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Barriers to Geothermal Power Development and the Importance of Governmental Policies

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ABSTRACT

This paper compares the generation cost structure of geothermal power and thermal power alternatives, and it analyzes quantitatively the barriers of geothermal power development along with the effects of governmental policies. Geothermal power development has two major barriers; large upfront investment costs and substantial resource risks. The large upfront investment costs engender a strong correlation between generation costs and the capital cost of investment. Since the capital cost for Independent Power Producers (IPPs) is high, the generation cost of geothermal power tends to rise if developed by IPPs. Accordingly, IPPs are likely to prefer thermal power since it requires less upfront investment than geothermal energy. Resource risks, the second barrier, stem from uncertainty regarding the conditions of the reservoir. The production of geothermal steam depends greatly on factors like temperature, pressure, permeability, etc. If these factors turn out better than expected, generation costs decline; however, generation costs can rise precipitously if they are worse. This aspect of geothermal energy resembles gambling more than a professional business venture, which is another reason why IPPs are circumspect about entering the geothermal development business.

Government can play an important role in mitigating these two barriers to geothermal power development. For example, measures to lower the cost of capital, such as providing low-interest-rate loans or utilizing state-owned enterprises (SOEs), can be effective ways to lower the aforementioned large upfront investment costs. To reduce resource risks, initial explorations undertaken by the government or an attractive purchase price policy can be effective. In reality, governments of countries that have been successful in increasing geothermal power generation are implementing various forms of geothermal promotion policies. The key to success here depends on the incentives that government policies put into place. This paper demonstrates the effect of those incentives through numerical analyses employing a financial model based on reservoir engineering.

1. INTRODUCTION

Geothermal energy is a valuable renewable energy source that can provide an extensive volume of low-carbon electricity without daily or seasonal fluctuation. The pace of development of geothermal energy, however, does not necessarily live up to expectations. This is because geothermal energy has two major barriers; large upfront investment costs and considerable resource risks. Due to these barriers, IPPs in many countries are not particularly attracted to geothermal projects. This paper analyzes the extent to which these two barriers discourage IPPs from developing geothermal energy by using a financial model for geothermal power generation. It also discusses countermeasures for coping with them by highlighting actual policies.

Section 2 of this paper explains the main parameters of the financial model and compares the generation cost structure of geothermal power with that of thermal power alternatives. Sections 3 and 4 describe the impact of the aforementioned two barriers on the generation cost of geothermal power. Section 5 analyzes the effect of some incentive policies using the financial model, while Section 6 browses examples of policies that some countries have implemented. The paper concludes by emphasizing the importance of governmental policies in promoting geothermal power development.

2. FINANCIAL MODEL

2.1 Main Parameters

Here we elaborate a hypothetical geothermal field for illustrative purposes, the main parameters for which are as follows. The reservoir is liquid-dominated with a depth of 2,000 meters, a temperature of 240 °C, a pressure of 150 bar, and kh (permeability-thickness product) of 5 darcy-meter. A 55 MW_e flash-type geothermal power plant is to be developed using this reservoir that will operate for 30 years (hereinafter referred to as the Model project). If the conditions of the reservoir are as described above, steam output equivalent to 5.7 MW_e is obtainable for each production well with a 7-inch diameter bottom liner. Meanwhile, the amount of brine rendered from the geothermal production cycle is 4.6 times the amount of steam.

It is further assumed that it takes seven years to develop the Model project. The first two years (Year -7 and Year -6) are exploration stage. In this stage, two production-size test wells are drilled, and one well is assumed to be successful. The next two years (Year -5 and Year -4) are confirmation stage to assess the resource capacity. In this stage, four production-size test wells are drilled, of which three wells are assumed successful. Based on this result, the steam field facilities and the power plant are built in the next three-year construction stage (Year -3 to Year -1). In the construction stage, eight production wells and nine reinjection wells are drilled. Six of the eight production wells and eight of the nine reinjection wells are assumed to be successful. Namely, ten successful production wells are prepared before operations start. In addition, steam pipelines and power transmission lines are built in this stage.

In the Model project, the drilling cost of a production-size well is assumed to be US$ 2,500 per meter. Based on this drilling cost, the cost of the exploration stage is approximately US$ 18 million and that of the confirmation stage is about US$ 37 million. The construction cost of steam field facilities is about US$ 100 million and that of the power plant is around US$ 88 million. Hence, total development costs come to US$ 243 million, excluding interest during construction (IDC). These costs are financed by equity only in the exploration and confirmation stages. In the construction stage, 70% of the construction cost is financed by bank loans and 30% is covered by equity. The cost of equity, i.e. the expected return on equity, is set at 17% for IPPs and 12% for SOEs. The cost of debt, i.e. interest rate of a commercial bank loan, is 6% and the repayment period is 10 years. In the operation stage, the Model project is subject to a corporate income tax rate of 25% and a royalty amounting to 1% of sales is imposed. During the 30-year operation period of the Model project, 16 production wells and 10 reinjection wells are drilled as makeup wells due to the 5% annual decline in production and reinjection well capacity, respectively. Finally, it is assumed that inflation holds constant at 2% per year during the construction and operation periods, and that financial evaluation is performed on a real term basis over the entire project period.

Table 1: Main parameters of the Model project.

Power Plant		**Development schedule**	
Plant size (MWe)	55	Exploration	Year -7 ~ Year -6
Plant capacity factor	90%	Confirmation	Year -5 ~ Year -4
Operation period (years)	30	Construction	Year -3 ~ Year -1
Geothermal Reservoir		**Estimated cost (w/o IDC)**	
Estimated depth (meter)	2,000	Exploration (M$)	18
Estimated temperature (degree C)	240	Confirmation (M$)	37
Estimated pressure (bar)	150	Construction of steam field (M$)	100
Estimated kh (darcy-meter)	5	Construction of power plant (M$)	88
Production well output (MWe/well) (*)	5.7	Total (M$)	243
Reinjection well capacity (t/h)	300	**Capital source**	
Water/steam ratio (*)	4.6	Exploration & Confirmation	100% Equity
Steam Field		Construction of steam field & power plant	30% Equity, 70% Debt
Necessary number of production wells	10	**Cost of Capital**	
Production wells to be drilled	14	Cost of equity (IPP)	17%
Necessary number of reinjection wells	8	Cost of equity (SOE)	12%
Reinjection wells to be drilled	9	Cost of debt (Interest rate)	6%
Makeup wells		Repayment period of debt (years)	10
Declining rate of steam production	5% a.n.	**Tax rate**	
No. of makeup production wells in 30 years	16	Corporate income tax	25% of net income
Declining rate of reinjection capacity	5% a.n.	Royalty	1% of sales
No. of makeup reinjection wells in 30 years	10	**Inflation**	2% a.n.

(*) Based on wellbore simulator developed by West Japan Engineering Consultants, Inc. (West JEC) and Kyushu University.

