Proceedings World Geothermal Congress 2026
Calgary, Canada, June 8 – 11, 2026

Determining the Tariff Threshold for Financial Viability and Bankability of a Greenfield Geothermal Project in the Philippines

Andal, Jeffrey M.
Department of Energy
jandal@doe.gov.ph

Keywords: Tariff, cost, greenfield, bankable, Philippines

ABSTRACT

The Philippines aims to increase the share of renewable energy (RE) in its generation mix to 35% by 2030 and 50% by 2050. To achieve this goal, the government has introduced several policies and programs to boost RE production. However, geothermal investment remains concentrated in existing geothermal fields, with limited activity in greenfield prospects due to the following: (1) exploration and resource confirmation, (2) environmental and social permitting, (3) power offtake and transmission constraints, and (4) investment financing. This study identifies the tariff required for a hypothetical 25 MW greenfield geothermal project to achieve both financial viability and bankability. A project finance model was developed and sensitivity analyses were conducted to evaluate how variations in interest rates, total investment costs, capacity factors, operation and maintenance (O&M) expenses, resource depth, and well productivity affect overall project economics.

The result shows that a tariff of USD 0.1354/kWh is necessary to ensure the project's financial viability and bankability. Additionally, among these key parameters, it was found that the capacity factor has the strongest influence on both bankability and financial viability. This study provides a replicable modelling framework that can help policymakers determine appropriate tariff levels for geothermal projects under competitive mechanisms such as the Green Energy Auction Program or the Feed-in Tariff System.

1 INTRODUCTION

To meet the targets set under the Philippine Energy Plan, which aims to increase the share of RE in the generation mix to 35% by 2030 and 50% by 2050 (Department of Energy (DOE), 2024a), the country has been aggressive in implementing policies and programs that promote RE development. With the DOE's strong push for RE as a driver of economic growth, several initiatives have been introduced to encourage the use of indigenous, low-cost, and environmentally friendly energy sources. However, despite these efforts, new geothermal developments remain largely limited to existing geothermal fields.

The geothermal energy sector in the Philippines plays a vital role in meeting the country's energy demand. As of 2024, the total installed geothermal capacity reached 1,951.734 MW, with annual gross generation of approximately 10,789 GWh of electricity, equivalent to about 8.5% of the national power mix (DOE, 2025a). The industry continues to grow, with 74.273 MW of new capacity added in the first three quarters of 2025, bringing total installed capacity to 2,026.007 MW. Furthermore, two additional power plants are anticipated to come online between late 2025 and 2026, potentially contributing an additional 33.645 MW.

According to the Asian Development Bank (ADB) (2024), the four major barriers in geothermal development in the Philippines are: (1) exploration or resource confirmation, (2) environmental and social approvals and permits, (3) power offtake, and (4) investment financing. These challenges contribute to investor reluctance and have slowed the development of new geothermal prospects, despite the country's abundant untapped potential.

The DOE has been proactive in introducing new policies and programs to help RE developers address these barriers. Table 1 presents some of these initiatives, while additional details and updates are available at DOE (2025b).

Table 1. Policies and programs to address the identified major barriers

Major Barriers (ADB, 2024)	Policies and Programs	Summary / Remarks

1. Exploration and resource confirmation	Various projects focusing on geothermal resource inventory and assessment (Andal, 2019)	DOE conducted geological, geochemical, and geophysical surveys to accelerate geothermal resource development. Data packages were offered to RE developers through the Open and Competitive Selection Process.
	Philippine Geothermal Resource Derisking Facility (Status: ongoing finalization)	To implement a 50:50 cost-sharing scheme with qualified RE developers for exploration drilling. If the project was deemed commercially viable, the shared funds are repaid; otherwise, the support is converted into a grant to reduce exploration risk.
2. Environmental and social permitting	Revised Omnibus Guidelines Governing the Award of RE Contracts	Simplifies RE contract application and enables developers to conduct pre-development activities for up to three years prior to the official start of the contract term.
	Energy Virtual One-Stop Shop	Streamlines permitting and regulatory approvals for power generation, transmission, and distribution projects.
	Certificate of Energy Project of National Significance	Expedites processing and approval of energy projects critical to national energy security and economic growth.
3. Power offtake and transmission constraints	Renewable Portfolio Standards	Mandates that all power distributors source a minimum and annually increasing share of electricity from RE sources.
	Smart and Green Grid Plan (Status: ongoing finalization)	Enhance grid reliability and RE integration through advanced transmission and smart grid technologies.
4. Investment financing	Green Energy Auction Program	A competitive bidding mechanism aims to accelerate the development of RE. In February 2025, a total of 30.887 MW of geothermal capacity was awarded at rates ranging from ₱5.1092 to ₱7.6441 per kWh, or USD 0.0892 to 0.1334/kWh, based on the foreign exchange rate of USD 1 to PHP 57.297 as of September 03, 2025 (Bangko Sentral ng Pilipinas (BSP), 2025), with delivery scheduled between 2025 and 2027.

