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Location-Based Electricity Emissions and Potential Vegetation Carbon Removals in Yogyakarta, Indonesia

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ABSTRACT

Sub-national decarbonization planning often combines electricity-emission accounting with nature-based measures without clearly separating source reductions from potential carbon removals. This study develops an integrated framework for Yogyakarta, Indonesia, combining activity-data × grid-factor accounting, literature-based vegetation removal scenarios, and a causal loop diagram (CLD). The 2023 BPS electricity-distribution value and audited 2024 PLN electricity sales are reported with their distinct bases; 2025 is a provisional extrapolation from a local first-half growth signal, and 2026 uses the 4.2% Java-Madura-Bali (JAMALI) planning growth rate. A 2019 JAMALI combined-margin (CM) ex-ante coefficient of 0.83 tCO_2/MWh is retained as a reference, with 0.80–0.87 used as a published-coefficient sensitivity range. Under the prudent 2026 energy scenario, energy efficiency (EE)/ demand-side management (DSM), 160 GWh of rooftop-photovoltaic (PV) displacement, and a policy emission factor (EF) of 0.75 tCO_2/MWh reduce gross electricity emissions by 20.3%. Vegetation results are planning estimates, not verified offsets: mature portfolios could remove 0.160–0.269 $MtCO_2$/year (5.7–9.6% of the post-energy residual). If planting begins in 2026, the assumed first-year 0.3 ramp gives a combined mitigation potential of 21.6–22.6%. The CLD explicitly separates gross emissions, potential removals, and the scenario net balance.

1. INTRODUCTION

Electricity generation remains an important source of energy-related CO_2 emissions in Indonesia because the interconnected power system is still strongly dependent on fossil generation [1]. For sub-national accounting, electricity-related emissions can be estimated transparently as electricity activity (MWh) multiplied by a documented grid emission factor [2]. Because Yogyakarta is supplied through the Java-Bali power system, regional generation-mix assumptions are material to mitigation analysis; Java-Bali power-system modelling has shown that generation choices strongly influence CO_2 outcomes [3]. In the Special Region of Yogyakarta (DIY), sectoral electricity-demand forecasting has documented substantial household and business demand and changing sectoral patterns [4]. In this study, changes in the baseline series are not interpreted as an empirical attribution of causality: because the reference emission factor is held constant, changes in calculated baseline emissions arise arithmetically from changes in reported or projected electricity activity.

Mitigation therefore requires two distinct accounting streams. First, source-side measures such as energy efficiency (EE), demand-side management (DSM), rooftop photovoltaic (PV) generation, and grid decarbonization reduce gross electricity emissions. Second, vegetation can potentially remove part of the remaining atmospheric CO_2 while also providing ecosystem co-benefits. Urban tree cover provides important ecosystem services [5], and global restoration studies indicate substantial biophysical carbon-removal potential [6]; urban vegetation can also contribute air-quality co-benefits [7]. However, vegetation removals should not be treated as verified offsets unless additionality, permanence, project boundaries, and measurement-reporting-verification (MRV) requirements are demonstrated [8-10]. Species and site selection can also materially affect sequestration performance [11].

For urban and peri-urban settings, vegetation-based planning must distinguish carbon stock from annual stock change. Allometric equations estimate biomass stock at a measurement date; annual sequestration is verified only from repeated measurements or defensible growth models. In the absence of local repeated tree measurements in this study, the vegetation component is explicitly treated as a planning scenario based on literature-derived annual removal rates, with a proposed MRV pathway for later verification.

Earlier work by the authors addressed separate pieces of the present problem: sector-specific carbon footprints and tree-number recommendations in livestock, retail, and energy applications [12-14], electricity-demand and power-system dynamics [15, 16], and a conceptual renewable-energy causal loop diagram (CLD) [17]. Those studies did not provide a common accounting boundary that (i) separates gross electricity emissions from potential vegetation removals, (ii)

distinguishes historical data from forward-looking scenario assumptions, (iii) exposes the age and type of the grid coefficient and its sensitivity, and (iv) links quantified accounting results to a policy CLD without treating conceptual feedbacks as measured effects.

Indonesia's RUPTL 2025–2034 and the DIY regional energy plan provide the policy context for renewable deployment, demand management, and system planning [18, 19]. The RUPTL reports an average national electricity-demand growth assumption of 5.3%, while the Java-Madura-Bali (JAMALI) regional sales projection is lower, at about 4.2% on average [18]. This distinction is important because a national growth rate should not be applied uncritically to a provincial projection.

The research gap is therefore methodological rather than merely combinational. Existing electricity inventories, vegetation-removal studies, and CLD/system-dynamics studies generally use different boundaries and time frames [2, 8-11, 15-17]. The present study contributes a boundary-consistent sub-national framework in which the electricity inventory estimates gross emissions, the vegetation module estimates potential removals under explicit scenario assumptions, and the CLD describes policy interactions while marking which links are quantified and which remain conceptual.

Accordingly, the framework has three components: (a) electricity accounting for 2023–2026 using documented BPS/PLN activity data and an explicitly identified JAMALI reference coefficient; (b) literature-based vegetation-removal portfolios whose areas, rates, survival assumptions, ramp-up, and verification requirements are shown transparently; and (c) a CLD that separates gross electricity emissions, potential vegetation removals, and the scenario net balance. The sequence is avoid–reduce–remove: reduce grid purchases first, test a lower policy EF second, and only then estimate potential removal of residual CO_2.

Yogyakarta was selected because its electricity demand is dominated by household and commercial uses and because the province combines dense urban areas with peri-urban and riparian landscapes [4, 19]. However, this study does not claim to have completed a land-suitability or low-NDVI mapping exercise. The proposed vegetation areas and tree counts are scenario assumptions that require a subsequent land-availability and project-matching assessment before implementation.