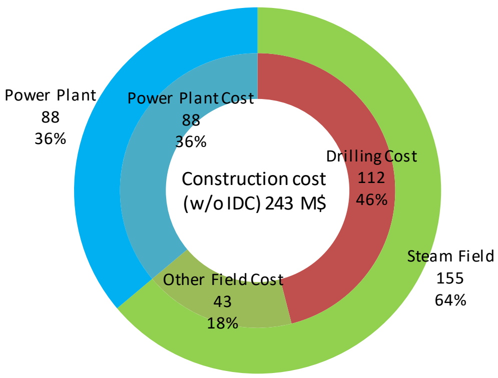


Figure 1: Construction cost of the Model project

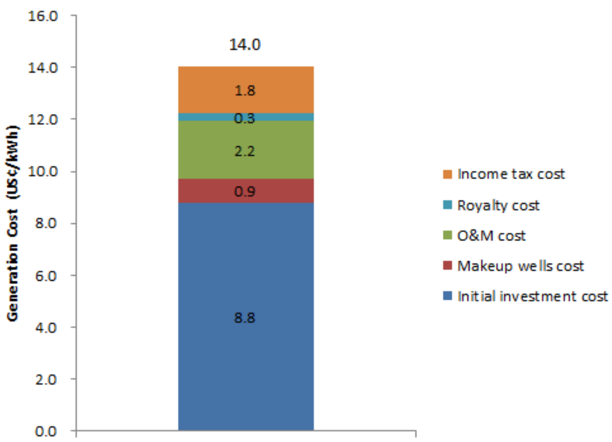


Figure 2: Generation cost of the Model project

2.2 Construction Cost and Generation Cost

Construction cost exclusive of IDC is generally referred to as overnight construction cost (OCC). The OCC of the Model project is US$ 243 million, of which 64% is for steam field development and 36% is for power plant construction. The combined drilling costs of exploration, production and reinjection wells account for 46% of the OCC. The OCC per kW is US$ 4,420 (Figure 1).

The generation cost of the Model project is taken as the levelized cost of energy (LCOE), which is calculated by dividing total discounted costs in the exploration, confirmation, construction and operation stages by the total discounted amount of energy generated in the operation stage. As for the discount rate, the weighted average costs of capital (WACC), which consist of equity and debt costs, is used. The generation cost includes corporate income tax imposed on net income at a 25% tax rate. For our purposes, then, the generation cost is defined as "LCOE that includes income tax and is discounted by WACC."

When implemented by an IPP with an equity cost of 17% and a debt cost of 6%, the Model project has WACC of 13.9% with an equity/debt ratio of 72/28. The generation cost calculated by using this WACC is 14.0 US¢/kWh, which is broken down as follows (refer to Figure 2 for a graphical representation of this breakdown);

- Initial investment cost: 8.8 US¢/kWh (62.6%),
- Makeup wells cost: 0.9 US¢/kWh (6.5%),
- Operation and maintenance cost: 2.2 US¢/kWh (15.9%),
- Royalty cost: 0.3 US¢/kWh (2.0%), and
- Income tax cost: 1.8 US¢/kWh (13.0%).

As a reference, let us compare the generation costs of the Model project and sample thermal power projects. Assumptions for a sample coal-fired project, a sample gas combined-cycle project, and a sample diesel project are enumerated in Table 2, while the cost comparison for these projects is shown in Figure 3. One can readily glean from Figure 3 that the cost structure of the Model project is very different from that of thermal power projects. The investment cost, i.e. initial investment cost plus makeup wells cost, accounts for 69% of generation costs in the Model project, compared to 23% to 29% for the thermal power projects. On the other hand, fuel accounts for 64% to 85% of the generation cost of thermal power projects, while the Model project does not have any fuel costs. This big difference in the cost structure between geothermal and thermal power projects is further discussed in Section 3.

Table 2: Assumptions of sample thermal power projects.

Item	Coal-fired	Gas Combined cycle	Diesel
Capacity	500 MW	500 MW	55 MW
Construction costs (w/o IDC)	US$ 850 million	US$ 640 million	US$ 70 million
Capacity factor	90%	90%	90%
Fuel heat value	6,000 kcal/kg	1,027 BTU/c.f.	9,200 kcal/L
Fuel price	110 US$/ton	10 US$/MMBTU	70 US$/BBL
Plant heat efficiency	35%	45%	38%
Equity cost	17%	17%	17%
Interest rate of debt	6%	6%	6%
WACC	8.8%	8.8%	8.8%

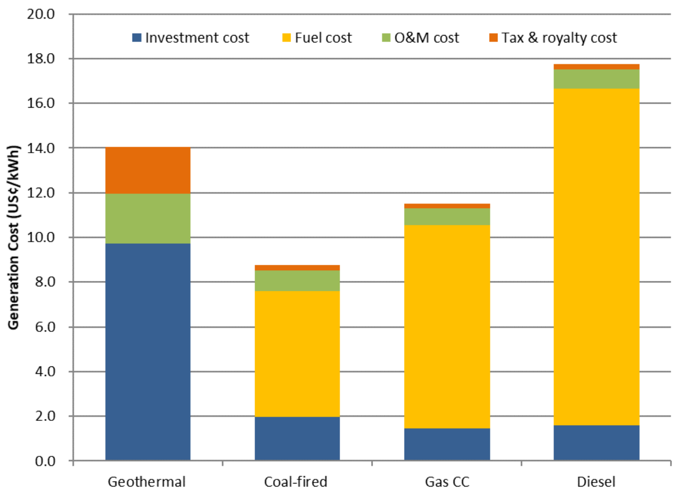


Figure 3: Comparison of generation cost structure between the Model project and sample thermal power projects.

3. THE FIRST BARRIER: LARGE UPFRONT INVESTMENT COSTS

Since investment costs account for a large portion of the generation cost of geothermal energy, as explained above, equity and debt costs likewise significantly affect it. Figure 4 shows the relationship between the generation cost and the capital cost (WACC) of initial investment in both the Model project and sample thermal power projects. The generation cost rises as WACC increases for all projects, but the Model project has a steep upward slope whereas the thermal power projects have a gentle upward slope. This owes to the fact that initial investment costs account for a small part of the generation cost of thermal power projects; so, the capital cost (WACC) of thermal power projects does not affect their generation cost as much as with geothermal energy.

When an IPP develops the Model project, equity alone usually covers the costs of the exploration and confirmation stages. The IPP can use debt only when the project arrives at construction stage, which is when the project becomes bankable. Since the exploration and confirmation stages occur early on, the equity/debt ratio of the Model project is relatively high then, at around 72/28 when the time value of money is considered. The WACC of the Model project turns out to be 13.9%, with an equity cost of 17% and debt cost of 6%. On the other hand, since thermal power plants have a short development period and debt can cover a considerable portion of their cost from the start, the equity/debt ratio of the sample thermal power projects is much lower, at around 25/75. As a result, the WACC of thermal power is as low as 8.8% with the same equity cost of 17% and debt cost of 6%.

Thus, the geothermal generation cost has two unfavorable factors: (i) there is a strong correlation between the capital cost of projects (WACC) and generation cost, and (ii) WACC tends to be high due to an early disbursement of equity. These two factors tend to make geothermal generation costs higher than thermal power generation costs, as shown in Figure 3. For this reason, IPPs are likely to select coal-fired or gas-fired thermal power projects rather than geothermal power projects. This result is also consistent with country experiences. Case studies suggest that in many countries with liberalized power generation markets, the share of thermal power is expanding while hydropower and geothermal power are stagnating. Again, IPPs have not been willing to implement hydropower or geothermal power projects and instead opt for thermal power projects that need less upfront investment and require shorter development time. This characteristic of geothermal power is one of the major barriers inhibiting IPP participation in geothermal energy projects.