Among these challenges, investment financing remains the most critical bottleneck as developing geothermal projects is capital-intensive and risky. Financiers often demand a significant premium and private equity investors typically expect relatively high returns on their invested capital, commonly in the range of 20% to 30% per year (Gehringer, M. & Loksha, V., 2012). To address this, a tariff that makes the project bankable and ensures adequate returns on investment, while accounting for risk, could be a key driver for investors to develop greenfield prospects.

This paper aims to determine the tariff threshold necessary to achieve financial viability and bankability for developing a 25 MW power plant in a greenfield geothermal prospect in the Philippines. Using data from the DOE, international publications, and other relevant literature, a project finance–based approach is employed to evaluate key financial indicators under varying scenarios of interest rates, total investment costs, capacity factors, O&M expenses, resource depth, and well productivity. The findings of this study aim to guide future policies and pricing mechanisms that will attract private investment and support the country's long-term geothermal development goals.

2 PROJECT DEVELOPMENT PARAMETERS AND COST ASSUMPTIONS

According to IRENA (2024), from 2010 to 2023, the total installation cost ranged between 2,000 to 6,000 USD/kW. Building on this global benchmark, this section presents the parameters and cost assumptions used to develop a hypothetical 25 MW power plant on a greenfield geothermal prospect. The objective is to establish cost estimates that reflect the Philippine setting by referencing data from the DOE, international studies, and other relevant literature.

2.1 Exploration and Preliminary Development Activities

This study adopts the DOE's (2024b) estimate of the minimum financial commitment necessary during the early stages of geothermal project development, excluding appraisal drilling, which is roughly USD 2.4 million. This sum includes activities such as securing permits and licenses, conducting geoscientific investigations, and

drilling slimholes. The cost of appraisal drilling is excluded from this component and is instead addressed in the succeeding section to provide a more realistic representation of the total drilling expenditure and the risks associated with drilling success rates.

2.2 Drilling

Drilling is one of the most capital-intensive components of geothermal development, accounting for 34% to 51% of total investment costs (Gehringer et al., 2012; Purwanto et al., 2021). According to Purwanto et al. (2024), drilling prices vary by country, ranging from 752 to 3,600 USD/meter. Drilling costs in the Philippines are considerably higher, ranging from 2,286 to 3,786 USD/meter (ADB, 2024), with depths typically between 1,000 to 3,400 meters (DOE, 2025c).

Beyond cost, drilling also carries significant risks. According to the International Finance Corporation (IFC) (2013), the average success rates are approximately 59% during the exploration phase, 74% during the development phase, and 83% once the field becomes operational.

For this study, drilling cost and well depth are assumed to be USD 3,100/meter and 2,500 meters, respectively. In addition, a conservative success rate of 65% is applied for both the exploration and development phases, while 75% is assumed for make-up wells during field operation. It is also assumed that the unsuccessful or non-producing wells could be used for reinjection. In a real scenario, this is not always possible as some wells may not be useful for either production or reinjection. These assumptions are conservative, as the cost and depth values chosen are at the higher end of the reported ranges, while the success rates are lower than those cited by IFC. This provides a conservative but realistic foundation for the financial model, reflecting the uncertainties inherent in greenfield geothermal development.

2.3 Surface installation

Surface installation cost, as defined in this study, refers to the total expenses incurred in constructing the power plant, steam-gathering system, transmission line, and other related surface facilities. Estimating this cost is difficult because it varies greatly even among geothermal facilities of comparable capacity. Variations occur because of differences in resource characteristics, site-specific design requirements, and current market conditions. In some cases, plants are also designed with enhanced structural resilience to withstand severe weather events, further affecting total costs. To estimate the surface installation cost, this study reviewed programmed costs from recent geothermal capacity additions in the Philippines (DOE, 2025d) as well as data and references available in the published literature (Cross, J. et al., 2009; Stefansson, V., 2012; IRENA, 2015). The total cost was then adjusted using the Consumer Price Index (US Inflation Calculator, 2025) to account for inflation. However, due to the confidentiality of some project cost data, this study only presents the derived trendline from the available data, as shown in Figure 1.

