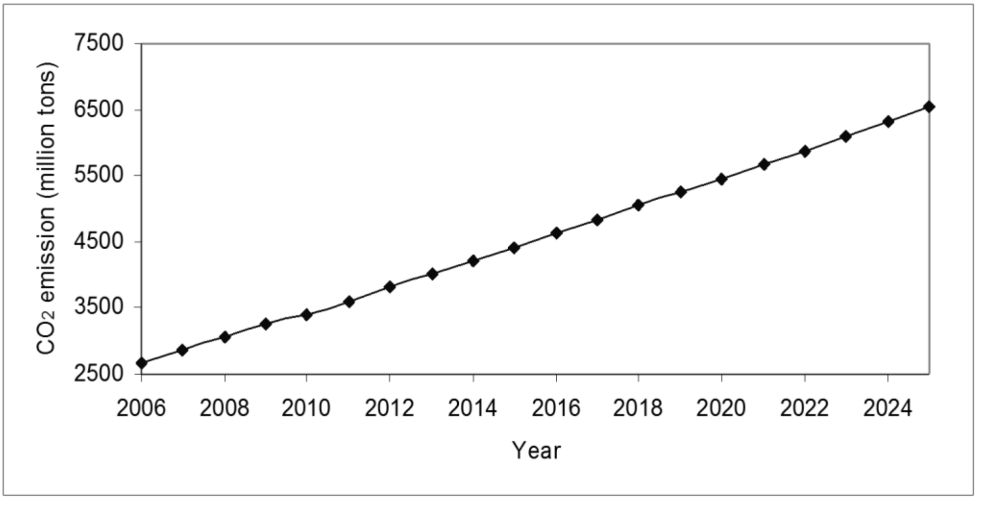

Figure 5.2: Annual CO_2 emission in the base case

Figure 5.3 shows the annual CO_2 intensity of electricity generation (measured in tons of CO_2 emission per MWh) in the base case during 2006-2025. Although the CO_2 intensity is not monotonically increasing during the initial years, there would be a monotonic and significant increase in the CO_2 intensity after year 2013.

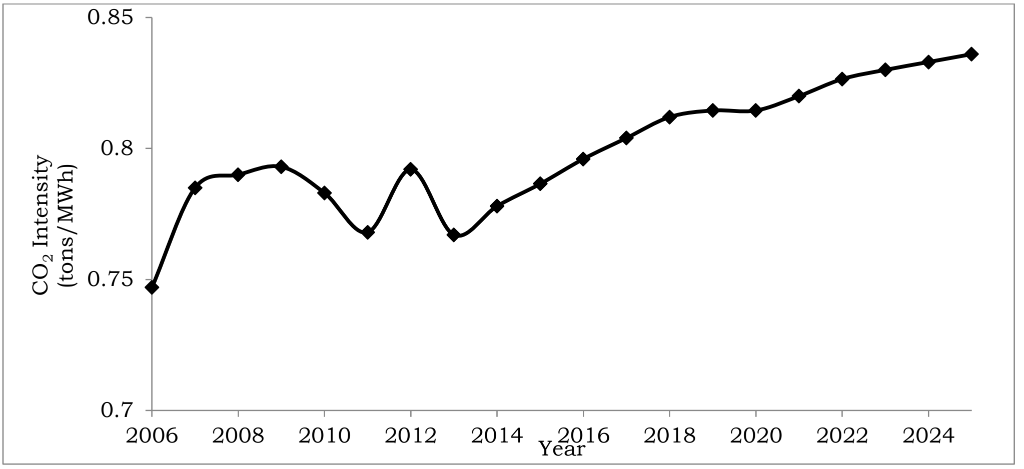

Figure 5.3: Annual CO_2 intensity in the base case

Local/regional pollutant emissions

Figures 5.4 and 5.5 show the annual SO_2 and NO_x emissions in the base case during 2006-2025. The SO_2 emission is estimated to increase at a CAGR of 8.5% during 2006-2025 and would be 12.3 million tons in 2025. This amount is about four times the SO_2 emission in 2006. The cumulative SO_2 emission during the period would be about 135 million tons.

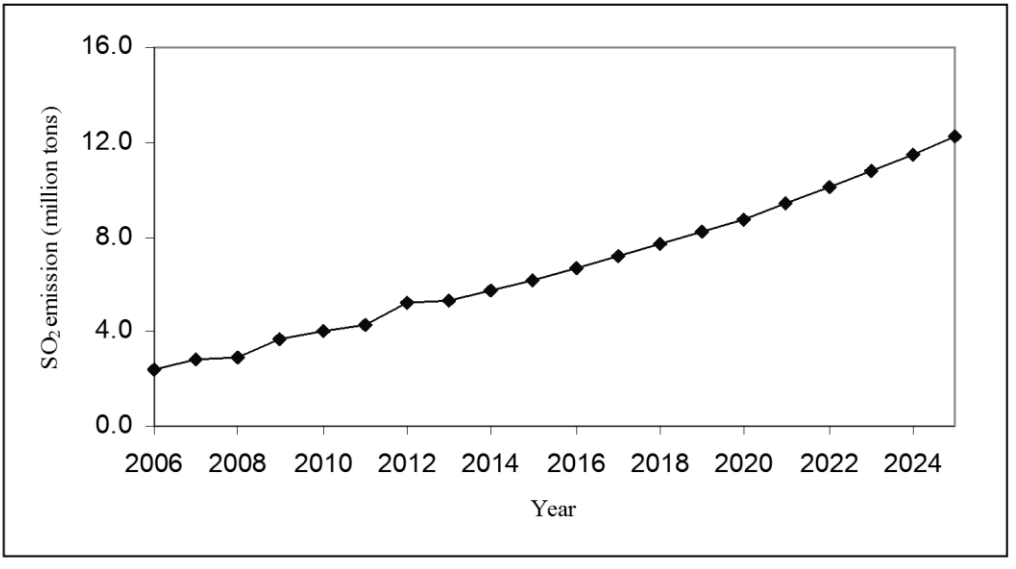

Figure 5.4: Annual SO_2 emission at the base case

NO_x emission would increase at a CAGR of 6.2% in the base case during 2006-2025. The NO_x emission would increase from about 1.5 million tons in 2006 to 5.1 million tons in 2025.

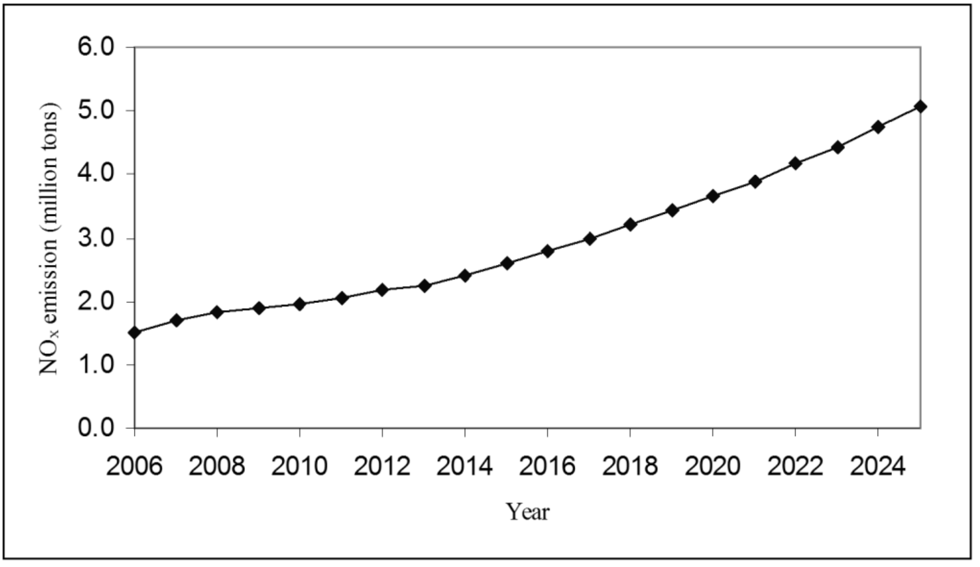

Figure 5.5: Annual NO_x emission in the base case

5.2.5. Economic Implications

The total discounted cost during the planning period was found to be about \$42,429 million. Fuel and variable O&M costs were about 66% of the total cost. The total undiscounted cost in the base case was found to be about \$830,215 million. The average incremental cost ($AIC_{overall}$) of electricity generation would be ¢3.3/kWh, while the long run average cost (LRAC) of generation would be ¢3.2/kWh.

5.3. Effects of Carbon Tax

A carbon tax would not only change the CO_2 emission, but there would also be implications for technology selection, energy mix, local pollutant emissions and costs. In the case of India, the various effects of the tax are discussed in this section.

5.3.1. Utility planning implications

Generation technology capacity mix

Table 5.4 presents power generation capacity additions by type of technology during 2006-2025 at selected carbon tax rates. With the imposition of carbon tax, the conventional coal power plant additions start to decrease. Up to the tax rate of \$25/tC, there would be a marginal decrease in the addition of coal-fired steam plants. At tax rates of \$50/tC, conventional coal plant capacity additions would be completely substituted by coal-fired supercritical plants (except for 25,000 MW of the lignite based capacity). With a further increase in the carbon tax to \$100 and \$150/tC, the supercritical capacity would be partly replaced by biomass-fired steam plants of 12,500 MW, which are not subject to the carbon tax (since biomass is considered to be produced on a sustainable basis). Interestingly, as shown in Table 5.4, total hydropower plant capacity would not necessarily increase with a carbon tax. Up to tax rate of $10/tC, the addition of hydropower capacity would remain constant at 23,481 MW. At the tax rate of $25/tC, there would be a smaller capacity addition of 20,681 MW due to the demand-side effect. When tax is increased to $50/tC, the hydro capacity addition would increase to 25,681 MW to substitute the coal-fired steam power plant additions. At the tax rates of $100 and $150/tC, hydro capacity additions would again decrease due to the additions of biomass plants. Further, as expected, the total addition of the power generation capacity would decrease with the increase in the carbon tax.

Table 5.4: Generation capacity additions by plant type during 2006-2025 at selected carbon tax rates (GW) +

Plant type	Carbon tax ($ /tC)						
	0	5	10	25	50	100	150
Coal-fired steam	252.0	248.0	248.0	243.0	25.0	25.0	25.0
Hydro	23.4	23.2	23.2	20.7	25.7	20.3	16.9
CCGT	28.8	28.8	28.8	28.8	28.8	28.8	28.8
Supercritical	-	-	-	0.4	177.9	150.8	144.8
Wind	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Biomass steam	-	-	-	-	-	12.5	12.5
BIGCC	-	-	-	-	-	-	-
Total	314.2	310.0	310.0	302.9	267.4	247.4	238.0

+ A '-' sign means either zero or a negligible quantity.

Electricity generation mix

Table 5.5 presents the total electricity generation and percentage shares of big hydro-, thermal- and renewable-based generation during 2006-2025 at the selected carbon tax rates. In the case of India, there would be no significant change in the generation mix with carbon tax rates of up to $50/tC. The share of coal-based generation is found to decrease significantly at the carbon tax of $100/tC and higher mainly due to replacement of a part of the coal-based generation by biomass-based generation, hydropower- and nuclear- based generation.[2] Table 5.5 also shows that there would be about 9.8% decrease in total electricity generation at the tax rate of $150/tC when compared to that in the base case. This is because with the introduction of carbon tax, the electricity price would increase and hence the decrease in the demand for electricity.

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[2] It should be noted that this study does not consider any new addition of nuclear power generation plants.

Table 5.5: Cumulative electricity generation mix during 2006-2025 at selected carbon tax rates (%).

Carbon tax ($/tC)	Hydro	Coal	Oil	Gas	Renewable	Nuclear	Total generation+ (TWh)
0 (Base case)	14.2	72.8	0.5	8.3	2.4	1.8	29,943
5	14.4	72.7	0.5	8.2	2.4	1.9	29,819
10	14.4	72.7	0.5	8.1	2.4	1.9	29,642
25	14.8	72.4	0.5	7.9	2.4	1.9	29,227
50	15.2	72.2	0.5	7.6	2.5	1.9	28,631
100	15.7	66.9	0.5	7.3	7.5	2.0	27,612
150	16.4	64.8	0.5	7.3	8.9	2.1	26,992

+ Cumulative power generation during the entire period.

Fossil fuel consumption for power generation

Table 5.6 presents the cumulative fossil fuel use by type of fuel during 2006-2025 at the selected tax rates considering both demand- and supply-side effects. As can be seen from the table, with the introduction of carbon tax of up to $150/tC, there would be a reduction in coal and gas use without significant change in the use of oil. The reduction of coal consumption at tax rates of $5, $10, $25, $50, $100 and $150/tC would be 0.6%, 1.1%, 2.8%, 8.4%, 17.3% and 21.9%, respectively. The gas consumption would be reduced by 1.4%, 3.2%, 6.9%, 11.6%, 18.2% and 20.0% at the tax rates of $5, $10, $25, $50, $100 and $150/tC, respectively. The percentage reduction of total fossil fuel use during 2006-2025 would be 0.6%, 1.3%, 3.1%, 8.6%, 17.3% and 21.6% at the tax rates of $5, $10, $25, $50, $100 and $150/tC, respectively.

Table 5.6: Cumulative fossil fuel use in electricity generation, by fuel type, during 2006-2025 at selected carbon tax rates (Mtoe).

Carbon tax ($/tC)	Coal	Oil	Gas	Total
0 (Base case)	5,639	39	462	6,139
5	5,607	39	455	6,100
10	5,575	39	447	6,061
25	5,483	38	430	5,952
50	5,166	38	408	5,612
100	4,662	38	378	5,078
150	4,403	38	369	4,811

Generation system efficiency

As can be seen in Figure 5.6, the overall efficiency of the thermal generation during the planning period need not necessarily improve with the carbon tax (see Section 2.3 in Chapter 2 for explanation on WATGE). The WATGE remains almost unchanged till the carbon tax of $25/tC. Although an increase in efficiency is observed at the carbon tax of $50/tC due to substitution of conventional coal-based generation by supercritical coal plants, the efficiency is found to decline again at tax rates of $100 and 150/tC because less efficient biomass-based steam plants would become cost effective to use at these tax rates.

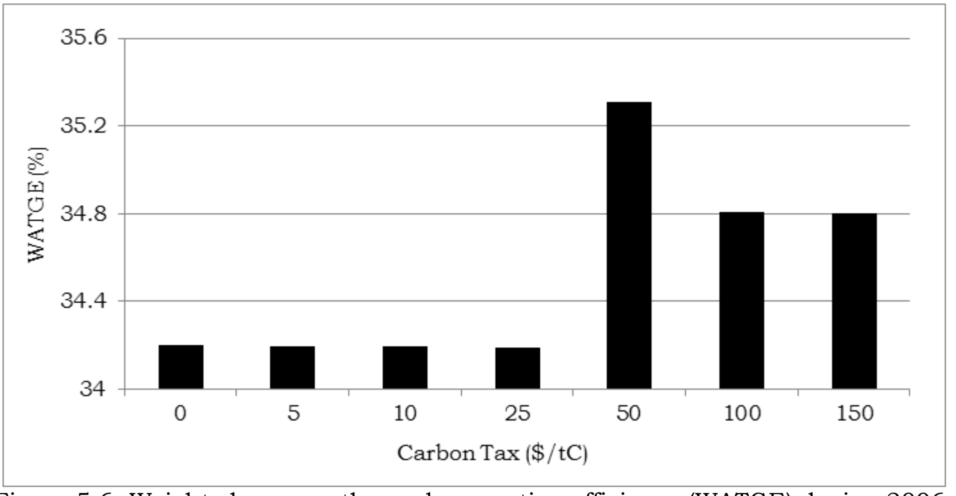

Figure 5.6: Weighted average thermal generation efficiency (WATGE) during 2006-2025 at selected carbon tax rates.

5.3.2. Economic implications

Electricity generation system cost

As shown in Table 5.7, the discounted total generation capacity cost during 2006-2025 would decrease from $42.4 billion in the base case to $39.9 billion at the carbon tax of $25/tC due to a reduction in electricity demand following the carbon tax. However, the cost would again increase to $41.7 billion at the carbon tax of $50/tC mainly due to the replacement of conventional coal-fired plants by supercritical coal-fired plants. On the contrary, at the carbon tax of $100/tC, the total capacity cost would decline to $39.9 billion due to a fall in electricity demand with the tax. The total capacity cost would increase again to $41.1 billion at the carbon tax of $150/tC. Although no additional supply-side effect is observed at the tax rate of $150/tC as compared to the case of of $100/tC tax, and total capacity additions are also lower, the total discounted capacity cost at the tax rate of $150/tC is found to increase due to an earlier additions of some cleaner power generation capacity during the planning period. The variable cost under the carbon tax increases by up to 65.2% at the carbon tax rate of $150/tC as compared that in the base case.

Table 5.7: Contribution of capacity, fixed O&M and variable O&M costs to the total cost at the selected carbon tax rates during 2006-2025+.

Carbon tax ($ /tC)	Capacity cost ($10^{12}$$)	Fixed O&M cost ($10^{12}$$)	Variable O&M and fuel cost including tax ($10^{12}$$)	Total cost ($10^{12}$$)	Total cost increment (%)
0 (Base case)	42.4	29.4	140.5	212.5	-
5	42.1	29.3	146.2	217.7	2.5
10	41.4	29.2	151.6	222.2	4.6
25	39.9	28.8	168.4	237.2	11.7
50	41.7	26.7	192.0	260.5	22.6
100	39.9	27.8	239.5	307.3	44.7
150	41.1	28.6	281.4	351.0	65.2

+ A '-' sign means either zero or a negligible quantity.

Carbon tax revenue

As shown in Table 5.8, the undiscounted tax revenue would increase from $33 billion (which is 3.9% of the total undiscounted cost) with the carbon tax of $5/tC to $765 billion (which is 59.7% of the total undiscounted cost) with the tax of $150/tC. The total undiscounted cost of electricity generation net of carbon tax (i.e., total non-tax cost) would decrease from about $830 billion in the base case to $516 billion at the carbon tax of $150/tC. The total net-tax cost of electricity generation as a percentage of total cost would range from 96.1% with the carbon tax of $5/tC to 40.2% with the carbon tax of $150/tC.

Table 5.8: Carbon tax revenue and total undiscounted cost during 2006-2025 at selected carbon tax rates*.

Carbon tax ($/tC)	Total cost (gross)+ (10^6 $)	Carbon tax revenue (10^6 $)	Total undiscounted cost net of tax (10^6 $)
0 (Base case)	830	-	830
5	845	33	812
10	859	65	794
25	907	152	755
50	980	296	684
100	1,137	540	598
150	1,281	765	516

+ Total cost including carbon tax revenue

* A '-' sign means either zero or a negligible quantity.

Unit cost of electricity generation

Table 5.9 presents the long run average cost (LRAC) of electricity generation and the overall average incremental cost ($AIC_{overall}$) of electricity supply (expressed as the sum of average incremental costs (AIC) of generation and long run marginal cost (LRMC) of transmission and distribution) (see Section 2.5 in Chapter 2 for calculation of $AIC_{overall}$). LRMC of transmission and distribution is ¢1.00/kWh. As can be seen, the LRAC varies from ¢3.24/kWh in the base case to ¢5.94/kWh at the tax rate of $150/tC, whereas the $AIC_{overall}$ varies from ¢3.26/kWh in the base case to ¢6.42/kWh at $150/tC.

Table 5.9: LRAC and $AIC_{overall}$ at the selected carbon tax rates.

Carbon tax ($/tC)	LRAC (¢/kWh)	$AIC_{overall}$ (¢/kWh)	Electricity price(¢/kWh)
0 (Base case)	3.24	3.26	4.26
5	3.33	3.36	4.36
10	3.42	3.49	4.49
25	3.70	3.82	4.82
50	4.15	4.35	5.35
100	5.08	5.38	6.38
150	5.94	6.42	7.42

5.3.3. Environmental implications

Figure 5.7 shows the cumulative CO_2 emission from the power sector during the study period at the selected carbon tax rates. Low carbon tax rates of up to $25/tC are only able to reduce the CO_2 emission during 2006-2025 by about 3.1%. However, at the carbon tax rates higher than $25/tC, CO_2 emission would decrease significantly during 2006-2025. That is, at carbon tax rates of of $50, $100 and $150/tC, CO_2 emission would be reduced by 16.0%, 23.6% and 27.8%, respectively as compared to the emission level in the base case (i.e., without carbon tax). The reduction of CO_2 emission at a tax rate of $50/tC is mainly due to the replacement of conventional coal-fired plants by supercritical plants, while the further reductions in emission at the tax rates of $100 and 150/tC are mainly due to the replacement of supercritical plants by biomass power plants.

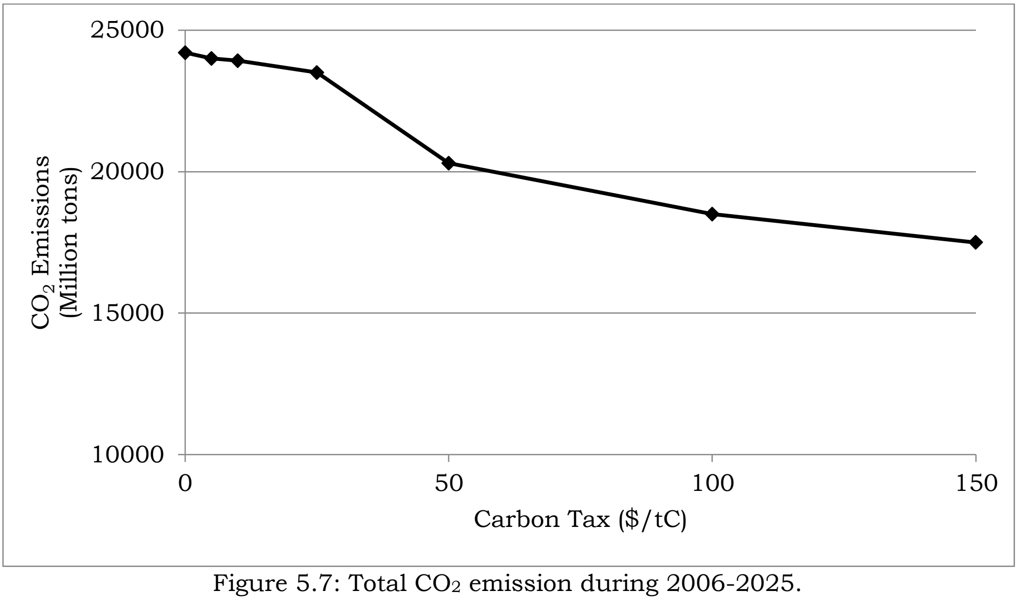

Figure 5.7: Total CO_2 emission during 2006-2025.

Decomposition of CO_2 emission reduction: Role of supply- and demand-side effects

The change in total CO_2 emissions with the introduction of carbon tax can be decomposed into supply (i.e., technological substitution effect) and demand-side (i.e., price effect) effects. Table 5.10 presents the decomposition of total CO_2 emission reduction at the selected carbon tax rates into the reduction components due to the supply- and demand-side effects (see Section 2.6 in Chapter 2 for calculation of decomposition of CO_2 emission reduction). The table shows that at the carbon tax of up to \$25/tC, the contribution of the demand-side effect in the CO_2 reduction is larger than that of the supply-side effect. This suggests that the carbon tax of up to \$25/tC would not be able to achieve a significant change in the capacity and generation mix in the power sector in India. At higher tax rates, i.e., \$50/tC and above, the supply-side effect of the carbon tax is found to be the dominant factor in CO_2 reduction and the demand-side effect would play a much smaller role.

Table 5.10: Contributions of demand- and supply-side effects to the power sector cumulative CO_2 reductions during 2006-2025.

Carbon tax (\$ /tC)	CO_2 emission reduction (10^6t)	Decomposition	
		Demand-side effect (%)	Supply-side effect (%)
5	152	84.2	15.8
10	310	83.1	16.9
25	761	80.5	19.5
50	3,855	19.7	80.3
100	5,697	18.9	81.1
150	6,711	27.7	72.3

The CAGR of CO_2 emissions up to the carbon tax rate of \$25/tC was found to be constant at 6.5%. However, if carbon tax rates of \$50/tC and higher were introduced, the growth rates of CO_2 emission would be significantly lower. At carbon tax of \$50, \$100 and \$150/tC, the CAGR of CO_2 emissions would be about 5.3%, 4.9% and 4.8%, respectively.

Implication on CO_2 emission intensity

Figure 5.8 presents the overall CO_2 emission intensity (measured as tons of CO_2 emission per MWh) during 2006-2025 at the selected carbon tax rates. As shown in the figure, although no significant change in the overall CO_2 emission intensity is observed at low tax rates of up to \$25/tC, the overall CO_2 emission intensity is found to decline beyond a certain tax rate (i.e., \$50/tC). At higher tax rates of \$50/tC and above, the supply-side effect) of carbon tax is found to be the dominant factor in CO_2 reduction (see Table 5.10). The decrease in the overall CO_2 emission intensities at these tax rates is mainly due to this reason.

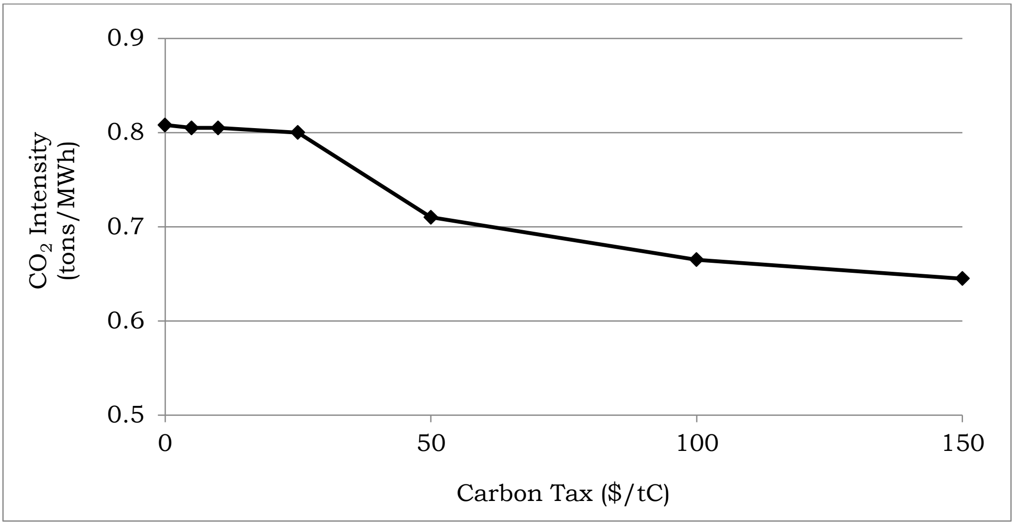

Figure 5.8: Overall CO2 emission intensity during 2006-2025 at selected carbon tax rates.

Carbon tax elasticity of CO_2 emission

The study has found the CO_2 emission from the power sector in India to be inelastic to changes in carbon tax (see Section 2.2 in Chapter 2 for calculation of carbon tax elasticity of CO_2 emission). The carbon tax elasticities (i.e., percentage change in CO_2 emission associated with a percentage change in carbon tax) are found to be inelastic as shown in Table 5.11.

Table 5.11: Carbon tax elasticities of CO_2 emission from the power sector at the selected tax rates.

Carbon tax ($ /tC)	Elasticity
0 – 5	0
5 – 10	-0.01
10 – 25	-0.02
25 – 50	-0.21
50 – 100	-0.14
100 – 150	-0.14

Local/regional pollutant emissions

The changes in the emissions of SO_2 and NO_x from the power sector of India at the selected carbon tax rates are presented in Table 5.12. The SO_2 emission is reduced by 0.6% at $5/tC as compared to the emission at the base case, while it would be reduced by 40.1% at $150/tC carbon tax rate. Similarly, NO_x emission would be reduced by 0.6% at the tax rate of $5/tC and by as high as 31.5% at $150/tC.

Table 5.12: Cumulative emissions of SO_2 and NO_x during 2006-2025 at selected carbon tax rates+.

Carbon tax ($ /tC)	SO_2 pollutant		NO_x pollutant	
	Emission (10^6t)	Reduction (%)	Emission (10^3t)	Reduction (%)
0 (Base case)	134.9	-	58.7	-
5	134.0	0.64	58.3	0.64
10	133.1	1.34	57.9	1.30
25	130.1	3.54	56.9	3.15
50	92.3	31.56	44.3	24.55
100	85.5	36.59	42.0	28.37
150	80.4	40.41	40.2	31.50

+ A '-' sign means either zero or a negligible quantity.

The CAGR of both SO_2 and NO_x emissions would remain almost unchanged, i.e., at about 8.4% and 6.2%, respectively, up to the tax rate of $25/tC. However, at the carbon tax rates of $50/tC to $150/tC, the SO_2 and NO_x emissions would grow at slower rates. That is, the CAGR of SO_2 emissions would be 4.8%, 4.2% and 4.1% respectively at the tax rates of $50/tC, 100/tC and 150/tC, while in the case of NO_x emission, the corresponding values would be 3.7%, 3.4% and 3.4%, respectively.

5.4. Effects of Energy Tax

Unlike the carbon tax, the purpose of the energy tax is to improve efficiency of energy supply and utilization. In this section, the implications of the energy tax on power generation capacity mix and electrical energy generation mix by technology type as well as fuel mix in power generation and thermal power generation efficiency in India are discussed. Furthermore, it discusses the effects on CO_2 and local level pollutant emissions as well as on costs of power generation.

5.4.1. Utility planning implications

Generation technology capacity mix

Table 5.13 presents the additions of power generation capacity by plant type during 2006-2025 at selected energy tax rates. As shown in the table, the total additional power generation capacity requirement would decrease from 314.2 GW in the base case to 227.9 GW with the imposition of energy tax of $5/MBtu.

As to the effect on generation capacity mix, at the energy tax rate of $0.5/MBtu, there would be a smaller coal-fired generation capacity addition than that in the base case and no change in other capacities (mainly due to a reduction in electricity demand associated with the tax. At a higher tax rate of $1/MBtu, there would be a reduced requirement to add the capacity of coal-fired steam- and hydropower- plants. It should be noted here that biomass-fired power plants would not be cost-effective even at the tax rate of $5/MBtu.

Table 5.13: Capacity additions by plant type during 2006-2025 at selected energy tax rates (GW)+.

Energy tax ($/MBtu)	Coal-based technologies		CCGT	Hydro	Wind	Total
	Coal-fired steam	Supercritical				
0 (Base case)	252	-	28.8	23.5	10	314.2
0.5	242	-	28.8	23.5	10	304.6
1	240	-	28.8	20.3	10	299
2	25	173.6	28.8	17.8	10	255.1
5	-	172.4	28.8	16.8	10	227.9

+ A '-' sign means either zero or a negligible quantity.

Electricity generation mix

Table 5.14 presents the total electricity generation and percentage shares of different technologies (i.e., big hydro, coal, oil, gas, nuclear and renewables) in electricity generation during the study period at the selected energy tax rates. As can be seen from the table, the total electricity generation during the period would decrease with the energy tax due to the reduction in electricity demand with the tax. There would be a reduction in the electricity generation by about 12% at the tax rate of $5/MBtu from the generation level in the base case.

The share of coal-based generation is maintained at above 70% even at a relatively high tax rate of $5/MBtu. There would be no significant change in generation mix up to the energy tax of $2/MBtu. Although conventional coal-fired power plants are completely replaced by supercritical coal plants at the energy tax of $5/MBtu, the share of total coal-based power generation would decrease only by 2.5% during 2006-2025. In addition, although the hydropower capacity addition decreases with the energy tax, the share of hydro-based generation would increase from 14.2% in the base case to 16.9% at an energy tax of $5/MBtu.

Table 5.14: Cumulative electricity generation mix during 2006-2025 at different energy tax rates (%).

Energy tax ($/MBtu)	Hydro	Coal	Oil	Gas	Wind	Nuclear	Total generation during the period (TWh)
0 (Base case)	14.2	72.8	0.5	8.3	2.4	1.8	29,943
0.5	14.5	72.7	0.5	8.0	2.4	1.9	29,420
1	15.0	72.4	0.5	7.8	2.4	1.9	28,912
2	15.4	72.0	0.5	7.5	2.5	2.0	28,090
5	16.9	70.3	0.6	7.5	2.7	2.1	26,301

Fossil fuel consumption

Table 5.15 presents the structure of the fossil fuel used for power generation during the entire study period at the selected tax rates. As can be seen from the table, the introduction of the energy tax would result in the reduced use of both coal and gas. Coal use would be reduced by 1.9%, 3.8%, 10.3% and 20.7% at the tax rates of $0.5, $1, $2 and $5/MBtu respectively, while the corresponding values for gas use would be 5.2%. 9.3%, 14.6% and 20.3%, respectively. The reduction of coal use at the lower tax rates is due to the demand effect, while at higher tax rates, reductions is mainly due to supply-side effect (i.e., replacement of conventional coal-fired plants by supercritical plants). In the case of gas, the reduction in gas use with the energy tax rates is due to the demand-side effect.

Table 5.15: Cumulative fossil fuel by fuel types use during 2006-2025 at selected energy tax rates (Mtoe).

Energy tax ($/MBtu)	Coal	Oil	Gas	Total
0 (Base case)	5,639	39	462	6,139
0.5	5,531	38	438	6,008
1	5,423	38	419	5,880
2	5,057	38	395	5,490
5	4,469	38	368	4,876

Generation system efficiency

Figure 5.9 shows the values of weighted average thermal generation efficiency (WATGE) during 2006-2025 at the selected energy tax. Although no efficiency gain is observed at low energy taxes, the WATGE is found to increase after a certain tax rate (i.e., $2/MBtu). The increase in WATGE at the higher tax rates is due to the replacement of less efficient conventional coal-fired plants by efficient supercritical coal-fired plants.

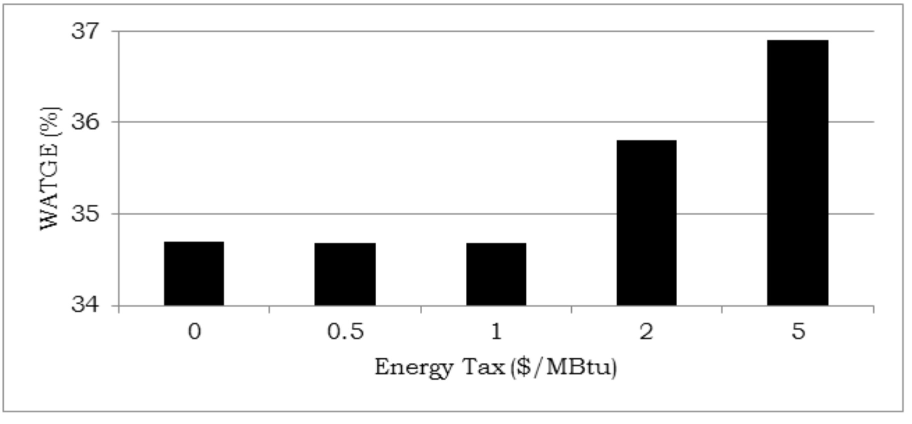

Figure 5.9: Weighted average thermal generation efficiency (WATGE) during 2006-2025 at selected energy tax rates.

5.4.2. Environmental implications

Figure 5.10 shows the power sector's total cumulative CO_2 emission during 2006-2025 at the selected energy tax rates. As can be seen from the figure, there would be no significant reduction in the CO_2 emission at low tax rates of up to $1/MBtu. However, at the energy tax rates of $2/MBtu and above, there would be a significant reduction in CO_2 emissions mainly due to the replacement of conventional coal-fired plants by supercritical coal-fired plants. The reductions in CO_2 emissions at the tax rates of $0.5, $1, $2 and $5/MBtu would be about 2.2%, 4.3%, 17.8% and 31.2%, respectively.

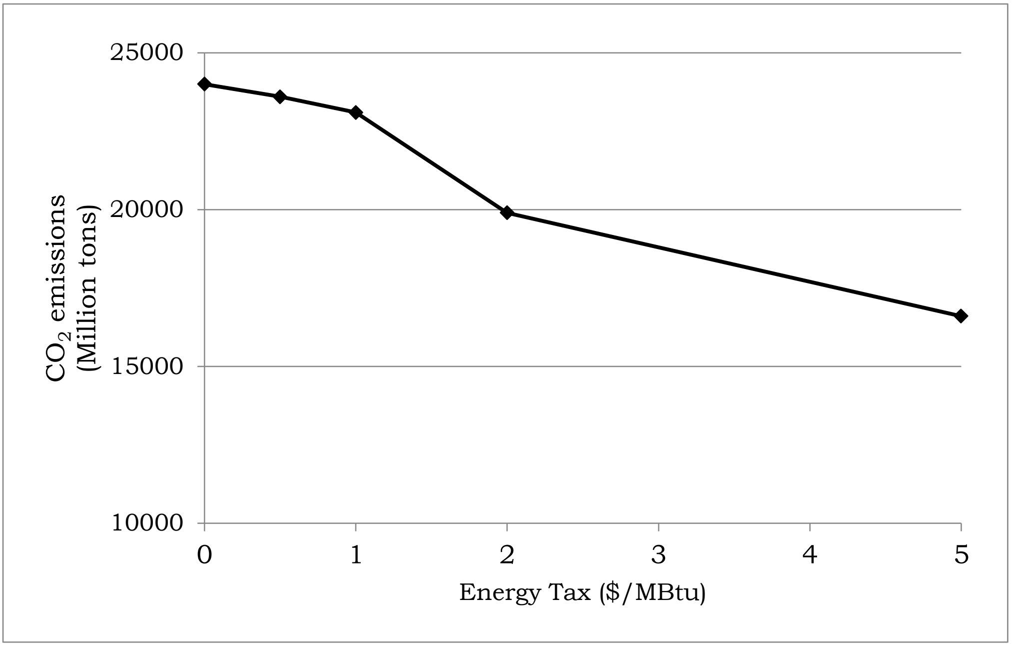

Figure 5.10: Total cumulative CO_2 emission during 2006-2025.

Decomposition of CO_2 emission reduction: The role of supply- and demand-side effects

Table 5.16 presents the total reductions in CO_2 emission at the selected energy tax rates and the contributions of the supply- and demand-side effects in the total CO_2 emission reductions. The table shows that the CO_2 reduction is mainly due to the demand-side effect at the energy tax rates of up to $1/MBtu. At the tax rates of $2/MBtu and above, the supply-side effect is found to be a more important contributor to the total CO_2 emission reduction than the demand-side effect because of a larger scale of technological substitution of conventional coal-fired plants with supercritical plants at such energy tax rates.

Table 5.16: Contributions of demand- and supply-side effects to the power sector cumulative CO_2 emission reductions during 2006-2025

Energy tax ($/MBtu)	CO_2 emission reduction (10^6ton)	Demand-side effect (%)	Supply-side effect (%)
0.5	529.58	82.53	17.47
1	1034.78	79.86	20.14
2	4291.47	24.08	75.92
5	7530.73	27.99	72.01

Energy tax elasticity of CO_2 emission

The results of this study show that the CAGR of CO_2 emission would remain unchanged at 6.5% up to the energy tax rate of $1/MBtu. However, if energy tax rates of $2 and $5/MBtu were introduced, the CAGR of CO_2 emissions would decrease to 5.1% and 4.7%, respectively. How would the CO_2 emission from the power sector change with an energy tax rate? For this purpose, the energy tax elasticity of CO_2 emission was calculated. It was found that the elasticities were inelastic (see Table 5.17).

Table 5.17: Energy tax elasticities of CO_2 emission from the power sector at the selected tax rates.

Energy tax ($ /MBtu)	Elasticity
0 – 0.5	-0.00
0.5 – 1	-0.02
1 – 2	-0.14
2 – 5	-0.11

Implications on CO_2 emission intensity

Figure 5.11 presents the overall CO_2 emission intensity during 2006-2025 (measured in tons of CO_2 emission per MWh) at the selected energy tax rates. As shown in the figure, although no improvement in CO_2 emission intensity is observed up to the tax rate of $1/MBtu, the intensity is found to decline at tax rates of $2/MBtu and higher.

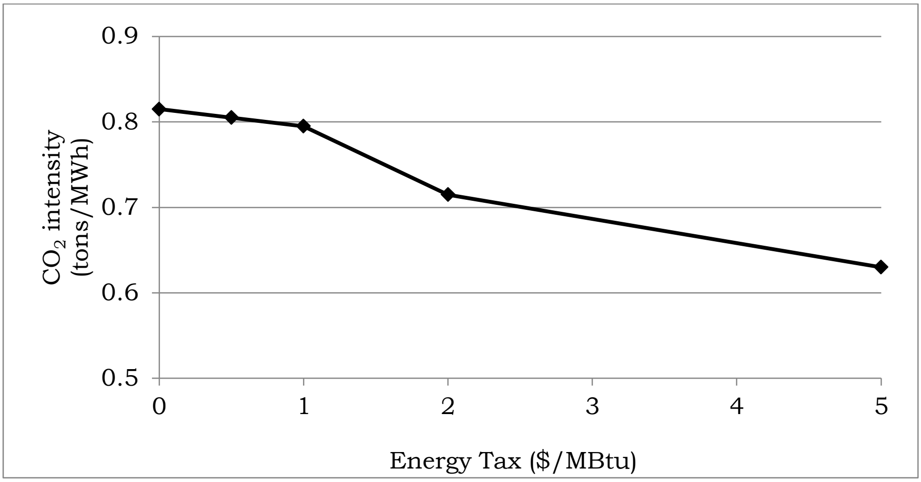

Figure 5.11: Overall CO_2 intensity of power generation at selected energy tax rates during 2006-2025

Local/regional pollutant emissions

Energy tax also results in other environmental benefits such as a reduction in the emission of some local level air pollutants (e.g., SO_2 and NO_x). As shown in Table 5.18, there would be no significant reduction in the emissions of both SO_2 and NO_x up to tax rate of $1/MBtu. However, significant reductions in both these emissions are observed at the tax rates of $2/MBtu and above. There would be a reduction in SO_2 emission by 2.4% at $0.5/MBtu as compared to the emission at the base case; the emission would be reduced by 61.7% at the tax rate of $5/MBtu. Similarly, NO_x emission would be reduced by 2.2% at $0.5/MBtu and by as high as 38.7% at $5/MBtu.

Table 5.18: Total cumulative emission of SO_2 and NO_x during 2006-2025 at selected energy tax rates+

Energy tax ($/MBtu)	SO_2 pollutant		NO_x pollutant	
	Emission (10^6t)	Reduction (%)	Emission (10^6t)	Reduction (%)
0 (Base case)	134.9	-	58.7	-
0.5	131.6	2.4	57.4	2.2
1	128.6	4.6	56.2	4.3
2	90.4	33.0	43.4	26.2
5	51.6	61.7	35.9	38.7

+ A '-' sign means either zero or a negligible quantity.

Up to energy tax rates of $1/MBtu, the CAGRs of SO_2 and NO_x emissions would remain almost constant around 8.5% and 6.2%, respectively. However, at the tax rates of $2/MBtu and above, the CAGRs of both SO_2 and NO_x emissions would decline significantly. At energy tax rates of $2 and $5/MBtu, the CAGRs of SO_2 emissions would be 4.1% and 1.5%, respectively, while the corresponding values for NO_x pollutants would be 3.3% and 3.1%, respectively.

5.4.3. Economic implications

Electricity generation system cost

As shown in Table 5.19, during 2006-2025, the discounted capacity cost would decrease from $42.4 billion in the base case to $38.8 billion at the energy tax of $1/MBtu. The reduction in the cost is due to the reduced level of total generation capacity additions required, which, in turn, is due to the demand-side effect of the tax. However, the total capacity cost would increase again at the tax rates of $2 and $5/MBtu due to the replacement of conventional coal-fired plants by capital-intensive supercritical plants. The total electricity generation cost is found to increase with the energy tax: the total cost at the energy tax rate of 5$/MBtu would increase by 82% higher than that in the base case.

Table 5.19: Break-down of total cost of power generation system development cumulative discounted cost during 2006-2025 at selected energy tax rates [+]

Energy Tax ($ /tC)	Capacity Cost ($10^9$$)	Fixed O&M Cost ($10^9$$)	Variable O&M and Fuel Cost including tax ($10^9$$)	Total Cost ($10^9$$)	Increment (%)
0 (Base case)	42.4	29.4	140.5	212.5	-
0.5	40.5	28.9	160.3	229.8	8.2
1	38.8	28.5	180.9	248.3	16.9
2	39.7	26.4	217.9	283.9	33.6
5	41.6	25.5	318.6	385.6	81.5

[+] A '-' sign means either zero or a negligible quantity.

Energy tax revenue

As shown in Table 5.20, the undiscounted tax revenue over the planning period due to energy tax is found to increase with tax. The tax revenue would increase from $117 billion (which is 13.1% of total undiscounted cost) at the energy tax of $0.5/MBtu to $967 billion (which is 71.8% of total undiscounted cost) at the energy tax of $5/MBtu.

Table 5.20: Energy tax revenue and total undiscounted cost (gross and net of tax) and energy tax revenue during 2006-2025 at selected energy tax rates.

Energy tax ($/MBtu)	Total cost (gross)[+] (billion $)	Energy tax revenue (billion $)	Total cost net of tax, (billion $)
0 (Base case)	830	0	830
0.5	893	117	776
1	954	233	722
2	1,075	435	639
5	1,345	967	379

[+] Total cost including energy tax revenue

Unit cost of electricity generation

Table 5.21 presents the long run average cost (LRAC) and the overall average incremental cost ($AIC_{overall}$) of electricity generation. The LRAC ranges from ¢3.2/kWh at the base case to ¢6.7/kWh at the energy tax of $5/MBtu, whereas the $AIC_{overall}$ is in the range of ¢4.26/kWh to ¢8.0/kWh.

Table 5.21: LRAC and AICoverall at different energy tax rates

Energy tax ($/MBtu)	LRAC (¢/ kWh)	AIC (¢/kWh)	$AIC_{overall}$ (¢/kWh)
0 (Base case)	3.24	3.26	4.26
0.5	3.56	3.65	4.65
1	3.92	4.02	5.06
2	4.61	4.72	5.86
5	6.69	6.90	8.01

5.5. Summary

The study shows that coal-based power plants would dominate the Indian power sector in the base case during 2006-2025. In the year 2025, the share of coal-based power plants in the power sector of India would be 70.3% with additions of about 252,000 MW of conventional coal-fired plants. Hydropower would account for the second largest share in total power plant capacity in the country. In the year 2025, the share of hydro-based power plants would be 16.2%. The study also shows that it would be cost effective to install wind power capacity of 10,000 MW by year 2015 even without any carbon tax. The CO_2 emission from the power sector would increase from 590 million tons in 2006 to 2,097 million tons by 2025. The annual average growth rate (AAGR) of CO_2 emission during these years would be 6.5%.

The study shows that the total (cumulative) CO_2 emission during 2006-2025 would be reduced by 0.6% at the carbon tax rate of $5/tC and by 27.8% at the carbon tax rate of $150/tC, when compared to the base case emission. In the case of energy taxes, the total CO_2 emissions would be reduced by 2.2% at the energy tax of $0.5/MBtu and 31.2% at the highest tax rate of $5/MBtu, when compared to the emission level in the base case.