The main contribution is thus a transparent separation of measurement, scenario estimation, and policy logic. The study updates the electricity baseline with an audited 2024 PLN value, distinguishes provisional 2025–2026 projections from observations, documents the 2019 JAMALI coefficient used in the calculations, makes vegetation rates reproducible at the portfolio level, and prevents the CLD from conflating gross emissions with carbon removals.

2. METHODOLOGY

2.1 Research design and system boundary

This study uses a policy-oriented single-case design for DIY. The quantitative component has two deliberately separate ledgers: (i) gross electricity-related CO_2 calculated from electricity activity and a stated grid coefficient, and (ii) potential vegetation carbon removals calculated from literature-based planning rates. The vegetation-accounting logic is aligned with IPCC agriculture, forestry and other land use guidance [20] and pan-tropical biomass allometry [21]. The qualitative component is a causal loop diagram (CLD) used to structure policy interactions; it is not a calibrated dynamic simulation.

The study period covers 2023–2026. The 2023 value is the BPS measure of electricity distributed by province [22]. The 2024 value is audited PLN electricity sales for DIY; the official PLN source is documented in Appendix A. Previous building-level research in Yogyakarta has likewise used electricity consumption to estimate indirect CO_2 emissions [23]. The 2023 and 2024 official sources use slightly different reporting labels; therefore, the pair is shown for context rather than used to infer a precise growth rate. As a consistency check, the BPS preliminary 2024 value (3,891.18 GWh) differs from audited PLN sales (3,893.71 GWh) by only about 0.07%. The 2025 value is a provisional scenario that applies the reported 4.81% first-half DIY growth signal to the 2024 PLN baseline [24]. The 2026 projection then applies the RUPTL JAMALI planning growth rate of 4.2% rather than the 5.3% national average [18].

The framework integrates three complementary but non-equivalent outputs. The electricity module estimates gross CO_2 emissions; the vegetation module estimates potential annual CO_2 removal under planning assumptions; and the CLD organizes policy relationships. No vegetation quantity in this study is presented as a verified carbon credit or measured MRV outcome.

2.2 Activity data and emission factor

Electricity activity data were compiled from BPS [22], official audited PLN Statistics 2024 (primary source documented in Appendix A), the local 2025 growth signal [24], and RUPTL 2025–2034 [18]. The central coefficient, 0.83 tCO_2/MWh, is not a 2023–2026 measured average factor. It is adopted from the official 2019 JAMALI combined-margin (CM) dataset, whose primary source is documented in Appendix A. Peer-reviewed Java-Bali power-system analysis supports the use of a regional grid basis for emissions scenario analysis [3]. The official dataset reports JAMALI operating-margin and build-margin values and CM variants around the 0.80–0.87 range; accordingly, 0.83 is retained only as a documented reference coefficient for scenario consistency, while 0.80–0.87 is used as a bounded deterministic sensitivity range rather than a statistical confidence interval.

Because the cited coefficient originates from 2019 and from a CM methodology, absolute emission totals should be interpreted as planning estimates rather than an audited contemporary inventory. The factor is expressed in tCO_2/MWh; accordingly, electricity results are reported as CO_2 rather than CO_2e. Updating the calculation with a newer official location-specific average factor is a priority when such a factor becomes available. Grid-loss reductions are not separately credited in the quantitative scenarios, preventing double counting with any future factor or activity data that may already embed system-efficiency improvements.

The 2025 projection is an extrapolation, not an official full-year observation: the 4.81% growth reported for the first half of 2025 is applied to audited 2024 DIY sales only to construct a provisional scenario [24]. For 2026, the study uses the JAMALI regional planning growth assumption of 4.2% from RUPTL rather than the 5.3% national average [18]. This does

not imply that DIY will necessarily grow at exactly 4.2%; it provides a transparent regional planning anchor until official provincial sales become available.

2.3 Location-based emissions calculation

Gross electricity-related CO_2 is calculated as Electricity activity (MWh) × Reference grid coefficient (tCO_2/MWh). The 0.83 tCO_2/MWh coefficient is held constant in the baseline series solely to isolate the effect of activity changes. The 0.80–0.87 range is a deterministic coefficient sensitivity check. Potential vegetation removals are recorded in a separate ledger and are subtracted only when a scenario net balance is explicitly reported.

Annual provincial electricity emissions are calculated for each year (y) as follows [2]:

$$E_y = C_y \times EF_y$$

where,

E_y = gross electricity-related emissions in year y (tCO_2),

C_y = electricity consumption in year y (MWh),

EF_y = grid emission factor applied in year y (tCO_2/MWh).

GWh are converted to MWh (×1,000). For each year y:

1. Convert C_y(GWh) → C_y^*(MWh) = $1000 \times C_y$.

2. Point estimate: $E_y = C_y^* \times EF_{central}$.

3. EF sensitivity: $E_{y,low} = C_y^* \times 0.80$; $E_{y,high} = C_y^* \times 0.87$.

4. Sectoral breakdown uses PLN 2024 class shares $p_{y,s}$: $E_{y,s} = p_{y,s} \times E_y$(mass-balance tolerance <0.5%).

where, C_y^* is electricity consumption converted from GWh to MWh; $EF_{central}$ is the central reference emission factor (0.83 tCO_2/MWh); E_y is the calculated gross electricity-related emissions for year y; $E_{y,low}$ and $E_{y,high}$ are the sensitivity estimates obtained using 0.80 and 0.87 tCO_2/MWh, respectively; $p_{y,s}$ is the PLN 2024 electricity-sales share of sector s; and $E_{y,s}$ is the corresponding sectoral electricity-related emissions.

For policy scenarios, annual grid purchases are first reduced by EE/DSM and rooftop-PV displacement. A policy emission coefficient is then applied to the residual purchases. The 0.75 tCO_2/MWh value is a forward-looking policy scenario (a 9.6% decrease from the 0.83 reference), not part of the 0.80–0.87 published-coefficient sensitivity range. Rooftop PV is assumed to displace grid purchases one-for-one on an annual-energy basis; curtailment and storage are not modeled. Loss reduction is retained in the CLD as a proposed system lever but receives no separate numerical credit in the headline results.

