



Technical Documentation

MASS Report

Methodologies, Assumptions, Scenarios, and Sensitivities

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Key message

NetZero Brasil NetZero Brazil is an open, collaborative platform for creating, comparing, and visualizing pathways for Brazil to reach net-zero or negative greenhouse gas emissions by mid-century. .

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Acronyms and abbreviations

Acronym	Meaning
AFOLU	Agriculture, Forestry and Other Land Use
GDP	Gross Domestic Product
GHG	Greenhouse gas
IOM	Input-output model
MACRO	Energy and industrial system optimization model
MASS	Methodologies, Assumptions, Scenarios, and Sensitivities
NZB	NetZero Brasil
SEALS	Spatial Economic Allocation Landscape Simulator

Introduction

1 Introduction

This report, together with accompanying files embedded as links, documents the methods, assumptions, scenarios, and sensitivities developed so far in the Net-Zero Brazil project. An overall summary description of the project is available in the Institutional Document [1]. The goal of this report is to communicate as transparently as possible the foundations of the multiple models underlying the NZB User Platform (accessible at <https://netzero.eco.br>). The Modeling framework (Section 2) provides an overview of each of the models that work in an integrated fashion on the Platform. This is followed by Section 3, Model components and formulation, describing details regarding key design elements of each model, as well as key input assumptions and datasets. The final section, Scenario building (Section 4), explains each of the current 39 variables included in the Platform that a user may vary to create their own scenarios. None of the resulting scenarios should be taken as predictions of the future. Rather, scenarios are designed to help decision makers see more clearly how transition pathways would need to be shaped to achieve desired objectives.

Finally, this is the first edition of the MASS document, and the team will update it on a regular basis as the capabilities of the NZB models and Platform are improved and enhanced. Comments, suggestions, and criticism from readers are welcome and will help identify necessary improvements.

Modeling framework

2 Modeling framework

2.1 Models and integration

The NZB modeling workflow is structured around an integrated set of 8 computational tools. Each tool has a defined role, input data, output data, temporal resolution, spatial resolution, and interface with other tools.

Energy Pathways - energy demand accounting

Purpose. Generate national long-term energy demand scenarios with spatial, sectoral, and technological detail for the industry and buildings sectors.

Typical outputs. Energy demands, equipment stocks, activity levels, and emissions to be offset.

Transportation and agriculture energy demand accounting tool

Purpose. Generate national long-term energy demand scenarios for transportation and agriculture sectors, with spatial and technological detail.

Typical outputs. Energy demands, equipment stocks, activity levels, and emissions to be offset.

Waste accounting tool

Purpose. Calculate yearly waste-sector emissions and energy supply under defined waste-treatment assumptions.

Typical outputs. Waste-sector emissions, methane recovery, energy outputs, and residual emissions.

MACRO - energy supply optimization

Purpose. Find national least-cost energy and industrial decarbonization pathways with spatial, temporal, and technological resolution.

Typical outputs. Capacity, generation, fuel use, emissions, costs, infrastructure deployment, and sectoral supply choices.

MAGPIE_Brazil - land-use and agriculture optimization

Purpose. Global simulation of how agriculture, land demand, food demand, trade, and policies interact to shape land-use and environmental outcomes.

Typical outputs. Brazil-specific coarse spatial resolution (0.5 deg) land use patterns: cropland, pasture, restoration, production, land-use change, and emissions/removals.

AFOLU accounting tool

Purpose. Allocates pasture and cropland area across pasture health and crop management systems while estimating emissions and removals.

Typical outputs. Area shares, management classes, emissions, removals, and land-use accounting variables.

SEALS - spatial downscaling

Purpose. Downscale MAgPIE-Brazil land-use projections to high-resolution spatial maps.

Typical outputs. 300m gridded land-use allocation, territorial impacts, and map layers for visualization.

Input-output model - jobs and GDP

Purpose. Estimate socioeconomic effects, including employment, output, and state-level GDP implications.

Typical outputs. Jobs, GDP, sectoral output, regional economic effects.

The structure runs in four sequential steps:

1. Run EnergyPathways (EP), Transportation and agriculture energy demand accounting tool (Transport) and Waste accounting tool (Waste);
2. With the results from above, run MACRO;
3. With the results from all above, run MAgPIE-Brazil;
4. With the results from all above, run the AFOLU accounting tool, SEALS and the input-output model.

2.2 EnergyPathways

Energy Pathways (EP) is an open-source tool that allows the development of models to project demands for energy and industrial commodities [2]. Models can include multi-sector, multi-geography, top-down (*i.e.*, energy and commodities demand projection based on demand history and drivers) or bottom-up (*i.e.*, demand projections based on stock of technologies and service demand) demand scenarios. The EP is used in the NZB project to project the energy demand for the sectors:

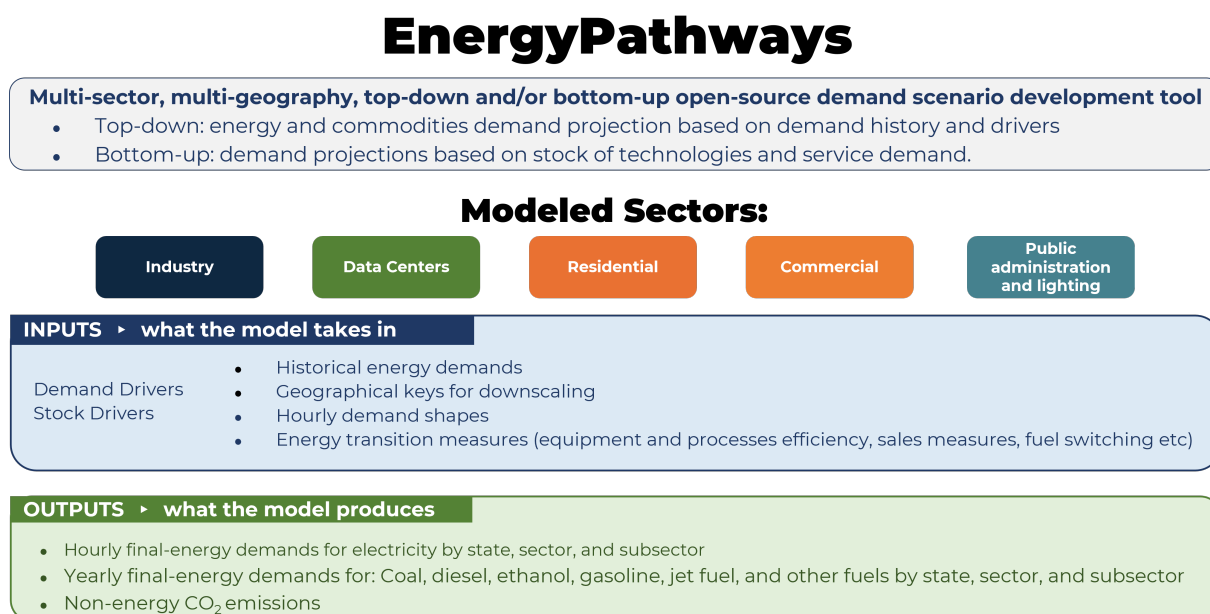


Figure 1: High-level depiction of EnergyPathways modeling framework.

- Industry;
- Buildings:
 - Residential;
 - Commercial;
 - Public lighting;
 - Data centers.

EP is also capable of including transportation and agriculture sectors in demand projections, but in this iteration of NZB's modeling toolset, demand projections for those sectors are developed using a separate tool described in Section 2.3.

The NZB's EP model uses a database created with data from several sources, which will be described further in this report. Data include different scenarios of GDP projection, the effect of global warming on cooling degree days, the effect of population on equipment stock, the industrial activity under different scenarios of economic growth, and others.

Including historical data and energy transition measures (equipment and processes efficiency, sales measures, fuel switching, etc), the model projects at state-level (27), disaggregated by sector:

- Yearly demand for various fuels: Coal, Diesel, Charcoal, Firewood, Natural gas, Sugarcane bagasse, LPG, Ethanol/Gasoline, Heavy fuel oil, Jet fuel, Hydrogen etc;
- Non-energy emissions of CO₂.

These information are fundamental for MACRO, the tool used to optimize the supply side. Other information that are useful to the user can also be addressed, such as equipment stock, substitution costs, energy consumption by subsector and equipment, etc.

Readers are referred to the EP user guide [3] for details on the operational structure of the software. One particularly useful feature is EP's ability to generate profiles of hourly electricity demand. Each sub-sector or equipment may have a different profile of electricity consumption and different projections may change the profile of electricity demand. The model is capable of reconciling different hourly demands in one unique demand at the state level.

2.3 Transport and agriculture energy demand accounting tool

The transport and agriculture energy demand accounting tool, referred as "Transport model" in this document, projects energy demands for transportation and agriculture, complementing the energy demands accounted for in EnergyPathways in the NZB context.

The Transport model was developed by IEMA specially for NZB aiming at mirroring general capabilities of EnergyPathways and feeding into MACRO, while being able to reproduce exact methods established in the Brazilian transport emissions context, mainly the National on-Road Vehicles Atmospheric Emissions Inventory [4].

The Transport model is composed by three parts: road transport, non-road transport, and agriculture. These parts are described, respectively, in sections 3.1.1, 3.1.2 and 3.1.9.

In the current version of NZB, the Transport model does not run on-the-fly inside the integrated modeling structure of NZB. Instead, it runs on Microsoft Excel and all possible sets of results are pre-fed into the integrated modeling infrastructure. As sections 3.1.1, 3.1.2 and 3.1.9 will show, the Transport model is affected by four user-dependent variables: GDP (section 4.1.4), urban mobility (section 4.4.1), vehicle technology (section 4.4.2) and biofuels mandates (section 4.7.4). The combination of all choices for these 4 variables result in 36 possible sets of results, which the integrated modeling infrastructure picks according to the scenario built by the user.

2.4 Waste Tool

The Waste Tool serves as a specialized component of the NZB modeling framework to estimate greenhouse gas emissions and energy generation potential from the treatment of solid waste and wastewater (Figure 2). It takes inputs such as waste generation/reduction rates, recycling rates, composting and anaerobic digestion rates, incineration rates, landfill gas collection efficiencies, wastewater collection rates, and wastewater treatment plant optimization to calculate emissions and energy outputs in different waste management scenarios. This is done by breaking down solid waste streams into anaerobic digestion, composting, open burning, incineration, and solid waste disposal sites, and wastewater streams into domestic and industrial treatment pathways, associating each

pathway with system-specific emission factors.

Under the NetZero initiative, there was no existing program or platform capable of producing this type of emissions estimate for the waste sector, which made the development of a dedicated tool necessary. The Waste Tool produces waste emissions, the amount of landfill gas and biogas generated, and the amount of electricity produced through incineration, with future versions planned to incorporate investment and operating costs by technology, as well as socioeconomic indicators.

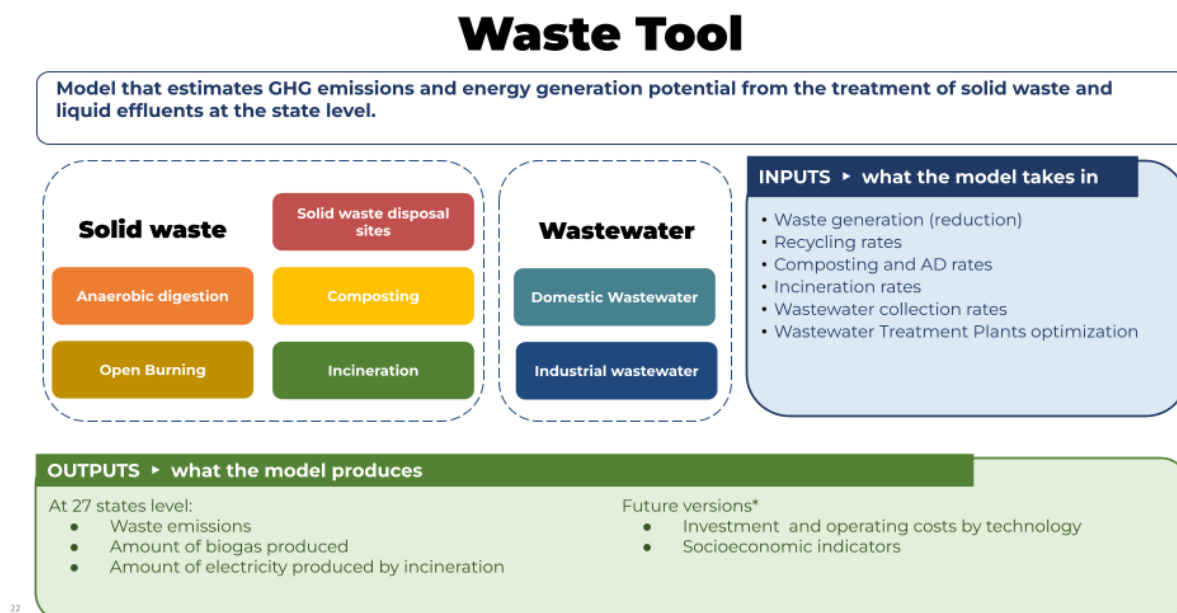


Figure 2: Waste Tool Model

2.5 MACRO

MacroEnergy.jl ("MACRO") is a state-of-the-art, open-source, sector-coupled, high-performance, highly-configurable energy and industrial systems modeling framework for co-optimizing system design and operation (Figure 3). The MACRO model has been developed collaboratively by researchers from Princeton, MIT, NYU, the European Institute on Economics and the Environment, and elsewhere. It was first released in 2025 [5].

With the capability to incorporate a wide range of energy conversion, transmission, and storage technologies, MACRO finds the least-cost combination of technologies that meets exogenously-specified final-energy demands under exogenously-specified resource, capacity expansion, and/or policy constraints. For the NZB project, state-by-state final-energy demands are provided to MACRO from EnergyPathways and the Transport model. Resource constraints include state-specific cost-supply curves for fossil fuels, several biomass feedstocks, solar PV electricity, wind electricity, CO₂ storage, and others. Technology-specific caps on new capacity expansion rates can be set to reflect limiting physical and/or socio-political factors. Policy constraints can include specified carbon dioxide emissions reduction trajectories, limits on biofuel blending, and others.

MACRO

State-of-the-art, open-source, bottom-up, sector-coupled model for high spatial and temporal resolution modeling of least-cost national or regional energy and industrial system transition pathways.

Incorporating all key technology investment options, MACRO finds least-cost technology transition pathways to meet projected final-energy demands under exogenous resource, emissions, and other constraints.

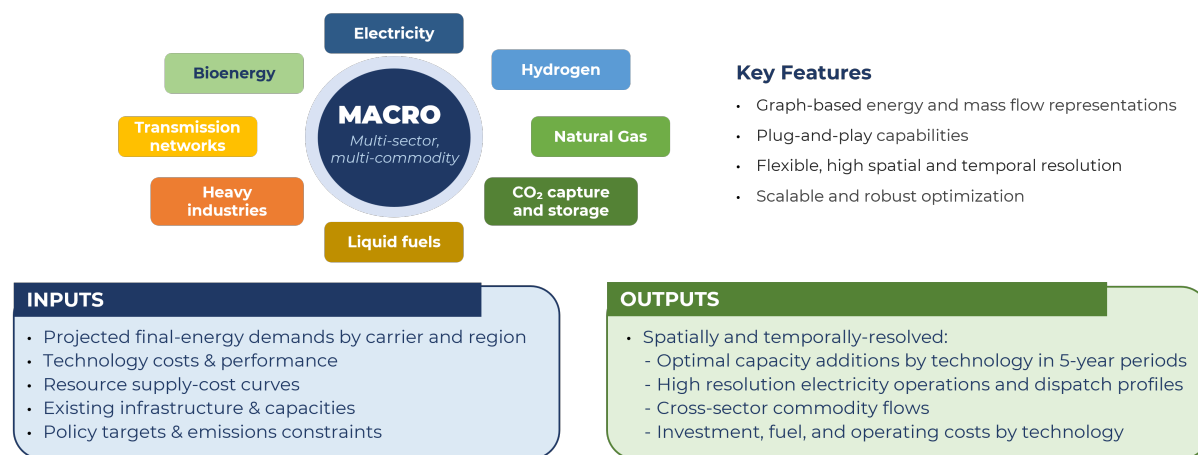


Figure 3: High-level depiction of MacroEnergy.jl ("MACRO") modeling framework.

2.5.1 Spatial Resolutions

Figure 4 shows an example of technology and commodity linkages in MACRO for a single spatial zone (left panel) and for a multi-zone system with inter-zonal connections (right panel). MACRO's design enables different spatial resolutions for different features of the energy system. Most of the NZB model features, for example installed electricity generator capacities and operations and biomass energy conversion capacities, are modeled at state-level resolution (27 zones for Brazil).

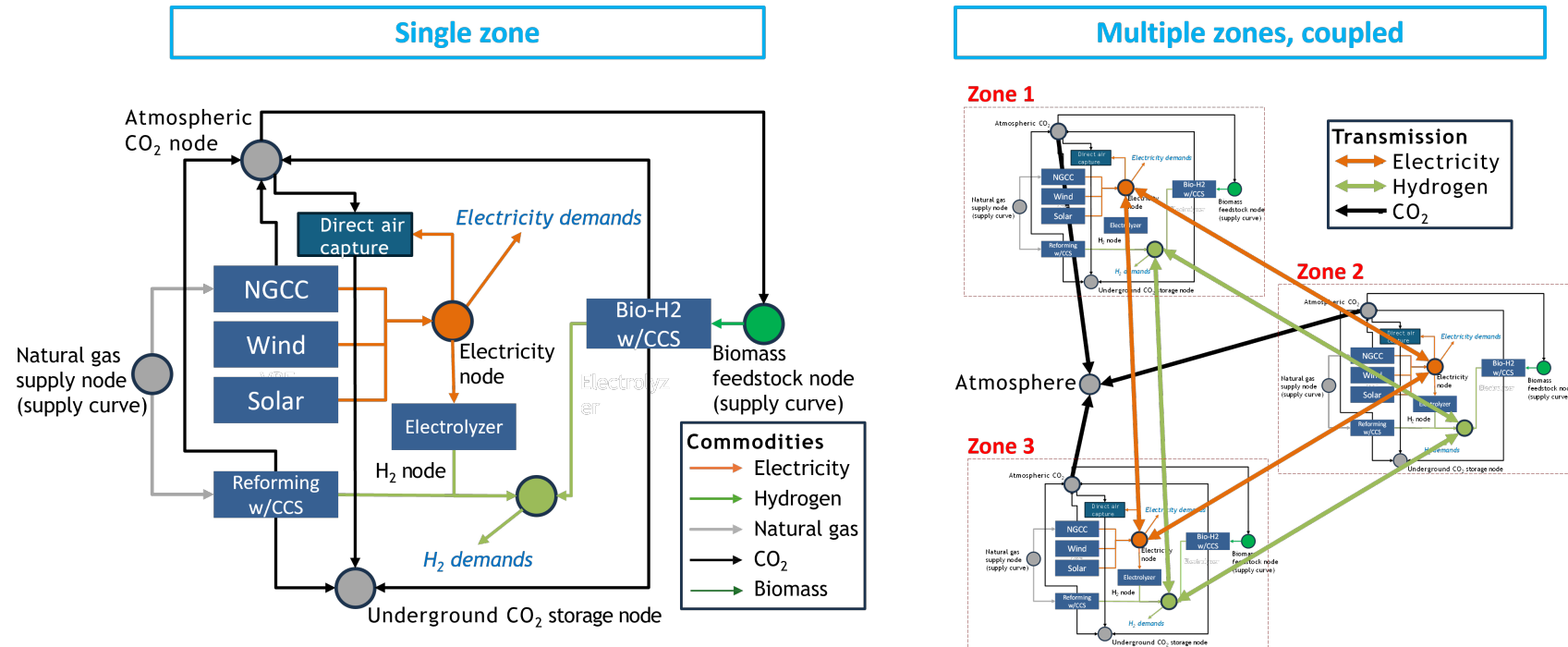


Figure 4: Illustrative, simplified depiction of a single-zone energy supply system structure (left) and of multiple zones with inter-zonal commodity exchanges (right).

For certain sectors and technologies, state-based resolution does not appropriately capture the underlying physical constraints governing the sector. These include hydropower generation, CO₂ storage, and electricity transmission, each of which is instead represented using a zonal structure defined by the sector's own physical characteristics rather than administrative boundaries, as summarized briefly here and elaborated in Section 3.2.

Hydropower is represented across a set of 15 river-basin-defined zones, reflecting the fact that hydrological availability and cascading dam operation are governed by watershed boundaries rather than administrative boundaries. Hydropower capacity is also disaggregated into run-of-river and reservoir-based assets. The largest basins by combined installed capacity today are Amazonas (approximately 23.7 GW), Paraná (approximately 13.6 GW), Tocantins (approximately 13.0 GW), São Francisco (approximately 10.6 GW), and Paranaíba (approximately 8.3 GW).

CO₂ storage is likewise represented across a distinct set of zones defined by the physical extent of sedimentary basins identified as geologically suitable for CO₂ storage in Brazil. Within the current NZB MACRO configuration, CO₂ storage capacity is distributed across 10 such basin-level zones. Storage capacity is highly concentrated among a small number of these. The Paraná basin and the Santos basin together account for roughly 95% of total estimated storage capacity.

Electricity transmission in MACRO is represented using a zonal structure that reflects the physical topology of Brazil's National Interconnected System (SIN) rather than administrative state boundaries. This approach is consistent with documents elaborated by the National Electric System Operator (ONS), such as the Medium-Term Electrical Operation Plan (PAR/PEL) and Grid Procedures – Module 3 – Operation Planning [6]. Within the current NZB MACRO configuration, transmission is disaggregated into seven such zones: four aggregate regional subsystems – North (N), Northeast (NE), Southeast/Center-West (SE), and South (S), together with three additional nodes representing the two major generation complexes connected to load centers via dedicated transmission infrastructure (Itaipu (ITA) and Belo Monte (BM)) and a dummy node at Imperatriz (IMP) in Maranhão that serves as an interconnection point among the Southeast/Center-West, North, and Northeast subsystems.

Figure 5 summarizes the heterogeneous zonal structures adopted in our study. Although the zonal definitions differ across sectors and layers, the system as a whole remains interconnected across zones through a base definition of which states are associated with each zone, allowing commodities and information to flow consistently between sectors despite their differing spatial resolutions. In general, higher spatial resolutions entail greater computation burden. The spatial resolutions adopted in the NZB work produce capacity planning and operational results at socio-politically meaningful scales with acceptable model run times.

2.5.2 Temporal Resolution

Energy system optimization planning models fundamentally aim to determine optimal investment and operational decisions over time. To accurately represent system behavior, models require sufficient temporal resolution to capture variations in renewable resource availability, energy demand patterns, and storage operation. Ideally, this representation would be performed at hourly resolution over each modeled year. However, explicitly modeling 8,760 hours across all resource availabilities, technology and infrastructure options, and zonal regions is computationally complex and often intractable.

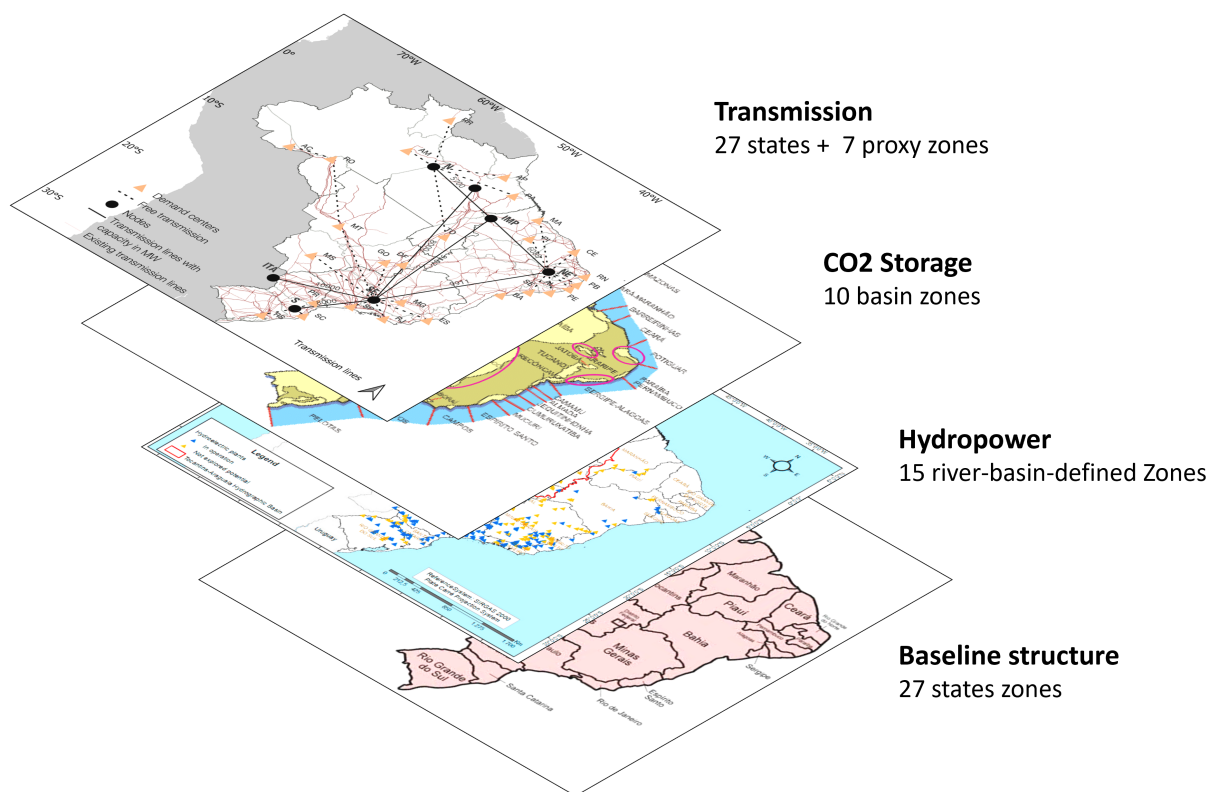


Figure 5: *Heterogeneous spatial resolution adopted across sectors in MACRO, shown as layered zonal structures*

We adopt Time Domain Reduction (TDR) to address this trade-off between temporal fidelity and computational tractability [7]. The fundamental principle of TDR is to reduce the temporal dimensionality of the optimization problem while preserving the operating conditions most relevant to system-level decision making. Rather than representing every hour of the year explicitly, the annual time horizon is approximated using a limited set of representative periods, typically defined as representative days or weeks. These periods are selected to capture the dominant temporal characteristics of the system, including seasonal variations in renewable resource availability, periods of peak demand, and prolonged low-renewable conditions. Each representative period is assigned a weighting factor corresponding to the number of actual periods it represents throughout the year. Annual system costs and operational outcomes are reconstructed through weighted aggregation of representative period outcomes. For example, a representative winter week corresponding to fifteen actual weeks contributes proportionally to annual cost and operational calculations.

While specific implementations of TDR vary across modeling platforms, TDR has been widely shown to yield substantial gains in computational tractability for energy system planning problems while maintaining temporal fidelity [8]. The effectiveness of TDR is based on the observation that long-term investment decisions are primarily driven by a relatively limited number of distinct operating conditions rather than by every individual hour of the year. By selecting representative periods that adequately span this diversity, TDR preserves the temporal information most relevant to capacity expansion and operational planning while avoiding the computational burden associated with repeatedly modeling similar system conditions.

Within the current NZB MACRO modeling framework, twelve representative weeks are used to ap-

proximate the annual temporal profile. Although this reduced representation substantially decreases computational requirements relative to full-year hourly modeling, the number and length of representative periods remain significant contributors to overall model complexity, and their selection accordingly constitutes an important modeling consideration to balance computational efficiency against solution fidelity while enabling responsive and interactive model execution.

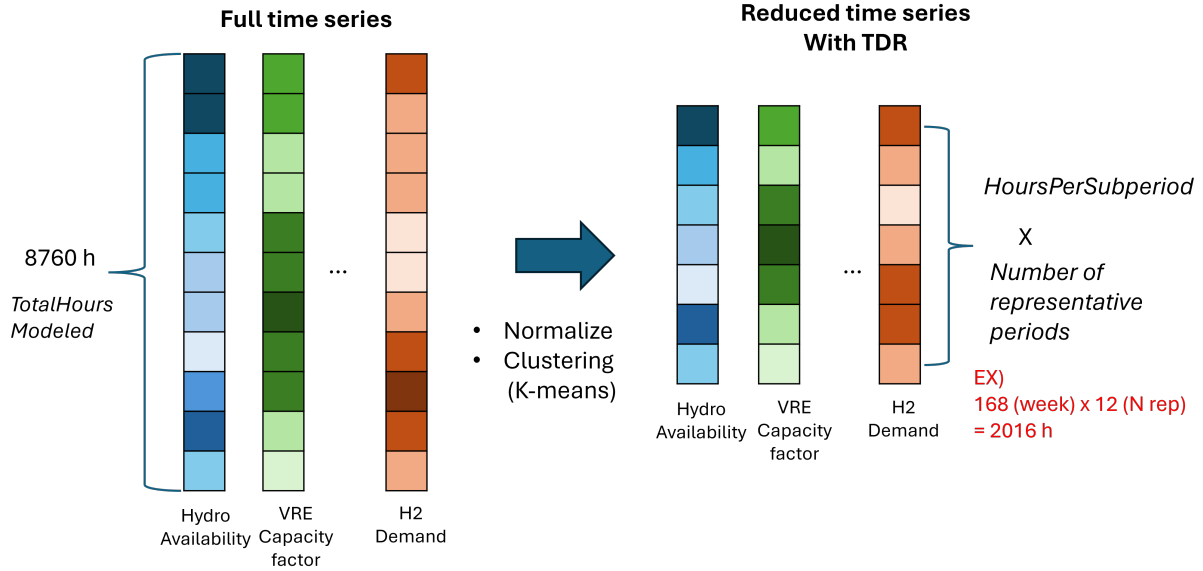


Figure 6: Conceptual example of the TDR process applied to multiple time-series datasets

As illustrated in Figure 6, representative periods are constructed by applying K-means clustering [9] to all explicitly time-resolved input data defined over the full 8,760-hour annual horizon, including hourly electricity and hydrogen demand, hydropower availability, solar and wind capacity factor, and biomass supply cost curves, grouping time steps that exhibit high similarity into representative periods. While a range of period lengths is in principle feasible, a weekly resolution is adopted in this study, as it captures intra-week variability in demand and resource availability with greater fidelity than shorter periods while still preserving the seasonal patterns that longer periods would tend to obscure, thereby offering a balanced trade-off between solution fidelity and computational efficiency.

The reduced temporal representation is implemented through a representative period mapping and associated weighting scheme. Each original period within the modeled time horizon is assigned to one representative period through a predefined period map. Consequently, the optimization problem is solved only over the representative periods, while annual quantities are reconstructed through weighted aggregation. If (N) denotes the number of representative periods and (n_i) the number of original periods assigned to representative period (i). The weight, w , associated with representative period (i) is computed as:

$$w_i = \alpha \cdot n_i, \quad \text{where } \alpha = \frac{\text{TotalHoursModeled}}{\sum_{i=1}^N \text{HoursPerSubperiod} \cdot n_i} \quad (1)$$

Accordingly, the contribution of each representative period to annual system quantities is proportional to the number of original periods it represents. Operational costs, energy production, resource consumption, and emissions are therefore evaluated over the representative periods and subsequently aggregated using the corresponding weights. In general, any time-dependent quantity (X) is

reconstructed as:

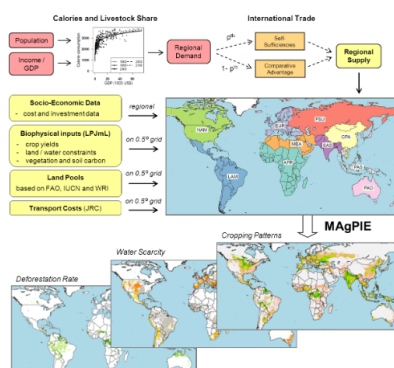
$$\sum_{i=1}^N w_i X_i \quad (2)$$

where (X_i) denotes the quantity evaluated over representative period (i) . This weighting formulation enables the optimization problem to be solved over a substantially reduced temporal domain while preserving consistency between representative-period results and annual system-level quantities. Within the current implementation, the same weighting mechanism is applied consistently across all time-dependent model outputs, including operating costs, commodity flows, resource utilization, and carbon emissions.

2.6 MAgPIE-Brazil

The Model of Agricultural Production and its Impact on the Environment (MAgPIE) is a global land use allocation model that is used in the NZB modeling framework to establish future land-use allocations for Brazil at a coarse spatial scale under different global scenario assumptions. MAgPIE-Brazil takes into account regional economic conditions such as demand for agricultural commodities, technological development, and production costs, as well as spatially explicit data on potential crop yields, land and water constraints (Figure 7)([10]). The model aims to minimize total cost of production globally for given demands, and produce results on specific land use patterns, yields, and total costs of agricultural production at a resolution of $0.5^\circ \times 0.5^\circ$. Regional food energy demand is defined for an exogenously given population in 10 food energy categories, based on regional diets. Future trends in food demand are derived from a cross-country regression analysis, based on future scenarios on GDP and population growth.

MAgPIE-Brazil



MAgPIE Model of **Agricultural Production** and its **Impact on the Environment**

dynamic recursive optimization cost minimization of consecutive time slices with a length of 5-20 years until 2100

3 spatial layers global | 5-20 world regions | 50-2000 spatial clusters

balance biophysical and economic side bringing together biophysical (plant growth, carbon, nutrients, water) and economic (costs, prices, demand, policies) aspects

INPUTS ▶ what the model takes in

- GDP and POP for agricultural products demand
- Potential crop yields
- Production costs
- Production and land use data for calibration
- Policy targets & emissions constraints

OUTPUTS ▶ what the model produces

- Spatially and temporally-resolved
- Optimal production by commodity
- Land Use patterns
- AFOLU emissions
- Yield-increasing technological change
- Socioeconomic indicators

Figure 7: High-level depiction of the MAgPIE-Brazil model framework.

For the base year 1995, total agricultural land is constrained to the area that was actually in agriculture in 1995 within each grid cell, according to the input dataset. For future projections, the model works

on a 5-year time step in a recursive dynamic mode. The link between two consecutive periods is established through the land-use pattern. The optimized land-use pattern from one period is taken as the initial land constraint in the next. If necessary, additional land from non-agricultural areas can be converted into cropland at additional costs and generating GHG emissions (mainly CO₂).

The NZB project uses a version of the global MAgPIE-Brazil model that is specially calibrated using Brazilian national data. The NZB project uses MAgPIE-Brazil [11], a recently developed version of MAgPIE-Brazil developed by researchers at the University of Lisbon and the Potsdam Institute for Climate Impact Research (PIK). MAgPIE-Brazil includes extensive adjustments and calibration to Brazilian national statistics and datasets. It splits Brazil out as a standalone region and replaces the original initialization land use map with a new map derived from national sources, combining MapBiomass annual land cover with the national agricultural census [12, 13], and reconciling both to the model's spatial grid, as described in [14][11]. Several structural improvements have been made to the default global model. In this version, Brazil is given extra weight in a spatial clustering algorithm [15] so it is represented at 58 clusters of similar 0.5° cells rather than the default 13 that would result from a simple splitting it out of LAM with equal weighting. This adjustment allows the model to better capture the heterogeneity of Brazilian agricultural expansion, land-use transitions, and biome-specific dynamics. In addition, the model uses a new implementation of a GHG emissions cap as described in Section 3.

2.7 AFOLU Accounting Tool

The AFOLU Accounting Tool (AAT) is a dedicated accounting component within the NZB modelling framework developed to represent agricultural management and land-condition dynamics that are not explicitly captured by the core land-use modelling system. While MAgPIE-Brazil simulates land-use allocation, agricultural production, and land-use transitions, it does not explicitly represent management heterogeneity within individual land-use classes. For example, pasture areas are not differentiated according to pasture vigor classes, and cropland areas are not allocated among alternative crop management systems. These factors can substantially influence carbon emissions and removals, and the overall mitigation potential of agricultural systems. To address this gap, the AFOLU Accounting Tool was developed as a complementary framework that links land-use projections to management-specific accounting of emissions and removals.

The AAT operates as a post-processing component within the NZB modelling framework. The tool combines projected cropland and pasture extent from MAgPIE-Brazil with scenario-specific assumptions regarding pasture vigor and crop management systems. Cropland areas are allocated among alternative management systems, while pasture areas are distributed across pasture vigor classes. Management-specific emission and removal factors are subsequently applied to estimate carbon dioxide (CO₂) emissions and removals associated with different AFOLU mitigation pathways (Figure 8).

Future versions of NZB may further strengthen the integration between land-use allocation and management representation. In particular, the incorporation of MapBiomass-based information into the SEALS downscaling framework will be evaluated as a potential approach for spatially allocating and projecting pasture vigor classes. Additional efforts will also investigate opportunities to incorporate agricultural management dynamics directly into the land-use and agriculture modelling system,

AFOLU Accounting Tool (AAT)

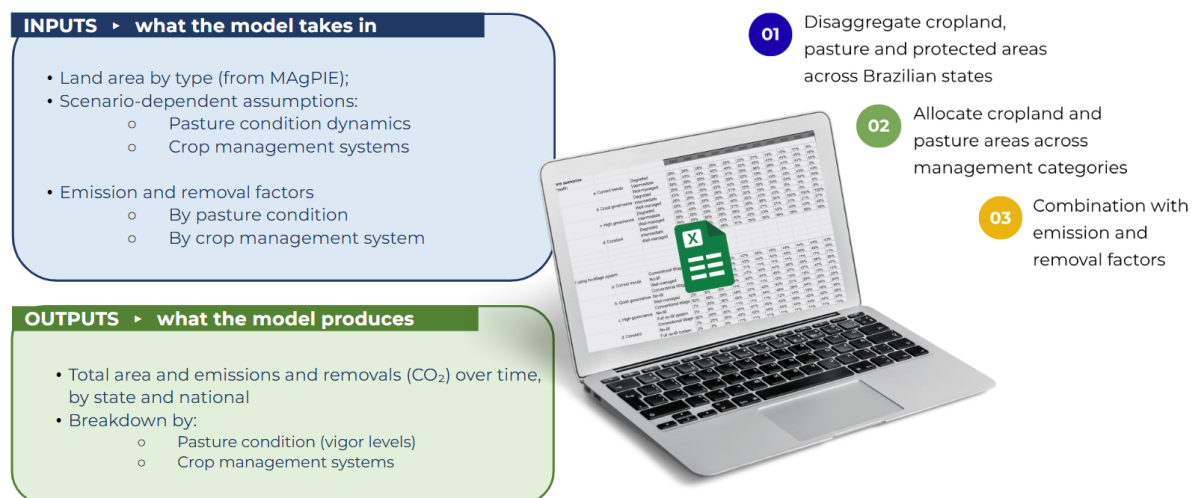


Figure 8: High-level description of the AFOLU Accounting Tool framework.

reducing reliance on ex-post accounting approaches and allowing a more integrated representation of management-related mitigation measures.

2.8 SEALS

SEALS, the Spatial Economic Allocation Landscape Simulator, is a land-use change model that downscales predictions of land-use change from aggregate (regional or coarse-gridded) inputs (such as those produced by MAgPIE-Brazil) to a finer resolution (300m in the current NZB framework) [16]. Its allocation processes are based on empirically calibrated adjacency relationships, physical suitability, and conversion eligibility information (Figure 9). The SEALS model uses trained coefficients from historical land-use change patterns to predict future land-use changes based on adjacency (i.e., whether cropland tends to grow close/far from urban areas). The shape of these adjacency effects is derived for numerous parameters using machine learning algorithms.

For the NZB project, Mapbiomas time series data [12] were used to retrain SEALS for both (i) coefficients typical to SEALS, and (ii) new coefficients relevant to Brazil's net zero policy pathways.

SEALS

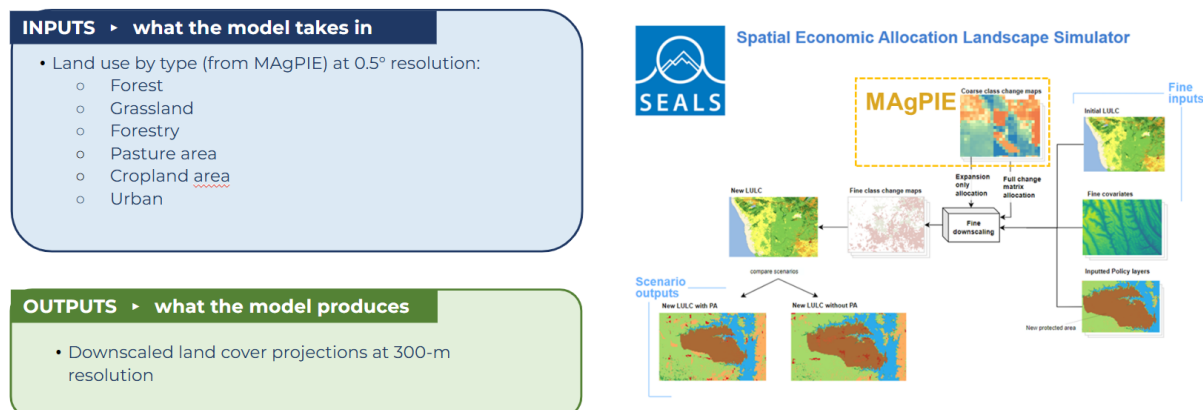


Figure 9: High-level depiction of the Seals model framework.

2.9 Input-Output Model

The Input–Output Model (IOM) is the socioeconomic assessment component of the Net Zero Brazil (NZB) modelling framework. Its purpose is to translate projected changes in energy demand, energy supply, and agricultural production into changes in gross economic output, Gross Domestic Product (GDP), employment, and the regional distribution of economic activity. To this end, input–output analysis represents the economy as an interconnected production network in which each activity purchases goods and services from other activities to produce its own output. Consequently, a change in one activity can propagate through multiple supply chains, generating both direct and indirect economic effects [17].

Within the NZB framework, the IOM links the results generated by Energy Pathways (EP), MACRO, and the Model of Agricultural Production and its Impact on the Environment (MAgPIE) to the Brazilian interregional economic structure. More specifically, EP determines the level and destination of energy demand, whereas MACRO provides information on the technological composition and geographical origin of energy supply. In turn, MAgPIE-Brazil provides projected changes in Brazilian agricultural production associated with the land-use allocations generated under each scenario. Together, these model outputs define the external changes that are translated by the IOM into socioeconomic impacts.

Accordingly, the IOM does not optimize the energy or land-use systems themselves. Instead, it evaluates the socioeconomic consequences of pathways defined externally by EP, MACRO, and MAgPIE-Brazil (Figure 10). The resulting estimates are therefore conditional on the assumptions, scenario definitions, and outcomes of these upstream models.

Because the transition is expected to be spatially heterogeneous, the IOM retains the interregional structure of the Brazilian economy. The current implementation covers all 27 federative units and 29 economic sectors spanning industrial activities, energy production, agriculture, and services, resulting in 783 region–sector activities. Each activity represents a specific sector operating within a given federative unit. This structure allows the model to capture not only sectoral supply-chain effects but also economic spillovers across Brazilian regions.

Input-output model

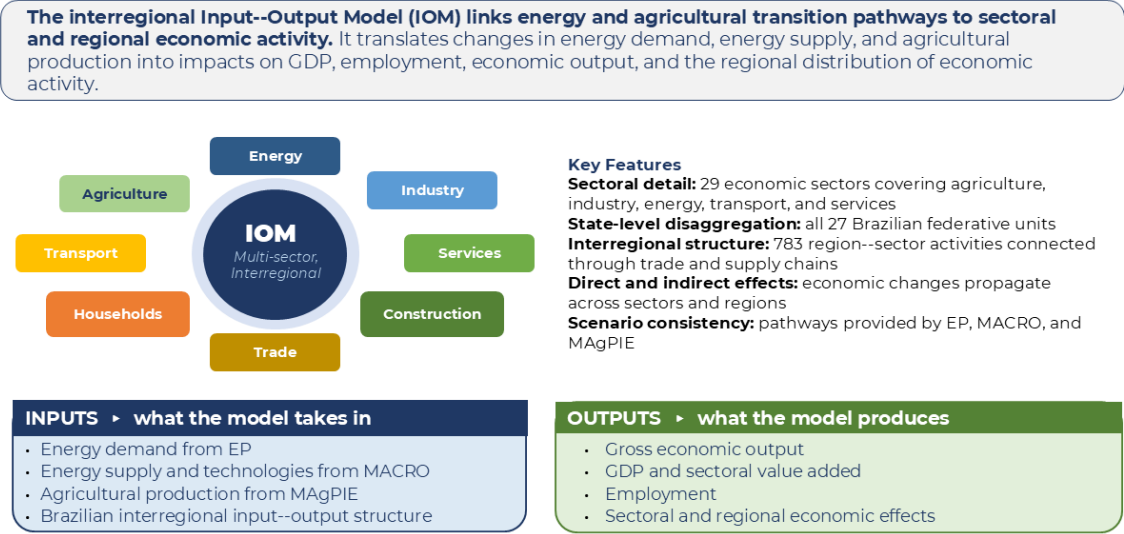


Figure 10: High-level depiction of the Input-Output model framework.

Modules

3 Model components and formulation

This section of the MASS details key assumptions, input data, and operational features of the submodels that make up the NZB framework.

3.1 Energy demand modeling

The energy demand modeling framework is used to project energy demand across all sectors of the Brazilian economy (transport, industry, agriculture, households, commercial buildings, and public facilities) on an annual basis from 2025 to 2050.

Statistics from the National Energy Balance (Balanço Energético Nacional — BEN) [18] are used as the baseline for these projections.

The framework comprises seven sub-models, each using its own methodology to project future energy demand in specific sectors: (i) road transport, (ii) non-road transport and agriculture, (iii) industry, (iv) households, (v) commercial buildings, (vi) data centers, and (vii) public lighting. The methodologies, assumptions, references, and sensitivities used in each of these sub-models are presented in the following sections.

In general, exogenous GDP pathways are used as the main proxies determining future energy demand, based on the historical relationship observed between GDP and energy demand. The model then estimates demand for different energy carriers, including fuels, electricity, and hydrogen. This demand may vary in both magnitude and composition across energy products. For example, under a given scenario of assumptions, road transport may require less total energy than under another scenario to provide the same level of transport service. It could be achieved through a more energy-efficient vehicle fleet. Similarly, in a given scenario, the fleet may rely on a larger share of electricity and a smaller share of ethanol - or vice versa - to meet the same travel demand. All these sort of outcomes depend on the assumptions adopted in each sub-model, as detailed in the following sections.

The resulting energy demands are ultimately passed on to the Macro model, which determines how the required energy demands will be met with optimized (minimized) costs while meeting specified emission reduction goals.

3.1.1 Road transport

The road transport energy demand is calculated by the Transport model (section 2.3). The general framework for projecting road transport energy demand is shown in Figure 11, and the steps illustrated in the figure are described throughout this section.

To provide greater detail and better reflect the Brazilian context, the energy demand projection model for road transport, covering both passenger and freight transportation, is based on the methodology of the National Inventory of Atmospheric Emissions from Road Motor Vehicles [4].

Initially, historical statistics on annual sales of new passenger cars, motorcycles, buses, light commercial vehicles, and trucks were compiled. For each of these categories, the shares of different vehicle sizes and powertrain technologies were also collected on an annual basis, including diesel

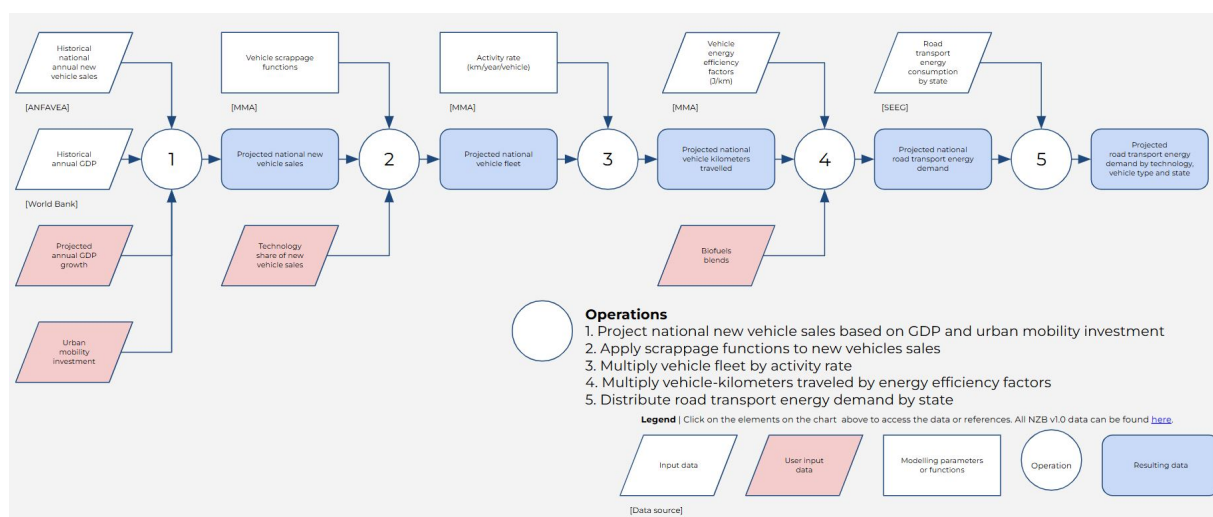


Figure 11: Road transport energy demand projection: input data, operations and resulting data.

engines, gas engines, battery electric powertrains, hydrogen fuel cell electric powertrains, gasoline-only engines, ethanol-only engines, flex-fuel engines, and hybrid powertrains (plug-in or non-plug-in) running on gasoline, diesel, or flex fuel. Based on these data and vehicle scrappage curves, which make it possible to estimate the number of vehicles in each category and technology that are retired from circulation each year according to their respective ages, the circulating vehicle fleet in Brazil was estimated through 2024 (the base year of the model presented here) — see Figure 12.

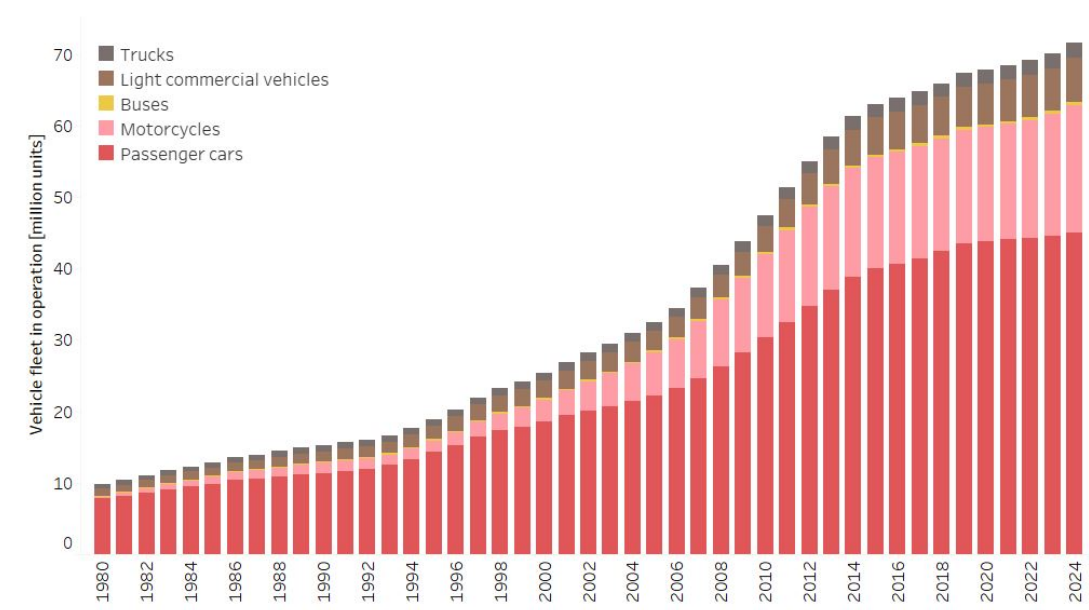


Figure 12: Evolution of the road motor vehicle fleet in Brazil by vehicle category.

As a next step, different approaches were adopted to project vehicle-kilometers, fleet composition, and energy demand for road freight transport (carried out by light commercial vehicles and trucks) and passenger transport (using passenger cars, motorcycles, and buses).

3.1.1.1 Freight transport

All light commercial vehicles and trucks are considered freight vehicles. The historical relationship between the country's GDP per capita and sales of these vehicles is used to estimate future sales for each vehicle size — light commercial vehicles and light, semi-light, medium, semi-heavy, and heavy trucks — based on exogenous GDP and population projections for the years from 2026 to 2050.

Projected sales by vehicle category and size are allocated among different powertrain technologies according to three technology penetration scenarios:

- **Current trend**, characterized by modest fleet technology renewal rates, based on the Ten-Year Energy Plan 2035, prepared by the Brazilian Ministry of Mines and Energy (MME) [19]. The values projected by the MME for the shares of vehicle sales by category and technology are available for 2030 and 2035. To obtain values for the periods 2025–2029, 2031–2034, and 2036–2050, linear interpolation was applied.
- **Medium** penetration of electrified vehicles in new vehicle sales, combined with the continued significant share of internal combustion engine vehicles, as assumed in the São Paulo State Energy Plan 2050 [20]. Since values were available only for 2030, 2040, and 2050, numbers for the intervening years were obtained through linear interpolation.
- **Fast** penetration of battery electric vehicles, following an ambitious scenario developed by the ICCT for 2030, 2040, and 2050 [21]. As in the previous cases, values for the periods 2025–2029, 2031–2039, and 2041–2049 were obtained through linear interpolation.

As an illustrative example, Figure 13 presents, for each of the technology penetration assumptions described above, the shares of battery electric vehicles (BEVs) relative to total light commercial vehicle sales for the years available in the respective references.

