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Investigating the Impact of Carbon Tax to Power Generation in Java-Bali System by Applying Optimization Technique

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Investigating the Impact of Carbon Tax to Power Generation in Java-Bali System by Applying Optimization Technique

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Abstract

Java-Bali power system dominates the national installed capacity and will contribute to about 76% of the national CO_2 emissions from the electricity sector in the future. Thus, minimizing CO_2 emission from the Java-Bali system can help Indonesia to reduce the national CO_2 emissions level. We apply optimization approach to investigate this problem by including carbon tax into the cost function. We analyzed data based on electricity generating system in 2008. In general the optimization showed that diesel and gas turbine is not needed in the power plant system. Further, the simulation showed that if Indonesia adopted carbon tax by US$56/ton CO_2 - USD 86/tCO_2; it will lead to three major changing. First, carbon tax will increase the cost of power plant or equivalently increase tax revenue to about 2.1% of GDP in a year. Second, combine cycle has important role to offset decreasing output in steam power plant. Finally, by implementing carbon tax, daily CO_2 can decrease by 77,586 ton per day. By applying sensitivity analysis, we also found a structural break in marginal cost when carbon tax is higher than US$ 50/tCO_2. There are some weaknesses from this study such as not use strong assumption for availability factor and generating costs. This study proposed that government needs to optimize utilization of combine cycle power plan to offset steam power and implement carbon tax above US$ 50/ ton CO_2, to reduce CO_2 emissions significantly.

JEL: C6, Q4

Power generation, Carbon tax, Optimization

Keywords:

Power generation, Carbon tax, Optimization

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1. Introduction

According to the Electricity Law No 30/2009, state has the highest authority to provide electricity. Business on electricity covers four main areas namely generating, transmissions, distribution, and retail or sell electricity for final consumption. For the sake of public interest, it is possible to do business integration in one business area or monopoly, but the highest priority will be given to state owned company. As can be seen from Table 1, PT. PLN is state own company that has monopoly power to conduct business on electricity sector. However, between 2003 and 2008, share of PT. PLN's installed capacity decreased, while private sector increased from 15.6% to about 17.1%. This is mainly because average growth of installed capacity from the private or independent power producer (IPP) is higher than PT. PLN. Table 1 shows that average growth of PLN's power plant was about 4.42%, while private sector increased by 6.57%. Because transmission and distribution are still monopolized by PT. PLN, private sector has to sell the electricity to PT. PLN.

Table 1 Installed Capacity of Power Plant at the National Level (MW)

Power Plant	2003	2004	2005	2006	2007	2008	Average growth (%)
PLN PLN'S Power Plant	25,139	26,424	26,602	29,739	30,300	30,866	4.42
Private Power (IPP)	3,933	4,084	4,087	4,893	5,077	5,272	6.57
Share Private sector (%)	15.6	15.5	15.4	16.5	16.8	17.1	

Note: IPP (Independent Power Producer)
Source: Directorate General of Electricity and Energy Utilization - Ministry of Energy and Mineral Resources (2009)

Operational area of PT PLN (Persero) is divided into three regions: West part, East part and Java-Bali[2]. In 2008, total installed capacity was about 36,138 MW and about 22,637 MW installed in Java-Bali region or it was 63% of total national capacity. As can been seen from Table 2, Java-Bali system is served by 12 business units under PLN control plus the private sector. Further, in 2008, about 84% of Java-Bali system was served by two dominant companies namely PT. Indonesia Power and PT. PJB. Those companies are subsidiaries of PT. PLN. From Table 2, we can conclude that share of installed capacity of private sector in Java-Bali system is much higher than at the national level that was about 22%. Installed capacity of geothermal from the private sector is much higher than PT. PLN and share of installed capacity from private sector for steam and turbine power plant were about 41% and 26.5% respectively of PLN's installed capacity. Next, private companies did not have installation on combine cycle power plant, but 41% of installed steam power was owned private sector.

[2] West part area covers Sumatera and West Kalimantan; the East part covers Kalimantan (except West Kalimantan), Sulawesi, Maluku, Papua, East Nusa Tenggara, and West Nusa Tenggara.

Table 2 Installed Capacity of Power Plant in Java-Bali based on type (MW) in 2008

No	Region/Business unit	Hydro	Geothermal	Steam	Diesel	Turbine	Combine cycle	Total
1	Bali	-	-	-	4	-	-	4
2	East Java	2	-	-	12	-	-	15
3	Central Java	0	-	-	-	-	-	0
4	Yogyakarta	0	-	-	-	-	-	0
5	West Java	1	-	-	-	-	-	1
6	Banten	-	-	-	0	-	-	0
7	Jakarta Raya and Tanggerang	-	-	-	-	-	-	0
8	*PT Indonesia Power*	1,104	375	3,900	92	846	2,676	8,993
9	*PT PJB*	1,289	-	2,100	-	80	3,037	6,507
10	Muara Tawar	-	-	-	-	858	-	858
11	Cilegon	-	-	-	-	-	740	740
12	Tanjung Jati B	-	-	1,420	-	-	-	1,420
	Total PLN	2,397	375	7,420	108	1,785	6,453	18,538
13	**Private (IPP)**	-	575	3,050	-	474	-	4,099

Note: IPP (Independent Power Producer)
Source: Directorate General of Electricity and Energy Utilization - Ministry of Energy and Mineral Resources (2009)

Installed capacity in Java-Bali system depends on steam power plant and in 2008 share of steam power plant was about 46.3% from total installed capacity (calculated from Table 2). Because of low generating cost, low investment cost and abundant supply of coal, stem power is used more intensively than others plants. However, stem power plant has the highest carbon content (see Figure 1). This means CO_2 emissions from electricity sector tend to increase as the power system uses steam power more intensively. Raising CO_2 emission from electricity sector can negatively affect the national target to reduce total CO_2 emission by 26% in 2020. Although, government has not declared target of CO_2 reduction from electricity sector, Indonesia has moral obligation to reduce or even stabilized the CO_2 emissions from electricity sector in the future.

Following the government estimate, CO_2 emissions between 2010 and 2019 will increase from 123 million ton to about 256 million ton and about 80% comes from coal burning (PT. PLN, 2010). Further share of Java-Bali emission to total emissions will be around 76% (PT. PLN, 2010). Thus, minimizing CO_2 emission from the Java-Bali system can help Indonesia to reduce the national CO_2 emissions level. This paper aims to analyze optimal power plant expansion under two scenarios. In the first scenario we include cost of carbon dioxide (CO_2) emissions or carbon tax into the model. In the second scenario, we minimize production cost with consider only construction and generating costs. We applied linear programming approach to investigate this situation. This paper organizes into six parts namely introduction, data description, optimization approach, optimization analysis, conclusions and policy recommendations.

