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Optimization of Indonesian Geothermal Energy Resources for Future Clean Electricity Supply: A Case of Java-Madura-Bali System

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Abstract

Total of geothermal potential for power generation in Indonesia is estimated to be around 28 GW, equal to 40% of world's potential. Around 36% of Indonesian geothermal potential is located in Java and Bali Islands. In 2006, total installed capacity of geothermal power plants was only 852 MW or 3% of total potential in the country. The Philippines, in comparison, has higher geothermal utilization for electricity generation. It is around 12.7% of the national capacity. Meanwhile, Indonesian government's current policy concerning the power sector is to promote coal utilization. However, coal power generation faces environmental emission issue. This study examined utilization of geothermal energy for future electricity supply expansion in Java-Madura-Bali (Jamali) system, the largest electricity consumer in Indonesia, by using Long-range Energy Alternatives Planning (LEAP) model from 2006 to 2025. This study uses three scenarios of geothermal utilization to maintain reserve margin of 30%, according to the government plan, in 2025. In the first scenario, it was added with 50 MW of geothermal power plant, in the second scenario 100 MW of geothermal power plant was added, and in the last scenario 124 MW was added to the existing capacity. It was found that in the end of the period, by implementing the first scenario, the geothermal capacity increases by 5.7 GW. In the second and the third scenarios, the estimated increase is 8.2 GW and about 10 GW respectively. It was also found that in 2025 CO_2 emission reduction in each scenario were 12.9%, 21.5%, and 25% respectively, compared to the BAU scenario. Additionally, in the end of projection, the costs of each scenario were 6.6 Billion USD, 6.8 Billion USD and 7.1 Billion USD respectively, compared to 6.3 Billion USD in the BAU scenario. By considering externality from power generation, the first, second and third scenarios reduce external costs by 46.3, 71.6 and 80.8 million USD respectively, when compared with the BAU scenario. However, by including the external costs in the total cost, it does not make all geothermal scenarios cheaper than the BAU scenario.

Keywords Indonesian geothermal energy, Electricity expansion planning, LEAP model, Clean electricity supply, Emission reduction, Externality cost.

1. Introduction

Indonesia is the largest archipelago in the world. It consists of over seventeen thousand islands. It is located between the eastern end of Mediterranean volcanic belt and western side of Circum Pacific volcanic belt[1]. Indonesia has more than 200 volcanoes located along Sumatera, Java, Bali and the islands of eastern Indonesia[2]. It is known as part of "Pacific Ring of Fire", the terminology refers to the chain of volcanoes that was created by the upward intrusion of magma (molten rock) at the edge of the Pacific Plate. The 'ring' extends along the western part of the American continent, the Aleutian Islands, Japan, the Philippines, Indonesia, the South Pacific and New Zealand. It makes Indonesia abundant of geothermal resources.

Indonesian geothermal potential is estimated to be around 28 GW, which is equal to 40% of world's potential. In 2005, the total installed geothermal capacity was 797 MW or 2.2 % of the total potential in the country and increased to 3 % in 2006. The largest world geothermal energy user among the other countries is United States (US), followed by the Philippines (Table 1).

Table 1 Worldwide geothermal power generation in early 2005.[3]

Country	Installed capacity (MW)	% of national capacity
Costa Rica	163	8.4
El Salvador	151	14
Iceland	202	13.7
Indonesia	797	2.2
Kenya	129	11.2
Mexico	953	2.2
New Zealand	435	5.5
Philippines	1930	12.7
US	2564	0.3

