Just Energy Transition Partnership Indonesia

Captive Power Study

Deep Dive into Indonesia’s Industrial Power Landscape and Green Energy Transition Opportunities

Thematic Report

December 2025

JETP INDONESIA

jetp-id.org

Foreword from Just Energy Transition Partnership (JETP) Secretariat

Indonesia continues to strengthen its national climate and energy agenda, with decarbonising the power sector remaining central to achieving national emission-reduction targets. Ensuring the success of this agenda requires extending decarbonisation efforts beyond the on-grid power sector to include captive power systems, while safeguarding Indonesia's trajectory toward high and sustainable economic growth.

At COP30 in Brazil, Indonesia underscored that meeting its emission-reduction targets will require scaling up renewable energy, strengthening grid reliability, and expanding market-based mechanisms. In this context, greening the captive power sector is no longer optional. Addressing emissions from this segment—which accounts for approximately a quarter of Indonesia's total installed electricity capacity and remains heavily reliant on coal—is essential to achieving meaningful emissions reductions. At the same time, transitioning the sector to clean energy is critical to safeguarding energy security for key industries and accelerating progress toward Indonesia's net-zero emissions target.

This thematic study on captive power is intended to support Indonesia in assessing the impact of captive power operations. By using a curated captive power database as foundation, this study provides a comprehensive assessment of the technical and policy challenges associated with transitioning captive power systems from fossil fuels to cleaner energy within the broader JETP framework. It outlines potential transition pathways, including an emissions-reduction roadmap, options for renewable energy integration, and policy reforms that must be implemented transparently and accountably.

The study forms part of the broader JETP analytical framework and complements key documents, including the CIPP 2023, the JETP Progress Report 2025, and thematic studies on carbon pricing, energy efficiency and electrification, and just transition. Policy recommendations across the JETP work programme are intentionally distributed among these thematic reports, each addressing a specific dimension of Indonesia's energy transition.

Looking ahead, the JETP Secretariat remains committed to supporting continued progress and the delivery of tangible outcomes under the partnership. The Secretariat extends its appreciation to partners, experts, and stakeholders whose constructive insights have strengthened this report and reinforced its recommendations. We look forward to continued collaboration in advancing the next phase of Indonesia's energy transition.

Paul Butarbutar

Head of JETP Secretariat

Disclaimer: This document forms part of the Indonesia Just Energy Transition Partnership (JETP) thematic reporting. It does not constitute a legally binding document. It is a strategy document that the Government of Indonesia may use as a basis for power sector planning and policymaking as part of the JETP process. For more information about JETP Indonesia, please refer to the 2023 Comprehensive Investment and Policy Plan (CIPP) and 2025 Progress Report. The CIPP is a document for the implementation of the Joint Statement agreed in November 2022.

Acknowledgement and Authorship

This Thematic Report was prepared by the JETP Indonesia Secretariat, mainly by the Technical Working Group (TWG). The JETP Indonesia TWG consists of the International Energy Agency (IEA), Institute for Essential Services Reform (IESR), Rocky Mountain Institute (RMI), Indonesia Denmark Energy Partnership Programme (INDODEPP), and World Bank. The Asian Development Bank (ADB) provided institutional support to the JETP Secretariat.

The JETP Secretariat gratefully acknowledges the support from Yayasan Visi Indonesia Raya Emisi Nol Bersih (ViriyaENB) and the EU–Indonesia Cooperation Facility (EUICF) for valuable support in enabling this study to commence.

The JETP Secretariat would like to extend special appreciation for close collaboration, feedback, and support to all counterparts including Coordinating Ministry for Economic Affairs, Coordinating Ministry for Infrastructure and Regional Development, Ministry of Energy and Mineral Resources, Ministry of Industry, and other counterparts in the Government of Indonesia; the IPG, led by Germany and Japan, comprises the governments of Canada, Denmark, the European Union, the Federal Republic of Germany, the French Republic, Norway, the Republic of Italy, and the United Kingdom of Great Britain and Northern Ireland; to the Glasgow Financial Alliance for Net Zero (GFANZ); to Indonesia Energy Transition (IET) Implementation Joint Office, PT Perusahaan Listrik Negara (Persero) (PLN), Private Sectors/Companies, Labor Unions, Civil Society Organizations, Academias, Think tanks, and other organizations.

Advisor:

Paul Butarbutar

Main Authors:

Abraham Octama Halim
Alexandra Hegarty
Andika Akbar Hermawan
Axel Priambodo
Budi Prayogo Sunariyanto
Harry Gembira
Michael Waldron
Morten Egestrand
Putu Indy Gardian
Selim Sardag
Sigfried Looho
Sodi Zakiy Muwafiq

Contributors:

Balada Amor
Desak Putu Adhityani Putri
Emi Fatma Widayani
Hasti Wiandita
Heeweon Hyun
Isaac Portugal
Luca Lo Rey
Ryo Yamasaki
Steve Brown

Supporting Unit:

Aditya Nugroho
Nicholas Francis Tjahja

Disclaimer: This document forms part of the Indonesia Just Energy Transition Partnership (JETP) thematic reporting. It does not constitute a legally binding document. It is a strategy document that the Government of Indonesia may use as a basis for power sector planning and policymaking as part of the JETP process. For more information about JETP Indonesia, please refer to the 2023 Comprehensive Investment and Policy Plan (CIPP) and 2025 Progress Report. The CIPP is a document for the implementation of the Joint Statement agreed in November 2022.

Table of Contents

List of Figures

List of Tables

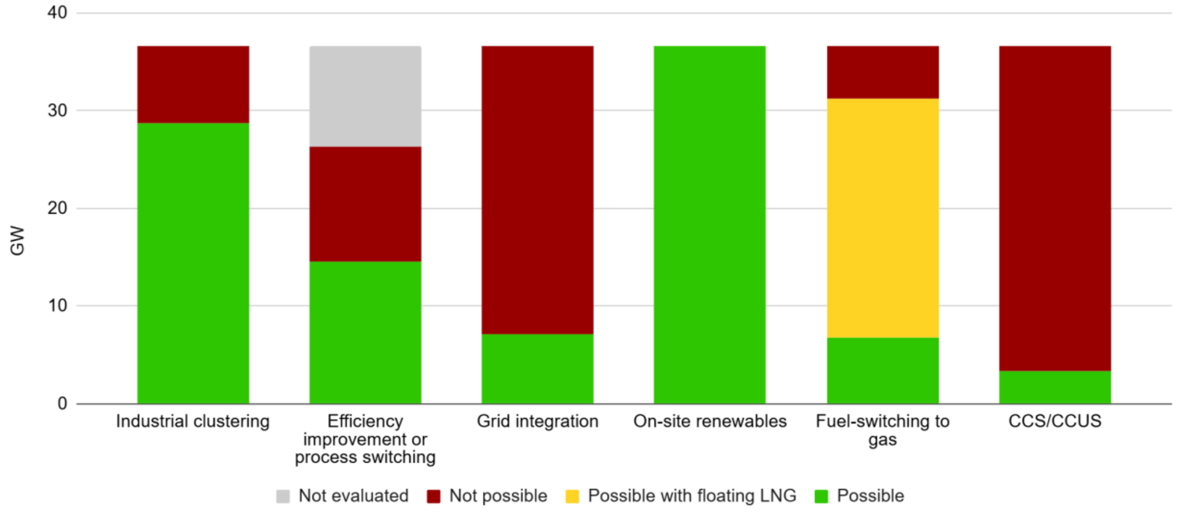
Executive Summary

Indonesia's rapid industrialisation over the past decade, particularly in energy-intensive sectors such as nickel processing, aluminum, steel, and pulp and paper, has brought about a substantial expansion of captive power generation. These on-site or dedicated power systems have become the backbone of industrial growth, ensuring reliable electricity for operations that require constant, high-quality supply. Much of this expansion, however, has relied on coal, resulting in rising greenhouse gas emissions, mounting regulatory pressures, and emerging concerns about long-term competitiveness within global markets that are increasingly demanding low-carbon materials. The Captive Power Study was undertaken to examine the scale of this challenge, identify realistic transition pathways, and understand the implications for Indonesia's JETP commitments, industrial development, and economic resilience.

The study begins by examining the role of captive power in Indonesia's industrial ecosystem. Captive power has enabled the rapid growth of mineral processing, especially nickel, where Indonesia now contributes more than half of global supply, and has supported national downstreaming objectives. Yet, the same coal-heavy trajectory now exposes industries to tightening domestic regulations, particularly those introduced under Presidential Regulation No. 112/2022, which prohibits new coal plants except under limited conditions and requires existing facilities to reduce emissions by 35 percent within ten years and for coal captive plants to cease operations by 2050. As global buyers, financiers, and regulators increasingly prioritise low-carbon supply chains, Indonesia's reliance on coal for industrial power is becoming a strategic liability.

Recognising the need for greater clarity around alternatives and transition opportunities, the study then comprehensively tracks Indonesia's captive power assets through the JETP Captive Power Database, which identified 25.9 GW of operating captive power in 2024, and 36.7 GW captive power in total, including plants under construction and in planning stages. This tracking shows that over three-quarters of captive power is currently based on coal.

The study then conducts a comprehensive technical screening of 173 captive power sites identified in the database across six clean energy and emissions reduction interventions. The results reveal a strong untapped potential for cleaner energy solutions. Across the sites assessed, renewable power opportunities are significant, mainly coming from solar PV, biomass and hydropower potential. Other options such as process efficiency improvements, grid integration, fuel switching to gas, and enhanced investment and operational optimisation through industrial clustering, further broaden the range of transition opportunities.



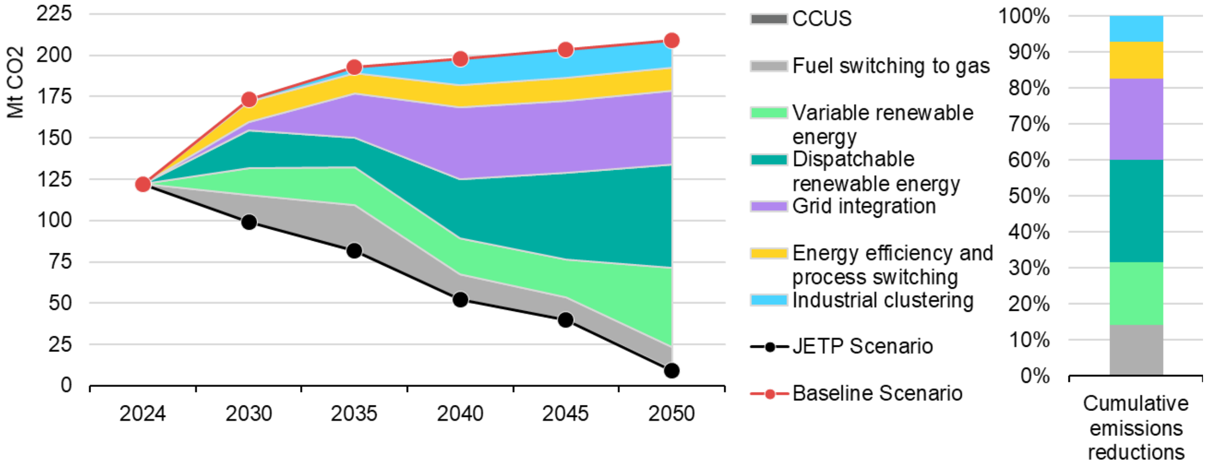
Result of Technical Screening for 173 Captive Sites: Captive Power Capacity by Intervention

At the same time, the study acknowledges the ground-level considerations that will shape real-world implementation. Industrial facilities often face land constraints for renewable deployment; some operations require firm, uninterrupted power that would require variable renewable sources to be hybridized with battery storage or other dispatchable power solutions; and many captive coal plants were not initially designed for flexible operations and operating at lower utilization rates that would facilitate renewables integration. These issues underscore that successful transition strategies must be customised for different industrial contexts rather than rely on a single, uniform solution.

Building on this technical foundation, the study develops the JETP Captive Scenario, an energy and emissions pathway that demonstrates how Indonesia's captive power sector and energy-intensive industrial facilities can transform to cleaner electricity generation mix in line with national climate commitments while maintaining reliability and supporting continued industrial activity. Using the Balmorel modelling tool, which integrates the technical assumptions, energy strategies and policy enhancements set out in the study, the scenario shows that a full and cost-effective transition away from captive coal power is achievable by 2050. The JETP Captive Scenario takes a differentiated approach according to the status of the captive coal power assets: for those already operating or under construction the pathway for power generation and emissions is developed in accordance with the transition provisions of Presidential Regulation No. 112/2022; for those at the planning stage, the pathway prioritizes renewable power and lower emissions alternatives to avoid new captive coal through Asset-Level Alternatives Analysis.

In the scenario results, coal-based captive generation, which stood at more than 100 terawatt-hours in 2024, gradually declines to zero as renewable generation, storage technologies, and grid integration solutions scale up, complemented by fuel-switching to gas in some cases. Demand-side measures, industrial clustering and energy efficiency, play a critical role in improving system efficiency, reducing the need for new supply and redundant capacity, and facilitating renewables integration. As a result, by 2030, renewable power is projected to comprise 34% of captive generation, from 9% in 2024, with this share rising to 55% by 2040 and over 80% by 2050. In total, adoption of such technical measures enables the JETP

Captive Scenario to achieve 75% lower carbon emissions in 2030 compared with a Baseline Scenario based on current capacity plans in the JETP Captive Power Database, with greater emissions reductions over time, and reach net zero emissions by 2050. While the JETP Captive Scenario results in somewhat higher electricity costs compared with the Baseline Scenario, scenario variant analysis demonstrates that more rapid cost declines and a greater role for cost-effective solar PV and flexibility measures can enhance the sustainability and affordability of captive power transitions, especially compared with a case where fossil fuel prices are low.



Projected Emissions Reductions, by Intervention, in the JETP Captive Power Scenario compared with the Baseline Scenario

To further understand the practical implications of this transition, the study then examines three representative industrial case studies: an off-grid RKEF nickel facility, an on-grid HPAL nickel plant, and a pulp and paper mill with cogeneration. Each case highlights different transition challenges and opportunities. For RKEF operations, which require highly stable power and are often located in remote industrial parks, the most promising pathway combines solar PV and hydropower resources with battery storage and more flexible operations of existing coal plants. For HPAL operations, lower electricity intensity and the presence of significant waste-heat recovery potential reduce the need for large storage systems, making renewable integration more cost-effective. In the pulp and paper sector, electrification measures, biomass co-firing, and solar PV integration offer substantial emissions reductions at reasonable cost. Across the three industries, the proposed pathways deliver emissions reductions ranging from roughly a quarter to nearly half of each facility’s baseline, while enhancing long-term cost stability and offering valuable commercial advantages. These potentially include greater access to international buyers seeking low-carbon materials, eligibility for premium markets, lower exposure to fossil fuel price volatility, and reputational benefits for companies adopting credible transition strategies.

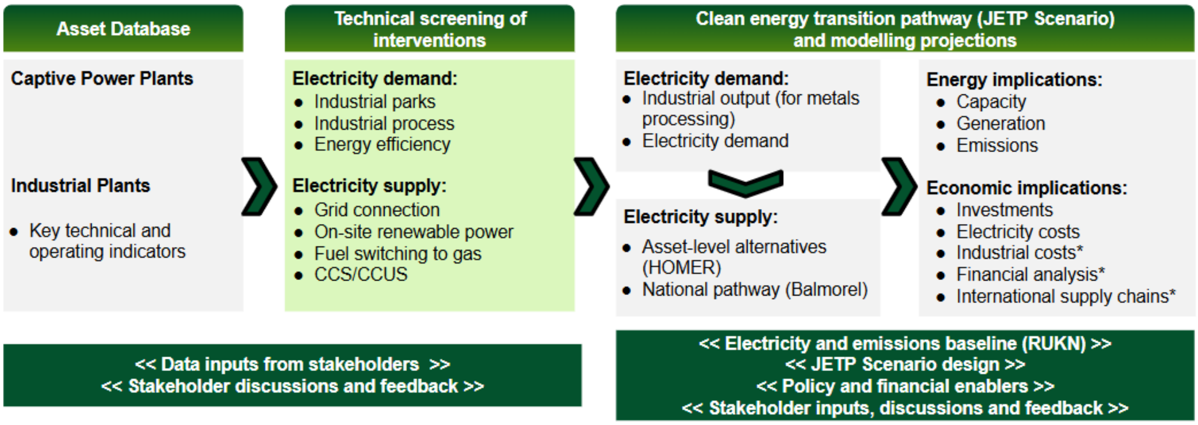
Further, the study also identifies several enabling conditions that must be strengthened to enable the results of the JETP Captive Scenario and support practical implementation. Clear, coordinated planning between industrial development agencies and the power sector is essential, including enhanced and harmonised planning, permitting, licensing, and grid access rules. Carbon pricing mechanisms, now advancing under Presidential Regulation No. 110/2025, will play an increasingly important role in aligning financial incentives with low-carbon investment decisions. Meanwhile, the financial system must evolve to support transition investments through instruments such as sovereign transition bonds, corporate transition finance linked to verifiable transition plans, and early retirement schemes tailored to smaller captive coal plants. Ensuring that Indonesia's sustainable finance taxonomy is interoperable with global standards will also be crucial in mobilising international capital for industrial decarbonisation.

Finally, the study considers the broader economic and supply-chain implications of clean energy transitions for captive power. Although electricity is an important cost component in energy-intensive sectors, the analysis finds that clean energy transitions do not undermine industrial competitiveness. In fact, they have the potential to strengthen it. While some transition measures may marginally raise short-term energy costs, they can reduce long-term exposure to fossil fuel price volatility and help secure access to rapidly growing markets and interest in low-carbon materials such as for battery-grade nickel, green aluminum, and sustainable packaging, when complemented by appropriate certification and verification schemes. They also position Indonesia more favourably in the context of emerging carbon border adjustment mechanisms and other global climate-related trade provisions. Aligning captive power with global sustainability norms is therefore not only compatible with Indonesia's industrial strategy—it is central to sustaining it.

Overall, the findings of the Captive Power Study point to a clear conclusion: Indonesia's industrial growth and its long-term competitiveness are increasingly dependent on the decarbonisation of captive power. A credible, well-supported transition pathway exists, built on substantial renewable potential, proven technologies, and economically sound strategies tailored to industry needs. With coordinated policy action, innovative financing, and early engagement from industrial players, Indonesia has a golden opportunity to take a leading role in global clean industrial development, safeguarding its economic future while advancing its climate commitments.

Introduction: Overview of the Analytical and Modelling Approach

Complimentary to JETP Scenario presented in CIPP 2023 document, this study presents a scenario for Indonesia's captive power (hereinafter referred to as JETP Captive Scenario), seeking to align the captive sector with a clean energy transitions pathway. For the purpose of this analysis, captive power is defined as generation for private use of businesses or industrial facilities and includes the following licence types: 1) IUPTLS; 2) PPU (not reliant on PLN system), which are described in more detail in Chapter 1. The captive power analysis in this report takes a rigorous, asset-level approach shown in Figure I-1 below.



*Note: * designates analysis to be carried out by an external partner for the JETP Captive Power Report.*

Source: JETP Secretariat and Working Groups, 2025.

Figure I-1 Overview of Analytical Approach for JETP Captive Scenario

The report is divided into 6 main chapters, which are:

- **Chapter 1:** assessing the economic landscape for captive power development in Indonesia and tracking captive power and energy-intensive industrial plants;
- **Chapter 2:** technically screening those plants for clean energy and emissions reduction options;
- **Chapter 3**: modelling a clean energy transitions pathway (JETP Captive Scenario) aligned with the goals set out in the JETP Joint Statement, as an alternative to the Baseline Scenario based on the starting capacity mix; assessing implications in terms of CO_2 emissions, electricity costs, and investments; and testing scenario variants.
- **Chapter 4:** presenting case studies for select captive power assets that seek to assess technical and financial feasibility of transitions in a more detailed manner;
- **Chapter 5:** setting out key policy and financing levers and approaches to enable captive power to shift to a low-carbon pathway; and

- **Chapter 6:** analyzing the industrial and economic parameters impacted by a shift towards clean electricity for energy-intensive industries and assessing international market conditions to enable such a shift.

The starting point is the power plant and industry tracking in the JETP Captive Power database, developed by the Technical Working Group (TWG) over June 2024-July 2025. Captive power data for over 500 power plant units was sourced from the MEMR Directorate General of Electricity, a JETP Focus Group Discussion (FGD) with industrial companies in January 2025, Global Energy Monitor, and other sources, including desk research. Units were then grouped and categorized into 173 captive power sites for representation in the technical screening and modelling. Captive power sector data in Indonesia is characterized by discrepancies across sources. Continued data verification and alignment are critical to establish a consistent baseline view and to address information gaps, especially around operational performance and industrial plants associated with the captive power listings.

Chapter 1: Role of Captive Power and Industrial Development in Indonesia

This chapter presents the economic and energy context of industrial development in Indonesia and maps the current landscape for captive power development. The first part focuses on the economic and energy backdrop of industrial development, including -

- Assessing the role of energy-intensive industries, who often rely on captive power, in Indonesia's economy and economic development goals; and
- Characterizing the role of critical minerals downstreaming in sustainable development.

The second part of the chapter provides an overview of the captive power sector, including -

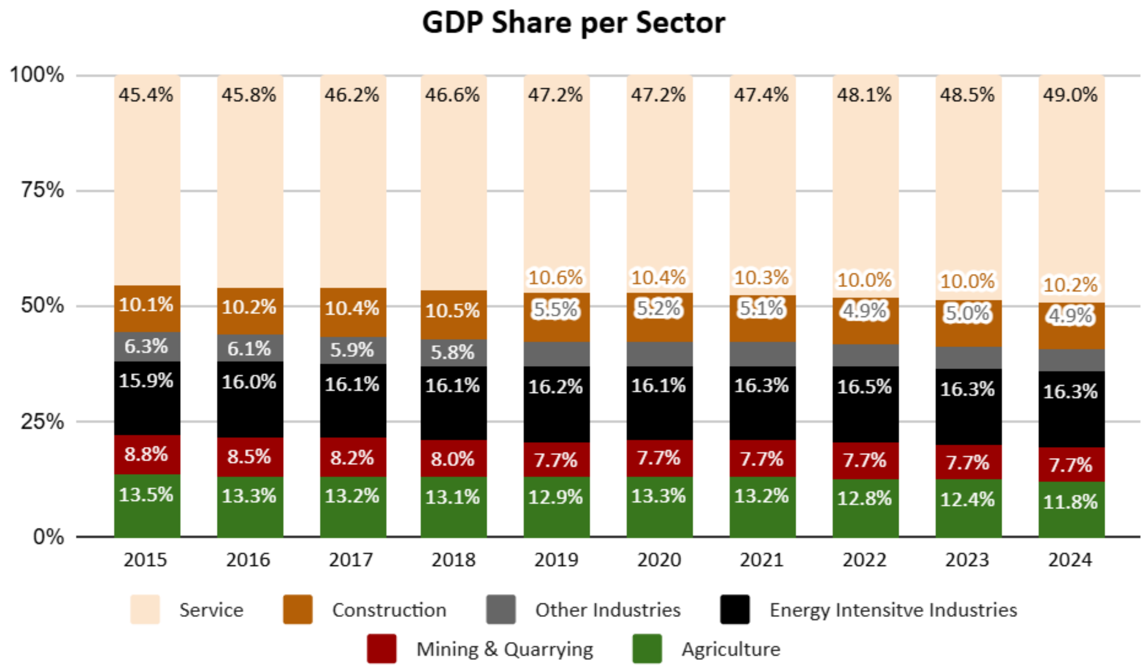
- Describing the drivers of captive power adoption by industries in Indonesia;
- Describing the current regulatory framework and permitting and licensing regime; and
- Presenting the capacity landscape, as tracked in the JETP Captive Power Database.

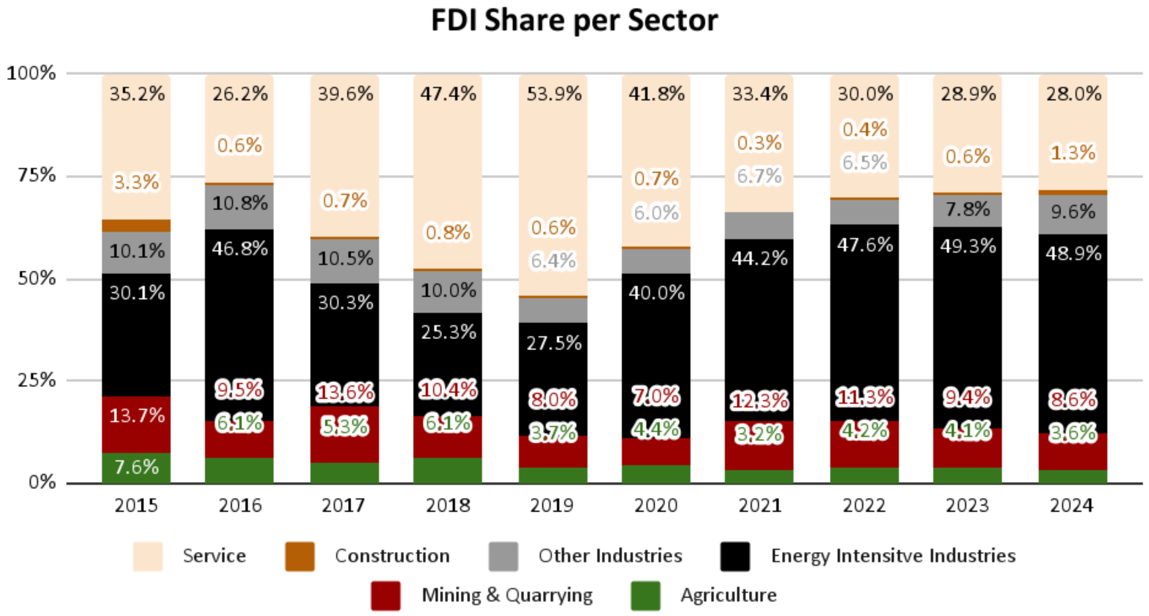
1.1 Economic and Energy Context of Indonesia's Industrial Development

In Indonesia, energy-intensive industries have a strong relationship with industrialization and economic development. Understanding such factors is critical to understanding energy drivers and setting clean energy transition strategies that support broader economic goals.

1.1.1 Economic Development Goals in Indonesia and The Role of Energy-Intensive Industries

Energy-intensive industries – including critical minerals and metals processing, pulp and paper, chemicals, and other industries – play a key role in Indonesia's economy. Such industries, who are often reliant on captive power for its reliable electricity output and unavailability/insufficient electricity supply from the grid, have consistently contributed around 13% of Indonesia's gross domestic product (GDP) over the past decade. These industries are also a rising contributor to total investment (domestic and foreign), with their share surge from a quarter to nearly half over the past decade, surpassing that from the services sector.

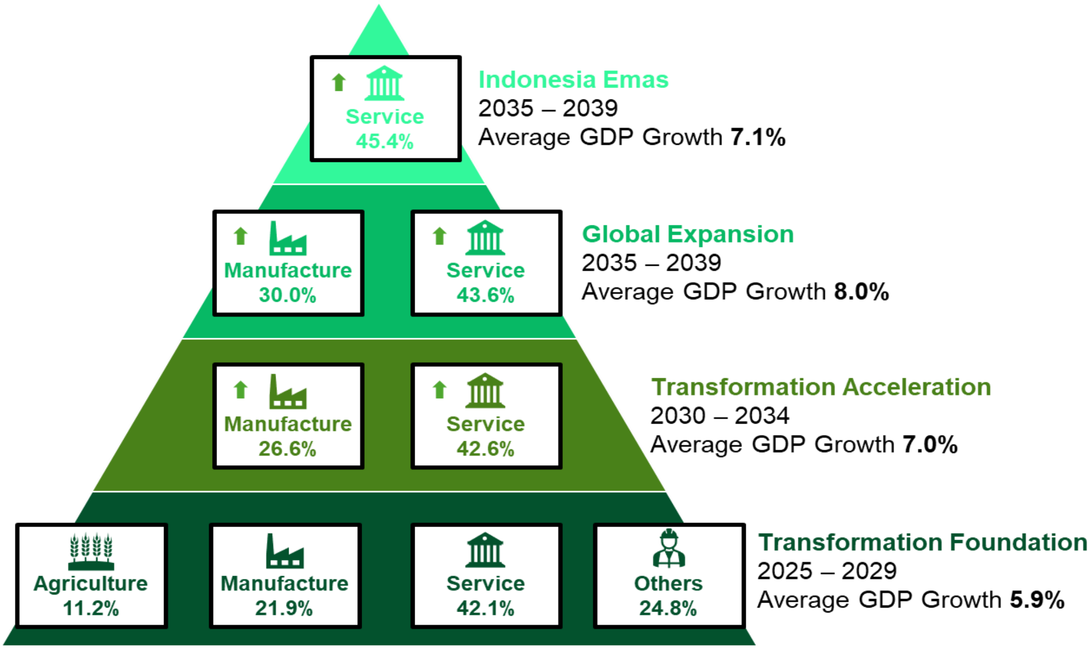




Source: (JETP Secretariat and Working Groups, 2025) based on (BPS, 2024) and (Ministry of Investment, 2024).

Figure 1.1.1-1&2 Indonesia Sectoral Share of GDP (top) and foreign direct investment (FDI) (bottom)

Indonesia's economic development goals are underpinned by the Indonesia Vision 2045, with the objective of Indonesia reaching high-income country status by 2045. The economic vision emphasizes sectoral transitions, aiming for an average GDP growth rate of 7% to 8% from 2030 to 2045, up from an annual average of ~5% over the past decade. The manufacturing and services sectors are projected to be the primary drivers of this accelerated economic growth. Such growth is envisaged to be underpinned by greater economic diversification and inclusiveness from a geographic perspective, with a rising contribution of island areas outside Java, particularly Sumatra, Kalimantan, Sulawesi and other Eastern Region provinces.



Source: (JETP Secretariat and Working Groups, 2025) based on National Mid-Term Development Plan 2025-2029

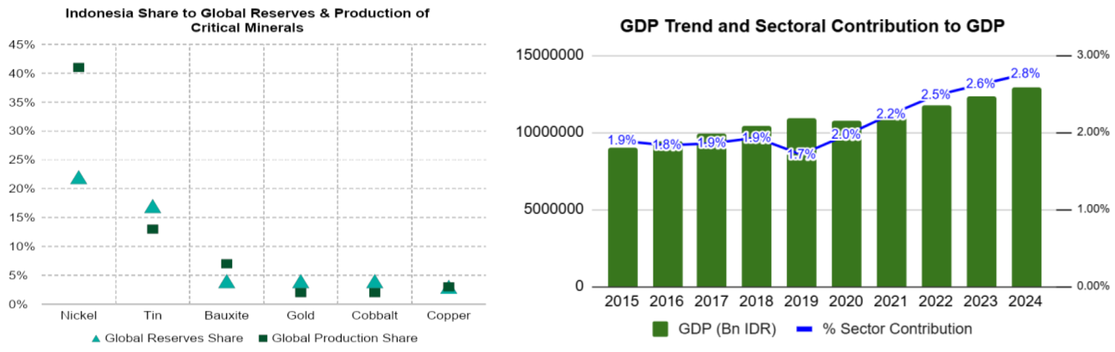
Figure 1.1.1-3 Indonesia Vision 2045 GDP Growth Targets and Sector Contributions

Indonesia has set ambitious medium-term goals to achieve the long-term vision, including targeting economic growth of 8% by 2029 and boosting private investment in high value-added industrial projects. Notably, the National Medium-Term Development Plan (RPJMN) lays out 77 National Strategic Projects (PSN) pertaining to industrial downstreaming, development of dedicated industrial estates, food self-sufficiency, energy self-sufficiency and other areas, which also have the potential to boost energy and electricity demand needs.

1.1.2 Critical Minerals Downstreaming and Sustainable Development

Underpinned by abundant domestic resources, critical minerals sectors - including the metal ore mining and basic metals industries – have increasingly contributed to Indonesia's GDP growth and are viewed as crucial drivers of economic development going forward. This is particularly true in the nickel sector, where Indonesia accounts for over one-fifth of global reserves and over 40% of global production.

Leveraging critical minerals for economic development hinges on capturing more value-added from critical minerals supply chains through industrial downstreaming. For example, in nickel, this means increasing investment in areas beyond extraction of nickel ore, to processing ore into intermediate products and the manufacturing of final products based on these intermediate inputs. To gain maximum value-added, Indonesia could also prioritize high value-added products derived from nickel, notably clean energy technologies such as batteries and electric vehicles, aside from the existing route of investing in the stainless steel industry. Indonesia has put in place policies, such as a ban on nickel ore exports and creation of a new state-owned enterprise focused on the development of battery supply chains, in support of this downstreaming strategy, but challenges remain in ensuring that such industries can scale over time in a competitive and sustainable manner[1].



Source: (JETP Secretariat and Working Groups, 2025) based on (US Geological Survey and World Mining Data, 2024) and (BPS, 2024).

Figure 1.1.2-1 Indonesia Shares of Critical Minerals (left) and Sectoral Contribution to GDP (right)

On a global scale, a shift towards clean energy adoption is creating new market opportunities for critical minerals producers, with demand for critical minerals set to increase strongly under any long-term energy transition scenario. Notably, in the IEA Announced Pledges Scenario, global demand for nickel has been projected to grow by over half from 2023 to 2030 and to double in size from 2023 to 2040, with clean energy technologies comprising nearly 55% of demand in 2040, up from 15% in 2023[2]. Global growth prospects for other critical minerals and metals inputs for clean energy technologies, such as aluminum and copper, also appear robust.

Nevertheless, as global markets increasingly prioritize environmental sustainability, industrial competitiveness will depend on reducing carbon intensity of industrial products. Countries are introducing carbon border taxes (e.g. Carbon Border Adjustment Mechanism in EU), while global companies monitor emissions across their supply chains. To stay competitive, Indonesia needs to invest in research and development and clean industrial development, particularly in downstreaming focus areas e.g. battery manufacturing and critical mineral processing. While transitioning away from emissions-intensive sources of energy may initially reduce government revenue from coal, JETP investments could potentially create new revenue streams through green industries and infrastructure.

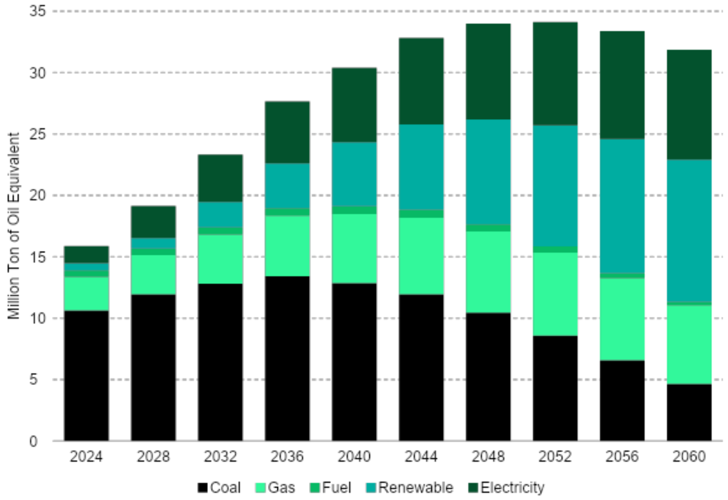
Enhancing sustainable business practices in an affordable and value-added manner is key. Addressing such issues aligns with industrial decarbonization pathways under Indonesia's draft Roadmap for Net Zero Emissions (NZE) 2060. For example, in the basic metals industry - which drives critical minerals development and is the largest captive power user - a shift away from direct use of fossil fuels, especially coal; increased efficiency and electrification of

---

[1] Further detail on Indonesia's nickel production and electricity demand from captive power are in Chapter 3.
[2] IEA Global Critical Minerals Outlook 2024.

industrial processes; more direct use of renewable energy; and accelerated uptake of clean power, as in the JETP goals are critical to meeting NZE objectives, even as energy demand for this sector is projected to more than double over the next three decades (Figure 1.1.2-2).

This report focuses on strategies to accelerate clean energy transitions for industrial power users, and specifically their electricity demand from captive power. Still, it is important to note that comprehensive approaches to industrial energy transitions involve addressing the direct use of fuels for heat and chemical processes as well. Such processes currently account for the bulk of industrial energy demand in Indonesia, as well as associated carbon emissions.



Source: (JETP Secretariat and Working Groups, 2025) based on (MEMR, 2024).

Figure 1.1.2-2 Energy demand for the Basic Metals Industry in the Indonesia NZE 2060 Scenario

1.2 Overview of Captive Power in Indonesia

1.2.1 Introduction to Captive Power and Its Role in Industrial Development

For the purpose of this study, captive power is defined as a power plant which generates electricity for private use of businesses or industrial facilities, and is not reliant on supply from the PLN grid system. In Indonesia, captive power is mostly associated with energy-intensive industries and industrial downstreaming facilities, such as minerals processing, which are often located away from the PLN grid system.

To date, energy-intensive industries have developed significant captive power based on coal. This is due to coal being viewed as the most cost-effective, timely and firm source of power supply, particularly for industrial facilities that lack suitable access to the PLN grid system, have high and stable electricity demand requirements and face significant cost competition. For industries with ready access to local fuel and feedstock supply – such as pulp and paper, crude palm oil or oil and gas – bioenergy and gas have also emerged as attractive dispatchable options for captive power. Moreover, thermal power plants are also preferable for some industries that need heat energy for their process, which could be co-generated along with the electricity.

Captive power can help such industries maintain stable production processes, manage power outage risks, and meet specific operational needs, thereby optimizing efficiency and reducing downtime. However, while captive power in Indonesia has emerged as a practical option for enhancing power reliability and energy security for energy-intensive industries in areas where the main grid is underdeveloped, it is also associated with several emerging challenges. Building captive power supply requires significant upfront capital for industrial companies and ensuring consistent fuel supply can pose logistical challenges, particularly in remote areas.

Regulatory inefficiencies exacerbate the technical and economic factors that have led asset owners to develop captive power and, to date, have contributed to energy-intensive industries developing single captive coal power plants rather than shared clean energy solutions at scale[3]. Increased reliance on individual captive power plants is suboptimal from an integrated power system planning and operations perspective. As governments and industries around the world increasingly focus on supply chain sustainability, the increase of captive coal power utilization creates potential market risks and financing risks for Indonesia's industrial output, in addition to negative environmental and climate change impacts. Such risks could jeopardize the opportunity for Indonesia to compete in the global export market and attract FDIs which demand a cleaner supply chain.

1.2.2 Regulatory Framework and Permitting and Licensing for Captive Power

In Indonesia, all electrical generation and supply (above a certain capacity threshold) including in the context of captive power requires a license from the central government with support and involvement from other levels of government. There are two different types of electricity supply business licenses:

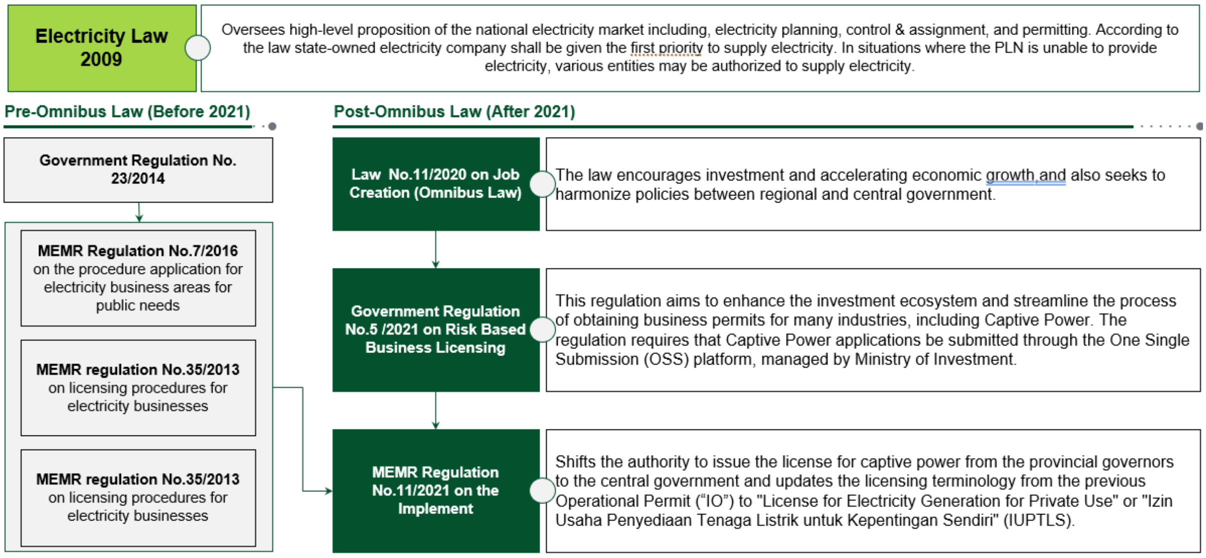
- for private use; and
- for public use.

In Indonesia's regulatory context, "private use" refers to electricity generated solely for self-consumption, with no sale involved (except by using excess power selling scheme). A private use license allows a business entity to supply power for its own operations, typically to support a particular entity's primary business activities. On the other hand, if electricity is supplied to an entity other than the business area license holder, requiring a sale and purchase transaction, a license for "public use" is required.

The Law No. 30/2009 on Electricity, provides comprehensive oversight of the national electricity market, encompassing aspects such as electricity planning, control, assignment, and permitting. Regulations for captive power were previously defined under MEMR Regulation No.12 of 2019 concerning the Electricity Generating Capacity for Own-Use Executed Based on an Operational Permit ("IO"). This regulation authorized provincial governments to issue the IO license for the operation of captive power plants.

---

[3] More details of the regulatory inefficiencies will be discussed in the section on Enhancing Planning, Permitting and Licensing in Chapter 5.



Oversees high-level proposition of the national electricity market including, electricity planning, control & assignment, and permitting. According to the law state-owned electricity company shall be given the first priority to supply electricity. In situations where the PLN is unable to provide electricity, various entities may be authorized to supply electricity.

The law encourages investment and accelerating economic growth and also seeks to harmonize policies between regional and central government.

This regulation aims to enhance the investment ecosystem and streamline the process of obtaining business permits for many industries, including Captive Power. The regulation requires that Captive Power applications be submitted through the One Single Submission (OSS) platform, managed by Ministry of Investment.

Shifts the authority to issue the license for captive power from the provincial governors to the central government and updates the licensing terminology from the previous Operational Permit ("IO") to "License for Electricity Generation for Private Use" or "Izin Usaha Penyediaan Tenaga Listrik untuk Kepentingan Sendiri" (IUPTLS).

Source: (JETP Secretariat and Working Groups, 2025).

Figure 1.2.2-1 Regulatory Framework Underpinning the Development of Captive Power

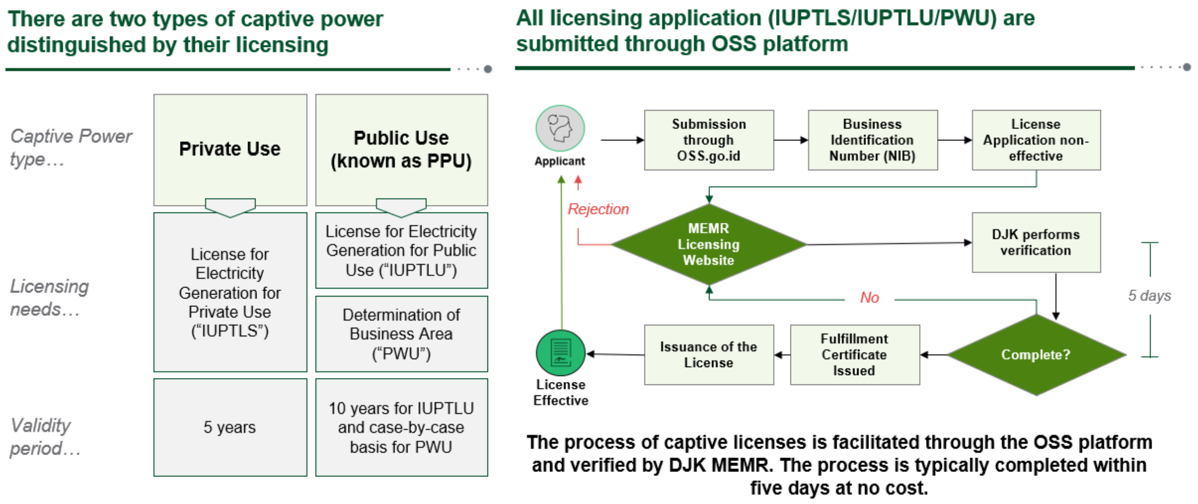
License issuance was changed through the 2021 Omnibus Law and the MEMR Regulation No. 11/2021, which brought greater authority to the Central Government. Prior to the 2021 Omnibus Law and MEMR Regulation No. 11/2021, the captive power licensing was issued under provincial governments' authority. Under the current regime, private use licenses are now issued by the provincial government only for power plants with a capacity up to 10 MW, and are issued by the Minister for capacities above 10 MW. Licenses for public use power plants are generally issued by the Minister with few exceptions[4]. Currently MEMR is in progress to reconcile the scattered license data through AMPERE Gatrik platform.

The introduction of Government Regulation No. 5/2021 also enhanced the investment ecosystem and streamlined the process of obtaining business permits. To manage licensing, the regulation directs applications be submitted through the One Single Submission (OSS) platform, managed by the Ministry of Investment (BKPM). Power plants with a capacity exceeding 500 kW are required to apply; those with a capacity of up to 500 kW are not required to apply for a license and only notify relevant ministries or government bodies.

Captive power license characteristics differ by type of business. For private use, the asset owner requires a License for Electricity Generation for Own-Use ("IUPTLS") , which permits generation of electricity solely for their own consumption. Captive power intended for public use, also known as Private Power Utility (PPU), necessitates two licenses: License for Electricity Generation for Public Use ("IUPTLU") and Integrated Business Area ("PWU"). Captive power designated for public use is permitted to generate and supply electricity in areas where PLN is unable to provide electricity service. License validity ranges from 5 years for IUPTLS to 10 years or longer for PPUs.

---

[4] The Governor issues these licenses where the power plant provides electricity to an electricity distributor whose license is issued by the provincial government.



There are two types of captive power distinguished by their licensing

	Private Use	Public Use (known as PPU)
Captive Power type…	Private Use	Public Use (known as PPU)
Licensing needs…	License for Electricity Generation for Private Use ("IUPTLS")	License for Electricity Generation for Public Use ("IUPTLU") Determination of Business Area ("PWU")
Validity period…	5 years	10 years for IUPTLU and case-by-case basis for PWU

All licensing application (IUPTLS/IUPTLU/PWU) are submitted through OSS platform

The process of captive licenses is facilitated through the OSS platform and verified by DJK MEMR. The process is typically completed within five days at no cost.

Source: (JETP Secretariat and Working Groups, 2025).

Figure 1.2.2-2 Regulatory Requirements for Captive Power Permitting and Licensing

Notes: PPU = private power utility; OSS = online single submission; DJK = MEMR Directorate General of Electricity. Public and private entities include BUMN (state-owned enterprise), BUMD (regional-owned enterprise), private companies, cooperatives, and self-supporting communities engaged in the supply of electrical power ("Swadaya Masyarakat").

The technical requirements to apply for IUPTLS are relatively straightforward and include an analysis of the electricity demand, a layout drawing, a line diagram, the type and capacity of the power plant, and a construction and operations schedule. For an integrated or sales/distribution IUPTLU license, a key requirement for obtaining is securing a *Wilayah Usaha* (Business Area). IUPTLU applicants are also subject to more extensive documentation, including financial feasibility, operational feasibility, and network interconnection studies. Technical requirements include a comprehensive analysis of electricity supply needs aligned with business activities (distribution, sales, or integrated). IUPTLU applicants must also provide a Power Purchase Agreement (PPA) with potential customers. More discussion on requirements is provided in Chapter 5 and Appendix 1.

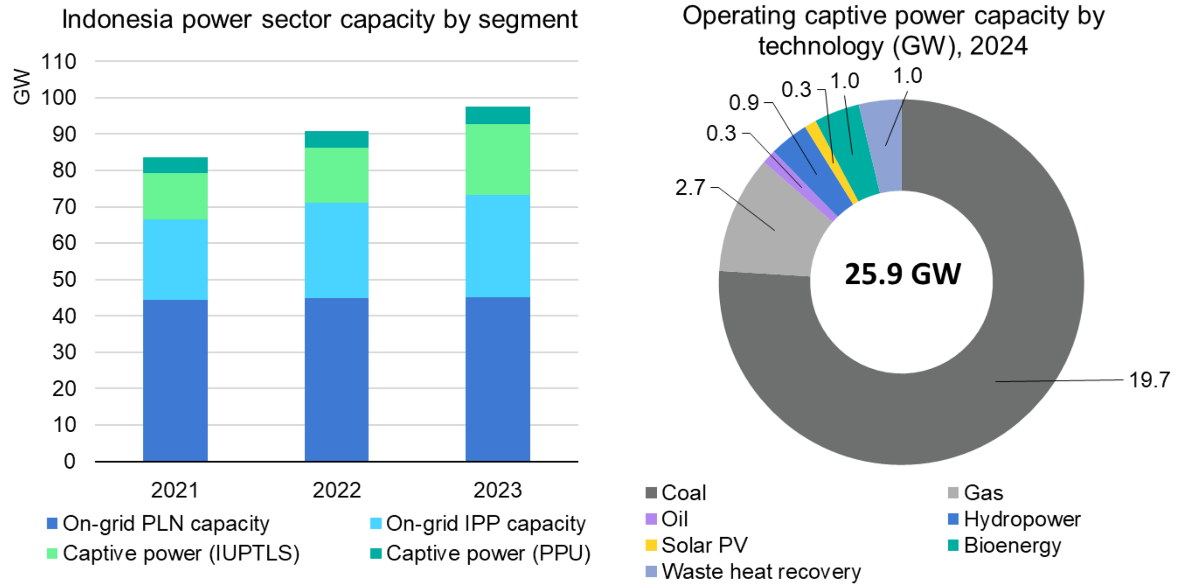
Oversight of captive power in Indonesia involves specific reporting obligations to the license authority. All captive power license holders are required to submit an annual report detailing their business activities, but operators of non-IUPTLS power plants with a capacity of 500 kW or less are only required to submit a one-time report to the Directorate General of Electricity.

1.2.3 Landscape of Captive Power Plant Capacity

Operating captive power capacity

In the JETP Captive Scenario, the initial analysis on the size and composition of the captive power fleet is based on the JETP Captive Power Database. For 2023, that database tracked 24.0 GW (net capacity) of captive power in operation, with the total estimated to have risen to 25.9 GW in 2024. With the size of on-grid power capacity at 73 GW in 2023, as reported in the RUKN, captive power comprises a growing share of national power capacity at around

25%, up from 20% in 2021, driven by the demand needs of energy-intensive industries as described above.



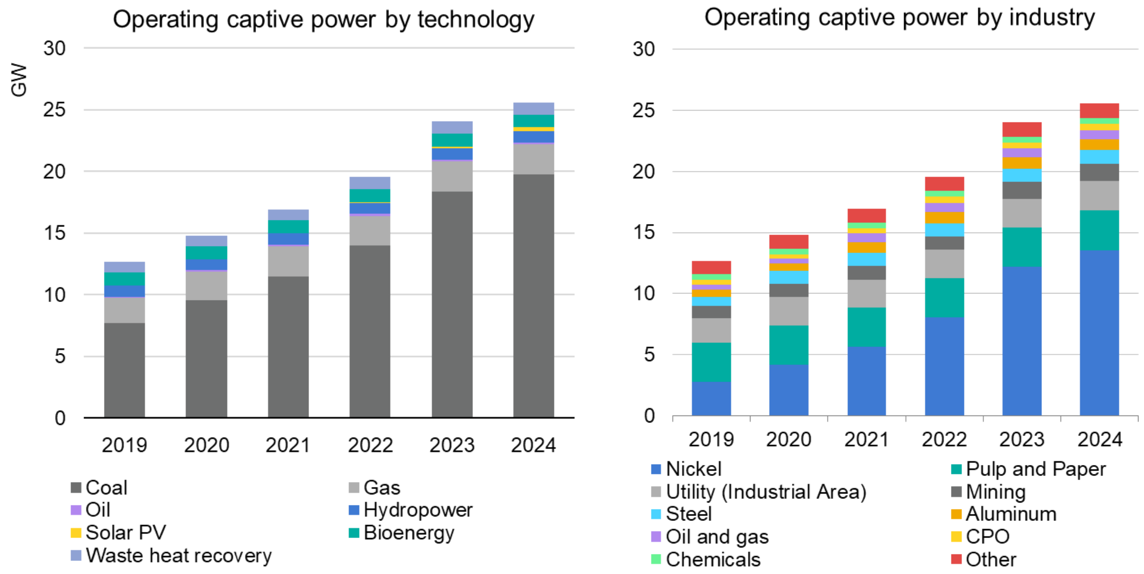
Source: (JETP Secretariat and Working Groups, 2025). Historical on-grid power capacity is from the RUKN (MEMR, 2025), while captive power estimates are from the JETP Captive Power Database.

Figure 1.2.3-1 Total Power Sector Capacity by Segment (Left) and Operating Captive Power Capacity in 2024 by Power Plant Technology (Right)

Notes: In line with the presentation in the RUKN and CIPP 2023, capacities in JETP Captive Report 2025 are expressed in net power capacity terms (i.e. excluding power consumption by the power plant itself); a uniform derate factor of 7% is applied to any nameplate capacity to express net capacity. IPP = independent power producers; IUPTLS = Izin Usaha Penyediaan Tenaga Listrik Untuk Kepentingan Sendiri license; PPU = Private Power Utility license.

Over the past five years, captive power capacity has expanded by over 12 GW, more than doubling from 2019 levels, following the rapid development of downstream industries such as critical mineral processing. Coal power represents the most-utilized technology - over 75%, or nearly 20 GW - of operating captive capacity in 2024 and has increased almost three-fold from around 7 GW in 2019. The next largest source of captive capacity is gas power, at 10%, or 2.7 GW in 2024. The role of renewable sources in captive power is limited to less than 10% of captive power, or 2.2 GW, mostly from hydropower, as well as bioenergy and recent additions of solar PV.

Captive power plants are licensed under two license types, which are described in the previous section. Most operating captive power, around 80% is under the *Izin Usaha Penyediaan Tenaga Listrik untuk Kepentingan Sendiri* (IUPTLS/private use license) scheme, where asset-owners develop power plants only for their own consumption. The remaining capacity operates under the PPU (private power utility) scheme, which allows asset owners to sell electricity to multiple parties within integrated power areas.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 1.2.3-2 Historical Captive Power Capacity by Technology (Left) and Industry (Right)

Notes: Nickel, Aluminium and Steel pertain to metals processing; mining-related capacity for those metals is under Mining; CPO = crude palm oil; Other = agriculture, cement, coke, copper, sugar, textiles, wood and other unspecified industries.

In line with the demand projections presented above, over half of operating captive power now serves nickel processing. While over 15 different industries currently rely on captive power to some degree, nickel processing has accounted for 85% of the captive power expansion over the past five years and by 2024 this industry had become the largest user of captive power, with 13.9 GW, followed by pulp and paper at 3.2 GW and diversified utility industrial areas at 2.4 GW.

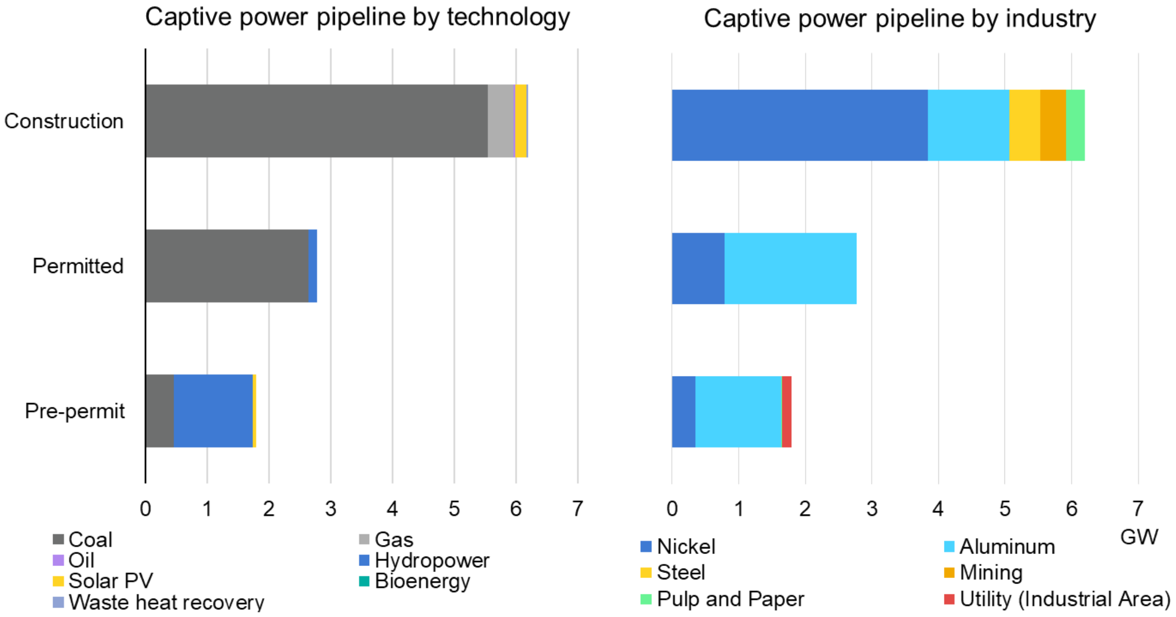
Captive power is distributed across all major islands. As of 2024, Sulawesi has the highest operating capacity at 10.5 GW, followed by Sumatra (5.2 GW) - mostly based on pulp and paper - and Maluku (4.5 GW), reflecting Indonesia's nickel and mining industry. In Java, captive power (3.5 GW) reflects diverse industries including pulp and paper, chemicals and steel. Capacity in Kalimantan (1.9 GW) is largely aluminum and mining industries.

Captive power capacity pipeline

Looking ahead, the size of the pipeline of future captive power—including plants in the construction, permitting and pre-permit phases—is assessed at nearly 11 GW. Currently, 6.2 GW of captive power is under construction, of which 5.5 GW is coal power. An additional 4.6 GW is in the planning (permitted or pre-permit) stage, of which 3.1 GW is coal. It is worth noting that power plants with permitted and pre-permitted status have a high degree of uncertainty to be built.

These future plants are planned to primarily serve nickel and aluminum processing, as well as industrial parks, steel and other industries. Based on the pipeline of identified projects and already operating assets, total captive coal power capacity may top 28 GW by the early 2030s without concerted efforts to shift the business plans of asset owners.

Note: the JETP Captive Scenario presented in Chapter 3 models alternatives to avoid coal power for the planned captive coal capacity, as well as to transition operating and under construction coal power generation in accordance with the emissions reduction provisions of Presidential Regulation No. 112/2022.



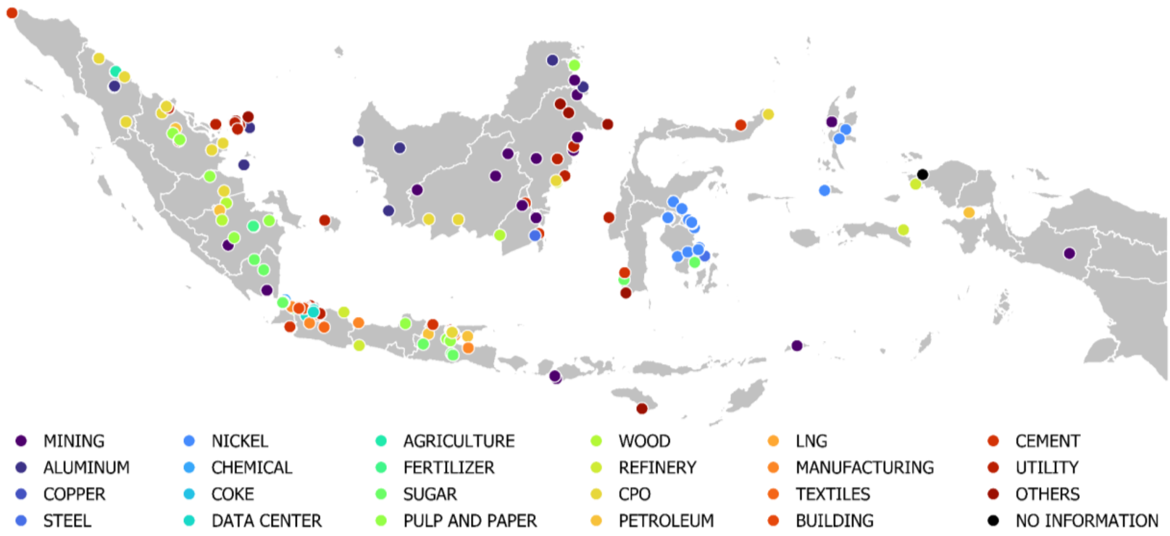
Source: (JETP Secretariat and Working Groups, 2025).

Figure 1.2.3-3 Captive Power Capacity Pipeline until 2030 by Status, Technology (Left) and Industry (Right)

Mapping captive power sites and data considerations

The JETP Captive Power Database was developed by the JETP Technical Working Group (TWG) over June 2024-July 2025. Asset-level captive power data for over 500 power plant units across more than 50 data fields was sourced from the MEMR Directorate General of Electricity, a JETP Focus Group Discussion (FGD) with industrial companies in January 2025, Global Energy Monitor, and other sources, including considerable desk research.

These units were then grouped and categorized into 173 captive power sites, based on common owner and location, to represent the captive power sector in the technical screening and modelling, which is described further in Chapters 2 and 3. To illustrate, a mapping of these captive power sites is provided in Figure 1.2.3-4.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 1.2.3-4 Mapping of Captive Power Sites (operating and pipeline) by Industry in Indonesia

Notes: Data as of July 2025; map represents captive power areas with power plant assets grouped by common owner and location.

Given the dynamic nature of energy-intensive industries in Indonesia, the commercially sensitive nature of their business operations, complex ownership arrangements and recent changes in regulatory framework, captive power sector data in Indonesia is characterized by significant discrepancies across different sources. For some assets in the JETP Captive Power Database, there is uncertainty over power capacity size, power plant type, commercial operations date, exact location, and characteristics related to ownership and industrial process, among other factors. Continued data verification and alignment are critical to establish a consistent baseline view of the sector and to address notable information gaps, especially around asset operational performance and the industrial facilities associated with the captive power listings.

The capacity estimates above consider captive power for use as a main power source and exclude power capacity identified for back-up use. It is worth noting there is uncertainty over the degree of excess captive power capacity maintained by energy-intensive industries. Notably, the captive power demand assessed for 2024, at 139 TWh (see Chapter 3 for more details), implies an overall utilization rate of around 60-65% (without accounting for losses) of the total captive power capacity for that year.

While this headline calculation masks underlying asset and technology dynamics, it indicates that the captive power tracked in the JETP Captive Power Database represents a degree of capacity surplus relative to its use. This surplus may be due to companies maintaining reserve capacity to ensure a high level of reliability and adequacy for industrial processes, the ongoing ramp-up of new industrial plants, use of thermal power capacity for industrial process heat (which is not accounted for in the JETP Captive Scenario), oversizing capacity in licensing applications and projects to give flexibility for future industrial expansions and increasing electricity demand needs in fast moving sectors (such as nickel and aluminium), and/or cheap investment costs for coal power that can lead to oversizing capacity, among other factors.

Chapter 2: Technical Screening for Clean Energy Transition Measures

In the JETP Captive Scenario, each captive power site and associated industrial plant is screened for potential clean energy transition measures. This screening, based on the JETP Captive Power Database, aims to evaluate the technical potential for clean energy and emissions reduction interventions that can transition industrial assets from current reliance on captive coal power and avoid new captive coal power. The results of this screening serve as inputs to the captive power demand and supply modelling described in Chapter 5.