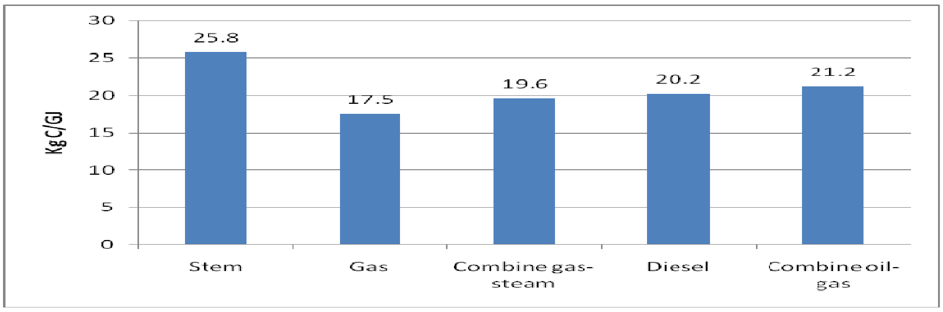


Figure 1. Carbon content by type of power generation

Source: IPCC (2006)

2. Data description

2.1 Electricity sector and CO_2 emissions

The COP 13 on December 2007, reached agreement on the Bali Action Plan that produced five major elements of the Bali Action Plan (Aldy and Stavins, 2009): a long term global climate policy goal, emissions mitigation, adaptation, technology transfer, and financing. As part of mitigation actions, sectoral approaches have been developed for electricity sector[3]. A carbon dioxide emission in Indonesia comes from many sources such as peat, land-use change and forestry, energy/fossil fuel combustion and other sources such as waste. Figure 2 shows the level of emissions for each component. Although, the energy sector did not contribute significantly to the national CO_2 emissions before 2005 compare to land-use change and forestry, the trend tends to increase in the future.

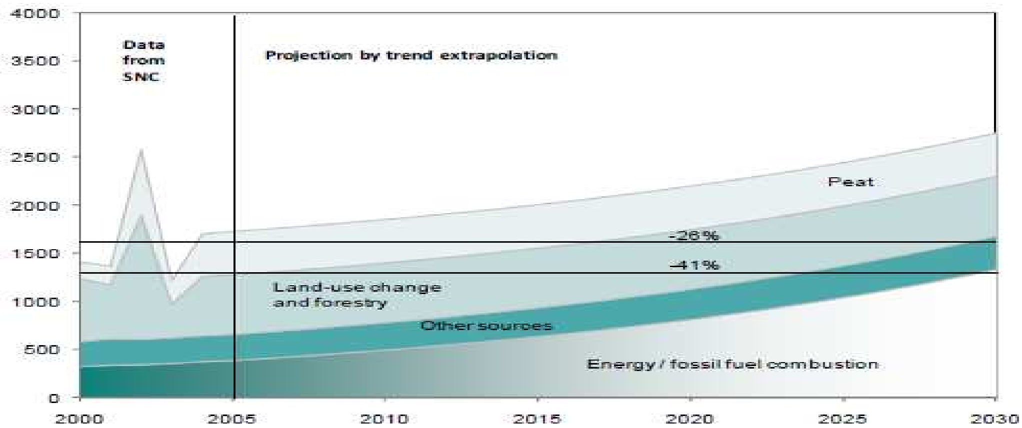


Figure 2. A Business as usual scenario for Indonesia's greenhouse gas emissions, based on current trend, MT CO2-e/year

Source: Ministry of Finance (2009)

3 Mitigation means reducing greenhouse gas emissions.

Following the Copenhagen COP15 Conference, on 19 January 2010, the National Council on Climate Change send letter to the executive secretary of UNFCCC that state Indonesia plans to reduce GHG emissions by 26% to 41% of CO_2 (this scenario can be seen from Figure 2)[4]. This means reduction of around 6% and 24% respectively below 2005 emissions levels under business as usual (BAU) scenario (Ministry of Finance, 2009). Reduction emission target covers seven major areas namely peat-land, forestry, agriculture, energy, industry, transportation and waste. However, the second letter delivered on 30 January 2010 and it stated the voluntary mitigation action will be at level 26% by 2020.

Further, if we decompose CO_2 emissions from the energy sector, we can conclude that Industrial sector had the highest contribution and followed by power generation and transportation sector (see Figure 3). However, as can be seen from Figure 4, annual growth of CO_2 emissions from the power sector is the highest compare to other sectors that is about 8.12% per year. Thus we may conclude that in the near future, electricity sector will become the highest emitter of CO_2 emissions, especially if the power supply highly depends on coal as one primary energy sources. The strategies to control CO_2 emissions from electricity sector rest on three pillars (IEA, 2009): (i) significant improvement in energy efficiency of electricity end uses that can reduce pressure on building more capacity in the future; (ii) policy incentives to move towards a decarbonisation of power supply; and (iii) enhanced R&D in low-carbon generation technology.

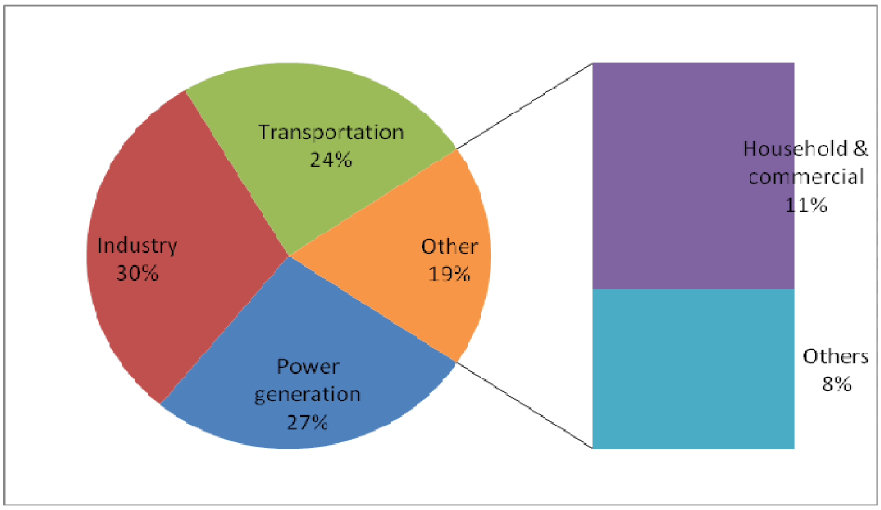


Figure 3 Share of CO_2 emissions from energy sector by source in 2005

Source: Calculated from MEMR (2006)

[4] 26% reduction means the emissions will level off around 1,625 Mt CO_2/year while 41% reduction means the emissions will stabilize about 1,250 Mt CO_2/year.