2.4 Vegetation carbon uptake (tropical allometry)

The vegetation module uses literature-derived planning rates because no project-specific repeated diameter at breast height (DBH), height, wood density, or survival measurements were collected. Urban-tree removal is represented by a central planning rate of 18 kg CO_2 tree^{-1} yr^{-1} with an 80% effective survival factor, within the broader 10–30 kg CO_2 tree^{-1} yr^{-1} literature range [25]. Restoration/agroforestry blocks use portfolio-specific rates within a common 5–15 tCO_2 ha^{-1} yr^{-1} literature envelope. These are scenario inputs, not measured local sequestration rates.

The Chave allometric model [21] is used here to define the future MRV pathway for biomass stock estimation, not to generate the annual removal values reported in the scenario tables. At a measurement date, above-ground biomass (AGB) and below-ground biomass (BGB) are converted to carbon stock and then to CO_2. Verified annual removal would be calculated from the change in biomass carbon stock between repeated measurements, divided by the measurement interval, with mortality and replanting recorded explicitly [20, 21].

AGB follows the pan-tropical model [21]:

$$AGB = 0.0673 \times (\rho \cdot DBH^2 \cdot H)^{0.976}$$

where,

AGB = above-ground biomass (kg),

ρ = wood density (g/cm^3),

DBH = diameter at breast height (cm),

H = tree height (m).

BGB may be approximated as 0.24 × AGB for planning [20]. Total biomass is converted to carbon using a carbon fraction of 0.47 and then to CO_2 using the molecular-weight ratio 44/12. For MRV, the same plots would be remeasured every 12–24 months so that annualized stock change, rather than a single stock estimate, becomes the basis of verified removal.

$$CO_2,stock = 0.47 \times (AGB + BGB) \times 44/12$$

For provincial scenario planning, the common literature envelopes are 10–30 kg CO_2 tree^{-1} yr^{-1} for urban trees and 5–15 tCO_2 ha^{-1} yr^{-1} for actively growing non-peat secondary forest/agroforestry [25]. The proposed 12,000–24,000 ha and 300,000–500,000 trees are scenario-scale assumptions; this study has not demonstrated that those areas are presently available or secured.

1. Urban trees: scenario calculation = number of trees × 18 kg CO_2 tree^{-1} yr^{-1} × 0.80 effective survival.

2. Restoration/agroforestry blocks: scenario calculation = area × portfolio-specific rate within the 5–15 tCO_2 ha^{-1} yr^{-1} literature envelope.

Three Low/Medium/High portfolios are evaluated as scale scenarios. A temporal ramp of 0.3× in year 1, 0.6× in year 2, 0.8× in year 3, and 1.0× from year 4 onward is used only for scenario illustration. For comparability with the 2026 energy scenario, planting/establishment is assumed to start in 2026; thus, first-year removals equal 0.3× mature annual potential.

2.5 Measurement-reporting-verification

1. Proposed MRV would use permanent plots stratified by intervention type. DBH, height, species/wood density, mortality, and survival would be measured at establishment and every 12–24 months. AGB/BGB and carbon stock would be estimated at each round; verified annual removal would equal the change in CO_2 stock divided by elapsed years [20, 21].

2. Survival and establishment: record annual survival for years 1–3, replanting, and mortality; do not credit removed/dead biomass without an appropriate permanence treatment.

3. Remote sensing is optional corroborative evidence only; no GIS- or NDVI-based prioritization result is claimed in this study.

4. MRV quality may progress from literature/default parameters (planning) to species-specific factors and repeated local plots (verification).

2.6 Causal loop diagram construction and policy synthesis

The CLD is revised to distinguish quantified accounting relationships from proposed causal effects. Solid links represent relationships quantified in this study (grid purchases × coefficient, policy reductions, potential removals, and scenario net balance). Dashed links represent conceptual effects such as UHI–cooling–waste-heat feedback and vegetation cooling, which are not quantified here. Gross electricity emissions, potential vegetation removals, and the scenario net balance are shown as separate nodes. Loss reduction remains conceptual and is not included as an additional numerical reduction.

2.7 Uncertainty and sensitivity

1. Coefficient sensitivity: 0.80–0.87 tCO_2/MWh is reported as a deterministic range spanning the official 2019 JAMALI coefficients documented in Appendix A; it is not a probabilistic confidence interval.
2. Activity uncertainty is separated by data status: 2023–2024 are published historical values, whereas 2025–2026 are scenario projections. No arbitrary ±2% uncertainty is assigned to the historical observations.
3. Vegetation uncertainty is represented transparently by the stated removal-rate ranges and the temporal ramp. No Monte Carlo simulation is used for the reported results.

2.8 Implementation screening and land-feasibility boundary

District-level weighted screening is outside the scope of this study because a complete district input dataset (criteria, weights, scores, and rankings) is not available for transparent reporting and reproducibility. The analysis therefore reports scenario-scale mitigation potentials only. For implementation, candidate sites should subsequently be screened using electricity-demand concentration, public-roof availability, public right-of-way/riparian land, operation and maintenance (O&M) feasibility, and social co-benefits. The proposed 12,000–24,000 ha block areas and tree counts remain scenario assumptions until matched against cadastral/land-use data and existing restoration projects. No geographic information system (GIS) priority map or low-Normalized Difference Vegetation Index (NDVI) result is claimed.

2.9 Data management and reproducibility

The calculation workbook provided in the Appendix records the activity values, reporting basis, grid-coefficient assumptions, policy-scenario calculations, vegetation portfolio inputs, and the temporal ramp. No simulation output is reported because the analysis relies on deterministic scenario and sensitivity calculations only.