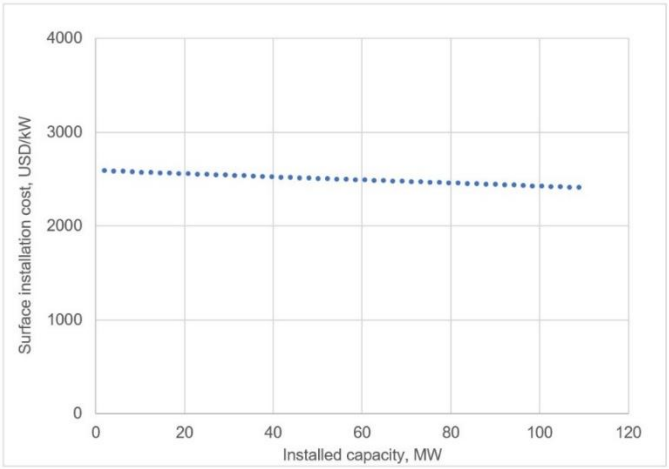


Figure 1 Surface installation cost

The collected data for surface installation costs varies widely, ranging from 1,600 to 5,200 USD/kW, with a general trend of decreasing cost as plant capacity increases. The dataset also does not show a consistent relationship between cost and technology type; for instance, a binary plant reported a surface installation cost as high as USD 5,200/kW, while another binary plant reported a cost less than USD 2,000/kW. Despite this

variability, an exponential trend line still provides a reasonable fit for the relationship between surface installation cost (C_s) and installed capacity (P), expressed by the following equation:

$$C_s = 2600e^{-0.0007(P)} \quad (1)$$

2.4 Operations and maintenance (O&M)

From 2022 to 2024, the recorded O&M costs in the Philippines varied from 13.68 to 254.76 USD/kW, with an average cost of USD 84.34/kW per year (DOE, 2025d). It was observed that facilities with higher costs are currently implementing improvements to their existing facilities, while those with lower costs only encompass the routine O&M requirements of the power plant, steamfield, and transmission facilities. On the other hand, according to IRENA (2025), the O&M cost assumed for projects commissioned in 2024 was USD 125/kW. This cost assumption is higher than the average O&M cost in the Philippines, because it includes two sets of wells for make-up and reinjection to sustain performance over the 25-year life of the project.

For this study, to capture the risk associated with drilling and its impact in the event of unsuccessful drilling, the O&M cost will be separated into the cost for make-up drilling. The annual O&M cost of USD 84.34/kW, based on the average annual O&M cost in the Philippines, is kept as the baseline. While this value may appear high if the O&M cost is limited to routine power plant and steamfield operations, it is intentionally maintained to account for other expenses not explicitly included in this study, such as community and social development programs, government share payments, regulatory compliance, and various site-specific operating requirements.

2.5 Supplementary assumptions for project development and cost parameters

In addition to the cost components discussed in the preceding sections, the following parameters are assumed in constructing the model for the hypothetical 25 MW power plant in a greenfield geothermal prospect:

a. Each successful production well is assumed to have a wellhead potential of 5 MWe.
b. The average decline rate of wellhead potential in the Philippines is approximately 5% per year; this same rate is adopted in this study.
c. To determine the total number of wells to be drilled prior to power plant operation, the combined capacity of successful wells must reach at least 120% of the target installed capacity, taking into account a 65% drilling success rate for the exploration and development phase. This buffer ensures that potential declines in reservoir performance over time can be accommodated without compromising generation output.
d. To simplify the projection of steam supply capacity, it is assumed that make-up drilling will occur only when the available steam capacity drops below 26 MWe. This threshold optimizes resource utilization by preventing premature drilling that could otherwise lead to waste and unnecessary expenditures.
e. The success of make-up well drilling is determined probabilistically using a random number generation method in Excel. If the number generated is lower than the assumed success rate, which in this study is 75%, the well is deemed successful; otherwise, it is considered a failed well. In cases of failed drilling, the subsequent drilling activity is assumed to occur in the following year. Although various simulation methods can be employed for this purpose, this method is chosen for its simplicity and to maintain the straightforward integration of the resource and financial models.
f. According to IRENA (2025), depending on the technology, the capacity factor of flash-type plants is 87%, while the average for single flash/binary plants was 96%. In this study, a conservative capacity factor of 85% is used to account for station use, grid losses, and potential outages during plant operation.
g. Regular preventive maintenance schedules (PMS) are essential to maintain optimal plant performance. To allow for these planned maintenance activities, an annual availability factor of 92% is assumed for the power plant.
h. Although the service contract granted to geothermal developers typically covers a 50-year term (DOE, 2024b), this study limits the operating life of the power plant to 30 years. This assumption reflects the time needed for the exploration and construction of power facilities, as well as the likelihood of technical obsolescence and efficiency decline beyond this period, which could warrant major rehabilitation.