The introduction of both carbon and energy taxes will cause reduction in the use of coal and gas in the power sector. The gas and coal consumption would decrease by about 1.4% and 0.6%, respectively at the carbon tax rate of $5/tC; the corresponding figures at the carbon tax rate of $150/tC would be 20.0% and 21.9%, respectively. Introduction of carbon tax of up to $25/tC has been observed to not achieve a significant change in terms of the capacity and generation mix due to the demand-side effect. There would be a reduction in coal consumption by 20.7% at $5/MBtu due to the replacement of the traditional coal-fired power plants by supercritical plants (i.e., supply-side effect). As a result, the CO2 emission has been observed to decrease more dramatically due to the energy tax rates of $2/MBtu and higher

The carbon and energy taxes would have a positive effect in the reduction of SO_2 and NO_x emissions. SO_2 emissions would be reduced in the range of 0.64% to 40.4% at the carbon tax rates of $5/tC to $150/tC, and NO_x emissions would be reduced in the range of 0.64% to 31.5% in the range of the carbon tax rates considered. Similarly, in the case of the energy tax ranging from $0.5/MBtu to $5/MBtu, the emission of SO_2 would decrease in the range of 2.4% to 61.7%, whereas the NO_x emission would decrease in the range of 2.2% to 38.7%.

The analyses of the effects of the carbon and energy taxes show that both the carbon and energy taxes can be effective in introducing a cleaner coal technology, such as supercritical power plants, in the Indian power sector. Biomass-based power plants would penetrate the market at the carbon tax rate of $100/tC. Results of the present study show that the energy tax would not be effective in introducing biomass-based power generation technologies. In this study, biomass energy was subjected to the energy tax as biomass burning results in emissions of local air pollutants. Both the carbon and energy taxes are not found effective in the promotion of solar-based power generation due to its high capacity cost.

<u>Post-script</u>

As this study was carried out during 2004-2005, it is expected to find some differences between the results of the study and the actual data available so far on power sector since then. Such differences could arise due to various factors, e.g., the differences between the values of projected electricity demand considered in the study and the actual demand over time. Also there could be differences in the values of plant capacity costs, fuel prices and efficiency of candidate power plants considered in the study and their actual values. In addition, there have been major changes in national energy policies in India to increase the role of renewable energy and energy efficient technologies in power generation. Since these policies came into force after the study was conducted, the actual power generation capacity could be considerably different from the estimated values in the present study. In this section, an attempt is made to briefly describe some of these factors in the power development sector in the case of India.

The peak demand for electricity has been reported to have increased at a CAGR of 5.5%, i.e., from 93,255 MW in the fiscal year 2005/06 to 135,453 MW in 2012/13 (CEA, 2013b and CEA, 2014). The data available recently (i.e., in 2015) shows that the installed power generation capacity in the country had actually grown at the CAGR of 8.4% during 2006-2014 (CEA, 2013c and CEA, 2014). This is significantly higher than the estimated growth of the total installed capacity in this study that is at a CAGR of 6.8% (from 165,168 MW in 2006 to 297,485 MW in 2015).

The available data as of 2015 shows that electricity generation had actually increased at the CAGR of 5.4% (i.e., from 578.8 TWh in 2005/06 to 788.4 TWh in 2013/2014) (CEA, 2013b and CEA, 2014). However, the present study estimated that the electricity demand and hence electricity generation in India would grow at a higher CAGR of 6.2% during 2006/2015. As the present study used a higher demand forecast than what happened actually since the study was carried out, the installed capacity estimates in this study has been higher than the actual values of the installed capacity during 2006-2014.

According to CEA (2014), the shares of coal, gas, oil, nuclear and hydro in electricity generation in 2014 were 55.1%, 10.2%, 1.0%, 2.7% and 26.0%, respectively. The shares are similar to the corresponding estimated values in the base case of this study (see Table 5.3). The actual shares of the renewables (i.e., 5.0%) in 2014, however, have been found to be higher than the share (i.e., 3.1%) in 2015 as has been estimated by this study. Since the cost of solar plants considered in the study were significantly higher in 2004-2005 (i.e., $6,660/kW), solar power technologies have not found to be cost effective in the study. In hindsight, however, it can be seen that as the solar technology matured, its capacity cost decreased rendering it to be a suitable choice for power generation in the Indian power generation system. As the actual cost of solar has gone down to $1,054/kW (MNRE, 2015a), solar based installations have been increasing at a high CAGR of 12.5% in electricity generation from 2012 to 2015.

Besides the decrease in capacity costs, a major reason for the higher growth in renewable energy installations than that estimated by this study is the implementation of several favorable government policies and acts in India. As mentioned in the 11th Five year plan (2007-2012), the Government of India had plans to increase the percentage share of grid connected renewable energy-based power generation to 5% with its installed capacity exceeding 25 GW by 2012 (Schmid, 2011). The Renewable Purchase Obligations (RPO) has been the major driving force in India to promote the renewable energy sector. The country has state-wise RPO to develop renewable energy-based power generation. Feed-in-tariffs (FITs) and RPOs constitute the backbone of the policy of a majority of states to promote renewable energy-based power in India (MNRE, 2015b). India has identified eight national missions which include the missions for solar development, enhancing energy efficiency, sustainable habitat, etc. As mentioned in the "National Action Plan on Climate Change (NAPCC)", the government of India has mandated the retirement of inefficient coal-fired power plants and is supporting the research and development of IGCC and supercritical technologies. According to the Electricity Act 2003 and the National Tariff Policy 2006, the central and the state electricity regulatory commissions must facilitate the purchase of a certain percentage of grid-based power from renewable sources (GoI, 2008). However, during the time, when this study was conducted, such policies were not introduced and hence not considered in the analysis. Thus, the differences between the results of this study and actual development in the power sector in India will have to be seen in this light.

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6. Power Sector Development in Indonesia: Effects of Carbon and Energy Taxes[1]

6.1. Introduction

Power sector development in Indonesia has grown rapidly in recent years. Electricity production increased from 99.5 TWh in the year 2000 to 182.3 TWh in the year 2011 (IEA, 2013). Electricity generation in Indonesia is heavily based on fossil fuels. Accordingly, electricity production is one of the major sources of CO_2 emission in the country. CO_2 emission from the electricity sector increased from 67.1 million tons in 2000 to 137.6 million tons in 2011.

Some of the major direct policy instruments to mitigate CO_2 emissions include carbon tax and carbon emission permits, while indirect instruments include energy tax. This study analyses the effects of introducing selected carbon and energy tax rates in the power sector of Indonesia.

The analysis presented in the following sections was carried out during 2004-2005; it assesses the utility planning, environmental and economic implications of introducing carbon and energy taxes in the power sector of Indonesia (during the planning period of 2006-2025). Electricity demand forecast and other relevant data available at that time were used for the study. Six selected carbon tax rates (i.e., \$5/tC, \$10/tC, \$25/tC, \$50/tC, \$100/tC and \$150/tC) and four selected energy tax rates (i.e., \$0.5/MBtu, \$1/MBtu, \$2/MBtu and \$5/MBtu) were considered in the study. The results of the least cost generation planning in the "Base Case" (i.e., without carbon and energy taxes) are presented in Section 6.2, which is followed by a discussion of the results on the effects of carbon and energy taxes in Sections 6.3 and 6.4, respectively. A summary of key findings are presented in Section 6.5, which is followed by a post-script at the end of the chapter. The differences between the results of the base case of this study and the actual data related to the growth in electricity generation, generation-mix and capacity additions and energy policies related to the power sector, in recent years (i.e., during 2006-2013), after the study was carried out is briefly discussed in the post-script.

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6.2. Base Case Analysis

6.2.1. Definition of base case

Input data and assumptions

The data used in this study for electricity generation system planning (e.g., existing, committed and candidate power plants and cost data) are based on the PTP (2005).

The technical characteristics and cost of candidate power plants considered in this study are presented in Tables 6.2 and 6.3. Candidate power plants for the Java-Bali islands are mainly based on gas and coal. Oil-based power plants would not be considered following the national energy policy to not exceed 20% of the total energy supply according to the Presidential Regulation No. 5/2006. The capacity of renewable energy-based power plants (such as hydropower and geothermal power plants) is limited to the levels as stated in PTP (2004). Nuclear power plants are not considered as a candidate option for power generation in this study. All prices (in US dollars) used in the present analysis are the prices in year 2000. The discount rate used in this study is 10%. The price elasticity of electricity demand used in this study is -0.35. It should be noted that demand-side management (DSM) options are not considered in this study[2]. The growth in peak power demand and electrical energy requirement considered in the base case are as shown in Table 6.1.

Table 6.1: Peak load and energy forecast during 2002-2025.

Year	Peak Load (MW)	Energy (GWh)	Year	Peak Load (MW)	Energy (GWh)
2002	13,374	108,441	2014	30,121	244,230
2003	14,310	116,032	2015	32,229	261,326
2004	15,312	124,154	2016	34,485	279,619
2005	16,384	132,845	2017	36,899	299,192
2006	17,531	142,144	2018	39,482	320,136
2007	18,758	152,094	2019	42,246	342,545
2008	20,071	162,741	2020	45,203	366,523
2009	21,476	174,133	2021	48,367	392,180
2010	22,979	186,322	2022	51,753	419,632
2011	24,588	199,364	2023	55,376	449,007
2012	26,309	213,320	2024	59,252	480,437
2013	28,150	228,252	2025	63,400	514,068

Source: PTP (2005)

[2] For a study of carbon tax in the power sector considering DSM options, see Shrestha and Marpaung (1999).

Table 6.2: Technical characteristics and cost data of candidate hydro power plants+.

Plant name	Plant type	Fuel type	No. of units	Unit capacity (MW)	Heat rate (kcal/ kWh)	Capacity cost at year 2000 prices (US$/kW)	Emission factors (g/kWh)		
							CO_2	SO_2	NO_x
Rajamandala [a]	Hydro	-	1	55	-	1,482	-	-	-
Kesamben [a]	Hydro	-	1	33	-	2,835	-	-	-
Lesti [a]	Hydro	-	1	11	-	2,296	-	-	-
Jawa PS [a]	Hydro	-	1	1,000	-	539	-	-	-

Source: PTP (2005).

[a] Firm energy availability from Rajamandala, Kesamben, Lesti and Jawa PS hydro plants are 120 GWh, 96 GWh, 28.9 GWh and 1,460 GWh respectively.

+ A '-' sign means either zero or a negligible quantity.

Table 6.3: Technical characteristics and cost data of candidate thermal power plants+.

Plant type	Fuel	Capacity (MW)	Heat rate (Kcal/kWh)	Efficiency (%)	Capacity cost (US$/kW)	Variable O&M (US$/ MWh)	Fixed O&M (US$/ kW/yr)	Emission factors (g/kWh)		
								CO_2	SO_2	NO_x
CCGT	Gas	600	1,654	52	550	2.0	16.5	382	0.001	0.728
GT	Gas	100	2,263	38	440	5.0	13.2	523	0.002	0.996
IGCC	Coal	500	2,200	39.08	1,420	1.87	42.6	859	0.005	0.429
PFBC	Coal	500	2,195	39.17	1,440	2.10	43.2	857	0.252	0.856
Super-critical	Coal	400	1,810	47.51	1,329	2.10	39.87	707	0.012	0.882
Pulverized coal	Coal	400	2,388	36	1,021	3.25	30.63	988	5.801	4.934
Geo-thermal	Geo	55	8,162	11	1,626	-	43.5	-	-	-
BIGCC	Paddy	75	2,390	35.98	1,626	5.2	48.78	-	-	-
Wind	-	1		-	965	-	28.95	-	-	-
Solar	-	1		-	5,500	-	95.55	-	-	-

Source: PTP (2005)

+ A '-' sign means either zero or a negligible quantity.

6.2.2. Power sector development during 2006-2025

Table 6.4 shows the installed power generation capacity mix in selected years in the base case. About 63,980 MW of power plants would have to be added to the power system during 2006-2025 in this case. The present study shows that renewable energy technologies (RETs) such as Biomass Integrated Gasification Combined Cycle (BIGCC) and wind as well as energy efficient technologies (EETs) such as Combined Cycle Gas Turbine (CCGT) would be cost-effective during the period, whereas CCTs such as Integrated Gasification Combined Cycle (IGCC), Pressurized Fluidized Bed Combustion (PFBC) and Super Critical (SC) plants would not be cost-effective. Conventional coal-fired power plant is found to be cost-effective and is used significantly during the period, since its capacity cost is lower than that of the CCTs and the price of coal is relatively low. This result is in line with the National Energy Policy of Indonesia since coal is considered as the most secure source of energy supply in the country. Hydropower plants (i.e., storage and pumped storage plants) would also be cost-effective during 2006-2025, whereas solar-based power generation still looks too expensive during the period. The capacity cost of geothermal power plants are still too high because of which such plants are not found as an attractive option during the period. The additional power plants mentioned above would cause the total installed capacity in year 2025 to reach about 86,036 MW. Of the total capacity added, the coal-based power plants would have the largest share (around 56.5%), and is followed by gas-based power plants (31.5%) and oil-based power plants (5.7%). The share of hydro-, geothermal-, biomass-, and wind-based power plants in that year would be about 2.9%, 1.5%, 1.0% and 0.9%, respectively.

Table 6.4: Installed power generation capacity mix at selected years in the base case (MW).

Fuel type	Year				
	2006	2010	2015	2020	2025
Coal	8,720	14,920	24,120	33,720	48,920
Gas	5,799	7,464	8,064	16,464	27,264
Oil	4,953	4,953	4,953	4,953	4,953
Hydro	1,459	1,459	2,459	2,514	2,514
Geothermal	1,125	1,305	1,305	1,305	1,305
Biomass	-	825	825	825	825
Wind	-	40	78	132	255
Total	22,056	30,966	41,804	59,913	86,036

+ A '-' sign means either zero or a negligible quantity.

The cumulative electricity generation during 2006-2025 would be about 5,235 TWh. Coal-fired plants would have the largest share (77.1%) in the total electricity generation during the period and are followed by of the gas- and oil-based power plants, which account for 12.4% and 3.7% of the electricity generation, respectively. The share of electricity generation from hydro-, biomass-, geothermal- and wind-based power plants would be 2.5%, 2.3%, 1.9% and 0.1%, respectively.

Table 6.5 shows the generation mix at selected years in the base case. In 2025, the share of coal, gas and oil would be 81.0%, 12.9% and 2.0%, respectively whereas the share of hydro, geothermal, biomass and wind would be 1.5%, 1.1%, 1.4% and 0.2%, respectively.

Table 6.5: Electricity generation mix at selected years in the base case (GWh).

Fuel type	Year				
	2006	2010	2015	2020	2025
Coal	66,299	115,879	185,224	266,219	386,909
Gas	34,450	18,413	17,834	37,539	61,454
Oil	10,001	9,618	9,618	9,618	9,618
Hydro	5,645	5,645	7,105	7,225	7,225
Geothermal	4,354	5,063	5,063	5,063	5,063
Biomass	-	6,725	6,725	6,725	6,725
Wind	-	114	222	376	726
Total	120,749	161,457	231,791	332,765	477,720

+ A '-' sign means either zero or a negligible quantity.

Table 6.6 shows the amount of fossil fuel and biomass used for power generation during 2006-2025. The cumulative use of energy for power generation during the period is estimated to be around 1,195 Mtoe. Coal would account for 83.4% of the total fuel consumption; this is followed by gas (10.2%), oil (4.0%), and biomass (2.4%). The high share of coal is in line with the government policy that aims to have the share of coal above 33% in the fuel mix since it is considered to be the most secure source of energy in Indonesia.

Table 6.6: Use of fossil fuels and biomass for power generation in selected years (Mtoe).

Fuel types	Year				
	2006	2010	2015	2020	2025
Coal	15.69	28.12	45.66	66.14	96.67
Gas	7.96	3.67	3.55	6.78	10.74
Oil	2.46	2.36	2.36	2.36	2.36
Biomass	0.00	1.61	1.61	1.61	1.61
Total	26.12	35.76	53.17	76.90	111.38

Generation system efficiency

Figure 6.1 shows the estimated overall weighted average thermal power generation efficiency (WATGE) of the power system in Indonesia during 2006-2025 (see Section 2.3 in Chapter 2 for explanation on WATGE). The growing dominance of coal-based power plants in electricity generation during the period would result in a decreasing overall efficiency of the power generation system. The average WATGE of power generation system during 2006-2025 is estimated to be 37.7%.

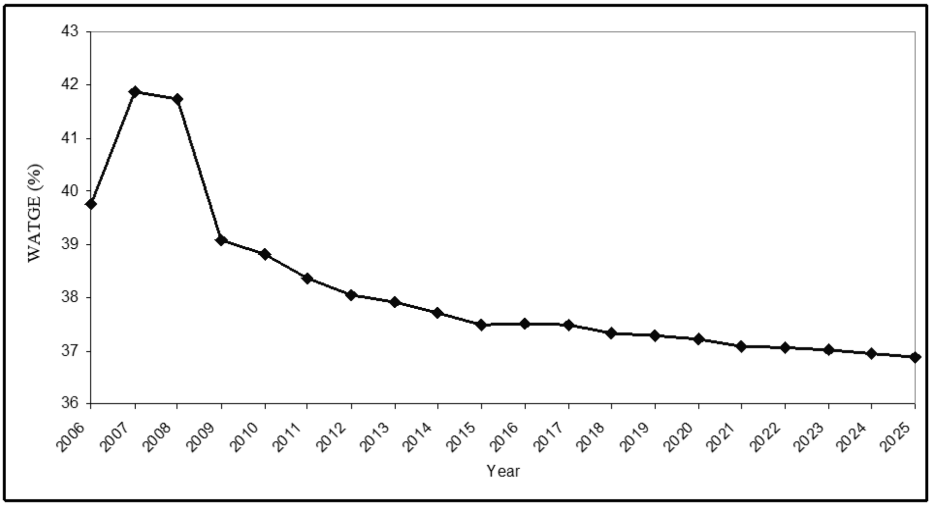

Figure 6.1: Annual overall electricity generation efficiency during 2006-2025 in the base case.

6.2.3. Environmental implications

Figure 6.2 shows the annual CO_2 emission from power generation in the base case. The cumulative CO_2 emission during 2006-2025 at the base case is estimated to be about 4,678 million tons.

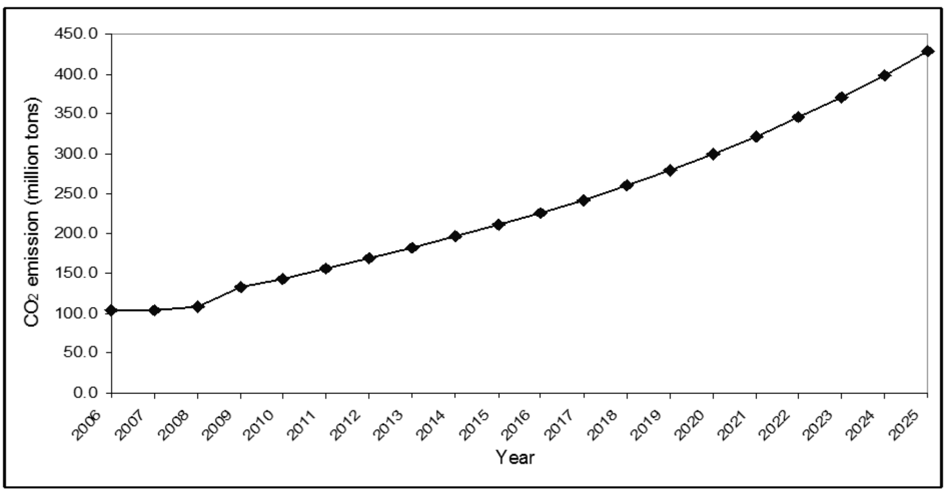

Figure 6.2: Annual CO_2 emission in the base case.

The CO_2 emission in year 2025 would be about 428 million tons, which is a 3.1 fold increase from that in 2006. The CAGR of the CO_2 emission during the period would be 7.8%.

Figure 6.3 shows the annual CO_2 intensity during 2006-2025 in the base case. The figure shows mostly an increasing trend in CO_2 intensity during the period due to an increasing use of coal. The CO_2 intensity is estimated to increase from 25.8 gC/MJ in 2006 to 28.1 gC/MJ in 2025.

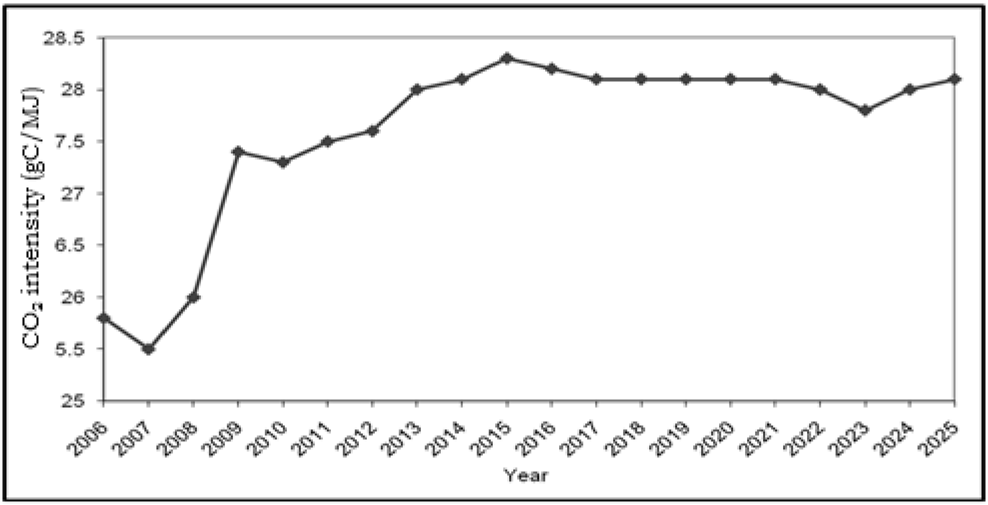

Figure 6.3: Annual CO_2 intensity in the base case.

Figure 6.4 shows annual SO_2 emissions during 2006-2025 in the base case. The SO_2 emission in 2025 is estimated to be 2,189 thousand tons, which is about 6.5 times of that in 2006. The CAGR of SO_2 emission during the period is found to be 10.8%. The high CAGR of the SO_2 emission is due to increasing reliance on coal-fired power generation during the period.

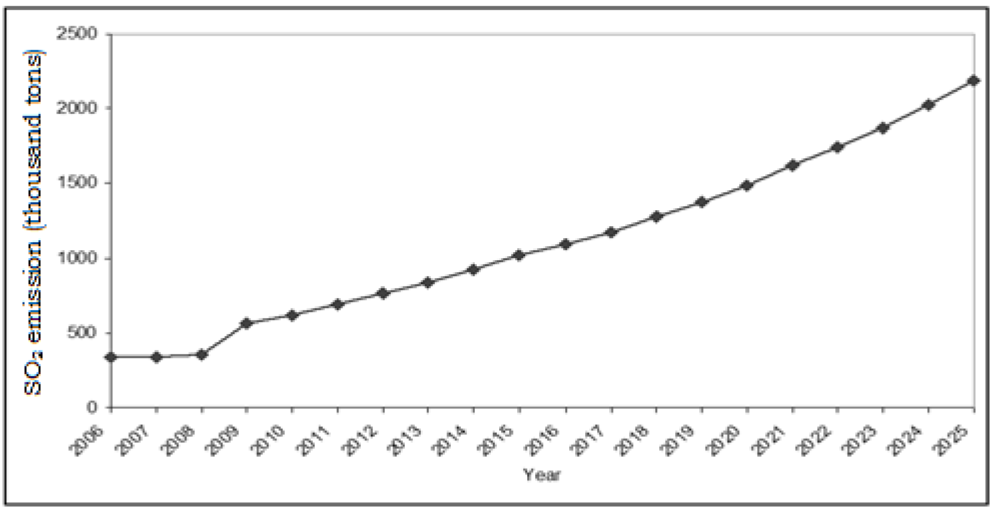

Figure 6.4: Annual SO_2 emission in the base case.

Figure 6.5 shows the annual NO_x emissions during 2006-2025 in the base case. The CAGR of NO_x emission during 2006-2025 is about 10%. The NO_x emission was about 328 thousand tons in 2006 and would increase to 1,902 thousand tons by 2025.

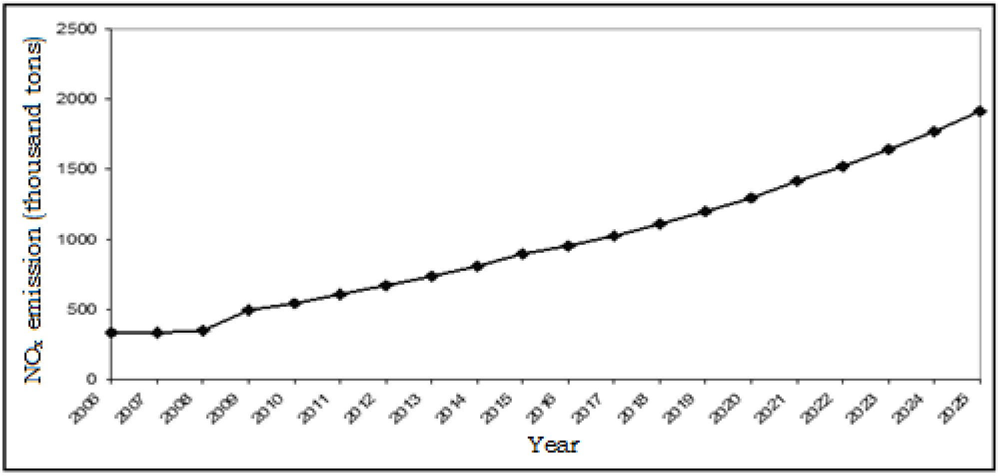

Figure 6.5: Annual NO_x emission in the base case.

6.2.4. Economic implications

The total cumulative cost of power generation during 2006-2025 is estimated to be 172,085 million US dollars, of which 73.9% would be fuel and variable O&M costs. The share of the capacity cost in the total cost would be 17.6%, while the fixed O&M cost would account for 8.5%. The average incremental cost ($AIC_{overall}$) is estimated to be ¢3.46/kWh, while the long run average cost (LRAC) would be ¢4.11/kWh.

6.3. Effects of Carbon Tax

This section discusses the utility planning, environmental and cost implications of introducing the carbon tax rates in the power sector of Indonesia.

6.3.1. Utility planning implications

Generation technology capacity mix

This study shows that the biomass-based power generation would become increasingly cost-effective with the introduction of carbon tax (see Table 6.7). This is because carbon tax would not affect the cost of biomass-based power generation since biomass is assumed to be produced at a sustainable basis. At carbon tax rates up to $10/tC, natural gas (a low carbon-fossil fuel) would be more attractive than biomass for power generation. Conventional coal-fired power plant is found to be more attractive than CCGT and BIGCC even at low tax rates (i.e., $5/tC and $10/tC). This is because coal is much cheaper than natural gas. Unlike renewable energy power plants (such as BIGCC), CCTs, such as IGCC, PFBC and SC plants, would not be cost-effective even at the carbon tax rate of $150/tC due to the relatively high capacity investment cost of CCTs. Of the two non-dispatchable RETs considered in this study, only wind energy is found to be cost-effective and

Table 6.7: Power generation capacity additions by technology type during 2006-2025 at selected carbon tax rates (MW).

Power plant technology	Base case	Carbon tax ($/tC)					
		5	10	25	50	100	150
Conv. coal	39,600	37,200	23,600	-	-	-	-
IGCC	-	-	-	-	-	-	-
PFBC	-	-	-	-	-	-	-
SC	-	-	-	-	-	-	-
CCGT	19,800	19,800	19,800	20,400	12,600	11,400	9,600
GTPP	1,400	1,200	1,300	800	400	-	-
Geothermal	-	-	-	-	-	-	-
BIGCC	825	2550	15,300	38,100	44,625	43,950	43,725
Hydro	55	-	-	-	55	55	55
Pumped storage	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Wind	255	487	653	260	365	656	1,000
Solar	-	-	-	-	-	-	-
Total	62,935	62,237	61,653	60,560	59,045	57,061	55,380

[+] A '-' sign means either zero or a negligible quantity.

increasingly more attractive at higher carbon taxes. Solar power plants are not found to be attractive even at the carbon tax of $150/tC. Power plants that are found cost-effective at different carbon tax rates and their capacity are shown in Table 6.7.

The total installed capacity at carbon tax rates of $5/tC, $10/tC, $25/tC, $50/tC, $100/tC and $150/tC in year 2025 would be decreasing from 85,338 MW, 84,754 MW, 83,661 MW, 82,146 MW, 80,162 MW and 78,681 MW, respectively. The total installed capacity at the lowest tax rate (i.e., at $5/tC) would be about 99% of that in the base case, which would decrease to about 89% of that in the base case at the highest tax rate (i.e., at $150/tC).

The total electricity generation during 2006-2025 at carbon tax rates would decrease from the base case (i.e., zero tax case) by 0.8%, 2.0%, 2.8%, 4.5%, 7.0% and 8.7% at carbon tax rates of $5, $10, $25, $50, $100 and $150/tC, respectively. This decrease in the electricity generation is due to the decrease in demand for electricity as a result of the increasing electricity price.

Electricity generation mix

Figure 6.6 shows the annual electricity generation in the base case and carbon tax cases during 2006-2025. At the carbon tax rate of $150/tC, the total electricity generation requirement during 2006-2025 would be about 9% less than that in the base case. Although the capacity cost of biomass-based power plant is higher than coal- and gas-based power plants, the biomass-based power plant becomes more effective with the introduction of carbon tax. At the carbon tax of $25/tC, more than 50% of the electricity generation would be from biomass-based power plants during the period. Note that wind-based power generation would be cost-effective even without carbon taxes. However, wind potential in the country is very limited, so the level of wind power generation does not increase much with the carbon tax. Electricity generation from coal would be based on conventional coal-fired power plants only; there would be no electricity generation from clean coal technologies such as IGCC, PFBC and SC since these plants would not be attractive even at high carbon tax rates.

Figure 6.7 shows the electricity generation by fuel type in 2025 at the selected carbon tax rates. At the base case and carbon tax rates of $10/tC and lower, coal-based power plants would account for the highest share in the electricity. Coal-based electricity generation would decrease with the increase in the carbon tax rate. The utilization of coal-based power plant capacity would be decreasing with the carbon tax rate of $10/tC and higher. At the carbon tax rates of $25/tC and higher, the biomass-based power plants would have the highest share in electricity generation. Thus, a carbon tax policy would help the government to promote the use of renewable energy for power generation and achieve the target of more than 5% renewable energy in the national primary energy mix by 2020. Nevertheless, the share of coal- and gas-based power plants in electricity generation at the carbon tax $150/tC is relatively low (i.e., 13%) and at $25/tC it is very close (i.e., 27%) in 2025) when compared to the government target of more than

30% coal and gas in the national primary energy mix by 2025. This indicates that although coal resources are abundant in Indonesia, its consumption would decrease with the increase in the carbon tax rates.

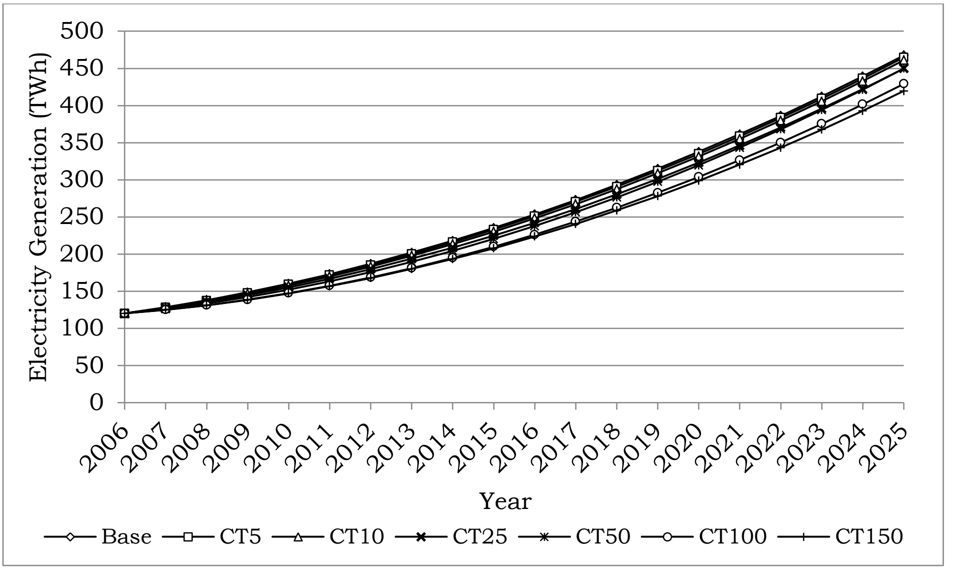

Figure 6.6: Annual electricity generation in the base case and carbon tax cases.

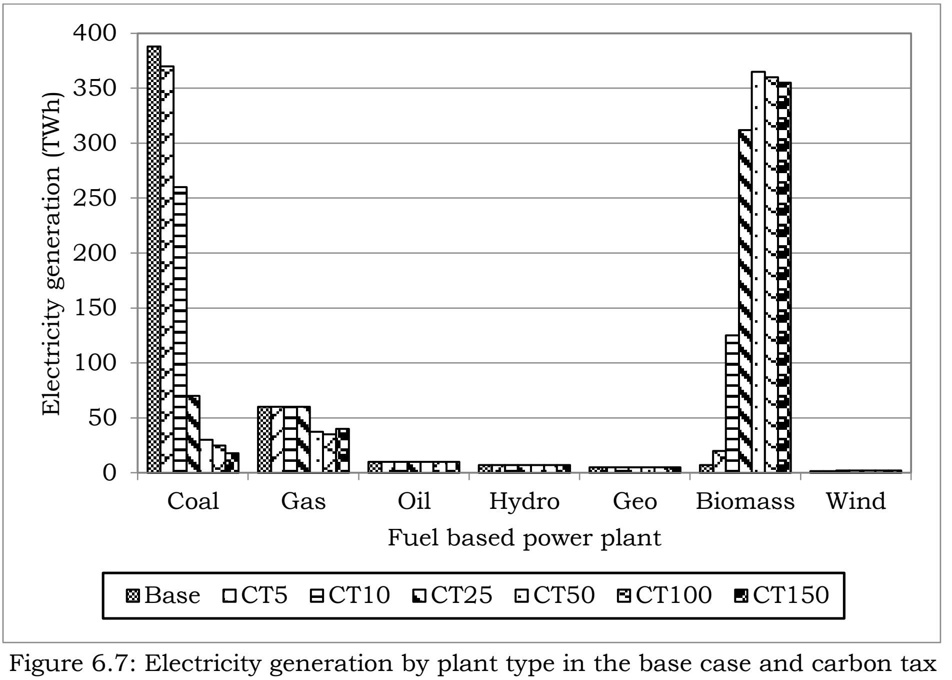

Figure 6.7: Electricity generation by plant type in the base case and carbon tax cases in 2025.

Fossil fuel consumption for power generation

In the case of the Indonesian power sector, carbon tax is seen to encourage fuel switching from fossil fuels to mainly biomass-based fuels although the effect will be very small at a tax rate of $5/tC.

This study estimates that the carbon tax would significantly reduce the use of coal and oil, i.e., the resources, which are being promoted by the National Energy Policy of Indonesia[3]. At the carbon tax rate of $150/tC, the share of coal and oil used for electricity generation in year 2025 would be reduced to about 4.6% and 6.9%, at carbon tax case of $150/tC, from 86.5% to 9.21% in the base case, respectively, while the share of biomass would increase to nearly 85.9% at $150/tC from 2.02% in the base case (see Figure 6.8).

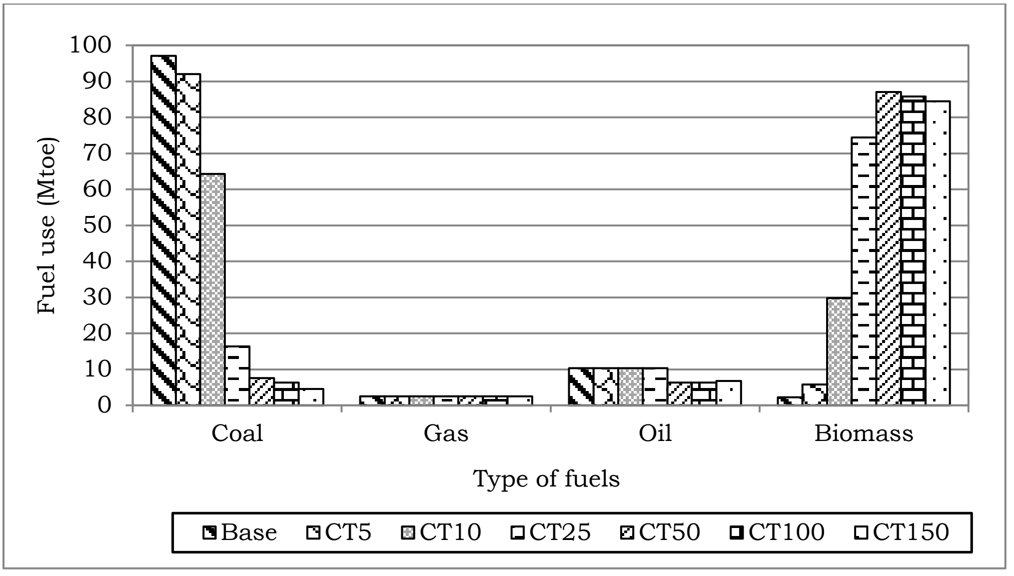

Figure 6.8: Fuel use in the base case and carbon tax cases in 2025.

Generation capacity utilization

Figure 6.9 presents the weighted average capacity factor (WACF) of the power system during 2006-2025 at different values of carbon tax. The figure shows that the capacity factor would decrease with the increase in carbon tax rate (see Section 2.4 in Chapter 2 for explanation on WACF). This is because electricity generation from the existing thermal plants would decrease drastically and that from new plants would increase at higher tax rates. As a result, the WACF of existing plants would decrease drastically.

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[3] However, the reduction in the shares of coal and gas in the national primary energy mix is not in line with the goals of National Energy Policy of Indonesia (Presidential Regulation No. 5/2006), which has envisaged that gas and coal would account for more than 30% and 33%, respectively of the total energy use by 2025.

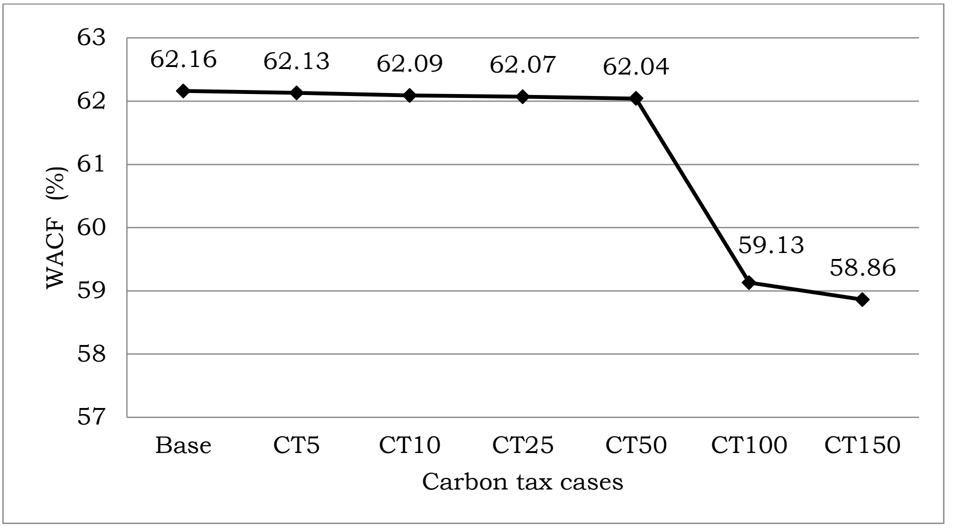

Figure 6.9: Weighted average capacity factor (WACF) in the base case and carbon tax cases.

Generation system efficiency

Figure 6.10 shows the weighted average thermal generation efficiency (WATGE) at the base case and carbon tax cases (see, section 2.3 in Chapter 2 for more details on WATGE). The figure shows that the overall generation system efficiency would be mostly decreasing during 2006-2025. It also shows that the efficiency does not necessarily increase with the carbon tax rate. The overall generation system efficiency during 2006-2025 in the base case would be 38.6%, while it would be 38.7%, 39.4%, 39.7%, 39.3%, 39.2% and 39.4%, under carbon tax rates of \$5, \$10, \$25, \$50, \$100 and \$150/tC, respectively.

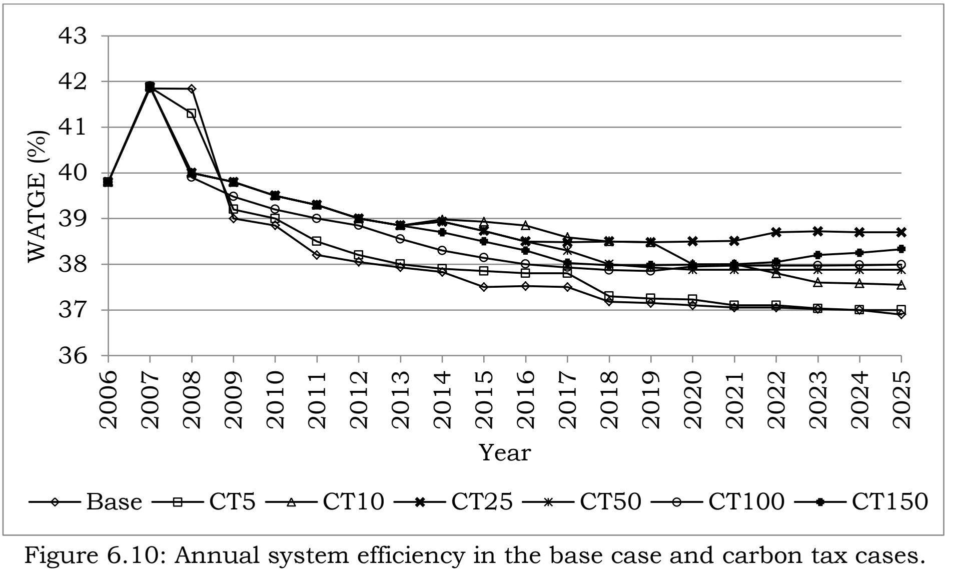

Figure 6.10: Annual system efficiency in the base case and carbon tax cases.

6.3.2. Environmental implications

Carbon tax elasticity of CO_2 emission

Carbon tax elasticities of CO_2 emission are calculated at different carbon tax rates for this purpose. The present study has also calculated the carbon tax elasticity of CO_2 emission at different carbon tax rates and has found the CO_2 emission to be inelastic (see section 2.2 in Chapter 2 for definition on carbon tax elasticity of CO_2 emission): the elasticity would range from -0.02 to -0.68 (see Table 6.8).

Table 6.8: Carbon tax elasticities of CO_2 emission from the power sector at the selected tax rates.

Carbon tax ($ /tC)	Elasticity
0 – 5	-0.02
5 – 10	-0.61
10 – 25	-0.50
25 – 50	-0.35
50 – 100	-0.68
100 – 150	-0.24

Implication on CO_2 emission intensity

Figure 6.11 shows the annual CO_2 emission intensity (i.e., carbon dioxide emissions per unit of energy consumed) at the base case and carbon tax cases.

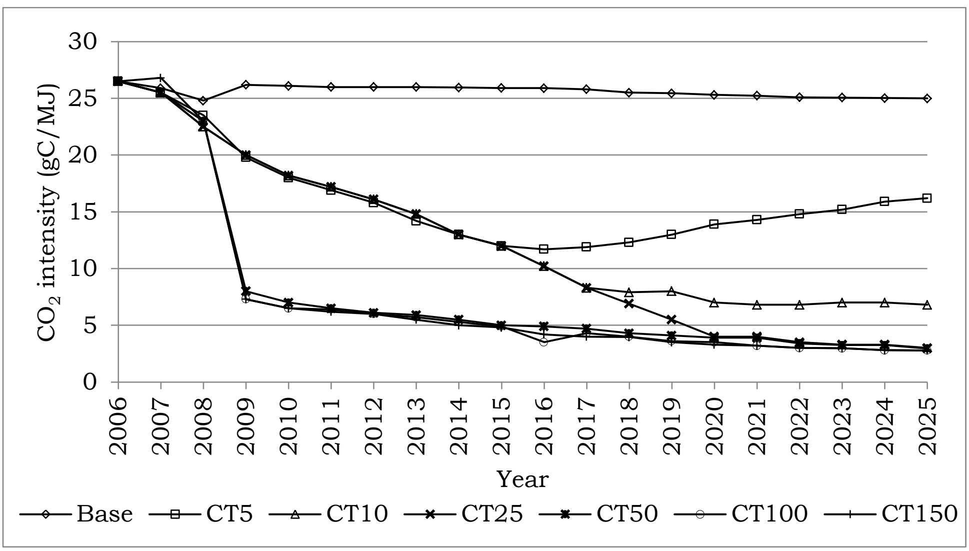

Figure 6.11: Annual CO_2 emission intensity in the base case and carbon tax cases.

Figure 6.11 shows that the CO_2 emission intensity would be decreasing over time in all cases except in the carbon tax case of $5/tC, in which the intensity would show an increasing trend after 2016. This shows that introducing a carbon tax would not necessarily improve the CO_2 emission intensity in the Indonesian power sector.

During 2006-2025, the overall CO_2 emission intensity would decrease from 25.5 gC/MJ at the base case to 5.5 gC/MJ at carbon tax of $50/tC. At carbon tax rates of $50/tC to $150/tC, the CO_2 emission intensity would lie in the range of 5.28 gC/MJ to 5.80 gC/MJ. This is because at carbon tax rates of $50/tC, $100/tC and $150/tC the generation system is heavily dominated by BIGCC, which accounts to 76%, 77% and 79%, respectively of the total electricity generation during 2006-2025. An insight from this analysis is that carbon tax rates above a threshold rate (e.g., $50/tC in the present analysis) would not be effective to improve the carbon intensity of power generation for a given set of electricity generation options.

CO_2 intensity (measured in tons of CO_2 emission per MWh) would decrease from 0.89 tons/MWh in the base case to 0.86 tons/MWh at $5/tC and 0.18 tons/MWh at $150/tC.

Decomposition of CO_2 emission reduction: The role of supply- and demand-side effects

Table 6.9 shows that the CO_2 emission during 2006-2025 is found to decrease from 4,678 million tons at the base case to 4,466 million tons at $5/tC carbon tax rate, a reduction of just about 4.5% of the total CO_2 emission at the base case. However, if carbon tax rate of $150/tC were introduced, the CO_2 emission would be reduced by 81.5% from the base case emission. Note that at the carbon tax rates of $10/tC and above, the CO_2 mitigation would increase significantly compared to that at $5/tC.

Table 6.9 also presents the shares of the supply-side (i.e., technological substitution effect) and demand-side (i.e., price effect) effects in the total CO_2 mitigation due to the various carbon tax rates considered (see Section 2.6 in Chapter 2 for calculation of decomposition of CO_2 emission reduction). The table shows that the supply-side effect plays a predominant role in all tax cases in the case of Indonesia. This is because renewable energy sources (biomass, in particular), are favored by a carbon tax to replace coal-based power generation.

Table 6.9: Contributions of demand and supply-side effects in CO_2 emission reduction due to carbon tax during 2006-2025.