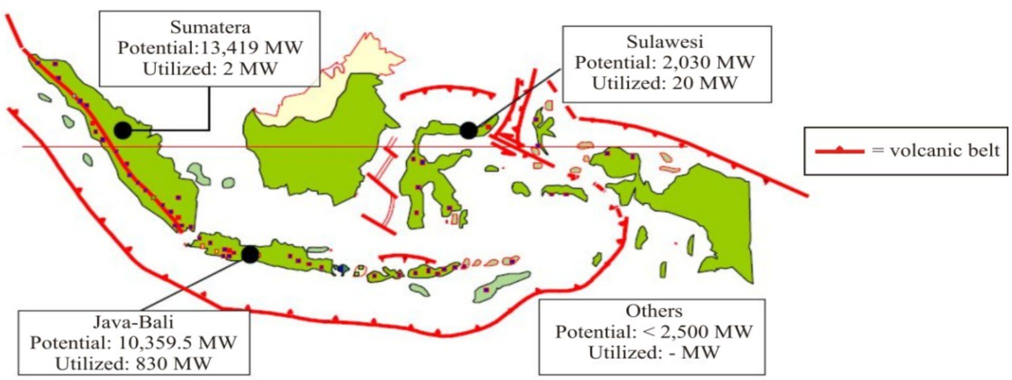

Fig. 1 Map of geothermal resources in Indonesia.

2. Indonesian Geothermal Resource Development and Current Policy

Most of Indonesian geothermal resources are located in Java and Sumatera islands, while the rest are in east of Indonesia. Fig. 1 shows location of geothermal resources in Indonesia and details of resources is given in Table 2. Almost 36% of total Indonesian geothermal resources is located in Java-Bali islands and the biggest resource is located in Sumatera with potential capacity of 13.4 GW.

Table 2 Geothermal resources in Indonesia.

Location	Resources (MW)
Sumatera	13,419
Java	10,059
Bali	301
Nusa Tenggara	1,375
Sulawesi	2,030
Maluku	734
Kalimantan	45
Papua	50
Total	28,013

Despite the huge geothermal potential in Indonesia, it has been relatively little developed. Only 3% of total geothermal resources has been tapped and most of it is located in Java-Bali areas. Currently, about 830 MW or 97% of total installed geothermal capacities are located in Java-Bali islands while the rest are in Sulawesi and Sumatera islands with 20 MW and 2 MW respectively (Table 3). Most of geothermal reservoir types in Indonesia are liquid such as Dieng, Lahendong, Salak and Wayang Windu, while the others are steam. The reservoir temperature is about 240-330^{o}C and the depth is around 1,000-2,000 meters.

According to Presidential Decree no. 45/1991, the government appointed the PERTAMINA (National Oil Company) to conduct exploration and exploitation of geothermal resources. The private sector is able to take part as contractor to PERTAMINA and regulated by a joint operation contract. At the downstream site, the geothermal electricity business is under the authority of state company called PLN as mentioned in Electricity Law no. 15/1985. The geothermal development was also included in the Blueprint of National Energy Management 2005-2025, which expects that the geothermal utilization would reach up to 3.8 % of national energy mix in 2025.

Table 3 Geothermal power plants and their capacities.

Working Area	Location	Total Capacity (MW)
Kamojang	West Java	140
Lahendong	North Sulawesi	20
Sibayak	North Sumatera	2
Salak	West Java	375
Darajat	West Java	145
Wayang Windu	West Java	110
Dieng	Central Java	60

3. Electricity Sector in Indonesia

Electricity generation in Indonesia is under state authority and conducted by PLN. Total installed capacity was 30 GW in 2006. About 70% of it was located in Java-Madura-Bali (Jamali) islands. As the central activity place of the country, Jamali area consumed around 79% from total electricity consumption, in 2006,. In July 2006, Indonesian government assigned PLN to accelerate coal power plant development by the Presidential regulation no. 71/2006, an effort requiring to accelerate the energy diversification for electricity generation from oil to other resources before 2012. The power plant type is the coal steam power plant with total capacity of 10,000 MW, where in Jamali system it would be installed by 6,650 MW. The next committed power plant after 2012 is only nuclear power plant.

