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Assessing Greenhouse Gas Mitigation Options for the Thai Power Sector

This article examines the potential for greenhouse gas (GHG) mitigation in the Thai power sector and evaluates the possibility of GHG reduction due to new government plans and policies for the power sector through the year 2030. First, electricity demand and supply are estimated for the base case or "business-as-usual" scenario by assuming that present patterns of electricity production and use continue in the future. The amount of fuel used for power generation and subsequent GHG emissons are calculated for the base case scenario. General mitigation options for reducing GHG emissions in the Thai power sector are evaluated. Mitigation options include reducing electricity use via energy efficiency and energy conservation; shifting to low-carbon fuels (e.g., coal to oil or natural gas); using nonfossil related energy sources (e.g., renewable energy); and using nuclear energy. This analysis shows that the government's new emissions standards for power plants and new policies regarding demand-side management (DSM), although they were not designed primarily for reducing CO_2 emissions, could reduce CO_2 emissions by as much as 12 million tons in 2010 and 26 million tons in 2030.

INTRODUCTION

Electricity demand in Thailand tripled between 1984 and 1993. The annual growth rate for electricity demand was 13%, very high compared to the 8.9% average annual growth of GDP in the same period. Final energy consumption in Thailand was 39 328 thousand tons of oil equivalent (ktoe) in 1993, of which 4795 ktoe was from electricity consumption. The share of electricity in total energy consumption increased from 9% in 1984 to 12% in 1993.

In 1989, Thailand emitted about 112 mill. tons of CO_2 and 6.9 mill. tons of CH_4. Of total CO_2 emissions, 70.9 mill. tons. (63.3%) was attributable to energy consumption (Fig. 1). The remaining CO_2 emissions resulted from cement production (5.2%) and changes in land use (31.7%).

The power sector is the second largest energy consumer after the transport sector and thus is responsible for a large portion of Thailand's greenhouse gas (GHG) emissions. In 1989, the power sector emitted about 21 mill. tons of CO_2, 18.8% of CO_2 emissions in Thailand or 29.6% of the CO_2 emissions resulting from energy consumption in the same year (Fig. 2). Electricity demand is expected to grow at an average of 6.6% annually through the year 2030. This high growth in electricity demand will require high growth in electricity generation and fuel consumption and, if no action is taken, could result in increased GHG emissions.

In this paper, GHG emissions from the Thai power sector are forecasted and potential GHG mitigation options are examined. First, electricity demand and supply are estimated for the base case or "business-as-usual" scenario by assuming that present patterns of electricity demand and production continue in the future. The amount of fuel used for power generation, and the subsequent GHG emissions, are then calculated for the base case scenario. Finally, GHG mitigation options are evaluated. Generally, there are four recognized options for reducing GHG emissions in the power sector: reducing electricity use via energy efficiency and energy conservation; shifting to low-carbon fuel (e.g., coal to oil or natural gas); using nonfossil related energy sources (e.g., hydropower and renewable energy); and using nuclear energy. In this paper, these are the four mitigation options examined for the Thai power sector.

ELECTRICITY DEMAND AND SUPPLY FORECAST (2)

Assumptions and Methodologies

The demand forecast is made under the business-as-usual scenario and represents what would happen in the future if present trends and patterns of electricity production and use continue. The scenario takes into account technological changes and shifts in the structure of production by assuming that energy intensity is decreasing at the rate of 1% per year. The demand forecast was performed on a sectoral basis with detailed end-use models consisting of six levels: Sector; Subsector; End-Use; Devices/Equipment; Specific Consumption (Fuel Consumption Norm, FCN); and Electricity Consumption. The level of disaggregation and detail vary from sector to sector depending on the level of analysis required and on available data.

At the Sector level, the model contains five major electricity end-use sectors: residential; commercial; industrial; agricultural; and transport. The Subsector level subclassifies each of the five

Figure 1. CO_2 emissions in 1989 (1).

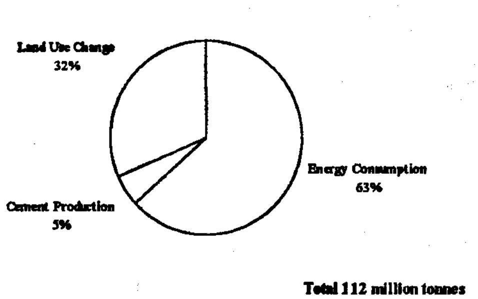
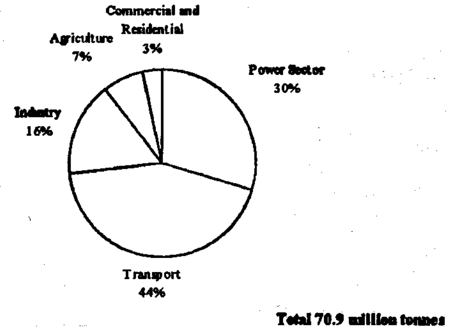


Figure 2. CO_2 emissions from energy consumption (1).