3 FINANCIAL MODELLING

This section outlines the methodological framework employed to assess the financial viability and bankability of a hypothetical 25 MW power plant in a greenfield geothermal prospect. Building on the project development and cost parameters presented in the previous section, the model is designed to estimate the tariff required to make the project financially viable and bankable. To assess financial viability and bankability, the model calculates

key financial indicators, including net present value (NPV), equity internal rate of return (IRR), and debt-service coverage ratio (DSCR). Furthermore, this section outlines the sensitivity analyses conducted to examine the effects of variations in key parameters on the project's financial performance.

3.1 Financial viability evaluation

The NPV and Equity IRR are used to evaluate the financial viability of the hypothetical 25 MW power plant in a greenfield geothermal prospect. By comparing the current value of future cash inflows to its cost, the NPV measures whether the project investment will be profitable. A positive NPV implies that the project is economically viable, while a negative NPV suggests otherwise (Fernando, J., 2025a). Meanwhile, the Equity IRR measures the rate of return earned by investors after accounting for the effects of project financing or leverage (Wall Street Prep, Inc., 2024). In general, a higher Equity IRR indicates a more financially attractive and rewarding investment.

3.2 Bankability evaluation

The DSCR is employed to assess the bankability of a hypothetical 25 MW power plant in a geothermal power prospect. It measures the project's capacity to use its available cash flow to meet its debt obligations (Fernando, J., 2025b). A DSCR greater than 1.0 indicates that the project's operating income is adequate to cover its debt-service requirements, while a ratio below 1.0 suggests potential repayment difficulties. According to the ADB (2003), internally generated cash is expected to be 1.2 to 1.5 times the debt service obligations, ensuring liquidity and solvency. Accordingly, this report adopts 1.2 as the minimum DSCR threshold for evaluating the project's bankability.

3.3 Tariff determination

The tariff is determined using the financial model developed in this study, wherein the Goal Seek function in Microsoft Excel is employed to adjust the tariff until the DSCR reaches the target value of 1.2. This method ensures that the computed tariff meets the minimum debt-servicing requirement.

3.4 Sensitivity analysis

To evaluate the robustness of the financial model, two types of sensitivity analyses were performed: bankability and financial sensitivity analysis. The bankability sensitivity analysis identifies the tariff required to maintain a minimum DSCR of 1.2 under varying conditions of key parameters. In contrast, the financial sensitivity analysis assesses how variations in these same parameters affect the project's financial performance, measured in terms of NPV and Equity IRR, while holding the modelled tariff constant.

The key parameters examined include the interest rate, total investment cost, capacity factor, O&M cost, resource depth, and average well productivity. Each parameter was independently varied above and below its base-case value to simulate both favorable and adverse project conditions. All parameters, except for average well productivity, were analyzed using the same simulated resource model. For average well productivity, a separate resource simulation was developed to capture its direct impact on reservoir performance and financial outcomes (see Annex A for the simulated geothermal resource under varying wellhead productivity).

3.5 Supplementary assumptions for financial modelling

The financial model incorporates the following supplementary assumptions to provide a realistic basis for evaluating the 25 MW power plant in a greenfield geothermal prospect:

a. The project is assumed to be financed through a mix of 30% equity and 70% debt.
b. According to Quinlivan, P. et al. (2015), bilateral or multilateral international development banks typically offer interest rates ranging from 4% to 8%. For this study, a conservative interest rate of 7% per annum is assumed, with a repayment period of 20 years.
c. In accordance with the fiscal incentives provided under Republic Act (RA) No. 9513 or the Renewable Energy Act of 2008, the hypothetical greenfield project is assumed to benefit from a seven-year Income Tax Holiday (ITH). Upon expiry of the ITH, a corporate income tax rate of 10% is applied.
d. A zero percent Value-Added Tax (VAT) rate is applied to electricity generated, also pursuant to RA No. 9513.
e. Other expenses, such as community and social development programs, government share payments, regulatory compliance, and various site-specific operating requirements, as mentioned in Section 2.4, shall be covered by the annual O&M expenses.

f. It is further assumed that the project will not be subjected to major natural disasters, catastrophic events, or other extraordinary circumstances that could materially affect its operation or financial performance.