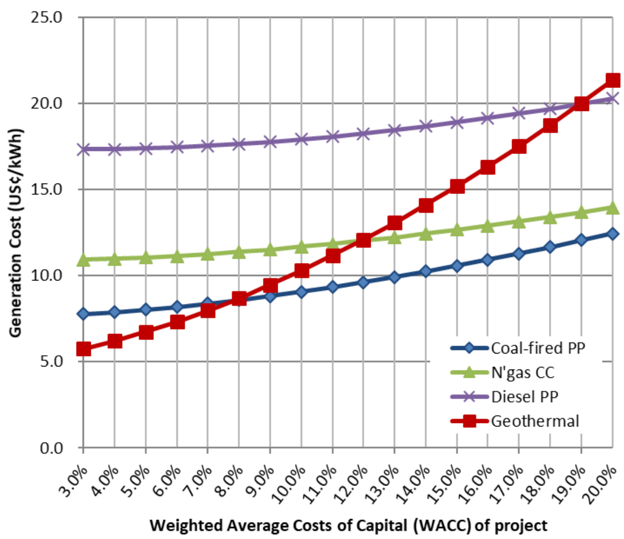


Figure 4: Relationship between generation cost and capital cost of the Model project and sample thermal power projects.

4. THE SECOND BARRIER: SUBSTANTIAL RESOURCE RISKS

Another major barrier to geothermal power development are substantial resource risks. Geothermal is site-specific energy, so there is no standard design as with thermal power. For example, one of the key design features of geothermal projects is steam flow-rate. If the steam flow-rate, or power output, of production wells is small, it is necessary to drill a large number of them and the generation cost increases accordingly. In other words, the output of production wells greatly affects the generation cost of geothermal power. However, the output of production wells depends on reservoir conditions like temperature, pressure and permeability, which can differ site by site. Furthermore, the output of production wells is knowable only after exploration and confirmation drilling has proceeded to a certain extent. These uncertainties constitute geothermal resource risks.

Figures 5 and Figure 6 illustrate how the reservoir temperature affects the output of production wells along with the generation cost. In the Model project, the reservoir temperature is assumed to be 240 °C, the pressure is 150 bar and kh is 5 darcy-meter. Figure 5 shows that the output of the production well under these conditions is 5.7 MW_e. Output jumps to 9.1 MW_e if the temperature is 260 °C, yet if it is 220 °C output drops to 2.6 MW_e — less than half as much than if the temperature is 240 °C. This means both that the sensitivity of production well output to reservoir temperature is very strong and twice as many production wells are required if the reservoir temperature is 20 °C less than originally expected.

Figure 6 shows the effect of different reservoir temperatures on the generation cost of the Model project. The generation cost curve is approximately hyperbolic with respect to temperature. The generation cost increases significantly as the reservoir temperature decreases. The reason why the generation cost becomes hyperbolic in Figure 6 can be explained as follows. Assuming that output of the production well is Pw and the reservoir temperature is T, Pw can be approximated to a linear function of $Pw = aT + b$ from Figure 5 (a, b: constant). Assuming that the number of production wells required to develop a power plant of output Pp is N, $N = Pp / Pw$. The construction cost (OCC) of the power plant can be expressed as $OCC = \alpha N + \beta$ (α, β: constant). Therefore, the OCC is hyperbolic with respect to T; $OCC = \alpha Pp / (aT + b) + \beta$. The generation cost is also hyperbolic with respect to temperature T.

Figure 6 suggests that geothermal projects entail huge resource risks. For example, when the reservoir temperature is 240 °C, the generation cost is 14.0 US¢/kWh. When the reservoir temperature degrades to 220 °C, the generation cost increases to as high as 20.8 US¢/kWh. If development started with the expectation of a reservoir temperature of 240 °C, but the actual temperature turns out to be just 220 °C, not only will original expectations with respect to production go largely unmet but also the result would be financially disastrous if the power purchase agreement set the selling price at 14.0 US¢/kWh. In reality, this adverse outcome can easily occur and is even more reason why many IPPs are very cautious about entering the geothermal development business.

Let us evaluate these resource risks quantitatively. In the Model project, the central parameter values found in Table 3 originally characterized the physical state of the reservoir. In this section, we instead assume that any value between the minimum and maximum parameter values listed in Table 3 could characterize it. The probability of occurrence follows the triangular probability distribution with the central value as the vertex. Based on these assumptions, the generation cost is calculated by the Monte Carlo method. Figure 7 shows the generation cost distribution resulting from 1,000 trials.

The distribution of the generation cost ranges widely from 10.9 US¢/kWh to 28.4 US¢/kWh. The expectation value (μ) of the distribution is 14.6 US¢/kWh, slightly higher than the original generation cost of 14.0 US¢/kWh (i.e., with reservoir conditions set at the central values listed in Table 3). The standard deviation (σ), which indicates the spread of the distribution, is 2.27 US¢/kWh. In business administration theory, the standard deviation of the probability distribution is defined as “business risks.” It follows that the risk of this geothermal development business is evaluated as 2.27 US¢/kWh. Furthermore, distribution of the generation cost is not symmetrical, with the long tail depicting high generation costs and the short tail depicting low generation costs. This shape portends a high probability that the generation cost becomes high but a low probability that the generation cost will be low. It owes to the fact that the relationship between the reservoir parameters and generation cost is hyperbolic, as shown in Figure 6. In other words, geothermal projects have a risk profile such that the rewards for favorable reservoir conditions are small while the penalty exacted for poor reservoir conditions is large. This seems like a bad bet, making resource risks the second barrier inhibiting many IPPs from engaging in geothermal development.

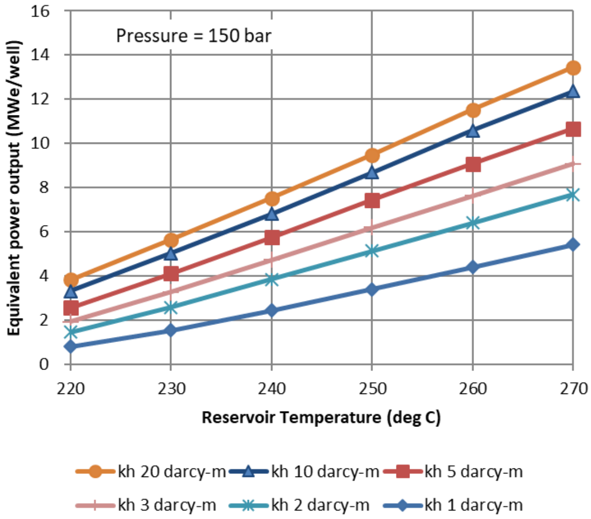


Figure 5: Output of production well (by wellbore simulation).

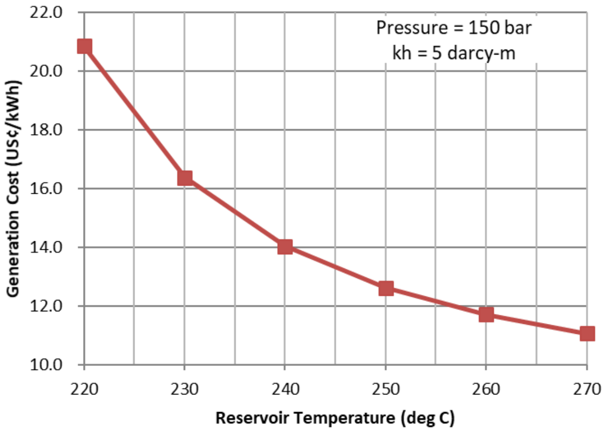
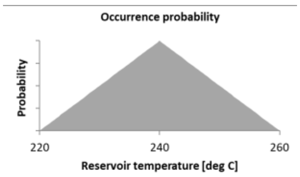


Figure 6: Generation cost at different temperatures.