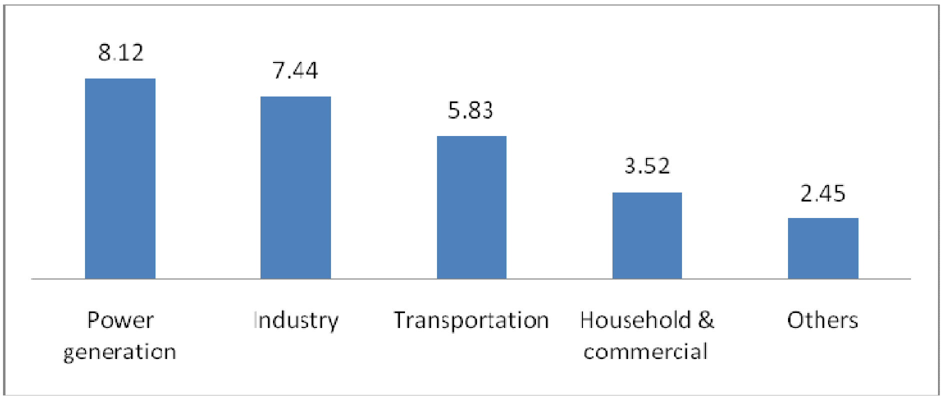


Figure 4 Growth of CO_2 emissions from energy sector by source between 1990-2005 (in %)

Note: growth calculate by applying linear function after taking log for the data
Source: Calculated from MEMR (2006)

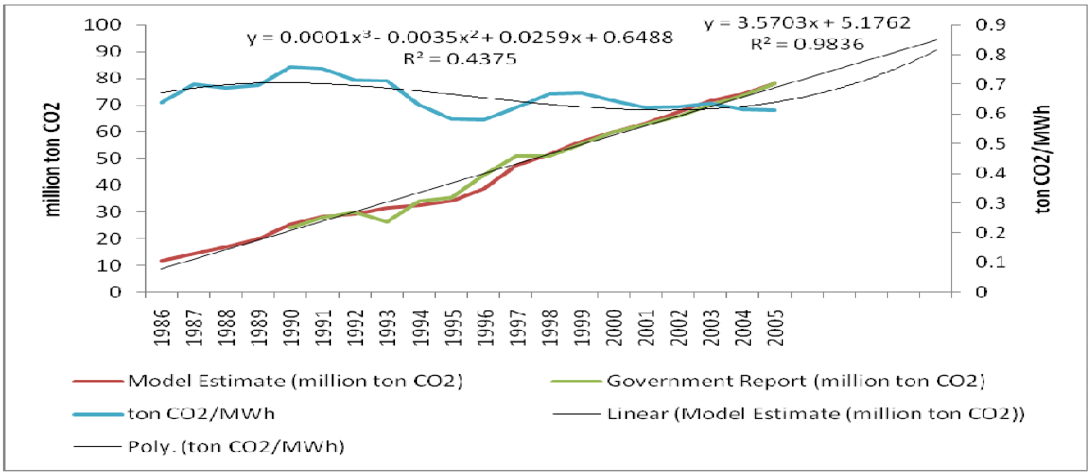


Figure 5. Model estimate of CO_2 emission from electricity sector at the national level

Note: for model estimate see Sambodo&Oyama (2010)
Source: Calculated from MEMR (2006)

As can be seen from Figure 5, CO_2 emissions from electricity sector show an upward trend. However, CO_2 emissions for one megawatt-hour of electricity show non-linier form. Because, CO_2 emissions depend on fuel consumption, when power generation with low CO_2 carbon content is used, CO_2 emissions will relatively low compare to high content. In the early 1990s, CO_2 intensity for one unit of power supply was relative high compare to the mid 1980s. As can be seen from Figure 6, share of coal consumption in early 1990s was higher than in mid 1980s. Next share of hydro power also showed a decreasing share. Further, in mid 1990s, CO_2 intensity for a unit of electricity supply was decrease. This is mainly driven by rising share of gas power plants in the system. Finally, when share of coal consumption increased, intensity of CO_2 emissions start to increase.

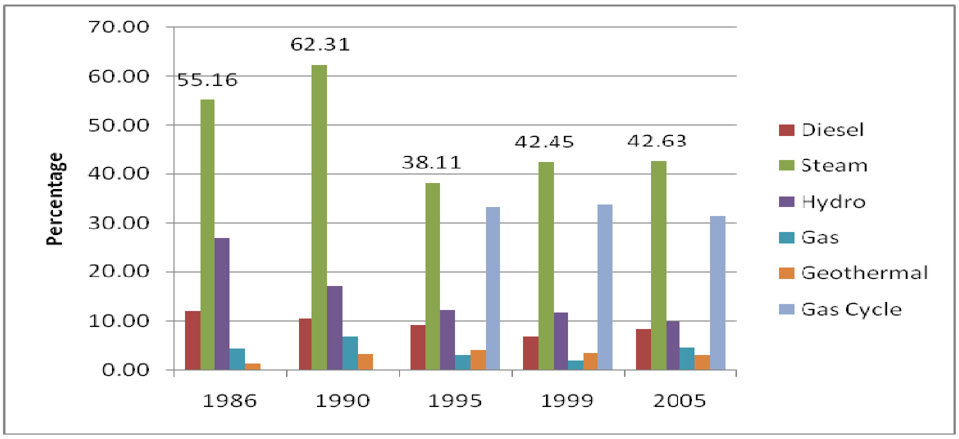


Figure 6. Electricity production by sources at national level (in %)

Source: Calculated from MEMR (2006)

2.2 Java-Bali System

The starting point in analyzing capacity expansion problem is to obtain load duration curve. Basically, load curve represents demand on electricity and its relation for a specific time period (Rowse, 1978). Following the data from the Indonesia Energy Outlook and Statistics 2006, we estimate roughly the area under the daily load duration curve[5].

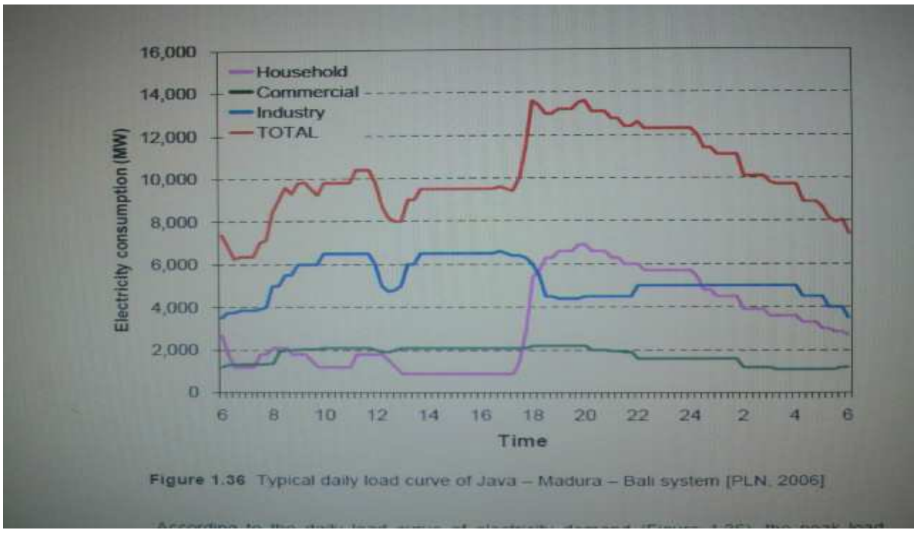


Figure 7. Typical daily load curve of Jawa - Bali System 2006

Source: PEUI (2006)

[5] We cannot calculate the load curve precisely because of lack of data

Figure 7 shows daily curve of PT. PLN at Java – Bali system. Generally speaking, industrial and household sector have significant impact on shaping the load curve. Those sectors are responsible for two upwards swing of daily load curve. Starting from 6 am, electricity consumption from industrial sector increases rapidly and reached a peak between 10 am and 12 am. During that time, electricity consumption in Industrial sector increased from about 3,500 MW to about 6,500 MW or it increased for about 85.7%.