This paper analyzes Indonesian electricity supply in Jamali system for electricity generation from 2006 to 2025. The geothermal energy utilization is applied for long term Indonesian electricity supply planning. The study is developed by using the Long–range Energy Alternatives Planning (LEAP) model.

4. Methodology

4.1 Final Energy Demand Analysis

In the LEAP model, energy demand analysis is calculated as the product of the total activity level and energy intensity at each given technology branch. Energy demand is calculated for the current year or the base year and for each future year (Equation 1):

$$D_{b,s,t} = TA_{b,s,t} \times EI_{b,s,t} \quad (1)$$

Where, D is energy demand, TA is total activity, EI is energy intensity, b is the branch, s is scenario and t is year (ranging from the base year to the end year). Energy intensity is the annual average final energy consumption per unit activity (Equation 2):

$$EI = \frac{EC}{activity\ \ level} \qquad (2)$$

The total activity level for a technology is the product of the activity levels in all branches from the technology branch back to the original demand branch (Equation 3):

$$TA_{b,s,t} = A_{b',s,t} \times A_{b'',s,t} \times A_{b''',s,t} .... \qquad (3)$$

Where, A_b is the activity level in a particular branch b, b' is the parent of branch b, b'' is the grandparent, etc.

4.2 Electricity Transformation

The planning reserve margin is used by LEAP to decide automatically when to add additional endogenous capacity. The LEAP will add sufficient additional capacity to maintain the planning reserve margin on or above the set values. Planning reserve margin is defined as follows:

$$PRM = 100(MC - PL)/PL \qquad (4)$$

Where, PRM is the planning reserve margin (%), MC is the module capacity in MW and PL is the peak load in MW. Module capacity for all process in the module is defined as:

$$MC = Sum(Capacity \times Capacity\ Value) \qquad (5)$$

Exogenous capacity values are used to reflect existing capacity as well as planned/committed capacity additions and retirements, while endogenous capacity values are those which are internally calculated by LEAP in order to maintain a minimum planning reserve margin. Endogenous capacity additions occur in addition to the exogenous level of capacity specified on the exogenous capacity.

Peak system power requirements on the module are calculated as functions of the total energy requirements and the system load factor.

$$PR = \frac{ER}{LF \times 8760} \qquad (6)$$

Where, PR is peak requirement in MW, ER is energy requirement in MWh, and LF is the load factor.

The reserve margin before the addition of endogenously calculated additions is calculated as follows:

$$RM_{BA} = \left[\frac{CA_{BA} - PR}{PR}\right] \qquad (7)$$

Where, RM_{BA} is the reserve margin before additions and CA_{BA} is capacity before additions. The amount of endogenous capacity additions required (EC_{AR}) is calculated as follows:

$$EC_{AR} = (PRM - RM_{BA}) \times PR \qquad (8)$$

4.3 Emission from Electricity Generation

The LEAP uses the most up-to-date global warming potential (GWP) factors recommended by the IPCC (Intergovernmental Panel on Climate Change). The emission is calculated as:

$$Emissions_{t,y,p} = EC_{t,y} \times EF_{t,y,p} \qquad (9)$$

Where, t is type of technology (fuel), y is year, and p is pollutant. The LEAP contains data on the GWPs for carbon dioxide, methane, nitrous oxide and the most common non-energy sector gases with high GWPs (SF6, CFCs, HCFCs and HFCs).

4.4 Costs of Scenarios

The LEAP performs cost-benefit calculations from a societal perspective by counting up all of the costs in the energy system. The LEAP can include all of the following cost elements; demand costs (expressed as total costs, costs per activity, or costs of saving energy relative to some scenario), transformation (capital, operating and maintenance costs), primary resources costs, and environmental externality costs. Capital costs are annualized (spread-out over the plant lifetime) using a standard mortgage formula as follows:

$$Annualized\ cost = Total\ cost \times CRF \qquad (10)$$

Where,
$$CRF = \frac{i \cdot (1+i)^n}{(1+i)^n - 1} \qquad (11)$$

Where, i is the interest rate, n is the plant lifetime and CRF is the capital recovery factor.