Table 3: Assumptions of reservoir conditions in Monte Carlo method.

Parameter	unit	Minimum	Central	Maximum
Temperature	deg C	220	240	260
Pressure	bar	130	150	170
kh	darcy-meter	2	5	8
Depth	meter	1,500	2,000	2,500
Reinjection capacity	t/h	250	300	350



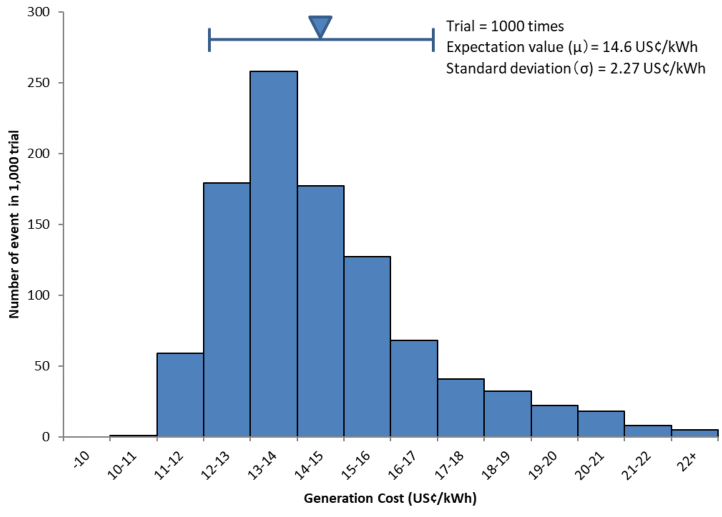


Figure 7: Distribution of the generation cost of the Model project by Monte Carlo method.

5. NUMERICAL SIMULATION OF EFFECTS OF INCENTIVE POLICIES

5.1 Incentive Policies to Lower the Generation Cost

In Section 3, we saw that geothermal generation cost tends to be high because of large upfront investment and long lead times, making it difficult for IPPs to participate in geothermal projects. In this section, we will discuss how we can lower the generation cost of geothermal power with policies such as tax incentives and carbon credits plus arrangements to lower the capital cost of geothermal projects.

5.1.1 Tax Incentive

One method to lower the generation cost of geothermal power is to extend tax incentives. As shown in Figure 3, the geothermal generation cost comprises a larger amount and share of tax than thermal power alternatives (tax and royalty costs are 2.1 US¢/kWh and 15.0% of geothermal generation cost, whereas they are 0.2 ~ 0.3 US¢/kWh and 1.4 ~ 3.0% for thermal power). This is consistent with findings in the literature, as Jenkins et al. (1996) point out a large disparity between the tax burdens of capital-intensive renewable energy and thermal power projects.

Several countries have deployed tax incentives to encourage the production of renewable energy (including geothermal). For example, Indonesia has an investment tax concession that allows companies to deduct 5% of their initial investment in certain industries, including geothermal, from their taxable net income for six years of operation (the total tax deduction amount is 30%). In addition, the Philippines introduced a tax holiday incentive that exempts income tax for renewable energy projects during the first seven years of operation. The United States, for its part, introduced a production tax credit exempting 2.4 US¢/kWh of income tax per 1 kilo-watt-hour of renewable energy generated over 10 years.

Figure 8 shows the effects of tax incentives adopted by the above-mentioned countries on the generation cost of the Model project. Compared to the generation cost prevailing under the Base case (14.0 US¢/kWh), Indonesia's investment tax concession reduces the generation cost by 0.5 US¢/kWh (to 13.5 US¢/kWh), and the Philippines's tax holiday incentive reduces the cost by 1.0 US¢/kWh (to 13.0 US¢/kWh). The U.S. production tax credit has the biggest effect, reducing the generation cost remarkably by 2.4 US¢/kWh (to 11.6 US¢/kWh).

5.1.2 Carbon Credits

Carbon credits and carbon trading are effective ways to lower the generation cost of geothermal given its ability to supply a large amount of low carbon electricity in a stable manner. Carbon credits assign value to the amount of carbon dioxide (CO_2) or equivalent greenhouse gases (GHGs) that would be foregone when a GHGs reduction project is implemented instead of a business as usual (BAU) project. Projects that reduce GHGs can earn income by selling credits in carbon trading markets, and the income derived from carbon credits can offset their otherwise high generation cost.

Figure 9 shows the effect of carbon credits on the generation cost of the Model project. The generation cost is 14.0 US¢/kWh in the Base case (no credit), but it declines to 13.5 US¢/kWh when the carbon credit price is 10 US$/ton-$CO_2$. The generation cost declines even more to 13.1 US¢/kWh with a carbon credit price of 20 US$/ton-$CO_2$.

5.1.3 Reduction of capital cost of project

Since geothermal projects are capital intensive, lowering their capital cost can significantly reduce the generation cost. Since the cost of capital is a weighted average of the costs of both equity and debt, the generation cost can be lowered by reducing either or both of these costs. In the following analysis, the generation cost in the Base case of the Model project is compared to the following cases: (a) an IPP that uses a governmental soft loan (low interest rate loan), (b) a SOE that uses a commercial loan, and (c) a SOE that uses a concessional Official Development Assistance (ODA) loan.

(a) IPP using soft loan

Assuming that an IPP company with an equity cost of 17% implements the project using a commercial loan with an interest rate of 6%, the WACC is 13.9% and the generation cost becomes 14.0 US¢/kWh (the Base case). If this company can use a low interest rate loan of 3% (soft loan) from governmental banks, the WACC drops to 13.1% and the generation cost is reduced to 13.3 US¢/kWh. This cost reduction is the direct effect of a governmental soft loan.

(b) SOE using commercial loan

Next, if the developer of the Model project is a SOE, the equity cost is expected to be less. This is because a SOE's primary objective is to promote geothermal development, and obtaining profit is secondary. In addition, by accessing governmental credit, SOEs can procure capital less expensively than can private companies. Here let us assume that the equity cost for a SOE is 12% (while the equity cost for an IPP is 17%). In such a case, even if the interest rate of a commercial loan is 6%, the WACC of the SOE's geothermal power project decreases to 10.2% and the generation cost falls to 10.4 US¢/kWh.

(c) SOE using concessional ODA loan

SOE geothermal developers have one more advantage; they can receive ODA loans from development partners such as the World Bank, the African Development Bank, Japan International Cooperation Agency (JICA) and so on. The conditions of ODA loans are very concessional. The interest rate of JICA's yen loan, for example, to low- and middle-income countries (GNI 1,006 – 3,955 US$/person) is 1.25% and has a repayment period of 30 years, including a 10-year grace period. If SOEs utilize such yen loans, the WACC falls to 8.7%, and the generation cost declines the furthest as a result to 9.4 US¢/kWh (Figure 10). This means that ODA loans serve as a very powerful tool to lower the generation cost of, and thereby promote, geothermal energy projects.