Each captive power site (173) was mapped using a Geographic Information System (GIS) tool and an asset-level possibility matrix was created for each intervention. The analysis does not focus on economic factors or other non-technical considerations; rather it seeks to determine the extent to which clean energy and emissions reduction interventions are technically possible for each captive power area. The assessment takes into account the unique characteristics of each site and asset, as well as the local context of potential clean energy solutions.

The interventions consist of the following demand-side and supply-side measures:

- **Industrial clustering** around shared infrastructure, enabling plants in proximity to benefit from centralized energy management,economies of scale and access to greater resource potential in procuring renewable power (demand-side);
- **Industrial process switching and energy efficiency** measures, which enable electricity intensity improvements and energy savings for industrial plants (demand-side);
- **Grid connection** potential with the on-grid power system, which enables industrial facilities to be integrated into the on-grid PLN system rather than rely on captive power (supply-side);
- **On-site renewable power**, based on local technical potential for dispatchable (bioenergy, geothermal, hydropower) and variable (solar PV, wind) renewable power sources (supply-side);
- **Fuel-switching from coal to gas** power, based on proximity to gas network infrastructure; (supply-side); and
- **Carbon capture and storage** (CCS)/carbon capture, utilization and storage (CCUS), based on proximity to designated storage sites.

The technical potential of each intervention for a captive power area is categorised into two possibility levels, which are represented as colour-coded maps. The levels are: POSSIBLE (green) and NOT POSSIBLE (red). The on-site renewable power intervention is displayed using a capacity potential spectrum on the maps instead of a possibility level.

The methodology used in this assessment combines data analysis from the JETP Captive Power Database, including location coordinates, with GIS proximity analysis to obtain the parameters necessary for determining the technical possibility of the interventions.

Technical Screening Criteria and Results

Industrial Clustering

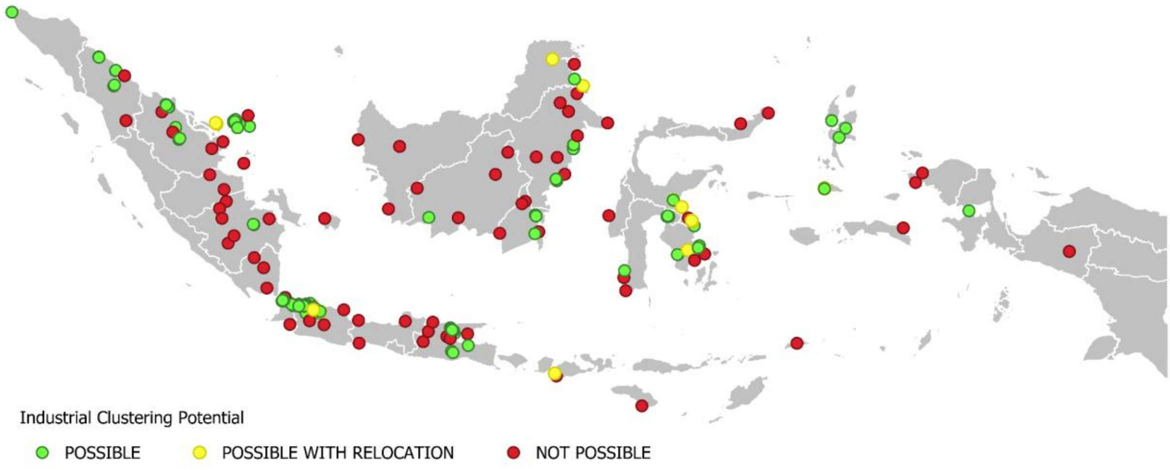
This intervention evaluates the potential of industrial plants reliant on captive power to cluster within industrial parks, with aggregated demand based on shared infrastructure and energy system operations. Benefits of industrial clustering for captive power emission reduction include:

- Demand aggregation creates opportunities for systemic and resource efficiency (e.g. inter-plant waste heat recovery);
- Demand optimization for better load balancing and facilitating the adoption of renewable energy; and
- Economies of scale in supply-side technologies and ability to access greater resource potential, such as larger capacity solar plant installations, more feasible adoption of CCUS or fuel-switching by addressing one larger plant instead of multiple captive power plants, scattered in multiple locations.

To be considered POSSIBLE for the industrial clustering intervention, an asset must satisfy ONE of these conditions:

- Identified in the JETP Captive Power Database as part of an existing industrial park;
- Located within the area of an existing industrial park, determined through GIS mapping the coordinates of an asset relative to the location of existing industrial parks (as per the Center for Global Sustainability's Industrial Park Dashboard); or
- Located within a 10 km radius of at least one other asset with a different owner, with the assumption that these assets can be clustered as an industrial park.

The result of the industrial clustering technical screening is shown in Figure 2-1. The analysis identified potential clustering opportunities for 96 captive power sites across over 25 industrial clusters, including existing and new clusters.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-1 Industrial Clustering Potential of Captive Power Areas

Industrial Process Switching or Energy Efficiency Improvement

The main parameter considered in this intervention screening is the estimated starting electricity intensity (electricity demand per tonne of output) of the industrial production process associated with each captive power area. Improving electricity intensity can save energy and reduce the need for captive power supply. This analysis considers two ways to reduce electricity intensity:

- Switching to an equivalent industrial process with a lower electricity intensity; or
- Improving the electrical efficiency of the existing process if no alternative process is available.

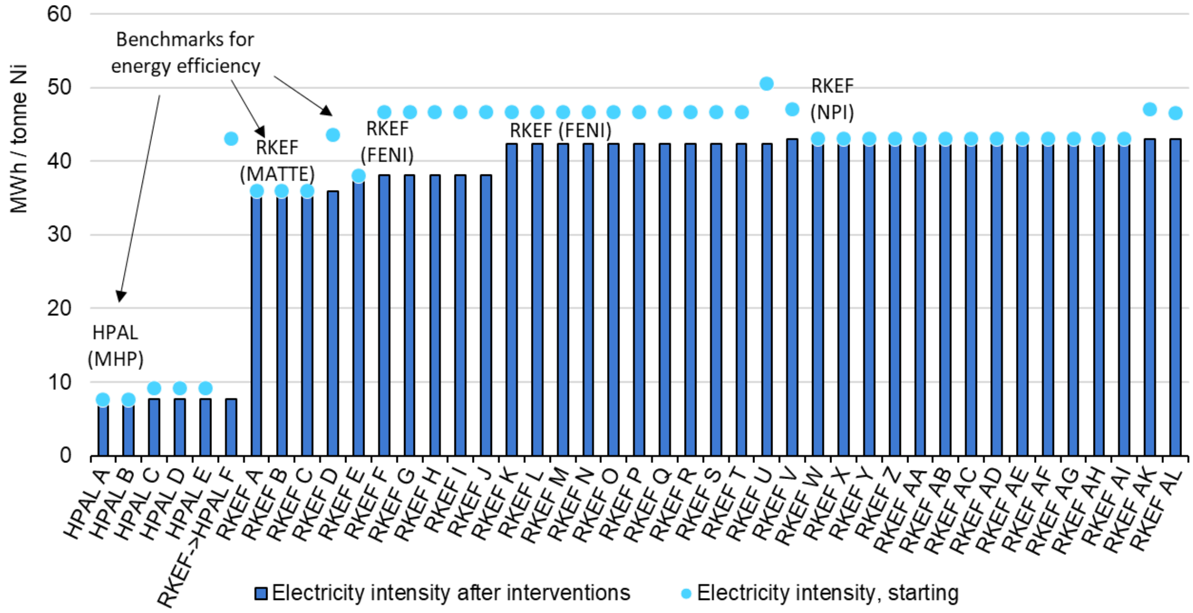
The scope of the analysis is limited to the industrial process use of electricity and does not consider direct combustion (i.e. process heat) and chemical processes. The screening is also limited to the metals processing (nickel, aluminium, and steel) industries, based on the availability of data from the Ministry of Industry, the JETP Captive Power Focus Group Discussion with industry actors, and other specialised industry sources.

Starting electricity intensities for metals processing plants were determined through available data on demand and production. For plants without reported intensities, the starting value for that asset is assumed to be the same as that of a similar asset with comparable ore quality, industrial process, and product type. Electricity intensity benchmarks were then determined by selecting the lowest electricity intensity among assets with the same product type. In this screening, it is assumed that other assets within the same product type should also be capable of achieving this lower electricity intensity. However, in practice, multiple factors - e.g. material input and output and engineering parameters - would impact potential intensity improvements for a given plant.

To be considered POSSIBLE for this intervention, the asset must satisfy one of these conditions:

- Industrial process switching: for plants still in the permitted or pre-permit stage, it is assessed to be technically possible for the developer to carry out the alternate process, absent evidence of financial/contractual commitments to develop a certain production route. In this screening, this intervention is only assessed for the nickel industry, in switching from rotary kiln-electric furnace (RKEF) to high-pressure acid leach (HPAL) process, which is a less electricity intensive production route.
- Efficiency improvements: the starting electricity intensity is greater than the benchmark - in that case the electricity intensity is adjusted downwards to achieve the benchmark.

An illustration of the electricity intensity assumptions and benchmarks for nickel assets in the database is shown in Figure 2-2.

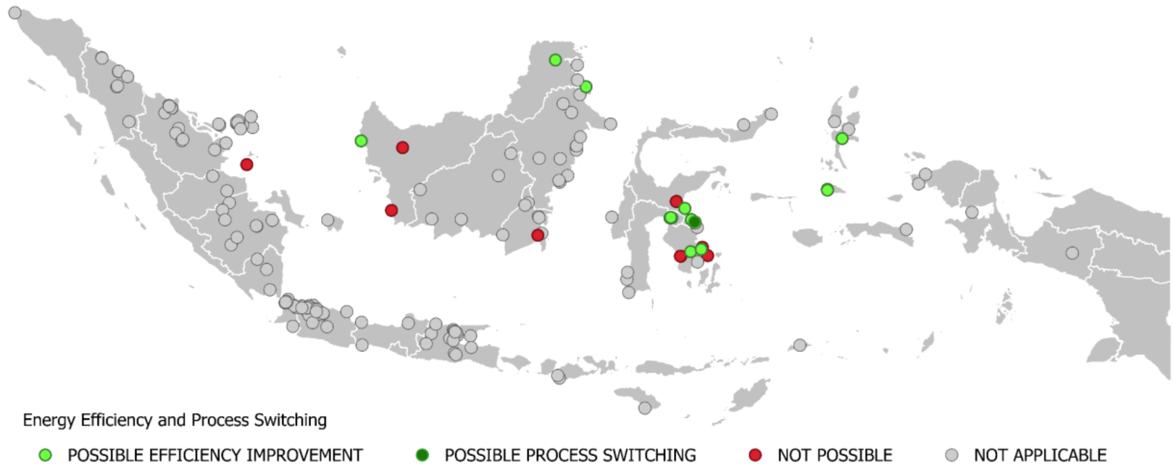


Source: (JETP Secretariat and Working Groups, 2025) based on data from (Wood Mackenzie, 2025).

Figure 2-2 Electricity Intensity Assumptions and Screening for Nickel Smelters in the JETP Captive Scenario

Notes: *RKEF = rotary kiln-electric furnace; HPAL = high-pressure acid leach; NPI = nickel pig iron; FENI = ferronickel; MHP = mixed hydroxide precipitate. FENI benchmarks are presented for two different ore grades.*

This screening does not specify the efficiency measures that are technically possible for each asset, but based on industry feedback the main opportunities for this are assessed to include waste heat management or the use of process heat recovery as the heat source for electricity generation and implementation of enhanced energy management systems. The result for the industrial process switching or energy efficiency improvement screening is shown in Figure 2-3.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-3 Energy Efficiency and Process Switching Potential for Captive Power Areas

Integration with The On-grid Power System

Integrating the demand from captive power users into the on-grid (PLN) power system, as the share of renewables increases in the JETP Scenario for the on-grid power system as set out in CIPP 2023, can provide industries with access to a cleaner and more reliable power supply, while reducing dependence on captive coal power plants, which are assumed to no longer operate as main power sources once the demand is integrated. This intervention evaluates the technical possibility of connecting assets to the on-grid power system, based on the distance to PLN substations and considering the reserve margin of the subsystem to which the asset will be connected.

In terms of the technical screening, to be considered POSSIBLE for integration to the on-grid power system, the asset must satisfy the following conditions:

- Not located on an isolated island system; and
- Located within 30 km of a PLN substation, based on GIS mapping of the assets and the coordinates of PLN's substations (in collaboration with PLN STI and RSL Division).

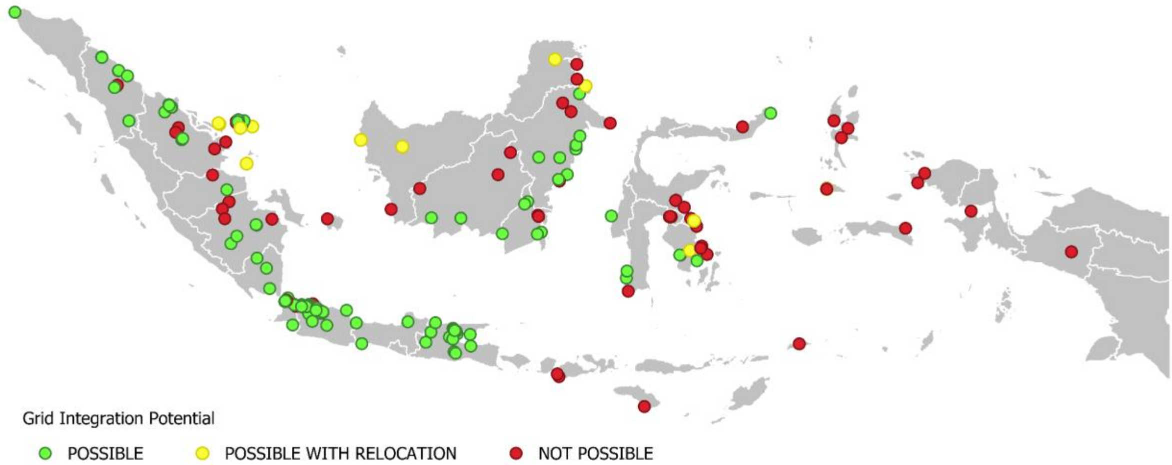
To ensure the reliability of the subsystem, the alignment of captive power capacity is checked against the voltage level of the subsystem grid.

The screening further includes technically possible plans for captive power sites to be integrated into the PLN grid system, as set out in Appendix E of the PLN RUPTL 2025-34.

Potential grid integration interventions set out in Appendix E of the PLN RUPTL 2025-34, which align with power plant listings in the JETP Captive Power Database, are integrated into the JETP Captive Scenario and comprise around 4.4 GW of captive power capacity that could be shifted to the PLN grid system. In the JETP Captive Scenario a further 2.8 GW of grid integration opportunities are assessed as technically possible, based on their distance to the nearest substation, bringing total potential candidates to 7.2 GW in the Scenario.

Based on the screening, opportunities are sequenced for implementation based on the size of capacity to be integrated (with smaller capacities integrated in 2030 and 2035) and COD years identified in the PLN RUPTL 2025-34.

The result of the on-grid power system integration technical screening is shown in Figure 2-4.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-4 Grid Integration Potential for Captive Power Areas

While this screening sets out potential grid integration opportunities with the on-grid system, which are reflected in the modelling and pathway detailed in Chapter 3, actual implementation of grid integration measures for captive power requires further consideration and feasibility study for each opportunity. For implementation, there are an important set of demand and supply factors to be considered by PLN and the captive asset owner.

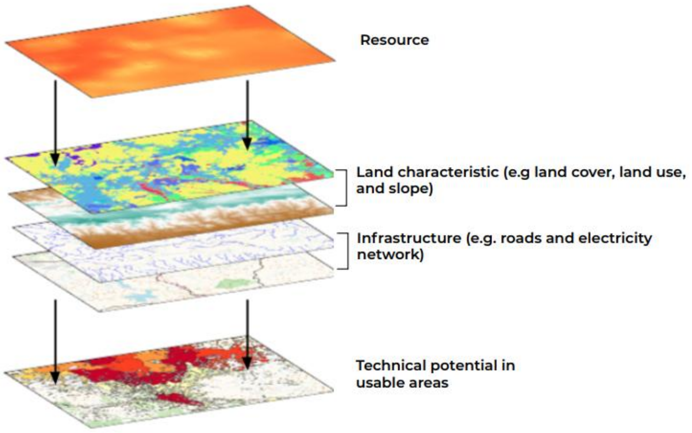
From PLN's perspective, the most important factor for integrating captive sites into the grid relates to the commitment of the captive owner and certainty around future demand from the associated industrial facility. This can be demonstrated by asset owner plans to maintain or increase electricity consumption over long time frames and the willingness to pay grid connection fees and comply with technical grid code requirements. However, the economics of switching to PLN industrial tariffs from captive power supply would need to be sufficiently attractive for asset owners. Additional study on the interaction of industrial clustering and grid integration would also be valuable.

On the supply side, the integration of any captive power plants would need to comply with PLN system requirements as well as avoid carbon leakage from shifting captive coal power to the on-grid system. For captive industrial facilities with high-level of uncertainty on their business continuation, grid integration could present stranded asset concerns that may need to be managed when those plants do not continue operating. PLN would also need to provide adequate power supply and grid infrastructure to integrate the industrial demand. Current plans for the development of transmission grids in Southeast Sulawesi and North Kalimantan represent an opportunity for the potential integration of nickel and aluminum industrial plants, respectively, in particular.

On-site Renewable Power

This screening looks at solar PV, onshore wind, hydropower, biomass, and geothermal as the options for the renewable power sources. The potential capacity and annual generation of each renewable resource are obtained a filtering method illustrated in Figure 2-5, which involves:

- Filtering out protected and conservation areas[5] (UNEP-WCMC, 2019), restricted water bodies, roads, electricity networks, airports, and other restricted areas;
- Mapping the usable area across Indonesia (IESR, 2021) or identifying potential points of renewable power plants (EBTKE, 2024);and
- Calculating the potential capacity and annual generation based on the usable area.



Source: IESR (2021). Beyond 443 GW: Indonesia's infinite renewable energy potentials. Institute for Essential Services Reform.

Figure 2-5 Filtering Method to Calculate the Usable Area for Renewable Energy

Each plant is assigned a specific radius perimeter, and the potential area for that plant is determined by the overlap with the usable area identified in the preliminary filtering. The caveat in using most of the renewable energy sources, except for biomass and geothermal, is their unavailability to co-generate supply for heat required by certain industries. Thus, the utilization of RE for this technical screening is only regarding electricity demanded by the industries.

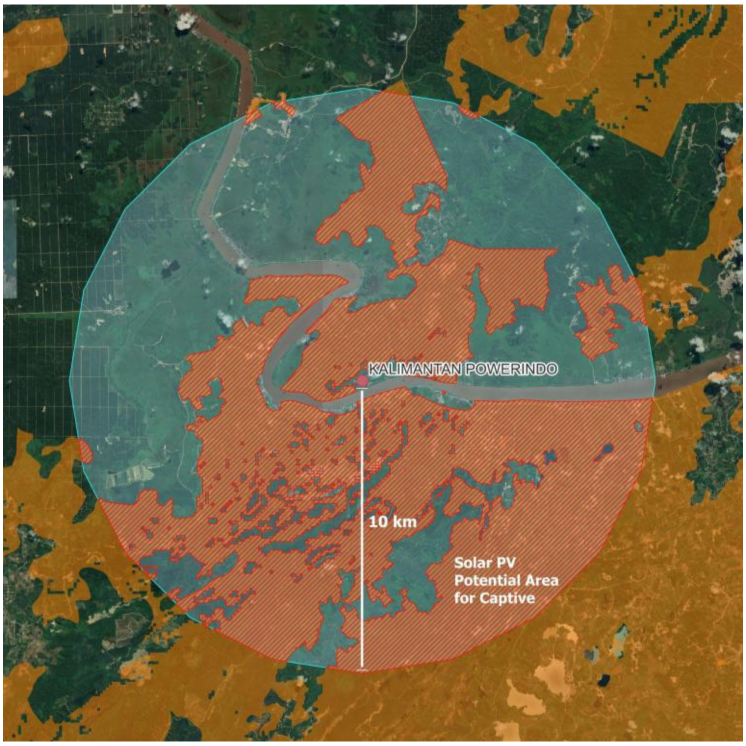
Solar PV

In this screening, data from IESR (2021) is used as a reference. The resulting distribution of usable area closely aligns with that of EBTKE. Excluding residential areas, the total solar PV potential considered in the screening is 496 GW.

To assess the potential for on-site solar PV, a 10 km radius perimeter is applied for each asset. The overlap between the area within this perimeter and the usable area determines the potential space available for that specific asset to build solar PV power plants. Figure 2-6 provides an example of this analysis for one asset in the GIS software.

---

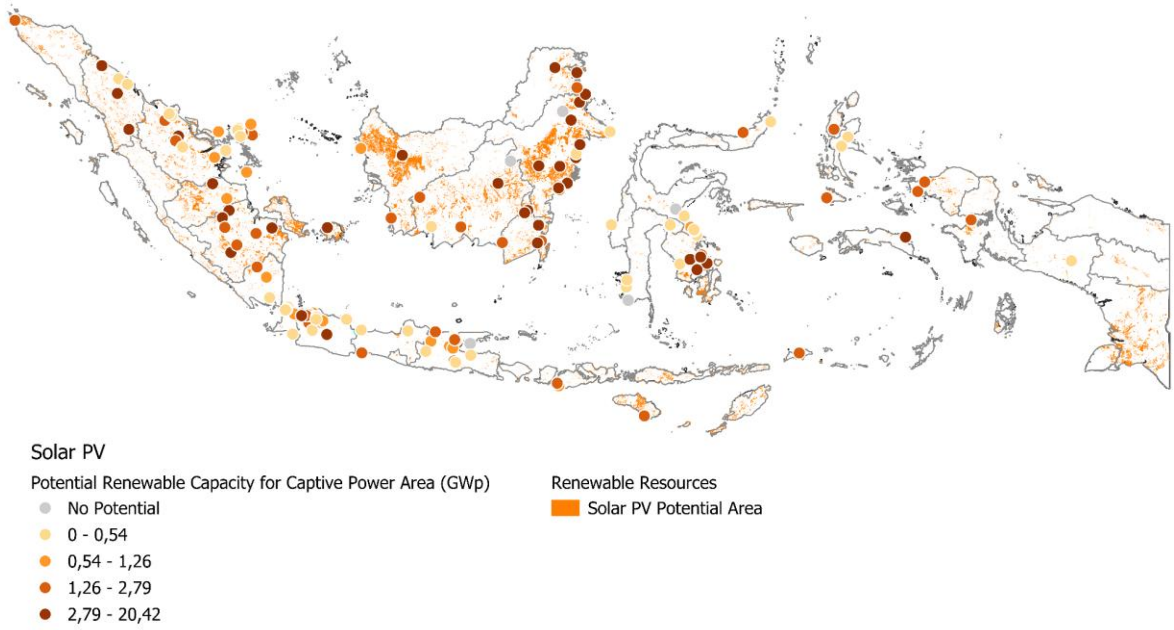
[5] UNEP-WCMC. (2019). User Manual for the World Database on Protected Areas and world database on other effective area-based conservation measures: 1.6. UNEP-WCMC: Cambridge, UK.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-6 Example Screenshot of Solar PV Potential for Selected Captive Power Area

To calculate the potential solar PV capacity, the asset potential area is multiplied by the solar PV power density from the Technology Data for the Indonesian Power Sector: Catalogue for Generation and Storage of Electricity (MEMR and DEA, 2024). Electricity generation potential is then calculated by multiplying the potential solar PV capacity with the daily average of estimated generation (kWh/kWp), which varies according to location (Global Solar Atlas, 2024). The result of the on-site solar PV technical screening is shown in Figure 2-7.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-7 Solar PV Potential for Captive Power Areas

Given the wide distribution of solar resources across Indonesia, solar PV implementation is possible for most of the captive power plants in the database, albeit to varying extents. The results point to the potential to maximize installed solar PV capacity at these locations to reduce emissions and support clean transitions, even though it may not completely replace fossil-fuel generation.

A challenge with solar PV as a variable renewable energy source (VRE) is meeting 24-hour dispatchable generation needs for energy-intensive industries with near constant load requirements. In this context, battery storage emerges as a viable solution to address this issue, while also optimizing the sizing of the solar PV systems at captive sites. Integration of battery storage with solar PV is analysed as part of the power supply modelling.

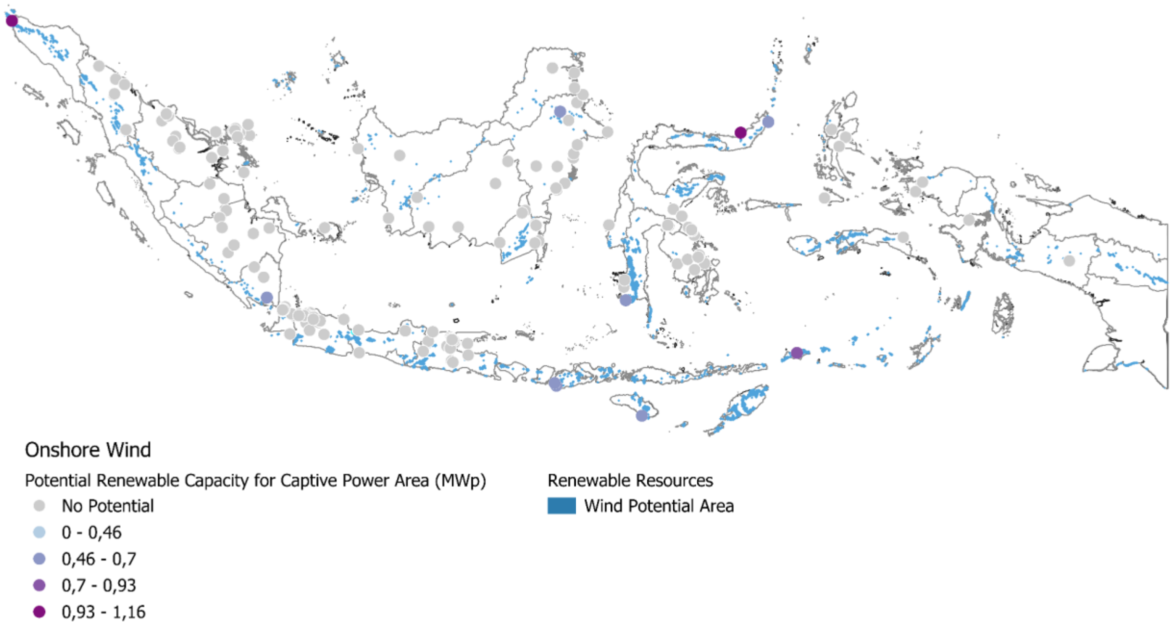
Subject to the extent of on-site solar PV and battery storage potential, these sources may only partially replace fossil-fuel power plants. As a result, other on-site renewable sources, other dispatchable sources (e.g. gas) or a robust supporting grid network may be important to meet the demands of energy-intensive industries.

Industrial clustering can help to improve the economies of scale in accessing solar PV at greater distances. While the map above shows the available potential for captive sites at a 10 km distance, in the case of modelled industrial clusters, far-away solar PV (based on province-level potential) is enabled in the system modelling carried out in Chapter 3.

Onshore Wind

Data from Scenario 1 in IESR (2021) is used. For now, the screening excludes offshore wind potential. To assess the potential for on-site wind power, a 10 km radius perimeter is applied for each asset. The overlap with the usable area determines the potential space available for that specific asset to build wind power plants.

To calculate the potential onshore wind capacity for an asset, the potential area is multiplied by the wind turbine power density from the Technology Data for the Indonesian Power Sector: Catalogue for Generation and Storage of Electricity (MEMR and DEA, 2024). Electricity generation potential is then calculated by multiplying the potential wind power capacity with the capacity factor of an ICE type III wind turbine (Global Wind Atlas, 2024). ICE type III is selected because it is typically used for areas with low wind speeds. The result of the on-site onshore wind power technical screening is shown in Figure 2.8.



Source: (JETP Secretariat and Working Groups, 2025).

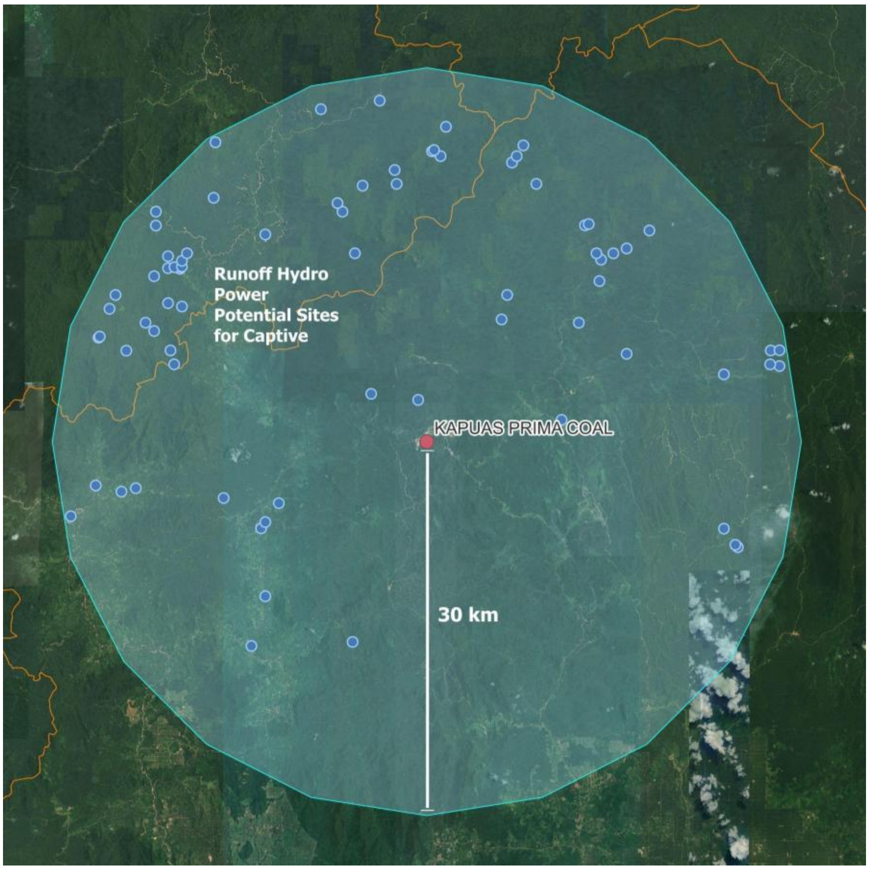
Figure 2-8 Onshore Wind Potential for Captive Power Areas

In contrast to solar PV, the potential for onshore wind energy at captive sites is assessed to be minimal, primarily due to the low inland wind potential in Indonesia.

Hydropower

The distribution of hydropower potential across Indonesia is represented by the potential points of run-of-river hydropower plants. Data from MEMR's New and Renewable Energy One Map is used, ranging from micro- to large-scale run-of-river hydropower. This data also presents the potential hydropower capacity of each point.

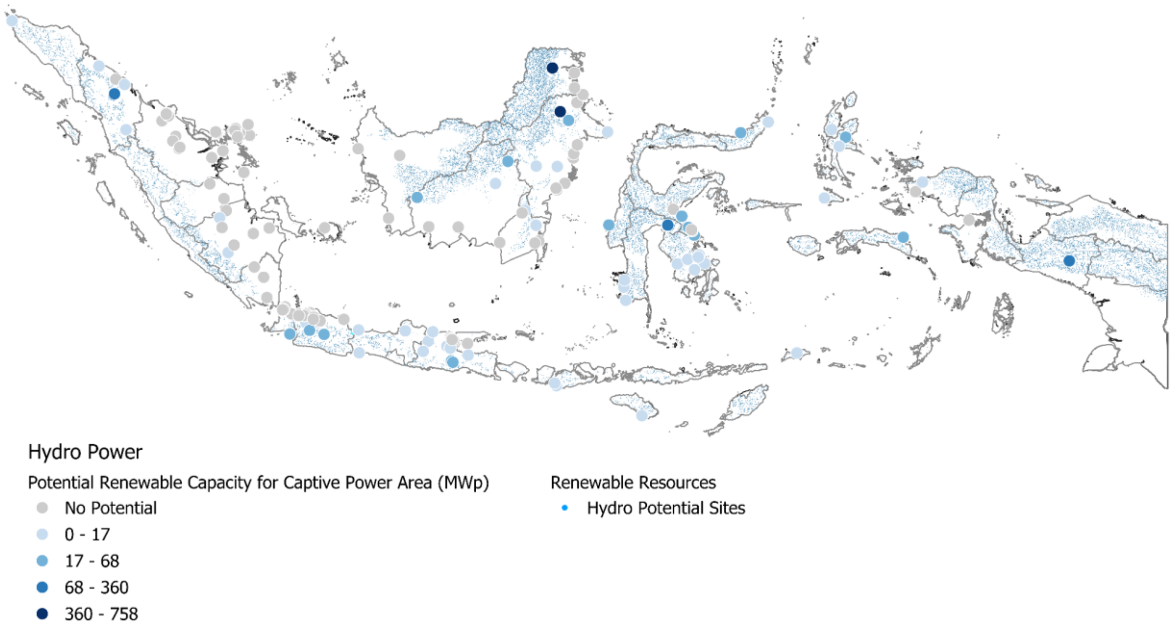
To assess the potential for on-site hydropower, a 30 km radius perimeter is applied for each asset. The hydropower potential points within this perimeter determine the sites available for that specific asset to utilize for hydropower plants. Figure 2-9 provides an example of this analysis for one asset in the GIS software.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-9 Example Screenshot of Hydropower Potential for Selected Captive Power Area

The total potential hydropower capacity for an asset is calculated by summing the capacities of all potential points within the perimeter. The electricity generation potential is then determined by multiplying this total capacity by the capacity factor of hydropower plants, which is based on their scale and obtained from the Technology Data for the Indonesian Power Sector: Catalogue for Generation and Storage of Electricity (MEMR and DEA, 2024). The result of the on-site hydropower technical screening is shown in Figure 2-10.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-10 Hydropower Potential for Captive Power Areas

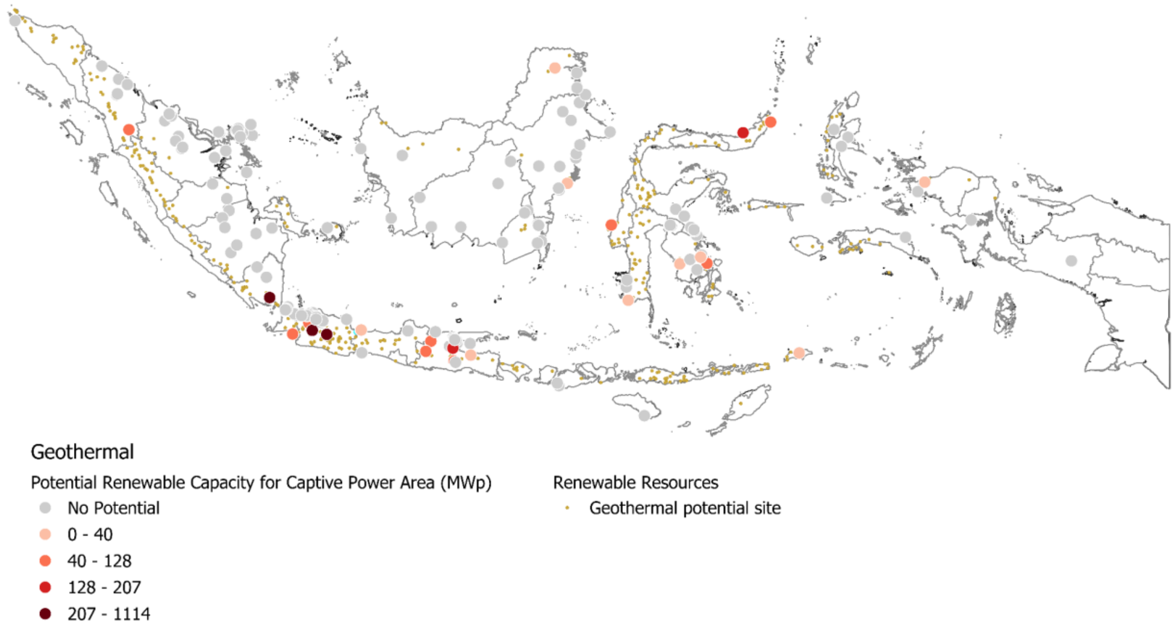
Currently, the technical screening is limited to run-of-river hydropower due to data constraints. However, determinations for reservoir hydropower will be included in the supply modeling, based on the potential capacity and generation values derived from this screening.

Industrial clustering can help to improve the economies of scale in accessing hydropower at greater distances. While the map above shows the available potential for captive sites at a 30 km distance, in the case of modelled industrial clusters, far-away hydropower (based on province-level potential) is enabled in the system modelling carried out in Chapter 3.

Geothermal

The distribution of geothermal potential across Indonesia is represented by the potential points of geothermal plants using data from MEMR's New and Renewable Energy One Map. This data also presents the potential geothermal capacity of each point.

To assess the potential for on-site geothermal power, a 30 km radius perimeter is applied for each asset. The geothermal power potential points within this perimeter determine the sites available for that specific asset. The total potential geothermal power capacity for an asset is calculated by summing the capacities of all geothermal power potential points within the perimeter. The electricity generation potential is then determined by multiplying this total capacity by the capacity factor of geothermal power plants, which is obtained from the Technology Data for the Indonesian Power Sector: Catalogue for Generation and Storage of Electricity (MEMR and DEA, 2024). The result of the on-site geothermal power technical screening is shown in Figure 2-11.



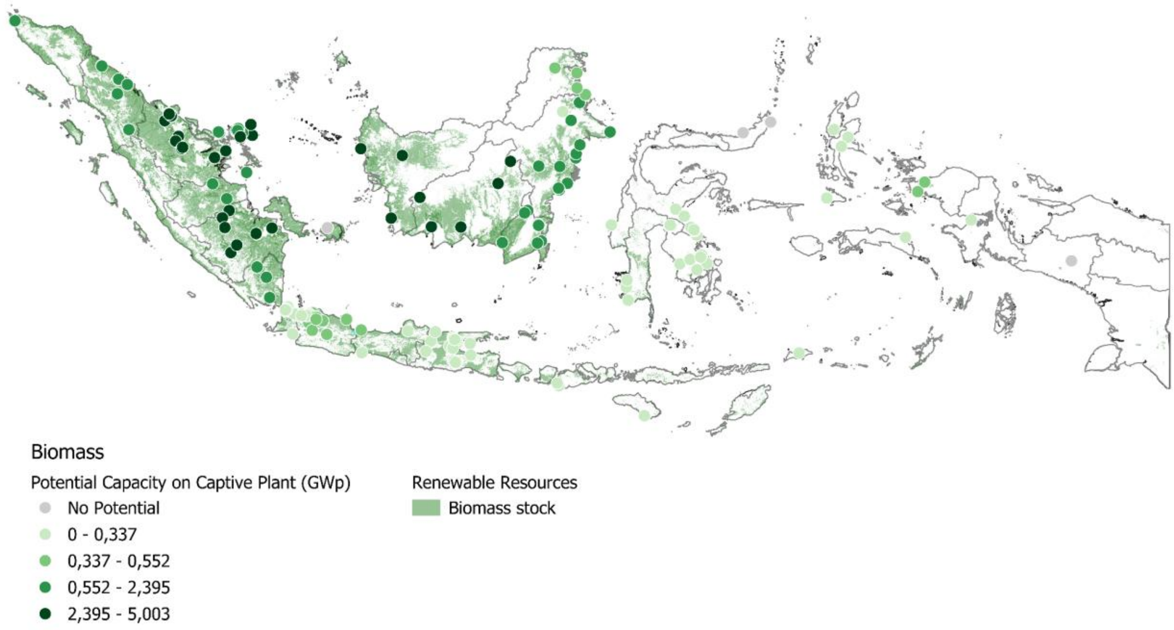
Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-11 Geothermal Potential for Captive Power Areas

Biomass

The distribution of biomass potential across Indonesia is based on data from MEMR's New and Renewable Energy One Map. The potential biomass objects calculated are obtained from the potential of food crops, plantations, and municipal waste. The food crop commodities come from rice (husk and straw waste) and corn (cobs, skin, stems and leaves) while the plantation commodities are in the form of coconut (shell and fiber), oil palm (stems, fronds, empty bunches, and fiber) and sugar cane (bagasse and leaves). For municipal waste, the biomass potential is obtained from paper, plastic, cloth, and food/organic waste. This data calculates the potential biomass capacity on a province level. The biomass potential for each asset is considered equivalent to the potential capacity of the province in which it is located, assuming transportation is possible within the province. This allows the asset to technically utilize the available resources throughout the entire province.

The electricity generation potential is then determined by multiplying the total biomass power capacity by the capacity factor of biomass power plants, which is obtained from the Technology Data for the Indonesian Power Sector: Catalogue for Generation and Storage of Electricity (MEMR and DEA, 2024). The result of the on-site biomass technical screening is shown in Figure 2-12.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-12 Biomass Potential for Captive Power Areas

While the map above shows the local technical potential for standalone bioenergy available for captive sites, for the co-firing of bioenergy with coal power, the technical potential is assessed at 10% of coal power generation for each captive coal plant.

Fuel-switching from Coal to Gas Power

This screening assesses the potential of building a gas power plant (instead of a coal power plant) at a given site or shifting an existing power plant from coal to gas based on potential access to gas infrastructure. The possibility of sourcing gas supply from pipeline gas or a floating LNG plant are taken into account. Benefits of fuel-switching from coal to gas for emission reduction include:

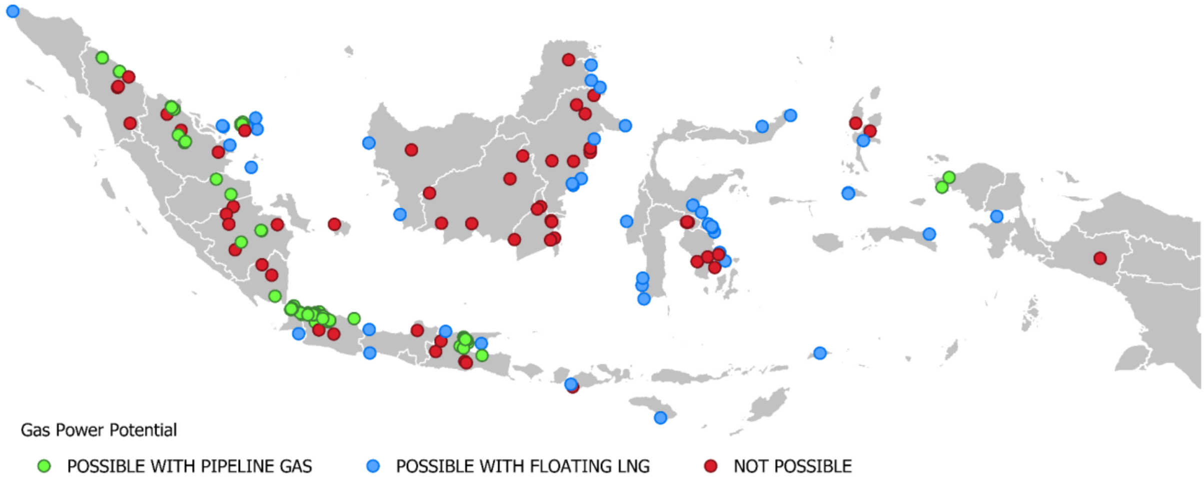
- Natural gas can serve as a transitional fuel for coal power plants, providing a cleaner alternative while still being dispatchable;
- Natural gas releases fewer emissions per unit of electricity generated compared to coal; and
- Using a gas turbine to generate electricity, instead of a steam-based generator with a gas-fueled boiler, offers further benefits due to the higher efficiency of gas turbines.

To be considered POSSIBLE for fuel-switching to gas, the asset must satisfy ONE of these conditions:

- Pipeline gas access: Located within 10 km of an existing gas distribution line. This is analysed using GIS by mapping the assets and the coordinates of the existing gas distribution lines (obtained from MEMR’s Oil and Gas Geoportal); or
- Floating LNG access: Located within 10 km of the nearest non-protected shoreline. This is determined using GIS proximity analysis, which calculates the distance from

the asset to the nearest shoreline, while excluding Marine National Parks and Protected Waters (data obtained from MoEF's SIGAP Geoportal).

The result of the fuel-switching to gas technical screening is shown in Figure 2-13.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-13 Gas Power Potential for Captive Power Areas Based on Gas Infrastructure Potential

CCS/CCUS

This screening focuses on potential opportunities for retrofitting captive coal power plants with CCUS, which can be relevant for enabling emissions reductions for assets that are either operational or in late stages of construction. While it is technically feasible to install a CCS/CCUS module on a generating unit, the economic viability is often challenged by the energy penalty, which is the additional energy required to capture, compress, transport, and store CO_2 compared to the energy consumed by the original industrial process or power plant without CCUS.

Several technologies are available for capturing CO_2 directly at the source of emissions, categorised into three main types:

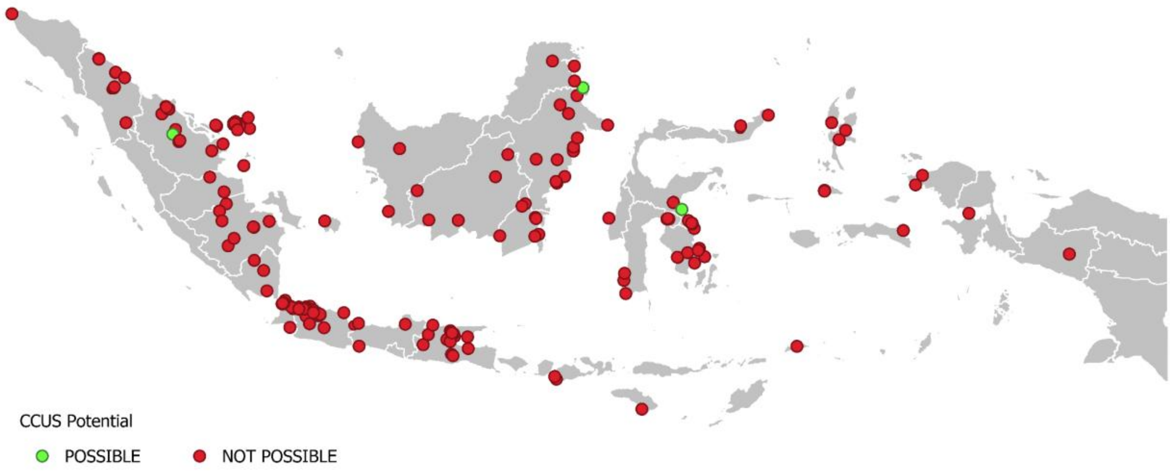
- Post-combustion carbon capture
- Pre-combustion carbon capture
- Oxy-fuel combustion systems

This screening focuses on retrofitting as the CCUS implementation method for CFPPs, given that most plants in the database are either operational, in late stages of construction, or have a target COD within the next five years. Post-combustion is the most suitable method, as it requires no major modifications to retrofit existing power plants, while also resulting in lower LCOE and CO2 avoidance costs compared to pre-combustion and oxy-fuel methods (PLN Enjiniring & ITB, 2023).

Therefore, to be considered POSSIBLE for CCS/CCUS retrofitting, the asset must satisfy ALL of these conditions:

- The unit capacity is at least 600 MW. According to literature (World Bank, 2015, p. 18), power plants need a minimum unit capacity of 600 MW to compensate for the energy penalty and the added investment costs of CCUS;and
- Located within the potential storage basin area. This is analysed using GIS by mapping the coordinates of the assets onto the area of potential carbon storage basin (obtained from MEMR's Geology Geoportal).

The result of the CCS/CCUS technical screening is shown in Figure 2-14.



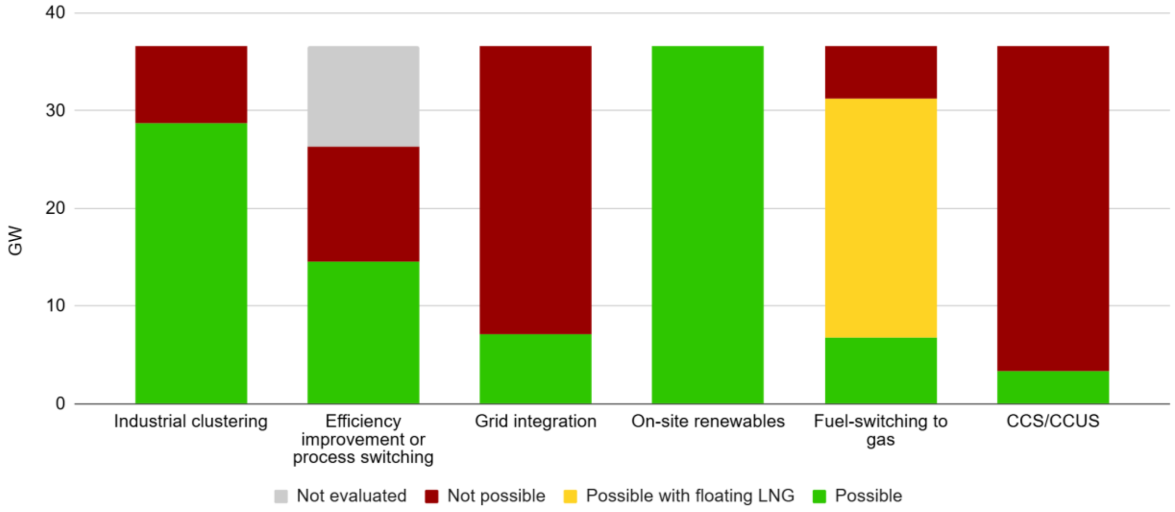
Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-14 CCUS Potential for Captive Power Areas

The majority of the plants listed in the database do not satisfy the requirements for CCUS implementation. Very few plants meet the size criteria, with just 3% of those in the database having a capacity of at least 600 MW. Among those plants, only four are co-located with potential storage sites identified by MEMR.

Results Summary

The overall results of the technical screening show that there is good technical potential for industrial sites to prioritize clustering and demand-side interventions, pursue grid integration opportunities, maximize available on-site renewables, and explore alternative options for gas to cover residual demand needs. Notably, all captive power sites have some degree of potential for on-site renewable power. The demand-side interventions, industrial clustering and efficiency improvement, follow with relatively high total capacity possible for intervention. Furthermore, floating LNG may present an untapped possibility for fuel-switching to gas for captive sites.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 2-15. Captive Power Capacity by Technical Screening Intervention

Note: Data indicate the amount of captive power capacity for which a given intervention is assessed as possible or not possible but does not reflect the total technical potential of each intervention; data are in net capacity terms and include all captive power tracked in the JETP Captive Power Database. The capacity evaluated for process switching and efficiency improvement is lower than other interventions due to more limited scope, which only covers metals industries (Nickel, Aluminum, Steel) in the database.

Renewable power source	Technical potential capacity
Biomass	241.7 GW
Run-of-river hydropower	3.2 GW
Geothermal	3.7 GW
Solar PV	496.3 GWp
Onshore wind	8.1 MW

Source: (JETP Secretariat and Working Groups, 2025).

Table 2-1. Total Technical Potential Capacity for Each Renewable Source Across All Captive Power Sites

There are considerable technical and economic challenges, however, in accelerating clean energy transitions for captive power (including managing legacy coal power assets, accessing renewable resources, meeting demand needs for firm power, etc.), pointing to the need for deeper consideration and analysis in making investment decisions. The system modelling carried out in Chapter 3 starts to tackle these issues in developing an energy and emissions pathway based on the technical screening carried out in this chapter.

Chapter 3: Energy and Emissions Pathways for Captive Power

3.1. Introduction and Summary of JETP Captive Scenario results

This chapter describes the results from the JETP Captive Scenario modeling from both the demand and power supply perspective, compared with a Baseline Scenario based on the starting capacity mix in the JETP Captive Power Database. Summary tables with the scenario results for captive power generation and capacity are presented here, with analysis of the projections across key dimensions found in the subchapters that follow. Scenario variants analyzing the impacts of lower renewables technology costs and lower fossil fuel prices as well as a section focused on system adequacy and flexibility with hourly dispatch results are found toward the end of this chapter.

Table 3.1-1 JETP Captive Scenario Captive Power Generation Projection by Technology

Source: (JETP Secretariat and Working Groups, 2025).

TWh	2024	2030	2035	2040	2045	2050
Coal	106.8	83.9	63.6	40.3	29.0	0.0
Natural gas	11.4	28.2	39.1	27.2	26.0	26.3
Oil	1.1	0.0	0.0	0.0	0.0	0.0
Waste Heat Recovery	7.0	7.6	7.6	7.6	7.6	7.6
Bioenergy	6.3	18.2	19.3	36.3	51.2	54.2
Geothermal	0.0	0.0	1.0	1.2	1.2	1.2
Hydropower	6.2	20.9	18.2	18.6	20.3	27.0
Solar PV	0.2	22.6	35.1	36.5	38.6	65.2
Wind	0.0	0.0	0.0	0.0	0.0	0.0
Total generation	**139.0**	**181.5**	**184.0**	**168.0**	**174.0**	**181.6**

Table 3.1-2 JETP Captive Scenario Captive Power Capacity Projection by Technology

Source: (JETP Secretariat and Working Groups, 2025).

GW	2024	2030	2035	2040	2045	2050
Coal	19.7	23.4	22.5	20.0	19.9	0.0
Natural gas	2.7	5.6	7.3	6.5	6.3	6.1
Oil	0.3	0.1	0.1	0.1	0.1	0.0
Waste Heat Recovery	1.0	1.0	1.0	1.0	1.0	1.0
Bioenergy	1.0	2.0	2.2	5.4	7.8	10.5
Geothermal	0.0	0.0	0.1	0.3	0.3	0.3
Hydropower	0.9	3.4	2.9	3.0	3.3	4.3
Solar PV	0.3	16.3	27.0	30.2	32.0	51.7
Wind	0.0	0.0	0.0	0.0	0.0	0.0
Total generation capacity	**25.9**	**51.8**	**63.1**	**66.4**	**70.5**	**73.9**
Battery storage	0.0	0.7	0.7	0.7	0.7	13.2

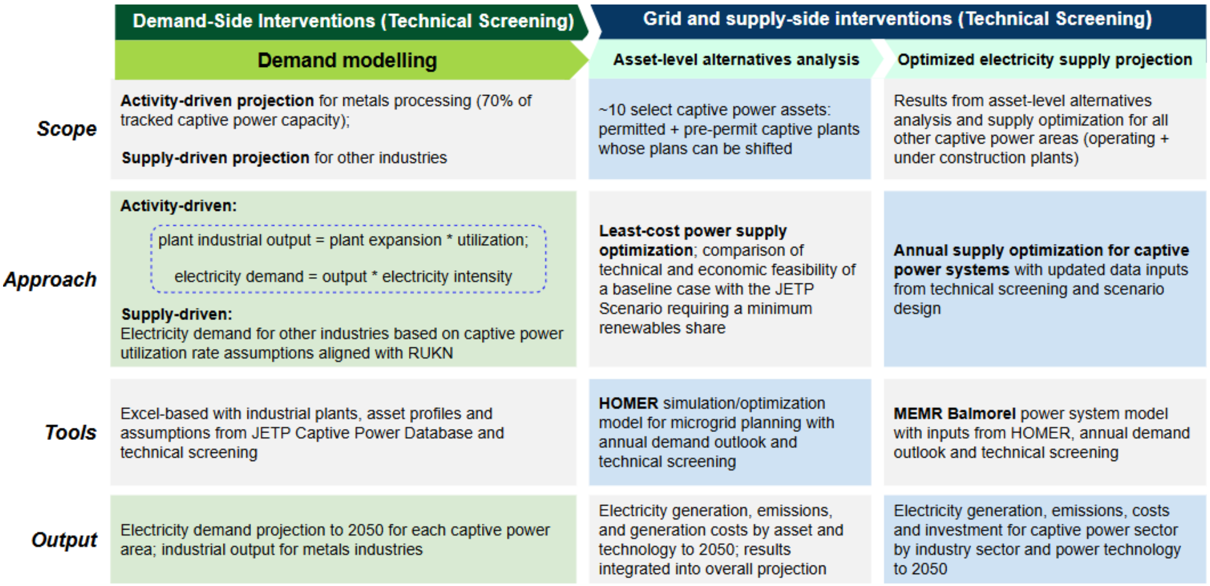
3.2. Modelling Approach and Key Assumptions

Modelling Approach for The Captive Power Sector

Guided by the possible clean energy interventions identified by the technical screening in Chapter 2, the JETP Captive Scenario takes a differentiated approach to modelling electricity demand and supply based on the type of industry and captive power plant status.

Electricity demand is projected on an asset-level basis. An activity-driven approach is taken for metals processing industries (aluminium, nickel, steel), which comprise 70% of captive power capacity in the captive power database. Industrial output is projected based on the industrial capacity expansion tracked in the database and a production utilization assumption. Electricity demand is based on an electricity intensity assumption derived from the technical screening for each production process. For other industries, the demand outlook is based on utilization rate assumptions for captive power and reported historical data on private power utilities (PPU) from the MEMR RUKN 2025.

The JETP Captive Scenario assumes a flat hourly and seasonal load profile for industrial electricity demand due to data limitations. This stable profile means that captive power generation systems need to provide power on a continuous 24-hour per day, 7-day per week basis, which creates a particular challenge for meeting demand through variable renewables supply sources. In practice, access to more granular industry- and asset-specific demand profiles is critical for designing optimal power supply solutions for energy intensive industries.



	Demand-Side Interventions (Technical Screening)	Grid and supply-side interventions (Technical Screening)	
	Demand modelling	**Asset-level alternatives analysis**	**Optimized electricity supply projection**
Scope	**Activity-driven projection** for metals processing (70% of tracked captive power capacity); **Supply-driven projection** for other industries	~10 select captive power assets: permitted + pre-permit captive plants whose plans can be shifted	Results from asset-level alternatives analysis and supply optimization for all other captive power areas (operating + under construction plants)
Approach	**Activity-driven:** plant industrial output = plant expansion * utilization; electricity demand = output * electricity intensity **Supply-driven:** Electricity demand for other industries based on captive power utilization rate assumptions aligned with RUKN	**Least-cost power supply optimization**; comparison of technical and economic feasibility of a baseline case with the JETP Scenario requiring a minimum renewables share	**Annual supply optimization for captive power systems** with updated data inputs from technical screening and scenario design
Tools	Excel-based with industrial plants, asset profiles and assumptions from JETP Captive Power Database and technical screening	**HOMER** simulation/optimization model for microgrid planning with annual demand outlook and technical screening	**MEMR Balmorel** power system model with inputs from HOMER, annual demand outlook and technical screening
Output	Electricity demand projection to 2050 for each captive power area; industrial output for metals industries	Electricity generation, emissions, and generation costs by asset and technology to 2050; results integrated into overall projection	Electricity generation, emissions, costs and investment for captive power sector by industry sector and power technology to 2050

Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.2-1 Modelling Approach for the JETP Captive Power Scenario

Electricity supply modelling incorporates the demand and technical screening inputs described above and is carried out using two different simulation and optimization tools.

For selected captive coal power plants which are in the permit and pre-permit stage of development, Asset-Level Alternatives Analysis is carried out using the HOMER Pro simulation/optimization model for microgrid planning, with the objective of avoiding planned captive coal power development in favor of a lower-emissions solution (see discussion on generation outlook below and Appendix B for a guide on the asset-level alternatives approach and detailed results for each asset).

The Balmorel model (which is also used by MEMR to develop the RUKN) is used to develop an optimized supply pathway for the remaining captive power sites, using the demand and technical screening inputs, in accordance with the emissions reduction measures set out in Presidential Regulation No. 112/2022 (see discussion on scenario design). The representation of captive power sites in the model takes the JETP Captive Power Database and associated demand projection (without efficiency or grid integration measures) as the Baseline for generation modelling, with adjustments to demand made in the JETP Captive Scenario based on the interventions (e.g. industrial clustering, grid integration, energy efficiency/process switching) from the technical screening.

The Balmorel model then consolidates capacity results from the asset-level alternatives analyses and calculates a JETP pathway for power capacity, generation, emissions, investments and generation costs based on an accelerated renewable power trajectory.

Key Assumptions for Captive Power

Similar to assumptions for the JETP Scenario for the on-grid power system in CIPP 2023, the macroeconomic, fuel price and technology investment cost assumptions for captive power are generally based on the MEMR RUKN, with an adjustment to reflect the historical coal price in 2024.

Table 3.2-1 Key Macro and Fuel Price Assumptions in the JETP Captive Scenario

Source: (JETP Secretariat and Working Groups, 2025), (Ministry of Energy and Mineral Resources, 2023).

	2024	2030	2040	2050
Macroeconomic				
GDP growth rate	5.0%	6.0%	7.0%	4.7%
Population (million)	283	294	313	324
Discount rate	10%	10%	10%	10%
Fuel and carbon prices				
Biomass (USD/tonne)	70	70	70	70
Biomass price (USD/tonne) imported	85	85	85	85
Coal price, captive power (USD/tonne at 4400 kcal/kg)	85	100	100	100
Natural gas price, LNG (USD/MMBTU)	12	12	12	12
Natural gas price, pipeline (USD/MMBTU)	7	7	7	7
Oil price – fuel oil (USD/barrel)	88	98	97	95
Oil price – diesel (USD/barrel)	60	70	69	67
Carbon price (USD/tonne)	model output	model output	model output	model output

Baseline assumptions for the cost and performance of technologies are from *Technology Data for the Indonesian Power Sector: Catalogue for Generation and Storage of Electricity* (Ministry of Energy and Mineral Resources and Danish Energy Agency, 2024). The boundary for cost and performance data are the generation assets plus infrastructure required to deliver power to the local grid. The catalogue uses a learning curve approach to project future costs. Levelized cost of electricity (LCOE) calculations are made within the model; results are described in the subchapter on generation costs.

Technical potentials for demand-side interventions, grid integration opportunities, on-site renewables, natural gas and CCUS are derived from the technical screening described in Chapter 2. Renewables resource potential is also adjusted to reflect potential already allocated to the JETP Scenario for on-grid power generation set out in CIPP 2023. The captive power capacity expansion includes identified operating and under construction captive power projects in the JETP Captive Power database, with generation investments modeled from 2027 onwards (renewable power, gas power, CCS/CCUS). Investment is based on a least-cost expansion, subject to local resource potentials, minimum required renewables shares, emissions constraints, firm capacity and other supply factors. Generation is based on economic dispatch, subject to constraints described herein.

As described below in the scenario design, depending on the captive plant status, the modelling aims to (1) avoid planned captive coal power development with an alternative power solution that achieves a minimum share of renewable generation (determined through the modelling) or (2) transition existing and under construction captive coal power through achieving a CO_2 emissions reduction of 35% by year 10 of operations and ceasing operations by 2050, in line with Presidential Regulation No. 112/2022. Emissions constraints are employed in the model to guide compliance with Presidential Regulation No. 112/2022. Fuel emissions factors are aligned with the RUKN.

Table 3.2-2 Select Technology Investment Cost Assumptions in the JETP Captive Scenario

Source: (Ministry of Energy and Mineral Resources and Danish Energy Agency, 2024).