major end-use sectors. For example, the residential sector is subclassified into households located in the metropolitan area and those located in the provincial area to identify variations in socioeconomic characteristics and patterns of electricity demand in different areas. The End-Use level identifies different end-use activities (e.g. lighting, cooking, cooling, refrigeration). For each end-use activity, different types of Devices or Equipment are identified. For example, devices for residential cooling are separated into air conditioners and table fans. The Specific Consumption, or FCN, determines the amount of electricity consumed by each type of device per year. It takes into consideration the capacity, usage hours, and efficiency of each particular device. In general, Electricity Consumption in each sector for each type of end-use is finally estimated by multiplying the number of devices by the FCN of each device. This basic model structure is used for all end-use sectors except transport. Electricity is not currently used in the transport sector in Thailand. However, three mass-transit systems are being planned for Bangkok over the next few years. The electricity demand for transport is thus estimated based on the electricity requirements of these three projects.

The required electricity capacity and generation are estimated based on the forecast of electricity demand. Total station use and transmission and distribution losses are applied to the end-use electricity demand in order to determine the amount of electricity that must be generated from power plants. A system load factor is then applied to determine the end-use peak demand of final customers. Finally, a planning reserve margin is applied to determine the amount of capacity that would be required in order to ensure a reliable electricity supply. Assumptions regarding these variables are based on the latest Power Development Plan (PDP 95–01) of the Electricity Generating Authority of Thailand (3) and are summarized in Table 1.

In modeling capacity by fuel type, many assumptions are based on the PDP 95–01. These were supplemented by data on energy resources obtained from domestic sources and neighboring countries as well as EGAT's internal guidelines regarding fuel mix. The study assumes adoption of some technologies for reducing certain air emissions resulting from future electricity generation; for example, the electrostatic precipitator (ESP) will be attached to all new plants to reduce emissions of suspended particulate matter (SPM) (4), and all new lignite and coal plants utilize fluidized bed combustion (FBC) technology to burn fuel more efficiently and cleanly. In addition, the study considers less conventional technologies, currently under development and demonstration, for meeting Thailand's electricity capacity demand. In particular, fuel cells and integrated gasification combined-cycle (IGCC) plants are promising technologies and are expected to become more widely used during the study period.

The study uses the same fuel prices that EGAT used in its PDP 95–01. EGAT forecasts modest real increases in fuel prices through 2005, with no real escalation after 2005 for most fuels. Because the fuel prices do not change significantly over time, the study uses a single real levelized fuel price over the course of the study period. In addition, the study assumes constant construction and operating costs in real terms over time.

Future power capacities by fuel type are assumed to coincide with the EGAT Plan through the year 2011, while the additional capacity from Independent Power Producers (IPPs) was distributed evenly between imported coal plants and LNG combined-cycle plants. Beyond 2011, the capacity mix is estimated using many assumptions such as the economic life of different types of power plants (for setting up plant retirement schedules) (5), the availability of resources, and government policy. No new lignite or hydropower plants are assumed after Unit 13 of Mae Moh and the Kiridharn Pumped Storage projects are completed. Due to dwindling reserves of domestic natural gas, only 2000 MW of additional combined-cycle plant capacity is assumed to be constructed between 2010 and 2030, requiring about 200 mill. $ft^3\ day^{-1}$ from domestic sources. In addition, most of the additional gas plants are assumed to utilize LNG because of the limited gas reserves available by pipeline from neighboring countries. The only recent finding of significance is the Yetagun gas field in offshore Burma which could potentially supply an additional 200 mill. $ft^3\ day^{-1}$ for about 15 years.

For the forecast of future energy generation, the study assumes that plant capacity factor is about 80% for base load units and about 12% for peak load units. Improved plant operation and maintenance, and the introduction of new and more efficient plants in the future, are expected to raise the average plant factors of base load plants. For the years in which capacity factors resulted in generation that was higher than projected generation requirements, capacity factors for peak load plants and the more expensive base load plants were reduced until energy generation matched the energy requirement. Total electricity generation includes electricity generated from domestic power plants; dedicated hydro and lignite plants in Laos; and electricity imports from Laotian and Malaysian electric utilities and elsewhere. However, due to uncertainty regarding their availability over the longterm electricity imports from Laos, interconnection and other purchases were not considered in 2020 and 2030.

Results

Forecasted electricity consumption by sector for the business-as-usual scenario is shown in Table 2. Total electricity consumption is projected to increase from about 36 TWh in 1990 to 95 TWh in 2000. Consumption is projected to be 473 TWh by the year 2030, a more than tenfold increase from its 1990 level. The industrial sector will continue to be the largest user of electricity, followed by the commercial and residential sectors. A very minor share (about 1% of the total) will be accounted for by the agricultural and transport sectors.

In order to meet domestic electricity requirements, total installed generating capacity is estimated to grow from about 9700 MW in 1990 to about 93 000 MW in 2030. The distribution by fuel type is estimated using the WIGPLAN program and the results are shown in Table 3.

The distribution of power plants by fuel type shows an increasing share of lignite/coal plants, from only about 15% in 1990 to

Table 1. Energy and capacity requirements in Base Case Scenario.