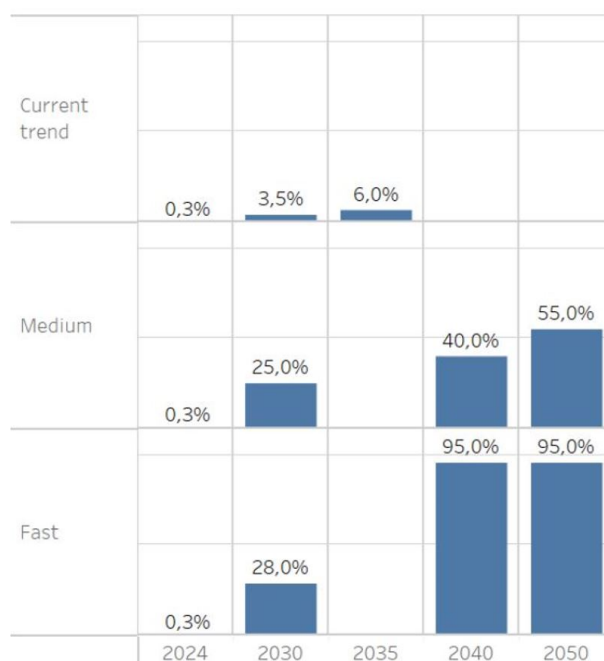


Figure 13: Percentages of sales of battery electric vehicles (BEVs) relative to total light commercial vehicle sales under three distinct road transport electrification scenarios, based on different years available in the references identified in the literature review [19] [20] [21].

By applying vehicle scrappage curves to the pre-existing vehicle stock combined with newly sold vehicles, the evolution of the vehicle fleet from 2025 to 2050 is obtained. Vehicle-use intensity rates (km/vehicle), differentiated by vehicle category, size, and age, are then applied to this fleet [4]. With the resulting annual distance traveled for each vehicle category, size, and powertrain technology, it is possible to estimate demand for different energy sources, including gasoline, ethanol, diesel, biodiesel, electricity, methane, and hydrogen. For this purpose, the fuel consumption factors (J/km) available in the National Road Transport Emissions Inventory are used [4], with a linear decline in these factors through 2050 applied in accordance with the historical trend observed.

3.1.1.2 Passenger transport

For passenger transport, two scenarios define the kilometers traveled by cars, motorcycles, urban buses, and minibuses through 2050, both drawn from the study “Compact Cities Electrified: Brazil” [22]:

1. **2050 Business as Usual**; and
2. **2050 Mode Shift**.

Under the **Business as Usual scenario**, individual road transport by cars and motorcycles is assumed to remain the target of substantial investments by cities and society as a whole, resulting in individual transport activity, measured in passenger-kilometers (p.km), nearly doubling between 2025 and 2050. In contrast, collective transport (urban buses and minibuses) gradually loses ground, increasing by only 7% in passenger-kilometers over the same period.

In the **Mode Shift scenario**, greater priority is given to collective and active mobility in cities, leading to a reversal of this trend: while cars and motorcycles combined would produce only 5% more p.km in 2050 than in 2025, buses would produce 115% more over the same period.

Using these two fixed passenger-kilometer scenarios (Figure 14), the aim is to assess the sensitivity of emissions reductions to policies that either prioritize or do not prioritize collective and active mobility in Brazil.

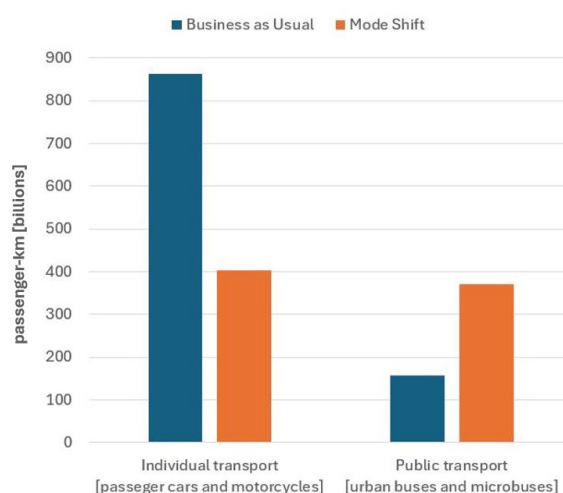


Figure 14: Transport activity (in billion passenger-km) in 2050 for individual modes (cars and motorcycles) and collective modes (urban buses and minibuses), under two different scenarios prioritizing collective and active mobility.

For each of these scenarios, the required sales of each vehicle category are calculated to achieve the projected annual distance traveled through 2050, taking into account average vehicle occupancy rates, as well as annual vehicle scrappage and use-intensity curves [4].

Vehicle sales are allocated among different powertrain technologies under three possible scenarios (Current trend, Medium electrification, and Fast electrification), as described in the previous subsection. Finally, the energy demand required for the projected vehicle stock (fleet) to provide the specified transport service (distance traveled) is calculated, also accounting, where necessary, for the shares of biofuels and fossil fuels in commercial fuels.

It is worth noting that the energy demand for intercity buses follows the same methodology applied to freight vehicles, described in the previous subsection. This is because this vehicle category was not included in the scope addressed by the report “Compact Cities Electrified: Brazil”. Sales of these vehicles, however, are considerably lower than those of motorcycles, passenger cars, and even other bus categories.

3.1.1.3 Distribution of road transport energy demand by Brazilian state

Following the methodology applied by SEEG [23], the estimated energy consumption obtained in the steps described above was disaggregated across each of Brazil’s 27 Federative Units (UF) using state-level fuel sales statistics for the road transport sector in 2024. These data are provided by the National Agency of Petroleum, Natural Gas and Biofuels (ANP), and the following equation represents the approach adopted.

$$Consumption_{fuel,vehicle,year,UF} = Consumption_{fuel,vehicle,year}^{BR} * \frac{Sales_{fuel,UF}^{2024}}{Sales_{fuel}^{2024,BR}} \quad (3)$$

It is worth noting that this approach involves some simplifying assumptions:

- Fuel sales and fuel consumption/demand are considered equivalent.
- The same percentage share of fuel sales in a given state is applied to all vehicles consuming that energy source.
- The distribution of fuel sales across Brazilian states is assumed to remain unchanged through 2050.

For the specific case of electricity and hydrogen demand in road transport, as consolidated data by state are not available, the following state-level shares were used:

- The total amount (in Joules) of gasoline and ethanol sold in each state relative to national sales of these fuels, to allocate electricity and hydrogen demand for light-duty vehicles (passenger cars, motorcycles, and light commercial vehicles);
- The percentage share of diesel sales in each state, to allocate demand for electricity and hydrogen among heavy-duty vehicles (trucks and buses).

3.1.1.4 Hourly distribution of electricity demand from road motor vehicles

To ensure that the electricity system to be modeled by MACRO will be capable of supplying electricity for vehicle charging during every hour of any given day, it is necessary to distribute the annual electricity demand in each state across the 8,760 hours of the year, thereby determining the hourly load profile for the road transport sector.

To achieve this, average hourly electricity demand profiles for vehicles on a weekday and on a weekend day were used [24]. For simplicity, these same profiles were applied uniformly to all days of the year, differentiated only between weekdays and weekends, and were assumed to be the same for all vehicles (Figure 15).

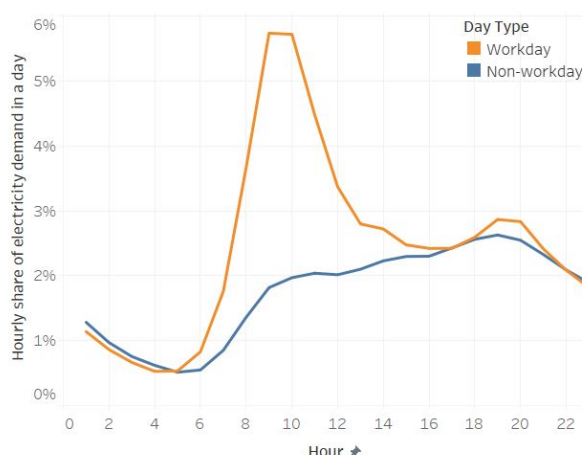


Figure 15: Hourly electricity demand distribution curve for electric vehicle charging over a day [24].

3.1.2 Non-road transport

Non-road transport includes rail, water and air transport. By simplification, these modes of transport are treated as a single group in the current version of NZB and their total energy demand is calculated using the Transport model (section 2.3).

To estimate non-road transport energy demand through 2050 under different projections of Brazilian GDP growth, the energy intensity rate of 2024 was assumed to remain constant. This energy intensity rate was calculated by dividing Brazil's GDP in 2024 [25] by the final energy consumption of electricity and fuels in non-road transport, as reported in the National Energy Balance [18].

The energy mix is considered constant except for the content of sustainable aviation fuel (SAF) in aviation kerosene that is determined by a chosen mandate according to the user variable "biofuels mandates" (see section 4.7.4).

The energy consumption is then allocated by state according to the allocation factors for 2024 calculated by SEEG [23].

Figure 16 summarizes the modeling framework for energy demand in the non-road transport sector.

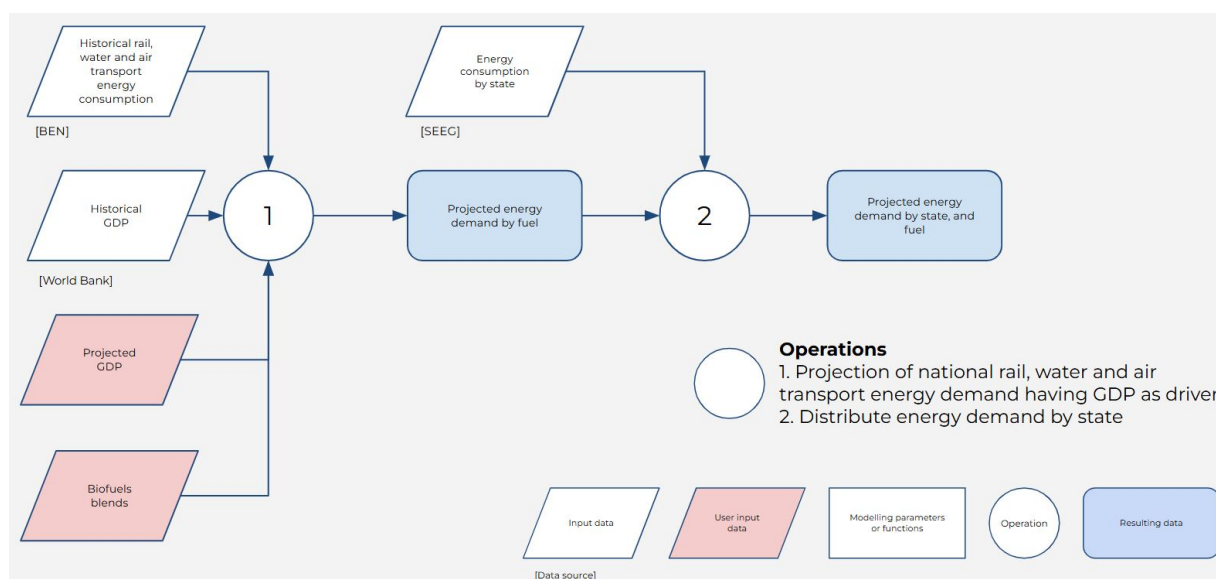


Figure 16: Non-road transport energy demand projection: input data, operations and resulting data

3.1.3 Industry

3.1.3.1 Data base

Industrial energy demand projections begin from energy consumption, production, and value-added statistics available in the Brazilian Energy Balance (BEB) of 2026 for the industrial sectors national database.

The same disaggregation of the industrial sector used in the matrices of the BEB was adopted for this project, *i.e.*: mining and pelletization¹; pig-iron and steel; iron-alloys; non-ferrous and other metals; cement; ceramics; foods and beverages; chemical; paper and pulp; textiles; and other industries. Chapters 3 and 7 of the current BEB [26] present national annual statistics, from 1970 to 2025, for:

- (i) the total energy consumption and the consumption by energy source, in tonnes of oil equivalent (toe), for these 11 industrial sectors (chapter 3 of BEB);
- (ii) the production, in tonnes (t), and unit energy consumption (total energy consumption per ton), in toe/t, for the following industrial sectors: pig-iron and steel; iron-alloys; non-ferrous and other metals; cement; and paper and pulp (Table 7.8 of chapter 7 of BEB); and
- (iii) the Brazilian Gross Domestic Product (GDP), the value-added, in million US\$ ppp² (2010³) (Table 7.4 of chapter 7) and the energy intensity, in toe/million US\$ ppp (2010) (Table 7.5 of chapter 7 of BEB), for the following industrial sectors: mining and pelletization; non-metals (includes cement and ceramics); ferrous and non-ferrous metals (includes pig-iron and steel, iron-alloys and non-ferrous and other metals); chemical; food and beverages; textiles; pulp and paper; and other industries (Table 7.4 of chapter 7).

The stacked area graphs of Figures 18 to 28 show the evolution, from 1970 to 2025, of the total energy

¹The production of petroleum and natural gas is excluded, since they are part of the energy sector in the BEB.

²ppp: purchasing power parity

³Constant dollar of 2010.

consumption and of the energy sources used in each of the 11 industrial sectors of the BEB. The aggregated energy consumption is shown in Figure 17 and the share of each subsector in the total energy consumption in recent years is given in Table 1.

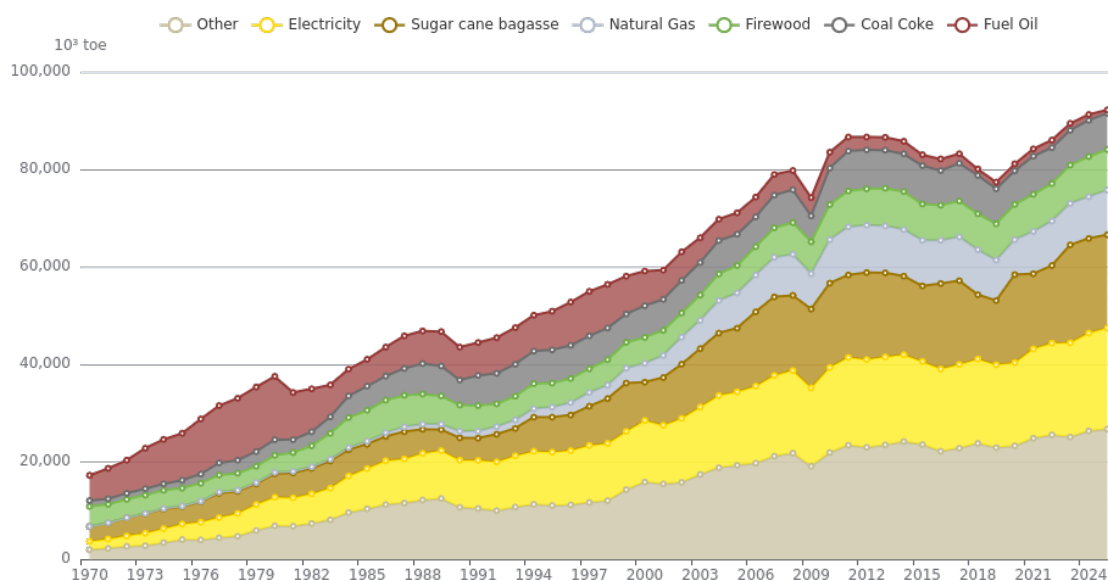


Figure 17: Consumption, from 1970 to 2025, of energy carriers, in 10^3 toe, in the Brazilian industry. Source: [27]

Table 1: Share of each industrial subsector in total industry energy consumption (%).

Subsector	Year					
	2020	2021	2022	2023	2024	2025
Cement	1.69	1.97	2.32	2.37	2.52	2.58
Pig iron and steel	7.33	8.36	7.86	6.98	7.14	6.75
Iron-alloys	0.17	0.18	0.17	0.09	0.09	0.08
Mining and pelletization	0.82	0.92	0.88	0.94	1.11	1.14
Non-ferrous metals	2.30	2.89	2.53	2.30	2.60	3.73
Chemical	4.64	5.10	4.87	4.45	4.05	3.89
Food and beverages	48.10	42.28	41.89	47.59	45.41	44.00
Textiles	0.52	0.55	0.49	0.41	0.41	0.38
Pulp and paper	24.01	25.40	26.26	23.45	25.28	25.91
Ceramics	6.94	7.84	7.20	6.56	6.54	6.42
Other	3.48	4.52	5.54	4.85	4.85	5.14

As shown in Figure 18, the largest energy consumption carrier in the food and beverages industry has been sugarcane bagasse, followed by firewood and electricity.

The largest shares of energy consumption in the ceramics industry come from firewood, mostly consumed in the production of red ceramics (bricks, roof tiles, blocks), natural gas, the most important energy carrier in the production of white body ceramics, porcelain stoneware and vitreous china, and

electricity, in this sequence, as depicted in Figure 19. The decarbonization expectations to decrease the dependence on fossil fuel natural gas rely on biomethane in the short and medium terms and hydrogen in the long term.

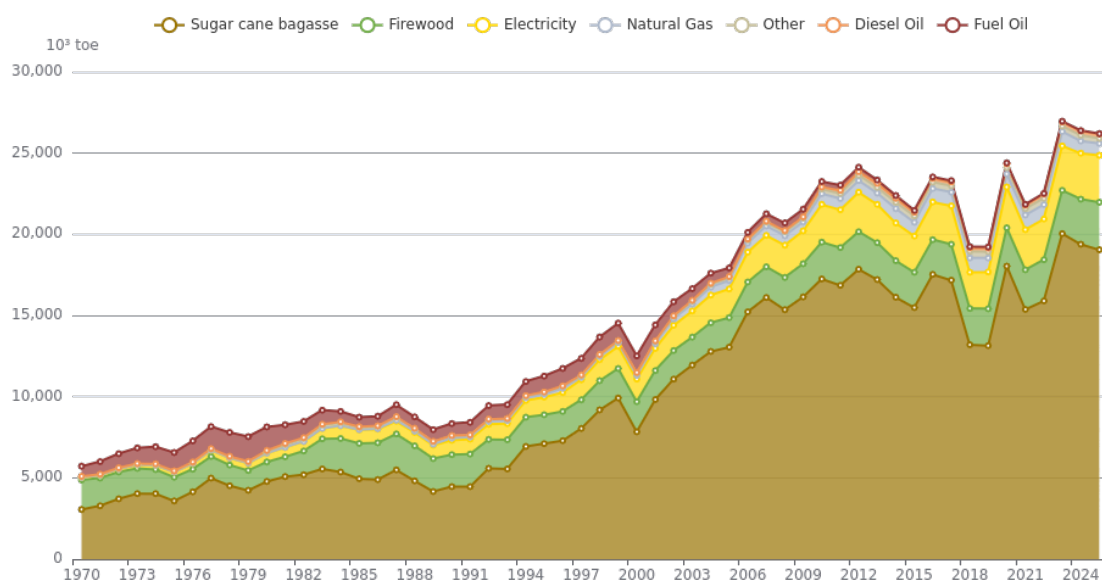


Figure 18: Consumption, from 1970 to 2025, of energy carriers, in 10^3 toe, in the Brazilian food and beverages industry. Source: [27]

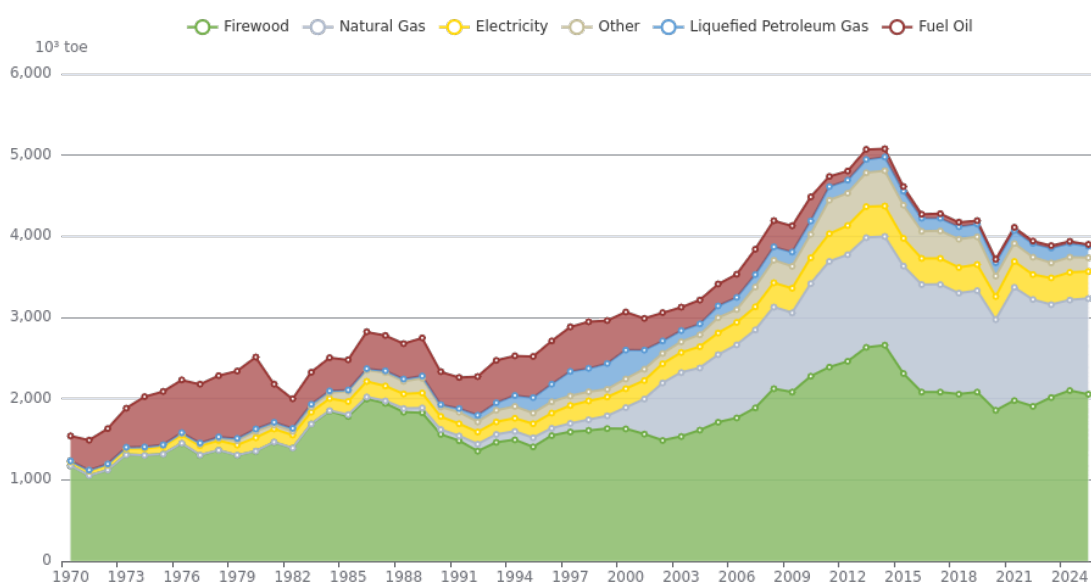


Figure 19: Consumption, from 1970 to 2025, of energy sources, in 10^3 toe, in the Brazilian ceramics industry. Source: [27]

Figure 20 reveals that petroleum coke has been, in the current century, the most consumed fuel in the production of cement in Brazil. It has been the cheapest fossil fuel to fire the clinker furnaces. The “other fuels” category, which includes various types of residues and biomass, and electricity, also has significant consumption in this industry, which plans to decrease the use of petroleum coke in the future with a larger use of residues and smaller shares of clinker in the cement composition.

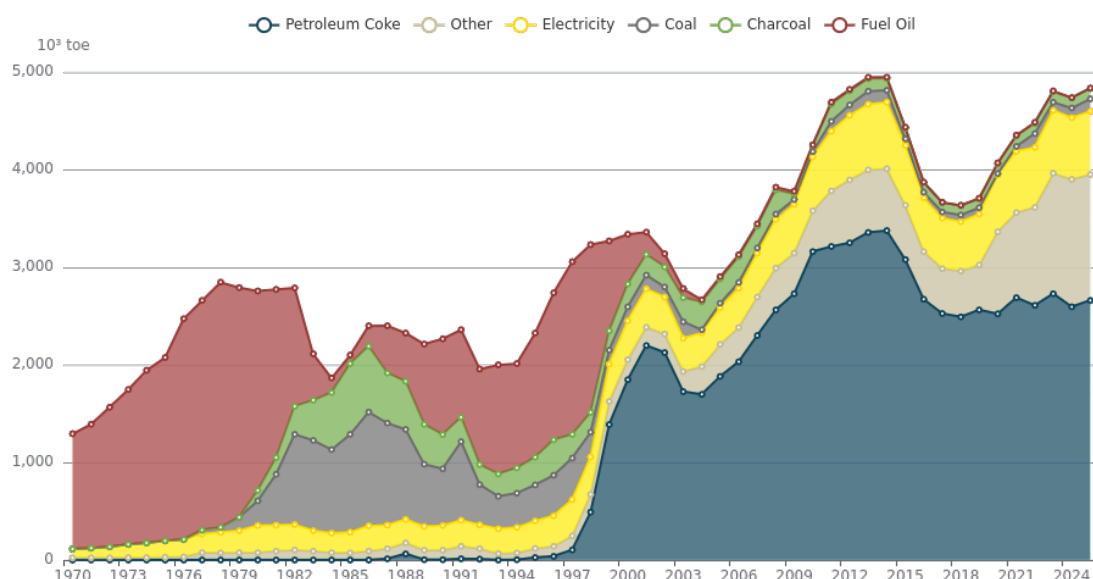


Figure 20: Consumption, from 1970 to 2025, of energy carriers, in 10^3 toe, in the Brazilian cement manufacturing. Source: [27]

The main energy source consumed in the Brazilian pig-iron and steel industry has been coal coke, followed, in sequence, by charcoal, the “other fuel” category, whose main component is pulverized coal, and electricity, as shown in Figure 21. The two most important strategies to substitute, at least partially, in the future, the fossil fuels coal coke and pulverized coal are a larger share of electric arc furnaces in the production of steel and the direct reduction of iron ore into sponge iron, using, initially, natural gas and, then, gradually, green hydrogen.

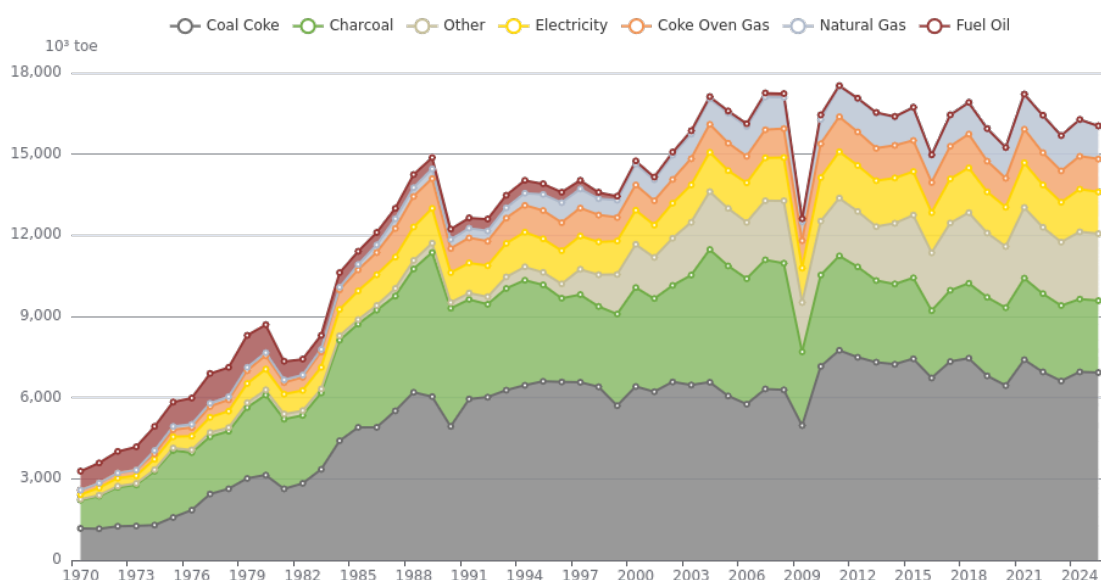


Figure 21: Consumption, from 1970 to 2025, of energy sources, in 10^3 toe, in the Brazilian pig-iron and steel industry. Source:[27]

Figure 22 shows that the main energy carrier in the Brazilian iron-alloys industry is electricity, followed closely by the renewable energy sources charcoal and firewood. Thus, it is an electricity-intensive

industry.

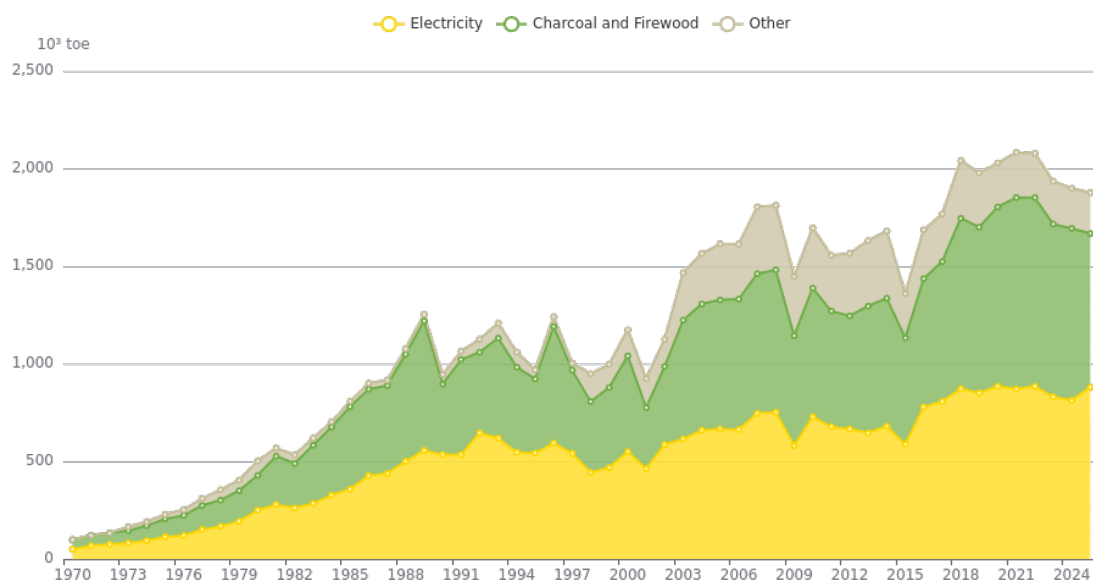


Figure 22: Consumption, from 1970 to 2025, of energy carriers, in 10^3 toe, in the Brazilian iron-alloys industry. Source: [27]

The Brazilian non-ferrous and other metallurgical sector is also an electricity-intensive industry, since electricity is its main energy source, followed by natural gas and coal/coal coke (Figure 23). Decarbonization initiatives will be directed in the future to the substitution of the fossil fuel coal/coal coke intakes.

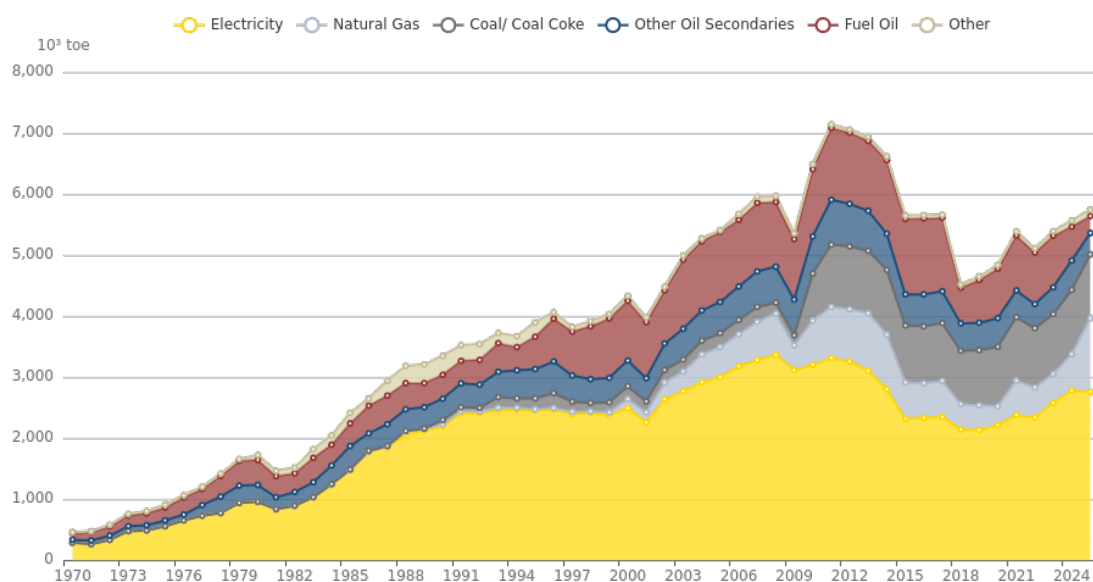


Figure 23: Consumption, from 1970 to 2025, of energy sources, in 10^3 toe, in the Brazilian non-ferrous and other metallurgical sector. Source: [27]

Electricity is the largest energy source consumed in the Brazilian mining and pelletization industry, but the consumption of fossil diesel oil and natural gas is also significant (Figure 24).

Figure 25 shows the nearly ever-growing total energy consumption of the Brazilian pulp and paper

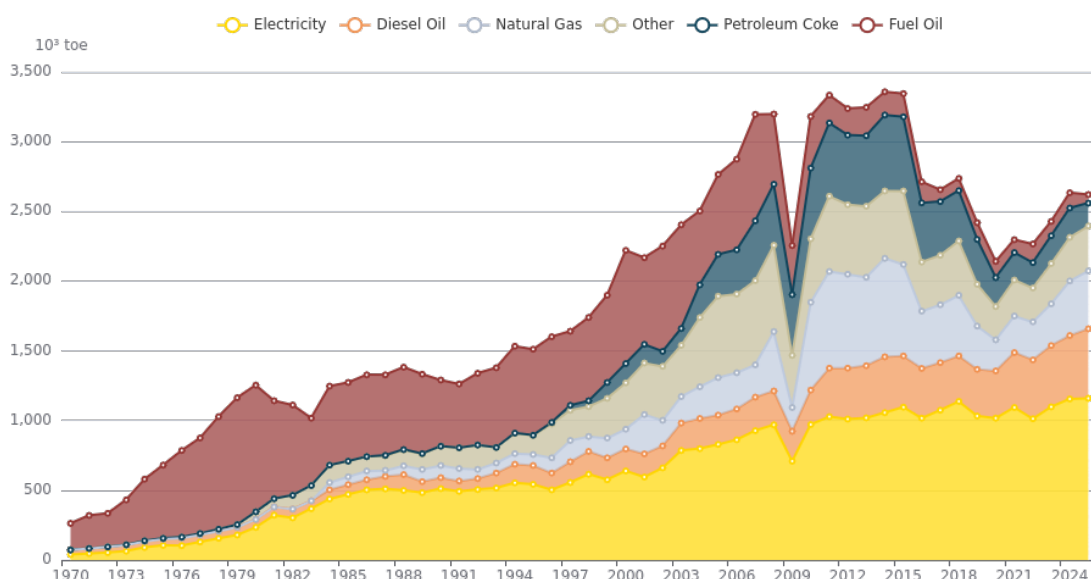


Figure 24: Consumption, from 1970 to 2025, of energy carriers, in 10^3 toe, in the Brazilian mining and pelletization industry. Source:[27]

industry, with a sharp increase in the current century, due to the large exports of pulp produced from the fast-growing eucalyptus. The main energy source of this industry has been black liquor, a residue with origin in the pulp-making Kraft process, included in the “other” category in Figure 25. Electricity is the next energy carrier, followed by firewood.

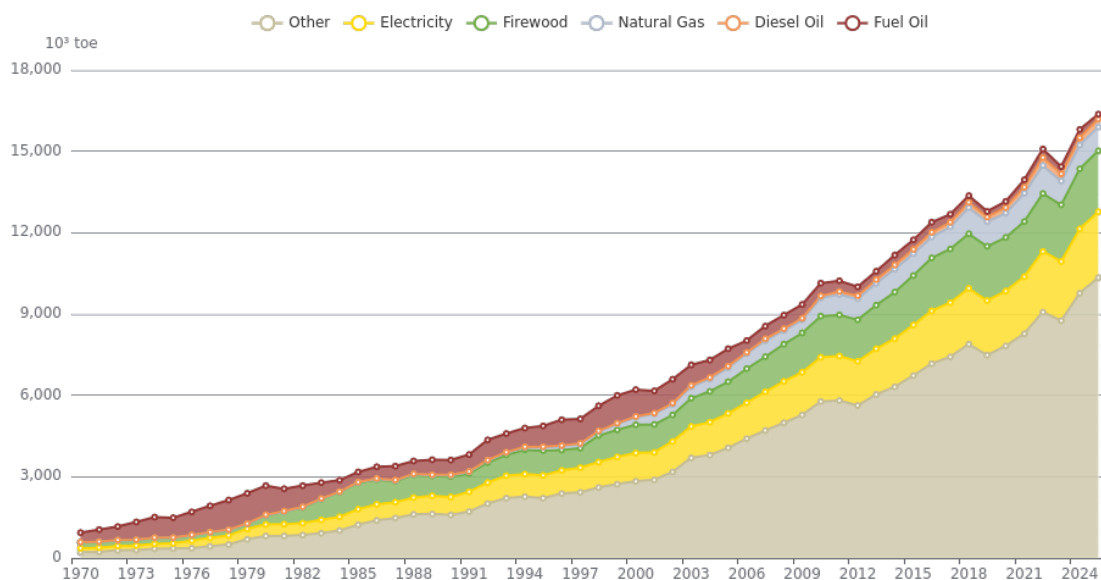


Figure 25: Consumption, from 1970 to 2025, of energy sources, in 10^3 toe, in the Brazilian pulp and paper industry. Source: [27]

The largest energy carrier consumption in the Brazilian chemical industry comes from electricity, followed closely by natural gas, as depicted in Figure 26. Natural gas is used in the chemical industry as both fuel and chemical feedstock, and both uses are accounted for in the BEB.

The Brazilian textiles industry has been shrinking since around 2010, as reflected in its declining total

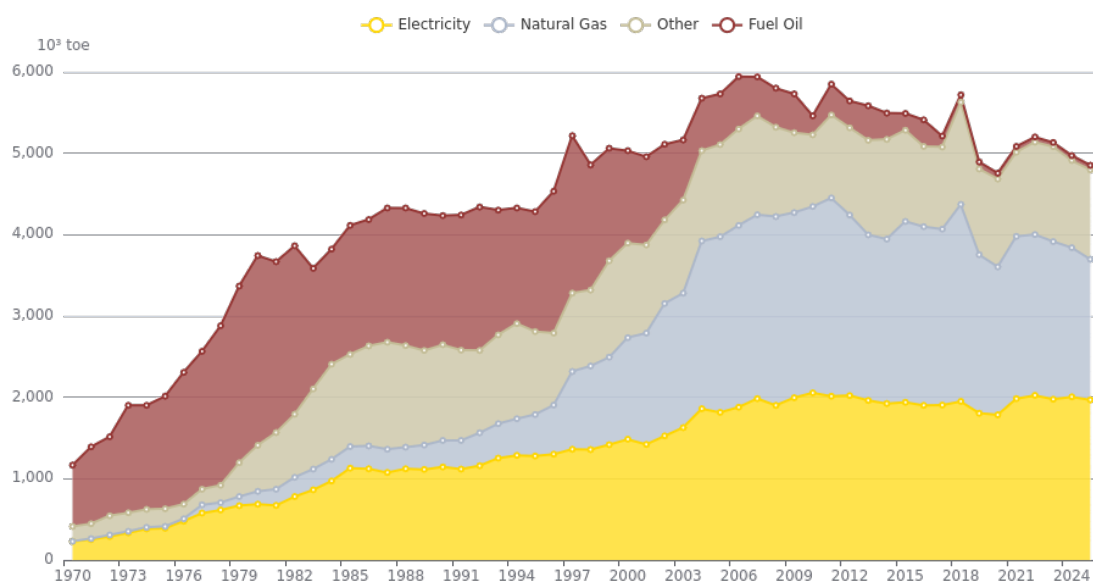


Figure 26: Consumption, from 1970 to 2025, of energy carriers, in 10^3 toe, in the Brazilian chemical industry.
Source: [27]

energy consumption (Figure 27). The main energy carrier in this industry is electricity, followed by natural gas.

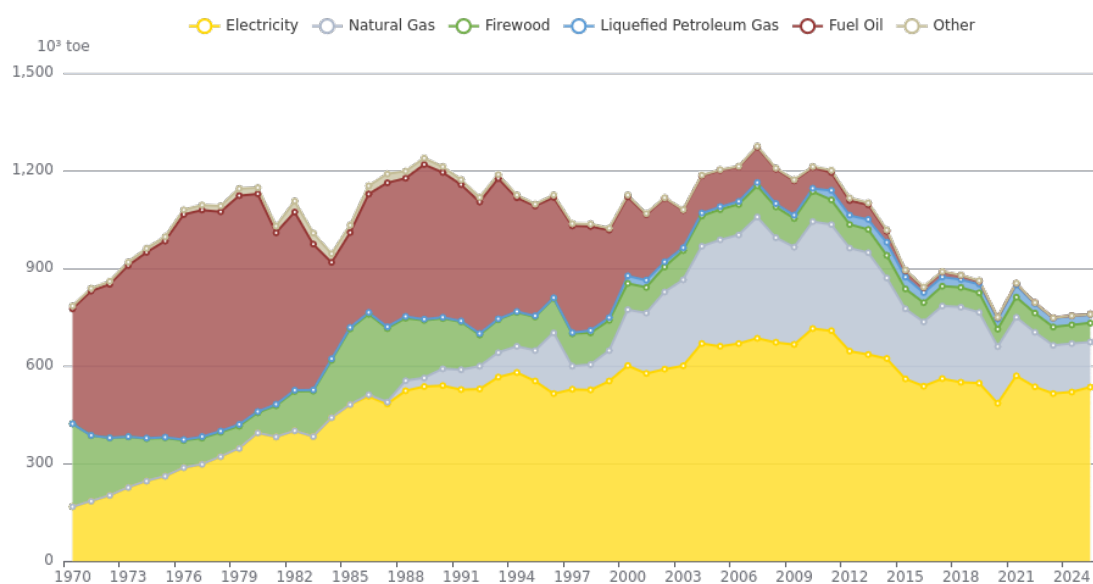


Figure 27: Consumption, from 1970 to 2025, of energy sources, in 10^3 toe, in the Brazilian textiles industry.
Source: https://dashboard.epe.gov.br/apps/livro-ben/book/en/capitulo_3.html#industrial-sector, accessed in July 9th, 2026

The “other industries” group in Brazil comprises industrial sectors that, in general, are not energy-intensive. Figure 28 shows that the total energy consumption of this group has been growing most of the time. Electricity is the energy carrier most consumed, followed by natural gas and firewood.

Unfortunately, very few Brazilian states publish regularly energy balances for their economies, in general, and their industrial sectors, in particular. So, adequate indicators, available for all the states,

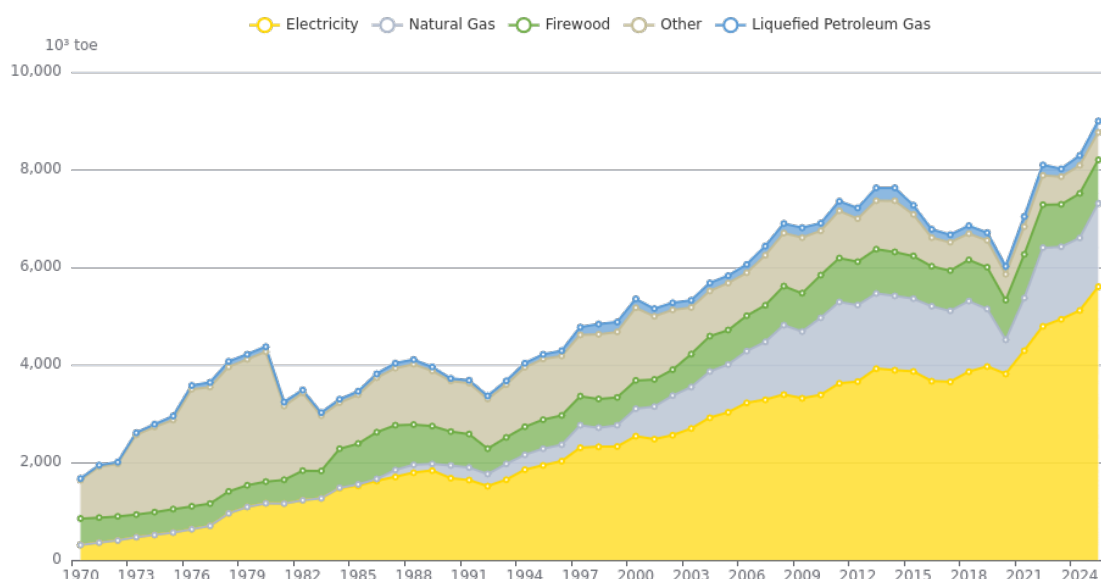


Figure 28: Consumption, from 1970 to 2025, of energy carriers, in 10^3 toe, in the Brazilian “other industries” group. Source: [27]

such as the Industrial Transformation Value, published by the Brazilian Institute of Geography and Statistics (IBGE) [28], should be used to disaggregate the national industrial energy consumption statistics for each state.

Complementary input data, from several sources, are also used to form the assumptions adopted in developing future scenarios for industrial energy demand beyond the business as usual (trend) scenario. These data are presented, together with the corresponding assumptions, in section 4.5.

3.1.3.2 Forecasts of the total energy demand

Decomposition equations are used to project several scenarios for the total energy demand for the 11 industrial sectors in 2050. The scenarios variously capture the influence of GDP growth, structural changes among industrial sectors' shares within the GDP, and the sectors' energy intensities. These are the three drivers of the total energy consumption projections.

Given the long-term period of the forecast and the highly non-regular behavior of the Brazilian economy, it is pointless to try simulating the path followed by demands up to 2050. Linear annual changes are assumed from 2025 to 2050.

Whenever production statistics are available, the industrial sector's future energy intensity is calculated as the product of projected unit energy consumption and projected ratio between production and value-added.

When production statistics are not available, the energy intensity statistics available in the Brazilian Energy Balance are employed to obtain a corresponding projected value for 2050.

In industrial sectors with relatively homogeneous products which can be expressed in tonnes, the specific energy consumption reflects better than energy intensity technological changes and the effect of energy conservation programs.

The behavior of the decomposition equations components along the period 1970 to 2025 and, particularly, in the latter years is analyzed in order to provide elements for the assumptions taken for the projected values adopted for 2050.

The food and beverages industry has heterogeneous products and, therefore, the decomposition equation for the total energy consumption, EC_{FB} , in toe, is given by:

$$EC_{FB} = \frac{EC_{FB}}{VA_{FB}} \cdot \frac{VA_{FB}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP} \cdot GDP$$

where:

$\frac{EC_{FB}}{VA_{FB}}$: energy intensity of the food and beverages industry, in toe/ 10^6 US\$ppp (2010);

$\frac{VA_{FB}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP}$: share of the food and beverages industry's value-added in the GDP;

VA_{FB} : value-added of the food and beverages industry, in 10^6 US\$ppp (2010);

VA_{IND} : value-added of the Brazilian industry, in 10^6 US\$ppp (2010); and

GDP : Gross Domestic Product of the Brazilian economy, in 10^6 US\$ppp (2010).

IBGE and the Brazilian Energy Balance do not provide annual time series of value-added for the ceramics and cement industries, but, rather, they present value-added data for the non-metals category, which includes ceramics and cement. So, the decomposition equations for these two industries employ the value-added of this aggregate category.

The ceramics industry also has heterogeneous products, thus energy intensity, related to the non-metals category value-added, is used in the decomposition equation employed to project the total energy consumption, EC_{CER} , in toe, of this industrial sector:

$$EC_{CER} = \frac{EC_{CER}}{VA_{NM}} \cdot \frac{VA_{NM}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP} \cdot GDP$$

where:

$\frac{EC_{CER}}{VA_{NM}}$: energy intensity of the ceramics industry, in toe/ 10^6 US\$ppp (2010); and

$\frac{VA_{NM}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP}$: share of the non-metals industry's value-added in the GDP;

VA_{NM} : value-added of the non-metals industry, in 10^6 US\$ppp (2010).

Cement can be considered a homogeneous product measured in tonnes and the unit energy consumption can be employed in the decomposition equation, together with the non-metals value-added, to forecast the total energy consumption, EC_{CEM} , in toe:

$$EC_{CEM} = \frac{EC_{CEM}}{PF_{CEM}} \cdot \frac{PF_{CEM}}{VA_{NM}} \cdot \frac{VA_{NM}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP} \cdot GDP$$

where:

$\frac{EC_{CEM}}{PF_{CEM}} \cdot \frac{PF_{CEM}}{VA_{NM}}$: energy intensity of the cement industry, in toe/ 10^6 US\$ppp (2010); and

$\frac{EC_{CEM}}{PF_{CEM}}$ unit energy consumption of cement manufacturing, in toe/t;

$\frac{PF_{CEM}}{VA_{NM}}$: inverse of the value-added productivity of cement production regarding the non-metals;

PF_{CEM} : production of cement, in t.

Annual time series of value-added for the pig-iron and steel, iron alloys and non-ferrous and other metallurgical industries are not published by IBGE and the Brazilian Energy Balance. Instead, they present value-added data for the metallurgical industry, which includes the pig-iron and steel, iron-alloys and non-ferrous and other metallurgical sectors. Therefore, the decomposition equations for these three industries use the value-added of this aggregate category.

There are historic time series available for the production of pig-iron and steel in Brazil, in tonnes, and, consequently, the unit energy consumption participate in this industry's decomposition equation used to project its total energy consumption, EC_{IS} , in toe:

$$EC_{IS} = \frac{EC_{IS}}{PF_{IS}} \cdot \frac{PF_{IS}}{VA_{MET}} \cdot \frac{VA_{MET}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP} \cdot GDP$$

where:

$\frac{EC_{IS}}{PF_{IS}} \cdot \frac{PF_{IS}}{VA_{MET}}$: energy intensity of the pig iron and steel industry, in toe/10⁶ US\$ppp (2010); and

$\frac{EC_{IS}}{PF_{IS}}$ unit energy consumption of pig iron and steel industry, in toe/t;

$\frac{PF_{IS}}{VA_{MET}}$: inverse of the value-added productivity of pig iron and steel production regarding the metallurgical industry value-added;

PF_{IS} : production of pig iron and steel, in t.

The same types of data of the pig-iron and steel industry are available for the iron-alloys industry. So, a similar decomposition equation applies to project the total energy consumption of the iron-alloys sector, EC_{IA} , in toe:

$$EC_{IA} = \frac{EC_{IA}}{PF_{IA}} \cdot \frac{PF_{IA}}{VA_{MET}} \cdot \frac{VA_{MET}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP} \cdot GDP$$

where:

$\frac{EC_{IA}}{PF_{IA}} \cdot \frac{PF_{IA}}{VA_{MET}}$: energy intensity of the iron-alloys industry, in toe/10⁶ US\$ppp (2010); and

$\frac{EC_{IA}}{PF_{IA}}$ unit energy consumption of iron-alloys industry, in toe/t;

$\frac{PF_{IA}}{VA_{MET}}$: inverse of the value-added productivity of iron-alloys production regarding the metallurgical industry value-added;

PF_{IA} : production of iron-alloys, in t.

The decomposition equation used to project the total energy consumption of the non-ferrous and other metallurgical sector, EC_{NF} , in toe, has a similar structure as the equations employed for the pig-iron and steel, and iron-alloys industries:

$$EC_{NF} = \frac{EC_{NF}}{PF_{NF}} \cdot \frac{PF_{NF}}{VA_{MET}} \cdot \frac{VA_{MET}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP} \cdot GDP$$

where:

$\frac{EC_{NF}}{PF_{NF}} \cdot \frac{PF_{NF}}{VA_{MET}}$: energy intensity of the non-ferrous and other metallurgical industry, in toe/10⁶ US\$ppp (2010); and

$\frac{EC_{NF}}{PF_{NF}}$ unit energy consumption of non-ferrous and other metallurgical industry, in toe/t;

$\frac{PF_{NF}}{VA_{MET}}$: inverse of the value-added productivity of non-ferrous and other metallurgical production regarding the metallurgical industry value-added;

PF_{NF} : production of non-ferrous and other metallurgical, in t.

The products of the mining and pelletization industry are heterogeneous. Therefore, the energy intensity indicator should be employed in the decomposition equation used to project the total energy consumption of this industrial sector, EC_{MP} , in toe:

$$EC_{MP} = \frac{EC_{MP}}{VA_{MP}} \cdot \frac{VA_{MP}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP} \cdot GDP$$

where:

$\frac{EC_{MP}}{VA_{MP}}$: energy intensity of the mining and pelletization industry, in toe/10⁶ US\$ppp (2010); and

$\frac{VA_{MP}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP}$: share of the mining and pelletization industry's value-added in the GDP; and

VA_{MP} : value-added of the mining and pelletization industry, in 10⁶ US\$ppp (2010).

There are time series statistics available for both production and value-added of the Brazilian pulp and paper industry. Thus, to forecast the total energy consumption for this industry, EC_{PP} , in toe, the decomposition equation takes the following form:

$$EC_{PP} = \frac{EC_{PP}}{PF_{PP}} \cdot \frac{PF_{PP}}{VA_{PP}} \cdot \frac{VA_{PP}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP} \cdot GDP$$

where:

$\frac{EC_{PP}}{PF_{PP}} \cdot \frac{PF_{PP}}{VA_{PP}}$: energy intensity of the pulp and paper industry, in toe/10⁶ US\$ppp (2010); and

$\frac{EC_{PP}}{PF_{PP}}$ unit energy consumption of pulp and paper industry, in toe/t;

$\frac{PF_{PP}}{VA_{MET}}$: inverse of the value-added productivity of pulp and paper production regarding the metallurgical industry value-added;

PF_{PP} : production of pulp and paper, in t.

Equation 3.1.3.2 is the decomposition equation used to forecast the total energy consumption of the Brazilian chemical industry, EC_{Chem} , in toe, which has a very diverse range of product types:

$$EC_{Chem} = \frac{EC_{Chem}}{VA_{Chem}} \cdot \frac{VA_{Chem}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP} \cdot GDP$$

where:

$\frac{EC_{Chem}}{VA_{Chem}}$: energy intensity of the chemical industry, in toe/10⁶ US\$ppp (2010); and

$\frac{VA_{Chem}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP}$: share of the chemical industry's value-added in the GDP; and

VA_{Chem} : value-added of the chemical industry, in 10⁶ US\$ppp (2010).

There is a broad range of product types in the Brazilian textiles industry. The forecasting of this industry's total energy consumption, EC_T , in toe, is carried out by the decomposition equation 3.1.3.2:

$$EC_T = \frac{EC_T}{VA_T} \cdot \frac{VA_T}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP} \cdot GDP$$

where:

$\frac{EC_T}{VA_T}$: energy intensity of the textile industry, in toe/10⁶ US\$ppp (2010); and

$\frac{VA_T}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP}$: share of the textile industry's value-added in the GDP; and

VA_T : value-added of the textile industry, in 10⁶ US\$ppp (2010).

The “other industries” group in the Brazilian Energy Balance is characterized by a large range of product types. Equation 3.1.3.2 represents the decomposition equation used to forecast the total energy consumption of this group, EC_{OI} , in toe:

$$EC_{OI} = \frac{EC_{OI}}{VA_{OI}} \cdot \frac{VA_{OI}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP} \cdot GDP$$

where:

$\frac{EC_{OI}}{VA_{OI}}$: energy intensity of the “other industries” group, in toe/10⁶ US\$ppp (2010); and

$\frac{VA_{OI}}{VA_{IND}} \cdot \frac{VA_{IND}}{GDP}$: share of the “other industries” group's value-added in the GDP; and

VA_{OI} : value-added of the “other industries” group, in 10⁶ US\$ppp (2010).

The time series available in the Brazilian Energy Balance for the components of the decomposition equations 3.1.3.2 to 3.1.3.2 are presented in Figures 29 to 37. Figure 29 depicts the evolution of the Brazilian GDP from 1970 to 2025, in 10⁶ 2010 constant dollars based on purchase power parity (ppp).

