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Cost Recovery Frameworks for Geothermal Projects: Insights from Oil and Gas and Their Relevance to PLN's Geothermal Operations in Indonesia

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Abstract. Some of PLN's Geothermal Working Area (GWA) has suboptimal resource quality, which leads to high exploration costs and longer development times that hinder national geothermal targets. To address this, PT Perusahaan Listrik Negara (Persero) (PLN) has established a strategic partnership model called the Geothermal Exploration & Energy Conversion Agreement (GEECA) to improve efficiency and share exploration risks with partners, including cost recovery schemes similar to those in oil and gas. The development processes for oil, gas, and geothermal projects are similar: identifying reserves, exploration drilling, facility development, production, and site closure. The risks associated with geothermal, oil, and gas projects share similarities. The cost recovery scheme and GEECA include a mechanism for reimbursing exploration costs to partners or contractors. While they share fundamental concepts, the reimbursement methods differ significantly. In the cost recovery system, reimbursement occurs from production income before profits are shared between the government and the contractor. In contrast, GEECA employs a more definitive approach, ensuring that PLN will reimburse all exploration costs within two years after the power plant starts commercial operations. In Indonesia's geothermal development, especially with PLN's GWA, GEECA can enhance the appeal of partnerships. For other GWAs, PLN should consider enriching the data to reduce uncertainty and attract more partners.

Keywords: *PLN, GWA, GEECA, cost recovery, oil and gas, geothermal.*

1 Introduction

Electricity demand is vital in everyday life. PT Perusahaan Listrik Negara (Persero) (PLN), the only state-owned company overseeing Indonesia's electricity system, generates energy from various sources, manages transmission networks, and distributes electricity across urban and remote areas. As the sole operator in the national electricity sector, PLN ensures the supply's availability, reliability, and sustainability.

PLN prioritizes Environmental, Social, and Governance (ESG) matters for sustainability, aiming for Net Zero Emissions (NZE) by 2060. Its roadmap targets

69% power production from renewables, 15% from gas, 8% from coal and gas plants with carbon capture, and 7% from new energy sources (PLN, 2022) [1]. The government has assigned PLN eight Geothermal Working Area (GWA), with two statuses currently outlined (PLN, 2024) [2].

a. Geothermal Working Areas—Exploration: These GWAs include fields still under exploration, such as Kepahiang, Tangkuban Perahu, Ungaran, Atadei, Tulehu, and Songa Wayaua.

b. Geothermal Working Areas – Operational: These GWA, such as Ulumbu and Mataloko, are already operational.

Some of PLN's GWA have suboptimal resource quality, leading to high exploration costs and longer development times, hindering national geothermal targets. Challenges also stem from the differing characteristics of Indonesia's western and eastern regions. The West has a higher energy demand and various alternative sources like coal and natural gas, while the East has a lower demand and relies on diesel plants. The electricity price policy significantly influences the attractiveness of geothermal projects. The price set by Presidential Regulation No. 112/2022 often does not reflect actual exploration and development costs [3]. To address this, PLN has created a strategic partnership model called the Geothermal Exploration & Energy Conversion Agreement (GEECA) to improve efficiency and share exploration risks with partners, including cost recovery schemes similar to oil and gas. GEECA provides advantages for geothermal development.

2 Cost Recovery in the Oil and Gas Industry in Indonesia

2.1 Production Sharing Contracts (PSC)

Production Sharing Contract (PSC) involves cooperation between the government, which owns oil and gas resources, and contractors, who implement exploration, development, and production activities. Under this arrangement, the contractor covers all costs of the initial activities and recovers costs after production begins, with the remaining revenue (profit oil/gas) shared between the government and the contractor according to an agreed percentage. (Soesanto *et al.*, 2024) [4].

PSC is modeled after the Indonesian customary law on profit-sharing agreements outlined in Law No. 2 of 1960. It was initially utilized in the oil and gas industry through a partnership between the government, previously represented by Pertamina, and international firms. In executing the PSC, the government is represented by SKK Migas, which oversees operations to ensure adherence to regulations (Soesanto *et al*., 2024) [4].