While electricity consumption from industrial sector decreases sharply at 5 pm; electricity consumption from household sector increases significantly. Thus, the net electricity demand increased about 4,000 MW at that time. The peak time is usually happen between 6 pm and 7 pm and it reached about 13,500 MW. After 8 pm, electricity consumption from household sector decreased gradually from 7,000 MW to about 3,000 MW at 6 am. Finally, rising demand from household sector has significant impact on expanding load duration curve compare to industrial sector. With this situation demand side management is very important to minimize the peak load. Shrestha and Marpaung (1999) suggested two measures such as replacing incandescent lamp with CFL in residential sector, and replacing standard motor size with energy efficient motors.

Measuring demand

Demand for daily electricity is the area under the load daily curve. Table 3 is derived from Figure 7 and demand for 2006 is the area under the load curve. We divided time horizon into 7 periods. Generally speaking there is no consensus for choosing the number of segment suffice. For example Meier (1984) mentioned the segment could be four or five sectors, but in his model Meier (1984) and also Rowse (1978) indentified three sectors that represent base, intermediate and peak modes. Further, demand in 2007 and 2008 is estimated from year 2006 and we assumed demand growth by 5.6% in 2007 and 0.3% in 2008. This assumption follows PT. PLN (Persero) calculation electricity consumption growth during the peak hour (PT.PLN, 2010).

Table 3 Daily Electricity Demands (in MWh) for Java-Madura-Bali System

Period	Time	Demand 2006	Demand[e] 2007	Demand[e] 2008
1	0am-6am	60,000	63,360	63,550
2	6am-9am	24,000	25,344	25,420
3	9am-12pm	30,000	31,680	31,775
4	12pm-2pm	17,500	18,480	18,535
5	2pm-6pm	30,500	32,208	32,305
6	6pm-10pm	52,000	54,912	55,077
7	10pm-0am	25,000	26,400	26,479

Note: [e]following the PT. PLN estimation, we conducted linear approximation for the area under the demand curve
Source: derive from Figure 7

Table 4 Costs Description of power generation by type

No	Power plant	Construction cost ($ per kW)	Generating cost of PT. PLN in 2005 (Rupiah kWh)[a]	Generating cost $/kwh (2008, exclude maintenance cost)[e]
1	Hydro	2,000	114.71	0.015627
2	Steam	1,200	316.72	0.043147
3	Gas turbine	750	953.79	0.129937
4	Combine cycle	1,050	560.78	0.076396
5	Geothermal	3,350	514.7	0.070119
6	Diesel	1,200[b]	925.18	0.126039

Note: construction and O&M costs for 2015 scenario, generating cost used 2005 information-it adjusted for inflation and it converted to US$ by use average exchange rate in the corresponding year.
Sources: Construction cost obtain from IEA (2008), [a] from PEUI (2006), b from Wahid, e (estimate).

Information on generating cost obtained from PEUI (2006). Unfortunately data for 2008 is not available. Thus we estimate generating cost in 2008 by using information in year 2005 as the base year. We inflated the generating price by using consumer price index and use average exchange rate of Rupiah against the US dollar[6]. As can be seen from Table 4, geothermal has the highest construction cost, but relatively low generating cost. On the other hand, although gas turbine has the lowest construction cost, it has relatively high generating cost. Thus, there is a tradeoff between construction cost and generating cost, except for steam power plant that show relatively low construction and generating costs.

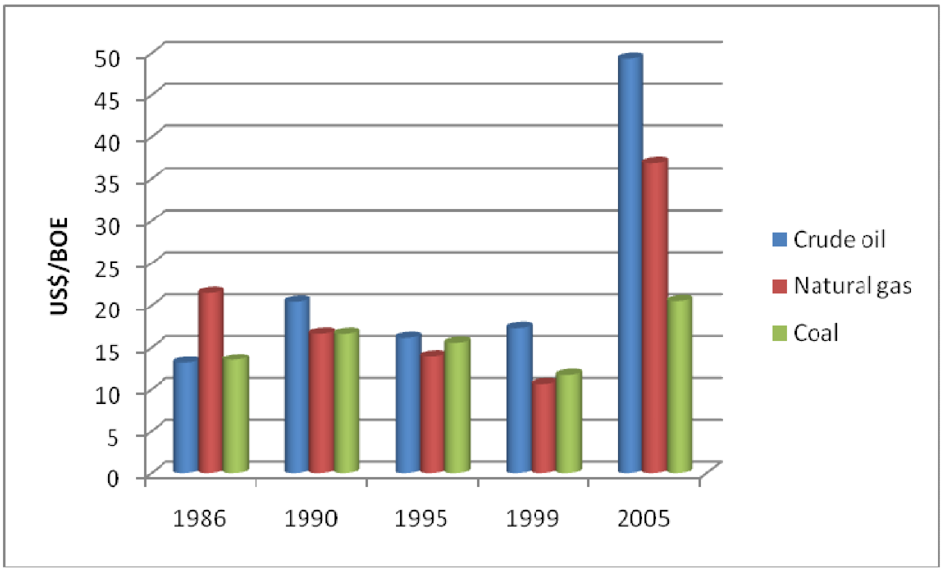


Figure 8. Price of Primary Energy Source in US $ per Barrel of Oil Equivalent (BOE)

Source: calculated from PEUI (2006)

[6] Data for inflation and exchange rate obtain from ADB key indicators

As can be seen from Figure 8, after we convert the entire energy unit into barrel of oil equivalent. Before 2005, price of natural gas tended to decrease, while price of crude oil was the highest compare to the other since the early 1990s. Further, the gap in energy price between crude oil and coal and natural gas and coal became huge in 2005.We can conclude that the price of fossil fuel start to increase rapidly in 2005. At that time world had rapid increased in energy demand especially from China to fuel its rapid economic growth. Crude oil increased dramatically and it has been above the price of natural gas and coal. Further, price of coal was the cheapest. Thus in terms of generating cost, stem power plant is the cheapest compare to other fossil fuel power plant. For countries that provide subsidy on electricity, need to promote coal power plant that can help government to minimize the subsidies.