	1990	1995	2000	2010	2020	2030
Final energy demand (GWh)	36 170	62 233	95 203	195 610	318 582	473 403
Station uses and T&D losses (%)	14	13	12	12	11	10
Generation requirements (GWh)	41 172	70 373	106 608	219 161	353 626	520 743
System load factor (%)	70	74	75	78	79	80
Peak demand (MW)	6763	10 812	16 140	32 157	51 099	74 307
Reserve margin (%)	20	20	25	25	25	25
Capacity requirements (MW)	8115	12 975	20 176	40 197	63 874	92 884

about 34% by 2030 (Table 4). Despite a sharp rise in LNG use, the capacity of gas plants (natural gas and LNG) compared to total capacity is expected to fall from about 45% in 1990 to 44% in 2030 due to a declining supply of both domestic natural gas and natural gas obtained through pipelines from neighboring countries. Oil-fired (fuel oil and diesel) plants are expected to increase their share in the fuel mix from about 16% in 1990 to 20% by 2030. Hydro plants are expected to account for a smaller share of total capacity as the domestic potential for large-scale projects is exhausted and opposition to hydro-plant construction continues.

Table 5 shows the amount of electricity generated by fuel type from 1990 to 2030. Total electricity generation is estimated to rise from about 45 TWh in 1990 to about 521 TWh in 2030 and will be sufficient to meet the generation requirements of the economy.

The total fuel requirements that correspond to the amount of electricity generated are shown in Table 6 (6) .

Forecast of CO_2 Emissions in the Power Sector

To estimate the amount of CO_2 emitted, the default values of the carbon content of various types of fuels, as proposed in the IPCC Guidelines, were used. The carbon emission coefficient of local lignite, however, was estimated by conducting a detailed analysis of the characteristics of the lignite used in existing Mae Moh power plants (7). Using the mass balance approach, an average carbon content of 36.7 kg C GJ^{-1} for local lignite was derived. This estimate is about one-third higher than the IPCC proposed default value for lignite of 27.6 kg C GJ^{-1}.

A combustion efficiency of 99% was used to estimate CO_2 emissions for all power plants using fossil-based fuels other than lignite. Although the amount of carbon that remains unoxidized depends on variables such as fuel type consumed, combustion technology used, age of equipment and operation, and maintenance practices, we assumed the level of unoxidized carbon to be 1%, which is consistent with the global default assumption recommended in the IPCC Guidelines.

Based on the amount of fuel

Table 2. Electricity consumption by sector (GWh).

Sector	1990	1995	2000	2010	2020	2030
Residential	8259	15 278	23 258	39 493	54 598	68 531
Commercial	9887	16 209	20 391	32 203	58 085	94 637
Industrial	17 928	30 499	50 453	121 576	202 891	306 394
Agricultural	96	247	451	1288	1959	2791
Transport	–	–	650	1050	1050	1050
Total	36 170	62 233	95 203	195 610	318 583	473 404

Note: Totals may not add up due to rounding.

Table 3. Power plant generating capacity (MW).

Type of fuel	1990	1995	2000	2010	2020	2030
Lignite	1459	2659	2625	2475	1200	–
Imported coal	–	–	300	9100	19 800	31 700
Natural gas	4387	6864	10 915	10 209	3926	1326
Steam - Domestic	2430	3630	3630	2300	–	–
Steam - Import	–	–	–	1400	1400	–
Combined cycle - Domestic	1831	3094	4345	2509	1326	1326
Combined cycle - Import	–	–	2800	4000	1200	–
Gas turbine	126	140	140	–	–	–
Oil steam	1016	1078	938	5100	10 800	15 500
LNG	–	–	–	4800	21 500	39 200
Diesel	522	1327	1246	1546	2100	2800
Gas turbine	98	816	746	1046	1600	2300
Diesel engine	424	511	500	500	500	500
Hydro	2274	2883	3383	5058	4610	2393
Total	9657	14 810	19 406	38 287	63 935	92 918
Imported from Laos	–	–	1311	1611	–	–
Interconnection/Other	–	–	300	300	–	–
Grand total	9657	14 810	21 017	40 198	63 935	92 918

Note: Totals may not add up due to rounding.

Table 4. Share of total power plant generating capacity, by fuel type *(%).*

Type of fuel	1990	1995	2000	2010	2020	2030
Lignite/Coal	15.2	18.0	13.9	28.8	32.8	34.1
Natural gas	45.4	46.2	51.9	25.4	6.1	1.4
Oil steam	10.5	7.3	4.5	12.7	16.9	16.7
LNG	0.0	0.0	0.0	11.9	33.6	42.2
Diesel	5.4	9.0	5.9	3.8	3.3	3.0
Hydro	23.5	19.5	16.1	12.6	7.2	2.6
Imported intercon-nection and other	0.0	0.0	7.7	4.8	0.0	0.0
Total	100.0	100.0	100	100	100	100

Table 5. Electricity generation (GWh).