4 RESULTS AND DISCUSSION

Following the model setup from the previous section, the estimated total investment cost for the hypothetical 25 MW power plant in a greenfield geothermal prospect is USD 143.8 million, equivalent to USD 5,751/kW. This estimate falls within the higher end of the range reported by IRENA (2024), which places global geothermal installation costs between 2,000 and 6,000 USD/kW. The relatively high figure reflects the conservative assumptions used in this study, particularly the elevated drilling and surface installation costs, as well as the moderate success rate typical of a greenfield projects.

Drilling activities constitute the largest expenditure, accounting for approximately 53.9% of total investment. Surface installation costs, which include the power plant, steamfield facilities, transmission, and other surface installations, account for approximately 44.4% of total capital. The remaining 1.7% covers exploration and preliminary development activities. This cost distribution is consistent with geothermal development in Indonesia (Purwanto et al., 2021), supporting the validity and realism of the cost assumptions adopted in this study.

To establish the foundation for the financial model, the resource simulation incorporates the natural decline in wellhead potential and the schedule of make-up drilling. As illustrated in Figure 2, the total available capacity declines by 5% annually, prompting the need for make-up well drilling to sustain production. Each successful drilling event (represented by the green dashed line) contributes an additional 5 MWe to the remaining capacity, while an unsuccessful attempt (represented by the red dashed line) triggers another drilling activity in the following year. Based on the simulated resource, make-up well drilling typically occurs every three to four years to sustain optimal generation output throughout the 30-year project life.

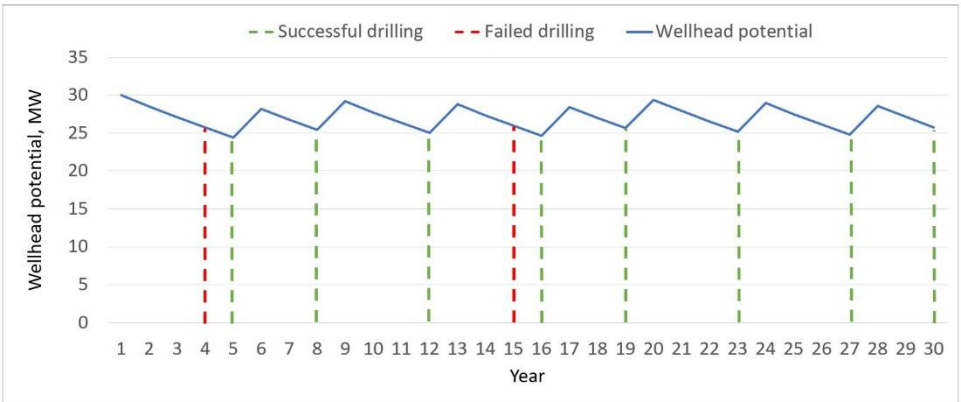


Figure 2 Simulated geothermal resource

Using the simulated geothermal resource and the cost assumptions, the financial model derived key financial indicators describing the project's economic performance. The results indicate that, at a modelled tariff of USD 0.1354/kWh, the project achieves an NPV of USD 75.16 million, an Equity IRR of 18.92%, and a LCOE of USD 0.0804/kWh, while maintaining a DSCR of 1.2 to ensure the bankability of the project. Notably, the modelled tariff is slightly higher than the awarded tariff range of 0.0892 to 0.1334 USD/kWh under the Green Energy Auction Program.

These results indicate that the project is financially viable and bankable within the assumed parameters, with sufficient cash flow to meet debt obligations while maintaining a modest return to equity holders. To better interpret these findings, Figure 3 presents the simulated annual cash flow distribution over the 30-year project life. The figure provides insight into the project's financial resilience and its capacity to sustain operations under the assumed tariff scenario.