2.2 Cost Recovery

Cost recovery is a mechanism in the PSC for the oil and gas sector that enables contracting companies to reclaim the costs they incur during exploration, development, and production of oil or gas. These costs are refunded from the production revenue before the profits are shared between the government and the contractor. (Soesanto *et al*., 2024) [4]. This program assures investors that they can recoup the significant expenses from the initial exploration stages, thus alleviating financial risks in the unpredictable oil and gas sector.

Cost recovery is founded on the idea that the government retains ownership of natural resources without incurring initial investment costs. This aligns with Article 33, paragraph 2 of the Constitution of 1945, which confirms the state's authority over strategic resources. Within this framework, cost recovery acts as an investment incentive. It plays a crucial role in promoting the sustainability of upstream oil and gas projects, fostering exploration, and ultimately aiding national economic growth through state revenue, job creation, and energy infrastructure development. (Soesanto *et al*., 2024) [4]. **Figure 1** shows the flow of cost recovery in Indonesia.

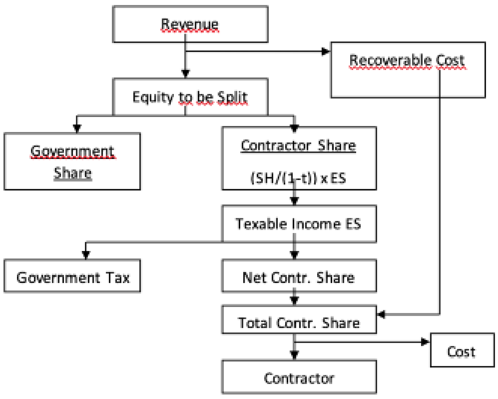

Figure 1 Flow Cost Recovery in PSC (Arifin and Hidayat, 2021) [5]

Cost recovery is crucial for national economic development. It ensures the sustainability of upstream oil and gas operations, mitigating financial risks and maintaining energy supply. It boosts state revenue through taxes, royalties, and profit sharing for infrastructure and public services. Additionally, it attracts foreign and domestic investment by offering financial incentives and a multiplier effect for other sectors. Funds from cost recovery support energy infrastructure development, enhancing national security. It also promotes economic growth in remote areas by improving local economies and contributing to corporate social responsibility programs. Ultimately, cost recovery is a strategic tool for national development, relying on transparent management and oversight (Soesanto *et al*., 2024) [4].

In Indonesia, cost recovery is governed by Government Regulation No. 79/2010, which addresses Refundable Operating Costs and Income Tax Treatment in Upstream Oil and Gas Business Activities, and was subsequently revised by Government Regulation No. 27 of 2017. (Lingard *et al*., 2020) [6]. PSC has evolved through seven generations, modifying aspects such as First Tranche Petroleum (FTP), cost recovery limits, tax distribution, investment credits, Domestic Market Obligation (DMO), depreciation, interest recovery, and well closure obligations. PSC agreement lasts for 30 years and encompasses a 10-year exploration phase and a 20-year production phase, with an option for extension. (Pereira *et al*., 2023) [7].

Unlike several other countries, Indonesia does not impose a maximum cap on cost recovery. However, Government Regulation No. 27/2017 imposes administrative and substantive limitations, stating that operational costs can only be claimed if activities align with the approved Work Program and Budget (WP&B) by the Head of Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi (SKK Migas). Costs must adhere to the "fair value" principle and follow good business practices. (Lingard *et al*., 2020) [6].

2.3 Historical Implementation in Indonesia

Cost recovery began in Indonesia in 1966 with a PSC between Pertamina and Independent Indonesian American Petroleum Company (IIAPCO) in the North West Java Offshore Block. Indonesia pioneered this system, where oil and gas contractors cover exploration and production costs upfront and receive refunds from successful production. This model offers an alternative to the traditional concession system that granted foreign companies total resource control. The cost recovery PSC allows the government to keep sovereignty over resources while attracting foreign investment fairly (Roach and Dunstan, 2018) [8]. Cost recovery implementation grew significantly before 2017 with the introduction of gross split contracts. While it attracted investment, the scheme faces criticism for alleged contractor cost inflation, lack of transparency, and the fiscal burden on the country during low oil prices (Soesanto *et al*., 2024) [4].