Type of Fuel	1990	1995	2000	2010	2020	2030
Lignite	11 053	14 447	17 255	16 270	7888	–
Imported coal	–	–	1840	51 489	115 881	182 261
Natural gas	24 208	38 357	58 136	62 688	26 988	9293
Steam - Domestic	18 421	16 119	11 228	8410	–	–
Steam - Import	–	–	–	9811	9811	–
Combine cycle - Domestic	4997	21 211	27 554	16 434	9293	9293
Combine cycle - Import	–	–	18 396	28 033	7884	–
Gas turbine	790	1027	958	–	–	–
Oil steam	3657	3994	1361	24 372	69 729	102 667
LNG	–	–	–	31 536	126 324	222 259
Diesel	260	821	270	399	611	872
Gas turbine	227	807	256	385	597	858
Diesel engine	33	14	14	14	14	14
Hydro	4976	4375	5131	6842	6205	3391
Total	44 154	61 994	83 992	193 596	353 626	520 743
Imported from Laos	–	–	6839	10 615	–	–
Interconnection/Other	717	8242	15 777	14 950	–	–
Grand total	44 871	70 236	106 608	219 161	353 626	520 743

Note: Totals may not add up due to rounding.

Table 6. Fuel requirements for electricity generation.

Fuel type	1990	1995	2000	2010	2020	2030
Lignite (thousand tons)	9875	12 284	15 490	14 444	6,882	–
Imported coal (thousand tons)	–	–	622	17 413	37 449	58 901
Domestic natural gas (mmscf)	172 735	235 425	283 399	167 612	69 252	69 252
Imported natural gas (mmscf)	–	–	179 161	341 815	187 861	–
LNG (thousand tons)	–	–	–	7426	29 748	52 340
Heavy oil (million litres)	2456	3625	1688	7156	15 414	22 680
Diesel (million litres)	82	497	88	230	167	237

used to generate the electricity required from 1990 to 2030, total CO_2 emissions from the power sector were estimated to reach about 324 mill. tons by 2030 due to an increase in fossil-based fuels in the power system mix (Table 7, Fig. 3).

Table 7. Total emissions from the power sector (thousand tons).

Emissions	1990	1995	2000	2010	2020	2030
CO_2	33 732	46 032	56 259	129 719	223 601	324 288

Evaluation of Mitigation Options in the Thai Power Sector

Generally, the most cost-effective mitigation options for reducing GHG emissions in the power sector include adopting more energy efficiency and conservation measures and switching to lower-carbon fuels. The appropriateness of these measures depends on the situations in individual countries. This section discusses the potential benefits of these mitigation options for the Thai power sector.

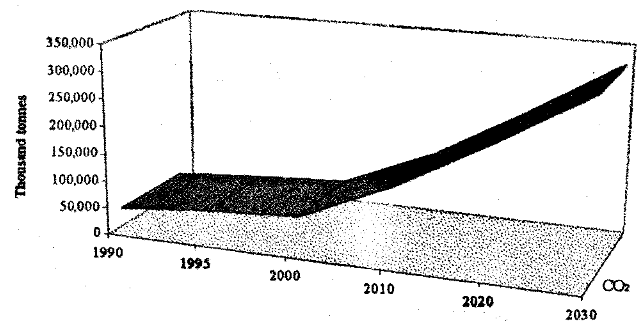


Figure 3. CO_2 emissions from the power sector: Business-as-Usual Scenario.

Programs Promoting Energy Efficiency and Energy Conservation

Demand-Side Management (DSM) Programs: Thailand became the first Asian country to formally incorporate energy-efficiency programs into its power-sector planning process when it adopted a comprehensive 5-year DSM program in 1991. The program is implemented by the DSM Office of EGAT. The 5-year pilot program consists of six major sub-groups. Residential programs focus on energy-efficient lighting equipment, more efficient refrigerators, and more efficient air conditioners. The program also requires manufacturers to produce more efficient equipment and gradually phase out previous products within a specific time period. Business/Government/State Enterprise programs target electricity savings in state enterprises as well as business centers such as large shopping centers and hotels. Industrial programs emphasize the replacement of inefficient motors with more efficient motors and also encourage the use of efficient lighting in manufacturing facilities. Energy Demand Management programs assess the potential for peak-load control options. In these programs, buildings are audited to estimate the potential for load-management benefits from efficiency improvement in large central air conditioning systems. Awareness Building programs provide educational packages and organize activities related to electricity efficiency and energy conservation for students of primary schools in the Bangkok area. In addition, EGAT's DSM Evaluation Program is used to develop a data base system for program evaluation.

The DSM programs were initially designed for the period 1993 to 1997 with a total electricity savings goal of 1427 GWh. This plan was revised in March 1995 after being implemented for two years and more ambitious saving goals were set at 3404 GWh in electricity savings and a 1400 MW reduction in peak demand by the end of 1998. Demand savings are expected mainly from lighting (35%) followed by air conditioners (34%), motors (17%), refrigeration (5%), and load management (9%).

EGAT's long-term marginal cost for new power plants is 1.56 baht kWh^{-1} (about 6.24¢ kWh^{-1}) (8). EGAT projects that DSM will not cost more than 1.45 baht kWh^{-1} (about 5.8¢) (3). The total budget allocated for the DSM Pilot Program from 1993 to 1998 (according to the revised Plan) was USD 192 mill. The financing for DSM, as approved by the government, will be recovered through electricity tariffs. The UNDP/World Bank has also provided USD 30 mill. under the Global Environmental Facility (GEF) to supplement the efforts of the utility DSM program.