5. Development of Scenarios

5.1 Business as usual (BAU) Scenario

In this study, the BAU scenario starts from 2006 as the base year. The data on existing, committed and candidate power plants and electrical demand profile are based on reports [4,5]. The population growth rate is assumed to be 1% per year and the expected electrification ratio is assumed to be 93% in 2026. The demand sector is divided into four categories: household, commercial, public and industry. The electricity demand in 2006 and expected growth rate per 5 years are given in Table 4.

Table 4 Electricity demand in 2006 and expected growth until 2025 in Jamali system.

Sector	Demand in 2006 (GWh)	Growth rate/year (%)			
		2006-2010	2011-2015	2015-2020	2021-2025
Household	32,334	8.9	8.2	7.1	6.2
Commercial	14,595	9.6	8.5	7.8	7.2
Public	4,932	10.7	11.1	10.7	10.7
Industry	39,661	4.0	3.5	3.6	3.8

In Jamali system, the current total installed capacity is 19,615 MW. Due to lack of small scale power plants' data, the total installed capacity in LEAP modeling is only 19,531 MW. All power plants are operated based on their ascending merit order[1]. Table 5 shows operation of power plant based on merit order. Merit order 1 indicates power plant for the base load, merit order 2 indicates power plant for the middle load, and merit order 3 indicates power plant for the peak load.

[1] The merit order of a process indicates the order in which it will be dispatched. Plants will be dispatched according to their specified merit orders as defined in the merit order variables. Each plant will be run (if necessary) up to the limit of its maximum capacity factor in each dispatch period.[6]

Table 5 Dispatch of power plant.

Type of power plant	Merit order
Coal Steam	1
Geothermal	1
Combined Cycle	1
Hydro	2
Gas Turbine	2
Diesel	3

The efficiency of transformation and distribution branches was calculated by using losses. In 2006, the losses were 15% and assumed to be reduced by 1% per five year. Table 6 shows expected losses in transmission and distribution from 2006 to 2025.

Table 6 Expected losses in transmission and distribution.

Year	Losses (%)
2006 – 2010	15
2011 – 2015	14
2016 – 2020	13
2021 – 2025	12

Table 7 shows committed power plants in Jamali system from 2006 to 2011 including committed coal steam power plant project. The supply planning was based on required reserve margin. For Jamali, the projected reserve margin is 35% until 2019, and then from 2020 onwards the reserve margin is reduced to 30%. The discount rate is assumed to be 10%.

Table 7 Committed power plants in Jamali system from 2006-2011.

Type of power plant	Capacity (MW)
Gas Turbine	790
Geothermal	470
Coal Steam	9,810
Total	11,070

The next committed power plant after 2010/2011 is only nuclear power plant. It is expected that nuclear power will be fed into Jamali system in 2016, 2017, 2023 and 2024 by a capacity of 1,000 MW for each year. Since there is no more data for committed power plants, the other additional power would be calculated as the input in endogenous capacity variable, and the power plant operation follows the government's intention in order to promote using coal resources optimally. The additional power plants after 2011 are presented in Table 8.

Table 8 Additional power plants from 2011-2025.

Additional order[2]	Type of power plant	Additional size (MW)	Fuel type	Merit order
1	Coal Steam	150	Coal	1
2	Combined Cycle	100	NG	1
3	Gas Turbine	100	NG	2

Note: NG stands for natural gas.

[2] The LEAP calculates the additional power plants based on the additional order entered by user. Should further additions be required in any given year to maintain the reserve margin, then an additional 150 MW of new steam power plant will be built, followed by an additional 100 MW of combined cycle power plant and so on.[6]

5.2 Geothermal scenario

Three scenarios of geothermal energy utilization are considered including 50 MW of geothermal power plant in the first geothermal (1G) scenario, 100 MW of geothermal power plant in the second geothermal (2G) scenario, and 124 MW in the last geothermal (3G) scenario in the endogenous capacity. Table 9 presents additional geothermal capacity of each scenario.