The value-added by the “other industries” group has been, in the current century, much higher than the value-added of the rest of processing industry plus mining and pelletization, as illustrated in Figure 30, which also shows the strong fall in industry's value-added from 2014 to 2020, the similar behavior of the “other industries” group curve to the whole industry curve, and the relatively little variations of the rest of processing industry plus mining and pelletization curve since 1987.

The share of the valued-added of industry in the Brazilian GDP have shown a downward trend

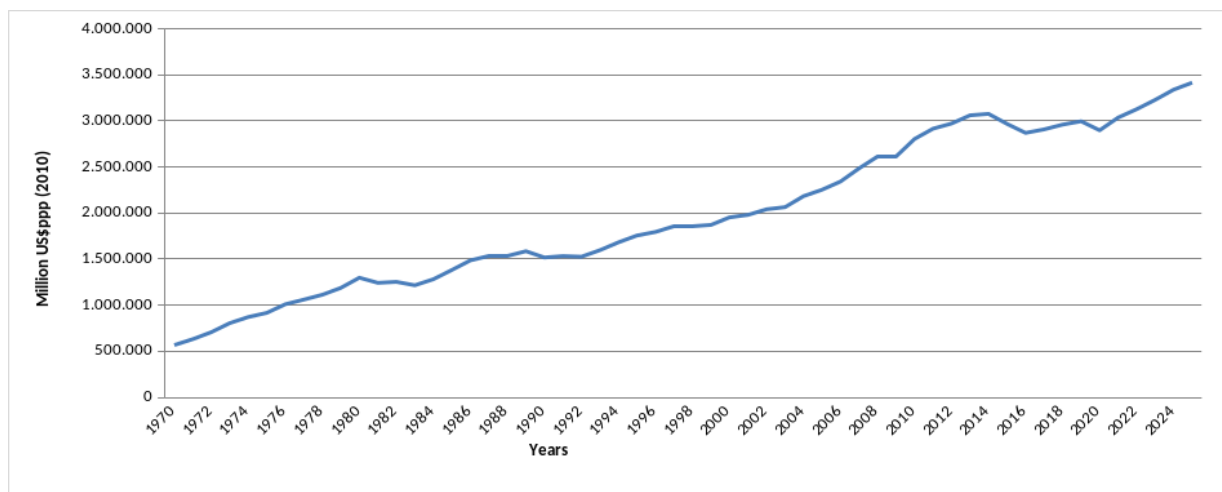


Figure 29: Brazilian GDP, from 1970 to 2025, in million US\$ppp (2010). Source: EPE/MME (2026)

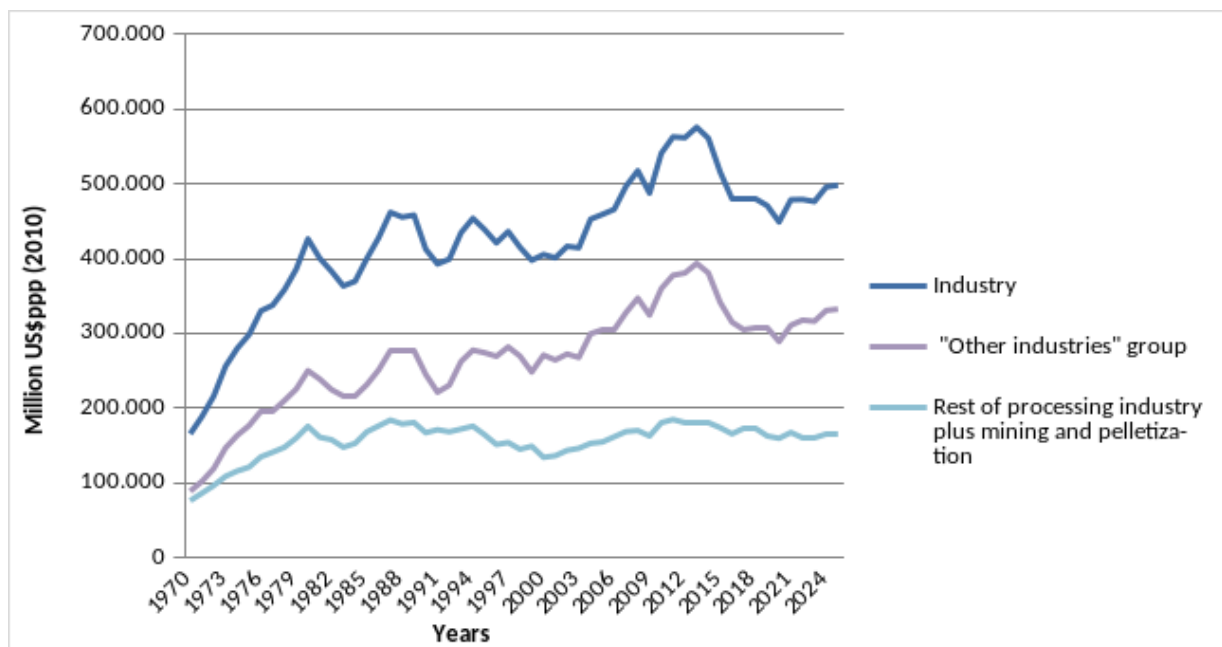


Figure 30: Value-added of industry, "other industries" group and the rest of processing industry plus mining and pelletization in Brazil, from 1970 to 2025, in 10⁶ US\$ppp (2010). Source: EPE/MME (2026)

since 1989, as depicted in Figure 31, which also shows that the opposite trend have occurred in the participation of the “other industries” group’s value-added in the industry’s value-added.

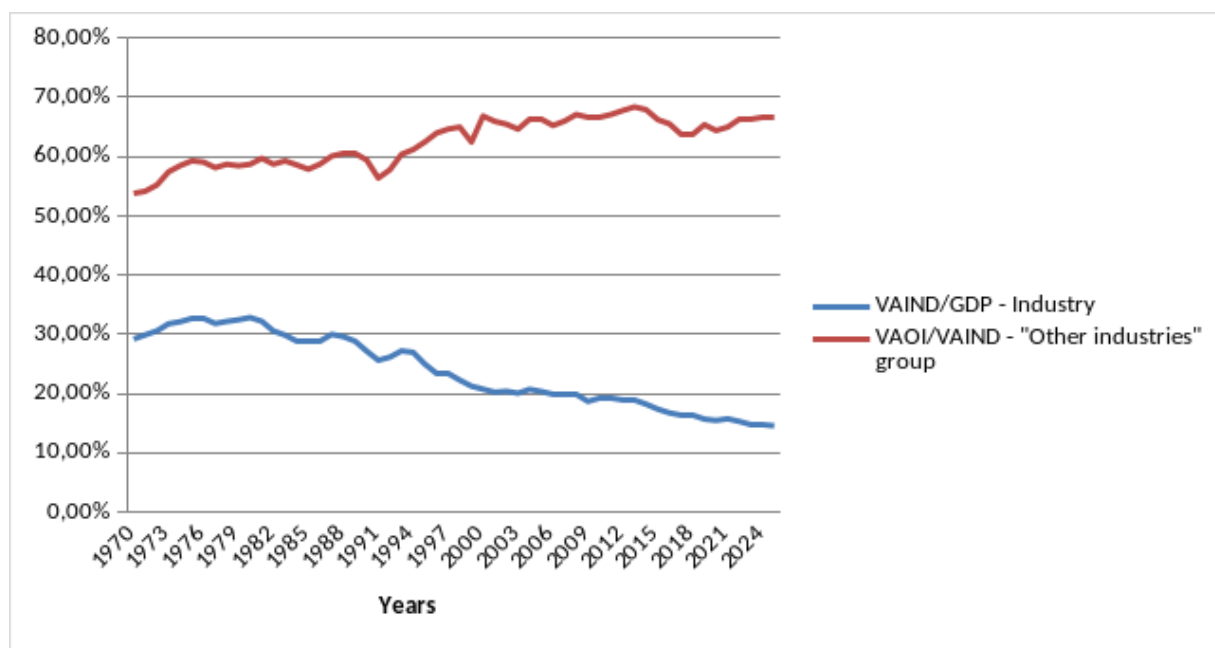


Figure 31: Share of the value-added of industry in the Brazilian GDP and share of the value-added of the “other industries” group regarding the value-added of industry, from 1970 to 2025, in % .Source: EPE/MME (2026)

Figure 32 presents the value-added statistics for the mining and pelletization, non-metals, ferrous and non-ferrous metals, chemical, foods and beverages, textiles, and pulp and paper industries in Brazil during the period 1970 – 2025. It can be seen the downward or stagnation trends in these statistics in the last years for most of these industrial sectors, with the exception of the food and beverages, and pulp and paper industries.

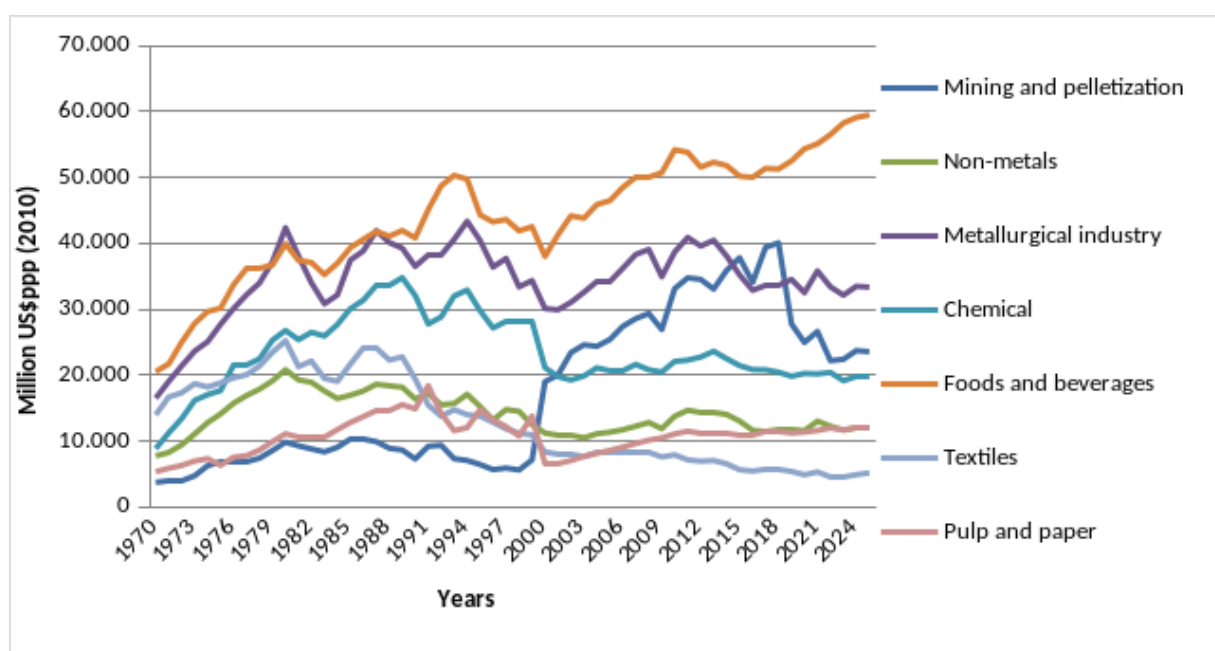


Figure 32: Source: EPE/MME (2026)

Dividing the values-added of the industrial sectors of Figure 32 by the value-added of industry as a whole results in the time-series of Figure 33, which reveals the same sort of results of Figure 32, *i.e.*, only the food and beverages, and pulp and paper industries show upward trends for this ratio in the last years.

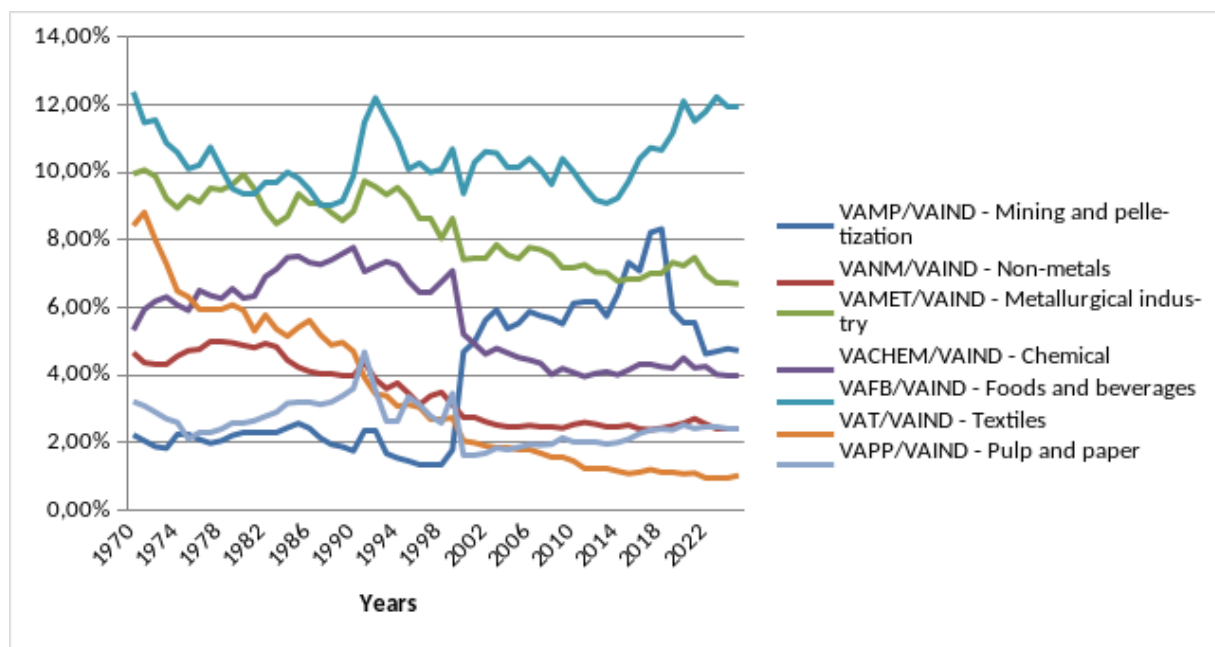


Figure 33: Shares of the values-added of the mining and pelletization, non-metals, metallurgical industry, chemical, foods and beverages, textiles, and the “other industries” group regarding the value-added of industry, from 1970 to 2025, in %. Source: EPE/MME (2026)

The production, in the period 1970-2025, of the Brazilian cement, pig-iron and steel, iron-alloys, non-ferrous and other metals, and pulp and paper industries is depicted in Figure 34. It stands out, in this figure, the nearly continuous growth of the pulp and paper production and the rapid increase in the production of cement since 2018.

The availability of production statistics for the industrial sectors represented in Figure 34 allows the calculation of unit energy consumption time series for these sectors, as indicated in Figure 35. The iron and steel industry is the only one, among the five sectors, that shows a clear and continuous reduction in this indicator, reflecting more efficient new plants, more exports of unrolled steel plates and energy efficiency measures in some older plants.

Figure 36 reveals that the inverse of the value-added productivity of the industrial sectors belonging to the metallurgical industry varied very little in recent years, while this indicator has been growing, during this period, for the cement and pulp and paper industries, meaning that more production is required to create the same value-added.

For the industrial sectors with heterogeneous products – mining and pelletization, chemical, foods and beverages, textiles and the “other industries” group – energy intensity is an indirect and less precise indicator of energy efficiency. Figure 37 shows that none of these sectors have improved their efficiency in recent years, according to this indicator.

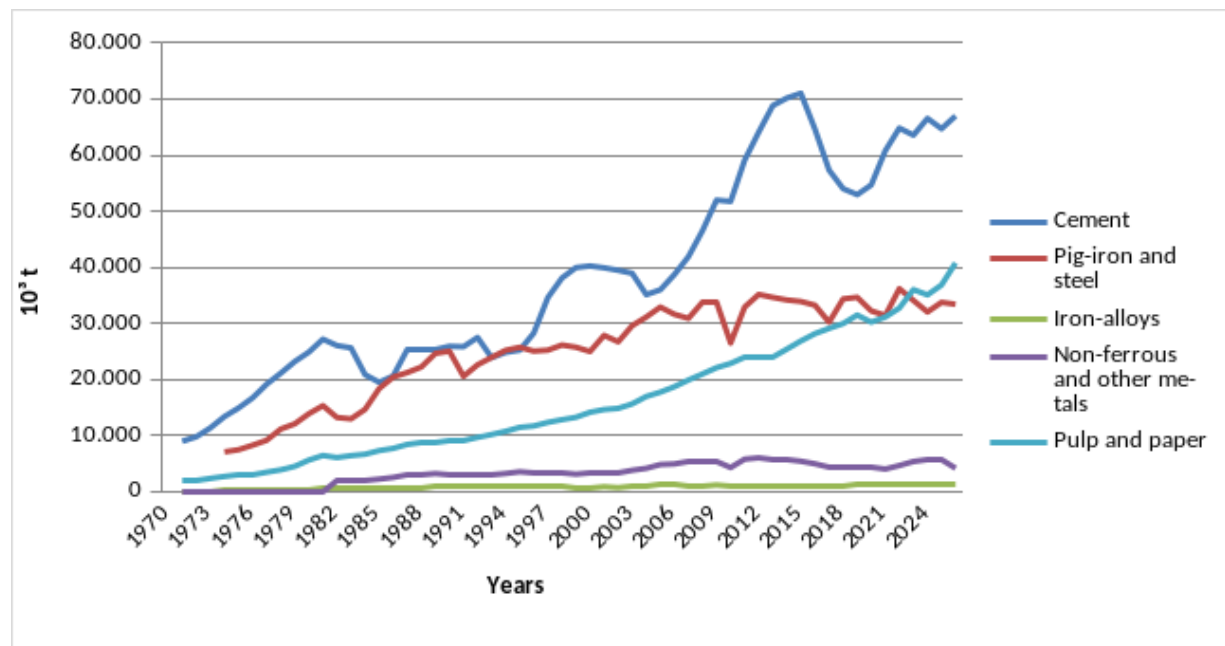


Figure 34: Production, in 10^3 t, of the cement, pig-iron and steel, iron-alloys, non-ferrous and other metals, and pulp and paper industries in Brazil, from 1970 to 2025. Source: EPE/MME (2026)

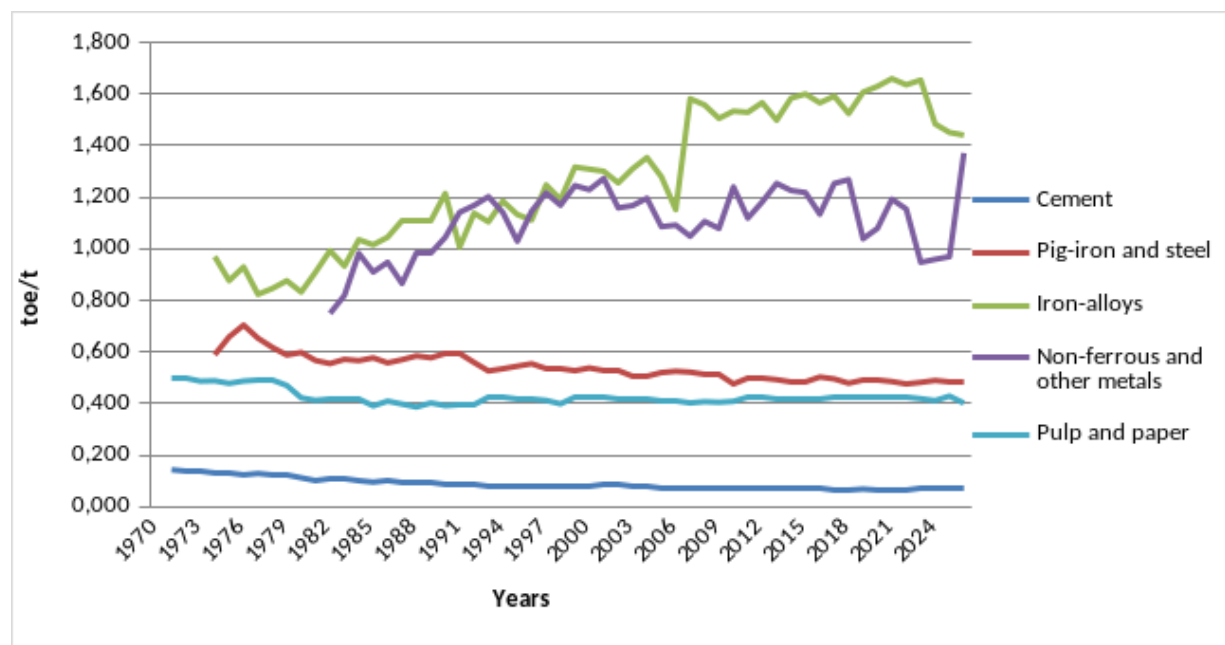


Figure 35: Unit energy consumption, in toe/t, of the cement, pig-iron and steel, iron-alloys, non-ferrous and other metals, and pulp and paper industries in Brazil, from 1970 to 2025. Source: EPE/MME (2026)

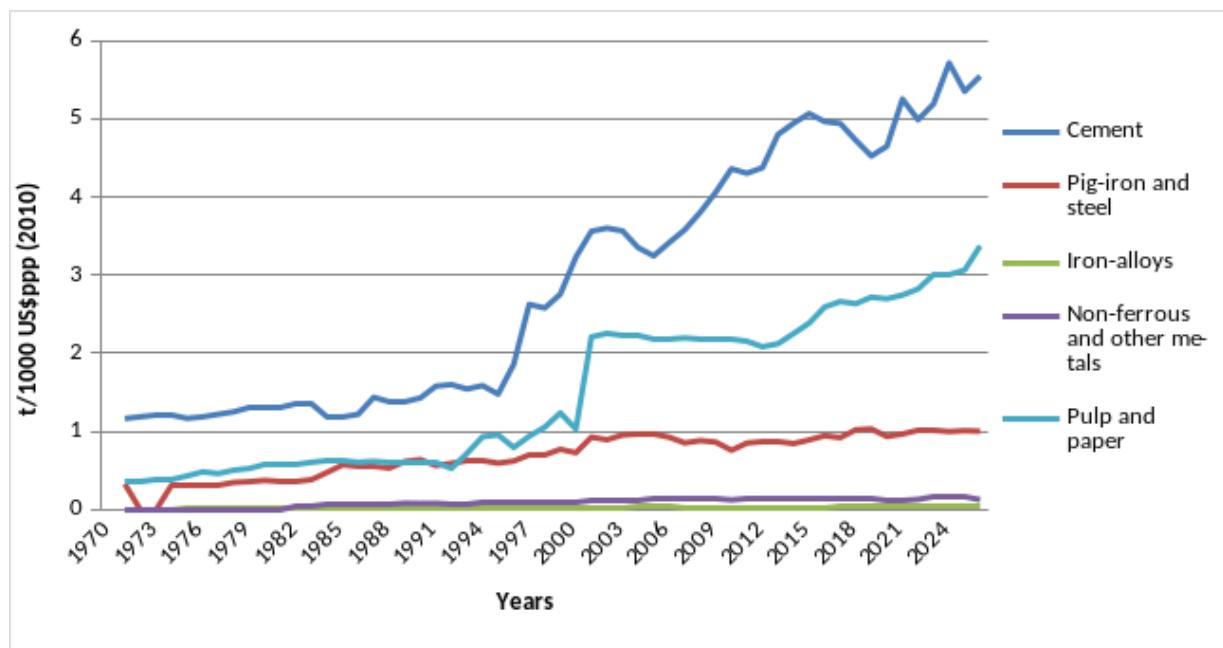


Figure 36: Inverse of the value-added productivity, in t/1000 US\$ppp (2010), of the cement, pig-iron and steel, iron-alloys, non-ferrous and other metals, and pulp and paper industries in Brazil, from 1970 to 2025. Source: EPE/MME (2026)

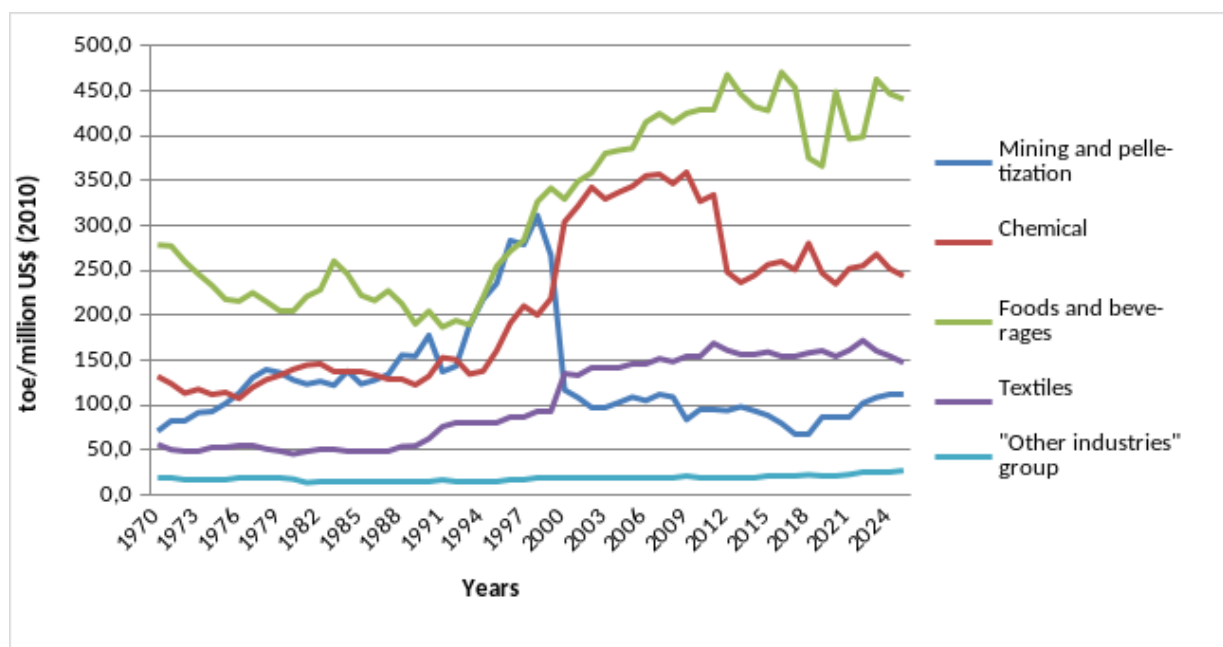


Figure 37: Energy intensity, in toe/10⁶ US\$ (2010), of the mining and pelletization, chemical, foods and beverages, textiles, and "other industries" group in Brazil, from 1970 to 2025. Source: EPE/MME (2026)

3.1.3.3 Downscaling the national consumption of the industrial sectors' energy sources among the Brazilian states level

As stated in section 3.1.3.1, a very small group of Brazilian states publish regularly energy balances for their industrial sectors. Therefore, some proxy indicators were adopted to disaggregate the national consumption of energy carriers of the industrial sectors among the Brazilian states.

Statistics of petroleum products published by the Brazilian Agency for Petroleum, Natural Gas and Biofuels (ANP) for each Brazilian state were employed to disaggregate the national consumption of those fuels. This statistics include data of sales of diesel, petroleum coke, lpg, kerosene, naphta, heavy fuel oil and others. Pipeline natural gas is not included in those data. Although biodiesel is not a petroleum derived fuel, it is blended to fossil diesel in a predetermined amount, which makes the sales of biodiesel linked to the sales of fossil diesel. Excluding the fuels contained in ANP's statistics, the production of cement, and pig-iron and steel, in each state, were adopted as proxies to disaggregate the national consumption of the other fuels and electricity of the cement and pig-iron and steel sectors, respectively. For the remaining energy carriers and industrial sectors, the VTI state-level statistics were used as an adequate proxy indicator.

The Industrial Transformation Value (VTI), published by the Brazilian Institute of Geography and Statistics (IBGE), available for all the states, was used to disaggregate the national consumption of each of the energy carriers, which are not derived from petroleum, in the industrial sectors that do not have statistics regarding their physical production. IBGE publishes every year the results of the Annual Industrial Survey (PIA) [29]. The survey of 2023 was used to calculate the disaggregation index, defined, for each of these industrial sectors, as the VTI of that sector in each state divided by the sector's national VTI. For each sector, multiplying the corresponding national VTI by this index for each state of the federation, result estimates of the state-level consumptions of their energy sources. A brief summary of the proxies used to disaggregate the national fuel consumption to the state level is given in Tables 2 and 3.

Table 2: Proxies used in the downscaling of national energy consumption to the state level

Subsector	tar	sugarcane bagasse	biodiesel	petroleum derived	coal
Food and beverages	VTI	VTI	ANP	ANP	VTI
Ceramics	VTI	VTI	ANP	ANP	VTI
Cement	cement production	cement production	ANP	ANP	cement production
Pig-iron and steel	steel production	steel production	ANP	pig-iron production	
Iron-alloys	VTI	VTI	ANP	ANP	VTI
Mining and pelletization	VTI	VTI	ANP	ANP	VTI
Non-ferrous metals	VTI	VTI	ANP	ANP	VTI
"Other industries"	VTI	VTI	ANP	ANP	VTI
Pulp and paper	VTI	VTI	ANP	ANP	VTI
Chemical	VTI	VTI	ANP	ANP	VTI
Textiles	VTI	VTI	ANP	ANP	VTI

Tables 4 and 6 present the disaggregation indices based on VTI for the ceramics, pulp and paper, chemical, foods and beverages, textiles, mining and pelletization and the "other industries" group sectors distributed among the Brazilian states. As IBGE's Annual Industrial Surveys do not produce VTI values for the iron-alloys and non-ferrous and other metals industries, the VTI statistics for the

Table 3: *Proxies used in the downscaling of national energy consumption to the state level (continued)*

Subsector	charcoal	electricity	natural gas	firewood	other biomass
Food and beverages	VTI	VTI	VTI	VTI	VTI
Ceramics	VTI	VTI	VTI	VTI	VTI
Cement	cement production	cement production	cement production	cement production	cement production
Pig-iron and steel	pig-iron production	steel production	steel production	steel production	steel production
Iron-alloys	VTI	VTI	VTI	VTI	VTI
Mining and pelletization	VTI	VTI	VTI	VTI	VTI
Non-ferrous metals	VTI	VTI	VTI	VTI	VTI
“Other industries”	VTI	VTI	VTI	VTI	VTI
Pulp and paper	VTI	VTI	VTI	VTI	VTI
Chemical	VTI	VTI	VTI	VTI	VTI
Textiles	VTI	VTI	VTI	VTI	VTI

metallurgy sector, shown in Table 4, are used to disaggregate their total energy consumption by the states.

3.1.3.4 Calculation methodology for possible future scenarios for the mix of the energy sources consumed in the Brazilian industrial sectors

The available time series, in the Brazilian Energy Balance, for the consumption of each energy source in each of the industrial sectors (depicted in Figures 18 to 28) allows the capture of their timeline trends for a reference scenario, driven by the existing public policies directed to foster energy efficiency gains and modernization, as well as by the companies’ business expansion plans.

Assumptions are made for alternative scenarios about possible different evolution pathways for these sources, particularly for the energy carriers targeted by decarbonization strategies. A more detailed description of the alternative scenarios is given in 4.5.

3.1.4 Buildings Sector: scope and modelling approaches

The next three sub-sections document the buildings block of the demand modules: the residential sector (Section 3.1.5), the commercial or services sector including public lighting (Section 3.1.6), and data centers (Section 3.1.7). The methodology is deliberately not uniform across them: each sub-sector is modelled with the approach its data allow, which means that the projections do not all carry the same kind of evidence and should not be read with the same degree of confidence. This sub-section sets out that conceptual basis before the individual modules are described.

Three approaches are used, and they can be placed on a spectrum running from fully data-driven reconstruction to fully exogenous specification:

- **(i) Bottom-up by equipment or establishment, with residual closure against the BEN** — residential (Section 3.1.5) and commercial (Section 3.1.6). An inventory of appliances or of representative establishments is used to reconstruct present-day demand; whatever the inventory fails to explain is retained explicitly as a residual (“ghost” or “Others”) term so that the base year reproduces the National Energy Balance by construction. The strength of this approach is that it makes end-use structure visible and scenario-addressable; its limitation is that the share of

Table 4: VTI-based disaggregation indices for the metallurgy, ceramics, and pulp and paper industries across Brazilian states.

Regions/States	Industrial sectors		
	Metallurgy	Ceramics	Pulp and paper
<i>North region</i>			
Rondônia (RO)	1	4	0
Acre (AC)	n.a.	n.a.	n.a.
Amazonas (AM)	5	7	7
Roraima (RR)	n.a.	n.a.	n.a.
Pará (PA)	0.027	23	5
Amapá (AP)	n.a.	n.a.	n.a.
Tocantins (TO)	0.002	n.a.	n.a.
<i>Northeast region</i>			
Maranhão (MA)	19	13	32
Piauí (PI)	1	4	0
Ceará (CE)	35	28	8
Rio Grande do Norte (RN)	n.a.	n.a.	n.a.
Paraíba (PB)	1	17	1
Pernambuco (PE)	9	28	9
Alagoas (AL)	0	4	1
Sergipe (SE)	0	12	1
Bahia (BA)	33	35	90
<i>Central-West region</i>			
Mato Grosso do Sul (MS)	7	30	91
Mato Grosso (MT)	9	33	0
Goiás (GO)	14	20	13
Distrito Federal (DF)	0	10	0
<i>Southeast region</i>			
Minas Gerais (MG)	365	63	72
Espírito Santo (ES)	49	54	27
Rio de Janeiro (RJ)	113	368	16
São Paulo (SP)	213	77	351
<i>South region</i>			
Paraná (PR)	18	84	131
Santa Catarina (SC)	53	73	80
Rio Grande do Sul (RS)	26	10	66

Note: n.a. = not available.

Source: Author's elaboration based on data from [29].

Table 5: *Disaggregation indices based on VTI for the chemical, foods and beverages, textiles, mining and pelletization and other industries in the Brazilian states*

Region/State	Industrial sectors				
	Chemical	Foods and beverages	Textiles	Mining and pelletization	Other industries
Northern region					
Rondônia (RO)	0	9	0	1	1
Acre (AC)	n.a.	1	n.a.	0	0
Amazonas (AM)	9	20	2	1	62
Roraima (RR)	n.a.	0	0	0	0
Pará (PA)	7	16	2	316	4
Amapá (AP)	n.a.	0	0	0	0
Tocantins (TO)	1	5	0	0	0
Northeastern region					
Maranhão (MA)	5	6	0	7	1
Piauí (PI)	1	5	0	1	1
Ceará (CE)	7	16	43	3	18
Rio Grande do Norte (RN)	n.a.	5	9	10	2
Paraíba (PB)	3	3	16	3	4
Pernambuco (PE)	28	29	15	0	19
Alagoas (AL)	3	11	1	1	1
Sergipe (SE)	4	4	13	2	2
Bahia (BA)	60	29	34	28	22
Center-western region					
Mato Grosso do Sul (MS)	5	29	8	3	5
Mato Grosso (MT)	22	46	6	9	5
Goiás (GO)	22	69	4	18	15
Distrito Federal (DF)	0	3	1	0	1
Southeastern region					
Minas Gerais (MG)	78	127	82	418	80
Espírito Santo (ES)	9	7	3	11	8
Rio de Janeiro (RJ)	62	21	18	116	42
São Paulo (SP)	506	296	369	26	408
Southern region					
Paraná (PR)	66	111	51	8	84
Santa Catarina (SC)	28	59	277	8	107
Rio Grande do Sul (RS)	73	71	46	8	107

n.a.: not available

Source: Own elaboration based on data available at

<https://biblioteca.ibge.gov.br/index.php/biblioteca-catalogo?view=detalhes&id=71719>, accessed in July 16th, 2026

Table 6: VTI-based disaggregation indices for selected industrial sectors across Brazilian states.

Region/State	Industrial sectors				
	Chemical	Food and beverages	Textiles	Mining and pelletization	Other industries
<i>North region</i>					
Rondônia (RO)	0	9	0	1	1
Acre (AC)	n.a.	1	n.a.	0	0
Amazonas (AM)	9	20	2	1	62
Roraima (RR)	n.a.	0	0	0	0
Pará (PA)	7	16	2	316	4
Amapá (AP)	n.a.	0	0	0	0
Tocantins (TO)	1	5	0	0	0
<i>Northeast region</i>					
Maranhão (MA)	5	6	0	7	1
Piauí (PI)	1	5	0	1	1
Ceará (CE)	7	16	43	3	18
Rio Grande do Norte (RN)	n.a.	5	9	10	2
Paraíba (PB)	3	3	16	3	4
Pernambuco (PE)	28	29	15	0	19
Alagoas (AL)	3	11	1	1	1
Sergipe (SE)	4	4	13	2	2
Bahia (BA)	60	29	34	28	22
<i>Central-West region</i>					
Mato Grosso do Sul (MS)	5	29	8	3	5
Mato Grosso (MT)	22	46	6	9	5
Goiás (GO)	22	69	4	18	15
Distrito Federal (DF)	0	3	1	0	1
<i>Southeast region</i>					
Minas Gerais (MG)	78	127	82	418	80
Espírito Santo (ES)	9	7	3	11	8
Rio de Janeiro (RJ)	62	21	18	116	42
São Paulo (SP)	506	296	369	26	408
<i>South region</i>					
Paraná (PR)	66	111	51	8	84
Santa Catarina (SC)	28	59	277	8	107
Rio Grande do Sul (RS)	73	71	46	8	107

Note: n.a. = not available.

Source: Author's elaboration based on data from [29].

demand actually resolved bottom-up can be small, in which case most of the projection is in fact carried by the aggregate residual and its statistical drivers.

- **(ii) Sector-census anchor with age-structured stock turnover** — public lighting (Section 3.1.6, “Public lighting”). A sectoral census fixes the base-year stock and its technology mix; the projection is then governed by a lamp-stock turnover model in which units retire at the end of their service life and are replaced by a policy-determined technology mix. This approach is well suited to a homogeneous, inventoried stock, and its confidence depends primarily on the quality of the census and on the specification of the stock-expansion driver.
- **(iii) Exogenous, anchored on planned or announced capacity** — data centers (Section 3.1.7). Demand is not derived from population or floor-area drivers at all but from an installed-capacity trajectory taken from sector plans and announcements, combined with load-factor and power-usage effectiveness assumptions. This is the appropriate treatment for a segment whose growth is decoupled from the underlying demographic drivers, but it makes the projection a direct function of the announced pipeline rather than of an estimated behavioural relationship.

Table 7 summarises the correspondence between sub-sector, approach, base-year anchor and the main driver of the 2050 trajectory.

Table 7: *Modelling approach by buildings sub-sector*

Sub-sector	Approach	Base-year anchor	Main driver of the 2050 trajectory
Residential	Appliance bottom-up + residual (“ghost”) closure	BEN 2019; PPH 2019 appliance survey	Projected dwellings and electricity intensity; explicit electrification ramp
Commercial (services)	Establishment bottom-up + residual (“Others”) closure	BEN 2023	Single national establishment growth rate (consumers/GDP blend); electrification ramp
Public lighting	Sector census + age-structured stock turnover	ABCIP 2023 census	Autonomous stock-growth rate from the BEN; LED penetration and efficacy targets
Data centers	Exogenous installed-capacity trajectory	Brasscom/ABDC, ANATEL, PDE 2035, ABDI	Announced/planned capacity expansion; PUE path; CDD by state

Source: own elaboration. The table is intended to help the reader calibrate the nature — and therefore the confidence — of each projection before reading the individual modules.

A consolidated view of the results of all four sub-sectors, by scenario, is given in Section 3.1.8.

How to read the refinement notes in this chapter

The buildings modules documented here are a first complete implementation, and this chapter documents them as they are actually coded rather than as they are intended to end up. Where a simplification is known to matter for the results, it is flagged in a **Refinement note** box stating what the model does today, why that was accepted for this version, and how it is to be addressed in the next model-refinement cycle. The density of these boxes in this chapter reflects the level of scrutiny the buildings modules have already received — including the external technical review of Report I of the Buildings module (G. M. Jannuzzi, August 2026) — and should be read as an explicit work programme, not as an indication that this block is less developed than the others. Where a note affects how a number should be interpreted, the direction of the likely bias is stated.

3.1.4.1 Data availability

All input datasets of the Buildings modules are publicly available as spreadsheets on Google Drive, one file per input element of the module flowcharts, with the caveat that they are still work in progress. Residential: population and residences, EPE residential consumers, BEN historical consumption (electricity, LPG, firewood), and PROCEL PPH 2019 appliance database. Commercial: BEN historical commercial consumption, PROCEL commercial-establishment survey, public-lighting and data center 2023 consumption, and IBGE/BEN commercial consumers. Public lighting: ABCIP 2023 census, ANEEL technology parameters, and BEN historical consumption. Data centers: predicted PUE, cooling degree days by state, historical national load capacity, load-capacity prediction, and predicted share of load capacity by state. The same links are embedded in the corresponding input boxes of the module flowcharts.

3.1.5 Residential sector

3.1.5.1 Overview

Key message

The residential model explains observed residential electricity use as the sum of an appliance-based “bottom-up” term and a residual “ghost” term, grows both to 2050 with statistically projected drivers, and adds the electricity that substitutes for LPG and firewood under three electrification scenarios (25%, 50%, and 100% fuel substitution by 2050).

This section documents the residential-sector energy-demand model developed for the NetZero Brasil (NZB) project. Throughout this section, “the model” refers to this Python application, not to EnergyPathways, which only consumes its exported results. The model is a bottom-up, appliance-based accounting framework that reconstructs residential electricity and fossil-fuel demand for each of Brazil’s 27 federative units (UFs) and for the country as a whole, and projects that demand to 2050 under a set of electrification scenarios. It is implemented as a self-contained Python application (4.41.py) built on `pandas`, `numpy`, `scipy`, `matplotlib`, and a `tkinter` graphical interface. The application loads historical series and an appliance database, fits statistical trends, reconciles the bottom-up estimate against the official energy balance, and finally exports the results in the tabular format consumed by the NZB demand model (“Energy Pathways” format).

The model is organised as a linear pipeline executed at start-up: (i) data loading; (ii) population

interpolation; (iii) statistical projection of the historical indicators; (iv) computation of a regionalization factor; (v) loading and regionalization of the appliance database; (vi) validation of the bottom-up estimate against the National Energy Balance (BEN); and (vii) scenario projection to 2050 with an equipment-stock turnover model. Each stage is described in the subsections that follow.

Figure 38 summarises this pipeline. Throughout the buildings modules the same graphical convention is used: parallelograms denote input data, with the primary source indicated in square brackets below each one; pink parallelograms denote assumptions selected by the user in the scenario interface; rectangles with a plain outline denote modelling parameters or functions; numbered circles denote model operations; and shaded blue rectangles denote the data produced by each operation. The module is implemented as a self-contained Python application whose outputs are exported to EnergyPathways; it runs on an annual time step and produces results at the state (UF) level. No intra-annual (hourly) load profile is applied in this version: demand is reported as annual totals.

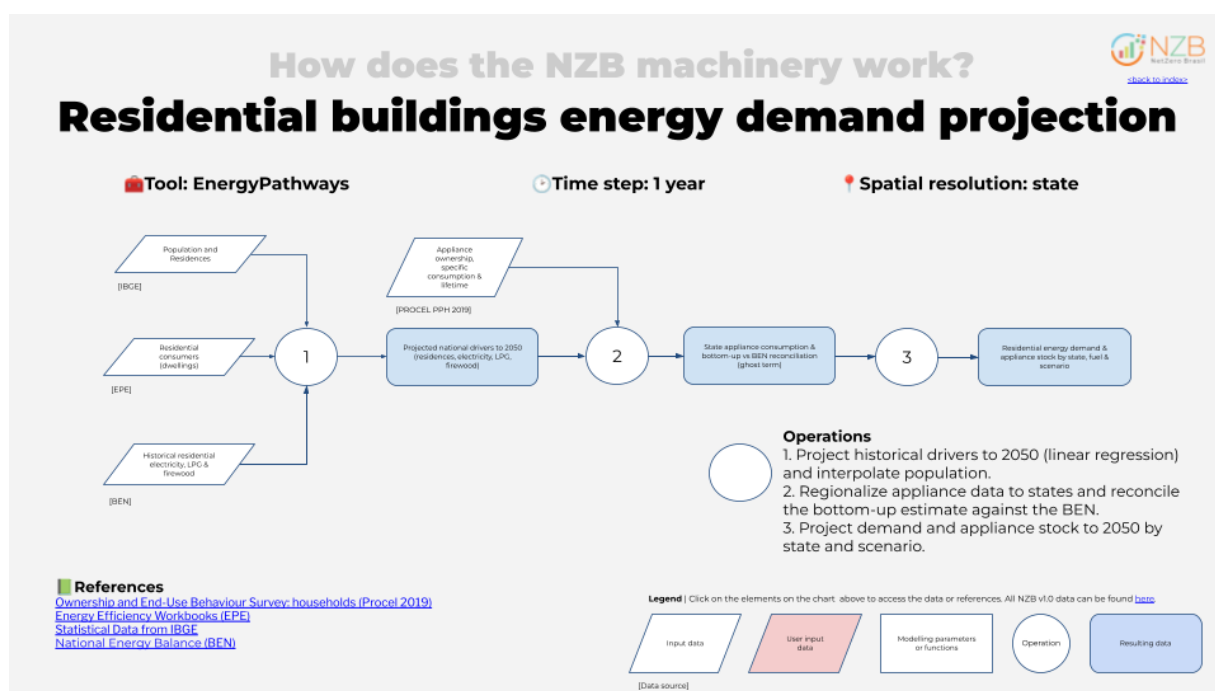


Figure 38: Residential buildings energy demand projection: input data, operations and resulting data.

Three families of input feed the module. The demographic and housing drivers — resident population and number of dwellings — are taken from the IBGE population projections [30], complemented by the number of residential electricity consumers reported by the EPE, which is used as a proxy for occupied dwellings [31]. The historical energy series — residential electricity, LPG and firewood — are taken from the National Energy Balance (BEN) [31]. The appliance layer — ownership rate, average number of units per household, specific consumption and useful life for each of the 75 appliance types — comes from the PROCEL/Eletrabras end-use and ownership survey (PPH 2019) [32, 33, 34].

The three operations shown in Figure 38 map directly onto the stages described below. **Operation 1** projects the historical drivers to 2050 by linear regression and interpolates the population series to annual resolution, producing the national driver set (dwellings, electricity, LPG and firewood). **Operation 2** regionalizes the national appliance data to the 27 UFs through the regionalization factor and reconciles the resulting bottom-up electricity estimate against the BEN; the unexplained difference

is carried forward as the residual “ghost” term, so that the sum of the appliance-based and residual components reproduces the observed consumption by construction. **Operation 3** rolls the appliance stock and the associated demand forward to 2050 for every state, fuel and electrification scenario, applying the equipment-stock turnover model and the fuel-substitution rules.

3.1.5.2 Data inputs

The model reads six comma-separated data files. Table 8 summarises each input, its unit, and its primary source. Energy quantities are handled internally in GWh (electricity) and tonnes of oil equivalent, tep (fossil fuels), with the conversion 1 tep = 11.63 MWh applied wherever electricity and fossil energy must be added together.⁴

Table 8: *Input datasets of the residential model*

Dataset (file)	Content	Unit	Source
Historical consumption (historico_consumo.csv)	Residential electricity, LPG and fire-wood consumption by UF and year (1989–2025)	GWh; 10 ³ tep	EPE, National Energy Balance (BEN) [31]
Residential consumers (historiconumero-deresidencias.csv)	Number of residential electricity consumers (proxy for occupied dwellings) by UF and year	units	EPE / utilities [31]
Population (populacao_interpolada.csv)	Estimated resident population by UF and year	inhabitants	IBGE population projections [30]
Average consumption (consumomedio...csv)	Average monthly consumption per consumer by UF	kWh/month	EPE / utilities [31]
Per-capita consumption (consumo_percapita.csv)	Per-capita residential electricity consumption by UF	kWh/inhab.	EPE / utilities [31]
Appliance database (EQUIPAMENTOS.csv)	Ownership, specific consumption, use intensity and lifetime of 75 appliance types	see Table 9	PROCEL/Eletrabras PPH 2019 [32, 33, 34]

Source: own elaboration based on the model source code and the cited references.

3.1.5.2.1 Appliance database

The appliance database (EQUIPAMENTOS.csv) is the heart of the bottom-up accounting. It contains 75 appliance types, each described by five parameters: national ownership rate (% of households owning the appliance), average number of units per household (units/household), estimated specific consumption per unit (MWh/year), intensity of use, and useful life (years). The *intensity of use* is taken from the PPH 2019 [32] as a pair of usage figures — average hours of use per day and average days of use per month — and is therefore expressed in h/day × days/month rather than as a single number.

The specific consumption per unit is obtained from those same two figures and the rated power of the

⁴1 tep = 11.63 MWh is the standard lower-heating-value oil-equivalent conversion used by the EPE in the Brazilian Energy Balance.

appliance,

$$e_k = \frac{P_k}{10^6} \times \underbrace{h_k d_k 12}_{\text{annual hours of use}} \quad [\text{MWh/year}], \quad (4)$$

with P_k the rated power in W, h_k the average hours of use per day and d_k the average days of use per month, all as reported in the PPH 2019. The model computes the three factors separately, but the PPH 2019 also publishes the resulting annual consumption per unit directly, and the two agree; the values in Table 9 are therefore the survey's own representative national figures rather than an independent estimate. Appliances are classified by energy source (*Fonte*): 62 are electric and 13 are fossil-fuelled, distributed across LPG (8), firewood (3), fuel oil (1), and kerosene (1). The electric appliances feed the electricity bottom-up; the LPG and firewood appliances feed the fossil validation and the electrification scenarios. Table 9 shows a representative extract.

Table 9: Extract of the appliance database (national parameters, base year 2019)

Appliance	Source	Ownership (%)	Spec. cons. (MWh/yr)	Life (yr)
Refrigerator	Electric	98.14	1.2089	15
Lamps	Electric	100.00	0.0839	10
Television	Electric	97.35	0.1343	10
Air conditioner	Electric	16.69	17.5935	12
Electric shower	Electric	40.18	0.2538	10
Washing machine	Electric	66.09	0.0319	12
Microwave	Electric	46.89	0.0383	10
Gas stove	LPG	—	—	—
Firewood stove	Firewood	—	—	—

Source: PROCEL/Eletrabras PPH 2019 [32], as encoded in `EQUIPAMENTOS.csv`. "Spec. cons." is the annual electricity consumption of one representative unit of the appliance, i.e. the national average reported by the survey for the equipment stock in use (Eq. (4)), not the consumption of a specific model. The air conditioner value is an annual figure for a unit in continuous seasonal use.

3.1.5.3 Methodology

3.1.5.3.1 Population interpolation

The population series is provided at annual resolution but may contain gaps. The model builds a continuous annual series for every UF over 2000–2050 by linear interpolation between the observed points,

$$P_u(t) = P_u(t_0) + (P_u(t_1) - P_u(t_0)) \frac{t - t_0}{t_1 - t_0}, \quad t_0 \leq t \leq t_1, \quad (5)$$

where t_0, t_1 are the observed years bracketing t . This hold-constant rule is only the endpoint behaviour of the gap-filling interpolation routine, and it applies within the historical window alone. The projection beyond the last historical year is not affected: population, like every other indicator, is extrapolated by the statistical projection described in the next paragraph.

3.1.5.3.2 Statistical projection of indicators

Each historical indicator—residential consumers, electricity, LPG, firewood, the firewood/LPG ratio, average and per-capita consumption, and population—is extrapolated independently for every UF (and for Brazil) by ordinary least-squares linear regression on the year,

$$\hat{y}_u(t) = a_u t + b_u, \quad (6)$$

where the slope a_u and intercept b_u are estimated from the observed series with `scipy.stats.linregress`. The projection covers 2019–2050. For each projected year the model also stores the coefficient of determination R^2 and a 95% prediction interval,

$$\hat{y}_u(t) \pm t_{0.975, n-2} \cdot s \cdot \sqrt{1 + \frac{1}{n} + \frac{(t - \bar{t})^2}{\sum_i (t_i - \bar{t})^2}}, \quad (7)$$

with s the square root of the residual mean square (s^2) and n the number of observations. The prediction interval is reported for transparency but is not propagated into the demand projection, which uses the central estimate $\hat{y}_u(t)$.

3.1.5.3.3 Regionalization factor

The appliance database provides national ownership and consumption parameters only. To distribute national quantities across states, the model computes a dimensionless regionalization factor f_u for each UF, defined as the average of the state's shares of three quantities in a reference year—electricity consumption, population, and residential consumers—subsequently normalised to sum to one:

$$f_u = \frac{g_u}{\sum_v g_v}, \quad g_u = \frac{1}{3} \left(\frac{E_u}{E_{BR}} + \frac{P_u}{P_{BR}} + \frac{R_u}{R_{BR}} \right), \quad (8)$$

where E , P and R are electricity consumption, population and residential consumers, and the subscript BR denotes the national total. In the denominator of f_u , v is a dummy summation index running over *all* 27 UFs — it is deliberately distinct from the free index u of the state being computed, so that the normalisation is the same for every state and the resulting factors sum to one. The reference year is the most recent year available in the historical consumption series.⁵ As an illustration, the resulting shares place São Paulo at about 0.24, Minas Gerais at 0.10, Rio de Janeiro at 0.08, and the smallest units (e.g. Roraima, Acre) below 0.004.

3.1.5.3.4 Electricity bottom-up and BEN validation

For each state the average annual electricity consumption of one dwelling is the ownership-weighted sum of the specific consumptions of the electric appliances,

$$c_u = \sum_{k \in \mathcal{E}} \pi_{k,u} e_k, \quad (9)$$

⁵The source code takes the reference year as the maximum year in `historico_consumo.csv`. In the original data this was 2019; in the current dataset the series extends to 2025, so the factor is computed on 2025 shares. For states without complete data the three shares default to the population share.

where $\pi_{k,u}$ is the ownership rate (fraction) of appliance k in state u and e_k its specific consumption (MWh/year); $\mathcal{E}$ is the set of electric appliances. Because appliance ownership is taken from the national survey, $\pi_{k,u} = \pi_{k,\text{BR}}$ for all states, giving a common per-dwelling consumption $c_u = c \approx 4.95$ MWh/year. The modelled state electricity consumption is then

$$\hat{C}_u = c_u R_u f_u, \quad (10)$$

with R_u the number of residences and f_u the regionalization factor.