Energy Efficiency Programs: The government has offered various energy-efficiency programs, such as appliance labeling and financial incentives for energy-efficient equipment. Compared to the DSM program, however, the government's efficiency programs seem to have less influence on electricity consumption because they do not share the DSM program's specific goal of changing the load curve. The government has also established standards and codes for buildings that will effect electricity use, but the DSM program promotes wider adoption of the most efficient model.

Energy Conservation Programs: The government of Thailand has been involved in energy conservation since the late 1970s. In the Seventh National Economic and Social Development Plan (1992-1996), the government defined short-term and medium-term targets and strategies for the development of the energy sector. The government plans to limit the annual growth rate of energy consumption from 13% to less than 10%. In order to achieve this targeted goal, the government implemented the Energy Conservation Act (ECA) in 1992. Under the ECA, the Energy Conservation Promotion Fund was established. The objectives of the Fund are to support individuals, businesses, NGOs, government agencies, and state enterprises, in research and development, policy planning, technology transfer, promotion and demonstration of work related to energy efficiency, and renewable energy projects. The sources of money for the Fund come from the Petroleum Price Stabilization Fund, an annual levy on petroleum and natural-gas refinery products, and funds received from private sector bilateral and multilateral foreign sources.

In addition, the ECA identifies general measures to reduce energy use in designated facilities and large buildings. The owners of designated facilities and controlled buildings are required to appoint a certified energy manager, conduct energy audits of their facilities and buildings, keep records of energy consumption and conservation and submit them to the government, set goals and plans for conservation, and submit a conservation plan to the government for review and approval. Three years are given to the owners of designated facilities and buildings to meet conservation requirements. There will be penalties in the form of electricity rate increases for failure to comply. The government has also issued regulations governing the minimum efficiency of machinery, equipment, appliances, building materials, control systems, and related items. Producers and distributors of high-efficiency equipment, appliances, and materials can apply for assistance from the Energy Conservation Promotion Fund.

In 1994, the government designed new energy conservation programs (ENCON) that were classified as the Compulsory, Voluntary, and Complementary programs. The Compulsory program enforces the requirements of the ECA in designated facilities and buildings. This includes retrofitting existing factories and buildings over the last four years. The Voluntary program provides technical and financial assistance to any factory, manufacturer, institute, or NGO involved in producing energy-efficient equipment, voluntarily introducing and disseminating renewable energy technologies, developing new technologies, or improving the efficiency of existing technologies. Finally, the Complementary program is designed to train personnel in both the government and private sector as well as to raise the awareness of the general public with respect to energy conservation. The purpose of the Complementary program is to broaden support for the government's energy conservation program.

The ENCON program could help reduce electricity demand significantly if it is effectively implemented. The energy savings expected from ENCON, after the first five years of operation, are estimated to be 2000 ktoe yr^{-1}, approximately 23% of the present energy consumption in the industrial sector (9). One area in which the program could have a large impact is cogeneration by small power producers (SPPs). Cogeneration is highly efficient, particularly with biomass fuel. Consequently, if the ENCON fund is used for development and installation of cogeneration, large savings from the grid could be expected. However, the ENCON program has progressed rather slowly since its inception in 1994 due to a number of obstacles. One persistent problem is that a large number of technical details must be documented, particularly in factories and buildings specified under the compulsory program.

Switching Fuel Options

Renewable Energy Resources: In Thailand, the potential for generating power using renewable energy resources in place of fossil fuels is limited by a number of constraints, particularly economic constraints. Thailand's hydropower potential is estimated to be about 12 734 MW. Of this capacity, only 3371 MW has been exploited so far. The remaining potential appears to be less attractive economically and difficult to develop due to environmental and social pressures. Thus, the potential for domestic hydropower is limited to a few of the most economic and environmentally benign, small- to medium-scale, new projects and pumped storage stations for peak generation. Geothermal energy in Thailand is limited to the north, with maximum capacity estimated at 100-200 MW. The current electricity generation capacity of geothermal is only about 0.5 MW. After 1997, it is expected that Thailand will produce approximately 12 mill. kWh of electricity from geothermal resources. The use of wind energy for power generation is limited to the coastal areas and islands. As of 1993, only about 5800 wind pumps and eight demonstration electricity-generating wind turbines of 22 kW had been installed in Thailand.

At present, approximately 25% of the total energy consumed comes from biomass, which is mostly used in rural areas. Typically, two types of biomass are used: wood fuels (firewood and charcoal) which arise from forestry operations; and paddy husk and bagasse which are by-products of food production and processing. Biomass accounted for 26% of final energy supply to Thailand in 1993; of this biomass, 40% was charcoal, 36% was fuelwood, 19% was baggasse, and 5% was paddy husk (10).