Carbon tax ($ /tC)	CO_2 emission reduction (10^6t)	Demand-side effect (%)	Supply-side effect (%)
5	212	42.5	57.5
10	1,716	2.4	97.6
25	2,766	0.2	99.8
50	3,167	1.2	98.8
100	3,723	1.2	98.8
150	3,812	1.3	98.7

Local/regional pollutant emissions

The SO_2 emission from the power sector would be growing at the CAGR of 10.8% in the base case and 1.43% in the carbon tax case of $25/tC. At carbon tax rates of $50/tC and higher, the SO_2 emission would be almost unchanged or decreasing over time during 2006-2025. In the case of NO_x, its emission from power generation would be growing during the period at the CAGR of 9.8% in the base case and 1.4% in the carbon tax case of $25/tC. At carbon tax rates of $50/tC, the NO_x emission would be either almost constant or decreasing over time.

Table 6.10 shows the cumulative amounts of SO_2 and NO_x emissions during 2006-2025 in the base case and carbon tax cases as well as the levels of the pollutant emissions mitigated under the carbon tax cases. The cumulative SO_2 emission during the period at the carbon tax of $150/tC would be reduced to about 18% of that in the base case. In the case of NO_x, the cumulative emission during 2006-2025 under the carbon tax of $150/tC would be about 25% of the emission in the base case.

Table 6.10: Cumulative SO_2 and NO_x emissions during 2006-2025 under the base case and carbon tax cases (10^3 tons).

Carbon tax ($/tC)	SO_2		NO_x	
	Emission	Emission reduction with the tax	Emission	Emission reduction with the tax
0 (Base case)	22,311	-	19,566	-
5	21,163	1,148	18,568	998
10	12,788	9,523	11,402	8,164
25	7,374	14,937	6,745	12,821
50	6,272	16,039	5,724	13,842
100	4,447	17,864	4,203	15,363
150	4,012	18,299	3,919	15,647

+ A '-' sign means either zero or a negligible quantity.

6.3.3. Economic Implications

Electricity generation system cost

Table 6.11 shows the total undiscounted cost during 2006-2025 at the selected carbon tax rates. The table shows that the total cost would increase by 1.5% at the carbon tax rate of $5/tC and by 19.6% at the tax rate of $150/tC. The total discounted cost would increase in the range of 1.2% to 17.8% with the carbon tax in the range of $5/tC to $150/tC (see Table 6.12). The total cost consists of capacity cost, fixed operation and maintenance (O&M) cost as well as fuel and variable O&M cost. As shown in the table, the fuel and variable O&M cost has the largest contribution in the total cost (i.e., in the range of 61% to 74%), followed by capacity cost (in the range of 17% to

28%) and fixed O&M cost (in the range of 8% to 12%) in the cases considered.

Table 6.11: Contribution of capacity, fixed O&M and fuel and variable O&M costs to the total undiscounted cost in the base case and selected carbon tax cases during 2006-2025.

Cases	Capacity cost		Fixed O&M cost		Fuel and variable O&M cost		Total cost
	(10^6 $)	(%)*	(10^6 $)	(%)*	(10^6 $)	(%)*	(10^6 $)
0 (Base case)	30,261	17.58	14,667	8.52	127,157	73.89	172,085
5	31,071	17.78	15,023	8.60	128,645	73.62	174,738
10	39,266	22.19	18,130	10.25	119,542	67.56	176,937
25	43,259	23.86	19,489	10.75	118,554	65.39	181,302
50	44,992	24.00	19,913	10.62	122,585	65.38	187,490
100	54,368	27.52	22,600	11.44	120,620	61.05	197,588
150	53,187	25.84	22,275	10.82	130,359	63.34	205,821

(*) These numbers show the cost as the percentage of the total cost.

Table 6.12: Contribution of capacity, fixed O&M and fuel and variable O&M costs to the total discounted cost in the base case and selected carbon tax cases during 2006-2025.

Carbon tax ($/tC)	Capacity cost		Fixed O&M cost		Fuel and variable O&M cost		Total cost
	(10^6 $)	(%)*	(10^6 $)	(%)*	(10^6 $)	(%)*	(10^6 $)
0 (Base case)	8,767	19.2	4,067	8.9	32,882	71.9	45,716
5	11,251	24.3	4,997	10.8	30,013	64.9	46,261
10	11,875	25.5	5,218	11.2	29,553	63.4	46,646
25	12,421	26.1	5,361	11.3	29,889	62.7	47,671
50	12,551	25.5	5,390	10.9	31,348	63.6	49,289
100	14,701	28.4	6,007	11.6	30,988	59.9	51,696
150	14,400	26.7	5,925	11.0	33,547	62.3	53,872

(*) These numbers show the cost as the percentage of the total cost.

Carbon tax revenue

Table 6.13 shows the carbon tax revenue at different tax rates. The tax revenue would increase from $4,027 million at $5/tC to $33,070 million at $150/tC. The tax revenue would be 2% of the total cost at the carbon tax rate of $5/tC and the corresponding figure would be 16% at the tax rate of $150/tC.

Table 6.13: Carbon tax revenue (undiscounted) at carbon tax cases during 2006-2025.

Carbon tax ($/tC)	Carbon tax revenue	
	(10^6 $)	(%)*
5	4,027	2.3
10	5,382	3.0
25	10,333	5.7
50	18,501	9.9
100	24,194	12.2
150	33,070	16.1

(*) These numbers show the tax revenue as the percentage of the total cost

Unit cost of electricity generation

Figure 6.12 presents the $AIC_{overall}$ and LRAC at the carbon tax rates considered (see Section 2.5 in Chapter 2 for calculation of $AIC_{overall}$). The figure shows that the LRAC would increase from ¢3.5/kWh at the base case to ¢3.9/kWh at the carbon tax of $150/tC, whereas the $AIC_{overall}$ would increase from ¢4.1/kWh in the base case to ¢5.3/kWh at the carbon tax of $150/tC.

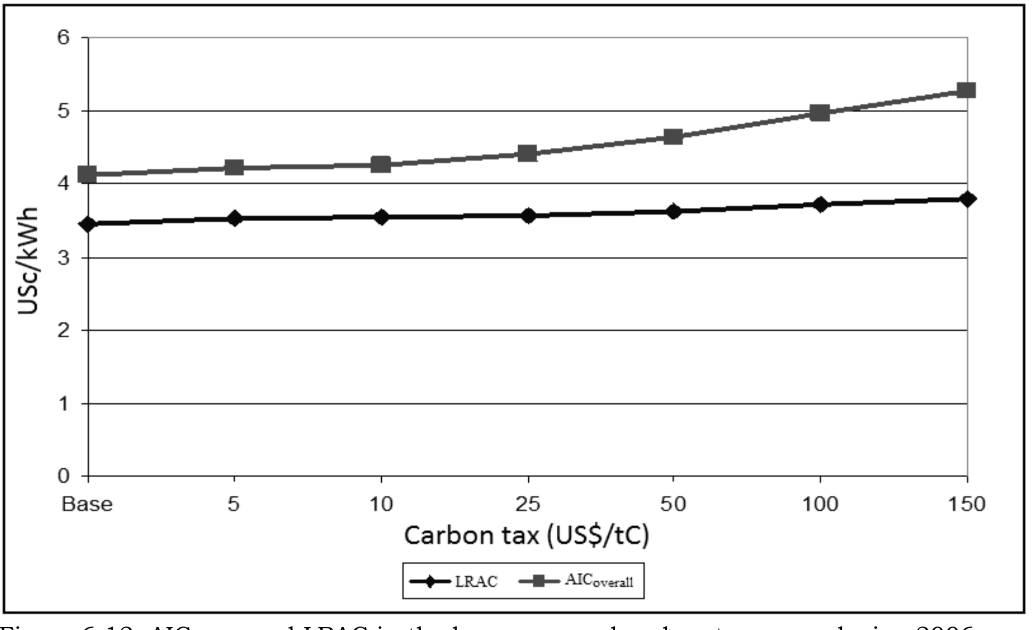

Figure 6.12: $AIC_{overall}$ and LRAC in the base case and carbon tax cases during 2006-2025.

6.4. Effects of Energy Tax

In this section, the effects of energy tax on power generation capacity requirements, generation capacity mix by technology type, electricity generation mix by technology or fuel type, emissions of CO_2, SO_2 and NO_x, efficiency of thermal power generation system and CO_2 intensity are discussed. Also discussed are the effects of the tax on generation system costs and per unit cost of electricity generation.

6.4.1. Utility planning implications

Generation technology capacity mix

Table 6.14 shows additional generation capacity by power plant type during 2006-2025 under the energy tax rates considered. Note that cleaner coal technologies (CCTs) such as IGCC, PFBC and SC, despite being more efficient than the conventional coal- fired plants, would not be cost-effective during 2006-2025 because of their higher capacity costs. At energy tax rates lower than $5/MBtu, energy efficient technologies (EETs), such as CCGT, are found to be less cost-effective. As such, at these tax rates, a smaller capacity of CCGT plants would be cost-effective during 2006-2025 than that in the base case. However, at the energy tax rate of $5/tC, the CCGT plants would become much more attractive and about 42,600 MW of CCGT capacity would be added during 2006-2025. Non-dispatchable RETs such as wind power plants would become more cost-effective with the increase in energy tax rates, whereas solar power plants would still be too expensive. Other RETs such as BIGCC would become less cost-effective with the increase in energy tax rate. For example, as can be seen from Table 6.14, BIGCC would not be attractive anymore at the energy tax rate of $5/MBtu. Although geothermal energy is not affected by the energy tax, geothermal power plants would not be cost-effective during 2006-2025 primarily due to their high capacity cost.

By 2025, the total installed capacity at the energy tax rates of $0.5, $1.0, $2.0 and $5.0/MBtu would be 83,362 MW, 80,789 MW, 76,553 MW and 68,456 MW, respectively; i.e., the total installed capacity would be lower by about 4%, 8%, 15% and 30% respectively than that in the base case.

Figure 6.13 shows the installed generation capacity based on fuel use at the base case and energy tax cases in the year 2025. The installed capacity of conventional coal-fired power plant in year 2025 would decrease with the energy tax. Conventional coal-fired power plants would account for about 57% of the total installed capacity in the year 2025 at energy tax rates of $2.0/MBtu and less whereas in the base case (2006-2025), its share is higher (i.e., 63%). However, at the tax rate of $5.0/MBtu, their share would decrease drastically to 14%. The share of gas-based power plants would be decreasing with increase in the energy tax rate from $0.5/MBtu up to $2.0/MBtu, i.e., it would decrease from 27% in the base case to 25.5% at the tax rate of $0.5/MBtu to 22.5% at the energy tax rate of $2.0/MBtu. At the tax rate of $5/MBtu, the share of gas-based power plants would increase significantly to 48.7%. The share of oil-based power plants would be the same at all tax rates. This is because no oil-based candidate power plant has been considered in the study following the government policy. The share of BIGCC would decrease with the increase in the energy tax rates; however, its share is below 1% in all cases except with the tax rate of $5/MBtu, in which no BIGCC capacity would be installed. The share of wind power plant would increase with the introduction of the energy tax (i.e., from 0.95% in the base case to 2.2% at the tax rate of $5/MBtu). The share of geothermal capacity would be almost the same (i.e., around 2%) in all cases, while the share of hydropower capacity would be around 3% in all cases.

Table 6.14: Capacity addition, by plant types, over the planning period (2006-2025) at selected energy tax rates (MW).

Power plant technology	Base	Energy tax ($/MBtu)			
		0.5	1	2	5
Conv. coal	39,600	38,000	36,400	34,000	-
IGCC	-	-	-	-	-
PFBC	-	-	-	-	-
SC	-	-	-	-	-
CCGT	19,800	18,600	18,600	16,800	42,600
GTPP	1,400	1,000	-	-	200
Geothermal	-	-	-	-	-
BIGCC	825	525	450	225	-
Hydro	55	-	-	-	55
Pumped storage	1,000	1,000	1,000	1,000	1,000
Wind	255	1,136	1,238	1,427	1,500
Solar	-	-	-	-	-
Total	62,935	60,261	57,688	53,452	45,355

+ A '-' sign means either zero or a negligible quantity.

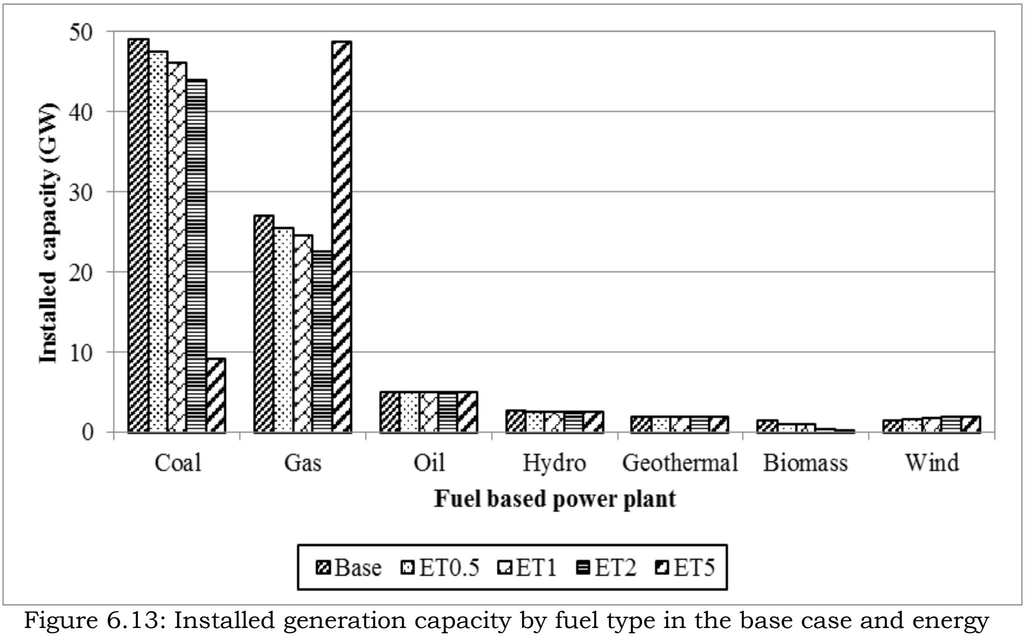

Figure 6.13: Installed generation capacity by fuel type in the base case and energy tax cases by 2025.

Electricity generation mix

Figure 6.14 shows the annual electricity generation at the base case and energy tax cases during 2006-2025. The total electricity generation during 2006-2025 at energy tax rates of $0.5, $1, $2 and $5/MBtu would be about 5,059 TWh, 4,901 TWh, 4,640 TWh and 4,133 TWh, respectively (i.e., about 0.97, 0.94, 0.89 and 0.79 times of that at the base case, respectively).

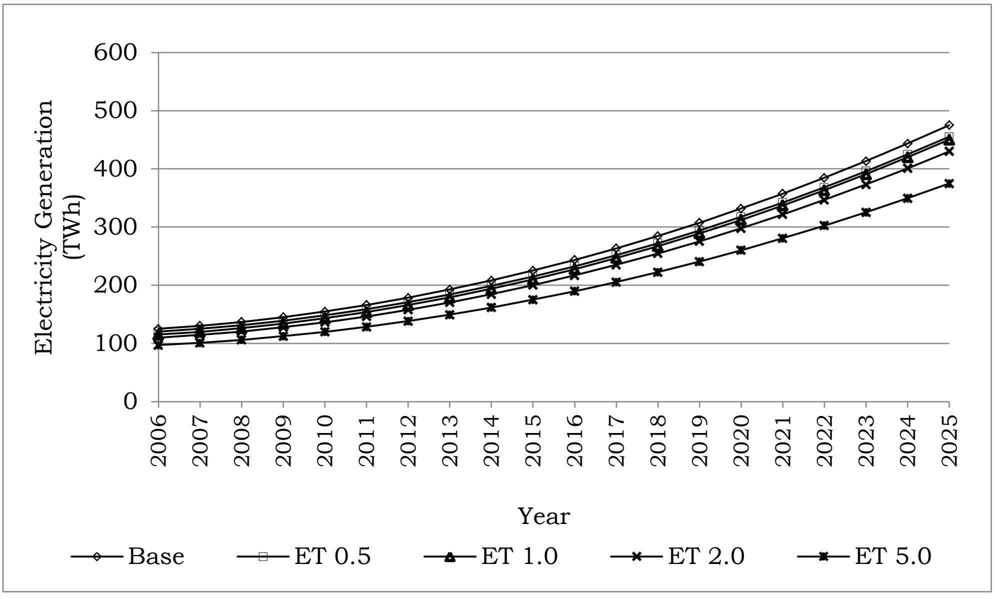

Figure 6.14: Annual electricity generation in the base case and energy tax cases during 2006-2025.

Figure 6.15 shows the electricity generation by fuel type in the base case and energy tax cases in the year 2025. The electricity generation in the base case in 2025 would be 478 TWh whereas the corresponding figures with the energy tax rates of $0.5, $1, $2 and $5/MBtu would be about 461 TWh, 447 TWh, 423 TWh and 377 TWh, respectively. The share of fossil fuel- based electricity generation would be almost the same in all cases (i.e., coal, gas and oil would be about 81%, 13% and 2%, respectively) except at the energy tax of $5/MBtu. In the energy tax case of $5/MBtu, the shares of coal- and gas-based generation would be about 16% and 77%, respectively, whereas oil-based generation share would remain the same as in other cases. The shares of BIGCC would increase with the increase in energy tax, whereas the share of wind power would decrease. The shares of both these RETs would be less than 1% in 2025. The shares of hydropower and geothermal in electricity generation would be around 2% and 1%, respectively in all the cases.

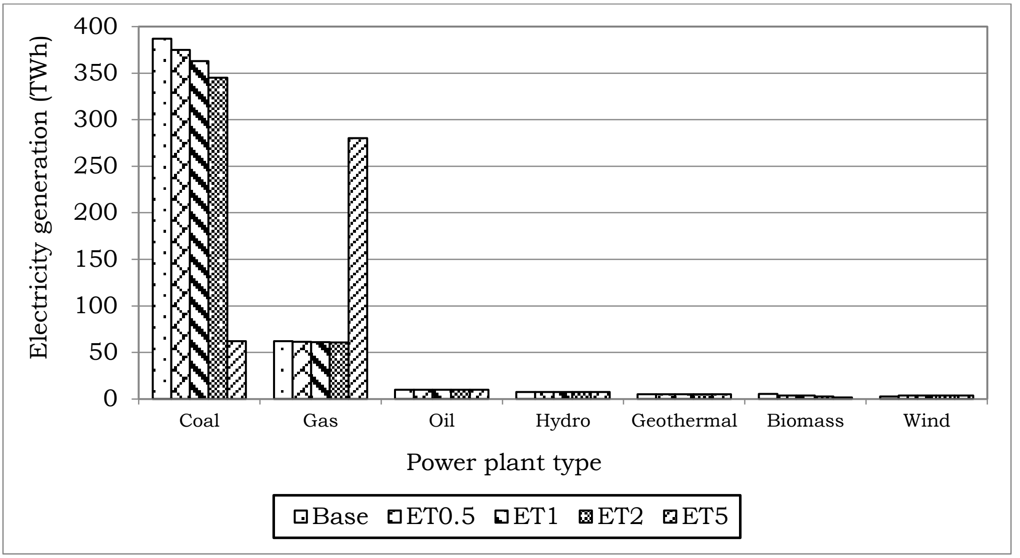

Figure 6.15: Electricity generation by fuel type in the base case and energy tax cases in year 2025.

Fossil fuel consumption for power generation

Figure 6.16 shows the annual total fuel consumption for electricity generation in the base case and energy tax cases. The CAGR of total fuel use at energy tax rates $2/MBtu and lower is estimated to be 8%, while it would be 6.3% at $5/MBtu. The cumulative fuel use during 2006-2025 in the base case would be 1,195 Mtoe, while with the energy tax rates of $0.5, $1, $2 and $5/MBtu, it would be about 1,148 Mtoe, 1,108 Mtoe, 1,041 Mtoe and 758 Mtoe, respectively.

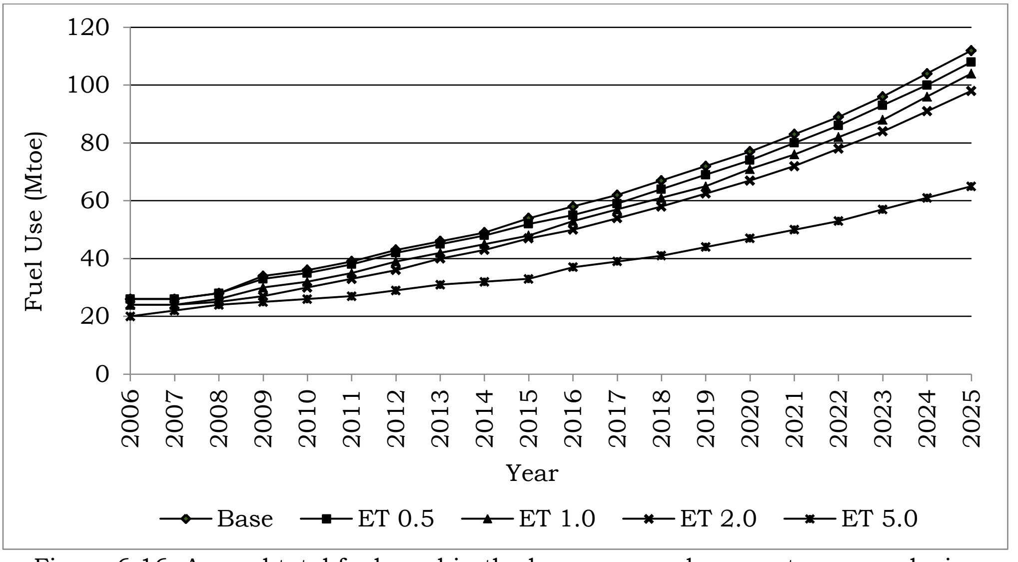

Figure 6.16: Annual total fuel used in the base case and energy tax cases during 2006-2025.

Figure 6.17 shows the different fuel use in year 2025. The total fuel use in 2025 at the base case would be 111 Mtoe, while at energy tax rates of $0.5, $1, $2 and $5/MBtu, it would be about 107 Mtoe, 103 Mtoe, 98 Mtoe and 65 Mtoe, respectively. The shares of coal use in 2025 at energy tax rates of $2/MBtu and lower would be about 87%, and it would decrease to 22% at the energy tax rate of $5/MBtu. The share of gas would be around 9% at energy tax rate of $2/MBtu and lower, and it would increase to 22% at energy tax rate of $5/MBtu. The share of oil use would be around 2% in all tax cases, while that of biomass would be below 1% in all energy tax cases.

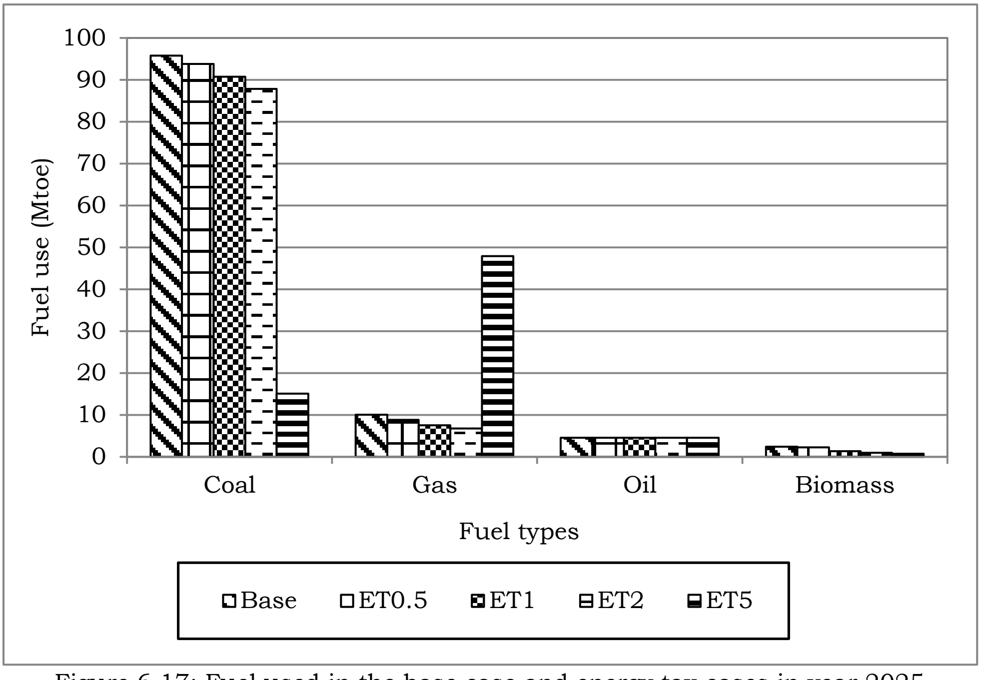

Figure 6.17: Fuel used in the base case and energy tax cases in year 2025.

Generation system efficiency

Figure 6.18 shows the WATGE at the base case and energy tax cases. The WATGE at energy tax of $2/MBtu and lower would be almost the same as that in the base case (the efficiencies lying in the range of 38.6% and 39.2%). The picture would be much different with the energy tax of $5/MBtu: there would be a significant improvement in the generation system efficiency at that tax rate. This is because more EETs such as CCGT would be installed during 2006-2025 to replace the conventional coal-fired power plant.

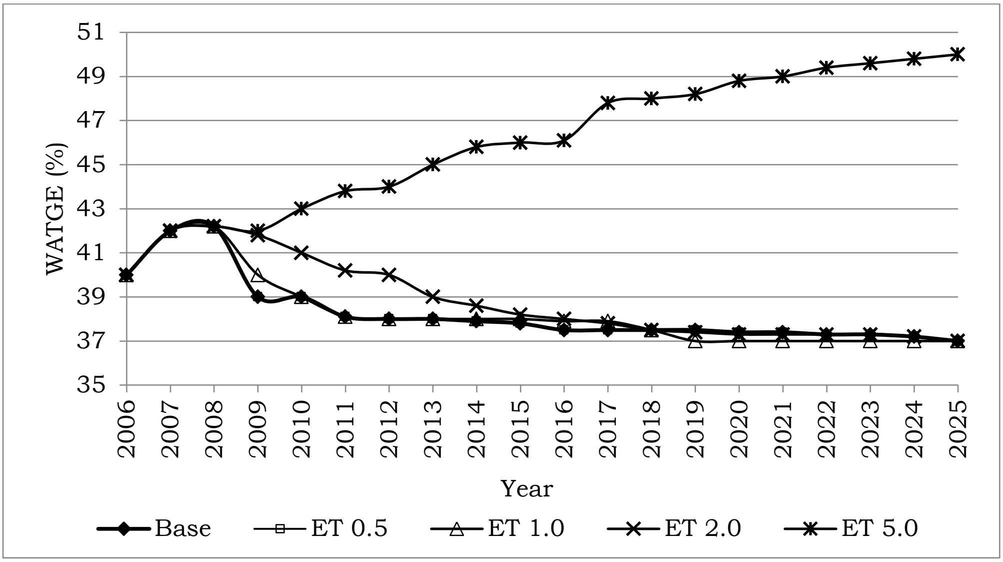

Figure 6.18: Weighted average thermal generation efficiency (WATGE) in the base case and energy tax cases.

6.4.2. Environmental implications

Energy tax elasticity of CO_2 emission Figure 6.19 shows the annual CO_2 emissions at the base case and energy tax cases. The figure shows a significantly lower annual growth of CO_2 emissions at the energy tax rate of \$5/MBtu compared to the lower tax rates considered in the study. The CAGR of CO_2 emission at energy tax rates of \$2/MBtu or lower would be in the range of 7.5% to 7.8%, whereas it would be 4.0% at the tax rate of \$5/MBtu. This low growth in the \$5/MBtu case is due to the use of a large share of CCGT-based electricity generation in the system.

How would the CO_2 emission change with the change in the energy tax? This is assessed by calculating the energy tax elasticity of CO_2 emission. The CO_2 emission from the power sector is found to be energy tax inelastic (see Table 6.15).

Table 6.15: Energy tax elasticities of CO_2 emission from the power sector at the selected tax rates.

Energy tax ($/MBtu)	Elasticity
0 – 0.5	-0.01
0.5 – 1	-0.04
1 – 2	-0.07
2 – 5	-0.5

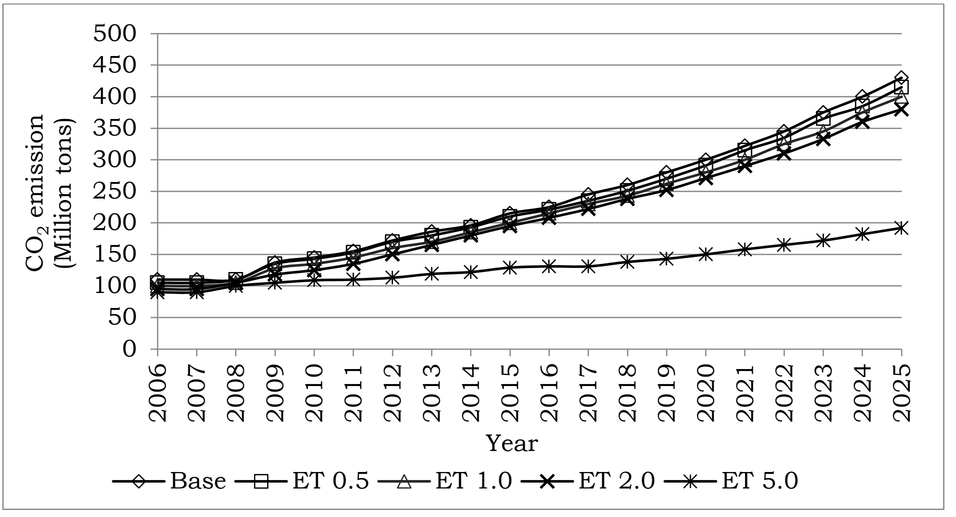

Figure 6.19: Annual CO_2 emission in the base case and energy tax cases during 2006-2025.

Implication on CO_2 emission intensity

Figure 6.20 shows the annual CO_2 intensity at the base case and energy tax cases during 2006-2025. As can be seen the overall CO_2 intensity would increase with the energy tax in the range of \$0.5 to \$2/MBtu throughout the period; however, it would be mostly declining over time in all cases. In the case of the energy tax of \$5/MBtu, the intensity would be significantly lower than that in the case of lower tax rates during the period except in the initial few years. This is because of the significantly large share of energy efficient and less carbon intensive (gas based) power generation based on CCGT at that tax rate. CO_2 intensity (measured in tons of CO_2 emission per MWh) would increase from 0.89 tons/MWh in the base case to 0.90 tons/MWh at \$1/MBtu and then decrease to 0.64 tons/MWh at \$5/MBtu.

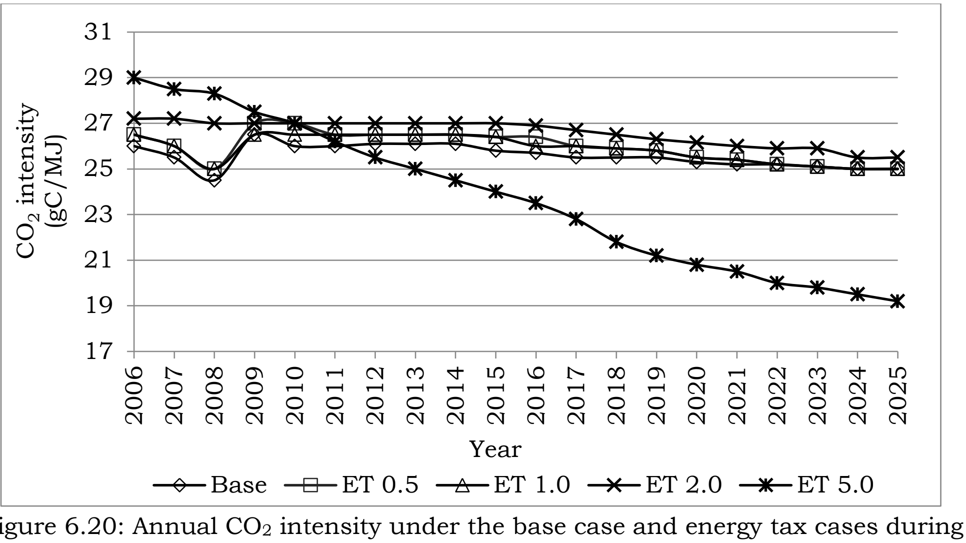

Figure 6.20: Annual CO_2 intensity under the base case and energy tax cases during 2006-2025.

Decomposition of CO_2 emission reduction: The role of supply- and demand-side effects

Table 6.16 presents the total CO_2 emission reduction at various energy tax rates and the contributions of the supply-side and demand-side effects to the total emission reduction. The table shows that in the cases of energy tax rates of \$0.5, \$1 and \$2, the demand-side effect is predominant in CO_2 emission mitigation, while the opposite is the case with the energy tax rate of \$5/MBtu.

Table 6.16: Decomposition of cumulative CO_2 emission reduction during 2006-2025 at selected energy tax rates.

Energy tax (\$/MBtu)	CO_2 emission reduction (10^6t)	Demand-side effect (%)	Supply-side effect (%)
0.5	130	97.7	2.3
1	261	96.6	3.4
2	522	94.6	5.4
5	2,052	20.1	79.9

Local/regional pollutant emissions

Introducing energy tax would also affect the SO_2 and NO_x emissions. Figures 6.21 and 6.22 show the annual SO_2 and NO_x emissions respectively in the base case and energy tax cases. At the energy tax rates of \$0.5, \$1, \$2 and \$5/MBtu, the SO_2 emission would grow at the CAGR of 10.5%, 10.1%, 9.7% and -0.2%, respectively during 2006-2025, the while the NO_x emission would grow at the CAGR of 9.8%, 9.5%, 9.3% and 2.6%, respectively. There is a significant difference in terms of the growth in SO_2 and NO_x emissions in the case of the energy tax rate of \$5/MBtu, i.e., the SO_2 emission would be slightly declining over time at that tax rate (due to increasing use of CCGT for power generation), whereas the NO_x emission would still have a positive, although low, CAGR.

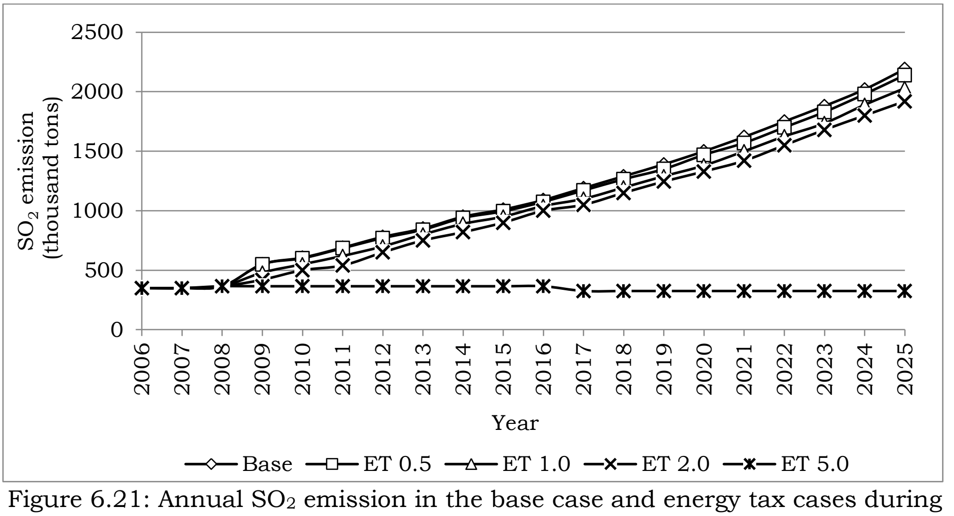

Figure 6.21: Annual SO_2 emission in the base case and energy tax cases during 2006-2025.

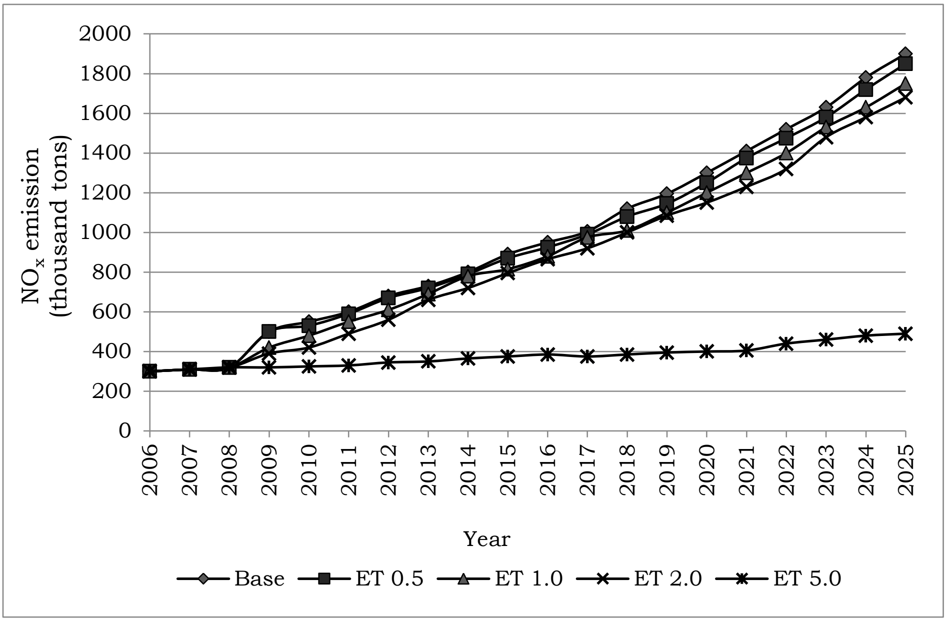

Figure 6.22: Annual NO_x emission in the base case and energy tax cases during 2006-2025.

As shown in Table 6.17, the cumulative SO_2 emission during 2006-2025 would decrease from 22,311 thousand tons in the base case to 6,686 thousand tons at the energy tax of $5/MBtu, while the NO_x emission would decrease from 19,566 thousand tons in the base case to 7,508 thousand tons at the energy tax of $5/MBtu.

Table 6.17: Cumulative emissions and mitigations of SO_2 and NO_x during 2006-2025 in the base case and at selected energy tax rates.

Energy tax ($/MBtu)	SO_2 (10^3 tons)		NO_x (10^3 tons)	
	Emission	Mitigation+	Emission	Mitigation+
0	22,311	-	19,566	-
0.5	21,644	667	18,964	602
1.0	20,974	1,337	18,367	1,199
2.0	19,731	2,580	17,317	2,249
5.0	6,686	15,625	7,508	12,058

+ A '-' sign means either zero or a negligible quantity.

6.4.3. Economic Implications

Total generation system cost

Table 6.18 shows the undiscounted costs of the generation system during 2006-2025 at the base case and energy tax cases, and Table 6.19 presents the discounted costs during the period. The total undiscounted cost during the period would be 5.9%, 12.1%, 24.4% and 55.8% higher than that in the base case with the energy tax rates of \$0.5, \$1, \$2 and \$5/MBtu, respectively (see Table 6.18). In the case of total discounted cost (see table 6.18), the cost would increase by 5.7% with the energy tax of \$0.5/MBtu; the corresponding figure in the case of \$5/MBtu would be 54.9%. It should be noted here that the total cost includes the energy tax payment besides the capacity-, fixed O&M- as well as fuel and variable O&M- costs. The fuel and variable O&M cost is estimated to have the highest share in the total cost (i.e., in the range of 71% to 93%); it is followed by the capacity cost (i.e., in the range of 4% to 20%) and fixed O&M cost (i.e., in the range of 3% to 9%) (see Table 6.18 with the total undiscounted cost). Note that the capacity and fixed O&M costs would decrease with the increase in energy tax rate according to Table 6.18. This is because the electricity demand and hence the generation capacity requirement would decrease with an increase in the energy tax rate. At the energy tax rate of \$5/MBtu, the capacity and fixed O&M costs are estimated to be about 68% and 31% less, respectively than the corresponding costs in the base case. Unlike the capacity cost and fixed O&M cost, the fuel and variable O&M cost would increase with the increase in the energy tax. The fuel and variable O&M cost at \$5/MBtu energy tax rate would be about nearly double of that in the base case. The total cost (inclusive of the tax payment) at the energy tax rate of \$5/MBtu would be about 60% higher than that in the base case.

Table 6.18: Contribution of capacity, fixed O&M and fuel and variable O&M costs to the total undiscounted cost in the base case and energy tax cases.

Energy tax (\$/MBtu)	Capacity cost		Fixed O&M cost		Fuel and variable O&M cost		Total cost (10^6 \$)
	(10^6 \$)	(%)*	(10^6 \$)	(%)*	(10^6 \$)	(%)*	
0	30,261	17.58	14,667	8.52	127,157	73.89	172,085
0.5	28,001	15.28	14,095	7.69	141,177	77.03	183,273
1	25,969	13.39	13,600	7.01	154,337	79.59	193,906
2	22,441	10.43	12,790	5.94	179,996	83.63	215,226
5	10,776	4.00	10,674	3.96	248,213	92.05	269,662

Table 6.19: Contribution of capacity, fixed O&M and fuel and variable O&M costs to the total discounted cost in the base case and energy tax cases.

Energy tax (US\$/MBtu)	Capacity cost		Fixed O&M cost		Fuel and variable O&M cost		Total cost (10^6 US\$)
	(10^6 US\$)	(%)*	(10^6 US\$)	(%)*	(10^6 US\$)	(%)*	
Base	8,767	19.18	4,067	8.90	32,882	71.93	45,716
0.5	8,044	16.64	3,884	8.04	36,403	75.32	48,331
1	8,449	16.58	4,217	8.27	38,298	75.15	50,964
2	7,818	13.93	4,102	7.31	44,212	78.76	56,132
5	6,495	9.17	3,734	5.27	60,619	85.56	70,848

* These numbers show the cost as percentage of the total cost.

Energy tax revenue

Table 6.20 presents the tax revenue that would result from the introduction of the energy tax in the power sector in Indonesia during 2006-2025. The tax revenue would be 9% of the total cost at the energy tax rate of $0.5/MBtu and it would increase to 46% when the energy tax rate is increased to $5/MBtu. The table shows that at price elasticity of -0.35 as has been considered in this analysis, the tax revenue would increase from $17,187 million, at the energy tax rate of $0.5/MBtu, to $123,644 million at the tax rate of $5/MBtu.

Table 6.20: Energy tax revenue (undiscounted) at the selected energy tax rates during 2006-2025.

Energy tax ($/MBtu)	Tax revenue	
	(10^6 $)	(%)*
0.5	17,187	9.38
1	33,199	17.12
2	62,437	29.01
5	123,644	45.85

* These numbers show the tax revenue as percentage of the total cost.

Unit cost of electricity generation

Figure 6.23 presents the LRAC and $AIC_{overall}$ in the base case and energy tax cases. The figure shows that the LRAC would increase from ¢3.5/kWh in the base case to ¢7.0/kWh with the energy tax of $5/MBtu. The $AIC_{overall}$ would increase from ¢4.1/kWh in the base case to ¢8.2/MBtu with an energy tax of $5/MBtu.

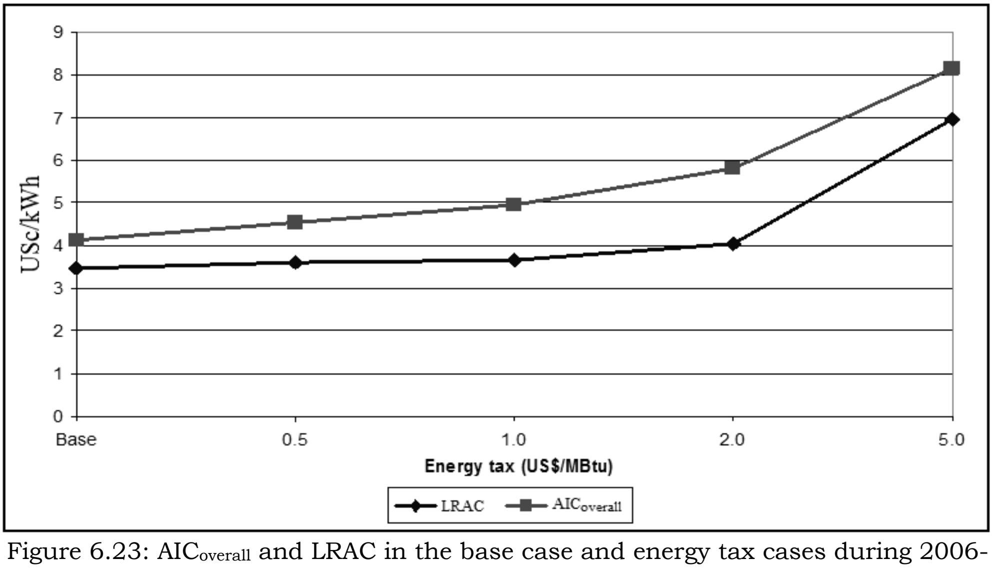

Figure 6.23: $AIC_{overall}$ and LRAC in the base case and energy tax cases during 2006-2025.

6.5. Summary

The power generation capacity in Indonesia would be dominated by conventional coal-fired power plants in the base case, for carbon tax rates of \$5 and \$10/tC along with energy tax rates of \$0.5, \$1 and \$2/MBtu. Gas-based power plants, i.e., CCGT plants would also be cost-effective to install in Indonesia in the base case and carbon tax cases although their capacity woud not be as large as the capacity of the conventional coal-fired plants. RETs, such as BIGCC, hydro, pumped storage and wind would also be cost-effective in the Indonesian power sector during the base case although the share will be relatively small compared to the plant technologies mentioned above (i.e., CCGT).

If carbon tax is introduced in the Indonesian power sector, the role of BIGCC plants would be increasing in the generation capacity as well as electricity generation. Conventional coal-fired power plants would be attractive at the carbon tax rates \$5 and \$10/tC; they would not be cost-effective at the tax rates of \$50/tC and higher.

Unlike in the carbon tax cases, BIGCC would not be cost-effective under the energy tax rates considered and would be replaced by CCGT. Conventional coal-fired power plants would be cost-effective only up to the energy tax rate of \$2/MBtu. Wind power would be increasingly attractive with increase in the energy tax rates.

The study shows that there would not be a significant gain in terms of CO_2 emission reduction with the increase in carbon tax beyond \$100/tC. There would be a reduction of CO_2 emissions in the range of 4.5% to 81.5% with an increase in the carbon tax rate from \$5 to \$150/tC. Similarly, the reduction in CO_2 emission would be in the range of 2.8% to 43.9% with introduction of increasing energy tax rates from \$0.5 to \$5/MBtu. The CO_2 emission is found to be inelastic with respect to the carbon tax as well as the energy tax. The carbon tax elasticity of CO_2 emission is found to vary significantly (i.e., from -0.02 to -0.68) at different tax rates considered in the study although no consistent pattern in the change of the elasticity was observed with the increase in the tax rate. The energy tax elasticity of CO_2 emission is found to vary in the range of -0.04 to -0.54 at the energy tax rates considered.

Electricity generation would decrease from 5,235 TWh in the base case to 5,191 TWh at the carbon tax of \$5/tC due to an increase in electricity price and a resulting decrease in demand associated with the carbon price. If the carbon tax rate is increased to \$150/tC, the electricity generation would decrease to 4,777 TWh. In the case of introducing an energy tax, the electricity generation would decrease to 5,059 TWh with the energy tax rate of \$0.5/MBtu and it would decrease to 4,133 TWh with the energy tax of \$5/MBtu.