3 Overview of Geothermal Development in Indonesia

3.1 Geothermal regulatory framework

The Indonesian government recognized the importance of developing renewable energy to meet increasing energy demands and reduce reliance on fossil fuels. According to Bramantio *et al*. (2021) in references [9], [3], [10], and [11], some of the energy regulations that govern geothermal energy are as follows.

a. Act No. 21/2014 about Geothermal, provides a legal framework for geothermal development, encompassing environmental and governance aspects.

b. Presidential Regulation of the Republic of Indonesia No. 22/2017 regarding the Rencana Umum Energi Nasional (RUEN) establishes a target for increasing the capacity of Geothermal Power Plants (GPP).

c. Presidential Regulation of the Republic of Indonesia No. 112 of 2022 regarding Acceleration of Renewable Energy Development for Electricity Supply sets the ceiling price for purchasing electricity from GPP based on the plant's capacity and the project location. The price applies in two stages in years 1-10 and 11-30.

Azmi *et al*. (2024) in [12] identify three regulatory and governance challenges in geothermal projects. First, the selling price of new electricity is fixed after signing the Power Purchase Agreement (PPA), imposing high risks and exploration costs on developers until price certainty is achieved. The PPA negotiation can take 2–3 years, complicating financing and budgeting. Second, fulfilling Tingkat Komponen Dalam Negeri (TKDN) is challenging, as many local geothermal plant components are unavailable; the domestic industry's capacity meets only 24% of the 33% target. Third, inconsistent government incentives, like untimely tax incentives, hinder project sustainability. Enhanced support, such as UN exemptions, tax reductions, and forest use permit restorations, could bolster the geothermal industry's prospects.

3.2 Investment Challenges: Exploration Risk, Tariff Setting, Long Payback Period

The development process of a geothermal project involves various stages that cumulatively increase the investment cost, as described in **Figure 2** by the Energy Sector Management Assistance Program (ESMAP) [13]. Each stage involves initial surveys, exploration drilling, production development, and operations, all requiring substantial investment and high early-stage risk. The most significant risks arise during initial exploration due to resource capacity and quality uncertainties, including temperature, pressure, and fluid flow potential. A World Bank report indicates this uncertainty significantly hinders investment attraction, particularly from the private sector, due to the high risk of losses from insufficient resources for further development (ESMAP, 2016) [13]. According to Stringfellow & Dobson in Azmi *et al*. in [12], only about 50% of exploration wells are successful in Indonesia, increasing to 59% with more drilling. Surface surveys like geology, geochemistry, and geophysics yield indirect and limited data, complicating investment decisions. If reserves underperform, developers must drill more, straining financial viability. Setiawan in [14] noted that high upstream problems stem from insufficient backup data during auctions, leading investors to avoid high bids and complicating project financing. The significant initial exploration cost risks losses if projects fail. Moreover, 41.6% of the geothermal potential is in protected forest areas, hindered by forestry regulations treating it as mining. This risk decreases with successful drilling and testing, yielding more accurate resource data.

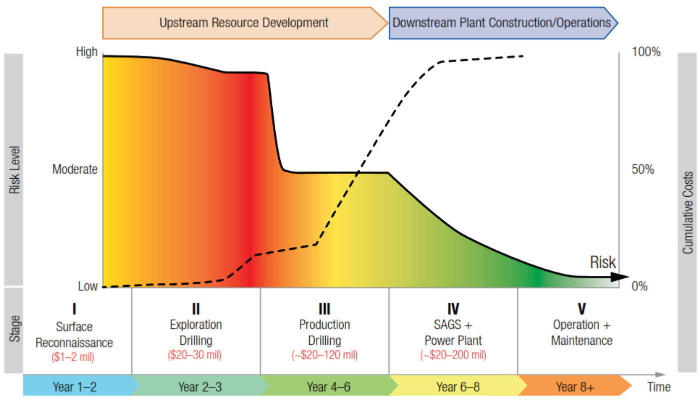

Figure 2 A Conceptual Representation of Risks and Costs during the Different Stages of a Geothermal Development (ESMAP, 2016)