3. RESULTS

3.1 Analysis of carbon emissions in the electricity sector using the IPCC approach in the Special Region of Yogyakarta

Table 1 reports the source and reporting basis for each annual activity value. The 2023 BPS value (3,564.23 GWh) is electricity distributed by province [22]. The audited 2024 PLN value (3,893.71 GWh) is electricity sold in DIY and is the projection anchor; the official source is documented in Appendix A. The 2025 scenario applies +4.81% to 2024 [24], giving 4,081.00 GWh. The 2026 scenario applies the 4.2% JAMALI planning growth rate [18], giving 4,252.40 GWh. Table 2 then reports the deterministic sensitivity of the calculated gross CO_2 totals to the published JAMALI coefficient range.

For the 2026 scenario, 4,252.40 GWh × 1,000 = 4,252,400 MWh.

At the 0.83 tCO_2/MWh reference coefficient, gross electricity emissions are 3.529 $MtCO_2$.

The reference coefficient is held constant only for the baseline comparison; it is not claimed to be the observed 2026 grid-average factor.

Figure 1 visualizes the resulting gross electricity-related CO_2 trajectory for 2023–2026 under the stated coefficient sensitivity range.

In the prudent policy scenario, an 8% EE/DSM reduction lowers grid purchases to 3,912.21 GWh; rooftop PV is assumed to displace a further 160 GWh one-for-one, leaving 3,752.21 GWh. Applying the policy coefficient of 0.75 tCO_2/MWh gives 2.814 $MtCO_2$, a 20.3% reduction from the 2026 gross baseline.

Table 1. Electricity activity, reporting basis, reference coefficient, and calculated gross CO_2 emissions, 2023–2026

Year	Electricity (GWh)	Reporting Basis / Source	Reference EF (tCO_2/MWh)	Gross Emissions ($MtCO_2$)
2023	3,564.23	BPS electricity distributed [22]	0.83	2.958
2024	3,893.71	Audited PLN electricity sales (Appendix A)	0.83	3.232
2025*	4,081.00	2024 PLN × 1.0481 [24]	0.83	3.387
2026*	4,252.40	2025 scenario × 1.042 [18]	0.83	3.529

Note: *2025–2026 are scenarios, not observations. The 2023 BPS and 2024 PLN labels differ (distributed vs sold); the 2024 BPS preliminary value of 3,891.18 GWh is within ~0.07% of audited PLN sales, supporting practical consistency. The 0.83 tCO_2/MWh value is the 2019 JAMALI CM ex-ante (OM = 0.75, BM = 0.25) reference coefficient [3], emission factor (EF).

Table 2. Deterministic sensitivity of gross electricity CO_2 to published Java-Madura-Bali (JAMALI) coefficient values

Year	Consumption (GWh)	Emissions at EF = 0.80	Emissions at EF = 0.83	Emissions at EF = 0.87	Unit
2023	3,564.23	2.851	2.958	3.101	$MtCO_2$
2024	3,893.71	3.115	3.232	3.388	$MtCO_2$
2025*	4,081.00	3.265	3.387	3.550	$MtCO_2$
2026*	4,252.40	3.402	3.529	3.700	$MtCO_2$

*Notes: 2025–2026 are scenarios. The 0.80–0.87 values span published 2019 JAMALI coefficients [3] and are used only for deterministic sensitivity; they are not a confidence interval and do not represent updated 2023–2026 observed factors or emission factors (EF).

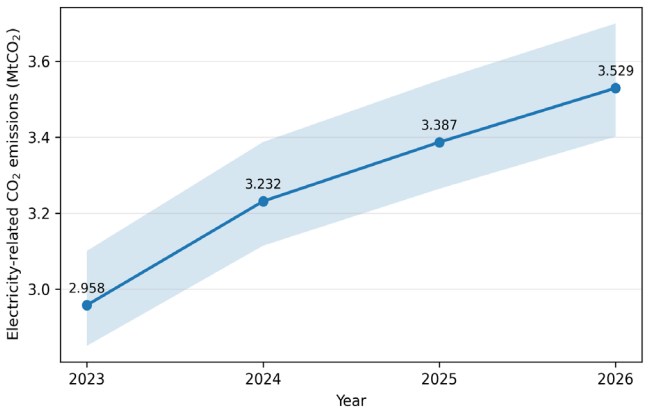

Figure 1. Gross electricity-related CO_2 under the 2019 Java-Madura-Bali (JAMALI) coefficient sensitivity range, 2023–2026

With the 0.83 reference coefficient held constant, calculated gross CO_2 rises from 2.958 Mt in 2023 to 3.529 Mt in the 2026 scenario. This increase is driven by activity in construction; it should not be interpreted as evidence that demand is the empirically dominant causal driver relative to changes in the actual grid mix. Using audited 2024 PLN sales (official source documented in Appendix A), households and business customers remain the largest activity categories; this pattern is consistent with regional demand-forecasting evidence [4].

1. Households: ≈1.739 $MtCO_2$
2. Business/commerce: ≈0.824 $MtCO_2$
3. Social (education, health, etc.): ≈0.300 $MtCO_2$
4. Industry: ≈0.235 $MtCO_2$
5. Government: ≈0.072 $MtCO_2$
6. Public lighting: ≈0.057 $MtCO_2$

The sectoral total ≈3.23 $MtCO_2$ (consistent with the 2024 total; <0.2% difference due to rounding). The dominance of households + commerce suggests that building EE/DSM and rooftop PV on public-campus-retail roofs are the fastest levers to reduce emissions.

Deterministic sensitivity:

1. Using 0.80 instead of 0.83 lowers calculated gross CO_2 by 3.6%; using 0.87 raises it by 4.8%.
2. No ±2% uncertainty is assigned to published 2023–2024 activity data; projection uncertainty for 2025–2026 is represented by their explicit scenario status.
3. No Monte Carlo result is reported; the analysis relies on transparent deterministic coefficient and scenario sensitivities only.