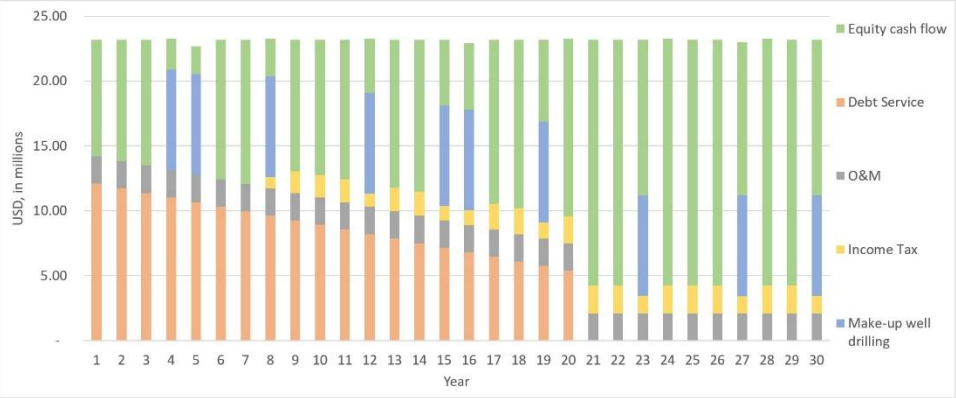


Figure 3 Annual cash flow distribution

The Bankability Sensitivity Analysis evaluates how variations in key parameters influence the tariff required to maintain a project's bankability, defined by a minimum DSCR of 1.2. As illustrated in Figure 4, the model is most sensitive to changes in the capacity factor. A reduction in capacity factor directly lowers energy generation and project revenues, thereby necessitating an increase in the tariff to sustain bankability. Resource depth and total investment cost follow as the next most influential parameters. Resource depth exerts a stronger effect, as it impacts both total investment and make-up well drilling costs, whereas total investment cost only influences the project's overnight capital expenditure. Lastly, changes in interest rate, O&M cost, and well productivity have minor effects on the required tariff. It is noteworthy that well productivity demonstrates an asymmetric influence, as changes in this parameter also alter the simulated reservoir model.

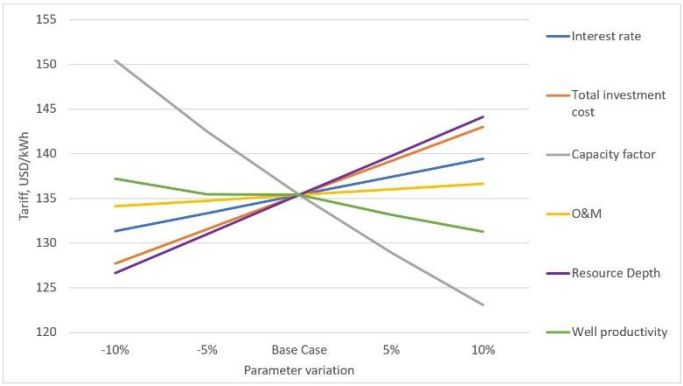


Figure 4 Bankability sensitivity analysis

To complement the Bankability Sensitivity Analysis, a Financial Sensitivity Analysis was conducted to evaluate the project's viability in terms of NPV and Equity IRR. As shown in Figure 5, both indicators are most sensitive to variations in the capacity factor, where higher generation significantly enhances returns, while reductions sharply reduce profitability. The interest rate and total investment cost exhibit comparable effects on NPV, though their influence on equity IRR diverges: changes in interest rate have a moderate effect, while variations in total investment cost generate significant changes in equity profitability. Variations in resource depth and well productivity also impact financial outcomes, but their influence is less pronounced than that of the aforementioned parameters. Lastly, O&M cost variations have minimal effect on both indicators, suggesting that the project is relatively resilient to changes in operating expenses.