CO_2 Emissions from electricity sector

To calculate CO_2 emissions, we follow Intergovernmental Panel on Climate Change (IPCC) guidelines for national greenhouse gas inventory. The formula can be written as follows:

$$CO_2E = \sum_{allfuels}[((AC_{fuel} \times CF_{fuel} \times CC_{fuel}) \times 10^{-3} - EC_{fuel}) \times COF_{fuel} \times 44/12] \qquad 1)$$

where CO_2E is carbon dioxide emissions, AC is apparent consumption (fuel consumption), CF is conversion factor, CC is carbon content, EC is exclude carbon (in this case it is zero), COF is carbon oxidation factor. Further, according to IEA (2009), cost of carbon would reach USD 180/tCO_2 at the margin by 2030, and USD 200 to USD 500/tCO_2 – and possible higher – by 2050 to achieve a 450 ppm concentration objectives[7]. Similarly, Shrestha and Marpaung (1999) considered four scenarios for carbon price such as US$ 5, US$50, US$100, and US$200. In this simulation we followed USD180/tCO_2, but we need to conduct an adjustment. We need to deflate the carbon price and we chosen 5% and 10% interest rate and we obtained carbon tax about USD86/ tCO_2 and USD56/ tCO_2[8].

Table 5 shows fuel consumption for every type of power generation and there are three findings. First, coal is only used by steam power plant. Second, combine cycle consumes the highest amount of oil. Third, oil consumption for diesel power plant is the lowest. We use fuel consumption to calculate CO_2 emission for each type of power plant. By knowing fuel consumption and electricity production we can calculate emissions factor for each type of power plant. Table 5 also shows that in terms of CO_2 emissions, steam power plant has the highest intensity, while combine cycle has the lowest CO_2 emissions for one unit of electricity produced.

[7] World Energy Outlook 2008 introduced 550 and 450 policy scenario (IEA, 2009). This represents an effort to preserve 450 ppm and 550 ppm concentration of CO_2. With this level of concentration, in 2030, the increase in global temperature above pre-industrial levels should not to exceed 2°C to 3°C. With this scenario, in 2030 global CO_2 emissions will reach between 26 and 33 gigatonnes that are lower than 2005 emissions level.

[8] We used future value formula as follow FV = PV (1 + rt); where FV = future value, PV = present value, r = interest rate, t = time; FV = USD180/tCO_2, r = 5% and 10%, and t = 22 years (2030 – 2008).

Table 5 Fuel Consumption by Power Plant in Java-Bali System in 2008

No	Power Plant	Fuel	Consumption	CO_2 Emissions (million ton)[a]	Electricity production (GWh)[b]	Ton CO_2/MWh[c]
		Steam oil (KL)	2,423,227			
		Steam coal (ton)	18,330,134			
1	Steam	Natural gas (mmscf)	6,903	55.912	46,210.73	1.210
		Oil (KL)	1,370,931			
2	Gas turbine	Natural gas (mmscf)	1,705,135	3.812	3,925	0.971
		Oil (KL)	3,212,448			
3	Combine cycle	Natural gas (mmscf)	140,562	16.751	30,400.74	0.551
4	Diesel	Oil (KL)	58,954	0.161	202.26	0.796
5		Total		76.64	89,551.60	0.856

Note: [a] we calculate the emissions by following the IPCC formula (see equation 1); [b] this information obtain from DJLPE (2009); [c]calculate by dividing CO_2 emissions with electricity production

3. Optimization approach

First, we identify the *decision variables* that need to be taken to obtain the solution; we wish to know how much electricity needs to produce for every type of power plant to minimize the total daily cost for every period. Thus, decision variables are continuous number. Costs consist of three elements: investment / constructing cost, generating cost, and environmental cost.

Parameters:

CC_i = construction cost (\$/MW) for plant type i
IC_i = installed capacity of the ith type (MW)
LEN_t = duration of load block p in hours
DEM_t = power demand in MWh in a period t
GC_i = generating cost (\$/MWh) for plant type i
EC_i = emissions factor for the ith type (ton CO_2/MWh)

Index:

i = plant type, i = 1 (hydro), i = 2 (steam), i = 3 (gas turbine), i = 4 (combine gas steam), i = 5 (geothermal), i = 6 (diesel), i = 1, …, I
t = period, t = 1, …, 7

Variable:

pro_{it} = output produce (MWh) from a type *i* in period *t*.

Objective:

$$MinZ_1 = \sum_{i=1}^{6} CC_i \cdot CI_i + \sum_{i=1}^{6} \sum_{t=1}^{7} \left(GC_i \times pro_{it} + A_i \times EC_i \times pro_{it} \right)$$

Note: total cost express in dollar terms and A_1 = USD86/tCO_2 (at 5% discount rate) and A_2 = USD56/tCO_2 (at 10% discount rate).

Constraints:

1. ***Capacity constraint:*** The output of each type of power generation unit cannot exceed the total capacity of the existing plants and multiplied by the corresponding availability factor and operating time. In this case we assume availability factor is 0.95% for all type of power generation[9]. This assumption is generally very high and every type of power plant has different percentage of availability factor.

   $pro_{it} \leq 0.95 \times IC_i \times LEN_t$, for all *i*, and *t*

2. ***Demand satisfaction***. Sum of electricity production must be higher than demand at all time

   $$\sum_{i=1}^{6} pro_{it} \geq DEM_t , \forall t$$

3. ***Security reserve***. The power production demand at time must be satisfied a 20% increase in the demand[10].

   $$\sum_{i=1}^{6} pro_{it} \geq 1.20 \times DEM_t , \forall t$$

The model run under the Xpress software and the command can be seen as follow.

[9] Measure the ability of power plant to perform its operational function (http://www.euronuclear.org). In terms of equipment availability is the ratio of available time (operating and standby time) to the calendar period (http://www.euronuclear.org).

[10] Technically speaking, demand satisfaction condition has been absorbed in security reserve condition. Conducting optimization by consider security reserve condition will not change the result.

BOX 1
Xpress command

```
model "Electricity production"
 uses "mmxprs"

 declarations
  NT = 7
  TIME = 1..NT                    !Time periods
  TYPES = 1..6                    !Power generator types

  LEN, DEM: array(TIME) of integer   !Length and demand of time periods
  CC: array(TYPES) of integer        !Construction cost
  IC: array(TYPES) of integer        !Installed capacity
  EC: array(TYPES) of real           !Emissions coefficient
  GC: array(TYPES) of real           !Generating cost

  pro: array(TYPES,TIME) of mpvar    !Production
 end-declarations

 initializations from 'project1.dat'
 LEN DEM CC IC EC GC
 end-initializations

! Objective function: total daily cost
 Cost:= sum(p in TYPES) CC(p)*IC(p) + sum(p in TYPES, t in TIME) GC(p)*pro(p,t) + sum(p in TYPES, t in TIME) 180*EC(p)*pro(p,t)
!Satisfy capacity
forall(p in TYPES, t in TIME) pro(p,t) <= 0.95*IC(p)*LEN(t)
!Satisfy demands
forall (t in TIME) sum(p in TYPES) pro(p,t) >= DEM(t)
!Security reserve of 20%
forall(t in TIME) sum(p in TYPES) pro(p,t) >= 1.20*DEM(t)
!Other condition
forall (p in TYPES, t in TIME) pro(p,t) is_integer
! Solve the problem
 minimize(Cost)
! Solution printing
 writeln("Daily cost: ", getobjval)
 end-model
```