The prudent policy package uses three explicit assumptions. First, EE/DSM = 8% is a policy-planning value rather than a measured DIY program outcome. Second, rooftop PV = 160 GWh/year corresponds to roughly 100 MWp at an 18.3% annual capacity factor and is assumed to displace 160 GWh of grid purchases; a rooftop-inventory feasibility study is still required. Third, EF = 0.75 tCO_2/MWh is a prospective policy coefficient representing approximately a 9.6% decline from the 0.83 reference, motivated by the RUPTL decarbonization direction [18]. It is not an observed factor and is not part of the 0.80–0.87 sensitivity band. Grid-loss reduction is not credited separately in any package.

Table 3 consolidates the 2026 electricity-side baseline and three policy packages (Minimum viable, Prudent, and Accelerated). For each package, the table reports the EE/DSM reduction, rooftop-PV displacement, policy EF, remaining grid purchases, calculated gross CO_2 emissions, and percentage reduction relative to the 2026 baseline. The prudent package is the headline scenario used in Figure 2. Vegetation-removal portfolios are not included in Table 3 and are reported separately in Table 4. The prudent package is illustrated in Figure 2.

Table 3. Electricity-side inputs and calculated outcomes for 2026 policy packages

Package	Inputs	Outcomes
Baseline	EE/DSM 0% PV 0 GWh EF 0.83	Grid 4,252.40 GWh CO_2 3.529 Mt Red. 0.0%
Minimum viable	EE/DSM 5% PV 80 GWh EF 0.79	Grid 3,959.78 GWh CO_2 3.128 Mt Red. 11.4%
Prudent	EE/DSM 8% PV 160 GWh EF 0.75	Grid 3,752.21 GWh CO_2 2.814 Mt Red. 20.3%
Accelerated	EE/DSM 12% PV 250 GWh EF 0.72	Grid 3,492.11 GWh CO_2 2.514 Mt Red. 28.8%

Note: Demand-side management (DSM), photovoltaic (PV), energy efficiency (EE), emission factor (EF).

Figure 2 shows the prudent electricity-side sequence: 8% EE/DSM, 160 GWh/year of rooftop-PV displacement, and a policy coefficient of 0.75 tCO_2/MWh. Gross CO_2 declines from 3.529 to 2.814 $MtCO_2$, a reduction of 0.715 $MtCO_2$ (20.3%). No vegetation removal or loss-reduction credit is included in this figure.

Vegetation removals are reported separately from the 20.3% electricity reduction and are only combined when expressed for the same year (i.e., under an explicit establishment timeline and ramp assumption). At operational maturity (year ≥4), the Low–High portfolios in Table 4 represent 5.7–9.6% of the 2.814 $MtCO_2$ post-energy residual. If establishment begins in 2026 and the year-1 multiplier is 0.3, the first-year potential removal is only 0.048–0.081 $MtCO_2$, giving a combined mitigation potential of approximately 21.6–22.6% relative to the 2026 gross baseline.

Thus, the 20.3% figure is an electricity-emission reduction, whereas larger percentages that include vegetation are scenario net-balance potentials. The two should not be described interchangeably.

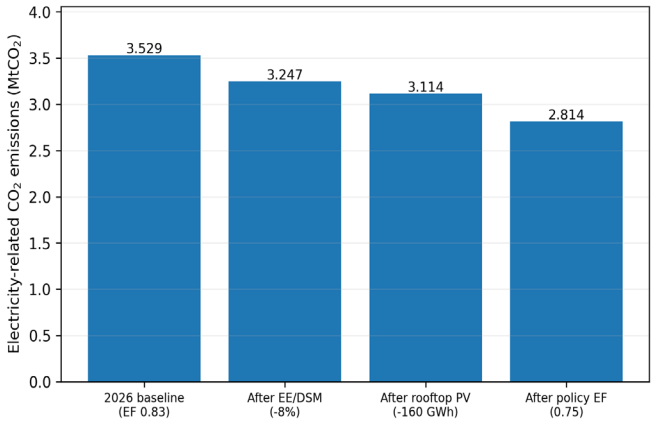

Figure 2. Prudent 2026 electricity-side reduction scenario (vegetation removals excluded)

Table 4. Vegetation-removal planning scenarios and transparent calculation inputs

Portfolio	Row/Park Trees (Units)	Block Area (Riparian + Coastal + Peri-Urban, ha)	Tree Uptake ($ktCO_2/yr$)	Block Uptake ($ktCO_2/yr$)	Total ($MtCO_2/yr$)
Low	300,000	12,000	4–6	155–180	0.16–0.19
Medium	400,000	18,000	5–7	195–235	0.20–0.24
High	500,000	24,000	6–8	229–262	0.235–0.270

Table 4 is retained exclusively for vegetation-removal planning portfolios, thereby separating vegetation assumptions from the electricity policy packages reported in Table 3.

3.2 Potential vegetation carbon removals

The vegetation results in Table 4 are planning estimates, not measured sequestration and not verified offsets. They are reported separately from electricity-side emission reductions. Mature annual potential and first-year ramped potential are both shown so that the time basis is explicit.

3.2.1 Calculation framework and main assumptions

The scenario calculations use literature-derived annual rates. The allometric equations define how future field MRV would estimate biomass stock and its change over repeated measurements; they do not themselves generate the annual rates used here. For urban trees, the central planning input is 18 kg CO_2 $tree^{-1}$ yr^{-1} × 80% effective survival. For restoration/agroforestry blocks, the Low, Medium, and High scale scenarios use 13.0–15.0, 10.8–13.0, and 9.5–10.9 tCO_2 ha^{-1} yr^{-1}, respectively. The declining rate with scale is a scenario assumption representing inclusion of progressively less productive sites; it is not an observed district ranking.

1. Urban-tree calculation: N trees × 18 kg CO_2 $tree^{-1}$ yr^{-1} × 0.80 survival.

2. Block calculation: area (ha) × stated portfolio rate (tCO_2 ha^{-1} yr^{-1}), with all rates constrained to the common 5–15 literature envelope.

Soil carbon and dead wood are excluded. Mangrove-specific enhancement is not credited because no dedicated local methodology or MRV data are available.