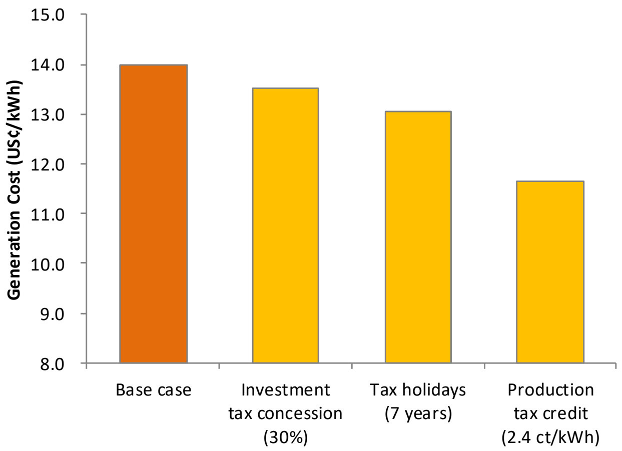


Figure 8: The effect of tax incentives on the Model project.

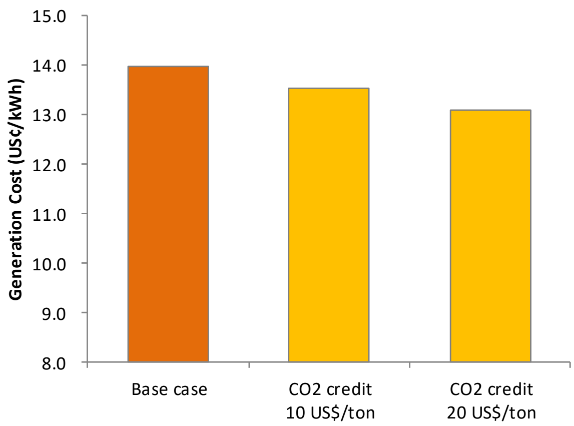
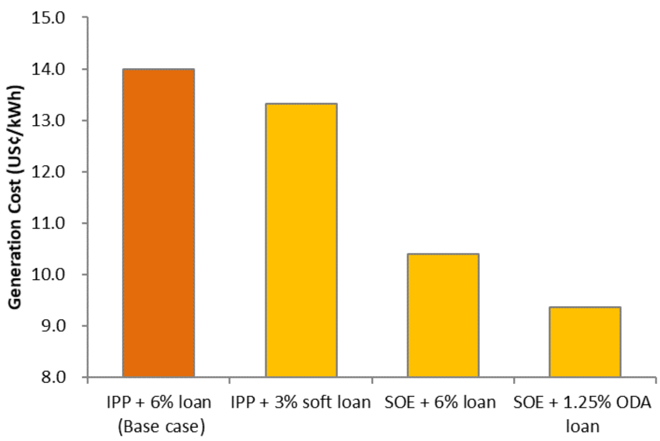


Figure 9: The effect of carbon credit on the Model project.



Equity	17%	17%	12%	12%
Debt	6%	3%	6%	1.25%
WACC	13.9%	13.1%	10.2%	8.7%

Figure 10: The effect of SOE developer and ODA loan on the Model project.

5.2 Policies to Address Resource Risks

In Section 4, we observed that IPPs are likely to avoid geothermal projects because of large resource risks. In this section, we will discuss countermeasures that can mitigate geothermal resource risks, such as (a) purchase price policy, (b) initial exploration by the government, and (c) portfolio management.

5.2.1 Purchase Price Policy

Since there is great uncertainty in predicting the generation cost of geothermal projects beforehand (as discussed in Section 4), a purchase price policy that adds a certain risk-premium to the geothermal purchase price is one effective measure to promote private sector participation in geothermal projects. It is worthwhile here to revisit the generation cost distribution of the Model project using the Monte Carlo method (Figure 7). If the purchase price is set at 14.0 US¢/kWh, the number of cases where the purchase price exceeds the generation cost is 501, which means about half of the 1,000 cases considered will make profits and the other half will incur losses. This high probability (about 50%) of incurring losses discourages IPPs from initiating geothermal projects. However, if the purchase price is set 2 US¢/kWh higher at 16.0 US¢/kWh, the number of cases where the purchase price exceeds the generation cost increases to 802 (Figure 11). With this high probability (about 80%) of making profits, some IPPs might decide to venture into geothermal energy. In short, a purchase price policy that adds an appropriate risk-premium to the geothermal purchase price can have a positive influence in promoting geothermal development.

5.2.2 Governmental Initial Exploration

Governments can greatly reduce resource risks for IPPs and lower the geothermal generation cost by undertaking initial exploration. The extent to which IPPs can take risks is limited. Nevertheless, if the government carries out initial exploration and finds promising resources, IPPs can join later in developing them—saving funds and time that otherwise would have been spent exploring on their own.

Figure 12 shows the generation cost distribution when government handles the exploration stage and hands over a promising reservoir to IPPs, based on the Monte Carlo trials from Figure 7. In this case, it is assumed that IPPs do not take over development of unpromising reservoirs, which are defined by the overlapping conditions of temperature below 230 °C, pressure under 140 bar and less than 3 darcy-meter kh. In other reservoir cases, IPPs take over development by paying the cost of exploration to the government (US$ 18 million). Such favorable reservoir cases occurred 732 times out of 1,000 times in Figure 7. The generation cost distribution of these 732 favorable cases ranges from 9.8 US¢/kWh to 20.3 US¢/kWh, with an expectation value (μ) of 13.1 US¢/kWh and a standard deviation (σ) of 1.73 US¢/kWh (Figure 12). By avoiding the development of unpromising reservoirs, the expected value (μ) of generation cost is reduced by 1.5 US¢/kWh (from 14.6 US¢/kWh, as shown in Figure 7), and the standard deviation (σ), or the index of risks, is reduced by 24% from 2.27 US¢/kWh to 1.73 US¢/kWh. This reduction in the generation cost and resource risks is a salutary effect of governmental initial exploration.

5.2.3 Portfolio Management

If only one geothermal field is developed, the result will be either success or failure. If, however, multiple fields are developed, we may expect the overall success rate to remain in a certain range because even if some fields fail others will succeed. This effect is called "risk diversification by portfolio." Figure 13 shows the distribution of average generation costs for four fields when IPPs develop them as a portfolio, supposing the generation cost of each field follows the distribution shown in Figure 7. The expectation value (μ) of this distribution is 14.6 US¢/kWh, the same as in Figure 7, but the standard deviation (σ) declines from 2.27 US¢/kWh to 1.13 US¢/kWh. That means the resource risk has decreased by half when compared to the case presented in Figure 7. This phenomenon is due to the Central Limit Theorem in statistics. The Central Limit Theorem holds that for n samples from a certain distribution with expectation value of μ and standard deviation of σ, a new distribution of the average of n samples approaches a normal distribution with expectation value of μ and standard deviation of $\sigma/\sqrt{n}$.

According to this Theorem, the risk of the whole portfolio reduces to 1/2 if four geothermal fields are developed and to 1/3 if nine fields are developed. Following this logic, Figure 13 elaborates a new distribution of the average generation costs for four geothermal fields from the distribution cited in Figure 7. While the expected value is the same in Figures 7 and 13, the standard deviation halves with the portfolio approach, meaning that resource risks are reduced to half. One implication of this portfolio effect is that for geothermal developers to reduce geothermal resource risks, they need to develop multiple fields. Congruently, the implication for policy makers is the importance of fostering large-scale geothermal developers that are capable of developing multiple fields in their country. Perhaps the best example of a large-scale developer is a SOE geothermal developer that can handle all domestic geothermal fields. In many countries where geothermal energy is well developed, SOE geothermal developers have played an important role.