USD (2022)/kW	2023	2030	2050
Generation			
Bioenergy (palm oil/rice husk)	2450 (1670 - 2310)	2083	1837.5 (1300 - 2200)
Geothermal (large)	4400 (3300 - 5500)	4400	3960 (1700 - 5100)
Hydropower (large)	2200 (1650 - 2750)	2112	1,958 (1,468 - 2,447)
Hydropower (medium)	2500 (1875 - 3125)	2400	2225 (1669 - 2781)
Solar PV (utility-scale)	960 (828 - 1500)	672	480 (288 - 600)
Solar PV (industrial)	1080 (1032 - 1728)	756	540 (324 - 1296)
Wind (onshore)	1650 (1200 - 2350)	1200	950 (600 - 1850)
Wind (offshore)	4100 (3500 - 4500)	3567	2870 (1550 - 3200)
Coal power (subcritical)	1880 (1140 - 1940)	1820	1760 (1140 - 1938)
Coal power (supercritical)	1600 (1200 - 2000)	1550	1500 (1130 - 1880)
with CCUS	+2240	+1910	+1270
Coal power (ultra-supercritical)	1730 (1300 - 2170)	1680	1630 (1220 - 2040)
Gas power (gas turbine)	1120 (850 - 1750)	1064	985.6 (600 - 1250)
Gas power (combined cycle)	1090 (740 - 1140)	1036	959.2 (630 - 1030)
Nuclear power plant (pressurized water reactor)	9000 (7000 - 12000)	7900	6800 (5000 - 10000)
Nuclear power plant (small modular reactor)	(5600 - 20000)	9600	7300 (5000 - 10000)
Electricity Grids			
Transmission (70 kV - 500 kV, USD/km)	300k - 1000k	300k - 1000k	300k - 1000k
Storage			
Battery (4-hour standalone, utility-scale) (USD/kWh)	470 (350 - 540)	330	230 (170 - 450)
Battery (10-hour standalone, utility-scale) (USD/kWh)	420	284	192
Pumped hydro storage	1200 (600 - 6000)	1200	1200 (600 - 6000)

Notes: Range of uncertainty is expressed in ( ); ranges only available for 2023 and 2050. "+" corresponds to additional cost to the same technology without CCUS.

Scenario Design and Key Comparisons for Captive Power

The JETP Captive Scenario follows guidance set out in the JETP Joint Statement. With regards to captive power systems for industrial uses, the Joint Statement calls for -

- *Restricting the development of captive coal fired power plants in accordance with the Presidential Regulation No. 112/2022 and collaborating to find and implement potential zero-emission and renewable solutions for power generation facilities outside Jawa-Bali, including captive power facilities, provided that the solutions are affordable (priced similar or better than the non-renewable alternatives), reliable (can provide base load), accessible, and timely (can be deployed within similar or better timeline than the non-renewable alternatives) to balance the imperative of industrial development and economic growth of Indonesia with the commitment on net zero; and*

- *Developing a strategy to avoid new captive coal and to successfully identify investments in renewable electricity supply as alternatives for all new captive projects.*

In developing a pathway to transition existing and under construction captive coal power plants and avoid the development of new ones, the JETP Captive Scenario integrates the full set of technical assumptions and energy strategies presented in this Chapter and from Chapter 2. The pathway also reflects policy reforms set out in Chapter 5 to enhance planning, permitting and licensing for captive power and industrial areas and to implement enhanced CO2 pricing and financing strategies.

The JETP Captive Scenario takes a differentiated approach according to the status of the assets:

- **Transition**: for captive coal power plants already operating or under construction - and thus difficult to fully change business plans before operation - the pathway for power generation and emissions is developed in accordance with provisions of Presidential Regulation No. 112/2022, but implementation is enhanced compared with current policy settings to prioritize early and regular progress towards emissions reductions over the lifetime of the asset and assure credible clean energy transitions.
- **Avoidance**: for captive coal power plants at the permitted or pre-permit stage - and thus possible to shift business plans ahead of construction - the pathway for power generation and emissions prioritizes renewable power and lower emissions alternatives to avoid new captive coal through Asset-Level Alternatives Analysis (see Appendix B for further detail and results).

Implementation of an enhanced version of Presidential Regulation No. 112/2022 is carried out through emissions constraints applied to captive coal power sites in the modeling. First, baseline emissions for each asset are determined from coal power generation in the first year of normal operation output.[6] Next, the required reduction by year ten of operations is calculated by applying the 35% factor stated in the regulation against the baseline emissions. An annual emissions cap for each asset is determined by apportioning the emission reduction linearly over the first ten operational years of an asset. The caps for each asset within a captive power site and industrial cluster are aggregated to give site-level and cluster-level emissions constraint values, which are then implemented in the Balmorel model.

For captive coal power assets commencing operations from 2022 and onwards, emissions reductions start from the first year of operation.[7] For captive coal power assets commissioned prior to 2022, emissions reductions start from the estimated year of license renewal, which is assessed to occur on a regular five-year basis (see discussion in Chapter 1 and Chapter 5 for more detail on captive power licensing). For captive coal power assets assessed as under construction with a commissioning date of 2027 onwards, the JETP Captive Scenario applies the full 35% emissions reduction from the first year of operations, considering the available time for those plants to make investments that can enable the site to pre-comply with the regulation.

---

[6] The modelling incorporates ramp-up assumptions for new industrial and power capacity. For most industries normal generation output is assumed to be reached in the second year of operations; for the nickel industry, the ramp-up to normal output levels is generally assumed to occur in the third year of operations.

[7] For captive coal power commissioned in 2022, emissions reductions are assumed to start from 2023, given that Presidential Regulation No. 112/2022 was enacted in September of 2022.

To align with longer term requirements under Presidential Regulation No. 112/2022 for captive coal assets to cease operations by 2050, a further linear emissions reduction is carried out over ten years starting in the year following the initial 35% reduction until the annual utilization of the coal plant reaches a 20% minimum load assumption, which is required to ensure reliable technical operation[8]. As described below, this coal phase-down may need to be enabled by targeted investments in operational flexibility for existing coal power assets. Coal power assets then fully cease operations in 2050 or at the end of their 30-year lifetime, whichever occurs sooner, bringing the coal emissions reduction for a given captive coal to 100% by 2050. Coal power assets reaching their end of life are replaced with modelled alternative generation sources, per the avoidance strategy described above.

The consolidated supply modelling in the Balmorel model involves the following steps to develop the JETP Captive Scenario results presented throughout this Chapter:

(1) **Modelling a Baseline Scenario** using a Baseline demand projection that excludes energy efficiency and grid connections, with initial capacity based on the JETP Captive Power Database and capacity expansion limited to coal power and solar PV.
(2) **Setting CO_2 policies for the JETP Captive Scenario** through the enhanced implementation of Implementation of Presidential Regulation No. 112/2022 via annual caps on coal emissions for coal assets, as described above.
(3) **Modelling an initial JETP Captive Scenario at site-level** based on the JETP demand projection (reflecting energy efficiency and grid integration measures), initial capacity based on the JETP Captive Power Database and Asset-level Alternatives Analysis, site-level coal CO_2 policies, least-cost capacity expansion with all technologies possible, excluding coal, and technical potentials from the clean energy screening.
(4) **Modelling the main JETP Captive Scenario with industrial clustering** based on implementation of the JETP Captive Scenario in (3) at cluster-level to enable more optimized dispatch, access greater renewables resource potential and make investments at scale; hourly model runs are carried out to assess system operations.
(5) **Modelling scenario variants** with an alternate Baseline Scenario Case testing the cost implications of following the Baseline Scenario with lower coal and gas prices and an alternate JETP Captive Scenario Case testing the generation mix and cost implications of lower cost solar PV/battery storage and enhanced demand flexibility.

A summary of the key scenario design features and comparisons is found in Table 3.2-3.

Table 3.2-3 Key Scenario Design Features and Comparisons for the Main JETP Captive Scenario for Captive Power Compared with a Baseline Scenario

Source: (JETP Secretariat and Working Groups, 2025).

	Baseline Scenario based on JETP Captive Power Database	**JETP Captive Scenario** Operating and Construction captive power	**JETP Captive Scenario** Permitted and Pre-Permit captive power
Annual average demand growth	6.3% over 2024-30 2.6% over 2024-50	4.6% over 2024-30 (5.2% including grid injections) 1.2% over 2024-50 (2.3% including grid injections)	
Demand profile	Flat hourly and seasonal demand profile	Flat hourly and seasonal demand profile	

---

[8] IRENA, “Flexibility in Conventional Power Plants” (2019)

Industrial clustering	Captive power sites modelled individually	Captive power sites modelled as aggregated demand areas when in proximity or located within industrial park	
Industrial process	Based on original process	Based on original process	Switch to more efficient process when possible
Energy efficiency	Not included	Electricity intensity improvement to benchmark level where possible	Electricity intensity improvement to benchmark level where possible
Demand in 2030 / 2050	201 TWh / 253 TWh	181 TWh / 180 TWh (188 TWh / 236 TWh [including grid injections])	
Grid integration	Not included	Grid injected demand into on-grid power system of 6 TWh from 2030 and 55 TWh from 2040	
Coal power policies	Not included	Presidential Regulation No.112/2022 applied to captive CFPPs licensed from Sep. 2022; and applied to older plants at license renewal: • Minimum 35% GHG emissions reduction by year 10 of operation vs baseline emissions, with reductions phased in linearly from year 1; • Emissions reductions through direct measures, e.g. energy efficiency and/or renewable energy; carbon offsets excluded; co-firing of bioenergy up to 10%; and • Cease operations by 2050.	The JETP Captive Scenario presents alternative power options for permitted and pre-permit captive coal power plants, thereby avoiding the commissioning of new captive coal in those status categories.
Additional supply policies	• Fuel prices and renewable costs assumptions aligned with JETP Captive Scenario	• Enhanced planning, permitting and licensing for captive power; • No renewables LCR; • Renewables PPAs and procurement aligned with market standards; • Coal price above DMO cap (on energy equivalent basis) [nb the DMO and price cap do not apply to captive power]; • No new gas power investments after 2035 to align with NZE goals; • Bioenergy share of generation limited to 30% to reflect uncertainty over supply chain development; and • Implementation of enhanced carbon pricing.	
RE generation share 2030 / 2050	12% / 16%	34% / 81%	
VRE generation share 2030 / 2050	3% / 7%	12% / 36%	
CO_2 emissions intensity in 2030	0.86 kg/kWh	0.55 kg/kWh	
CO_2 emissions in 2030	173 Mt	99 Mt	
Final year of CFPP operation	Not included	2050	

Notes: DMO = domestic market obligation; LCR = local content requirement; RE = renewable energy; VRE= variable renewable energy.

3.3. Outlook for Electricity Demand from Captive Power

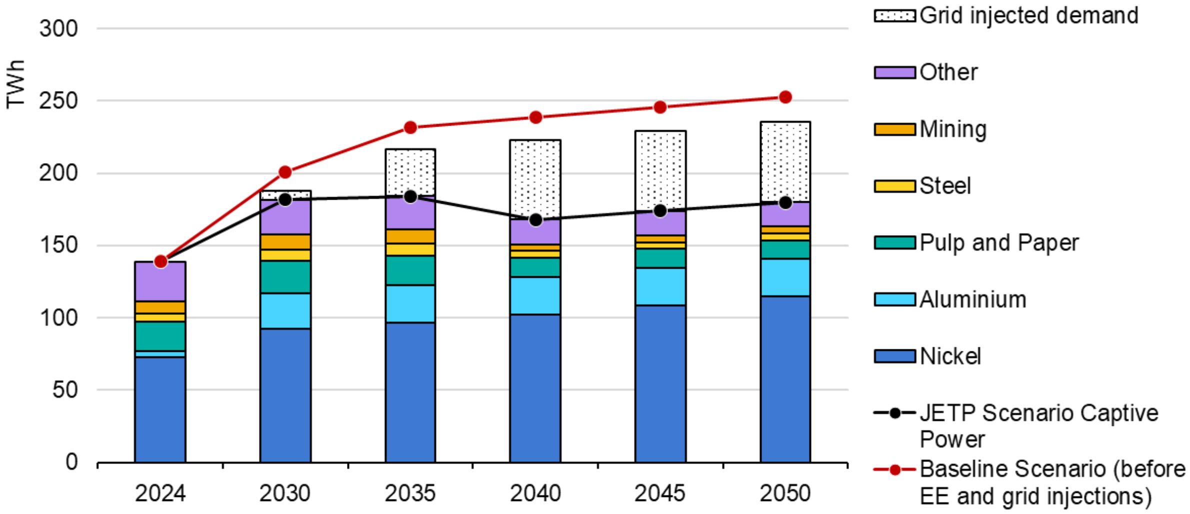
In the JETP Captive Scenario, electricity demand from captive power sites is primarily based on the asset-level capacity expansion, estimated output of industrial facilities (for aluminum, nickel and steel), and utilization of captive power plants (for all other industries) tracked in the JETP Captive Power Database as of July 2025.

As described below and in Chapter 2, industrial process switching and energy efficiency measures to reduce electricity intensity are assessed for aluminum, nickel and steel and are assumed to be implemented by 2030[9]. Such assessments are not made for other industries, given incomplete facility-level detail in the Database. The demand projection also excludes

---

[9] In metals processing, significant energy demand also comes from direct use of fuels for process heat. Fully optimizing this demand, including electricity, requires a more detailed assessment of the entire industrial process, including heat/chemical processes and material efficiency - such analysis falls outside this report's scope.

captive power sites integrated into the on-grid system in the year that the grid connection is made. While such grid injected demand becomes allocated to the on-grid system, and is not modelled as part of the captive power supply optimization, it is shown in the charts below for completeness. The JETP Captive Scenario demand projection for captive power is also compared to a Baseline Scenario projection, which sets out a demand trajectory before including the grid and demand-side efficiency interventions described above.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.3-1 Captive Power Electricity Demand by Industrial Sector in the JETP Captive Scenario

Notes: Data for 2024 are estimated values. Baseline demand excludes energy efficiency and grid injections. EE= energy efficiency; Nickel, Aluminum and Steel pertain to metals processing; mining-related demand for those metals is under Mining. Other includes diversified industrial areas, chemicals, crude palm oil, sugar, oil & gas, textiles and other industries.

The demand projection does not represent a comprehensive view of all electricity consumption within given industry sectors at national level, which may also depend on on-grid power[10]. No assumptions are made for additional industrial output or captive power, except in illustrative cases for nickel and aluminum processing presented below. The flattening trajectory of the demand projection over time aligns with planning (e.g. Presidential Regulation No. 112/2022) designed to limit new coal power and the government's objectives to prioritize the grid integration of energy-intensive industries over the long term. The trajectory is also broadly consistent with the recent Government Regulation (*Peraturan Pemerintah*) 28/2025 restricting new investment permits for nickel smelters, though there is uncertainty over the application of this regulation to individual plants tracked in the JETP Captive Power Database, which mostly includes nickel smelters already operating or under construction.

For 2024, electricity demand from captive power is estimated at 139 TWh, with over half from nickel processing. Pulp and Paper is the second largest industrial user of captive power, accounting for nearly 15% of demand. For context, on-grid power demand was reported in the MEMR RUKN at 285 TWh for 2023.

---

[10] Data limitations make it difficult to separate sectoral demand into captive and on-grid power supply. In nickel processing, captive power is estimated to currently account for over 90% of that industry's power supply capacity.

Looking ahead, electricity demand from captive power is projected to grow robustly in the JETP Captive Scenario by 4.6% annually to 181 TWh in 2030, but then level off to 2050 due to the effects of energy efficiency and the grid integration of an increasing amount of industrial electricity demand. In the JETP Captive Scenario projection, grid injected demand into on-grid power system rises to 6 TWh from 2030 and 55 TWh from 2040. The implementation of integrating this captive power demand from given sites into the on-grid system requires further feasibility study and addressing technical, regulatory and economic factors, as described further in Chapters 2 and 5. Overall, the combined impacts of efficiency and grid integration make the captive power demand projection 10% lower in 2030 and 30% lower in 2040 compared with the Baseline projection.

By 2030, around 45% of the projected demand growth comes from the nickel processing sector, 45% from aluminum processing (including aluminum and alumina production), and around 5% each from pulp and paper, mining, and steel.

As an illustration, projections for Nickel and Aluminum industries below integrate higher and lower industrial production levels and assume that incremental demand from this production is met through captive power. In the high production case, overall captive power demand would reach 206 TWh in 2030 and 249 TWh in 2050; in the low case, captive power demand would rise to only 163 TWh in 2030 and 178 TWh in 2050.

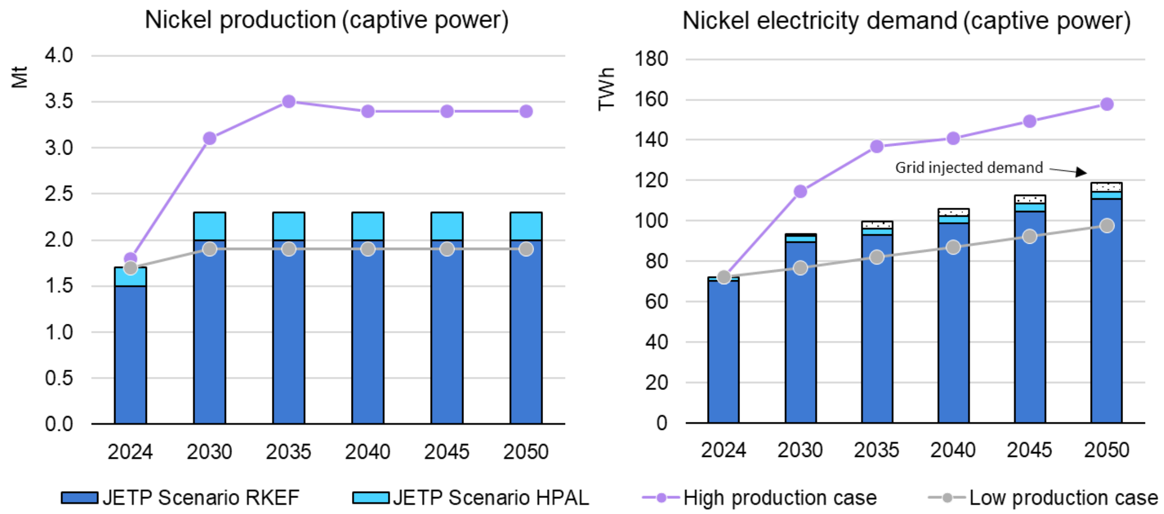
By comparison, captive power demand in the RUKN 2025 ranges from 155-198 TWh in 2030, depending on economic growth, and rises to a higher level of 262-433 TWh in 2050.

Focus on Nickel Demand

In the JETP Captive Scenario, nickel production from the pipeline of nickel processing plants based on captive power in the JETP Captive Power Database is projected to rise to 2.3 Mt in 2030, from an estimated 1.7 Mt in 2024, and level off thereafter. The outlook reflects a three-year ramp-up for individual plants to reach full production. Compared with the global outlook for refined nickel demand in the IEA Announced Pledges Scenario, Indonesia nickel production based on captive power would meet nearly 50% of nickel demand in 2030.

Around 74% of the production in 2030 is projected to come from nickel production routes based on rotary kiln-electric furnaces (RKEF) that primarily produce nickel pig iron and ferronickel intermediate products for stainless steel. A smaller share (13%) of total production in 2030 is projected to be from RKEF plants producing nickel matte, an intermediate product that can be refined into battery-grade nickel. Around 13% of the nickel production in 2030 is estimated to come from high-pressure acid leach (HPAL) processes, which produce mixed hydroxide precipitate (MHP) and mineral sulfide precipitate (MSP) intermediate products that can be refined into battery-grade nickel.

Based on this production outlook, captive electricity demand in Nickel is projected to rise to 93 TWh by 2030, up from around an estimated 72 TWh in 2024. The demand outlook is driven by the expansion of processing capacity, led by RKEF smelters, incorporation of energy efficiency and process switch measures, where possible, and declining ore quality input over time, which boosts demand to 115 TWh in 2050 even as overall nickel production remains relatively stable from 2030 onwards.



Source: (JETP Secretariat and Technical Working Group analysis, 2025).

Figure 3.3-2 Nickel Production and Electricity Demand Based on Captive Power by Processing Technology in the JETP Captive Scenario Compared with High and Low Nickel Production Cases

Notes: Projection includes demand (~4 TWh) identified for injection into the grid by 2040. RKEF = rotary kiln-electric furnace; HPAL = high-pressure acid leach.

The choice of nickel production route has an important impact on electricity demand. RKEF routes have significantly higher electricity intensities of production - with assumptions in the JETP Captive Scenario ranging from 34-43 MWh/tonne of produced nickel depending on product - compared with HPAL, whose intensity is assessed at around 8 MWh/tonne of nickel.

In the JETP Captive Scenario, energy efficiency improvements are screened on a top-down basis using the electricity intensity indicator. A starting intensity is assessed for each asset. Plants are then assumed to achieve the lowest intensity in Indonesia for the same production route and product through efficiency measures (e.g. waste heat recovery). The integration of these lower intensities (values noted in the paragraph above) helps the JETP Captive Scenario to achieve electricity savings of around 9% compared with the starting intensities. Further details on the screening, intensities and benchmarks are found in Chapter 2.

The JETP Captive Scenario also screens for industrial process switching from RKEF to HPAL. However, there are considerable technical, economic and environmental challenges in shifting technology for a given plant, especially those existing or already in construction. Only one process-switch candidate was integrated into the JETP Captive Scenario, which resulted in additional electricity savings of 2%, on top of the efficiency gains noted above.

Compared with the size of nickel captive power demand, the role of grid integration is projected to remain relatively modest, with only around 4 TWh, or less than 4%, of captive power demand from nickel assessed to be integrated into the on-grid power system by 2040. The limited role of grid integration stems from the remote location of nickel plants in Sulawesi and North Maluku compared with planned development of the PLN grid system.

The outlook also incorporates assumptions of declining nickel ore quality over time as the increasing exploitation of ore leads to natural declines in quality. The JETP Captive Scenario assumes a 1.5% annual ore grade decline rate, with a floor of 0.7% by 2060 (compared with

1.6% average grade in 2023)[11], which counteracts plant efficiency improvements and puts upward pressure on electricity intensity. Still, there is uncertainty over how the sourcing of ore (e.g. domestic vs imported) may evolve and the degree to which industry actors would maintain production utilization rates over time in the face of this dynamic.

Given uncertainty over the evolution of domestic and global nickel processing markets, two scenario variants (high and low case) for Indonesia's nickel production were analyzed to illustrate a potential range for the electricity demand projections. The difference between the two cases is significant, with electricity demand ranging from 77 TWh (low case) to 115 TWh (high case) by 2030 and from 98 TWh (low case) to 159 TWh (high case) by 2050.

In the high production case, Indonesia covers 50% of the global demand-supply gap for nickel in the IEA Net Zero Emissions scenario, an ambitious pathway with rising global nickel demand to meet material needs for clean energy technologies. In that case, Indonesia's nickel production rises to 3.4 Mt by 2050 and processing additions shift more towards HPAL technology. By contrast, the low production case recognizes economic uncertainties in the current global market, which is characterized by oversupply and weak production margins, and applies a strict interpretation by the government of a recently announced restriction on new development (see section above). In that case, only currently operating nickel smelters are included in the analysis.

Focus on Aluminum Demand

In the JETP Captive Scenario, production from the pipeline of aluminum processing plants based on captive power in the JETP Captive Power Database is projected to rise to 9.2 Mt of alumina and 1.5 Mt of aluminum in 2030, from 3.8 Mt of alumina and 0.2 Mt of aluminum estimated in 2024. This rapid expansion is partly driven by the ban on bauxite exports implemented by Indonesia in 2023 and assumes the full realization of significant new production capacity planned by industrial players.

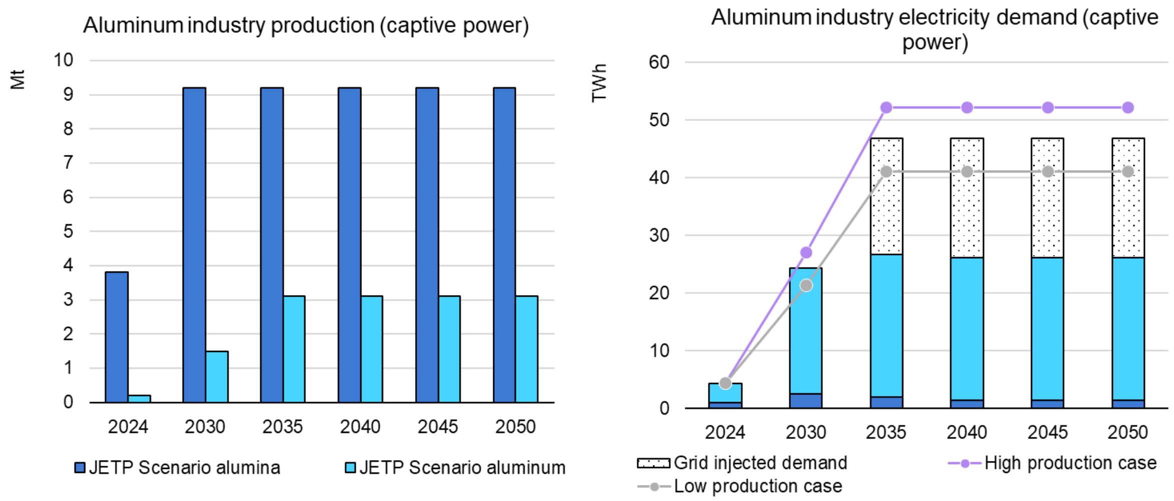
In the JETP Captive Scenario, captive power demand from aluminum processing (including alumina and aluminum production) is projected to rise to 24 TWh by 2030, from 4 TWh estimated for 2024, before settling at around 26 TWh over the subsequent period to 2050 as an increasing amount of industrial capacity is integrated into the on-grid power system.

The demand outlook is heavily influenced by the expansion of production routes to process alumina into aluminum. Alumina to aluminum processing has significantly higher electricity intensity of production compared with bauxite ore into alumina, whose intensity in the JETP Captive Scenario is assessed at 0.27 MWh/tonne of alumina. In the JETP Captive Scenario, the alumina to aluminum route has an electricity intensity of production of around 14.5 MWh/tonne of produced aluminium, depending on product.

Similar to nickel, energy efficiency improvements are screened on a top-down basis using the electricity intensity indicator. Plants are assumed to be able to achieve the lowest electricity intensity in Indonesia for the same production route and product through enhanced efficiency measures (e.g. waste heat recovery). The integration of these lower intensities helps the JETP Captive Scenario to achieve electricity savings in the aluminium industry of around 7% compared with the starting intensities. In the aluminium industry, no assumptions are made for industrial process switching between production routes.

---

[11] See https://link.springer.com/article/10.1007/s42461-020-00370-y for information on modeling nickel supply.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.3-3 Aluminum Industry Production and Electricity Demand Based on Captive Power by Product in the JETP Captive Scenario Compared with High and Low Production Cases

Notes: Data for 2025 are projected values. Alumina refers to bauxite-to-alumina production route; aluminum refers to alumina-to-aluminum production. The aluminum industry includes both of these production routes.

The role of grid integration into the on-grid system is projected to play a significant role in stabilizing captive power demand after 2035, with around 21 TWh, or 44%, of potential captive power demand assessed to be integrated into the on-grid power system by 2040. This notable role of grid integration stems from the proximity of some aluminum industry plants in Sumatra and Kalimantan to the planned development of the PLN grid system.

Given uncertainty over aluminum markets, two scenario variants (high and low production case) were analyzed to illustrate a potential range for the electricity demand projections. The difference between the two cases is notable, with electricity demand ranging from 21 TWh (low case) to 27 TWh (high case) by 2030, and from 41 TWh (low case) to 52 TWh (high case) in 2050. In the high case, alumina and aluminum production utilization rates average 95% whereas the low case utilization rates are assessed at 75%. Such variants illustrate the impacts of varied industrial production and are not adjusted for grid integration interventions.

3.4. Outlook for Captive Power Generation and Capacity

In the JETP Captive Scenario, Indonesia's captive power generation mix is projected to shift significantly, as the share of coal power, at over 75% in 2024, declines in favor of renewable power generation, which rises to surpass captive coal by 2035. Based on the clean energy demand and supply interventions in the technical screening and enhanced policies, financing and market signals to avoid new captive coal and transition existing captive coal, renewable power accounts most generation growth to 2030 and 2050, complemented by a greater role for gas, while reliance on coal declines.

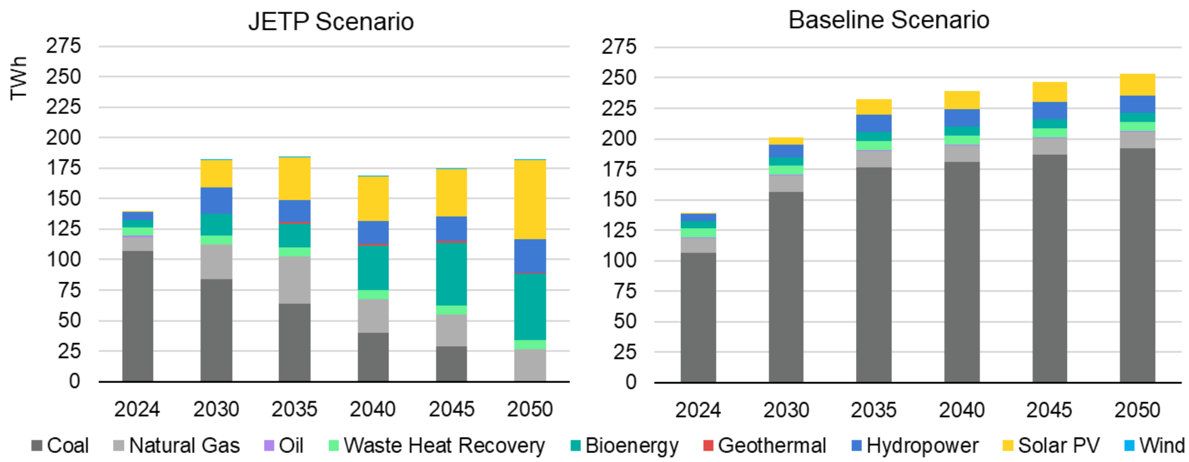
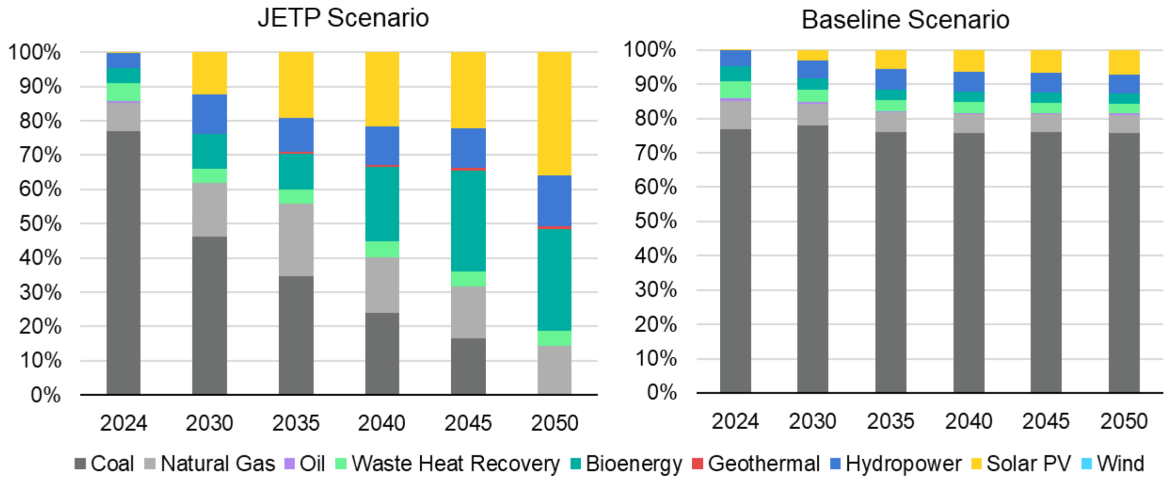


Figure 3.4-1 Captive Power Generation Projection: JETP Captive Scenario vs Baseline Scenario Based on Captive Database

Notes: Notes: Bioenergy co-firing (at 10% in the JETP Captive Scenario) with coal generation is allocted as part of bioenergy in generation but remains part of coal in capacity.

In the JETP Captive Scenario, the renewables share of captive power generation reaches 34% by 2030, 55% by 2040 and 81% by 2050, from 9% in 2024. Through 2030, generation growth is led by solar PV, which can be deployed quickly and cost effectively, followed by hydropower, which provides cost-effective firm power to captive sites in areas with access to good hydropower resources (largely in Sumatra and Kalimantan), gas and bioenergy, which supports renewables growth and phasing-down coal power, through 10% co-firing with coal in the near-term with standalone bioenergy deployed more over time. Over the next two decades, the share of variable renewables (largely solar PV) rises from minimal levels in 2024 to 12% by 2030, 22% in 2040 and 36% in 2050, complemented by the deployment of battery storage, especially in the second half of the projection period.



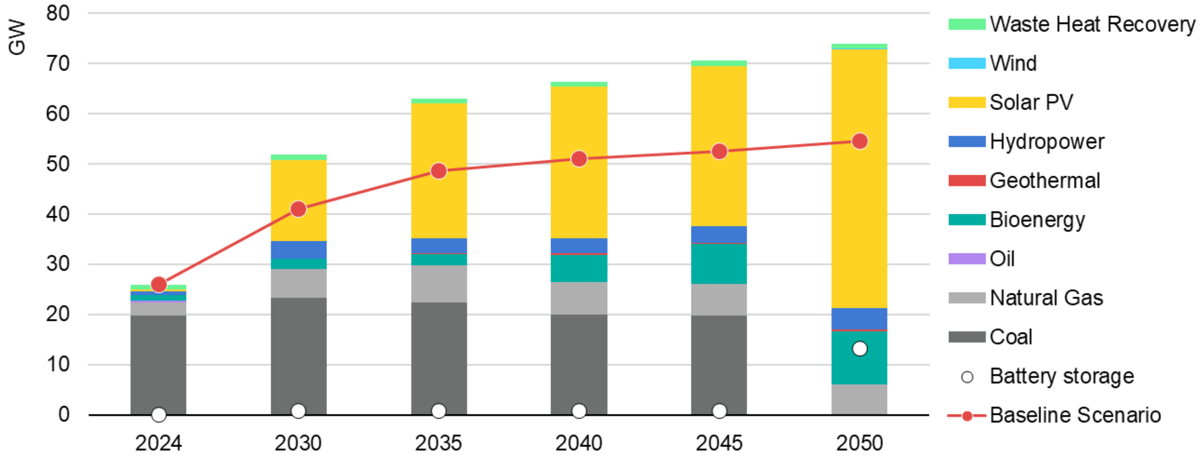
Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.4-2 Captive Power Generation Share Projection: JETP Captive Scenario vs Baseline Scenario Based on Captive Database

Notes: Notes: Bioenergy co-firing (at 10% in the JETP Captive Scenario) with coal generation is allocated as part of bioenergy in generation but remains part of coal in capacity.

As coal power declines – following the implementation of emissions reduction provisions under Presidential Regulation 112/2022, and the avoidance of new captive coal plants – and is eventually phased out by 2050, bioenergy (through a mix of standalone plants and co-firing) and gas power play an increasingly important role in the 2030s and 2040s, given continuous firm power needs by industries. However, new investment in gas is limited after 2035 to avoid potential emissions lock-in vis-à-vis net zero emissions by 2050 goals. The share of bioenergy generation in the JETP Captive Scenario is also limited to 30% of captive generation, given uncertainties over supply chain development for biomass feedstock. Existing waste heat recovery plants[12] play a small, but important role, accounting for nearly 5% of generation in 2030, while a small amount of geothermal development takes place from 2035 onward in sites with resource potential.

By contrast, in the Baseline Scenario based on modelling generation from the current capacity plans identified in the JETP Captive Power Database and new investments to meet growing demand - without explicit energy efficiency, clean energy or policy interventions - generation needs are much higher and the share of renewable power reaches only 12% in 2030 and tops out at 16% by 2050, with coal remaining the dominant power source at above a 75% share of generation throughout the projection period.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.4-3 Captive Power Capacity Projection: JETP Captive Scenario vs Baseline Scenario Based on Captive Database

Notes: Bioenergy co-firing (at 10% in the JETP Captive Scenario) with coal generation is allocated as part of bioenergy in generation but remains part of coal in capacity.

The captive power sector is currently marked by a degree of overcapacity due to a rapid build-out of coal power and preferences by industries, such as metals smelting, to maintain reserve capacity to ensure a high degree of reliability (see Chapter 1). For 2024, the average captive power utilization rate is estimated at just over 60%. Overall utilization of power capacity

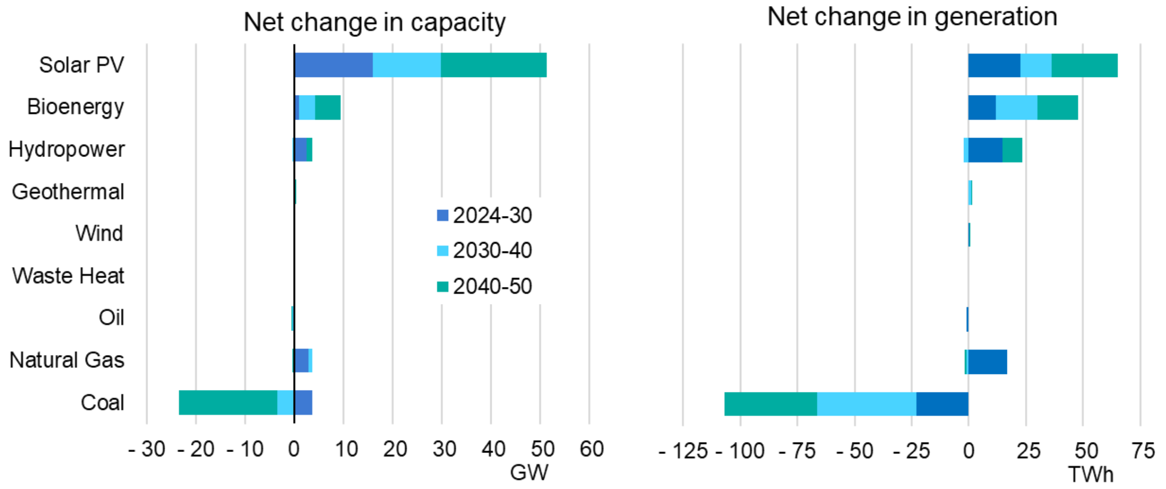
---

[12] Waste heat recovery plants are assessed to be powered by heat captured from industrial processes. In the JETP Scenario, waste heat is considered to be zero emissions for power generation, but given uncertainty over energy sources used for the associated process heat, waste heat is not considered to be a part of renewable energy.

declines in the JETP Captive Scenario as demand remains relatively stable, captive coal power is phased-down and alternate generation sources (e.g. solar PV) fill generation gaps, but supply adequacy is maintained throughout the projection through the deployment of adequate firm power sources (see System Adequacy and Flexibility subchapter below).

In the JETP Captive Scenario, solar PV leads captive power capacity deployment with important contributions from dispatchable sources. Captive solar PV rises from less than 1 GW in 2024 to reach over 16 GW in 2030 and 30 GW in 2040, complemented by battery storage, which rises to 0.7 GW in 2030 and over 13 GW by 2050. Hydropower reaches 3.4 GW by 2030, but rises to only 4.3 GW by 2050 due to resource potential constraints. Standalone bioenergy capacity reaches 2 GW by 2030 and plays a growing role from 2040 onwards to meet firm power needs, rising to around 11 GW to help fully replace coal capacity by 2050.

Overall, captive power power capacity in the JETP Captive Scenario is 28% higher in 2030 and 60% higher in 2050, compared with the Baseline Scenario due to the larger role of solar PV and battery storage, which require greater overall capacity to replace generation from captive coal power.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.4-4 Net Change in Captive Power Capacity and Generation in the JETP Captive Scenario

Notes: Bioenergy co-firing (at 10% in the JETP Captive Scenario) with coal generation is allocated as part of bioenergy in generation but remains part of coal in capacity.

Under the technology cost, financing and flat industrial demand profile assumptions of the JETP Captive Scenario, modelled investment decisions and generation dispatch to meet industrial firm power needs on a least-cost basis tend to favour dispatchable sources – hydropower (when available), bioenergy and gas – to replace coal generation in the near term, compared with increased reliance on solar PV hybridized with battery electric storage systems.

This choice by the model occurs even though bioenergy and gas tend to be relatively more costly on a levelized generation cost basis due to the need to overbuild the solar PV and battery system to provide sufficient generation to meet night-time demand requirements. Over the projection period, more solar PV and battery storage is deployed in the scenario as their technology costs come down. To further explore this dynamic and understand potential outcomes under accelerated cost reductions, a sensitivity analysis was conducted to evaluate the power generation mix and cost implications of lower cost solar PV and battery storage and enhanced demand shifting from night-time to daytime (see subchapter on Assessing impacts of scenario variants).

While captive coal plants, which are young on average, represent the largest generation source in 2030, their share in the JETP Captive Scenario declines to 46% from 77% in 2024. This occurs even as their capacity rises from 19.7 GW to 23.4 GW, with the commissioning of remaining plants under construction. Captive coal power capacity begins to decline after 2030 as plants reach the end of their lifetime and are replaced with alternate sources of generation.

The JETP Captive Scenario employs strategies to reduce emissions from the captive coal fleet and facilitate renewables deployment. For captive coal plants identified in the permitted or pre-permit stage, the JETP Captive Scenario employs the strategy of modelling an alternative power system that completely avoids the new coal power asset. Standalone asset-level alternatives analysis is carried out for some 3 GW of planned coal power, with the results demonstrating a renewable generation share of 65% and emissions reduction of 90%, compared with a modelled Baseline case based on the original coal power plants. Site-level results can vary significantly, however, with asset-level renewable shares assessed for the JETP Captive Scenario ranging from 31% to 100%, depending on the availability and costs associated with different renewable resources. (see Appendix 2 for more details and results of individual sites).

Captive coal plants in operation or under construction follow the 35% emissions reduction requirement of Presidential Regulation 112/2022 within their first ten years of operations and cease operations by 2050 under the regulation. The JETP Captive Scenario implements an enhanced version of Presidential Regulation 112/2022, which supports early and continuous emissions reductions for captive coal power sites over time, as described in detail in the section above on Scenario Design. These reductions are implemented through a modelled climate policy (i.e. emissions cap) that encourages a shift away from coal generation in economic dispatch decisions and incentivizes investment in alternatives.

As the share of variable renewables increases in the JETP Captive Scenario, the role of captive coal power also starts to shift from providing stable power supply to more of a load-following and balancing function (see subchapter on System Adequacy and Flexibility for further illustration), which is enabled by targeted investments for repurposing coal power assets to support more flexible utilization and operations[13]. The phase-down of coal power continues until plants reach 20% annual utilization, corresponding to their assessed potential technical minimum load after required investments to support operational flexibility (IRENA,

---

[13] In the JETP Scenario, repurposing investments for coal power flexible operations are required by the time an asset reaches 50% annual utilization rate, a threshold agreed with MEMR and PLN during CIPP 2023. Practical implementation of operational flexibility requires more detailed feasibility study to understand specific plant-level technical capabilities and requirements.

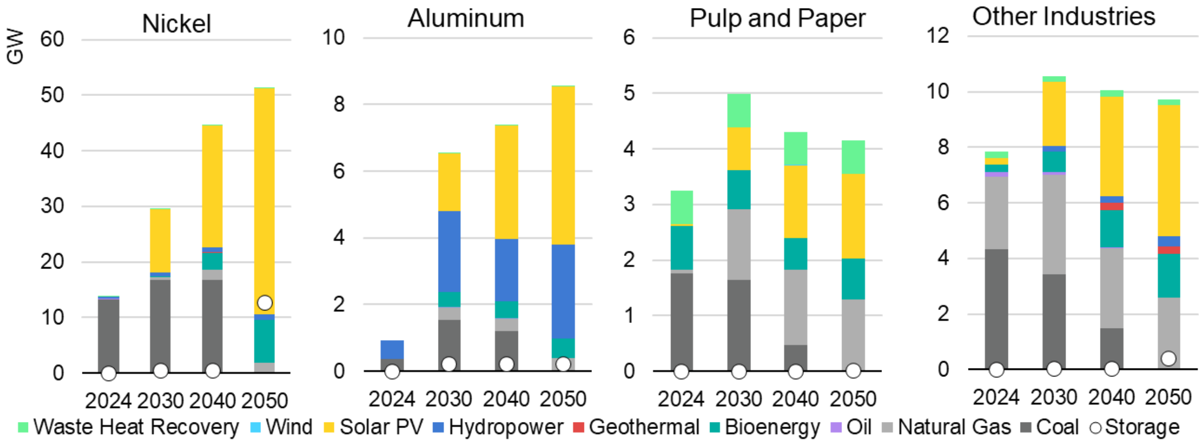
2019). Plants are phased-out (i.e. retired) and replaced when they reach the end of their lifetime or 2050, whichever occurs sooner.

In terms of fuel consumption needs in the JETP Captive Scenario, bioenergy feedstock requirements for captive power rise to 13 million tonnes (Mt) in 2030 and to 42 Mt in 2050. By comparison, Indonesia's total industrial demand and supply of biomass in 2024 stood at 20.7 Mt (MEMR, 2025). This comparison suggests that current industrial biomass supply would need to approximately double over the next 25 years to fulfill the pathway results, which could be seen as manageable given lead times to develop supply chains.

For gas in the JETP Captive Scenario, fuel consumption for captive power reaches a maximum level of 223 billion standard cubic feet (BSCF) in 2035. Compared with national Net Production (2,490 BSCF) in 2024, maximum gas demand corresponds to around 10% of domestic production, which suggests that the overall call on domestic gas may be manageable. Compared with industrial demand for gas in 2024, at 478 BSCF, the JETP Captive Scenario maximum gas demand is 47% of this level.

Focus on Industry Outlook for Capacity and Generation

Captive power projections in the JETP Captive Scenario vary considerably by industry and depend on starting coal power capacity, demand needs and local resource potentials.



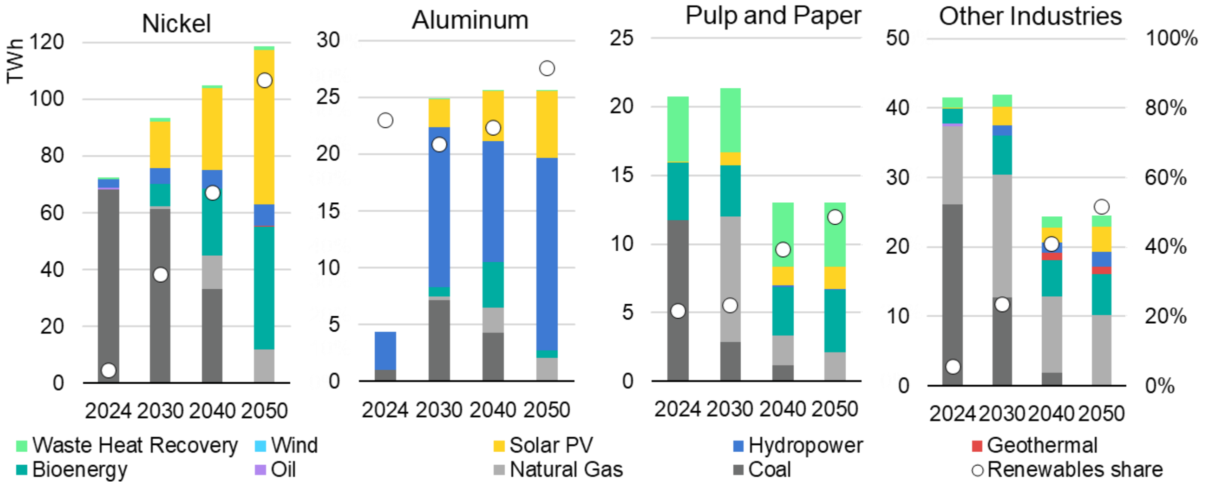
Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.4-5 Captive Power Capacity Projection in the JETP Captive Scenario for Key Industries

For Nickel, captive power capacity and generation grows strongly due to rising demand and limited grid integration opportunities. Transitions rely mostly on energy efficiency, solar PV (with battery storage) and bioenergy, complemented by fewer proximate hydro resources in Sulawesi and North Maluku, where most nickel processing is located. In the JETP Captive Scenario, the share of renewables in generation rises to 32% by 2030 from 4% in 2024, but the nickel industry remains the largest source of coal power, at just over 60 TWh. As coal is phased-down in the JETP Captive Scenario, the industry is projected to reach a renewables generation share of 56% in 2040 and 89% in 2050, underpinned mostly by an expansion of solar PV and bioenergy, complemented by gas and hydropower.

For Aluminum, access to excellent low-cost hydropower resources combined with energy efficiency allows captive power in that industry to achieve a 70% renewables share by 2030 in the JETP Captive Scenario, driven by 1.8 GW of hydropower capacity additions. This renewables generation share is somewhat lower than in 2024 due to the commissioning of captive coal capacity under construction, which partly offsets new hydropower and solar PV, but grows over time to 74% in 2040 and 92% in 2050, supported by the grid integration of around 20 TWh of demand by 2035, which reduces captive power generation needs.

Such an outcome depends strongly on the timely development and construction of those new hydropower projects, which can be subject to extended lead times and the commitment of aluminum asset owners and PLN to support the grid integration of some large smelters in a timely manner. In addition to those factors, the phase-down and eventual phase-out of remaining coal power in Aluminum is mostly projected to come through increased deployment of solar PV, battery storage, bioenergy and gas.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.4-6 Captive Power Generation Projection in the JETP Captive Scenario for Key Industries

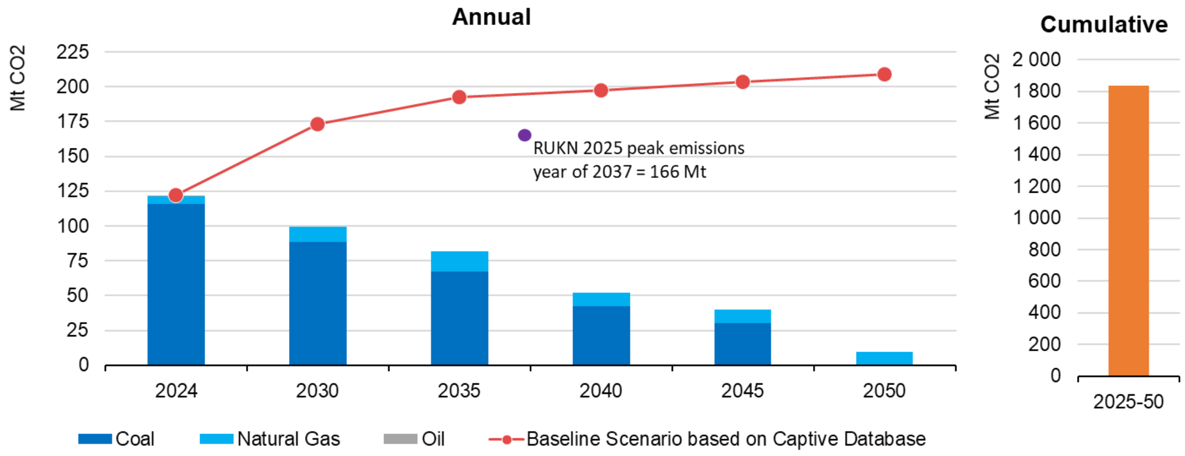
For Pulp and Paper, existing waste heat and bioenergy captive capacity, leveraging on-site bioenergy resources and waste, contribute strongly to meeting generation needs. However, the renewables generation share in that industry reaches only around 22% by 2030, up from 20% in 2024, due to the increased role of gas in displacing coal power. Pulp and Paper plants tend to be concentrated in Sumatra and Java, which are locations that tend to have better access to lower-cost pipeline gas. The role of solar PV also rises in the projection, and the total renewable generation share climbs to 38% in 2040 and 48% in 2050, partly enabled by reduced captive power demand needs through the grid integration of around 10 TWh of captive demand by 2040.

For Other Industries, the renewables share of captive power generation rises to 24% in 2030, from 5% in 2024, boosted by increased bioenergy, solar PV and hydropower. With such industries tending to be located in Java and Sumatra, gas remains the largest contributor to displacing coal power by 2030. Over time, the grid integration of 21 TWh of captive power demand from these industries by 2040, helps to decrease generation requirements and increase the role of renewables as solar PV, bioenergy and geothermal capacity (for select sites with good potential) expand.

3.5. Outlook for CO2 Emissions from Captive Power Generation

The accelerated renewables pathway of the JETP Captive Scenario results in strong and continuous reductions in captive power CO_2 emissions, enabled by enhanced policies and market conditions to support clean energy transitions in the sector. In the JETP Captive Scenario, captive power CO_2 emissions decline by nearly one-fifth from an estimated 122 Mt in 2024 to 99 Mt by 2030 to 52 Mt by 2040 and reach under 10 Mt by 2050. On a cumulative basis, CO_2 emissions in the JETP Captive Scenario total just above 1.8 gigatons over 2025–2050, compared with 4.9 gigatons in the Baseline Scenario.

These results are enabled by the clean energy technical interventions identified in this report and policies that seek to avoid new captive coal power and to transition operating and under construction captive coal plants with a climate policy, which caps captive coal emissions in the model at around 105 Mt in 2030 and reduces them gradually to a limit of around 50 Mt by 2040. The long-term emissions pathway is conditional upon the timely retirement and replacement of all remaining captive coal power capacity during the 2040-50 decade. The emissions reduction pathway for grid integrated industrial facilities and captive power plants is conditional on the timely grid connection of those assets, with sites then following the pathway for the on-grid power system from CIPP 2023, with safeguards required to transition captive coal to backup power functions and prevent carbon leakage into the PLN grid system (see Chapter 5 for further discussion).



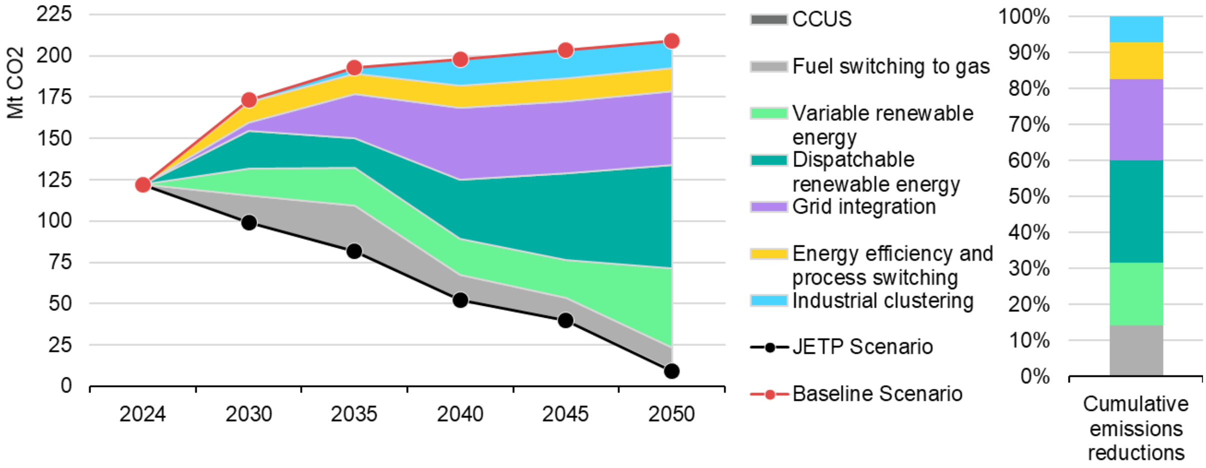
Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.5-1 Captive Power CO2 Emissions by Fuel: JETP Captive Scenario Compared with Baseline Scenario and RUKN 2025

By contrast, in the Baseline Scenario based on continued operation - without explicit clean energy or policy interventions - of captive coal power in the JETP Captive Power Database and new captive coal power investments to meet growing captive power demand, emissions would rise to 173 Mt in 2030 and 209 Mt in 2050. The JETP Captive Scenario also presents a more ambitious emissions reduction pathway than that set out in the MEMR RUKN 2025, where captive power emissions are projected to reach 166 Mt in 2037, the year of peak power system emissions under that plan.

An emissions decomposition analysis shows that in the JETP Captive Scenario, renewable energy generation acts as the largest source of emissions reduction compared with the Baseline Scenario, with dispatchable renewables (largely hydropower and bioenergy) comprising 39% of cumulative annual emissions reductions through 2030, 25% through 2040 and 28% over the entire projection through 2050 and variable renewables (largely solar PV) comprising 18% of emissions reductions through 2030, 20% through 2040 and 18% through 2050.

Grid integration of captive power accounts for only 4% of cumulative emissions reductions to 2030, but its role rises over time to comprise 18% of emissions reductions through 2040 and 23% through 2050. While this modelled result demonstrates the captive emissions reduction potential of this intervention, the practical implementation of integrating captive power from given sites into the on-grid system requires further feasibility study and addressing technical, regulatory and economic factors, as described further in Chapters 2 and 5, with safeguards to ensure that integrated captive coal power is relegated to backup function and coal power emissions are not transferred into the on-grid power system.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.5-2 Sources of Captive Power CO2 Emissions Reductions by Intervention in the JETP Captive Scenario Compared with the Baseline Scenario

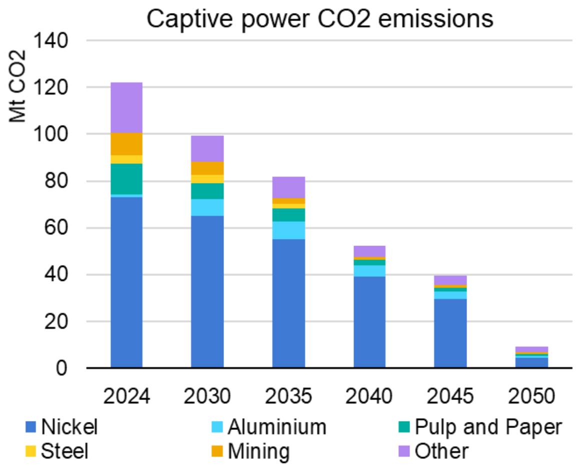
In addition, on the supply side, fuel switching to gas plays an important near-term role in enabling the JETP Captive Scenario emissions pathway, comprising 19% of cumulative emissions reductions through 2030. Nevertheless, the role of gas levels off and declines after 2035; it accounts for 21% of emissions reductions through 2040 and only 14% through 2050. Gas power fitted with CCUS technology plays a relatively minor role in emissions reductions, accounting for less than 1% through 2050, with development in few sites or clusters.

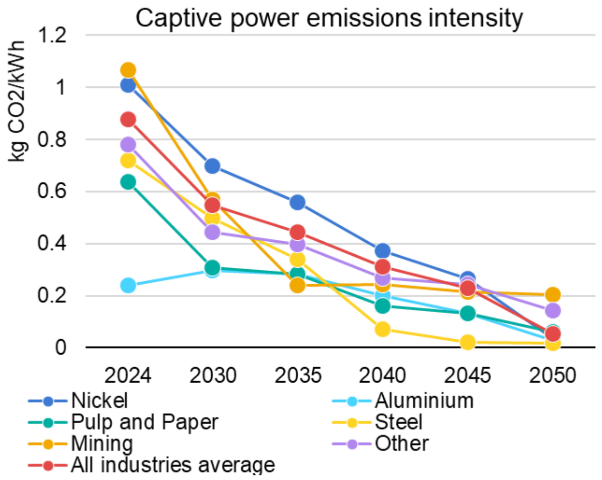
Demand-side interventions, including energy efficiency, process switching and industrial clustering play an important role, together comprising 21% of cumulative emissions reductions through 2030, 16% through 2040 and 17% through 2050. While their share remains relatively stable over time, such interventions have important overlap in enabling supply-side interventions through enhanced energy management, more optimized operations and aggregation of demand and renewables potentials. As such, this simplified analysis may understate the true role of these interventions in supporting captive emissions reductions for given sites.

While the JETP Captive Scenario sets out a pathway based on a portfolio of different emissions reduction measures, it is worth noting upside and downside risks for different interventions. Notably, challenges in realizing timely grid investments and the commitment of asset owners and PLN for integrating captive facilities in remote locations may create downside risks for grid integration opportunities. Less grid integration would likely result in higher required captive investments in renewable power and system costs to fulfill the emissions reduction requirements in the pathway. Growth in dispatchable power options may also be subject to risks based on available potential for hydropower, which may be distributed across multiple sites for a given area, and challenges in developing large-scale supply chains for bioenergy.

By contrast, the emissions reduction potential of demand-side interventions and variable renewable power (e.g. solar PV) has an upside that could be enabled by better feasibility assessments, more widespread market development, technology cost reductions, enhanced flexibility measures to support deployment.

In terms of industry results, the largest single industry emissions reduction in the JETP Captive Scenario occurs in Nickel, which sees captive power emissions decline from estimated 73 Mt in 2024 to 65 Mt by 2030 and to 39 Mt by 2040, followed by Pulp and Paper. While emissions rise initially in Aluminum, with the commissioning of captive coal under construction, they are mitigated over time with efforts to deploy alternative captive power sources and the role of grid integration for some large industrial plants. Most residual emissions in the JETP Captive Scenario are concentrated in other industries with access to pipeline gas supply in Java and Sumatra.





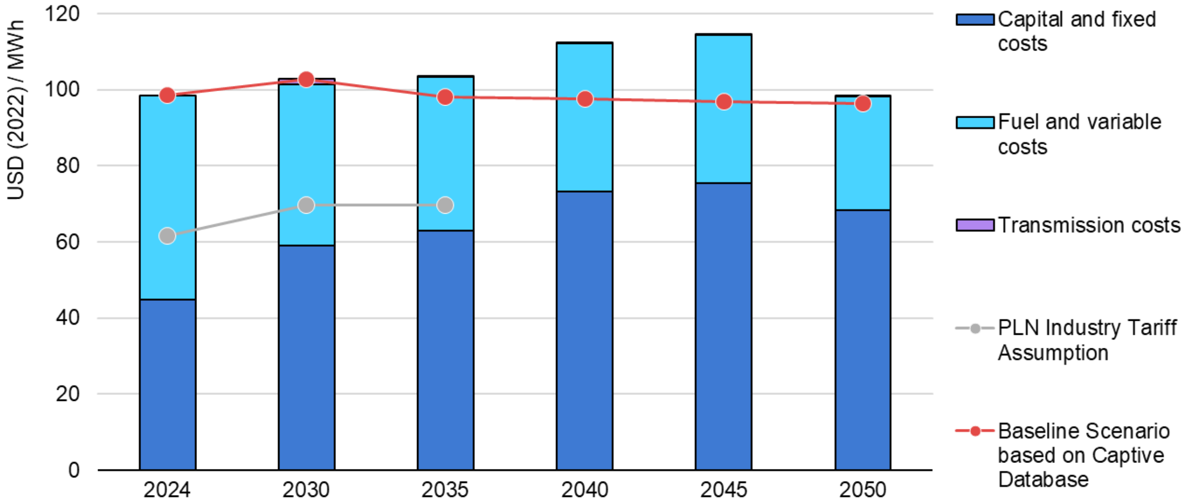
Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.5-3 Captive Power CO2 Emissions and Emissions Intensity by Key Industry in the JETP Captive Scenario

When assessing pathways, it is valuable to examine the emissions trends not only in absolute terms, but also in emissions intensity of generation. Intensity is an important performance indicator that helps to normalize the emissions comparisons between scenarios and industries given underlying differences in demand projections. Emissions intensities vary by industry pathway, but the overall captive emissions intensity drops from 0.88 kg CO_2/kWh in 2024 to 0.55 kg CO_2/kWh by 2030. This 2030 result is somewhat higher than the emissions intensity, at 0.47 kg CO_2/kWh in 2030, set out in the JETP Scenario for Indonesia's on-grid power system in CIPP 2023. This is due to greater technical challenges and higher starting share of coal power for decarbonizing captive power supply for energy-intensive industries with stable demand profiles.

3.6. Outlook for Captive Power Generation Costs

In the JETP Captive Scenario, average captive power generation costs on a per unit basis initially stabilize, then show an upward trajectory, and then decline by 2050, primarily due to the cost-effectiveness of renewables sources compared with fossil fuels. By 2030, solar PV is projected to become the least expensive new source of generation in Indonesia (see CIPP 2023 Chapter 5), as in many other regions around the world. However, the overall captive system costs reflect the generation mix of solar PV and other dispatchable sources, including storage, required to ensure firm power for industries with high and stable electricity demand profiles.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.6-1 Captive Power System Costs in the JETP Captive Scenario Compared with the Baseline Scenario

Notes: PLN industry tariff is from Statistics PLN 2024 and PLN RUPTL 2025; industry tariff for 2035 is extrapolated based on 2034 tariff and a 3.5% inflation assumption. All nominal PLN industry tariff data are adjusted to USD 2022 using a 3.5% inflation rate and IDR/USD exchange rate of 16,100.