BOX 2
Input Data
(Power plant generating information in 2008)

! Data file for `Electricity Production.mos'

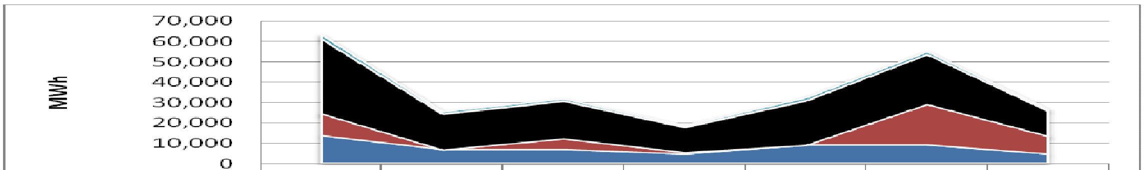
! Time periods
LEN: [6 3 3 2 4 4 2]
DEM: [63550 25420 31775 18535 32305 55077 26479]

! Power plants

CC: [2000000 1200000 750000 1050000 3350000 1200000]
IC: [2397 7420 1785 6453 375 108]
GC: [15.627 43.147 129.937 76.396 70.119 120.39]
EC: [0.00 1.21 0.971 0.551 0.00 0.796]

4. Optimization analysis

Simulation showed that the minimum cost to generate daily electricity production in Java-Bali system in 2008 was about US$ 1,745.41 million for 10% discount rate or US$ 1,749.47 million for 5% discount rate. This amount is about 0.34% of GDP[11]. As can be seen from Figure 9, to minimize the cost, diesel and gas turbine do not have to operate. From the figure we also conclude that hydro power plant and geothermal serve the base demand, while steam and combine cycle serve the intermediate and peak demand. However, before the peak hour (0 am – 6 pm), combine cycle produce the highest electricity supply, while during the peak hour steam power plant dominates the production and also between 10 pm and 0 am. Thus, diesel and gas turbine power plan is not needed in the system.



	0am-6am	6am-9am	9am-12pm	12pm-2pm	2pm-6pm	6pm-10pm	10pm-0am
Diesel	0	0	0	0	0	0	0
Geothermal	2,137	1,068	1,068	712	1,425	1,425	712
Combine cycle	36,782	17,521	18,391	12,260	21,772	24,521	12,260
Gas turbine	0	0	0	0	0	0	0
Steam	10,969	0	5,485	1,009	0	20,023	8,953
Hydro	13,662	6,831	6,831	4,554	9,108	9,108	4,554

Figure 9. Electricity Production by Type in MWh (with CO_2 emissions cost)

[11] Exchange rate Rp. 9,699/US$ and GDP in 2008 at current price is about US$510,777.3 million

We also conducted sensitivity analysis by changing marginally the price of CO_2 from US$1/ton CO_2 to US$ 100/ton CO_2. As can been seen form Figure 10, when carbon tax increases gradually, total cost shows an upward trend. However, there is a structural break in marginal cost. When carbon tax in range US$1/ton CO_2 and US$50/ton CO_2, marginal cost on average is about US$210,600/ton CO_2 emissions, but when carbon tax between US$51/ton CO_2 and US$100/ton CO_2, marginal cost decrease to about US$136,000/ton CO_2 emissions. Reduction in marginal cost indicates the power system has shift away to less carbon intensive sources.

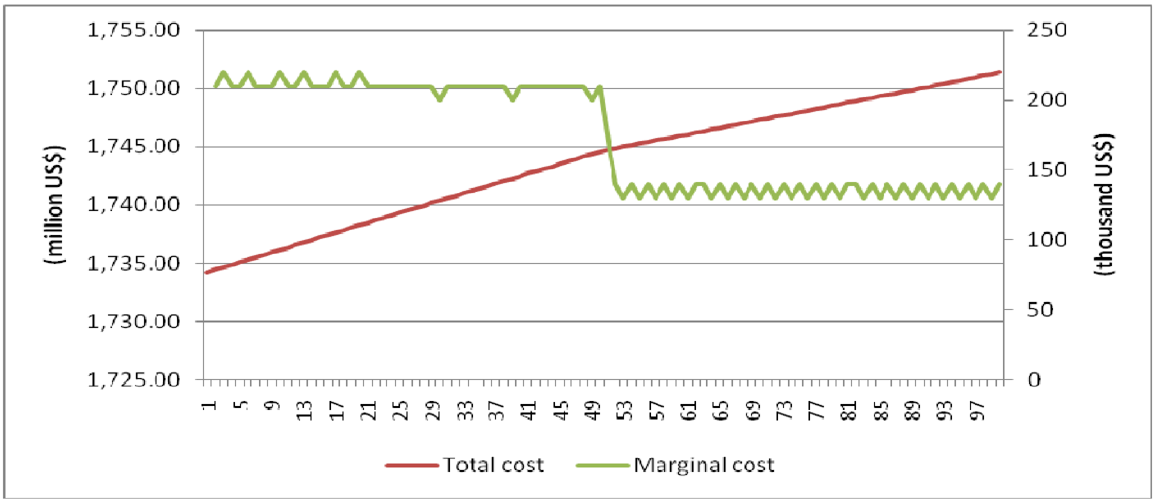


Figure 10. Total cost and marginal cost when carbon tax increases between US$1/ton CO_2 and US$100/ton CO_2

As can be seen from Table 6, structural break is happened because there is a change in power plant energy mixed. When carbon tax increase to about US$51/ton CO_2, power generating system cannot stay with the same energy mixed, because it can push the cost most higher. Alternatively, power system needs to make adjustment toward less carbon intensive power plant to minimize the tax. This situation can be happened if, power system shifts from steam power plant to combine cycle, while the rest is remain unchanged. Further, changing in energy mixed does not change the total output. Thus combine cycle can offset decreasing output from steam power plant.