The present analysis shows that the overall efficiency of the thermal power generation system would increase from 38.6% in the base case to 38.7% in the carbon tax case of \$5/tC, and to 39.4% in the carbon tax case of \$150/tC. The analysis also shows that introducing a carbon tax would not necessarily improve the overall electricity generation system efficiency. In the present case, the overall efficiency of the thermal generation system during 2006-2025 at the carbon tax rate of $25/tC would be higher than that at the higher tax rates considered in the study. In the case of the energy tax, the overall efficiency is found to increase with the energy tax rate. The overall generation efficiency of the Indonesian power sector would increase in the range of 38.8% to 48.0% with the energy tax rates in the range of $0.5/MBtu to $5/MBtu.

The study also shows that the CO_2 intensity of electricity generation would decrease with the introduction of carbon tax, however, the same would not necessarily happen in the case of energy tax. The CO_2 intensity would decrease from 25.5 gC/MJ in the base case to 15.2 gC/MJ in the carbon tax rate of $5/tC; it would further decline to 5.2 gC/MJ at the tax rate of $150/tC. In the case of energy tax, the CO_2 intensity would increase to 26.4 gC/MJ in the energy tax rate of $2/MBtu when compared to the base case. However, in the energy tax case of $5/MBtu, the CO_2 intensity would decrease to 22.6 gC/MJ. Although the primary purpose of energy tax is energy efficiency improvement, it is found that it could also reduce the CO_2 emission as well.

Results also show that in the base case, the total cost (in undiscounted value) is $172,085 million. The total cost (in undiscounted value) would increase in the range of $174,738 million to $183,273 million if carbon tax rates in the range of $5/tC to $150/tC were introduced. In the case of energy tax, the total cost would increase in the range of $183,273 million to $269,662 million if energy tax rates of $0.5/MBtu to $5/MBtu were introduced.

There would be a significant increase in the SO_2 and NO_x reductions with introduction of both the carbon and energy taxes. The reduction of SO_2 would be in the range of 5% to 82% and reduction in NO_x would be in the range of 5% to 80% with introduction of carbon tax in the range of $5/tC to $150/tC. In the same way, the reduction of SO_2 would be in the range of 3% to 70% and reduction of NO_x would be in the range of 3% to 62% with the introduction of energy tax in the range of $0.5/MBtu to $5/MBtu.

With the introduction of carbon tax, the $AIC_{overall}$ would increase from ¢4.1/kWh in the base case to ¢5.7/kWh with the carbon tax rate of $150/tC. With the energy tax, to the $AIC_{overall}$ would be ¢4.6/kWh at $0.5/MBtu and ¢8.2/kWh at $5/MBtu. The carbon tax elasticities of CO2 emission would lie in the range of 0.012 to 0.153 at the tax rates considered in this study. Similarly, the energy tax elasticities of CO_2 emission would lie in the range of 0.056, to 0.458 for the range of energy tax considered.

Post-script

Since this study was carried out in 2004-2005, some differences between the actual data on the power sector development and the corresponding estimated values in the study can be anticipated. Factors behind the differences could include the differences between the projected values of power demand available at the time the present study was carried out and the actual growth in demand since then. In addition, the differences could also reflect the differences in the values of plant capacity costs, fuel prices and efficiency of candidate power plants considered in the study and their actual values. The various national policy measures related to the promotion of renewable energy options and energy efficient technologies, which were implemented in Indonesia after the study was conducted, are another important factor behind the differences between the results of the study and actual power sector development in the country. In this section, an attempt is made to describe briefly some of these factors in the case of Indonesia.

The study has considered a higher CAGR of the peak demand (i.e., 6.9%) as compared to the actual growth rate of the peak load during 2002-2013 (i.e., at the CAGR of 5.4% during 2002-2013). However, this study had considered a lower growth in the total installed capacity (i.e., a CAGR of 7.4% between 2006 and 2015) when compared to the actual growth of the installed capacity (i.e., 8.2%) during 2006-2013 (MoEMR, 2014).

The MoEMR (2014) in Indonesia has stated that the share of fossil fuel in the actual power generation decreased from 90% to 85% during 2006-2013. The estimated shares of fossil fuels in this study are higher than the actual shares (i.e., 80% in 2006 to 87% in 2013) and range from 89% to 92% between 2006 and 2015 (see Table 6.6). This study has found that with the introduction of carbon tax of $150/tC, the consumption of coal and oil would be reduced by 81.9% and 2.3%, respectively compared to the base case consumption levels. The high reduction in coal consumption at this tax rate could be due to the fact that carbon capture and storage (CCS) technology has not been considered in thermal power plants in this study.

According to the MoEMR (2014), there has been an actual decline in the share of hydropower plants in the capacity mix (i.e., from 13% in 2006 to 10% in 2013), whereas the estimated share of hydropower in this study is only in the range of 3-5% between 2006 and 2015. The installation of hydropower capacity, however, has been increasing at a CAGR of 4.5% between 2006 and 2013. Introduction of the Feed-in Tariff scheme in 2012, when the Ministry of Energy and Mineral Regulation decided to purchase excess power generated from small and medium scale renewable generation has encouraged installation of hydropower and other renewables in Indonesia.

Renewable resources (such as, geothermal, biomass, solar, wind) are envisaged to play an increasingly more important role in Indonesia in the future and these resources are expected to have a share of 23% of the total energy mix by 2025 (IEA, 2015). In addition to energy diversification, energy efficiency improvement is also a part of the national policy according to the Presidential Decree No. 43/1991.

There are several technology options towards low carbon green growth in Indonesia. However, the adoption of these technologies to mitigate CO_2 emission would not take place without policy interventions from the government. To facilitate this, the Ministry of Finance passed a regulation concerning the “Provision of Exemption Facilities or Reduction of Income Tax (2011) and “Tax and Custom Facilities for Renewable Energy Utilization (2010)” to promote the purchase of renewable energy technologies (MoEMR, 2012). Further, the government of Indonesia has enacted the National Energy Policy (2014) and passed regulations on “Energy Conservation” in 2009. These energy policies were not introduced at the time the present study was carried out. These developments should help a reader to understand the differences between the estimated renewable energy generation in this study and the corresponding actual figures since the study was carried out.

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7. Power Sector Development in Sri Lanka: Effects of Carbon and Energy Taxes[1]

7.1. Introduction

The Sri Lankan electricity generation sector has been dominated by hydroelectricity for many years. The country has an estimated total hydroelectric potential of 2,000 MW (Wijayatunga, 2005). In 2010, the contribution of hydropower to the total was 46.2% (4,989 GWh), while in 2012 the share decreased to 23% (2,727 GWh). The share of hydro again increased to 29% (3,650 GWh) in 2014 (SLSEA, 2014). By the year 2010, the total installed capacity of hydropower stations added up to 1,383 MW (SLSEA, 2014). Depending on the rainfall in different years, the proportion of electricity generated at hydropower plants has been varying from about 35% to 70% during the last several years. For instance, out of the total generation of 7,087 GWh in 2002, hydropower plants supplied only 2,588 GWh (37%) while in 1998 hydropower plants supplied 3,915 GWh (69%) out of a total generation of 5,675 GWh. The shortfall is always covered by thermal power stations fuelled partly by petroleum products such as fuel oil, auto diesel and partly by coal since the commissioning of the Sri Lanka's first coal power plant in November 2011.

The electricity demand in Sri Lanka increased at a CAGR of 6.5% during 1997-2012; i.e., from 4,039 GWh in 1997 to 10,389 GWh in 2012. The electricity demand is estimated to grow at a CAGR of 5.2% during 2013-2036 (CEB, 2013). The hydropower potential in Sri Lanka has been utilized to a great extent. The expansion of large hydroelectric systems in the future is expected to be limited to Uma Oya, Gin Ganga and Moragolla. Apart from this, additions of capacity in the existing hydropower plants have also been considered. The development of the remaining hydropower potential through large projects is not attractive because of high economic costs and environmental and resettlement considerations. The small-hydropower potential is in the range of about 400 MW, of which almost 230 MW had been developed by 2013. It is estimated that there will be a significant shortfall between the demand and hydropower output, which needs to be bridged by thermal generation. Harnessing other renewable sources like wind, solar and biomass, which have large technical potential (Wijayatunga et al, 2002a and SARI/Energy, 2003) for electricity generation was limited to generation of 78 MW of wind power, 16 MW biomass plants and 1.4 MW of

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solar photovoltaic systems by 2013 (SLSEA, 2014). There is no liquefied natural gas (LNG)-based power plants in the country. In the absence of any other reliable indigenous primary energy source that can be used for large scale electricity generation, Sri Lanka is left with only one option, that is, addition of thermal power plants based on imported fossil fuel sources to satisfy the continuously increasing demand. Growing concerns on GHG and other harmful emissions from thermal power generation requires careful examination of all the tools that are available to promote clean and energy efficient technologies (CEETs) for electricity generation, including carbon and energy taxes.

A study of the utility planning, environmental and economic implications of introducing carbon and energy taxes in the power sector of Sri Lanka, for the planning period of 2006-2025, was carried out during 2004-2005 using the electricity demand forecast and other relevant data available at that time. Six different carbon tax rates i.e., $5/tC, $10/tC, $25/tC, $50/tC, $100/tC and $150/tC and four energy tax rates i.e., $0.5/MBtu, $1/MBtu, $2/MBtu and $5/MBtu were considered in the study. This chapter presents the findings of that study in Sections 7.2 to 7.5. The results of the least cost generation planning in the base case (i.e., without carbon and energy taxes) is presented in Section 7.2; they are followed by a discussion of the results on the effects of carbon and energy taxes in Sections 7.3 and 7.4 respectively. A summary of key findings are presented in Section 7.5. A postscript is added at the end of the chapter to discuss briefly the differences between the results of the base case of this study and the actual data related to the growth in recent years (i.e., during 2006-2013) in electricity generation, generation-mix, capacity additions and energy policies related to the power sector after the study was carried out.

7.2. Base Case Analysis

7.2.1. Definition of base case

Input data and assumptions

The electricity demand and the peak power demand forecasts were based on the generation expansion plan study of Ceylon Electricity Board (CEB, 2003 & 2004); these are shown in Table 7.1. The annual average growth rate (AAGR) of peak demand is 7.1% for the planning period. Note that the CEB (2004) only presents the electricity and power demand forecasts until 2019; in the present study, the same AAGRs for the demands during the period 2015-2019 were assumed to forecast the demand for the rest of the planning period, i.e., during 2020-2025. The price elasticity of electricity demand used in this study is -0.33. It should be noted here that demand-side management (DSM) options are not considered in this study.

Table 7.1: Estimated electricity- and peak power- demand during 2006-2025.

Year	Peak demand MW	Electricity GWh	Year	Peak demand MW	Electricity GWh
2006	1,855	10,065	2016	3,933	20,416
2007	1,985	10,802	2017	4,240	21,857
2008	2,126	11,641	2018	4,570	23,354
2009	2,298	12,506	2019	4,923	24,939
2010	2,484	13,453	2020	5,301	26,712
2011	2,684	14,449	2021	5,707	28,604
2012	2,900	15,524	2022	6,142	30,612
2013	3,131	16,620	2023	6,608	32,773
2014	3,380	17,808	2024	7,108	35,055
2015	3,647	19,092	2025	7,648	37,510

Source: CEB (2003 & 2004)

Existing and candidate power plants

Fourteen candidate thermal plants, four candidate hydropower plants and three candidate non-dispatchable plants were considered for the present analysis. The candidate thermal plants included conventional steam cycle plants using furnace oil, fuel wood and pulverized coal. Oil and coal-fired power plants are assumed to have the efficiency of 37.5%. Dendro-thermal plant, based on the steam cycle, is assumed to have an efficiency of about 20% and the moisture content of the wood feedstock is assumed to be 20% (Wijayatunga et al., 2002a). The capacity cost of the Dendro-thermal plants includes the wood (Glirisidia) plantation establishment costs. Also, the thermal plant candidates included diesel-fired gas turbine plants (35 MW and 105 MW). Diesel- and LNG-fired combined cycle plants were considered to have efficiency of about 50%. The capacity cost of the LNG-based combined cycle plant included the terminal cost in. The cleaner coal technologies (CCTs) considered in the analysis included pressurized fluidized bed combustion (PFBC) and integrated gasification combined cycle (IGCC) each having efficiency of 40%, and supercritical plants with efficiency of 42%. The parameters of the candidate plants are outlined in Table 7.2, Table 7.3 and Table 7.4. Distributed power generation (DPG) plants considered in the study include solar, wind and mini-hydro options. Nuclear power plants have not been considered in this study.

Table 7.2: Characteristics of candidate thermal plants.

Candidate plants	Unit Capacity (MW)	Capital Cost ($/kW)	Heat rate (kcal/kWh)	Emission factor (kg/MWh) +		
				CO_2	SO_2	NO_x
Steam – Furnace oil	150	1273	2,404	193.7	16.1	1.2
Steam – Furnace oil	300	1076	2,293	186.2	15.5	1.2
Coal – Tr	300	1255	2,293	228.8	3.4	2.7
Coal - Wc	300	1270	2,293	228.8	3.4	2.7
GT 35 - Diesel	35	625	3,060	256.0	3.1	3.6
GT 105 - Diesel	105	425	2,857	193.3	2.3	2.7
CCY - Diesel	150	879	1,846	122.3	1.5	1.7
CCY - Diesel	300	716	1,788	121.9	1.5	1.7
CCY - LNG	500	1345	1,722	381.9	-	-
Dendro	10	1500	4,560	-	-	-
IGCC	300	1610	1,981	203.5	0.1	0.3
PFBC	300	1550	2,091	215.7	0.3	0.4
BIGCC	10	1813	3,230	-	-	-
Supercritical	300	1580	2,054	181.7	0.3	0.4

Source: CEB (2002), Wijayatunga et al. (2002b), SARI/Energy (2003)
+ A '-' sign means either zero or a negligible quantity.

Table 7.3: Characteristics of candidate hydropower plants.

Parameters	Units	Candidate plants			
		Gingang	Broadlands	Uma Oya	Moragolla
Unit capacity	MW	49	35	150	27
Available year		4	4	5	4
Availability		0.98	0.98	0.98	0.98
Capital cost	10^3 $	154,203	105,245	475,650	120,420
Fixed O&M	10^3 $/MW/mth*	0.3286	0.3286	0.3286	0.3286
Available energy in season 1	MWh	68,020	359,49	185,360	28,500
Available energy in season 2	MWh	144,050	90,242	261,340	84,150

* mth: month
Source: CEB (2002)

Table 7.4: Characteristics of candidate DPG plants.

Parameters	Units	Candidate plants+		
		Wind	Mini Hydro	Solar
Unit capacity	MW	30	15	1
Availability		0.9	0.9	0.98
Capital cost	10^3 $	36,000	22,500	5,500
Operating cost	10^3 $/MWh	-	-	0.0012
Annual maintenance	hrs	720	720	600
Fixed O&M	10^3 $/MW/mth	0.75	0.3286	0.83

Source: Fernando et al. (2002)

+ A '-' sign means either zero or a negligible quantity.

7.2.2. Power sector development during 2006-2025

The base case analysis shows that the share of installed capacities of hydropower, oil, wind and mini-hydro would be decreasing during 2006-2025 (see Table 7.5). The most significant decrease would be in the share of large hydropower plants i.e., from 45.4% in 2006 to 15.9% in 2025. The share of oil-based generation in the capacity mix would be decreasing from 39.5% in 2006 to 17.3% in 2025. There were no coal, biomass or solar plants in 2006, but in 2025, the share of coal-fired power plants would be the most dominant technology accounting for 60.7% of the total generation. In addition, power plants based on biomass and solar would be selected in 2025. This means, fuel switching would take place from oil and hydropower to mostly coal, and to some extent to biomass and solar, during 2006-2025.

Table 7.5: Generation capacity mix by fuel types at selected years in the base case (MW).

Year	2006	2010	2015	2020	2025
Hydro	1,185	1,335	1,335	1,335	1,335
Oil	1,030	1,279	848	1,093	1,455
Coal	-	600	1,500	3,000	5,100
Biomass	-	-	-	-	10
Mini-Hydro	120	235	235	235	235
Wind	273	273	273	273	270
Solar	-	-	-	-	2
Total	2,608	3,722	4,191	5,936	8,407

+ A '-' sign means either zero or a negligible quantity.

The electrical energy generation mix (or "generation mix") is also found to follow the pattern of the capacity mix. Table 7.6 shows the electricity generation mix in the base case in 2006 and in 2025. In 2025, the coal-fired power plant would dominate the electricity generation mix (with a share of 78.3%); the hydropower plants would contribute more than the oil-fired plants.

Thus, the analysis shows coal to be the dominant source of power generation in Sri Lanka's power system in the base case scenario. The new capacity added to the system in the base case during 2006-2025 is 6,272 MW. The total installed capacity in 2025 would be 8,407 MW and the corresponding total generation would be 40,594 GWh. The energy efficient coal technologies like supercritical, pressurized fluidized bed combustion (PFBC) and integrated gasification combined cycle (IGCC) or wood-based technologies like BIGCC were not found to be cost-effective due to their relatively expensive capital and operation/maintenance costs.

Table 7.6: Electricity generation mix by fuel types at selected years in the base case (GWh)+.

Year	2006	2010	2015	2020	2025
Hydro	4,194	4,724	4,724	4,724	4,724
Oil	4,762	2,762	2,891	3,034	2,849
Coal	-	4,446	10,491	19,127	31,763
Biomass	-	-	-	-	6
Mini-Hydro	378	741	741	741	741
Wind	512	512	511	512	506
Solar	-	-	-	-	5
Total	9,846	13,184	19,358	28,137	40,594

+A '-' sign means either zero or a negligible quantity.

The total cumulative CO_2 emission during 2006-2025 in the base case would be 250 Mt. The CO_2 emission from the power sector during 2006-2025 is estimated to increase from 3 Mt to 28 Mt.

7.3. Effects of Carbon Tax

One of the main objectives of the study is to examine the impact of a possible carbon tax on the generation planning process and the subsequent effect on other sectors. This section summarizes the utility planning and environmental implications of carbon tax on Sri Lanka's power sector under carbon tax rates of $5/tC, $10/tC, $25/tC, $50/tC, $100/tC and $150/tC.

7.3.1. Utility planning implications

Changes in electricity demand

The total electricity demand would decrease with the carbon tax; this is because a carbon tax would increase the electricity price, resulting in a decrease in electricity demand. In the case of Sri Lanka, the decrease in demand with carbon tax is shown in Figure 7.1. The total electricity demand during 2006-2025 is found to decrease by 7.5% and 9.0% at carbon tax rates of $100/tC and $150/tC, respectively when compared to the base case electricity demand.

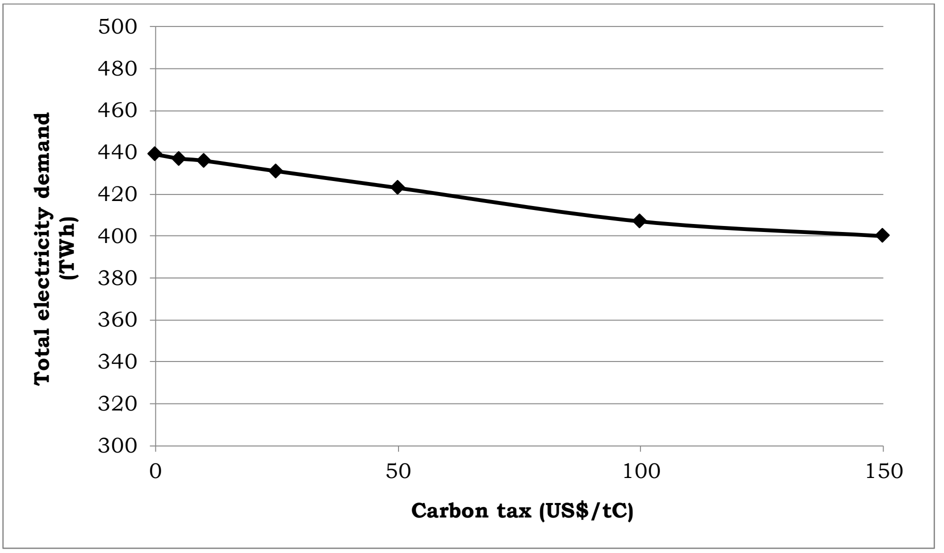

Figure 7.1: Total electricity demand during 2006-2025 at selected carbon tax rates.

Generation technology capacity mix

Figure 7.2 shows the total installed power generation capacity additions in the year 2025 at the selected carbon tax rates. As can be seen, the capacity additions would gradually decrease up to the carbon tax rate of $100/tC by about 10% compared to that in the base case. Then it would increase from 5,669 MW at the carbon tax rate of $100/tC to 5,959 MW at the carbon tax rate of $150/tC due to the replacement of thermal plants by renewable energy plants, which have relatively low plant capacity factors.

The power sector responds to the carbon tax by substitution of fuels and introduction of cleaner technologies in the supply-side. The total capacity additions and the capacity mix would change after the introduction of carbon tax. Table 7.7 shows the change in capacity additions under the different carbon tax scenarios. As can be seen, the total coal-fired power plants capacity added during 2006-2025 would decrease from 5,100 MW in the base case to 900 MW with the carbon tax of $150/tC. The total addition of plantation-based biomass power plants, i.e., BIGCC and Dendro, would each increase from zero in the base case to 3,720 MW and 40 MW, respectively at the carbon tax rate of $150/tC. The share of oil-based gas turbines is fairly constant throughout 2006-2025. It is noted that the total availability of domestic mini hydro resources would be fully utilized at the carbon tax rate of $5/tC and above. Thus, fuel substitution takes place in displacing high carbon content fuels (like coal) by low carbon fuels (like renewable resources) with the introduction of carbon tax in the power sector.

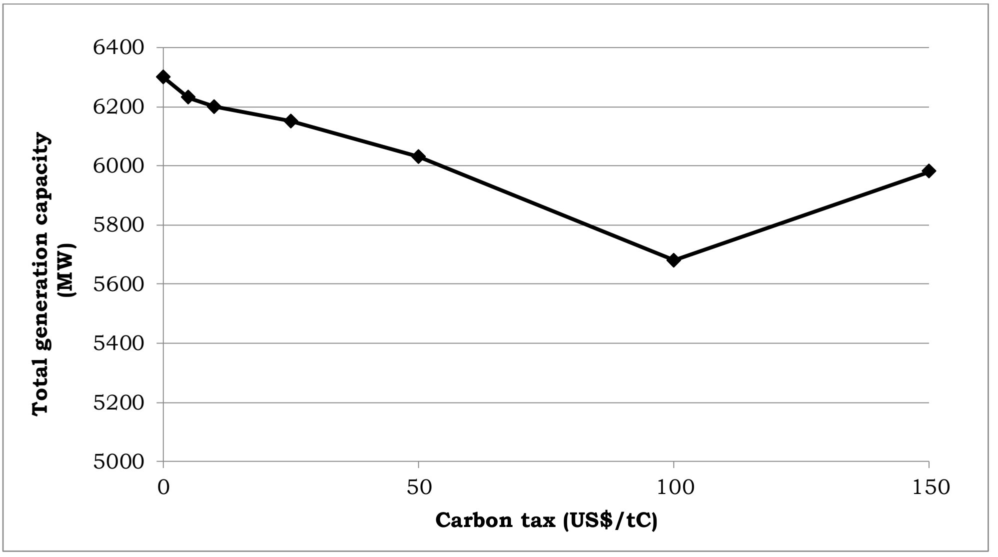

Figure 7.2: Total generation capacity in 2025 at selected carbon tax rates.

Table 7.7: Generation capacity additions by plant type during 2006-2025 at selected carbon tax rates (MW).

Plant type	Carbon tax ($/tC)⁺						
	0 (Base case)	5	10	25	50	100	150
Hydropower	-	-	-	-	35	84	84
Coal-fired steam	5,100	5,100	5,100	5,100	4,800	4,500	900
Gas turbine (Oil)	875	875	840	735	840	735	875
BIGCC	-	-	-	-	-	20	3,720
Dendro (steam)	-	-	-	-	-	-	40
Wind	270	210	210	270	300	300	300
Mini Hydro	15	30	30	30	30	30	30
Solar	2	-	-	1	-	-	-
Total	6,262	6,215	6,180	6,136	6,005	5,669	5,949

⁺A '-' sign means either zero or a negligible quantity.

Electricity generation mix

Introduction of carbon tax would normally change the generation mix towards less carbon intensive fuels and technologies. The most noticeable change under the carbon tax scenario in the case of Sri Lanka is the replacement of coal-fired power plants by hydro- and biomass-based power generation (renewable).

Table 7.8 presents the total electricity generation and percentage shares of large hydropower, thermal and renewable generation during 2006-2025 at selected carbon tax rates. As can be seen from the table, there would be no significant changes in the generation mix up to the carbon tax of $100/tC. However, if the carbon tax is increased to $150/tC, the coal-based generation is found to decrease drastically and is substituted by renewable-based generation (mainly biomass). The present analysis shows that at the carbon tax of $150/tC, the coal-based generation would account for only 2.9% of the total electricity generation. Note that carbon tax is not applied to biomass-based power generation since the net lifecycle carbon emission of biomass-based generation is assumed to be zero.

Table 7.8: Cumulative electricity generation mix during 2006-2025 at selected carbon tax rates.

Carbon tax ($/tC)	Hydropower (%)	Coal (%)	Oil (%)	Renewable (%)	Total electricity generation (GWh)
0 (Base case)	21.3	58.5	14.6	5.6	438,795
5	21.4	58.6	14.7	5.3	436,961
10	21.5	58.6	14.7	5.3	435,134
25	21.7	58.0	14.5	5.8	429,987
50	22.3	56.3	15.2	6.3	421,659
100	23.7	54.7	14.8	6.8	405,806
150	24.3	2.9	14.8	58.0	399,355

Fossil fuel consumption for power generation

With the introduction of carbon taxes, the fossil fuel consumption would decrease (see Figure 7.3) both due to the demand-side (i.e., price effect) and supply-side (i.e., technological substitution effects of the tax (see Section 2.2 in Chapter 2 for detailed explanation on these effects). As can be seen from the figure, the use of fossil fuels in electricity generation would be reduced from 73 million toe in the base case to less than 20 million toe at the carbon tax rate of $150/tC. The reduction in fossil fuel used is particularly high as the tax rate increases to $150/tC. This is because at the high carbon tax rates, there would be a shift in the power generation mix in Sri Lanka, i.e., a reduction in the share of generation from coal-fired power plants and an increase in generation from renewable energy-based plants (mainly biomass).

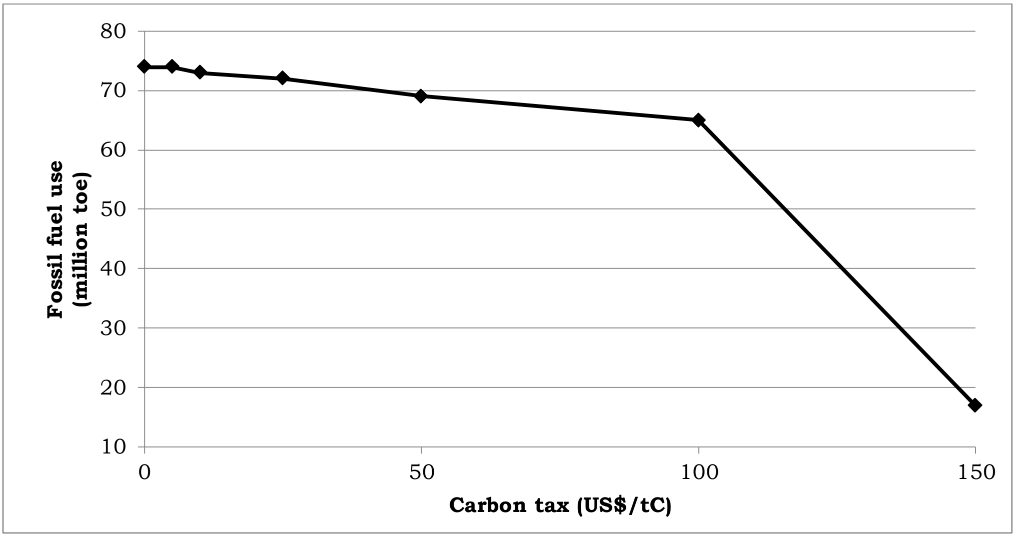

Figure 7.3: Total fossil fuel use during 2006-2025 at different carbon tax rates.

Generation system efficiency

As previously observed, higher carbon tax in the Sri Lankan power system could result in fuel substitution in power generation, affecting the overall thermal generation efficiency. In this study, the overall efficiency of thermal power generation is as the weighted average thermal generation efficiency (WATGE) during the planning period, with shares of different types of thermal power plants being the corresponding weights (see Section 2.3 in Chapter 2 for explanation on WATGE). Interestingly, as can be seen from Table 7.9, the WATGE would decrease drastically at the carbon tax rate of $150/tC: The WATGE would reduce from 37.6% in the base case to 28.9% at the carbon tax rate of $150/tC. This is mainly due to the selection of 3,720 MW of less efficient BIGCC plants (with power generation efficiency of 26.6%) at $150/tC as compared to 5,100 MW of conventional coal-based power plants in the base case.

Table 7.9: Weighted average thermal generation efficiency (WATGE) during 2006-2025 at selected carbon tax rates.

Carbon tax ($/tC)	WATGE (%)
0 (Base case)	37.6
5	37.6
10	37.6
25	37.6
50	37.5
100	37.5
150	28.9

Generation system reserve margin

The average reserve margin of the power system during 2006-2025 would increase from 19.2% of the total generation capacity in the base case to 23.7% at a carbon tax rate of $150/tC (see Figure 7.4). This is because more renewable energy plants of lower plant factors are found cost-effective at higher carbon tax resulting in a comparatively higher total generation capacity to meet the electricity demand.

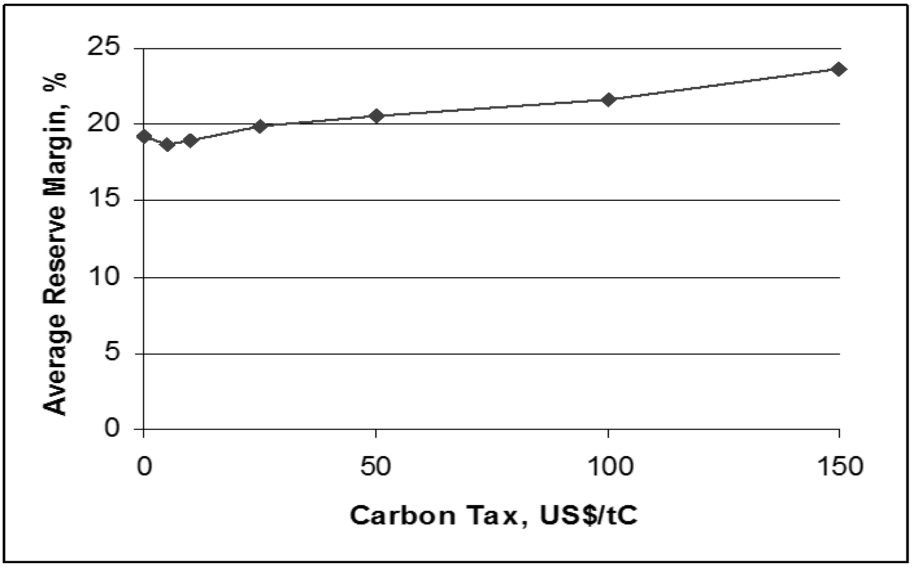

Figure 7.4: Average reserve margin during 2006-2025.

Generation capacity utilization

Carbon tax would also affect the power system's capacity utilization, which can be expressed in terms of capacity factor (CF). Figure 7.5 the weighted average capacity factor (WACF) of the power system as a whole along with WACFs of existing and new power plants (see Section 2.4 in Chapter 2 for explanation on WACF). As can be seen from the figure, WACF of the system would decrease with an increase in the carbon tax. It would decrease by 4.2% at the carbon tax of $150/tC as compared to that in the base case. This reduction in WACF at higher tax rates is mainly because of the addition of new renewable-based power plants.

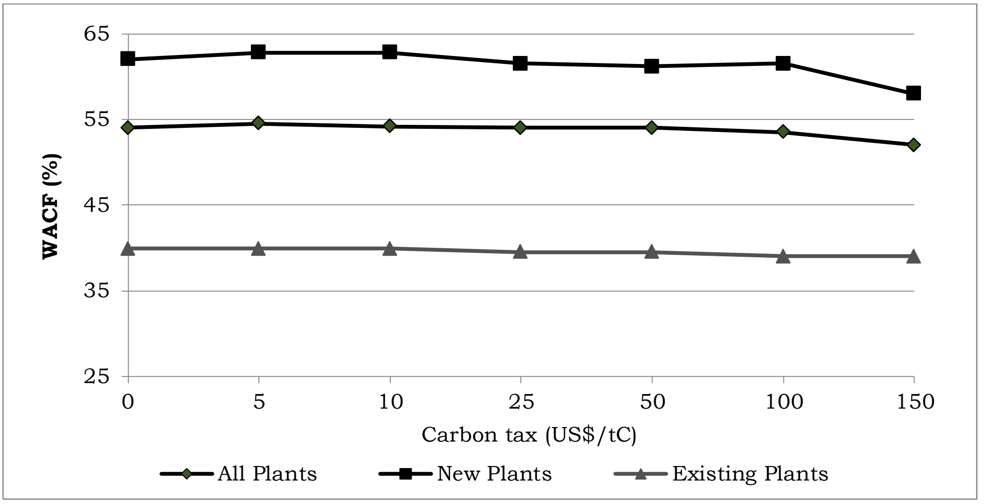

Figure 7.5: Weighted average capacity factor (WACF) over the planning period 2006-2025 at different carbon tax rates (%).

7.3.2. Economic implications

Electricity generation system cost

Table 7.10 shows the total cost of electricity generation during 2006-2025 at selected carbon tax rates. The total cost (discounted) consists of capital cost, fixed O&M cost, fuel and variable O&M cost. The total cost would increase in the range of 0.9% to 24.2% when the carbon tax rate increases from $5/tC to $150/tC. As shown in Table 7.10, the fuel and variable O&M costs have the highest contribution in the total cost (in the range of 67% to 71%) followed by the capacity cost (in the range of 19% to 26%) and fixed O&M cost (in the range of 4% to 7%). The increase in overall costs with the introduction of the carbon tax can be attributed to the increase in capital and fixed O&M costs resulting from higher penetration of renewable energy plants and underutilization of conventional plants.

Table 7.10: Contribution of capacity, fixed O&M, fuel and variable O&M costs to the total cost at selected carbon tax (discounted value) during 2006-2025.

Carbon tax ($/tC)	Capacity cost		Fixed O & M cost		Variable cost		Total cost ($10^6$$)
	($10^6$$)	(%)*	($10^6$$)	(%)*	($10^6$$)	(%)*	
0	1,107	24.4	187.7	4.1	3,240	71.4	4,535
5	1,077	23.5	185.1	4.0	3,315	72.4	4,577
10	1,075	23.3	185.0	4.0	3,358	72.7	4,618
25	1,098	23.1	186.7	3.9	3,461	72.9	4,746
50	1,042	21.1	184.5	3.7	3,721	75.2	4,948
100	1,041	19.7	183.5	3.5	4,067	76.9	5,292
150	1,427	26.0	371.1	6.8	3,685	67.2	5,483

* These numbers are the percentage of the total cost. All costs are discounted to the base year 2000.

Carbon tax revenue

Table 7.11 presents undiscounted tax revenue that would result from the introduction of selected carbon tax rates in the power sector of Sri Lanka during 2006-2025. The tax revenue is found to increase from \$372 million at the carbon tax rate of \$5/tC to \$6,639 million at the tax rate of \$100/tC and decrease thereafter mainly due to fuel switching from coal to biomass.

Table 7.11: Carbon tax revenue and total non-tax cost (nominal-value) during 2006-2025 at selected carbon tax rates.

Carbon tax (\$/tC)	Total cost (10^6 \$)	Tax revenue (10^6 \$)+	Total non-tax cost (10^6 \$)
0 (Base case)	17421	-	17421
5	17,737	372	17,365
10	18,004	746	17,258
25	18,760	1,834	16,927
50	20,267	3,547	16,720
100	22,428	6,639	15,789
150	22,495	2,350	20,145

+ A '-' sign means either zero or a negligible quantity.

Unit cost of electricity generation

Figure 7.6 presents the average incremental costs ($AIC_{overall}$) (used here as a proxy for LRMC) and long run average costs (LRAC) at the selected carbon tax rates. The figure shows that LRAC would increase from ¢4.9/kWh in the base case to ¢6.7/kWh at the carbon tax rate of \$150/tC, whereas the average incremental cost would increase from ¢4.9/kWh in the base case to ¢7.3/kWh at the carbon tax rate of \$150/tC. The large increase in $AIC_{overall}$ (see Section 2.5 in Chapter 2 for calculation of $AIC_{overall}$) at the higher tax rates is due to the higher level of penetration of expensive renewable energy-based plants.

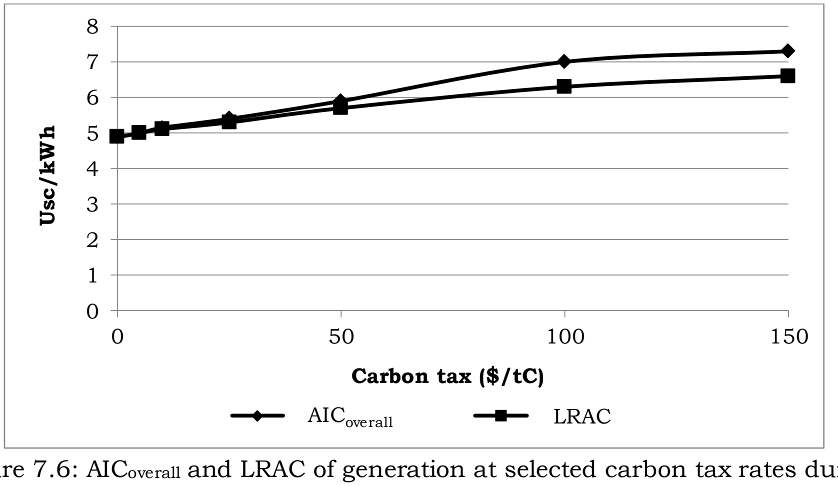

Figure 7.6: $AIC_{overall}$ and LRAC of generation at selected carbon tax rates during 2006-2025.

7.3.3. Environmental implications

The cumulative levels of CO_2 emission and corresponding values of CO_2 mitigation during the planning period at the selected carbon tax rates are presented in Figure 7.7. As can be seen, there would be no significant reduction in the emission of CO_2 up to the carbon tax rate of $100/tC (the CO_2 emission would be reduced by about 12% at the carbon tax of $100/tC). At the higher carbon tax rate of $150/tC, the study shows that the CO_2 emission during planning period would be 83% less than that in the base case (i.e., without the tax).

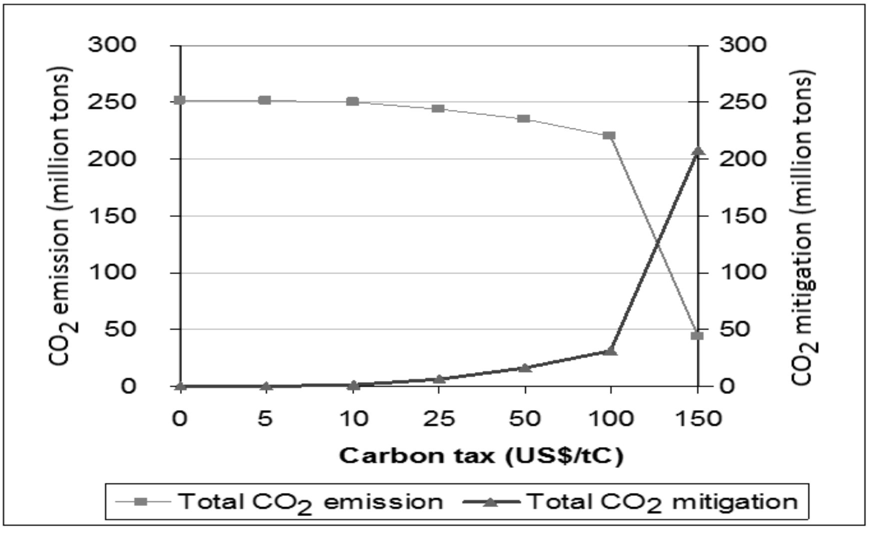

Figure 7.7: Cumulative CO_2 emission and mitigation during the planning period 2006-2025 at selected carbon tax rates.

Implications on CO_2 emission intensity

There is no significant change in CO_2 intensity (measured in tons of CO_2 emission per MWh) in carbon tax up to $25/tC. CO_2 intensity would decrease from 0.57 tons/MWh in the base case to 0.55 tons/MWh at $50/tC and 0.11 tons/MWh at $150/MBtu.

Decomposition of CO_2 emission reduction: The role of supply- and demand-side effects

The total change in CO_2 emissions with the introduction of carbon tax is caused by two types of effects, i.e., the supply-side and of demand-side effects (see Section 2.6 in Chapter 2 for calculation of decomposition of CO_2 emission reduction). Table 7.12 presents the total reduction in CO_2 emission under different carbon tax rates and the contributions of the supply-side and demand-side effects in the emission reduction. As can be seen from the table, the share of CO_2 reduction due to the demand-side effect is larger than that due to the supply-side effect at carbon tax rates of $5/tC to $100/tC, but as the carbon tax rate increases to $150/tC, the share of CO_2 mitigation due to supply-side effect is found to be more than that due to the demand-side effect.

Table 7.12: Contribution of the demand- and supply-side effects to the power sector cumulative CO_2 reductions during 2006-2025 at selected carbon tax rates.

Carbon tax ($/tC)	CO_2 emission reduction (10^6 tons)	Decomposition	
		Demand-side effect (%)	Supply-side effect (%)
5	0.51	90.2	9.8
10	1.95	94.9	5.1
25	7.23	90.7	9.3
50	16.01	90.6	9.5
100	31.46	82.2	17.8
150	207.16	2.4	97.6

Local/regional pollutant emissions

As shown in Figure 7.8, the cumulative SO_2 emissions during 2006-2025 would decrease to 1.05 million tons at the carbon tax rate of $5/tC, whereas the emission would be reduced to 200 thousand tons at the carbon tax rate of $150/tC. Similarly, the NO_x emissions would be reduced to 876 thousand tons at the tax rate of $5/tC and to 200 thousand tons at $150/tC. Since the coal use in electricity generation is substituted by biomass and other renewable energy sources at higher tax rates, the reductions in SO_2 and NO_x are expected.

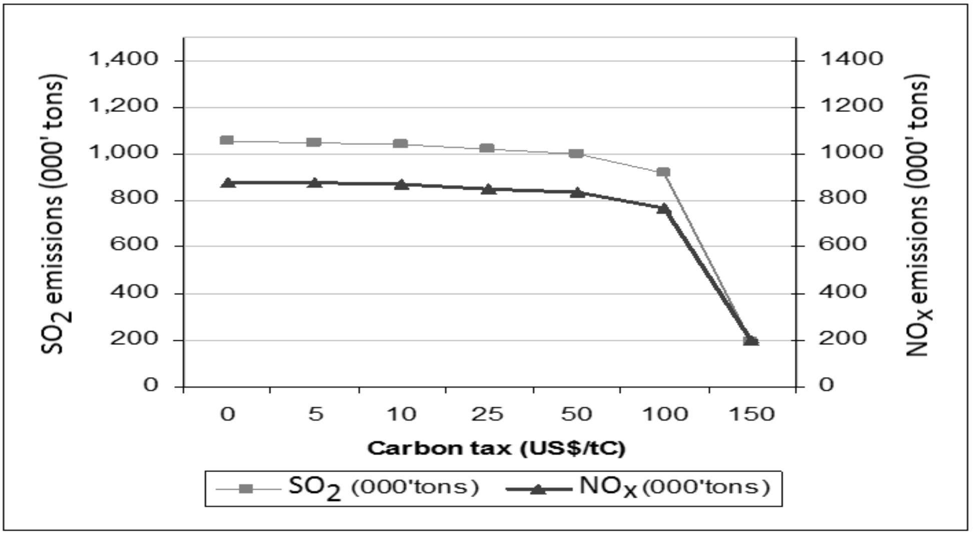

Figure 7.8: Cumulative emissions of SO_2 and NO_x during 2006-2025 at selected carbon tax rates, 10^3 tons

Carbon tax elasticity of CO_2 emission

As can be seen from Table 7.13, the carbon tax elasticity of CO_2 emission (see Section 2.2 in Chapter 2 for calculation of carbon tax elasticity of CO_2 emission) is found to be inelastic (in the range of -0.0016 to -0.0733) except for the tax increase from $100/tC to $150/tC, when it becomes elastic (i.e., -3.9952). Thus, it can be seen that the main turning point is carbon tax of $150/tC, at which the renewable energy substitution becomes significant.

Table 7.13: Carbon tax elasticity of CO_2 emission from the power sector at selected carbon tax rates

Carbon tax range ($/tC)	Carbon tax elasticity
0-5	-0.0016
5-10	-0.0115
10-20	-0.0364
25-50	-0.0733
50-100	-0.13.58
100-150	-3.9952

7.4. Effects of Energy Tax

This section discusses the implications of introducing energy tax on the power sector development, environment and costs of electricity generation.

7.4.1. Utility planning implications

Changes in electricity demand

As illustrated in Figure 7.9, the level of electricity demand and hence generation decreases with an increase in the energy tax. This is expected because the energy tax would increase the electricity price. As a result, the total electricity generation during 2006-2025 would decrease by about 17% at the energy tax rate of $5/MBtu.

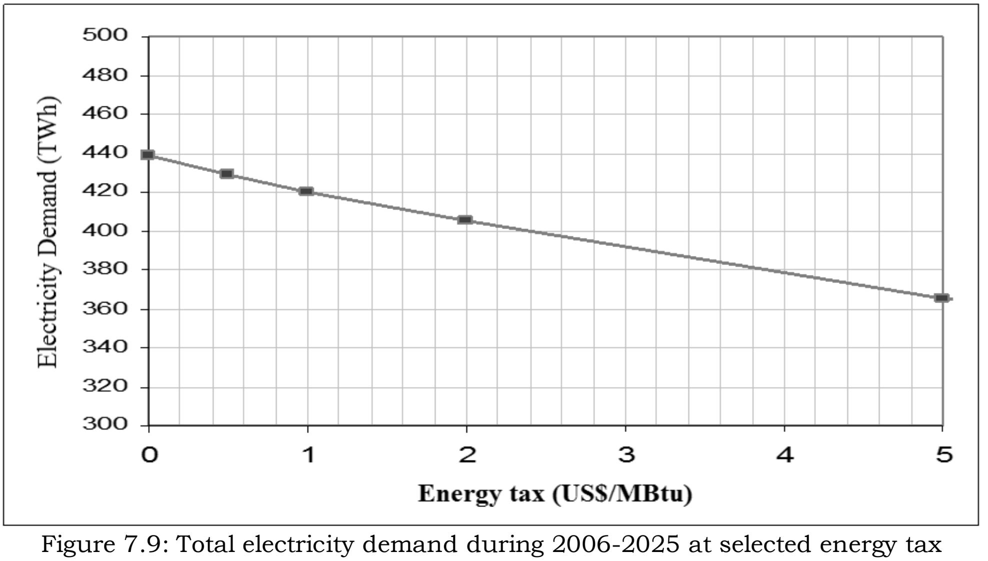

Figure 7.9: Total electricity demand during 2006-2025 at selected energy tax

Generation technology capacity mix

Figure 7.10 shows the total addition of installed capacity at the end of the planning period (i.e., 2006-2025), i.e., in the year 2025 at selected energy tax rates. It can be seen that the total installed capacity would decrease gradually and it would be 20% less at an energy tax rate of $5/MBtu, compared to the base case.