3.2.2 Ten-year dynamics and ramp-up

Assuming establishment begins in 2026, potential removal ramps as follows: year 1 = 0.3×, year 2 = 0.6×, year 3 = 0.8×, and year 4 onward = 1.0× mature annual potential. For the Low–High portfolios, first-year potential is approximately 0.048–0.081 $MtCO_2$. At maturity, the ranges are 0.160–0.269 $MtCO_2$/year, equivalent to 5.7-9.6% of the prudent post-energy residual (2.814 $MtCO_2$).

The earlier 10-year cumulative headline values are removed because land availability, planting phasing, and local growth rates have not yet been validated.

3.2.3 Main breakdowns and sensitivities

The dominant uncertainties are the assumed block removal rate, tree survival, and the unverified availability of suitable land. For this reason, Table 4 reports explicit ranges rather than a single point estimate. Before implementation, each portfolio must be matched to cadastral/land-use constraints and existing restoration projects.

3.3 Revised causal loop diagram and policy interpretation

Figure 3 separates three accounting nodes: gross electricity emissions, potential vegetation carbon removals, and the scenario net balance. Solid arrows indicate relationships quantified in this study. Dashed arrows indicate conceptual relationships that require local data before quantification. The R1 return path is explicitly shown as cooling demand → air-conditioning waste heat → UHI → cooling demand. Thus, peak shaving, UHI cooling, and vegetation-induced electricity savings are proposed mechanisms rather than measured results in the present analysis.

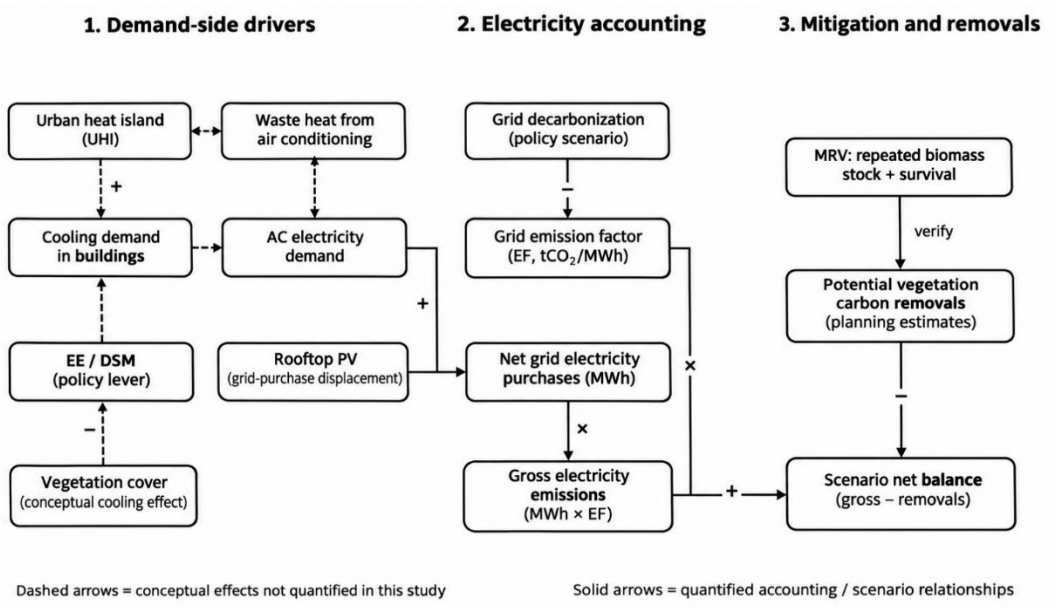

Figure 3. Causal loop diagram (CLD) separating gross electricity emissions, potential vegetation removals, and scenario net balance

The CLD therefore supports policy sequencing without converting every causal link into a numerical claim. Electricity-side results are quantified in Table 3; potential vegetation removals are quantified separately in Table 4; loss reduction, UHI feedback, and cooling co-benefits remain conceptual until local measurements are available.

3.3.1 Core structure

1. R1-UHI–cooling–waste-heat feedback (conceptual). UHI can increase cooling demand; AC operation can reject waste heat back to the urban environment. This loop is not quantified here.
2. B1-Efficiency & DSM (quantified in policy scenarios). Reduces annual grid purchases through an explicit EE/DSM percentage.
3. B2-Rooftop PV (quantified in policy scenarios). Annual PV generation is assumed to displace an equal quantity of grid purchases; peak-shaving effects are not quantified.
4. B3-Grid decarbonization (policy scenario). A lower scenario coefficient is applied to residual grid purchases; 0.75 is not an observed 2026 factor.
5. Vegetation cooling (conceptual). Potential microclimate and cooling-demand effects are shown with dashed links and are not credited in the electricity calculations.
6. Potential vegetation removal. Literature-based planning estimates are subtracted only in an explicitly labeled scenario net balance; they are not verified offsets.
7. Loss reduction (conceptual in this study). Although loss reduction could reduce upstream generation required for a given delivered load, it is not separately credited in the quantified scenarios to avoid double counting with the activity data basis (sales/distribution) and the applied grid coefficients.

Adoption enablers such as public awareness and green finance remain qualitative policy considerations.

3.3.2 Policy pathway from the causal loop diagram

1. Phase 1 (0–2 years): prioritize measurable EE/DSM programs and rooftop PV where technical feasibility is demonstrated.
2. Phase 2: pilot vegetation projects only after land availability, tenure, species, survival, and MRV plans are confirmed.
3. Phase 3: update the grid coefficient with newer official data and quantify network-loss interventions separately from the grid factor.

Suggested implementation KPIs include:

1. EE/DSM: verified annual kWh savings against a defined baseline.
2. PV: installed MWp, measured annual generation, and verified grid-purchase displacement.
3. Grid: updated official coefficient and renewable-generation share.
4. Vegetation: surviving trees, mapped project area, repeated biomass stock, and annualized ΔCO_2 stock.
5. Losses: feeder-level technical/non-technical loss indicators, reported separately.
6. Adoption: participation and finance indicators, without treating them as emission reductions.