Table 6 Evaluating the structural break

Type\Time	0am-6am	6am-9am	9am-12pm	12pm-2pm	2pm-6pm	6pm-10pm	10pm-0am	Total
Hydro A	13,662	6,831	6,831	4,554	9,108	9,108	4,554	54,648
Hydro B	13,662	6,831	6,831	4,554	9,108	9,108	4,554	54,648
Steam A	42,294	17,521	21,147	13,269	21,772	28,196	14,098	158,297
Steam B	10,969	0	5,485	1,009	0	20,023	8,953	46,439
Gas turbine A	0	0	0	0	0	0	0	0
Gas turbine B	0	0	0	0	0	0	0	0
Combine cycle A	5,457	0	2,729	0	0	16,348	7,115	31,649
Combine cycle B	36,782	17,521	18,391	12,260	21,772	24,521	12,260	143,507
Geothermal A	2,137	1,068	1,068	712	1,425	1,425	712	8,547
Geothermal B	2,137	1,068	1,068	712	1,425	1,425	712	8,547
Diesel A	0	0	0	0	0	0	0	0
Diesel B	0	0	0	0	0	0	0	0
Total A	63,550	25,420	31,775	18,535	32,305	55,077	26,479	253,141
Total B	63,550	25,420	31,775	18,535	32,305	55,077	26,479	253,141

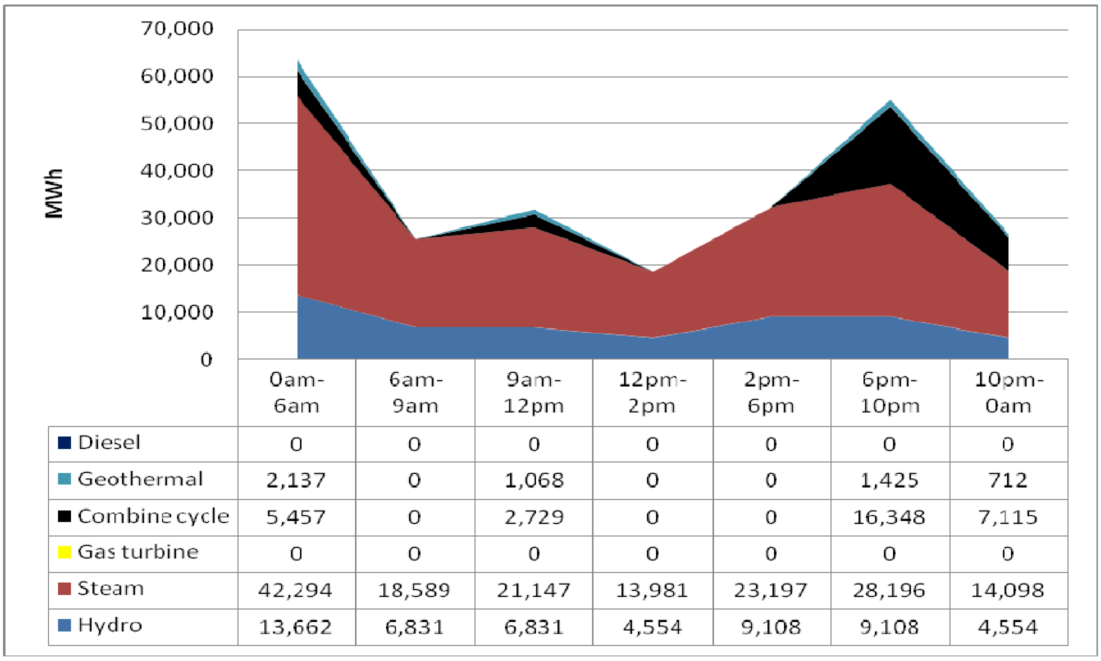
Note: A means with US$50/ton$CO_2$ carbon tax and B means with US$51/ton$CO_2$.

Further, we also conducted a simulation by not including CO_2 emissions cost to the total cost. Now the total cost is about US$ 1,734.03 million or it decreases by US$10.38 million for 10% discount rate and 15.44 million for 5% discount rate. This amount is reflects daily carbon tax on electricity system if we adopt carbon tax. Another way we can say that if Indonesia adopts US$56/ton CO_2 and US$86/ton CO_2, total cost in a year it will around 0.75% – 1.12% of GDP. Surprisingly, by not including carbon tax into the electricity system, there is a change in production mixed between steam and combine cycle power plant, while electricity production from renewable energy such as hydro is unchanged (see Figure 11). Now, geothermal power plants do not have to operate for all the time. This indicates optimizing operation time of renewable energy is happened if government implements carbon tax. Thus, by increasing installed capacity of renewable energy, it is not necessary will increase its utilization if government does not implement carbon tax on fossil fuel power plants. Further, the optimization also shows that diesel and gas turbine is not needed in the power plant system. We can conclude that implementing carbon tax will change fuel mixed toward less carbon content. In term of daily electricity production, there is no change with and without implementation of carbon tax. This indicates that carbon tax did not cause reduction in electricity output. This is happened because we do not include demand side management in the simulation.

Further, as can be seen from Figure 9 and 11, carbon tax has impact on energy mix during the peak hour[12]. This indicates, the existing system can reduce carbon intensity during the peak hour. However, the substitution is happened from steam power to combine cycle, while for renewable energy is remain the same. This is because lack of installed capacity for renewable energy. Further, by comparing Figure 9 and 11, we can conclude that without including carbon tax, electricity

[12] Different carbon taxes do not affect power plant energy mixed.

system depends on steam power plant, while implementing carbon tax can create more space for combine cycle to operate more intensively.



	0am-6am	6am-9am	9am-12pm	12pm-2pm	2pm-6pm	6pm-10pm	10pm-0am
Diesel	0	0	0	0	0	0	0
Geothermal	2,137	0	1,068	0	0	1,425	712
Combine cycle	5,457	0	2,729	0	0	16,348	7,115
Gas turbine	0	0	0	0	0	0	0
Steam	42,294	18,589	21,147	13,981	23,197	28,196	14,098
Hydro	13,662	6,831	6,831	4,554	9,108	9,108	4,554

Figure 11. Electricity Production by Type in MWh (without CO_2 emissions cost)

Figure 12 shows the difference between including and not including carbon tax on the electricity production[13]. It is clear that carbon tax forces combine cycle power plant to work because this is important to offsets decreasing production from steam power plant. Combine cycle can take this chance for two reasons. First, in terms of installed capacity combine cycle is the second highest after steam power. Second, combine cycle has lower carbon content than steam power.

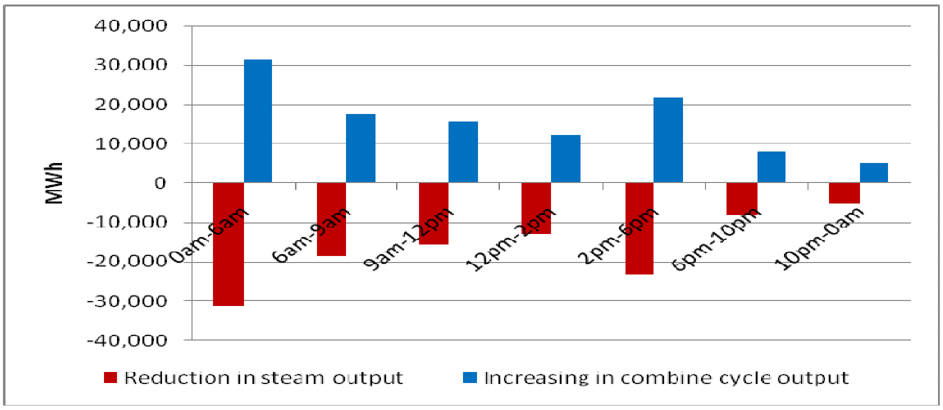


Figure 12. Comparing steam and combine cycle output with and without carbon tax

[13] Implementing $US56/ton$CO_2$ and $US86/ton$CO_2$ do not change the output from each type of power plant.