The bottom-up estimate is validated against the residential electricity reported in the BEN for the base year 2019. For each geography the model reports the absolute and relative difference and a correction factor,

$$\Delta_u = \frac{\hat{C}_u - C_u^{\text{BEN}}}{C_u^{\text{BEN}}}, \quad \kappa_u = \frac{C_u^{\text{BEN}}}{\hat{C}_u}. \quad (11)$$

The gap between the appliance bottom-up and the BEN total is retained explicitly in the projection as a residual (“ghost”) term, described in Section 3.1.5.3.6.

3.1.5.3.5 Fossil-fuel validation

The LPG and firewood appliances are treated analogously. The modelled consumption of a fossil appliance k in state u , expressed in tep, is

$$M_{k,u} = \frac{\pi_{k,u} e_k R_u f_u}{11.63}, \quad (12)$$

and the state total per fuel is compared with the corresponding BEN residential consumption of LPG and firewood. As with electricity, the comparison quantifies how much of the reported fuel use the appliance inventory reproduces.

3.1.5.3.6 Projection to 2050 and electrification scenarios

The demand projection combines the statistically projected drivers with the appliance bottom-up. Two dimensionless growth factors are defined relative to 2019: a residence-growth factor and an electric-intensity factor,

$$\phi_u^R(t) = \frac{R_u(t)}{R_u(2019)}, \quad \phi_u^I(t) = \frac{E_u(t)/R_u(t)}{E_u(2019)/R_u(2019)}, \quad (13)$$

where $E_u(t)$ and $R_u(t)$ are the projected electricity and residences. The appliance-based (“bottom-up base”) electricity is grown with these factors,

$$B_u(t) = c_u \phi_u^R(t) \phi_u^I(t) f_u, \quad (14)$$

and the residual not captured by the appliance inventory—the ghost term—is the non-negative difference between the projected BEN electricity and the bottom-up base,

$$G_u(t) = \max(0, E_u(t) - B_u(t)). \quad (15)$$

Electrification is represented as a progressive substitution of LPG and firewood by electricity. A

scenario is defined by a target substitution share s reached in 2050, ramped linearly from zero in 2019,

$$\lambda(t) = s \frac{t - 2019}{2050 - 2019}. \quad (16)$$

The residual fossil consumption is $(1 - \lambda)$ times the projected fossil demand, and the energy no longer supplied by LPG or firewood is converted to electricity,

$$A_u(t) = \left(F_u^{\text{LPG}}(t) + F_u^{\text{firewood}}(t) \right) \lambda(t) \frac{11.63}{1000}, \quad (17)$$

with the fuel demands F in tep and A_u in GWh. Note that the two carriers enter Eq. (17) as a single aggregate and are converted at the plain energy-equivalence factor $1 \text{ tep} = 11.63 \text{ MWh}$: no end-use efficiency coefficient is applied, so one unit of substituted fuel energy becomes one energy-equivalent unit of electricity.⁶ Total residential electricity is the sum of the three components,

$$C_u^{\text{tot}}(t) = B_u(t) + G_u(t) + A_u(t). \quad (18)$$

The national projection is obtained by summing the state projections. The three electrification scenarios — in addition to the no-substitution base case, in which $A_u = 0$ and total electricity follows the projected BEN trend — are listed in Table 10.

Refinement note — LPG and firewood treated as a single substitution block

In this version LPG and firewood are added together in Eq. (17), share a single substitution ramp $\lambda(t)$, and are converted to electricity at the plain energy-equivalence factor, with no end-use efficiency coefficient. The team is aware that this is a strong simplification on two counts. First, the *end-use efficiency* of the two carriers is very different: replacing LPG by electricity typically requires of the order of half the delivered energy, whereas replacing firewood — especially in traditional open or low-efficiency combustion — requires of the order of one quarter, so a tep of firewood delivers substantially less useful energy than a tep of LPG. Treating both at energy-equivalence therefore tends to overstate the substitution electricity, and to overstate it more for firewood than for LPG. Second, the *feasible pace* of substitution also differs: LPG is more readily displaced (the electricity grid is already in place and the transition cost is lower), while firewood use is more persistent in specific regions and income groups for reasons of cost, availability and habit, so a single ramp to 2050 mixes two transition dynamics of very different speed. The simplification was retained here because the appliance bottom-up reproduces only about 1.6% of BEN LPG and 0.3% of BEN firewood (Table 11), so almost all of those fuel demands enter through the aggregate residual term and no equipment-level basis for differentiation is currently available. The next model-refinement cycle will (i) split the trajectory into two independent ramps, $\lambda_{\text{LPG}}(t)$ and $\lambda_{\text{firewood}}(t)$, with separate 2050 targets and speeds; (ii) introduce carrier-specific conversion-efficiency factors (indicatively of the order of $2\times$ for LPG→electricity and $4\times$ for firewood→electricity, to be calibrated against end-use efficiency literature); and (iii) align the residential treatment with the commercial module, which already applies an efficiency gain. Until then, the residential electrification results should be read as an *upper bound* on the electricity required to displace residential thermal fuels.

⁶This is a deliberate simplification of the present model version, adopted because the appliance inventory resolves only a marginal share of residential LPG and firewood use (Table 11) and therefore offers no empirical basis for carrier-specific efficiency coefficients. It differs from the commercial module, which applies a generic electrification efficiency gain $\eta_j > 1$ (Section 3.1.6.3.7). See the refinement note below.

Table 10: Electrification scenarios

Scenario	Substitution by 2050	Description
A	25%	One quarter of LPG and firewood demand electrified by 2050.
B	50%	Half of LPG and firewood demand electrified by 2050.
C	100%	Full electrification of LPG and firewood (fossil appliance ban).

Source: own elaboration based on the model source code. The substitution share ramps linearly from 0 in 2019 to the target in 2050.

3.1.5.3.7 Equipment-stock turnover

In parallel with the energy projection, the model tracks the installed stock of each appliance. The initial stock in the base year is the ownership rate times the number of residences, $S_{k,u}(2019) = \pi_{k,u} R_u(2019)$, and it evolves by a simple turnover balance,

$$S_{k,u}(t) = S_{k,u}(t-1) - \frac{S_{k,u}(t-1)}{L_k} + \pi_{k,u} (R_u(t) - R_u(t-1)), \quad (19)$$

where L_k is the useful life of appliance k (so $1/L_k$ is the annual replacement rate) and the last term is the addition of appliances into newly added dwellings (floored at zero). Ownership rates $\pi_{k,u}$ are held at their PPH 2019 values throughout, so the turnover balance replaces retiring units and equips new dwellings *at the observed 2019 penetration*; it does not raise penetration over time.

Refinement note — space conditioning: ownership growth and climate response

Space conditioning is currently represented as one of the 75 appliances of the PPH 2019 database, with a single national ownership rate (16.69%, Table 9) applied uniformly to all 27 UFs. Because Eq. (19) holds $\pi_{k,u}$ constant, the model has no mechanism by which air-conditioning penetration rises with income, and no mechanism by which it responds to the regional climate signal: Cooling Degree Days (CDD) are computed and projected to 2050 in this report, but only inside the data center module (Section 3.1.7), where the same $+0.25^\circ\text{C}$ per decade warming assumption is adopted. The team is aware that this is one of the main limitations of the beta version: space conditioning is precisely the end use expected to grow structurally faster than the sector average, driven jointly by purchasing power and by climate, and its growth is strongly heterogeneous across the country — regions already operating close to the thermal-comfort limit (North, Northeast, parts of the Centre-West) should see a more than proportional response to warming, while milder regions (South, higher-altitude areas) should see a much smaller net effect. In the present version this growth is captured only implicitly, through the aggregate dwelling and electricity-intensity drivers $\phi_u^R(t)$ and $\phi_u^I(t)$, which carry the historical average of all end uses. The next model-refinement cycle will introduce a dedicated air-conditioning penetration trajectory, specified as a function of projected per-capita income and of the state-level CDD path already available from the data center module, so that ownership — and not only unit consumption — becomes a scenario variable with explicit regional differentiation.

3.1.5.3.8 Technology-stock export

The stock series is not only an intermediate step of the energy projection: it is itself one of the outputs of the module. Once the turnover balance has been solved for every appliance, state and scenario, the series is written out as the technology-stock export — the `stock.csv` file of Table 14 — alongside the technology definitions in `techs.csv`, which give the subsector, useful life and decay function of each appliance, and the per-unit performance parameters in `tech_main_efficiency.csv`. Together these files describe the residential sector as an explicit technology stock rather than as an aggregate demand curve, so that the appliance categories used here can be carried forward consistently in the downstream demand model. Because ownership rates are held at their PPH 2019 values in Eq. (19), the exported stock reflects the replacement of retiring units and the equipment of new dwellings only; it should therefore be read together with the refinement note above, which sets out how penetration growth is to be introduced in the next refinement cycle.

3.1.5.4 Illustrative results

The results in this section were regenerated by re-executing the model's computational core on the datasets provided with the code. They are indicative: exact values depend on the vintage of the input files and on the reference year of the regionalization factor.

Table 11 reports the 2019 validation. The electricity bottom-up reproduces roughly one quarter of the BEN residential total, and the fuel bottom-up captures a small fraction of reported LPG and firewood use; the unexplained balance is carried forward as the ghost term. These gaps reflect the share-based regionalization, in which the per-dwelling consumption is weighted by a factor that sums to one across states rather than applied to the full dwelling count, and they are the reason the model retains an explicit residual term rather than relying on the appliance inventory alone.

Table 11: *Bottom-up versus BEN, Brazil, base year 2019*

Carrier	Bottom-up	BEN 2019	Difference
Electricity (GWh)	35,006	142,572	−75.4%
LPG (10 ³ tep)	173	10,636	−98.4%
Firewood (10 ³ tep)	38	13,083	−99.7%

Source: own elaboration by re-running the model. Electricity correction factor $\kappa_{BR} \approx 4.07$.

Table 12 summarises the projected national drivers, and Table 13 the projected 2050 residential electricity by scenario. Under the base scenario national residential electricity rises from about 146 TWh in 2019 to about 257 TWh in 2050, following the projected BEN trend; full electrification (Scenario C) raises the 2050 total to about 580 TWh while eliminating residential LPG and firewood.

Table 12: *Projected national drivers, 2019 and 2050*

Indicator	2019	2050
Residences (million)	73.8	126.2
Electricity, BEN trend (GWh)	145,606	257,617
LPG (10 ³ tep)	10,711	12,740
Firewood (10 ³ tep)	12,209	15,232

Source: own elaboration (linear-regression projection of the national historical series). The 2019 column reports the fitted trend values, which differ slightly from the observed BEN figures of Table 11.

Table 13: *Projected national residential electricity and residual fossil use in 2050, by scenario*

Scenario	Electricity (GWh)	Added by elec. (GWh)	Residual LPG (10 ³ tep)	Residual firewood (10 ³ tep)
A (25%)	337,996	80,771	9,489	11,346
B (50%)	418,767	161,542	6,326	7,564
C (100%)	580,309	323,084	0	0

Source: own elaboration by re-running the model. “Added by electrification” is the electricity that substitutes for LPG and firewood relative to the base scenario. The scenario totals are sums of the 27 state projections, whereas Table 12 reports the regression of the national series; the two differ by about 0.15% in 2050 (257,225 versus 257,617 GWh).

3.1.5.5 Model outputs

On request the application writes its results as a set of CSV files structured for the NZB demand model (“Energy Pathways” format), together with a text summary. The exported files are listed in Table 14. All labels and category values are translated to English on export. The scenario written to the demand and stock files is the one selected in the interface.

Table 14: *Files exported by the residential model*

File	Content
demand_drivers.csv	Projected population and residences by geography and year, tagged as demand drivers.
energy_demands.csv	Projected electricity (GWh), LPG and firewood (tep) by geography, year and scenario.
sales_share.csv	Appliance ownership shares by geography (base year 2019).
stock.csv	Projected appliance stock by geography, year and scenario.
tech_main_efficiency.csv	Per-unit specific consumption and useful life of each appliance.
techs.csv	Technology definitions (subsector, lifetime, decay function).
export_summary.txt	Human-readable summary of the run.

Source: own elaboration based on the export routines of the model.

3.1.5.6 Assumptions and limitations

The main assumptions and known limitations of the current implementation are:

- **National appliance parameters.** Ownership rates, specific consumptions and lifetimes are national values applied uniformly to every state; regional variation enters only through the aggregate regionalization factor, not through appliance-level differences.
- **Share-based regionalization.** The regionalization factor is a share that sums to one across states. Because per-dwelling consumption is weighted by this share rather than applied to the full dwelling count, the appliance bottom-up systematically understates the BEN totals; the difference is absorbed by the ghost term.
- **Linear trends.** All indicators are extrapolated with linear regression, which can produce implausible long-run values for saturating or declining series and does not capture structural change, saturation, or policy effects other than the explicit electrification switch.
- **Linear electrification.** Fuel substitution is imposed as a linear ramp to a fixed 2050 target, independent of costs, appliance turnover, or regional conditions.
- **Reference-year drift.** The regionalization reference year is the latest year in the historical file, whereas the bottom-up validation is fixed at 2019; keeping the input files aligned is required for internal consistency.
- **Efficiency held constant within the module.** Appliance specific consumptions are held at their base-year values over the whole horizon; efficiency improvement is not modelled here, but is applied downstream by the equipment-efficiency (MEPS) scenario lever of Section 4.6.1, which acts on the technology efficiencies exported by the module when the scenario is run in EnergyPathways.
- **Ownership held constant.** Ownership rates are fixed at their PPH 2019 values, so the stock

turnover replaces and equips new dwellings at the 2019 penetration and never raises it. Air-conditioning ownership is the clearest case where this matters: its penetration is known to depend jointly on household income, on the age structure of the population (older households are more sensitive to heat and spend more time indoors) and on the regional climate, so that the same income gain produces very different cooling uptake in the North and Northeast than in the South. The current version therefore does not represent air conditioning as a growing end use, and does not differentiate that growth by income class, age group or region; the team is aware that this is the single largest source of downward bias in the residential electricity projection under a warming climate.

- **No climate driver.** Cooling Degree Days are computed and projected in this report only for the data center module; the residential projection carries no explicit temperature or CDD response, nor any representation of the local warming induced by urbanisation (heat islands, reduced ventilation), which in large metropolitan areas adds to the regional climate signal.
- **LPG and firewood treated as one block.** The two carriers share a single substitution ramp and are converted to electricity at plain energy equivalence, with no end-use efficiency coefficient and no differentiation of substitution speed.

These limitations are documentation of the model as currently coded and indicate the priorities for its further development.

3.1.5.6.1 Consolidated assumptions, sources and parameter ranges

Table 15 brings together, in a single place, the hypotheses adopted in the residential module, the source of each variable, the range of values used and the reference year, following the reporting standard also applied in the public-lighting and data center modules.

Table 15: Residential module — consolidated assumptions, sources and parameter ranges

Assumption / variable	Value or range adopted	Source	Ref. year
Appliance ownership, units per household, specific consumption, useful life	75 appliance types (62 electric, 13 fuel-fired); ownership 0–100%; lifetimes 10–15 yr	PROCEL/Elektrobras PPH 2019 [32, 33, 34]	2019
Per-dwelling electricity consumption	$c \approx 4.95$ MWh/yr (national, applied to all UFs)	Derived from the appliance database	2019
Resident population	IBGE projections, linearly interpolated to annual resolution	IBGE [30]	2000–2050
Dwellings	Residential electricity consumers used as proxy	EPE/BEN [31]	1989–2025
Historical electricity, LPG, firewood	Series by UF	EPE/BEN [31]	1989–2025
Driver projection method	OLS linear regression on the year, per UF; central estimate used (95% prediction interval reported, not propagated)	Own elaboration	2019–2050
Regionalization factor f_u	Mean of electricity, population and consumer shares, normalised to sum to one	Own elaboration	Latest year of the input file
Energy conversion	1 tep = 11.63 MWh	EPE/BEN convention [31]	—
Electrification targets	25%, 50%, 100% of LPG + firewood by 2050, linear ramp from 2019	Scenario definition (Section 4.6)	2019–2050
Electrification efficiency gain	None applied (energy equivalence) — see the refinement note above	Model as coded	—
Appliance efficiency improvement	None (specific consumptions held at base-year values)	Model as coded	2019

Source: own elaboration based on the model source code and the cited references.

3.1.6 Commercial sector

3.1.6.1 Overview

Key message

The commercial model decomposes services-sector electricity into an end-use “bottom-up” term for six explicit subsectors (education, health, hotels, restaurants, supermarkets, and beauty salons), plus public lighting and data centers, and closes the remaining gap to the BEN commercial total with a residual “Others” term. It grows every subsector to 2050 by projecting the number of establishments at a combined consumers-and-GDP growth rate, and then converts a subsector-specific “thermal” share of demand from fuels to electricity under three electrification scenarios (25%, 50%, and 100% substitution by 2050).

This section documents the commercial-sector (services-sector) energy-demand model developed

for the NetZero Brasil (NZB) project. The model is a bottom-up, end-use accounting framework that reconstructs historical commercial electricity and thermal-fuel demand for each of Brazil's 27 federative units (UFs) and for the country as a whole, and projects that demand to 2050 under a set of electrification scenarios. It is implemented as a self-contained Python application (4.24.py) built on pandas, numpy, and a tkinter graphical interface, supported by a set of data modules that encode the building and equipment characteristics of each commercial subsector. The application loads historical series and per-subsector establishment inventories, estimates a 2023 bottom-up consumption for each subsector, reconciles the estimate against the official energy balance, and finally exports the results in the tabular format consumed by the NZB demand model ("Energy Pathways" format).

The model is organized as a linear pipeline: (i) data loading (historical consumption, consumers, GDP and population, and the subsector establishment databases); (ii) bottom-up estimation of 2023 electricity consumption for each commercial subsector; (iii) closure of the balance against the National Energy Balance (BEN) through a residual "Others" term; (iv) computation of a regionalization coefficient to distribute national quantities across states; (v) projection of the number of establishments and of consumption to 2050 with a combined consumers/GDP growth rate; (vi) application of electrification scenarios that progressively substitute thermal fuels by electricity; and (vii) export to the demand-model format. Each stage is described in the subsections that follow.

Figure 39 summarises this pipeline, using the same graphical convention as the residential module (Figure 38): parallelograms are input data with the source in square brackets, numbered circles are operations, and shaded blue rectangles are the data produced by each operation. The module runs in EnergyPathways on an annual time step with a state-level (UF) spatial resolution.

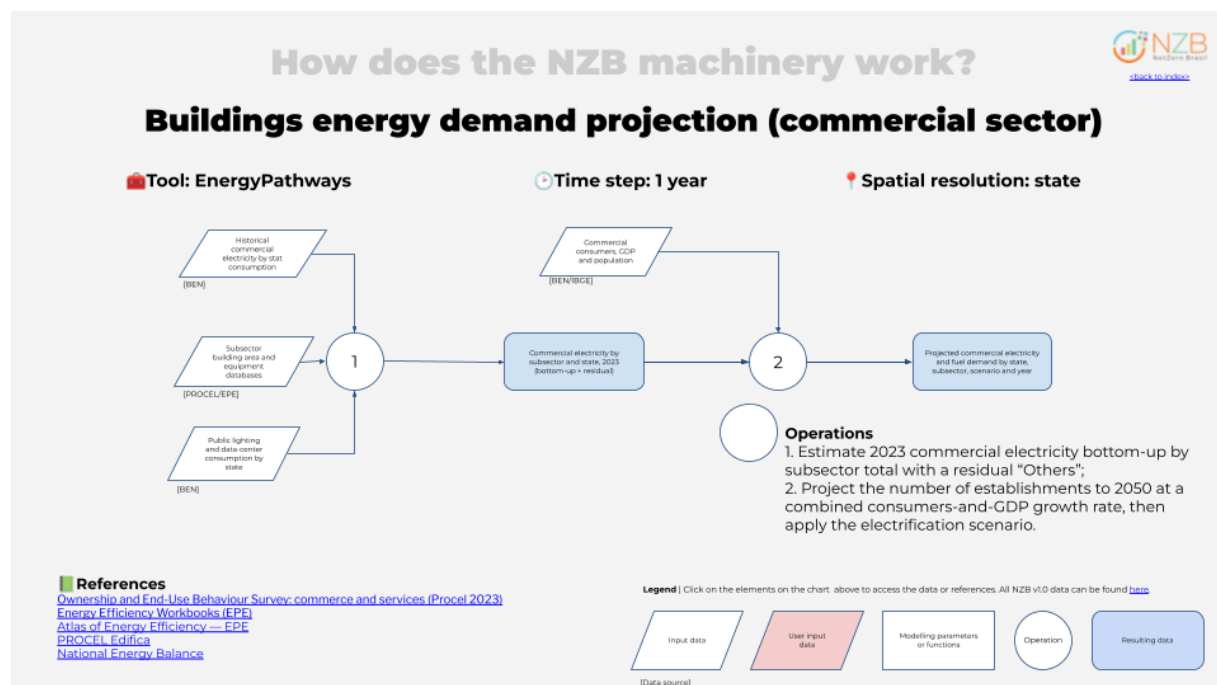


Figure 39: Buildings energy demand projection (commercial sector): input data, operations and resulting data.

The left-hand branch of the diagram assembles the base year. Historical commercial-sector electricity consumption by state comes from the BEN [35]; the subsector building-area and equipment databases

— average constructed area of a typical establishment, equipment counts, installed power and hours of use — come from the PROCEL end-use survey for commerce and services and from the EPE energy-efficiency workbooks and Atlas [36, 37]; and public-lighting and data center consumption by state are read from dedicated files, documented respectively in the public-lighting (Section 3.1.6.7) and data center (Section 3.1.7) parts of this report. **Operation 1** combines these into the 2023 commercial electricity matrix by subsector and state: the six explicit subsectors plus public lighting and data centers are estimated bottom-up, and the residual “Others” term closes the balance against the BEN commercial total.

The right-hand branch drives the projection. The number of commercial electricity consumers, GDP and population [35, 38] determine the combined consumers-and-GDP growth rate that **Operation 2** applies to the number of establishments of each subsector up to 2050. The selected electrification scenario is then applied to the thermal (fuel-supplied) share of each subsector, yielding the projected commercial electricity and fuel demand by state, subsector, scenario and year.

3.1.6.2 Data inputs

The model reads its inputs from a set of embedded Python data modules and three comma-separated files. Table 16 summarises each input, its content, and its primary source. Energy quantities are handled internally in GWh; the “thermal” (fuel) demand that is a candidate for electrification is tracked in GWh of useful/final energy alongside the electricity series.

Table 16: *Input data of the commercial model*

Input (module/file)	Content	Source
Commercial consumption (dadosBENconsumo.py)	Commercial-class electricity consumption by UF and year (2011–2024)	EPE, National Energy Balance (BEN) [35]
Commercial consumers (dadosBENconsumidores.py)	Number of commercial electricity consumers by region and year, and the UF-to-region map	EPE / distributors [35]
GDP and population (dadosPIBPOP.py)	Historical GDP and resident population, Brazil and states	IBGE [38]
Equipment database (dadosequipamentos.py)	Generic equipment list, categories and power/usage factors	PROCEL / EPE [36, 37]
Subsector databases (dadoseducacao.py, dadoshoteis.py, dadosrestaurante.py, dadossaude.py, dadossupermercados.py, dadossalao.py)	Per-region building area, equipment counts, ownership percentages and estimated population served for each of the six explicit subsectors	PROCEL/EPE surveys and own elaboration [36, 37]
Public lighting (consumoIP2023.csv)	Public-lighting electricity consumption by UF, 2023	EPE/ANEEL [35]
Data centers (datacenters.csv)	data center electricity consumption by UF, 2023	own elaboration (see the data center section 3.1.7)
Climate (optional) (CDD_REGIONAL_COMPLETO.csv)	Regional mean temperature and cooling degree days	INMET

Source: own elaboration based on the model source code and the cited references. The climate file feeds an exploratory temperature/CDD tab and is not used in the demand projection of the current version.

3.1.6.2.1 Subsector establishment databases

The heart of the bottom-up accounting is the set of six subsector databases. Each provides, for every Brazilian region, the average constructed area of a typical establishment, the average count (or ownership percentage) of the main electricity-consuming equipment, and the population served by the region. The model turns these into an average annual consumption per establishment by summing, over the relevant equipment, the product of installed power, hours of use per day, and days of use per year, plus a floor-area lighting/general term. As an illustration, a typical education establishment sums lighting and general use ($\text{area} \times 15 \text{ W/m}^2 \times 6 \text{ h} \times 200 \text{ days}$), refrigeration, electric stoves and ovens, exhaust hoods, administrative computers, classroom air conditioning weighted by the penetration rate, and electric showers. Each subsector has its own equipment list and duty cycles; supermarkets, for example, are dominated by vertical and horizontal refrigeration, self-service counters, display cases and central air conditioning.

3.1.6.3 Methodology

3.1.6.3.1 Bottom-up consumption per subsector

For a subsector j the annual electricity consumption of a representative establishment is

$$u_j = a_j \ell_j + \sum_{k \in \mathcal{K}_j} n_{k,j} \frac{P_k h_k d_k}{10^3}, \quad (20)$$

where u_j is in kWh/year, a_j is the average constructed area (m^2), ℓ_j a floor-area lighting/general-use intensity in $\text{kWh}/(\text{m}^2 \cdot \text{year})$, $n_{k,j}$ the average number (or ownership fraction) of equipment k , and P_k , h_k , d_k its power (W), daily hours and yearly days of use — so that the second term, $P_k h_k d_k / 10^3$, is also in kWh/year. The subsector's national consumption is obtained by scaling the per-establishment value by the population served,

$$C_j = \frac{u_j}{10^6} \sum_r \text{POP}_r, \quad (21)$$

with u_j in kWh/year and C_j in GWh/year, summed over regions r (the national row is excluded to avoid double counting). The six explicit subsectors are education, health, hotels, restaurants, supermarkets and beauty salons.

3.1.6.3.2 Public lighting, data centers, and the residual “Others”

Public lighting and data centers are not modelled bottom-up; their 2023 consumption is read directly from the two input files (`consumoIP2023.csv` and `datacenters.csv`). The remaining commercial consumption not attributed to any explicit subsector is captured by a residual “Others” term, computed so that the sum of all components reproduces the BEN commercial total,

$$C_{\text{Others}} = \max\left(0, C_{\text{com}}^{\text{BEN}} - C_{\text{IP}} - C_{\text{DC}} - \sum_j C_j\right), \quad (22)$$

where $C_{\text{com}}^{\text{BEN}}$ is the 2023 commercial-class total from the BEN, C_{IP} and C_{DC} are the public-lighting and data center totals, and the sum runs over the six explicit subsectors. By construction the calculated total then equals the BEN total, and “Others” plays the same role as the residual (“ghost”) term in the residential model.

Public lighting and data centers belong to the commercial class of the BEN, but they are modelled in independent codes because each follows its own flowchart and methodology (a lamp-stock turnover model and a capacity-driven projection, respectively). Subtracting their 2023 consumption from the commercial gross figure therefore serves two purposes: it prevents double counting within the sector aggregate, and it keeps the 2023 validation coherent with the PPH reference, which covers the six explicit subsectors only. In the next stage the Buildings modules will be centralised into a single application; data centers, however, will remain disaggregated in the reporting, because their expected exponential growth — combined with the fact that a data center is already an essentially all-electric facility, with no fuel-to-electricity substitution lever — would otherwise mask the inferences drawn from sustainable-policy scenarios in the other subsectors.

3.1.6.3.3 Validation against the BEN

The bottom-up estimate is compared, for the base year 2023, against indicative target shares of the commercial total drawn from the BEN technology breakdown. For each component the model reports

the calculated consumption, its share of the calculated total, and the target share; the difference measures how far the end-use inventory is from the reference structure. Because “Others” absorbs the balance, the comparison is diagnostic for the six explicit subsectors and for public lighting and data centers — all the components read or built independently of the residual — rather than a closure test on the total.

3.1.6.3.4 Regionalization coefficient

To distribute national quantities across states the model computes, for each UF, a regionalization coefficient equal to the average, over the available years, of the mean of two shares—the state’s share of national commercial consumers and its share of national commercial consumption,

$$\beta_u = \frac{1}{|\mathcal{T}|} \sum_{t \in \mathcal{T}} \frac{1}{2} \left(\frac{N_u(t)}{N_{BR}(t)} + \frac{C_u(t)}{C_{BR}(t)} \right), \quad (23)$$

where N is the number of consumers, C the commercial consumption, and $\mathcal{T}$ the set of years for which both the consumer and the consumption series are observed. Unlike the residential regionalization factor, β_u is *not* renormalised to sum to one across states; it is an average of shares used to split national figures, and its cross-state sum is below unity.

3.1.6.3.5 Establishment count and growth rate

The number of establishments of each subsector in the base year is derived from the national population through a fixed ratio (for example, one education establishment per 3,000 inhabitants, one hotel per 10,000, one restaurant per 1,500, one health establishment per 5,000, one supermarket per 8,000, and one beauty salon per 3,000). These ratios are not arbitrary: they result from dividing the PPH 2023 estimate of the number of establishments of each subsector by the BEN count of commercial consumers by UF, i.e. they are establishments-per-consumer ratios observed in the base year and applied to the national population. The stock is then grown with a single national growth rate that blends the historical growth of commercial consumers and of GDP,

$$g = \max(0.005, 0.4 \bar{g}_N + 0.6 \bar{g}_{GDP}), \quad (24)$$

where $\bar{g}_N$ and $\bar{g}_{GDP}$ are the average year-on-year growth rates of consumers and GDP. The weights (0.4, 0.6) are a judgement-based blend of two proxies for the expansion of the services sector: the growth of the number of commercial consumers (a proxy for the physical expansion of the establishment stock) and the growth of GDP (a proxy for the economic activity that drives services), with the larger weight on GDP expressing the hypothesis that services activity follows income more closely than it follows the count of electricity connections. The floor of 0.005 is a safeguard that guarantees a minimum growth of 0.5%/yr even if the historical series produce a negative or near-zero rate. The number of establishments in year t is $n_j(t) = n_j(2023) (1 + g)^{t-2023}$.

Refinement note — GDP series and the magnitude of the growth rate

The GDP series currently feeding $\bar{g}_{\text{GDP}}$ is in nominal terms (current R\$), so it embeds inflation; over the historical window it yields $\bar{g}_{\text{GDP}} \approx 10\%/yr$ and a combined rate of roughly $6.6\%/yr$, well above the plausible real growth of the sector. This is the main driver of the high 2050 commercial totals reported in this section, and it was identified during the documentation stage, after the datasets had been delivered to the integration pipeline. The correction — substituting real GDP, which would bring the combined rate to roughly $2\%/yr$, consistent with the $2.5\%/yr$ default the code itself adopts when the GDP series is unavailable — is scheduled for the next model-refinement cycle. Until then, the 2050 levels in this section should be read as an upper envelope, with the scenario *differences* (which are driven by the electrification mechanism, not by the growth rate) remaining meaningful.

3.1.6.3.6 Projection to 2050

Consumption per establishment is held at its 2023 value and the subsector consumption grows with the establishment count,

$$C_j(t) = n_j(t) \frac{C_j(2023)}{n_j(2023)}, \quad (25)$$

for $t = 2026, \dots, 2050$.

Public lighting and data centers are projected directly from their 2023 level at the same rate g . An optional toggle “BEN convergence” rescales the base-year subsector consumptions by the factor $C_{\text{com}}^{\text{BEN}} / \sum_j C_j(2023)$ so that the calculated 2023 total matches the BEN exactly before projecting.

Refinement note — space conditioning is not an explicit lever in the commercial module

Space conditioning enters Eq. (20) only implicitly, inside the floor-area intensity ℓ_j and the equipment list of each subsector, and it is then projected forward with the establishment count at the single national growth rate g . There is consequently no dedicated lever through which cooling demand can intensify — neither with rising purchasing power nor with the projected warming signal — even though the climate/CDD file is loaded by the model (Table 16) and CDD trajectories to 2050 already exist in the data center module (Section 3.1.7). The team is aware that cooling is the commercial end use most likely to grow faster than the subsector average, and with a strong regional gradient. The next model-refinement cycle will separate the conditioning share of ℓ_j from the remaining uses and drive it with the state-level CDD path and an income term, so that the commercial and residential modules represent cooling on the same basis.

3.1.6.3.7 Electrification scenarios

Each subsector is assigned a “thermal fraction” θ_j —the share of its demand supplied by fuels (LPG, natural gas, firewood) and therefore a candidate for electrification (Table 17). A scenario is defined by a target electrification share s reached in 2050, ramped linearly from 2026,

$$\lambda(t) = s \frac{t - 2026}{2050 - 2026}, \quad t \geq 2026, \quad (26)$$

with $\lambda = 0$ up to 2025. Splitting demand into a non-thermal part and a thermal part, the electricity assigned to subsector j in year t is

$$C_j^{\text{elec}}(t) = C_j(t) \left[(1 - \theta_j) + \theta_j (1 - \lambda(t)) + \theta_j \frac{\lambda(t)}{\eta_j} \right], \quad (27)$$

and the residual thermal-fuel demand is

$$C_j^{\text{gas}}(t) = C_j(t) \theta_j (1 - \lambda(t)), \quad (28)$$

where $\eta_j > 1$ is an electrification efficiency gain (1.2 for education, 1.3 for hotels and restaurants, and 1.15 otherwise). The role of η_j is to preserve *useful* energy in the substitution: fuel demand is normalised to final energy by the BEN convention (1 tep = 11.63 MWh), but the electricity needed to deliver the same service is the fuel energy divided by the ratio of appliance efficiencies, $\eta = \eta_{\text{elec}}/\eta_{\text{fuel}}$. The generic value follows directly from the efficiencies the model itself declares in its technology export (0.85 for the electric technology against 0.70 for the gas technology, giving $0.85/0.70 \approx 1.2$). The sectoral deviations reflect the end-use profile of each subsector: hotels and restaurants (1.3) have a thermal share dominated by cooking, where the advantage of electric appliances is largest (induction/resistive at roughly 0.80–0.90 against roughly 0.60–0.65 for LPG); education (1.2) mixes cooking and water heating, in line with the generic ratio; and the remaining subsectors (1.15) have more heterogeneous thermal uses, warranting a more conservative gain. These sectoral values are assumptions — the data needed to estimate a precise η_j per subsector do not exist for Brazil — but a single uniform ratio would be harder to defend, since each establishment profile carries an entirely different equipment mix. Because the not-yet-electrified thermal share is retained in the electricity series at full value while the electrified share is scaled by $1/\eta_j$, higher electrification targets slightly lower the total electricity figure while progressively eliminating the thermal-fuel demand. The three scenarios are listed in Table 18.

Refinement note — fuel-blind thermal fraction and generic efficiency gain

The thermal fraction θ_j (Table 17) aggregates LPG, natural gas and firewood into a single electrifiable block per subsector, and both the substitution ramp $\lambda(t)$ and the efficiency gain η_j are defined at subsector level rather than by carrier. The team is aware that end-use efficiency and the feasible pace of substitution differ markedly between these carriers — firewood, in particular, delivers far less useful energy per unit of input than LPG or natural gas, and is displaced more slowly — so that a single (λ, η_j) pair applied to the whole thermal block cannot reproduce the carrier-specific dynamics. Note also that η_j is more conservative than the residential module, which applies no efficiency gain at all (Eq. (17)); harmonising the two is a known consistency gap. The next model-refinement cycle will disaggregate θ_j by carrier and attach a carrier-specific ramp and conversion-efficiency factor to each, with the residential and commercial modules parameterised on a common basis.

Table 17: *Thermal fraction θ_j by subsector*

Subsector	Thermal fraction θ_j
Restaurants	0.45
Hotels	0.40
Education	0.35
Beauty salons	0.30
Others	0.25
Health	0.20
Supermarkets	0.15
Public lighting / Data centers	0.00

Source: own elaboration, computed from the PROCEL/Eletrabras PPH end-use and equipment data [32], as encoded in the model source code. The six explicit subsectors are precisely those covered by that survey, so its equipment and fuel-use structure was taken as the reference for the whole commercial class; the “Others” value is the residual category calibrated on the same basis. The thermal fraction is the share of a subsector’s demand treated as fuel-supplied and therefore electrifiable.

Table 18: *Electrification scenarios*

Scenario	Substitution by 2050	Description
A	25%	One quarter of the thermal demand electrified by 2050.
B	50%	Half of the thermal demand electrified by 2050.
C	100%	Full electrification of the thermal demand.

Source: own elaboration based on the model source code. The substitution share ramps linearly from 0 in 2026 to the target in 2050.

3.1.6.3.8 Equipment and technology stock

For the demand-model export the model also carries the number of establishments as a “stock” and defines, for each subsector, an electric and a gas technology with assumed efficiencies (0.85 and 0.70) and lifetimes (electric: 10–20 yr, mean 15; gas: 12–25 yr, mean 18) following an exponential stock-decay function. Sales shares between the electric, gas and biomass technologies are derived from the thermal fraction and the electrification ramp.

3.1.6.4 Illustrative results

The figures in this section were produced by re-executing the model’s computational core on the data modules provided with the code. They are indicative: exact values depend on the vintage of the input files.

The 2023 commercial-class total read from the BEN is about 90,611 GWh (≈ 91 TWh). Table 19

reports the bottom-up decomposition against the indicative target shares. Supermarkets and public lighting are the largest explicit components; education, hotels, health, restaurants and beauty salons are individually small; and the residual “Others” absorbs about 38% of the total. By construction the calculated total equals the BEN total.

Table 19: *Bottom-up decomposition of commercial electricity, Brazil, base year 2023*

Component	Calculated (GWh)	Share (%)	Target (%)
Education	2,662	2.9	4.0
Health	5,040	5.6	9.0
Hotels	2,465	2.7	7.0
Restaurants	4,598	5.1	7.0
Supermarkets	19,514	21.5	10.0
Beauty salons	2,313	2.6	0.0
Public lighting	20,023	22.1	22.1
Data centers	2	0.0	0.0
Others (residual)	33,995	37.5	63.0
Total	90,611	100.0	—

Source: own elaboration by re-running the model. The data center figure is negligible in the current input file. “Target” shares are the indicative BEN structure encoded in the model. The public-lighting line reproduces the 20,023 GWh read from the commercial input file; the 2023 base year of public lighting has since been settled on the ABCIP census (13,484.9 GWh, Section 3.1.6.7), which puts the component at 14.9% of the commercial class and reassigns the difference of about 6,538 GWh to the residual “Others” (about 40,532 GWh, 44.7%). The commercial total is unaffected, because the residual is defined so that the components reproduce the BEN commercial class.

The unit consumption of a representative establishment (Table 20) ranges from about 0.034 GWh/yr for restaurants and beauty salons to 0.769 GWh/yr for supermarkets. Two effects drive this spread and they compound: the refrigeration-intensive equipment mix of supermarkets, and the difference in average constructed area a_j between subsectors, which scales the floor-area term $a_j \ell_j$ of Eq. (20). A supermarket therefore differs from a beauty salon both in what it operates and in how much floor area it lights and conditions.

Table 20: *Estimated 2023 electricity consumption per establishment*

Subsector	Establishments	GWh/establishment
Supermarkets	25,385	0.769
Health	40,616	0.124
Hotels	20,308	0.121
Education	67,693	0.039
Beauty salons	67,693	0.034
Restaurants	135,386	0.034

Source: own elaboration. Establishment counts are derived from the 2023 population through fixed per-capita ratios.

The regionalization coefficients concentrate demand in the Southeast: São Paulo ($\beta \approx 0.21$), Rio de Janeiro (0.07) and Minas Gerais (0.07) lead, followed by Paraná (0.05), Santa Catarina and Bahia (0.03 each). The combined consumers-and-GDP growth rate estimated from the historical series is about 6.6% per year, which compounds to a large stock expansion over the horizon.

Table 21 summarises the projected national totals in 2050 by scenario, including public lighting and data centers. Total commercial electricity rises from about 110 TWh in 2026 to roughly 490–502 TWh in 2050; the residual thermal-fuel demand grows to about 72 TWh under 25% electrification and is eliminated under full electrification.

Table 21: *Projected national commercial demand in 2026 and 2050, by scenario*

Scenario	Elec. 2026 (GWh)	Elec. 2050 (GWh)	Fuel 2026 (GWh)	Fuel 2050 (GWh)
A (25%)	109,674	501,609	20,715	71,566
B (50%)	109,674	498,024	20,715	47,711
C (100%)	109,674	490,852	20,715	0

Source: own elaboration by re-running the model. “Fuel” is the residual thermal-fuel demand. The electricity total falls slightly as electrification rises because electrified thermal energy is scaled by an efficiency factor greater than one (Section 3.1.6.3.7).

3.1.6.5 Model outputs

On request the application writes its results as seven CSV files structured for the NZB demand model (“Energy Pathways” format). The files cover all 27 UFs plus the national aggregate and the years 2000–2050, with the historical portion (2000–2025) disaggregated from the BEN by subsector and state share and the projected portion (2026–2050) taken from the stock projection under the selected scenario. The exported files are listed in Table 22.

Table 22: *Files exported by the commercial model*

File	Content
DemandDrivers.csv	Population, GDP and establishment-stock drivers, with the electricity and gas demand values by subsector, geography and year.
DemandEnergyDemands_historical.csv	Historical (2000–2025) electricity and gas demand by subsector and geography.
DemandEnergyDemands_complete.csv	Full 2000–2050 electricity and gas demand under the selected scenario.
DemandSalesShareMeasures.csv	Electric/gas/biomass sales shares by subsector, geography and year.
DemandStock.csv	Number of establishments (stock) by subsector, geography and year.
DemandTechMainEfficiency.csv	Efficiency of the electric and gas technologies of each subsector.
DemandTechs.csv	Technology definitions (lifetime, decay function, cost of capital).

Source: own elaboration based on the export routines of the model. Labels are written in English on export.

3.1.6.6 Assumptions and limitations

No intra-annual (hourly) load profile is applied in this version of the commercial module: demand is computed and reported on an annual time step. Sub-daily and seasonal load curves for the residential and commercial sectors are already available in the project database (daily, weekday and monthly resolution), but their use was deferred: allocating the electrified cooking and water-heating loads to the correct hours requires an end-use time-allocation study (e.g. when the cooking peak of the restaurant subsector actually starts), without which an incorrect distribution would create artificial peaks. This refinement is planned for the Buildings modules as a whole, with the exception of data centers.

The main assumptions and known limitations of the current implementation are listed here. These are the model limitations as currently coded and indicate the priorities for its further development.

- **Residual closure.** “Others” is defined as the balance that makes the calculated total equal the BEN commercial total, so the sum matches the BEN by construction and the bottom-up accuracy can only be judged component by component, not on the total.
- **Fixed per-capita establishment ratios.** The number of establishments of each subsector is a fixed ratio of population; regional and structural differences in the density of services are not represented.
- **Single national growth rate.** All subsectors grow at one combined consumers/GDP rate (about 6.6%/yr on the current data), applied as compound growth to 2050; the rate is not subsector-specific and can produce large long-run stocks.
- **Constant unit consumption.** Consumption per establishment is held at its 2023 value; equipment efficiency improvement and changes in service intensity are not modelled *inside the module*, except through the explicit electrification switch. Efficiency improvement is instead applied downstream, by the equipment-efficiency (MEPS) scenario lever of Section 4.6.1, which acts on the technology efficiencies exported by the module when the scenario is run in EnergyPathways. The module output should therefore not be read as a statement that efficiency is assumed frozen to 2050 in the scenarios.
- **Thermal fractions and efficiency gains are assumptions.** The electrifiable share θ_j and the efficiency gains η_j are fixed per-subsector parameters, and the electricity series retains the not-yet-electrified thermal share at full value, which makes the total electricity fall slightly as electrification rises.
- **Un-normalised regionalization.** The regionalization coefficient is an average of two shares and is not renormalised to sum to one across states.
- **Input-file dependence.** Public lighting and data centers are read from external files; in the dataset used here the current data center consumption is negligible, and the climate/CDD file is used only for exploratory analysis, not in the demand projection.
- **Fuel-blind thermal block.** The thermal fraction θ_j aggregates LPG, natural gas and firewood, and both the substitution ramp and the efficiency gain η_j are subsector-level rather than carrier-level parameters. The θ_j values are derived from the PPH equipment structure of the six surveyed subsectors and extended to the residual category; they are not measured fuel shares by subsector, and calibrating them against subsector-level fuel statistics is a pending refinement.

- **Space conditioning without a dedicated lever.** Cooling is embedded in the floor-area intensity ℓ_j and grows only with the establishment count; there is no income or CDD-driven intensification of air-conditioning use.

3.1.6.6.1 Consolidated assumptions, sources and parameter ranges

Table 23 consolidates the hypotheses of the commercial module, the source of each variable, the range of values used and the reference year.

Table 23: *Commercial module — consolidated assumptions, sources and parameter ranges*

Assumption / variable	Value or range adopted	Source	Ref. year
Explicit subsectors	Education, health, hotels, restaurants, supermarkets, beauty salons; balance in a residual “Others”	Own elaboration	2023
Establishments per inhabitant	1 per 1,500 (restaurants) to 1 per 10,000 (hotels)	Own elaboration	2023
Per-establishment consumption	Floor-area intensity ℓ_j plus equipment inventory (power, daily hours, days per year)	Equipment data modules of the application	2023
Commercial-class total	$\approx 90,611$ GWh (national)	EPE/BEN [31]	2023
Establishment growth rate g	$\max(0.5\%, 0.4\bar{g}_N + 0.6\bar{g}_{\text{GDP}})$; $\approx 6.6\%/yr$ on the current data; single national rate	Own elaboration from BEN consumers and GDP	2023–2050
Regionalization coefficient β_u	Mean of consumer and consumption shares, averaged over available years; not renormalised	Own elaboration	Multi-year
Thermal fraction θ_j	0.15 (supermarkets) to 0.45 (restaurants); 0.00 for public lighting and data centers	Own elaboration	2023
Electrification efficiency gain η_j	1.15 (default), 1.20 (education), 1.30 (hotels, restaurants)	Own elaboration	—
Technology efficiencies / lifetimes	Electric 0.85, 10–20 yr (mean 15); gas 0.70, 12–25 yr (mean 18)	Own elaboration	—
Electrification targets	25%, 50%, 100% of thermal demand by 2050, linear ramp from 2026	Scenario definition (Section 4.6)	2026–2050
Unit consumption trend	Held constant at the 2023 value	Model as coded	2023
Climate (CDD)	Loaded but used for exploratory analysis only	INMET / ASHRAE [39]	2020

Source: own elaboration based on the model source code and the cited references.

3.1.6.7 Public lighting

Key message

The public-lighting model anchors 2023 electricity use to the ABCIP census (13,484.9 GWh), then projects demand to 2050 with a dynamic lamp-stock model in which lamps retire at the end of their service life and are replaced by a mix that shifts progressively towards LED. Demand is driven by three levers: the LED penetration target in 2050 (30%, 60% or 100%), the annual LED efficacy improvement (0.5% or 2.0%), and a projected growth rate for the number of lighting points taken from the BEN.

3.1.6.7.1 Overview

This section documents the public-lighting energy-demand model developed for the NetZero Brasil (NZB) project. The model is a bottom-up, technology-stock accounting framework that reconstructs public-lighting (*iluminação pública*, IP) electricity demand for each of Brazil's 27 federative units (UFs), for the five macro-regions, and for the country as a whole, and projects that demand to 2050 under a set of lamp-replacement and LED-efficiency scenarios. It is implemented as a self-contained Python application (2.1.py) built on `pandas`, `numpy`, `matplotlib`, and a `tkinter` graphical interface. The application loads the 2023 national lighting census and the historical energy balance, calibrates the base year to the census, and then rolls an age-structured lamp stock forward to 2050, exporting the results in the tabular format consumed by the NZB demand model ("Energy Pathways" format).

The model is organised as a pipeline executed for the selected geography: (i) loading of the ABCIP census and the National Energy Balance (BEN); (ii) lamp powers derived from luminous efficacy; (iii) a trend growth rate estimated from the BEN; (iv) a base-year scale factor that reconciles the bottom-up estimate with the census; (v) construction of an age-structured initial stock; (vi) a dynamic stock-turnover projection to 2050; and (vii) computation of derived indicators and export. Each stage is described in the subsections that follow.

Figure 40 summarises this pipeline. In addition to the elements already used in the residential and commercial diagrams, the public-lighting flowchart makes explicit the block of *user input data* (shown in pink): the LED penetration target in 2050, the LED-efficiency scenario, the daily operating hours, and the electricity tariff (R\$/kWh). The tariff deserves a remark: it does not feed back into the demand projection — consumption is driven by the lamp stock, the operating hours and the technology mix, not by price — and is used only to convert the resulting consumption into the monetary indicators reported by the standalone tool; in the NZB project, electricity prices are determined endogenously by the MACRO supply-side model. These are the switches exposed to the user in the model interface (the scenario panel of the application), and they are what distinguishes one public-lighting projection from another.

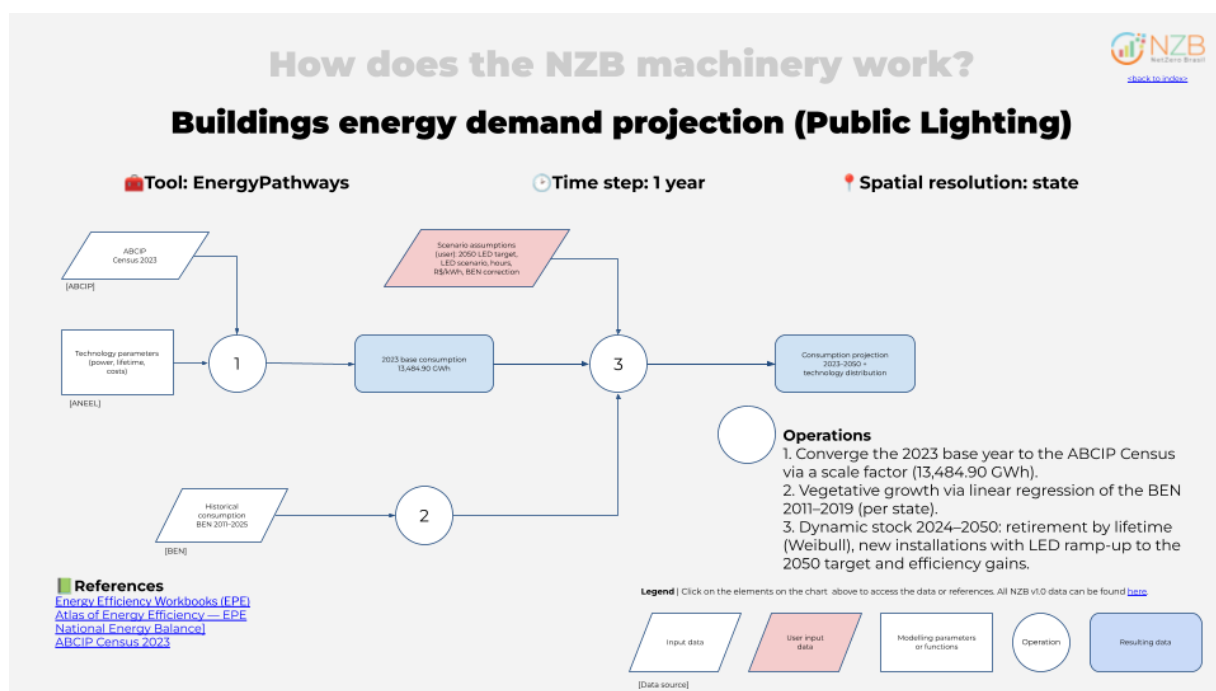


Figure 40: Public lighting energy demand projection (commercial sector): input data, operations and resulting data.

The module has two external inputs and one internal parameter set. The ABCIP 2023 lighting census [40] provides the number of lighting points, the consumption by UF and region, the technology distribution of the installed stock and the average luminous efficacy; the historical BEN series (2011–2025) [31] provides the observed public-lighting consumption by state; and the technology database — power derived from luminous efficacy, service life and installation and maintenance costs of the nine technologies — follows the ANEEL and model defaults reported in Table 25.

Operation 1 converges the base year to the census: the bottom-up estimate obtained from the stock and the derived powers is multiplied by a dimensionless scale factor so that the 2023 base consumption reproduces the census figure of 13,484.90 GWh. **Operation 2** estimates the trend growth of the number of lighting points from a linear regression of the BEN consumption series (2011–2019, per state), i.e. the growth that the lighting stock would follow in the absence of any technology-substitution policy. **Operation 3** rolls the age-structured stock forward from 2024 to 2050: each year, lamps that have reached the end of their service life are retired according to the assumed decay function, the stock is expanded by the projected growth rate, and the resulting new installations are allocated between LED and the incumbent technologies along a ramp that reaches the user-selected LED target in 2050, with the LED unit power falling at the selected annual efficiency-gain rate. The output is the consumption projection for 2023–2050 together with the evolution of the technology distribution of the stock.

3.1.6.7.2 Data inputs

The model reads two comma-separated data files and a set of internal technology parameters. Table 24 summarises the external inputs, their unit, and their primary source. Electricity is handled internally in GWh; lamp powers are handled in watts and converted to annual energy with the common operating assumption of $h = 11.5$ hours per day over 365 days.

Table 24: *External input datasets of the public-lighting model*

Dataset (file)	Content	Unit	Source
Lighting census (censo_abcip_2023.csv)	Total lighting points, points and consumption by UF and region, technology distribution, average luminous efficacy and average LED power, base year 2023	units; GWh; % ; lm/W; W	ABCIP 2023 census [40]
Historical consumption (dados_ip_ben.csv)	Public-lighting electricity consumption by UF and year (2011–2025)	GWh	EPE, National Energy Balance (BEN) [31]

Source: own elaboration based on the model source code and the cited references. A national BEN series (2011–2025) is also embedded in the code for the correction step.