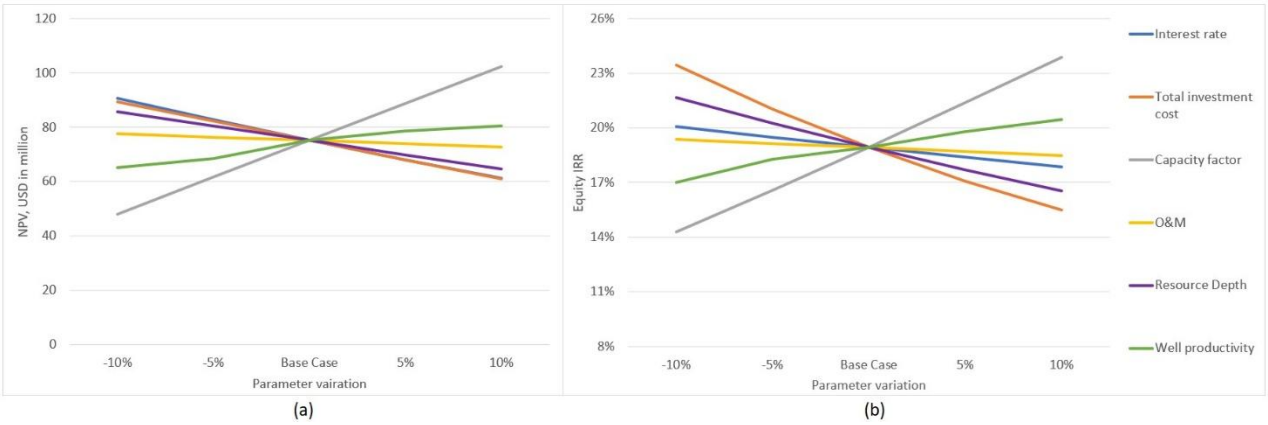


Figure 5 Financial sensitivity analysis - (a) NPV and (b) Equity IRR

5 CONCLUSION AND RECOMMENDATION

The study highlights the importance of tariff design in ensuring the bankability and financial viability of geothermal power projects in the Philippines. By combining project finance modelling and sensitivity analyses, the study determines how changes in key parameters, particularly the capacity factor, total investment cost, and resource depth, affect both the tariff required to achieve bankability and financial viability. Based on the analyses and findings, the following conclusions and recommendations were derived:

- The modelled hypothetical 25 MW power plant in a greenfield geothermal prospect for the Philippines setting is estimated to entail a total development cost of approximately 5,751 USD/kW, which lies toward the upper end of the IRENA (2024) global cost range of 2,000–6,000 USD/kW.
- To ensure both bankability and financial viability, a tariff of 0.1354 USD/kWh is required. Under this scenario, the project attains a NPV of USD 75.16 million, an Equity IRR of 18.92%, and a LCOE of USD 0.0804/kWh, while maintaining a DSCR of 1.2.
- Among the parameters tested, the capacity factor exerts the strongest influence on both bankability and financial viability, underscoring the importance of achieving high plant availability and resource productivity. This is followed by total investment cost and resource depth.
- The project finance model developed in this study can serve as a decision-support tool for policymakers to determine appropriate tariff levels under competitive mechanisms such as the Green Energy Auction Program or the Feed-in Tariff framework, ensuring realistic, bankable, and financially viable for developing geothermal greenfield development.
- Beyond tariff estimation, the methodology provides a replicable framework for evaluating project-level financial resilience under uncertainty, offering insights that could guide long-term strategies for geothermal expansion and financing in emerging markets.

REFERENCES

ADB: Special Evaluation Study of Cost Recovery in the Power, (2003). Retrieved October 28, 2025, from https://www.adb.org/sites/default/files/evaluation-document/35457/files/ses-power-sector_6.pdf

ADB: Roadmap to Derisking Geothermal in the Philippines (Regional Technical Assistance Completion, Report No. 55140-001), (2024).

Andal, J. M.: Power plant and Thermoeconomics Modelling of Low- to Intermediate- Temperature Geothermal Resource in Montelago, Philippines, *United Nations University - Geothermal Training Program*, **no. 9**, (2019), 83–114

BSP: Reference Exchange Rate Bulletin, (2025). Retrieved September 04, 2025, from https://www.bsp.gov.ph/sitepages/statistics/exchangerate.aspx

Cross, J, & Freeman, J: 2008 Geothermal Technologies Market Report, (2009). https://doi.org/10.2172/979824

DOE: Philippine Energy Plan 2023-2050, (2024a). Retrieved October 28, 2025, from https://legacy.doe.gov.ph/pep/philippine-energy-plan-2023-2050-0

DOE: Department Circular No. DC2024-06-0018: Revised Omnibus Guidelines Governing the Award and Administration of Renewable Energy Contracts and the Registration of Renewable Energy Developers,

(2024b). Retrieved October 28, 2025, from https://legacy.doe.gov.ph/sites/default/files/pdf/issuances/dc2024-06-0018.pdf

DOE: 2024 Power Statistics, (2025a). Retrieved October 28, 2025, from https://legacy.doe.gov.ph/sites/default/files/pdf/energy_statistics/02_Summary.pdf

DOE: Department of Energy Philippines, (2025b). Retrieved October 30, 2025, from https://doe.gov.ph/

DOE: Geothermal Well Inventory. Department of Energy, Taguig, Philippines, unpublished internal report, (2025c).