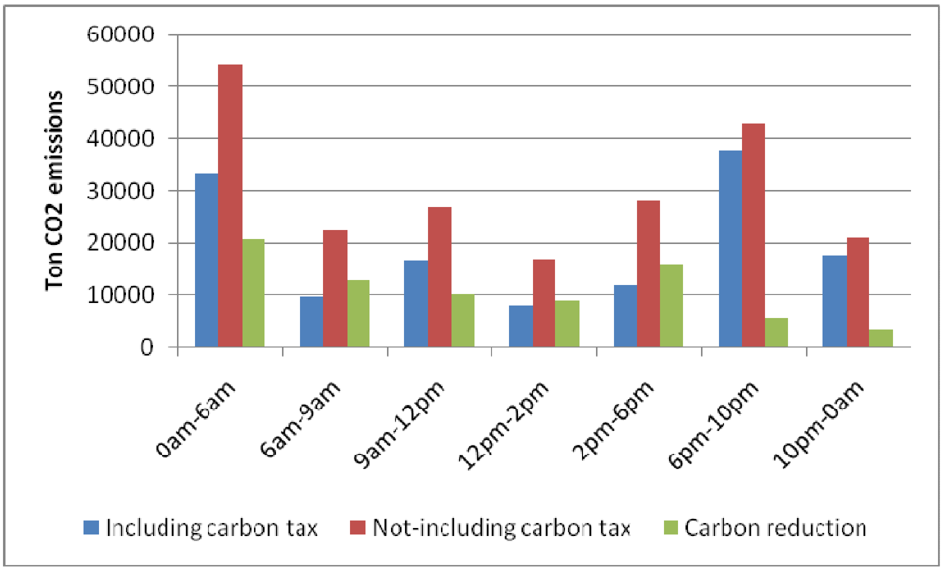


Figure 13. Comparing CO_2 emissions with and without considering carbon tax

Finally Figure 13 shows that CO_2 emissions from power plant decrease after implementing carbon tax. Generally speaking implementing US$ 86/ ton CO_2 emissions or US$ 56/ ton CO_2 emissions is similar with implementing carbon tax above US$ 50/ ton CO_2 emissions, because there is no change in power plant mixed. Thus emissions reduction will be the same that is 77,586 ton per day or it is about -36.5% reduction compare without carbon tax. However, if carbon tax is less than or equal to US$ 50/ ton CO_2, emissions reduction will be 3,878 ton per day or it about -1.82% reduction. Thus implementing for about US$ 1/ ton CO_2 or US$ 50/ ton CO_2 will not have any impact on CO_2 emissions reduction, but implementing carbon tax above US$ 50/ ton CO_2 can significantly reduce the emissions. Further, implementing carbon tax above US$ 50/ ton CO_2 can cause reduction on emissions by 28.3 million ton per year or it is about 36.3% reduction from power generating sector base on 2005 emissions level[14].

5. Conclusions

By law, electricity production, distribution and transmission are monopolized by state own enterprise. However, share of independent power producer in terms of installed tends to increase. About 63% of total national capacity installed in Java-Bali system. However, Java-Bali system is still dominated by steam power plants that depend on coal. There are three reasons why coal is used more intensively such as low generating cost, low investment cost and abundant supply of coal. However, coal burning will cause higher CO_2 emissions from the electricity sector and more than 76% of emissions will come from Java-Bali system. Thus, minimizing CO_2 emission from the Java-Bali system can help Indonesia to reduce the national CO_2 emissions level. At the national level, we showed that a rising share of steam power plant increases intensity of CO_2 emissions, while reduction in the intensity was happened when government use gas power plants in the system.

[14] We assume the level of emissions is constant for 365 days and CO_2 emissions from electricity sector in 2005 were about 78 million ton.

In Java-Bali system, industrial and household sector are responsible for two upwards swing of daily load curve, but raising demand from household sector has significant impact on expanding load duration curve compare to industrial sector. We show that there is a tradeoff between construction cost and generating cost for every type of power plant. In terms of generating cost, stem power plant is the cheapest compare to other fossil fuel power plant.

In general the optimization showed that diesel and gas turbine is not needed in the power plant system with and without implementing carbon tax. This may indicate that in the future Indonesia can shift away from diesel and gas turbine to other sources. The optimization model constructs under condition of 20% increase in electricity demand and we applied 450 ppm scenario where the carbon price would reach US$ 56/tCO_2 – US$ 86/tCO_2. We analyzed data based on electricity generating system in 2008. The simulation showed that implementing carbon tax will increase the cost of power plant or similarly increase tax revenue to about 2.1% of GDP. Further, the simulation also showed that combine cycle has important role to offset decreasing output in steam power plant, but total electricity production was not changed after implementation of carbon tax. Next, by implementing carbon tax, daily CO_2 can decrease by 77,586 ton per day. Finally, the simulation suggests that, there is a structural break in marginal cost when carbon tax is higher than US$ 50/tCO_2, this indicates that significant reduction in CO_2 emissions will happened if Indonesia increase carbon tax more than US$ 50/tCO_2.

There are some weaknesses of this study. First, the model used estimated value for load daily demand. Second, the model assumes availability factor is 0.95% that may not be true. Third, the model use estimate generating costs. Although be allowing 20% increase in demand can minimize problem one, further study need to be done to obtain clear information on problem two and three.

6. Policy recommendations

Indonesia needs to purse sustainable development principle in electricity production. However, the room for greater role of renewable energy is still limited and most of reduction in steam power plant is offset from the combine cycle that also has positive carbon content. Although in the short term this strategy will effective, but the Indonesia government needs to provide more space for renewable energy. Further, growing interest of private sector to construct steam power needs to be controlled by government. We propose five strategies.

1. By implementing carbon tax higher than US$ 50/ ton CO_2, Indonesia can significantly reduce CO2 emissions.
2. Government need to change subsidy policy from fossil fuel toward promoting renewable energy. For example, energy subsidy in 2008 was about 4.5% of GDP (fuel subsidy was 2.8% of GDP; electricity subsidy was 1.7% of GDP).
3. Because electricity is monopolized by state own enterprise, government needs not only to push its efficiency but also to enhance or to set certain target to enhanced renewable energy utilization.
4. Private sector has showed positive interest to develop geothermal power plant, government needs to provide more incentives such as to provide land, and tax exemption on capital goods and equipments, or event interest rate subsidy.

5. In terms of demand side policy, government needs to enhance high standard of efficiency. This can minimize electricity demand from the household and industrial sector especially during the peak hours.

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