Table 9 Additional capacity of geothermal power plants in geothermal scenarios.

Scenario	Additional size (MW)
1G	50
2G	100
3G	124

Besides geothermal, to maintain planning reserve margin, the other plant types must be included as the additional capacity in each scenario; namely, combined cycle, gas turbine, and coal steam.

6. Result and Discussion

6.1 Scenario Results

6.1.1 Business as Usual (BAU) scenario

The electricity generation capacity in the BAU scenario, in the end of period, is increasing over three times compared with the base year. Total electricity generation in the BAU scenario is about 66 GW in 2025, increased from 19.5 GW in 2006. The rapid electricity capacity growth is influenced by high growth rates of electricity consumption.

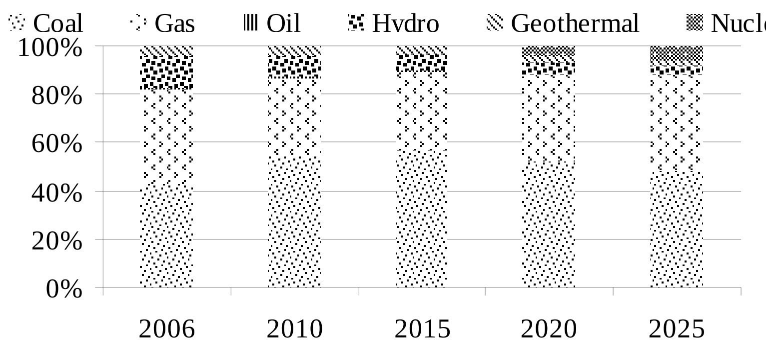

Fig 2. Capacity mixes in the BAU scenario.

The capacity mix in the BAU scenario is illustrated in Fig 2. The coal utilization is rapidly growing from the base year until mid of the period with a share of 60% in total capacity generation. However, in the end of period, coal utilization trend is going to decrease. In 2025, the natural gas utilization takes the second place after coal about 26 GW or 40% of total capacity. The nuclear power plant takes the third place with 6% share, while geothermal power plant is in the last place with only 1.3 GW or it shares around 2 % in total capacity.

6.1.2 Geothermal Scenario

6.1.2.1 First Geothermal (1G) Scenario

Fig. 3 shows capacity mix in the 1G scenario. In 2025, the total geothermal power plant capacity is almost 6 GW, approximately 4% of total generation capacity, and increased from 830 MW in 2006. Meanwhile, in 2025, in the BAU scenario, it is only 1.3 GW. The coal power plant capacity is 7% less than the BAU scenario in the end of period. However, it still has the largest share in total capacity, and followed by natural gas power plant with 40% share.

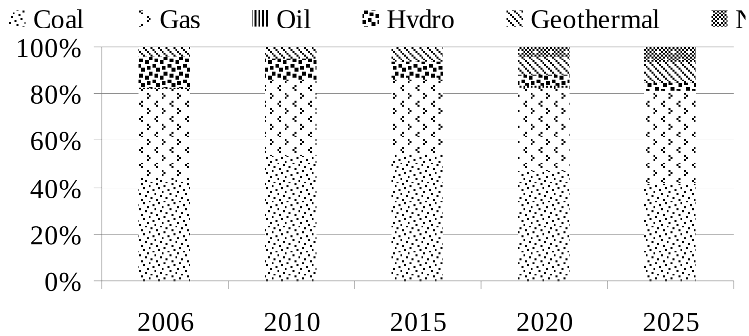

Fig. 3 Capacity mixes in the first geothermal scenario.