DOE: Geothermal Total Investment Cost From 2009-2025. Department of Energy, Taguig, Philippines, unpublished internal report, (2025d).

Fernando, J.: Net Present Value (NPV): What It Means and Steps to Calculate It, Investopedia, (2025a). Retrieved October 30, 2025, from https://www.investopedia.com/terms/n/npv.asp

Fernando, J.: Debt-service coverage ratio: how to use and calculate it, Investopedia, (2025b). Retrieved October 30, 2025, from https://www.investopedia.com/terms/n/npv.asp

Gehringer, M., & Loksha, V.: Geothermal handbook: Planning and Financing Power Generation, the World Bank Group, Energy Sector Management Assistance Program (ESMAP), Washington DC, USA, (2012), 164 pp.

IRENA: Renewable Power Generation Costs in 2014, IRENA, Abu Dhabi, United Arab Emirates, (2015). http://www.irena.org/DocumentDownloads/Publications/IRENA_RE_Power_ Costs_2014_report.pdf.

IRENA: Renewable Power Generation Costs in 2024, IRENA, Abu Dhabi, United Arab Emirates, (2025). http://www.irena.org/DocumentDownloads/Publications/IRENA_RE_Power_ Costs_2014_report.pdf.

Purwanto, E. H., Surwarno, E., Hakama, C., Pratama, A. R., & Herdiyanto, B.: An Updated Statistic Evaluation of Drilling Performance, Drilling Cost and Well Capacity of Geothermal Fields in Indonesia. *Proceedings,* World Geothermal Congress 2020+1, Reykjavik, Iceland, (2021).

Quinlivan, P., Batten, A., Wibowo, M., Hinchliffe, S., Rahayu, D., Doria, I., Yahmadi, A., & Tondang, H. Y. T.: Assessing Geothermal Tariffs in the face of uncertainty, a probabilistic approach, *Proceedings*, World Geothermal Congress 2015, Melbourne, Australia (2015).

Stefansson, V.: Investment cost for geothermal power plants, *Geothermics*, **31**, (2002), 263-272.

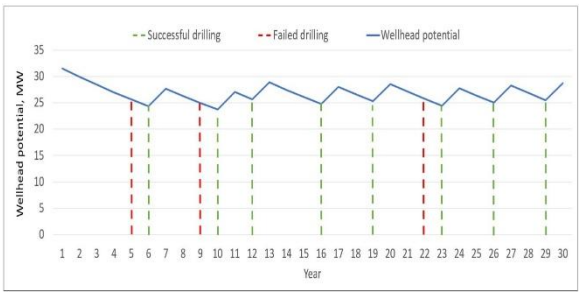
US Inflation Calculator: Consumer Price Index Data from 1913 to 2025, (2025). Retrieved October 01, 2025, from https://www.usinflationcalculator.com/inflation/consumer-price-index-and-annual-percent-changes-from-1913-to-2008/

Wall Street Prep, Inc.: Levered IRR. Wall Street Prep, Inc., (2024). Retrieved October 30, 2025, from https://www.wallstreetprep.com/knowledge/levered-irr/

ANNEX A: Resource simulation for varying wellhead productivitiy



1. Simulated geothermal resource (Base scenario: WHP = 5 MWe)



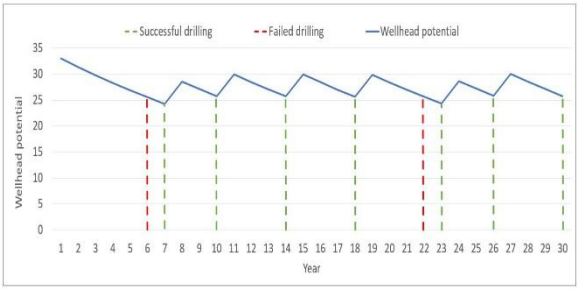
2. Simulated geothermal resource (WHP = 4.5 MWe)



3. Simulated geothermal resource (WHP = 4.75 MWe)



4. Simulated geothermal resource (WHP = 5.25 MWe)



5. Simulated geothermal resource (WHP = 5.5 MWe)