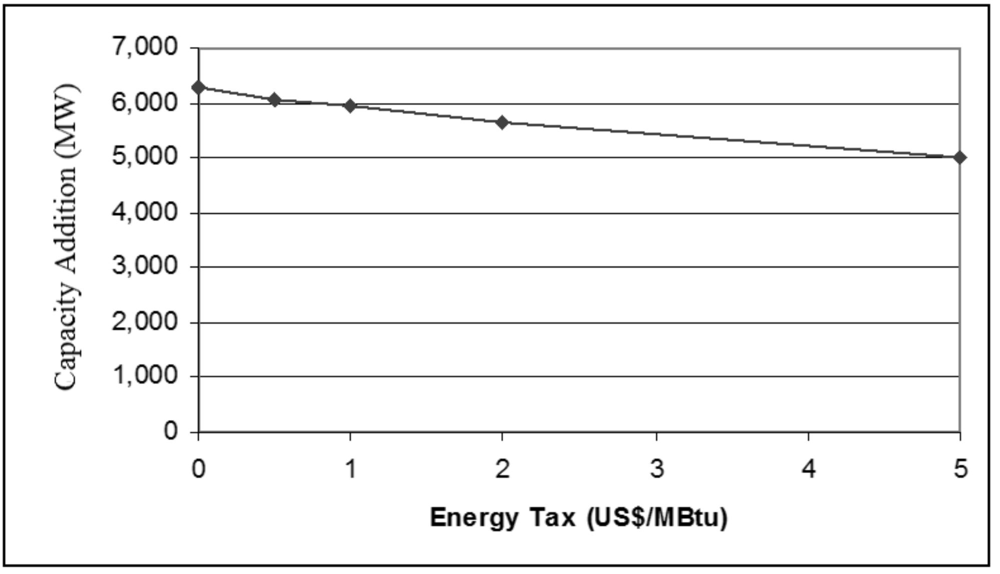

Figure 7.10: Total generation capacity additions in 2025 at selected energy tax rate

Table 7.14 shows the change in capacity additions under the selected energy tax scenarios. As can be seen, the addition of coal-fired power plant capacity would decrease from 5,100 MW in the base case to 2,400 MW at the energy tax of $5/MBtu. The share of IGCC plants would increase from zero in the base case (i.e., without energy tax) to 1,500 MW with the energy tax of $5/MBtu. The share of oil-based gas turbines would change slightly during 2006-2025. The total available domestic mini hydro resources are fully utilized at the energy tax rate of $1/MBtu and above. The installation of large hydropower plant capacity would also increase at higher energy tax rates. Furthermore, at higher energy tax rates, the conventional coal-fired steam capacity additions would be partially substituted by efficient IGCC plants.

Table 7.14: Capacity additions by plant types during 2006-2025 at selected energy tax rates (MW)

Plant type	Energy tax ($/MBtu)				
	0 (Base case)	0.5	1	2	5
Hydropower	0	0	0	84	234
Coal-fired steam	5,100	5,400	5,100	4,500	2,400
Gas turbine (Oil)	875	455	560	735	525
IGCC	0	0	0	0	1500
Dendro	10	0	0	10	0
Wind	270	180	270	300	300
Mini Hydro	15	15	30	30	30
Solar	2	0	0	0	0
Total	6,272	6,050	5,960	5,659	4,989

Electricity generation mix

The introduction of an energy tax would change the fuel prices according to their energy content. As a result, generation mix would change towards more energy efficient technologies. The most noticeable change under the energy tax scenario in the case of Sri Lanka is the replacement of conventional coal-fired power plants by IGCC plants.

Table 7.15 presents the total electricity generation and percentage shares of large hydro, thermal and renewable generation during 2006-2025. As can be seen from the table, the total electricity generation would decrease with the increase in energy tax mainly due to an increase in electricity price due to the energy tax and hence a decrease in energy demands. At the energy tax rate of $5/MBtu, there would be substantial change in the generation mix, i.e., coal-based generation would decrease drastically due to substitution of electricity generation from coal-fired steam plants by that from IGCC and hydro plants. The share of oil-based generation would also decrease with the energy tax.

The share of conventional coal-based power generation would decrease from 58.5% in the base case to 22.2% at the energy tax rate of $5/MBtu, while the corresponding share of power generation from IGCC and hydropower (large) plants would increase from zero and 21.3% in the base case to 30.0% and 28.0% at the energy tax of $5/MBtu, respectively. The renewable energy based generation (mainly wind and mini hydro) would increase from 5.6% in the base case to 7.2% at the energy tax rate of $5/MBtu.

Table 7.15: Cumulative electricity generation mix during 2006-2025 at selected energy tax rates (TWh)

Energy tax ($/MBtu)	Plant type				Total electricity generation
	Hydropower	Coal	Oil	Renewable	
0 (Base case)	93.4	256.8	64.2	24.4	438.8
0.5	93.4	252.3	62.5	20.9	429.1
1	93.4	240.2	61.5	25.2	420.3
2	96.1	223.1	60.0	26.4	405.6
5	102.2	180.1	56.9	26.4	365.6

Fossil fuel consumption for power generation

With the introduction of energy tax, the fossil fuel consumption would decrease (see Figure 7.11). The total fossil fuel consumption in power generation would decrease by 44% at the energy tax rate of $5/MBtu (i.e., from 73 million toe in the base case to 41 million toe with the tax).

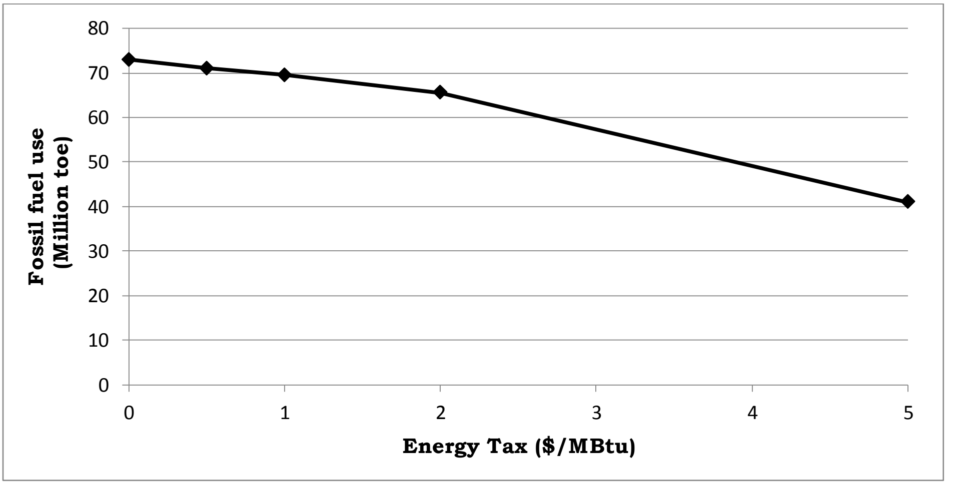

Figure 7.11: Cumulative fossil fuel use during the planning period 2006-2025 at different energy tax rates

Generation system efficiency

Table 7.16 shows that the WATGE of the power system remains constant at 37.6% up to the tax rate of $2/MBtu and increases to 39.9% at the tax rate of $5/MBtu. This improvement in the efficiency is mainly due to the shift in electricity generation from the less efficient conventional coal-fired power plants to more efficient IGCC plants.

Table 7.16: Weighted average thermal generation efficiency (WATGE) during 2006-2025 at selected energy tax rates

Energy tax ($/MBtu)	WATGE (%)
0 (Base case)	37.6
0.5	37.6
1	37.6
2	37.6
5	39.9

Generation system reserve margin

Energy tax would also affect the reserve margin of the power system. The average reserve margin of the power system during 2006-2025 would increase from 19.2% in the base case to 25% at an energy tax rate of $5/MBtu (see Figure 7.12). This is because it would be cost-effective to install more renewable generation plants with low plant capacity factors at higher energy tax rates.

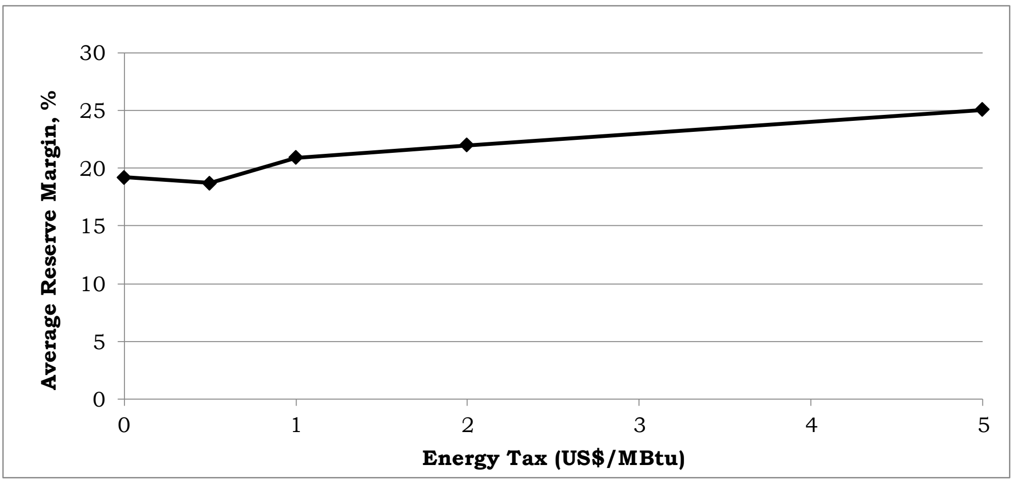

Figure 7.12: Average reserve margin during 2006-2025 at selected energy tax rate

Generation capacity utilization

As can be seen from Figure 7.13, the power generation capacity would be utlilized less intensely with the increase in the energy tax. With the energy tax of $5/MBtu, the weighted average capacity factor (WACF) of the power generation system would be 3.65 percentage points below that in the base case. Note that the overall capacity utilization factors of both new and existing power plants would be suffering a decline with the energy tax. The main reason behind the decrease in WACF is the increased share of renewable energy based power plants in the case of new plants and the reduced use of less efficient existing thermal power plants in the case of the existing power plants.

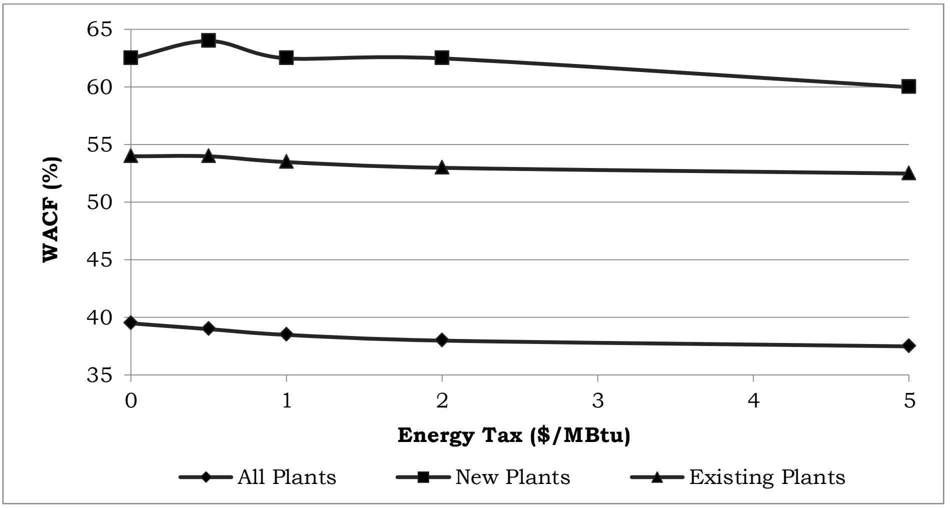

Figure 7.13: Weighted average capacity factor (WACF) during 2006-2025 at selected energy tax rates

7.4.2. Economic implications

Electricity generation system cost

Table 7.17 shows the total cost of electricity generation during 2006-2025 at selected energy tax rates. The total cost would increase in the range of 3% to 43% when energy tax rates of $0.5/MBtu to $5/MBtu are introduced. As shown in the table, the fuel and variable O&M costs combined constitute 71% to 78% of the total cost, and is followed by the capacity cost (in the range of 19% to 24%) and fixed O&M cost (about 4%). Note that with an increase in the energy tax, the share of fuel and variable operating cost would increase, while that of the capacity cost would decrease.

Table 7.17: Breakdown of total cost of power generation system development cumulative discounted cost during 2006-2025 at selected energy tax rates

Energy tax ($/MBtu)	Capacity cost		Fixed O&M cost		Fuel and variable O&M cost		Total cost (10^6 $)
	(10^6 $)	(%)*	(10^6 $)	(%)*	(10^6 $)	(%)*	
0 (Base case)	1,107	24	188	4	3,240	71	4,535
0.5	1,050	22	183	4	3,438	74	4,671
1	1,075	22	185	4	3,544	74	4,804
2	1,040	21	183	4	3,834	76	5,057
5	1,057	19	203	4	4,349	78	5,609

* These numbers are the percentage of the total cost.
All costs are discounted to the base year 2000.

Energy tax revenue

Table 7.18 presents the undiscounted tax revenue resulting from the introduction of selected energy tax rates in the electricity sector of Sri Lanka during 2006-2025. As expected, the tax revenue increases with an increase in the energy tax rate and lies in the range of 10% to 61% of the total undiscounted cost. The table also shows that at the price elasticity of electricity demand of -0.33, the tax revenue would increase from \$1,855 million at the energy tax rate of \$0.5/MBtu to \$14,843 million at the tax rate of \$5/MBtu.

Table 7.18: Energy tax revenue and total non-tax cost (nominal-value) during 2006-2025 at selected energy tax rates

Energy tax (\$/MBtu)	Tax revenue (10^6 \$)[+]	Undiscounted total cost (10^6 \$)	Total non-tax cost (10^6 \$)
0 (Base case)	-	17,421	17,421
0.5	1,855	18,364	16,509
1	3,590	19,226	15,636
2	6,899	20,986	14,087
5	14,843	24,387	9,544

[+] A '-' sign means either zero or a negligible quantity.

Unit cost of electricity generation

Figure 7.14 presents the overall average incremental costs ($AIC_{overall}$) and long run average costs (LRAC) at the selected energy tax rates. The figure shows that the LRAC would increase from ¢4.9/kWh in the base case to ¢7.3/kWh at the energy tax rate of \$5/MBtu, whereas the $AIC_{overall}$ would increase from ¢4.9/kWh in the base case to ¢8.5/kWh at the energy tax rate of \$5/MBtu. The large increase in the value of $AIC_{overall}$ at higher energy tax rates is due to the penetration of more expensive efficient power plant technology options.

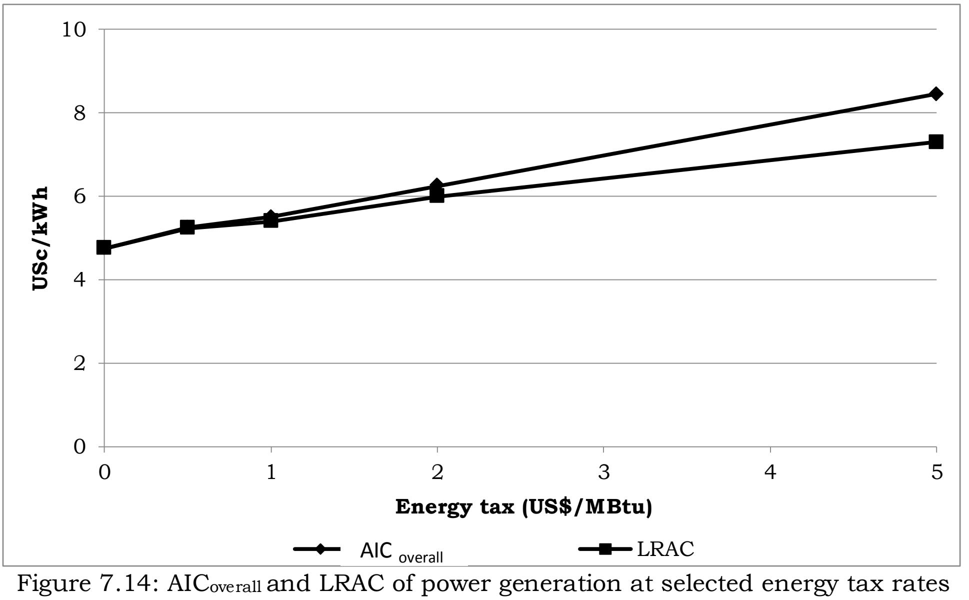

Figure 7.14: $AIC_{overall}$ and LRAC of power generation at selected energy tax rates during 2006-2025

7.4.3. Environmental implications

Total CO_2 emission during 2006-2025 from the power sector at the selected energy tax rates are shown in Figure 7.15. There would be no significant reduction in CO_2 emission up to the energy tax rate of $2/MBtu (the energy tax of $2/MBtu is only able to reduce the CO_2 emission during the planning period by about 12%). However, at the higher energy tax of $5/MBtu, the CO_2 emission during the planning period would be about 31% less than that in the base case.

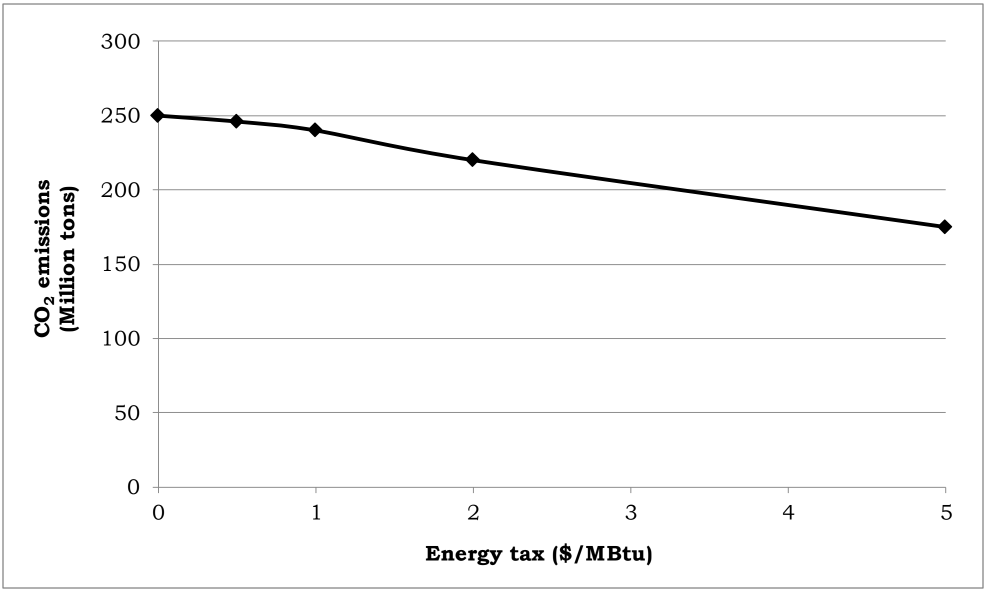

Figure 7.15: Cumulative CO_2 emission during 2006-2025 at selected energy tax rates

Implications on CO_2 emission intensity

There is no significant change in CO_2 intensity (measured in tons of CO_2 emission per MWh) at energy tax cases of $0.5/MBtu. At higher energy taxes, CO_2 intensity would decrease from 0.57 tons/MWh in the base case to 0.56 tons/MWh at $1/MBtu, 0.54 tons/MWh at $2/MBtu and 0.47 tons/MWh at $5/MBtu.

Decomposition of CO_2 emission reduction: The role of supply- and demand-side effects

Table 7.19 presents the total CO_2 reduction with the introduction of selected energy tax rates and the contributions of the supply-side and demand-side effects to the reduction. As can be seen from the table, the demand-side effect would have a larger share in the CO_2 reduction than the supply-side effect under each of the energy tax rates considered in the present study.

Table 7.19: Decomposition of cumulative CO_2 emission reduction during 2006-2025 at selected energy tax rates

Energy tax ($/MBtu)	CO_2 emission reduction (10^6 tons)	Decomposition	
		Demand-side effect (%)	Supply-side effect (%)
0.5	4.82	86.1	13.9
1	15.35	90.7	9.3
2	30.68	86.0	14.0
5	77.94	75.2	24.8

Local/regional pollutant emissions

As shown in Figure 7.16, the cumulative SO_2 emissions during 2006-2025 would decrease to 1,031 thousand tons, from 1050 thousand tons at the base case, at the energy tax rate of $0.5/MBtu and it would decrease to 403 thousand tons, from 850 thousand tons at the base case, at the tax rate of $5/MBtu. Similarly, the cumulative NO_x emissions from power generation during 2006-2025 would decrease to 876 thousand tons at the tax rate of $0.5/MBtu and to 400 thousand tons at the tax rate of $5/MBtu. Since the conventional coal-fired power plants are mostly substituted by clean coal technologies such as IGCC and renewable energy sources like hydropower, reductions in SO_2 and NO_x emissions are expected.

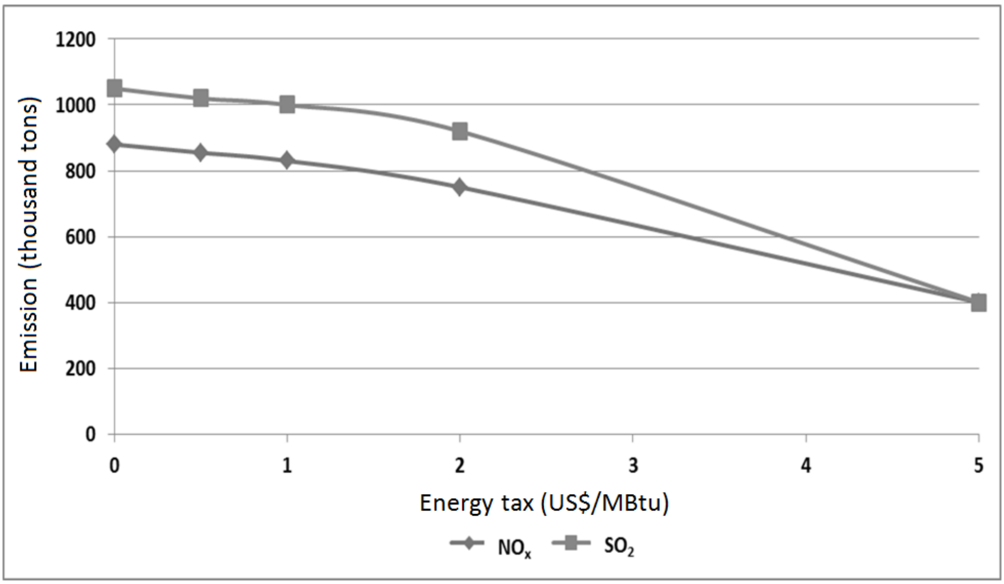

Figure 7.16: Total emissions of SO_2 and NO_x during 2006-2025 at selected energy tax rates (10^3 tons)

Energy tax elasticities of CO_2 emissions

The energy tax elasticities of CO_2 emission in the case of the power sector of Sri Lanka are shown in Table 7.20. As can be seen, the CO_2 emission from power sector is found to be inelastic in the range of the energy tax rates considered in the present study.

Table 7.20: Energy tax elasticity of CO_2 emission from the power sector at selected energy tax rates

Energy tax ($/MBtu)	Energy tax elasticity
0- 0.5	-0.0097
0.5-1.0	-0.0655
1.0-2.0	-0.1008
2.0-5.0	-0.2800

7.5. Summary

This study which was conducted during the period of 2004-2005, has examined the utility planning, economic and environmental implications of introducing carbon and energy taxes for the development of the power sector in Sri Lanka during the planning period of 2006-2025.

A major finding of the study is that lower carbon tax rates (below $100/tC) may not be effective to reduce CO_2 emissions. At the higher carbon tax rate of $150/tC, it would be possible to achieve a reduction in CO_2 emissions by as high as 82.4%. This is mainly due to replacement of conventional coal-fired power plants by BIGCC power plants. The present study shows that the mitigation of CO_2 emission through carbon tax in Sri Lanka would be costly. Further, the contribution of demand-side effect on CO_2 emission reduction is larger than the supply-side effect at the lower carbon tax rates, whereas the supply-side effect would be increasingly more influential at higher carbon tax rates. It also shows that the overall thermal generation efficiency would decrease at higher carbon tax rates due to the use of less efficient plants like BIGCC. Clearly, it indicates that the overall thermal generation efficiency does not always improve with the carbon tax.

Both carbon and energy taxes would have a beneficial effect in the emission of local/regional pollutants. Emission of both SO_2 and NO_x would have maximum reduction of 81% and 77%, respectively at the carbon tax rate of $150/tC due to substitution of coal-based electricity generation by biomass and other renewables. With the introduction of the energy tax rate of $5/MBtu, there would be a reduction in SO_2 and NO_x by 61% and 54%, respectively, as more efficient technologies such as IGCC and hydropower replace the conventional coal power plants.

Carbon tax elasticity of CO_2 emission is found to be inelastic in Sri Lanka for the carbon tax rates considered in the present study except for the increase in the tax from $100 to $150/tC. At the tax rate of $150/tC, there would be a substantial replacement of coal-fired steam plants, in the capacity mix, by BIGCC (62.5%) and 83% reduction in the CO_2 emission.

Although the imposition of energy tax would result in a 40% increase in total undiscounted cost of power generation over the planning period (2006-2025) at $5/MBtu, about 61% of the increment would be in terms of the energy tax revenue. At the energy tax rate of $5/MBtu, the average incremental cost ($AIC_{overall}$) of the generation system as a whole would increase by 72.3% when compared to that in the base case.

Similarly, the carbon tax revenue would be in the range of 3% to 39% of the total undiscounted cost with the carbon tax rates in the range of \$5/tC to \$150/tC. Note here that this study has not considered the recycling of revenue generated by carbon and energy taxes.

The impact of energy tax rates on CO_2 emission is low (< 13% reduction) at tax rates of up to \$2/MBtu; however, at a higher energy tax of \$5/MBtu, the CO_2 emission would be reduced by about 31% during the planning period. This is because cleaner coal options like IGCC power plants (1,500 MW) would cost-effectively substitute conventional coal-fired power plants at such tax rate.

Post-script

As stated earlier, the case study presented in this chapter was carried out during 2004-2005. As such, the quantitative results presented in the foregoing sections are likely to be different from those results if carried out at present. Such differences could arise due to several factors, e.g., the differences between the demand projections available at the time of the study and the actual growth in demand, as well as the differences between the values of plant capacity costs, fuel prices and efficiency of candidate power plants considered in the study and their actual values since the study was carried out. Furthermore, changes in national energy policies to promote renewable energy options and energy efficient technologies could also be an important factor in influencing the power sector development during the last decade. In this section, an attempt is made to briefly describe some of these factors in the case of Sri Lanka.

Table 7.21 shows the actual values of installed capacity and electricity generation in Sri Lanka during 2006-2013. However, this study estimates that the total electricity generation capacity in the base case would increase at a slightly higher CAGR (i.e., 5.4%) from 2608 MW in 2006 to 4191 MW in 2015, as compared to the actual CAGR of 4.7% of the power generation capacity during the period. Although capacity of fossil fuel plants has been increasing, policies that were later enacted to encourage installation of renewable energy technologies have caused an increase in the RET adoption during 2006-2013. There has been only a nominal decrease in the share of the RETs in the actual installed capacity (i.e., from share of 54% in 2006 to 52% in 2013), while the present study shows a much larger reduction in the share (i.e., from 61% to 44%) during 2006-2015, The installed power generation capacities of hydropower and oil-based thermal plants are reported to have actually increased at CAGRs of 1.7% and 0.4% respectively during 2006-2013 (CEB, 2006 and CEB, 2013), whereas this study has estimated that the hydropower would increase by a CAGR of 2.08% and oil-based plants would decrease by a CAGR of 2.14% from 2006 to 2015. Coal-based plants have also been added to the system to meet the demand not met by hydropower, i.e., a 300 MW of coal-based power plant known as Lakvijaya Power Station (also known as Norocholai power station) was installed and it came into operation in March 2011 (MoPE, 2012). This coal-based plant occupied a share of 8.9% in the total capacity mix of the country in 2012. The share of oil-based thermal power generation in the total capacity mix in this study has been estimated to decrease from 48% to 15% during 2006-2015. Further, this study has estimated that the share of oil-based capacity would decrease at a higher rate than the actual rate (i.e., decreasing from 45.8% in 2006 to 39.7% in 2013).

Table 7.21: Actual capacity mix and electricity generation mix in Sri Lanka during 2006-2013

	Installed Capacity in MW			Gross Generation in GWh		
	2006	2010	2013	2006	2010	2013
Large Hydro	1,207	1,207	1,361	4,289	4,988	6,010
Thermal	1,115	1,390	1,575	4,805	5,063	4,820
NCRE	111	221	355	349	731	1,171
Total	2,443	2,818	3,291	9,498	10,801	12,020

Note: #NCRE means non-conventional renewable energy (solar, dendro, biomass, wind)
Source: Sri Lanka Sustainable Energy Authority (2015)

This study has estimated that the total electricity generation in Sri Lanka was estimated to grow by almost two times during 2006-2015 in the base case; however, Table 7.21 shows that it actually increased by only 1.3 times during 2006-2013. In 2006, the electricity generation mix of Sri Lanka was dominated by oil-based thermal power generation (i.e., around 50.6% in actual and 48% in this study), which was followed by hydropower (i.e., around 49.4% in actual and 46% in the study) and wind (i.e., around 0.04% in actual and 5% in the study). According to SLSEA (2014), in 2013 hydropower dominated the electricity generation mix of the country with its share of around 50% in the total electrical energy generation; it was followed by oil-based thermal power generation (27.9%), coal-based thermal power generation (12.2%) and non-conventional renewable energy (NCRE) with a share of 11%. However, in the present study, it is estimated that the electricity generation mix in 2015 would be dominated by fossil fuel-based plants (with a share of 69%) followed by hydropower (i.e., 28%) and wind (i.e., 3%). The share of NCRE in the actual generation in 2006 has been increasing mainly due to various incentives the government has been providing to develop small hydropower since the late 1990s (Wijayatunga, 2012).

As stated in the "National Energy Policy & Strategies of Sri Lanka", the Government has formulated altogether nine energy policy elements, which include providing basic energy needs, ensuring energy security, promoting energy efficiency and conservation, promoting indigenous resources, adopting an appropriate pricing policy, etc. (MoPE, 2008). The government has formulated plans to rapidly move from the two energy resource-based electricity generation (i.e., mainly hydro and oil), to a multiple resource based generation. The government would not initiate or entertain any proposal to build power plants that would use oil, oil-based products in order to achieve fuel diversity in the electricity generation mix. This initiative would remain in force until 80% of the country's electrical energy supplied to the national grid is based on non-oil based fuels. According to the generation mix proposed by MoPE (2008), the share of hydropower, coal and NCRE in the total electricity generation should be 28%, 54% and 10% respectively by 2015 and that the share of oil should be 8% at the maximum by that year. Similarly the shares should be 13% for hydropower, 7% for oil and 80% for coal and NCRE by 2025 (NRI, 2015). The present study also depicts a similar pattern in generation mix, i.e., by 2025, coal would attain a higher share (i.e., 78.3%) in the total generation mix of the country, followed by hydro (11.6%), oil (7.0%) and renewable energy (3.1%).

The Government of Sri Lanka has targets to reach 100% country-wide household electrification by end 2015 (at beginning of 2015, 98% of the households were electrified). In order to achieve this target, capital subsidies are being provided to promote off-grid electrification in a limited number of areas that do not have access to the grid. The Government has also emphasized the need to promote biomass both as a commercial crop and as a fuel option to generate electricity (SLSEA, 2010). The government had a strategy to gradually decrease the transmission and distribution energy losses in the electricity sub-sector to a maximum of 13.5% net generation by the end of 2009. As a result of this strategy, the transmission and distribution losses decreased from 16.6% in 2006 to 10.8% in 2013 (CEB, 2006 and 2013).

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8. Power Sector Development in Thailand: Effects of Carbon and Energy Taxes[1]

8.1 Introduction

The power sector in Thailand has been heavily dependent on fossil fuels for many years. Due to its limited and dwindling energy sources, Thailand is heavily dependent on fossil fuel imports, which is expected to increase with the growing demand for electricity in the country. Electricity demand in Thailand grew at an average of 8.0% between 1992 and 2005 and 4.9% between 2000 and 2009. The total installed capacity in the grid (including private generators) expanded from 11,045 MW in 1992 to 31,447 MW by 2011 (EGAT, 2013). In 2011, fossil fuel-based electricity generation contributed by 86.7% in total generation. The shares of natural gas, coal/lignite and oil in power generation were 67.0%, 19.0% and 1.1%, respectively (EPPO, 2012).

There is a significant contribution of the power sector in GHG emissions. The total CO_2 emission from fossil fuel combustion in Thailand in 2011 was 243.2 million tons (IEA, 2013), of which the power sector accounted for 36.0% (EPPO, 2012). The shares of coal, natural gas, and oil in the total CO_2 emissions from the power generation sector in 2011 were 38.7%, 60.4% and 0.9%, respectively (EPPO, 2012). CO_2 emission in Thailand is estimated to rise with the growing consumption of fossil fuels. The future development of the CO_2 emission intensity of this sector depends strongly on the fuels used to generate electricity and on the level of use of renewable energy sources together with the power generation efficiencies of fossil fuel plants.

This study was carried out during 2004-2005 using the electricity demand forecast and relevant data available for Thailand at the time of the study. This chapter discusses the utility planning, environmental and economic implications of introducing carbon and energy taxes in the power sector of the country. Six selected carbon tax rates[2], i.e., \$5/tC, \$10/tC, \$25/tC, \$50/tC, \$100/tC and \$150/tC and four selected energy tax rates[3], i.e., \$0.5/MBtu, \$1/MBtu, \$2/MBtu and \$5/MBtu were considered in this

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[1] The authors of this chapter are: Janak Shrestha, Bundit Limmechokchai and Ram M. Shrestha.

[2] Carbon tax, such as \$5/tC, is also referred to as CT5. Similar connotations have been used for other carbon tax values.

[3] Energy tax, such as \$0.5/MBtu, is also referred to as ET0.5. Similar connotations have been used for other energy tax values.

study. The plan of this chapter is as follows: Section 8.2 contains the results of the least cost generation planning in the "Base Case" (i.e., without carbon and energy taxes). Sections 8.3 and 8.4 discusses the effects of carbon and energy taxes, respectively in the power sector development. Section 8.5 summarizes the key findings, which is followed by a postscript at the end of the chapter. The post-script presents a discussion on the differences between the results of the base case of this study and the actual data related to the growth in electricity generation, generation mix and capacity additions and energy policies related to the power sector in recent years after the study was carried out.

8.2 Base Case Analysis

8.2.1 Definition of the base case

Input data and assumptions

The base case in this study represents a reference scenario of the power sector development in Thailand without any climate and energy policy interventions (i.e., without considering the introduction of carbon and energy taxes). This section presents the electricity demand forecast and information about the technical characteristics and costs of existing and candidate power plants used in the analysis.

The projected electricity demand considered in this study was based on long-term load forecasts prepared by the National Institute of Development Administration (NIDA) Consulting Centre (EPPO, 2006). Of the various scenarios considered for the projection of the load growth, the moderate economic growth scenario corresponding to an annual average growth rate (AAGR) of 5.7% during 2006-2020 was considered in this study[4]. The load forecast study by EPPO covered a period of 16 years (2005-2020). The AAGR of peak load projection was estimated to be 5.7% during 2006-2025 (see Table 8.1).

In this study, based on data from EGAT (2006)[5], the monthly load data were grouped to represent load patterns for three seasons, each of four months: rainy (July to October), winter (November to February) and summer (March to June).

Based on the historical load patterns from the data received from EGAT, the load factor of 75% has been assumed throughout the planning period (i.e., 2006-2025).

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[4] The updated PDP-2007 is available presently as PDP-2010. It should be noted that the AAGR of 5.7% used in the present study is close to AAGR of 4.2% for the period of 2008-2021 in the PDP-2010.

[5] The daily load curve data was provided by EGAT on September 2006. The data can be made available upon request.

Table 8.1: Peak load projections (MW).

Year	Peak Load (MW)	Year	Peak Load (MW)
2005	21,222	2016	39,452
2006	22,290	2017	41,711
2007	23,500	2018	44,089
2008	24,910	2019	46,594
2009	26,445	2020	49,234
2010	28,046	2021	52,012
2011	29,722	2022	54,935
2012	31,480	2023	58,009
2013	33,326	2024	61,242
2014	35,266	2025	64,642
2015	37,306		

Source: Based on EPPO (2006)

Existing and candidate power plants

Natural gas-based combined cycle power plants (NGCC) have dominated the power generation system of the country accounting for more than 60% share in the capacity mix and generation mix.

All combined cycle plants in Thailand use natural gas and serve the base and the intermediate load of the system. Gas turbine and hydropower plants are used to meet the peak load demands. The installed capacity of existing hydropower plants in Thailand was 2,886 MW in 2001/2002 (EGAT, 2013). The average annual generation of all hydro plants was 4,700 GWh. In PDP-2004, there were no plans to add new hydroelectric capacity in Thailand due to public concerns about environmental effects of hydropower plants. However, EGAT purchased 340 MW of hydropower from Lao PDR since 1998/99, with the addition of 2,080 MW by 2014 (EGAT, 2015; EPPO, 2015). The committed plants in the future are mainly based on imported coal[6].

[6] Coal found in Thailand is ranked from lignite to sub-bituminous. Most of the domestically produced coal is of rather low quality, giving low calorific value. There has been public opposition to local pollutants (NO_x and SO_x) from coal-fired power plants and has forced several proposed projects to switch to natural gas and/relocate to alternate sites. In order to improve public acceptance and means to increase power system security and minimize generating cost, the greater import of coal (of higher quality than local production) and the uptake of cleaner coal technologies have been encouraged by the Thai Government. A regulation has been introduced in Thailand on mandatory requirement of installing Selective Catalytic NO_x Removal (SCR), Flue Gas Desulphurization Plant (FGD) and Electrostatic Precipitator (ESP) along with the implementation of coal-fired power plant in Thailand.

EGAT has the policy to buy back the electricity generated by small power producers.

Besides conventional power plants, the candidate plants considered in this study include cleaner and energy efficient technologies (CEETs) such as integrated gasification combined cycle (IGCC), pressurized fluidized bed combustion (PFBC), biomass integrated gasification combined cycle (BIGCC) and biomass-fired power plants. Two renewable energy based non-dispatchable technologies (i.e., solar and wind) are also considered as candidate plants in this study, whereas the nuclear power generation has not been considered as an option. Also, no new hydropower plant has been considered as a candidate in the study except for the 340 MW hydropower project in Lao PDR, which was considered as imported power. In this study, the low-speed wind turbine of 150 kW per plant unit (at the capacity cost of $1,100 per kW) has been considered as an option due to the low wind energy potential in the country. In this study, the candidate PV plants each of 1 MW capacity with the capacity cost of $4,500 per kW were considered.

The discount rate used in this study is 10%. A reserve margin of 15% is assumed throughout the planning period (i.e., during 2006-2025) in compliance with PDP-2005. Three seasons, i.e., rainy (with 123 days), winter (120 days) and summer (122 days) per year are considered. The transmission loss of 2.9% as is reported in the PDP-2005 is used in the study.

8.2.2 Power sector development during 2006-2025

This section presents the generation expansion plan in the base case during the planning period of 2006-2025. The least-cost generation expansion planning exercise shows that about 46,439 MW of the power generation capacity would be added to the system resulting in a total installed capacity of 74,311 MW by the year 2025 (see Table 8.2).

Table 8.2: Generation capacity mix by fuel types at selected years in the base case (MW).

Power plant type	Year				
	2006	2010	2015	2020	2025
Coal	2,700	4,046	7,546	6,946	5,646
Gas	15,754	19,954	24,754	39,644	57,133
Oil	2,774	3,113	2,638	1,091	1,091
Hydro	4,682	4,682	4,682	4,682	4,682
Renewable*	1,962	2,301	3,286	4,611	5,759
Total	27,872	34,096	42,906	56,974	74,311

* Including bagasse, paddy husk, corncob, cassava and fuel wood.

This study shows that mostly combined cycle gas turbine (CCGT) capacity would be added during 2006-2025 while the conventional coal-fired power plants with local air pollutant control devices would become less cost-effective. Some new capacity based on clean coal technologies (CCTs) (such as IGCC and supercritical plants (SC)) and renewable energy technologies (RETs) such as BIGCC and conventional biomass-steam would also be cost-effective during the period. There would be no additional hydropower plants (except for the already committed hydropower plant for import of power from Lao PDR). The wind and solar-based power plants are not found to be cost-effective due to their high capacity costs despite the fact that the costs had been falling significantly when the study was carried out. Of the total generation capacity, the share of the gas-based power plant would be around 77%, followed by hydro- (14%), coal- (7.6%) and oil- (1.5%) based power plants. The share of RETs such as PV, biomass-based power plants, etc. would be about 7.7%.

This study shows that the total annual electricity generation in Thailand would grow from 150.7 TWh in 2006 to 436.8 TWh by 2025. As can be seen from Table 8.3, natural gas would maintain its dominance in total power generation in the country during 2006-2025 with its share increasing from 67.9% in 2006 to 78.5% by 2025. The share of renewables (excluding hydro) would vary from 8.8% to 9.6% during the period.

Table 8.3: Electricity generation mix by plant types in selected years in the base case (%).

Power plant type	Year				
	2006	2010	2015	2020	2025
Coal	12.6	15.0	21.2	14.8	9.2
Gas	67.9	65.9	62.4	71.3	78.5
Oil	5.0	3.9	2.4	0.6	0.5
Hydro	5.0	6.4	4.8	3.6	2.8
Renewable*	9.5	8.8	9.2	9.6	9.1
Total (GWh)	150,698	189,614	251,986	332,629	436,800

* Including bagasse, paddy husk, corncob, cassava and fuel wood.

Table 8.4 presents the energy used for power generation by type of energy source. The cumulative energy use for power generation during 25 years (i.e., 2006-2025) is estimated to be 285 Mtoe, of which the share of gas was about 66%, followed by coal (17%), renewable fuel (15%) and oil (2%). The high share of gas is in line with the government policy, as the Thai Government policy on CEET has focused on fuel switching and increasing the use of cleaner fossil fuels such as natural gas or low-sulfur content coal. A number of coal power plants already committed during the early years explain the increased share of coal during those years. . The share of gas in the total fuel consumption, on the other hand, would dramatically increase post-2015 as the gas-based power generation technologies are found to be more cost-effective than the efficient coal-fired power plants.

Table 8.4: Fuel use in power generation in selected years (Mtoe).

Fuel Type	Year				
	2006	2010	2015	2020	2025
Coal	5.3	7.7	13.2	12.0	9.3
Gas	21.1	25.5	31.4	44.7	64.1
Oil	2.06	2.04	1.60	0.51	0.51
Renewable*	5.0	5.9	8.1	10.8	13.6
Total	33.5	41.1	54.3	68.1	87.5

* Including bagasse, paddy husk, corncob, cassava and fuel wood.

Generation system efficiency

As shown in Figure 8.1, the annual weighted average thermal generation efficiency (WATGE) (see section 2.2.5 for a detailed explanation on WATGE) would be increasing during 2006-2025 and that the WATGE in 2025 would be 13.3 percentage points higher than that in 2006. This is because more efficient gas-based power plants (such as CCGT) would be installed over time, while less efficient power plants (such as oil-based power plants) would be discontinued by year 2025. The overall WATGE of the system during 2006-2025 would be about 38.9%.

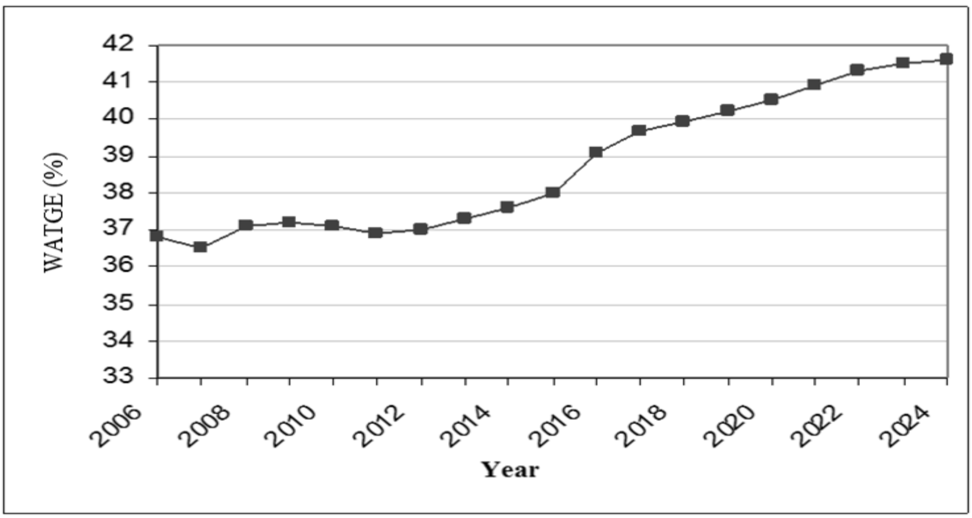

Figure 8.1: Annual weighted average thermal generation efficiency (WATGE) in the base case.

8.2.3 Environmental implications

The total cumulative CO_2 emission during 2006-2025 in the base case is estimated to be about 2,384 million tons (see Figure 8.2). The CO_2 emission in the year 2025 would be about 164 million tons, which is more than double the amount in 2006. The CAGR of the CO_2 emission from the power sector during 2006-2025 would be around 4%.

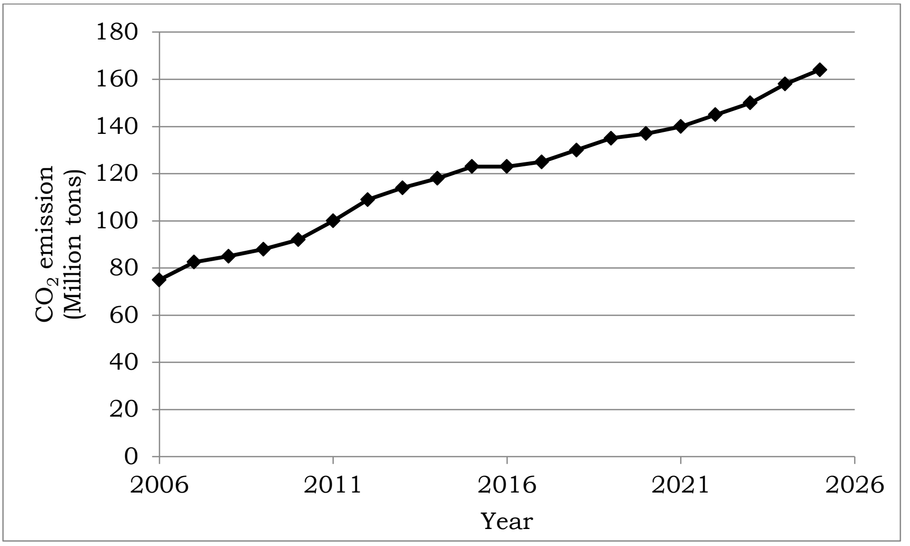

Figure 8.2: Annual CO_2 emission in the base case.