The use of biomass as a substitute for fossil fuel in the total energy supply in the future will be limited. Eucalyptus is the tree type seen as suitable for growing stock in Thailand. The average production of this biomass is about 137.5 $m^3 ha^{-1} yr^{-1}$. Consequently, large areas will be required to ensure enough biomass stock for a medium-size electricity generating capacity. Data from the Department of Energy Development and Promotion (DEDP) indicate that about 28 mill. m^3 of estimated reserve biomass, equivalent to 6 mill. tons of crude oil, would be needed to generate 3600 MW of electricity per year. About 203 636 ha would be required to grow this biomass stock. In addition to the problem of land limitation, the current price of feed stock (about 700 baht ton^{-1} = USD 28 ton^{-1}) renders the use of biomass as fuel for power generation uneconomical. Similarly, both rice and sugar cane are facing market constraints and their production is expected to decline in coming years. This would consequently reduce the availability of paddy husk and bagasse stocks.

At present, about 30 000 m^2 of solar collectors are installed in Thailand. These collectors produce 2.25 mill. liters of hot water every day, equivalent to the energy production of 78 MWh per day. Thailand had about 400 kW of installed photovoltaic devices in 1990 and 1400 kW in 1993. The 1993 capacity was divided almost equally among telecommunication devices (360 kW), water pumping (379 kW), and battery charging for remote off-grid sites (374 kW). Another 600 photovoltaic (PV) water pumps are expected by the end of 1996 (11). While these small-scale, decentralized solar applications may have important economic and social benefits, they are unlikely to be major contributors to the future expansion of the electricity supply.

Uses of Low-Carbon Fossil Fuels: Currently, the main fuels used in the power sector are natural gas and lignite, both of which come from domestic sources. Natural gas is a clean fuel and causes less pollution than other fossil fuels. Comparatively, the use of lignite causes high SO_2 emissions and ash problems. The policy for future power sector development is for EGAT to phase out the use of lignite and encourage independent power producers to use natural gas or imported coal (which is higher quality than domestic lignite) as fuels in their new power plants. Because the domestic gas supply is limited, the natural gas used in the future will be pipeline gas from the region and/or LNG from the Middle East, which will raise the production costs. Therefore, imported coal is expected to take part of the gas share in the future total fuel mix. Gas will remain the principal fuel in the power sector, but its share is expected to decline as coal's share increases. It thus seems that, instead of moving toward lower-carbon fuels like natural gas, Thailand will use more coal for power generation in the future.

Nuclear Option: In 1992, EGAT proposed to build the first nuclear power plant in Thailand by the year 2006. But the plan had to be dropped in 1994, due to the public's antinuclear sentiments, lack of a clear government policy, and prohibitive investment cost. With the new policy, it is unlikely that a nuclear power plant will be constructed in Thailand before 2010.

Assessing the CO_2 Emission Reductions Resulting from Government Policies

Reductions in CO_2 emissions in the Thai power sector are most likely to result from the DSM program and new emissions standards for power plants. Although these policies were not designed with the prime objective of reducing GHG emissions, they will ultimately mitigate global climate change.

CO_2 Emission Reductions from the DSM Program

The 1995 study by Intarapravich et al. (2) estimates CO_2 emission reductions through the year 2030 for the scenario that takes into account electricity savings from DSM measures and the effects of new emissions standards. Under this scenario, electricity requirements will be lowered due to the savings from DSM activities. In addition, in order to meet new emissions standards, all new plants would incur additional costs to account for the installation of control technologies for SO_2, NO_X and SPM. The incorporation of these additional control costs into the cost of electricity production slightly alters the power supply mix in favor of more hydro and oil plants and thus will lower CO_2 emissions.

The study forecasts the potential electricity savings from the DSM program to the year 2030. The forecast is made in a conservative way and assumes the same measures and end-use savings as the current DSM program. The penetration rates for each sector and end use are estimated based on DSM experiences in the US and the estimates of the International Institute for Energy Conservation (IIEC). An adjustment is made, however, to make it reasonable considering Thailand's situation and consistent with EGAT's current DSM target.

The results show total potential electricity savings of 4877 GWh in 2000 and almost 43 000 GWh by the end of 2030 (Table 8). Of the total savings, air conditioners make up the largest share, about 41% in 2030, followed by lighting (25%), motors (14%), refrigerations (13%), and load management (7%).

Using the same assumptions regarding energy losses (about 10–13%), system load factor (about 74–80%), and reserve margin (about 20–25%) as in the business-as-usual scenario (Table 1), the generation and capacity requirements with the DSM program were estimated (Table 9). The results show that the capacity savings due to the DSM program are about 270 MW in 1995 and 16 200 MW in 2030. With lower capacity requirements, there is less need for new power plants. Moreover, due to lower capacity requirements in the year 2010, an additional 4000 MW of new coal thermal plants can be deferred to later years

Most of the capacity savings arising from DSM measures were assumed to reduce the need for additional LNG combined-cycle plants. Only about a quarter of the capacity savings due to DSM were allocated to imported coal plants in order to maintain a maximum of 35% coal contribution to the supply mix. Consequently, the share of natural gas to the supply mix falls slightly from about 43% of total installed capacity by 2030 in the business-as-usual scenario to about 38% in the DSM scenario.