3.1.6.7.2.1 Note on the base-year source

The ABCIP 2023 census [40] is used as the anchor of the base year for the number of lighting points, the technology distribution of the stock and the average luminous efficacy. It is adopted here because it is the best national source currently available on the Brazilian public-lighting stock, but its known limitations should be stated explicitly: coverage is uneven across municipalities and states, part of the reported stock is estimated rather than surveyed, the technology shares and efficacies are national averages published at limited resolution, and the census reports a stock whose reported consumption is not fully consistent with the bottom-up product of points, powers and operating hours — a discrepancy absorbed here by the base-year scale factor α (Eq. (33), $\alpha \approx 0.869$ nationally). The census is therefore treated as a calibration anchor for 2023, not as an inventory of measured wattages, and results for individual states with thin census coverage should be read with corresponding caution. The team intends to revisit this anchor as updated census editions or municipal registries become available.

3.1.6.7.2.2 Technology database

The census distributes the national lamp stock across nine lighting technologies. Each technology is described by its share of the installed stock, its average luminous efficacy, a service life, and unit cost parameters (installation and maintenance). Rather than reading a nominal wattage per technology, the model derives an equivalent power from the luminous efficacy relative to LED (see Section 3.1.6.7.3.1). Table 25 lists the nine technologies with their census share, efficacy, derived power and service life.

Table 25: *Lighting technologies (national parameters, base year 2023)*

Technology	stock share (%)	Efficacy (lm/W)	Derived power (W)	Life (yr)
LED (light-emitting diode)	19.6	115.0	110.0	12
High-pressure sodium	59.0	80.0	158.1	5
Mercury vapour	9.2	50.0	253.0	3
Metal halide	7.2	65.0	194.6	4
Fluorescent	1.6	75.0	168.7	2.5
Mixed (blended)	0.6	60.0	210.8	2
Halogen	0.5	20.0	632.5	1
Incandescent	0.5	15.0	843.3	0.5
Other	1.8	53.1	238.2	2

Source: stock share and efficacy from the ABCIP 2023 census [40]; derived power computed as $P_k = P_{\text{LED}} \eta_{\text{LED}} / \eta_k$ with $P_{\text{LED}} = 110 \text{ W}$ and $\eta_{\text{LED}} = 115 \text{ lm/W}$; service life from the model defaults.

3.1.6.7.3 Methodology

3.1.6.7.3.1 Lamp power from luminous efficacy

The census reports the average luminous efficacy η_k (lumens per watt) of each technology k . Assuming that all technologies deliver the same luminous service as an LED point of reference power $P_{\text{LED}} = 110 \text{ W}$ and efficacy $\eta_{\text{LED}} = 115 \text{ lm/W}$, the equivalent electrical power of technology k is

$$P_k = P_{\text{LED}} \frac{\eta_{\text{LED}}}{\eta_k}. \quad (29)$$

Less efficient technologies therefore draw proportionally more power for the same light output, which is the physical basis for the energy savings from LED retrofitting.

3.1.6.7.3.2 Trend growth from the BEN

The number of lighting points is assumed to grow at a trend annual rate estimated from the historical BEN consumption. For a given geography the model fits an ordinary least-squares line to the annual series over 2011–2019,

$$C^{\text{BEN}}(t) \approx m t + q, \quad (30)$$

and expresses the growth rate as the slope normalised by the mean of the fitted window,

$$g = \frac{m}{\overline{C^{\text{BEN}}}} \times 100\%. \quad (31)$$

At the national level the estimated rate is $g \approx 3.08\%$ per year. The rate is computed per UF; the pre-2020 window is used so that the post-2020 efficiency-driven decline does not bias the long-run trend.

Refinement note — growth of the lighting stock is not tied to urban population

The expansion of the lighting stock is obtained in Eq. (31) as an autonomous statistical extrapolation of historical *energy consumption*: it carries no explicit link to projected population, to urbanisation, or to population density by state. Future public lighting is therefore treated as a trend continuation rather than as the outcome of a structural relationship with demographic dynamics, which is a recognised weakness for a 2050 horizon — in particular for states whose urbanisation trajectories diverge sharply from the national average, and because a rate estimated on consumption inherits any past efficiency and coverage effects embedded in that series. The team is aware of this and retained the specification for the beta version because it is directly estimable from the BEN, requires no additional data, and reproduces the observed 2011–2019 dynamics. The next model-refinement cycle will re-specify the driver so that the number of lighting points (or its expansion rate) is a function of the projected *urban* population by UF and, where data allow, of an urbanisation/density indicator, retaining the present national rate as a sensitivity case for comparison. As an order-of-magnitude check on why this matters, compounding g over 2023–2050 multiplies the lighting stock by about 2.3, whereas the dwelling driver used by the residential module (Table 12) grows by a factor of about 1.7 over a comparable horizon: the present specification therefore has public lighting expanding appreciably faster than the housing stock that it serves, without any structural relationship justifying the gap. A second effect points the same way and is also absent from the current formulation: rising incomes, continued population growth and the progressive electrification of thermal end uses all add pressure to electricity demand in urban areas, and public lighting is expected to follow that pressure rather than a trend fitted on past consumption alone.

3.1.6.7.3.3 Base-year convergence (scale factor)

For the base year the electricity consumption of technology k is the product of the number of points, their power, and the operating hours,

$$C_k = N_k P_k h \frac{365}{10^9} \text{ [GWh]}, \quad N_k = N^{\text{tot}} \delta_k, \quad (32)$$

where δ_k is the census stock share, N^{tot} the total number of points, and $h = 11.5$ h/day. Summing (32) with the raw census points gives a first estimate $\hat{C}$ that does not exactly match the census consumption C^{ABCIP} . The model therefore applies a single dimensionless scale factor to the base year,

$$\alpha = \frac{C^{\text{ABCIP}}}{\hat{C}}, \quad (33)$$

so that the calibrated 2023 stock is $N^{\text{tot}} \alpha$ and the base-year consumption reproduces the census value exactly. At the national level $\alpha \approx 0.869$, i.e. the census consumption is reproduced by an effective 19.1 million calibrated points against 22.0 million raw census points.⁷

3.1.6.7.3.4 Initial age-structured stock

To let lamps retire realistically, the base-year stock of each technology is distributed over installation vintages. For a technology with calibrated count N_k and service life L_k , relative ages are drawn from a Beta(2, 2) distribution scaled to $[0, L_k]$,

$$a \sim L_k \cdot \text{Beta}(2, 2), \quad (34)$$

⁷The scale factor absorbs the joint effect of the efficacy-derived powers, the fixed operating hours, and rounding in the census shares. It is applied only to the base year; the 2024–2050 trajectory is governed by the stock model.

and rounded to integer years, so that each lamp is assigned an installation year $2023 - a$. The Beta(2, 2) shape concentrates ages near the middle of the service life. A fixed random seed makes the construction reproducible.

3.1.6.7.3.5 Dynamic stock projection to 2050

For each year t from 2024 to 2050 the model performs a stock-turnover balance. First, lamps whose installation year is older than $t - L_k$ are retired, yielding the retirements $D_k(t)$ and the surviving stock $S_k(t)$. The desired total stock follows the growth rate applied to the calibrated base,

$$N^{\text{tot}}(t) = N_{2023}^{\text{tot}} (1 + g)^{t-2023}, \quad (35)$$

and the number of new lamps installed in year t is the non-negative gap between the desired stock and the total survivors,

$$I(t) = \max(0, N^{\text{tot}}(t) - \sum_k S_k(t)). \quad (36)$$

The technology mix of the new lamps shifts towards LED over time. With progress variable $\rho(t) = (t - 2023)/(2050 - 2023)$, base LED share δ_{LED} and 2050 target θ , the LED share of new installations is

$$\sigma_{\text{LED}}(t) = \text{clip}(\delta_{\text{LED}} + (\theta - \delta_{\text{LED}}) \rho(t) 1.5, 0.1, 1.0), \quad (37)$$

where the factor 1.5 front-loads the transition. The remaining share is distributed over the non-LED technologies in proportion to their census weight, attenuated as the transition advances,

$$\sigma_k(t) \propto \delta_k \frac{1 - \sigma_{\text{LED}}(t)}{1 - \delta_{\text{LED}}} (1 - 0.8 \rho(t)), \quad k \neq \text{LED}, \quad (38)$$

and all shares are renormalised to sum to one. New lamps are added to the stock as vintage t , giving the end-of-year stock $S_k^{\text{end}}(t) = S_k(t) + \sigma_k(t) I(t)$.

Lamp efficiency evolves over the horizon. LED efficacy improves at the scenario rate r (compounded), so its power declines,

$$P_{\text{LED}}(t) = P_{\text{LED}} \frac{\eta_{\text{LED}}}{\eta_{\text{LED}}(1 + r)^{t-2023}} = \frac{P_{\text{LED}}}{(1 + r)^{t-2023}}, \quad (39)$$

while each non-LED technology improves at a fixed 0.5% per year, $P_k(t) = P_k (1 - 0.005)^{t-2023}$. The annual electricity consumption is then the stock-weighted sum

$$C(t) = \sum_k S_k^{\text{end}}(t) P_k(t) h \frac{365}{10^9}. \quad (40)$$

Investment cost accrues from the installation cost of retired-and-replaced lamps, and operating cost from electricity (at a user tariff) plus per-lamp maintenance; these feed the cost and savings indicators.

3.1.6.7.3.6 Policy and LED-efficiency scenarios

A scenario is the combination of a replacement policy—which sets the 2050 LED penetration target θ —and an LED-efficiency case—which sets the annual efficacy improvement r . Table 26 lists the options; the model can export all six combinations at once.

Table 26: *Public-lighting scenarios*

Dimension	Setting	Meaning
Replacement policy	Base ($\theta = 30\%$)	LED reaches 30% of the stock by 2050.
	Sustainable ($\theta = 60\%$)	Moderate incentives; 60% LED by 2050.
	Very sustainable ($\theta = 100\%$)	Full LED conversion by 2050.
LED efficiency	Low ($r = 0.5\%/yr$)	Efficacy roughly stable over the horizon.
	High ($r = 2.0\%/yr$)	Significant technological improvement.

Source: own elaboration based on the model source code. The LED share of new installations ramps towards θ following (37).

3.1.6.7.3.7 Derived indicators

From the consumption trajectory the model reports carbon emissions using a fixed grid emission factor of $0.5 \text{ tCO}_2/\text{MWh}$,

$$E(t) = C(t) \times 10^3 \times 0.5 \quad [\text{tCO}_2], \quad (41)$$

the avoided emissions relative to the base year, the accumulated investment cost, the total operating cost, and the electricity-bill savings relative to 2023. Among these indicators, only the investment cost is relevant for the NZB project. The other indicators derive from the MACRO energy supply modeling. The remaining indicators are reported by the standalone tool for municipal users and are not carried into the NZB results.

3.1.6.7.4 Illustrative results

The figures in this section were produced by re-executing the model's computational core on the datasets provided with the code, for the national geography and with the default technology and cost parameters. They are indicative: exact values depend on the vintage of the input files and on the scenario selected.

By construction the calibrated 2023 consumption reproduces the census total, $C_{2023} = 13,484.9 \text{ GWh}$, at an effective stock of about 19.1 million points (scale factor $\alpha \approx 0.869$) and a growth rate of $g \approx 3.08\%$ per year. Table 27 reports the national 2050 consumption and its change from 2023 for the six scenario combinations. Emissions are not reported here: in the NZB project they are computed by the MACRO supply-side model from its endogenous generation mix.

Table 27: *Projected national public-lighting electricity in 2050, by scenario*

Policy	LED eff.	2050 (GWh)	Change 2023–50
Base	Low	19,244.8	+42.7%
Base	High	14,519.2	+7.7%
Sustainable	Low	17,834.5	+32.3%
Sustainable	High	12,255.4	−9.1%
Very sustainable	Low	17,517.7	+29.9%
Very sustainable	High	11,742.4	−12.9%

Source: own elaboration by re-running the model.

The results show that the autonomous growth of the lighting stock is strong enough to raise total consumption in most scenarios, and that the annual LED efficacy improvement is the single most influential lever: moving from the low to the high efficiency case reduces 2050 consumption by roughly a quarter within each policy. An absolute reduction below the 2023 level is obtained only when an aggressive replacement policy is combined with the high-efficacy case.

3.1.6.7.5 Model outputs

On request the application writes its results as a set of CSV files structured for the NZB demand model (“Energy Pathways” format), together with a text summary. The files are written per state (the UF is used as the geographic analysis unit) and every scenario combination is stored in a *sensitivity* column. The exported files are listed in Table 28.

Table 28: Files exported by the public-lighting model

File	Content
DemandDrivers_IP.csv	Projected number of lighting points by state and year, tagged as demand driver.
DemandEnergyDemands_IP.csv	Projected electricity (GWh) by state, technology, year and scenario; a version truncated at 2024 and a full-horizon version.
DemandEnergyDemands_IP_2050.csv	
DemandSalesShareMeasures_IP.csv	Substitution shares from each technology towards LED.
DemandStock_IP.csv	Projected lamp stock by state, technology, year and scenario.
DemandTechs_IP.csv	Technology definitions (subsector, lifetime, Weibull decay parameters).
DemandTechsMainEfficiency_IP.csv	Per-technology power trajectory (W per point) by year and scenario.
Resumo_Cenarios.txt	Human-readable summary of all scenarios.

Source: own elaboration based on the export routines of the model.

3.1.6.7.6 Assumptions and limitations

The main assumptions and known limitations of the current implementation are:

- **National technology mix.** The census stock shares and luminous efficacies are national values applied uniformly to every state and region; regional variation enters only through the total number of points and the per-UF growth rate, not through a technology mix that differs by state.
- **Efficacy-derived powers.** Lamp powers are inferred from luminous efficacy relative to LED (Eq. 29) under an equal-service assumption, rather than measured wattages; the base-year scale factor absorbs the resulting bias so that 2023 matches the census.
- **Base-year-only calibration.** The scale factor acts only on 2023. The 2024–2050 path is governed entirely by the stock model and the trend growth rate.
- **Linear growth, not tied to population.** The growth rate is a constant estimated from the BEN 2011–2019 consumption window and compounded to 2050; it is a statistical extrapolation with no explicit link to projected urban population, urbanisation or population density by UF, and it does not capture saturation of the lighting stock or policy effects other than the explicit LED transition.
- **Census-based base year.** The base-year stock, technology mix and efficacies come from a single sectoral census whose coverage is uneven across municipalities and states; the residual inconsistency between the census consumption and the bottom-up product of points, powers and hours is absorbed by the scale factor $\alpha \approx 0.869$ rather than resolved.
- **Heuristic LED ramp.** The LED share of new installations follows a fixed accelerated ramp (Eq. 37) with a 1.5 front-loading factor and a 0.1–1.0 clip, and the non-LED attenuation coefficient 0.8 is a

calibration choice rather than an estimated parameter.

- **Stochastic initialisation.** The initial age structure is sampled from a Beta(2, 2) distribution with a fixed seed; results are reproducible but depend on that distributional assumption for the timing of early retirements.

These limitations document the model as currently coded and indicate the priorities for its further development.

3.1.7 Data centers

3.1.7.1 Overview

Key message

Data centers are projected as an exogenous new electric load. Installed load capacity follows a single logistic (S-shaped) build-out — the trajectory shape of the IEA *Energy and AI* Base Case — fitted through the 2024 historical stock, the capacity anchor of each scenario (13.4 GW in 2038 from official planning, or 26.3 GW in 2037 if all signalled projects materialise), and a 2050 target at which growth has settled to the long-run rate of the commercial sector ($\approx 2.8\%/yr$). Electricity demand then follows from $E = \text{Capacity} \times \text{Capacity factor} \times \text{Full-load specific consumption} \times \text{PUE}$, with the fleet-average PUE improving from 2.00 in 2024 to 1.40 (Scenario A) or 1.20 (Scenario B) by 2050.

The Energy Research Office (EPE), which prepares Brazil's ten-year energy expansion plans, has not yet released to the public the methodology it is using to project data center electricity consumption in Brazil. During 2025 and early 2026, the EPE has been collecting data from companies and electricity distributors in order to identify the current load, the new projects expected in the short term, and future prospects for load growth, so as to plan future electricity demand and transmission infrastructure. In the official EPE materials consulted, such as the latest Ten-Year Energy Expansion Plan (PDE 2025–2034) and related webinars, no mention was found of data center energy efficiency. Because the EPE has not yet disclosed the assumptions, technical information, and energy-efficiency figures behind the data center projections it has produced for Brazil, this section presents our own estimates based on official references and on the Brazilian data center sector.

Like the residential and commercial modules, the data center module is a self-contained Python application: it computes the capacity and demand trajectories described below for Brazil and for each of the 27 states, and writes the results as EnergyPathways-ready CSV files — installed capacity as a demand driver, electricity demand by state, and the PUE and specific-consumption series as technology-efficiency inputs. Throughout this section, “the model” refers to this application; EnergyPathways only consumes its exports. The module runs on an annual time step and is strictly all-electric: there is no fuel-substitution lever, so the scenario space acts on how much capacity is built and how efficiently it operates. Its two scenarios, A (Reference growth) and B (Rapid expansion), correspond one-to-one to options A and B of User Variable 22 (Section 4.6.4).

Figure 41 summarises the structure of the module and the two operations that organise the sections that follow. As in the other buildings modules, parallelograms denote input data with the source in square brackets, numbered circles denote operations, and shaded blue rectangles denote the data

produced. **Operation 1** builds the projected installed load capacity by state: it combines the national historical capacity of the Brazilian data center stock [41], the estimated share of that capacity by state derived from the sector white paper prepared for ANATEL [42], and the capacity anchors recognised in Brazilian energy planning [43, 44], joining them with a single logistic build-out curve. **Operation 2** converts capacity into electricity demand through an explicit identity involving the capacity factor, the full-load specific consumption of the IT equipment [45], and the projected PUE path of each scenario. (The flowchart artwork still shows the Cooling Degree Days database as an Operation 2 input; as of the current model version that database is retained but is not an active driver — see the refinement note at the end of this section — and the figure will be updated in the next report version.)

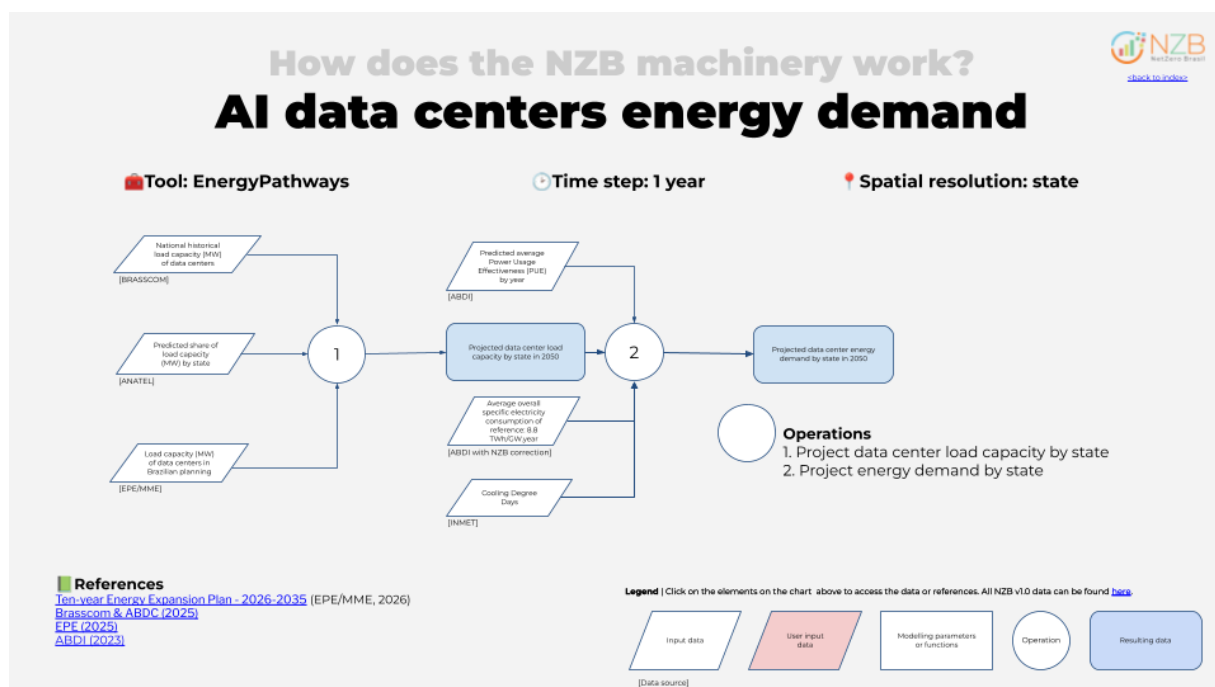


Figure 41: AI data centers energy demand: input data, operations and resulting data.

3.1.7.2 Operation 1: Projected data center load capacity by state in 2050

3.1.7.2.1 Input: National historical load capacity (MW) of data centers

According to a study commissioned by the Brazilian Data Center Association (ABDC) [41] (p.5), the historical installed capacity from 2019 to 2024 is given in Table 29.

Table 29: *Data center installed capacity, Brazil (2019–2024)*

Year	MW	GW
2019	281	0.281
2020	335	0.335
2021	336	0.336
2022	465	0.465
2023	558	0.558
2024	843	0.843

Source: [41], p. 5.

3.1.7.2.2 Input: Predicted share of load capacity (MW) by state

No historical data on installed capacity (MW) of data centers by state in Brazil were found. To work around this, the following assumptions were adopted:

- For the historical series, the total national installed capacity was distributed according to the share of the number of data centers per state;
- For the future projection, the installed capacity was distributed by state based on the forecasts identified by the EPE in the PDE 2035 and on the published results of the EPE's data center data collection.

These are acknowledged to be fragile assumptions. However, until the EPE is able to provide the state-level capacity data it used for planning purposes, these are the assumptions adopted here.

Following assumption 1, the approximate number of data centers in Brazil is 162, distributed as shown in Table 30, built from the data center White Paper published by Anatel [42] (p.36).

Table 30: *Distribution of the number of data centers by region*

Region	Share (%)	No. of data centers
Midwest (CO)	5%	8
North (N)	1%	2
Northeast (NE)	10%	16
Southeast (SE)	68%	110
South (S)	16%	26
Total	100%	162

Source: own elaboration based on Figure 9 of [42].

The state-level distribution (Table 31) was produced using the data presented in the White Paper [42].

Table 31: *Distribution of the number of data centers by state, from Anatel*

State	Data centers per state	Region	Data centers per region
Others	12	—	12
DF	6	CO	6
CE	10	NE	10
PR	10		
SC	6	S	26
RS	10		
MG	8		
RJ	21	SE	107
SP	78		
Total	162	—	162

Source: own elaboration based on Figure 9 of [42]. The number of data centers per state was estimated by scale.

Comparing Table 31 with Table 30, the number of data centers in the South region (26) is the same as the sum of the three states in the region. For the Midwest region, two data centers are missing (8 minus 6); for the Northeast, six are missing (16 minus 10); and for the Southeast, three are missing (110 minus 107).

As there are twelve data centers classified under “other states”, they need to be distributed among some of them. For the Southeast region, the only missing state is Espírito Santo (ES), so three data centers are allocated to this state to reach the region’s total of 110. In the North region, one data center was allocated to Amazonas (AM) and one to Pará (PA)⁸ to total the region’s two data centers. In the Midwest region, one data center was allocated to Goiás (GO) and one to Mato Grosso do Sul (MS)⁹ to reach the eight data centers. In the Northeast region, two data centers were allocated to Pernambuco (PE), one to Bahia (BA), one to Maranhão (MA), one to Paraíba (PB), and one to Sergipe (SE)¹⁰. The result is presented in Table 32.

⁸According to the Data Center Map of Brazil (accessed 22 Jun 2026), maintained by the Brazilian Data Center Association (ABDC), there are data centers in these two states in the North region. This map was not used because it lists fewer data centers (128) than those officially mapped in Anatel’s White Paper.

⁹In the Data Center Map database (accessed 22 Jun 2026), the existing data centers in the Midwest region are in the Federal District, Goiás, and Mato Grosso do Sul.

¹⁰These are the states that have data centers in the Data Center Map database (accessed 22 Jun 2026). Pernambuco received more because, both in this database and in the Data Center Map of Brazil (accessed 22 Jun 2026), it is the state with the most data centers after Ceará (CE).

Table 32: *Distribution of the number of data centers by state for the NZB project*

State	Data centers per state	%	Region	Data centers per region
DF	6	3.7%	CO	8
GO	1	0.6%		
MS	1	0.6%		
BA	1	0.6%	NE	16
CE	10	6.2%		
MA	1	0.6%		
PB	1	0.6%		
PE	2	1.2%		
SE	1	0.6%		
AM	1	0.6%	N	2
PA	1	0.6%		
PR	10	6.2%	S	26
SC	6	3.7%		
RS	10	6.2%		
ES	3	1.9%	SE	110
MG	8	4.9%		
RJ	21	13.0%		
SP	78	48.1%		
Total	162	100%	—	162

Source: own elaboration based on Figure 9 of [42], the Data Center Map (accessed 22 Jun 2026), and the Data Center Map of Brazil (accessed 22 Jun 2026).

With the distribution of data centers by state (Table 32), the total installed capacity in 2024 (843 MW) is distributed among the states. The result is presented in Table 33.

Table 33: *Distribution of data center installed capacity by state*

State	Data center capacity (MW)	%	Region	Data centers per region
DF	31.2	3.7%	CO	8
GO	5.2	0.6%		
MS	5.2	0.6%		
BA	5.2	0.6%	NE	16
CE	5.2	6.2%		
MA	5.2	0.6%		
PB	5.2	0.6%		
PE	10.4	1.2%		
SE	5.2	0.6%		
AM	5.2	0.6%	N	2
PA	5.2	0.6%		
PR	5.2	6.2%	S	26
SC	31.2	3.7%		
RS	5.2	6.2%		
ES	15.6	1.9%	SE	110
MG	41.6	4.9%		
RJ	109.3	13.0%		
SP	405.9	48.1%		
Total	843	100%	—	162

Source: own elaboration.

3.1.7.2.3 Input: Load capacity (MW) of data centers in Brazilian planning

According to the Ten-year energy expansion plan — PDE 2035 [43], data centers in Brazil are projected to reach a load of 13.4 GW by 2038, a massive growth compared to 2024 (0.843 GW). The average forecast load of the entire Northeast subsystem of the National Interconnected System is 14.1 GW for 2026 and 17.4 GW for 2030.¹¹ We use this as a basis for one of two scenarios for future data center demands.

As the EPE did not disclose the state-level distribution of this data center load expansion, but reported that it will be concentrated in São Paulo, Rio Grande do Sul, and Ceará — the states with the highest current concentration — the expansion was assumed to be distributed in proportion to the shares in Table 33. On this basis, the accumulated load in 2038 is presented in Table 34.

¹¹According to 1st Four-Monthly Revision of monthly load forecasts with DG of the Annual Energy Operation Planning 2026–2030

Table 34 also presents the load projected for 2037 under the second, higher data center expansion scenario (Scenario B) adopted in this work. This scenario assumes that the full 26.3 GW of data center projects reported to the MME by companies [43] are implemented.

Table 34: *Projected distribution of data center installed capacity by state for the two study scenarios — years 2037 and 2038*

Region	State	%	Capacity (MW)	Scenario A (GW)	Scenario B (GW)
				2038	2037
CO	DF	3.7%	31.2	0.50	0.97
	GO	0.6%	5.2	0.08	0.16
	MS	0.6%	5.2	0.08	0.16
NE	BA	0.6%	5.2	0.08	0.16
	CE	6.2%	52	0.83	1.62
	MA	0.6%	5.2	0.08	0.16
	PB	0.6%	5.2	0.08	0.16
	PE	1.2%	10.4	0.17	0.32
	SE	0.6%	5.2	0.08	0.16
N	AM	0.6%	5.2	0.08	0.16
	PA	0.6%	5.2	0.08	0.16
S	PR	6.2%	52	0.83	1.62
	SC	3.7%	31.2	0.50	0.97
	RS	6.2%	52	0.83	1.62
SE	ES	1.9%	15.6	0.25	0.49
	MG	4.9%	41.6	0.66	1.30
	RJ	13.0%	109.3	1.74	3.41
	SP	48.1%	405.9	6.45	12.66
Total		100%	842.8	13.4	26.3

Source: own elaboration.

3.1.7.2.4 Capacity trajectory: a single logistic build-out

Projecting the installed load to 2050 requires extending the anchors above beyond the planning horizon. Simply carrying forward the compound annual growth rates of the first period — 21.8%/yr to 2038 in Scenario A and 30.3%/yr to 2037 in Scenario B, both inflated by the very low 2024 base of 0.843 GW — would compound to capacities of roughly 143 GW and 820 GW by 2050, against a total installed power capacity of about 200 GW in the whole Brazilian electricity system in 2024. Instead, the module describes the build-out with a single logistic curve,

$$\text{Cap}(t) = \frac{K}{1 + b e^{-r(t-2024)}}, \quad (42)$$

with the parameters K , b and r solved so that the curve passes exactly through three anchors: the historical capacity in 2024; the scenario capacity at its reference year (13.4 GW in 2038 for Scenario A, 26.3 GW in 2037 for Scenario B); and a 2050 target obtained by letting the post-reference annual growth rate decelerate linearly from an initial value (5%/yr in Scenario A, 8%/yr in Scenario B) down to the long-run stability rate g_∞ discussed below. The resulting trajectory is continuous in level and in slope over the whole horizon: a rapid take-off while the signalled projects materialise, an inflection before the reference-year anchor, and a progressive accommodation towards saturation. This is the same qualitative shape that the IEA *Energy and AI* Base Case projects for global data-centre electricity use — approximately 415 TWh in 2024, growing at about 15%/yr to some 945 TWh in 2030 and then decelerating to roughly 4.9%/yr towards $\sim 1,200$ TWh in 2035 [46] — and the post-reference initial rates of the two scenarios were calibrated on that Base Case (Scenario B starting from a value between the IEA Base Case and its faster “Lift-Off” sensitivity).

3.1.7.2.5 The long-run stability rate

The rate at which the S-curve settles in 2050, g_∞ , is not a free parameter: it is anchored on a citable reference. The default anchor is the historical growth of Brazilian commercial-sector electricity consumption — data centers are commercial-sector loads, and once the implantation wave has passed and the efficiency gains are exhausted, the segment is assumed to tend to the growth rhythm of its host sector. The compound annual growth rate of commercial electricity consumption computed from the BEN series for 2011–2024 (67 to 96 TWh) is 2.78%/yr [35], and this is the value used in the projections reported here. Alternative citable anchors implemented in the model interface are: commerce and services growth in the PDE 2035 (4.7%/yr) and total electricity demand in the same plan (3.3%/yr) [43]; total electricity demand in the PNE 2050 (up to 3.5%/yr) [47]; and, as a conservative lower bound, the near-saturated logistic of the BEN consumer-unit series ($\approx 0.03\%$ /yr). The chosen anchor enters the module at two points: it sets the deceleration target that defines the 2050 capacity anchor of Equation (42), and it sets the end-of-horizon consumption floor described in Operation 2.

This conservative anchoring is deliberate. There is as yet little theory or empirical precedent for projecting data center growth over a 25-year horizon — the published outlooks, including the IEA’s, stop at 2030–2035 — and extrapolating the early-period rates without constraint saturated the integrated modeling: in test integrations, data center demand alone came to dominate projected national electricity consumption in EnergyPathways, overwhelming the signal of every other sector. Tying the long-run rate to the host commercial sector keeps the 2050 totals inside a defensible envelope while preserving the near-term surge imposed by the planning anchors. The intention for future versions of the MASS is to broaden the scenario set — more trajectories, and more diverse ones, including faster-saturation and re-acceleration variants — as longer-horizon references become available.

3.1.7.2.6 State disaggregation

Each state’s trajectory is a logistic of the same form fitted to that state’s share of the national anchors: the reference-year and 2050 anchors of a state are the national anchors multiplied by the state’s share of installed capacity (Table 33, carried in the module database as the *Capacity share* category). The sum of the 27 state trajectories therefore reproduces the national trajectory by construction. The

resulting national build-out reaches 22.5 GW in 2050 in Scenario A and 59.5 GW in Scenario B (Table 36).

3.1.7.3 Operation 2: Projected data center energy demand by state in 2050

Electricity demand follows from the identity

$$E(t) = \text{Cap}(t) \times CF \times e_{\text{FL}} \times \text{PUE}(t), \quad (43)$$

where $\text{Cap}(t)$ is the installed IT load capacity of Equation (42); $CF = 50\%$ is the capacity factor, the average utilisation of the installed IT capacity over the year [48, 46]; $e_{\text{FL}} = 8.8 \text{ TWh/GW}$ per year is the full-load specific consumption of the IT equipment (one GW of IT load running for the 8,760 hours of a year); and $\text{PUE}(t)$ scales the IT electricity up to the whole facility, including cooling and building services. All four factors are explicit and are exported separately to EnergyPathways. This formulation replaces the one used in earlier versions of this module, in which a reference specific consumption embedded both the load factor and a reference PUE of 1.82; unpacking the identity removes the ambiguity between capacity factor and PUE that the embedded form invited, and corrects the reference PUE itself (see below).

3.1.7.3.1 Input: Average overall specific electricity consumption (TWh/GW.year)

A study commissioned by ABDI [45] to encourage attracting data centers to Brazil provides an analysis of capital and operating costs for a data center representative of the main data center service providers in the country. The analysis includes the electricity consumption required to serve the IT equipment, the cooling needs, and the building's service infrastructure. From these data, the annual electricity consumption per installed capacity can be obtained.

However, a correction to the consumption data was necessary because ABDI [45] assumed that the data center operates at full load at all times — that is, a load factor of 100% — which does not match reality, as noted, for example, by [48]. For this correction, a capacity factor of 50% was assumed, which is roughly the value reported by [46] in its projection study of data center consumption worldwide.

ABDI [45] assumed a capacity of 4.998 MW for the data center and the electricity consumption shown in Table 35. Considering the 50% load factor for the IT equipment and for the cooling consumption — assuming its demand follows that of the IT equipment — and that the facilities consumption is the same because it is independent of the data center load, the consumption values in the last column of Table 35 are obtained. The corrected reference facility therefore consumes 43.8 GWh per year over 4.998 MW of installed IT capacity, i.e. 8.8 GWh/MW (equivalently TWh/GW) per year at the 50% load factor — with an implied fleet-average PUE of 2.00 (see below). Note that this whole-facility figure coincides numerically with the full-load specific consumption of the IT equipment alone, $e_{\text{FL}} = 8,760 \text{ h/yr} \times 1 \text{ GW} \approx 8.8 \text{ TWh/GW}$, because at these reference conditions the product $CF \times \text{PUE} = 0.5 \times 2.00 = 1$. This coincidence is why the figure of 8.8 TWh/GW should *not* be read as a 100% capacity factor: in the demand identity of Equation (43) the value $e_{\text{FL}} = 8.8 \text{ TWh/GW}$ enters as the full-load IT term, and the capacity factor and the PUE enter explicitly as separate factors.

Table 35: *Electricity consumption for a reference data center used by ABDI (2023)*

	From ABDI (2023)	Recalculated
Electricity consumption (GWh/year)	79.7	43.8
IT equipment	43.8	21.9
Cooling	27.9	14.0
Facilities	8.0	8.0
Specific consumption (TWh/GW per year)	15.9	8.8

Source: own elaboration based on [45].

3.1.7.3.2 Input: Average Power Usage Effectiveness (PUE)

The energy-efficiency indicator used for data centers is the PUE (“power usage effectiveness”), which is the total amount of energy used by a data center divided by the amount of energy used by its IT equipment. The higher the PUE, the less efficient the data center. Reductions in PUE come both from improvements in equipment, software, and network architecture, and from the use of more efficient cooling equipment and buildings.

The ABDI study [45] did not report the PUE it assumed, but the PUE can be derived from the electricity-consumption breakdown it provides. Taken at face value, that breakdown yields a PUE of 1.82; this figure, however, is an artefact of the study’s implicit 100% load-factor assumption. Correcting the load factor to 50% — with cooling consumption following the IT load and the facilities consumption unchanged, as in Table 35 — the implied average PUE of the Brazilian stock is $43.8/21.9 = 2.00$, and this is the 2024 reference value adopted by the NZB project. (Earlier versions of this module used 1.82 as the reference; the correction to 2.00 propagates to the exported PUE series and to the demand identity above.)

A stock average of 2.00 leaves substantial efficiency headroom. For comparison, the weighted-average PUE of US data centers was about 1.9 in 2010 [49]; the same authors projected 1.51 for 2020 under then-current trends and 1.25 under best practices, and shortly afterwards identified facilities operating at 1.1 or lower [48]. IEA reports a global average PUE of 1.41 in 2024 and, in its high-efficiency case, considers 1.21 in 2030 and 1.13 in 2035 [46].

In **Scenario A (Reference growth)**, the average PUE declines linearly from 2.00 in 2024 to 1.40 in 2038 and is then held constant to 2050. This represents efficiency gains obtained from the natural renewal of equipment and cooling systems, on the assumption that the factors of production (energy, labor, land, taxes) are low enough for investors to obtain their capital gains without needing to invest further in energy efficiency. In **Scenario B (Rapid expansion)**, the PUE follows the same decline to 1.40 by 2037 but then continues falling linearly to 1.20 in 2050, as a result of national regulations, monitoring and evaluation capacity, and local scientific and technological capacity.

3.1.7.3.3 End-of-horizon consumption floor

Near 2050 the capacity logistic saturates (growth below 1%/yr) while, in Scenario B, the PUE is still falling at about 1.2%/yr; left unconstrained, the efficiency effect would come to dominate and projected

consumption would turn downwards at the end of the horizon. The module therefore imposes a consumption floor: wherever demand growth would fall below the stability rate g_{∞} , demand is held to that minimum growth and the capacity series is recalculated at the same point from Equation (43), preserving the identity in the exported files. The correction is proportional, so the state trajectories continue to add up to the national one; in the projections reported here it binds only in the final years of the horizon.

3.1.7.3.4 Results

Table 36 reports the projected national capacity, PUE and electricity demand under the two scenarios. Demand grows from 7.4 TWh in 2024 to 139 TWh in 2050 in Scenario A (11.9%/yr on average) and to 314 TWh in Scenario B (15.5%/yr) — in the latter case, more than three times the electricity consumed by the *entire* Brazilian commercial sector in 2024 (96 TWh). This demand magnitude is one of the reasons data centers are reported separately from the rest of the commercial sector throughout this report. The other reason is its specific demand methodology.

Table 36: *Projected national data center capacity, PUE and electricity demand by scenario*

Year	Scenario A — Reference			Scenario B — Rapid expansion		
	GW	PUE	TWh	GW	PUE	TWh
2024	0.84	2.00	7.4	0.84	2.00	7.4
2030	3.58	1.74	27.4	5.20	1.72	39.5
2035	9.20	1.53	61.9	18.32	1.49	120.3
2038	13.40	1.40	82.5	30.35	1.38	184.9
2040	15.85	1.40	97.6	37.62	1.35	224.1
2045	19.66	1.40	121.1	48.78	1.28	274.1
2050	22.55	1.40	138.9	59.55	1.20	314.4

Source: own elaboration (data center module v1.3). Scenario anchors: 13.4 GW in 2038 (A) and 26.3 GW in 2037 (B); stability rate 2.78%/yr (BEN commercial series 2011–2024).

3.1.7.3.5 Integration with the commercial sector

Data center demand is modelled independently but belongs to the commercial (services) sector: its 2023 consumption is netted out of the commercial gross figure to avoid double counting (Section 3.1.6), and its projection is delivered to EnergyPathways as a separate subsector. Data centers remain disaggregated in all reporting, both because of the expected exponential growth documented above and because the subsector is already essentially all-electric, with no fuel-to-electricity substitution lever. The module is strictly annual: no hourly load profile is used, and hourly data for Brazilian data centers do not currently exist; unlike the residential and commercial modules, it will remain annual in the model-refinement cycle.

3.1.7.3.6 Supporting database: Cooling Degree Days (CDD)

The cooling degree day (CDD) is the difference between the average daily temperature and the base temperature, as given by the equation below.

$$\text{CDD} = \text{ADT} - \text{BT}$$

where:

- CDD = Cooling Degree Days (°C);
- ADT = Average daily temperature, considering the maximum and minimum temperature for a single day (°C);
- BT = Base temperature (°C).

To illustrate its calculation, considering an average daily temperature of 24 °C for a specific day and a base temperature of 18.3 °C, the CDD for that specific day is:

$$\text{CDD} = 24 \text{ °C} - 18.3 \text{ °C} = 5.7 \text{ °C}$$

The annual CDD is the sum of the CDDs calculated for each day of the year.

The average temperatures were obtained from the data provided by INMET [50] by e-mail in response to a formal request. In the files sent, several weather stations were included. The stations selected for each state capital were used, and these temperatures were assumed to be representative for that state. For the states of Rio de Janeiro, Goiás, Mato Grosso, Rondônia, and Pernambuco, INMET had no database. Thus, for these states, the CDD was estimated as the regional average of the respective state.

The year 2020 was adopted as the reference for the CDD projection. The CDD was calculated by state for 2020. The estimated projections were made for the years 2030, 2040, and 2050, assuming an average-temperature growth rate of 0.25 °C every 10 years [51].

With this database and considering a base temperature of 18.3 °C [39], an Excel spreadsheet was developed to calculate the CDD. The national CDD was obtained as the average of the regional CDD, while the regional CDD was obtained from the CDDs of the capitals.

The regional CDD was obtained from the arithmetic mean of the CDDs of the capitals of the respective states, while the national CDD was obtained as the average of the regional CDD. This method can be improved by computing the national CDD as the average of municipal CDDs or by weighting the regional CDDs by the area of the regions.

The CDD data adopted are in this table.

Refinement note — the CDD database is not yet an active driver

In the current version of the module, the CDD series does not enter the demand calculation: the PUE trajectories are defined at the national level and the conversion of capacity into energy applies Equation (43) uniformly across states. The state-level CDD series and its projection to 2030, 2040 and 2050 under a $+0.25^{\circ}\text{C}$ -per-decade warming assumption [51] are maintained in the module database so that, in the model-refinement cycle, the cooling share of the facility load can be modulated by each state's climate — in step with the planned connection of the same climate signal to the residential and commercial cooling end uses (see the refinement notes in Sections 3.1.5 and 3.1.6). The caveats registered there carry over: the demand response to warming is strongly heterogeneous across regions, and construction-side mitigation (passive conditioning, higher-performance envelopes, bioclimatic design) can offset a substantial part of the additional cooling need.

3.1.8 Buildings: consolidated results and outlook

The three preceding sub-sections report results module by module. This sub-section brings them together, so that the buildings sector — residential, commercial (services), public lighting and data centers — can be read as a whole rather than as four separate projections.

Table 37 consolidates the projected 2050 electricity demand and the residual thermal-fuel demand of the sector by scenario. Two cautions apply to its reading. First, the modules are calibrated on different base years, each inherited from the reference year of the source that anchors it: 2019 for the residential module (PROCEL PPH appliance survey), 2023 for the commercial and public-lighting modules (BEN commercial class and ABCIP lighting census) and 2024 for the data center module (first year for which the installed capacity of the sector is documented). The base-year column is therefore a set of source-consistent anchors rather than a single consistent snapshot, and aligning them is a question of data availability rather than of model design. The same reading applies to the other divergences reported below: in this first round the four Buildings modules were built and run as separate applications, and the refinement note at the end of this section sets out how their integration removes those divergences in the next stage. Second, public lighting and data centers are also components of the commercial class in the National Energy Balance; the consolidated row therefore reports them separately and nets them out of the commercial figure to avoid double counting.

Table 37: *Buildings sector — consolidated projection to 2050 by scenario*

Sub-sector	Scenario	Base year (GWh)	2050 (GWh)	Residual thermal fuel in 2050
Residential	A (25%)	145,606	337,996	9,489 10 ³ tep LPG; 11,346 10 ³ tep firewood
	B (50%)	—	418,767	6,326; 7,564
	C (100%)	—	580,309	0
Commercial (services, gross)	A (25%)	90,611	501,609	71,566 GWh
	B (50%)	—	498,024	47,711 GWh
	C (100%)	—	490,852	0
Public lighting	Base / low efficacy	13,484.9	19,244.8	—
	Sustainable / high efficacy	—	12,255.4	—
	Very sustainable / high eff.	—	11,742.4	—
Data centers (base year 2024; not added to the totals)	Reference	7,400	138,900	—
	Rapid expansion	—	314,400	—
Buildings total (indicative, gross)	Low electrification	249,702	778,079	394,659 GWh
	High electrification	249,702	1,082,903	0

Source: own elaboration from Tables 13, 21 and 27. *Low electrification* sums the residential Base case, commercial scenario A and public lighting Base/low efficacy; *high electrification* sums residential scenario C, commercial scenario C and public lighting Very sustainable/high efficacy. Residual thermal energy is converted to GWh at 1 tep = 11.63 MWh for comparability. The totals are **indicative upper bounds**: the commercial figures are gross, i.e. they still contain the public-lighting and data center components read from the input files, so public lighting is counted twice — and the two representations differ widely: the public-lighting component embedded in the commercial figure is 22.1% of it as read from the commercial input file (Table 19), or 14.9% once the 2023 base year is anchored on the ABCIP census, so that carrying it forward at the single commercial growth rate — a factor of about 5.5 between 2023 and 2050 — gives of the order of 75 TWh in 2050, against 12–19 TWh from the public-lighting module itself. The gap is driven by the growth rate rather than by the base-year level: the commercial module escalates public lighting with commercial activity, whereas the lamp-stock model moves it by between –13% and +43% over the same period. This is not a disagreement about how public lighting grows; it follows from the commercial module having to carry a public-lighting component of its own while the modules are run separately. In the integrated application the lamp-stock model is the single representation of public lighting and the commercial series is reported net of it, so the two give the same figure by construction. Data centers are reported from Table 36 but are not added to the totals, because their scenarios (Reference and Rapid expansion) are an independent exogenous-demand dimension rather than a level of the electrification ambition along which the two total rows are built; including them would require reporting the total as a matrix of electrification scenario by data center scenario. Finally, the base-year column mixes the 2019, 2023 and 2024 references discussed above. The removal of the double counting and the inclusion of data centers in the totals require the harmonisation step described below.

Three findings stand out across the sub-sectors. First, buildings electricity demand grows substantially in every scenario, and the growth is driven at least as much by *structural expansion of the end use* — more dwellings, more establishments, more lighting points, new data center load — as by the technology efficiency that the scenario levers act upon. The orders of magnitude involved are worth stating explicitly, because they are not symmetric. In the residential sector, activity growth alone raises demand by about +77% between 2019 and 2050 (146 to 257 TWh) with no efficiency improvement modelled at all, and electrification can add up to a further +323 TWh. In the commercial sector, demand grows by a factor of about 5.5 (91 to 502 TWh) purely from the compound establishment growth rate, while the entire electrification lever moves the 2050 electricity figure by only about 2%. In public lighting the two effects are directly comparable and act against each other: structural stock growth alone gives +42.7% by 2050, whereas the most ambitious LED and efficacy combination turns that into –12.9% — a spread of roughly 55 percentage points, which is the measure of what the efficiency levers can and cannot offset. In other words, the technology-efficiency levers documented in Section 4.6 act on a demand whose *level* is set mainly by activity drivers that the scenarios do not currently control.

Refinement note — activity effect and efficiency effect are not separated

The comparison above is assembled by hand from the module result tables; the models do not currently report a formal decomposition of the 2019/2023–2050 change into an activity effect and an efficiency effect. Producing that decomposition per sub-sector and per scenario — and reporting it as two explicit columns of Table 37 — is part of the next model-refinement cycle, and is the natural way to make the structural growth of each end use auditable rather than inferable.

Second, the electrification levers shift the carrier of thermal demand rather than its magnitude, so their main visible effect is a large addition to the residential electricity series and the progressive elimination of residual LPG, natural gas and firewood. Third, in public lighting the efficiency gain from LED substitution is largely offset by the growth of the stock: only the combination of an ambitious LED target with the high-efficacy case delivers an absolute reduction relative to 2023.

Refinement note — what remains to be consolidated

In this first modelling round the four Buildings modules — residential, commercial, public lighting and data centers — were developed and run as independent applications, each reading its own input files and each carrying its own base year, scenario vocabulary and ramp start year. That is the origin of the divergences visible in Table 37: where two modules disagree, they disagree because they were calibrated in parallel and not because the underlying sources contradict one another. The next stage integrates the four modules into a single Buildings application, which removes those divergences by construction — one base year, a single public-lighting series produced by the lamp-stock model and netted out of the commercial series (so that public lighting has one value rather than two), one scenario vocabulary and one ramp start year — so that the sector total becomes additive without a separate reconciliation step. The gaps in Table 37 — gross commercial figures, data centers reported outside the totals, base years inherited from the underlying sources — are therefore not omissions but the explicit work program for that integration. Closing them requires: (i) harmonizing the base years of the four modules onto a single reference year; (ii) netting public lighting out of the commercial gross figures so that the sector total is additive — the data center component is already netted out and is in any case negligible in the current input file. The base-year source has been settled in favour of the census: the ABCIP figure of 13,484.9 GWh is the 2023 reference for public lighting, so the 20,023 GWh read by the commercial module from its input file (Table 19) is superseded and the file has to be corrected in the next model run. Because the commercial total is anchored on the BEN commercial class, that correction moves about 6,538 GWh from public lighting to the residual “Others” and leaves the commercial total unchanged; (iii) mapping the module-level scenarios — which currently use different labels, different substitution targets and different ramp start years (2019 in the residential module, 2026 in the commercial module and in the scenario levers) — onto the common scenario space of Section 4.6; and (iv) reporting the residual thermal energy in a single unit across sub-sectors. The team is aware that until these four steps are done, the sector-level total cannot be stated without qualification, which is why the individual sub-sector rows are reported here rather than a single aggregate number. Once the four modules run inside a single application, these steps stop being a reconciliation exercise carried out after the fact and become properties of the integrated model, so the divergences documented in this section are expected to disappear rather than to be corrected one by one.

3.1.9 Agriculture

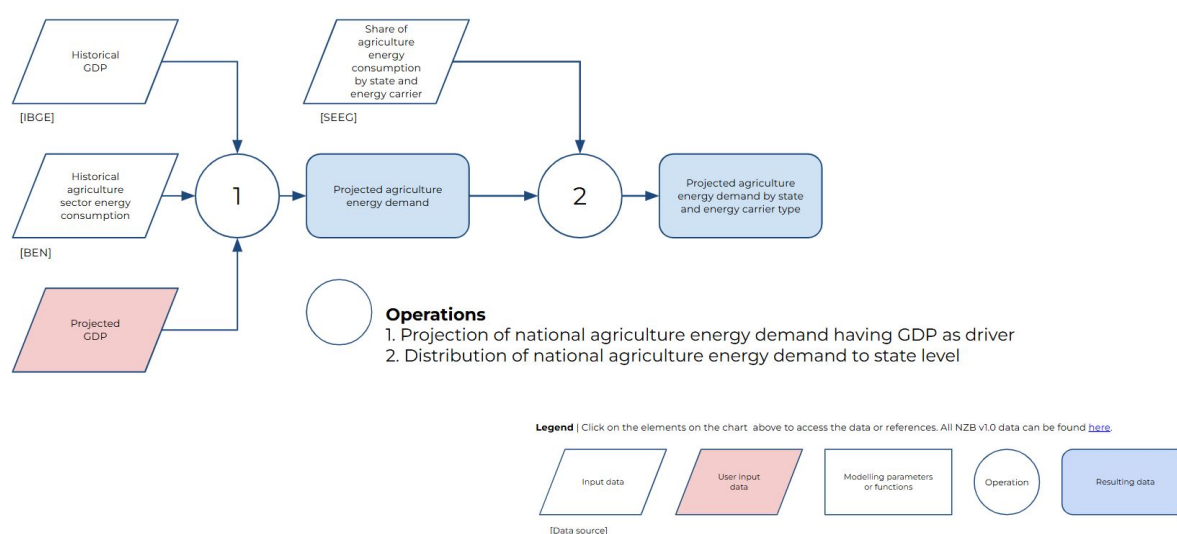


Figure 42: Agriculture energy demand projection: input data, operations and resulting data.

The Agriculture sector encompasses energy use on farms and other types of agricultural properties, including applications such as irrigation and agricultural machinery. The modeling framework for this energy demand is presented in the Figure 42 and follows exactly the same simplified approach adopted for the non-road transport sector - for further details, see Section 3.1.2.

3.2 Energy supply modeling

This section describes and documents the assumed availability and cost of primary energy resources and the performance and cost characteristics of energy conversion technologies and the infrastructure for electricity transmission and CO₂ transport and storage included in the MACRO energy supply optimization model.

3.2.1 Energy Resources

The energy resources explicitly included in the MACRO model are variable renewables (solar and wind energy), bioenergy, and fossil fuels, the underlying quantitative characterization of each of them being described in this section. Water resources for hydropower generation and uranium resources for nuclear power generation are included in MACRO as embedded characteristics of hydro and nuclear power generation technologies, as described in Section 3.2.2.1.

3.2.1.1 Candidate Project Areas (CPAs) for renewable energy

Candidate Project Areas (CPAs) refer to the available land in the model that limits the expansion of a specific technology or feedstock. This work considers a common basis for land exclusion for utility-scale PV, onshore wind farms, and feedstocks for biofuel production.

Exclusion zones were applied according to environmental, social, and technical considerations:

- Environmental: protected areas and public forests; low and medium pasture vigor (exclusively for feedstock expansion) and; bird concentration and bird threatened (exclusively for wind farms).
- Social: indigenous and quilombola territories, and urban areas were excluded with a 1 km buffer.
- Technical/financial: sites with a slope greater than 10% were removed, as steep terrain significantly increases construction costs. Existing utility-scale PV plants and onshore wind farms were also excluded to prevent double counting of already occupied land. For existing utility-scale PV, exclusion areas were derived based on current installed capacity and a capacity density of 33 MW/km², and then a square buffer was applied from the coordinate point.