Figure 8.3 shows the annual CO_2 intensity during 2006-2025. The CO_2 intensity would decrease from 14.6 gC/MJ in 2006 to 12.2 gC/MJ in 2025. Note that during 2006-2015, the carbon intensity of energy use in power generation would decrease slightly during 2006-2010. It increases slightly during 2010-2015 (as the share of coal in the total fuel consumption would increase and that of natural gas would decrease slightly till 2015) and decline significantly thereafter until 2025 (see also the fuel-mix in Table 8.5). The decrease in CO_2 intensity of the power sector during 2015 to 2025 is due to a shift to the low carbon energy resource (i.e., gas) in Thailand. Note that the share of gas use or power generation in the country would increase from 63.0% in 2006 to 73.3% by 2025.

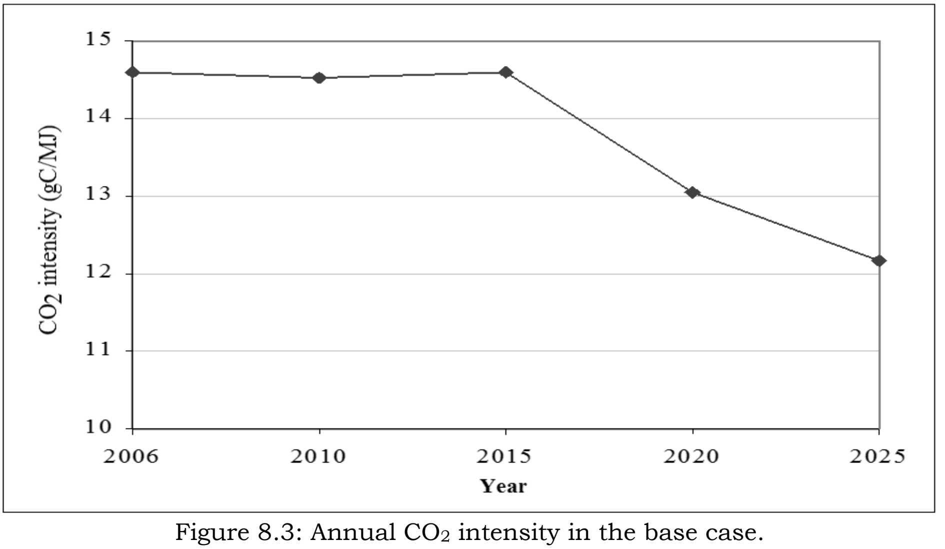

Figure 8.3: Annual CO_2 intensity in the base case.

Figure 8.4 shows the annual SO_2 and NO_x emissions during 2006-2025. As can be seen from the figure, the SO_2 emission would remain almost stable and decrease significantly by the year 2025 compared to that in 2006. The results show that the SO_2 emission in the year 2025 would be about 14% of that in the year 2006. This reduction is because of the substantial amount of electricity generation coming from gas and efficient coal power generation technologies (e.g., supercritical and IGCC) during the later part of the planning horizon (i.e., 2020-2025). Unlike SO_2 emission, the NO_x emission would increase with the CAGR of 5% during the period. The NO_x emission in 2025 would be about 2.3 times of that in 2006.

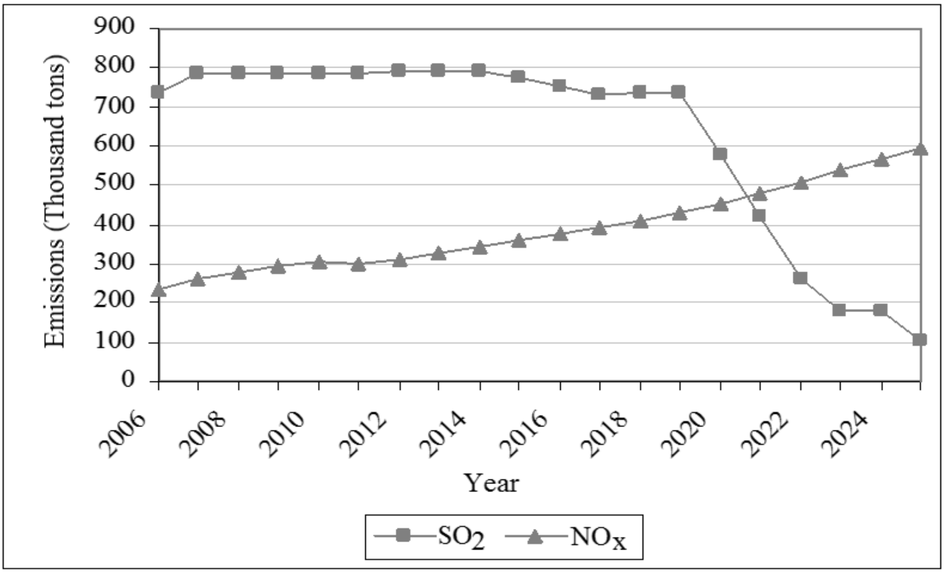

Figure 8.4: Annual SO_2 and NOx emission in the base case.

8.2.4 Economic implications

The total cost of power generation during 2006-2025 was estimated to be about \$236,505 million, about 84.3% of which was fuel and variable operation and maintenance cost. The overall average incremental cost of electricity generation ($AIC_{overall}$) was found to be ¢4.96/kWh, while the long-run average cost (LRAC) was ¢4.57/kWh.

8.3 Effects of Carbon Tax

8.3.1 Utility planning implications

Generation technology capacity mix

In line with most other studies, the carbon tax will encourage switching from carbon-intensive fuels to low carbon fuels. In this study, biomass-based power plants would become increasingly attractive with the introduction of a carbon tax (see Table 8.5). This effect is because the biomass power plants are assumed to have zero net CO_2 emission[7]. As shown in Table 8.5, the number of biomass-based power plants added to the system would increase with the increase in the carbon tax rate while fossil-based power plants (such as CCGT, IGCC, etc.) would decrease with the increase in the tax rate. Nevertheless, the share of gas-based power plants added to the system during 2006-2025 is still much higher than that of the biomass-based power plants, even at the highest carbon tax rate. The reason is on account of the limited biomass resources in Thailand. The non-dispatchable renewable energy technology power plants (such as the wind and solar) would not be attractive[8], even with the introduction of the carbon tax. This is due to their capacity costs and low plant capacity factors.

Table 8.5: Generation capacity additions by plant types during 2006-2025 at selected carbon tax rates (MW).

Power plant technology	Base case	Carbon tax ($/tC) +					
		5	10	25	50	100	150
Conventional coal	-	-	-	-	-	-	-
Gas turbine	-	-	-	-	-	-	-
Advanced gas turbine	-	-	-	-	-	-	-
CCGT	50,100	54,000	53,100	52,800	52,500	51,900	51,300
Supercritical	500	-	-	-	-	-	-
PFBC	-	-	-	-	-	-	-
IGCC	3,500	-	-	-	-	-	-
BIGCC	525	525	750	750	750	750	750
Biomass conventional	2,971	2,996	3,621	3,721	3,721	3,746	3,721
Total	57,596	57,521	57,471	57,271	56,971	56,396	55,771

+ A '-' sign means either zero or a negligible quantity.

Coal-based power plants are only attractive in the base case (i.e., in the absence of carbon tax). In the carbon tax cases, such plants would not be attractive even at the lowest carbon tax rate considered. The effect of carbon tax on the capacity of different types of power plants can be seen in Figure 8.5.

The total installed capacity in carbon tax rates of $5/tC, $10/tC, $25/tC, $50/tC, $100/tC and $150/tC in year 2025 would be 74,311 MW, 74,286

[7] In the present study, carbon emission from biomass fuel combustion would not be taxed as biomass fuels are assumed to be produced in a sustainable manner.

[8] The combination of technologies (combined cycle gas turbine and biomass) serving base and intermediate load appears to be the most cost-effective technologies for Thai power system with steady load demand (75% Load factor) against low capacity factor of non-dispatchable solar and wind technologies whose availability in the system depends upon solar insolation and wind supplying power to a grid intermittently.

MW, 74,236 MW, 74,036 MW, 73,736 MW, 73,161 MW and 72,536 MW, respectively. The decrease of the total installed capacity is due to the decrease in demand for electricity resulting from the increase in electricity price due to the introduction of the carbon tax. The total installed capacity at the lowest tax (i.e., at $5/tC) would be slightly lower than that in the base case while, at the highest tax (i.e., at $150/tC), it would be 3.17% lower than that in the base case.

The reduction in the installed capacity of coal- and oil-fired power plants at different carbon tax rates considered would remain almost at the same level as that would take place at the tax rate of $5/tC. On the other hand, there would be an increase in the installed capacity of the gas-fired power plant at $5/tC and only a marginal gradual decrease with further increase in the tax rate. The capacity of renewable power plant (biomass) would be increased at the tax rate of $10/tC but would remain unchanged thereafter at higher tax rates.

Generation Mix

The cumulative electricity generation during 2006-2025 would decrease from 5,434 TWh in the base case to 5,433 TWh, 5,429 TWh, 5,415 TWh, 5,392 TWh, 5,347 TWh and 5,304 TWh at CT5, CT10, CT25, CT50, CT100 and CT150, respectively. The decrease in electricity generation with the carbon tax is due to the decrease in demand for electricity as a result of the increase in electricity price. Figure 8.5 shows the cumulative generation mix at the base and the carbon tax cases during 2006-2025. The shares of hydro and oil would remain almost the same in carbon tax cases. In the carbon tax cases, the share of coal would decrease while that of gas and renewable (i.e., biomass) would increase as compared to that in the base case.

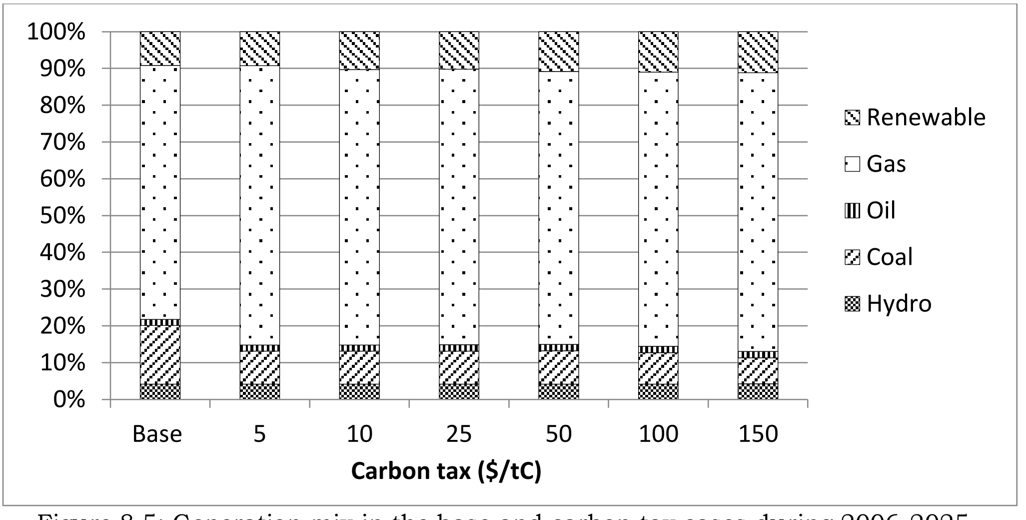

Figure 8.5: Generation mix in the base and carbon tax cases during 2006-2025.

Fossil fuel consumption

In the case of Thailand's power sector, a carbon tax would encourage a switch from fossil fuels to renewables (mainly indigenously produced biomass-based fuels) for power generation (see Table 8.6). Note that the share of coal in electricity generation would decrease with the increase in a carbon tax.

Table 8.6: Share of fuel use in the base case and selected carbon tax rates during the planning period (Mtoe).

Carbon Tax (US$ /tC)	Coal	Oil	Gas
Base Case	15.94	1.72	69.06
5	8.98	1.72	75.93
10	8.98	1.72	74.89
25	9.01	1.72	74.95
50	9.05	1.73	74.23
100	8.52	1.74	74.59
150	7.06	1.76	75.78

Generation capacity utilization

Figure 8.6 presents the weighted average capacity factor (WACF) of the power system during 2006-2025 at different values of carbon tax considered (see Section 2.1.6 in Chapter 2 for an explanation on WACF). The figure shows that the capacity factor is found to decrease with the increase in the carbon tax rate. This is because the electricity generation from existing plants (i.e., existing coal- and oil-fired plants) decreases and is substituted by new plants. Furthermore, the carbon tax would lead to underutilization and redundancy of some power plants. As a result, the WACF of existing plants would decrease at the higher tax rates.

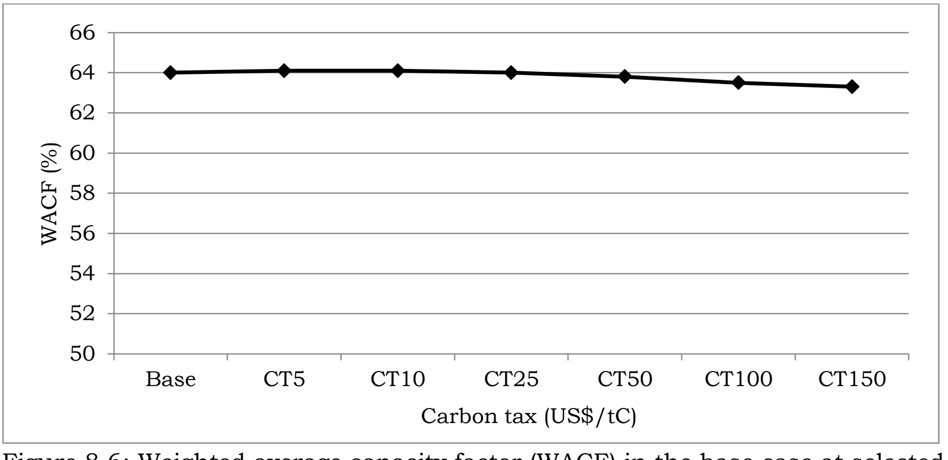

Figure 8.6: Weighted average capacity factor (WACF) in the base case at selected carbon tax rates.

Power generation system efficiency

Figure 8.7 shows the annual weighted average thermal generation efficiency (WATGE) of the power system in the base case and carbon tax cases (see Section 2.1.5 in Chapter 2 for an explanation of WATGE and its calculation).

The figure shows that the WATGE would be mostly increasing over time during 2006-2025 although there are some fluctuations from year to year. It is however found that there is no significant increase in overall WATGE in carbon tax cases as compared to the baseline during 2006-2025.

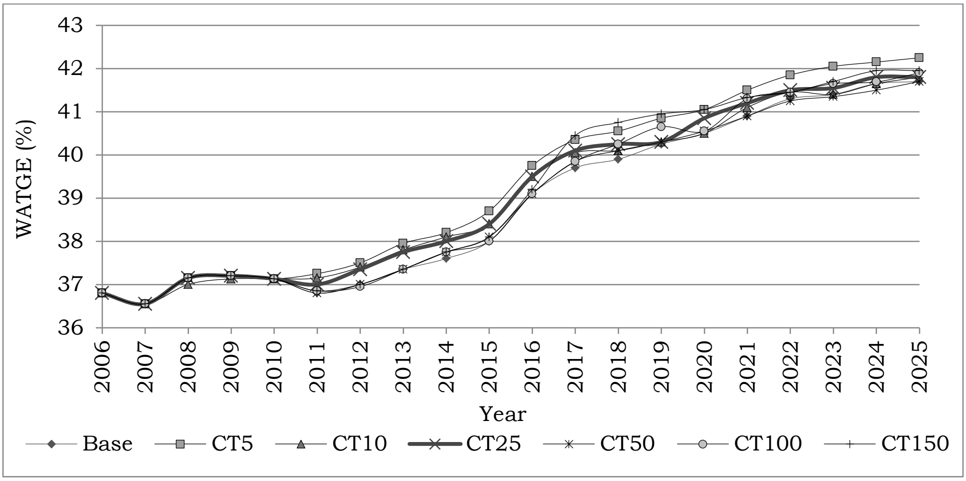

Figure 8.7: Weighted average generation system efficiency (WATGE) in the base and carbon tax cases.

8.3.2 Environmental implications

Figure 8.8 shows the annual CO_2 emission during 2006-2025 at selected carbon tax rates. The cumulative CO_2 emission during the period is found to decrease from 2,384 million tons in the base case to 2,225 million tons at the carbon tax rate of \$5/tC, i.e., a reduction of about 7% as compared to the emission in the base case. However, if a carbon tax rate of \$150/tC were introduced, the total CO_2 emission would be 2,068 million tons, i.e., a reduction of 13.2% as compared to the base case.

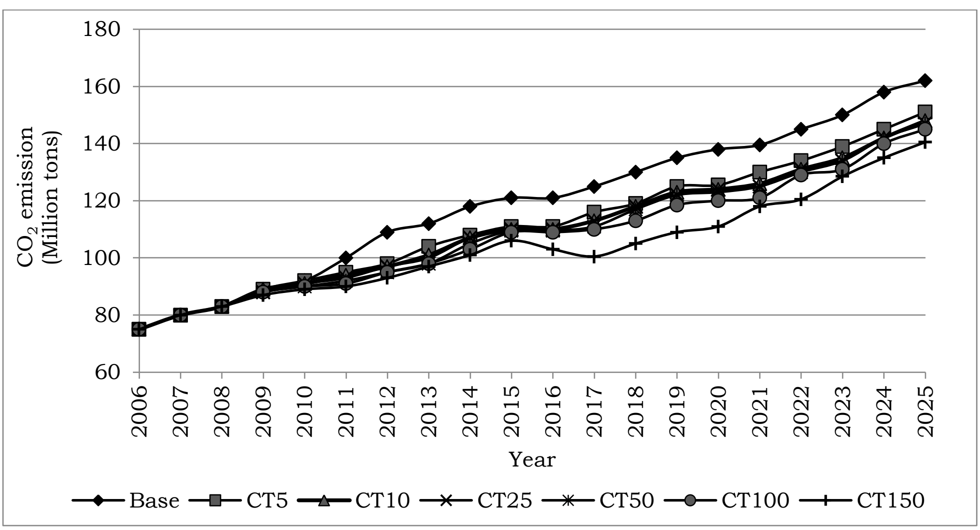

Figure 8.8: Annual CO_2 emission in the base case and carbon tax cases.

The CO_2 emission would grow less rapidly with the introduction of the carbon tax. At carbon tax rate of $5/tC, the CAGR would be 3.8% and would decrease to 3.6% at $150/tC carbon tax rate. Both of these are lower than the CAGR of CO_2 emission in the base case, which would be around 4%.

Carbon tax elasticity of CO_2 emission

Carbon tax elasticities of CO_2 emission are calculated at different carbon tax rates considered in this study to understand how the CO_2 emission responds to a change in carbon tax (see Section 2.1.4 in Chapter 2 for an explanation on the elasticity of CO_2 emission). The result shows that the CO_2 emission is found to be inelastic on the carbon tax studied (see Table 8.7)

Table 8.7: Carbon tax elasticities of CO_2 emission from the power sector at the selected tax rates.

Carbon tax ($/tC)	Elasticity
0 – 5	-0.035
5 – 10	-0.015
10 – 25	-0.0019
25 – 50	-0.015
50 – 100	-0.028
100 – 150	-0.081

Decomposition of CO_2 emission reduction: The role of supply- and demand-side effects

Table 8.8 presents the total CO_2 mitigation at various levels of carbon tax as well as the contributions of the supply- and demand-side effects in the emission mitigation (see Section 2.2 for estimation of supply- and demand-side effects of the carbon tax). The table shows that CO_2 mitigation due to the demand-side effect is always smaller than that due to the supply-side effect. This is because of the significant replacement of coal-based power plant with biomass-based power plant (which is assumed to be carbon neutral) under the carbon tax rates.

Table 8.8: Power sector CO_2 reductions and decomposition of CO_2 reduction during 2006-2025.

Carbon tax ($/tC)	CO_2 emission reduction (10^6t)	Demand-side effect (%)	Supply-side effect (%)
5	159.9	1.0	99.0
10	182.3	0.3	99.7
25	186.0	0.0	100.0
50	207.5	9.2	90.9
100	247.8	14.7	85.3
150	316.3	14.8	85.2

Implications on CO_2 emission intensity

Figure 8.9 shows the annual CO_2 emission intensity in the base case and carbon tax cases. The figure shows that the CO_2 emission intensity of power generation would be improving consistently after 2010 in all the carbon tax cases. In 2025, for some particular years, introducing a carbon tax to the Thailand's power sector would not necessarily improve the CO_2 emission intensity. These are affected by the fluctuation in electricity generation from different types of power plants. In the base case, the CO_2 emission intensity would decrease from 14.6 gC/MJ in 2006 to 12.2 gC/MJ in 2025, whereas the intensity would decrease from 14.3 gC/MJ in 2006 to 10.8 gC/MJ with the tax rate of $150/tC.

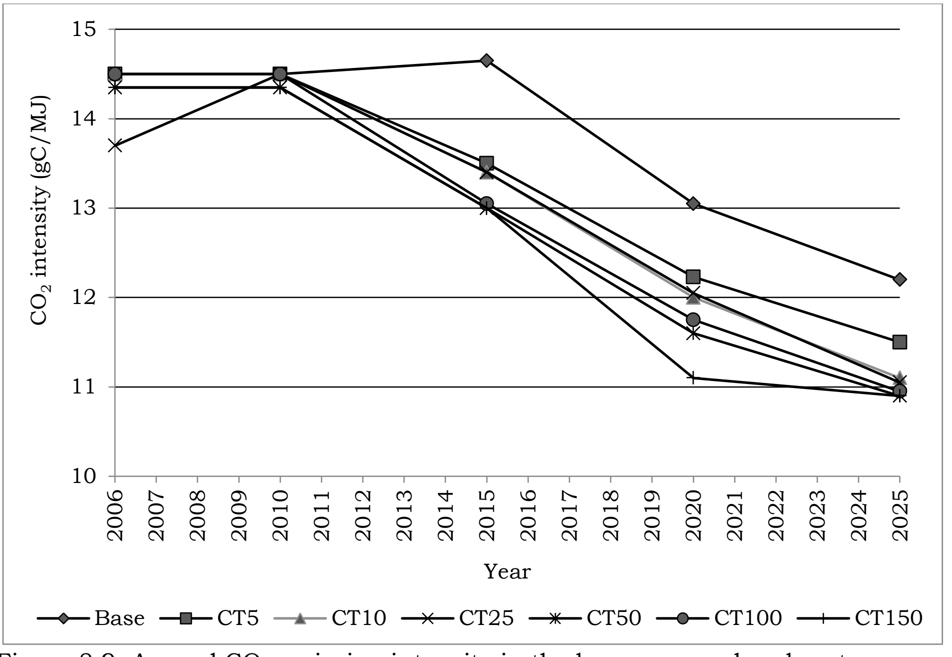

Figure 8.9: Annual CO_2 emission intensity in the base case and carbon tax cases.

CO_2 intensity (measured in tons of CO_2 emission per MWh) would decrease from 0.44 tons/MWh in the base case to 0.41 tons/MWh at $5/tC and 0.39 tons/MWh at $150/tC.

Local/regional pollutant emissions

Figures 8.10 and 8.11 show the annual SO_2 and NO_x emissions, respectively in the base case and carbon tax cases. The emission of SO_2 from the power sector would be decreasing in the base and carbon tax cases. The reductions would be more noticeable under the carbon tax rates of $100/tC and $150/tC after 2017. The CAGR of SO_2 emission in the base and carbon tax cases would lie in the range of -8.3% to -11.1%. Unlike the SO_2 emission, the emission of NO_x would be increasing at a CAGR of 5.0 to 5.3% under the base and carbon tax cases considered.

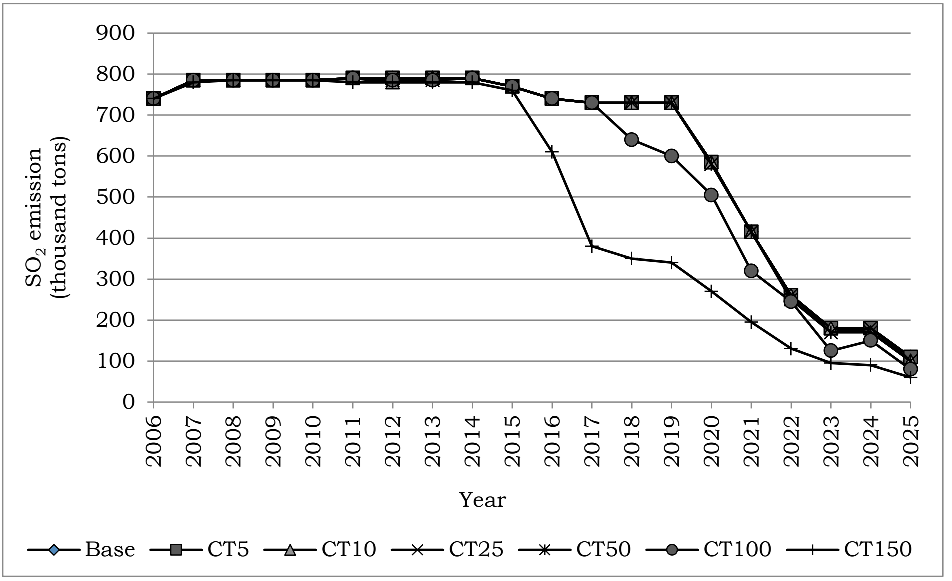

Figure 8.10: Annual SO_2 emission in the base case and carbon tax cases.

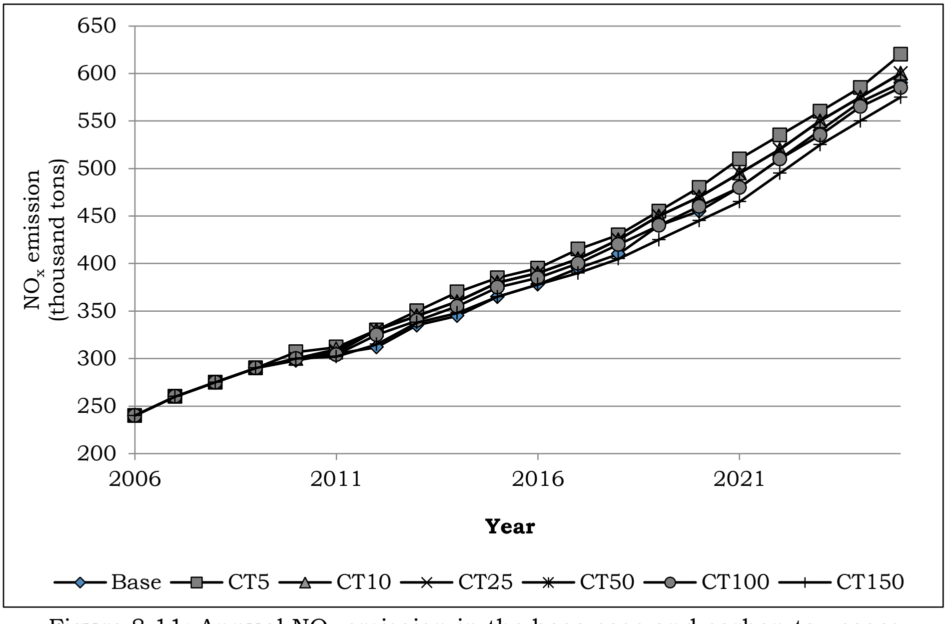

Figure 8.11: Annual NO_x emission in the base case and carbon tax cases

Table 8.9 shows cumulative emissions of SO_2 and NO_x during 2006-2025 in the base and carbon tax cases as well as the reductions in the emissions under different tax rates as compared to the cumulative base case emissions. In the case of SO_2 pollutant, there would be very large reductions in SO_2 emission at the carbon tax rates of $100/tC and $150/tC, while there would be a gradual reduction in NO_x emission with the introduction of carbon tax (see Table 8.9).

Table 8.9: Cumulative SO_2 and NO_x emissions and mitigations due to carbon tax during 2006-2025 (1000 tons).

Carbon tax ($/tC)	SO_2		NO_x	
	Emission	Mitigation	Emission	Mitigation
0 (Base case)	12,480	0	7,767	0
5	12,392	88	8,070	4,411
10	12,399	82	7,988	4,492
25	12,398	82	7,976	4,505
50	12,398	82	7,895	4,585
100	11,902	579	7,778	4,702
150	10,260	2,220	7,628	4,852

8.3.3 Economic implications

Electricity generation system cost

Table 8.10 shows the total cost of power generation in Thailand during 2006-2025 at the base and selected carbon tax cases. The total cost would increase in the range of 1.2% to 33.3% in the range of the carbon tax rates considered in this study. As shown in the table, the fuel and variable O&M cost would have the highest share in the total cost (i.e., in the range of 84% to 91%), followed by the capacity cost (i.e., in the range of 6% to 11%) and fixed O&M costs (i.e., in the range 3% to 6%) in all cases.

Table 8.10: Contribution of capacity, fixed O&M and variable O&M costs to the total cost at selected carbon tax rates (Discounted value) during 2006-2025.

Carbon tax	Capacity cost		Fixed O&M cost		Variable cost		Total cost ($10^6$$)
($/tC)	($10^6$$)	(%)*	($10^6$$)	(%)*	($10^6$$)	(%)*	
0 (Base case)	5,846	10.6	2,826	5.1	46,536	84.3	55,208
5	4,767	8.5	2,654	4.8	48,439	86.7	55,860
10	4,882	8.6	2,687	4.8	48,931	86.6	56,499
25	4,864	8.3	2,683	4.6	50,832	87.1	58,378
50	4,929	8	2,706	4.4	53,857	87.6	61,492
100	4,914	7.3	2,704	4	60,025	88.7	67,643
150	4,879	6.6	2,699	3.7	66,037	89.7	73,615

*These numbers show the cost as the percentage of the total cost.

Carbon tax revenue

As shown in Table 8.11, the tax revenue would increase from $4,732 million at the carbon tax rate of $5/tC to $175,977 million at the tax rate of $150/tC. In the range of the carbon tax considered (i.e., $5 to $150/tC) the tax revenue would lie in the range of 2% to 42% of the total cost.

Table 8.11: Cumulative carbon tax revenue and total undiscounted total cost (gross and net of tax) during 2006-2025 at selected carbon tax rates.

Carbon tax ($/tC)	Tax revenue	
	(10^6 $)	(%)*
5	4,732	2
10	9,336	4
25	23,313	9
50	46,075	17
100	91,166	31
150	134,401	42

* These numbers show the tax revenue as the percentage of the total cost

Unit cost of electricity generation

Figure 8.12 presents the $AIC_{overall}$ and LRAC at different carbon tax rates. The figure shows that the LRAC would increase form ¢4.57/kWh in the base case to about ¢6.25/kWh at the carbon tax of $150/tC. Similarly, the $AIC_{overall}$ would increase from ¢4.96/kWh in the base case to about ¢6.40/kWh at the tax rate of $150/tC.

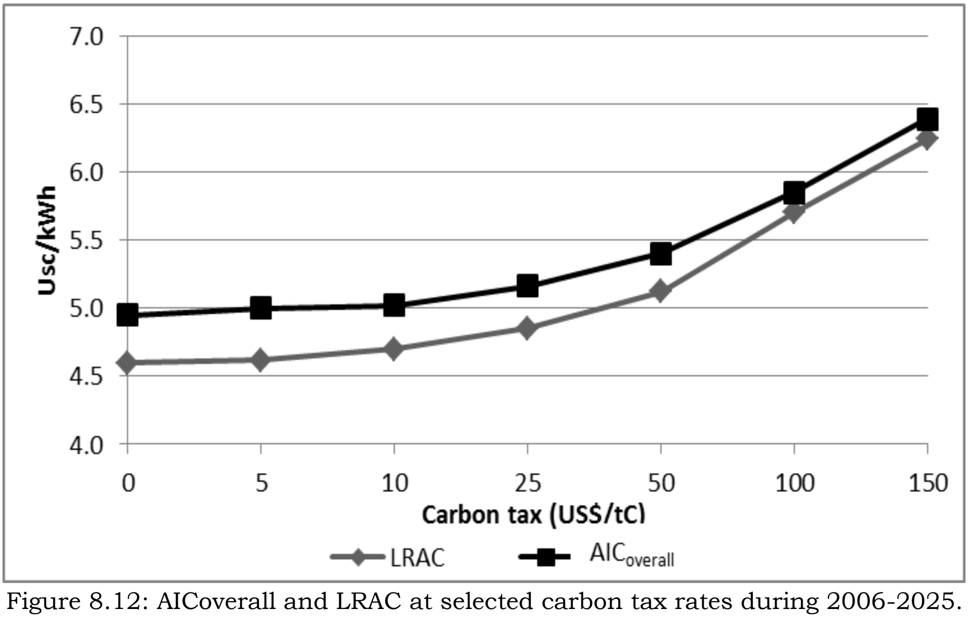

Figure 8.12: AICoverall and LRAC at selected carbon tax rates during 2006-2025.

8.4 Effects of Energy Tax

8.4.1 Utility planning implications

Generation technology capacity mix

Table 8.12 shows the power plant technology selection in the base and energy tax cases. The table shows that CCTs (such as IGCC, PFBC, and SC) would not be cost-effective during 2006-2025 although these plants were considered as candidate plants. This is because of the relatively high capacity costs of these plants. In the energy tax cases, only CCGT and conventional biomass power plants would be cost-effective during the period. BIGCC plants would be economically attractive only at energy tax rate of $1/MBtu. The total capacity of conventional biomass power plants added cost-effectively would decrease with the increase in energy tax rates while the total capacity added of CCGT plants would increase with the increase in energy tax rates. This is because the efficiency of a conventional biomass-based power plant is lower than that of a gas-based combined cycle power plant. Furthermore, the capacity cost of the biomass-based power plant is higher than that of the gas-based combined cycle power plant.

Figure 8.13 shows the installed generation capacity based on fuel use in the base case and energy tax cases in the year 2025. The total installed capacity required for power generation during 2006-2025 is found to decrease with the energy tax. The total generation capacity would be 73,941 MW, 73,541 MW, 71,140 MW and 71,015 MW by 2025 at energy tax rates of $0.5/MBtu, $1/MBtu, $2/MBtu and $5/MBtu, respectively; i.e., the total installed capacity requirement would be reduced by 1%, 2%, 4% and 5% respectively than that in the base case.

Table 8.12: Capacity addition by plant types during 2006-2025 at selected energy tax rates (MW)+.

Plant type	Base case	Energy tax ($/MBtu) +			
		0.5	1	2	5
Conventional coal	-	-	-	-	-
Gas turbine	-	-	-	-	-
Advanced gas turbine	-	-	-	-	-
CCGT	50,100	54,300	53,700	54,000	54,000
Supercritical	500	-	-	-	-
PFBC	0	-	-	-	-
IGCC	3,500	-	-	-	-
BIGCC	525	-	150	-	-
Conventional biomass	2,971	2,876	2,926	2,023	250
Wind	-	-	-	-	-
Solar	-	-	-	-	-
Total	57,596	57,176	56,776	56,023	54,250

+ A '-' sign means either zero or a negligible quantity.

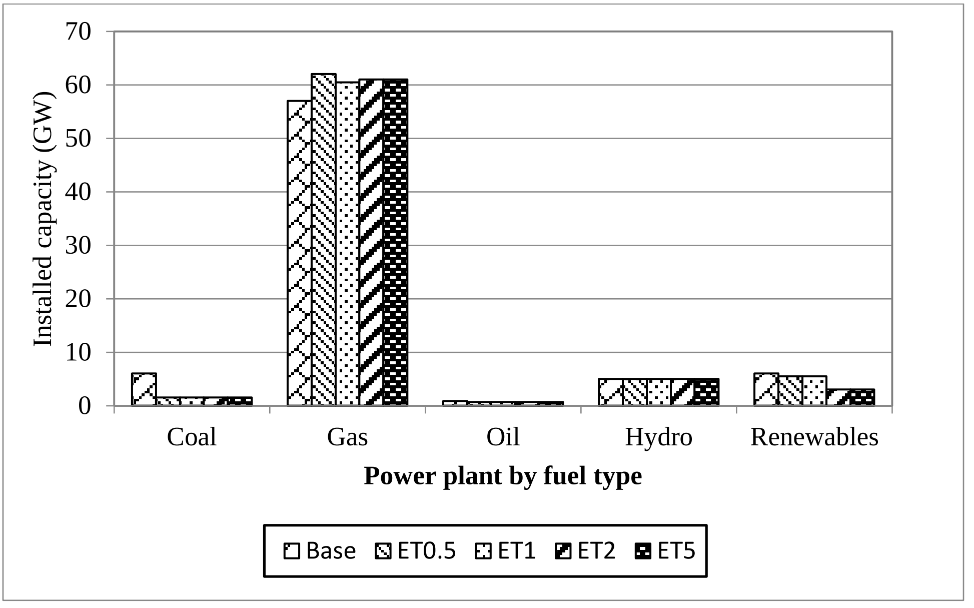

Figure 8.13: Installed generation capacity based on fuel use in the base case and at selected energy tax rates in the year 2025

The gas-based power plants have the predominant share in the total generation capacity (in the range of 83% to 87%) in the energy tax cases. The total installed capacity of the conventional coal-fired power plant during the period would decrease significantly even at the energy tax rate of $0.5/MBtu and would not change much with higher tax rates. The share of conventional coal-fired power plants in the total installed capacity would lie in the range of 2% to 3% at the energy tax rates considered. The share of renewable-based power plants in the total generation capacity during the period would decrease from 7% at the energy tax rate of $0.5/MBtu to 3.6% at the tax rate of $5/MBtu. The share of hydro-based power plants would be maintained in the range of 6% to 7% in the energy tax cases while that of oil-based power plants would lie below 2%.

Electricity generation mix

Figure 8.14 shows annual electricity generation in the base and energy tax cases. The CAGR of the electricity generation in the base case and energy tax cases would be around 7.5%. The cumulative electricity generation during 2006-2025 in the base case would be 5,433 TWh whereas it would be about 5,408 TWh, 5,379 TWh, 5,323 TWh and 5,185 TWh at energy tax rates of $0.5/MBtu, $1/MBtu, $2/MBtu, $5/MBtu, respectively. The total electricity generation would be reduced by about 0.5% at the energy tax of $0.5/MBtu and by about 5% at the tax of $5/MBtu as compared to that in the base case due to the increase in electricity price resulting from the energy tax.

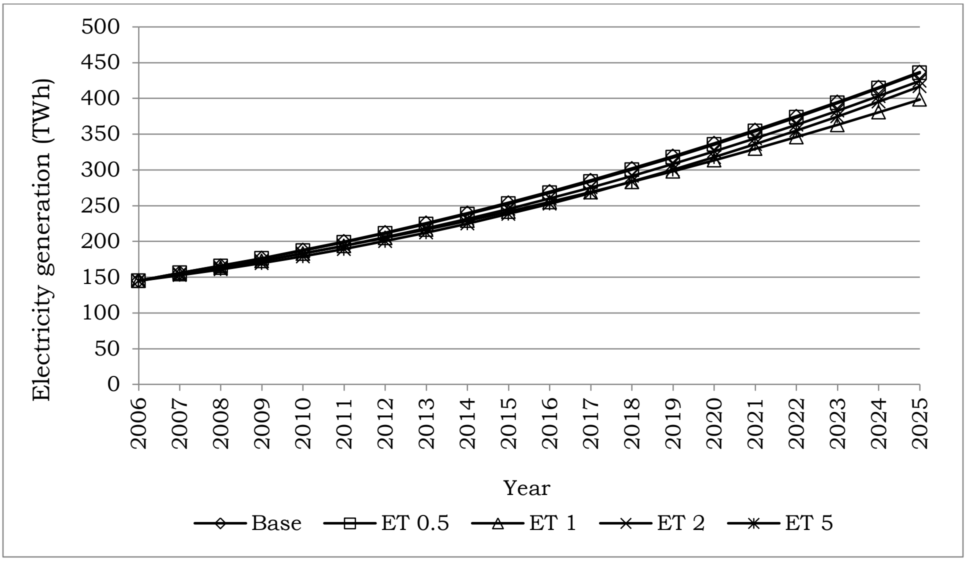

Figure 8.14: Annual electricity generation in the base case and energy tax cases

As can be seen in Table 8.13, there would be a significant increase in the share of gas-based electricity generation with energy tax. The share of coal would decrease substantially even at the relatively low energy tax of $0.5/MBtu; however, the share would not change significantly at higher tax rates. Furthermore, the share of renewable (i.e., biomass) is found to decrease significantly with the energy tax. The table also shows that there would not be noticeable changes in the shares of hydro and oil with the energy taxes.

Table 8.13: Electricity generation mix in the base and energy tax cases during 2006-2025

Energy Tax	Share (%)					Total Electricity Generation GWh
($/Mbtu)	Hydro	Coal	Oil	Gas	Renewable	
0 (Base Case)	4.1	15.9	1.7	69.1	9.2	5433.7
0.5	4.1	9.0	1.7	78.2	7.0	5407.6
1	4.2	9.1	1.7	78.3	6.8	5378.6
2	4.2	9.2	1.7	80.3	4.6	5322.9
5	4.3	9.0	1.8	82.9	2.0	5184.6

Fossil fuel consumption

Figure 8.15 shows the total fuel consumption in the base and energy tax cases in the selected years. The fuel use at energy tax cases is lower than that in the base case. This is partly due to the deployment of more efficient power plants and partly due to the reduced demand for electricity with the introduction of energy tax.

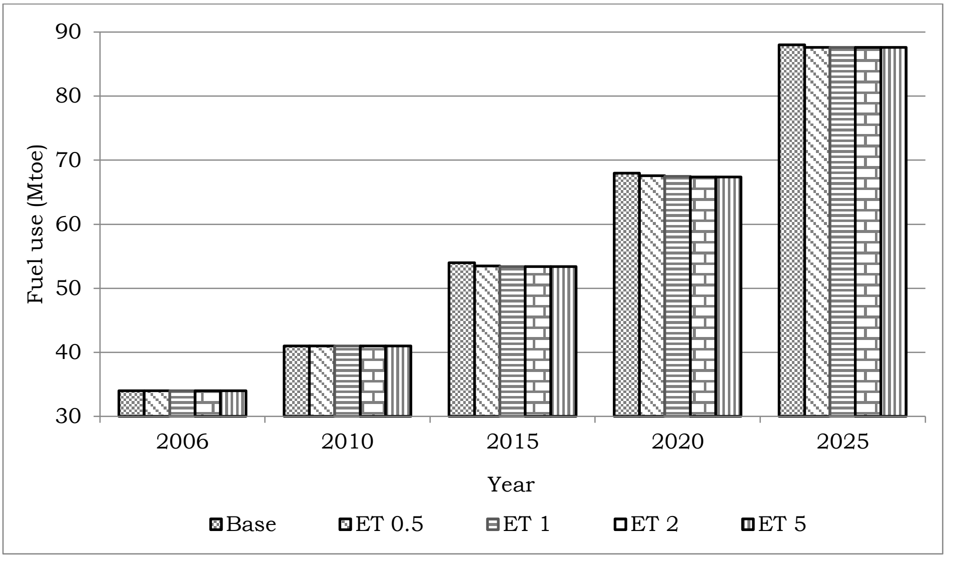

Figure 8.15: Annual total fuel used in the base case and energy tax cases

Table 8.14 shows that there is a marginal reduction in fossil fuel consumption (i.e., 1%) at energy tax rate of $2 and $5/Mbtu.

Table 8.14: Share of total fuel consumption in Mtoe in 2006-2025.

Energy Tax US$/Mbtu	Coal	Oil	Gas	Total	Percentage reduction
0	214.8	25.3	725.2	965.3	
0.5	131.4	25.2	812.8	969.4	0%
1	131.4	25.2	809.7	966.3	0%
2	131.4	25.2	821.1	977.7	-1%
5	125.4	25.2	826.1	976.8	-1%

Generation system efficiency

Figure 8.16 shows the annual WATGE of thermal power generation in the base and energy tax cases. As can be seen, there would be an improvement in generation system efficiency with the introduction of energy tax in the power sector; this would be particularly noticeable after 2010.

The overall WATGE during 2006-2025, i.e., averaging of efficiencies weighted by the total production of each thermal power plant, is found to increase from 38.9% in the base case to 41.5% at the carbon tax rate of $5/MBtu.

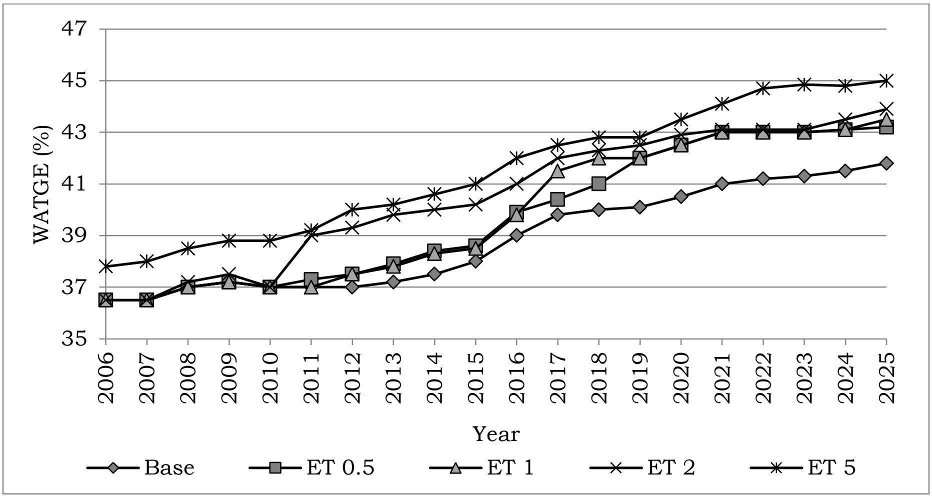

Figure 8.16: Weighted average annual generation system efficiency (WATGE) at the base case and selected energy tax cases

8.4.2 Environmental implications

CO_2 emission mitigation

Figure 8.17 shows the total CO_2 emissions in the base and energy tax cases during 2006-2025. The cumulative CO_2 emissions under the energy tax rates considered were found to be less than that in the base case. However, the cumulative emission was not found to decrease monotonically with the energy tax. That is, in the case of Thailand, the present study shows that introducing higher energy tax rates would not necessary result in a lower level of CO_2 emission. This result is understandable as the primary objective of the energy tax is to improve the efficiency of energy use and not the reduction of GHG emission.