6.1.2.2 Second Geothermal (2G) Scenario

The geothermal power plant capacity in 2025 is increasing over seven times compared to the base year (Fig. 4). It is around 8.2 GW, compared to 830 MW in the base year. Moreover, in the end of the period, the geothermal capacity in the 2G scenario is increasing over six times compared to the BAU scenario. In 2025, the natural gas power takes the largest share in capacity again, while the coal power takes the second largest share.

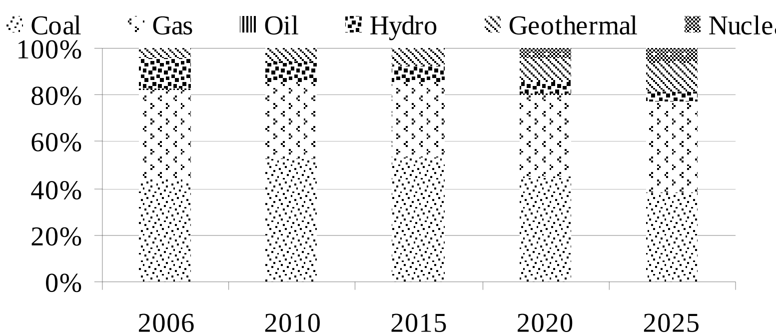

Fig 4. Capacity mixes in the second geothermal scenario.

6.1.2.3 Third Geothermal (3G) Scenario

In the end of the period of the 3G scenario, the coal power plant capacity reduces to 25.8 GW. Meanwhile, the geothermal power plant capacity increases to about 10 GW, which is 12 folds higher than the base year. Furthermore, the increase of geothermal capacity gives effect on reducing natural gas generation capacity as well as coal generation. In 2025, the total natural gas generation capacity is around 23 GW or reduced by 3 GW compared to the BAU scenario, while coal is reduced by 6 GW.

Fig. 5 illustrates the electricity generation capacity mix in the 3G scenario. In the base year, the generation capacity consists of 43% of coal, 39% of natural gas, 13% of hydro, 4% of geothermal and the rest is oil. The generation capacity composition in 2025 changes to 39% of coal, 35% of natural gas, 16% of geothermal, 6% of nuclear and the rests are hydro and oil.

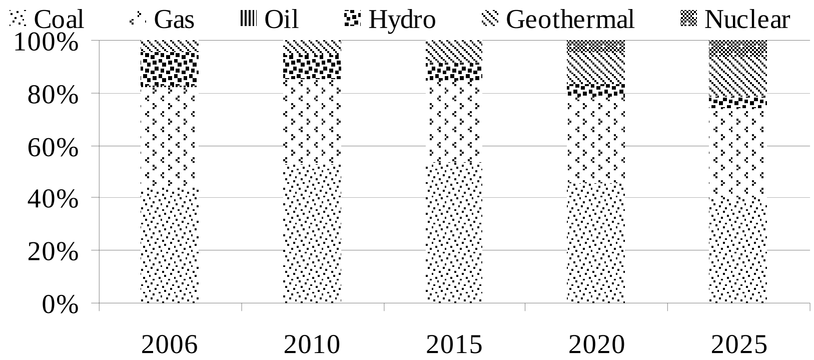

Fig. 5 Capacity mixes in the third geothermal scenario.

6.2 Cost Analysis

Cost is one of the important parameters that must be carefully analyzed in the electricity planning. Table 9 presents related costs in each scenario. For capital cost, the geothermal has the highest cost when compared to the other power plant types. It costs 1.8 million US$/MW. Meanwhile, nuclear costs about 1.7 million US$/MW. In terms of fuel cost, gas turbine is the most expensive generator with 86 US$/MWh, and the next is the combined cycle with 52 US$/MWh, while nuclear is the cheapest generator in Indonesia with 4 US$/MWh. In case of O&M cost, gas turbine is the most expensive generator about 11.69 US$/MWh. It is followed by nuclear, while the cheapest generator is the coal steam.

Table 9 Components of cost in all scenarios.