The selling price of geothermal electricity has not attracted investors, especially before 2009, as it was not proportional to production costs. The auction price of GWA did not align with PLN's selling price. After 2009, the government set tariffs via Ministry Regulation Energi dan Sumber Daya Mineral (ESDM) No. 32/2009 and No. 2/2011 at a maximum of 9.7 cents/kWh, yet this was still seen as low, particularly in eastern Indonesia. Ministry Regulation ESDM No. 22/2012 introduced a Feed-in Tariff (FIT) scheme with fixed regional prices, but the policy was deemed unfair to PLN due to the absence of price negotiations. The geothermal market is a monopsony, with only one buyer (PLN), weakening developers' bargaining positions. Currently, prices are regulated by Presidential Regulation No. 112/2022, establishing ceiling prices based on plant capacity and project location, affecting pricing in two stages for years 1-10 and 11-30

(Setiawan, 2014) [14]. Geothermal investors seek commercial reserves, attractive energy prices, guaranteed payments, and certainty in long-term contracts. Project financing feasibility heavily depends on electricity prices, which must provide an Internal Rate of Return (IRR) equal to or greater than the Required Rate of Return (RRR). Factors like production period, generation capacity, investment costs, taxation, and electricity prices determine IRR. Given the high-risk nature of geothermal projects, investors typically set an RRR of at least 16%, adhering to the principle of "high risk, high return" for financial attractiveness (Azmi *et al*, 2024) [12].

Regarding ESMAP [13], risk mitigation mechanisms like cost-sharing drilling schemes and geothermal risk insurance, successfully implemented in various countries, are needed to overcome uncertainty. This strategy enables risk-sharing between the government and private developers, reducing the exploration risk burden and facilitating project development. Thus, integrated risk management is essential for the economic and technical sustainability of geothermal projects at all development stages.

3.3 Challenges of Geothermal Energy Development in the PLN side

From the PLN perspective, geothermal development presents numerous challenges, including the following [15].

a. High exploration risks and significant uncertainty below the surface.

b. Government policies and regulations impacting the development of geothermal projects, coupled with overlapping regulations.

c. Social issues arise between developers and local or regional governments in areas with high geothermal energy potential.

d. The risks associated with exploration, licensing, and social issues in geothermal development are notably high, impacting the financial feasibility of the project.

e. Demand in certain GWA locations is relatively low, limiting development capacity and affecting the economics of scale projects.

f. Global economic conditions lead to increased prices for goods and services related to drilling activities and the construction of plants for geothermal development. t.

4 Comparative Analysis: Oil & Gas vs. Geothermal Sector

4.1 Project Phases

Based on Santos *et al*., (2021) in [16], the phases in developing oil and gas projects can be divided into five main stages: discovery, appraisal, development, production, and abandonment. Each phase consists of several main things, which can be seen in the **Figure 3**.

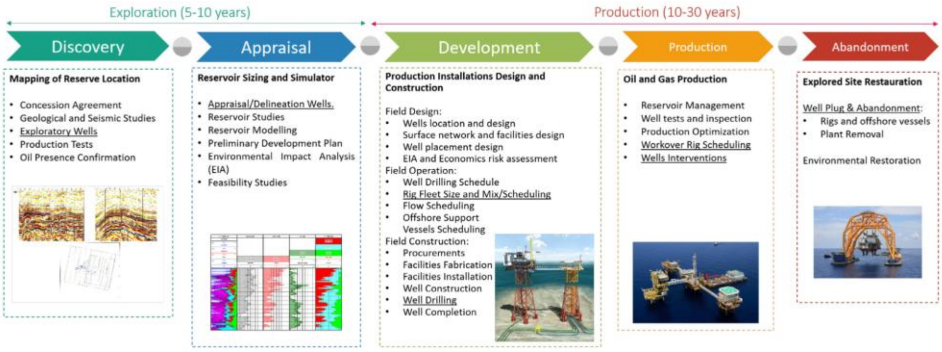

Figure 3 Exploration and Production of Oil and Gas Phase (Santos *et al*., 2021) [16]

As for the development of geothermal projects, there are several phases, namely the following **. The** identification stage results greatly influence whether to proceed to exploration or stop the project. A positive result allows the project to continue, while a negative result may lead to termination. This also applies to the exploration stage, where the results dictate funding for the exploitation stage. This tiered decision-making process extends to the Engineering, Procurement, Construction, and Commissioning (EPCC) and operations phases.