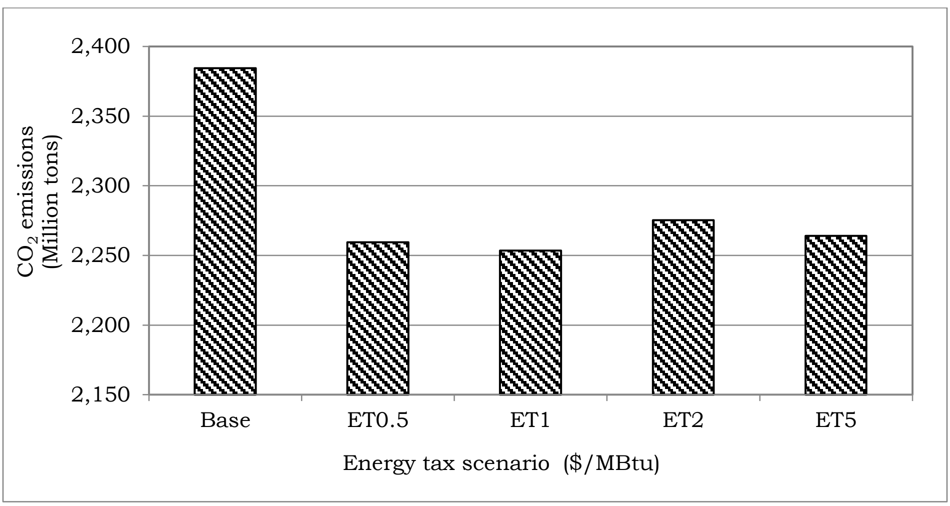

Figure 8.17: Total CO_2 emission at selected energy tax rates during 2006-2025

Energy tax elasticity of CO_2 emission

This study has also calculated the energy tax elasticity of CO_2 emission; it finds the CO_2 emission to be inelastic as shown in Table 8.15.

Table 8.15: Energy tax elasticities of CO_2 emission from the power sector at the selected tax rates.

Energy tax ($/MBtu)	Elasticity
0 – 0.5	-0.027
0.5 – 1	-0.004
1 – 2	0.014
2 – 5	-0.006

Decomposition of CO_2 emission reduction: The role of supply- and demand-side effects

Table 8.16 presents the levels of total CO_2 emission mitigation due to different energy tax rates considered and the influence of supply- and demand-side effects in the mitigation. The table shows that at the high energy tax rate of $5/MBtu, the mitigation of CO_2 due to the demand-side effect would be larger than that due to the supply-side effect. The opposite would be the case for the energy tax rates of lower than or equal to $2/MBtu, that is the supply-side effect would be more influential than the demand-side effect.

Table 8.16: Power sector CO_2 reductions and decomposition of CO_2 reduction during 2006-2025[9]

Energy tax ($ /MBtu)	CO_2 emission reduction (10^6t)	Demand-side effect (%)	Supply-side effect (%)
0.5	124.97	1.5	98.5
1	130.84	22.7	77.3
2	109.08	40.6	59.4
5	120.46	80.7	19.3

Implications on CO_2 emission intensity

There is no significant change in CO_2 intensity (measured in tons of CO_2 emission per MWh) in energy tax cases. CO_2 intensity would decrease from 0.439 tons/MWh in the base case to 0.418 tons/MWh at $0.5/MBtu and 0.437 tons/MWh at $5/MBtu. CO_2 intensity would increase at energy tax above $0.5/MBtu.

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[9] Note that the sum of the demand- and supply-side effects is not exactly equal to the total emission reduction as there is also a residual (or error) term.

Local/regional pollutant emissions

Figure 8.18 shows total emissions of SO_2 and NO_x in the base and energy tax cases during 2006-2025. As can be seen, SO_2 emission would slightly decrease with the introduction of energy tax: At $5/MBtu, the total emission of SO_2 would be about 5% less than that in the in the base case. Unlike SO_2 pollutants, the emission of NO_x in the energy tax cases would be higher than that in the base case. However, in energy tax cases, introducing higher energy tax rates would cause a marginal increase in NO_x emissions in the period 2006-2025. The NO_x emission at energy tax rate of $5/MBtu would be higher by about 2% than that in the base case, however, it is lower about by 2.2% than that in energy tax of $0.5/MBtu.

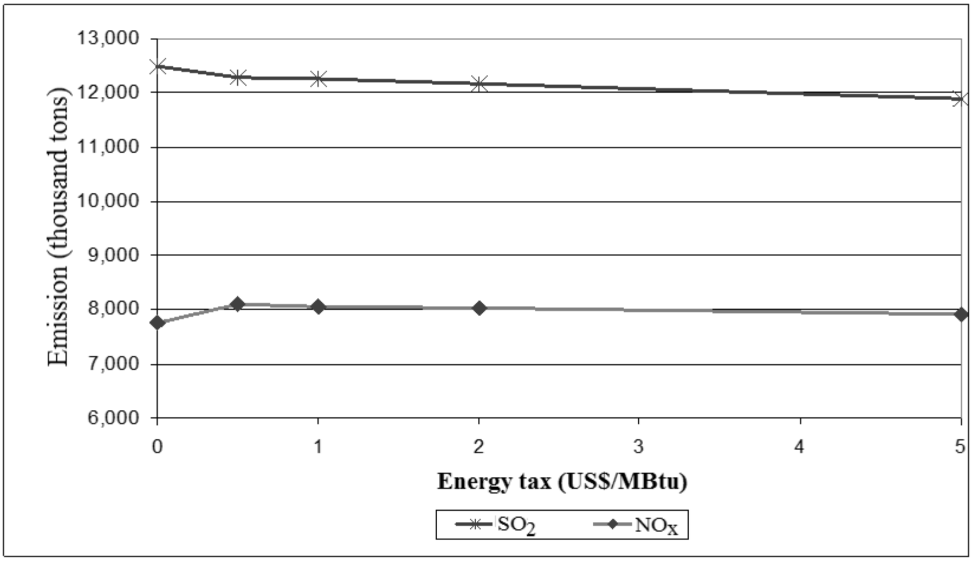

Figure 8.18: Cumulative SO_2 and NO_x emissions in the base case and energy tax cases during 2006-2025

[Note: Increase in NO_x in all the tax cases as compared to baseline is obviously due to decreased in Coal consumption and increased in Gas. However a slight decrease in NO_x with an increase in Tax (0.5 to 5) is mainly explained by the demand side effect (i.e., reduce in electricity generation)].

8.4.3 Economic implications

This section analyzes the implication of introducing energy tax on generation system cost, energy tax revenue and electricity price.

Total generation system cost

Table 8.17 shows the total cost of generation system during 2006-2025 in the base case and selected energy tax cases. With the introduction of the energy tax rates of $0.5/MBtu, $1/MBtu, $2/MBtu and $5/MBtu, the total generation system cost would increase by 7.3%, 14.6%, 28.7%, and 68.8%, respectively, compared to that in the base case. It should be noted here that the total cost here is net of the energy tax. Energy tax payment includes the tax amount to be paid besides the capacity cost, fixed O&M cost and fuel and variable O&M costs. As shown in Table 8.14, the fuel and variable O&M cost would have the highest share in the total cost (i.e., in the range of 84% to 93%), followed by capacity cost (i.e., in the range of 5% to 11%) and fixed O&M cost (i.e., in the range of 3% to 5%). The table also shows that the capacity cost and fixed O&M cost would decrease with the increase in energy tax. This is because the electricity demand (hence the capacity requirement) would decrease with the increase in energy tax rates. At $5/MBtu energy tax rate, the capacity cost would decrease by 26%, and fixed O&M cost would decrease by 10% from their respective values in the base case. On the contrary, the fuel and variable O&M cost would increase with the increase in energy tax. At the energy tax rate of $5/MBtu, the fuel and variable O&M cost would be about 1.85 times of that in the base case. The total cost at the energy tax rate of $5/MBtu was found to be about 0.6 times of that in the base case.

Table 8.17: Breakdown of total cost of power generation system development at selected energy tax rates (discounted value)

Energy tax	Capacity cost		Fixed O&M cost		Fuel and var. O&M cost[#]		Total cost
($/MBtu)	(10^6 $)	(%)*	(10^6 $)	(%)*	(10^6 $)	(%)*	(10^6 $)
0 (Base case)	5,846	11%	2,825	5%	46,536	84%	55,208
0.5	4,640	8%	2,624	4%	51,989	88%	59,253
1	4,616	7%	2,621	4%	56,020	89%	63,256
2	4,598	6%	2,608	4%	63,839	90%	71,045
5	4,333	5%	2,537	3%	86,313	93%	93,182

[#] Net of tax revenue.

*These numbers show the cost as the percentage of the total cost

Energy tax revenue

Table 8.18 presents the total tax revenue during 2006-2025 under different energy tax rates. As can be seen from Table 8.13, the tax revenue would be in the range of 8% to 49% of the total cost with the energy tax rate in the range of $0.5 to $5/MBtu.

Table 8.18: Energy tax revenue (in nominal value) at energy tax rates during the planning period of 2006-2025.

Energy tax	Tax revenue	
($/MBtu)	(10^6 $)	(%)*
0.5	21,861	8.46
1	43,388	15.70
2	84,428	27.10
5	200,917	48.76

* These numbers show the tax revenue as the percentage of the total cost

Unit cost of electricity generation

Figure 8.19 presents the $AIC_{overall}$ and LRAC in the base case and energy tax cases. The figure shows that the LRAC would increase from ¢4.57/kWh in the base case to ¢8.09/kWh at the energy tax rate of $5/MBtu. Similarly, the $AIC_{overall}$ would increase from ¢4.96/kWh in the base case to ¢8.00/kWh at the energy tax of $5/MBtu.

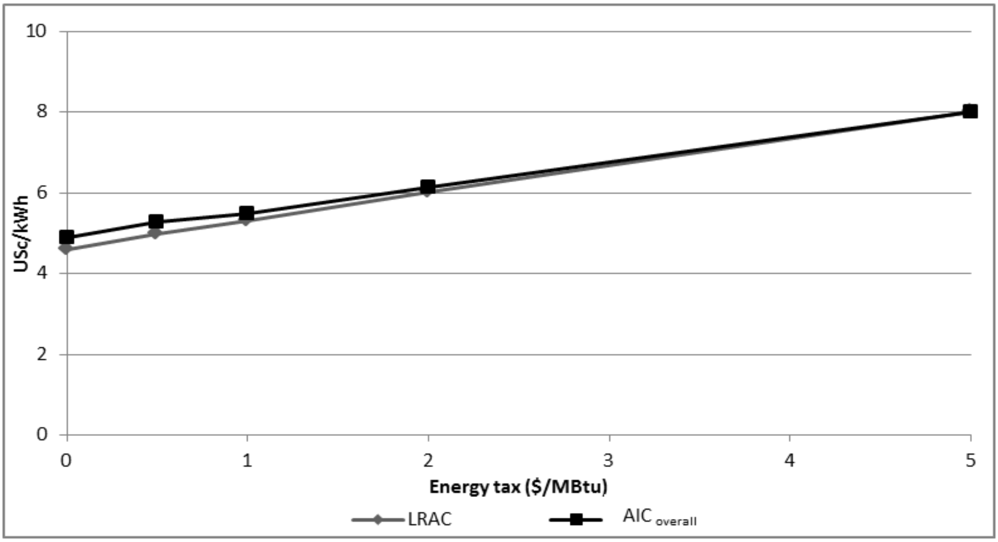

Figure 8.19: AICoverall and LRAC in the base case and at selected energy tax cases during 2006-2025

8.5 Summary

The gas-based power plants would still dominate Thailand's power sector during 2006-2025 in the base case. These types of plants would still contribute as the largest share in the system under the carbon and energy taxes. CCTs would not be attractive under both taxes considered in the study. Power generation based on wind and solar would also not be attractive with the introduction of carbon tax and energy tax. Biomass-based power generation would be attractive with the introduction of the carbon tax, but would not be so under the energy tax. The electricity generation would continue to be predominantly gas-based (77%) while the renewable energy sources would account for 7.7% of the total generation in 2025. Conventional biomass-based power generation would be less cost-effective, and its share would decrease from 5.2% in the base case to 0.4% at the energy tax rate of $5/MBtu. The capacity of CCGT plants would increase in the range of 7.2% to 8.3% in the range of energy tax rates considered.

Since the main purpose of an energy tax is mainly to promote energy efficiency improvement and that of a carbon tax is primarily to reduce CO_2 emission, the study shows that, in the case of Thailand, increasing the energy tax rate would not necessarily result in a lower CO_2 emission.

Despite the replacement of coal by gas in Thailand, a maximum SO_2 reduction of only 18% would be observed at the carbon tax rate of $150/tc whereas over 55% would increase the NOx reductions at the carbon tax rate of $5/tC and higher. There would be a relatively smaller reduction in both SO_2 (5%), and NO_x (2.2%) emissions at the energy tax of $5/MBtu during 2006-2025 as the generation mix was consistently dominated by CCGT plants in the base and energy tax cases. There would even be a slight increase in NO_x emissions with the energy tax rate of $0.5/MBtu due to use of biomass-based plants

At carbon tax rates of $5/tC and $150/tC, electricity generation would be reduced from less than 1% to 2.4%, respectively, while CO_2 emission would be reduced by 6.7% and 13.2%, respectively. Similarly, at energy tax rates of $0.5/MBtu and $5/MBtu, the CO_2 emission would be reduced by 4% and 2%, respectively, while electricity generation would decrease by 0.5% and 5%, respectively.

At the given carbon tax rates, the supply-side effect would play a bigger role in CO_2 emission mitigation than the demand-side effect. Renewable energy sources (particularly, biomass) would make a significant contribution to reducing CO_2 emissions from the power sector under the tax rates considered.

In the case of the energy tax, the demand-side effect plays a bigger role in CO_2 emission mitigation than the supply-side effect at the energy tax rate of $5/MBtu, while, at the tax rate of $2/MBtu and less, the supply-side effect would be more influential than the demand-side effect.

<u>Post-script</u>

As the country case study presented in this chapter was carried out during 2004-2005, the results presented in the preceeding sections are expected to be different from the actual data that are available now (in 2015). Such differences could arise due to several factors, e.g., the differences between the demand projections available at the time the present study was carried out and the actual growth in demand, as well as the differences between the values of plant capacity costs, fuel prices and efficiency of candidate power plants considered in the study and their actual values over time. Furthermore, changes in national energy policies to promote renewable energy options and energy efficient technologies could also be an important factor in influencing power sector development during the last decade. In this section, an attempt is made to describe briefly some of these factors in the case of Thailand.

The actual capacity installations and power generation in Thailand have been observed to be considerably lower than the values estimated in the study. Although the peak load and installed capacity considered in this study was estimated to grow at a CAGR of 5.7% and 4.9%, respectively during 2005-2015 (according to Thailand's Long-Term Load Forecasts (2006)), the actual peak load and installed capacity both grew at a lower

CAGR of 3.1% between 2005 and 2014 (EPPO, 2015 and EGAT, 2015). Electricity import, on the other hand, during 2006-2025 was limited to 340 MW at the time this study was carried out (i.e. during 2004-2005), which has increased to 2,404 MW in 2015 (includes import from Laos and exchange from Malaysia) 2012 (EPPO, 2013b).

This is partly explained by the higher electricity demand forecast used at the time of the study. One of the reasons for the lower growth in electricity generation in Thailand is the success of energy efficiency promotion policies/programs. Thailand was one of the first countries in Asia, in 1991, to have adopted the demand-side management plan in power sector development which was useful in curbing the growth in electricity demand. Also, the Power Development Plan (PDP) in 2010 (PDP 2010, version 3) released in 2012 had incorporated the 20-year Energy Efficiency Development Plan (EEDP), resulting in lower electricity demand and lower installed capacity (EPPO, 2013a). The target of EEDP is to reduce energy intensity in 2030 by 25% when compared to the business-as-usual case. Furthermore, in 2015 the Thai Government has increased the target of reducing energy intensity by 30% in 2036.

EPPO (2015) shows that the shares of coal, gas, oil and hydro in electricity generation in 2014 were 20%, 65%, 1% and 3%, respectively, which seems to be quite close to the estimated future values in the base case of this study (i.e., 21%, 62%, 2% and 5%, respectively in 2015) (see Table 8.3). However, the actual share of the renewables is found to be significantly lower (2.2% in 2014) as compared with its share of 9.2% in 2015 as was estimated by this study. Power generation based on wind and solar was not attractive with the introduction of carbon tax and energy tax at the time the study was carried out. However, because the price of solar PV, for example, fell by 47% between 2005 and 2010 (i.e., from \$4.5/W in 2005 to \$2.4/W in 2010), PV installations grew at the AAGR of 66% between 2006 and 2010.

In 2007, the Thai Government formulated the Renewable Energy Development Plan (2008-2022) introducing the feed-in-tariff scheme for renewable-based power generation, in order to promote solar, wind and bioenergy. Another scheme was offered in 2013 to solar-based generation, which was amended in 2014 (OECD/IEA, 2015). Despite several attempts to promote renewable energy, the share of renewable-based power generation in Thailand is still significantly lower than the estimated value in this study. In an effort to enhance growth in the RE sector, the Ministry of Energy launched the 10-year Alternative Energy Development Plan (AEDP) in 2012 to increase the share of renewable energy up to 25% in final energy consumption in 2021 (the plan is called “AEDP 25%”) (DEDE, 2012). AEDP provides adder to those facilities that install solar, the wind, hydropower and other RE technologies. The introduction of this adder scheme has caused the installation of solar, wind and hydropower to grow by AAGRs of 61%, 55% and 37%, respectively (DEDE, 2012). Furthermore, in 2015 the Thai Government has upgraded the target for the share of renewable energy from 25% to 30% (i.e., from AEDP 25% to AEDP 30%) and the target year has also been extended from 2021 to 2036. Similar to AEDP and EEDP, the Power Development Plan 2015 (PDP 2015) has committed to a share of renewable electricity generation of 8% in 2036. All these plans are set to the target year of 2036 to correspond with the period of Thailand's National Economic and Social Development Plans (NESDB, 2015).

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9. Power Sector Development in Vietnam: Effects of Carbon and Energy Taxes[1]

9.1. Introduction

The economic reforms in Vietnam have increased its demand for electricity over the years. The demand for energy in the country had increased at an average growth rate of about 6.0% per year during 1990-2011 when there was an average GDP growth of 9.3%. The per capita electricity consumption increased from 97.8 kWh/capita in 1990 to 1073.0 kWh/capita in 2011 (IEA, 2013a). Electricity is generated from diversified sources of energy in Vietnam, i.e., coal, natural gas, oil and hydro. The use of natural gas in power generation has been increasing since 1995. Natural gas has the largest share in total electricity generation. In 2011, the shares of coal, hydro, natural gas and oil in total electricity generation were 21.1%, 30.1%, 43.9% and 4.8%, respectively (IEA, 2013b).

Emissions of greenhouse gases (GHGs) as well as other local and regional air pollutants have been increasing in the country partly due to an increase in electricity production based on fossil fuels. The annual average growth rate (AAGR) of CO_2 emission from the power sector in Vietnam during 1990-2011 was 11.1% (i.e., from 3.4 $MtCO_2$ in 1990 and 137.36 $MtCO_2$ in 2011) (IEA, 2013a).

The Vietnamese government has issued various environmental laws to control emissions of pollutants from electricity production and to promote sustainable energy development. Some of the proposed measures for the mitigation of environmental impacts due to power projects are the use of clean and energy efficient thermal power generation technologies, renewable energy technologies (RETs) and demand-side management.

A study of the utility planning, environmental and economic implications of introducing carbon and energy taxes in the power sector of Indonesia during the planning period of 2006-2025 was carried out during 2004-2005 using the electricity demand forecast and other relevant data available at that time. Six selected carbon tax rates (i.e., $5/tC, $10/tC, $25/tC, $50/tC, $100/tC and $150/tC) and four selected energy tax rates (i.e., $0.5/MBtu, $1/MBtu, $2/MBtu and $5/MBtu) were considered in the study. This chapter presents the findings of that study in Sections 6.2 to 6.5. The results of the least cost generation planning (without carbon and energy taxes) (i.e., “Base Case”) is

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presented in Section 6.2; they are followed by a discussion of the results on the effects of carbon and energy taxes in Sections 6.3 and 6.4 respectively. A summary of key findings are presented in Section 6.5. A postscript is added at the end of the chapter to discuss briefly the differences between the results of the base case of this study and the actual data related to the growth in electricity generation, generation mix and capacity additions and energy policies related to the power sector in recent years after the study was carried out.

9.2. Base Case Analysis

9.2.1. Definition of base case

Input data and assumptions

Most of the data (technical and economic) used for electricity generation system planning (EGP) (e.g., existing, committed, and candidate power plant data) in this study are based on Institute of Energy (IE, 2005) and JICA & IE (2005). The planning period considered for the study is 2006-2025 with the year 2000 as the base year for cost calculations. All prices are based on the constant prices of 2005 in US dollars.

Table 9.1 presents the estimated values of power and electrical energy demand during 2005-2025. Of the various scenarios considered in IE (2005), the median load growth scenario is considered in this study. The IE report presents the load growth during 2005-2020. The AAGR of electricity generation is considered to be 11.5% during 2006-2015, 7.5% during 2015-2020 and 4.3% during 2020-2025 (IE, 2006a). Linear extrapolation is used to make the projection of power demand thereafter (i.e., from 2020 to 2025). The load factor was 64.2% in 2005 and is assumed to increase linearly to 69% in 2020 and to be maintained at that value thereafter until 2025 (JICA & IE, 2005). A discount rate of 10% is used in the present analysis. The price elasticity of electricity demand used in this study is -0.30. It should be noted here that demand-side management (DSM) options are not considered in this study. The reserve margin of 15% to 2015 and 20% during the rest of 2006-2025 is used.

Existing and candidate power plants

In the base year (i.e., 2005), the power system of Vietnam was dominated by hydropower plants with the share of 48% in the capacity mix. The shares of natural gas and coal were around 30% and 14%, respectively. All the gas-based combined cycle and conventional coal-fired power plants in Vietnam use domestic natural gas and coal as fuels, which serve the base load of the system. Gas turbine plants are operated during the peak hours. The hydropower plants are used as intermediate plants in the Vietnam power system and their capacity factor is in the range of 50-60%. In the base year, there was a negligible share of other renewable energy technology-based power plants in Vietnam despite having enormous potential for renewables.

Table 9.1: Electrical energy and peak power demand during 2005-2025.

Year	Peak demand (MW)	Energy demand (GWh)	Year	Peak demand (MW)	Energy demand (GWh)
2005	9,512	53,461	2016	29,058	172,355
2006	10,745	60,702	2017	31,271	186,357
2007	12,130	68,866	2018	33,467	200,382
2008	13,625	77,736	2019	35,643	214,410
2009	15,252	87,446	2020	37,721	228,001
2010	17,002	97,956	2021	38,852	234,839
2011	18,854	109,171	2022	40,773	246,449
2012	20,773	120,865	2023	42,694	258,058
2013	22,733	132,827	2024	44,615	269,668
2014	24,760	145,452	2025	46,535	281,277
2015	26,883	158,677			

Source: IE (2005) and JICA & IE (2005)

Table 9.2: Characteristics of candidate thermal plants.

Candidate plants	Unit capacity (MW)	Capacity cost ($/kW)	Heat rate (kcal/ kWh)	Emission factor (kg/MWh) +		
				CO_2	SO_2	NO_x
Conventional - diesel	145	400	2,529	784.5	1.770	0.810
Steam – fuel oil	600	580	2,263	695.3	7.780	3.540
Coal – imported	500	950	2,263	939.3	1.060	3.020
Coal - domestic	1200, 600, 500, 300,100, 98	950	2,263	1000.7	1.060	3.020
GT - domestic gas	750, 720, 600	600	1,792	371.9	0.003	1.480
CCY – domestic gas	720	600	1,792	371.9	0.003	1.480
CCY – imported gas	720, 435	600	1,792	350.9	0.003	1.480
DC* - bagasse	25	1,500	2,743	-	0.052	0.058
DC* - rice husk	12	1,510	2,742	-	0.027	0.058
Geothermal	20	2,140	7,715	-	-	-
Supercritical	400	1,580	2,054	852.6	0.228	0.141
IGCC	600	1,610	1,981	822.3	0.235	0.600
PFBC	500	1,440	2,091	867.9	0.255	0.771
BIGCC	75	1,626	2,390	-	0.294	0.232

* Direct combustion

+ A '-' sign means either zero or a negligible quantity.

Source: IE (2006a), IE (2006b)

Besides conventional power plants considered in the expansion planning, the candidate plants include cleaner and more energy efficient technologies (CEETs) like Supercritical, integrated gasification combined cycle (IGCC), pressurized fluidized bed combustion (PFBC) and biomass-based integration gasification combined cycle (BIGCC). The candidate power plants considered included 33 thermal power plants, 62 medium and large hydropower plants along with power plants based on renewable energy, geothermal, wind, solar, as well as small- and mini-hydro. The nuclear option was not considered in this study due to various controversies regarding the use of nuclear power plant and its safety. Tables 9.2 and 9.3 present the technical, economic and environmental characteristics of the candidate plants considered for the generation system planning.

Table 9.3: Candidate non-dispatchable plant data.

	Units	Wind	Small Hydro	Mini Hydro	Solar
Capacity	MW	1.8	5	1	1
Availability		0.98	0.48	0.08	0.98
Capacity cost	103 $	1,000	1,200	900	5,500
Operating cost	103 $/MWh	0.00075	0.0001	0.0001	0.0012
Annual maintenance	hrs	600	600	600	600
Fixed O&M	103$/MW/month	2.17	5.2	5.2	0.83

Source: IE (2006a), IE (2006b), IE (2006c)

Vietnam has a large potential for wind energy. Around 31,000 km^2 of land area is available for wind energy development in which 865 km^2 is equivalent to 3,572 MW of wind power (Nguyen, 2007). Therefore, 9,000 MW of wind power has been considered in the present analysis. The wind turbine of 1.8 MW was considered with a capacity cost of $1,000/kW (Nguyen, 2007). Also, 6,000 MW of solar, 1,400 MW of small hydro and 400 MW of mini hydro as well as 630 MW of biomass and 400 MW of geothermal potential were considered in the present analysis.

The prices of the domestic gas, imported gas, and oil used in the base case of Vietnam are $3.2/MBtu, $3.4/MBtu and $60/barrel, respectively, while the prices of domestic and imported coal are $24.4/ton and $52.0/ton, respectively. No escalation of fuel cost is considered in real terms in the base case (i.e., fuel prices were assumed to be constant at 2005 prices throughout the planning period).

Import of power from China

It was considered that 500 MW of import capacity from China would be available from the year 2007 and 2000 MW from the year 2016 (IE, 2005).

9.2.2. Power sector development during 2006-2025

This section presents the utility planning implications of power sector development in the base case.

The added capacity in the base case is shown in Table 9.4. With the availability of many candidate hydro options, the capacity addition of hydropower plants would increase from 1,077 MW in 2010 to 9,280 MW in 2025. As shown in Table 9.4, conventional coal-fired steam power plants would play a major important role in meeting the future electricity demand in Vietnam. The addition of coal-fired power plant capacity would increase from 2,898 MW to 18,896 MW during 2010-2025. However, clean and energy efficient power generation technologies such as supercritical, PFBC and IGCC would not be economically feasible in the base case. Gas turbine capacity of 750 MW would be added in the year 2020 and would further increase to 4,230 MW in the year 2025. Furthermore, 3,030 MW of combined cycle power plants' installation is expected by the year 2025. The renewable options were not found to be attractive in the base case because of their high cost in comparison to the conventional technologies. Only 10 MW of small hydropower capacity would be cost-effective in the base case.

Table 9.4: Cumulative capacity additions in the selected years (MW)$^{+}$.

Year	Hydro	Conventional coal	Gas turbine	Combined cycle	Small hydro	Total
2010	1,077	2,898	-	-	-	3,975
2015	4,112	9,598	-	-	-	13,710
2020	6,817	16,496	750	-	-	24,063
2025	9,280	18,896	4,230	3,030	10	35,446

$^{+}$ A '-' sign means either zero or a negligible quantity.

Table 9.5 shows the generation mix in Vietnam during 2006-2025. The generation share of coal-based power plants would substantially increase from 27.5% in 2006 to 50% in 2025 with the rise in the power demand during the analysis period. Even though power generation based on hydro and gas would increase, their shares in total generation would decrease during 2006-2025; i.e., the proportion of hydro would decrease from 33.7% in 2006 to 25.5% in 2025, and that of gas would decrease from 36.6% in 2006 to 24.1% in 2025. Similarly, the share of oil in power generation would decrease from 2.3% in 2006 to 0.3% in 2025. The share of imported power from China would remain fairly constant during the period.

Table 9.5: Electricity generation mix by fuel type at selected years in the base case (GWh)$^{+}$.

Year	Hydro	Coal	Oil	Gas	Renewable	Import from China	Total generation
2006	24,719	20,138	1,673	26,829	-	-	73,359
2010	35,560	45,115	1,673	33,713	-	64	116,125
2015	58,194	91,520	1,340	27,266	-	88	178,408
2020	69,730	137,108	1,007	42,109	-	377	250,331
2025	78,819	154,330	1,007	74,284	21	365	308,826

$^{+}$ A '-' sign means either zero or a negligible quantity.

The total cumulative CO_2 emission during 2006-2025 in the base case would be 2,207 Mt. The CO_2 emission from the power sector during 2006-2025 is estimated to increase from 35 Mt to 183 Mt.

9.3. Effects of Carbon Tax

This section discusses the various implications of introducing six different rates of carbon tax (i.e., \$5/tC, \$10/tC, \$25/tC, \$50/tC, \$100/tC and \$150/tC) in the power sector in Vietnam.

9.3.1. Utility planning implications

Changes in electricity demand

The total (cumulative) electricity demand would decrease with the increase in the carbon tax (see Figure 9.1). This result is expected because the carbon tax would increase the electricity price that leads to decrease in the demand for electricity. As mentioned in the methodology chapter, a demand curve with constant elasticity is assumed for the analysis. Hence, the resulting equilibrium level of demand over the planning period is shown in Figure 9.1. The total electricity generation during 2006-2025 is found to decrease by 9.4% and 8.7% at the carbon tax rates of \$100/tC and \$150/tC, respectively.

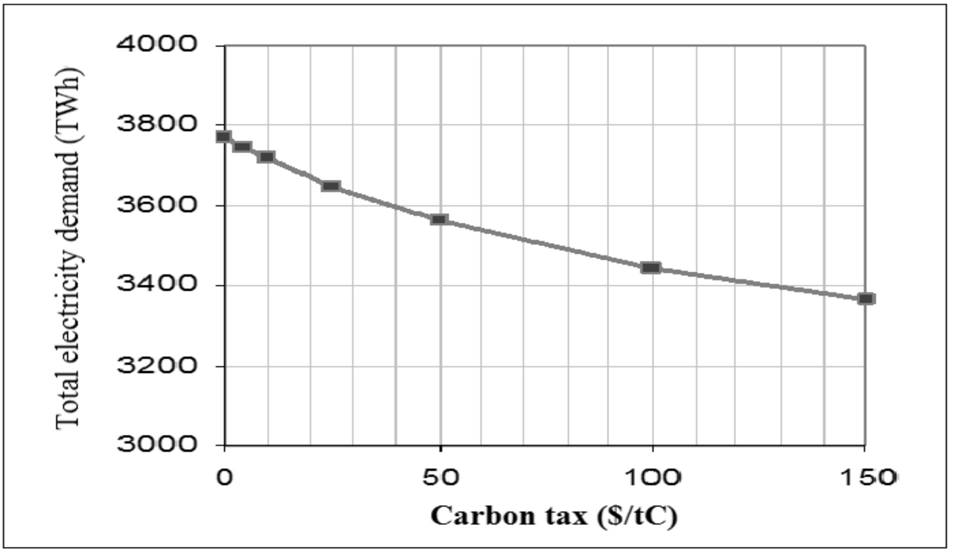

Figure 9.1: Total electricity demand over the planning period 2006-2025.

Generation technology capacity mix

With the introduction of the carbon tax, the power generation system shifts towards low carbon intensive fuels and cleaner technologies with higher energy efficiency. This leads to change in capacity additions in the power sector. Table 9.6 shows the change in capacity additions under different carbon tax scenarios.

Table 9.6: Capacity additions during 2006-2025 at selected carbon tax rates, MW+.

Carbon Tax ($/tC)	0 (Base case)	5	10	25	50	100	150
Hydro	9,280	9,633	9,719	9,152	10,103	10,480	10,480
Coal-fired steam	18,896	18,896	18,896	18,896	7,198	-	-
Gas turbine (Gas)	4,230	4,230	4,230	4,230	4,230	4,230	4,230
Combined cycle (Gas)	3,030	2,310	1,875	1,440	10,380	10,380	10,380
BIGCC	-	-	-	-	-	150	150
Geothermal	-	-	-	-	-	100	340
Biomass (agricultural residues)	-	-	-	-	-	350	325
Wind	-	-	5	5	1,683	5,774	9,000
Small hydro	10	5	-	-	-	1,400	15
Total	35,446	35,074	34,725	33,723	33,594	32,864	34,920

+ A '-' sign means either zero or a negligible quantity.

As can be seen, the capacity additions of coal-fired power plants would decrease from 18,896 MW in the base case (i.e., without a carbon tax) to zero MW at the carbon tax of $100/tC during 2006-2025. The coal-fired power plant would not be cost-effective at carbon tax rate of $100/tC and higher . The capacity additions of hydro would increase from 9,280 MW without carbon tax to 10,480 MW at the carbon tax of $150/tC, whereas the capacity additions of wind, agricultural residual, and geothermal power plants would increase from zero without carbon tax to 9000 MW, 325 MW, and 340 MW, respectively, at the carbon tax of $150/tC. The capacity additions of gas-based combined cycle and BIGCC plants would also increase from 3,030 MW and nil, respectively, in the base case to 10,380 MW and 150 MW, respectively, at the carbon tax rate of $150/tC. However, the capacity addition of gas turbines remains constant at 4,230 MW during 2006-2025. These changes reflect fuel substitution as a result of the carbon tax, i.e., displacement of high carbon content fuels (e.g., coal) by low carbon fuels (e.g., renewable resources) in the power sector. Furthermore, the changes also show an adoption of efficient technologies like BIGCC and gas-based combined cycle plants with the introduction of carbon tax in Vietnam.

Electricity generation mix

It is expected that introduction of a carbon tax would change the fuel prices with their carbon content and as a result, the generation mix could change towards less carbon-intensive fuels and technologies. In the case of Vietnam, the present study shows that there would be a noticeable switch from fossil fuel to renewables and more efficient technologies under the carbon tax scenario. Table 9.7 shows the total electricity generation and percentage shares of hydro, fossil fuels, renewable energy based power generation options as well as power import during 2006-2025 at different carbon tax rates, considering both the fuel substitution and of demand-side (i.e., electricity price) effects. According to the table, the shares of hydro, gas, renewable and imported power in the cumulative generation during 2006 to 2025 would increase from 29.6%, 20.8%, 0.0% and 0.08% in the base case (i.e., without carbon tax) to 39.0%, 45.9%, 4.4% and 6.4%, respectively under the carbon tax of $150/tC. The share of coal, on the other hand, would decrease from 48.8% to 3.6% during the same period. Furthermore, the oil-based generation would remain almost constant. It should be noted that the carbon tax is not applied to biomass-based power generation as biomass production, and use is considered to be sustainable.

Table 9.7: Electricity generation mix by fuel types during 2006-2025 at selected carbon tax rates.

Carbon tax	% share of total generation during the period*						Total electricity generation+ (TWh)
($/tC)	Hydro	Coal	Oil	Gas	Renewable	Imported power	
0	29.6	48.8	0.7	20.8	-	0.08	3769.0
5	29.9	48.6	0.7	20.8	-	0.08	3743.4
10	30.6	48.1	0.7	20.5	-	0.08	3718.4
25	32.2	46.0	0.7	21.0	0.01	0.07	3647.8
50	35.3	15.1	0.8	47.2	1.6	0.07	3563.3
100	37.8	11.3	0.8	42.9	3.8	3.5	3443.9
150	39.0	3.6	0.8	45.9	4.4	6.4	3362.2

+Cumulative power generation during the entire period.

* A '-' sign means either zero or a negligible quantity.

Figure 9.2 shows the power generation mix under the carbon tax of $150/tC in the selected years. As can be seen, there would be a significant reduction in the share of coal- and hydro-based power generation under the carbon tax of $150/tC, specifically in the later part of the study period.

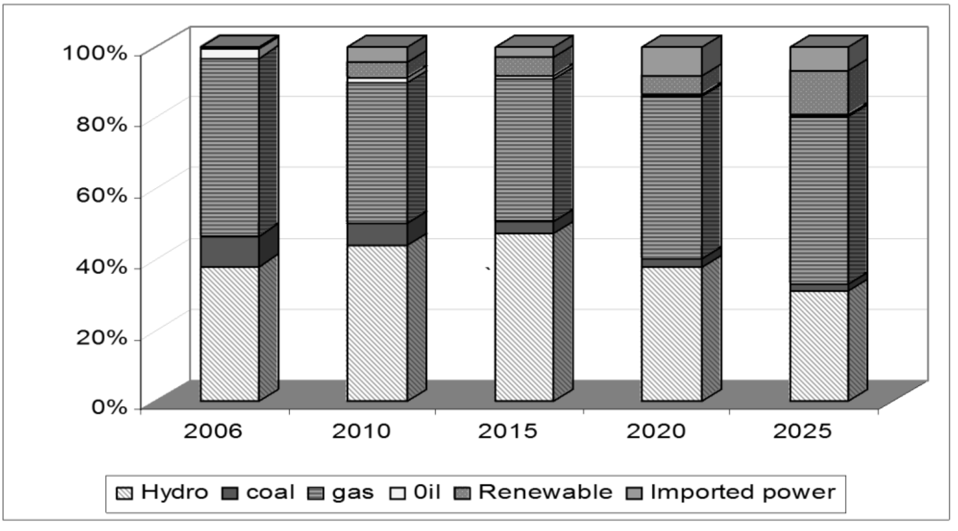

Figure 9.2: Generation mix at the carbon tax rate of $150/tC during 2006-2025.

Fossil fuel consumption for power generation

With the introduction of carbon taxes, the fossil fuel consumption would decrease (see Figure 9.3) due to both demand- and supply-side effects. In the demand-side effect, the increase in fuel price due to the carbon tax would decrease the electricity demand thereby requiring less fossil fuel use for power generation. In the case,of the supply-side effect, there would be the usage of less carbon intensive (i.e., more cleaner and efficient generation) technologies. This would also drive the system with lower fossil fuel consumption. The total fossil fuel consumption would fall from 530 million toe in the base case to about 230 million toe at the carbon tax rate of $150/tC.This represents nearly a 57% reduction from the base case fossil fuel consumption.

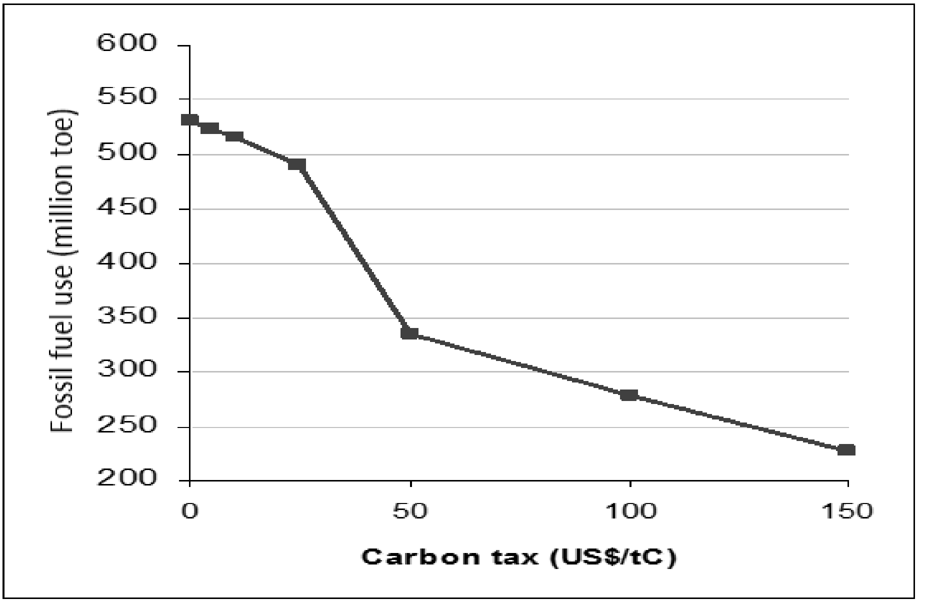

Figure 9.3: Total fossil fuel use during 2006-2025 at selected carbon tax rates.

Generation system efficiency

The introduction of a carbon tax would affect the overall thermal generation efficiency. In this study, overall thermal generation efficiency is being computed as weighted average thermal generation efficiency (WATGE), which is estimated as the ratio of total electricity generation by thermal plants to energy input regarding fuel consumption in the corresponding plants (see Section 2.3 in Chapter 2 for an explanation on WATGE). Interestingly, WATGE would have a significant increase (42.38%) with higher tax rates ($150/tC) when compared to the base case (see Table 9.8). Furthermore, the base case WATGE is also significantly high in the case of Vietnam because there would be higher number of efficient gas-based combined cycle plant selection in the base case.

Table 9.8: Weighted average thermal generation efficiency (WATGE) during 2006-2025 at selected carbon tax rates.

Carbon tax ($/tC)	WATGE (%)
0	36.84
5	36.85
10	36.83
25	36.96
50	40.89
100	41.18
150	42.38

Figure 9.4 illustrates the variations in annual WATGE at different tax rates. It is noted that at the tax rates of $25/tC and lower, WATGE would decrease during 2006-2019 as the decrease in generation from coal- and oil-based power plants are less compared to the increase in generation from efficient combined cycle plants. However, the WATGE would increase after 2019 with the increase in generation from efficient combined cycle plants. Also, for higher tax rates (i.e., $50/tC or higher), the WATGE would increase from the beginning of the planning period (i.e., 2006-2025) with the addition of efficient combined cycle and BIGCC plants.

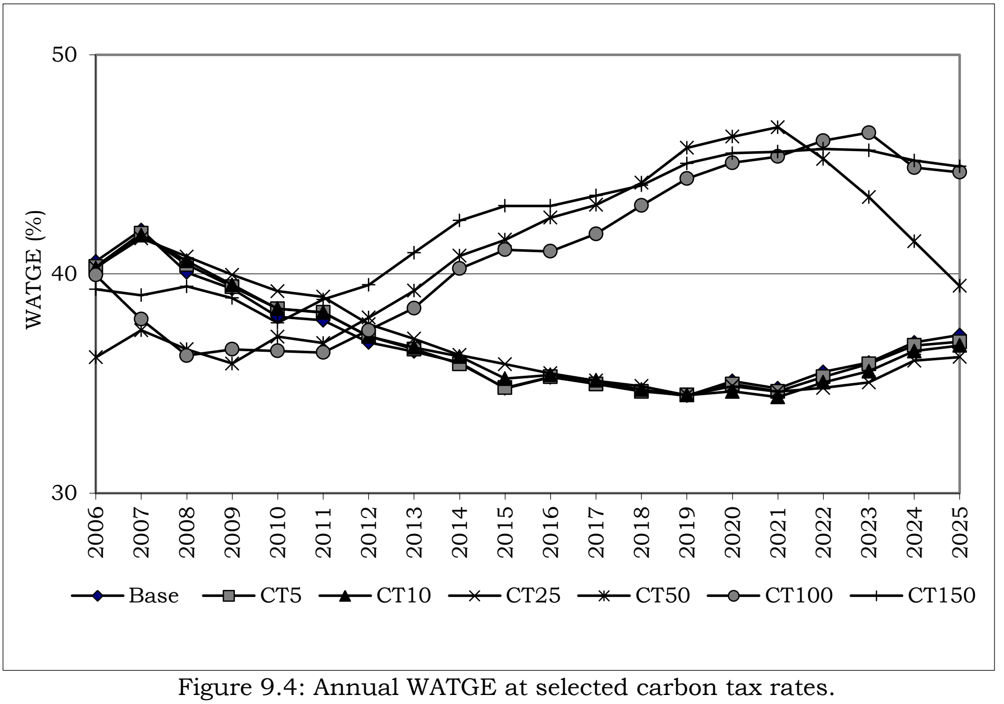

Figure 9.4: Annual WATGE at selected carbon tax rates.

Generation system reserve margin

The carbon tax is also found to affect the reserve margin of the power system. The average reserve margin of the power system during the planning period would increase from 28.8% in the base case to about 36% at the carbon tax rate of $150/tC (see Figure 9.5). This is mainly because of the increasing share of hydro and wind power plant capacity at the higher carbon tax rates.

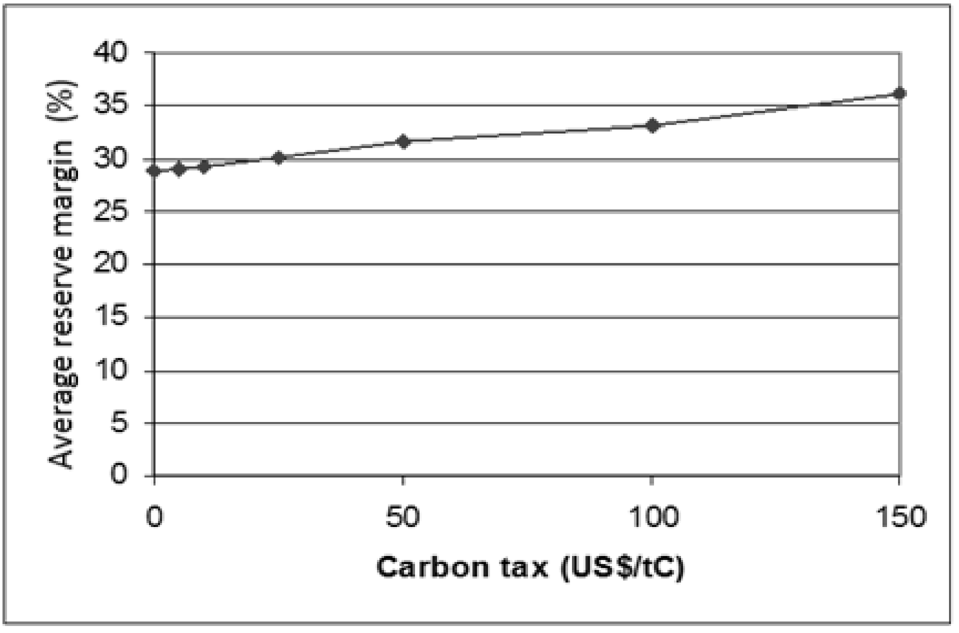

Figure 9.5: Average reserve margin over the planning period 2006-2025.

Generation capacity utilization

The carbon tax is also found to affect the capacity utilization, which can be measured in terms of capacity factor (CF)[2]. As can be seen from Figure 9.5, the weighted average capacity factor (WACF) of the power system would decrease from 55% in the base case to about 51% at the carbon tax rate of $150/tC (see Section 2.4 in Chapter 2 for an explanation on WACF). This is mainly due to the increasing share of hydropower and wind power capacity at the higher tax carbon rates. As shown in the figure, the WACF of the power plants added during 2006-2025 would be greater than that of the existing plants.

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[2] Capacity factor (CF) is the ratio of total electricity generation to the maximum potential generation with the total installed capacity.