Type of power plant	Capital cost (10^3 US$/MW)	Fuel cost (US$/MWh)	O&M cost (US$/MWh)
Steam	1,226 a)	26.76 b)	2.15 b)
Gas turbine	550 b)	86.47 b)	11.69 b)
Combined cycle	600 c)	52.34 b)	5.37 b)
Geothermal	1,800 d)	48.19 b)	3 b)
Nuclear	1,728 e)	4.4 e)	8.3 e)

Source:

a) BATAN, 2002 [7]
b) PLN, 2005 [8]
c) IEA, 2005 [9]
d) Sanyal, 2005 [10]
e) BATAN, 2006 [11]

Table 10 Total cost of each scenario.

Scenario	Total cost (million USD)				
	2006	2010	2015	2020	2025
BAU	358.7	1494.3	2641	4168.8	6255.6
1G	358.7	1512.7	2702	4337.9	6580.3
2G	358.7	1531.9	2755.5	4468	6793.2
3G	358.7	1560.2	2806.9	4607.6	7071.7

Total cost of each scenario was analyzed by using LEAP and shown in Table 10. In 2025, the 3G scenario is the most expensive scenario as compared to the other scenarios since total geothermal capacity increases to 10 GW. The BAU scenario is the cheapest scenario and the follower is the 1G scenario. The reason is that less geothermal power development would decrease total cost. Moreover, coal steam development has lower cost when compared to geothermal.

6.3. Emissions

6.3.1. Global Warming Potential (GWP)

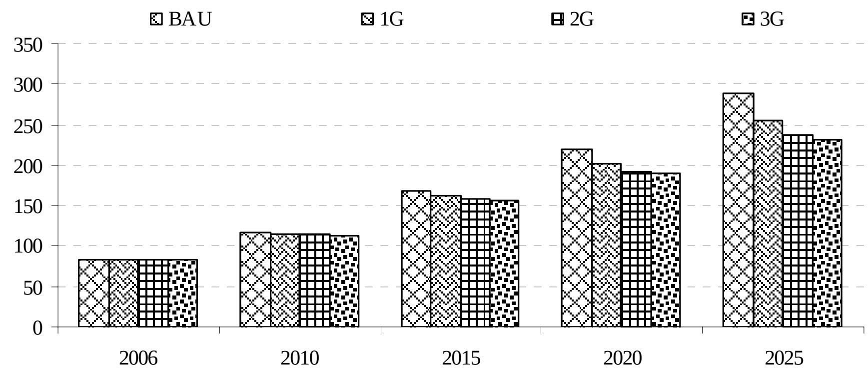

Fig. 6 Total emission projection from 2006 to 2025.

Another purpose of this research is to analyze Indonesian geothermal utilization due to emission reduction for the long term electricity planning. The total GWP emission of each scenario is illustrated in Fig 6. The BAU scenario produces 288 million tonnes of CO_2 equivalent. It is being implemented to promote coal utilization in optimal way as intended by the government of Indonesian. The most significant emission reduction comes from the 3G scenario. Approximately 58 million tonnes of CO_2 equivalent is reduced from the BAU scenario. It occurs since 10 GW of geothermal is developed to reduce coal utilization. Though the costs in geothermal scenarios are higher, emissions in the 1G and 2G scenarios are reduced by 12.9% and 21.5% respectively, compared to the BAU scenario.

6.3.2. Other Environmental Emissions

The other environmental emissions that can come from geothermal power plants are discussed based on analysis from Murphy and Niitsuma [12] and Brophy [13].

1. Hydrogen sulfide is a common emission from geothermal wells. High concentrations which are greater than 10 ppm (14 mg/m^3) can affect human health. However, smaller concentrations may result in corrosion. This problem can be solved by increasing efficiency of possible resources which cause H_2S including well drilling and testing, steam venting during power plant start-ups and shut-ins, wells on bleed, power plant operations as condenser off-gas and cooling tower drift or fugitive emissions.
2. Most geothermal reservoirs produce arsenic, boron, silica, chlorides, sulfates and other contaminants. For plants that actually discharge their effluent to surface waterways, treatment is normally required. More often, however, the effluent is re-injected into the reservoir that was the source of the contaminants. Many geothermal plants condense the steam exiting their turbines and then re-inject all effluents, so that the only environmental release consists of the non-condensable in the steam.