Table 38: *Constraints used to estimate suitable land for utility-scale PV, wind farms and feedstock for biofuel production.*

Criteria	Category	Type	File	Source
Protected areas	Environmental	Exclusion	Shapefile	[52]
Public forests	Environmental	Exclusion	Shapefile	[52]
Indigenous territories	Social/Environmental	Exclusion	Shapefile	[52]
Quilombola territories	Social	Exclusion	Shapefile	[53]
Slope	Technical/Financial	Available land with slope below 10%	Raster	[54]
Urban areas	Social	Exclusion	Shapefile	–
Existing utility-scale PV plants	Technical	Exclusion	Shapefile	[55]
Existing onshore wind parks	Technical	Exclusion ⁽¹⁾	Shapefile	[55]
Pasture degradation	Technical	Retained	Raster	[56]

⁽¹⁾ Area estimated as capacity divided by 5.2 MW/km².

⁽²⁾ Low and medium pasture vigor.

Spatial processing of suitable land

Each exclusion criterion was converted into a binary mask aligned with a 250m × 250m analysis grid and reprojected to EPSG:5880 – SIRGAS 2000 / Brazil Polyconic. Continuous slope rasters from Topodata/INPE [54] were reclassified into binary form, excluding all pixels with slopes greater than 10%.

The final suitability map was generated by integrating all exclusion layers into a single raster dataset. Each criterion was first converted into a binary raster, assigning a value of 1 to suitable pixels and 0 to excluded pixels. These layers were then combined using the raster calculator through sequential multiplication (e.g., (Raster1 = 1) * (Raster2 = 1) * (Raster3 = 1)). This procedure ensured that a pixel was classified as suitable (value = 1) only if it satisfied all conditions simultaneously; otherwise, the multiplication returned 0, indicating exclusion.

Maps of exclusion criteria

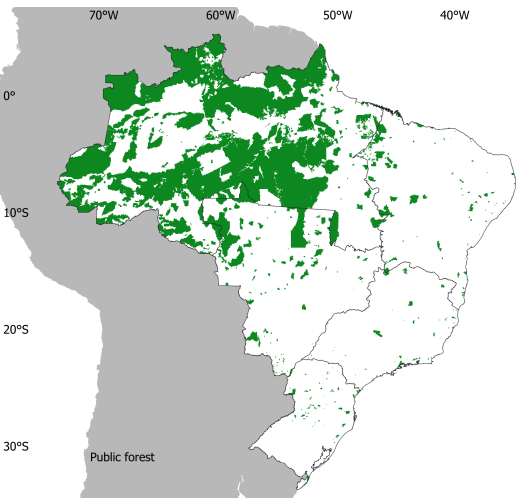


Figure 43: Public forest.

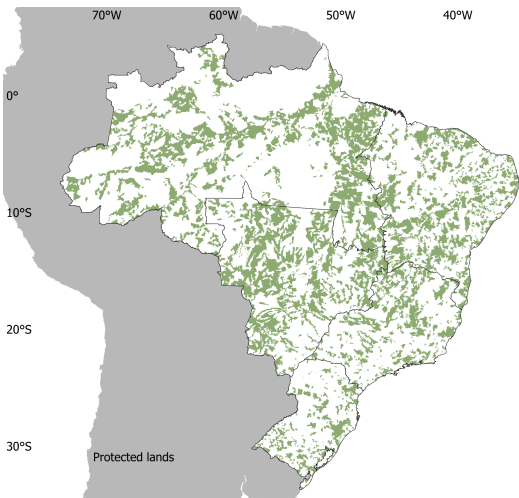


Figure 44: Protected areas.

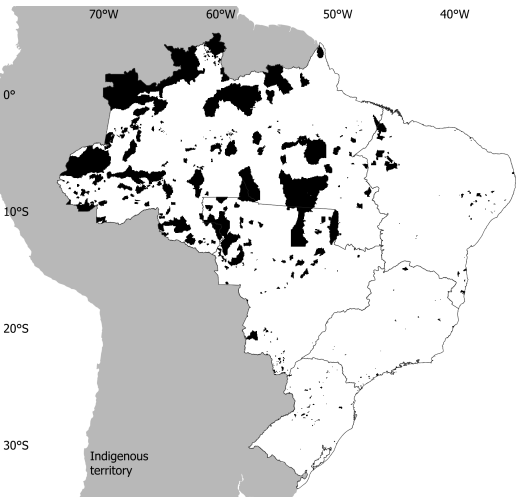


Figure 45: Indigenous territory



Figure 46: Quilombolas' territory

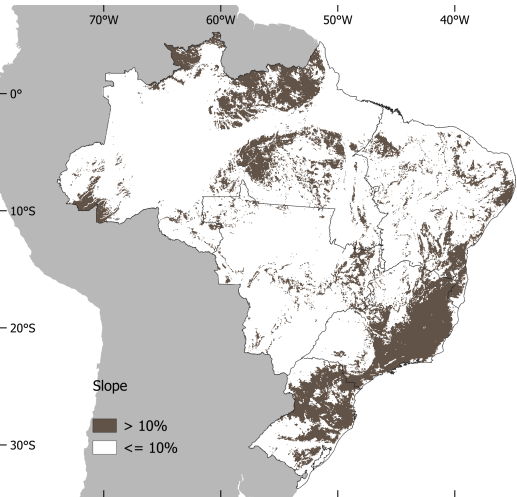


Figure 47: Slope > 10%.



Figure 48: Urban areas.

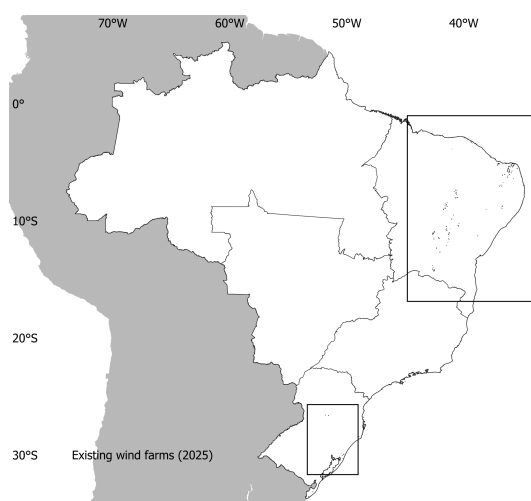


Figure 49: Existing wind farms (2025).

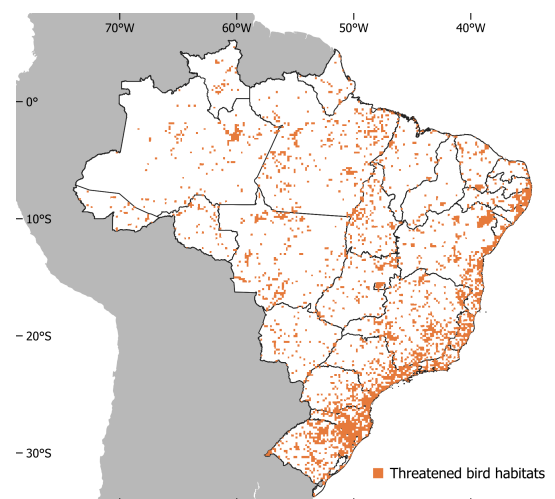


Figure 50: Threatened bird habitats (exclusion criterion only for wind farms).

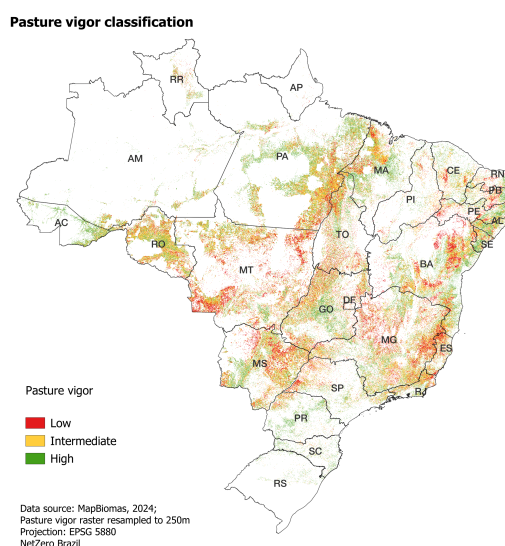


Figure 51: Spatial distribution of pasture vigor in Brazil. Pasture vigor is used to represent the condition of existing pasturelands and identify areas potentially suitable for feedstock expansion.

3.2.1.2 Bioenergy feedstocks

Feedstock options include food, feed or energy crops (sugarcane, corn, soybean, and macaúba), lignocellulosic residues of crop harvesting (sugarcane straw, corn stover, and rice straw), and woody materials (planted forest wood and tree-harvesting residues). Due to computational complications, the option of macaúba as a bioenergy feedstock is excluded from the initial version of the NZB MACRO model, but this option will be included in a future revision of the model, so we include documentation of it here.

We developed spatially explicit supply curves for feedstocks that require dedicated land (sugarcane, soybean, corn, planted forests, and macaúba) through a geoprocessing workflow implemented in Python within QGIS, using GDAL and NumPy. We harmonized all spatial layers to a common 250m raster grid and used nearest-neighbor resampling to preserve categorical values. MACRO

then determines the annual tonnages required of each of these feedstocks. Outcomes are then incorporated into land-use modeling in the MAGPIE-Brazil model, which includes the production of these tonnages as additional land-use demands.

We first identified land that was potentially available for cultivating each feedstock (see Section 3.2.1.1 for the exclusion criteria). We developed a land-availability mask that excluded indigenous and quilombola territories, urban areas, protected areas, public forests, rivers, and land with slopes exceeding 10%. To limit competition with food production and prevent land conflict with natural vegetation, we restricted biofuel feedstock expansion to low and intermediate-vigor pasturelands, identified as classes 1 and 2 in the MapBiomass dataset [12]. Previous research identifies the conversion of degraded pasturelands as a strategy for sustainably expanding biomass feedstock production in Brazil [57].

For sugarcane, soybean, and planted forests, we combined the expansion areas with the existing cultivated areas mapped by MapBiomass [12], as indicated in Figures 52a and 52b. We then aligned a spatially explicit cost raster for each feedstock with its corresponding availability mask.

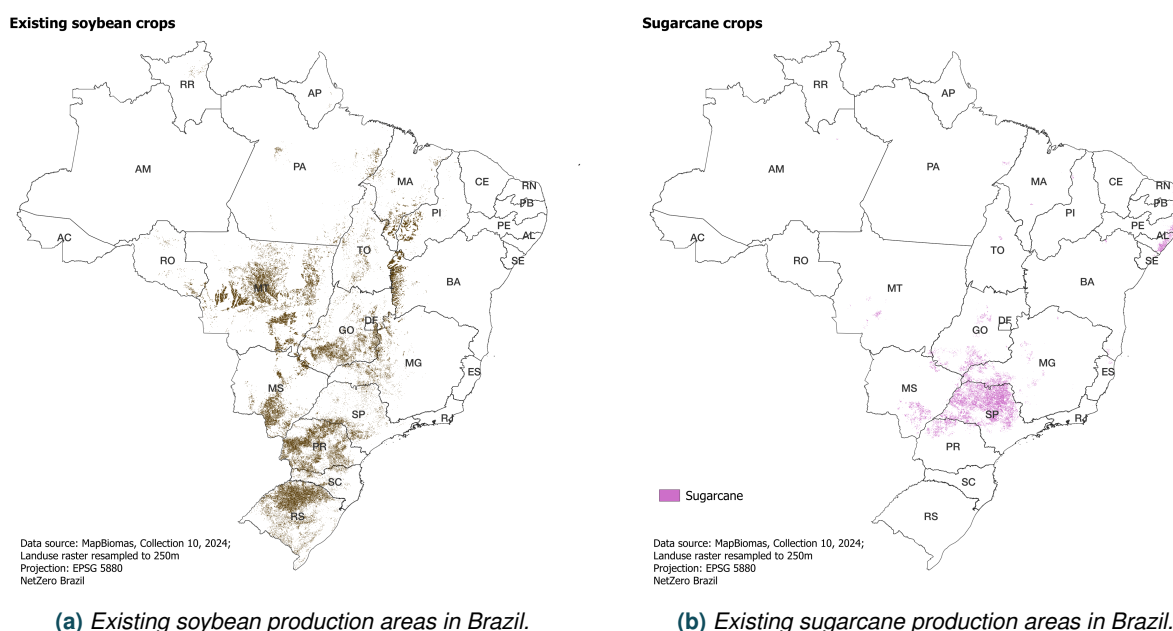


Figure 52: Existing production areas for the main biofuel feedstocks considered in the model.

For sugarcane, we used cost estimates from SAFmaps [58]. As SAFmaps did not provide nationwide coverage at the time of the study, we complemented it with the sugarcane suitability map developed by Embrapa [59] (Figure 53). We assigned representative costs to the Embrapa suitability classes.

SAFMaps reports costs in Brazilian reais (BRL), with 2018 as the reference year. We adjusted these values to 2025 prices using the agricultural component of the General Producer Price Index (IPA) from [60] and converted them into 2025 US dollars (BRL 5.59 per USD). See [61] for values used in MACRO. Thus, high suitable areas are associated with the cost R\$80/t (USD 34.7, after conversion), R\$90/t (USD 31.2) for moderately suitable areas, and R\$100/t (USD 27.8) for areas with low suitability.

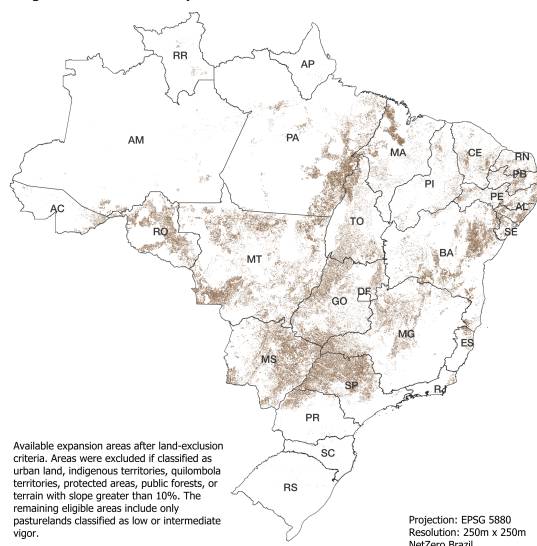
Finally, we merged the reclassified Embrapa layer with the masked SAFmaps raster to produce a spatially explicit national sugarcane cost surface. Sugarcane costs are expressed per unit of total

recoverable sugar (TRS, ATR in Portuguese). We converted these costs assuming an average sugarcane quality of 140 kg ATR per tonne of sugarcane (14% by mass), consistent with EPE's projection for the Brazilian sugarcane sector [62].

We ranked the state-level areas by production cost, from lowest to highest, and calculated the cumulative available area and feedstock production. This process generated state-specific supply curves, linking marginal production costs to cumulative land availability and production potential.

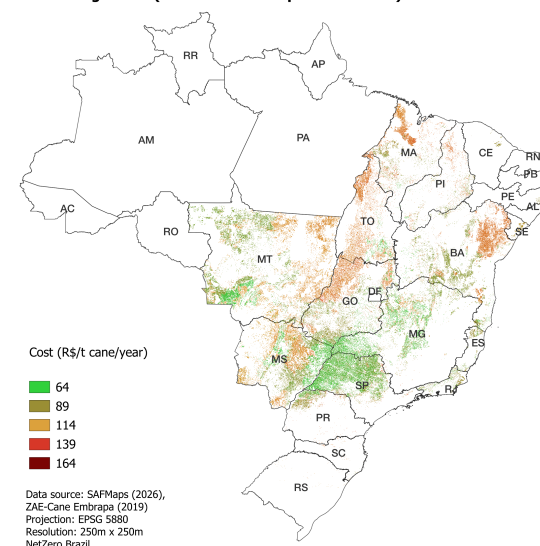
Our estimate of the supply potential of sugarcane applies for sugarcane that would be harvested to make sugar or ethanol. Since we do not model sugar production in MACRO we assume that only half of our estimated sugarcane potential (at each level of cost per tonne of cane) is potentially available for ethanol production. This assumption is based on the fact that over the past 25 years, the use of harvested cane has been split nearly equally between sugar and ethanol production (see Figure 5 in [63]). Albeit this assumption, note that the actual modeled amount of sugarcane harvested for sugar production is generated in the MAgPIE-Brazil model, and may differ from the harvest level assumed in MACRO for purposes of estimating the potential sugarcane availability for ethanol production.

Sugarcane: available expansion after land exclusion



(a) Available areas for sugarcane expansion.

Costs of sugarcane (harvest and transport to the mill)



(b) Estimated costs of sugarcane expansion are categorized into three levels: low (below 80 R\$/t), medium (80–100 R\$/t), and high (above 100 R\$/t).

Figure 53: Spatial distribution of feedstock expansion and estimated costs. The original cost reference year is 2018. Costs were converted from 2018 BRL to 2025 USD using a factor of 2.077, based on the IPA index and the average 2025 exchange rate. Moisture is assumed to be 30% per tonne of sugarcane.

For soybean, corn, planted forests, and macaúba, we combined the masked cost surfaces with crop-specific spatially explicit rasterized yield data from SAFMaps [58]. Figure 54 shows the costs for soybean, Figure 55a, Figure 55b, and Figure 56 illustrate the costs of macaúba, planted forests, and corn, respectively. As for sugarcane, we generated state-specific supply curves, linking marginal production costs to cumulative land availability and production potential. We also applied the same currency-year and exchange rate conversions to express costs in 2025 US\$.

For corn, soybeans, and macauba used for energy, we adjust the above-explained supply costs to account for the value of co-products (in the case of corn and soybeans) and for the cost of oil extraction

from the harvested crop (in the case of soybeans and macaúba), as explained next.

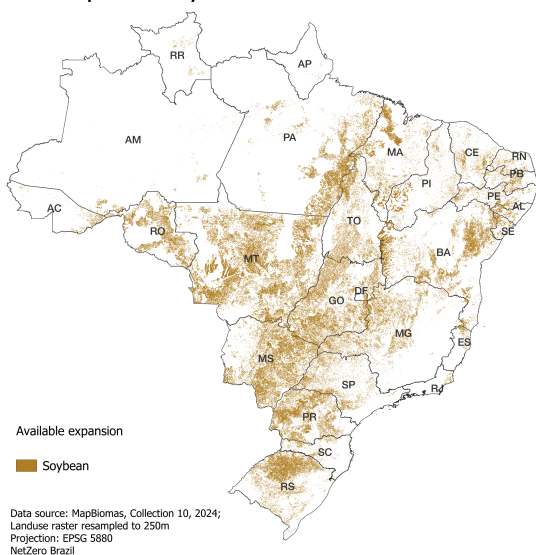
The bioenergy option for corn in our model is dry-mill ethanol production, as described in the Section 3.2.2.2. Dried distillers grain (DDG) and oil are two important co-product revenue sources for these facilities, and we include estimated revenues from these as credits against the cost of corn-ethanol production. We base our credit estimates on yield data and co-product values from the well-established US corn-ethanol industry. From October 2014 - June 2025, regression of monthly yields of DDG and of oil per unit of corn input show clear linear downward and upward trends, respectively [64]. We use the most recent regression-based estimates in this time series: 15 pounds DDG and 0.97 pounds of corn oil per standard bushel of corn. Considering a standard bushel is 56 pounds (with 15% moisture content), these yields correspond to 0.27 and 0.017 tonnes per tonne of input (15% mc) corn for DDGs and oil, respectively. In the US, DDG prices are closely correlated with input corn feedstock prices [65], with the price per tonne of DDG roughly equal numerically to the price per tonne of corn. We assume this relationship here. Correlations between corn and corn oil prices are less clear. One recent generic analysis for Mato Grosso state, where Brazilian corn-ethanol production is growing most rapidly, indicates that corn oil revenue is equivalent to about 30% of DDG revenue [66]. We assume this relationship here. In MACRO, we account for these assumed values of DDG plus oil co-products by adjusting the input corn feedstock supply-cost curve: the effective input corn feedstock cost is $(\$/t_{corn}) \times (1 - (0.27 \times 1.3)) = 0.65 \times \$/t_{corn}$, where $\$/t_{corn}$ is the original delivered cost of corn we established based on SAFmaps.

The conversion technology options for using soybean feedstocks in our model are production of fatty acid methyl esters (FAME) or hydrotreated vegetable oils (HVO/HEFA). Each of these processes use soybean oil as input feedstock. Soybean oil is produced by crushing and refining of raw soybeans, a process that co-produces soy meal sold for animal feed. For our modeling, we incorporate the cost of oil extraction from as-harvested soybeans plus oil delivery to the biofuel facility into operating costs for the FAME and HVO/HEFA processes (as described in the Section 3.2.2.2. We account for the value of the soy meal co-product by adjusting the supply costs for soybeans reported in SAFmaps as follows. We assume that crushing one tonne of soybeans (with 13% moisture) produces a standard yield of 201 kg of oil and 766 kg of meal, the reported average for Brazilian producers between 2014 and 2025 [67]. The oil's share of the total oil-plus-meal "crush value" has fluctuated between 0.3 and 0.5 in Brazil during the past 30 years [68]. We assume 0.4 as a representative oil crush value share. The effective soybean feedstock cost for FAME or HVO processes in our model is then $\$/t_{sb} \times \text{CrushValueShare}_{oil}$, where $\$/t_{sb}$ is the cost of as-delivered soybeans to a crushing facility (based on SAFmaps) and $\text{CrushValueShare}_{oil} = 0.4$.

For macauba feedstocks, we apply a similar approach for adjusting the costs as we do for soybeans. Macauba is not yet a well established commercial oil crop, but has similar properties to oil palm, so we assume costs for oil extraction from fresh macauba fruit will be the same as for oil extraction from oil palm per unit of oil extracted. Man and Baharum [69] estimated the palm oil extraction cost for a Malaysian facility processing 60 tonnes per hour of fresh fruit bunches (FFB) to be 36.25 Malaysian Ringgit per tonne FFB (in 2009 RM). Applying a 2009 exchange rate of 3.52 MR\$ per US\$ and escalating the result using the CEPCI gives a cost of about US\$₂₀₂₅ 16/FFB. We ignore the value of other co-products of oil extraction such as palm kernel cake, and use the extraction cost estimate to adjust macauba feedstock input costs in MACRO so that the effective feedstock cost for FAME or HVO processes in our model is $\$/t_{macaubaFF} + 16$, where $\$/t_{macaubaFF}$ is the original production cost (in

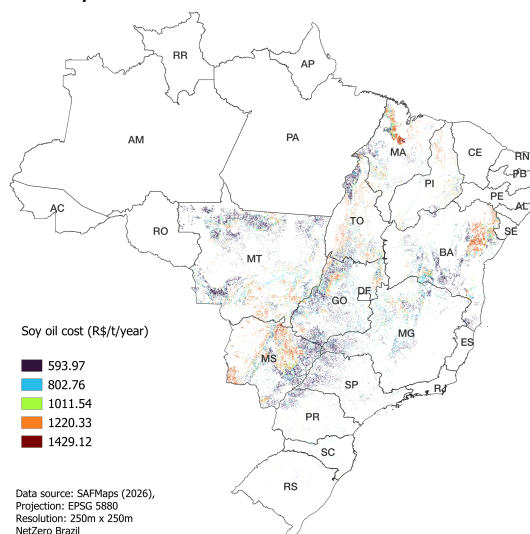
2025 US\$/t) based on SAFmaps.

Available expansion for soybean



(a) Available areas for soybean expansion.

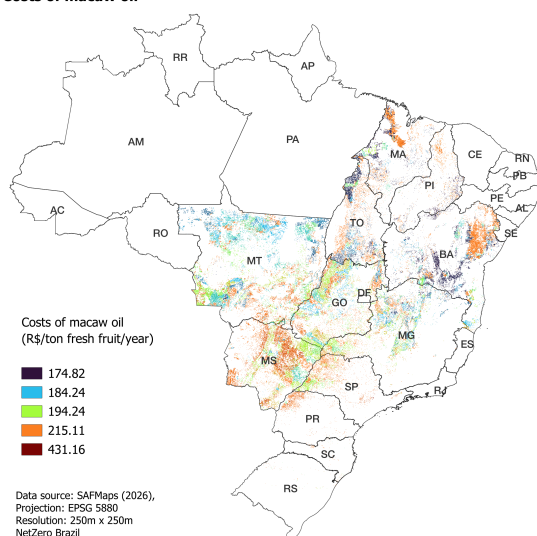
Costs of soy oil



(b) Estimated costs of soybean expansion.

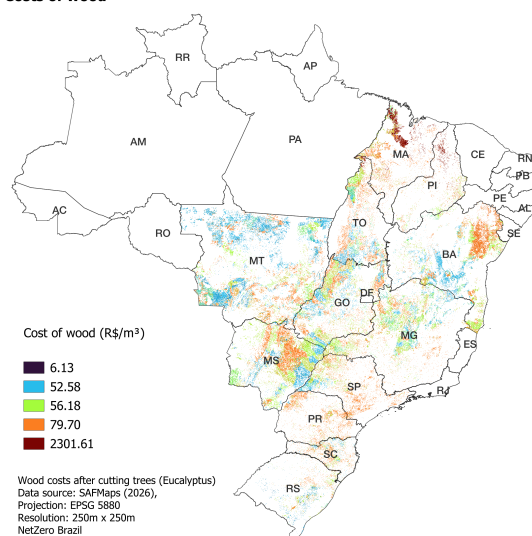
Figure 54: Spatial distribution of soybean feedstock expansion and estimated costs. The original cost reference year is 2018. Costs were converted from 2018 BRL to 2025 USD using a factor of 2.077, based on the IPA index and the average 2025 exchange rate. Moisture is assumed to be 13% per tonne of soybean.

Costs of macaw oil



(a) Estimated costs of macaúba expansion.

Costs of wood



(b) Estimated costs of planted-forest expansion.

Figure 55: Spatial distribution expansion for macaúba and planted forests, and estimated costs. The original cost reference year is 2018. Costs were converted from 2018 BRL to 2025 USD using a factor of 2.077, based on the IPA index and the average 2025 exchange rate. We assume an oil yield of 23% per dry tonne of fruit.

We excluded oil palm from our analysis because its reported potential is relatively small.

To ensure consistency between land used to grow bioenergy crops in MACRO and land-use change modeled by MAGPIE-Brazil, the bioenergy crop requirements determined in MACRO are passed to

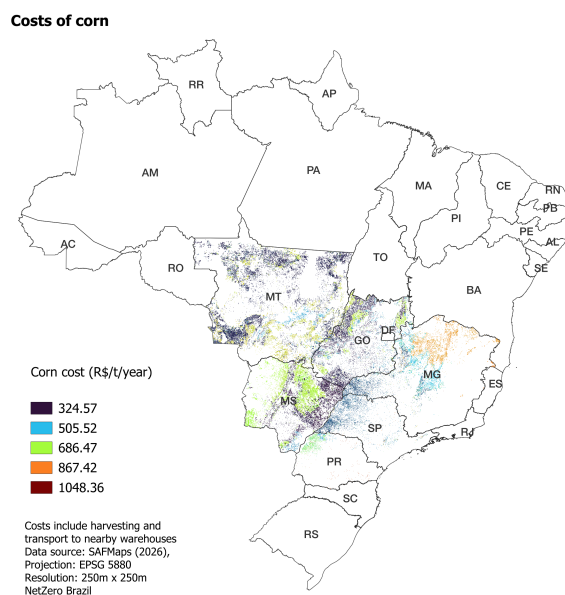


Figure 56: *Estimated costs of corn expansion. The original cost reference year is 2018. Costs were converted from 2018 BRL to 2025 USD using a factor of 2.077, based on the IPA index and the average 2025 exchange rate. Moisture is assumed to be 14% per tonne of corn.*

MAGPIE-Brazil as an additional demand that must be met. MAGPIE-Brazil crop production levels are expressed on a dry tonnage basis, so bioenergy crop tonnages from MACRO are converted to a dry matter basis before passing to MAGPIE-Brazil. For these conversions, we assume each tonne of sugarcane processed in MACRO is 30% dry matter [70] (sugarcane demand for sugar production is estimated within MAGPIE-Brazil's food demand module and is additional to the sugarcane needed to meet bioenergy demand from MACRO). For corn, we assume each tonne processed in MACRO is 14% moisture, the typical content of traded corn [71]. We assume soybeans are harvested with 13% moisture, the U.S. standard today (Brazil's Ministry of Agriculture established 14% as the limit for traded soybeans in 2007 [72], but a reduction to 13% has been under discussion in recent years [73]). For macauba palm, we assume a 23% yield of oil per dry tonne of fruit (19.6% pulp oil and 3.4% kernel oil) [74], or 4.3 dry tonnes of fruit per tonne of macauba oil. MACRO's planted forest wood supply-cost curves are derived from SAFmaps [58], which reports eucalyptus wood supply potential in cubic meters of freshly harvested wood. To represent wood flows in dry tonnes in MACRO, these volumes are converted using a density of 0.483 dry t/m^3 , calculated from the SAFmaps forest-gate parameters of 0.985 t/m^3 green density at 104% moisture content (dry basis).

In addition to the wood demand estimated endogenously within MACRO, the exogenous mass-based demands must be added. The charcoal demand, originating from both EnergyPathways and the transport-agriculture model, is one of MACRO's inputs, since it includes charcoal production assets. Wood demand for charcoal production is therefore an output of MACRO. Consequently, to avoid double counting, only firewood demand bypasses MACRO and is added to its wood output. The exogenous firewood demand, however, is reported on a wet basis, so the same moisture content cited above is assumed for the summation with MACRO's wood output before passing the final mass demand for wood to MAGPIE-Brazil.

For sugarcane straw, the amount potentially available for energy uses depends on the total level of sugarcane harvested (for sugar and for ethanol). We assume the total harvest is two times the

amount harvested for ethanol production for reasons discussed earlier in this section. We assume each tonne of as-harvested sugarcane (70% moisture content) generates 120 kg (dry basis) of straw [75]. For a typical sugarcane yield of $75 \text{ t}_{70\%mc}$ per ha, this yields $9 \text{ t}_{drystraw}/\text{ha}$. The amount of this straw that can be sustainably removed typically varies from field to field, but in tests reported by [75], removing up to one-third of the available straw was generally found to be non-detrimental to soil health and sugarcane yields. Accordingly, we assume an allowable removal of up to one-third of the straw generated during harvesting of sugarcane.

The SUCRE study estimated the cost of collecting $3 \text{ t}_{drystraw}/\text{ha}$, baling it, and transporting it (35 km) to be $138 \text{ R\$}_{2019}/\text{t}$ (or $35 \text{ US\$}_{2019}/\text{t}$ with the exchange rate used by SUCRE). We escalate this to $218 \text{ R\$}_{2025}/\text{t}$ using the Brazilian IPA index [60] and then apply a 2025 currency exchange rate (5.59 R\$/US\$) to reach $39 \text{ US\$}_{2025}/\text{t}$. We add to this a cost for unbaling and shredding estimated by [75] to be $69 \text{ R\$}_{2019}/\text{t}$, or $19.5 \text{ US\$}_{2025}/\text{t}$, for a total delivered cost of boiler- or gasifier-ready feedstock of $58.5 \text{ US\$}_{2025}/\text{t}$.

For corn stover and rice straw, the potential tonnages assumed to be available in our model are based on Frudit [76], who estimated residue production from primary crop production levels in each municipality where corn or rice were grown in 2023. To estimate total residue availability, Frudit assumed residue-to-primary crop ratios from the literature and that 40% of residues are sustainably removable. The resulting useable residue fractions are $0.75 \text{ t}_{drystover}/\text{t}_{corn}$ and $0.55 \text{ t}_{drystraw}/\text{t}_{rice}$, where the primary grain tonnages include 14% water (our model fixes future potential state-by-state corn stover and rice straw levels at Frudit's values, regardless of future primary crop production levels). For corn stover, [77] estimates collection and baling costs of $68.4 \text{ R\$}_{2012}$ for removal of $3 \text{ t}_{drystover}/\text{ha}$. We escalate this to $\text{R\$}_{2025}$ using the IPA index and then convert the result to $28.9 \text{ US\$}_{2025}$ using the 2025 currency exchange rate. We add $8.4 \text{ US\$}_{2025}/\text{t}_{drystover}$ for transporting bales 32 km (based on [78]) and unbaling and shredding costs of $19.5 \text{ US\$}_{2025}/\text{t}_{drystover}$ (as estimated above for sugarcane straw), for a total delivered cost of boiler- or gasifier-ready feedstock of $56.8 \text{ US\$}_{2025}/\text{t}_{drystover}$. We assume delivered rice straw costs would be similar ($57 \text{ US\$}_{2025}/\text{t}_{dryricestraw}$).

The final category of residue biomass feedstocks in our model is forestry residues. We adopt state-aggregated estimates from SAFmaps [58] of the potential availability of residues from eucalyptus harvesting. Eucalyptus accounts for over 70% of planted forest production [79]. SAFmaps estimates the total amount of eucalyptus harvesting residues generated by first estimating the eucalyptus wood production level as of 2018 on a municipality-by-municipality level and then assuming a residue ratio of 0.167 tonnes per m^3 of wood, where the assumed moisture content of the residues is 11.6%. Finally, SAFmaps assumes that 50% of the generated residues could potentially be removed for and used for energy. We assume zero potential residue availability for states that SAFmaps estimates generated less than 30,000 $\text{t}_{dry}/\text{year}$ of recoverable residues. We assume the cost for residues delivered to conversion facilities is $45.1 \text{ US\$}_{2025}$ (based on [80]).

Aggregated nationally, the total potential availability of forestry residues in our model is 21 million $\text{t}_{dry}/\text{year}$. Our modeled national total potential for usable corn stover and rice straw are 99 million and 6 million $\text{t}_{dry}/\text{year}$. The potentially usable sugarcane straw (using our assumptions described above) was 31 million t_{dry}/y for the 2023 sugarcane harvest level of 783 million t_{c} [13]. The state-by-state potential residue availabilities included in the MACRO model are tabulated in [61].

Seasonality of biomass feedstock supplies

The biomass feedstock supply-cost curves described above provide annual tonnage values. We use the capability of the MACRO framework for incorporating varied temporal resolutions to distribute annual supply to better reflect seasonal patterns in feedstock availability. Variability in feedstock supply is evident in the significant monthly variations observed in Brazilian ethanol production today [81]. National output typically peaks in the fourth quarter, coinciding with peak sugarcane harvesting.

To model feedstock seasonality in MACRO, annual harvestable quantities are exogenously constrained on a monthly basis, with the maximum allowable utilization in each month determined by the underlying biomass seasonal pattern. In the case of corn and soybeans, these are both harvested seasonally. Corn is grown predominantly as a second crop ("safrinha") after soybeans are harvested. Both of these crops can be stored for extended periods without significant degradation, so fuel production facilities can and do draw on these feedstocks more-or-less continuously throughout the year. This is evident in Brazil's biodiesel production today, which exhibits relatively little month-to-month variation [82]. Accordingly, our MACRO model assumes corn and soybeans are available to energy producers with no temporal constraints.

Sugarcane exhibits significant seasonality, and we derive monthly availability profiles from two complementary sources. ANP [83] publishes monthly ethanol production statistics for five regions of Brazil (North, Northeast, Center-West, Southeast, and South), offering the most spatially complete picture of national seasonality, but reports only aggregate ethanol production without distinguishing between sugarcane-derived and corn-derived ethanol. UNICA [82] complements this by reporting monthly processing volumes with sugarcane-ethanol and corn-ethanol production disaggregated, though its coverage is concentrated primarily in the Centro-Sul region centered on São Paulo state, where most sugarcane is grown in Brazil today. We use the ANP data as the primary basis for deriving the monthly seasonal allocation across the five regions, while UNICA data are used to isolate the sugarcane-specific share of ethanol in the ANP data and thereby refine the allocation for the Centro-Sul region. We normalize the monthly shares of sugarcane-ethanol availability and applies these to the annual total to determine temporal sugarcane availability. A notable feature of the resulting seasonal patterns is that harvest is concentrated within a similar window across the Center-West, Southeast, and South regions. The Northeast region follows a distinct calendar, driven by differing climatic conditions.

3.2.1.3 Fossil Fuels

Natural gas

MACRO includes the supply of fossil natural gas produced in Brazil. In this version, no distinction is made between gas produced offshore and onshore, and it is assumed that all Brazilian states have access to natural gas at the same price. In practice, this is a simplification that will be refined in future versions, since Brazil's existing natural gas transport and distribution network remains limited: 10 of the 26 states plus the Federal District currently have no transport pipelines [84]. Nevertheless, natural gas infrastructure planning already envisions a significant expansion of the transport network¹², as shown in Figure 57.

¹²According to EPE's classification, projects are categorized as: *Planned* (works under contract, or with consolidated schedules and formal expansion instruments); *Indicative* (technical-economic studies pointing to future needs, without guaranteed execution); and *Authorized* (projects with concessions granted or licenses issued by regulatory bodies) [85].



Figure 57: Brazilian natural gas infrastructure planning. Source: [86]

Wholesale prices assumed in MACRO for natural gas vary with the user-selected price scenario, as described in Section 4.7.2. The base price (11 US\$/MMBtu) for the first projection period was taken as the average of the natural gas city-gate prices (PGC) projected by EPE for 2024 and 2025 [85]. The PGC comprises two components: the molecule price charged by commercial agents and an equivalent average transport tariff.

CO₂ emissions associated with end-use combustion of natural gas is determined endogenously in MACRO. For modeling purposes, upstream CO_{2e} emissions related to methane leakage and fuel combustion are accounted for within the upstream emissions associated with crude oil production. In this first version, liquefied petroleum gas (LPG) consumption is accounted for as natural gas consumption. A separate representation of LPG will be introduced in the second version.

Petroleum-derived fuels

MACRO includes petroleum-derived end-use fuels (gasoline, diesel, and jet) as options for meeting fuel demands. Our modeling assumes that these fuels are refined in Brazil from crude oil produced in or outside Brazil. CO_{2e} emissions associated with end-use combustion of the fuels is determined endogenously in MACRO. Upstream CO_{2e} emissions associated with crude oil production and refining to make these fuels are specified exogenously: 0.0827 tCO_{2e}/t_{crudeoil} for production and 0.235 tCO_{2e}/t_{crudeoil} for refining. These estimates are based on historical values (1970-2024), calculated using [87] and [31] data as documented in [88].

Alternative future scenarios for how much crude oil will be produced in Brazil can be selected by a user (see Section 4.7.10). For scenarios in which crude oil production exceeds domestic demand, we assume the difference is exported. In such cases, MACRO accounts for the emissions associated with the production of the crude oil (0.0827 tCO_{2e}/t_{crudeoil}), but refining and end-use combustion emissions are considered only for the portion of the crude oil that goes to meet domestic demands.

Wholesale prices assumed in MACRO for petroleum-derived fuels vary with the user-selected price

scenario, as described in Section 4.7.2. The base prices considered for the first projection period correspond to refinery-gate Gasoline A (producer price, excluding taxes), refinery-gate Diesel Oil A, and refinery-gate Jet Fuel (QAV), estimated at R\$2.50/liter, R\$3.50/liter, and R\$4.80/liter, respectively [89][90]. Because MACRO's demand inputs must be expressed in MWh, fuel prices were converted to US\$/MWh. The R\$-to-US\$ conversion used the average 2025 exchange rate (R\$5.22/US\$), while the liter-to-MWh conversion for each fuel was based on its higher heating value (HHV) - 11,220 kcal/kg for Gasoline A, 10,750 kcal/kg for Diesel Oil, and 11,090 kcal/kg for QAV - and its density - 0.742 kg/L for Gasoline A, 0.840 kg/L for Diesel Oil, and 0.799 kg/L for QAV - together with the constant 1 MWh = 859,845 kcal. All values were obtained from BEN [91]. Applying these conversions yields base wholesale prices of approximately US\$49.5/MWh for Gasoline A, US\$63.9/MWh for Diesel Oil A, and US\$89.2/MWh for QAV.

For other petroleum-derived fuels, whose consumption is estimated by the demand models, only the emissions associated with their use are considered. These emissions are estimated exogenously and passed to MACRO, where they are accounted for as atmospheric CO₂ emissions.

Coal

MACRO considers both domestic and imported coal as supply options. No distinction is made between coal sourced from open-pit or underground mines. Wholesale prices assumed in MACRO for coal vary with the user-selected price scenario, as described in Section 4.7.2.

The base price for domestic coal, R\$406.38/t, corresponds to the price quoted by ANEEL for the Jorge Lacerda thermal power plant [92]. The base price for international coal, R\$750/t, is based on Intratec's Brazil coal (thermal) average price reference [93]. As with the other fuels described above, these base prices were converted to US\$/MWh using each coal type's higher heating value (HHV) - 4,500 kcal/kg for domestic coal and 6,000 kcal/kg for international coal [91] - together with the constant 1 MWh = 859,845 kcal and the average 2025 exchange rate of R\$5.22/US\$, yielding approximately US\$14.9/MWh for domestic coal and US\$20.6/MWh for international coal.

Fugitive emissions from coal production comprise both CH₄ emissions from coal mining and processing (open-pit and underground mines) and CO₂ emissions from spontaneous combustion in waste-rock piles. According to BEN [91], Brazilian steam coal production in 2024 totaled $5,992 \times 10^3$ t. For the same year, SEEG reports emissions of 1,250,799 t CO_{2e} from open-pit and underground mining operations [87], corresponding to an average mining emission factor of 0.2087 tCO_{2e}/t_{coal}. Upstream CO_{2e} emissions related to coal mining in Brazil are determined endogenously in MACRO using this average 2024 emission factor.

3.2.2 Conversion Technologies

3.2.2.1 Power system

Hydropower

Hydropower availability is represented by Natural Energy Inflow (NEI), which depends on river inflows and the productivity of the hydropower plants. The interconnected operation of reservoirs and run-of-river plants within cascaded river systems allows water released by upstream plants to be used by downstream facilities. Hydropower data were obtained from the Brazilian National System Operator

(ONS) for all run-of-river and reservoir plants under its operation [94]. ONS determines NEI using two inputs: natural flow (Q_{nat}) given in m^3/s and from the average production (p) of the turbine-generator ensemble linked to the elevation difference between the water level associated with 65% of the usable water volume in the upstream reservoir and the water level at the tailrace, given in $MW/m^3/s$. Here, i is the hydropower plant, n represents the number of hydropower plants in a basin, and t indicates the period.

$$NEI = \sum_{i=1}^n Q_{nat}(i, t) \cdot p(i) \quad (44)$$

To capture the main effects of cascaded operation and the spatial transferability of hydropower resources, individual plants were aggregated by river basin, as shown in Figure 58. For each basin, the resulting hydropower time series was divided between run-of-river and reservoir generation in proportion to the installed capacity of the two plant types.



Figure 58: Hydropower plants by basin.

The model uses 2013 as the reference year. Missing or negative observations were replaced with the nearest valid non-negative value in the time series. The complete dataset is available at the GitHub repository.

Reservoirs provide temporal flexibility by storing water that can be converted into electricity. The maximum energy storage capacity of each basin, in GWh, was calculated as the sum of the maximum storage capacities of its individual reservoirs. Not all of this theoretical storage capacity is available for electricity generation because minimum reservoir levels must be maintained to support environmental flows, navigability, and operational security. The usable storage capacity was therefore constrained

according to the average operational security levels adopted by ONS (Table 39).

Table 39: *Security levels adopted for hydropower reservoirs by basin and subsystem. The values represent the minimum storage level (as a percentage of total reservoir capacity) maintained to ensure operational reliability and water availability under varying hydrological conditions.*

Basin	Region	Security level in %
Amazonas	North/Southeast-Midwest	10
Tocantins	North/Southeast-Midwest	20
São Francisco	Northeast/Southeast-Midwest	30
Paraguaçu	Northeast	10
Paraíba do Sul	Southeast-Midwest	19.7
Jequitinhonha	Northeast	10
Paranaíba	Southeast-Midwest	20
Paraná	Southeast-Midwest	46.4
Doce	Southeast-Midwest	-
Grande	Southeast-Midwest	22.3
Paranapanema	Southeast-Midwest	20
Tietê	Southeast-Midwest	45.5
Capivari	South	10
Uruguai	South	20
Jacuí	South	30
Iguaçu	South	20

For existing hydropower plants, we assumed capex to be zero because these assets are already installed, while we obtained opex from the Brazilian National Energy Plan (PNE) [95]. For inventoried hydropower expansion, we assigned capex (in 2025 US\$/kW) according to plant size, following the PNE cost ranges: US\$2,600/kW for plants up to 299 MW, US\$1,800/kW for plants between 300 and 999 MW, and US\$1,300/kW for plants of 1,000 MW or more. These values were weighted by the potentially installed capacities of the inventoried projects in each technology category, resulting in average CAPEX values of US\$1,932/kW for run-of-river hydropower and US\$2,215/kW for reservoir hydropower (see spreadsheet for costs in [61]).

Variable Renewable Energy

Variable renewable energy (VRE) refers here to solar photovoltaic electricity (utility-scale or roof-top generators) and wind-generated electricity (onshore and offshore turbine generators). These assets were parameterized in MACRO starting from highly spatially resolved assessment of resource potentials (described in Section 3.2.1.1) that were clustered for state-level representation in our model.

Clustering of renewable energy sites

For utility-scale solar and wind candidate project areas (CPA), the areas were grouped using k-means clustering into representative technology classes based on generation costs and grid connection

features. K-means clustering is commonly used in energy system models to aggregate renewable energy data into fewer representative classes, thereby reducing computational requirements [96].

Each 250m x 250m CPA was linked to the existing substation dataset (provided by the national operator [97]) by matching the nearest connection point associated with each site. The clustering used three attributes: the levelized cost of electricity (LCOE), distance from each pixel to the nearest substation, and distance from each pixel to the load center. The capitals of states were considered load centers. This multidimensional clustering captures techno-economic similarity among candidate sites and supports the construction of representative renewable supply zones.

A preliminary levelized cost of electricity (LCOE) was calculated to cluster CPAs. This estimate was used exclusively as a techno-economic ranking indicator and not as the technology cost assumed in the energy system optimization. The preliminary LCOE was calculated as:

$$\text{LCOE}_i = \frac{\text{capex} \times \text{CRF} + \text{opex}_{\text{fix}}}{8760 \times CF_i}, \quad (45)$$

where LCOE_i is expressed in US\$/MWh for CPA i , capex is the assumed overnight capital cost in US\$/MW, opex_{fix} is the assumed annual fixed operation and maintenance cost in US\$/MW-year, and CF_i is the capacity factor of the corresponding renewable resource. The denominator represents the expected annual electricity generation per MW of installed capacity, expressed in MWh/MW-year.

Capacity factors were simulated from ERA-5 reanalysis data using a $0.5^\circ \times 0.625^\circ$ spatial grid. Each CPA was assigned the capacity factor of its nearest simulated grid point. The capex and opex_{fix} assumptions for wind and solar technologies were obtained from the Brazilian Energy Research Office (EPE) [98].

The capital recovery factor (CRF) annualizes the upfront investment over the economic lifetime of the project:

$$\text{CRF} = \frac{r(1+r)^N}{(1+r)^N - 1}, \quad (46)$$

where r is the real weighted average cost of capital (WACC) and N is the project lifetime. We assumed a real WACC of 10.75%, consistent with the value reported by the International Energy Agency for Brazil [99], and an economic lifetime of 25 years.

To indicate grid connection conditions, each CPA was connected to its nearest eligible substation, and each substation was connected to the nearest load center. The reference cost for new transmission lines was obtained from the most recent ANEEL transmission auction [100]. Because the auction reports investment costs in US\$/km, the cost was converted to US\$/MW/km using an approximate transfer capacity derived from Equation 47 [101]:

$$P_{\text{MW},s} = \sqrt{3} V_{\text{kV},s} \left(\frac{I_A}{1000} \right) pf n_{\text{circuits}}, \quad (47)$$

$$c_{\text{line},s} = \frac{C_{\text{km}}}{P_{\text{MW},s}}, \quad (48)$$

where $P_{\text{MW},s}$ is the estimated power capacity associated with substation s , $V_{\text{kV},s}$ is its voltage, I_A

is the assumed line current, pf is the power factor, and n_{circuits} is the number of equivalent circuits. The factor 1000 converts kVA to MVA when voltage is expressed in kV and current in amps (A). We assumed $A = 1000$ amps, a power factor of 0.95, and one circuit. The reference transmission-line construction cost was set to $C_{\text{km}} = \text{US\$ } 844,988/\text{km}$.

Note that these preliminary estimates of generation and transmission costs were used only to cluster and rank the CPAs. They were therefore kept separate from the scenario-specific capex and opex assumptions used in the energy system model (see Section S25).

To estimate the maximum potential expansion capacity of wind and solar farms, eligible CPAs were aggregated by state and resource class (cluster). Each $250 \text{ m} \times 250 \text{ m}$ pixel represents an area of 0.0625 km^2 . The resulting available area was converted into installed capacity using power density assumptions of 33 MW/km^2 for solar PV [102] and 5.2 MW/km^2 for onshore wind [103].

Figures 59 and Figure 60 present the spatial distribution of the resource classes used to represent onshore wind and utility-scale solar PV potential, respectively.

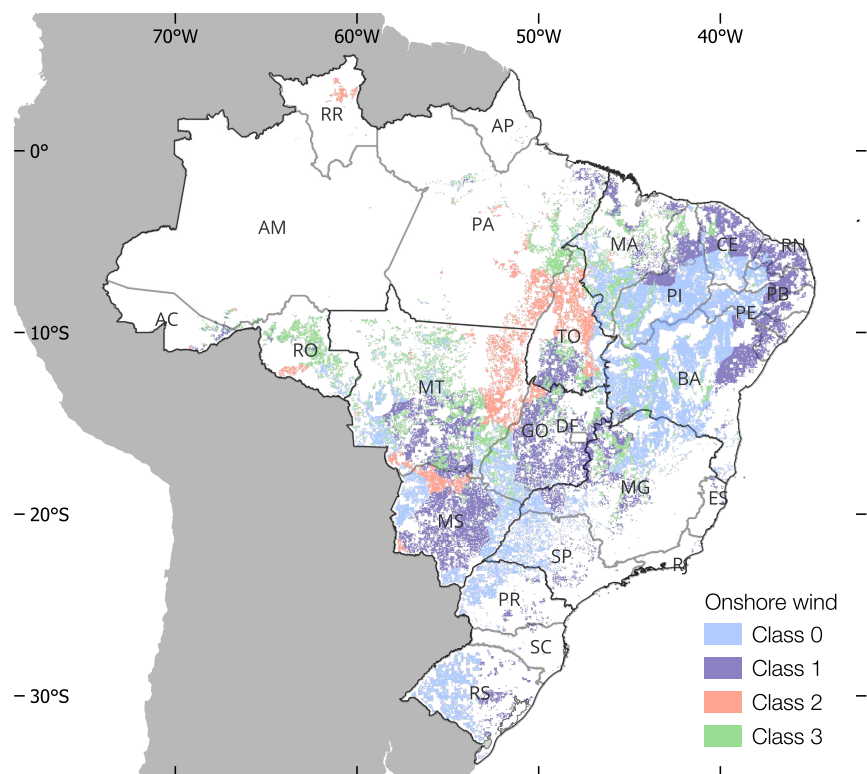


Figure 59: Classes of onshore wind farms.

Resources and technical parameters

Wind and solar generation profiles were simulated for a set of representative coordinate points distributed across Brazil.

For wind power, hourly wind speed data from the ERA-5 reanalysis were processed using the Windpowerlib Python package [104]. Wind generation was calculated for 1,923 coordinate points by converting wind speed at each location into turbine power output according to the technical elements of the selected wind turbine (hub height equals 100m, turbine model Vestas 126 3.5 MW). Capital and operating costs are estimated based on [105].

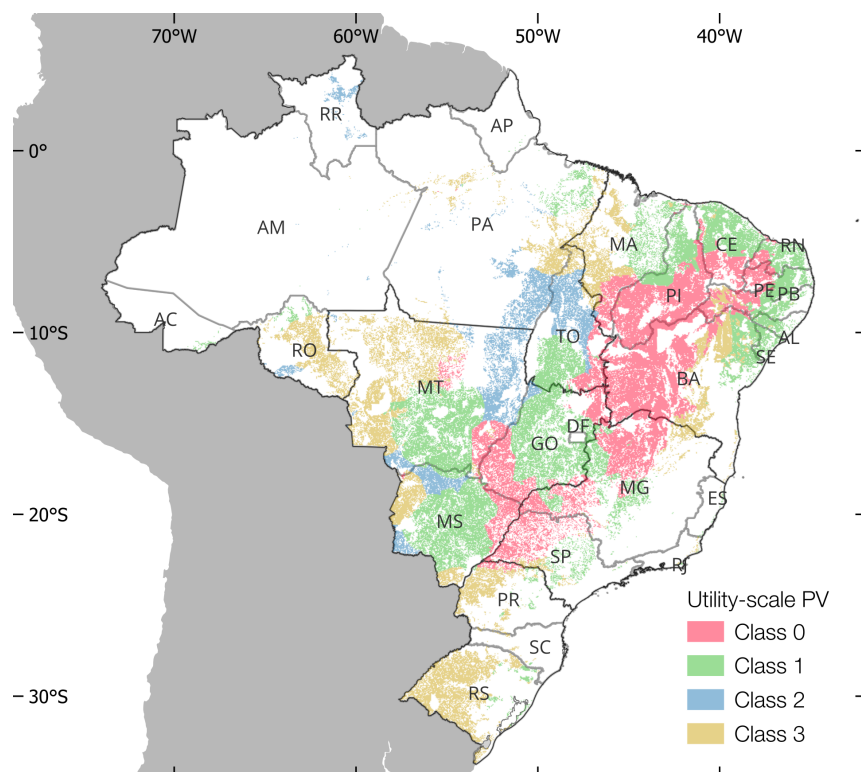


Figure 60: *Classes of utility-scale solar PV.*

Utility-scale solar PV generation was simulated for 2,267 coordinate points using the PV-GIS [106]. The simulations were set to use ERA-5 solar data, assuming crystalline-silicon PV modules and a single-axis tracking system. The resulting hourly power output was normalized by the nominal PV capacity to obtain the capacity factor time series. Capex and opex of the module are based on [105].