Based on the capacity investment and generation dispatch in the JETP Captive Scenario, captive power generation costs are on average nearly US$ 103/MWh in 2030, up from US$99/MWh in 2024, with an increased role of hydropower and solar PV in generation. These system costs also include capital expenditures required to enable lower technical minimum load and more flexible operation of existing captive coal plants, which is important for the integration of renewables and coal phase-down over time. Due to data limitations, the system costs do not include potential investments in energy efficiency on the demand side.

Overall system costs rise over 2035-45 as gas (notably LNG) and then bioenergy increase to support coal transitions and to meet industrial demand needs. Based on the JETP Captive Scenario assumptions, the system modelling assesses that the use of dispatchable generation is more economical in those years to meet flat industrial demand profiles than a combination of greater solar PV plus battery storage[14]. Generation costs eventually decline to US$ 98/MWh 2050 with the phase-out of remaining coal capacity and a larger role for lower cost solar PV and battery storage.

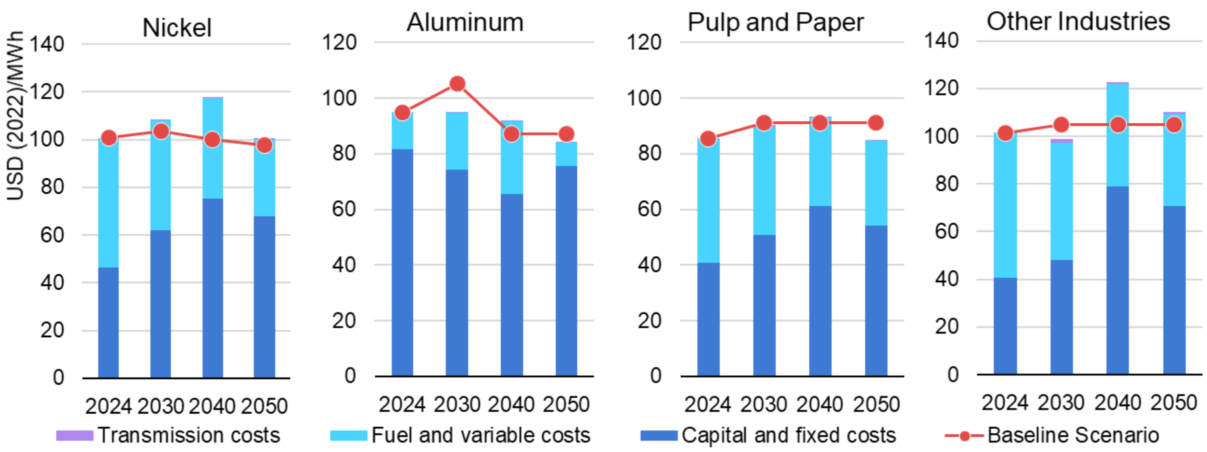
Overall, system costs are higher than those in the Baseline Scenario, but with differences across the years. In 2030 costs are similar, in 2035 they rise to 8% higher, while over 2040-2045 system costs are around 18-21% higher than in the Baseline Scenario. By 2050, JETP Captive Scenario system costs decline to only 2% higher than in the Baseline Scenario. The PLN assumption for industrial tariff is also included for comparison, which shows that captive owners could potentially save electricity costs through opportunities to integrate into the on-grid system, as identified in the JETP Captive Scenario. Nevertheless, the technical and financial feasibility of such grid connections requires further study and conditions from both PLN and the asset owner, as described above.

Transforming the captive power mix changes the nature of the underlying costs in the JETP Captive Scenario, as the power sector becomes more capital intensive. Capital and fixed costs for generation account for a rising share of the total costs, from just over 45% in 2024 to nearly 70% by 2050. This stems mainly from the rapid growth of solar PV, battery storage and hydropower, where most costs are incurred during construction, fuel costs are zero and operation and maintenance costs are relatively low.

While fuel costs decline over time with progressively reduced utilization of captive coal power plants and their eventual retirement, fuels comprise around 30% of total costs in 2050, reflecting conversions of retiring coal to run on bioenergy as well as a small remaining role for gas power. The generation cost calculations do not include potential additional financial compensation costs for accelerated captive coal power plant retirements over 2045–2050.

---

[14] Economic and technical factors that would enable a greater share of solar PV and battery storage are tested in the scenario sensitivity analysis in the subchapter on Assessing impacts of scenario variants..



Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.6-2 Captive Power System Costs by Key Industry in the JETP Captive Scenario compared with the Baseline Scenario

System costs also include an estimate for additional transmission required for integrating capacity power capacity to the PLN system and grid investment costs associated with industrial clustering of captive power and industrial facilities in proximity. Such transmission costs can be significant for individual captive power sites, but this category comprises a relatively small share of system-wide captive power costs, at around 1% in 2030 and 0.5% in 2050. The generation cost calculations do not include potential additional financial compensation costs for accelerated captive coal power plant retirements as a result of integration with the on-grid power system.

From an industry perspective, total captive power system costs vary strongly in 2030, with costs for Aluminum, Pulp and Paper and Other Industries around US$ 90-99/MWh and Nickel (still mostly reliant on coal in that year) at US$ 108/MWh. Growing roles for bioenergy and gas in some industries tend to raise costs over time, while solar PV and energy efficiency tends to reduce them. Costs remain comparable or somewhat higher than those in the Baseline Scenario for most industries with increased substitution of capital and fixed costs for fuel and variable costs over time.

The impacts of industry-level electricity costs from the JETP Captive Scenario on the economics of industrial production in Nickel and Aluminum and potential product pricing implications from implementing the JETP Captive Scenario for captive power are further assessed in Chapter 6.

The JETP Captive Scenario also assesses the CO2 abatement costs - a proxy for the CO2 price that would be required to achieve the emissions reductions in the pathway. As described in Chapter 5, implementation of enhanced carbon pricing helps to enable the pathway.

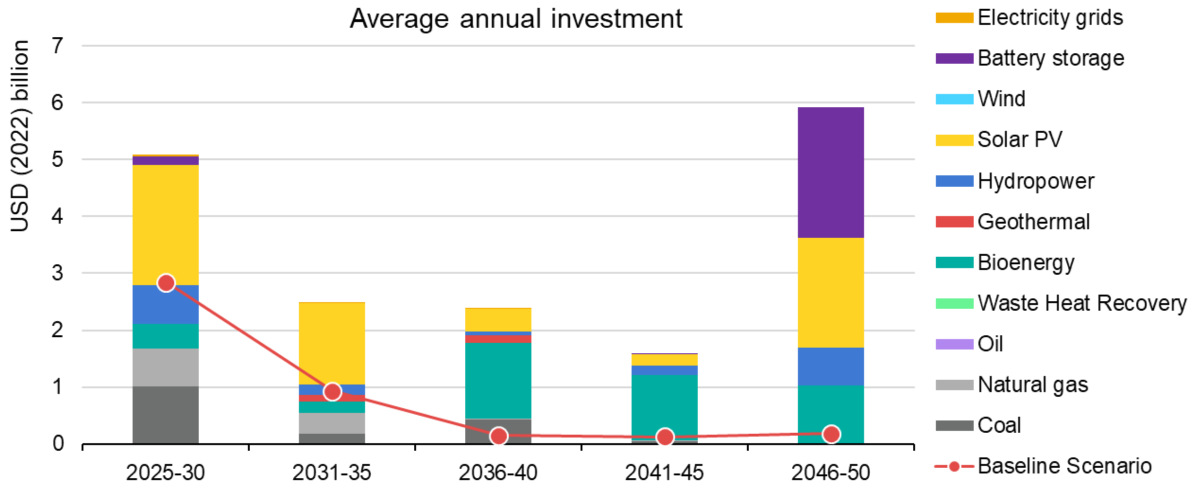
Based on the JETP Captive Scenario emissions pathway, the average marginal abatement cost is projected at around US$ 9/t in 2030, US$ 45/t in 2040 and US$ 62/t in 2050. Consistent with the system cost trajectory, such costs rise to 2040 with an increased reliance on bioenergy and gas, but then decline by 2050 with a larger role for lower cost solar PV and battery storage. It is important to note that these averages include a wide range of abatement costs that vary strongly by captive power site or cluster. For some sites where achieving the

JETP Captive Scenario emissions pathway results in lower system costs, the abatement cost is zero. For some large clusters, however, marginal abatement costs rise as high as around US$ 80/t by 2050 in order to bring captive coal power emissions to zero and achieve net zero emissions overall.

By comparison, carbon price assumptions in the 2024 IEA Announced Pledges Scenario for emerging market economies such as Indonesia (assumptions which align with Indonesia's economy-wide net zero emissions by 2060 goal) stood at US$ 40/t in 2030 and US$ 160/t in 2050 (IEA, 2024). Such results and comparisons suggest that the clean energy interventions and coal reduction strategies implemented in the JETP Captive Scenario represent a cost-effective means to reducing captive power emissions.

3.7. Outlook for Captive Power Sector Investment

Under the JETP Captive Scenario, investment in the captive power sector initially rises, averaging US$ 5.1 billion annually between 2025 and 2030. While the US$20 billion of public and private financing committed under the JETP agreement provides an important catalyst, approximately US$31 billion of cumulative captive power sector investments are projected by 2030 under the JETP Captive Scenario. As the JETP funds represent only a fraction of the total investment needs, realizing the outlook depends on mobilizing much greater funding from diverse sources of capital.



Source: (JETP Secretariat and Working Groups, 2025).

Note: data correspond to overnight investments.

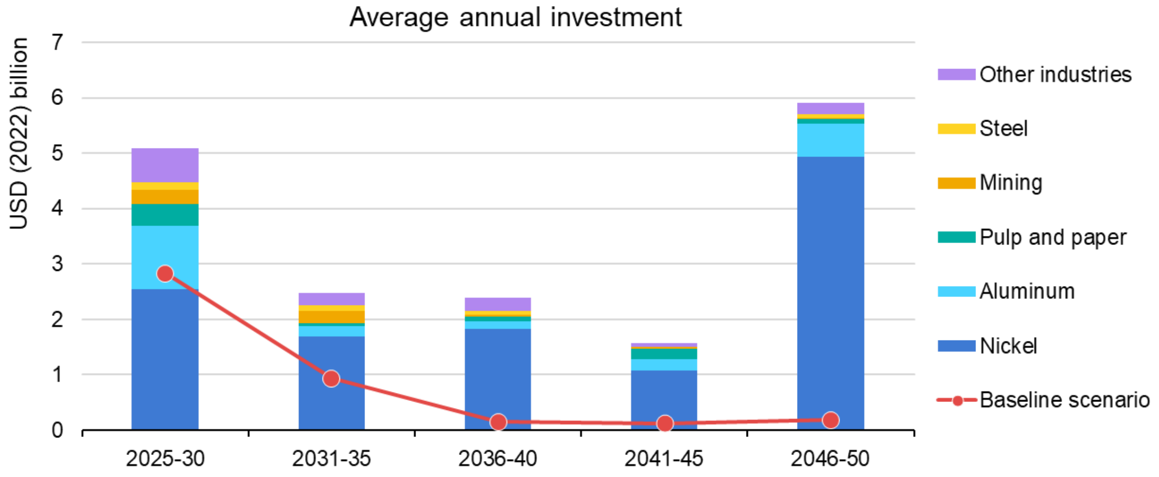
Figure 3.7-1 Captive Power Average Annual Investment in the JETP Captive Scenario Compared with the Baseline Scenario

Captive power investments through 2030 focus on deployment of renewable power and battery storage (comprising two-thirds of the total), led by solar PV (annual average US$ 2.1 billion) and hydropower (annual average US$ 0.7 billion). Investments in captive gas power and electricity grids (to support grid integration of some captive sites and industrial clustering) play a smaller but important role in enabling the pathway.

Investments through 2030 also reflect capital spending on captive coal power already under construction. They also include up to US$ 0.5 billion annual average investments required to enhance the operational flexibility of existing captive coal plants to reduce utilization rates and facilitate the integration of variable renewable power, through lowering technical minimum loads, increasing ramp rates and reducing start-up times, as demonstrated in the System Adequacy and Flexibility section below. Such investments in operational flexibility require further study to assess the real flexibility capabilities and needs of individual captive power sites and clusters.

Overall captive power investment then declines to lower levels in the next two decades, but rises in some technologies, notably bioenergy, to support clean firm power needs as captive coal power is phased down. Investment is projected to rise again toward 2050, reaching nearly US$ 6 billion annually, with solar PV and battery storage accounting for over 70% of capital spending to support the deployment of renewable energy sources to fully phase out captive coal and reach net zero emissions by 2050. A total of US$ 92 billion of cumulative investment is required under the JETP Captive Scenario through 2050. Solar PV is expected to account for the largest share, around 35%, and total over US$ 32 billion by 2050, with bioenergy (US$ 21 billion), battery storage (US$ 12 billion) and hydropower (US$ 10 billion) the next largest sources. Geothermal, by contrast, accounts for a smaller portion under the JETP Captive Scenario, at just over US$ 1 billion.

Although renewables and battery storage account for nearly 85% of cumulative investment, fossil fuels (coal and gas) continue to play a role in investment, including around US$6 billion of capital spending in captive gas power and up to around US$6 billion in repurposing investments for operational flexibility of existing captive coal power. Cumulative grid investments, at around US$ 0.3 billion remain small but strategically important for grid integration of captive sites and industrial clustering.



Source: (JETP Secretariat and Working Groups, 2025).

Note: data correspond to overnight investments.

Figure 3.7-2 Captive Power Average Annual Investment by Industry in the JETP Captive Scenario Compared with the Baseline Scenario

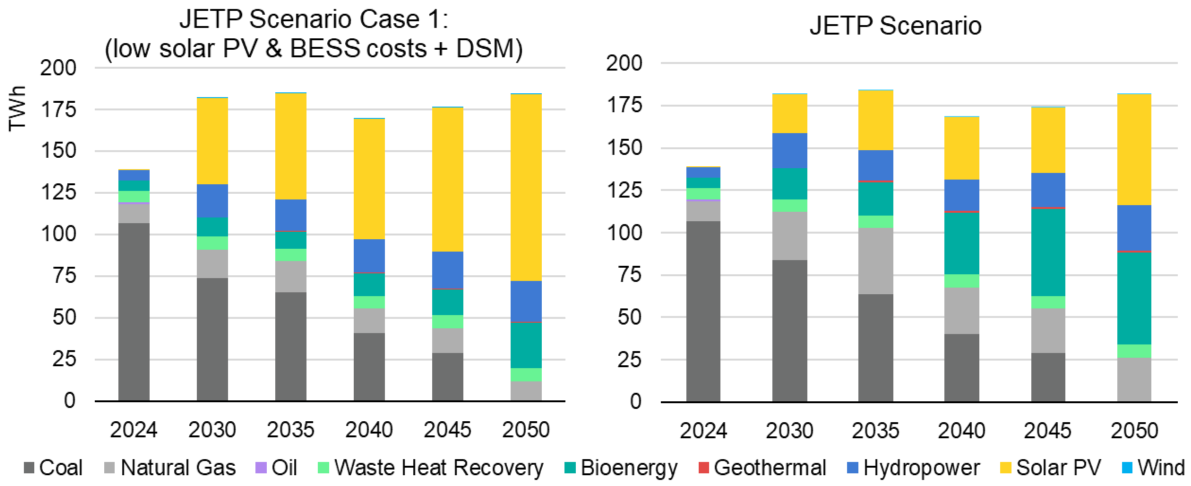
Overall, cumulative investments in the captive power sector under the JETP Captive Scenario are projected to be 3.7 times higher than those under the Baseline Scenario to 2050 though only 1.8 times higher to 2030, reflecting the accelerated shift towards more capital intensive cleaner energy sources and enabling infrastructure, compared with baseline reliance on captive coal power.

Across industries in the JETP Captive Scenario, Nickel accounts for the largest source of investment in the captive power sector, with nearly 50%, or on average US$ 2.5 billion annually through 2030 and 68% of the cumulative total, or US $63 billion, through 2050. This is followed by Aluminum, accounting for over US$ 1 billion on average through 2030 and 14% of the cumulative total, or US $13 billion through 2050. Other sectors, such as Pulp and Paper and Mining, Steel and Other Industries are individually lower, but together account for the remaining 18% of cumulative capital spending requirements in the JETP Captive Scenario.

3.8. Assessing Impacts of Scenario Variants

To more fully assess the impacts of potentially lower renewables technology costs and enhanced demand flexibility on the role of variable renewables and the implications of potentially lower fossil fuel prices on the economic comparisons between scenarios, two scenario variants were analyzed.

The first scenario variant (JETP Case 1) tests the generation mix and affordability implications of lower cost solar PV and battery storage and enhanced load shifting from nighttime to daytime. In this case, solar PV and battery storage technology costs follow a lower trajectory that is aligned with the average of solar PV costs in China and India and the global battery storage average cost in the 2024 IEA Announced Pledges Scenario (APS) (IEA, 2024). Such a trajectory recognizes the potential for further dynamic cost decreases as the market for these technologies expands in Indonesia.



Source: (JETP Secretariat and Working Groups, 2025).

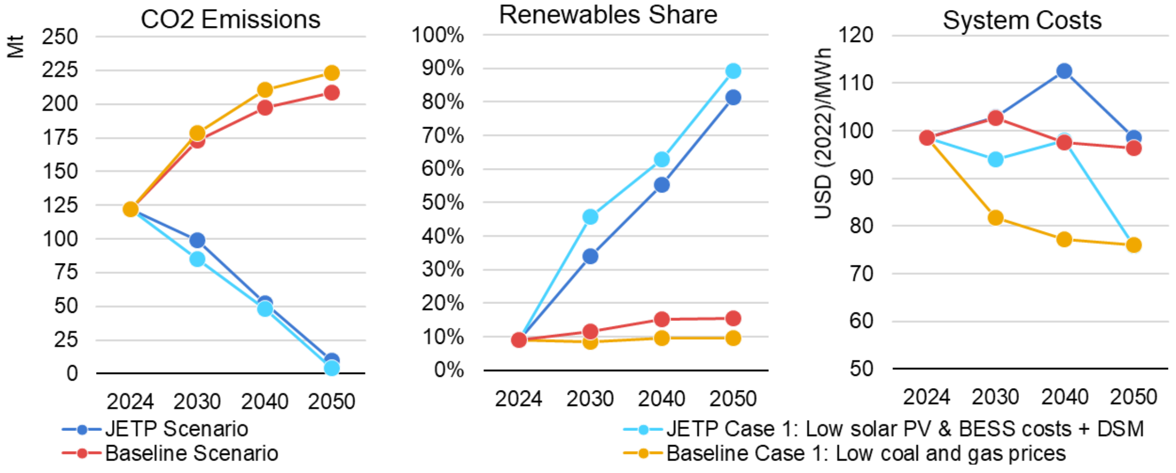
Figure 3.8-1 Captive Power Generation Projection: JETP Captive Scenario Case with Lower Renewables Costs vs Main JETP Captive Scenario

Notes: BESS = battery electric storage system; DSM = demand-side management. DSM implementation shifts 5% of nighttime demand to daytime hours.

This case also enables enhanced flexibility for industrial power demand, with the ability of industries to shift around 5% of their electricity load requirements from nighttime to daytime hours, when solar PV generation is available, increasing the direct uptake of solar PV generation and reducing reliance on battery storage to cover the demand during the night. Given uncertainties over technical configurations and potential investments for demand shifting for energy-intensive industries, such as smelters, this case maintains a conservative assumption for load shifting, recognizing that further study is required for industries in Indonesia. This case also does not try to estimate potential additional costs that may be associated with demand shifting.

The JETP Captive Scenario Case 1 demonstrates that a captive power pathway with a greater role for variable renewables is possible under enhanced cost and flexibility conditions. In the JETP Captive Scenario Case 1, the solar PV generation share rises to 43% by 2040 and 61% by 2050 with less generation from relatively more costly bioenergy and gas, compared with the main JETP Captive Scenario where the solar PV share reaches only 36% by 2050. Deployment of more cost-effective battery storage also follows a smoother, more progressive pattern over time compared with the JETP Captive Scenario, in which the bulk of battery installations are carried out towards the end of the projection period.

The second alternative scenario (Baseline Case 1) tests the generation cost implications of following the Baseline Scenario with lower coal and gas prices. Prolonged, low fossil fuel prices represent a risk to realizing the JETP Captive Scenario in terms of economic attractiveness and affordability. Coal prices (using the same coal quality assumption as in the JETP Scenario) are kept at USD 60/t (aligned with the 2024 IEA APS 2030 assumption) throughout the projection period, with LNG prices at USD 7/MMbtu (aligned with the 2024 IEA APS 2030 assumption) and pipeline gas at USD 6/MMbtu. The results of this Baseline Case 1 show an even stronger role for captive coal generation, with the share of coal rising to over 80%, but with average generation costs around 23-24% lower than in the Baseline Scenario.



Source: (JETP Secretariat and Working Groups, 2025).

Figure 3.8-2 Key Captive Power Performance Indicators in the JETP Captive Scenario, Baseline Scenario and Cases with Lower Energy Input Costs

Notes: BESS = battery electric storage system; DSM = demand-side management; Baseline Case 1: coal = USD 60/t; LNG = USD 7/MMbtu; piped gas = USD 6/MMbtu.

A comparison between all four scenarios across key performance indicators shows that increasing the role of cost-effective solar PV and flexibility is key to enhancing the sustainability and affordability of captive power transitions, especially compared with a Baseline Scenario Case where fossil fuel prices are low. The JETP Captive Scenario Case 1 with a stronger role for solar PV and demand-side flexibility enables lower CO2 emissions and a higher renewables generation share over time, compared with the main JETP Captive Scenario. Crucially, this case demonstrates lower captive power generation costs, ranging from 9% lower in 2030 to 23% lower in 2050, as increased solar PV and battery storage, enabled by demand shifting, are able to more cost effectively provide firm power, compared with the main scenario. While the system costs of the JETP Captive Scenario Case 1 generally remain higher than the Baseline Scenario Case 1 with low fossil fuel prices, system costs generally follow a downward trajectory and are comparable in 2050.

Table 3.8-1 Summary of Key Changes and Results in the Scenario Variant Analysis

Source: (JETP Secretariat and Working Groups, 2025).

	JETP Captive Scenario Case 1: Low PV & BESS costs + DSM	JETP Captive Scenario (Main Case)	Baseline Scenario Case 1: Low fossil fuel prices	Baseline Scenario
Demand profile	5% of nighttime load shifts to daytime	Flat	Flat	Flat
Future coal price (USD/t)	100	100	60	100
Natural gas price (USD/MMbtu)	Pipeline: 7 LNG: 12	Pipeline: 7 LNG: 12	Pipeline: 6 LNG: 7	Pipeline: 7 LNG: 12
Solar PV cost (USD/kW) in 2030 / 2050	415 / 280	672 / 480	672 / 480	672 / 480
BESS (4hr) cost (USD/kWh) in 2030 / 2050	170 / 125	330 / 230	330 / 230	330 / 230
RE generation share in 2030 / 2050	46% / 89%	34% / 81%	9% / 10%	12% / 16%
VRE generation share in 2030 / 2050	28% / 61%	12% / 36%	<1% / 1%	3% / 7%
CO2 emissions in 2030 / 2050 (Mt)	85 / 4	99 / 9	179 / 223	173 / 209
System costs in 2030 / 2050 (USD [2022] / MWh)	94 / 76	103 / 98	82 / 76	103 / 96

Notes: BESS = battery electric storage system; DSM = demand-side management; RE = renewable energy; VRE = variable renewable energy.

3.9 System Adequacy and Flexibility

Clean energy transitions for Indonesia’s captive power sector depend on sustained upgrades to sector planning and operations to ensure supply adequacy and system flexibility over time to meet the robust demand requirements of energy-intensive industries and provide appropriate system services, as well as enhanced grids to integrate demand within industrial clusters and into the PLN system. In the JETP Captive Scenario analysis, the captive power sector diversifies sources of firm power away from captive coal, as well as taps into new sources of flexibility on the supply and demand side.

Overall supply adequacy for captive power is maintained in the JETP Captive Scenario as growing dispatchable power (including storage) outpaces relatively stable peak demand. The captive power sector is currently marked by overcapacity due to a rapid build-out of coal power, some of which is maintained as reserve power for industries, such as metals smelting, which require a high degree of reliability (see Chapter 1). In the JETP Captive Scenario, captive coal capacity largely remains present until 2050, even as coal generation is phased-down in favor of renewable sources and gas, which helps to ensure long-term supply adequacy. System adequacy for short-term operations is similarly underpinned by the availability of alternative dispatchable sources as coal generation is reduced to meet emissions reduction goals.

At the same time, growing system flexibility is required at the captive site- and industrial cluster-level, with more limited balancing areas compared with the on-grid system, for industrial facilities with high and stable demand profiles, which makes the integration of variable renewables particularly challenging for the captive power sector.

To illustrate flexibility needs and capabilities the analysis includes hourly dispatch modelling to assess the system operations for select industrial clusters under the JETP Captive Scenario and the JETP Captive Scenario Case 1. The results in Figure 3.9-1 below show the modelled hourly dispatch throughout a sample week for an industrial cluster of nickel processing plants based in North Maluku with an initial demand of around 3 GW for years 2030, 2040, and 2050, demonstrating the development of system operation typical for a number of clusters in the two scenarios.

In the JETP Captive Scenario, the generation mix for this industrial cluster progresses over time from being based on coal to incorporating first solar PV, as well as hydropower and natural gas to help balance the system. In the long term, bioenergy and battery storage play more dominant roles in providing clean sources of flexible power.

In 2030, the system is dominated by coal, with a contribution of solar PV during the daytime hours to fulfill emissions reduction goals. During those hours, the coal capacity ramps down, in this case to around 30-50% of its own capacity, to make room for the solar PV. Improving captive coal plant dispatch and responsiveness, which also lowers overall coal power utilization, is an early enabler of renewables integration and emissions reduction in the JETP Captive Scenario. However, as described above, such operational flexibility may require investments in existing coal plants to reduce technical minimum load, increase ramp rates and reduce start-up times, depending on their starting flexibility capabilities[15].

By 2040, the system has evolved to include bioenergy and gas as well as a larger share of solar PV to meet emission reduction targets. The balancing of the solar PV generation is done by both gas, coal and bioenergy, by ramping down those plants down to their technical minimum load or switching them off altogether for shorter periods of time. There is a smaller share of hydropower generation in the system that also operates flexibly.

In 2050, when all coal capacity is out of the system, bioenergy takes the role as the largest source of power capacity. Battery storage becomes more economical relative to dispatchable

---

[15] In this example, it is assessed that the captive coal plants are providing electricity only and not combined heat and power for the industrial facility. In the case of heat provision (which affects few plants in the JETP Scenario), arrangements would be required to ensure delivery of industrial heat as coal power utilization decreases.

generation and is deployed to accommodate a larger share of solar PV. During peak solar PV generation periods, bioenergy ramps down to its technical minimum load and the battery storage system is charged from excess solar PV generation. During the nighttime hours, a combination of higher levels of bioenergy and the discharging of the battery storage helps to meet demand. Gas power and hydropower still operate flexibly, shutting down for shorter periods of time when solar PV generation is high. It is also important to note that further asssessment on impact of bioenergy utilization on other sector (example: land-use change impact) is crucial in order to ensure sustainable bioenergy supply chain in the process.

In the JETP Captive Scenario Case 1, the overall system development of this industrial cluster is similar to the JETP Captive Scenario in terms of diversifying the generation mix away from captive coal power, but the buildout of solar PV and battery storage is accelerated, enabled by lower technology costs and the implementation of a degree of demand-side flexibility that allows for shifting a part of nighttime demand to the daytime, resulting in more optimized system operations and cost-effective integration of solar PV.

By 2030, a higher level of solar PV penetration in the cluster is enabled by the additional balancing provided by demand-side flexibility, with no dedicated battery storage necessary to ensure the system stability. In 2040, compared to the JETP Captive Scenario, demand-side flexibility enables a greater build-out of solar PV and with more economical battery storage also providing balancing services. Contrary to the JETP Captive Scenario, there is no build-out of gas capacity to provide firm generation. Demand-side flexibility together with battery storage plays a key role in firming and balancing the solar PV generation. In 2050, emissions for the industrial cluster go to zero with the phase-out of coal power. Bioenergy supplies the majority of the generation, followed by solar PV. Due to the demand side flexibility, the need for dedicated battery storage is lower than in the JETP Captive scenario.

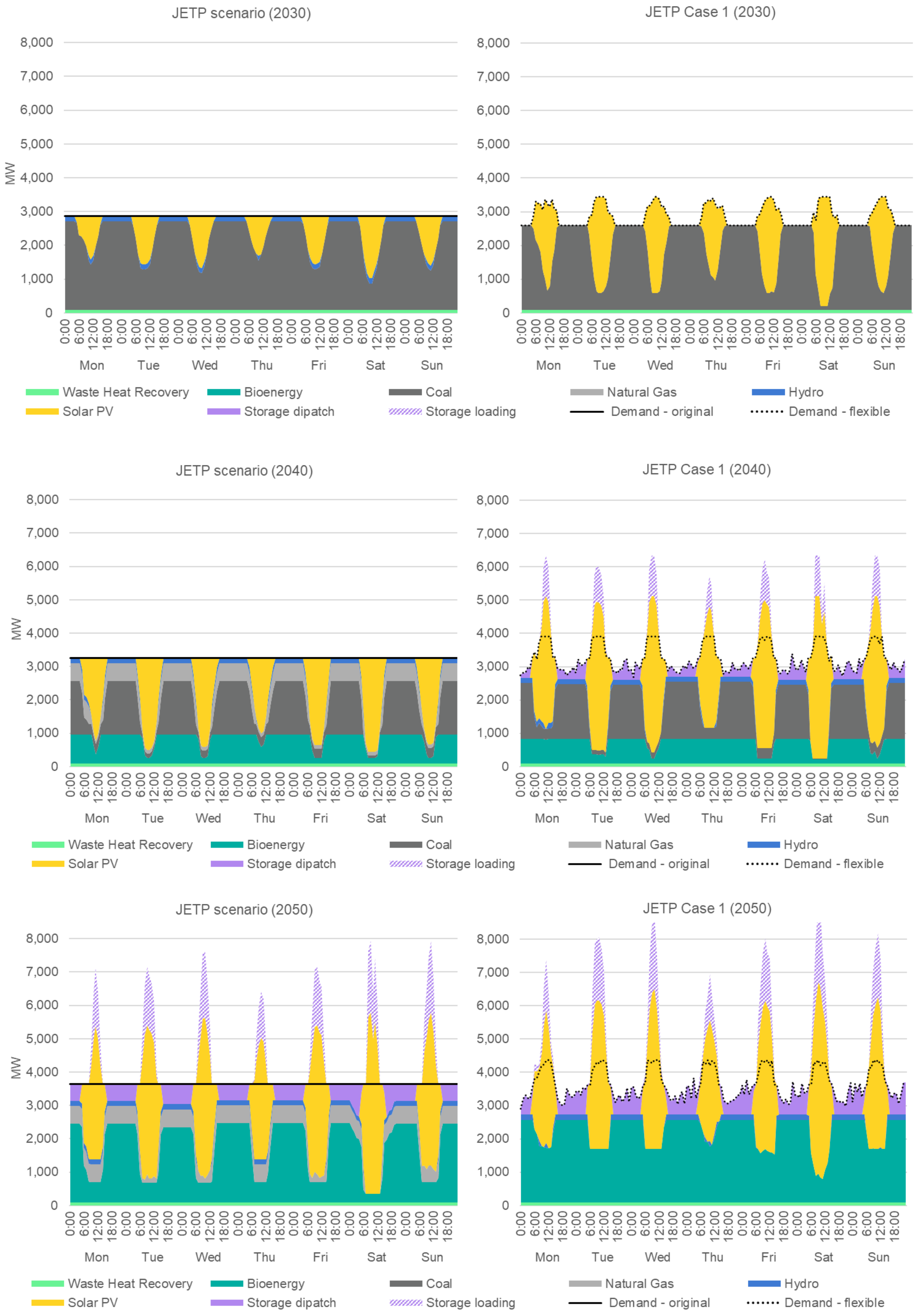


Figure 3.9-1 Hourly Dispatch by Technology for a Sample Industrial Cluster in the JETP Captive Scenario and JETP Captive Scenario Case 1

Source: (JETP Secretariat and Working Groups, 2025).

Disclaimer: This document forms part of the Indonesia Just Energy Transition Partnership (JETP) thematic reporting. It does not constitute a legally binding document. It is a strategy document that the Government of Indonesia may use as a basis for power sector planning and policymaking as part of the JETP process. For more information about JETP Indonesia, please refer to the 2023 Comprehensive Investment and Policy Plan (CIPP) and 2025 Progress Report. The CIPP is a document for the implementation of the Joint Statement agreed in November 2022.

The detailed system operation analysis indicates that the JETP Captive Scenario and scenario variant ensure adequate resources to fulfill the high, continuous power demand requirements in the industrial clusters. Utilizing solar PV as a main resource to cost-effectively reduce emissions requires significant flexibility from the other supply and demand sources in the given cluster. Nevertheless, with the modelled investments in generation, storage, demand side flexibility, as well as additional flexibility of coal and bioenergy plants the system has stable operations on an hourly basis.

The demand-side flexibility is an important enabler in the JETP Captive Scenario Case 1, ensuring system flexibility in a more optimized manner together with dedicated battery storage resources. Given the novelty of large-scale demand side flexibility at industrial sites, there are uncertainties in the practical implementation of this measure, which may also require additional investments that are not considered in the scenario. Still, the model simulations provide insights on the potential considerable benefits of this intervention.

In the case of limitations to demand-side flexibility beyond the technical assumptions in the scenario, the needed flexibility could be provided by additional battery storage capacity, resulting in slightly higher costs but similar system adequacy levels. The simulation results show variation in the utilization of the demand side flexibility, which sometimes exhibits a jagged pattern, that is partly due to the nature of the optimization algorithm used, where demand side and battery storage flexibility tend to be utilized simultaneously. In reality, the system operation and demand shifting is likely to be smoother with detailed planning and dedicated use of the different available flexibility sources.

Overall, enabling the captive power system adequacy and flexibility demonstrated in these results will depend on regulatory and business model enhancements that support industrial clustering and promote more optimized energy system planning and operations within the clusters, coordinated by centralized energy managers. For industrial companies, this type of model would provide a turnkey solution for energy, material and flexibility services. From a regulatory perspective, centralized energy management can simplify oversight and better enable cost-effective clean transitions for captive power. Such enhancements and enabling factors are discussed in more detail in Chapter 5.

Chapter 4: Case Studies on Clean Energy Transitions for Captive Power

4.1 Approach

4.1.1 Scope of Work

This chapter consolidates findings, in an abridged form, from three case study reports to identify the most viable energy transition options for specific captive power systems. It assesses each case through a consistent framework covering landscape assessment, potential transition pathways, technical feasibility, financial analysis, and risk evaluation. The aim is to develop practical insights and lessons that can inform broader applications of captive power decarbonisation.

The scope of work consists of five key components that together form the basis of this analysis:

- Landscape Assessment, the landscape assessment describes the current conditions of the captive power site, including existing infrastructure, energy consumption patterns, the type and scale of energy demand (e.g., thermal or electrical). It identifies key operational challenges and emerging opportunities within the site, setting the foundation for developing suitable energy transition options.

- RE Resource Assessment, this component identifies and evaluates the RE resources available in and around the captive power site, depending on the site's geographic and environmental context. The mapping helps determine the technical viability and potential scale of renewable energy deployment, informing the selection of appropriate technologies and system configurations.

- Potential Energy Transition Options, Various transition options are explored to suit each site's specific characteristics. These included renewable energy integration, hybrid systems, and efficiency improvements. Each pathway is assessed for its feasibility, cost implications, and potential impact on emissions and operations.

- Assessment of the Energy Transition Options, the technical assessment provides an analysis of the selected energy transition option. It evaluates the required technology specifications, infrastructure readiness, system integration, and potential implementation barriers. The section concludes with an assessment of the technical viability and long-term sustainability of the chosen option.

- Risk and Mitigation of the Energy Transition Options, this section identifies potential risks that may affect the successful implementation of the energy transition, such as technical, financial, regulatory, or operational risks. Each risk is analysed based on its likelihood and impact, followed by proposed mitigation measures and monitoring approaches.

While the work done on case studies result in prolific technical and financial analysis, there is limitation in the scope of studies. The studies do not assess the social aspect, particularly gender equality, disability and social inclusion (GEDSI).

4.1.2 Technical Assessment and Modifications Required for the Transition

HOMER Pro Analysis

In this study, HOMER Pro version 3.18 was used to analyse and optimise the power system. HOMER Pro evaluates hybrid renewable and conventional energy systems. It offers features that enable the simulation of power systems across a wide range of technical and economic conditions. This helps identify cost-effective and reliable energy configurations, which is important for decision-making in planning and optimisation. HOMER Pro can handle complex calculations quickly. HOMER Pro can perform detailed analysis of system designs, capture relationships between variables, and identify optimal configurations. It also offers sensitivity analysis features, allowing users to test multiple scenarios and different input data.

This analysis used HOMER Pro to perform three fundamental tasks based on the raw data provided: simulation, optimisation, and sensitivity analysis. It enabled the evaluation of various system configurations, including combinations of PV arrays, wind turbines, hydropower systems, generators, the utility grid, and Battery Energy Storage System (“BESS”). During simulation, HOMER Pro determines whether a configuration is feasible and estimates its life cycle costs. These estimates include both the initial installation cost, referred to as capital expenditure (“CAPEX”) and the ongoing operational expense, known as operational expenditure (“OPEX”), ensuring a holistic assessment.

HOMER Pro evaluated multiple electricity system scenarios to identify configurations that are both cost-effective and reliable. It is widely adopted because of its broad technology coverage, effective optimisation algorithms, intuitive user interface, and access to extensive datasets. The Figure 4.1.2-1 below presents a conceptual overview of the software workflow, from data inputs through to output generation.

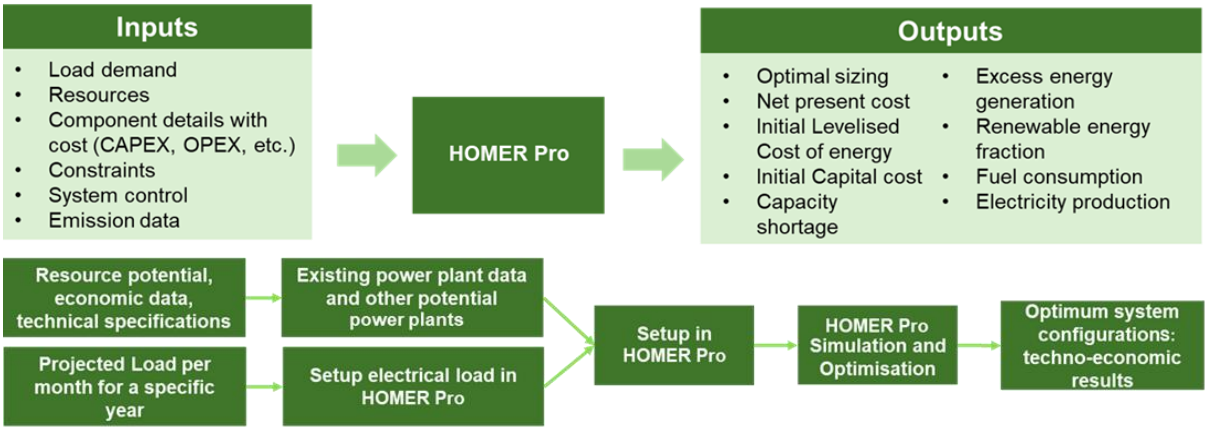


Figure 4.1.2-1 Overview of HOMER Pro Process[16]

---

[16] Technical Analysis

For each scenario, simulations were conducted over a full year using hourly time-step data to capture variability and ensure reliability. The modelling process included simulation, optimisation, and sensitivity analysis, enabling evaluation of different technology combinations and operational strategies. The primary objective was to identify the most cost-effective system configuration through iterative optimisation while meeting reliability and sustainability requirements. As part of this modelling approach, dispatch analysis assessed how different configurations perform under varying solar PV generation conditions within a one-day timeframe. This included comparing high and low solar PV scenarios to evaluate the system's ability to respond to changes in renewable availability, adjust grid purchases, and maintain stable operations.

The dispatch modelling examined the interactions among solar PV, CFPP, waste heat recovery, hydropower, cogeneration, BESS, biomass co-firing, and grid supply, with configurations varying across different cases. The energy sources examined through dispatch modelling were selected based on the outcomes of the technical analysis, which prioritised the most viable options. Wind and natural gas were excluded due to their low potential and limited feasibility within the study context. In some configurations, solar PV generation reduces reliance on grid electricity during daylight hours, while in others, constant operation of conventional sources provides baseline stability. In scenarios with high renewable penetration, instances of excess electricity generation are identified, highlighting opportunities for grid export and enhanced economic value.

This analysis provides insight into the operational flexibility of each configuration and supports strategic decision-making on renewable energy integration, system reliability, and potential commercial opportunities.

Flexibility Analysis

The flexibility analysis was conducted using the International Renewable Energy Agency's ("IRENA") FlexTool, a modelling platform widely applied in academic research and energy system studies. The objective of this analysis was to evaluate whether the proposed system configuration, derived from HOMER Pro modelling, can maintain reliability and operational flexibility under varying shares of variable renewable energy ("VRE").

The analysis was carried out in dispatch mode, with no additional investment allowed, focusing on operational feasibility rather than expansion planning. System configurations from HOMER Pro served as inputs to FlexTool to ensure consistency with the preferred transition options identified earlier. Flexibility was assessed across all modelled scenarios.

Key reliability parameters evaluated included loss of load, reserve adequacy, and capacity shortages, which indicate whether the system meets demand under modelled conditions. Curtailment levels were also analysed to understand the extent of renewable energy integration and potential inefficiencies. These metrics are critical for determining whether the proposed build-out can deliver a secure electricity supply while accommodating higher shares of VRE.

To validate system reliability, peak load values for each scenario were incorporated into the FlexTool model. This step ensured that the system remains adequately sized to handle maximum demand and operational fluctuations. The analysis also addressed limitations of HOMER Pro, which cannot simulate ramp-up rates and start-up times parameters essential for coal-fired plant flexibility when integrating renewables. FlexTool complements this by modelling operational dynamics more accurately.

The flexibility assessment confirmed whether the system operates without significant stability risks while integrating higher shares of renewables. It provided insights into curtailment behaviour, reserve adequacy, and the role of fossil generation and storage in balancing variability, forming a basis for evaluating the technical viability of the energy transition pathway.

Static Power Flow Analysis

The static power flow analysis evaluated the capability of the existing grid to accommodate additional electricity transmission from renewable energy sources. This assessment was critical to ensure that the grid can integrate new generation without requiring significant upgrades or creating operational constraints.

The analysis used a Microsoft Excel-based tool developed by Ramkhelawan and Musti (2019)[17], which applied a static power flow method. Dispatch results from HOMER Pro served as inputs, specifically focusing on periods when solar PV output is at its minimum. This condition represented a conservative scenario, allowing assessment of grid performance when renewable supply is high.

The analysis covered multiple scenarios, each representing different levels of renewable energy integration. It identified potential reverse flows from the local grid to adjacent systems during periods of surplus generation. These flows may present opportunities for electricity sales to nearby entities, subject to grid capacity and commercial viability.

Analysis for Potential Integration with PLN’s Grid

This study evaluated the feasibility of connecting existing off-grid industrial electricity systems at the case study sites to the PLN-operated national grid. As discussed in Chapter 2 on technical screening, connecting the captive industrial facility to the PLN grid creates a strategic opportunity to maximise the value of on-site renewable generation. Surplus electricity that would otherwise go unused can be exported, improving the economic performance of renewable investments while supporting wider renewable integration and grid stability, as long as carbon leakage does not occur. At the same time, the facility can draw cleaner electricity from the PLN’s grid during low-generation periods, reducing reliance on fossil-fuel assets without needing to develop excessively large on-site renewable systems.

---

[17] Ramkhelawan, R., & Musti, K. S. (2019). Power System Load Flow Analysis using Microsoft Excel – Version 2. Spreadsheets in Education, 12(1). Bond University. Retrieved from https://sie.scholasticahq.com

Utilising HOMER Pro modelling, the study simulated renewable energy deployment scenarios to estimate potential surplus electricity and assess how it could be absorbed within the current system or exported to the PLN grid. The analysis further examined the possibility of importing cleaner electricity from PLN during periods of low renewable output.

Renewable Energy Certificate Analysis

The analysis evaluated the feasibility of REC procurement as a decarbonisation strategy for industrial facilities connected to the grid. Grounded in the regulatory framework set by Government Regulation No. 40 of 2025 and the Commodity Futures Trading Regulatory Agency Regulation No. 11 of 2024, the analysis considered grid-based eligibility constraints and the operational integrity of PLN's electronic REC tracking system. This study limits the REC availability only from PLN quota, though it is also possible to procure REC from entities other than PLN.

Technical modelling simulated electricity demand and assessed REC-based decarbonisation under various scenarios. These scenarios vary the share of grid electricity offset through REC purchases ranging from partial to 100% to reflect different strategic pathways aligned with national energy transition goals. The modelling quantifies REC volumes required and evaluates their alignment with existing sustainability efforts and future targets.

On the supply side, the analysis also considered the non-transferable nature of environmental attributes embedded in each REC, ensuring carbon reduction claims remained verifiable and aligned with international standards. To ensure REC demand could be met for companies requiring REC purchases, an analysis of REC supply was conducted. As of October 2025, only 80,431 MWh of quota remained available for purchase from PLN. It was therefore crucial to assess the potential future REC supply by determining the renewable energy capacity to be added to the relevant grid. Grid load projections were estimated using least cost optimisation through an energy modelling software that applies optimisation and simulation techniques to forecast electricity demand and grid behaviour over long-term horizons. The model incorporated data from the RUPTL 2025–2034, reflecting PLN's planned generation expansion and transmission developments. Based on these projections, the renewable energy share of grid load was estimated, and under the assumption that all renewable generation could be converted into RECs, the potential REC quota for 2030 was calculated.

4.1.3 Case Study Modelled Scenarios

To ensure a structured and comparable analysis, three harmonised scenarios were developed: *Business-as-Usual ("BaU"), RE Integration, and JETP Optimistic Pathway*. Each scenario represented a progressively higher level of decarbonisation and renewable energy adoption. Although the definitions were consistent across all cases, each case study site iteration reflected its specific asset mix, resource potential, and operational constraints.

Scenario 1 — Business as Usual (*BaU)*

The *Business-as-Usual* scenario established the baseline for comparison. It reflected the current operating paradigm projected to 2030 and 2050, retaining the existing captive generation assets such as coal-fired or cogeneration units and any waste-heat recovery systems already in place. Grid imports continued at prevailing levels, and where ageing units required replacement, sizing was optimised within the *BaU* framework without introducing new low-carbon technologies.

This scenario provided a reference point for emissions and cost outcomes under normal operating conditions. It captured the prevailing fuel mix, operational practices, and reliance on grid electricity, forming the benchmark against which the benefits of renewable integration and more ambitious pathways were assessed.

Scenario 2 — *RE Integration*

The *Renewable Energy Integration* scenario introduced cost-effective renewable technologies into the existing system while maintaining existing technology, typically reflecting what the companies had already planned and sought to optimise. The optimisation process evaluated the least-cost combination of renewable energy sources and operational adjustments to increase the renewable fraction and reduce emissions without compromising reliability.

Technologies typically considered included the scale-up of solar photovoltaic systems, biomass utilisation (including co-firing within thermal units), waste-heat recovery, mini-hydropower, and BESS to address intermittency. Grid electricity purchases remained part of the supply mix for sites connected to the PLN network; however, a proportion could be offset through RECs to further reduce reported emissions. Where feasible, operational flexibility was introduced by enabling thermal units to operate at lower minimum loads, thereby accommodating variable renewables.

Scenario 3 — *JETP Optimistic Pathway*

The *JETP Optimistic Pathway* modelled an ambitious decarbonisation trajectory aligned with Indonesia’s energy transition agenda, targeting a substantial reduction in emissions from captive power systems by 2030, of at least 35%. This scenario built on the *RE Integration* approach but applies more progressive assumptions to maximise renewable penetration and minimise emissions.

Key levers included higher renewable capacity additions (solar PV and hydropower), supported by BESS to increase usable renewable output, and biomass co-firing where technically feasible. Thermal units were assumed to operate with significantly enhanced flexibility, reducing minimum stable load to create headroom for renewables and minimise curtailment. Efficiency improvements in both power generation and industrial processes further reduce overall demand and emissions intensity. Grid imports may be fully or largely matched with RECs to achieve deeper decarbonisation; however, this option applied only to sites connected to the PLN on-grid network.

This scenario represented the most transformative pathway, combining technological optimisation with operational changes to deliver ambitious environmental outcomes while maintaining reliability and cost competitiveness. These scenarios were iterated and tailored to each case study's preferences, constraints, and conditions. Accordingly, configurations and outcomes varied by site.

Focusing on aligning decarbonisation strategies of Indonesia's captive industrial facilities with national energy transition plans, financial and economic assessment is essential to ensure that proposed solutions are both technically viable and financially sustainable. This section presents the approach of the financial and economic assessments on the preferred energy transition option, including cost analyses, the funding and financing requirements, and the potential economic benefits.

4.1.4 Financial and Economic Assessment

Financial Assessment Approach

Following the technical feasibility assessment, which identified the optimal renewable energy mix to support the decarbonisation of captive power plants, a financial assessment was undertaken to assess the financial viability of the proposed transition pathways. It included analysing the financial impact of technology adoption, conducting sensitivity analysis on key parameters, and evaluating viability of decarbonisation up to the end of the CFPPs' operational lifetimes, with further studies required for post-CFPP power generation. The steps below outline the approach to the financial assessment.

The approach comprised the following components:

1. **Financial Impact Assessment:** The analysis began by assessing the projected impact of technology adoption on financial performance. This included evaluating incremental capital and operating expenditures, alongside potential cost savings and revenue implications. The assessment considered capital investment and operational assumptions such as load factors and fuel costs.
2. **Scenario Analysis**: The scenario analysis explored several initiatives that can be pursued to further reduce the First-Year Electricity Price. The initiatives are broken down into two scenarios, optimistic and conservative, where the optimistic scenarios are expected to yield greater reductions under more favourable conditions, explained below.

- **Applying for an income tax waiver:** Leveraging fiscal incentives such as corporate income tax ("CIT") waivers, as outlined in Ministry of Finance Regulation No. 130/2020, can enhance project financial viability. To qualify, renewable energy projects must have a minimum invested capital of IDR 100 billion, with larger investments eligible for extended incentives. Under the conservative scenario, the regulation allows for a 100% CIT waiver for the first 10 years, followed by a 50% waiver for the subsequent 2 years.
- **Utilising grant funding to cover transmission line capital expenditures:** Securing grant funding for Transmission and Distribution CAPEX can reduce electricity tariffs and improve project bankability. Grants are commonly provided by multilateral development banks and international partners to support early-stage development or projects in challenging geographies. Recent examples include the UK-Indonesia MENTARI programme, which allocated GBP 2.7 million to PT SMI as part of a blended financing scheme covering up to 20% of capital costs. In this study, given the high capital requirements and existing grant allocations for power plants, grant support for transmission was explored as a sensitivity scenario.
- **Accessing alternative financing schemes as a funding option:** Accessing alternative financing schemes offers a strategic opportunity to reduce electricity tariffs by lowering overall project financing costs. Project owners may issue green or sustainability-linked bonds through international markets. Under the conservative scenario, benchmarking against green bonds listed on the Singapore Exchange ("SGX") suggests an interest rate of approximately 5.31%, whereas an optimistic scenario assumes rates as low as 2.5% based on green bonds issued in China for similar tenors.
- **Leveraging carbon credit trading:** Engaging in carbon credit trading can help reduce electricity tariffs in renewable energy projects. Per POJK No. 14/2023, companies can sell carbon credits in the Indonesian market by obtaining a permit for a carbon exchange operator. Selling credits from reduced emissions opens new revenue streams in carbon markets. Based on the current carbon price range in the Indonesian market, a conservative and optimistic scenario was developed. Under the conservative scenario, carbon prices are assumed at USD 2/tonne CO_2 in 2025, escalating by USD 5 every five years, reflecting Indonesia's current price range. The optimistic scenario assumes USD 5/tonne CO_2 by 2030 with similar escalation.

3. **Sensitivity Testing:** Sensitivity analyses were carried out to examine how variations in key technical and cost assumptions may influence the financial outcomes of the case study site. The tests included reducing power plant capacity factors, revising electricity and biomass price escalations, and testing the impact on the electricity price in the case that the case study companies are required to purchase land for the Solar PV power plant outside of their respective industrial sites.

These sensitivities provided insights into which variables may have the greatest influence on project viability under different operational and market conditions.

For this financial approach, a financial model was developed and heavily utilised for the scenario's assumption. The model incorporated key technical and financial parameters, including investment requirements, operating costs, and system configurations. It was built on a set of stated assumptions derived from the technical assessment and supplemented by publicly available sources. These assumptions covered aspects such as load factors, fuel costs, escalation rates, and financing structures.

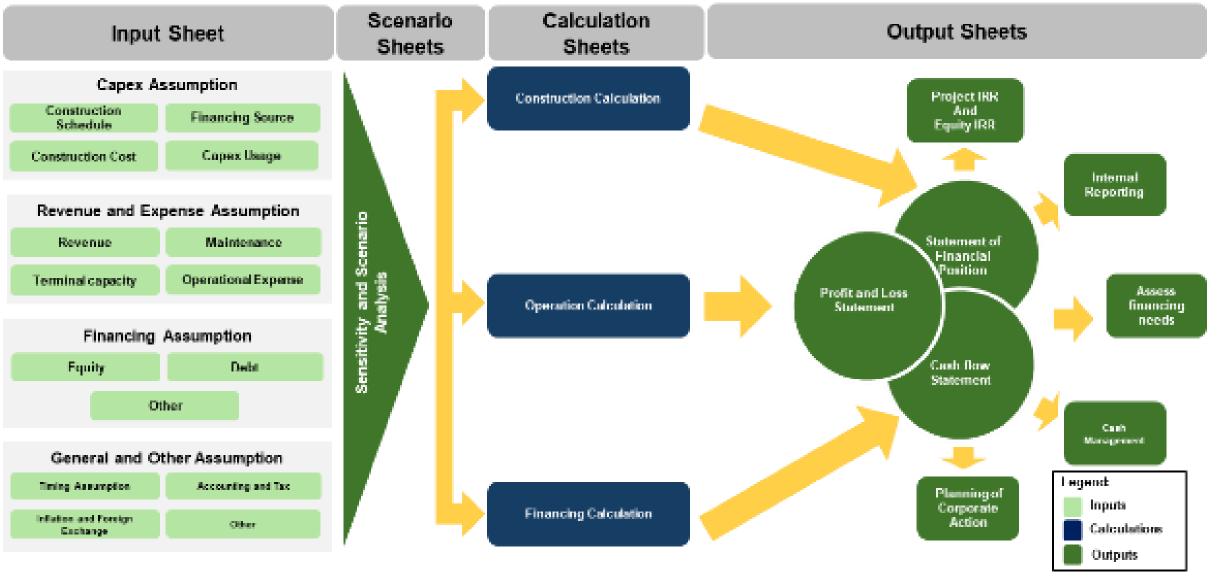


Figure 4.1.4-1 Financial Modelling Framework

The aim of the financial model is to calculate the electricity price to ensure breakeven for equity investors. It utilised a "goal seek" method that sets the Net Present Value ("NPV") of future cash flows to zero. The tariff assumed continuous electricity sales over the power plants' lifetime, excluding future plant replacements. A single-tariff analysis assessed the overall financial viability of the case study company's entire powerplant portfolio, integrating total generation, CAPEX, and OPEX.

4.1.4.2 Economic Assessment Approach

Following the technical feasibility and financial assessment conducted earlier in this report, an economic analysis of each case study was conducted through a Cost-Benefit Analysis ("CBA") and abatement costs analysis.

Cost Benefit Analysis

The CBA was conducted to evaluate the broader economic implications of implementing the preferred transition option, as identified through the preceding technical and financial assessments. The analysis aimed to determine whether the proposed decarbonisation pathway yields net economic benefits to society, beyond its financial viability. Economic feasibility was assessed using three key indicators:

1. **Economic Net Present Value ("ENPV"):** A positive ENPV indicates that the present value of economic benefits exceeds that of economic costs.
2. **Economic Rate of Return ("ERR"):** The ERR reflects both financial and non-financial (intangible) benefits expressed in monetary terms. If the ERR exceeds the Social Discount Rate ("SDR"), assumed at 10%, the project is considered economically viable.
3. **Benefit-Cost Ratio ("BCR"):** A BCR greater than 1 indicates that economic benefits outweigh associated costs.

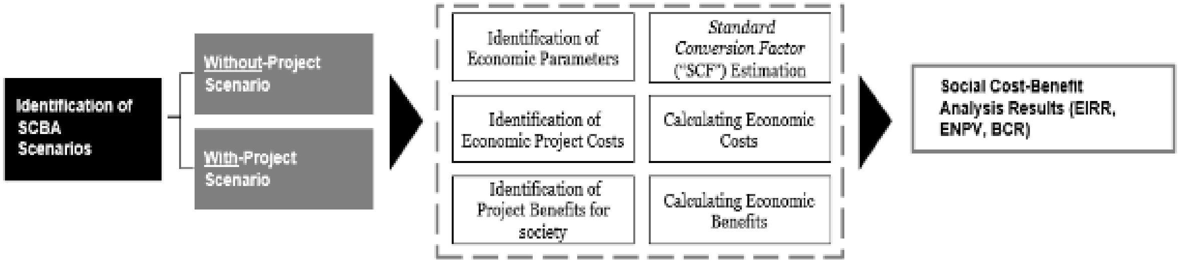


Figure 4.1.4-2 Cost-Benefit Analysis Framework

The CBA encompasses the economic costs and benefits over the project's duration, viewed from the perspectives of relevant stakeholders and compares the incremental costs and benefits. It adopts a *'Without-Project*' and *'With-Project*' framework. The *Without-Project* scenario represented a business-as-usual situation without implementing any decarbonisation measures under the preferred and prioritised transition framework option. This pathway led to ongoing coal dependency and elevated health-related costs due to pollution-related illnesses.

In contrast, the *With-Project* scenario involved implementing the decarbonisation pathway using the preferred transition option as analysed in the technical and financial assessments. This scenario is expected to deliver substantial carbon emission reductions. The CO_2 reduction (in tonnes) is based on technical analysis using HOMER Pro and monetised using the EU carbon price, as the EU Emissions Trading System is one of the most mature and most established carbon pricing mechanisms globally, providing a reliable benchmark for carbon pricing. Additionally, the EU carbon price already incorporates the broader societal impacts of carbon emissions, such as health-related costs and environmental degradation.

The CBA analysis estimated the gross economic benefits associated with each scenario over the assessment period, using monetised values for avoided emissions, healthcare savings, environmental externalities, and operational efficiencies. These estimates were derived through structured modelling and valuation techniques applied to both scenarios.

Economic costs include the direct and indirect costs of the project. Direct costs include all financial expenses incurred during the project, categorised under CAPEX and OPEX, with the exclusion of taxes and other subsidies or transfer payments. Indirect costs include indirect environmental and social costs, which are borne by third parties, known as externalities. Economic costs are estimated by converting market prices into economic prices using the Standard Conversion Factor ("SCF") to reflect opportunity costs, as stipulated in the Regulation of the Minister of National Development Planning/Head of Bappenas No. 7 of 2023 ("Permen PPN 7/2023"). If the market price does not reflect the opportunity cost, then the economic (shadow) price is used.

All costs and benefits were evaluated at present value using the social discount rate ("SDR"), in line with public investment appraisal practices in Indonesia and international institutions, which is 10%.

As part of the economic approach, sensitivity analyses were performed. While the base analysis estimated emissions using data from HOMER Pro, the sensitivity analysis examined an alternative quantification method based on Scope 1 using the Intergovernmental Panel on Climate Change ("IPCC") methodology, which calculates emissions from fuel consumption using the following equation:

$$\textbf{\textit{Emissions}} = \textit{Fuel Consumption (TJ)} * \textit{Emission Factor (kg gas/TJ)}$$

Separately, another sensitivity analysis explored the impact of alternative carbon pricing. This analysis replaced EU carbon prices with alternative carbon prices.

Abatement Cost Analysis

To assess the cost-effectiveness of emission reduction interventions, an abatement cost analysis was applied, which estimates the cost incurred to reduce one tonne of carbon dioxide (CO_2) emissions. This metric, expressed in USD per tonne of CO_2 abated, enabled a direct comparison across different decarbonisation options and provides a more targeted assessment than evaluating total capital and operational expenditures alone.

The abatement cost was calculated by estimating the net present value of incremental costs associated with the intervention, including investment, operations and maintenance ("O&M"), financing, and tax expenses, relative to a baseline scenario. These incremental costs represent the additional expenses incurred to reduce emissions compared to the *BaU* scenario. In some cases, incremental costs may be negative, indicating cost savings achieved through efficiency improvements or reduced fuel consumption[18].

---

[18] The World Bank Group. (2023).

4.2 Key Findings

4.2.1 Nickel industry

Indonesia plays a prominent role in the global nickel market. According to the U.S. Geological Survey[19], the country has 42% of global nickel reserves and 51% of global mine production[20]. Major reserves are concentrated in Sulawesi and Maluku. As of 2024, Indonesia's nickel resources were reported at 8.2 billion tonnes, with 2.3 billion tonnes[21] classified as reserves. Figure 4.2.1-1 illustrates the distribution of these reserves.

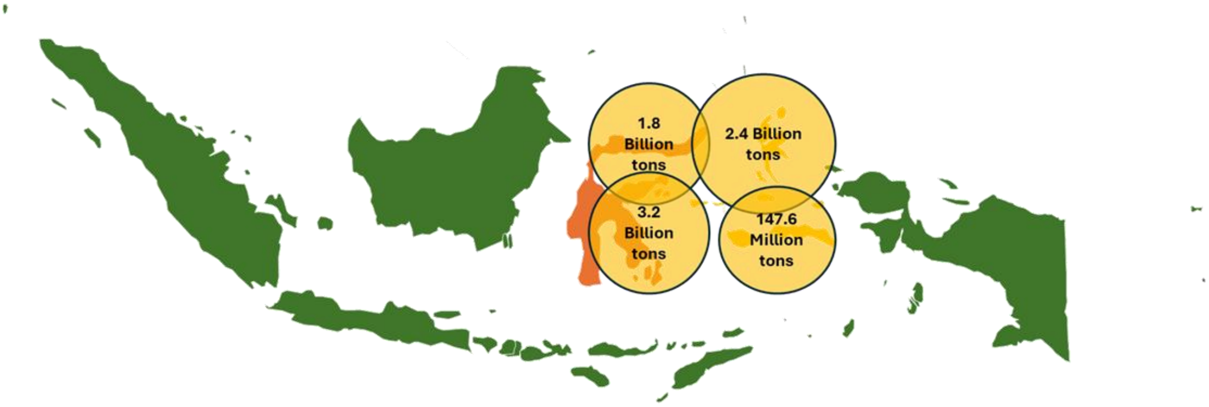


Figure 4.2.1-1 Distribution of Indonesian Nickel Ore Reserves as of 2020

Indonesia has emerged as a leading global nickel producer, driven by large-scale mining and processing infrastructure. Industrial parks and integrated facilities support both extraction and downstream activities, attracting substantial investment and enhancing smelting capacity and downstream value creation. This growth aligns with Indonesia’s strategic objective to harness its mineral resources for domestic development and to meet rising international demand, particularly for stainless steel and electric vehicle batteries. Nickel ore production has surged from 20.9 million tonnes in 2017 to 137.8 million tonnes in 2023[22], underscoring Indonesia’s expanding role in global supply chains. Figure 4.2.1-1 illustrates the distribution of reserves, while Figure 4.2.1-2 illustrates the sharp upward trend in annual production.