6.4 Externality cost

From cost and emission analyses, it is clearly explained that applying geothermal scenario will reduce emissions in the power sector. Nevertheless, costs to develop its scenario are higher than the BAU scenario. Furthermore, the conventional concept of electricity expansion is making electricity abundant and cheap since it is able to pass most of the costs from power system to consumers and society at large. In order to be able to assess and compare the external effects with each other and with costs, it is advantageous to transform them into a common unit. Thus converting external effects into monetary units results in external costs. The unit damage cost will be adopted from the ExternE 2005.[14] The value of unit damage is €19/tonnes of CO_2. The rate adopted for this purpose is €1 = US$ 1.4.

Table 11 All scenario cost in the end of period (in million USD).

	BAU	1G	2G	3G
External cost	403.9	357.6	332.3	323
Total cost including externality	6659.5	6937.9	7125.5	7394.7

In the end of period, all geothermal scenarios reduce external costs significantly. The reductions of the 1G, 2G, and 3G are 46.3, 71.6, and 80.8 million USD respectively from the BAU scenario. Details of external costs are presented in Table 11. However, by internalizing the external cost into total cost, it still does not make all geothermal scenarios having lower total cost as compared to the BAU scenario.

7. Conclusions

Indonesia has the largest geothermal resources in the world. However, if it compared to the other countries, the development of the geothermal resources is quite slow. This is due to the fact that Indonesia still relies on fossil fuels to generate electricity. Merely 3% of the total capacity comes from geothermal energy. The slowness of geothermal development is caused by several factors;

1. Geothermal development is a high risk type of investment, although the long-term costs are low, geothermal development needs extensive upfront capital for survey and site development.
2. Producing electricity from geothermal source is more expensive than other types of electricity generation. Moreover, Indonesian government subsidizes oil fuel.
3. PLN as a single buyer has financial limitation to purchase electricity from geothermal energy. It is certainly not competitive.
4. Most of geothermal resources are located in remote areas. Consequently, it needs extra cost to connect the electricity production to the main grid.

In this paper three geothermal scenarios are considered for future electricity planning in Indonesia from 2006 to 2025. In 2025, 50 MW of geothermal power plant was added in the first scenario; in the second scenario, 100 MW of geothermal power plant was added; and in the last scenario, 124 MW was added in the endogenous capacity.

It was found that in the end of the period, by implementing the 1G scenario, the geothermal capacity generation increases by 5.7 GW. Meanwhile, the 2G scenario implementation increases 8.2 GW and for the 3G scenario increases about 10 GW as well. It also found that in 2025 emission reductions in each scenario were 12.9%, 21.5%, and 25% respectively, compared to the BAU scenario. Additionally, in the end of projection the generation costs of each scenario were 6.58 Billion US$, 6.79 Billion US$ and 7.07 Billion US$ respectively, compared to 6.25 Billion US$ in the BAU scenario. By considering externalities from power generation, the total costs of each scenario would be 6.66 Billion US$, 6.94 Billion US$ and 7.39 Billion US$ respectively, compared to 6.66 Billion US$ in the BAU scenario. However, by including the external costs in the total cost, it will not make geothermal power cheaper than the BAU scenario.

Those problems should be solved in order to increase competitiveness of geothermal power. The important effort applied by Indonesian government is reducing oil subsidies to promote energy diversification and conservation, and reallocate it for geothermal subsidy. Moreover, the clean development mechanism (CDM) can make geothermal power competitive to conventional plants.

8. Acknowledgments

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