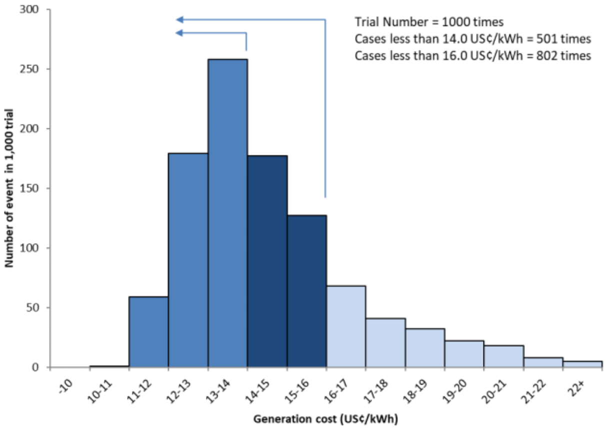
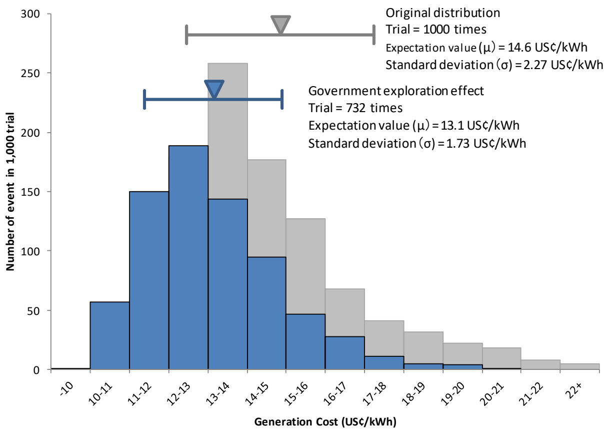


Figure 11: The effect of purchase price policy on generation cost of the Model project.



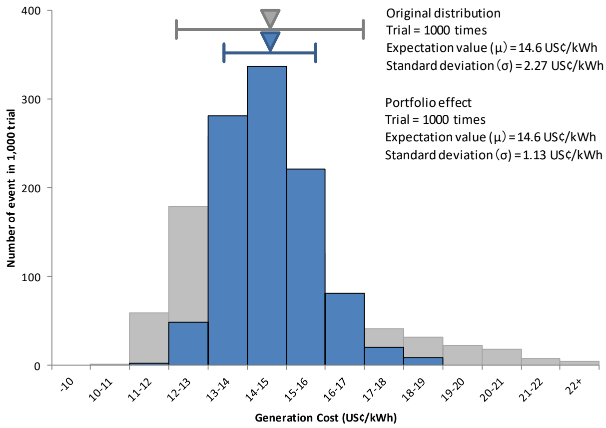


Figure 12: The effect of initial exploration by government.

Figure 13: The portfolio effect of four geothermal fields.

6. EXAMPLES OF ACTUAL POLICIES

6.1 Tax Incentives

Some countries have introduced tax incentives to promote renewable energy. Among these tax incentives, production tax credits (PTCs) have had a significant effect on reducing geothermal generation costs in the United States, as shown in Figure 8. The U.S. launched PTCs in 1992 to promote wind and biomass power. Geothermal power became eligible for the PTCs in 2004, with an initial tax deduction period of five years that was subsequently extended to 10 years in 2005. The application of PTCs reactivated stagnant geothermal development in the U.S. throughout the 2000s. (Note: The U.S. terminated geothermal PTCs in 2015 through projects under construction as of the end of 2017. The U.S. geothermal industry is calling for the revival of PTCs.)

6.2 Carbon Credits

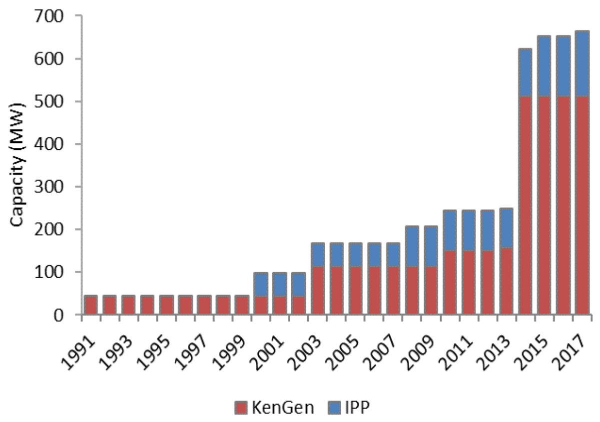
Typical examples of carbon credits are the European Union - Emissions Trading Scheme (EU-ETS) and the Certified Emission Reduction (CER) trading scheme under the Clean Development Mechanism (CDM) managed by the United Nations Framework Convention on Climate Change (UNFCCC). The EU-ETS, the first international emissions transaction, launched in 2005 and is the world's largest emissions trading scheme, covering 45% of all EU emissions. The price of the GHG emission allowance (EUA) under the EU-ETS was around 30 €/ton-CO_2 in 2008, although it decreased with the global economic downturn in 2009 and stagnated to around 5 €/ton-CO_2 thereafter. However, the price has risen since the middle of 2018, recovering to around 25 €/ton-CO_2 as of July 2019.

The CDM is one of the Kyoto mechanisms agreed upon at COP3 of the UNFCCC, held in 1997. According to the UNFCCC, more than 8,000 CDM projects are registered to date. Of these, 29 are geothermal power projects. The CER price generated by the CDM was 35 US$/ton-$CO_2$ in 2008 but has since dipped and, unfortunately, only stood at less than 1 US$/ton-$CO_2$ as of July 2019. More recently, the Paris Agreement adopted at COP21 in 2015, which succeeds the Kyoto Protocol, refers to additional measures to reduce GHGs using market mechanisms like the CDM.

6.3 Reduction of the Capital Cost of Project (utilization of SOE / ODA Loan support)

Kenya and Indonesia are two of recent good example countries where SOEs have successfully developed geothermal energy with the support of ODA loans. The first geothermal power plant in Kenya was developed in 1981 with the support of the World Bank. Kenya, which used to rely on hydropower, perceived the value of geothermal energy in generating stable power year-round after it experienced serious power shortages in the wake of a severe drought in 2000. Since then, geothermal power development has progressed rapidly in Kenya. For example, Olkaria-I Extension (140 MW_e) and Olkaria-IV (140 MW_e) were launched in quick succession in 2014. In 2018, Kenya's installed geothermal capacity reached 667 MW_e, and the share of geothermal energy in Kenya's total power generation reached 47.6% in 2017/2018, the largest share in the world. Kenya Electricity Generating Company (KenGen), a SOE of which the Kenyan government owns 70%, has carried out most of the country's geothermal development to date. Yet ODA loans have also played an important role in promoting geothermal development in Kenya (Figure 14). According to Ouma (2018), the development of Olkaria-I Extension and Olkaria-IV cost US$ 1,065 million. Of this total, the Kenyan government contributed US$ 316 million, KenGen paid US$ 103 million and ODA loans from the World Bank, JICA, KfW, the European Investment Bank and AFD covered the remaining 60%. Furthermore, China also provided loans for drilling exploration and production wells. JICA has also provided US$ 406 million worth of yen loans for the development of Olkaria-V (140 MW_e). To underscore this point, Figure 15 shows the purchase prices by Kenya Power and Lighting Company (KPLC), an off-taker, of geothermal energy from KenGen and the IPP that carried out development of Olkaria-III (150 MWe) (estimated by the author from annual reports of KPLC and KenGen). One can see that KenGen, a SOE and a beneficiary of ODA loans, is providing geothermal energy at a lower price than the IPP.