The three electricity-side policy packages are quantified in Table 3; vegetation scenarios are not embedded in those percentages.

Key implementation risks include rebound, rooftop-PV feasibility/curtailment, delayed grid decarbonization, vegetation survival, and land availability. These risks should be monitored with program-specific triggers rather than assumed to be captured by the headline scenario percentages. Co-benefits such as thermal comfort, biodiversity, and flood mitigation are plausible but are not quantified in this study. Accounting boundary:

Gross electricity CO_2 = grid purchases × grid coefficient. Potential vegetation removals are a separate planning ledger. Scenario net balance = gross electricity CO_2 after electricity-side policy − potential vegetation removals for the stated time horizon. Loss reduction, UHI cooling, and peak shaving are not separately credited in the reported numerical results.

Implementation implication: the quantified electricity packages should be treated as scenario targets that require verification of realized EE/DSM savings, rooftop-PV generation, and updated grid emission factors. Vegetation portfolios should proceed only after land availability, tenure, species selection, survival management, and MRV arrangements are confirmed.

4. DISCUSSION

The results should be interpreted as scenario analysis rather than an audited mitigation inventory. The prudent electricity package reduces calculated gross 2026 CO_2 by 20.3% under explicit assumptions, while vegetation contributes a separate potential removal whose magnitude depends on portfolio scale and time since establishment. This distinction is consistent with RUED/RUPTL policy direction while avoiding the earlier conflation of electricity reduction, grid-factor change, loss reduction, and offsets [18, 19].

Nature-based carbon literature reinforces the need for explicit project boundaries, additionality, permanence, and monitoring [8-10]. In the present study, these requirements are not yet satisfied for specific DIY projects; therefore, the vegetation quantities are planning estimates only. The proposed 12,000–24,000 ha and tree counts must be validated against land availability and existing projects before any crediting or implementation claim is made.

Evidence of over-crediting risks in forest-offset programs [8] supports the conservative accounting boundary adopted here: gross electricity reductions are reported first, and potential removals are shown separately. Conversely, evidence of positive spillovers [10] indicates that future project evaluation should examine effects both inside and outside formal boundaries rather than assuming either leakage or benefit.

The literature also shows that species and site selection can materially affect urban-forestry performance [11]. However, without local species-specific growth measurements, the present portfolio rates should not be interpreted as local empirical sequestration coefficients. Repeated biomass measurements are required to move from planning estimates to MRV-based removal.

The CLD adds policy value by showing where quantified accounting ends and conceptual system behavior begins. In particular, vegetation cooling, peak shaving, and loss reduction are represented as conceptual links and are not quantified or credited in the reported results due to the absence of local supporting data. This makes the framework more reproducible and reduces the risk of double counting. From an implementation perspective, evidence from Pakistan links national climate policy to firms' sustainable investment, with environmental regulation and media attention shaping this relationship [26]. Evidence from Chinese firms associates low-carbon awareness with soft, but not hard, low-carbon

behaviors, highlighting the distinction between awareness and substantive action [27].

Uncertainty is dominated by model structure and scenario choice rather than a single probabilistic error term. The 2019 JAMALI coefficient is stale for a 2023–2026 application; 2025–2026 electricity activity is projected; 0.75 is a policy coefficient; and vegetation rates and land areas are scenario assumptions. These limitations are now made explicit rather than summarized through an unsupported Monte Carlo interval.

Vegetation may also provide cooling, biodiversity, flood-mitigation, and air-quality co-benefits, but these outcomes were not measured in this study and are therefore presented as future evaluation dimensions rather than quantified findings.

This study has four principal limitations. First, the 0.83 tCO_2/MWh coefficient is a 2019 JAMALI CM ex-ante reference rather than a contemporary provincial average. Second, 2025 and 2026 electricity values are scenarios, with 2025 extrapolated from a half-year local growth signal and 2026 anchored to the JAMALI regional RUPTL growth assumption. Third, vegetation removal rates and areas are literature-based planning assumptions without local repeated biomass measurements or land-suitability verification. Fourth, the CLD is conceptual and does not dynamically simulate UHI, cooling, peak load, or loss-reduction effects.

Future work should update the grid coefficient with the latest official average value, replace provisional demand projections with observed provincial sales, conduct a cadastral/land-suitability assessment, and establish permanent vegetation plots for repeated biomass-stock measurements. Only after those steps should vegetation quantities be considered for verified MRV or offset claims.

5. CONCLUSIONS

Using a constant 0.83 tCO_2/MWh reference coefficient, calculated gross electricity CO_2 increases with electricity activity by construction. For the 2026 scenario based on 4.2% JAMALI growth, gross emissions are 3.529 $MtCO_2$. The prudent electricity-side package (8% EE/DSM, 160 GWh rooftop-PV displacement, policy EF 0.75) lowers this to 2.814 $MtCO_2$, a 20.3% reduction. Vegetation is reported separately: mature Low-High portfolios have a planning potential of 0.160–0.269 $MtCO_2$/year (5.7–9.6% of the post-energy residual), but if establishment begins in 2026, the assumed first-year 0.3 ramp yields only 0.048–0.081 $MtCO_2$. The resulting first-year combined mitigation potential is therefore approximately 21.6–22.6%, not 25–27%. These vegetation values are planning estimates, not verified offsets.

The main methodological contribution is the explicit separation of gross electricity emissions, electricity-side policy reductions, potential vegetation removals, and the scenario net balance, together with transparent identification of historical data, projected activity, published grid coefficients, and policy assumptions. This accounting discipline makes the framework more reproducible while defining clear next steps for updated grid factors, land-feasibility analysis, and field-based vegetation MRV.

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DATA AVAILABILITY

The numerical inputs and calculations used for Tables 1–4 and Figures 1 and 2 are provided in Appendix A. The workbook records source/basis, formulas, policy assumptions, vegetation-rate ranges, and the temporal ramp. No Monte Carlo simulation output is included because this study does not conduct a Monte Carlo analysis.