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Table 1 Geothermal Development Phase (Dewi *et al*., 2022) [17]

	Identification	Exploration	Exploitation	EPCC
Activities	Geoscientific survey, Geotechnical study, environmental study, temperature gradient well, conceptual model, resource estimation, pre-feasibility study	Exploration infrastructure construction, 2–3 wells drilling, well logging, well testing, refining conceptual model, determination of well productivity for production, design for development well, forecast of reservoir performance, project budget and revenue projection, ESIA Assessment,	Infrastructure construction, development drilling, well logging, well testing, update conceptual model, update reservoir model	Engineering, Procurement, Construction, and Commissioning
Duration Estimation	1 year	1–2 years	2–3 years	2–3 years

The development of oil and gas and geothermal projects follows a similar process: identifying reserves, exploration drilling, facility development, production, and site closure. Both involve geological surveys, environmental studies, reservoir modeling, and economic planning, requiring phased evaluations to minimize project failure risk.

4.2 Risk Profile

Based on Saptarani and Nainggolan in [18], the oil and gas industry is closely related to uncertainty and risk. As one of the non-renewable energy sources, its resources are invisible beneath the surface, increasing the uncertainty in its development. Activities in the oil and gas industry are divided into upstream and downstream. Here is the division in **Table 2**.

Table 2 Upstream and Downstream Activities in the Oil & Gas Industry (Suda *et al.*, 2015) [19]

Upstream Activities	Downstream Activities
Exploration	Refining (gas processing and transmission)
Conceptual Development	Gas distribution
Development	Retail
Production	Petrochemicals

The oil and gas industry faces key risks: economic, political, environmental, safety, and geological. These include low oil prices, unmet production targets, missing gas contracts, cost overruns, procurement delays, decreased global gas demand, rising costs, major accidents, complacency, higher Abandonment and Site Restoration (ASR) funding, environmental pollution, and drilling delays (Saptarini *et al.*, 2022) [18]. Suda *et al.* in [19] categorize risks into exploration, production, transport and terminals, pipelines, refining processes, and community impacts. Risks are present from exploration to production and distribution.

Based on **Figure 2** The risks associated with geothermal energy are categorized into five areas: initial surveys, exploratory drilling, production drilling, Engineering, Procurement, and Construction (EPC), and operation and maintenance. Similarly, the oil and gas industry faces risks throughout all stages, from exploration to production. Thus, it is evident that both the geothermal and oil and gas sectors encounter risks at each phase of development.

5 GEECA

The Public-Private Partnership (PPP) model is a collaborative strategy between the government and the private sector to accelerate energy project development, including geothermal energy. This scheme allocates responsibilities and risks according to each party's expertise. In geothermal projects, PPP addresses significant capital challenges and high exploration stage risks. PLN, Indonesia's sole electricity offtaker, has created an institutionalized Public-Private Partnership (iPPP) approach to attract private investment in geothermal projects in the GWA managed by PLN (Nusiaputra et al.) [20]. It shows in **Figure 4** dan **Figure 5**.