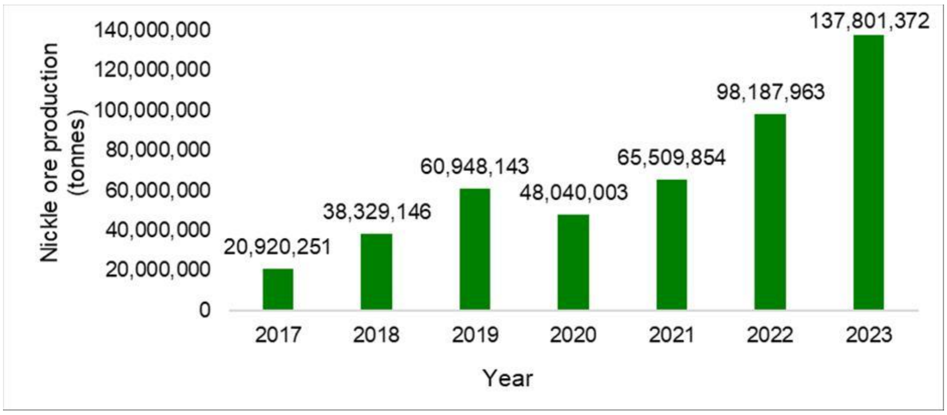


Figure 4.2.1-2 Indonesia's Annual Nickel Production in Tonnes (BPS, 2023)

This expansion is primarily driven by regulatory reforms, notably Law No. 3 of 2020 and MEMR Regulation No. 17 of 2020, which mandate domestic processing and ban unprocessed ore exports. Complementary policies, such as Presidential Regulation No. 55 of 2019 on electric vehicle acceleration, have further catalysed downstream industrial development.

The shift from raw ore exports to refined nickel products has significantly increased energy demand across Indonesia's nickel industry. Smelting technologies such as Rotary Kiln Electric Furnace ("RKEF") used for producing Nickel Pig Iron and Ferronickel, and High-Pressure Acid Leach ("HPAL"), used for processing low-grade laterite ores, are particularly energy intensive. These processes rely heavily on electricity for heating, pressure, and chemical reactions, while thermal energy is also required for drying and calcination stages. As production scales up, the energy intensity of nickel processing emerges as a critical factor, with implications for both sustainability and cost efficiency.

This study analysed two types of technologies within the nickel industry, namely the RKEF process and the HPAL configuration. The RKEF and HPAL process overview are shown below.

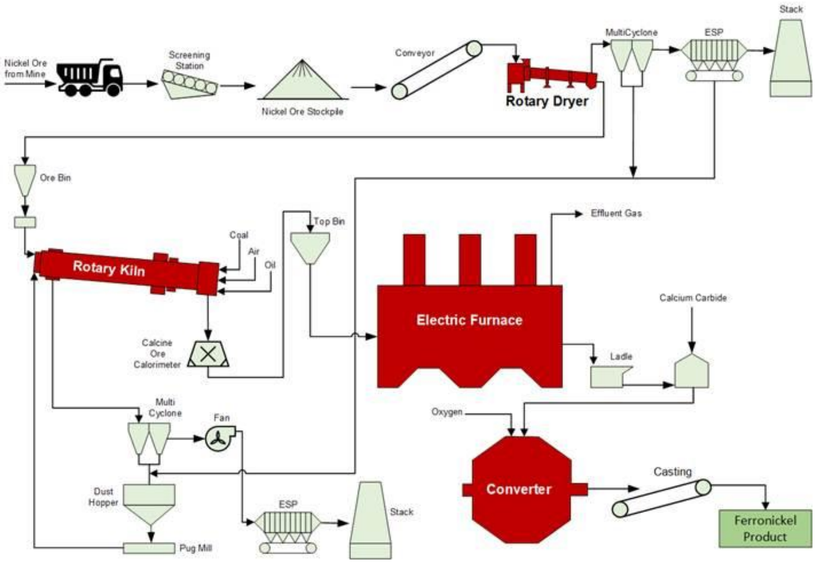


Figure 4.2.1-3 Overview of RKEF Process[23]

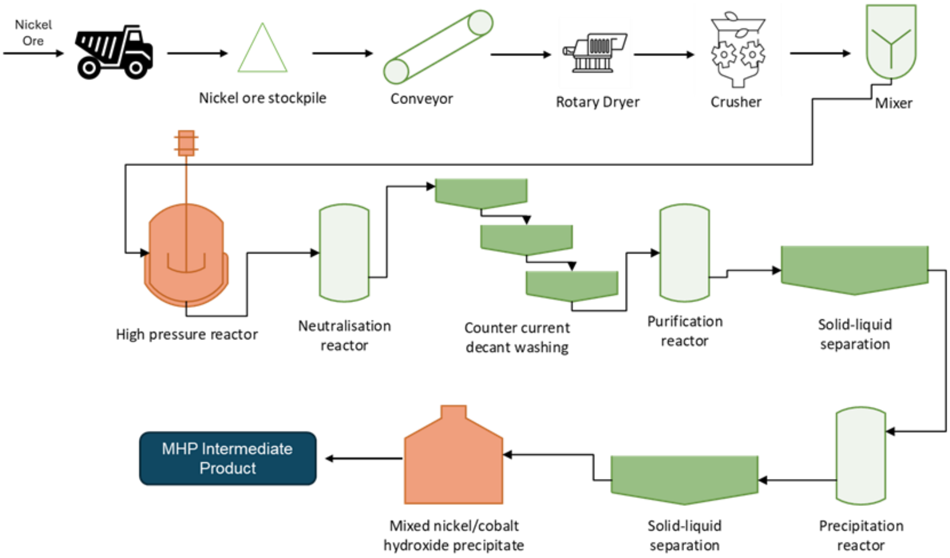


Figure 4.2.1-4 Overview of HPAL Process[24]

The case studies on the RKEF-processed and the HPAL-processed nickel industry are based on an assessment of the sector in Indonesia, using information provided by companies operating within it.

4.2.1.1 Case Study 1: RKEF Processed Nickel

Technical Findings

The RKEF processed nickel case study site operation primarily relies on a CFPP for its electricity supply. Using the site's renewable energy potential to explore decarbonisation pathways, several available technologies within the region are assessed using the analytical approach described in Section 2.3. Through this process, multiple alternative configurations were modelled across different scenarios to evaluate renewable integration. Four distinct scenarios were developed, with varying levels of renewable energy penetration, operational optimisation, and flexibility within the power system as seen in Figure 4.2.1-5.

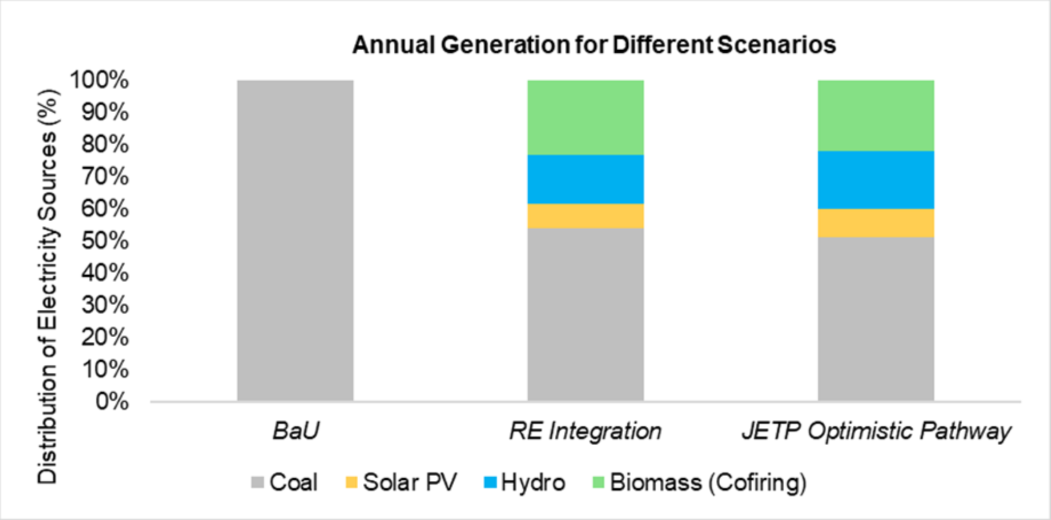


Figure 4.2.1-5 Percentage of Energy Used for Case Study 1[25]

The *BaU* scenario served as the baseline, representing continued dependence on coal-based generation. The *RE Integration* scenario introduces solar and hydropower into the mix, illustrating potential emission reductions but with increased system costs due to higher capital and operational requirements. The *JETP Optimistic Pathway* scenarios build upon this by exploring progressively ambitious levels of renewable integration and CFPP flexibility, aligned with national decarbonisation initiatives. The *JETP Optimistic Pathway* scenario assesses the technical feasibility of deeper emission reductions under varying operational assumptions and policy support conditions.

In this case study, the CFPP was assumed to adopt biomass co-firing technology to partially abate carbon emissions while maintaining baseload reliability. The detailed decarbonisation results and comparative performance of each scenario are going to be further discussed in Section 4.

---

[23] Technical Analysis
[24] Technical Analysis
[25] Technical Analysis

Even though the minimum loading ratio of the CFPP is set at 25% in the JETP Optimistic Pathway Scenario, actual operations showed the CFPP operates at an average minimum loading ratio of approximately 47% during periods of high solar PV and hydropower output. This underscored its continued role as a baseload power source to meet steady demand. Hydropower generation followed a seasonal pattern, with higher output typically observed in months such as March and December, while solar PV reaches its peak around midday. During night-time hours, when solar PV is unavailable, electricity demand is met through a combination of CFPP, hydropower, and BESS, demonstrating the importance of BESS in maintaining system reliability and balancing supply. During low hydropower generation periods, the CFPP operates at a higher minimum loading ratio of around 51.6%, emphasising its role in balancing the system when VRE sources generate less electricity. When solar PV reaches peak load, CFPP generation is gradually reduced, operating at approximately 48% capacity factor. This variability needs reliable ramp rates in accommodating VRE generation to ensure that fossil fuel generation can adjust dynamically to optimise renewable energy utilisation. The dispatch profile is shown below.

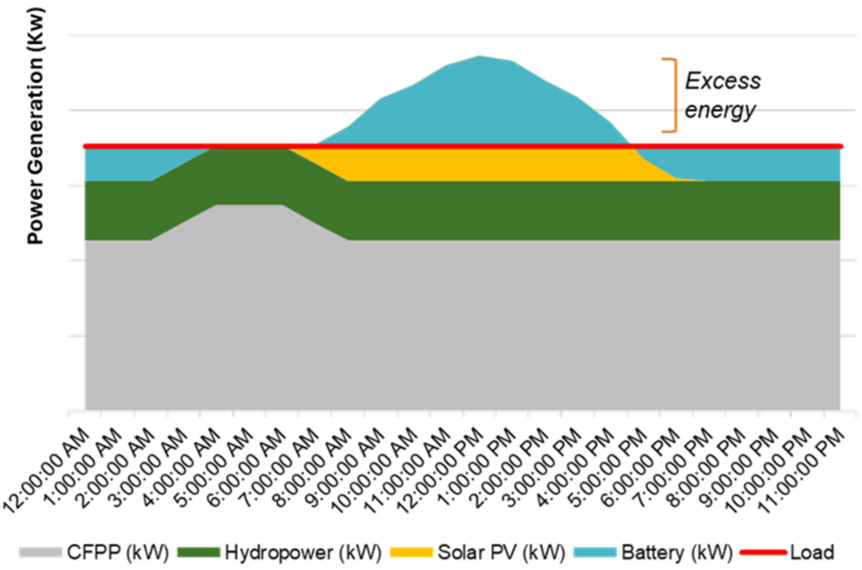


Figure 4.2.1-6 Dispatch Analysis of the JETP Optimistic Pathway for Case Study 1[26]

Battery storage played a crucial role in the *JETP Optimistic Pathway* scenario, charging during periods of high solar generation and discharging during low solar hours to balance supply and demand. The coordinated operation of flexible CFPP dispatch, VRE generation, and BESS ensured a stable and efficient power system, supporting Indonesia's JETP decarbonisation goals while maintaining grid reliability.

Based on a consistent peak load used in the HOMER Pro simulation, the FlexTool analysis confirms that the system is adequately sized to manage demand fluctuations. Fossil generation provides baseline stability, while solar PV, hydropower and battery storage reduce fossil reliance and smooth load variations.

---

[26] Technical Analysis

Under the JETP Optimistic Pathway, surplus electricity is below 0.005% of annual output. This negligible curtailment indicates the pathway effectively meets demand. System stability also indicates that the proposed energy transition scenario is technically feasible, enabling a higher renewable share without compromising reliability.

Furthermore, static power flow analysis evaluates whether the existing network can handle growing flows during periods of strong renewable output. The findings indicate that higher solar PV capacity and improved renewable power generation increase exports from the system's busbar to the grid. As renewable energy increases, peak generation rises while demand remains relatively unchanged, creating surplus electricity that must be curtailed or exported to the grid for sale to other entities.

Assessment of Integration with PLN Grid

The PLN grid integration assessment examined two approaches: delivering electricity to the facility when the grid source was largely renewable to support decarbonisation or feeding surplus renewable electricity back into the grid to boost its renewable share. A technical evaluation using HOMER Pro aimed to determine whether such surplus electricity was available. Linking the site's grid to the PLN grid would allow this surplus to be exported while also enabling the site to purchase cleaner electricity when renewable output is insufficient. As electricity demand in the nickel-processing sector continues to grow, such integration positions the site to meet future clean-energy needs more flexibly and support potential new industrial users that may rely on externally sourced renewable power.

Table 4.2.1-1 Grid Integration Capex Calculation

Project Parameters	Unit Cost Value	Project Parameter	Subtotal (USD)
Transmission Line Cost	890,000 USD/km	40 km	35,600,000
Substation Cost	97.09 USD/kW	150,000 kW	19,418,000
Land Cost	6.45 USD/m2	128,000 m2	825,600
Total CAPEX (USD)			55,843,600

The cost estimation assumed that the *RKEF Processes Nickel Case Study Site* may need to construct a transmission line that has a 150 MW capacity and approximately 40 km in length to connect to PLNs nearest grid network. Based on a high-level assessment, the total CAPEX for this integration is estimated at around USD 56 million. However, this estimate did not include land clearing costs, which could add significant expenditure depending on geographical conditions. Further analysis may be required to provide a more accurate and comprehensive cost estimate.

Financial Findings

As shown in Figure 4.2.1-7, decarbonisation requires substantial CAPEX, which initially increases tariffs in scenarios that integrate NRE. This is mainly due to upfront costs for assets such as BESS, leading to higher initial tariffs. However, this increase does not represent the long-term cost profile of NRE integration. Over time, continued reliance on fossil fuels is likely to push tariffs even higher, driven by rising fuel costs, price volatility, and future carbon-related compliance obligations. This highlights the importance of prioritising decarbonisation. While coal dependency may keep tariffs lower in the short term, it exposes projects to long-term financial risks from tightening regulations, potential carbon pricing, fuel-supply uncertainty, and compliance costs on carbon-intensive products.

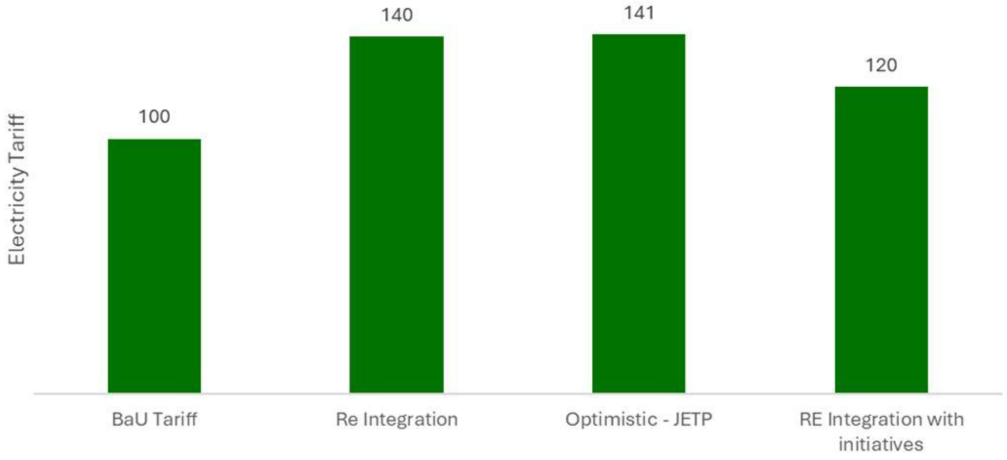


Figure 4.2.1-7 Tariff for Case Study 1[27,28]

It is also worth noting that the price difference between the company's plan under the *RE Integration* scenario and the more ambitious *Optimistic JETP* scenario is relatively small yet adopting the JETP scenario could reduce carbon emissions by up to 15.97% more than the company's plan.

Several initiatives such as carbon credits, tax holidays, grants, and green financing can help reduce electricity prices, as outlined in Section 4.1.4 Among these, green financing delivers the greatest impact on tariff reduction, while tax holidays provide a modest effect, as shown in Figure 4.2.1-8. The figure illustrates the relative size of each reduction compared to the tariff without initiatives, enabling comparison under both conservative and optimistic assumptions. Overall, the analysis suggests that these initiatives – carbon credit trading, fiscal incentive, grant funding, and green financing – can collectively create a more competitive tariff structure for the *RKEF nickel processed case study*. If all initiatives are implemented together, the tariff may be reduced by approximately 10.7–13.71% compared to the tariff without initiatives.

---

[27] Figures are indexed to 100% based on the BaU Tariff

[28] Initiatives to lower electricity price, e.g. leveraging carbon trading, tax holiday, green financing options, and grants

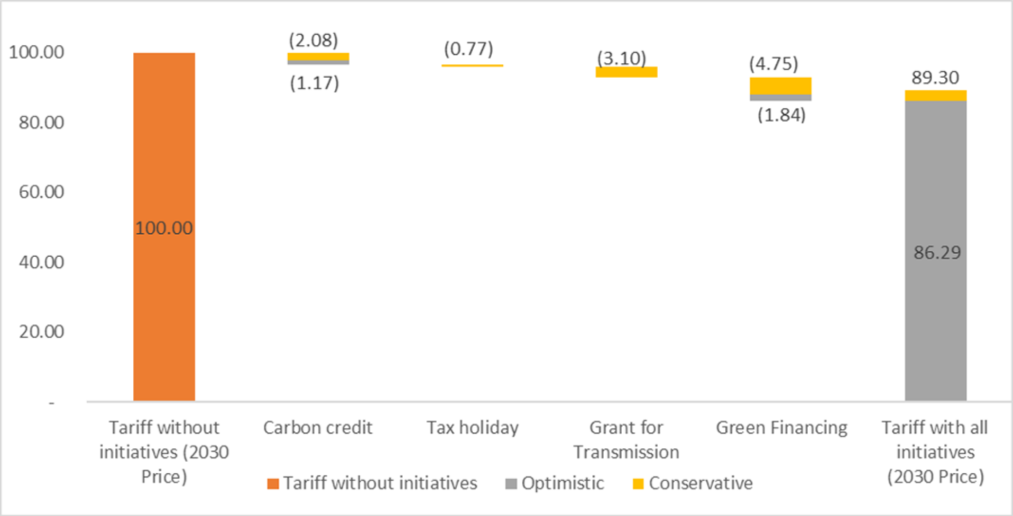


Figure 4.2.1-8 Tariff Reductions from Initiatives for Case Study 1[29]

Additional sensitivity analysis was conducted, which indicated that two factors may have a significant influence on tariff outcomes under the *RE Integration* scenario, which is the ability to sell excess electricity and biomass escalation rate. In the *RE Integration scenario*, the system is expected to produce 7.2% excess electricity which may play an important factor in the electricity tariff. Overall, the two factors: (1) the ability to sell 100% of the generated electricity without curtailment may reduce tariffs by approximately 6.5%; and (2) higher biomass price escalation assumptions, may increase tariffs by more than 7%.

Economic Findings

Implementing the preferred transition options is expected to deliver notable benefits for the case study site and the surrounding community. Beyond operational improvements, this shift can lead to measurable environmental and social gains. By integrating NRE, the site is projected to generate approximately 749,065 tCO_2/year under the *RE Integration* scenario and 593,557 tCO_2/year under the *JETP Optimistic Pathway*, reducing 23% and 39% against BaU, respectively, supporting Indonesia's coal phase-down and clean energy targets. These reductions may strengthen the company's sustainability profile, create opportunities for additional revenue through carbon trading, and reduced environmental cleanup costs due to coal consumption. Furthermore, the expected decrease in carbon emissions could help reduce overall health costs by lowering ISPA cases caused by pollution, contributing to better public health outcomes.

Table 4.2.1-2 summarises the project's economic outcomes under the *RE Integration* scenario and the *JETP Optimistic Pathway*. It reports respective scenarios BCR and ERR, providing a clear comparison of the project's economic performance across the two pathways.

Table 4.2.1-2 Summary of Economic Findings for Case Study 1

---

[29] Figures are indexed to 100% based on the Tariff without initiatives.

Scenario	Benefit Cost Ratio	Economic Internal Rate of Return
RE Integration	1.4	13.1%
JETP Optimistic Pathway	2.7	21.5%
Sensitivity Analysis on the RE Integration Scenario		
Scope 1 Emissions Calculated using IPCC Methodology	7.1	56.3%
Alternative Carbon Price[30]	0.4	-3.7%

The analysis indicates that the project is expected to deliver strong economic benefits under both transition pathways, with the more ambitious *JETP Optimistic Pathway* scenario offering even greater economic advantages due to higher ERR and BCR than *RE Integration*. However, the sensitivity analysis underscores that the project's economic performance is sensitive to variables such as carbon pricing and emissions calculation methodology. A higher carbon price enhances economic returns by increasing the value of avoided emissions, while a lower carbon price may diminish viability. Using an alternative carbon price, the RE Integration scenario may not be economically viable, as it results in a negative ERR and a BCR below 1. In contrast, applying Scope 1 emission calculations based on the IPCC methodology improves the project's economic viability, leading to a higher ERR and BCR.

This indicates that the economic viability of the project is not determined solely by the chosen transition pathway but is also strongly influenced by external factors such as carbon market dynamics, regulatory frameworks, and global pricing benchmarks.

---

[30] As explained in Section 4.1.4

4.2.1.2 Case Study 2: HPAL Processed Nickel

Technical Findings

The HPAL processed nickel case study site currently relies on a CFPP with limited solar PV. To explore decarbonisation options, several available technologies in the region were assessed using the method outlined in Section 2.3. The HPAL process itself generates substantial waste heat, which can be harnessed to produce electricity and improve overall energy efficiency. Building on this, different system configurations were modelled to determine how renewables and waste-heat recovery could meet the future energy needs shown in Figure 4.2.1-9 below.

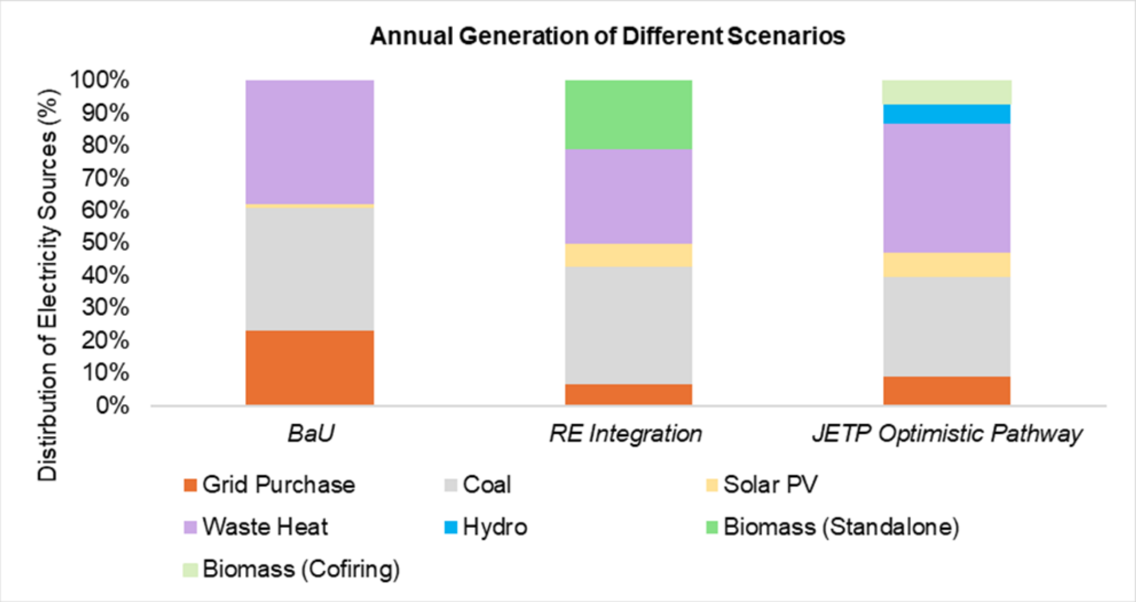


Figure 4.2.1-9 Percentage of Energy Used for Case Study 2[31]

The *BaU* scenario served as the baseline, reflecting the current reliance on CFPP and minimal renewable integration. The grid purchase was sourced from the industrial captive site, operating independently without any grid connection. The Renewable Energy Integration scenarios*,* introduce varying combinations of solar PV, biomass, and waste heat recovery systems. Both demonstrated meaningful emission reductions compared to the baseline, with differing outcomes in system cost and renewable contribution. *RE Integration* places greater emphasis on biomass utilisation.

The *JETP Optimistic Pathway* represents the most progressive scenario, optimising the mix of solar PV, waste heat, and biomass co-firing to maximise decarbonisation while maintaining operational reliability. Despite higher system complexity, the results indicated the potential for significant emission reduction without substantial cost escalation. The detailed decarbonisation results and comparative performance of each scenario were presented in Section 4.

In the *JETP Optimistic Pathway* scenario, biomass co-firing was implemented to the CFPP with a minimum load ratio of 40%. The co-firing rate of this scenario was calculated using the optimisation analysis in HOMER Pro. Results from the calculation reveals the co-firing rate

---

[31] Technical Analysis

was averaged around 17.5% annually. In the scenario when CFPP operates normally, such as during low or no solar PV generation, CFPP operation will adjust to the renewable energy generation. In this scenario, the system only produced minimal excess electricity per year, indicating minimal curtailment possible for grid sales.

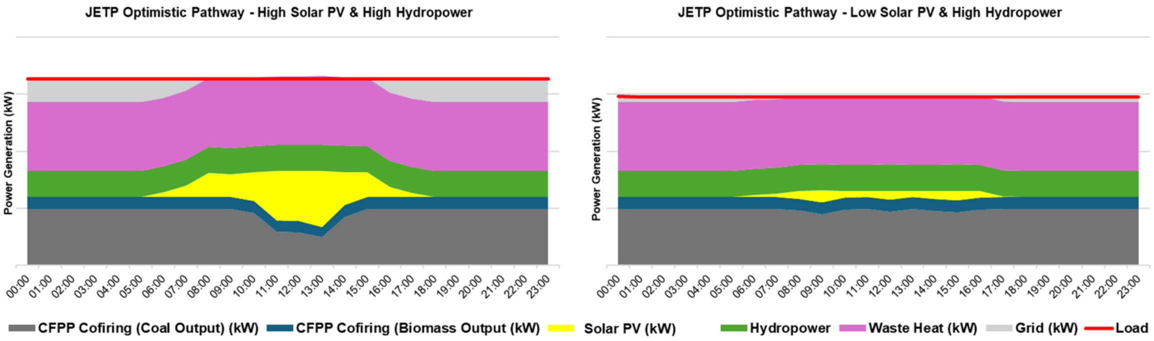


Figure 4.2.1-10 Dispatch Analysis for Case Study 2

Figure 4.2.1-10 presents the dispatch profile for the *JETP Optimistic Pathway* under periods of high and low solar PV generation. When PV is unavailable, such as at night, CFPP and waste heat provide the primary supply. On cloudy days with low PV output, CFPP operations are adjusted to integrate the available PV. When PV output is high, CFPP output is reduced further to accommodate a larger PV share. Hydropower is expected to run steadily throughout the day, with output mainly influenced by seasonal conditions. The presence of renewables can reduce daytime grid purchases to zero, although the number of hours achieved will vary over the year. The operational flexibility and renewable integration potential under the *JETP Optimistic Pathway* shows the system's ability to utilise renewable energy while maintaining reliability.

Furthermore, the FlexTool analysis results provide a breakdown of each power plant's contribution to system capacity, highlighting how different technologies respond to demand patterns, operational constraints, and flexibility requirements throughout the simulation horizon. Under the *JETP Optimistic* scenario, the system demonstrated strong technical viability for integrating higher shares of renewable energy into HPAL operations proven by negligible curtailment levels, indicating efficient system design. Some model leakage was observed, likely reflecting the added complexity of managing VRE at higher shares.

FlexTool confirms that the system was adequately sized to manage demand fluctuations. Dispatch results indicate fossil and waste heat generation operating as baseload, hydropower providing flexible generation and solar PV delivering midday peak shaving. These resources collectively contribute significantly to reducing fossil fuel dependence and balancing load variations.

Moreover, static power-flow analysis assesses whether the existing grid can accommodate the increased power flows from these renewable sources. As renewable output grows, peak generation rises while demand remains relatively steady, creating surplus electricity that must either be curtailed or exported for sale to other entities.

Overall, the flexibility and static power flow assessment supported the technical feasibility of HPAL operations under the *JETP Optimistic Pathway*, with minimal stability risks and strong potential for increased renewable integration.

Assessment of Integration with PLN Grid

The PLN grid integration assessment analysed two options: supplying electricity to the facility when the grid source was predominantly renewable to support decarbonisation or exporting excess renewable electricity back to the grid to increase the renewable energy mix. Technical analysis using HOMER Pro was intended to determine whether such excess electricity was available. This excess could be absorbed within the site's IUPTLS industrial grid, supporting nearby operations and improving overall system efficiency. Connecting the IUPTLS grid to the national utility grid would enable surplus energy to be exported while allowing the site to purchase cleaner electricity during periods of low renewable output. As electricity demand in the nickel-processing sector continues to grow, such integration provides a flexible pathway to meet future clean-energy needs while reducing the requirement for oversized on-site renewable capacity.

Table 4.2.1-3 Grid Integration CAPEX Calculation for Case Study 2

Project Parameters	Unit Cost Value	Project Parameter	Subtotal (USD)
Transmission Line Cost	890,000 USD/km	51.98 km	46,262,200
Substation Cost	97.09 USD/kW	150,000 kW	14,564,117
Land Cost	6.45 USD/m^2	166,336 m^2	1,039,600
		Total CAPEX (USD)	61,865,917

The cost estimation assumed that the *HPAL Processed Nickel Case Site* may need to construct a transmission line with a capacity of 150 MW and an approximate length of 51.98 km to connect to the nearest PLN grid. Based on the high-level cost estimation, the total CAPEX for integrating the site grid to PLN nearest grid was estimated to approximately cost USD 62 million. Further analysis is required to provide a more accurate cost estimation.

Financial Findings

As shown in Figure 4.2.1-11, the tariffs that integrate NRE are higher than the BaU. This is mainly due to the upfront costs for assets such as hydropower energy, leading to higher initial tariffs. However, these increases do not represent the long-term cost profile of NRE integration. Over time, continued reliance on fossil fuels is likely to push tariffs even higher, driven by rising fuel costs, price volatility, and future carbon-related compliance obligations. This highlights the importance of prioritising decarbonisation. While coal dependency may keep tariffs lower in the short term, it exposes projects to long-term financial risks from tightening regulations, potential carbon taxes, fuel-supply uncertainty, and compliance costs on carbon-intensive products.

Disclaimer: This document forms part of the Indonesia Just Energy Transition Partnership (JETP) thematic reporting. It does not constitute a legally binding document. It is a strategy document that the Government of Indonesia may use as a basis for power sector planning and policymaking as part of the JETP process. For more information about JETP Indonesia, please refer to the 2023 Comprehensive Investment and Policy Plan (CIPP) and 2025 Progress Report. The CIPP is a document for the implementation of the Joint Statement agreed in November 2022.

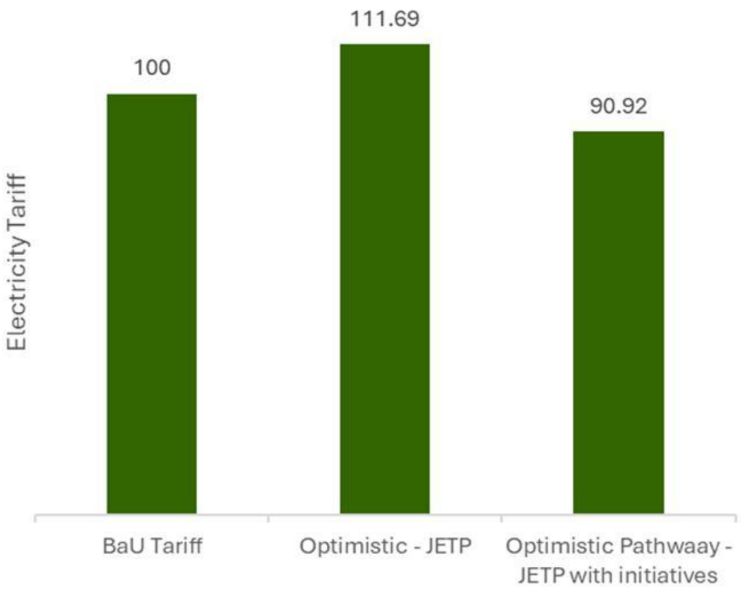


Figure 4.2.1-11 Electricity Tariff for Case Study 2[32][33]

The analysis highlights that the ambitious *JETP Optimistic Pathway* scenario tariff shows a 11.69% increase from the BaU tariff, while offering the potential to reduce carbon emissions by up to 49.95%. Moreover, this tariff could be further lowered through additional initiatives, ensuring that the pathway remains economically manageable and environmentally beneficial.

Several initiatives such as carbon credits, tax holidays, grants, and green financing may reduce electricity prices, as outlined in Section 4.1.4 Among these, carbon credit trading may deliver the greatest impact on tariff reduction, while tax holidays may provide only a modest effect, as shown in Figure 4.2.1-12. It illustrates the relative size of each reduction compared to the tariff without initiatives, making it easier to compare impacts under both conservative and optimistic assumptions. Overall, the analysis suggests that carbon credit trading, fiscal incentive, grant funding, and green financing may collectively create a more competitive tariff structure for the *HPAL nickel processed case study.* If all initiatives are implemented together, tariffs may be reduced by approximately 14.83% - 18.60% compared to the tariff without initiatives.

---

[32] Figures are indexed to 100% from the baseline tariff

[33] Initiatives to lower electricity price, e.g. leveraging carbon trading, tax holiday, green financing options, and grants

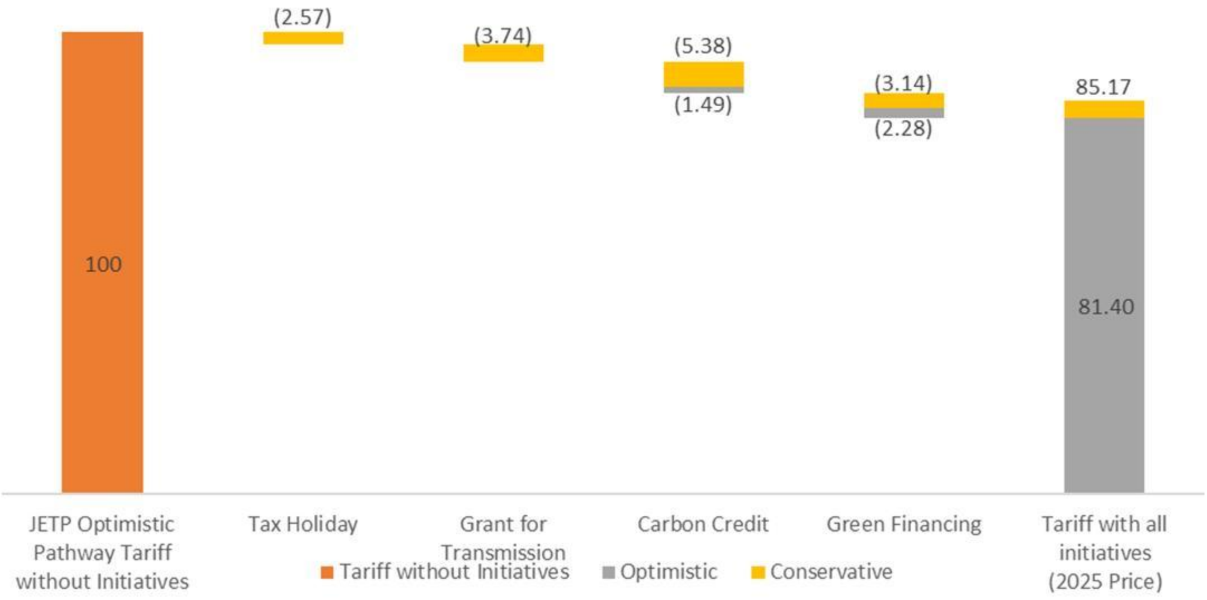


Figure 4.2.1-12 Tariff Reduction from Initiative for Case Study 2[34]

Additionally, sensitivity analysis was conducted, and it suggests that the waste heat power plant capacity factor is expected to be the most influential parameter that affect the tariff. A decrease of 50% in its capacity factor is expected to increase the tariff by more than 25%, indicating that variations in this assumption may significantly affect the financial projection.

Economic Findings

Implementing the preferred transition options is expected to deliver notable benefits for the case study site, and the surrounding community. Beyond operational improvements, this shift can lead to measurable environmental and social gains. Carbon emission under the BaU scenario is estimated to reach up to 800,025 tCO_2/year. However, by integrating NRE, the site is projected to generate approximately 400,404 tCO_2/year under the *JETP Optimistic Pathway*, supporting Indonesia's coal phase-down and clean energy targets. These reductions may strengthen the company's sustainability profile, create opportunities for additional revenue through carbon trading, and reduce environmental cleanup costs due to coal consumption. Furthermore, the expected decrease in carbon emissions could help reduce medical expenses by lowering ISPA cases, contributing to better public health outcomes. In addition, installations in solar, hydropower, and biomass co-firing may reduce coal consumption and electricity purchases from external sources, reduce operational cost, strengthen energy security, and support long-term sustainability by promoting cleaner energy use.

Table 4.2.1-3 summarises the project's economic results under the BaU and *JETP Optimistic Pathway* scenarios, followed by two sensitivity tests that assessed how changes in emission-quantity calculations and carbon-price assumptions affect the ERR and BCR outcomes.

---

[34] Figure are indexed to 100% from the Tariff Without Initiatives

Table 4.2.1-4 Summary of Economic Findings for Case Study 2

Scenario		Benefit Cost Ratio	Economic Internal Rate of Return
BaU		2.9	29.3%
JETP Optimistic Pathway		3.1	33.5%
Sensitivity Analysis			
BaU	Emissions Calculated using IPCC	0.79	4.5%
	Alternative Carbon Price[35]	2.6	27.3%
JETP Optimistic Pathway	Emissions Calculated using IPCC	2.5	28.7%
	Alternative Carbon Price[36]	2.8	30.9%

The analysis indicates that both the BaU and *JETP Optimistic Pathway* scenarios are likely to deliver positive economic results. In both scenarios, the ERR is expected to remain above the 10% social discount rate, and the BCR is projected to exceed one. This suggests that the economic benefits could outweigh the costs under these scenarios.

However, sensitivity tests show that results may vary depending on the emissions, and which carbon price benchmark is used. For example, under the IPCC method in the BaU scenario, the ERR falls below the social discount rate and the BCR drops below one because only Scope 1 emission reductions are counted, excluding reductions from lower electricity purchases (Scope 2). In contrast, using alternative carbon price assumptions produces stronger results. For the JETP scenario, both sensitivity scenarios continue to show positive economic outcomes, supported by reduced coal use and less dependence on grid electricity. Overall, these findings highlight that economic viability depends on the emissions calculation method and carbon pricing approach applied.

---

[35] As explained in Section 4.1.4

[36] Ibid.

4.2.2 Pulp and Paper Industry

The origins of Indonesia's pulp and paper industry date back to the 1970s, when the country began leveraging its rich natural resources to support economic modernisation. Encouraged by government policies promoting forest-based industries, the sector quickly gained momentum. International demand for paper products, particularly from Asia, Europe, and North America, further fuelled its expansion. By the 1990s, Indonesia had emerged as a major global player, with large-scale pulp mills established across the country[37]. Key industry players that emerged in the sector also shaped Indonesia's reputation as a key contributor to the global pulp and paper market. Now, Indonesia's paper production continues to grow steadily each year, as shown in the Figure 4.2.2-1 below, which displays annual output in tonnes across stationery, packaging, and graphic paper categories.

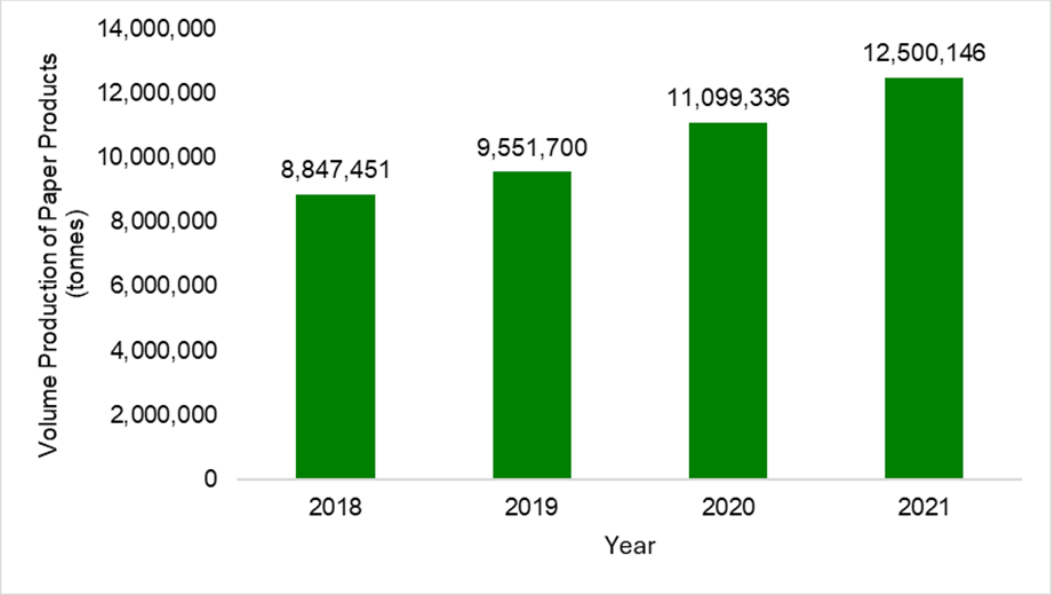


Figure 4.2.2-1 Indonesia Annual Paper Production in Tonnes[38]

Despite its economic significance, the pulp and paper industry is one of the most energy-intensive sectors in Indonesia. In fact, it ranks among the top five industries with the highest coal consumption, according to the Indonesian Energy Outlook 2022. The sector's global energy demand continues to grow steadily, increasing at an average rate of 2.49% per year, from 108.5 million barrels of oil equivalent ("BOE") in 2018 to a projected 135.4 million BOE by 2027[39].

The pulp and paper industry in Indonesia consumes substantial amounts of energy per unit of production. On average, it requires approximately 91.85 kWh of electrical energy and 1,619 MJ of thermal energy to produce one tonne of paper[40]. Another research also indicates that

---

[37] Dijk, van, M. (2005). Industry Evolution and Catch Up: The Case of the Indonesian Pulp and Paper Industry. [Phd Thesis 1 (Research TU/e / Graduation TU/e), Industrial Engineering and Innovation Sciences]. Technische Universiteit Eindhoven. https://doi.org/10.6100/IR58586

[38] APKI. (2022).

[39] Paminto, Ari Kabul et al. (2020). Kajian Efisiensi Energi di Industri Pulp dan Kertas.

[40] Pandey, A. and Prakash, R. (2018) Energy Conservation Opportunities in Pulp & Paper Industry. Open Journal of Energy Efficiency, 7, 89-99. doi: 10.4236/ojee.2018.74006.

energy usage for pulp and paper processing can account for 70 – 80% of the industry's total energy consumption, underscoring its heavy dependence on energy resources[41].

In paper production, the energy required to produce one tonne of paper varies significantly depending on the type of paper and the stage of the process, which is divided into forming & pressing and drying. The energy consumption is further categorized into electricity and heat, with each paper type, such as packaging, graphic, and specialty papers[42].

Table 4.2.2-1 Energy Consumption for Different Paper Processes (Rahnama, et al., 2021)

Paper Product	Process	Electricity Consumption (kWh/t_{paper})	Heat Consumption (kWh/t_{paper})
Printing (coated) paper	Forming & pressing	527.5	0
	Drying	29.3	5.48
Writing (uncoated) paper	Forming & pressing	527.5	0
	Drying	29.31	5.27
Packing paper	Forming & pressing	296.6	0
	Drying	14.7	4.22

4.2.2.1 Case Study 3: Paper Mill

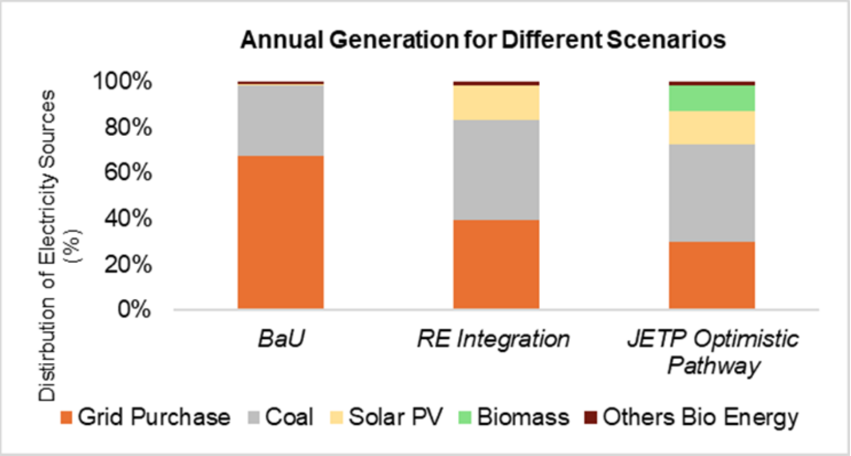
Technical Findings

Two sites were analysed for this case study. The same scenarios configurations are assessed to compare the results between Site A and Site B. The BaU scenario reflects the current energy configuration, which includes the existing cogeneration system and the ongoing use of others bioenergy sources such as sludge IPAL (sludge from the wastewater treatment plant), Refuse-Derived Fuel, and biogas with units assumed to be replaced only at the end of their technical life to maintain current production levels.This setup reflected the current energy configuration and serves as the basis for comparing decarbonisation options.

---

[41] Ashok Kumar Pandey, Ravi Prakash, "Energy Conservation Opportunities in Pulp and Paper Industry", Open Journal of Energy Efficiency, 2018, 7, 89-99

[42] Rahnama, Maedeh & Silva, Miguel. (2021). Pulp and Paper Industry: Decarbonisation Technology Assessment to Reach CO2 Neutral Emissions—An Austrian Case Study. Energies. 14. 1161. 10.3390/en14041161.



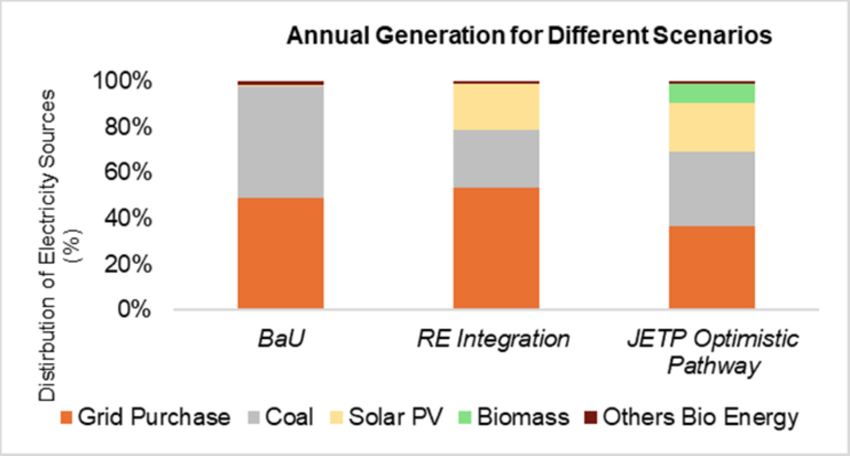


Figure 4.2.2-2 Percentage of Energy Used for Case Study 3: Site A (top) and Site B (bottom)

Under the *RE Integration* scenario, additional solar PV capacity was introduced to reduce the site's reliance on fossil-based cogeneration. Although this led to a clear decrease in carbon intensity, the impact remained limited by a 40% minimum loading requirement that constrained further renewable penetration and resulted in occasional curtailment during periods of excess generation.

The *JETP Optimistic Pathway* scenario built upon this by expanding solar PV deployment and incorporating partial biomass cofiring within the cogeneration system, using wood pellet and PKS (Palm Kernel Shell) as the designated biomass fuels. This integrated configuration demonstrated significant emissions reductions alongside modest cost improvements, highlighting the potential for balanced and sustainable energy transition. This scenario modified the system further by procuring RECs from the grid. The comparative analysis and detailed decarbonisation outcomes for all scenarios are further discussed in the next section.

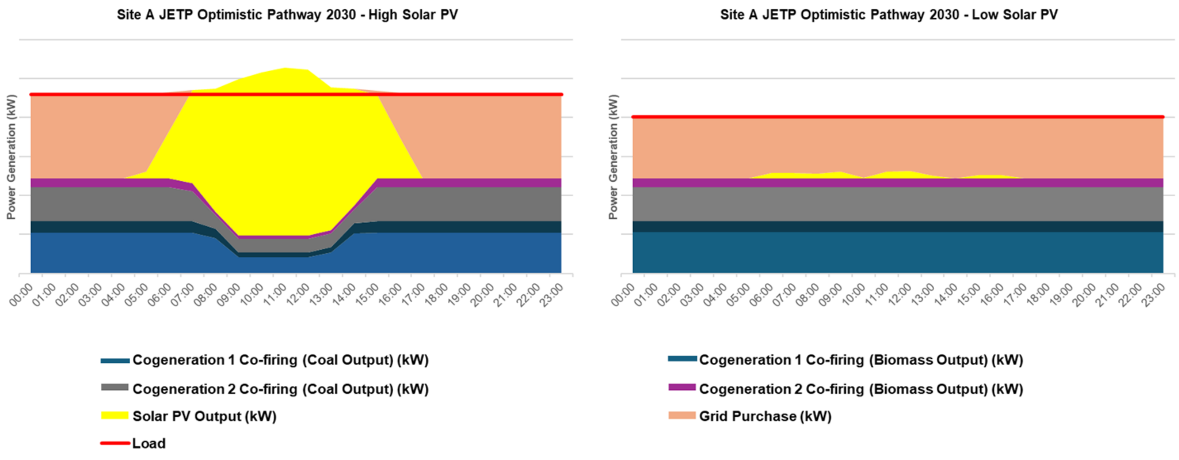


Figure 4.2.2-3 - Electricity Dispatch for Site A

The dispatch profile for the *JETP Optimistic Pathway* at the East Java site during periods of high and low solar PV output are presented. On both occasions, the system primarily relies on cogeneration units and grid purchase during nighttime. During the day, when solar PV output is high, cogeneration units' operation is reduced to accommodate electricity produced by solar PV. If the solar PV experiences low output, such as during rainy or cloudy days, cogeneration units operate constantly throughout the day while grid purchase is adjusted to include solar PV share. High solar PV produces excess electricity, which reduces the grid purchase to 0 MWh and enables export sales possibility to the grid.

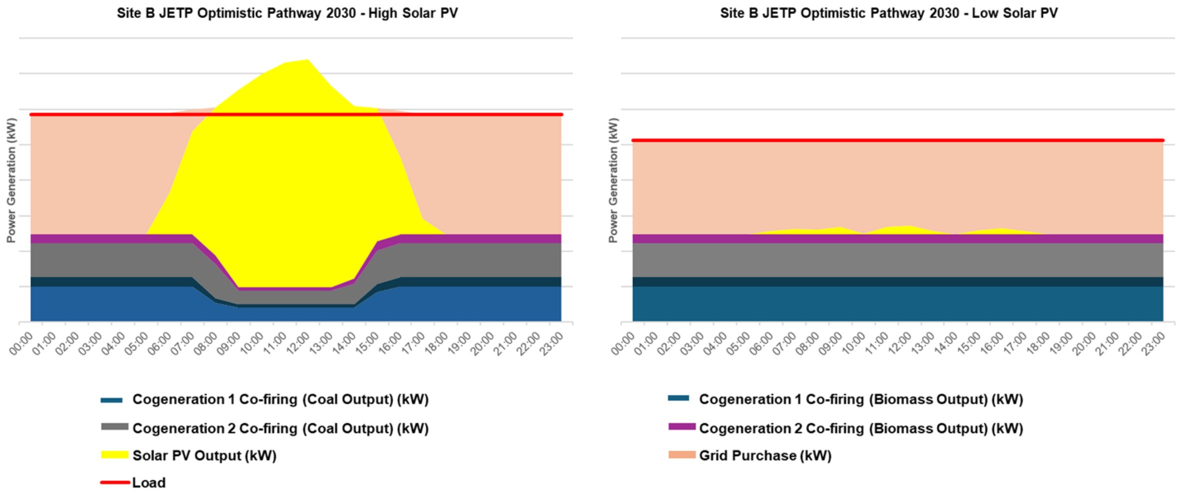


Figure 4.2.2-4 - Electricity Dispatch Analysis for Site B

Figure 4.2.2-4 shows the result for site B. Outcomes for site B are very similar to site A for both occasions when the solar PV output is high and low. The difference lies when it comes to the amount of excess electricity. In site B, the excess electricity reveals higher value than site A. Higher surplus electricity may be influenced by the system size's difference between site A and site B. Result in both sites shows that site B may have higher opportunity in grid sales compared to site A.

Disclaimer: This document forms part of the Indonesia Just Energy Transition Partnership (JETP) thematic reporting. It does not constitute a legally binding document. It is a strategy document that the Government of Indonesia may use as a basis for power sector planning and policymaking as part of the JETP process. For more information about JETP Indonesia, please refer to the 2023 Comprehensive Investment and Policy Plan (CIPP) and 2025 Progress Report. The CIPP is a document for the implementation of the Joint Statement agreed in November 2022.

In cases where electricity generation exceeds demand, surplus energy may be sold to the grid. This created an opportunity to monetise excess output, enhancing the economic value of the scenario. However, the amount of surplus electricity depends on the daily load variations, which may fluctuate by around 5%, determining whether excess generation occurs.

As both sites are practically connected to the same *Jawa-Madura-Bali* ("Jamali") PLN grid, their generation and demand profiles are assessed jointly to reflect system-wide performance. FlexTool analysis reveals how different technologies respond to demand patterns, operational constraints, and flexibility requirements throughout the simulation.

Under the *JETP Optimistic Pathway* scenario, the flexibility analysis evaluates the operational performance of both sites, which were assessed jointly due to their connection to the Jamali grid. The system showed no instances of load loss, reserve inadequacy or capacity shortages, indicating stable and reliable electricity supply.

Curtailment levels were slightly elevated due to the high share of solar PV yet remained minimal overall. In the JETP Optimistic Pathway scenario, surplus electricity amounts to only about less than 1% of annual output, but in absolute MWh terms it may still be material for sale to the grid. Exporting this excess renewable generation to the PLN network could generate additional revenue and help reduce JAMALI's overall emissions.

Peak load was driven by increased electric boiler requirements. FlexTool confirmed the system is adequately sized to manage demand fluctuations. Fossil fuel generation remains as a primary generator, while solar PV played key roles in reducing fossil reliance.

Furthermore, static power flow analysis is used to assess whether the existing network can accommodate high power flows during periods of high renewable output. Expanding solar PV and other renewables increases daytime exports from the system's central busbar to the grid. Surplus PV enables renewable electricity to be exported to PLN, helping to reduce overall emissions on the Jamali grid. Overall, the analysis confirmed that the energy transition strategy was technically viable under the *Optimistic – JETP* pathway, with minimal stability risks and strong potential for integrating higher shares of renewables.

REC Analysis

As the paper mill was already connected to the grid, some scenarios modelled technically assumed grid electricity purchases. To ensure these purchases supported decarbonisation efforts, REC procurement was also analysed. The assessment was divided into two parts: the demand side, which evaluated grid purchases across four scenarios and determined whether to purchase partially or fully; and the supply side, which assessed availability from PLN. From these assessments, it was concluded that without an increase in PLN's REC quota, available certificates could not meet demand. Consequently, an additional analysis was conducted to project future renewable energy generation embedded in the Jamali grid, as outlined in Section 4.1.2. Based on this projection, and assuming all renewable generation could be converted into RECs, the paper mill's REC procurement was deemed feasible.

Financial Findings

As shown in Figure 4.2.2-5, which represent both site A and site B, scenarios that integrate NRE increase tariffs. This is mainly due to upfront costs for assets such as biomass and solar PV, leading to higher initial tariffs. However, these increases do not represent the long-term cost profile of NRE integration. Over time, continued reliance on fossil fuels is likely to push tariffs even higher, driven by rising fuel costs, price volatility, and future carbon-related compliance obligations. This highlights the importance of prioritising decarbonisation. While coal dependency may keep tariffs lower in the short term, it exposes projects to long-term financial risks from tightening regulations, potential carbon pricing, fuel-supply uncertainty, and compliance costs on carbon-intensive products.

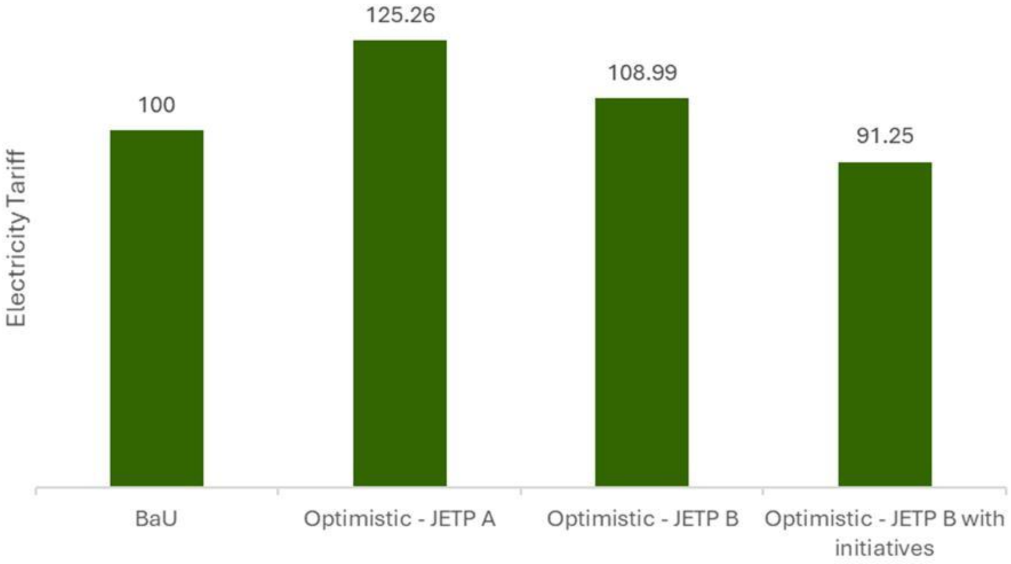


Figure 4.2.2-5 Electricity Tariff for Case Study 3[43,44]

The results show that the electricity cost of JETP A is higher than JETP B, mainly due to the additional capacity of solar PV and higher grid purchase. Implementing the *Optimistic JETP B* pathway requires only an 8.99% increase above the BaU tariff and it is expected to deliver an estimated 26.60% reduction in carbon emissions. With further strategic measures, the tariff under the Optimistic JETP B pathway could be reduced even more, strengthening its long-term financial and environmental viability.

Several initiatives such as carbon credits, tax holidays, grants, and green financing can help reduce electricity prices, as outlined in Section 4.1.4. Among these, green financing delivers the greatest impact on tariff reduction, while tax holidays provide only a modest effect, as shown in Figure 4.2.2-6.

---

[43] Figure are indexed to 100% from the Baseline Tariff

[44] Initiatives to lower electricity price, e.g. leveraging carbon trading, tax holiday, green financing options, and grants

It illustrates the relative size of each reduction compared to the tariff without initiatives, making it easier to compare impacts under both conservative and optimistic assumptions. Overall, the analysis suggests that carbon credit trading, fiscal incentive, grant funding, and green financing can collectively create a more competitive tariff structure. If all initiatives are implemented together, tariff may be reduced by approximately 12.10% –16.27% compared to the tariff without initiatives.

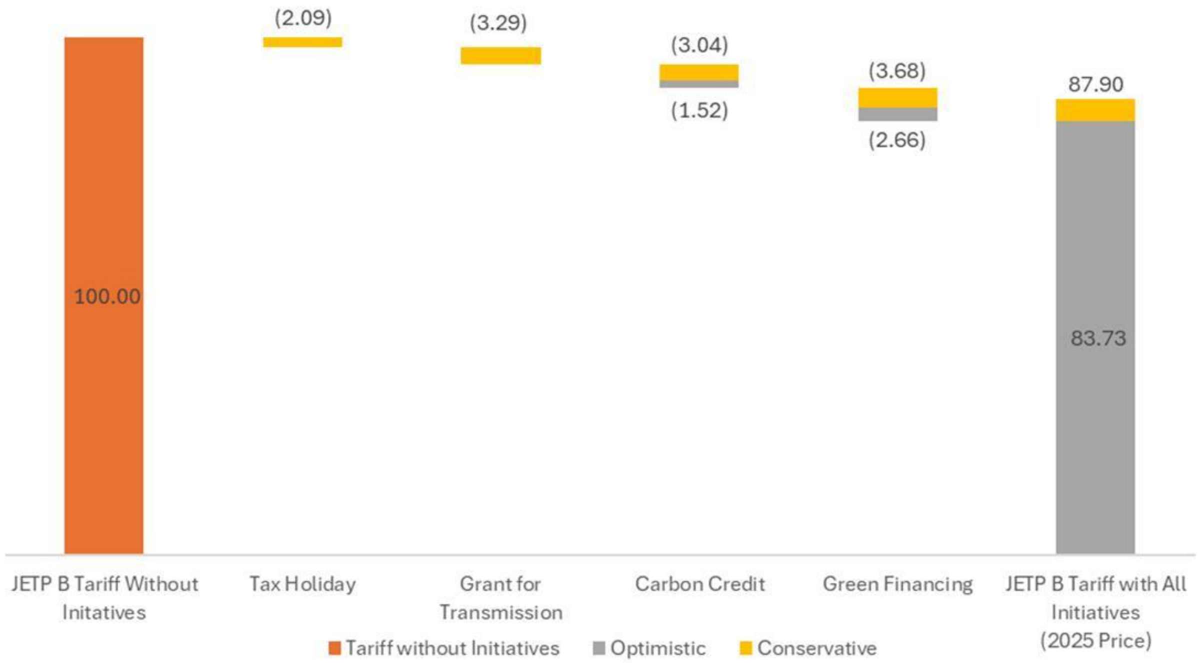


Figure 4.2.2-6 Tariff Reductions from Initiatives for Case Study 3[45]

Additionally, sensitivity analysis was conducted, and it indicates that two factors may have a significant influence on tariff outcomes: (1) biomass pricing and escalation, where higher escalation rates may increase tariffs by more than 8%, and (2) land acquisition strategy, where purchasing land instead of leasing may raise tariffs by over 6%. These variations indicate that assumptions on fuel cost trends and land procurement approach may significantly affect overall financial projection.