Due to the government's DSM program, about 134 mill. liters of diesel could be saved in 1995 and 1350 mill. liters of fuel oil could be saved in 2000. The largest savings, however, result from reductions in imported coal and LNG. By 2030, imported coal is estimated to decline to about 53.6 mill. tons, while LNG imports are expected to fall to about 44 mill. tons, compared to 58.9 mill. tons of coal and 52 mill. tons of LNG in the reference scenario. Heavy oil use, however, is expected to increase as new oil thermal plants operating on both natural gas and heavy oil are operated at capacity factors of up to 80% (12). The reduction in fuel use reduces the amount of CO_2 emitted from power generation by as much as 25 mill. tons in the year 2030 or about 8% from the "business-as-usual" scenario.

CO_2 Emission Reduction from New Emissions standards

Power sector CO_2 emissions could be indirectly controlled with new emissions standards for the power sector. In the past, emissions from power plants were bound to the standards controlling stack emissions from boilers, smelters, and basic metal industries rather than by emissions standards set specifically for the power sector. Only recently, the National Environmental Board approved emissions standards for power plants. These emissions standards are set by taking into consideration the plant size and fuel type and will be implemented in new power plants. The new standards will control emissions of SO_2, NO_x and SPM and will be more stringent for large plants than small ones (Table 10).

It is expected that the implementation of new emissions standards for SO_2, NO_x, and SPM will lead to significant shifts in the fuels chosen as utility managers redefine their least-cost generating strategies. These emissions standards will have an indirect result on CO_2 emissions. The more stringent emissions stand-

Table 8. Electricity savings resulting from DSM measures (GWh).

Programs	EGAT Forecast		TEI Forecast		
	1998	2000	2010	2020	2030
Lighting	1169	1585	3549	6794	10 755
Refrigeration	175	376	1550	3460	5400
Air conditioners	1165	1795	4557	10 281	17 491
Motors	583	654	1635	3274	6164
Load management	312	467	1244	2022	2799
Total	3404	4877	12 534	25 830	42 608

Note: Totals may not add up due to rounding.

Table 9. Impact of DSM on electricity generation and capacity savings.

	1995	2000	2010	2020	2030
Generation requirement w/o DSM (GWh)	70 373	106 608	219 161	353 626	520 743
Generation requirement with DSM (GWh)	69 576	101 147	205 118	324 955	473 875
Generation savings from DSM (GWh)	797	5461	14 043	28 671	46 868
Capacity requirements w/o DSM (MW)	12 975	20 176	40 197	63 874	92 884
Capacity requirements with DSM (MW)	12 703	18 244	35 314	53 941	76 681
Capacity savings from DSM (MW)	272	1932	4883	9933	16 203

Table 10: Emissions standards for new power plants.

Pollutants	Emissions Standards		
	Coal	Oil	Gas
Sulfur dioxide (ppm)			
Plant size: > 500 MW	320	320	20
300 - 500 MW	450	450	20
< 300 MW	640	640	20
Nitrogen dioxide (ppm)	350	180	120
Particulate matter (mg m^{-3})	120	120	120

Note: Concentrations are determined using reference conditions of 25°C, 760 mm. Hg, dry conditions and excess air from combustion at 50% or O_2 at 7%.

Table 11. Fuel requirements in the Alternative Scenario.

Fuel Type	1990	1995	2000	2010	2020	2030
Lignite (thousand tons)	9875	12 284	15 490	14 444	6882	0
Imported coal (thousand tons)	0	0	622	11 332	31 577	53 576
Domestic natural gas (mmscf)	172 735	235 425	283 399	167 612	90 143	58 807
Imported natural gas (mmscf)	0	0	179 161	334 131	192 980	0
LNG (thousand tons)	0	0	0	7921	26 074	43 921
Heavy oil (million liters)	2456	3625	338	7738	15 627	24 071
Diesel (million liters)	82	363	88	230	72	154

Table 12. Reductions in CO_2 emissions in the Alternative Scenario (thousand tons).

Scenario	1995	2000	2010	2020	2030
From DSM	369	4216	13 686	13 517	25 214
From new emissions standards	0	0	-1,299	822	396
Total reductions	369	4216	12 387	14 339	25 610
As percentage of Business-as-Usual scenario	0.80	7.49	9.55	6.41	7.90

Note: Totals may not add up due to rounding.

ards will provide an incentive to a power producer to shift toward a cleaner fuel so as to minimize the cost of installing the control technologies and thus, consequently, reduce CO_2 emissions.

Table 11 shows the fuel requirements for the "alternative scenario" in which the new emissions standards are implemented in addition to DSM measures.

The main impact of introducing emissions standards is reflected in the amount of pollutants released into the atmosphere. From 25–76% of SO_2 emissions, 13–63% of NO_X emissions, and 2–94% of SPM could be avoided during the period 2000 to 2030. In addition, fuel substitution resulting from the new emissions standards could reduce total CO_2 emissions by 396 000 tons, about 0.12% of the CO_2 emissions in the business-as-usual scenario in 2030.

The DSM program and new emissions standards combined could reduce CO_2 emissions by as much as 25.6 mill. tons in 2030 (Table 12, Fig. 5).