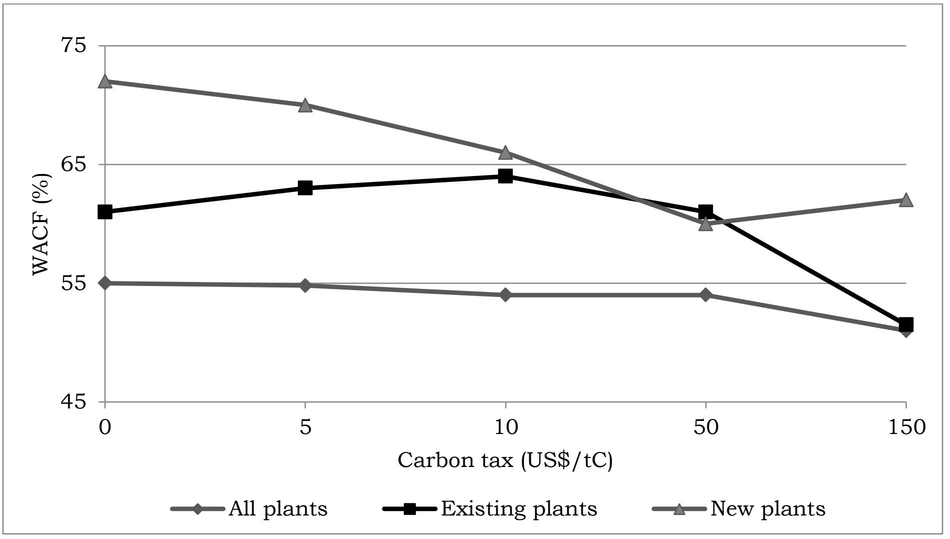

Figure 9.6: Weighted average capacity factor (WACF) during 2006-2025 at selected carbon tax rates (%).

9.3.2. Economic implications

Electricity generation system cost

Table 9.9 shows the total discounted cost of the electricity generation system during 2006-2025 at selected carbon tax rates. The table shows that the total cost would increase with the rise in the carbon tax rate. The total cost would increase in the range of 2.4% to 42.7% when the carbon tax rates are increased from $5/tC to $150/tC. The total cost consists of capacity, fixed O&M and variable O&M costs (including the fuel cost). As shown in Table 9.9, the contribution of variable cost to the total cost has the highest contribution, and it is in the range of 56.4% to 70.3%. Furthermore, the capacity cost ranges from 21.9% to 30.7% and fixed O&M cost ranges from 7.8% to 12.8% of the total cost.

Table 9.9: Contribution of capacity, fixed O&M and variable O&M costs to the total cost at selected carbon tax rates during 2006-2025.

Carbon tax ($/tC)	Capacity Cost		Fixed O & M Cost		Variable Cost		Total Cost ($10^6$$)
	($10^6$$)	(%)*	($10^6$$)	(%)*	($10^6$$)	(%)*	
0	5,176.0	30.7	2,165.5	12.8	9,512.0	56.4	16,853.5
5	5,122.5	29.7	2,141.8	12.4	9,996.9	57.9	17,261.2
10	5,116.5	29.0	2,113.1	12.0	10,431.3	59.1	17,660.9
25	5,069.1	27.0	2,030.1	10.8	11,686.5	62.2	18,785.7
50	4,695.0	23.2	1,861.6	9.2	13,680.3	67.6	20,236.9
100	4,919.5	21.9	1,798.4	8.0	15,739.6	70.1	22,457.6
150	5,298.8	21.9	1,885.9	7.8	17,044.5	70.3	24,229.2

* These numbers are the percentage of the total cost.

All costs are discounted to the base year 2005.

Carbon tax revenue

Table 9.10 presents an estimate of the undiscounted tax revenue resulting from the introduction of the carbon tax during the planning period of 2006-2025. The carbon tax revenue is found to increase from $2,327 million to $28,897 million as the carbon tax rate is increased from $5/tC to $150/tC. The share of the tax revenue in the total undiscounted gross cost (inclusive of tax) would lie in the range of 3% to 29% in the range of the tax rate considered.

Table 9.10: Carbon tax revenue and total cost (gross and net of tax) at selected carbon tax rates during 2006-2025.

Carbon tax ($ /tC)	Total cost (gross)+ (Million $)	Carbon tax revenue * (Million $)	Total cost net of tax, (Million $)
0	65,017	-	65,017
5	67,337	2,327	65,011
10	69,290	4,582	64,708
25	75,443	10,940	64,503
50	85,227	13,799	71,428
100	93,922	23,617	70,306
150	101,002	28,897	72,105

+Total cost including carbon tax revenue.

* A '-' sign means either zero or a negligible quantity.

Unit cost of electricity generation

Figure 9.7 presents the overall average incremental costs ($AIC_{overall}$) and long run average costs (LRAC) at the selected carbon tax rates (see Section 2.5 in Chapter 2 for calculation of $AIC_{overall}$). The figure shows that the LRAC would increase from ¢2.12/kWh to about ¢3.4/kWh at the carbon tax rate of $150/tC, whereas the overall average incremental cost ($AIC_{overall}$) would increase from ¢2.88/kWh to ¢4.3/kWh at the carbon tax rate of $150/tC. This significant increment in unit cost of electricity generation at higher tax rates is mainly due to the increase in the variable cost of power generation (see Table 9.9).

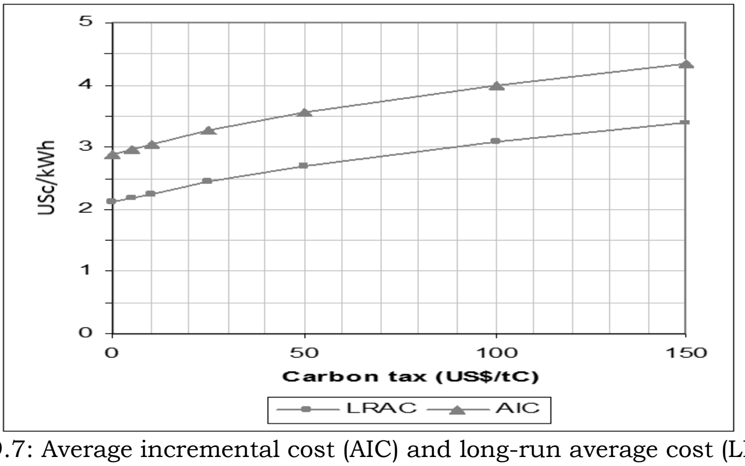

Figure 9.7: Average incremental cost (AIC) and long-run average cost (LRAC) of generation at selected carbon tax rates during 2006-2025.

9.3.3. Environmental implications

Total CO_2 emission from the power sector at selected carbon tax rates during 2006-2025 are illustrated in Figure 9.8. As expected, the total CO_2 emission is found to decrease with the increase in carbon tax rate as carbon intensive fuels are replaced with renewable resources and less efficient thermal power plants are replaced by efficient technologies like combined cycle power plants. The reduction in CO_2 emission would be significant at carbon tax of \$50/C and above also indicating the relatively large switching to cleaner fuels and efficient technology at such carbon tax rates.

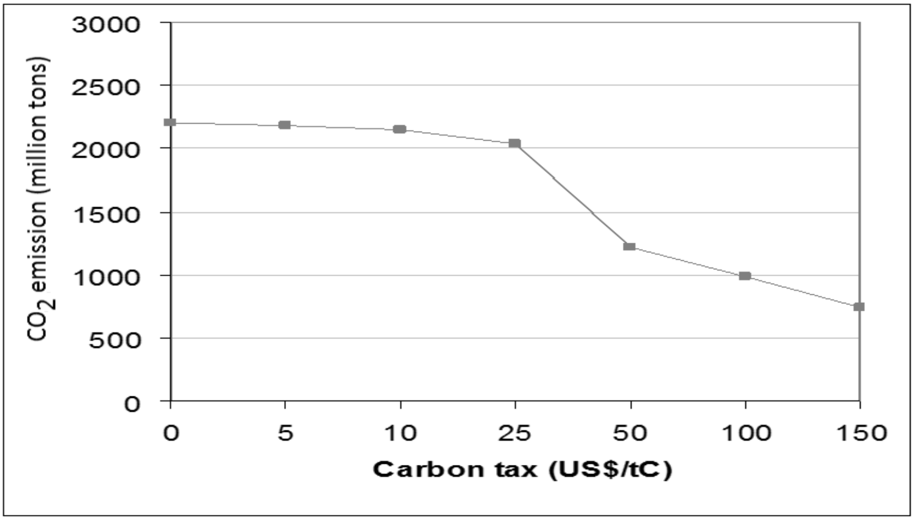

Figure 9.8: Total CO_2 emission during the planning period 2006-2025 at selected carbon tax rates.

Table 9.11 shows the total CO_2 emission due to the introduction of the carbon tax. The CO_2 emission is about 2,207 million tons in the base case and would decrease to 742 million tons at the carbon tax rate of \$150/tC. The total CO_2 emission reduction would be 1.1% at the carbon tax rate of \$5/tC and would be 66.3% at the carbon tax rate of \$150/tC with respect to the base case (i.e., without a carbon tax).

Table 9.11: Total CO_2 emission and % reduction during 2006-2025 at selected carbon tax rates (million tons).

Carbon tax (\$/tC)	Total CO_2 emission (10^6 tC)	% Reduction[+]
0	2,207	-
5	2,182	1.1
10	2,148	2.6
25	2,037	7.6
50	1,223	44.5
100	988	55.2
150	742	66.3

[+] A '-' sign means either zero or a negligible quantity.

Decompositions of CO_2 emission reduction: The role of supply- and demand-side effects

As discussed earlier, the total change in CO_2 emissions with the introduction of carbon tax is caused by two special effects: supply-side effect (i.e., technological substitution) and the demand-side effect (i.e., price effect) of the tax (see Section 2.6 in Chapter 2 for calculation of decomposition of CO_2 emission reduction). Table 9.12 presents the total CO_2 reduction under the carbon tax scenarios and its decomposition into supply- and demand-side effects. As can be seen from the table, the share of CO_2 reduction due to the demand-side effect is higher than the supply-side effect at the carbon tax rates of \$25/tC. At \$5/tC and \$10/tC, CO_2 emission reduction due to the supply-side effect is slightly higher than demand-side effect. However, beyond the tax rate of \$50/tC, the share of CO_2 mitigation due to the supply-side effect is found to be more significant than the demand-side effect. The primary cause for this would be the replacement of carbon-intensive fuels and inefficient technologies with the less carbon-intensive fossil fuels, renewables and efficient technologies.

Table 9.12: Contributions of demand- and supply-side effects to the power sector cumulative CO_2 reductions during 2006-2025.

Carbon tax (\$ /tC)	Cumulative CO_2 emission reduction (10^6t)	Demand-side effect (%)	Supply-side effect (%)
5	25	45.8	54.2
10	58	48.3	51.7
25	170	55.9	44.1
50	984	9.7	90.3
100	1,218	11.0	89.0
150	1,464	10.6	89.4

Implications on CO_2 emission intensity

There is no significant change in CO_2 intensity (measured in tons of CO_2 emission per MWh) in carbon tax cases up to \$50/tC. At higher carbon tax rates, CO_2 intensity would decrease from 0.59 tons/MWh in the base case to 0.34 tons/MWh at \$50/tC and 0.22 tons/MWh at \$150/tC.

Local/regional pollutant emissions

The introduction of a carbon tax would also decrease the local pollutants (such as SO_2 and NO_x) emissions. Table 9.13 shows thatthe cumulative SO_2 emissions would decrease by less than 1% at the carbon tax rate of \$5/tC and by 78% at the tax rate of \$150/tC. The table also illustrates there would be a cumulative reduction in NO_x emission during 2006-2025 from about 1% to 60% in the tax range considered.

Table 9.13: SO_2 and NO_x emissions and mitigations during 2006-2025 at selected energy tax rates[+].

Carbon tax ($/tC)	SO_2 emission		NO_x emission	
	(10^3tons)	Reduction (%)	(10^3tons)	Reduction (%)
0	4,125	-	6,621	-
5	4,101	0.6	6,542	1.2
10	4,071	1.3	6,433	2.8
25	3,940	4.5	6,095	7.9
50	2,659	35.5	3,988	39.8
100	2,336	43.4	3,199	51.7
150	908	78.0	2,687	59.4

[+] A '-' sign means either zero or a negligible quantity.

Carbon tax elasticity of CO_2 emission

The values of the carbon tax elasticity of CO_2 emission for different tax rates in the case of Vietnam are shown in Table 9.14 (see Section 2.2 in Chapter 2 for calculation of carbon tax elasticity of CO_2 emission). CO_2 emission is found to be inelastic for all carbon tax rates considered in the study and lie in the range of -0.006 to -0.749. The emission reduction is found to be much more inelastic at the low values carbon tax rates and relatively more elastic at higher carbon tax rates.

Table 9.14: Carbon tax elasticity of CO_2 emission from the power sector at selected carbon tax rates.

Carbon tax range ($/tC)	Carbon tax elasticity
0-5	-0.006
5-10	-0.024
10-20	-0.062
25-50	-0.749
50-100	-0.318
100-150	-0.711

9.4. Effects of Energy Tax

This section analyzes the effects of introducing an energy tax in Vietnam during 2006-2025. Four energy tax rates are considered for the study, i.e., $0.5/MBtu, $1/MBtu, $2/MBtu and $5/MBtu.

9.4.1. Utility planning implications

Generation technology capacity mix

Table 9.15 presents capacity additions by plant type at the selected energy taxes during 2006-2025. During 2006-2025, in the base case (i.e., without energy tax), there would be a total power generation capacity addition of

35,446 MW. As can be seen, there would not be much change in total capacity addition and capacity mix at the energy tax rate of $0.5/MBtu. A significant change in the capacity mix would, however, take place at energy tax rate of $1/MBtu and higher. The generation capacity mix would then shift towards renewables- (mainly hydro and wind) and gas-based combined cycle power plants.

Table 9.15: Capacity addition, by plant types over the planning period (2006-2025) at selected energy tax rates (MW)+.

Energy tax ($ /MBtu)	0 (Base case)	0.5	1	2	5
Hydro	9,280	9,519	9,963	9,963	10,480
Coal-fired steam	18,896	18,896	18,896	16,796	-
Gas turbine (gas)	4,230	4,230	2,910	-	4,230
Combined cycle (gas)	3,030	1,440	720	-	7,500
Geothermal	-	-	-	-	400
Wind	-	2	743	8,998	9,000
Small hydro	10	-	-	10	925
Total	35,446	34,087	33,232	35,767	32,535

+ A '-' sign means either zero or a negligible quantity.

Electricity generation mix

Fuel prices would change with the introduction of an energy tax and as a result, the generation mix can change towards environmentally friendly and efficient technologies. Table 9.16 presents the total electricity generation of hydro, thermal and renewable generation, and power import during the planning period at the selected energy tax rates, considering both the supply-side and demand-side effects. The energy tax is found to favor electricity generation from renewable sources (hydropower and wind) and gas-fired combined cycle power plants and discourage generation from coal and oil-fired plants. For example, the share of coal-based generation would decrease from 49% in the base case to 12% at the energy tax rate of $5/MBtu. Oil-based power generation is relatively very small under all the energy tax rates considered. The table also shows that there would be a shift from coal-based power generation to hydro-, gas- and renewable-based power generation and imported power in the country under the energy tax. For example, the share of hydro, gas, renewable and imports would increase from 30%, 21%, 0% and 0.08% in the base case to 42%, 33%, 5% and 6.7%, respectively over the planning period (i.e., 2006-2025) at the energy tax of $5/MBtu.

Figure 9.9 shows the relative contributions of different generation options in selected years during 2006-2025 under the energy tax rate of $5/MBtu. It shows that at this energy tax rate, there would be a considerable reduction in the share of coal-based generation compared to the base case.

Table 9.16: Cumulative electricity generation mix during 2006-2025 at selected energy tax rates (GWh).

Energy tax ($/MBtu)	0	0.5	1	2	5
Hydro	1,114,180	1,163,269	1,187,839	1,303,714	1,338,900
Coal	1,839,524	1,739,608	1,631,892	1,201,015	399,649
Oil	26,941	26,941	26,941	26,941	26,941
Gas	785,095	741,456	699,281	625,324	1,051,950
Renewable	21	5	31,034	120,176	160,583
Imported power	3,148	2,389	2,107	146,257	214,620
Total electricity Generation (GWh)	3,768,909	3,673,668	3,579,094	3,423,427	3,192,643

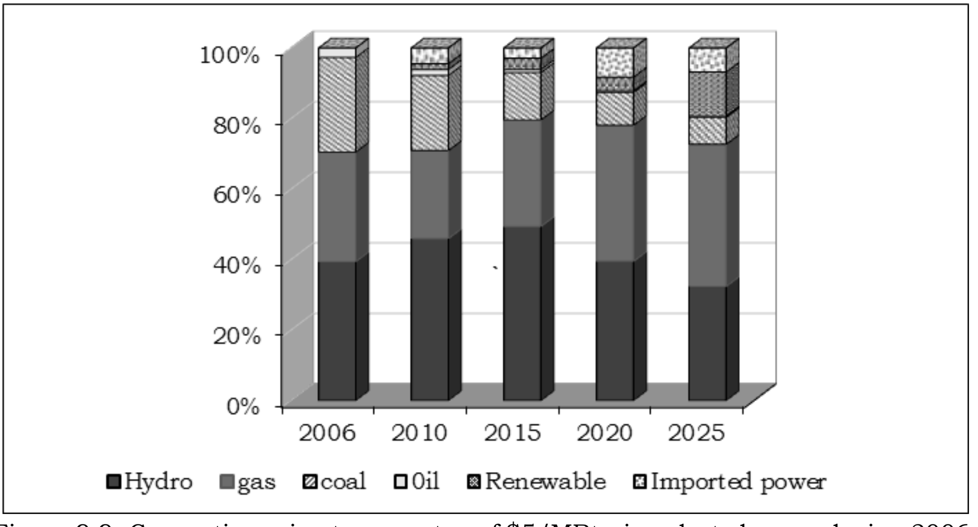

Figure 9.9: Generation mix at energy tax of $5/MBtu in selected years during 2006-2025.

Reduction in electricity demand

As mentioned in the methodology chapter, a demand curve with constant price elasticity of 0.30 was assumed for the present analysis. As illustrated in Figure 9.10, the total electricity demand would decrease with the increase in energy tax. The cumulative electricity generation during 2006-2025 is found to decrease by about 15% at the higher energy tax rate of $5/MBtu as compared to the base case.

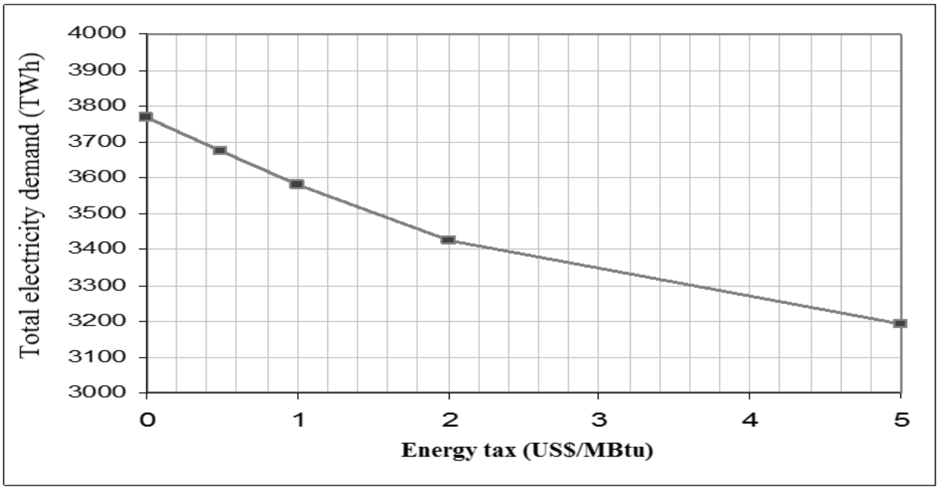

Figure 9.10: Reduction in cumulative electricity demand during 2006-2025 due to energy tax.

Fossil fuel consumption for power generation

Table 9.17 presents the fossil fuel use by fuel types over the planning period at selected energy tax rates considering both demand- and supply-side effects. As can be seen, with the introduction of the energy tax, the cumulative use of coal for power generation would fall from 428.8 Mtoe in the base case to 96.4 Mtoe at the energy tax rate of $5/MBtu. There is no change in oil consumption because there would not be any new oil plant additions over the planning period. Gas consumption would decrease from 94.3 Mtoe in the base case to 75.6 Mtoe at the energy tax rate of $2/MBtu, but it would increase significantly to 124.8 Mtoe at the energy tax rate of $5/MBtu due to the addition of more efficient combined cycle power plants. Total fossil fuel use (in the cumulative term) during 2006-2025 is found to decrease by 57% at the energy tax rate of $5/MBtu.

Table 9.17: Fossil fuel use in electricity generation during 2006-2025 at selected energy tax rates (10^6 toe).

Energy tax ($/MBtu)	Fossil fuel use (Mtoe)				Reduction (%)
	Coal	Oil	Gas	Total	
0	428.8	6.7	94.3	529.8	
0.5	405.8	6.7	89.3	501.7	5
1	380.9	6.7	84.5	472.1	11
2	281.2	6.7	75.6	363.4	31
5	96.4	6.7	124.8	227.9	57

Generation system efficiency

The introduction of energy tax would significantly affect the overall thermal generation efficiency over the planning period in the case of Vietnam as the supply-side effect is more prominent with the introduction of energy tax. As can be seen from Table 9.18, WATGE would increase from 34.9% in the base case to 41.25% at the energy tax rate of $5/MBtu. This is mostly due to the addition of highly efficient combined cycle plants displacing inefficient coal and oil based power plants at the higher tax rates.

Table 9.18: Weighted average thermal generating efficiency during 2006-2025 at selected energy tax rates (%).

Energy tax ($ /tC)	WATGE (%)
0 (Base case)	34.9
0.5	34.9
1	34.0
2	35.5
5	41.2

Figure 9.11 illustrates the variations in the annual WATGE at different tax rates. It is noted that at the tax rates of $2/MBtu and during 2006-2012, WATGE is found to increase due to the selection of efficient combined-cycle gas-fired power plants instead of the coal-fired steam power plants.

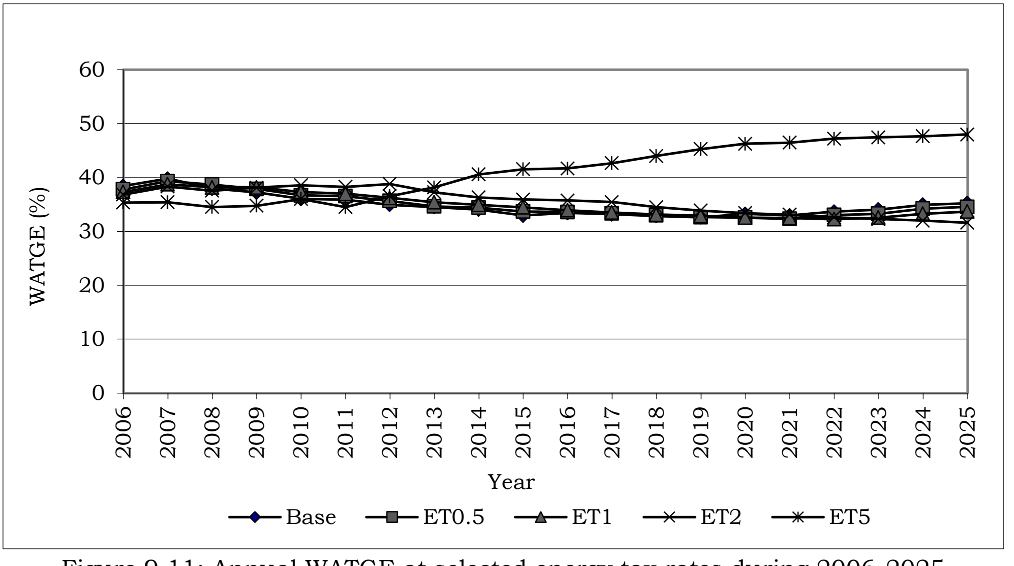

Figure 9.11: Annual WATGE at selected energy tax rates during 2006-2025

The WATGE would decrease gradually until year 2023 and increase thereafter slightly till 2025. The scenario is completely different at the energy tax rate of $5/MBtu, under which the WATGE would increase from 36.8% in 2006 to 48% in 2025. This is mainly due to the replacement of inefficient coal-fired steam plants by the efficient combined cycle gas power plants.

Generation system reserve margin

The energy tax would also affect the reserve margin of the power system. As can be seen in table 9.19, the average reserve margin of the power system during the planning period would increase with the increase in energy tax. The average reserve margin increases from 28.8% in the absence of the energy tax to 36.4% at the energy tax rate of $5/MBtu. The increase in the reserve margin at the higher values of the tax rate is mainly due to the higher share of renewable-based power generation capacity (mainly hydro and wind).

Table 9.19: System reserve margin during 2006-2025 at selected energy tax rates (%)

Energy tax ($ /tC)	System reserve margin (%)
0 (Base case)	28.8
0.5	30.0
1	31.3
2	33.2
5	36.4

Generation capacity utilization

The utilization of the power generation capacity can vary with the energy tax. Figure 9.12 shows the weighted average capacity factor (WACF) of the power generation system during 2006-2025. WACF of the system, as a whole, during the planning period, would decrease with the increase in energy tax as the WACF of both the existing plants and capacity plant would decrease with the increase in energy tax during the period. The decline in the capacity factor of the existing plants under the energy tax rates is due to the relatively larger usage of renewable energy based power plants and efficient fossil fuel-based plants that would be added the energy tax. The decreasing capacity factor of candidate power plant capacity, on the other hand, occurs due to the increasing share of renewable energy based power plants (mainly based on wind characterized with intermittent generation as well as hydropower).

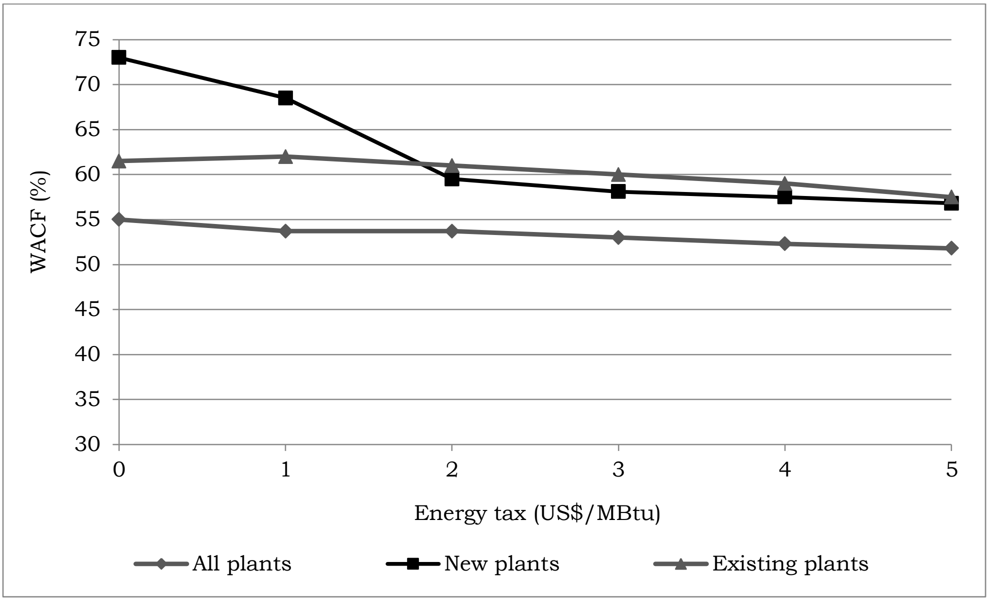

Figure 9.12: Weighted average capacity factor (WACF) of existing, new and all power plants during 2006-2005 at selected energy tax rates

9.4.2. Environmental implications

Figure 9.13 shows the cumulative CO_2 emission in the Vietnam power sector during 2006-2025 at selected energy tax rates. At lower energy tax rates of \$0.5/MBtu and \$1/MBtu, there would be a reduction in cumulative CO_2 emission by 5.2% and 10.8%, respectively, as compared to the base case, while the emission would be reduced by 31.9% and 61.9% at the energy tax rates of \$2/MBtu and \$5/MBtu, respectively (see Table 9.20).

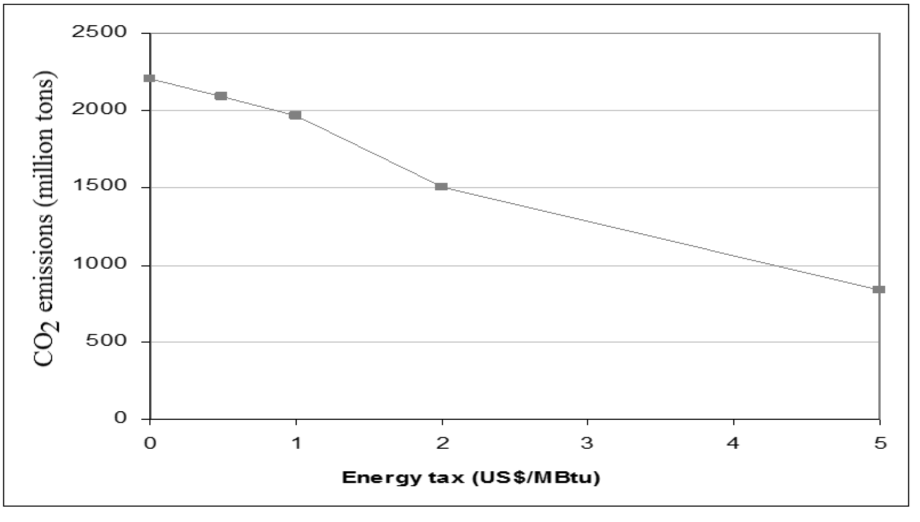

Figure 9.13: Total CO_2 emission during 2006-2025

Table 9.20 shows the CO_2 mitigation due to the introduction of the energy tax. The CO_2 emission would be reduced by about 116 million tons (compared to the base case emission) at the energy tax rate of $0.5/MBtu and would be reduced by 1,367 million tons at the tax rate of $5/MBtu.

Table 9.20: Total CO_2 emission and % reduction during 2006-2025 at selected energy tax rates (million tons)

Energy tax ($/MBtu)	Total CO_2 emission (Million tons)	Reduction (%)+
0 (Base case)	2,207	-
0.5	2,091	5.3
1	1,968	10.8
2	1,504	31.9
5	840	61.9

+ A '-' sign means either zero or a negligible quantity.

Local/regional pollutant emissions

Energy tax also results in a reduction of SO_2 and NO_x emissions. The emissions of SO_2 and NO_x at the selected energy tax rates are presented in Table 9.21. As can be seen, there would be a reduction in SO_2 emission in the range of 2.6% to 42.1% (as compared to the base case emission) with the energy tax rates considered in this study, while the NO_x emission reduction would range from 5.6% to 60.8% with the range of energy tax considered.

Table 9.21: SO_2 and NO_x emissions and reductions during 2006-2025 at selected energy tax rates +

Energy tax ($/MBtu)	SO_2 emission (10^3 tons)	Reduction (%)	NO_x emission (103 tons)	Reduction (%)
0 (Base case)	4,125	-	6,621	-
0.5	4,018	2.6	6,252	5.6
1	3,902	5.4	5,864	11.4
2	3,398	17.6	4,435	33.0
5	2,388	42.1	2,593	60.8

+ A '-' sign means either zero or a negligible quantity.

Decomposition of CO_2 emission reduction: The role of supply- and demand-side effects

As in the case of the carbon tax, a reduction in CO_2 emission, with the introduction of the energy tax, is a result of two effects, i.e., the supply- and the demand-side effect. Table 9.22 presents the total CO_2 emission reduction at different energy tax rates as well as the contributions of the supply-side and the demand-side effects to the emission reduction. The effect of demand- and supply-side in CO_2 emissions reduction at $0.5/MBtu is found to be almost similar. As can be seen from the table, the demand-side effect plays an increasing role in CO_2 reduction with an increase in the energy tax, while the relative contribution of supply-side effect decreases with the increase in the tax.

Table 9.22: Contributions of demand- and supply-side effects to the Power sector cumulative CO_2 reductions during 2006-2025

Energy tax ($/MBtu)	CO_2 emission reduction (10^6t)	Demand-side effect (%)	Supply-side effect (%)
0.5	116	50.0	50.0
1	239	45.2	54.8
2	703	58.3	41.7
5	1,366	82.9	17.1

Implications on CO_2 emission intensity

CO_2 intensity (measured in tons of CO_2 emission per MWh) decreases with increase in energy tax rates. CO_2 intensity would decrease from 0.59 tons/MWh in the base case to 0.55 tons/MWh at $1/MBtu, 0.44 tons/MWh at $2/MBtu and 0.26 tons/MWh at $5/MBtu. CO_2 intensity would be more effective at energy tax above $1/MBtu.

Energy tax elasticity of CO_2 emission

The energy tax elasticity of CO_2 emission is calculated at the selected energy tax rates. The computed different elasticities for energy tax rates lying in lower range (i.e., from $0 to $0.5 per MBtu) to higher range (from $2 to $5/MBtu) are presented in Table 9.23. As can be seen, CO_2 emission is found to be inelastic in all the energy tax ranges considered in the study. The main reason for the significant increase in the elasticity at higher tax ranges appears to be the higher level of technological substitution at the higher energy tax rates.

Table 9.23: Energy tax elasticities of CO_2 emission from the power sector at selected tax rates

Energy tax range ($/MBtu)	Energy tax elasticity
0 - 0.5	-0.027
0.5 - 1	-0.091
1 - 2	-0.401
2 - 5	-0.660

9.4.3. Economic Implications

This section will discuss how energy tax would affect the total cost of electricity generation, unit cost of electricity generation and energy tax revenue.

Electricity generation system cost

Figure 9.14 illustrates the increase in the total discounted cost during 2006-2025 with the energy tax rates considered. The total cost would increase in the range of 9% to 65% under the energy tax rates of $0.5/MBtu to $5/MBtu. As shown in Table 9.24, the contribution of fuel and variable O&M cost to the total cost is the highest (i.e., in the range of 56% to 75%), followed by capacity cost (i.e., in the range of 18% to 31%) and fixed O&M cost (i.e., in the range of 6% to 13%). As can be seen from the table, capacity and fixed O&M costs would decrease whereas fuel, and variable O&M cost would increase with the increase in energy tax over the planning period (i.e., 2006-2025).

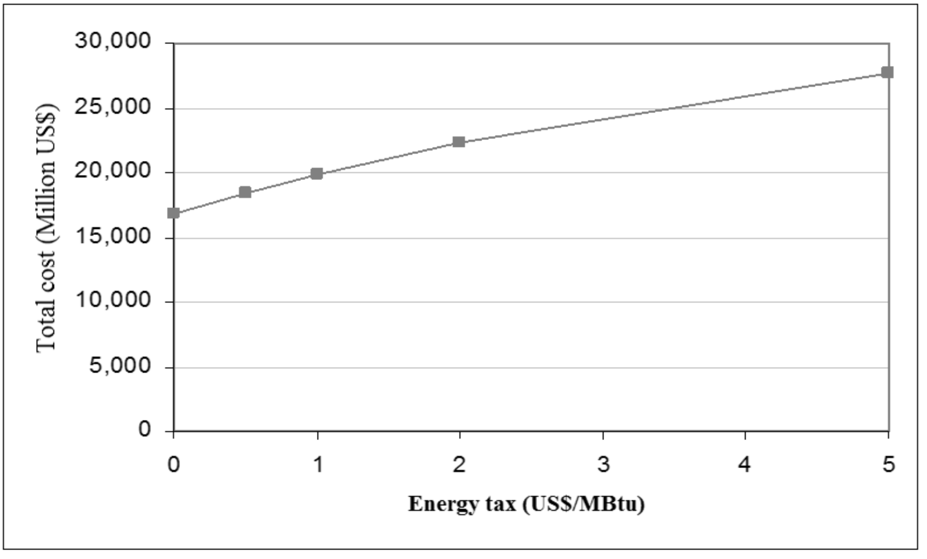

Figure 9.14: Total cost during 2006-2025 at selected energy tax rates

Table 9.24: Breakdown of total cost of power generation system development at selected energy tax rates (discounted value)

Energy tax ($/MBtu)	Capacity cost		Fixed O&M cost		Fuel and var. O&M cost		Total cost (10^6 $)
	(10^6 $)	(%)*	(10^6 $)	(%)*	(10^6 $)	(%)*	
0	5,176	31	2,165	13	9,512	56	16,854
0.5	5,148	28	2,069	11	11,206	61	18,423
1	5,158	26	2,023	10	12,681	64	19,862
2	5,416	24	1,850	8	14,996	67	22,262
5	5,079	18	1,739	6	20,925	75	27,743

* These numbers are the percentage of the total cost.

Energy tax revenue

Table 9.25 presents the energy tax revenue resulting from introducing energy tax in the power sector development in Vietnam during 2006-2025. The tax revenue would be in the range of 20% to 83% of the total undiscounted cost at the energy tax rates considered (i.e., from $0.5/MBtu to $5/MBtu) (see Table 9.25). The table shows that at the price elasticity of electricity demand of -0.3, the energy tax revenue would increase from $72,912 million (which is 20% of total undiscounted cost) at $0.5/MBtu to 119,400 million (which is 83% of total undiscounted cost) at $5/MBtu. Further, the total cost net of tax is found to be 10% to 69% (between energy tax of $0.5/MBtu to $5/MBtu) lower than the total cost in the base case.

More interestingly, in the range of energy tax of $0.5/MBtu to $5/MBtu, the total net cost of tax is found to be 10% to 69% lower than the total cost in the base case.

Table 9.25: Tax revenue (undiscounted) during 2006-2025 at selected energy tax rates

Energy tax ($/MBtu)	Total cost (million $)	Tax revenue (million $)	Total net cost of tax (million $)
0 (Base case)	65,017	0	65,017
0.5	72,912	14,630	58,281
1	80,189	28,283	51,907
2	90,844	49,805	41,040
5	119,400	99,030	20,369

Unit cost of electricity generation

Imposition of energy taxes would result in an increase in the higher cost of electricity power generation, which would be reflected in terms of a higher electricity prices. Table 9.26 presents the Long Run Average Cost (LRAC) and overall Average Incremental Cost ($AIC_{overall}$) of electricity generation at selected energy tax rates. It is found that LRAC would increase from ¢2.12/kWh in the base case to ¢4.1/kWh at the energy tax of $5/MBtu. Similarly, the $AIC_{overall}$ would also increase from ¢2.88/kWh in the base case to ¢5.26/kWh at the energy tax of $5/MBtu.

Table 9.26: AICoverall and LRAC during 2006-2025 (¢/kWh)

Energy tax ($/MBtu)	LRAC (¢/kWh)	$AIC_{overall}$ (¢/kWh)
0 (Base case)	2.12	2.88
0.5	2.37	3.19
1	2.63	3.51
2	3.07	4.07
5	4.10	5.26

9.5. Summary

This study has examined the utility planning, economic and environmental implications of the carbon and energy taxes for power development in Vietnam during 2006-2025.

The study shows that clean coal technologies like IGCC, PFBC and supercritical would not be cost-effective with the carbon and energy tax rates considered in the study. Among the thermal power plant options, efficient combined cycle gas-fired power plants would be cost-effective with both the carbon and energy tax rates considered. Furthermore, renewable technologies are found increasingly cost-effective at higher carbon and energy tax rates. Among the renewables, hydro and wind power are found to be the most attractive options with the carbon tax rates considered, followed by small hydro, geothermal, and BIGCC plants. A similar result was found with energy tax rates considered in the present study (with the exception that biomass (wood) based generation options would not be cost-effective).

A major finding of the study is that even at relatively low carbon tax rates, there is potential for a significant reduction in CO_2 emission from the power sector in Vietnam (i.e., a cumulative reduction of 25 million tC at $5/tC to 1,464 million tC at $150/tC). The potential level of reduction would be higher at higher tax rates. This is mainly because large hydro, renewable and combined cycle power plants are cost-effective and replace conventional coal-fired power plants. Furthermore, in terms of CO_2 emission reduction, the supply-side effect is more influential than the demand-side effect at the higher carbon tax rates. The opposite is found at the lower tax rates; i.e., the demand-side effect would play a dominant role in CO_2 reduction at the lower carbon tax rates.

The cumulative CO_2 emission during 2006-2025 is found to decrease by about 116 million tons (5.2%) at the energy tax rate of $0.5/MBtu; the corresponding reduction in CO_2 emission at $5/MBtu would be 1,366 million tons (62%). The present analysis shows that the supply-side effect in power generation would play a more dominant role in total CO_2 emission reduction than the demand-side effect in the range of energy tax considered in the study.

With the introduction of both carbon tax and energy tax, there would be a reduction in the use of coal for power generation. The percentage reduction of cumulative fossil fuel use during the planning period would be in the range of 5% to 57% between the energy tax rates of $0.5/Btu and $5/MBtu, where renewable technologies and power imports would replace the traditional coal plants. Similarly, a 57% decrease in the cumulative fossil fuel use at the carbon tax rate of $150/tC would be observed, when compared to the base case. A reduction in electricity demand due to the demand-side effect and increase in power generation from less carbon intensive technologies –such as hydro-, gas- and renewable-based technologies– due to the supply-side effect, would both play a major role in reducing fossil fuel consumption as a result of the carbon tax. The generation from power imports would increase in the range of 0.08% to 6.5%

in both the carbon tax rates (between \$5/tC and \$150/tC) and energy tax rates (between \$0.5/MBtu and \$5/MBtu).

Both carbon and energy taxes would have a beneficial effect in the emission of local/regional pollutants such as SO_2 and NO_x. The emission of both SO_2 and NO_x would be reduced in the range of 3% to 42% in the case of SO_2 and 5.5% to 61% in the case of NO_x at the energy tax rates of \$0.5/MBtu to \$5/MBtu. The introduction of a carbon tax would also substantially decrease the local pollutants (such as SO_2 and NO_x) emissions since the coal-based electricity generation is mostly substituted by hydro and other renewables (like wind, small hydro and geothermal). Mitigation of both SO_2 and NO_x emissions would be in the range of 0.6% to 78% in the case of SO_2 and 1.2% to 59.4% in the case of NO_x when the tax is increased from \$5/tC to \$150/tC.

The total cost would increase in the range of 9% to 65% as the energy tax rates of \$0.5/MBtu to \$5/MBtu are introduced. The contribution from fuel and variable O&M costs to the total cost is the highest (i.e., in the range 56% to 75%), followed by capacity cost and fixed O&M cost. The LRAC and $AIC_{overall}$ would also increase with the increase in energy tax from \$0.5/MBtu to \$5/MBtu. Similarly, with the introduction of carbon tax rates of \$5/tC to \$150/tC, the total cost would increase in the range of 2% to 44%. The contribution of variable O&M cost to the total cost would be the highest (i.e., in the range of 58% to 70%) between carbon tax rate of \$5/tC and \$150/tC.

This analysis has not considered the nuclear power generation option in either the carbon tax or energy tax. In Vietnam, there are lots of renewable options and hydro-power resources; therefore, CO_2 mitigation is mainly achieved through the supply-side effect that is, replacing fossil fuel plants by renewable and hydro power plants. The results could be different if nuclear options are also considered. In addition, it should be noted that the present analysis is based on supply-side options only. In particular, it does not consider demand-side options, for e.g., demand-side management. Thus, the results of the study would be different if demand-side options were also considered.

The tax revenue is in the range of 20% to 83% of the total undiscounted cost if the energy tax rate is increased from \$0.5/MBtu to \$5/MBtu and in the range of 3% to 39% of the total undiscounted cost when carbon tax rate is increased from \$5/tC to \$150/tC.

Post-script

The results presented in this study are expected to be different than the actual data available at the current time (in 2015) because this study was carried out in 2004-2005. Many factors may have influenced the actual development of the power sector since then. Some of the factors behind the differences between the results of this study and the actual evolution of the power sector since 2005 include (i) the differences between the actual growth in power demand and the demand projections made at the time of the study, (ii) the differences in the values of plant capacity costs, fuel prices and efficiency of candidate power plants used in the study and their actual values and (iii) the influence of national renewable energy policies for promotion of RETs after the study was carried out. This section attempts to briefly describe some of these factors in Vietnam.

In this study, the peak load (peak power demand) was estimated to grow at a CAGR of 11.8% during 2006-2012; however, the data available shows that the peak load during the same period actually grew at a slower rate of about 10% (ERAV, 2013).

This study estimated that the electricity generation would increase at CAGRs of 12.2% during 2005-2010 and 10.4% during 2006-2015. According to IAEA (2013), the generation actually increased at a CAGR of 12.1% during 2005-2012 (i.e., from 54,040 GWh in 2005 to 120,257 GWh in 2015); the growth rate happened to be very close to the estimated CAGR during 2004-2010 in this study.

With the implementation of renewable energy promotion policies, Vietnam saw thermal power plants being replaced by RETs. However, due to lack of effective policies on promotion of RETs at the time this study was carried out, the share of coal-based power generation was estimated to increase from 27.5% in 2006 to 38.9% in 2010 and 51.3% in 2015. However, according to IAEA (2013) the share of coal in total electricity generation actually remained around 18% in both 2005 and 2012 while the share of hydro increased from 36% in 2005 to 45% in 2012 (this study estimates that the share of hydro would decrease from 33.7% in 2006 to 30.6% in 2010 and to 32.6% in 2015). Although this study has estimated the share of imported electricity to remain below 0.2% during 2006-2025; it is reported that the share of imported electricity from China was actually 2% of the country's electricity supply mix in 2012.

This increase in the electricity generation from renewable energy technologies is attributable to the various policies implemented by Vietnam. The National Energy Development Strategy along with the Renewable Energy Action Plan and the Power Development Master Plan are a few of such policies. In 2011, the government of Vietnam has set a target to increase the share of RETs in the total installed capacity from 4.5% in 2020 to 6% 2030. Towards that end, policies to promote renewable energy like feed-in tariff for wind power plants, exemption of import tax on RET equipments, exemption of corporate tax and exemption of tax and land use fee for renewable energy projects were introduced (Hai, 2013; OECD/IEA, 2015).

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Power Sector Development with Carbon and Energy Taxes:
An Assessment in six Asian countries

This book presents country-specific analyses of the effects of carbon taxes and energy taxes on the development of the power sectors of China, India, Indonesia, Sri Lanka, Thailand and Vietnam. Using a least-cost generation system planning framework, the country case studies present an assessment of the implications of carbon and energy taxes on capacity requirements, the mix of renewable- and fossil fuel-based power generation technologies and energy resource-mix in electricity generation. The country case studies also analyze the implications of the taxes on total cost, investment requirements and average incremental cost of electricity generation. Furthermore, the studies discuss the effects of the taxes on overall efficiency of thermal power generation, capacity utilization and emissions of CO_2, SO_2 and NO_x as well as estimate the carbon and energy tax elasticities of CO_2 emissions from the power sector in the respective countries. The book additionally addresses the roles of changes in the demand- and supply-sides due to the taxes in the reduction of CO_2 emissions and includes the methodological framework used to analyze the various effects in the studies. It also includes a comparative analysis of the country studies discussing variations in the effects of the taxes across the countries. The book will be of significant interest to researchers and climate and energy policy makers involved in the sustainable development of the power sector in developing countries.

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