Economic Findings

Implementing the preferred transition options is expected to deliver notable benefits for the case study site, and the surrounding community. Beyond operational improvements, this shift can lead to measurable environmental and social gains. By incorporating NRE carbon emission under the *JETP Optimistic Pathway* scenario is estimated to reach up to 1,381,484 tCO_2/year in site A, representing a 47.7% reduction from the BaU and 1,545,027 tCO_2/year in Site B, a 26.60% reduction from the BaU, supporting Indonesia's coal phase-down and clean energy targets. These reductions may strengthen the company's sustainability profile, create opportunities for additional revenue through carbon trading, and reduce environmental cleanup costs due to coal consumption. Furthermore, the expected decrease in carbon

---

[45] Figure are indexed to 100% from the Tariff Without Initiatives

emissions could help reduce medical expenses by lowering ISPA cases, contributing to better public health outcomes.

In addition, installations in solar and adjustments to implement biomass co-firing may minimise reliance on coal and grid electricity, delivering cost efficiency, strengthening energy security, and supporting long-term sustainability by reducing dependence on finite resources, improving resilience to future energy price volatility, and contributing to climate objectives. Table 4.2.2-2 below presents the economic results for the *JETP Optimistic Pathway* scenario, together with a sensitivity test assessing how Indonesia's carbon-price assumption affects the ERR and BCR.

The *JETP Optimistic Pathway* scenario, shows strong economic viability, with an ERR above the social discount rate and a BCR above one indicating that project benefits exceed costs. However, when alternative carbon-price assumption is applied in the sensitivity analysis, the ERR falls below negative to a point where it cannot be calculated or N/A, and the BCR decreases to below 1, making the scenario economically unfavourable. This outcome highlights the importance of carbon-price levels in determining the project's overall feasibility.

Table 4.2.2-2 Summary of Economic Findings for Case Study 3

Scenario	Benefit Cost Ratio	Economic Internal Rate of Return
JETP Optimistic Pathway	1.9	120.7%
Sensitivity Analysis		
Alternative Carbon Price[46]	0.9	N/A

4.3 Decarbonisation Strategy

Decarbonisation strategies encompassed a combination of technological and market-driven approaches aimed at reducing greenhouse gas emissions across industrial operations. These approaches generally fall under three key pillars. The first is carbon emission reduction, achieved through fuel switching to lower-carbon alternatives and NRE integration. The second is energy efficiency, which focuses on optimising energy use and improving process performance. The third involves market strategies and risks and opportunities that result from decarbonisation activities. Together, these strategies form an integrated framework for achieving emission reductions while maintaining operational and economic viability.

---

[46] As explained in Section 4.1.4

4.3.1 Carbon Emission Reduction

Building upon the preceding assessments, the technical modelling provided an overview of potential CO_2 emission reductions under different transition pathways. The analysis demonstrated how renewable energy integration and alternative power strategies could substantially reduce operational carbon intensity. These findings summarised the overall decarbonisation potential for each case and scenario, forming the basis for the project's recommended transition approach. The results of this analysis are summarised in Table 4.3.1-1 below, that compared CO_2 reduction between scenarios, in which BaU Scenario reflects minimal change and serves as the baseline, RE Integration Scenario achieves moderate reductions through cost-effective renewables and flexibility, and JETP Optimistic Pathway Scenario delivers the most ambitious cuts by maximising renewable penetration and efficiency improvements, as further explained in Section 2.3.6.

Table 4.3.1-1 Summary of Carbon Emission Reduction

CO2 emission (tCO_2/year)								
Scenario	Case Study 1		Case Study 2		Case Study 3: Site A		Case Study 3: Site B	
BaU	976,678		800,025		2,898,220		2,791,828	
RE Integration	tCO2/year	% to BaU	tCO2/year	% to BaU	tCO2/year	% to BaU	tCO2/year	% to BaU
	749,065	-23.29%	707,396	-11.58%	2,066,574	-28.70%	2,107,851	-24.49%
JETP Optimistic Pathway	593,557	-39.26%	400,404	-49.95%	1,381,484	-47.70%	1,545,027	-26.60%

4.3.2 Energy Efficiency

The efficiency assumptions applied in the modelling are based on a review of existing literature and practical considerations for both RKEF and HPAL processes. These assumptions aimed to capture realistic improvements while maintaining technological and economic feasibility.

For RKEF-processed nickel, a 10% supply-side efficiency improvement was selected as a conservative estimate. This figure reflected findings from multiple studies reporting gains between 6% and 12% through measures that can be taken by a CFPP. Research by Jovic et al. (2018), Soto (2014), and Zhang (2020) demonstrated improvements through cooling system modifications and thermal optimisation, while Xu et al. (2024) and Yan et al. (2024) highlighted advanced strategies implemented to the CFPP such as calcium looping and machine learning-based boiler control. Given this range, 10% represented a balanced assumption that aligned with validated operational enhancements. On the demand side, a 10% efficiency improvement was applied, informed by studies indicating gains from 5% to 25% through process optimisation, waste heat recovery, and slag management (Romero et al., 2022; Liu et al., 2016; Quintero-Coronel et al., 2022; Rong et al., 2017). This conservative estimate ensured modelling reliability while reflecting achievable process adjustments.

For HPAL-processed nickel, the supply-side assumption of 10% efficiency improvement was derived from literature and studies by Marzouk. (2024) and Chen & Bollas. (2018) by reporting combined gains possibility for CFPP efficiency improvement. The improvement ranges from 10.92% to 33.92% through strategies such as controlled variable optimisation, dynamic load modelling and cooling system upgrades. Individual measures, such as steam extraction optimisation and heat storage integration, also contributed incremental improvements of 1.5% to 7.8%. To maintain a conservative approach, the lowest reported combined gain was adopted for simulation. On the demand side, efficiency improvements of approximately 5.21% were calculated based on enhanced nickel and cobalt recovery rates. Studies by Bana et al. (2025), Yao et al. (2014), and Dickson et al. (2025) report nickel leaching rate improvements of 3% to 5.8%, while cobalt recovery enhancements contributed an additional 0.85%.

Table 4.3.2-1 Energy Efficiency Comparison for Nickel Industry

Case		(%) RKEF-Processed Nickel	(%) HPAL-Processed Nickel
Input	Supply Side Energy Efficiency	10%	10%
Output	Reduced Coal Consumption	41%	38%
Input	Demand Side Process Efficiencies	10%	5.21%
Output	Reduced Electricity Consumption	5%	3%

The results demonstrated that supply-side measures deliver the largest reductions in coal consumption 41% for RKEF and 38% for HPAL primarily through CFPP efficiency upgrades and improved coal quality. Demand-side optimisations provide smaller gains, reducing electricity use by 5% for RKEF and 3% for HPAL. These results, illustrated in Figure 4.3.2-1, highlight the need to prioritise supply-side interventions while complementing them with targeted demand-side measures to achieve meaningful energy savings and emissions reductions in nickel processing.

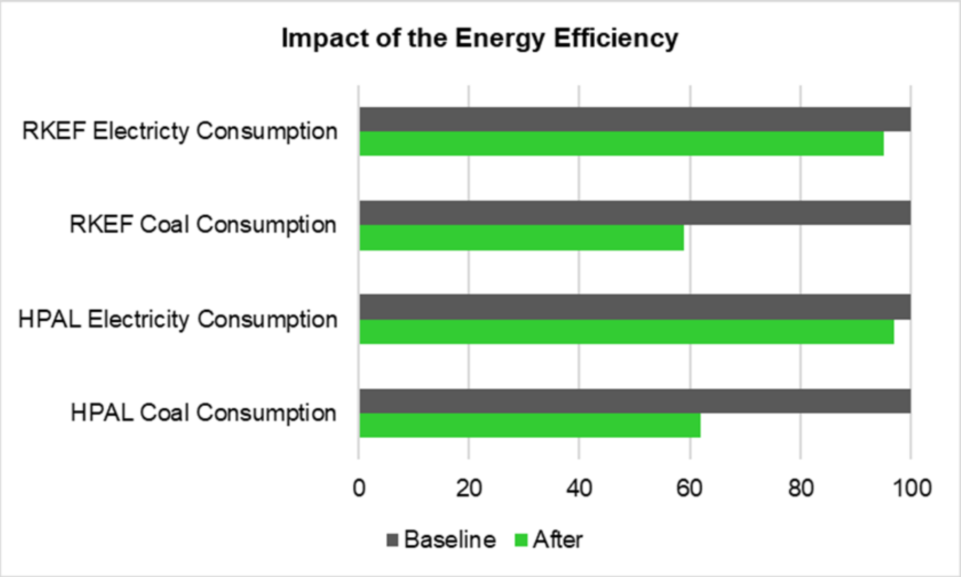


Figure 4.3.2-1 Result of Energy Efficiency on Nickel Industry

In the paper industry, efficiency gained focus primarily on demand-side measures due to the energy-intensive nature of pressing, drying, refining, and screening processes. While supply-side strategies such as downsizing cogeneration and introducing electric boilers can reduce emissions and improve flexibility, the greatest potential lies in optimising thermal and electrical performance within the production line.

Key opportunities included variable speed drives, improved batch digesters, and heat recovery systems. Studies showed that optimising drying sections and steam management can achieve gains of 3% to 16%, while condensate recovery and waste heat reuse further reduce thermal demand. Technical assessments indicate that a 25% improvement in thermal efficiency and 2% in electrical efficiency were realistic targets, aligning with industry best practices and supporting decarbonisation through process optimisation and electrification. Overall, thermal and electrical energy can be reduced by approximately 19%, reinforcing the potential for significant efficiency gains across operations.

practices and supporting decarbonisation through process optimisation and electrification.

4.3.3 Risks and Opportunities

To ensure structured risk management, risks were categorised into three main stakeholder groups: the government of Indonesia, the case study company, and shared risks. This categorisation clarified responsibilities and facilitated early planning and mitigation efforts to enhance project resilience and preparedness.

Alongside projected emission reductions, this analysis also examined key risks and corresponding mitigation strategies associated with the proposed transition options. These risks span the preparation, implementation, and operational phases of the project, as detailed in the table below.

Table 4.3.3-1 Key Risks and Mitigations

Key risk		Mitigation
Location Risk	Related to the physical and social characteristics of the project site, such as land availability, unforeseen ground conditions, and potential community disturbances that may affect project siting and acceptance.	Location risk was mitigated through social context assessments, site surveys, and technical evaluations, followed by a careful engineering approach.
Policy Risk	Stemmed from the possible changes in government direction, regulations, or administrative requirements that could alter tariff structures, local content obligations, or broader energy sector frameworks.	Policy risk was mitigated through regular monitoring of regulatory changes and carbon market trends, complemented by contingency planning to address potential disruptions.
Technical Risk	Involved uncertainties in design, performance, or operational reliability of deployed technologies, including variability in renewable output or commissioning challenges.	Technical risk was mitigated through continuous monitoring of renewable energy resources, realistic performance testing, and a feasibility study, supported by a maintenance plan.
Commercial Risk	Reflected market and business-related uncertainties, such as fluctuations in demand, pricing, or supply chain stability, which may influence project revenue and continuity.	Commercial risk was mitigated through strategic partnerships, contracting, diversified supply and sales channels, insurance coverage, and alignment of procurement and decision-making frameworks with long-term business objectives.
Financial and Economic Risk	Concerned assumptions and external factors affecting project viability, including potential cost deviations, market volatility, and macroeconomic shifts that impact long-term returns.	These risks were mitigated through benchmarking against similar projects, initiating early discussions with developers or tenants to negotiate contracts, and securing fixed-rate financing to lock in debt costs.

Although the assessment identified several potential risks, the preferred transition pathway still offers notable additional benefits beyond emission reduction. In practice, the pathway strengthened commercial resilience, preserved optionality under evolving regulation, and positioned the business to capture emerging demand for low-carbon products and services.

Key additional benefits included:

1. Capturing the increasing demand for sustainable products in the nickel and pulp & paper industries: For the nickel and EV supply chain, early alignment with buyer preferences, supported access to premium offtake agreements, reinforced market share, and reduced exposure to border carbon measures in export markets[47]. Likewise, in the pulp and paper industry, growing demand for carbon-neutral and eco-certified products, driven by sustainability commitments, packaging trends, and policies to reduce plastic waste, creates opportunities for early movers to capture price premiums and secure long-term contracts.

2. Capturing the opportunity to sell carbon credits as an additional revenue stream: Verified emission reductions from renewable generation can be monetised in carbon markets, improving project returns and diversifying revenue streams as national and regional frameworks mature. Surplus renewable capacity can also be channelled to the grid to strengthen electricity supply and reduce emission intensity, especially in scenarios where optimisation shows excess electricity that can be utilised rather than curtailed.

3. Developing a more predictable cost structure in the future: A renewable energy portfolio reduces exposure to fossil fuel price volatility, enabling more stable budgeting, improved cost visibility, and enhancing financial planning.

4. Lowering the cost of transitioning by making an early transition: Acting early limited retrofit and compliance costs, mitigated stranded asset risk, and avoided operational and financial disruption associated with compressed transition timelines.

5. Increasing financial performance by securing the competitive edge over competitors: First-mover capabilities in developing, operating, and commercialising renewable assets lower execution risk, accelerate time-to-market, and support superior capture of sustainable growth opportunities.

6. Mitigating potential financial risks from future regulations such as carbon tax and the possibility of not being able to extend the electricity business permit: Reduced emissions intensity lowers prospective carbon tax liabilities and supports compliance for captive power producers, including Electricity Supply Business License (“IUPTL”) extension requirements under Presidential Decree No. 112/2022.

7. Enhancing positive brand perception by contributing to the local community and environment: Cleaner energy delivered tangible co-benefits, improved air quality, local employment, supported for de-dieselisation and tariff savings, strengthening social licence and corporate reputation.

Collectively, these benefits strengthened the economic case for the preferred pathway by improving revenue quality, reducing cost volatility, and de-risking compliance, thereby reinforcing long-term competitiveness beyond the core goal of decarbonisation.

4.4 Learnings and Takeaways from Different Industries

This study examined the critical importance of transitioning captive power, particularly in energy-intensive sectors such as nickel processing and pulp & paper. Drawing insights from three distinct case studies, each representing different sites and operational setups, the findings revealed that effective decarbonisation requires tailored strategies that reflect each site's sectoral energy needs, available technologies, and renewable energy potential. The differences and similarities across the studied cases were summarised in the Table 4.4-1 below.

Table 4.4-1 Summary of Comparison Between Case Study 1, 2 & 3

Aspects	Case Study 1	Case Study 2	Case Study 3
Existing processes & assets	RKEF-processed nickel with off-grid CFPP	HPAL-processed nickel with CFPP & waste-heat steam units	Paper mills with cogeneration units and on-grid links
Renewable energy potential options	● Solar PV (with BESS) ● Hydro ● Biomass co-firing	● Solar PV ● Hydro ● Biomass ● Waste-heat recovery	● Solar PV ● Biomass ● REC procurement ● Electrification measures
Scenario options chosen	*JETP Optimistic Pathway* Off-grid system with solar and hydro replacing part of coal use, coal plant runs flexibly to allow more renewables.	*JETP Optimistic Pathway* Grid-connected system using solar, hydro, and waste-heat to reduce coal use; system stays stable without needing batteries.	*JETP Optimistic Pathway* On-grid mills using solar, electrification, and biomass, reduces grid reliance and cuts Scope 2 emissions.

---

[47] Nickel Institute. (2024).

Key findings showed that each industrial site presents distinct conditions that shape its decarbonisation strategy.

1. Case Study 1: Operated off-grid and used the electricity-intensive RKEF process, with good solar and hydro potential, the strategy focused on adding renewables, battery storage, and lowering coal plant minimum load.
2. Case Study 2: Utilised access to the grid and waste-heat recovery units, the strategy relied on firming renewables with waste-heat, reducing the need for storage and keeping costs lower.
3. Case Study 3: Connected to the grid and uses cogeneration, but had limited hydro potential, the strategy focused on solar PV, REC purchases, and electrification to reduce Scope 2 emissions while keeping operations stable.

Decarbonisation does not only benefit the environment, it brings real business value, as explained through Section 4. It helps capture rising demand for sustainable mining products by aligning early with buyer preferences, securing premium offtake agreements, and reducing exposure to carbon border measures. It opens new revenue streams through carbon credit sales from verified emission reductions and builds a more predictable cost structure by reducing exposure to fossil fuel price volatility. Acting early lowers transition costs, mitigates stranded asset risks, and avoids disruption from compressed timelines. It boosts financial performance by securing a competitive edge, strengthens resilience against future regulations such as carbon pricing instruments under PR No. 110/2025, including carbon levy, mandatory carbon trading, and allocation limits. It also enhances brand perception by delivering cleaner energy, improving air quality, and creating local jobs. Collectively, these benefits make revenue more reliable, reduce cost swings, and lower compliance risks, helping businesses stay competitive for the long term beyond just environmental goals.

Despite the technical analysis findings explained in Section 3 that identified feasible scenarios with economic viability, several operational challenges persist in decarbonising the nickel and pulp & paper industries. These include the need for workforce reskilling to operate renewable technologies, limitations in grid integration due to the remote location of captive plants, and the intermittency of renewable sources such as solar, which necessitate BESS to ensure reliability.

Further challenges involve the complexity of biomass supply chains for co-firing, the requirement for continuous power in industrial operations, and the dual energy needs of electricity and thermal energy. Additionally, constraints related to renewable resource availability, land use for solar PV deployment, and the technical incompatibility of existing coal-fired infrastructure with renewable systems present significant barriers to implementation.

Although challenges remain, there is a clear regulatory mandate for industrial decarbonisation under PR No. 112 of 2022. The regulation prohibits the development of new coal-fired power plants unless already included in PLN's Electricity Supply Business Plan (RUPTL) and mandates the complete phase-out of coal-fired power generation by 2050. Furthermore, it requires captive industrial facilities to achieve a minimum 35% reduction in carbon emissions within ten years of operation. These provisions reflect a strong policy push towards renewable energy adoption and reinforce that decarbonising the industrial sector is not only a strategic priority but a regulatory obligation.

Based on the clear benefits of decarbonisation, the regulatory mandate under PR No. 112 of 2022, and the demonstrated technical feasibility and economic viability of the preferred scenarios, the next step is to translate ambition into action through implementation. The integrated findings of this study highlight that the proposed energy transition options deliver clear benefits: they reduce emissions, improve operational efficiency, and strengthen long-term cost stability. By combining insights from technical, financial, and risk analyses, these solutions offer a practical pathway to sustainability while safeguarding competitiveness and compliance.

Chapter 5: Key Policy, Market and Financial Enablers

Achieving clean energy transitions in the captive power sector hinges upon promoting clean energy alternatives to avoid new captive coal development. It also depends on reducing emissions from the large fleet of existing captive coal assets.

This chapter sets out key policy, market and financing levers and approaches to enable captive power to shift to a low-carbon pathway, in line with the JETP Captive Scenario presented in Chapter 3.

This Chapter includes enabler discussions focused on the following areas:

- Planning, permitting and licensing for captive power and industries;
- Adopting carbon pricing instruments to encourage a shift from captive coal; and
- Promoting financial mechanisms to encourage transition from captive coal power.

In Chapter 6, there is more discussion on supply chains and international measures.

5.1. Enhancing Planning, Permitting and Licensing Processes to Accelerate Captive Power Transitions

5.1.1. Background and Context

Decarbonizing captive power presents a complex development challenge that entails difficult choices and trade-offs. Captive power plants in Indonesia serve a variety of industries, but a strong expansion in captive coal power capacity over the past five years has been led by the energy-intensive minerals processing industry, particularly nickel processing. Indonesia is a major producer of critical minerals, with over 50% of world nickel supply[48]. Furthermore, the Indonesian mining and processing industry is a significant contributor to economic growth, job creation, export earnings and foreign direct investment. The sector is also a dominant source of feedstock metals to global energy transition technologies.

Given nickel's importance for the global energy transition, there are potential global ramifications for policy changes that influence Indonesia's minerals processing industries. Other energy intensive industries with captive power plants include aluminum processing, steel, pulp and paper and diversified industrial areas[49]. However, these industries are associated with social and environmental impacts that when fully costed may offset some of the benefits for global energy transitions and Indonesia's economic development.

There will also be consequences to Indonesia's net-zero plan if the issues related to captive power are not tackled systematically, which in turn may pose a considerable risk to the competitiveness of Indonesia's industrial sector. Government policies and programs that govern the sector are therefore challenged to balance (a) decarbonization commitments within their NDC and NZE targets that include addressing captive coal, while (b) improving the performance of an industry having domestic and global importance.

---

[48] U.S. Geological Survey, Mineral Commodity Summaries, January 2024

[49] More detail on captive power market trends can be found in Chapter 1

This sub-chapter focuses primarily on market drivers that incentivize the industry to support clean energy transitions enabled by an integrated policy and industrial development approach. Such an approach requires coordination with implementing regulations with regards to a cornerstone of Indonesia's economic growth, which is the minerals downstreaming industry.

The Role of Captive Power in Clean Energy Transitions Strategy for the Power Sector

Indonesia's clean energy ambition has been enhanced via Presidential Regulation No. 112/2022. This regulation also specifically sets out the government's intention to accelerate the phase-out of CFPPs. Presidential Regulation No. 112/2022 prohibits the development of new CFPPs. However, Article 3 of Presidential Regulation No. 112/2022 grants an exemption for new CFPPs that:

- Have been declared in the approved RUPTL 2021-2030 before the presidential regulation was issued; or
- Meet all three of the following conditions:
    - The CFPP is integrated with an industry that is oriented to add value to natural resources or is listed as a strategic national project (PSN) that has a large contribution to the creation of job opportunities and/or national economic development;
    - Commits to reducing greenhouse gas emissions by a minimum of 35% within 10 years of operating compared to the average emissions for CFPPs in Indonesia in 2021, achieved through technology development, carbon offsets, and/or renewable energy sources; and
    - Ceases operation by 2050.

Since the promulgation of Presidential Regulation No. 112/2022, the MEMR has requested compliance with the provisions of Article 3 in the evaluation and issuance of business permits for new captive CFPPs. MEMR has also indicated that captive CFPPs permitted before Presidential Regulation No. 112/2022 will be subject to the Article 3 provisions during periodic license renewals.

Captive Power Licensing

In Indonesia, all electrical generation and supply (above a certain capacity threshold) including in the context of captive power requires a license from the central government with support and involvement from other levels of government[50]. There are two different types of electricity supply business licenses:

- for **private** use (*IUPTLS*); and
- for **public** use (*IUPTLU*).

In Indonesia's regulatory context, "private use" refers to electricity generated solely for self-consumption, with no sale involved. A private use license allows a business entity to supply power for its own operations, typically to support a particular entity's primary business

---

[50] For details of the licensing requirements outlined in this section, see Law No. 30/2009 on Electricity, as amended, and its implementing regulations.

activities. On the other hand, if electricity is supplied to an entity other than the license holder, requiring a sale and purchase transaction, a license for “public use” is required.

Up until 2021, captive power plant licenses were issued by the provincial government. This was changed through the 2021 Omnibus Law[51] and the MEMR Regulation No. 11/2021, which brought greater authority to the Central Government. Private use licenses are now issued by the provincial government only for power plants with a capacity up to 10 MW, and are issued by the Minister for capacities above 10 MW. Licenses for public use power plants are generally issued by the Minister with few exceptions[52].

Licensing Requirements for Private and Public Power Plants

The technical requirements to apply for a private use power plant license (IUPTLS) are relatively straightforward and include an analysis of the electricity demand, a layout drawing, a line diagram, the type and capacity of the power plant, and a construction and operations schedule. On the other hand, to apply for a public use power plant license (IUPTLU/PPU), the technical requirements include all those that are required for private use license applications, and also the following:

- Financial feasibility study;
- Operational feasibility study;
- Grid interconnection study;
- RUPTL; and
- Determination of business area from the Minister.

The technical requirements for this application are:

- An analysis of the electricity demand, which must include an infrastructure development strategy, availability of energy sources, business planning, investment and funding details and a risk assessment;
- A recommendation from the local government that includes the officially-recognized coordinates of the area, and confirmation that local permits will be issued; and
- An evaluation report from the government’s technical team, represented by the Directorate General of Electricity of the MEMR.

A key requirement for obtaining an integrated or sales/distribution IUPTLU license is securing a *Wilayah Usaha* (Business Area). Under Indonesia’s Electricity Law, a Business Area is a government-designated area/zone where a business entity is authorized to conduct electricity distribution or sales. Within each Business Area, only one entity is granted this exclusive right to operate an integrated electricity business or electricity sales/distribution, effectively establishing a regional monopoly over electricity supply in that area.

According to the Government Regulation No. 14/2012 and MEMR Regulation No. 11/2021, PLN is the default holder of the national business area covering the entire territory of

---

[51] Subsequently enacted as Law No. 6/2023 concerning the Stipulation of Government Regulations intended to become Law, in Lieu of Law No. 2/2022 concerning Job Creation.

[52] The Governor issues these licenses where the power plant provides electricity to an electricity distributor whose license is issued by the provincial government

Indonesia. According to MEMR Regulation No. 11/2021, other entities (e.g. regional SOEs, private developers) may apply for a Business Area if (i) PLN formally relinquishes its right, or (ii) PLN does not intend to or is unable to provide electricity in a given area. The regulation lays further detailed criteria for the granting of a Business Area, including the following:

- an existing business area holder is unable to provide electricity;
- an existing business area holder is unable to meet quality and reliability levels;
- an existing business area holder relinquishes parts or all of its business area to the MEMR;
- a proposed business area is not yet reachable by an existing business area holder; and/or
- a new business area is proposed by an applicant which comprises an integrated area (*kawasan terpadu*) that manages energy resources in an integrated manner according to its electricity needs.

A private use license is valid for up to ten years, whereas a public use license is valid for up to 30 years. Both license types can be renewed when they are due to expire. The pricing of electricity sales under public use licenses to industrial or other customers is regulated by the government. The government has the right to determine electricity pricing based on prevailing regulations, subject to parliament approval.

Industrial Plant Licensing

Licensing for the industrial facility associated with the captive power supply follows a separate process. Industrial operations must hold an industry business license known as *Izin Usaha Industri* (IUI). As the majority of captive power plants are linked to minerals processing facilities, a description of IUI licensing for minerals processing is provided herein.

There is a two-step process to obtain the IUI operating license, where the government initially issues a conditional license and then subsequently issues the final IUI license. The requirements for the application of a conditional IUI are that the applicant:

- Must be located in an industrial estate;
- Must obtain an environmental approval (if this has not already been obtained by the industrial park); and
- Must have already completed preparation activities which include construction, procurement and equipment installation.

After obtaining the conditional IUI, the company must fulfill the following additional commitments:

- Be registered in the National Industrial Information System (SIINas);
- Provide the requisite industrial data reflecting the actual implementation of the relevant industrial activities; and
- Must have been technically verified by the Ministry of Industry (MoI).

After fulfilling the commitments, the IUI will be fully effective for commercial operation.

Inter-Ministerial Coordination

Prior to Indonesia's era of regional autonomy, minerals processing activities were generally integrated with mining activities under a single business entity through the Contract of Work system. Licenses for any associated captive power plants were also granted with the Contract of Work, which was issued by the Minister for Energy and Mineral Resources. Under the Contract of Work, the Minister would have authority to evaluate the entire project feasibility taking into account mineral resources, processing technology, power plant infrastructure, logistics, environmental feasibility, etc.

When regional autonomy was introduced, local governments began issuing local mining licenses, which were known as *Kuasa Pertambangan* (KP). Typically, these were of smaller scale compared to the central government Contracts of Work, and usually involved direct export of unprocessed ore. These KP licenses were later translated into Mining Business License (*Izin Usaha Pertambangan* (IUP)) under the 2009 Mining Law. When unprocessed ore exports were banned in 2014, investors established minerals processing facilities under IUI licenses, which purchased ore from the IUP license holders. This entrenched a new pattern where mining and minerals processing activities were undertaken by separate business entities under separate licensing regimes.

Consequently, the Indonesian government has no single agency accountable to evaluate the feasibility of the entire value chain, as it did under the previous Contract of Work regime. The MEMR has authority for mining activities and power plant licensing, while the MoI has authority for minerals processing.

In 2025, the government established the National Downstreaming and Energy Security Task Force under Presidential Decree No. 1/2025 to plan priority business activities, spatial usage for downstreaming and energy security, and identify strategic projects to be funded. The Task Force focuses on minerals and coal, oil and gas, agriculture, forestry, maritime, and fisheries to enhance domestic value-added production and ensure energy security from both fossil fuels and renewables.

5.1.2 Rationale for Reform

A Need for Clean Energy Transition Strategies in Captive Power and Industrial Sectors

Energy-intensive industries such as mineral processing have built substantial captive coal power as, to date, this source has been viewed as offering the most cost-effective, reliable and timely power supply, especially in areas with limited PLN access as well as those that require consistently high demand at low pricing. These technical and economic drivers for captive coal power are exacerbated by regulatory barriers. All these issues contribute towards energy-intensive industries developing single captive coal power plants rather than shared clean energy solutions at scale.

Industries that rely heavily on fossil fuels are increasingly at risk of losing their competitiveness, market access, and financeability from global investors, who increasingly consider the emissions intensity of their investments. This risk is heightened by policies like the EU Carbon Border Adjustment Mechanism (CBAM), which imposes tariffs on carbon-intensive imports. In response, forward-looking companies are shifting to renewable energy sources to enhance the competitiveness of their products and maintain access to international markets. Conversely, the growing emphasis on sustainability across global supply chains may further erode the long-term competitiveness of carbon-intensive industries in Indonesia if they fail to adapt.

While the focus of the analysis is mainly on electricity, one key reason for the continued reliance on thermal power plants in Indonesia's industrial sector is the need for steam in some production processes which CFPPs can co-generate when configured accordingly. The limited roll-out of electrified heating technologies, due to technical and cost barriers, has constrained the shift away from fossil-fuel based steam generation.

Captive Power Related Implementing Regulations to Presidential Regulation No. 112/2022 are Missing and Necessary

There are opportunities to enhance existing power supply regulations on the basis of Presidential Regulation No. 112/2022. While the regulation provides clear ambition and a useful starting point, there are several challenges for the implementation of clean energy transitions in captive power:

- Captive coal-fired power plants for strategic industries are exempt from the ban;
- There are gaps in the design and implementation of Article 3 that raise uncertainties over how effectively it can enable a clean energy pathway for existing captive coal power plants and promote strategies to avoid new ones;
- Implementing regulations are not yet in place to ensure government agencies can effectively carry forward relevant strategies to meet the mandatory emissions reduction provisions; and
- The exemption for strategic industries does not require asset owners to undertake an assessment of cleaner energy alternatives to coal power.

Notably, determination of the 35% emissions reduction by year 10 will benefit from increased consistency in its application. Currently during permitting, captive coal power asset owners submit baseline emissions, from which the MEMR calculates the reduction. The calculation applies multiplier factors (ranging from 20-60%) which vary by captive coal power plant size, with larger plants subject to lower percentage reductions. The MEMR and the captive coal power owner then discuss the required reduction and measures to achieve it. This planning process should be revised to ensure consistent alignment with the minimum 35% requirement under the PR No. 112/2022.

In addition, the permitting process would benefit from a more clearly and publicly communicated mechanism for the monitoring and implementation of Presidential Regulation No. 112/2022. For example, despite MEMR Regulation No. 22/2019 requiring business actors in the power sector to report their emissions into the APPLE-Gatrik database, it is understood that there is significant variability in how companies are complying with these requirements and the completeness of data submitted.

In terms of the emissions reduction measures, the allowance of carbon offsets without guidance on the limitation of their usage or elaboration on the quality or monitoring of these offsets raises questions over their effectiveness. Moreover, the requirement of Article 3 to achieve emissions reductions only by year 10 of operations potentially misses an opportunity to encourage the phase-in of efficiency improvements and adding renewable power to sites over time. Finally, clear implementing regulations are required to define how captive coal plants will cease operations by 2050.

Aligning Industrial Policies with the Current National Electricity Planning

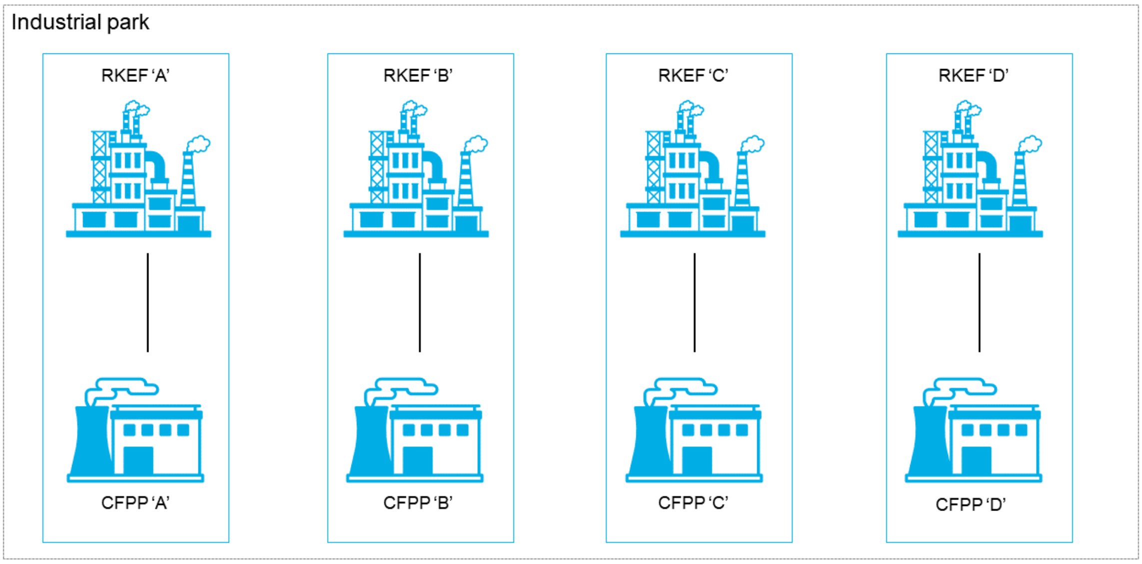
The government's industrial planning and its requirement for the clean power supply would benefit by more alignment. The JETP Captive Scenario for captive power and the RUKN 2025 identifies renewable sources of energy that can be developed for industrial parks through to 2050, but such sources require scale and careful integration with industrial demand needs, and become more accessible when industrial facilities are sited in areas with good renewables potential.

There are currently relatively few examples of the grid integration of minerals processing plants, in part due to the development of suitable grid infrastructure in the minerals-producing regions of Indonesia not keeping pace with the mining and minerals processing industry.

Consequently, industries such as nickel and aluminum processing have relied primarily on privately developed captive power plants. Even where multiple industrial plants operate within a single industrial park, each individual park tenant draws power from its own power plant, as shown conceptually in Figure 5.1.2-1.

While this configuration is economically suboptimal, captive power owners, especially nickel producers, have adopted this approach because the requirements to obtain an IUPTLS for private power plants are less stringent than those required for an IUPTLU. Economically, the more efficient configuration would likely be to develop a single power plant, or hybrid power applications, operating as an integrated power area with centralized energy management that provides electricity, including through shared energy efficiency solutions such as waste heat recovery, and balancing services, to all tenants within an industrial park.

Findings of the JETP Technical Working Group show that there are over 90 captive power sites that can be clustered, based on existing industrial parks or the creation of new ones based on sites in proximity to each other. Enhanced clustering would better enable energy efficiency and greater renewables deployment at scale, as in the JETP Captive Scenario.



Source: (JETP Secretariat and Working Group, 2025)

Figure 5.1.2-1. Conceptual Diagram of Power Supply Inside Industrial Parks

Achieving enhanced industrial clustering would require reforming the current regulatory and licensing constraints around PPU arrangements to allow specialist energy companies to design shared clean energy solutions and develop renewable energy projects. This would improve the economic and technical viability of captive renewable projects and enable wider adoption of low-emission power options for industrial actors.

Captive Power Licensing Reform

The current licensing regime falls short of providing adequate regulatory signals and incentives to encourage rapid emissions reductions and renewable energy adoption, aligned with the JETP goals. The regulatory and licensing settings outlined above place constraints and exacerbate technical and economic challenges faced by actors in the industrial sector to develop options for power supply and achieve clean energy transitions.

As mentioned above, a key component to obtain a public-use power plant license is obtaining a Business Area so that a captive power producer may distribute and sell electricity within the relevant industrial zone. In practice, this can only take place if PLN reduces its Business Area, i.e., if PLN is unable to supply power or relinquishes its rights. This process involves multiple steps, lengthy time, uncertainty and transaction costs. As a result, industrial users of captive power tend to favor IUPTLS licenses rather than PPU licenses.

Improving License Application Assessment

Within MEMR, the existing process to assess applications for power plant licenses does not formally address a range of matters related to the clean energy transition. The current requirements relate to financial and operational feasibility, grid interconnection and electricity supply, but do not consider clean energy alternatives, energy efficiency and emissions reductions.

Where new CFPPs are proposed under the Article 3 exemption, there is no formal requirement for proponents to demonstrate how the project will conform with the requirements of Presidential Regulation No. 112/2022. There is currently no requirement for proponents to justify the choice of a captive coal power plant as their initial main power source, or to consider clean energy alternatives to captive coal power at the outset. Similarly, there is no requirement for proponents to explain the energy efficiency and emissions reduction options that were considered. In addition, the license application process does not currently include a requirement to present details of emissions reductions in line with Presidential Regulation No. 112/2022.

Furthermore, power plant license renewal applications do not explicitly include a review of asset performance over time against approval conditions under Presidential Regulation No. 112/2022.

A Need to Consolidate Expertise in Power Supply

Holders or applicants of IUPTLS licenses are generally industrial companies that do not necessarily intend to obtain a PPU license from the outset because it is not their primary business or core expertise to produce and sell electricity. Consolidation of expertise for electricity generation and distribution across industrial players may therefore be necessary.

Moreover, renewable energy integration with smelters has been considered technically more challenging and requires expertise that is often found within specialist energy companies. Under current arrangements, the electricity demand from individual companies is often insufficient to justify extra measures (e.g. dedicated transmission lines) that may be necessary to integrate renewables even if this expertise could be hired directly into the industrial companies.

Integrating Power and Industrial Plant Licensing

The current licensing process uses a piecemeal approach, where different ministries review different aspects of a project development. For minerals processing investments, there is no coordinated review of project feasibility. Currently, the government only reviews the economic and technical feasibility of mining projects, while minerals processing feasibility is not assessed.

A mineral processing investment must obtain an IUI from the MoI and separately obtain its captive power license from the MEMR. Due to potential time lags between obtaining these two licenses, along with separate data reporting systems such as MoI SIINas and MEMR AMPERE-Gatrik/APPLE-Gatrik, government agencies lack an integrated view of captive power operations. This gap complicates sector monitoring, performance tracking, and development projections.

An integrated assessment of the economic, technical and environmental feasibility of a minerals processing project would give the government better visibility and ability to review the entire project scope and viability more holistically. This integrated assessment would cover ore supply, minerals processing, and all energy-related infrastructure including any captive power.

Expanding Grid Integration Supports Industrial Decarbonization But Requires Removal of Structural Barriers

Grid integration of captive power plants with the PLN grid system acts as a key intervention in the JETP Scenario for shifting energy-intensive industries to cleaner on-grid power supply and helps address regulatory and system inefficiencies from development of individual captive power plants. Realizing its potential depends on advancing existing PLN programs in this area as well as enhancing conditions for implementation.

As of November 2023, a total of 23 industrial customers had participated in PLN's Captive Power Acquisition Program (PACP), representing a cumulative transferred generation capacity of 438.7 MW. Of these, 22 customers are located within the Java-Madura-Bali (Jamali) grid system, while one customer is connected to the South Sulawesi, Southeast, and West Sulawesi (Sulselrabar) grid.

Through these acquisitions, PLN secured additional electricity sales totaling 1.43 TWh, equivalent to approximately IDR 1.14 trillion in revenue. Participating customers in 2023 recorded a 116% increase in their average monthly electricity consumption—from 130.61 GWh/month to 281.87 GWh/month. This was accompanied by an increase in average operating hours, rising from 183 hours/month to 346 hours/month.

PLN has conducted detailed analysis to identify additional customers as potential candidates for captive power conversion. Under current PLN assumptions, captive power can be acquired in the case where the asset owner is already a PLN customer and interconnection with the PLN grid system is already present, which limits potential candidates. The JETP Scenario for captive power set out in Chapter 3 aims to present an enhanced approach to the grid integration of captive power, which may involve investment in new grid connections and additional generation. Potential interventions set out in Appendix E of the PLN RUPTL 2025-34, which align with power plant listings in the JETP Captive Power Database, are integrated into the JETP Scenario and comprise around 4.4 GW of captive power capacity that could be shifted to the PLN grid system. In the JETP Scenario a further 2.8 GW of grid integration opportunities are assessed as technically possible, based on their distance to the nearest substation, bringing total potential candidates to 7.2 GW in the Scenario.

While expanding the PACP in such a manner has the potential to help some captive power owners transition to more efficient and cleaner power supply compared with captive coal, it also raises economic and system considerations to address in support of cost-effective clean energy transitions aligned with the JETP Scenario. Notably, the economics of switching to PLN industrial tariffs from captive power supply would need to be sufficiently attractive for asset owners. PLN would need sufficient demand certainty from new industrial customers, especially those in remote areas, to justify additional grid and generation investments. Moreover, on-grid system planning would need to focus on meeting new demand from industrial customers through renewable power and gas power, with rules that effectively phase out grid-integrated captive coal power plants and avoid their use as a main power source in the on-grid system.

5.1.3. Proposed Reform Roadmap

Address Regulatory Gaps in Clean Energy Transition of Captive Power and Boost Transparent Implementation of Presidential Regulation on Renewable Energy

Presidential Regulation No. 112/2022 provides a platform for clean energy transitions for the power sector in Indonesia. To ensure that it can be effectively implemented, the government could consider addressing regulatory gaps and boost transparent implementation, including by promulgating implementing regulations to Presidential Regulation.

The implementing regulations may limit new coal power plants qualifying for exemption under Article 3 in a way that supports alignment of Indonesia's power sector emissions and renewable energy ambitions with its NDC. In addition, new captive power license applications should include asset-level alternatives analysis, which considers clean energy alternatives to coal power and provides a justification for the selected option[53].

For existing captive coal power plants and those already permitted under Article 3, it is important to implement a more transparent process for determining baseline emissions, setting out plant/unit-level emissions reduction pathways and monitoring progress over time, including:

- Requiring power plant owners to prepare comprehensive measures to reduce emissions through on-site, direct measures including energy efficiency, renewable energy and integration with the PLN grid system;
- Consistent enforcement of a minimum 35% emissions reduction by year 10 of operations for all plants, to ensure larger plants are not subject to lower percentage reductions;
- Introduce a phased limit to the use of carbon credit offsets while ensuring their quality and enforcing monitoring; and
- Monitoring progress through power plant license renewals, to assess compliance with regulations.

Improve Government Processes and Transparency for Reviewing License Applications

To support the recommendations outlined above, the government should consider process improvements to comprehensively assess applications for captive power plant and industrial plant licenses. This should involve developing a transparent system for reporting and monitoring, along with building internal capacity. These improvements could include:

- More integrated assessment of minerals processing feasibility, including technical and economic feasibility of the entire project, including power infrastructure to provide better visibility of project scope and viability in relation to license issuance by the government;
- Clear and transparent requirements and guidelines that require the low-carbon energy supply options considered by proponents; including renewable and energy efficiency measures;
- Inclusion in the application of an emission reduction plan on how the proponent would reduce emissions by 35% within 10 years of operation;
- Development of an integrated database of captive power plants and industrial demand for energy, through involvement of related ministries and agencies, to aid in decision-making on power licenses, including through existing systems, such as the MoI SIINas database and ongoing enhancements to MEMR AMPERE-Gatrik and APPLE-Gatrik reporting systems;
- Mandatory and accountable reporting as a condition of approvals, so that captive power plant performance data can be accurately monitored; and
- Developing ministry assessment officers’ capacity through regular training and certification in clean energy asset-level alternatives analysis, including renewable energy options and energy efficiency, and international and national climate policy.

---

[53] A guide to Asset Level Alternatives Analysis for Captive Power can be found in Appendix 10.2.2.

Establishing Frameworks for Industrial Clustering and Integration to Deliver Clean and Efficient Power Supply

To support Indonesia's decarbonization agenda, it is necessary to develop a new policy and regulatory framework to enable industrial clustering for clean and efficient power supply, supported by targeted institutional reforms. The objective of these interventions is to facilitate shared clean energy infrastructure and to enable shared clean energy infrastructure across co-located industrial facilities.

The primary goals are to reduce the proliferation of ad hoc captive coal power plants and to support the development of large-scale renewable power. The intervention also seeks to promote grid integration and centralized energy management as a means to improve system reliability, operational efficiency, and power sector decarbonization. Delivering a workable policy intervention will require a comprehensive assessment of enabling conditions—including regulatory frameworks, technical system readiness, and commercial viability—supported by inter-agency coordination and alignment across key institutions and stakeholders.

The intended outcome is that industrial clusters will have access to shared power generation and transmission and distribution infrastructure. This shared infrastructure should enable enhanced energy and material efficiency among industrial facilities. While the scope of analysis is limited to electricity, industrial clustering is also expected to facilitate shared infrastructure and applications for industrial process heat, fuels, and emissions storage.

The intervention envisions that power and industrial licensing processes are aligned to ensure that demand projections, infrastructure planning, and project viability are coordinated. Multiple tenants would be connected to PLN or a licensed integrated operator, thereby avoiding duplicative captive power plants and supporting the development and integration of large-scale renewable power. For example, the finding of JETP Technical Working Group shows that there are three companies that are geographically close to PT Indonesia Morowali Industrial Park (IMIP) with a total CFPP capacity of 890 MW, highlighting the potential for coordinated energy integration.

Progress would be reflected in a rising share of renewable power generation—both dispatchable and VRE—within industrial clusters, as well as a reduction in emissions intensity per unit of generation and industrial output. These improvements are to be aligned with the JETP Captive Scenario and NZE targets, in contrast to reliance solely on captive coal power.

Effective industrial clustering depends on aligning the location of industrial demand with areas that have strong renewable energy potential. Concentrating energy-intensive industries in regions with available clean power—such as hydropower in Kalimantan or solar in NTT—enables more efficient grid integration, lowers system costs, and reduces reliance on long-distance transmission. This spatial alignment also strengthens the investment case for renewable energy projects by anchoring demand close to supply.

Furthermore, to enhance energy efficiency and sustainability in energy-intensive industries, policymakers should encourage the establishment of centralized energy managers within industrial parks. These entities would be responsible for designing and implementing integrated clean energy solutions, including on-site renewable power, grid infrastructure optimization, fuel switching, and other low-emission applications. By overseeing the balance of energy production and consumption, centralized energy managers would ensure a more efficient, resilient, and cost-effective energy system for industrial users. In addition, the centralized energy manager would coordinate a diverse mix of energy sources, such as gas, biomass, hydrogen, and heat, while also managing grid flexibility and ancillary services through battery storage, dispatchable power, and demand-side response. The manager would also oversee fuel procurement, to enable collective purchasing to optimize costs. For industrial companies, this model would provide a turnkey energy solution, reducing the need for specialist in-house energy expertise and reducing upfront capital investment in power infrastructure. From a regulatory perspective, the role of the centralized energy manager will be limited to coordinating integrated clean energy planning and implementing related strategies within industrial parks.

However, the implementation of industrial clustering for clean and efficient power supply faces a range of economic, regulatory, and technical challenges. These challenges must be systematically addressed to support the development of an effective policy and regulatory framework. The key barriers are outlined below to inform further analysis.

- From an **economic perspective**, interventions to promote industrial captive usage of RE such as hybridization of different electricity sources to provide firm power, the interconnection of captive power with local or PLN grids, and the development of distant renewable energy resources require significant investment similar to IPP projects. These solutions involve managing construction risks, such as land acquisition and additional upfront costs. Within industrial parks, investment in internal distribution networks involves last-mile costs, and there is currently a lack of clarity on who is responsible for those costs. In addition, the structuring of shared infrastructure will be complex. It is difficult to allocate costs, risks, and benefits fairly among industrial tenants and the power provider. Clear frameworks will also be required to define which entity will have the responsibility and therefore bearing the cost and risks for operating, maintaining, and governing the shared infrastructure. Moreover, variable or uncertain energy use from tenants—particularly those in commodity-based industries exposed to cyclical economic conditions—complicates the structuring of long-term offtake contracts and undermines the viability of shared infrastructure. This variability adds to the uncertainty and complexity of risk- and economic-sharing. In some cases, asset owners may still find it more economically attractive to maintain single-use captive coal power plants rather than paying electricity tariffs, which may include additional grid costs, to a third-party operator.

- On the **regulatory side**, current electricity law imposes constraints through the monopolistic single-owner Business Area (*Wilayah Usaha*) model, which limits shared power provision to one operator per zone. The practical implementation of grid integration would become complicated in the context when there are multiple IUPTLS holders or Business Area holders. For example, two private power plants holding separate IUPTLS licenses seeking to integrate their systems would need to apply for a single, jointly-owned Business Area. Similarly, where more than one Business Areas are involved, then those in principle may need to be integrated.

- **Industrial clusters will need to address site-specific technical challenges and develop bespoke renewable power solutions** that reflect their smaller scale (compared with the wider on-grid system),the unique renewable resource potential of each area and strong demand from energy-intensive industries for firm power (and process heat) supply. Furthermore, key enablers for VRE integration—including grid reinforcement, ancillary services, and energy balancing—would need to be managed over relatively small geographic areas in the case of industrial clustering. Adequate flexibility measures, such as battery storage, flexible generation, and demand response, would need to be adopted and managed with the appropriate operating practices, coordination mechanisms, and price signals by the integrated operator.

- **Clusters will also need to address legacy assets,** with the continued presence of existing captive coal power presenting a risk of lock-in. To remain aligned with the JETP Scenario and NZE targets, the transition to industrial clustering or PLN grid integration must be accompanied by safeguards to ensure that captive coal assets are phased down and ultimately relegated to back-up roles only.

Despite the regulatory, economic, and technical challenges, industrial clustering presents a clear opportunity to enhance system efficiency, reduce emissions intensity, and enable the integration of large-scale renewable energy. Unlocking these benefits will require coordinated action across policy, planning, and investment.

Incentivize the Push Towards Clustering of Industries

A combination of financial and regulatory incentives is critical to supporting investments in industrial clusters. Early-stage feasibility studies and detailed resource assessments, potentially funded through JETP financing, could help assess clustering opportunities and clean energy deployment options. To encourage investment, the government could offer fiscal incentives and facilitate financing for industries that adopt renewable energy solutions. It could also encourage the alignment of industrial park locational decisions with the availability of renewable energy resource potential. Establishing industrial clusters can streamline clean energy deployment, facilitate alignment with international standards for clean industrial products, and simplify regulatory processes, including land acquisition and grid connections for electricity and gas.

Review Current Decarbonization Policy Within the Minerals Sector and Inter-Ministerial Coordination

Policy makers of minerals development (MEMR), industrial development (MoI), electricity development (MEMR) and environmental/emissions strategy development (MOE) should coordinate closely on sectoral roadmaps and strategies to align technology development and policies with Indonesia’s climate ambitions. Furthermore, the government’s earlier plan to develop a Minerals grand strategy and master plan that would connect the demand from downstream industries to the upstream mining side can be revisited, now against the backdrop of Indonesia’s net-zero commitments. Moreover, MoI’s efforts in promoting the concept of ecoindustrial parks[54] can become a basis for selection of industrial cluster pilot projects that enable more integrated energy management and renewable power for multiple co-located industries.

Encourage Opportunities of Switching to Less Electricity-Intensive Nickel Processing Options with Adequate Safeguarding Measures

A market trend that Indonesia is likely to follow is the pursuit of lower carbon nickel processing. Encouraging asset owners to choose more energy efficient processing routes, as described below, can help reduce emissions while integrating safeguarding measures to mitigate other potential environmental and social risks.

Currently, most Indonesian nickel production uses RKEF[55] technology. Due to its higher electricity needs and current reliance on coal, this process has an emissions intensity approximately more than twice greater than high-pressure acid leach (HPAL) technology (Zhang et al, 2025). In addition to lower electricity and emissions intensity, HPAL has other advantages, including the ability to process lower grades of ore, the ability to process limonite (which is a more abundant type of ore compared to the high grade saprolite required by RKEF plants), and a greater potential for cobalt recovery. HPAL technology is also currently a more cost-effective method of producing Class 1 nickel for the batteries sector.

The main challenges associated with HPAL plants are slower construction timelines compared to RKEF plants, higher investment costs, the generation of tailings (waste), and the consumption of freshwater resources. The government may consider reviewing its environmental safeguarding rules and promoting good sustainability practices to anticipate these challenges. In particular, the government may consider investment in the dam safety commission, to ensure adequate resourcing for the government review of tailings dams for HPAL plants.

The summary of the aforementioned policy recommendations has been compiled in the following table.

Table 5.1.3-1. Policy Reform Roadmap for Captive Power Policy Reform

Expected Timeframe	Reform Area	Implementation guidelines
Short-term	● Address regulatory gaps in clean energy transitions strategy and boost transparent implementation ● Improve Government Processes and Transparency for Reviewing License Applications	● Introduce implementing regulations to Presidential Regulation No. 112/2022; ● Improve process to comprehensively assess applications for captive power plant and industrial plant license; ● Develop an integrated and transparent system of reporting and monitoring ● Build internal capacity to assess clean energy options and energy efficiency measures in license application. ● Closer inter-ministerial coordination.
Short-term	Promote shared power projects in industrial parks	● Undertake studies to identify and address barriers to industrial clustering and integration ● Promote centralized energy management within industrial parks for more viable and wider utilization of clean energy solutions;

---

[54] Ministry of Industry, November 2023

[55] RKEF stands for reduction kiln electric furnace, which is a form of pyrometallurgy that is more energy intensive than other nickel processing technologies.

		• Review licensing requirements that disincentivize joint development of renewable power generation and grid infrastructure.
Medium-term	Create incentive mechanisms for industrial clustering	Create steps to implement incentives to push towards clustering of industries particularly in terms of its power supply and align the location of industrial parks with renewables resources.
Medium-term	Develop integrated decarbonization for minerals sector	• Develop a minerals grand strategy and master plan that would connect the demand from downstream industries to the upstream mining side •
Medium-term	Encourage industries to switch to less energy-intensive nickel processing options	• Create incentive for nickel industries to switch to less energy-intensive practices; • Review and adjust the environmental safeguarding rules and promote good sustainability practices in nickel processing industries to anticipate slower construction timelines, higher investment costs, the generation of tailings (waste), and the consumption of freshwater resources.

Source: (JETP Secretariat and Working Group, 2025)

5.1.4. Expected Results

Table 5.1.4-1. Expected Results from Captive Power Policy Reform

Timeframe	Expected Results
Short-term	**Clearer Regulatory Framework and Guidelines for Clean Energy Investment in Captive Power** • Issuing implementing regulations for Presidential Regulation No. 112/2022 will enable provide legal certainty for investors, reduce regulatory delays, and enable increased adoption of clean energy technologies and energy efficiency integration in industrial sector; • Streamlined application and review processes for captive power and industrial plant licenses will lower administrative burden, reduce time to implementation, and improve investor confidence in renewable energy projects.
Medium-term	**Increased Development of Green Industrial Parks** • Promoting clustering will optimize land use, reduce infrastructure duplication, and facilitate coordinated clean energy deployment, making industrial zones more competitive and attractive to investors; • Centralized energy managers in industrial parks will unlock economies of scale in green energy procurement process by coordinating shared renewable generation, storage, and energy efficiency solutions—thereby reducing costs and improving reliability for industrial users.
Medium-term	**Maintain industrial competitiveness and ability to access global markets** Promoting cleaner and more efficient technologies such as high-efficiency nickel processing will help reduce emissions intensity, ensuring that Indonesian products can access global markets in light of stricter demands for sustainability and compliance. This will help Indonesia to maintain its competitiveness and leadership in the minerals sector.

Source: (JETP Secretariat and Working Group, 2025)

5.1.5. Risks and Mitigation Measures

Table 5.1.5-1. Risk and Mitigation Measures for Captive Power Policy Reform

Dimension	Risk	Mitigation
Economic effects of clean energy transition	Implementation of RE may require upfront capital cost for developers, which in turn would impact prices of nickel, cobalt and other critical minerals.	Mitigation of this risk depends on developing clean energy at scale through greater encouragement of industrial clustering, which would help to enhance the cost-effectiveness and reliability of such technologies for energy-intensive industries, compared with reliance on captive coal power plants.
Conflicting policy demands	There is a risk that clean energy transitions will be seen as having a negative impact on the minerals industry and the value-adding objectives of the government.	This risk can be mitigated by increasing awareness of Indonesia's position in the global nickel market and the likely effects of clean energy transitions. Minerals produced using clean energy will also have greater access to markets, especially in Europe.
Environmental Impacts	Expansion of HPAL nickel processing technology would reduce electricity and carbon emission intensity for nickel production but would pose new environmental risks, especially in relation to water quality and dam safety.	These risks can be mitigated with proper safeguarding requirements and good project planning, including adequate government review of project plans.

Source: (JETP Secretariat and Working Group, 2025)

5.2 Adopting Carbon Pricing Instruments to Encourage Shift from Fossil Fuels

5.2.1 Background and Context

"Carbon prices" refer to the price signals generated by various fiscal and other policy instruments that have an impact on the incentives to engage in carbon-intensive or carbon-abating activities. Carbon pricing can incentivize a shift away from industrial use of coal-fired generation, making this source of power less economically attractive compared with lower carbon technologies and incentivizing fuel switching to less carbon-intensive fuels (World Bank, IEA, ICAP, 2024). Carbon pricing achieves its greatest impact when it is part of a suite of climate policies (see Box 1).

Carbon prices can be direct or indirect. Direct carbon prices are policy instruments designed to be levied on a product or activity in proportion to the amount of carbon emissions generated. Examples include carbon taxes, cap-and-trade programs or emissions trading systems (ETSs), and crediting of GHG emissions reductions or carbon removals (also referred to as 'carbon credits'). Indirect carbon prices refer to instruments that change the price of products associated with carbon emissions in ways that are not directly proportional to the relative emissions associated with those products. These instruments provide a carbon price signal even though they are often primarily adopted for socioeconomic or revenue-raising objectives. Examples include fuel excise taxes which apply a tax to the volume of fuel, thereby disincentivizing consumption and *indirectly* discouraging emissions. Another example is fuel subsidies, which work in the opposite way and create a "negative" price signal.

Indonesia's carbon-pricing framework includes mechanisms to put a direct price on carbon (the focus of this section). These are in their early stages of development and their impact is currently muted by the extent of policies which indirectly create a carbon price signal in the opposite direction. In Indonesia's power sector, these are in the form of end-user subsidies for electricity and policies that affect the price and quantity of coal, namely, the DPO, which caps the price of coal sold to domestic power generators. In addition, the DMO requires that 25% of coal production is kept for domestic consumption.

For coal-fired generation specifically, direct carbon pricing instruments can take the form of:

- **Emissions trading systems (ETS)**: whereby the government sets emissions benchmarks, may impose a cap on emissions, and allow covered companies to trade emissions permits, or allowances;
- **A carbon tax**: whereby the government sets a price per ton of carbon emitted, and thus levies a tax on greenhouse gases emissions emitted by CFPPs;
- **Emissions reductions crediting**: whereby operators retire early unabated CFPPs and replace them with renewable energy capacity, and under certain circumstances this process allows them to issue carbon credits based on the resulting emissions reductions following a baseline-and-credit methodology. In theory, crediting could also occur from the phase-down of unabated coal, where full or early retirement of carbon-fired power plants is not possible. However, as of January 2025, existing initiatives focus solely on early retirement of CFPPs.

Box 1: Carbon Pricing Instruments in the Broader Policy Landscape

Carbon pricing is widely recognized as a powerful tool for reducing GHG emissions, as it creates economic incentives for cleaner energy production. However, as a standalone policy, it faces limitations in addressing key barriers to renewable energy adoption. While carbon pricing can effectively shift market preferences by making fossil fuels less competitive, it does not directly address structural challenges. These include the lack of infrastructure for renewable energy deployment, uncertainties in policy and investment environments, and high upfront costs for transitioning to new technologies. Without complementary policies, such as subsidies for renewable energy or mandates for installation, carbon pricing alone often leads to a gradual, rather than transformative, shift toward renewables. In the absence of viable alternatives, industries may opt for marginal efficiency improvements rather than full-scale transitions.

Additionally, the adoption of renewable energy depends heavily on human behavior and decision-making, which are influenced by three key elements: knowledge, capability, and willingness to change. Stakeholders must first have access to clear and credible information on the economic and technical viability of renewable energy. Beyond awareness, the technical capacity and infrastructure must exist to enable deployment. Finally, stakeholders need confidence in the feasibility and profitability of the transition. Carbon pricing alone often fails to address these factors, underscoring the need for complementary measures such as regulations and knowledge-sharing mechanisms.

The results underline the need for a multifaceted policy approach. While carbon pricing incentivizes cleaner energy, direct public investment and regulatory mandates address structural barriers by creating installation capacity, reducing investor uncertainty, and demonstrating feasibility. Additionally, by addressing behavioral factors—such as improving knowledge, building capability, and enhancing willingness to change—complementary policies can accelerate renewables adoption. Carbon pricing alone, though capable of achieving zero emissions over time, would do so slowly and at higher societal costs. A holistic strategy that integrates carbon pricing, public investment, regulatory support, and information-sharing mechanisms is essential for Indonesia to achieve a rapid and cost-effective decarbonization of its power sector.

Source: World Bank analysis

Overview of Carbon Pricing Instruments in Indonesia's Power Sector

In Indonesia, the role and effectiveness of direct carbon pricing in shifting the investment and operating decisions of coal power plants will depend on several factors. First, as of January 2025, the plans of the newly elected national government administration with respect to carbon pricing instruments appear to be in development. Elements, facts and plans described in this chapter are relevant as of January 2025 and might be subject to revision by the new administration. The ultimate effectiveness of these instruments will depend on the mix and price level of carbon pricing applied. The scope, level and robustness of cap and benchmarks are key, as they reflect the mitigation ambition and transition objectives underlying the ETS policy. The complementarity of the ETS with the carbon tax and associated price signals, as well as the ability of industrial facilities to pass on carbon costs through product pricing, will also be other important considerations for the GoI. As such, implementation of effective carbon pricing will depend on the presence of a strong regulatory framework for economy-wide emissions reductions and corresponding market and financial infrastructure to enable transactions.

Indonesia has already taken important steps towards the implementation of carbon pricing instruments. In October 2021, Indonesia adopted Law No. 7/2021 on the Harmonization of Tax Regulations (HPP Law), with a view to enforce it in 2025, which introduced Indonesia's carbon tax to control GHG emissions and to support the achievement of the emissions mitigation targets outlined in Indonesia's NDC. The original plan was to transform the ETS (described further below) into a hybrid "cap-tax-and-trade" system in the same year along with the enforcement of a carbon tax. However, as of January 2025 there seems to be no consideration of a carbon tax under the first Phase of the ETS, and how this will evolve for future phases under the new administration is still uncertain. According to Law 7/2021, the carbon tax rate will be set higher than or equal to the carbon market price per ton of CO_2-eq. Should the carbon price in the carbon market be lower than IDR 30,000 (USD 2.09), the carbon tax level would be set at a minimum of IDR 30,000 (USD 2.09). However, this level is much lower than the average carbon tax level applied worldwide (USD 34.6 / tCO_2-eq) as well as the average global carbon price in 2024 (USD 34 / tCO_2-eq).

The Presidential Regulation No. 98/2021, which later was replaced by newer Presidential Regulation No. 110/2025, outlined the legal framework for carbon pricing and included mechanisms such as carbon trading, carbon levies, and result-based payments to meet the country's NDC targets. The regulation also stipulated the need for a robust measurement, reporting, and verification (MRV) system, alongside introducing limits on GHG emissions for various sectors.