In Indonesia, geothermal power generation began in the 1980s and private companies continued investing in it throughout the early 1990s. However, after the Asian financial crisis in 1997, private companies retrenched and SOEs such as PT. Pertamina Geothermal Energy (PGE), National Electric Power Company (PT. PLN) and PT. GeoDipa became more active in geothermal development (Figure 16). As a result, Indonesia's geothermal capacity reached 1,949 MW_e in 2018, surpassing the Philippines and turning Indonesia into the world's second largest producer of geothermal energy. To date, JICA has provided a total of US$ 640 million-yen worth of ODA loans to support six projects undertaken by PGE and PT. PLN. According to Sukarna (2012), which recounts PT. PLN's purchase prices for geothermal energy as of 2012, purchase prices for SOE geothermal developers have been consistently less than for IPPs (Figure 17).



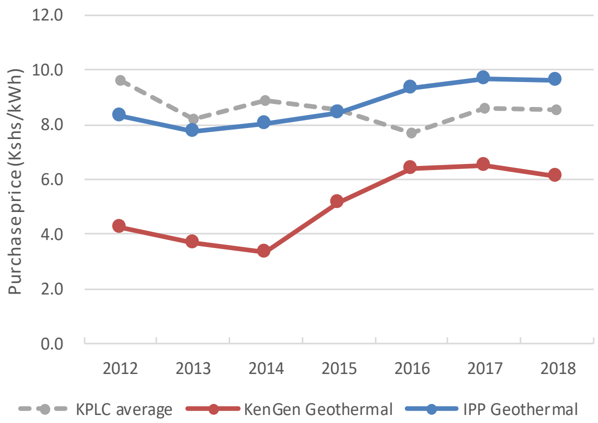
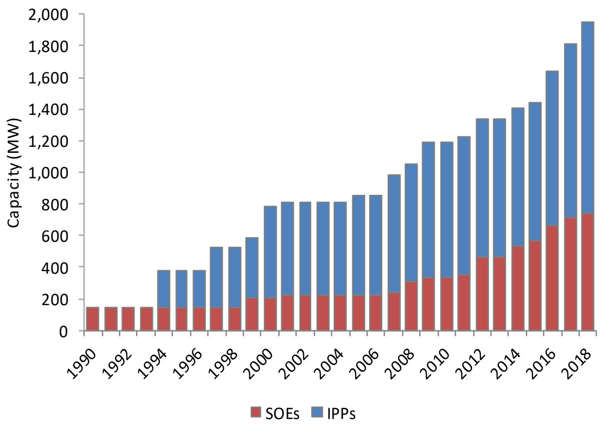


Figure 14: Geothermal development by SOE and IPP in Kenya. **Figure 15: Purchase prices of geothermal power by KPLC.**



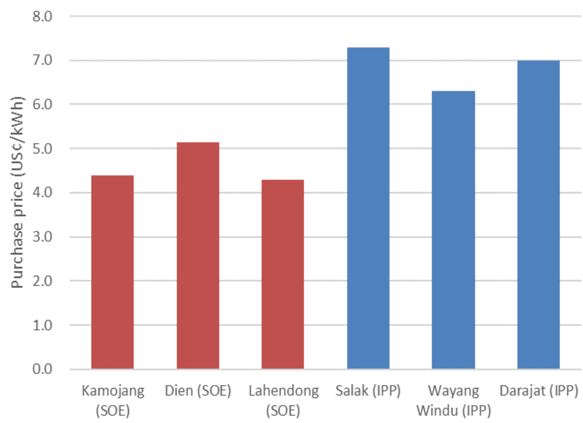


Figure 16: Geothermal development by SOEs and IPPs in Indonesia (left).

Figure 17: Purchase prices of geothermal power by PT. PLN (right).

6.4 Purchase Price Policy

Geothermal development involves hefty resource risks, but a purchase price policy is one effective measure to cope with these risks. A famous example of purchase price policy is the Public Utility Regulation Policies Act (PURPA) of the United States, enacted in 1978. The PURPA requires utilities to purchase renewable energy from IPPs at a rate equal to the utility's "avoided cost." Avoided cost is the incremental cost to the utility of generating the same amount of the energy purchased. According to Doris et al. (2009), this Act greatly promoted geothermal power (Figure 18).

A Feed-in Tariff (FIT) is the most well-known purchase price policy. According to Rickerson et al. (2012), 16 countries have introduced a FIT for geothermal energy. Germany, for instance, introduced a FIT policy in 1991, although it was broadened to include geothermal energy only in 2000. The current FIT price for geothermal energy in Germany is 25 €¢/kWh, regardless of scale. Due to this attractive FIT, Germany's first geothermal power plant was developed in 2003 and nine plants were operational as of 2017, producing a total of 36.2 MW_e (Figure 19).

In Japan, the accident that ensued at Fukushima No. 1 Nuclear Power Plant following the Great East Japan Earthquake in 2011 prompted an expansion of the country's renewable energy promotion policy. As part of this revamp, Japan launched a FIT in 2012 that encompasses geothermal energy. The Japanese FIT price for geothermal energy, over a 15-year purchase period, is 26 JPY/kWh (23.6 US¢/kWh) for 15 MW_e or more and 40 JPY/kWh (36.4 US¢/kWh) for anything less than 15 MW_e. This sound policy reactivated geothermal development in Japan, which had stagnated in the 2000s. (US$ 1 = JPY110 as of July 2019)

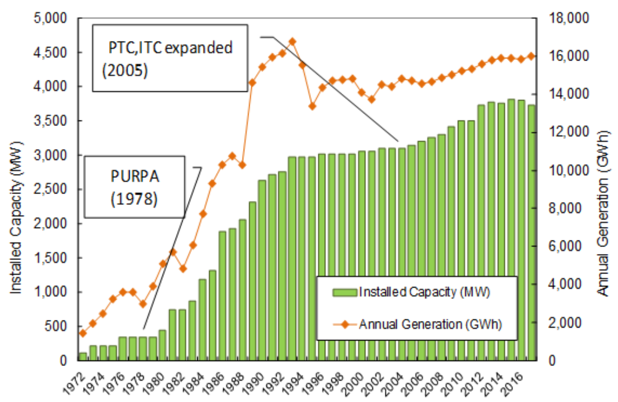


Figure 18: Geothermal development in the United States.

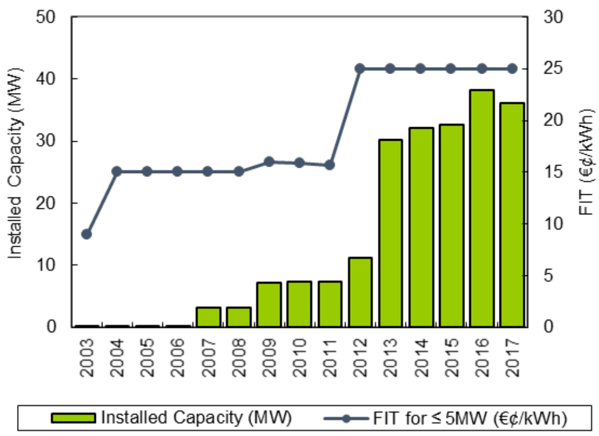


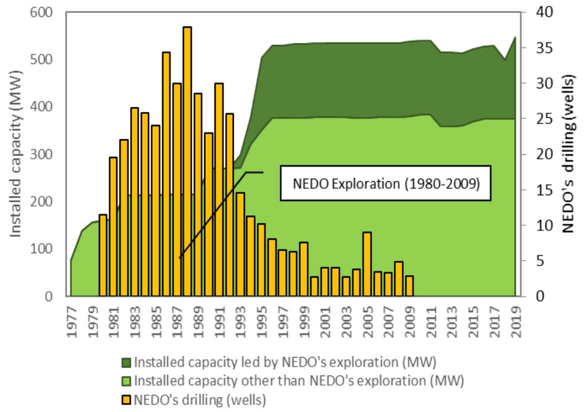
Figure 19: Geothermal development in Germany.