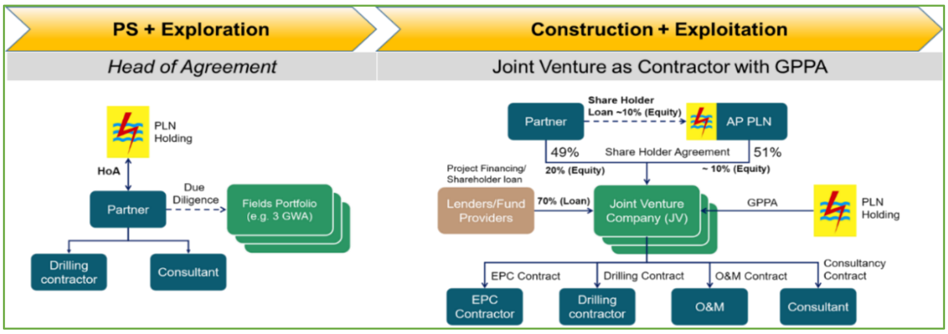

Figure 4 Geothermal iPPP Scheme (Nusiaputra, *et al.*) [20]

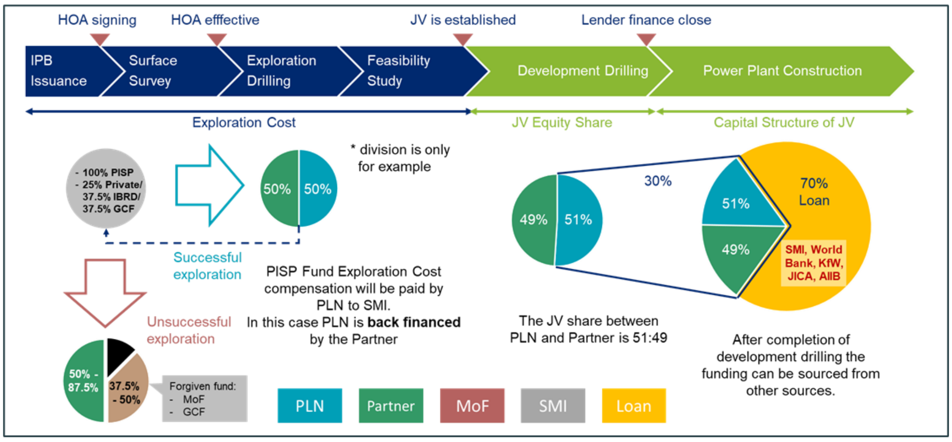

Figure 5 How exploration funds turn into paid-in capital in PLN geothermal iPPP (Nusiaputra, *et al.*) [20]

A key element of the iPPP scheme is sharing exploration risks, a significant hurdle for private investors. Early on, the government often covered these risks through funding mechanisms like the Geothermal Risk Mitigation Facility (GRMF), minimizing the risk of exploration failure for private partners. The government provides low-cost financing and policy stability to ensure project sustainability (Nyokabi *et al.*, 2023) [21].

Another advantage is the flexibility in financing and revenue sharing. After successful exploration, developing the power plant involves a joint venture between PLN and private partners, with share distribution reflecting each party's contributions. Typically, PLN retains majority shares for strategic control while private partners manage project efficiency, allowing for quicker completion than conventional models.

Additional government support, such as partial risk elimination and fiscal incentives, enhances the appeal of PPP schemes. Nusiaputra, *et al.*, in [20] state that this scheme accelerates GWA development and boosts financial viability in previously less economically viable areas. With transparent risk sharing and structured collaboration, the iPPP model promotes geothermal energy development in Indonesia.

However, challenges remain in adjusting regulations and aligning interests between the government and private partners. Flexible policies, responsibility transparency, and effective oversight are essential to overcome these. An integrated approach will help achieve the national geothermal capacity target, fostering sustainable energy development. In 2024, PLN will introduce the

GEECA, as a new cooperation concept for improved efficiency and shared exploration risk that shows on **Figure 6**.

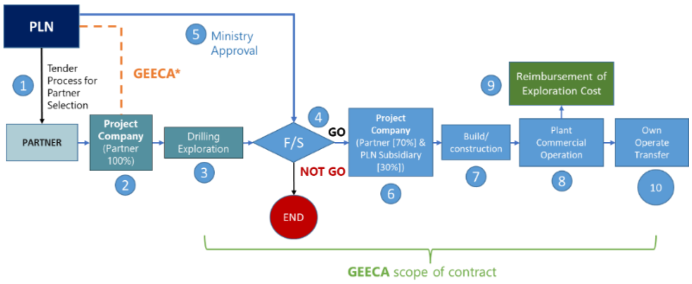

Figure 6 Geothermal Exploration & Energy Conversion Agreement (PLN, 2024) [22]

GEECA aims to reduce exploration risks and enhance efficiency in geothermal project management. Its main goal is to manage exploration risks through financially capable partners. The process starts with a tender to select a strategic partner responsible for the project's early stages. PLN chooses partners based on technical and financial criteria to form a Project Company with 100% partner ownership.