In October 2022, Indonesia took the first step for developing an ETS in its power sector, setting the legal basis for the implementation in MoEF Regulation No. 21/2022 on the "Procedures for Implementing Carbon Economic Value". It established the framework for implementing the NEK system, covering mechanisms for carbon trading, offsets, and performance-based payments and other mechanisms (to be announced). It outlines the roadmaps for carbon trading across sectors and provides detailed MRV procedures to ensure accurate tracking of carbon emissions and reductions. The regulation also defines the institutional arrangements for overseeing the system and sets forth the guidelines for the issuance and trading of carbon credits.

In December 2022, the MEMR issued MEMR Regulation No. 16/2022 on "Guidelines for Carbon Economic Value Implementation for the Power Generation Sub-sector", in response to Law No. 7/2021. These guidelines provide the legal basis for implementing an intensity-based ETS for power generators. This regulation sets specific guidelines for carbon pricing mechanisms. The regulation establishes the PTBAE, the technical approval issued by MEMR which sets the highest allowable GHG emission level (emissions benchmarks), for CFPPs and outlines three phases of implementation of the ETS, from 2023 to 2030, with emission cap adjustments every phase. Additionally, it details the criteria for carbon trading, defines the responsibilities of power plants under the system, and includes provisions for reporting and monitoring emissions. Notably, the regulation integrates mechanisms such as emissions offsets and direct carbon trading within the power sector through carbon exchanges or direct transactions.

In February 2023, Indonesia launched its intensity-based ETS, covering approximately 80% of the power sector. The total absolute emissions limit under the Indonesian ETS is the sum of individual, output-based limits for all covered entities. During the first phase, the ETS system currently operates as a cap-and-trade mechanism, where the absolute emission cap is set at 238.3 Mt CO_2-eq. Emissions allowances can be traded among businesses both within the country and, under certain conditions, cross-border. Power plants that emit beyond the output-based intensity limit will have the opportunity to purchase ETS allowances, carbon credits or pay a carbon tax to fulfil their compliance. This system incentivizes power generators to reduce emissions or face the need to pay an extra price on carbon, by purchasing additional ETS allowances, carbon credits or by paying the carbon tax.

The Indonesia ETS is rolled out in three phases:

- **Phase 1**: 2023 to 2024: the ETS system covers (i) CFPPs connected to PLN's grid with a capacity between 25 MW and 100 MW; (ii) mouth mine CFPPs with a capacity of 100 MW or above; and (iii) non-mouth mine CFPPs with a minimum capacity of 100 MW (but setting a different benchmark for those between 100 MW and 400 MW, and those above 400 MW). The ETS initially covers 99 CFPPs that account for 81.4% of the country's national power generation capacity, primarily owned by PLN. The total installed capacity covered by the ETS is 33.6 GW;
- **Phase 2**: 2025 to 2027: the ETS will be expanded to also CFPPs with a capacity below 25 MW, gas-fired power plants, and combined-cycle power plants and other CFPPs not connected to PLN's grid. These include (i) non-mine mouth CFPPs with a minimum capacity of 25 MW (between below 100 MW, between 100 MW and 400 MW, and above 400 MW); and (ii) mouth-mine CFPPs with a capacity of 100 MW or above; and
- **Phase 3**: 2028 to 2030: the ETS will be further expanded by covering all fossil fuel power plants and other CFPPs not connected to PLN's grid. These include all plants

that are covered during phases 1 and 2, as well as (i) non-mine mouth and mine mouth CFPPs with a capacity below 25 MW; (ii) gas-fired power plants of all capacities (including those with a capacity below 10 MW); (iii) combined-cycle power plants with a capacity below 300 MW; and (iv) diesel power plants with a capacity of 2 MW or above.

Table 5.2.1-1. Indonesia ETS Emissions Intensity Caps by Category

Power plant category	Capacity (MW)	2025	2026	2027	2028	2029	2030
CFPP	> 400	0.893	0.875	0.857	0.840	0.823	0.807
CFPP	100 – 400	0.991	0.971	0.952	0.933	0.914	0.896
CFPP	25 - 100	1.271	1.246	1.221	1.196	1.172	1.149
CFPP	< 25			1.757	1.722	1.687	1.654
Mine mouth CFPP	≤ 100	1.067	1.046	1.025	1.004	0.984	0.965

Note: The values in the table represent emissions caps (t CO_2/MWh) for the respective years.

Source: MEMR

In terms of emissions reductions crediting, MoEF Regulation No. 21/2022 outlined the key rules, modalities, and procedures for national carbon crediting. Supplementing this Regulation, in August 2023, the OJK issued OJK Regulation No. 14/2023 on Carbon Trading through Carbon Exchanges and provided guidelines for carbon unit eligibility as well as financial and operational standards for carbon exchange operators. Additionally, the regulation mandated due diligence for all participants, ensuring transparent and secure operations. Carbon units traded include those registered in the National Registry System for Climate Change Control (SRN-PPI), while international carbon units that are not registered in the SRN-PPI must meet standards including (i) registration, validation and verification by an international registry system organizer; (ii) meeting trading requirements on foreign carbon exchanges; and (iii) satisfy other requirements set by OJK before trading in Indonesia. The Indonesian Carbon Exchange (IDXCarbon) was also launched in September 2023.

Box 2: The Case for Transition Credits

In recent years, transition credits emerged as a practical solution to accelerate the shift away from coal-fired power generation and replacement with clean energy. Transition credits are carbon credits that are issued from the acceleration of the reduction of coal-fired power (e.g. from the early retirement of unabated CFPPs) and their replacement with clean energy capacity. By creating a market-based system rewarding emissions reductions from the reduction of coal-fired power, transition credits can mobilize capital to accelerate clean energy deployment and support affected communities through a JT.

Several international transition credits initiatives have seen the light in the last few years.

Examples include: (i) the Energy Transition Accelerator led by the U.S. Department of State, the Bezos Earth Fund, and the Rockefeller Foundation; (ii) Transition Credits Coalition (TRACTION) led by the Monetary Authority of Singapore; and (iii) the Coal to Clean Credits Initiative led by the Rockefeller Foundation and the Global Energy Alliance for People and Planet. The issuance and sales of such transition credits could provide an extra economic incentive for transitioning the power sector in Indonesia, where coal remains a dominant energy source.

It should be noted that these initiatives involve carbon crediting mechanisms that are very different and overlapping. For example, the Energy Transition Accelerator takes on a jurisdictional approach to crediting whereas CCCI are designed for the voluntary markets and TRACTION allows for corresponding adjustment.

However, these initiatives are still in early stages and no transition credit has been issued as of January 2025. Some of the known barriers and challenges are:

- **Demand**: it is difficult to estimate the demand for transition credits at the moment, as it also relates to wider carbon credit markets issues, which have seen turmoil in 2024 connected to environmental integrities concerns.
- **Risk of carbon leakage and corresponding risk management measures**: in the case of a project-based crediting methodology approach, the early retirement or retrofitting of one CFPP does not guarantee net emissions reductions as other CFPPs may or may not increase their capacity to generate power. If the phased-out (or phased-down) CFPP is young and its generation is filled-in by an old, existing CFPP, this may also lead to increased overall emissions.
- **Crediting methodologies development**: as of January 2025, some of the proposed methodologies for issuing transition credits are still under development. Their development and testing is likely to take some time.
- **Sustainable finance taxonomies**: for example, in the EU taxonomy, there is no categorization for managed phase-out. At the moment, EU FIs cannot provide financial flows for CFPP phase-down or phase-out.
- **Timing of financial flows**: transition credits will be issued only upon verification of the emissions reduced. This means that there will be a time lag between the moment in which the CFPP is phased-down or phased-out, and when the financial flows from carbon credits can reach the CFPP operators. The community is exploring ways, such as financing mechanisms and contractual arrangements, to bridge this time lag, especially because the capital to manage early retirement of CFPP is needed before the issuance of the credits.

Indonesian policymakers face the challenge of balancing affordability with the country's emissions reductions goals, particularly those from strategic industries reliant on captive power plants. The introduction of the ETS is a welcome step forward that can support the achievement of Indonesia's emissions reduction targets, and balance economic growth aims, if well designed and integrated in a wider set of policy measures for clean energy transitions and development. It can also help to better position Indonesian industries to respond to global market demand for more sustainable supply chains based on clean power.

5.2.2 Rationale for Reform

There are several areas of carbon pricing in Indonesia that would benefit from reform. While most broadly related to the effectiveness of carbon pricing overall, some relate specifically to captive power.

Current Low Effectiveness of Carbon Pricing, Due to Low Carbon Pricing Levels

The first is the low current effectiveness of carbon pricing, with the ETS allowance price too low to meaningfully encourage a shift away from coal. Thanks to generous free allowance allocation and emission benchmarks, the highest carbon unit transaction price recorded to date is below USD 2 per tCO_2—this would only increase the LCOE of a supercritical coal plant by USD 2 per MWh which is far too low to level the playing field compared to cleaner alternatives. In 2024, such carbon prices are also the lowest in the world (World Bank, 2024). Such a low price would not have a significant effect on investment decisions for captive power either.

Low carbon price levels may also disincentivize CFPP owners from implementing energy efficiency measures. One important aspect of MEMR Regulation No. 16/2022 is the implementation of energy efficiency measures for regulated power plants. However, the DPO provides that the on-grid coal price is effectively capped at USD 70 per ton of coal (adjusted for coal quality) for grid-connected CFPPs and the cost of coal is passed through to PLN. While fuel cost pass-through by IPPs is contingent on meeting initial contracted heat rates, uncertainty over the practical application of such provisions and the potential role of emissions in dispatch criteria suggests further study could help to clarify interactions with carbon pricing. Moreover, the presence of subsidies effectively provides little economic incentive for CFPP owners to further improve efficiency and reduce emissions. Given this backdrop, the upfront costs of investing in energy efficiency measures (e.g. upgrading equipment, improving processes) are unlikely to be cost-effective for CFPP owners, given that the financial savings from reduced coal consumption are minimal due to the artificially low-price cap under the DPO. Moreover, domestic plants still benefit from a DMO, which controls the volume of coal to supply domestic power.

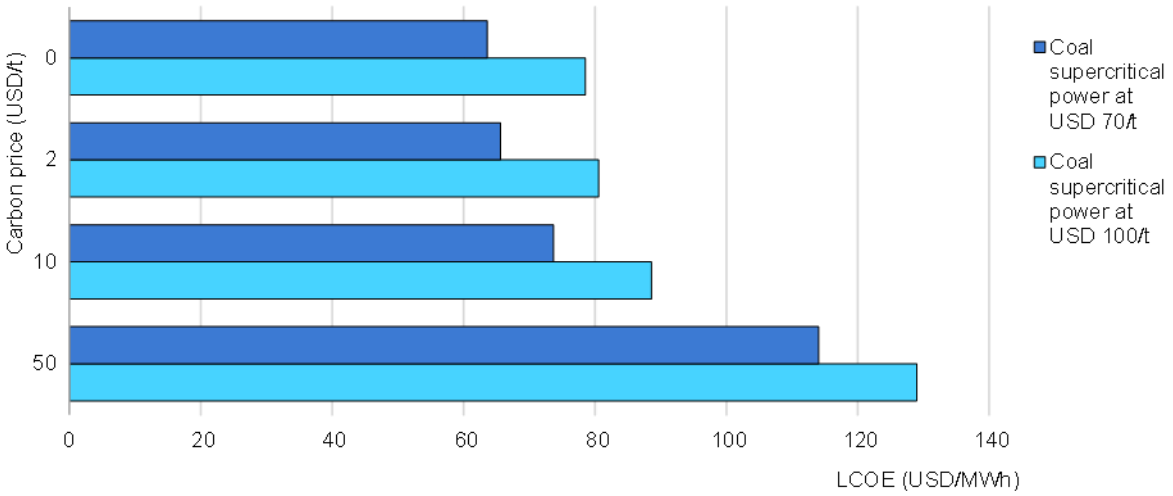
In addition, the PPAs signed between IPPs and PLN for grid-connected CFPPs include price adjustment provisions which could be triggered by a carbon price instrument. For example, a typical CFPP PPA stipulates that PLN's electricity purchase price may be adjusted to reflect any cost increases incurred by the IPP due to levies or other taxes imposed by new environmental regulations introduced after the PPA was signed or the imposition of administrative acts considered to be "unjustifiable". Similar to government force majeure clauses, these price adjustment provisions are a key component of a PPA's bankability.

As a result, if a carbon price is imposed on an IPP after the PPA is signed, that cost can be passed on to PLN. This mechanism effectively locks in income for CFPP power generation, weakening the effectiveness of carbon pricing. By shielding CFPP owners from the direct financial impact of the carbon price, it reduces their incentive to decarbonize.

Given PLN's regulated status, imposing carbon pricing instruments at the generation level would increase its costs and negatively impact its financial performance. Because electricity tariffs are highly regulated, PLN has limited ability to pass these cost increases on to consumers. Consequently, the increased electricity purchase price resulting from carbon pricing would likely be absorbed by the government through increased electricity subsidies or compensation payments to PLN. This would increase the government's fiscal burden as it continues to subsidize electricity for consumers.

Indonesia’s proposed low level for the carbon tax raises concerns about its effectiveness in incentivizing emissions reductions as it will have a weak/limited financial pressure on emitters and reduce the incentive to reduce emissions by adopting energy efficiency measures or cleaner technologies/energy sources. Furthermore, given the envisaged interaction between the carbon tax and the ETS, a low carbon tax level could undermine the effectiveness and liquidity of the country’s ETS by acting as a weak price ceiling, potentially suppressing allowance prices. Without a carbon tax that provides a stronger price signal, the ETS is likely to have difficulties in generating financial incentives to reduce emissions significantly, as CFPP owners may prefer to pay the low carbon tax instead of trading ETS allowances. However, within the ASEAN region Indonesia is one of the few countries with a carbon tax or carbon price in place in the power sector (IEA, 2024). As of January 2025, it is unclear when the carbon tax will effectively enter into force and, if it enters into force, whether the carbon tax will increase in the future.

A substantial increase in carbon pricing is necessary to incentivize a shift away from coal and drive investment in renewable energy. Without this, the ETS risks being ineffective in achieving its intended decarbonization objectives, especially in sectors reliant on coal-based energy. According to the analysis by International Monetary Fund using its Carbon Pricing Assessment Tool (CPAT), which provides country-specific projections of fuel use and CO_2 emissions, introducing a higher level of carbon price, such as USD 25 per ton of CO_2, could have a transformative impact on Indonesia’s emissions trajectory and economic growth. In that analysis, this level of pricing would reduce economy-wide GHG emissions by 16 percent. Additionally, a carbon price ranging USD 25 per ton of CO_2 could raise significant revenues for the Government of Indonesia, amounting to 0.7% of the country’s GDP, which could be channeled into further climate-related investments and supporting sectors in transitioning to a low-carbon economy. For reference, in IEA’s Announced Pledges Scenario (APS) which outlines a trajectory for the energy sector if all national energy and climate pledges (including long-term net zero emissions goals) are met on time and in full, a USD 40 per ton of CO_2 is applied to the energy sector of Indonesia by 2030, and this reaches USD 160 per ton of CO_2 in 2050.



Source: (JETP Secretariat, 2024)

Figure 5.2.2-1. Levelized Cost of Electricity (LCOE) for Supercritical Coal Power in Indonesia at Different Coal Prices and Carbon Price Levels

A higher carbon price would generate more revenues for the government of Indonesia. Targeted revenue recycling has the potential to help manage distributional and socio-economic challenges. Moreover, a higher level of carbon price would better align Indonesia critical minerals processing plants (reliant on captive power) with international mining initiatives, and help to future-proof those industries to remain market competitive in light of emerging sustainable procurement practices, and potential market export restrictions such as carbon border adjustment taxes. A higher carbon price (or higher electricity input costs potentially arising from cleaner alternatives) would not necessarily impact industrial producers' market share and profitability. Industrial producers could potentially pass on carbon prices or electricity input prices through industrial product prices. This could be especially relevant for metals processing (e.g. nickel, aluminum, copper, etc.). The economic impacts ultimately depend on the positioning of such industries in the overall market, including the degree of market power and market access, availability of alternatives, the willingness of buyers to purchase cleaner industrial products and the ability of producers to pass on additional costs potentially associated with investing in clean energy, among other factors.

Ultimately, the impact of the ETS and carbon tax on transitioning the coal power sector will depend on the Government of Indonesia's ability to set meaningful emissions benchmarks, enabled by enhanced availability of data from power plants—especially captive power plants—and the levels at which GHG emissions are capped for the sector as a whole and for each individual plant. The carbon tax, if implemented, should be set at a level that does not undercut the ETS allowance price signal and can provide financial incentives to reduce coal-fired generation, while safeguarding the competitiveness of the Indonesian industry sector. While higher carbon pricing does not necessarily lead to weakened competitiveness, there is a potential risk (especially in the short-term) of hindering Indonesia's industry sector as buyers may be unwilling to pay higher prices for cleaner industrial products. However, measures to set a higher/appropriate level of carbon price are likely to open more opportunities and improve the resilience of the country's industry over time. For example, in the mining industry, higher carbon prices can incentivize those critical minerals processing plants which rely on coal to reduce their coal-fired generation and use clean energy sources and align their processes with international mining initiatives and ensure market competitiveness. Moreover, with the emergence of carbon border taxes such as the EU's CBAM, decarbonization efforts by the industry will help avoid potential market access barriers.

Data Availability Issues May Challenge the Inclusion of Captive Power Plants in the Next Phase of the ETS

Another issue is emissions data availability from captive power plants, in particular, which can have a tangible impact on the inclusion of captive power plants in the second phase of the ETS. Despite MEMR Regulation No. 22/2019 requiring business actors in the energy sector to report their emissions to MEMR through the APPLE-Gatrik system, compliance remains uneven among captive power plant operators and owners. This non-compliance may effectively preclude many from participating in Indonesia's ETS, as mandated under Article 9 of MEMR Regulation No. 16/2022. Moreover, the lack of data availability also hinders robust review and refinement of emissions benchmarks for captive power plants and may limit the effectiveness of the ETS in driving emissions reductions.

Non-Restricted Use of Carbon Credits for ETS Compliance Can Pose Integrity Risks and Slow Down Clean Energy Transitions in the Power Sector

As of January 2025, Indonesia does not place limitations on the use of carbon credits in the ETS. Around 40% of carbon pricing instruments implemented globally allow the use of carbon credits to allow covered companies to purchase and use them in lieu of ETS allowances or carbon tax compliance. However, almost all have qualitative and quantitative limits on the use of carbon credits. These limits help to keep the focus of the decarbonization efforts within the target sector of the ETS, and to keep ETS allowance demand and prices high.

Capitalizing on Transition Finance Credits Opportunities Could Take Time

Another issue pertains to the potential reliance on transition finance carbon credits. Several international initiatives are exploring the possibility of using transition finance credits to fund the early retirement of CFPPs, replacing them with cleaner alternatives. However, there remains insufficient proof of concept and lack of approved emissions reductions crediting methodologies and standards, as these initiatives are still in their early stages and no transition credits have been issued as of January 2025. It could take years for these schemes to become fully operational and effectively mobilize capital for transitioning Indonesia's power sector.

5.2.3 Proposed Reform Roadmap

The proposed reforms, laid out below, aim to encourage a shift from coal by including measures (1) to enhance the design and implementation of the ETS for all generators, and (2) to more effectively apply carbon pricing instruments to captive power generators.

Enhance the Design and Implementation of ETS for All Generators

As mentioned above, an important improvement would be to raise the current level of carbon price (ETS allowance prices) to higher levels that could make an impact in terms of investment decisions towards a shift away from coal-fired power generation. Achieving this in a sustained and robust manner is not an easy task, and a mix of measures could be envisaged.

Explore the Optimal Cap for Each Type of Technology

Tightening the ETS cap and carbon emissions intensity benchmarks will also be crucial for aligning Indonesia's decarbonization efforts with the emissions trajectory outlined in the JETP Scenario. Adjusting the existing emissions benchmarks set under the PTBAE would be needed to ensure that Indonesia's energy sector contribution to its NDCs can be met, as per the MEMR Regulation No. 16/2022.

For comparison, there are several international examples of other jurisdictions that decided to apply emission intensity benchmarks or ETS emission caps that become more stringent over time in line with the jurisdiction's long-term decarbonization and development objectives. For instance, the EU ETS implements an absolute emissions cap that decreases annually throughout its four phases. While Phase 1 and 2 did not have an official linear reduction factor, Phase 3 and 4 introduced a linear reduction factor per year that increased throughout the phases. California's Cap-and-trade Program also introduced increasingly stricter emission cap reductions since its launch in 2013 in order to meet the program's mandate to reduce California's GHG emissions by 40% below 1990 levels by 2030. A planned, gradual reduction of the cap and tightening of the intensity benchmarks would provide predictability to the private sector, and can also put the power sector of Indonesia on a more ambitious emissions reduction, and create more scarcity over time for the Indonesia ETS allowances, driving up their costs.

Explore the Suitability of a Differentiated for On-Grid CFPPs

Further analysis of a potentially differentiated ETS emissions cap for on-grid and off-grid CFPPs could enhance the effectiveness of carbon pricing in Indonesia. Under the current regulatory framework and market design, applying carbon pricing to on-grid CFPPs may have a limited impact on emissions while increasing the fiscal burden to the Government of Indonesia. However, an ETS cap for on-grid CFPPs could still serve a valuable purpose for the Government of Indonesia as a revenue-generating mechanism, provided that allowances are at least partially auctioned rather than allocated for free. In contrast, off-grid, captive CFPP operators, particularly those serving industrial clients within their designated business areas, typically have greater flexibility to adjust tariffs. Alongside targeted efforts to improve the effectiveness of carbon pricing instruments for captive power generators (see below), this situation supports the case for a relatively stricter ETS cap for off-grid CFPPs, where an ETS could be more impactful and viable.

Clarify the Approach as to Carbon Tax

In parallel, once there is clarity about the new administration's plans regarding the carbon tax, if the tax is retained, the MoF should take the lead in developing a precise and clear roadmap for the implementation of the carbon tax and clarify its interaction with the ETS. Such a roadmap should build on scenario analysis of the application of different levels of the tax at different regulation points in the supply chain of the power sector in Indonesia, and provide clarity about the rollout of the tax and the specific conditions of applicability. The roadmap should also consider a price trajectory for the carbon tax that gradually increases over time. This will give CFPPs operators more clarity and predictability, and raise extra revenues for the Indonesian government while accelerating a shift away from CFPPs.

Implement a More Market-Based System for Coal Pricing

Furthermore, a key reform would be to remove the DPO price ceiling on domestic coal and shift towards a more market-based system of coal pricing, as recommended in CIPP 2023. Removing these inefficient fossil fuel subsidies is an essential first step to increase the effectiveness of any carbon pricing applied to the power sector. Fossil fuel subsidies in fact hinder the intended effect of carbon pricing. For more information about the DPO, please see Chapter 8.2 of the CIPP 2023 which discusses supply-side incentives in detail.

Optimize Policy on the Importation of Carbon Credit into the ETS

Moreover, the MEMR in close coordination with MoEF (the national authority for domestic carbon offsetting policy) should establish rules for limiting the use of carbon credits in lieu of ETS allowances as a complement to MEMR Regulation No. 16/2022. This regulation currently contains qualitative criteria for the type of national carbon credits that can be used for ETS compliance purposes, which must be issued from new and renewable energy power plants; transportation, construction, and industry including energy efficiency activities; and other activities in the energy sector. All such credits must be issued in the national registry. However, quantitative limits are not yet in place. In terms of quantitative limits, MEMR should consider setting a maximum threshold for the use of credits. Other EMDE jurisdictions apply for instance a range between 5 and 20% of the compliance obligations of covered entities, with the majority applying a range between 5 and 10% (ICAP, 2024). In terms of qualitative limits, to address environmental integrity concerns, MEMR could consider expanding the current qualitative criteria by establishing "positive lists" not only of project types but also of crediting standards, for instance requiring that eligible credits are labelled by the Core Carbon Principles (CCPs) of the Integrity Council for the Voluntary Carbon Market (ICVCM). MEMR could also consider setting a price corridor for eligible credits, such as setting a minimum and a maximum price that covered entities could pay, in a way to give predictability to both the covered entities and carbon credits project developers while signaling quality standards for offsets used for ETS compliance.

More Effectively Apply Carbon Pricing Instruments to Captive Power Generators

To address data gaps in the APPLE-Gatrik system on captive power generators, which could effectively mean captive power might not be eligible for being part of the ETS, it is important to ensure a stronger enforcement of MEMR Regulation No. 22/2019 that already mandates captive power plants operators to report emissions data via the APPLE-Gatrik system. These data are critical for establishing accurate emissions benchmarks for captive power plants within the ETS. Ensuring better compliance and reporting would allow the government to set more precise, ambitious and realistic emission benchmarks that can be tightened over time to reduce emissions from captive power generators from captive power generators. MEMR could consider ensuring stronger enforcement of data reporting through various activities, such as capacity building and training for facility-level emissions monitoring, reporting and verification, review of current regulation for facility-level reporting, and considering stronger penalties for non-compliance. Ongoing international technical assistance with MEMR to upgrade the APPLE-Gatrik database and train users could partly fill this recommendation.

Moreover, monetizing the issuance and sale of transition finance credits from the early retirement or retrofitting of coal captive power generators and their replacement with renewable energy could represent an extra financial incentive to accelerate the decarbonization of captive power in Indonesia, in parallel to the ETS efforts. However, how to tap into these opportunities is currently unclear. In this light, MEMR could conduct a study to assess the potential for monetizing international transition finance credits through existing initiatives (i.e. ETA, TRACTION and CCCI) and analyze what could be the barriers for the captive power of Indonesia to access these opportunities.

Table 5.2.3-1. Proposed Reform Roadmap for Carbon Pricing Adoption

Timeframe	Policy Recommendations	Implementation Guidelines
Short- to medium-term	Enhance the design and implementation of ETS for all generators	Phase out DPO to shift toward a market-based coal pricing system.
Short-term		Gradually tighten the ETS cap and intensity benchmarks, taking into account differentiation for captive power, to align with the emissions pathway of the JETP Captive scenario
Short- to medium-term		Develop a roadmap for the implementation of the carbon tax to act as a back-up mechanism if the ETS allowance price falls below the desired level
Short-term		Set quantitative limits for the use of carbon credits in lieu of ETS allowances as a complement in MEMR Regulation 16/2022; Expand the qualitative criteria to take into account international standards on environmental integrity; Set a price corridor for eligible credits.
Immediate action	More effectively apply carbon pricing instruments to captive power generators	Increase the law enforcement of MEMR Regulation 22/2019 Strengthen capacities for facility-level emissions reporting, stronger penalties for non-compliance.
Medium-term		Study the potential of monetizing on international transition finance credits; Provide clarity on the potential role of this new asset class of carbon credits in the carbon pricing instrument landscape applicable to the coal sector in Indonesia.

Source: (JETP Secretariat and Working Groups, 2025).

5.2.4 Expected Results

Table 5.2.4-1. Expected Results from Carbon Pricing Adoption

Timeframe	Expected Results
Short-term	● Fossil fuel subsidies reform allows removal of DPO which acts like a carbon subsidy (i.e. negative indirect carbon price) for the on-grid CFPPs and enables a more effective application of the carbon price on the coal sector in Indonesia; ● Improved data ability for captive power enables more accurate benchmarks and emissions tracking, allowing their participation in the ETS; ● Establishing clear rules for limiting the use of carbon credits in lieu of ETS allowances allows predictability and planning for the private sector in Indonesia.
Medium-term	● A planned, gradual tightening of the ETS cap and intensity benchmarks leads to faster decarbonization and transition out of coal, as well as higher ETS allowance prices; ● A roadmap for the implementation of the carbon tax allows captive coal power operators to plan business decisions accordingly.
Long-term	● A more effective carbon price that encourages the shift from coal to cleaner energy sources, alongside an improved data availability for captive power; ● Additional price incentives from carbon credits helps monetize investments in emissions reductions.

Source: (JETP Secretariat and Working Group, 2025).

5.2.5 Risk and Mitigation Measures

Table 5.2.5-1. Risk and Mitigation Measures for Carbon Pricing Adoption

Dimension	Risk	Mitigation Measures
Technical	**Low data availability for ETS intensity benchmarks for captive power** Risk of insufficient data for captive power benchmarks, leading to difficulties in accurately setting fair and effective carbon price baselines for captive power plants.	Ensure stricter enforcement of MEMR Regulation No. 22/2019, introducing penalties for non-compliance with reporting obligations, and strengthening the monitoring of the law's application. This will improve data quality and availability for captive power emissions.
Policy	**Distorted calibration of ETS emission benchmarks** Risk of setting overly tight or excessively lenient benchmarks for captive power, resulting in an ineffective carbon price signal, either burdening businesses by imposing overly high compliance costs and hurting their competitiveness in (domestic and international) markets, or insufficient incentives to transition away from coal.	Conduct a dedicated study to evaluate the impact of various benchmark scenarios on captive power plants, ensuring that benchmarks align with both decarbonization and economic growth, including potential impacts from international procurement practices and trade measures (e.g. CBAM). This will optimize the carbon price impact.
Economic	**Inconsistent application of carbon pricing across different sectors** Inconsistencies in carbon pricing applications across different sectors, resulting in uneven economic impacts and undermining the overall effectiveness of the carbon pricing mechanism.	Establish a coordinated cross-ministry task force, involving MEMR, MoEF, the MoF, and the MoI, to ensure a uniform approach across sectors and create consistency in carbon pricing implementation.
Demand-side	**Reputational risks related to issuance of transition finance carbon credits** Potential for accusations of low-quality carbon credit issuance from coal-based captive power, leading to reduced demand and low market prices for these credits, thus decreasing the financial incentives for decarbonization.	Collaborate with international stakeholders to ensure the use of best practices in carbon credit methodologies, additionality assurance, and MRV. This will enhance the credibility and market value of carbon credits issued from these projects.
Financial	**Investment slowdown**	Create flexible trading mechanisms to reduce the immediate financial impact of carbon pricing on

	Imposing carbon pricing mechanisms may result in slower investment and potential shutdowns in sectors like minerals processing, impeding Indonesia's value-adding strategy and reducing economic benefits from the sector. This poses significant risks given the critical importance of the minerals sector to the Indonesian economy.	high-priority industries such as minerals processing. Complement this with financial incentives for low-carbon technology adoption.
Industry	**Impact on nickel processing users of captive coal power** High carbon pricing could disproportionately affect Rotary Kiln-Electric Furnace (RKEF) nickel plants, which are more electricity- and emissions-intensive compared to HPAL plants.	Implement differentiated benchmarks based on type of industrial end-use technology, allowing RKEF plants more flexibility to transition while incentivizing the expansion of less emissions-intensive technologies i.e. HPAL.

Source: (JETP Secretariat and Working Group, 2025).

5.3 Promoting Financial Mechanisms to Accelerate Clean Energy Transitions in Captive Power

5.3.1 Background and Context

Transitioning energy-intensive industries away from reliance on captive coal-fired power plants, and avoiding the building of new captive coal power, presents a significant, multifaceted challenge. This transition will require the mobilisation of significant investments, not only into various clean energy technologies but also in mechanisms to manage the phase-down and phase-out of existing captive coal-fired power plants. The urgency of accelerating this shift necessitates the establishment of robust transition finance frameworks, which will play a pivotal role along with other sustainable finance tools, such as sustainable-linked financing. Currently, there is no unified definition of transition finance. However, several organisations such as International Capital Market Association (ICMA), Climate Bond Initiative (CBI), Glasgow Financial Alliance for Net Zero (GFANZ), OECD and others have developed guidance to shape and define transition finance.

In Southeast Asia, there has been notable progress in recent years in developing classification frameworks to guide capital allocation towards more sustainable activities and enable corporate clean energy and transition planning. For example, the ASEAN Taxonomy has been introduced, which includes an "amber" category specifically designed to classify certain transitional activities. Other key developments include the ASEAN Transition Finance guidance, Asia Transition Finance Guideline by Asia Transition Finance Study Group, and Indonesia Taxonomy for Sustainable Finance (TKBI) (OJK,2024).

The Indonesia Taxonomy for Sustainable Finance includes a specific classification for captive power plants. Notably, coal-fired power plants integrated with industry could be classified as "Transition" under certain conditions, which are aligned with emissions reduction measures set out in PR 112/2022 (see table 5.3.1-1).

Table 5.3.1-1 Technical Screening Criteria for New Coal-Fired Power Plants (PLTU) Integrated with Industry in the Indonesia Taxonomy for Sustainable Finance 2024

Classification: Transition For PLTU that is integrated with industry and built no later than 2030 and there are no other alternative energy sources in the area around the industry that can meet industrial energy needs:
Commit to GHG emission reduction of at least 35% within 10 years since the PLTU operates compared to the average PLTU emissions in Indonesia in 2021 through technology development and/or renewable energy mix and/or other carbon sequestration mechanisms; and mechanism and/or other carbon sequestration mechanisms;
For facilities that are equipped with CCS, then it must meet the criteria for CCS activities in this TKBI;
Have a minimum Green Company Performance Rating Assessment Program in Environmental Management (PROPER) or fulfill aspects of pollution control, environmental damage, management of B3 waste and management of non-hazardous waste/trash according to the requirements of the Green PROPER criteria; and
Operate until 2050 at the latest and have a transition plan

Source: OJK, 2024.

Ongoing global and regional efforts are expected to significantly contribute to addressing the challenges of financing the energy transition. However, in Indonesia, an acceleration of clean energy financial flows, enhanced transition planning and focus on solutions specifically tailored for energy-intensive industries reliant on captive power is particularly important to support the accelerated clean energy transition goals of the JETP over this decade and beyond.

5.3.2 Key Issues and Risks

Achieving a successful transition away from captive coal-fired power plants requires facilitating access to a diverse type of financial solutions. International and domestic finance sometimes compete at individual projects level, but within the context of the energy transition, these two types of financing have a complementary role. Domestic finance is suited for supporting region-specific initiatives and possible to provide finance based on the domestic currency. On the other hand, international finance, with its larger market scale, is essential for funding large-scale projects. Based on the huge potential financial needs for the transition from captive coal-fired power plants, international financing function is particularly important in emerging markets, where domestic capital markets are still developing and may lack the capacity to support major initiatives compared to their counterparts in developed economies. However, to leverage international finance, it is crucial to meet the criteria set by funding providers, and failing to meet their expectations—such as by not presenting a credible transition plan—can pose challenges for securing future financing. Notably, in the IEA Announced Pledges Scenario the share of international funding for clean energy investment in Indonesia is projected to increase from 25% today to over 50% by the mid-2030s.

This process will depend heavily on how governments, industries, and corporations engage in-depth dialogue with both international and domestic financial markets, including capital and lending markets. These discussions need to address the following critical factors:

- **Transition Plans:** Establishing credible clean energy and transition plans aligned with an ambitious energy transition pathway, as in the JETP Captive Scenario, especially by critical minerals asset owners and in government planning for captive coal-fired power industries (see recommendations around PR 112/2022 in section 5.1).
- **Taxonomy:** Treatment of captive coal-fired power and industries in domestic finance frameworks, notably the sustainable finance taxonomy issued by OJK.
- **Financial Markets:** Development of markets for transition finance and other sustainable finance.

However, despite the ongoing development of policies and initiatives, further in-depth consideration and effort for the three areas in above are needed by asset-owners, financial institutions and policymakers due to current strong sectoral growth drivers and the complexity of the transition process.

- Globally, while progress is being made, energy-intensive industries' preparation of transition plans remains at an early stage, particularly in emerging market economies. In Indonesia, there is a lack of transparent transition planning by captive coal power asset owners, insufficient signals for energy-intensive industries to invest in clean energy alternatives to building new captive coal power from the start, and lack of clear enforcement mechanisms. These factors increase the risk that the quality of the plans will not meet the expectations of financial stakeholders.
- While investment in new captive coal power is classified as a “transition” activity, so long as plants meet the transition planning and emissions reduction requirements of PR 112/2022, by the Indonesia Taxonomy for Sustainable Finance, there is a significant risk that such investments will not align with the JETP Captive Scenario. Additionally, due to the increase of the requirement for the detailed level disclosure of the transition planning by the international community, technical hurdles, and insufficient support for transition planning from the government, many transition plans may fall short of the finance industry's future needs for qualifying investment and lending activities.
- As of today, there has been almost no issuance in Southeast Asian countries, including Indonesia, of transition-labelled financial products.

These factors are causing uncertainty about future financing for industries and asset holders of captive coal-fired power plants, and there are concerns that this could be a risk factor in balancing the national economic activity growth and energy transitions.

5.3.3 Potential Actions and Solutions

Developing credible corporate transition plans

To foster the development of credible transition plans among captive coal-fired asset owners, a proactive role from the government is necessary. This includes improving the quality and content of the plans and providing clear guidance to assist companies in formulating them.

Offering a structured framework, can encourage asset owners with captive power assets, particularly those in the critical mineral sector, to develop credible transition plans focusing on ambition, action, and accountability (Transition Plan Taskforce, 2023). In Indonesia, the Coordinating Ministry For Economic Affairs along with the Ministry of Energy and Mineral Resources, the Ministry of Industry, and the Ministry of Finance could play a role in the development of a transition planning framework. Such plans could include detailed strategic ambition, implementation strategy based on the business structures, engagement strategy with value chain, industry, government and other relevant stakeholders. Clear accountability mechanisms including the setting of metrics and targets, and the governance structure for management and reporting are also important to ensuring the credibility of the plan. In general, these elements could work as fundamental information for international finance stakeholders to understand a company's initiatives and are useful for deepening dialogue with the international finance community.

To support companies' establishment of transition plans, the government, with the support of international stakeholders, can also provide technical assistance, such as convening industry and finance experts to develop sectoral roadmap guidelines for different industries reliant on captive power. Such roadmaps could serve as a reference for individual company transition plans and help enhance funding by providing credibility to transition initiatives. They would also assure alignment with system-level energy transition goals, a technically complex challenge for individual companies to navigate on their own.

International experiences potentially offer a template for implementation of such efforts in Indonesia. In Japan, for example, the Ministry of Economy, Trade and Industry and other relevant ministries established several technology roadmaps starting in 2021, for transition finance for each energy related sector and various hard-to-abate sectors, including iron and steel, chemical, cement, and others. These roadmaps, developed by expert committees comprising academic, public and private stakeholders, support efforts by corporations to create their transition plans aligned with carbon neutrality by 2050. Based on these sectoral roadmaps, Japanese corporates published their transition plans, and various companies used these for transition finance lending towards research and development and capital expenditures for energy transition. According to Bloomberg data, Japan issued in 2022 and 2023, approximately USD 3.5 billion transition bonds.

In the United Kingdom, the UK Transition Plan Taskforce (TPT) was announced by the government at COP26 in 2021 and officially launched in April 2022 with the intention of establishing a best practice reference framework for transition plans. TPT provided the sector specific transition plans for 30 financial and real economy sectors to share the key information and guidance source for each sector.

Enhancing the interoperability and equivalence of Indonesia's Taxonomy

In addition to the discussion of transition plans, to provide consistent signals for investment directions, the government could further explore ways to enhance the "interoperability" and "equivalence" of the Indonesia Taxonomy for Sustainable Finance with international frameworks. Achieving alignment of the individual country's taxonomy with the international taxonomy is not straightforward, as it involves accommodating different national energy transition pathways, such as the unique circumstances surrounding captive coal-fired power. However, promoting the interoperability of taxonomies across regions, supported by credible transition plans, could facilitate smoother financing from international capital markets, which are critical for funding the energy transition in Indonesia over the next decade. Also, the equivalence treatment for all taxonomies in each region should also be important.

Promoting financial instruments and mechanisms to unlock transition finance

Furthermore, the government could consider issuing sovereign transition bonds to help develop the transition finance market. Japan, for instance, issued its first sovereign transition bonds in 2024, directing funds toward energy transition investments, research and development in nascent clean energy technologies, and other related initiatives. This financial scheme includes some novel approaches such as bridging future carbon pricing revenues and current investment needs, and the government's intermediary function to enhance corporates' creditworthiness and eliminating the complexity of financing for small-scale projects. These schemes can potentially be repurposed for Indonesia and other emerging economies to support their energy transitions (IEA, 2024).

To develop the transition finance markets, corporate energy transition plans would support establishing the market credibility and allow financial institutions to participate. To accelerate the development, the government can select some companies to use transition finance for creating the leading model of transition finance, and greater effort to evaluate the incremental value of transition finance, mobilising affordable capital to the sectors where emission reductions are challenging would be important as well.

Connecting international financial efforts to support managed coal phase-out and phase-down activities to captive coal-fired power in Indonesia is also important. Enabling such activities depends on addressing the complexity of the process in emerging economies in Asia including the need for cost-effective alternative clean power supply and the alternative revenue models for recouping the unrecovered capital investments of these plants. Currently, there are pilot projects for the early retirement of on-grid coal-fired power plants and there is potential to expand this support for the early retirement of captive coal-fired power plants as well. To unlock this potential, it is essential to address this process alongside the development of alternative clean energy sources for the energy demand from industries, elaborate an appropriate transition process for the captive power based on their small-scale nature, and create a reliable methodology.

The development of these actions and solutions is crucial to mitigating the risk of losing future access to financial resources for corporations and ensuring that sufficient funding is available to support clean energy transitions in industries with captive coal-fired power plants. By aligning company transition plans with the goals of the JETP, Indonesia can enhance its competitiveness in global financial markets and better enable the investment needed to support clean energy transitions in captive power.

Chapter 6: Economic and Supply Chain Implications

This chapter analyzes industrial and national economic parameters impacted by a shift towards clean electricity for energy-intensive industries reliant on captive power and discusses the potential implications and opportunities for cleaner industrial products in international supply chains. The objective of the chapter is to establish a set of indicators to evaluate and monitor alignment of economic growth development goals with sustainable energy practices.

The first half of the chapter presents an economic impact analysis that assessed the impacts from changed electricity cost inputs - sourced from the JETP Scenario presented in Chapter 3 – for key energy-intensive industries reliant on captive power (notably nickel and aluminum), with a focus on microeconomic aspect on industrial operation costs and potential profit implications from adopting cleaner captive power sources.

The second half of the chapter provides an overview of the role of sustainability practices in international supply chains for these industries (nickel and aluminum), identifies potential challenges and opportunities from adopting cleaner power sources and identifies factors for enabling these opportunities.

This work is carried out in collaboration with KPMG as an external partner, as part of the larger UNOPS-ETP project on Industrial Decarbonization for Long-term Sustainable Economic Growth.

6.1 Industrial Operation Costs Implications

This section explores how changes in electricity sources—from captive coal-fired power plants to cleaner alternatives—may influence the cost structure of Indonesia’s major energy-intensive industries. Drawing on assumptions and data from the JETP Captive Scenario (Chapter 3) and KPMG’s economic assessment framework, the analysis looks at how variations in electricity costs affect overall industrial costs performance. The discussion centers on two major sectors—nickel and aluminum—which together account for most of the country’s captive power use. By comparing the role of electricity within each industry’s operation costs, this section highlights the potential financial implications and opportunities that could arise from a gradual shift toward cleaner captive power sources.

6.1.1 Overview of Approach and Data

The analysis applies a bottom-up approach using representative operation cost structures for selected products produced by each industry, supported by published financial data, company reports, and sector benchmarks. The cost structure components include energy costs (divided into electricity and heat), raw materials costs, labor costs, operations and maintenance (O&M) costs and other costs (e.g. taxes, licensing, etc.). The energy costs are estimated through bottom-up calculations using more detailed cost structures. The future energy cost is changing over time due to the impact of electricity cost resulting from the JETP Captive scenario. The other types of cost are estimated top-down through proxies based on financial statements of leading Indonesian companies within each industry. The cost of the other components in the future comes from the average of historical absolute value and remains constant over the scenario years. To be noted, the calculated costs shown are costs for a tonne of contained nickel/aluminum and do not include the capital investment needed to build the industrial facility other than the power plants.

Energy costs are estimated based on several assumptions, such as:

- Coal price of USD 100 per ton as upper bound and of USD 60 per ton as lower bound;
- Heat rate of 9.5 GJ/MWh for supercritical coal plant;
- Certain input-output grades for nickel and aluminum products;
- Ore grade degradation for nickel over time;
- Etc.

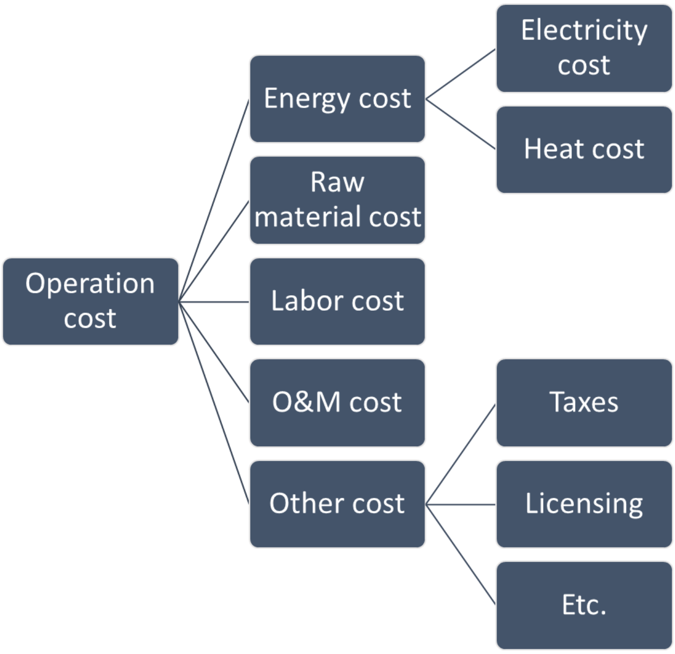


Figure 6.1.1-1. Illustration of Operation Cost Breakdown (USD/tonne of product)

Table 6.1.1-1 Examples of Costs Breakdown for Nickel

Category	Data Inputs	Key References
Industrial heat	• Coal prices for coal category • Calorific value of coal • Volume of coal required per unit of output	• Ministry of Energy and Mineral Resources (ESDM) • Just Energy Transition Partnership (JETP) • Standard and Poor's (S&P) • Det Norske Veritas (DNV) • Asia Investor Group on Climate Change (AIGCC) • Sustainable and Green Finance Institute: NUS SGFIN
Electricity	• JETP Captive Scenario assumptions and model	• JETP Captive Scenario assumptions and model
Labor	• % cost composition from	• TBP Nickel

	labor	
Raw materials	• Volume and price per unit for precursors (e.g. nickel ores) • Volume and price per unit for key chemical inputs (e.g. sulfuric acid, limestone, ammonia)	• Volumes: DNV, Argonne National Laboratory • Prices: TBP Nickel, World Integrated Trade Solution
O&M	Cost composition from the following cost items: • Repairs and maintenance • Depreciation • Other operation cost • Supplies • Loading and transportation • Rental • Other SG&A	• TBP Nickel
Other costs	• Cost composition from existing taxes and licenses, and other categories outside O&M	• TBP Nickel

Electricity cost components reflect the electricity demand intensities and modelled industry system cost results for Nickel and Aluminium from the Baseline and JETP Captive Scenarios presented in Chapter 3. These scenarios distinguish the current reliance on captive coal-fired generation with accelerated deployment of potential renewable energy options such as hydropower, solar photovoltaics (PV), and solar PV combined with battery energy storage systems (BESS). This framework provides a consistent basis for understanding how the transition to cleaner captive power could influence cost competitiveness across Indonesia’s priority industrial sectors.

In addition to Baseline vs JETP Captive Scenario, results from scenario variants are presented, named as Case 1 for each scenario, with details as follows:

- Baseline Scenario: minimum/no clean energy transition, using upper-bound coal price at USD 100 per ton,
- Baseline Scenario Case 1: minimum/no clean energy transition, using lower-bound coal price at USD 60 per ton,
- JETP Captive Scenario: reflects electricity intensity and system cost from JETP Captive Scenario with main RE price assumptions
- JETP Captive Scenario Case 1: reflects electricity intensity and system cost from JETP Captive Scenario with lower RE price assumptions

6.1.2 Cost and Pricing Analysis by Industry

This section will assess the operation costs for 3 types of product: Class 1 nickel, RKEF Nickel (Ferronickel/Nickel Pig Iron (NPI)) and aluminum. Class 1 nickel refers to high-purity nickel produced mainly from sulfide ores or high-grade laterites and used for batteries, plating, and high-end alloys. RKEF nickel is nickel produced by the Rotary Kiln–Electric Furnace process, where laterite ore is dried and reduced in a rotary kiln, then melted in an electric furnace to produce nickel pig iron (NPI) or ferronickel for stainless-steel production. Last but not least, aluminum here refers primary aluminum, a high-purity metal obtained by electrolytically reducing alumina (Al_2O_3).

Nickel – Class 1 from HPAL Process

For high-pressure acid leach (HPAL) production routes, which produce mixed hydroxide precipitate (MHP) and mineral sulfide precipitate (MSP) intermediate products that can be refined into battery-grade nickel, the raw materials—limonite ore, sulfuric acid, limestone, and ammonia—constitute the largest cost component in HPAL operations, collectively accounting for more than half of total operation costs.

Generally, for both baseline and JETP Captive scenarios, changes in electricity cost result in insignificant changes in HPAL nickel operating costs. This is due to the relatively small portion of electricity cost in the cost structure. In the base year (2024), the estimated electricity cost constituted 10 percent of the total operation cost. Under the Baseline Scenario, where captive CFPPs continue operating, energy costs for industrial heating and electricity are projected to rise steadily, reaching approximately 12% of total operation costs by 2050. This increase is primarily driven by the assumed decline in ore grades, which raises energy requirements for processing. In the Baseline Scenario Case 1, assuming a lower coal price of USD 60 per ton, energy costs are projected to be around 3 percentage points lower—equivalent to roughly 9% of total operation costs in 2050.

In clean energy transition scenarios, energy costs are estimated at 11% under the JETP Captive Scenario and 9% under the JETP Captive Scenario Case 1 by 2050. These results suggest that energy efficiency, integrating renewables through an optimized energy mix and strategic dispatch planning can deliver comparable or better economic advantages for Class 1 Nickel producers compared with coal-based power in the Baseline Scenario. Furthermore, as renewable energy technologies continue to advance and deployment costs decline, their overall cost competitiveness is expected to strengthen even further. These results reflect, in part, the relatively low electricity intensity of HPAL processes, which helps facilitate the cost-effective uptake of alternative power solutions to captive coal.

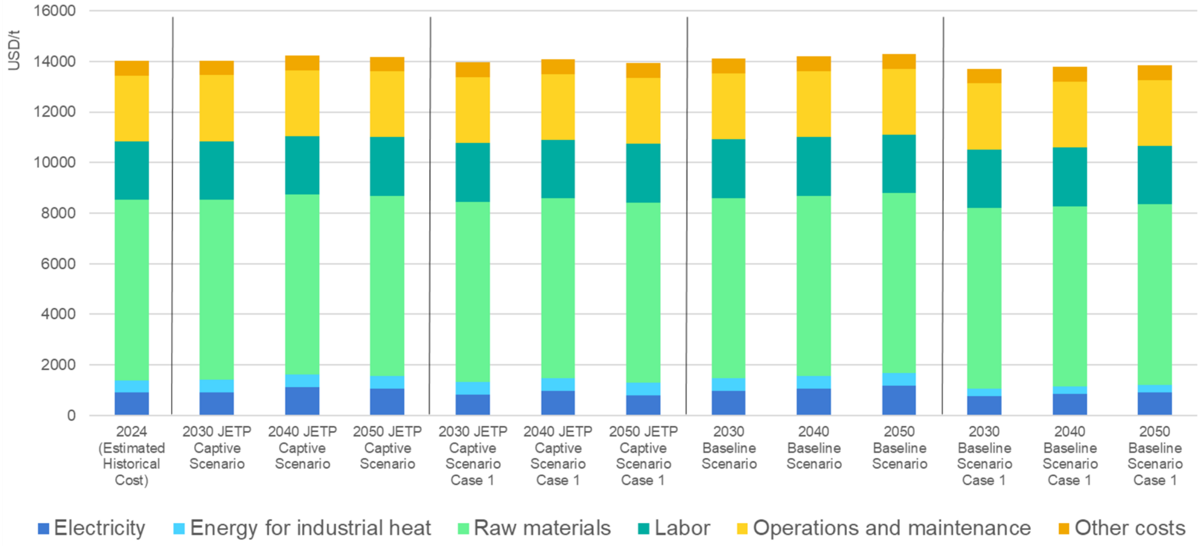


Figure 6.1.2-1. Operation Cost Breakdown for Nickel HPAL Process (USD/tonne of nickel)

Nickel – Ferronickel/NPI from RKEF Process

Compared with HPAL production routes, raw materials account for a smaller portion of total costs, and energy accounts for a much larger portion, in rotary kiln-electric furnaces (RKEF) production routes that primarily produce nickel pig iron (NPI) and ferronickel intermediate products for stainless steel. This is because NPI and ferronickel require less nickel ore as input, and because the RKEF process is less chemically intensive than HPAL. Overall, raw materials represent roughly one-quarter of total ferronickel operation costs.

Since RKEF is more energy-intensive than HPAL, energy costs are projected to account for 39–42% of total costs under the Baseline Scenario and 31–34% under the Baseline Scenario Case 1. This share is approximately three to four times higher than that of Class 1 Nickel production using HPAL. Under the JETP Captive Scenario, energy costs are projected to make up around 38–40% of total RKEF operation costs, while in the JETP Captive Scenario Case 1, they are estimated at approximately 36%.

Overall, electricity and other energy costs continue to make up a substantial share of total costs in RKEF production routes, even under clean energy transition scenarios. Notably, in terms of energy used, electricity accounts for only about one-quarter of total energy inputs in RKEF, compared to more than half in HPAL. Consequently, considerable amounts of coal, or biomass as alternative, would still be required for industrial heating in RKEF even if electricity generation were fully decarbonized. Therefore, pursuing fuel-switching options and energy efficiency improvements on the industrial heat side would also be critical to achieving deeper, long-term cost and emission reductions.

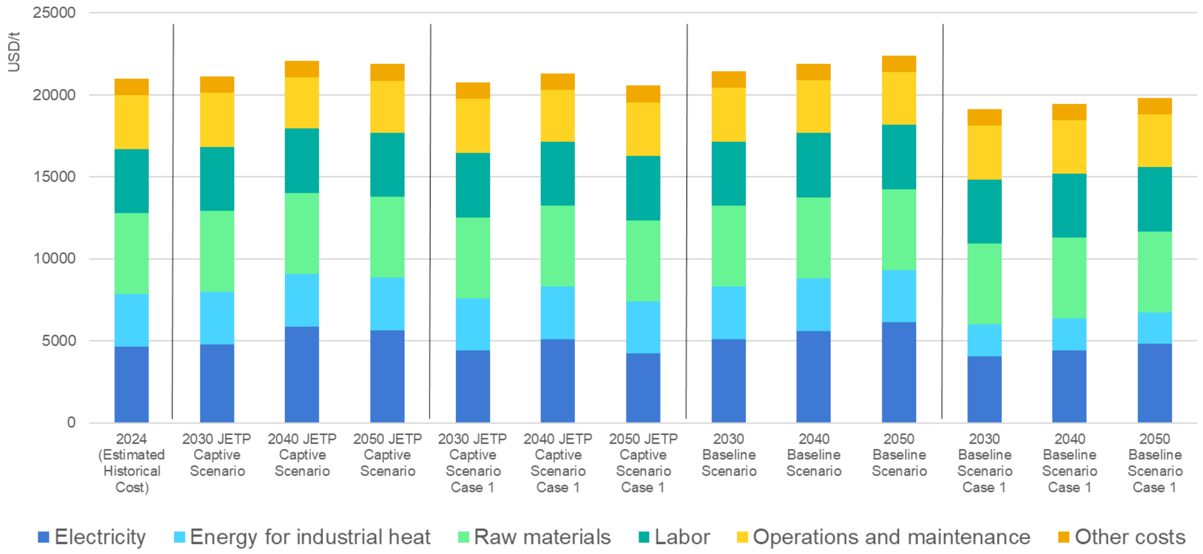


Figure 6.1.2-2. Operation Cost Breakdown for Ferronickel/NPI (USD/tonne of nickel)

Aluminum – Smelting and Refining

At first glance, the cost structure of aluminum production appears broadly similar to that of nickel RKEF production routes, although energy costs play an even more dominant role in aluminum. Raw materials—such as bauxite ore, carbon anodes, caustic soda, and lime—collectively account for around 20% of total aluminum operation costs.

However, the share of energy costs in aluminum production is significantly higher. Under the Baseline Scenario with captive CFPPs, energy costs are projected to comprise 63–67% of total operation costs. When applying a lower coal price under the Baseline Scenario Case 1, this share decreases to 54–58%, demonstrating a notable sensitivity to fuel price fluctuations. The JETP Captive Scenario maintains a similar energy cost share to the Baseline Scenario (61–64%), while the JETP Captive Scenario Case 1 results in slightly lower energy costs of 57–62%, but still higher than the Baseline Scenario Case 1.

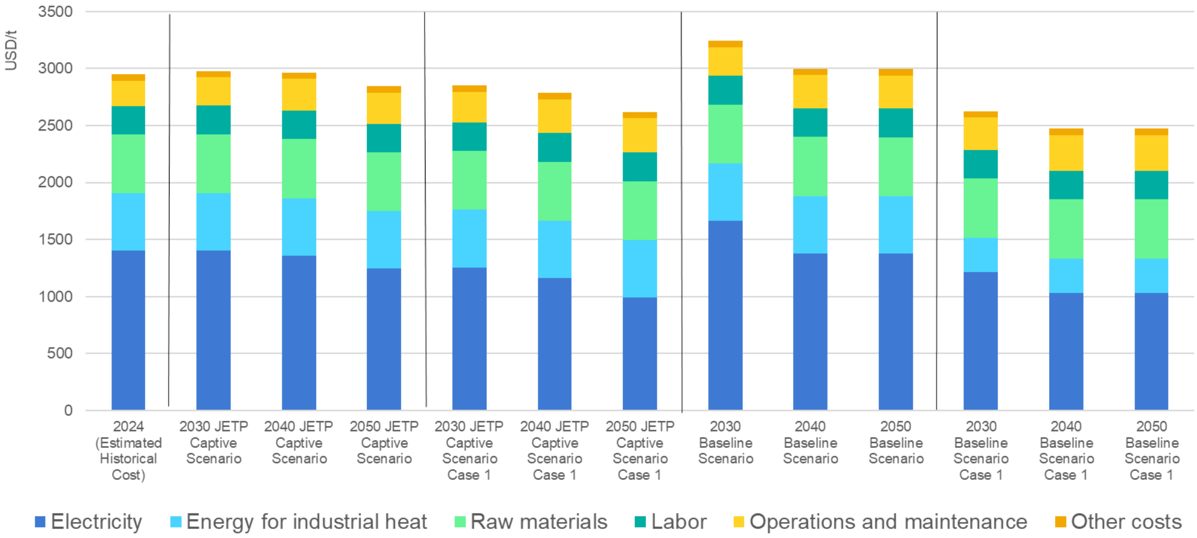


Figure 6.1.2-3. Operation Cost Breakdown for Aluminum Process (USD/tonne of aluminum)

Gaps between Cost and Price for Nickel and Aluminum Products

From the cost projections done in the previous part, there are gaps found between the costs resulting from the JETP Captive Scenario and the referenced product prices. The referenced product prices are mainly taken from 2021-2024 historical value, with a discount rate assumption for RKEF nickel products. Then, for the future prices, an average selling price (ASP) for each product is calculated and is assumed to remain constant throughout 2050. Table 6.1-2 below shows the price points used for the analysis.

Table 6.1.2-1 Historical and Averaged Selling Price for Nickel and Aluminum Products

Product	Price (USD/tonne of product)					Notes
	2021	2022	2023	2024	2021-2024 ASP	
Class 1 Nickel	18,049	25,387	22,824	16,814	20,768	Source: MEMR reference price
RKEF Nickel	16,244	22,848	20,541	15,133	18,692	Assumption of 10% discount from Class 1 Nickel price (Reference: PT Antam Indonesia)
Aluminum	2,397	2,747	2,275	2,419	2,460	Source: MEMR reference price

As seen, historical 2021-2024 ASPs for nickel products fluctuated dynamically, while aluminum prices were relatively stable. Though there may be caveats in using the ASP approach, this approach smooths out short-term volatility and captures a balanced view of both recent market highs and lows. It is also consistent with standard industry and institutional practices that use multi-year averages to produce conservative, defensible price projections.

Then, the historical product price averages are compared to the operating costs obtained from the calculations above to see the potential gap between the projected costs and these prices, which is an indicator of profitability. It is found that the projected costs for Nickel RKEF and Aluminum exceed the price assumptions in all scenarios. Meanwhile, the cost for Class 1 nickel is projected to be below the price assumptions. The difference in HPAL nickel case may occur due to exclusion of capex of industrial facilities other than power plants in the operation cost. These are shown in Table 6.1-3.

Table 6.1.2-2 Comparison of Price Assumptions and Projected Costs for Nickel and Aluminum Products under JETP Captive Scenario

Product	Price Assumption based on historical ASP2021-2024 (USD/tonne)	Operation Cost, per tonne of product (USD/tonne)					
		2030 JETP Captive Scenario	2040 JETP Captive Scenario	2050 JETP Captive Scenario	2030 JETP Captive Scenario Case 1	2030 JETP Captive Scenario Case 1	2030 JETP Captive Scenario Case 1
HPAL Nickel	20,768	14,038	14,221	14,181	13,970	14,076	13,931
RKEF Nickel	18,692	21,126	22,084	21,874	20,768	21,323	20,560
Aluminum	2,460	2,979	2,964	2,844	2,849	2,784	2,617

note: The operation cost does not include the capital investment for other than power plant facilities

6.2 Key Insights and Comparative Analysis

Relative Exposure to Electricity Cost Volatility

The degree of exposure to electricity cost volatility varies significantly across the three production processes, shaping their vulnerability to market and fuel price fluctuations. Aluminum, as the most electricity-intensive metal among the three, faces the greatest risk, with energy accounting for more than 60% of total operation costs. Any increase in fuel or power tariffs can therefore have an outsized impact on profitability, making long-term cost stability a key operational priority. RKEF-based nickel production, while less electricity-dependent, remains moderately exposed since both electricity and thermal energy play major roles in its energy mix. Conversely, HPAL-based nickel exposure to energy price movements is relatively limited, as its cost structure is dominated by chemical reagents and raw materials rather than power consumption. From an investment perspective, this means that aluminum and RKEF-based nickel producers have the strongest incentive to pursue renewable or hybrid energy systems (solar PV + BESS, hydropower, biomass, etc.) with low operating costs to hedge against price volatility and ensure stable operating margins. The adoption of renewables thus functions not only as an environmental decision but as a strategic move to enhance financial resilience and operational predictability in the face of future market uncertainty.

Economic Rationale for Shifting to RE Captive Power

The shift toward renewable captive power presents a compelling economic and strategic case, particularly in industries where energy constitutes a major share of operation costs. Renewables offer a structural advantage by decoupling operating costs from volatile global coal markets and stabilizing long-term electricity expenses. As technology costs trends for solar PV and battery storage continue to decline globally, the levelized cost of renewable power is projected to fall below that of fossil-based captive systems, even before accounting for potential carbon pricing or emission penalties.

From a strategic standpoint, integrating renewables enhances energy security by reducing reliance on imported or price-sensitive fuels and strengthens Indonesia's position in an increasingly carbon-conscious global marketplace. In the medium to long term, industries powered by renewables will likely benefit from improved investor confidence, lower financing risks, and preferential access to markets that reward low-carbon products, such as those subject to CBAM e.g. EU.

Implications for Product Competitiveness and Profitability

The transition to renewable energy has far-reaching implications for the competitiveness and profitability of Indonesia's nickel and aluminum industries. As shown in the previous section, there are notable gaps between estimated operating costs under different captive power scenarios and the recent year average selling price, which signals the market's willingness level to buy. Thus, bridging this gap is essential to increase the competitiveness of greener products. The major question is how to scheme a fair "burden sharing" to compensate for the gap.