For rooftop PV, generation profiles were simulated using PVGIS [**pvgis**] at the same representative locations used for utility-scale PV, but assuming fixed-tilt systems rather than solar tracking (slope and azimuth are optimized using PVGIS). The suitable rooftop area in each state was estimated by combining the available rooftop surface coefficients by region [**miranda2015**] with the number of households obtained from IBGE [107]. The maximum installable capacity was then calculated using a power density of 160 MW/km [108]. Existing capacity was aggregated by state using data from EPE [109].

The offshore wind time series were simulated for three strategic regions along the Brazilian coast, using the optimized node locations and bias-correction dataset proposed by [110]. The simulations were based on NASA's MERRA-2 reanalysis data [111] and assumed the Vestas V164 8-MW turbine at a hub height of 100m. Costs are also based on empirical equations and calculated in a previous offshore wind study from Borba et al. [110].

For all variable renewable energy, the long-term cost reductions are explored in Variable 25 (Energy Supply Innovation). The three options are based on normalized cost-reduction rates for conservative and advanced scenarios, as reported in [112]. The moderate case is our reference, and assumed to be the costs reported by EPE. See Section 4.7.3 for more details.

Natural gas simple-cycle gas turbine

The existing natural gas simple-cycle gas turbine fleet is surveyed using SIGA, the Brazilian Electricity Regulatory Agency's (ANEEL) generation information system [113]. The following categories of units were not considered, as they do not represent grid-connected, centrally dispatched thermal generation: shopping mall backup systems, general backup power systems, refinery-associated systems, factories, industrial plants, office buildings, hotels, residential condominiums, the CENPES research facility, airports, self-generation units, and units with less than 10 MW of installed capacity. This yielded 7 simple-cycle units, totaling approximately 2,021 MW of installed capacity.

Simple cycle units are treated as a single representative technology. Fuel consumption was considered as $2.6073 \text{ MWh}_{fuel,HHV}/\text{MWh}_{elec}$, corresponding to an implied net efficiency of approximately 38.4%, consistent with a simple-cycle turbine operating without heat recovery. Startup fuel consumption was set as $0.586 \text{ MWh}_{fuel,HHV}/\text{MW}_{installed_elec}$ per start. The emission rate ($0.1813 \text{ tCO}_2/\text{MWh}_{fuel,HHV}$) is consistent with the standard EPA/EIA default CO_2 emission factor for natural gas [114].

Cost parameters for new-build units are taken from EPE's PDE 2034 Cost Parameters Notebook [115]. The "Existing" Fixed O&M value equals the "New" value. Technical lifetime, capital recovery period, and WACC were considered as 50 years, 20 years and 8%, respectively.

Our model assumes that simple-cycle gas turbine generation is a fully-mature commercial technology, and no future capital cost reductions are assumed, regardless of the user-specified rate of energy-supply side technology innovation (user-selected variable #25).

Natural gas combined-cycle gas turbine

The existing combined-cycle natural gas fleet is surveyed using the same SIGA registry described above [113]. Within the natural-gas subset, only reciprocating combustion-engine units were removed. Every unit classified by ANEEL as combined-cycle natural gas was retained. This yields 30 combined-cycle units, totaling approximately 16,337 MW of installed capacity, listed in the Existing Thermal Power Plants Considered in the Model section below.

Combined-cycle gas turbines are treated as a single representative technology: the model assigns one fuel-consumption (heat-rate-equivalent) factor and one emission factor to the whole combined-cycle fleet rather than a plant-by-plant figure. The fuel consumption rate of $2.106 \text{ MWh}_{fuel,HHV}/\text{MWh}_{elec}$ corresponds to a net efficiency of approximately 47.5%, consistent with a modern F-class combined-cycle unit. The emission rate of $0.1813 \text{ tCO}_2/\text{MWh}_{fuel}$ is consistent with the standard EPA/EIA default CO_2 emission factor for natural gas combustion ($53.06 \text{ kg CO}_2/\text{MMBtu}$) [114], converted to a per-MWh-of-fuel basis.

Capital and operating cost parameters are taken from EPE's PDE 2034 Cost Parameters Notebook [115], converted from Brazilian reais to US dollars with conversion rate for 2025 USD. New-build parameters correspond to the fully flexible, LNG-fired, cost category. The "Existing" Fixed O&M value ($\text{US\$}146,227.4/\text{MW-yr}$) corresponds to the notebook's inflexible, natural-gas, baseload scenario, read as a scenario-based estimate rather than plant-level operating data for a specific existing unit.

Our model assumes that combined-cycle gas turbine generation is a fully-mature commercial technology, and no future capital cost reductions are assumed, regardless of the user-specified rate of energy-supply side technology innovation (user-selected variable #25).

Natural Gas Combined-Cycle Power Plant with Carbon Capture (NGCC-CCS)

The NGCC-CCS technology is represented in the model by NETL's Case B31B.90 [116]: an F-class, 2×1 combined-cycle configuration equipped with a post-combustion capture system using Cansolv amine solvent, sized for a nominal CO₂ capture rate of 90%. The plant has a net power output of 658 MW. There are no natural gas combined-cycle plants with carbon capture in commercial operation in Brazil, so all parameters presented here apply to new-build capacity only.

Fuel consumption is $2.107 \text{ MWh}_{fuel,HHV}/\text{MWh}_{elec}$, consistent with the reported net plant efficiency of 47.5% on an HHV basis. Startup fuel consumption is $0.586 \text{ MWh}_{fuel}/\text{MWh}_{elec}$, on the same basis adopted for the combined-cycle without carbon capture case. The CO₂ emission rate (released to atmosphere, post-capture) and the CO₂ capture rate are derived from the plant's carbon balance: a stack-gas carbon flow of 6,957 kg C/hr and a captured-product carbon flow of 62,490 kg C/hr, each converted to CO₂ mass at a stoichiometric ratio of 44/12 kg CO₂ per kg C and divided by the HHV thermal input. This yields an emission rate of $0.0184 \text{ tCO}_2/\text{MWh}_{fuel,HHV}$ and a capture rate of $0.1653 \text{ tCO}_2/\text{MWh}_{fuel,HHV}$.

Capital expenditure, fixed O&M and variable O&M are taken from [116], Case B31B.90, reported in 2023 US\$, which we have escalated to 2025 US\$ using CEPCI: capital expenditure is 3,136,000 US\$/MW, fixed O&M is 70,491 US\$/MW-yr, and variable O&M is 5.3 US\$/MWh. It was assumed a WACC of 10% and a capital recovery period of 20 years. Technical lifetime is assumed at 50 years, a generic engineering assumption applied across the fleet. Operational flexibility parameters are: ramp-up and ramp-down of 10.9% of nominal capacity per hour, a minimum up time and minimum down time of 12 hours each, and a minimum flow of 50% of nominal capacity. Start-up cost was assumed as 97 US\$/MW-start.

For the current version of the model, no future capital cost reductions are assumed, regardless of the user-specified rate of energy-supply side technology innovation (user-selected variable #25).

Hydrogen simple-cycle gas turbine

This technology has similar performance and cost characteristics to natural gas simple-cycle gas turbine. See [61]. For the current version of the model, no future capital cost reductions are assumed, regardless of the user-specified rate of energy-supply side technology innovation (user-selected variable #25).

Hydrogen combined-cycle gas turbine

This technology has similar performance and cost characteristics to natural gas combined cycle. See [61]. For the current version of the model, no future capital cost reductions are assumed, regardless of the user-specified rate of energy-supply side technology innovation (user-selected variable #25).

Nuclear power plants

Two nuclear power plants are in commercial operation in Brazil, Angra I and Angra II [113], together totaling 1,990 MW of installed capacity. A third unit, Angra III, with a capacity of 1,405 MW, has 65% of its physical infrastructure complete [117] but remains a suspended asset, amid the political, regulatory and financial issues surrounding it [118, 119]. Angra III is not in commercial operation and is not included as existing capacity in this model.

New nuclear capacity is represented in the model by two technology classes from NREL's 2024 Annual Technology Baseline (ATB) [120]: "Large," corresponding to advanced nuclear light-water and

non-light-water technologies at 1,000 MW of capacity, and “Modular,” corresponding to small modular reactors (SMR) at 300 MW of capacity. The heat rate is 10,497 Btu/kWh for the Large class and 9,180 Btu/kWh for the Modular class, equivalent to a fuel-consumption factor of $3.076 \text{ MWh}_{fuel}/\text{MWh}_{elec}$ (Large, 32.5% net efficiency) and $2.691 \text{ MWh}_{fuel}/\text{MWh}_{elec}$ (Modular, 37.2% net efficiency). Minimum plant load is 15% of nominal capacity for the Large class and 50% for the Modular class. Ramp rate is 5% of nominal capacity per hour for the Large class and 10% for the Modular class. Existing capacity is assigned the same technical parameters as the Large class.

Capital expenditure, fixed O&M and variable O&M for both new-build classes are taken from [120], considering the conservative case as the default input for this technology. Capital costs are held constant between 2022 and 2030. Long-term capital-cost trajectories beyond 2030 follow three scenarios: slower, mid-range and faster innovation, corresponding to NREL's (2024) Conservative, Moderate and Advanced normalized cost-reduction rates, of which the mid-range (Moderate) case is the model's general reference scenario. The capital recovery period is set to 30 years and the technical lifetime, 60 years, while WACC is assumed as 8%. Capital expenditure is US\$11,836,118/MW for the Large class and US\$12,680,100/MW for the Modular class, while fixed O&M is US\$204,000/MW-yr (Large) and US\$215,968/MW-yr (Modular), and variable O&M is US\$3.4/MWh (Large) and US\$2.8/MWh (Modular). Existing-capacity fixed and variable O&M are based on Ministério de Minas e Energia and Empresa de Pesquisa Energética [121]: US\$60/kW-yr (fixed) and US\$2.10/MWh (variable), reported in 2004 US\$ and escalated to 2025 US\$ using CEPCI, yielding US\$109.7/kW-yr (fixed) and US\$3.84/MWh (variable). Capital expenditure for existing capacity is assumed to be zero.

Coal power plants

The existing Brazilian coal-fired thermal fleet is surveyed using SIGA [113]. Plants below 10 MW were excluded. Applying these filters to plants in commercial operation yields eight coal-fired units (Table 40). Net efficiency and annual generation for each plant are obtained from IEMA's Thermal Power Plant Emissions Inventory 2024 - 2025 [122]. These figures are combined with each plant's reported fuel input and CO₂ emissions to derive two parameters used throughout the model: the emission rate, expressed in tCO₂ per MWh_{HHV} of fuel input, and the fuel consumption rate, expressed in MWh_{HHV} of fuel input per MWh of electricity generated. Both parameters are calculated directly from the IEMA-reported generation, fuel input and emissions data for each plant, preserving plant-specific efficiency differences. A single emission-rate parameter of $0.35 \text{ tCO}_2/\text{MWh}_{fuel,HHV}$ was used in the model, and was estimated based on the fuel-consumption-weighted average of the eight plant-level emission rates. This value is applied uniformly to both existing and new coal capacity.

New-build capital expenditure, fixed O&M and variable O&M are the midpoint of the ranges reported for new-build coal generation by [123]. For existing capacity, cost parameters draw on plant-level data for the Jorge Lacerda IV unit reported by Tamburini [tamburini2023]. The discount rate (WACC) of 8% and the 25-year economic life / capital recovery period follow EPE's PDE 2035 Cost Parameters Notebook [124]. It was assumed a technical lifetime of 50 years. The start-up cost corresponds to the capacity-weighted average cold-start cost reported for coal-fired units by APTECH [125].

Our model assumes that coal-fired power generation is a fully-mature commercial technology, and no future capital cost reductions are assumed, regardless of the user-specified rate of energy-supply side technology innovation (user-selected variable #25).

Existing fossil and nuclear power plants considered in MACRO

This section consolidates the full lists of existing thermal power plants considered in the model, together with each unit's contract expiration and the corresponding earliest retirement year used in MACRO. The end-of-concession date reported by ANEEL for each unit [113] is rounded to the nearest model's discrete decision year (2025, 2030, 2035, 2040, 2045, or 2050). This discretized year, not the exact concession date, is passed to MACRO as the earliest year from which the unit is allowed to retire. Although the retirement of existing assets is not permitted until the end of current contracts, all generators compete with one another to be dispatched. Table 40 indicates coal power plants, Table 41 natural gas combined-cycle, Table 42 natural gas simple-cycle, and Table 43 nuclear ones.

Table 40: *Existing coal power plants considered in MACRO. Source: [113, 122].*

Power plant	State	Installed capacity [MW]	End of concession	Earliest retirement
Jorge Lacerda I e II	SC	190	Jan/2041	2040
Jorge Lacerda III	SC	220	Jan/2041	2040
Jorge Lacerda IV	SC	330	Jan/2041	2040
Porto do Itaqui	MA	360	May/2044	2045
Porto do Pecém I	CE	720	Jan/2044	2045
Candiota III	RS	350	Sep/2041	2040
Porto do Pecém II	CE	365	Jan/2045	2045
Pampa Sul	RS	345	Mar/2050	2050

Table 41: *Existing natural gas combined-cycle power plants considered in MACRO. Source: [113].*

Power plant	State	Installed capacity [MW]	End of concession	Earliest retirement
Mauá 3	AM	591	Dec/2046	2045
Termobahia	BA	186	Oct/2029	2030
Fortaleza	CE	327	n/a	2030
Termo Ceará	CE	220	Oct/2031	2030
Parnaíba I + V	MA	1,041	Aug/2043	2045
Parnaíba II	MA	519	Aug/2043	2045
Maranhão III	MA	519	Mar/2047	2045
Maranhão IV	MA	338	Dec/2044	2045
Maranhão V	MA	338	Dec/2044	2045
MC2 Nova Venécia 2	MA	270	Nov/2044	2045
Ibirité (Aureliano Chaves)	MG	235	Dec/2031	2030
Três Lagoas	MS	386	Mar/2031	2030
Cuiabá	MT	529	Jan/2063	2060
Termopernambuco	PE	550	Dec/2030	2030
Araucária	PR	484	Dec/2029	2030
Baixada Fluminense	RJ	530	Mar/2047	2045
GNA I	RJ	1,338	Jun/2053	2050
Marlim Azul	RJ	566	May/2050	2050
Norte Fluminense	RJ	827	Aug/2030	2030
Santa Cruz	RJ	500	Jul/2035	2035
Termorio	RJ	989	May/2030	2030
GNA II	RJ	1,673	Jul/2053	2050
Vale do Açu	RN	110	Jul/2031	2030
Jaguatirica II	RR	141	Mar/2055	2055
Canoas	RS	249	Mar/2031	2030
Uruguaiana	RS	640	Jul/2027	2030
Porto de Sergipe I	SE	1,593	Nov/2050	2050
Cubatão (Euzébio Rocha)	SP	250	Dec/2030	2030
Nova Piratininga	SP	386	Apr/2031	2030
Rhodia Paulínia	SP	14	May/2037	2035

Table 42: Existing natural gas simple-cycle power plants considered in MACRO. Source: [113].

Power plant	State	Installed capacity [MW]	End of concession	Earliest retirement
Aparecida	AM	166	Jul/2030	2030
Juiz de Fora	MG	87	Dec/2029	2030
Parnaíba III	MA	178	Aug/2043	2040
Seropédica	RJ	360	Dec/2030	2030
Termomacaé	RJ	923	Dec/2030	2030
Camaçari	BA	131	Oct/2026	2025
William Arjona	MS	177	May/2056	2055

Table 43: Existing nuclear power plants considered in MACRO. Source: [113].

Power plant	State	Installed capacity [MW]	End of concession	Earliest retirement
Angra I	RJ	640	2044	2045
Angra II	RJ	1,350	2041	2040

Biomass power plants without and with CO₂ capture

In our model, feedstocks for standalone biomass power plants are limited to woody material (forestry residues or planted forest wood) or lignocellulosic crop residues (sugarcane straw, corn stover, or rice straw). Sugarcane bagasse is another potential biopower feedstock. Today the vast majority of bagasse is consumed onsite at sugarcane processing facilities to provide steam and electricity needed to process sucrose. Some mills generate an excess of bagasse beyond what is needed to meet onsite energy needs. Many of these mills generate excess electricity and export it to the grid. Sugarcane processing mills provided about 4% of total electricity supply in Brazil in 2024 [126]. Some mills sell excess bagasse to other users, including to stand-alone biopower generators, but the actual quantities of exported bagasse today are relatively small. As a simplification for modeling, we assume that all bagasse generated at a sugarcane processing facility is fully used onsite for heat or power generation. (See related discussion in the description of Ethanol-from-Sugarcane technology in the Biomass-based fuels production Section below.)

For biomass power plants without CO₂ capture, the performance assumed in our model is based on that of an existing Brazilian plant reported by Simioni et al [127] operating with a capacity of 28 MW and generating 0.48 MWh of electricity per tonne of 53% moisture woody forest residues input, or approximately 19% efficiency on a higher-heating value (HHV) basis. We assume a capital cost for such a facility based on [128] of 7500 R\$ per kW of generating capacity (December 2022 R\$), which we convert to US\$ at the prevailing 2022 exchange rate and escalate to 2025 US\$ using the Chemical Engineering Plant Cost Index (CEPCI). EPE does not specify the generating capacity corresponding to their cost estimate. We assume it applies to plants with capacity equivalent to the largest wood-fired power plants in Brazil today (52 MW, as reported by ANEEL [129]). We assume fixed O&M costs are the sum of "FOM" and "taxes" reported for biomass power plants in [128]. We assume a variable

O&M cost of 15 BRL/MWh (2020 R\$) based on Figure 50 from [130], which we convert to US\$ at the prevailing 2020 exchange rate and escalate to 2025 US\$ using the CEPCI.

For biomass power plants with CO₂ capture, our performance and cost estimates use the analysis of Domenichini, et al. [131], who evaluated a 75 MW capacity wood-fired subcritical steam power plant operating on wood chips (50% moisture content). When post-combustion amine-based capture of 90% of the flue gas CO₂ was included in the design, the net exportable generating capacity was reduced by 36% (to 49 MW) for the same feedstock input rate due to the diversion of some steam from power generation for use in regenerating the amine solvent and some added parasitic electricity use onsite for compression of captured CO₂ for pipeline transport. For a biomass plant with CCS in MACRO, we assume the relative reduction in output as in Domenichini's analysis, such that our assumed generating efficiency for biopower with CO₂ capture is $19\% \times 0.64 = 12\%$ (HHV basis). For capital cost of a biopower plant with CCS, we take the difference in absolute capital costs from Domenichini for the 75 MW plant without capture and the 49 MW plant with capture, and we assume the difference is the cost for CO₂ capture at a plant that generates 49 MW. After applying a currency conversion and CEPCI escalator, the cost for CO₂ capture comes to \$3054/kW (2025 US\$). We add this cost to our assumed cost for a 75 MW biopower plant without CO₂ capture, which we estimate from our cost for a 52 MW facility without CO₂ capture (described in the previous paragraph) by using a 0.6 scaling exponent. (The output of the 75 MW plant without CO₂ capture is assumed to be reduced to 49 MW when CO₂ capture is included.) Our all-in capital cost for the 49 MW capacity biopower plant with CO₂ capture is thus \$4912/kW in 2025 US\$/kW. Fixed O&M costs expressed as a fraction of capital cost is a weighted average of the FOM fraction for the above biomass power plant without CCS (4.5%) and the fraction for the CO₂ capture portion of the plant (3.1%). The latter is based on [132]. Variable O&M costs are the sum of VOM for the biomass plant without CCS, but escalated to account for the 36% reduction in output, and the VOM based on [132] for the CO₂ capture portion of the plant.

For the three speeds of assumed energy-supply side technology innovation (user-selected variable #25), we assume biopower without CO₂ capture is commercially mature technology today, and we assume no future capital cost reductions. For biopower with CO₂ capture, we assume capital cost falls by 25% by 2050 for the faster innovation option, but does not see any reduction with the slower or mid-range innovation assumptions.

For the initialization year of the model (2025), we assume that the existing installed capacity of stand-alone biomass based power generators (excluding industrial cogenerators) is negligible. In reality, the installed capacity of such generators is about 32 MW, according to the national electricity regulatory agency's dashboard that tracks capacity of small generators nationally [133, 134].

Grid batteries

Renewable sources—specifically solar photovoltaic and wind power—have grown significantly in their share of the country's electricity mix and are expected to continue growing. Solar energy stands out for its modularity, ease of installation, and the significant drop in investment costs over the years, enabling deployment at various scales—ranging from large centralized plants to, most notably, decentralized systems. Similarly, wind power has established itself as a key renewable source, particularly in regions with high wind potential (such as the Northeast¹³), and has contributed significantly to diversifying the

¹³As of September 2025, there were 1,132 wind farms in operation in the country, totaling 34.6 GW of installed capacity.

country's electricity mix.

Although increases in solar and wind generation are essential for decarbonization and the energy transition, their inherent variability (intermittency and uncertainty) poses significant challenges to the reliability, stability, and predictability of the energy supply. These challenges are compounded by uncertainty that also manifests significantly on the consumption side.

Thus, there is a need for resources capable of rapidly responding to generation fluctuations as the power system expands—serving as options to enable greater operational flexibility and ensure energy supply security—with energy storage technologies standing out in this regard.

Among the energy technologies that have stood out the most, batteries—particularly lithium-ion batteries—deserve mention for their advanced stage of development. They enable the storage of surplus energy generated during periods of high resource availability (solar and/or wind) and its release during periods of low resource availability or peak demand. In this way, batteries contribute to system stability, reduce losses, and improve the use of renewable sources. Battery energy storage is becoming an essential element for the modernization, sustainability, and, above all, the energy transition of the electricity sector.

Lithium-ion batteries are included as an electricity storage option in our model. Technical-economic data on batteries were obtained from the following publications: Distributed Generation & Behind-the-Meter Battery Energy Storage and Power Generation Costs Report 2021, both by EPE [136, 137]. The simulation parameter values are presented in Table 44.

The Northeast region hosted 1,026 of these wind farms, totaling 32.1 GW, representing 93% of the country's installed wind capacity [135].

Table 44: *Parameter values used for batteries. Source: [136, 137].*

Parameter	Value	Unit
Storage lifetime	10	years
Storage WACC	8%	-
Storage Capital recovery period	10	years
Storage fixed O&M costs	1,580	\$/MWh/yr
Storage variable O&M costs	0	\$/MWh
Storage investment cost	317,000	\$/MWh
Discharge lifetime	30	years
Discharge WACC	8%	-
Discharge capital recovery period	20	years
Discharge fixed O&M cost	430	\$/MWh/yr
Discharge investment cost	430	\$/MWh
Discharge variable O&M cost	1	\$/MWh
Discharge efficiency	94%	-
Charge variable O&M cost	1	\$/MWh
Charge efficiency	94%	-

Electricity transmission

Transmission assets in Macro represent a general commodity transmission infrastructure that links various geographic regions or nodes. Here describe the current transmission system and we document key simplifying assumptions and sources used for quantitative parameter values in modeling it and future potential expansions.

Brazil's transmission system

The electric power transmission system is a cornerstone of a country's energy infrastructure, with an essential role in linking generation to consumption centers and supporting economic development and energy security. In Brazil, this function is particularly critical given the country's vast territorial expanse, characterized by the uneven geographical distribution of energy resources and a high share of renewable sources—such as hydroelectric, wind, and solar power plants—which are often located far from major consumption centers. Consequently, transmission lines are a strategic element in ensuring the reliability, efficiency, and operational flexibility of the National Interconnected System (SIN).

The Brazilian transmission network is among the largest and most complex electrical grids in the world, aiming to optimize energy resource use (to pursue tariff parity) and improve supply reliability. As of 2024, the SIN comprised over 176,000 km of transmission lines and was operated by more than 150 transmission concessionaires. These companies secured 30-year concessions—renewable for an equal period—through public auctions conducted by the National Electric Energy Agency (ANEEL). They are responsible for implementing and operating the network that connects power plants to

distribution companies' facilities near consumption centers.

The SIN—also known as the Basic Grid—is the nationally interconnected transmission system that enables the transport of large blocks of energy between various regions, power plants, and consumption centers (see Figure 61). The Basic Grid operates at 230 kV or higher. In addition to the Basic Grid, there are sub-transmission networks—called "Other Transmission Facilities" (DIT) under regulations—that are not part of the Basic Grid. A large proportion of sub-transmission lines operate at voltages between 69 kV and 138 kV, and are the responsibility of distribution companies.

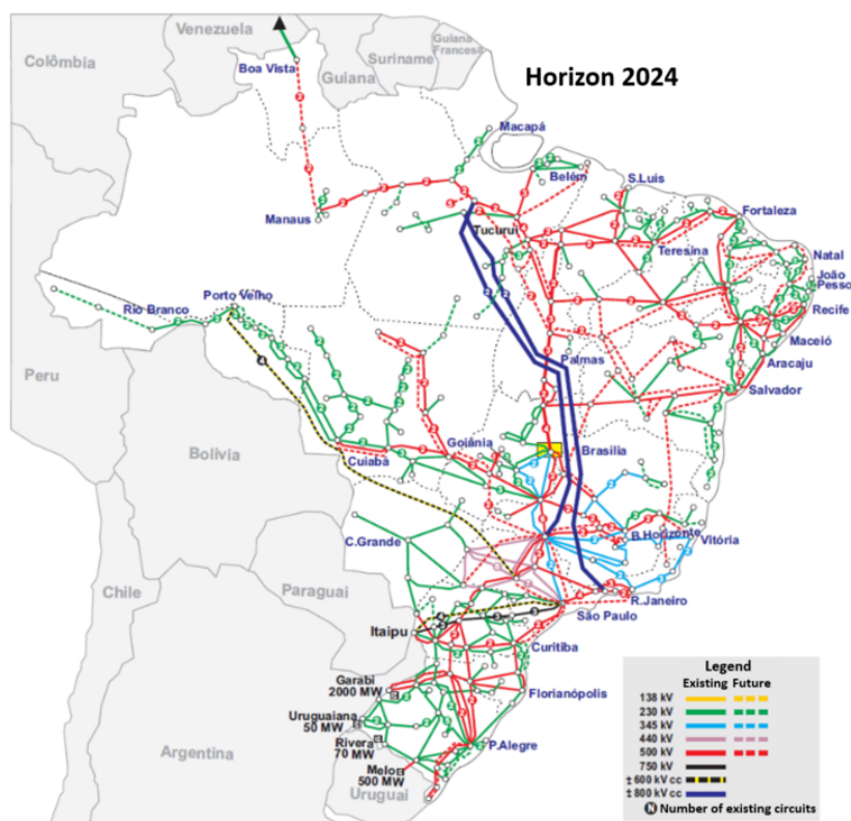


Figure 61: Brazilian electric power transmission system. Source: [138].

Despite the extensive transmission network, there are so-called Isolated Systems (SISOL)—located primarily in the country's Northern region—that are not connected to the SIN. These systems have independent electricity generation and distribution, and their consumption accounts for less than 1% of the country's total load. Energy demand in these regions is met primarily by diesel-fired thermal power plants [139, 138].

It is worth noting that, in addition to accounting for less than 1% of national consumption, SISOL systems are not interconnected with the SIN—that is, they have no physical connection to the transmission grid. As a result, they do not share grid expansion decisions with the interconnected system. With no physical power exchange occurring either with the SIN or among themselves (each isolated location typically operates as an autonomous system), there are no variables to optimize jointly with the rest of the system—from a grid perspective, each location functions as an isolated island. For this reason, SISOL systems are not included in Macro simulations; the Macro logic is suited to a set of electrically interconnected systems, as it enables the optimal solution to be found by minimizing expansion costs while accounting for the investment costs of interconnections between

subsystems.

Between 2015 and 2024, the installed kilometers of transmission lines grew at a steady rate of 4.5% per year, with the highest growth occurring between 2018 and 2019, when they expanded by approximately 6.8%. Transmission line voltage levels range from 132 kV to 800 kV, and lengths vary (see Figure 62).

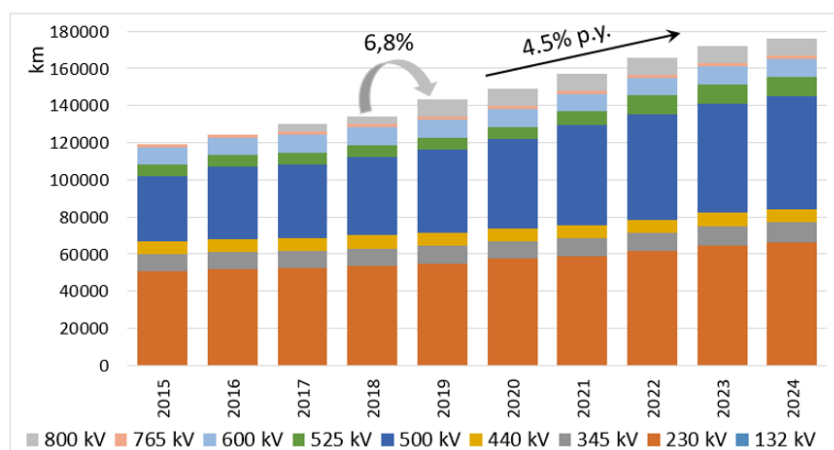


Figure 62: Transmission lines length by voltage in Brazil. Source: [140].

Transmission lines at 230 kV and 500 kV are the most common in Brazil, with their total lengths increasing at average annual rates of 3.1% and 6.4%, respectively. By 2024, these two voltage levels exceeded 126,000 km nationwide, accounting for approximately 72% of the total. The remaining voltage levels represent approximately 28% (about 49,200 km), see Figure 63.

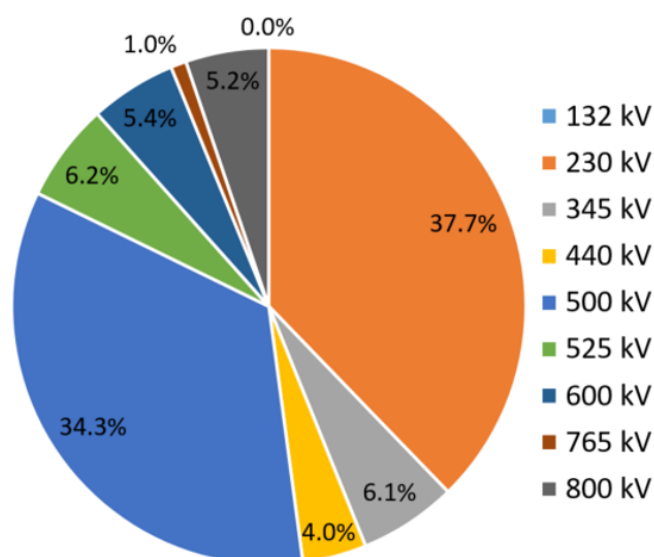


Figure 63: Transmission lines by voltage in Brazil in 2024. Source: [140].

Brazil's electric power generation and supply structure is unique. The country's vast size creates constraints on electricity transmission. As a result, the National Electric System Operator (ONS) and the Electric Power Commercialization Chamber (CCEE) divide the SIN into subsystems (or submarkets)—geographic and electrical divisions of the interconnected system—to simplify the

operation, planning, and commercialization of electric power.

As shown in Figure 64a, there are four subsystems: North (N), Northeast (NE), Southeast/Central-West (SE/CO), and South (S). A virtual node at Imperatriz (IMP) in Maranhão serves as an interconnection point among the Southeast/Central-West, North, and Northeast subsystems, as illustrated in Figure 64b.

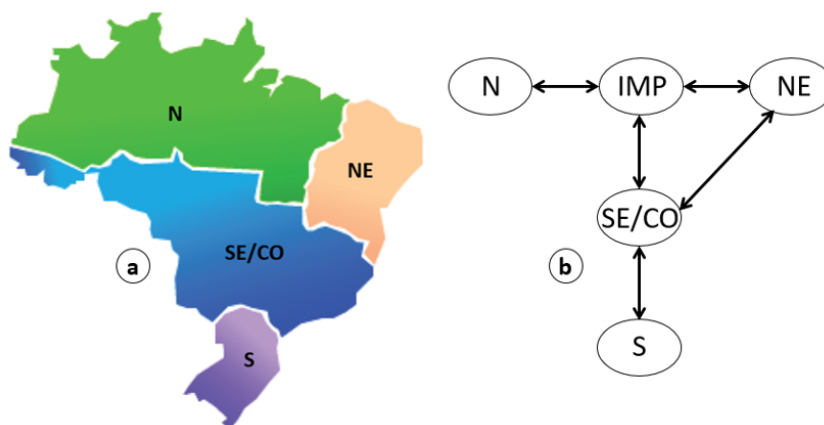


Figure 64: Brazilian electrical system: (a) division into subsystems and (b) schematic of interchanges, including the virtual Imperatriz node. Source: [141].

The North subsystem encompasses the states of Amazonas, Pará, Tocantins, Amapá, Rondônia, Acre, and Roraima (which is partially isolated). It is characterized by a strong presence of large-scale hydroelectric plants without storage reservoirs (run-of-river plants), and the region acts as an exporter during certain periods. The Northeast subsystem covers the entire Northeast region—with a notable emphasis on wind and solar photovoltaic energy—and can function as either an importer or an exporter depending on seasonality (wind and rainfall patterns).

The Southeast subsystem—the country's main load center—comprises the states of São Paulo, Minas Gerais, Rio de Janeiro, Espírito Santo, Goiás, Mato Grosso, and Mato Grosso do Sul, as well as the Federal District. Despite its extensive hydroelectric and thermal power infrastructure, it typically imports energy from other subsystems. Finally, the South subsystem, which encompasses the states of Paraná, Santa Catarina, and Rio Grande do Sul, features an energy mix of hydroelectric and thermal plants. It also engages in very limited energy exchange with neighboring countries like Argentina and Uruguay—usually amounting to less than 1% of consumption—alternating between importing and exporting. The NZB modeling neglects any energy exchanges with Brazil's neighbors.

Furthermore, there are approximately 160 isolated locations not connected to the electricity grid. Most are in the states of Rondônia, Acre, Amazonas, Amapá, and Pará, as well as on the island of Fernando de Noronha (Pernambuco) and in certain locations in Mato Grosso [139, 138].

The ONS is responsible for coordinating and overseeing the SIN's operation—carried out by generation and transmission companies under the oversight and regulation of ANEEL. One of the key benefits of this integration and coordinated operation is the ability to exchange electricity between regions (Figure 64b), a particularly important factor in a country like Brazil, where hydroelectric plants in regions with differing hydrological regimes predominate.

These subsystems are interconnected by extensive high- and extra-high-voltage transmission lines op-

erated by the ONS. These interconnection lines enable the optimized use of energy resources—particularly hydroelectric generation—by transferring surpluses from one region to others with higher demand or lower water availability. This reduces operating costs, enhances energy security, and mitigates risks associated with climate variability, while also facilitating the expansion of intermittent renewable sources such as solar and wind power.

As previously highlighted, the Imperatriz node is a virtual node and a strategic point in Brazil's electric power transmission system. Multiple transmission lines converge at this node, enabling energy exchange among subsystems and linking the North, Northeast, and Southeast subsystems.

Transmission line simulation

Detailed simulation of all transmission lines in the Brazilian electrical system poses a computational and modeling challenge not only because of its vast extent, but also because of the presence of multiple voltage levels, both Alternating Current (AC) and Direct Current (DC) transmission, hundreds of substations, thousands of transformers, and different topologies and loading levels, among other factors that result in distinct technical and economic characteristics.

In this regard, within the context of energy planning for the Brazilian power system—particularly in models such as DESSEM and NEWAVE, and in studies conducted by institutions such as the ONS, the CCEE, and the Energy Research Office (EPE)—the so-called interconnection nodes (or equivalent nodes) are used as a modeling tool to represent the grid in a simplified manner that remains faithful to its electrical behavior.

These nodes are not merely physical points in the network; during the planning stage, they serve as system abstractions where energy exchange between subsystems occurs. They may represent a single substation, a cluster of substations, or aggregated representations of SIN interconnections. Equivalent nodes provide a simplified representation of the electrical interconnections between regions (or subsystems) of the Brazilian power system. Instead of modeling every real transmission line and substation, a single equivalent exchange node can group them.

Within the SIN, the North, Northeast, Southeast, and South subsystems exchange energy with one another. These exchanges are represented by equivalent interchange nodes. An equivalent node can aggregate multiple transmission lines, transformers, electrical constraints, and operational limits, consolidating them into a single element with a defined capacity (MW) and an actual operational limit (maximum interchange).

Accordingly, for this study the following equivalent nodes were assumed (Figure 65): North (N), Northeast (NE), Southeast/Central-West (SE), South (S), Imperatriz (IMP), Belo Monte (BM), and Itaipu (IT). The transmission line acronyms and their corresponding symbols in the MacroEnergy model are listed in Tables 45 and 46.

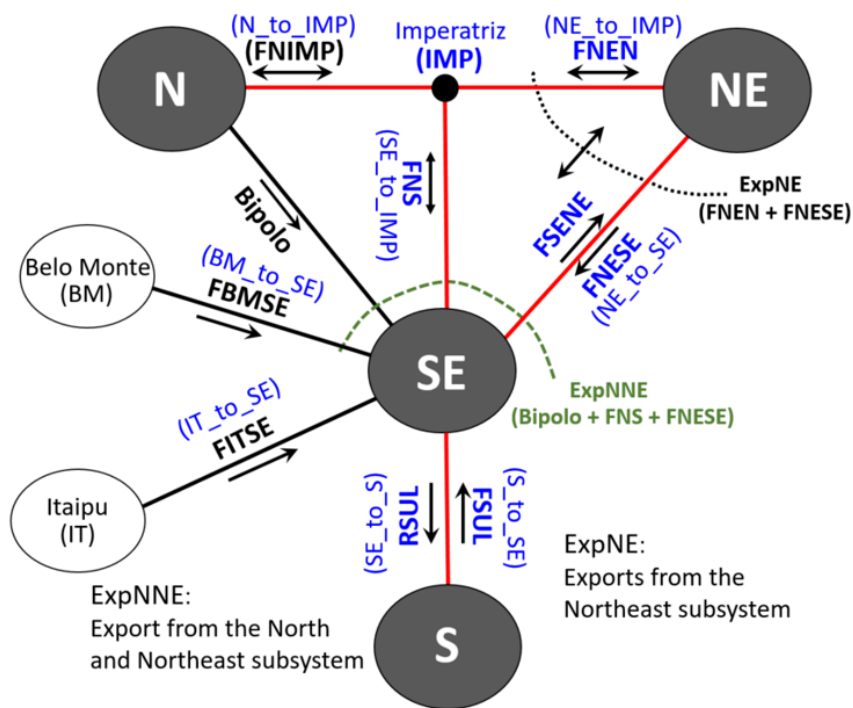


Figure 65: Interconnections among subsystems, considering the equivalent nodes. Source: [142].

Table 45: Acronyms used for the interconnection lines of the equivalent nodes. Source: The authors.

Acronym	Meaning
FNEN	Energy flow from the Northeast towards Imperatriz
FSENE	Energy flow from Southeast to Northeast
FNESE	Energy flow from Northeast to Southeast
FNS	Energy flow from Southeast to Imperatriz
RSUL	Energy flow from Southeast to South
FSUL	Energy flow from South to Southeast
FITSE	Energy flow from Itaipu to Southeast
FBMSE	Energy flow from Belo Monte to Southeast

Table 46: *Equivalent points and their symbols used in MacroEnergy. Source: The authors.*

Transmission Line	From	To
Norte-Imperatriz	North	Imperatriz
Nordeste-Imperatriz	Northeast	Imperatriz
Nordeste-Sudeste	Northeast	Southeast
Sudeste-Imperatriz	Southeast	Imperatriz
Sudeste-Sul	Southeast	South
Sul-Sudeste	South	Southeast
Itaipu-Sudeste	Itaipu	Southeast
Belo Monte-Sudeste	Belo Monte	Southeast

Energy transport—whether via the Basic Grid (transmission lines) or distribution networks—inevitably results in technical losses because a portion of the energy is dissipated during transport, voltage transformation, and metering due to the laws of physics. Technical losses in the Basic Grid are calculated as the difference between energy injection points (generated energy) and delivery points at load centers—specifically, consumer units directly connected to the transmission system and distribution networks. These losses are tallied monthly by the CCEE, and the associated costs are allocated 50% to generation and 50% to consumers. As noted by ANEEL, losses in the Basic Grid account for approximately 2.1% of generated energy [143].

Regional interconnections, which comprise the country's major transmission corridors, enable energy transfer between the various subsystems, fully leveraging the complementarity of energy sources across the vast national territory. Consequently, the transmission grid is essential for optimizing the use of available electric energy resources within each of the SIN subsystems. In this context, [144] defines exchange limits—characterized by the maximum power transferable between subsystems—by accounting for steady-state and dynamic performance (across various configurations and time periods), adhering to the premises and criteria established in the Grid Procedures, and incorporating the schedule of transmission projects granted by ANEEL (with updated completion dates) to ensure the secure operation of the SIN.

The Basic Grid is not a static structure. Throughout the planning horizon, new transmission facilities—lines, substations, transformers, and other equipment—are progressively integrated into the system in accordance with approved construction schedules. Each time a new set of facilities enters service, the grid topology changes; the resulting topology, valid until the next significant change, is referred to as a configuration. From the standpoint of electrical studies—power flow, electromechanical stability, and short-circuit analysis—each configuration constitutes a distinct grid scenario and must therefore be simulated independently. The addition of a new line or piece of equipment can substantially alter power flows, operational safety margins, and inter-regional transfer capacity.

Segmenting the study horizon into successive configurations thus allows ONS to evaluate system performance not only at the final expansion stage, but at every intermediate step—ensuring safe and adequate operation throughout the grid's evolution. Consequently, the methodology for calculating the transmission capacities of regional interconnections utilizes these exchange limits, taking into

account the configurations and time periods specified in [144], as detailed below.

The capacity of the Northeast-to-Southeast transmission line (FNESE) was calculated as the average of the power transfer limits between the Northeast and Southeast subsystems across configurations and time periods, as shown in Figure 66. The acronym FNESE stands for power flow from the Northeast to the Southeast, representing the scenario in which the Northeast subsystem (characterized by significant solar and wind generation) exports energy to the Southeast (which acts as an importer).

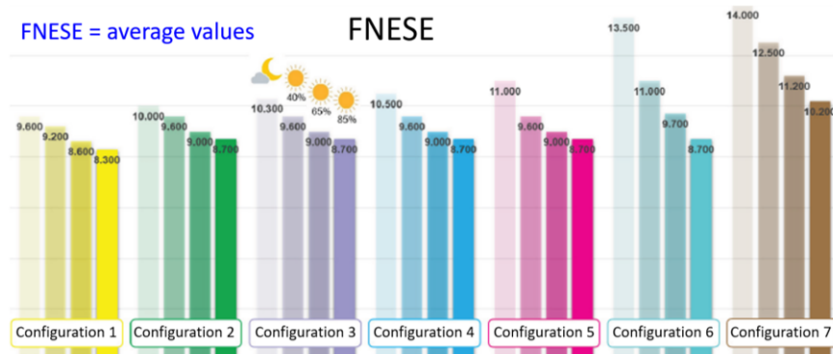


Figure 66: Energy transfer limits between the Northeast and Southeast subsystems across configurations and time periods. Source: [144].

The capacity of the Northeast-to-Imperatriz transmission line (FNEN) was calculated as the difference between the average export limits of the Northeast subsystem ($\text{ExpNE} = \text{FNEN} + \text{FNESE}$; see Figure 65)—across configurations and time periods—and the capacity of the Northeast-to-Southeast transmission line (FNESE). The average export limits of the Northeast subsystem (ExpNE), considering the various configurations and time periods, were calculated using the values shown in Figure 67, while the capacity of the Northeast-to-Southeast transmission line (FNESE) was determined in the previous step.

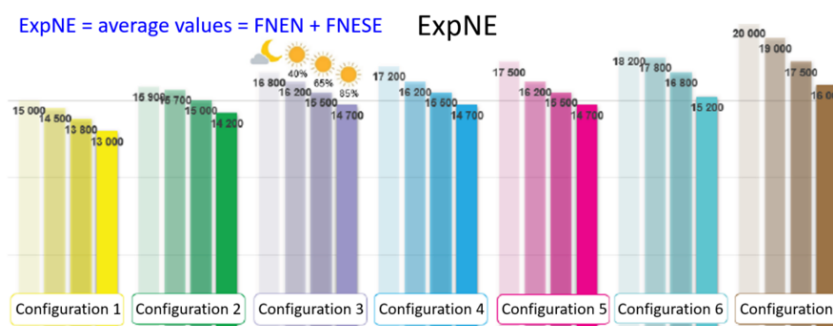


Figure 67: Energy export limits for the Northeast subsystem across configurations and time periods. Source: [144].

The capacity of the Southeast-to-South (RSUL) transmission line was calculated as the average of the South subsystem's power reception limits across configurations and over time, as shown in Figure 68.

The capacity of the Southeast-to-Imperatriz (FNS) transmission line was calculated as the difference between the average of the North and Northeast export limits ($\text{ExpNNE} = \text{Bipolo} + \text{FNS} + \text{FNESE}$; see Figure 65)—across configurations and time periods, as shown in Figure 69—and the sum of

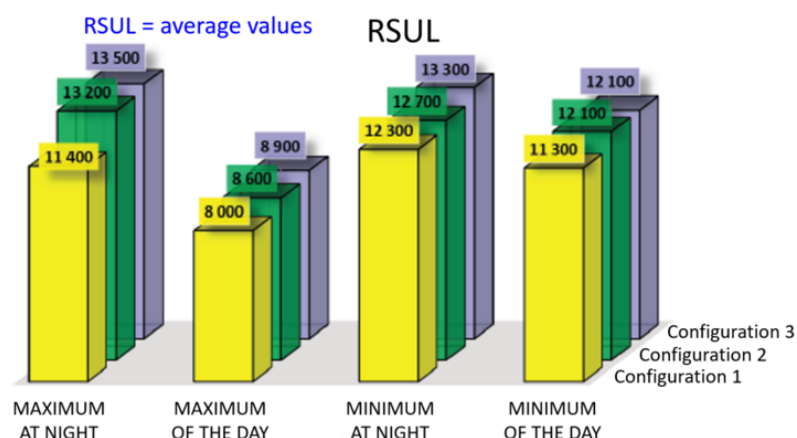


Figure 68: Energy reception limits for the South subsystem across configurations and time periods. Source: [144].

the Bipolo capacity (assumed independent of ExpNNE) and the Northeast-to-Southeast (FNESE) transmission line capacity.

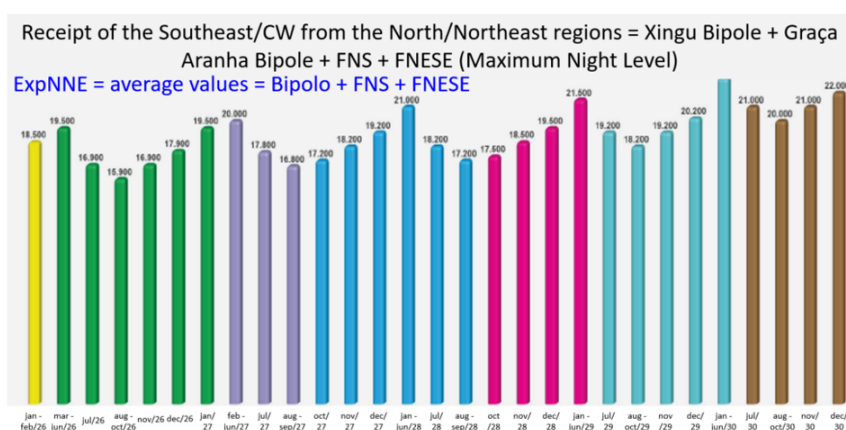


Figure 69: Export limits for the North and Northeast subsystems (ExpNNE) across configurations and time periods. Source: [144].

The capacity of the South-to-Southeast (FSUL) transmission line was calculated as the average of the South subsystem's supply limits across configurations and time periods, as shown in Figure 70.

The following additional assumptions underpinned the simulation:

- The capacity of the North-to-Imperatriz transmission line (FNIMP) is considered unlimited.
- The capacity of the Itaipu-to-Southeast transmission line (FITSE) is 10,000 MW, given the Itaipu power plant's output of 14,000 MW.
- The Belo Monte-Southeast (FBMSE) transmission line has a capacity of 8,000 MW, based on the Belo Monte power plant's 11,233 MW output.

Table 47 presents the capacity values for the transmission lines at the equivalent nodes, along with their distances (shown in Figure 71). At the state level, the transmission line considered is the distance between the state's load center (the state capital) and its respective subsystem; see Table 48 and

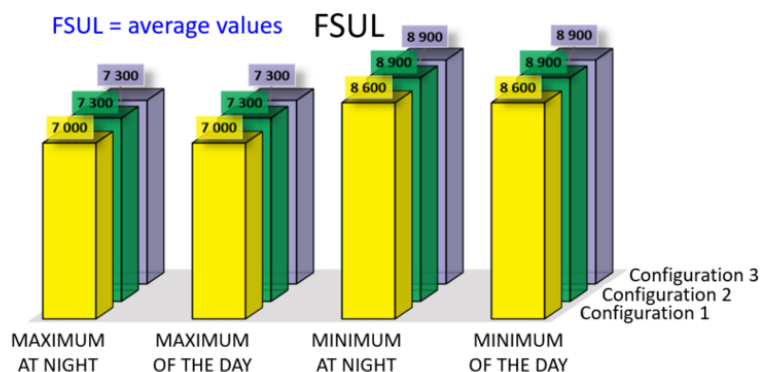


Figure 70: Export limits from the South subsystem to the Southeast subsystem (FSUL) across configurations and time periods. Source: [144].

Figure 71.

Table 47: Equivalent points and their symbols used in MacroEnergy. Source: The authors.

Transmission Line	From	To	Existing Capacity [MW]	Unidirectional	Distance [km]
Norte-Imperatriz	North	Imperatriz	100,000	No	1,046.7
Nordeste-Imperatriz	Northeast	Imperatriz	6,089	No	1,068.7
Nordeste-Sudeste	Northeast	Southeast	9,911	No	1,785.8
Sudeste-Imperatriz	Southeast	Imperatriz	9,107	No	1,806.9
Sudeste-Sul	Southeast	South	11,450	Yes	774.3
Sul-Sudeste	South	Southeast	8,000	Yes	768.5
Itaipu-Sudeste	Itaipu	Southeast	10,000	Yes	985.5
Belo Monte-Sudeste	Belo Monte	Southeast	8,000	Yes	2,143.2

Furthermore, Table 47 lists certain transmission lines that are unidirectional, while others are considered bidirectional. This distinction refers to the power-carrying capacity (MW) that a transmission line can handle in each direction of energy flow. Transmission lines capable of carrying the same maximum amount of power in either direction are classified as bidirectional transmission lines. Accordingly, the Norte-Imperatriz, Nordeste-Imperatriz, Nordeste-Sudeste, and Sudeste-Imperatriz lines are considered bidirectional, as they can carry the same maximum amount of power in both directions (for example, the maximum power capacity of the Nordeste-Imperatriz line from Northeast to Imperatriz is the same as from Imperatriz to Northeast, at 6,089 MW).

Conversely, transmission lines whose maximum power capacity depends on the flow direction are termed unidirectional. The Sudeste-Sul transmission line falls into this category: its transmission capacity is 11,450 MW from Southeast to South, but only 8,000 MW from South to Southeast. This difference is primarily due to the Southeast subsystem's limited capacity to absorb higher power levels, a consequence of local transmission constraints arising from excess solar photovoltaic generation—particularly in northern Minas Gerais—which can lead to curtailment in the region. Consequently, the maximum power flow from the South to the Southeast is 8,000 MW. The opposite

holds true for the South region, which faces fewer transmission constraints, allowing for a maximum power flow of 11,450 MW from the Southeast to the South ([144]). Besides, the Itaipu-Sudeste and Belo Monte-Sudeste transmission lines are likewise unidirectional, since they carry power generated by the Itaipu and Belo Monte hydroelectric plants, so by nature power flows only from the power plants to the subsystems, never in reverse.

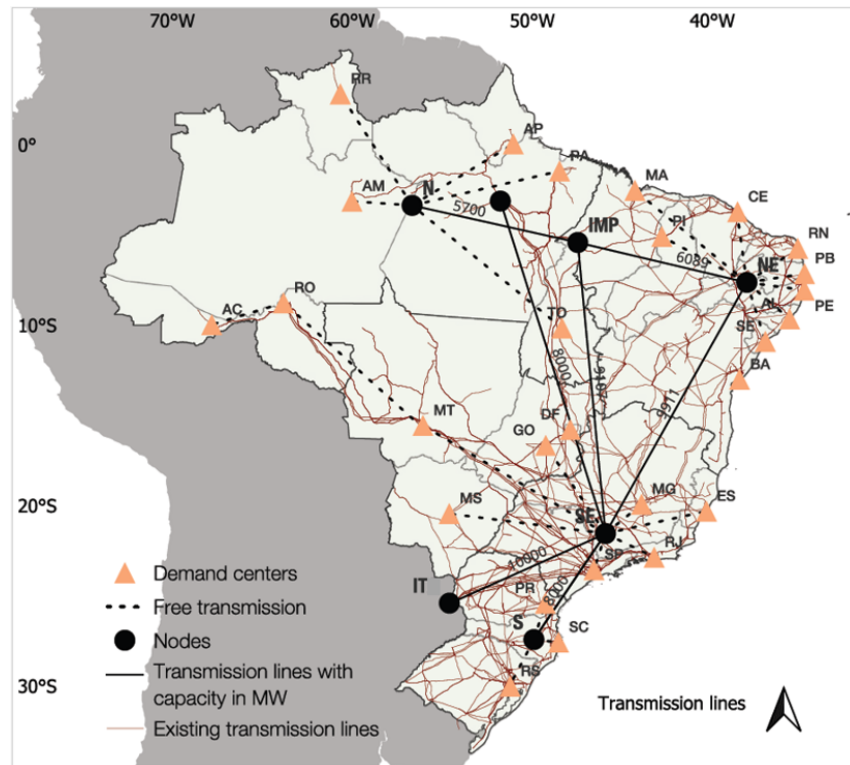


Figure 71: Transmission lines within states and subsystem interconnections. Source: [145, 138].