CONCLUSIONS

This study shows that DSM measures have greater impact on CO_2 emission reductions than the new emissions standards. Also, significant contributions are not expected from renewable energy resources and there are currently no plans for exercising the nuclear option in Thailand. The government's policies on DSM and new emissions standards for power plants will reduce CO_2 emissions although they were not designed to do so. The implementation of DSM measures helps to delay and avoid the construction of new power plants. A total of about 16 000 MW of generating capacity can be avoided during the period through 2030, which could result in as much as a 25.2 mill. ton reduction in CO_2 emissions compared to the business-as-usual scenario. The implementation of new emissions standards also results in CO_2 reduction, though to a lesser extent. The emissions standards make fuels that emit high levels of controlled gases more expensive and thus encourage consumers to switch to fuels that produce smaller quantities of controlled pollutants. Normally, cleaner fuel will produce less CO_2. With the implementation of DSM measures and new emissions standards, the CO_2 emissions from the power sector could be reduced by as much as 25.6 mill. tons in 2030, a reduction of about 8% compared to the business-as-usual scenario.

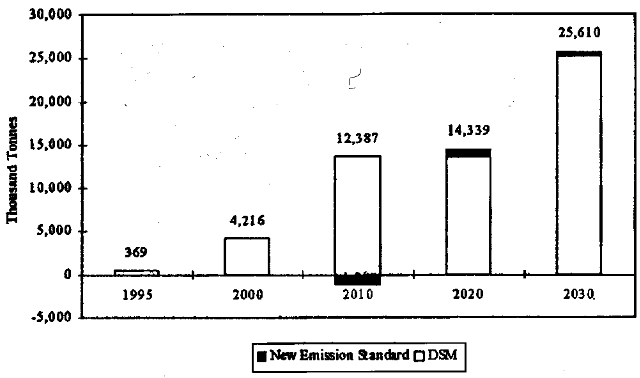
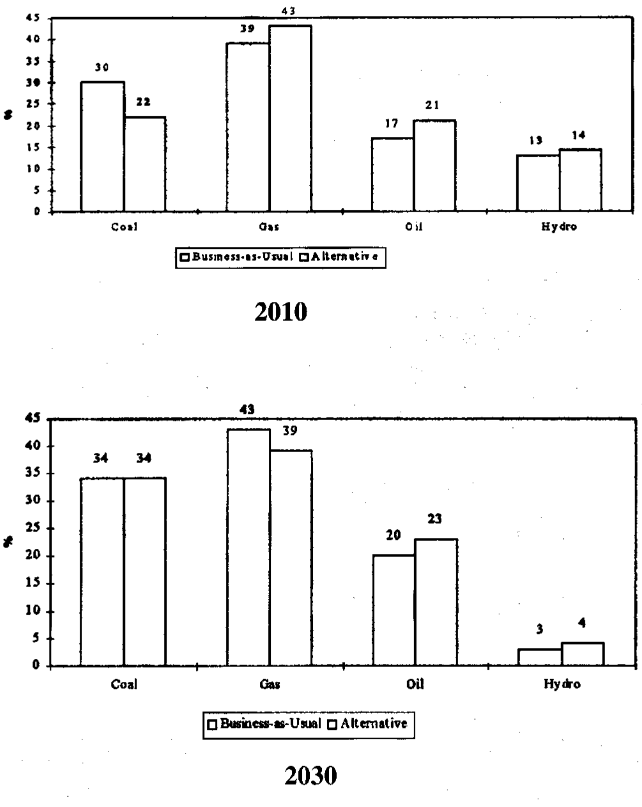


Figure 5. CO_2 reductions in the Alternative Scenario.

Figure 4. Fuel mix for power generation in 2010 and 2030: Business-as-Usual Scenario versus the Alternative Scenario.



References and Notes

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2. For the detailed models and assumptions, see Intarapravich, D., Lim, C., Resanond, A., Santisirisomboon, J., Shrestha, S. and Decosta, I. 1995. *Electricity: Meeting Needs with Least Environmental Impacts.* Thailand Environment Institute, Bangkok.
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4. At present, most EGAT plants are equipped with ESP.
5. Economic life of power plants is assumed as follows: 15 years for gas turbine; 20 years for combined-cycle; 25 years for thermal plants; 25 years for pumped storage hydro and 50 years for hydro power.
6. Fuel use is estimated using the current average heat rates of each type of plant and assumptions regarding improvements in the thermal efficiency of new plants. The efficiency of new steam plants, for example, was assumed to increase to 40%, while the efficiency of new combined-cycle plants would reach 47%. These improvements are likely to happen in the future as new and more efficient technologies are introduced and as existing power plants are operated at higher capacity factors.
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12. Due to constraints in natural gas supply to some dual-fired power plants, these plants are usually operated at higher plant capacity factors by using more expensive heavy oil. The generation cost of an existing 600 MW thermal plant operating using domestic natural gas is estimated at only 0.69 baht kWh^{-1} compared to 0.82 baht kWh^{-1} (USD??) using fuel oil. The analysis has not yet considered the government-mandated program of reducing the sulfur content of heavy oil.
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