Demand-side incentives could play a role in enhancing the green aluminum and nickel market. As global buyers—particularly in the electric vehicle, battery, and metals sectors—intensify their focus on low-carbon supply chains, producers with cleaner energy footprints may gain a measurable competitive edge with appropriate market demand signals and certification schemes in place. These specific demands could be monetized to incentivize manufacturers to produce greener products. Further analysis is provided in the following section.

6.3 International supply chain challenges and opportunities

Trends and Opportunities for Development of Clean Product Markets And Green Premia

Global industrial value chains are undergoing a structural transformation as downstream sectors accelerate their decarbonization commitments and demand low-carbon raw materials. This shift is giving rise to clean product markets, where materials such as low-carbon nickel, ferronickel, and aluminum are increasingly differentiated based on their embedded emissions. The trend is driven by the combined pressures of corporate net-zero targets, carbon border adjustment mechanisms (CBAMs), and consumer expectations for sustainable products. Major buyers in the electric vehicle, battery, and construction sectors are beginning to integrate carbon intensity into procurement criteria, creating clear market signals that favor producers able to demonstrate verifiable reductions in production emissions.

For Indonesia, this evolving landscape presents both a strategic opportunity and an industrial challenge. As one of the world's key producers of nickel and aluminum, Indonesia is well-positioned to capture a share of emerging clean material markets—particularly if renewable captive power, energy efficiency improvements, and cleaner process technologies are adopted. Producers capable of certifying lower carbon intensity through internationally recognized frameworks (e.g., ISO 14067, Carbon Disclosure Project, or verified LCA methodologies) could qualify for green premiums—price markups or preferential contracts offered by buyers seeking to decarbonize their supply chains.

Beyond direct pricing advantages, participation in clean product markets offers long-term strategic benefits. Access to green financing instruments, sustainability-linked loans, and favorable offtake agreements can reduce capital costs and enhance project bankability. Producers that transition early to low-carbon operations may also secure preferential entry into regulated markets where carbon intensity thresholds are enforced, safeguarding export competitiveness. Over time, the integration of renewables and cleaner technologies can also reduce operational risks associated with fuel price volatility, further strengthening cost resilience.

To unlock these opportunities, Indonesia's industrial ecosystem will need to align standards, infrastructure, and policy incentives to support certification, verification, and traceability of low-carbon production. Collaboration among government, industry, and international buyers will be key to establishing transparent carbon accounting frameworks and credible emission baselines. By positioning itself as a supplier of verified low-carbon materials, Indonesia can not only maintain competitiveness in a decarbonizing global economy but also capture value from the growing green premium segment—transforming environmental compliance into a tangible economic advantage.

Nickel: Emerging Low-Carbon Differentiation in the EV Supply Chain

The nickel sector is at the forefront of the global clean product transformation, primarily due to its central role in electric vehicle (EV) battery production. As EV manufacturers and battery producers pursue carbon-neutral value chains, the carbon intensity of Class 1 Nickel has become a defining metric of product competitiveness. Global automakers and battery manufacturers—including Tesla, CATL, and LG Energy Solution—have begun to prioritize procurement from suppliers that can demonstrate proven and measurable emission reductions.

This shift is stimulating the early formation of a low-carbon nickel market, where differentiation is achieved through verified lifecycle emissions data and transparent supply chain reporting. Producers investing in renewable captive power, fuel-switching for process heat, and energy efficiency improvements can position themselves to gain access to premium offtake agreements. For Indonesia—home to one of the largest nickel processing capacities globally—this trend represents a pivotal opportunity. Establishing certified low-carbon nickel could secure Indonesia's long-term role in the global EV supply chain, particularly as downstream policies in key export markets begin to favor cleaner materials. Developing a credible carbon accounting and verification framework for nickel products from HPAL and RKEF plants would enable Indonesian producers to quantify emission reductions from renewable energy adoption and capture emerging green premiums. In parallel, industry collaboration on transparent reporting and traceability platforms could reinforce Indonesia's position as a trusted supplier of sustainable nickel, enhancing both export resilience and investor confidence.

Aluminum: Expanding Market for Low-Carbon and "Green" Aluminum

The aluminum industry has already seen significant momentum in the development of clean product markets. Unlike nickel, where differentiation is emerging, aluminum markets are more advanced—driven by large-scale buyers in automotive, construction, and packaging sectors demanding low-carbon inputs. Producers in Europe, Canada, and the Middle East have begun marketing “green aluminum”—defined as aluminum produced with less than 4 tons of CO_2 per ton of aluminum, compared to the global average of ~16 tons. Leading examples include Hydro’s CIRCAL, Rusal’s Allow, and Alcoa’s ELYSIS, which command green premiums ranging from USD 50 to USD 200 per tonne.

Indonesia’s aluminum industry potentially faces a structural disadvantage in this emerging market segment. With energy accounting for over 60% of total operation costs and new captive electricity planned to be derived predominantly from coal for Indonesia’s leading producer, the carbon intensity of domestic production under Baseline Scenario conditions would remain high relative to global peers. However, this also highlights a major opportunity for transformation. Transitioning to renewable captive power—especially hydropower and solar—could significantly reduce both costs and emissions intensity over time.

Developing a low-carbon aluminum certification system aligned with international frameworks (such as the Aluminum Stewardship Initiative or London Metal Exchange’s Responsible Sourcing standards) would be essential to position Indonesian producers for entry into premium markets. By integrating renewables, modernizing smelting technologies, and investing in traceability systems, Indonesian aluminum could qualify for low-carbon branding and capture green premiums from buyers seeking to decarbonize their supply chains. Over the long term, aligning with these standards will not only enhance Indonesia’s export competitiveness but also attract green financing and sustainability-linked investments, thereby supporting market access and industrial expansion.

Appendices

Appendix A: Requirements for captive power licenses

Table A1 outlines the relevant information regarding the application, specific documents required for the licenses, and the issuance authority. Captive power owners must fulfill all licensing requirements for their intended use before the plants can commence commercial operations.

Table A.1. Summary of the Process and Requirements for Submitting a Captive Power Plant Permit

Application Requirements	IUPTLS (Private Use)	IUPTLU (Public Use)	PWU (Integrated Business Area)
Administrative Prerequisites	● Business Identification Number ("NIB")	● Business Identification Number ("NIB") ● Beneficiary Ownership ("*Daftar Penerima Manfaat")*	● Business Identification Number ("NIB") ● Beneficiary Ownership ("*Daftar Penerima Manfaat")*
Technical Documents Requirements	● Analysis of electricity demand, ● Location of the installation, including site layout, ● Single line diagram (SLD), ● Type, configuration, and capacity of electrical power supply facilities, ● Development schedule, and; ● Operation schedule	**1. Feasibility analysis, which includes:** ● Financial feasibility analysis ● Operational feasibility analysis ● Network interconnection study ● Location of the installation, including site layout, ● Single line diagram (SLD), ● Type, configuration, and capacity of electrical power supply facilities, ● Development schedule, and; ● Operation schedule	**1. Analysis of Electricity Supply aligned with the Business Activities (Distribution, Sales, or Integrated) based on RUKN, entailing (See Appendix for detailed information):** ● Introduction ● Strategy for Power Distribution/Sales Business ● Strategy for Integrated Electricity Supply Business ● Electricity Provision Plan ● Investment requirements, funding plans, electricity tariff plans, ● Risk Analysis **2. Recommendations from the governor or authorized official within the respective provincial local government.**

		0. **PPA agreement with prospective purchasers of electricity.**	3. **Technical Evaluation Results from the Technical Team**
Issuance Authority	1. The MEMR issues the IUPTLS if the installation covers across provinces, situated in the area beyond 12 nautical miles offshore, involves power plants exceeding 10 MW, and/or pertains to electricity installations for oil and gas operations. 2. Provincial governors are responsible for issuing licenses for installations within their province that	1. The MEMR issues the IUPTLU for activities conducted by the PLN or any business entities that extend their operational area across provincial boundaries, sell electricity to license holders designated by the Minister, and are engaged in integrated electricity supply activities. 2. Provincial governors issue the IUPTLU for business entities whose operational area is confined to a single province, those selling electricity to license holders authorized by the Governor, and entities that hold	The issuance of PWU is only made by the MEMR

	are up to 12 nautical miles offshore and/or for power plants with a total capacity of up to 10 MW.	operational areas but are not engaged in electricity generation.	

Appendix B: Guide to Asset Level Alternatives Analysis for Captive Power

Context for Asset-Level Alternatives Analysis

The JETP Captive Scenario for captive power will use asset-level alternatives analysis to implement an energy strategy of avoiding new captive coal power with clean power and lower emissions alternatives, in line with the scenario design set out in Chapter 3. The asset-level alternatives approach is a practical method used to efficiently evaluate and visualize different clean power options and develop pathways for industrial facilities planning to rely on captive power on an individual asset- basis.

The analysis carried out in the JETP Captive Scenario incorporates the demand- and supply-side interventions from the technical screening of captive power areas (see Chapter 2) to identify potentially feasible power solutions - from both a technical and economic standpoint - for selected assets, subject to site-specific constraints and resource availability. In addition, the analysis supports the policy recommendations in Chapter 5 that call for requiring new captive power plants to carry out an asset-level alternatives analysis as part of their licensing assessment process.

The objective of the approach is to explore how current plans to build 4.1 GW (net capacity) captive coal power assets that are permitted or in the pre-permitting stage can be shifted to align with the clean energy transition goals of the JETP Captive Scenario. Modelled solutions from the analysis are selected for the JETP Scenario based on criteria to avoid coal power, maximize the share of renewable power, and minimize carbon emissions, while ensuring overall cost-effectiveness and reliability, compared with a baseline case in which the electricity demand from the industrial facility is fully met through investment in and operation of captive coal power.[56]

Note: the analysis only seeks to identify alternative power supply options to meet industrial electricity demand; solutions that address process heat demand are not explicitly considered in the JETP Captive Scenario.

Methodology and Assumptions for Asset-Level Alternatives Analysis

The selected assets to be analyzed consist of ten captive power sites (anonymized for confidentiality reasons) that are permitted, or in the pre-permit stage, which suggests that their business plans could be shifted before starting construction. Most of these assets belong to either aluminum or nickel industry sectors and plan to use coal power plants under the baseline scenario, with capacities ranging from 40 MW to over 1.2 GW. The assets are located in various islands across Indonesia, spanning from Kalimantan, Maluku, Sulawesi and Kepulauan Riau. Without concerted efforts to shift the business plans of asset owners, these sites are all set to rely on coal power.

---

[56] At the time of modelling the asset-level alternatives, 4.1 GW of captive coal power was assessed to be in the permitted or pre-permit stage. Since then, it is assessed that 1.1 GW of this entered construction. While this appendix presents asset-level alternatives for the full 4.1 GW of captive coal, the treatment of under construction plants in the full JETP Captive Scenario, as presented in Chapter 3, follows the scenario design and modelling strategies set out in that chapter, which transitions rather than avoids captive coal already under construction.

Table B-1. Coal-Fueled Captive Power Plants Selected for Alternative Analysis at the Asset Level in the Captive JETP Scenario.

Source: (JETP Secretariat and Working Groups, 2025).

Plant	Province	Status	Industry	Planned Coal Power Capacity (MW)
Plant 1	RIAU	PERMITTED	ALUMINUM	900
Plant 2	SULAWESI TENGAH	PERMITTED	ALUMINUM	760
Plant 3	KALIMANTAN BARAT	PERMITTED	ALUMINUM	120
Plant 4	KALIMANTAN UTARA	PERMITTED	ALUMINUM	1,210
Plant 5	KEPULAUAN RIAU	PRE-PERMIT	UTILITY (INDUSTRIAL AREA)	40
Plant 6	MALUKU UTARA	PRE-PERMIT	NICKEL	380
Plant 7	KEPULAUAN RIAU	PRE-PERMIT	UTILITY (INDUSTRIAL AREA)	62
Plant 8	KEPULAUAN RIAU	PERMITTED	ALUMINUM	140
Plant 9	KALIMANTAN BARAT	PERMITTED	ALUMINUM	140
Plant 10	SULAWESI TENGAH	PERMITTED	NICKEL	700

Notes: plant capacity is expressed in nameplate terms; some captive sites also include plans for a small amount of diesel generator capacity - the modelling also seeks to avoid diesel generation in favor of gas or renewables, where applicable.

These sites are to be analyzed using HOMER (Hybrid Optimization of Multiple Electric Renewables) Pro, an energy modelling and optimization tool for designing and evaluating standalone microgrids, hybrid energy systems, and distributed power generation. HOMER Pro is particularly useful for this analysis due to its capability to assess off-grid power plants by simulating various system configurations to meet electricity demand while optimizing costs and emissions. In addition, it estimates the installation and operational costs, as well as emissions, compared to a baseline over the project's lifetime. Further description of HOMER Pro can be found in Chapter 4.

HOMER Pro was chosen for the asset-level alternatives analysis due to its ease of use, manageable computational requirements and user cost effectiveness in comparison with more complex simulation and optimization tools, which can better model larger integrated systems. In that light, HOMER Pro is a tool that can be readily adopted by regulators and planners to efficiently evaluate alternatives in standalone captive power licensing processes.

In terms of assumptions, the analysis incorporates multiple data inputs, which are consistent with the overall JETP Captive Scenario presented in Chapter 3, to ensure a comprehensive evaluation. The first set of inputs comes from the technical screening of captive power areas, which assesses demand- and supply-side interventions that could reduce reliance on coal-based generation, and the electricity demand outlook for captive power areas in the JETP Captive Scenario. Inputs include:

Demand:

- The demand outlook for each site is part of the projection presented in Chapter 3. It reflects sector-specific assumptions, including planned industrial production capacity, projected industrial output, and assessed electricity intensity of that output, which incorporates energy efficiency and process switching improvements, as noted in the technical screening in Chapter 2.
    - For example, alternatives for planned 900 MW of coal power (Asset 1) are modeled using the projected industrial production and electricity demand

requirements anticipated from the ramp-up of a 1 Mt aluminum smelter at that site. Hence, modelled power solutions align with anticipated industrial activity.

- Given data limitations, the analysis assumes a flat hourly and seasonal load profile for industrial electricity demand. In practice, industry- and asset-specific demand profiles are critical for designing optimal power supply solutions for energy intensive industries.

Supply:

- The technical screening in Chapter 2 provides resource potentials for local renewable power sources, including solar PV, wind, hydropower, geothermal, bioenergy and battery energy storage systems (BESS), to provide cleaner alternatives; and
- Potential for fuel switching to gas as a transitional measure to lower carbon intensity based on gas infrastructure availability (floating LNG or piped gas).
- The modelling includes a minimum power reserve of 10% of annual electricity demand, a level consistent with industry feedback on power configurations for smelters.
- The analysis models a coal-only baseline case and multiple alternative cases that fully avoid coal while testing minimum renewables shares of 0%, 25%, 50%, 75%, and 100%.
- A least-cost generation case is identified among avoidance cases, which optimizes power generation costs while meeting demand and system reliability needs (the modelling does not include potential extra costs associated with transmission to access far-away renewables resources).
- The case chosen for the JETP Captive Scenario reflects the avoidance case with the highest renewables share and whose generation costs - if higher – are still within 10% of the least-cost option, a level assessed to provide a cost-comparable solution while better supporting the JETP emissions reduction and renewables objectives.

Additional economic and technical specifications are incorporated to refine the model accuracy. Key economic parameters include capital expenditures, operational expenditures, asset lifetime, discount rates, and carbon pricing assumptions. Economic inputs are consistent with assumptions tables presented in Chapter 3. Technical specifications such as load profiles, calorific values, efficiency factors, and capacity factors are consistent with the overall JETP Captive Scenario and the MEMR RUKN, as set out in Chapter 2 and 3.

HOMER plays a central role in analyzing these inputs by simulating different energy configurations. It evaluates the feasibility of various technology mixes based on criteria such as net present cost, levelized cost of electricity (LCOE), fuel cost variations, system reliability, and emissions reductions.

Results of Asset-Level Alternatives Analysis

Baseline Case

Under baseline assumptions, coal power is built to fully meet the annual electricity demand for all sites. Based on this demand, the model sizes total required coal power capacity at 4.4 GW (net capacity) to ensure a continuous electricity supply. The model estimates a total annual average electricity generation of approximately 34 TWh, resulting in a total net present cost (NPC) of USD 25.3 billion, with an average annual generation cost of USD 83/MWh. However, the baseline case also results in the highest emissions profile, with annual CO2 emissions of approximately 33 million tonnes and an average emissions intensity of 0.97 kg CO2/kWh.

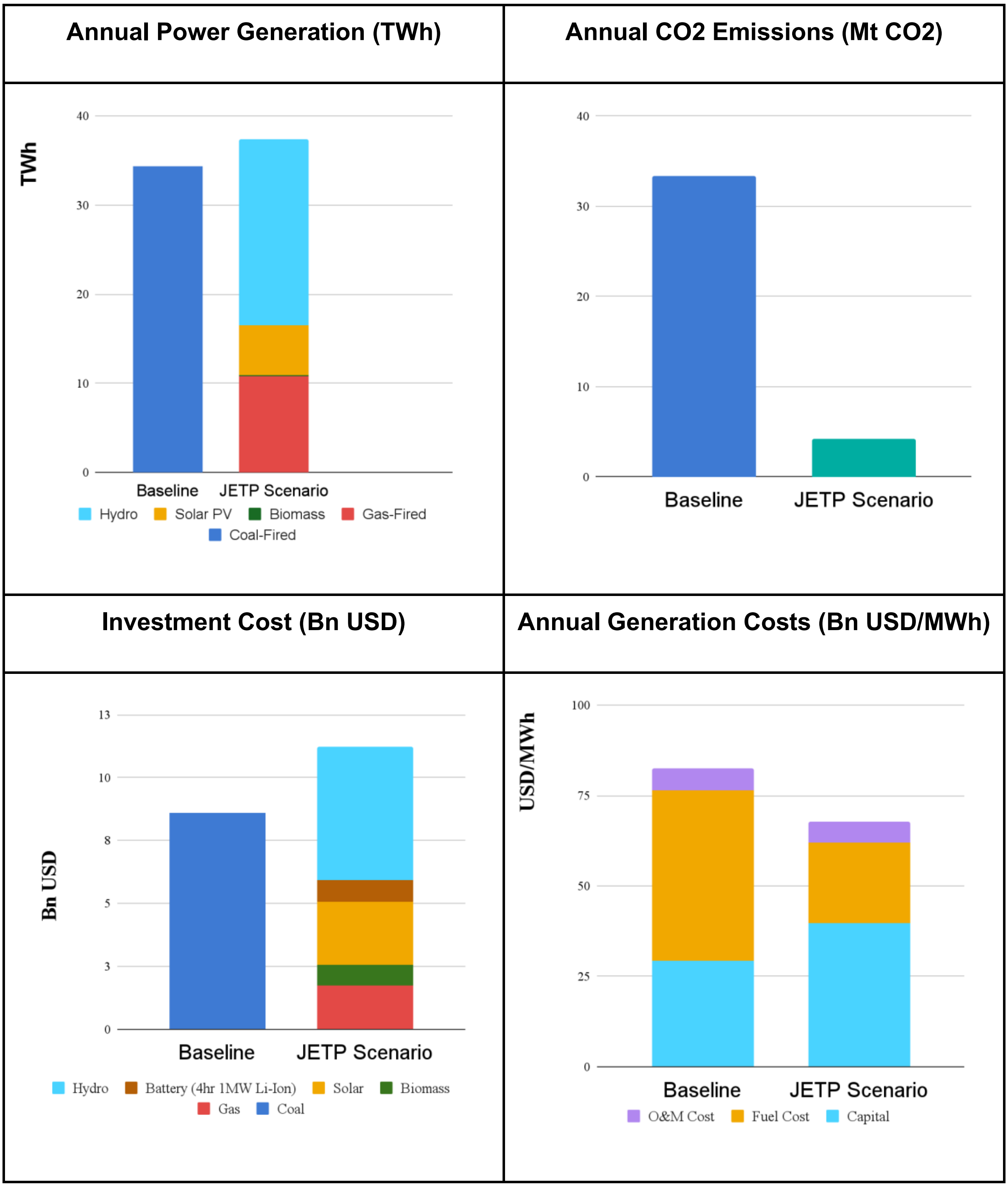
Summary of the JETP Captive Scenario (coal avoidance)

The modelled cases chosen for the JETP Captive Scenario, in accordance with the criteria described above, fully avoid the use of coal power in meeting electricity demand. Power generation from these cases totals 38.7 TWh annually on average, with 69% of generation sourced from renewable energy. Renewable generation is primarily supplied by hydropower (54% of total), solar PV (15%), and a small share of bioenergy (less than 1%). To meet capacity needs and support variable renewables integration, the case includes 3.9 GW of solar PV capacity and 2.8 GW total of battery energy storage systems (BESS) is deployed to enhance reliability and ensure round-the-clock power availability. Gas-fired generation also plays an important role in meeting demand needs, contributing 28% of total output.

The estimated NPC is USD 23.0 billion, with an average annual generation cost of USD 68/MWh. However, generation costs for individual sites vary considerably, ranging from USD 56/MWh to USD 96/MWh, based on the role of relatively economical hydropower and solar PV compared with relatively expensive gas generation and the need to invest in additional solar PV and battery storage capacity to meet continuous dispatch requirements.

In the coal avoidance case, aggregate CO_2 emissions drop to 4.2 million tonnes annually—an 88% reduction from the Baseline case—and the average emissions intensity is 0.11 kg CO_2/kWh. Based on a lower NPC compared with the Baseline Case, the modelled alternatives in JETP Scenario are able to reduce CO2 emissions at an average abatement cost of around USD -80/t. The negative abatement cost indicates that overall coal avoidance could reduce emissions while potentially generating net-economic savings.

Nevertheless, the coal avoidance case in the JETP Captive Scenario requires higher investment of USD 12.8 billion compared with USD 8.6 billion in the Baseline case, due to higher power capacity requirements (10.7 GW compared with 4.4 GW in the Baseline case), suggesting that the ability of industrial actors to finance higher upfront capital expenditures will be important to realizing potential generation cost and emissions savings over time. Moreover, the solutions and cost and emissions implications of avoiding coal power are site specific and often involve hybridization of multiple power sources and assets, as shown below, which can make the investment case complex, suggesting that opportunities for scale and standardization, potentially through industrial clustering, could help facilitate the results.



Annual Power Generation (TWh)

Annual CO2 Emissions (Mt CO2)

Investment Cost (Bn USD)

Annual Generation Costs (Bn USD/MWh)

Source: (JETP Secretariat and Working Groups, 2025).

Figure B-1. Annual Energy Generation and CO2 Emission (left), Investment Cost (middle) and LCOE (right) of Baseline Case vs. JETP Scenario.

Detailed asset-level results

Demonstration results for each asset are provided in the data dashboards found in the pages below. These results include an analysis of the hourly dispatch profile for the system chosen for the JETP Scenario, which shows how different power sources are utilized throughout the day.

It is worth noting that while the JETP Scenario demonstrates the potential for utilizing a high share of renewable generation overall (at around 70%) to avoid captive coal power, individual results can vary significantly, with asset-level renewable shares assessed for the JETP Scenario ranging from 31% to 100%, depending on the availability and costs associated with different renewables resources.

Asset-level alternatives analysis: Plant #1, aluminum smelter

Table A2.1 Key parameters assessed

Province	Kepulauan Riau
Status	Permitted
Industry	Aluminum
Process	Alumina-to-aluminum
Planned capacity	1 million tonnes
Electricity intensity	14.5 MWh/tonne
Planned power	900 MW CFPP
Local RE potential	Solar PV: CF = 15% Wind: limited Bioenergy: good Hydropower: limited Geothermal: limited
Gas potential	Possible with FLNG

Modelled findings based on assessed demand

Baseline case:

- 1.7 GW CFPP, with LCOE of USD 83/MWh.
- Emissions = 10.9 Mt CO2/yr; 0.891 kg CO2/kWh.

JETP Scenario:

- Adopts RUPTL 2034 supply plan (*Lampiran E), which includes grid integration,* 600 MW on-grid gas power and , 900 MW on-grid hydro, supplemented by additional, 1.5 GW solar PV, 1.7 GW/6.8GWh battery, and 200 MW biomass, with overall RE share of 68% and LCOE of USD 65/MWh.
- 1.7 GW gas power and 1.5 GW of solar PV, with LCOE of USD 93/MWh.
- Emissions = 1.74 Mt CO2/yr; 0.114322 kg CO2/kWh.

Least-cost coal avoidance case:

The least-cost system is the coal avoidance case with an RE generation share of 64%.

- While the JETP scenario is not the least cost solution, it provides the highest RE share and emissions savings for lower generation cost than the Baseline case.
- The JETP Scenario case is the least-cost case, with RE generation share of 16%.
- Other scenarios with higher renewable energy shares are assessed to be infeasible due to much higher generation costs .

Figure A2.1 Modelled annual generation and emissions across different technology cases

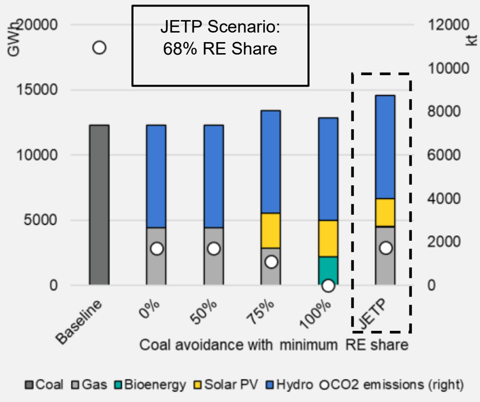
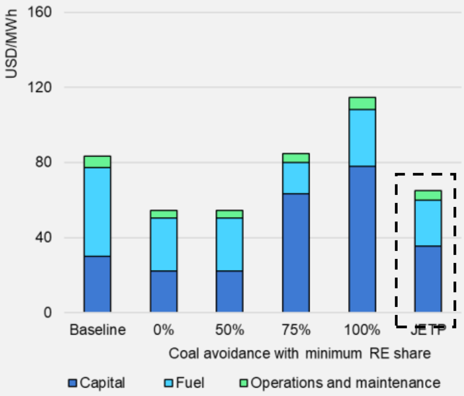
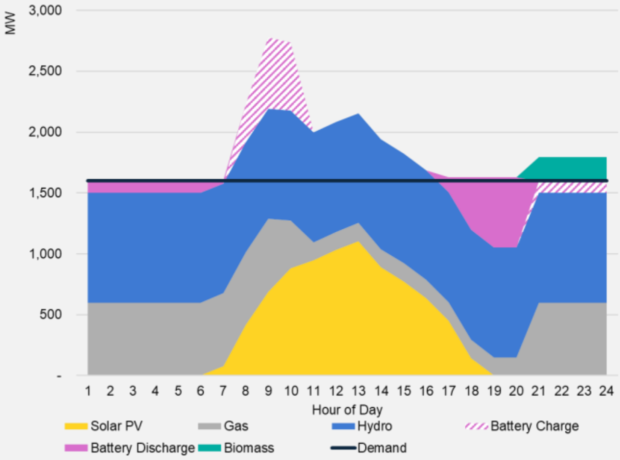


Figure A2.2 Modelled generation costs across different technology cases



Source: (JETP Secretariat and Working Groups, 2025).

Figure A2. 3 Hourly dispatch: avoidance (68% RE)	Hourly dispatch findings



Source: (JETP Secretariat and Working Groups, 2025).

Daytime:

- Solar PV contributes significantly to meeting demand.
- Gas and hydro remains an important sources of generation throughout the entire 24-hour period.

Evening/nighttime:

- Gas, hydro, and battery discharge meets 100% of the demand, during periods without solar energy.
- Biomass operates to charge the battery that will be used during the early part of the day.There is no battery discharge, and the system is heavily gas-dependent with stable output.

Asset-level alternatives analysis: Plant #2, aluminum smelter

Table A2.1 Key parameters assessed

Province	Sulawesi Tengah
Status	Permitted
Industry	Aluminum
Process	Alumina to aluminum
Planned capacity	500000 tonnes
Electricity intensity	14.5 MWh/tonne
Planned power	760 MW CFPP
Local RE potential	Solar PV: CF = 16% Wind: Limited Bioenergy: Limited Hydropower: Good at province-level Geothermal: Limited
Gas potential	Possible with FLNG

Modelled findings based on assessed demand

Baseline case:

- 810 MW CFPP, with LCOE of USD 81/MWh.
- Emissions = 6.2 Mt CO2/yr; 1.009 kg CO2/kWh.

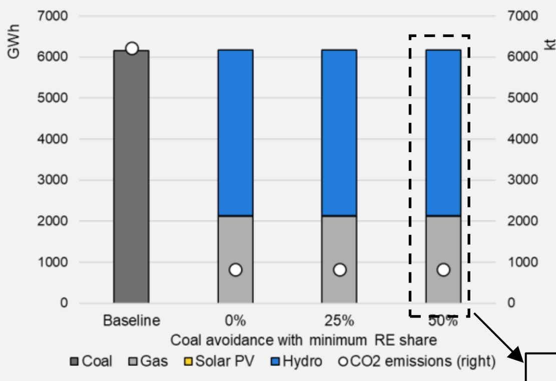
JETP Scenario:

- 300 MW gas power, 541 MW hydropower and 19 MW of solar PV, with LCOE of USD 80/MWh. RE generation share of 66%
- Emissions = 0.8 Mt CO2/yr; 0.133 kg CO2/kWh.

Least-cost coal avoidance case:

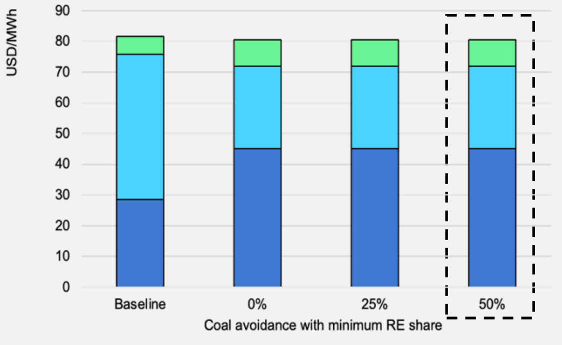
- The JETP Scenario case is the least-cost case,with RE generation share of 66%.
- The 75% and 100% RE share cases were assessed as infeasible due to much higher generation costs.

Figure A2.1 Modelled annual generation and emissions across different technology cases



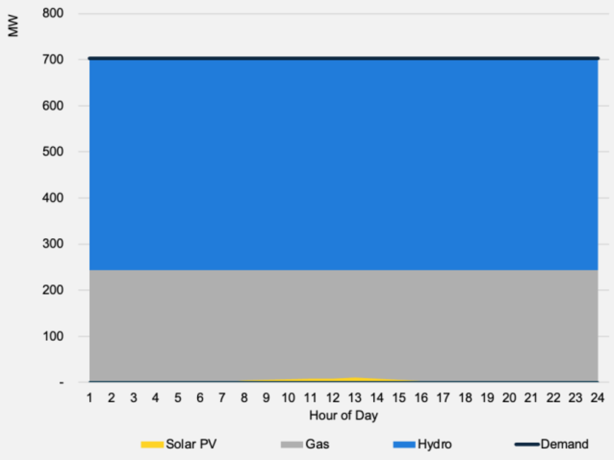
JETP Scenario:
66% RE Share

Figure A2.2 Modelled generation costs across different technology cases



Source: (JETP Secretariat and Working Groups, 2025).

Figure A2. 3 Hourly dispatch: avoidance (66% RE)



Source: (JETP Secretariat and Working Groups, 2025).

Hourly dispatch findings

Daytime:

- Solar PV has a small amount of generation, primarily helping reduce gas fuel costs to meeting demand.
- Hydro remains the dominant source of generation throughout the entire 24-hour period, supplemented with gas.

Evening/nighttime:

- As hydro and gas are not affected by intra-daily variation, there is little variability between daytime and nighttime.

Asset-level alternatives analysis: Plant #3, alumina refinery

Table A2.1 Key parameters assessed

Province	Kalimantan Barat
Status	Permitted
Industry	Aluminum
Process	Bauxite to Alumina
Planned capacity	1000000 toones
Electricity intensity	0.27 MWh/tonne
Planned power	120 MW CFPP
Local RE potential	Solar PV: CF = 15% Wind: Limited Bioenergy: Good Hydropower: Good at province-level Geothermal: Limited
Gas potential	Possible with FLNG

Modelled findings based on assessed demand

Baseline case:

- 32 MW CFPP, with LCOE of USD 82/MWh.
- Emissions = 245 kt CO2/yr; 1.009 kg CO2/kWh.

JETP Scenario:

- 15 MW gas power, 21 MW hydropower, and 30 MW of solar PV, with LCOE of USD 61/MWh. RE generation share of 75%.
- Emissions = 0.023 Mt CO2/yr; 0.09 kg CO2/kWh.

Least-cost coal avoidance case:

- Least-cost system is the coal avoidance case with a RE generation share of 68%, with an LCOE of USD 55.5/MWh.
- While the JETP Scenario case is not the least cost solution, it provides the highest RE share and emissions savings at 25% lower generation cost than the Baseline case.

Figure A2.1 Modelled annual generation and emissions across different technology cases

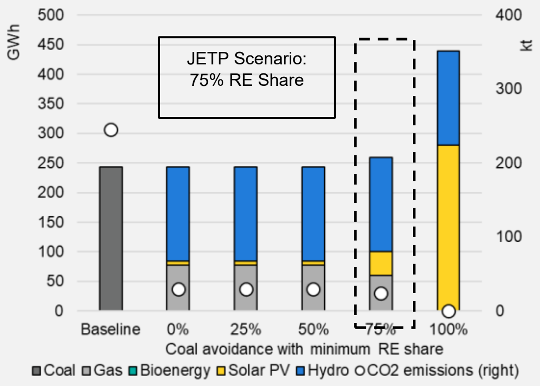
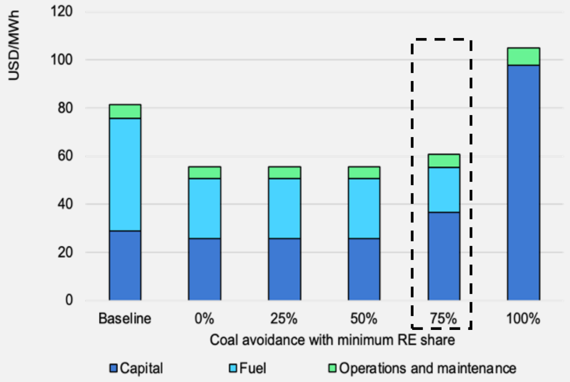
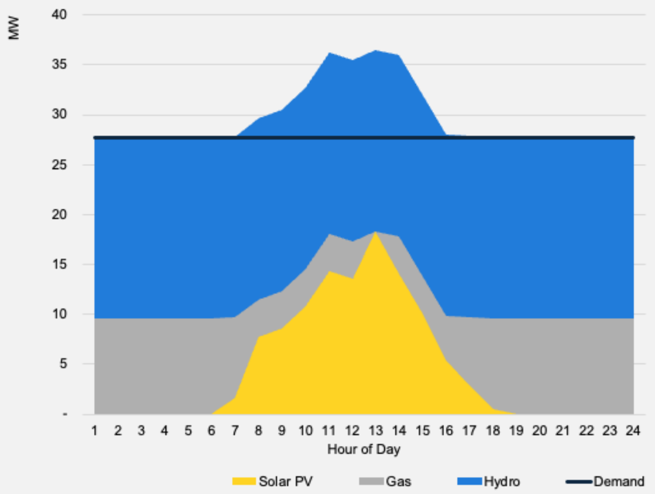


Figure A2.2 Modelled generation costs across different technology cases



Source: (JETP Secretariat and Working Groups, 2025).

Figure A2.3 Hourly dispatch: avoidance (75% RE)



Source: (JETP Secretariat and Working Groups, 2025).

Hourly dispatch findings

Daytime:

- Solar PV plays a relatively small role, helping reduce gas fuel costs to meet demand.
- Hydro remains the dominant source of generation throughout the entire 24-hour period, supplemented by gas.

Evening/nighttime:

- As hydro and gas are not affected by intra-daily variation, there is little variability between daytime and nighttime.

Asset-level alternatives analysis: Plant #4, aluminum smelter

Table A2.1 Key parameters assessed

Province	Kalimantan Utara
Status	Permitted
Industry	Aluminium
Process	Alumina-to-aluminum
Planned capacity	1,000,000 tonnes
Electricity intensity	14.5 MWh/tonne
Planned power	1200 MW CFPP
Local RE potential	Solar PV: CF = 15% Wind: Limited Bioenergy: Good Hydropower: Good at province-level Geothermal: Limited
Gas potential	Possible with FLNG

Modelled findings based on assessed demand

Baseline case:

- 1700 MW CFPP, with LCOE of USD 83/MWh.
- Emissions = 12 Mt CO2/yr; 1.009 kg CO2/kWh.

JETP Scenario:

- 500 MW gas power, 200 MW biomass, 1080 MW hydropower, 340MW/1360MWh battery, and 1100 MW of solar PV, with LCOE of USD 59/MWh. RE generation share of 76%.
- Emissions = 1.16 Mt CO2/yr; 0.09 kg CO2/kWh.

Least-cost coal avoidance case:

- Least-cost system is the coal avoidance case with RE generation share of 66%and an LCOE of USD 59.6/MWh.
- While the JETP Scenario case is not the least cost solution, it provides the highest RE share and emissions savings for lower generation cost than the Baseline case.

Figure A2.1 Modelled annual generation and emissions across different technology cases

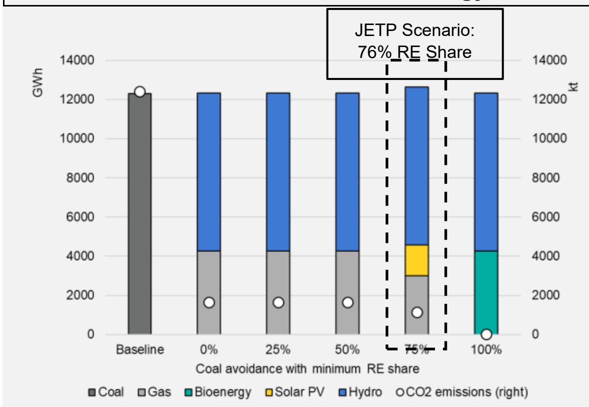
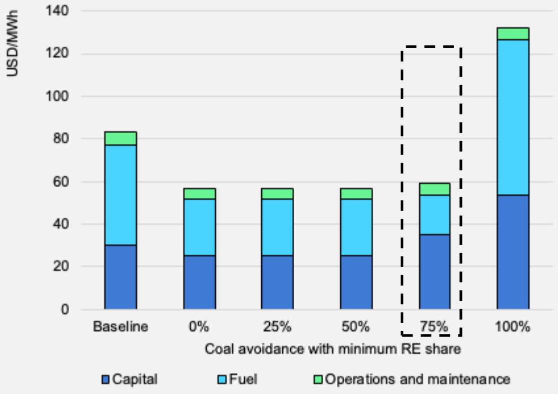
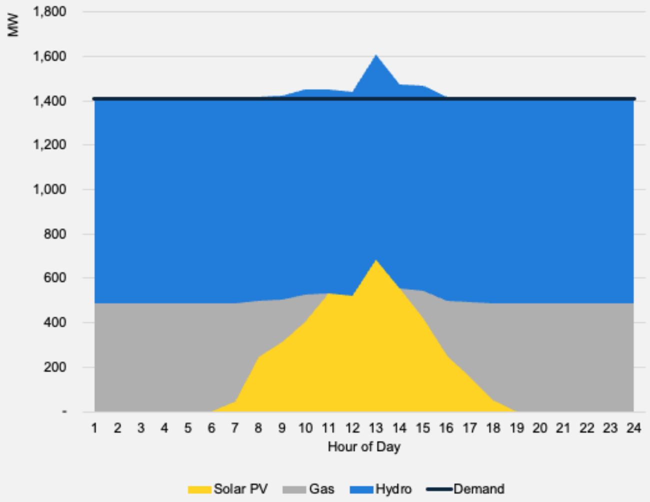


Figure A2.2 Modelled generation costs across different technology cases



Source: (JETP Secretariat and Working Groups, 2025).

Figure A2. 3 Hourly dispatch: avoidance (76% RE)



Source: (JETP Secretariat and Working Groups, 2025).

Hourly dispatch findings

Daytime:

- Solar PV has a relatively small amount of generation, primarily helping reduce gas fuel costs to meeting demand
- Hydro remains the dominant source of generation throughout the entire 24-hour period, supplemented with gas

Evening/Nighttime:

- As hydro and gas are not affected by intra-daily variation, there is little variability between daytime and nighttime

Asset-level alternatives analysis: Plant #5 & 7, utility (industrial area)

Table A2.1 Key parameters assessed

Province	Kepulauan Riau
Status	Pre-Permit
Industry	Industrial Area
Process	Utility (industrial area)
Planned capacity	-
Electricity intensity	-
Planned power	102 MW CFPP
Local RE potential	Solar PV: CF = 15% Wind: limited Bioenergy: good Hydropower: limited Geothermal: limited
Gas potential	Possible with FLNG

Modelled findings based on assessed demand

Baseline case:

- 102 MW CFPP, with LCOE of USD 83/MWh.
- Emissions = 782 kt CO2; 1.095 kg CO2/kWh

JETP Scenario

- 100 MW gas power,450 MW of solar PV, and 191 MW/764 MWh of BESS, with LCOE of USD 112/MWh
- Emissions = 122 kt CO2; 0.13 kg CO2/kWh

Coal avoidance cases (RE minimum = 25-100%):

- Least-cost system is the coal avoidance scenario with a RE generation share of 35%.
- While the JETP scenario is not the least cost solution, it provides the highest savings in emissions per unit of levelized cost.

Figure A2.1 Modelled annual generation and emissions across different technology cases

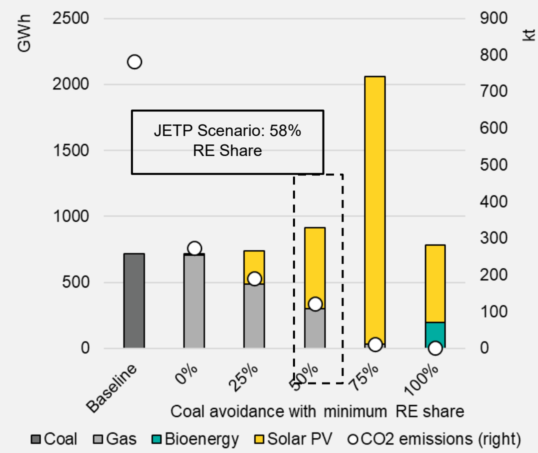
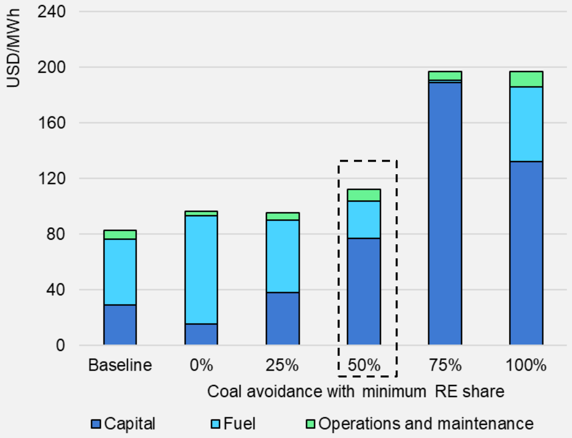
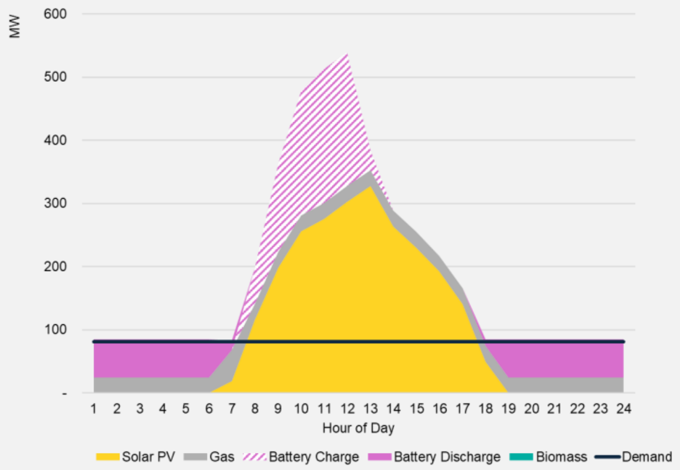


Figure A2.2 Modelled generation costs across different technology cases



Source: (JETP Secretariat and Working Groups, 2025).

Figure A2. 3 Hourly dispatch: avoidance (min 58% RE)



Source: (JETP Secretariat and Working Groups, 2025).

Hourly dispatch findings

Daytime:

- Solar PV contributes significantly to meeting demand
- When PV generation exceeds demand, surplus charges the battery

ning/nighttime:

- Battery is discharged during evening hours to help cover the load.
- Gas power ramps up in the morning and at night when solar output is minimal, and battery charge is insufficient to meet demand.

Disclaimer: This document forms part of the Indonesia Just Energy Transition Partnership (JETP) thematic reporting. It does not constitute a legally binding document. It is a strategy document that the Government of Indonesia may use as a basis for power sector planning and policymaking as part of the JETP process. For more information about JETP Indonesia, please refer to the 2023 Comprehensive Investment and Policy Plan (CIPP) and 2025 Progress Report. The CIPP is a document for the implementation of the Joint Statement agreed in November 2022.

Asset-level alternatives analysis: Plant #6, nickel (RKEF) smelter

Table A2.1 Key parameters assessed

Province	Maluku Utara
Status	Pre-permit
Industry	Nickel
Process	RKEF
Planned capacity	275,000 tonnes
Electricity intensity	38.09 MWh/tonne
Planned power	380 MW CFPP
Local RE potential	Solar PV: CF = 15% Wind: limited Bioenergy: good Hydropower: limited Geothermal: limited
Gas potential	Possible with FLNG

Modelled findings based on assessed demand

Baseline case:

- 160 MW CFPP, with LCOE of USD 81/MWh.
- Emissions = 1.184 Mt CO2/yr; 1.009 kg CO2/kWh.

JETP Scenario:

- 155 MW gas power and 739 MW of solar PV, and 479 MW/1916 MWh BESS, with LCOE of USD 88.6/MWh. RE generation share of 88%.
- Annual Emissions = 54 kt CO2/yr; 0.03 kg CO2/kWh.

Least-cost coal avoidance case:

- The JETP Scenario case is the least-cost avoidance case , with RE generation share of 88%.
- Higher RE cases are assessed as infeasible due to potential much higher generation costs .

Figure A2.1 Modelled annual generation and emissions across different technology cases

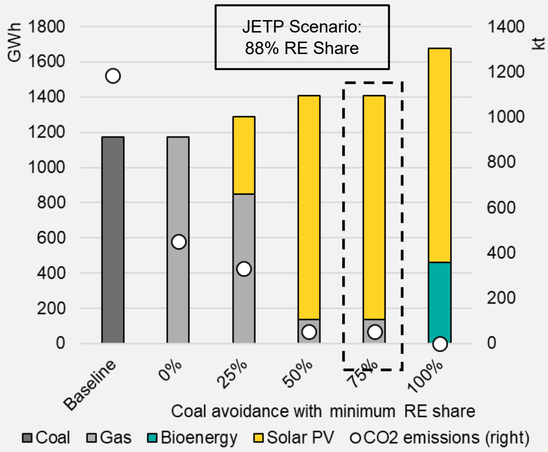
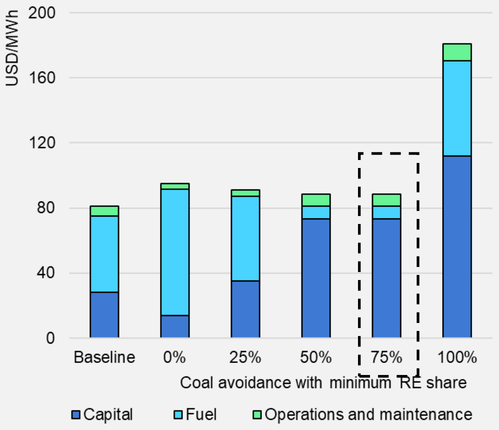
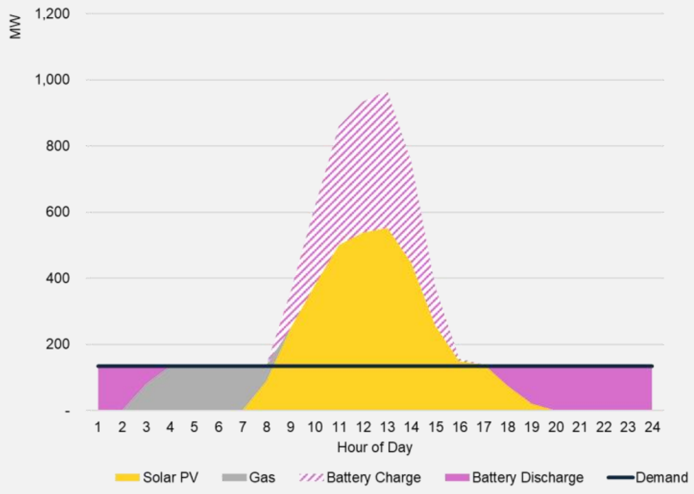


Figure A2.2 Modelled generation costs across different technological cases



Source: (JETP Secretariat and Working Groups, 2025).

Figure A2.3 Hourly dispatch: avoidance (88% RE)



Source: (JETP Secretariat and Working Groups, 2025).

Hourly dispatch findings

Daytime:

- Solar PV contributes significantly to meeting demand.
- When PV generation exceeds demand, the surplus charges the battery.

Evening/nighttime:

- The battery is discharged during evening hours to help cover the load.
- Gas is used as fast-ramping to briefly cover load gaps during the transition to daytime.

Asset-level alternatives analysis: Plant #8, alumina refining

Table A2.1 Key parameters assessed

Province	Kepulauan Riau
Status	Permitted
Industry	Aluminum
Process	Bauxite-to-alumina
Planned capacity	2 million tonnes alumina
Electricity intensity	0.27 MWh/tonne
Planned power	140 MW CFPP
Local RE potential	Solar PV: CF = 15% Wind: limited Bioenergy: good Hydropower: limited Geothermal: limited
Gas potential	Possible with FLNG

Modelled findings based on assessed demand

Baseline case:

- 60 MW CFPP, with LCOE of USD 81/MWh.
- Emissions = 500 kt CO2/yr; 1.095 kg CO2/kWh.

JETP Scenario:

- 70 MW gas power, 127 MW Solar PV, 28 MW/112 MWh BESS, with LCOE of USD 96/MWh. RE generation share of 31%.
- Annual Emissions = 132 kt CO2/yr; 0.252 kg CO2/kWh.

Least-cost coal avoidance case:

- The JETP Scenario case is the least-cost avoidance case, with RE share of 31%.
  - Other cases with higher renewable energy shares are assessed to be infeasible due to much higher generation costs.

Figure A2.1 Modelled annual generation and emissions across different technology cases

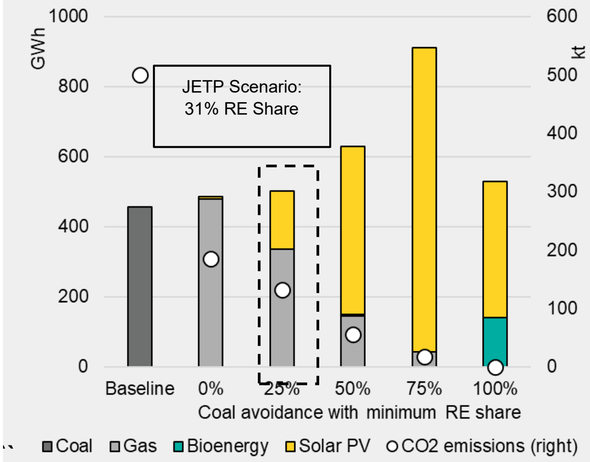
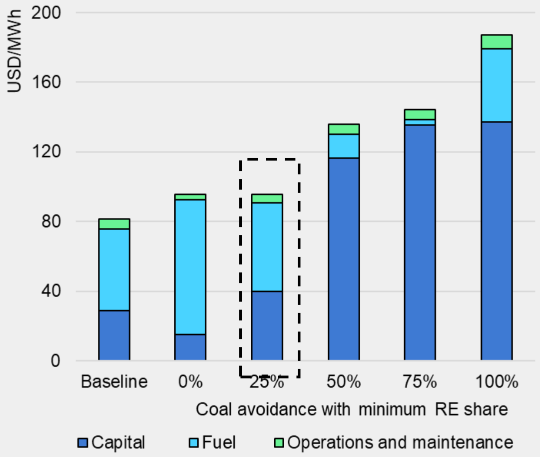
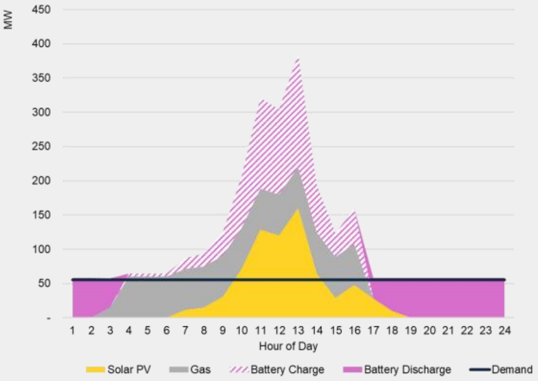


Figure A2.2 Modelled generation costs across different technology cases



Source: (JETP Secretariat and Working Groups, 2025).

Figure A2. 3 Hourly dispatch: avoidance (31% RE)



Source: (JETP Secretariat and Working Groups, 2025).

Hourly dispatch findings

Daytime:

- Solar PV contributes significantly to meeting demand.
- When PV generation exceeds demand, the surplus charges the battery.

Evening/nighttime:

- The battery is discharged during evening hours to help cover the load.
- Gas power ramps up in the morning and at night when solar output is minimal, and battery charge is insufficient to meet demand.

Asset-level alternatives analysis: Plant #9, alumina refining

Table A2.1 Key parameters assessed

Province	Kalimantan Barat
Status	Permitted
Industry	Aluminum
Process	Bauxite to Alumina
Planned capacity	2,000,000 tonnes
Electricity intensity	0.27 MWh/tonne
Planned power	140 MW CFPP
Local RE potential	Solar PV: CF = 16% Wind: Limited Bioenergy: Medium Hydropower: Good at local and province-level Geothermal: Limited
Gas potential	Possible with FLNG

Modelled findings based on assessed demand

Baseline case:

- 64 MW CFPP, with LCOE of USD 82/MWh.
- Emissions = 0.53 Mt CO2/yr; 1.095 kg CO2/kWh.

JETP Scenario:

- 20 MW biomass power, 150 MW of solar PV, 167 MW/668 MWh battery, 43 MW hydropower, with LCOE of USD 80/MWh. RE share of 100%.
- Annual Emissions = 0 Mt CO2/yr; 0 kg CO2/kWh.

Least-cost coal avoidance case:

- Least-cost system is the coal avoidance case with RE generation share of 66%.
- While the JETP scenario is not the least cost solution, it provides the highest renewable share and emissions savings for lower generation cost than the Baseline case.

Figure A2.1 Modelled annual generation and emissions across different technology cases

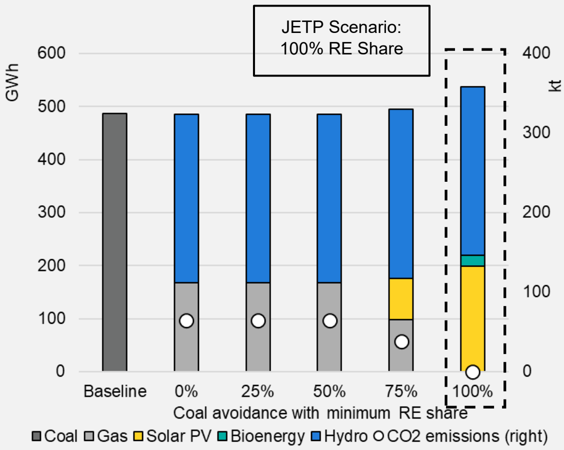
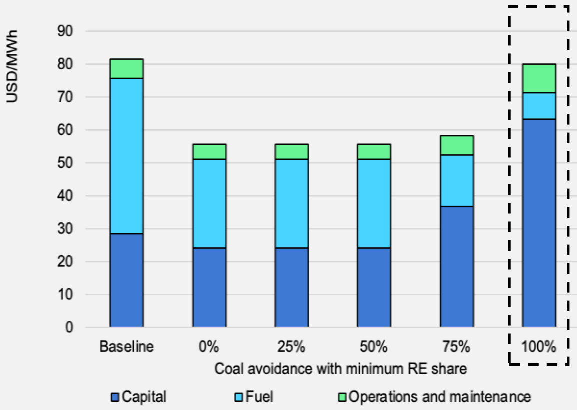
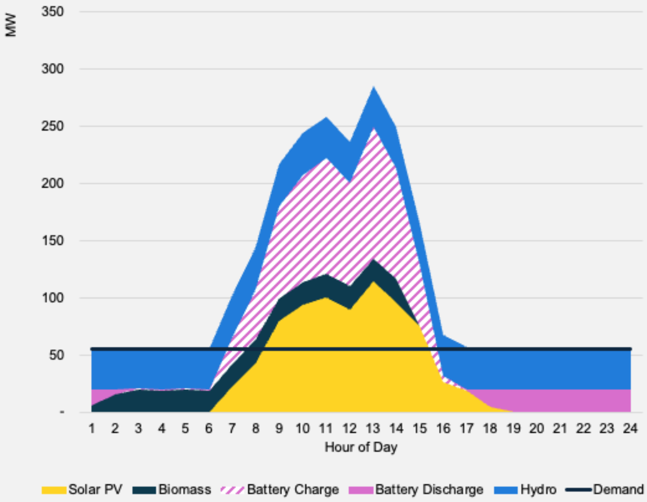


Figure A2.2 Modelled generation costs across different technology cases



Source: (JETP Secretariat and Working Groups, 2025).

Figure A2. 3 Hourly dispatch: avoidance (100% RE)



Source: (JETP Secretariat and Working Groups, 2025).

Hourly dispatch findings

Daytime:

- Solar PV is the dominant source of generation during the daytime, supplemented with hydropower an biomass.
- There is significant surplus generation during the daytime as the batteries are charged by solar PV and hydropower.

Evening/Nighttime:

- Hydropower replaces solar as the dominant generation source and is supplemented by discharging batteries. As the batteries discharge, biomass steps in.

Disclaimer: This document forms part of the Indonesia Just Energy Transition Partnership (JETP) thematic reporting. It does not constitute a legally binding document. It is a strategy document that the Government of Indonesia may use as a basis for power sector planning and policymaking as part of the JETP process. For more information about JETP Indonesia, please refer to the 2023 Comprehensive Investment and Policy Plan (CIPP) and 2025 Progress Report. The CIPP is a document for the implementation of the Joint Statement agreed in November 2022.

Asset-level alternatives analysis: Plant #10, nickel smelter

Table A2.1 Key parameters assessed

Province	Sulawesi Tengah
Status	Permitted
Industry	Nickel
Process	Laterite to MHP via HPAL
Planned capacity	190,000tonnes
Electricity intensity	7.68 MWh/tonne
Planned power	700 MW CFPP (based on original plan of RKEF smelter)*
Local RE potential	Solar PV: CF = 17% Wind: Limited Bioenergy: Limited Hydropower: Good at province-level. Geothermal: Limited
Gas potential	Possible with FLNG

Modelled findings based on assessed demand

Baseline case:

- 73 MW CFPP, with LCOE of USD 81/MWh*.
- Emissions = 0.55 Mt CO2/yr; 1.009 kg CO2/kWh.

JETP Scenario:

- 30 MW gas power, 49 MW hydropower and 19 MW of solar PV, with LCOE of USD 57/MWh. RE generation share of 70%.
- Emissions = 0.06 Mt CO2/yr; 0.116 kg CO2/kWh.

Least-cost coal avoidance case:

- The JETP Scenario case is the least-cost avoidance case, with a RE generation share of 70%.
- Other cases reach RE generation shares of 75%-100%, but with much higher generation costs at USD 100-130/MWh.

Figure A2.1 Modelled annual generation and emissions across different technology cases

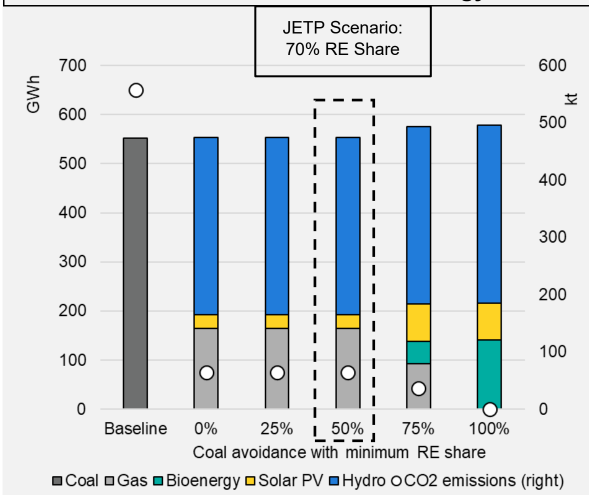
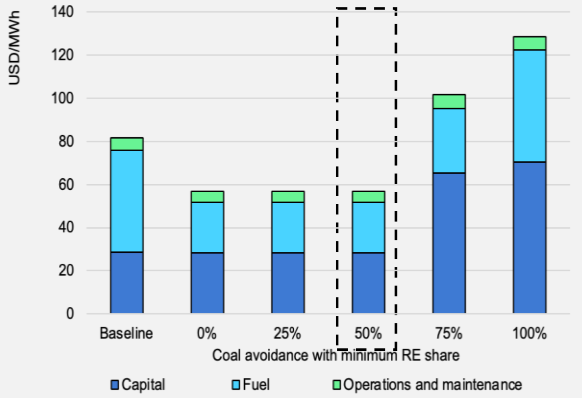
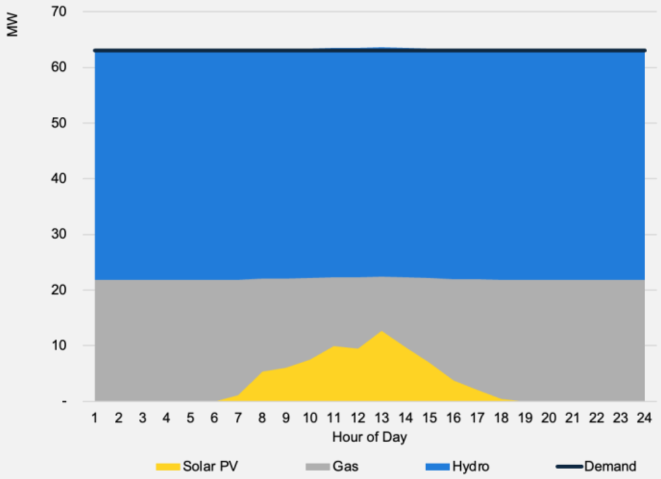


Figure A2.2 Modelled generation costs across different technology cases



Source: (JETP Secretariat and Working Groups, 2025).

Figure A2. 3 Hourly dispatch: avoidance (70% RE)	Hourly dispatch findings



Daytime:

- Solar PV has a relatively small amount of generation, primarily helping reduce gas fuel costs to meet demand.
- Hydro remains the dominant source of generation throughout the entire 24-hour period, supplemented with gas.

Evening/nighttime:

- As hydro and gas are not affected by intra-daily variation, there is little variability between daytime and nighttime.

**The plant is assumed to switch to HPAL from RKEF, reducing the total electricity demand which results in a capacity gap between the current capacity and the evaluated scenarios*
Source: (JETP Secretariat and Working Groups, 2025).

Disclaimer: This document forms part of the Indonesia Just Energy Transition Partnership (JETP) thematic reporting. It does not constitute a legally binding document. It is a strategy document that the Government of Indonesia may use as a basis for power sector planning and policymaking as part of the JETP process. For more information about JETP Indonesia, please refer to the 2023 Comprehensive Investment and Policy Plan (CIPP) and 2025 Progress Report. The CIPP is a document for the implementation of the Joint Statement agreed in November 2022.