During the exploration stage, partners drill to assess the feasibility of geothermal resources and prepare a Feasibility Study (FS). Strategic decisions are made based on the FS. If the FS indicates an unfeasible project (Not Go), it will be terminated to prevent losses. If feasible (Go), the Project Company will be re-established with a new ownership structure: 70% partners and 30% by PLN subsidiaries like Indonesia Power.

After finalizing the ownership structure, approval from relevant ministries is required to proceed to construction. This phase involves building a geothermal power plant with essential equipment. Once construction is complete, the plant begins commercial operations, and partners' exploration costs will be reimbursed as per the agreement.

The scheme culminates in the Own, Operate, and Transfer (OOT) mechanism, where partners manage the plant, ensuring it meets performance standards. After their operational period, ownership is transferred to PLN or another designated party. This plan reduces exploration risks and promotes efficient, sustainable project management.

GEECA offers several advantages for geothermal energy development. Firstly, it shares risks and rewards between PLN and partners, with PLN managing licensing, land acquisition, and social issues, while partners take on drilling risks, minimizing drilling cost uncertainties. Secondly, it enhances expertise sharing, allowing upstream partners to collaborate with PLN's downstream expertise, improving overall project execution. Lastly, GEECA improves project economics; PLN eliminates drilling cost uncertainties while partners benefit from upfront payments, including drilling cost reimbursement, increasing investment value (IRR), and attracting more investors.

With this scheme, PLN addresses geothermal exploration challenges and contributes to the national energy transition. With a 23% renewable energy target by 2025, developing geothermal energy is essential for reducing greenhouse gas emissions and supporting Indonesia's energy sustainability.

Currently, PT Ormat Geothermal Indonesia (OGI) signed contracts for two GWA owned by PLN—Songa Wayaua (2x5 MW) in North Maluku and Atedai (2x5 MW) in East Nusa Tenggara—on March 7, 2025, under the GEECA scheme, marking Indonesia's first contract using this approach. Ormat's interest was driven by competitive electricity tariffs because it followed PLN's economic costs. PLN will prepare infrastructure for nine months while OGI will drill 3-4 wells at each site in 2026 (Loesb, 2025) [23].

6 Comparative Analysis: Cost Recovery vs GEECA

The cost recovery scheme and GEECA feature a mechanism for reimbursing exploration costs to partners or contractors. GEECA integrates this principle to enhance the appeal of its cooperative schemes. While they share fundamental concepts, the reimbursement methods differ significantly. In the cost recovery system, reimbursement occurs from production income before profits are shared between the government and the contractor. This implies that the reimbursement process will be delayed if a contractor has not produced any output during a given period. The Gross Split method is not utilized in the development of the geothermal business at PLN because this model lacks a mechanism for reimbursing exploration and production costs directly. Instead, it facilitates the direct distribution of gross production between the government and contractors without first reducing costs. As a result, GEECA's business model appears unattractive to potential partners. Conversely, GEECA employs a more definite approach, ensuring that PLN will reimburse all exploration costs within two years after the power plant commences commercial operations. This arrangement clarifies partners and minimizes financial risk, as it does not rely on production results in the project's early phases.

7 Conclusion

In Indonesia's geothermal development, particularly with PLN's GWA, GEECA can enhance the appeal of partnerships. Evidence of collaboration in two GWAs demonstrates that this initiative attracts geothermal developers. The lack of sales for other PLN-owned GWAs may not indicate a failure of the scheme, but rather a shortfall of available data, rendering them less appealing. Moving forward, PLN should consider enriching the data for these GWAs to decrease uncertainty and attract more partners.

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