6.5 Government's Initial Exploration

New Zealand, Japan and Turkey offer successful examples of governments undertaking initial geothermal exploration. In New Zealand, the government conducted initial explorations in the 1960s-1980s, including the drilling of deep test wells. According to Bromley (2014) and the New Zealand Geothermal Association, most of the high enthalpy geothermal resources currently being developed in New Zealand was found through this government exploration. In addition, because of this government exploration, private companies can take part in geothermal development in New Zealand with low risks and with a high drilling success rate of about 85%, which is higher than the international standard.

In Japan, the New Energy and Industrial Technology Development Organization (NEDO), a governmental agency, conducted geothermal exploration between 1980 and 2009. This exploration constituted an attempt by the government to trigger development of promising geothermal fields but in which private companies had not expressed interest due to resource risks. With this exploration, around five deep exploratory wells were drilled after various surface surveys were conducted. By 2010, NEDO explored 67 fields across the country and eight geothermal power plants were built as a result. The total output of these plants is 177 MW_e, which accounts for 32% of Japan's total geothermal capacity (Figure 20). By helping to ensure that NEDO's exploration results are fully utilized, introduction of the FIT policy in 2012 has revitalized Japan's geothermal development.

In Turkey, the first geothermal power plant was built in 1984 but no other major development took place there until 2005. After that year, however, geothermal development progressed rapidly and reached 1,305 MW_e in 2018—making Turkey the world's fourth largest producer of geothermal energy. This rapid growth in a short time period is attributable to several factors. One is the initial exploration conducted by MTA (General Directorate of Mineral Research and Exploration of Turkey). MTA began undertaking geothermal surveys in 1962. According to Kara (2018), the geothermal exploration budget for MTA has increased since enactment of the Renewable Energy Act in 2005, and drilling operations have expanded. As of 2018, MTA has drilled a total of 629 exploratory wells with a total depth of 400 km. As a result of these activities, MTA found an estimated 5,000 MW_t of geothermal resources in 239 fields nationwide. Of these, 16 fields seem suitable for power generation. Based on the Geothermal Law enacted in 2007, MTA has transferred the development rights for promising fields to private developers through tenders. According to Oliver (2015), 12 out of 13 geothermal plants commissioned by the end of 2013 were on fields that MTA initially explored and drilled. Undoubtedly, initial exploration by MTA has been one of the key success factors behind the rapid growth of geothermal energy in Turkey (Figure 21).



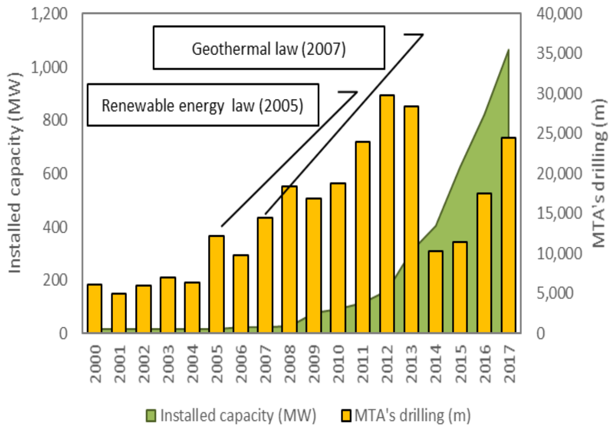


Figure 20: NEDO's exploratory drillings and geothermal development in Japan (left)

Figure 21: MTA's exploratory drillings and geothermal development in Turkey (right)

6.6 Utilization of SOEs (Portfolio Management)

Resource development risks will be reduced if development is done at multiple fields, as shown in Figure 13. The implication of this portfolio effect for policy makers is the importance of fostering large-scale geothermal developers that have the ability to undertake development of multiple fields and unlock the geothermal potential of their countries. A SOE geothermal developer is perhaps the ultimate form that this large-scale developer can take; besides Kenya and Indonesia, SOE geothermal developers are also found in Iceland, Italy, Mexico and the Philippines.

In Iceland, 708 MW_e of geothermal power has been developed (27% of total electricity production as of 2017), making it the country's most important power source after hydropower. Geothermal development in Iceland is spearheaded by three companies: Landsvirkjun (National Power Company), Reykjavik Energy and HS Orka hf. Landsvirkjun (National Power Company) is a SOE and Reykjavik Energy is a municipality-owned company established by Reykjavik and two other municipalities that supplies geothermal power and hot water. Meanwhile, the state and other municipalities initially established HS Orka hf. for the purpose of geothermal development, although the company was privatized following the financial crisis of 2009. In sum, publicly-owned enterprises (state- and municipality-owned) have played an important role in Iceland's geothermal development.

Italy was the first country in the world to utilize geothermal power, and the country's geothermal development has steadily advanced—with 916 MW_e of geothermal power installed there as of 2017. In Italy, ENEL (National Power Company) undertook the generation, transmission and distribution of power across the country from 1962-1992. ENEL built geothermal plants in those years and transferred them to Enel Green Power, a subsidiary, in 2008. Although ENEL has been gradually privatized in power sector reform process since 1999, the government still has 24% of its share as of 2017. Thus, the SOE has played a central role in Italy's geothermal development.

In Mexico, 957 MW_e of geothermal power was installed as of 2017 almost exclusively by a SOE, the Comision Federal de Electricidad (CFE; national power company). In 2014, Mexico enacted the Geothermal Law, which enables private companies to develop geothermal power. Currently, one private company has developed a power plant for self-use (36 MW_e), and three other private companies have acquired exploration rights. Nonetheless, CFE still plays an important role in Mexico's geothermal development.

The Philippines has been developing geothermal power since the 1970s, with significant progress made in the early 1980s and late 1990s. As of 2017, the Philippines had 1,916 MW_e of geothermal power installed. While the country's first two geothermal power plants were developed by a U.S. company (UNOCAL), the Philippines National Oil Company-Energy Development Corporation (PNOC-EDC), a SOE, has constructed all others. PNOC-EDC, which originally relied on technology transfer from foreign countries, has gradually become more technologically and financially capable than private companies. As a result, the SOE naturally monopolized geothermal development in the Philippines and accomplished such rapid growth that the country became the second largest producer of geothermal energy in the world briefly during the 1990s. Although power sector reform brought about the privatization of PNOC-EDC in 2006, the successes of the Philippines in the area of geothermal development are attributable in large part to when it was a SOE.

7. CONCLUSION

We have discussed defining characteristics of the generation cost structure of geothermal power and demonstrated how this cost structure is completely different from that of thermal power. Many IPPs are deterred from undertaking geothermal projects for this reason, although effective countermeasures can be taken at the level of national policy. Consequently, policy makers need to be fully aware of these barriers to geothermal development so that governments can devise appropriate policies for overcoming them.

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NOTICE

This paper is written by the author team and the views expressed herein do not necessarily represent the official views of West JEC or JICA.

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