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DECLARATION ON THE USE OF GENERATIVE AI AND AI-ASSISTED TECHNOLOGIES

The authors used generative artificial intelligence (AI) as a language-assistance tool during the preparation of this manuscript. Specifically, AI-assisted technologies were used to improve the clarity, grammar, readability, and academic presentation of the text. The conceptualization of the study, research design, methodology, data analysis, interpretation of the results, scientific conclusions, and all final editorial decisions were undertaken solely by the authors.

The authors carefully reviewed, verified, and edited all AI-assisted outputs and accept full responsibility for the accuracy, originality, and integrity of the content. No generative AI or AI-assisted technology was used to generate or fabricate research data, experimental results, analyses, figures, references, or scientific conclusions.

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NOMENCLATURE

AC	air conditioning
AGB	above-ground biomass, kg
BGB	below-ground biomass, kg
C	carbon stock
CDH	cooling degree hours
CLD	causal loop diagram
DBH	diameter at breast height, cm
DSM	demand-side management
EE	energy efficiency
EF	grid emission factor, tCO_2/MWh
H	tree height, m
MRV	measurement, reporting, and verification
MWh	megawatt-hour
PV	photovoltaic

ROW	right-of-way
RUPTL	Electricity Supply Business Plan
UHI	urban heat island
ρ	wood density, g/cm³

APPENDIX

Appendix A. Supporting Scenario Inputs and Reproducible Calculations

Tables A1–A3 document the activity-data basis, electricity-side policy-package calculations, vegetation-removal planning inputs, temporal ramp, and methodological clarifications used to reproduce the reported scenario results.

Primary data sources used for the scenario calculations are: the official 2019 JAMALI grid-emission-factor table (https://gatrik.esdm.go.id/assets/uploads/download_index/files/96d7c-nilai-fe-grk-sistem-ketenagalistrikan-tahun-2019.pdf), PLN Statistics 2024 (https://web.pln.co.id/statics/uploads/2025/07/Statistik-PLN-2024-Audited-Indo-Eng-Final-Compressed-update-sheet.pdf), BPS provincial electricity-distribution statistics (https://www.bps.go.id/id/statistics-table/2/ODU5IzI%3D/listrik-yang-didistribusikan-menurut-provinsi-), and the official RUPTL 2025–2034 page (https://www.pln.co.id/ruptl-en).

Table A1. Electricity activity data and reporting basis

Year	Electricity (GWh)	Reporting Basis / Status	Reference EF (tCO_2/MWh)	Gross CO_2 (Mt)	Source
2023	3,564.23	BPS electricity distributed / Published	0.83	2.958	BPS electricity statistics
2024	3,893.71	Audited PLN electricity sales / Published	0.83	3.232	PLN Statistics 2024
2025*	4,081.00	2024 PLN × 1.0481 / Scenario	0.83	3.387	Local H1 2025 growth signal
2026*	4,252.40	2025 scenario × 1.042 / Scenario	0.83	3.529	RUPTL JAMALI planning growth

Table A2. Electricity-side 2026 policy packages

Package	EE/DSM (%)	PV Displacement (GWh)	Policy EF (tCO_2/MWh)	Remaining Grid Purchases (GWh)	Gross CO_2 (Mt)	Reduction vs. Baseline (%)
Baseline	0	0	0.83	4,252.40	3.529	0.0
Minimum viable	5	80	0.79	3,959.78	3.128	11.4
Prudent	8	160	0.75	3,752.21	2.814	20.3
Accelerated	12	250	0.72	3,492.11	2.514	28.8

Note: Calculation logic for Table A2: After-EE grid purchases = Baseline × (1 − EE/DSM). Remaining grid purchases = After-EE purchases − PV displacement. Gross CO_2 = Remaining grid purchases × 1,000 × Policy EF ÷ 1,000,000. Reduction (%) = 1 − Gross CO_2 / Baseline CO_2. Rooftop PV is assumed to displace annual grid purchases one-for-one. No separate numerical credit is assigned to grid-loss reduction.

Table A3. Vegetation-removal planning portfolios

Portfolio	Trees	Tree Rate (kg CO_2 $tree^{-1}$ yr^{-1})	Survival	Tree Removal (kt CO_2/yr)	Block Area (ha)	Block Rate (t CO_2 ha^{-1} yr^{-1})	Block Removal (kt CO_2/yr)	Mature Total (Mt CO_2/yr)
Low	300,000	18	0.80	4.32	12,000	13.0–15.0	156.0–180.0	0.160–0.184
Medium	400,000	18	0.80	5.76	18,000	10.8–13.0	194.4–234.0	0.200–0.240
High	500,000	18	0.80	7.20	24,000	9.5–10.9	228.0–261.6	0.235–0.269

Note: Temporal ramp used for scenario illustration: Year 1 = 0.3×, Year 2 = 0.6×, Year 3 = 0.8×, and Year 4+ = 1.0× mature annual potential. These vegetation values are planning estimates, not measured MRV outcomes or verified offsets.

Accounting boundary and key parameter notes:

- 0.83 tCO_2/MWh: 2019 JAMALI CM ex-ante coefficient using OM = 0.75 and BM = 0.25; reference coefficient, not an observed 2023–2026 average.
- 0.80–0.87: Deterministic sensitivity spanning published 2019 JAMALI coefficients; not a confidence interval.
- 0.75 policy EF: Forward-looking policy scenario; not part of the 0.80–0.87 sensitivity range.
- 2025 activity: Provisional extrapolation of the 4.81% first-half DIY growth signal to the full-year 2024 PLN baseline.
- 2026 activity: Uses the 4.2% JAMALI regional RUPTL planning growth; not the 5.3% national average.
- Vegetation rates: Literature-based planning inputs; not locally measured annual sequestration.
- Land areas: 12,000–24,000 ha are scenario assumptions and require land-suitability/project matching.
- MRV: Verified annual removal requires repeated biomass-stock measurements, survival/mortality records, and annualized stock change.