Table 48: *Data on bidirectional transmission lines connecting load centers to the centers of their respective subsystems. Source: [145, 138].*

Transmission Line	Existing Capacity [MW]	Distance [km]
Amazonas-to-North	1,000	372.6
Roraima-to-North	1,000	817.3
Amapá-to-North	1,000	730.0
Pará-to-North	1,000	935.1
Tocantins-to-North	1,000	1,188.7
Ceará-to-Northeast	1,000	457.3
Rio Grande do Norte-to-Northeast	1,000	381.0
Paraíba-to-Northeast	1,000	358.3
Pernambuco-to-Northeast	1,000	357.4
Alagoas-to-Northeast	1,000	351.3
Sergipe-to-Northeast	1,000	393.0
Piauí-to-Northeast	1,000	598.0
Maranhão-to-Northeast	1,000	900.2
Bahia-to-Northeast	1,000	613.1
Rio Grande do Sul-to-South	1,000	316.9
Santa Catarina-to-South	1,000	135.6
Paraná-to-South	1,000	232.2
Goiás-to-Southeast	1,000	646.9
Minas Gerais-to-Southeast	1,000	276.9
Rio de Janeiro-to-Southeast	1,000	316.2
Espírito Santo-to-Southeast	1,000	599.9
São Paulo-to-Southeast	1,000	233.2
Mato Grosso do Sul-to-Southeast	1,000	911.0
Mato Grosso-to-Southeast	1,000	1,259.5
Roraima-to-Acre	1,000	469.3
Mato Grosso-to-Roraima	1,000	1,155.1

Transmission costs

One of the main challenges in determining transmission costs in Brazil is the high variability across projects. Transmission project costs are influenced by a wide range of variables, such as: electrical project (voltage level, number of circuits, transmission capacity, etc.), line length, tower structure, environmental license, logistics (road quality, transport of towers, transport of cables, availability of cranes, need for helicopters, etc.), material costs, labor, and geographic location.

These variables, combined with Brazil's continental scale, result in transmission projects with markedly diverse technical and economic characteristics, as illustrated in Table 49. The table shows some parameters from transmission auctions held in Brazil between 2015 and 2025: power transmission capacity [MW], transmission line length [km], and the corresponding CAPEX investment [US\$ 10⁶] for each auction. It should be noted that CAPEX investment involves not only the implementation of the transmission line itself but also complementary assets—such as substations, disconnect switches, and synchronous compensators—required for its full operation.

The table reveals substantial variability across projects: power transmission capacity ranges from 380 MW to 15,200 MW, transmission length span from roughly 515 km to 7,199 km, and CAPEX investments range from approximately US\$ 330 million to nearly US\$ 4.7 billion. This heterogeneity reflects the wide range of geographic, regulatory, and technical conditions under which transmission infrastructure is planned and built across the country.

It should be noted that the Macro model requires the power transmission capacity to be expressed in MW. However, the data provided by [100], shown in the second column of Table 49, are presented in MVA. Consequently, the power transmission capacity had to be converted from MVA to MW using a power factor (pf) of 0.95, as specified in [146]. The resulting power transmission capacity values, in MW, are shown in the third column of Table 49.

Table 49: *Historical costs of transmission auctions in Brazil, in current values of 2025. Source: [100].*

Auction	Power [MVA]	Power [MW]	Transmission Length [km]	CAPEX [US\$ 10 ⁶]
2025-04	2,000.0	1,900.0	1,079.0	1,099.6
2024-02	1,000.0	950.0	783.0	703.1
2024-01	9,200.0	8,740.0	6,464.0	3,875.5
2023-02	9,840.0	9,348.0	3,003.0	4,728.0
2023-01	400.0	380.0	6,184.0	3,455.9
2022-02	3,650.0	3,467.5	710.0	798.9
2022-01	6,180.0	5,871.0	5,425.0	3,490.4
2021-02	750.0	712.5	902.0	697.3
2021-01	2,600.0	2,470.0	515.0	329.5
2020-01	6,420.0	6,099.0	1,959.0	1,959.8
2019-02	8,747.0	8,309.7	2,321.0	1,174.3
2018-04	16,000.0	15,200.0	7,199.0	3,785.4
2018-02	14,000.0	13,300.0	2,626.0	1,766.3
2017-02	12,000.0	11,400.0	4,928.0	2,614.9
2016-05	16,000.0	15,200.0	7,069.0	3,996.2
2015-13	6,533.0	6,206.4	6,221.0	3,885.1
2015-13	8,449.0	8,026.6	3,438.0	3,883.1
2015-07	7,020.0	6,669.0	2,518.0	2,377.4
2015-05	6,282.0	5,967.9	1,999.0	2,505.8

To determine the transmission costs used in the Macro model, we adopted an approach based on the aggregation of power transmission capacity [MW], transmission length [km], and CAPEX investment [US\$ 10⁶] (in current values of 2025) across all projects undertaken in the country over the past ten years. Based on Table 49, the following procedure was adopted: First, the power transmission capacity [MW], transmission length [km], and CAPEX investment [US\$ 10⁶] values from transmission auctions held in the country over the last ten years were aggregated. This yielded a total power transmission capacity of 130,217.5 MW, a total transmission length of 65,343.0 km, and a total CAPEX investment of US\$ 47,126.3 million. Second, the total CAPEX investment was then divided by total power transmission capacity, total transmission length, and the product of total power transmission capacity and total transmission length, respectively, resulting in the following unit costs metrics of US\$ 361,905.7/MW, US\$ 721,216.3/km, and US\$ 5.5/MW-km.

The aggregation approach is more consistent than simply using average costs—as it preserves the relationship between the volume of expansion achieved and the financial resources actually deployed—and is also superior to using costs from a single auction, which could distort investment

costs due to project scale. Since the Macro model requires CAPEX investment to be expressed in US\$/MW, the investment cost adopted in the Macro model is US\$ 361,905.7/MW.

Besides, this approach is particularly well-suited for energy planning models that aim to represent the structural evolution of the power system. Several reasons led to the selection of this approach: it reflects the expansion actually carried out in the Brazilian power system; it avoids distortions caused by auctions of varying sizes; it yields a more representative unit cost (by enabling the calculation of a weighted average cost); it mitigates the effects of short-term market fluctuations; it ensures consistency with long-term expansion models; and it provides a better representation of historical market efficiency, among other factors.

In addition to the previously mentioned investment costs (CAPEX), fixed and variable Operation and Maintenance (O&M) costs are also important for simulating transmission lines in the Macro model. Fixed costs are those that do not depend on the amount of energy transmitted by the line (remaining virtually constant over time), whereas variable costs depend on the line's utilization level (increasing or decreasing with the energy transported).

A key characteristic of the transmission segment in the Brazilian electricity sector is that costs are predominantly fixed, with variable costs relatively low compared to fixed costs. This stems from the regulatory model adopted by ANEEL, under which the concessionaire receives a Permitted Annual Revenue (RAP) for keeping the facility available to the SIN, regardless of the amount of energy flowing through the line. Thus, a line may operate at low or high load levels, yet its capital and O&M costs remain virtually unchanged. Cost variations associated with increased power flow stem primarily from electrical losses and minor increases in maintenance requirements.

The RAP is the primary remuneration mechanism for electric power transmission concessionaires in Brazil. It represents the annual revenue a transmission company is entitled to receive for providing the public transmission service, provided its facilities are available for commercial operation. This definition is set by ANEEL in the Transmission Rules.

In this context, for simulation purposes within the Macro model, variable O&M costs for transmission lines are treated as negligible (Variable O&M costs = 0), while fixed O&M costs are derived from a document issued by the Federal Court of Accounts (TCU), which reports that these costs amount to approximately 1.8% of capital expenditure (CAPEX) [147]. Therefore, considering a specific transmission investment cost of US\$ 361,905.7 /MW, the fixed O&M cost to be considered in the Macro model is US\$ 6,514.3/MW-year.

Beyond costs, two other important characteristics of electric power transmission assets are their useful life and the Weighted Average Cost of Capital (WACC)—which is the rate typically used in the SIN's energy planning models for the guaranteed return on investment to transmission investors. The WACC is set by ANEEL and used in periodic reviews of the RAP. For Brazilian transmission, the WACC is set at 8% per annum (in real terms), and the facilities' useful life is 30 years [148, 146].

3.2.2.2 Biomass-based fuels production

The share of modern bioenergy in Brazil's energy mix today is among the highest in the world. This warrants an extensive representation of biofuel production technology options in MACRO (Figure 72). The energy-performance and capital and operating costs for these options are documented here.

Performance, capital cost, and non-feedstock operating costs are assumed to be independent of spatial location. Quantitative input assumptions related to bioconversion technologies are detailed in the companion spreadsheet, Technology Data [61]. Here, we document key simplifying assumptions and references sources relied upon for quantitative parameter values.

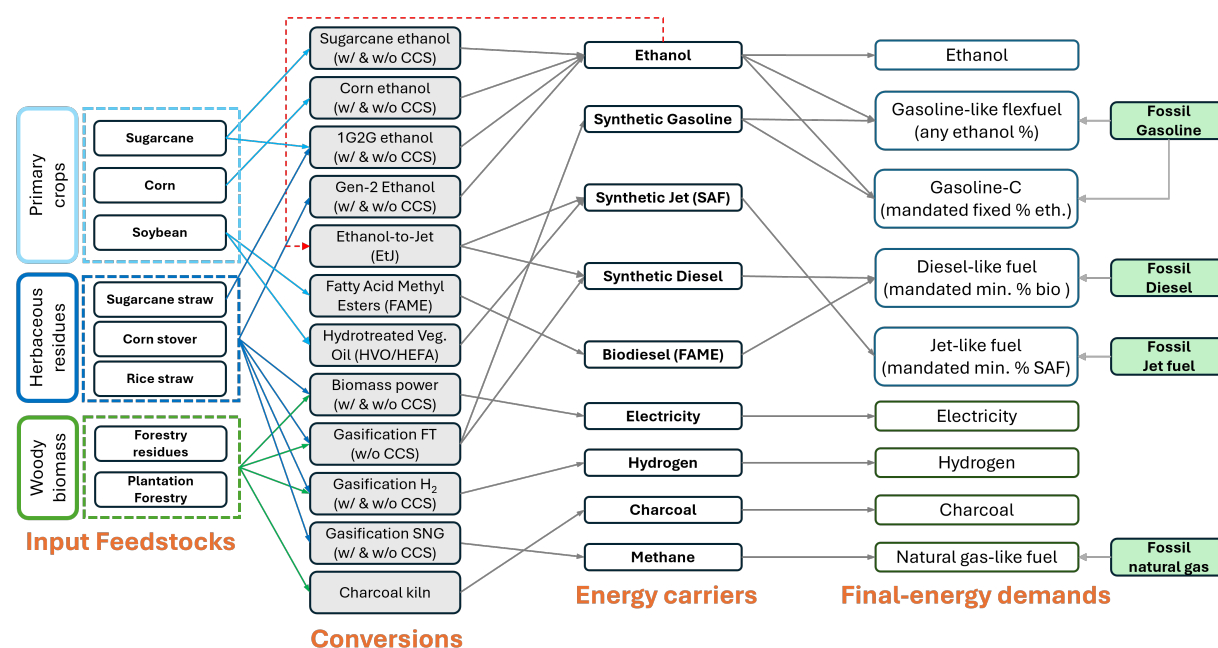


Figure 72: Bioenergy sector representation in MACRO, including feedstock options, conversion technologies, final energy carriers, and final-energy demands to be satisfied. For simplicity, inputs other than feedstocks are not shown, nor are co-products associated with some conversions.

Ethanol from sugarcane without CO₂ capture (1G ethanol)

Two types of assets are included in MACRO for production of ethanol from sugarcane without CO₂ capture: one represents existing capacity (operational in 2025). A second asset represents future, new-build capacity. The yield of ethanol from sugarcane for both types of assets is assumed to be 85 liters/tonne of cane, or 67 kg/tc, for cane with an assumed 70% moisture content [70]. We assume bLagasse derived from crushing of the cane is fully consumed onsite to provide all process steam and electricity plus some export of electricity exported to the grid. We assign a different level of electricity exports per tonne of cane crushed to existing ethanol production facilities versus future new builds.

For existing facilities, we assume 40 kWh/tc exported, which is about 20% higher than the average amount of electricity exported across all sugarcane processing facilities in Brazil today. Only about half of the cane crushing mills in Brazil export electricity today [149], many of which produce sugar. Because we do not explicitly model sugar production from cane, assigning a value of electricity exports per tc at ethanol facilities that is close to today's average across all cane processors effectively reflects the aggregate electricity exports from the cane processing industry today.

For new ethanol production capacity that MACRO builds, we assume greater export of electricity per tc processed, justified by the fact that capital investment for the plant is considered. [150] quantifies (in Table 5 in the paper) a range of surplus electricity generation levels possible at cane crushing facilities depending on the cogeneration technology used, whether electric-drive mills are used instead of steam drives, and whether bagasse or bagasse and cane straw are used as fuel. For “lower-technology”

steam turbine systems (with steam pressure of 65 bar or less) operating only during the cane crushing season with the available bagasse, [150]'s estimates of surplus electricity range up to 71 kWh/tc. We assume 70 kWh/tc exported electricity for new sugarcane ethanol capacity.

Capital costs for ethanol facilities are based on [151], which reports estimated capital costs of 730 BR\$ and 293 BR\$ (for greenfield and expansion retrofits, respectively) per tonne of cane crushing capacity per 200-day harvest season (December 2024 BR\$), or 400 BR\$ and 161 BR\$ per annual tc ($730 \times 200 / 365$; $293 \times 200 / 365$). We convert this to 2024 US\$ using the prevailing December 2024 exchange rate, apply the chemical engineering plant cost index (CEPCI) to convert to 2025 US\$, and translate the value to an ethanol output basis using the assumed 85 liters/tc yield and higher heating value of ethanol. For existing capacity, capital costs are assumed to be fully paid off. For new builds, because sugarcane-ethanol production is a commercially mature technology, capital costs are assumed to remain at the current level across the full modeling time horizon.

Non-feedstock operating costs per unit of production are assumed to be the same for greenfield and retrofit applications. These are derived from a table reporting first generation technology operational costs in Section SI.4 of the supplemental material of [152]. (From that table, we consider the values in the first eight rows to be variable operating and maintenance costs and the subsequent six rows as fixed operating and maintenance costs).

Considering the commercial maturity of sugarcane-ethanol processes today, we assume no future performance or cost reductions will occur, regardless of the assumed speed of energy-supply side innovation (user-selected variable #25) in a scenario.

Ethanol from corn without CO₂ capture (1G ethanol)

The use of corn as a feedstock for ethanol production is growing in Brazil. Some corn-derived ethanol is produced at existing sugarcane-ethanol plants during the sugarcane offseason, but the majority of corn-ethanol production occurs at stand-alone units dedicated to ethanol production from corn. Corn-ethanol production capacity represented in MACRO assumes dedicated dry-milling production facilities. All electricity and heat inputs required for processing corn into ethanol are typically provided today by onsite steam-turbine cogeneration fueled by wood chips from planted forests [153]. Mass and energy balances for such facilities reported by Gurgel, et al [153] in Figure S6 are used here to determine the assumed values for technical parameters of the corn-ethanol asset in MACRO. This includes some electricity generation beyond onsite needs, which MACRO assumes is exported to the grid.

The assumed capital cost for greenfield capacity is based on [151], which reports estimated capital costs of 2.7 BR\$ per output liter ethanol per year (December 2024 BR\$), which we convert to 2024 US\$ using the prevailing December 2024 exchange rate, then apply the CEPCI to convert to 2025 US\$, and use the higher heating value of ethanol to express cost on a 2025 US\$ per kW_{ethanolHHV} basis. Non-feedstock fixed and variable O&M costs are based on Table S10 of Gurgel et al. [153]. From that table, we assume "Labor" and "Other" constitute fixed costs, and "Enzymes" and "Chemical inputs" constitute variable costs. Corn-ethanol production is assumed to be commercially mature, so no future capital cost reductions are assumed.

Considering the commercial maturity of corn-ethanol processes today, we assume no future performance or cost reductions will occur, regardless of the assumed speed of energy-supply side innovation

(user-selected variable #25) in a scenario.

Ethanol from lignocellulosic feedstocks without CO₂ capture (2G ethanol)

The energy performance of the technology option for ethanol production from lignocellulosic feedstocks in MACRO is parameterized based on the design and simulation of Petersen et al [154] of a stand-alone facility with an input capacity of 220 wet tonnes (50% mc) per hour of bagasse. The plant has a production capacity of 276 liters of ethanol per dry tonne of feedstock input, or 266 million liters per year. Process waste solids are used internally as fuel to cogenerate all process steam and electricity needed onsite plus an excess of 0.41 MWh of electricity per dry tonne of bagasse input. We assume the excess electricity is exported to the grid.

Capital costs for 2G plants are as estimated by [151] (16.9 R\$_{Dec2024} per liter/yr of capacity), which we escalate to US\$₂₀₂₅. EPE indicates a typical unit production capacity of 82 million liters of ethanol per year. Operating cost estimates are based on [155]. For fixed O&M we add Zambello's estimate of labor cost to the indicated FOM cost, resulting in our FOM estimate of 3.4% of capital cost. We consider only the non-feedstock portion of Zambello's variable O&M cost, since MACRO endogenously determines feedstock costs.

For the three speeds of assumed energy-supply side innovation (user-selected variable #25), we assume, based on [156], no future 2G capital cost reductions with slow innovation, a 25% reduction by 2050 with the mid-range speed of innovation, and a 50% reduction by 2050 for the faster innovation option.

Ethanol from combined sugarcane and sugarcane straw (1G2G ethanol) w/o CO₂ capture

One additional process for making ethanol combines conventional 1G sugarcane conversion to ethanol integrated with 2G conversion of sugarcane straw. The process design adopted here is that of [70] for a facility processing 4 million tonnes (70% moisture content) per year of cane and 0.25 million tonnes (dry) per year of sugarcane straw to produce 433.9 m³/year of ethanol and export 69 kWh per tc to the grid. The ethanol produced is 78% 1G and 22% 2G. The estimated capital cost (converted from 2014 US\$ using the CEPCI) is 842 million US\$₂₀₂₅, 73% of which is accounted for by the 1G portion of the facility. For consistency with the standalone 1G and 2G processes also included in our model, we assume fixed O&M as fraction of capital costs are a 73 / 27 weighted average of FOM fractions assumed for the standalone 1G and 2G processes. Similarly, variable O&M costs for the 1G2G plant are taken to be an average of the 1G and 2G VOM costs, weighted by the fraction of ethanol output accounted for by 1G (78%) and 2G (22%) processing in the 1G2G facility.

For the three speeds of assumed energy-supply side innovation (user-selected variable #25), we assume that cost reductions for future 1G2G plants will mirror those described above for standalone 1G and 2G facilities in proportion to the fraction of the total 1G2G plant capital cost accounted for by the 1G and 2G portions, respectively.

Ethanol from sugarcane, corn, and/or lignocellulose with CO₂ capture

Capture of fermentation-derived CO₂ is an option, either as retrofit or as greenfield capacity, for all bio-ethanol production technologies considered in MACRO. (CO₂ capture from bagasse or wood-chip boilers integrated at ethanol production sites could also be an option, but this is not considered in the current version of the NZB MACRO model.) Fermentation stoichiometry dictates that 0.955 tonnes

of CO₂ are produced (in nearly pure form) per tonne of ethanol produced. Because of the high purity of the CO₂ stream, separating out the CO₂ (for subsequent storage or use) involves simply dehydrating the stream and then compression. We derive capital and operating costs for dehydration and compression from the “94.2” model reported in Section SI.8 in [132], where the input flue gas is assumed to be 94 mol% CO₂, with a flow capacity of 0.3 MtCO₂/yr. [132] estimates a total capital cost for this system of 71 million 2020 US\$. We convert this to 2025 US\$ using the chemical engineering plant cost index, divide by 0.3 MtCO₂/yr to express as a unit capital cost, and apply the stoichiometric relationship and ethanol higher heating value to convert to a per kW_{HHV} ethanol output basis. For greenfield plants, this capital cost (327 US\$₂₀₂₅/kW_{ethanolHHV}) is added to that for a facility without CO₂ capture. From [132], annual fixed O&M costs associated with the CO₂ capture portion of the facility are estimated to be 3.3% of CO₂ capture capital costs, electricity use for dehydration and compression is 16 kWh per MWh_{ethanolHHV}, and other variable O&M costs are negligible.

Capital costs for the CO₂ capture portion of facilities are assumed to remain at this level across the full modeling time horizon for the slower and mid-range supply-side technology innovation user scenario options (user variable #25). In the faster innovation scenario the CO₂ capture system portion of the capital cost is assumed to decline by 25% by 2050. The CO₂ capture fractions of total capital cost for sugarcane, corn, 2G, and 1G2G ethanol production are 23.6%, 35.4%, 7.9%, and 18.6%, respectively.

Biodiesel: Fatty acid methyl esters (FAME)

Biodiesel in the context of the NZB modeling work refers to fuel produced by transesterification of soybean or macauba oil by reaction with methanol. The resulting FAME molecules contain some oxygen, which places some limits on mixing with petroleum diesel or diesel fuel made by hydroprocessing of vegetable oils (HVO/HEFA).

Soybean as a feedstock for fuels production is included in the current version of the NZB model. Macauba will be included in a future version, but the techno-economic characteristics of macauba utilization are nevertheless described here.

Mass and energy balances assumed in MACRO for FAME production from soybean oil are as given by [157], and we assume these apply to either soybean oil or macauba oil. Mourad estimates that one tonne of biodiesel is produced from an input of 1.075 tonnes of vegetable oil. Fuel oil and firewood inputs in Mourad’s design are used to meet process steam and electricity generation. We assume that fuel oil energy is supplied by burning some of the biodiesel output (0.2%) instead and that wood chips from planted forests provide the wood input.

The assumed capital cost for a greenfield facility is based on [158], which reports estimated capital costs of 0.81 BR\$ per output liter biodiesel per year (December 2024 BR\$), which we convert to 2024 US\$ using the prevailing December 2024 exchange rate, then apply the CEPCI to convert to 2025 US\$ and express on an output fuel higher heating value basis (assuming 35.4 MJ_{HHV}/liter).

Fixed O&M costs include maintenance and labor costs given by Nogueira et al. [159]. Labor costs of 1.89 US\$/t biodiesel are also indicated, along with a maintenance cost of 3.5% of capital cost. A weighted average maintenance cost (across multiple plant sizes) of 3.1 US\$ per tonne biodiesel is also indicated (in Table S3 [159]). Accordingly, we assume labor costs add 1.89/3.1 = 61% on top of the specified maintenance cost, so that fixed O&M costs are 3.5% (1 + 0.61) = 5.6% of capital cost. Nogueira et al. indicate variable O&M costs of 101 US\$₂₀₁₅ per tonne of biodiesel, with methanol and

other chemical inputs accounting for about 70% this. We convert this to 2025 US\$ per MWh higher heating value basis.

In the case when soybean oil is the input feedstock, we include one additional variable O&M component to account for the cost of oil extraction from the as-harvested soybeans and transportation of the oil to the FAME facility. We estimate a levelized cost of US\$₂₀₂₅ 45 for oil extraction and degumming based on capital and operating costs for a 3000 t/day processing facility given by [160] in US\$₂₀₁₇. Assuming a yield of $0.201 \text{ t}_{\text{soybeanoil}} / \text{t}_{\text{soybean}}$ and an oil crush value share of 0.4 (as discussed earlier), the cost for oil extraction is estimated to be $[(45 \times 0.4) / 0.201 =] \text{ US\$}_{2025} 90 / \text{t}_{\text{soybeanoil}}$. For oil transportation cost, we assume oil is moved by tanker truck from extraction facilities to FAME production units. We use a cost estimate for bulk liquids transportation based on a study by INFRA S.A., the state-owned company linked to Brazil's Ministry of Transport and responsible for infrastructure planning for the transport sector [161]: Transport cost (R\$_{Dec2017} / tonne bulk liquid) = $16.6 + 0.21 \times d$, where d is one-way transport distance in kilometers. We assume an average distance of 50 km based on an analysis we conducted of the average distance between soybean crushing facilities [67] and biodiesel production units [162] in Brazil today. We convert the resulting transportation cost of 27 R\$_{Dec2017} / $\text{t}_{\text{soybeanoil}}$ to 8.2 US\$_{Dec2017} / $\text{t}_{\text{soybeanoil}}$ using the currency exchange rate prevailing in December 2017 and increase this to 2025 US\$ using the monthly transportation cost index for Brazil [163] to give a total transport cost of 17 US\$₂₀₂₅ / $\text{t}_{\text{soybeanoil}}$.

In the case when macauba oil is the feedstock we include only the transport cost of 17 US\$₂₀₂₅ / $\text{t}_{\text{macaubaoil}}$ as an added variable O&M cost. (Oil extraction costs are factored into the effective feedstock cost, as described earlier (Section 3.2.2.2 .)

Our model assumes that the FAME process for biodiesel production from vegetable oils is a fully-mature commercial process, and no future capital cost reductions are assumed for this technology, regardless of the user-specified rate of energy-supply side technology innovation (user-selected variable #25).

Hydrotreated vegetable oils

Hydrotreated vegetable oils (HVO, sometimes called Hydroprocessed esters and fatty acids, HEFA) in the context of the NZB modeling work refer to fuels produced by hydroprocessing of soybean or macauba oil to create molecules that are chemically identical to corresponding petroleum-derived fuel molecules. While diesel-like and jet-like fuels are typically produced from soybean or macauba oils today, it is also possible to produce gasoline-like fuels with appropriate processing. The initial version of the MACRO model assumes that the HVO/HEFA process produces only jet-like fuel.¹⁴

Soybean as a feedstock for HVO/HEFA fuels production is included in the current version of the NZB model. Macauba will be included in a future version, but the techno-economic characteristics of macauba utilization are nevertheless described here.

Capaz [164] in Table 2.1 indicate yields of jet-like, diesel-like and naphtha-like fuel from soybean or palm oil (in kg per tonne of oil) of 493, 233, and 60.5, respectively. Capaz assumes that the LPG-like fraction of the fuel product, supplemented by some natural gas input, is used to cogenerate process heat and electricity. Electricity generated in excess of process needs is exported to the grid. The required hydrogen input for HEFA production is 0.042 kg per kg of soybean oil from Table SM.3

¹⁴ Diesel-like and gasoline-like fuel production will be included in a future revision of the model.

in Capaz. To simulate a heat self-sufficient HEFA facility, we assume that the natural gas input is replaced by burning some (8%) of the fuel output instead.

For macauba oil as a feedstock, we assume fuel yield and hydrogen requirements for are the same as those reported by Capaz for palm oil. Capaz reports identical fuel yield per tonne of oil using palm or soybean oil as feedstock, but a slightly lower hydrogen input with palm oil [0.037 kg per kg oil (Table SM.4)].

In our MACRO model, the three output fuel fractions from a HEFA facility are aggregated, and the aggregate product is assumed to be able to satisfy demand for jet-like, diesel-like, or gasoline-like fuel. Higher heating values of the three fuel fractions used for the aggregation are 44.1, 48.1, and 45.6 MJ/kg, respectively.

The assumed capital cost for a greenfield HEFA production facility is based on [151], which reports estimated capital costs of 7.02 BR\$ per output liter of fuel per year (December 2023 BR\$). The cost estimate is for a facility producing roughly equal quantities of diesel-like and jet-like fuel from an input of vegetable oil. We convert the cost estimate to 2023 US\$ using the prevailing December 2023 exchange rate, then apply the CEPCI to escalate to 2025 US\$, and express on a fuel output higher heating value basis (assuming 33.5 MJ_{HHV}/liter).

Operating costs are based on [164], which gives fixed O&M costs of 7.2% of capital costs. Variable O&M costs excluding hydrogen feedstock and electricity are determined endogenously in MACRO. Capaz reports negligible other variable O&M costs. As with the FAME process, in the case when soybean oil is the input feedstock for HEFA production, we add a variable O&M component to account for the cost of oil extraction from soybeans and transport to the HEFA facility of $\text{US\$}_{2025} 107/t_{\text{soybeanoil}}$. In the case when macauba oil is the feedstock we include only the transport cost of $17 \text{ US\$}_{2025} / t_{\text{macaubaoil}}$ as a variable O&M cost, since oil extraction costs are included with the effective feedstock cost, as described earlier (Section).

Our model assumes that hydrotreating processes for vegetable oils to produce hydrocarbon fuels are fully-mature commercial technologies, and no future capital cost reductions are assumed, regardless of the user-specified rate of energy-supply side technology innovation (user-selected variable #25).

Ethanol to Jet fuel (EtJ)

The ethanol-to-jet process, despite its name, can also be designed to make diesel-like and/or gasoline-like fuels in addition to jet-like sustainable aviation fuel (SAF). Our MACRO model assumes that the EtJ process can be used to produce any of these three fuel types. The parameterization of the EtJ asset in MACRO is based on the S1 (scenario 1) process design described in [165]. Chireshe's design capacity includes inputs of anhydrous ethanol (30 tonnes per hour) and outputs of SAF (13.37 tonnes per hour) and diesel-like fuel (0.68 tonnes per hour). About 5% of the ethanol input is reformed to make the hydrogen needed in the process. The EtJ process steam and electricity demands are 18.3 tonnes per hour (tph) and 13.29 MW, respectively. The facility is designed to burn naphtha and liquefied petroleum gas (LPG) by-products to generate 14.4 tph of the needed process steam and 12.17 MW of the needed electricity. The design assumes the additional 3.9 tph of process steam and 1.12 MW of needed electricity are met by external inputs coming from an adjacently located sugarcane-ethanol production facility's cogeneration plant.

To generalize Chireshe's design for our model, we modify the S1 techno-economic parameters to

simulate an EtJ facility with all process steam provided internally. We assume the external input of process steam is satisfied by burning some of the diesel-like fuel product in a boiler with 80% efficiency (HHV basis) producing steam at 15 bar, 300 C. Chireshe's original S1 design has a total fuel mass yield (diesel + jet) / ethanol of 0.47, which is lower than some other assessments of EtJ, e.g., 0.53 by Geleynse et al. [166], primarily because Chireshe's design uses some of the input ethanol for hydrogen production and burns naphtha and LPG for process energy. With our additional process steam adjustment the total mass yield of fuel is reduced from 47% to 46%.

Chireshe estimates a capital cost for the S1 design of 270 million 2023 US\$. We convert this to 2025 US\$ using the chemical engineering plant cost index (CEPCI) and add to it a capital cost estimate of 1.3 million 2025 US\$ for an added boiler needed to supply 3.9 tph of process steam. (The latter is estimated based on [167].) We adopt Chireshe's fixed and variable O&M costs (8 million and 2 million 2023 US\$/year, respectively) and convert these to 2025US\$ using the CEPCI. We convert fixed O&M to a fraction of the estimated capital cost (3%), and variable O&M to a per unit output basis considering Chireshe's assumption of 8000 operating hours per year.

For the three speeds of assumed energy-supply side innovation (user-selected variable #25), we assume, based on [156], no future capital cost reductions with slow innovation, a 25% reduction by 2050 with the mid-range speed of innovation, and a 50% reduction by 2050 for the faster innovation option.

Fischer-Tropsch fuels via gasification with and without CO₂ capture

Liquid hydrocarbon fuels can be made via gasification of biomass, followed by catalytic processing of the resulting synthesis gas (water-gas-shift, CO₂ removal, and Fischer-Tropsch synthesis of the CO₂-lean gas) and refining of the synthesized liquid. CO₂ removal is intrinsic to the design regardless of whether the separated CO₂ is captured for storage or not. As a result, CO₂ capture for storage primarily involves dehydrating and compressing the separated CO₂ for pipeline transport. Cheng, et al. [168] have estimated performance and cost for this process with and without CO₂ capture. Those numbers have been adopted to parameterize these assets in MACRO, after expressing costs in 2025 US\$ using the CEPCI.

For the three speeds of assumed energy-supply side technology innovation (user-selected variable #25), we assume, based on [156], no future capital cost reductions with slow innovation, a 25% reduction by 2050 with the mid-range speed of innovation, and a 50% reduction by 2050 for the faster innovation option.

Hydrogen via gasification with and without CO₂ capture

The process design considered here for hydrogen production from lignocellulosic biomass includes gasification of the biomass, followed by removal from the syngas, full water-gas-shift of the remaining synthesis gas, pressure swing adsorption to separate hydrogen from the other gases, and finally compression of the hydrogen for transport [168]. Some CO₂ separation is intrinsic to the design regardless of whether the separated CO₂ is captured for storage or not. As a result, CO₂ capture for storage primarily involves dehydrating and compressing the separated CO₂ for pipeline transport. Performance and costs estimates of Cheng, et al. [168] for designs with and without CO₂ capture have been adopted to parameterize these assets in MACRO, after expressing costs in 2025 US\$ using the CEPCI.

For the three speeds of assumed energy-supply side technology innovation (user-selected variable #25), we assume, based on [156], no future capital cost reductions with slow innovation, a 25% reduction by 2050 with the mid-range speed of innovation, and a 50% reduction by 2050 for the faster innovation option.

Synthetic natural gas (SNG) via gasification with and without CO₂ capture

Methane can be made via gasification of biomass, followed by partial water-gas-shift of the resulting synthesis gas, removal of CO₂ from the shifted gas, and catalytic methanation of the remaining stream. CO₂ separation is intrinsic to the design regardless of whether the separated CO₂ is captured for storage or not. As a result, CO₂ capture for storage primarily involves dehydrating and compressing the separated CO₂ for pipeline transport. Cheng, et al. [168] have estimated performance and cost for this process with and without CO₂ capture. Those numbers have been adopted to parameterize these assets in MACRO, after expressing costs in 2025 US\$ using the CEPCI.

For the three speeds of assumed energy-supply side technology innovation (user-selected variable #25), we assume, based on [156], no future capital cost reductions with slow innovation, a 25% reduction by 2050 with the mid-range speed of innovation, and a 50% reduction by 2050 for the faster innovation option.

Charcoal kiln

Charcoal production from wood is modeled based on beehive kilns, the predominant technology used in Brazil today [169]. For four different technology design variants, Riberio, et al. [170] provide detailed techno-economic characterizations. The most economically attractive of the technologies is the "kilns-furnace" variant, and we parameterize the MACRO charcoal production asset using Riberio, et al.'s estimates for this variant.

Riberio, et al. indicate a charcoal gravimetric yield of 33.5%, or 335 kg per tonne of biomass input (dry basis). Assuming a higher heating value for charcoal of 29.6 MJ/kg, our assumed charcoal energy yield is 9.92 GJ per tonne of dry biomass input.

Riberio, et al. estimate capital costs of \$58,670 (2021 US\$) for a 4-furnace/16-kiln facility with an annual charcoal production capacity of 4284 m³/year. Fixed O&M costs equivalent to 43% of the capital cost are derived from Riberio, et al. assuming labor, other material inputs, and general and administrative expenses are fixed costs. Variable O&M costs are derived assuming these encompass sales expenses and taxes.

Existing charcoal production capacity in the model is characterized using state-level annual production data from the IBGE Forestry Production Survey (PEVS) [171], which reports charcoal output, in tonnes, for each Brazilian state (UF) and year. For each state, the reported tonnage is converted to an energy basis using the higher heating value of charcoal of 6,800 kcal/kg (7.91 MWh/t) reported in the National Energy Balance (BEN) [43]. Table 50 presents, by state, charcoal production for 2023 and 2024 in tonnes, together with the resulting 2024 production expressed in MWh.

National charcoal production totaled 7,181,647 tonnes in 2024. Production is distributed across all Brazilian states, although Minas Gerais alone accounts for more than 77% of national output. The resulting 2024 national total, on an energy basis, is used to characterize existing charcoal production capacity in the initial modeling year.

Table 50: Charcoal production, by state, in 2024. Source: based on [171] and [43].

State	Production [t]	Production [MWh]
Rondônia	869	7
Acre	1,740	14
Amazonas	1,040	8
Roraima	113	1
Pará	155,988	1,234
Amapá	1,230	10
Tocantins	1,370	11
Maranhão	475,878	3,763
Piauí	68,547	542
Ceará	8,011	63
Rio Grande do Norte	3,334	26
Paraíba	992	8
Pernambuco	7,805	62
Alagoas	30	0.2
Sergipe	21	0.2
Bahia	200,068	1,582
Minas Gerais	5,564,562	44,007
Espírito Santo	15,817	125
Rio de Janeiro	345	3
São Paulo	75,218	595
Paraná	91,556	724
Santa Catarina	13,473	107
Rio Grande do Sul	75,220	595
Mato Grosso do Sul	405,409	3,206
Mato Grosso	7,656	61
Goiás	3,917	31
Distrito Federal	1,438	11
Brazil	7,181,647	56,795

Our model assumes that the charcoal kiln technology is fully-mature commercially, and no future capital cost reductions are assumed, regardless of the user-specified rate of energy-supply side technology innovation (user-selected variable #25).

Existing bioenergy conversion capacities

Existing biofuels production capacity installed in Brazil today is concentrated in four pathways: biodiesel (FAME), sugarcane ethanol, and corn ethanol. EPE [172] provides a comprehensive dataset of capacity and production information for bioenergy liquid fuel plants across Brazil, and this dataset is used here to characterize existing capacity for the current modeling year.

The EPE dataset records a total of 455 ethanol 1G plants across 21 states: 383 sugarcane-ethanol, 49 corn-ethanol, 16 sugarcane sugar+ethanol co-production, and 7 others. Restricting to plants currently in operation, sugarcane-ethanol capacity amounts to 356,706 m³/day (342 plants) and corn-ethanol capacity amounts to 46,165 m³/day (25 plants), for a combined operating ethanol production capacity of 402,871 m³/day. By state, São Paulo accounts for the largest share of the sugarcane-ethanol capacity (600,502 tonnes/day sugarcane input, 175,078 m³/day ethanol output), followed by Goiás (170,376 tonnes/day input, 50,450 m³/day output) and Minas Gerais (135,660 tonnes/day input, 39,675 m³/day output). For corn-ethanol, Mato Grosso is the dominant state (160,054 tonnes/day corn input, 39,054 m³/day ethanol output), followed by Goiás (47,321/12,209), and Mato Grosso do Sul (43,946/10,600).

Total ethanol output at sugarcane-ethanol plants is further disaggregated into anhydrous ethanol (128,485 m³/day, 34.5%) and hydrated ethanol (243,946 m³/day, 65.5%). Our model does not separately track anhydrous and hydrous ethanol, but the difference in energy density between the two streams is nonetheless incorporated when they are combined, with both expressed on a higher heating value energy basis for purposes of the MACRO model. We assume hydrated ethanol contains 6.8% water content by mass [173]. The resulting anhydrous-equivalent energy flows are then summed to yield the single, aggregated existing ethanol production capacity used as the model's base-year input.

Most biodiesel production in Brazil today is from soybean oil. Some 77 plants are located across Brazil, with a combined output capacity of 17,444,956 m³/year (47,794 m³/day). Restricting to plants currently in operation (60 plants, 77.9% of the total plant count), installed capacity amounts to 14,669,131 m³/year (40,189 m³/day). By state, Mato Grosso accounts for the largest share of installed biodiesel capacity (3,961,513 m³/year), followed by Rio Grande do Sul (3,972,415 m³/year), Goiás (2,965,625 m³/year), Paraná (1,625,345 m³/year), and Bahia (1,148,093 m³/year). (We exclude from the base year existing capacity an additional 2,775,825 m³/year of authorized capacity expansions to existing facilities and some under-construction greenfield capacity.) As for ethanol, we convert the volumetric production capacity reported for biodiesel to a higher heating value energy basis for input to MACRO.

3.2.2.3 Special considerations for biogenic CO₂ and biogenic content of vehicle fuels

Given the potential importance of bioenergy in modeled outcomes, some additional explanation of two aspects of the approach to modeling bioenergy is warranted: sequestration (underground storage) of biogenic CO₂ and tracking of biogenic components in vehicle-fuel mixes.

Biogenic CO₂ sequestration

MACRO operates using the fundamental principle of carbon conservation over the entire lifecycle of each commodity, explicitly accounting for the intrinsic carbon content of each commodity as well as the CO₂ emitted or captured during processing. A detailed description of the general carbon flow framework in MACRO can be found in [174]. Here we focus on how biogenic CO₂ is handled, with an emphasis on CO₂ accounting and related considerations for biomass conversion to energy with CO₂

capture and storage.

MACRO conserves biogenic carbon and explicitly tracks it across all interconnected processes in bioenergy supply chains from feedstock harvesting, through intermediate products, final products, and emissions during conversion, to capture and storage. Figure 73 presents an overview of the carbon accounting structure at asset level using sugarcane-based processing for illustration. Carbon is tracked in the ethanol resulting from fermentation, along with carbon in the fermentation byproduct and carbon in bagasse used onsite for cogenerating heat and electricity to meet process needs and some exported electricity. When the ethanol output is further processed through the ethanol to jet fuel conversion pathway, the same conservation principle continues to apply. For each downstream asset, the total biogenic carbon content entering the process must equal the sum of carbon retained in all output products and co products, together with carbon in CO₂ off-gas streams, whether the CO₂ is emitted to the atmosphere or captured for underground storage.

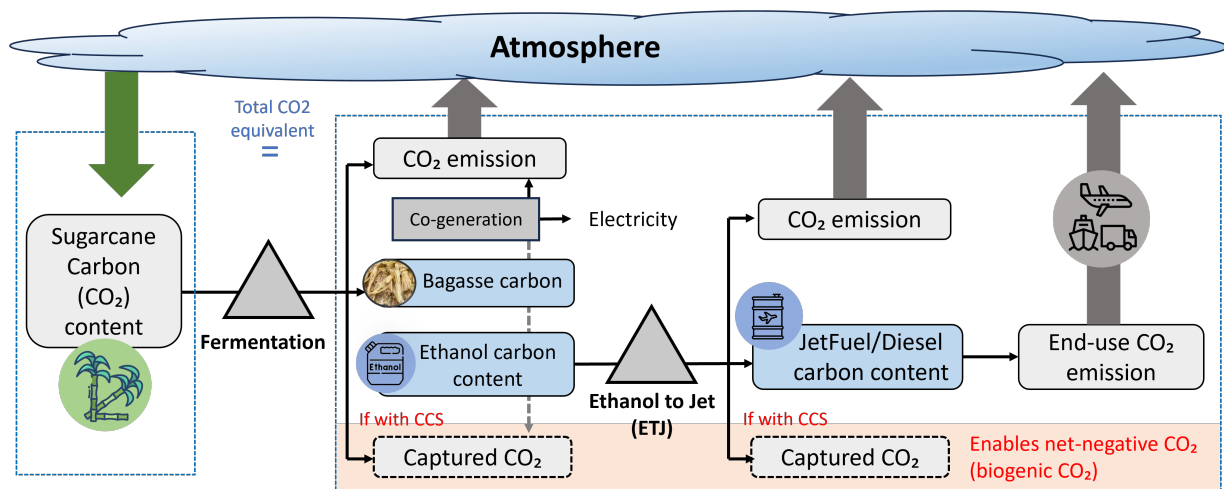


Figure 73: Conceptual Framework of Biogenic Carbon Flow and Conservation at the Asset Level: A Sugarcane-to-Ethanol Example

For each bioconversion asset, output mass or energy flows are first determined by applying a process conversion efficiency to the corresponding input flow. The carbon content embodied in the main product and any by-products is then calculated using commodity specific carbon fractions. Any stoichiometric imbalance, defined as carbon not embodied in physical products, is accounted for as process generated CO₂. This CO₂ stream is subsequently classified as either captured CO₂ or emitted CO₂, depending on the assumed capture performance of the asset. Accordingly, carbon conservation at the asset level can be expressed as:

$$C_{in,commodities} = C_{out,commodities} + C_{CO_2,emitted} + C_{CO_2,captured} \quad (49)$$

where $C_{in,commodities}$ denotes the total carbon content entering the asset, $C_{out,commodities}$ represents the carbon embodied in all output products and co-products, and the two remaining terms correspond to carbon emitted to the atmosphere or captured for storage. For assets that capture process generated CO₂ the fraction of process CO₂ captured depends on the underlying process:

- For post-combustion CO₂ capture, a typical capture rate of 90% of otherwise-emitted CO₂ [175] is assumed;

- For gasification with CO₂ capture, a capture rate of 85 - 95% is typically applicable [175];
- For high-purity CO₂ streams, such as fermentation by-product CO₂, a capture rate near 100% is feasible. [176].

The carbon embodied in the resulting product – whether a fuel, an intermediate commodity, or a co-product – is tracked endogenously within the model, alongside the process CO₂ that is emitted or captured. For example, carbon entering a process may be distributed such that 50% is retained in the product, 5% is emitted as CO₂, and 45% is captured. To determine the carbon content of each commodity, carbon content ratios summarized in Table 51 are used as the primary reference. These values are derived from molecular formulas expressed on a dry basis, stoichiometric carbon fractions, and established literature sources.

Table 51: Carbon content fractions of main feedstock and product commodities

Product	Carbon % (dry basis)	MC (as collected)
Sugarcane	46% [177]	70%
Corn	45% [178]	14%
Soybean	43–45%	13%
Biomass residue (dry) – Grasses/Straw	38% [179]	15% [179]
Wood	50% [179, 180]	51%
Biodiesel	77% [179]	–
Petroleum (Diesel, JetFuel, Gasoline)	86% [179]	–
Charcoal	87% (85–90% based on grade) [181]	–
Ethanol	52.1% [179]	–

Within MACRO, different commodities are represented using different units, depending on the commodity type. Biomass feedstock resource supply-cost curves are given on an as-harvested basis, in tonnes with assumed moisture contents as in Table 51. Energy contents of fuel, including hydrogen, are given on a higher heating value (HHV) basis, in MWh. Because carbon content is fundamentally a mass-based property, commodities represented on an energy basis must first be converted to a mass basis before their carbon content can be determined. This conversion is performed using the commodity's HHV, as shown in the following relationship.

$$E_{commodity,MWh} = M_{commodity,tonne} \cdot HHV_{commodity} \cdot \frac{1000}{3600} \quad (50)$$

$$M_{commodity,tonne} = E_{commodity,MWh} \cdot \frac{1}{HHV_{commodity}} \cdot \frac{1000}{3600} \quad (51)$$

Where $M_{commodity,tonne}$ denotes the commodity mass in tonnes, $HHV_{commodity}$ is the higher heating value expressed in MJ per kg, and the factor $1000/3600$ converts MJ per kg to MWh per tonne. Once the mass of a commodity is known, its carbon content can, in turn, be converted to an equivalent mass of CO_2 using the fixed ratio of molecular weights between CO_2 (44 g per mol) and elemental carbon (12 g per mol).

For each MACRO bioconversion asset a set of input commodities and output commodities are specified. MACRO determines output levels by applying conversion efficiencies per unit of input commodity. The latter is defined as one tonne of biomass on a dry basis. (Where source data are reported on a wet basis or as extracted products such as oil, the appropriate conversions to dry basis or extracted oil are applied.) The carbon content of each output commodity is derived from its total mass and intrinsic carbon fraction. Exogenously specified asset conversion parameter values, including CO_2 captured rate for processes involving CO_2 capture, are tabulated in the companion Technology Data spreadsheet [61], with supporting explanations and source documentation described above in Section 3.2.2.2.

Commodity Flows and Demand Representations with Biofuels

This section explains how the biogenic components of vehicle fuels that meet transportation fuel demands are tracked in MACRO.

FlexFuel and Gasoline demand pools

Within Brazil, light-duty vehicle transportation is the primary end use for ethanol and gasoline today. The widespread deployment of flex-fuel vehicles, which can operate using arbitrary mixes of ethanol and gasoline, provide flexibility in the fuel mix that can meet transportation demand. Flex-fuel vehicles dominate the Brazilian light-duty vehicle market. They accounted for 83% of new light-vehicle licensing in 2025, compared to 9.9% for diesel, 2.8% for gasoline-only, and 4.3% for electrified powertrains (battery electric, hybrid, and plug-in hybrid) according to EPE [182].

To represent the intrinsic operational flexibility in the Brazilian light-duty vehicle sector, the MACRO framework explicitly incorporates a demand pool structure that allows both ethanol and gasoline to jointly satisfy transportation fuel demands. The model is able to choose to meet light-duty vehicle fuel demand with pure ethanol, pure gasoline, or a blend of the two at any proportion equal to or greater than the legally-mandated minimum anhydrous ethanol content (currently 30%) established under the Fuel of the Future Law [183]. This fuel blend is called gasoline-C in Brazil. (Refer to the scenario-setting Section 4.7.4 for further discussion of biofuel mandates.)

EnergyPathways disaggregates light-duty fuel demand into three categories: ethanol for pure-ethanol vehicles, gasoline-C for gasoline-engine vehicles, and fuel for flexfuel vehicles. To meet these demands, MACRO will supply at least as much ethanol as needed to meet demands of the pure-ethanol vehicles plus the mandated ethanol fraction in gasoline-C. MACRO will meet the demand for the gasoline fraction of gasoline-C using fossil-gasoline and/or a synthetic gasoline fuel made via one or more of four pathways: Hydrotreated Esters and Fatty Acids (HEFA), Ethanol-to-Jet (EtJ), biogasification-Fischer-Tropsch synthesis (bio-FT), and synthesis from H_2 plus captured CO_2 .¹⁵ The optimal mix of ethanol, fossil gasoline, and synthetic gasoline needed to meet the fuel demand for flexfuel vehicles is determined endogenously by MACRO. Figure 74 schematically illustrates the

¹⁵In the initial version of macro, only the bio-FT pathway is active.

arrangement in MACRO for satisfying light-duty vehicle fuel demands.

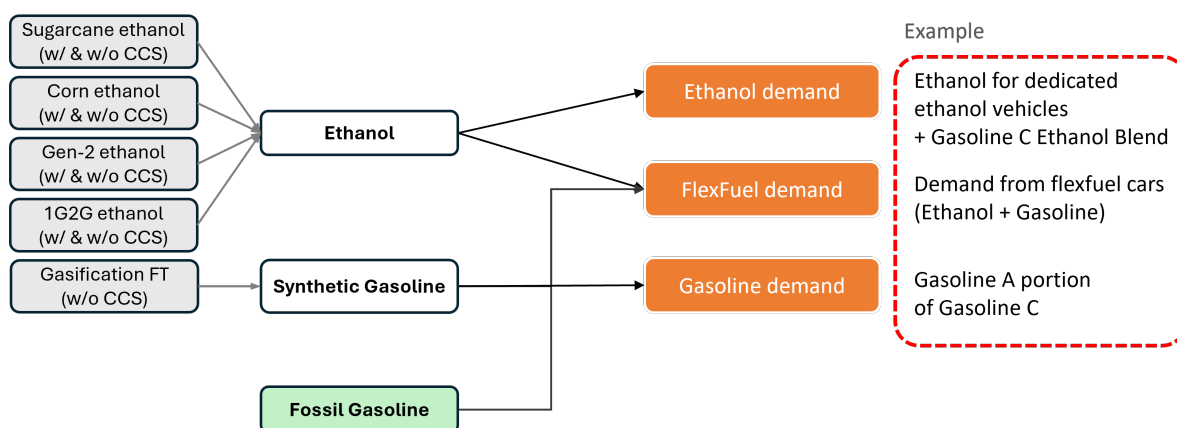


Figure 74: Demand pool structure for gasoline and ethanol, showing dedicated-vehicle demands and the flex-fuel pool

JetFuel demand pool

Similar to how MACRO satisfies the ethanol/gasoline demand pool, MACRO satisfies the JetFuel demand pool using a combination of fossil-derived jet fuel and sustainable aviation fuel. Driven by growing policy support for decarbonized aviation fuels, the share of jet fuel demand met by SAF is expected to expand steadily over the modeling horizon. SAF can be produced via four pathways; EtJ, HEFA, bio-FT, and catalytic synthesis from H_2 and captured CO_2 .¹⁶ To represent policy-driven SAF adoption requirements and blending constraints, the jet fuel demand pool is decomposed into three distinct demand components: SAF mandate portion, Fossil fuel required portion, Flexible portion. This structure captures two constraints typically imposed on SAF utilization: (i) a minimum uptake requirement, currently being driven in Brazil by the emissions reduction targets established under the Fuel of the Future Law [183], which is further discussed in Section 4.7.4; and (ii) a maximum uptake constraint, reflecting the certified blending limits for approved SAF pathways under [184], where most SAF pathways are currently limited to a maximum 50% blend with conventional jet fuel, which are systemically illustrated in Figure 75.

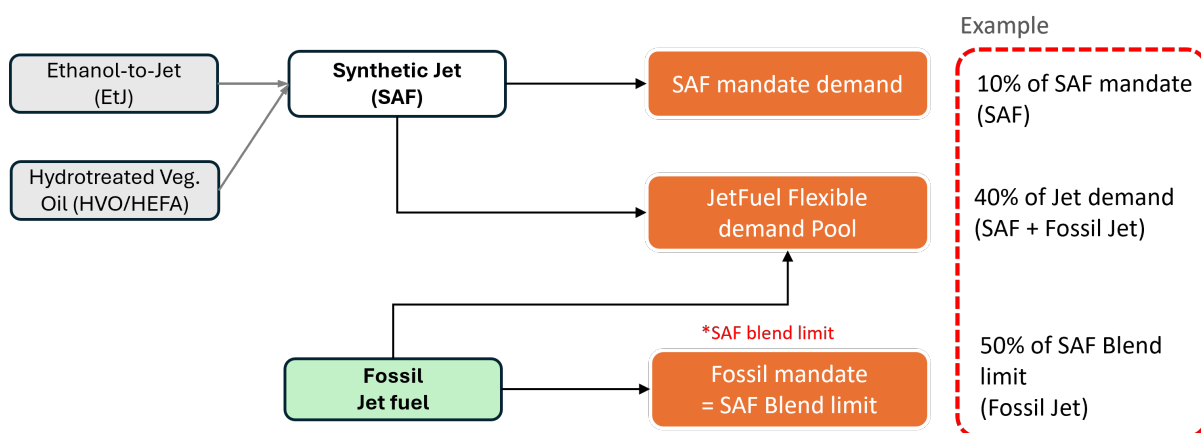


Figure 75: Demand pool structure for jet fuel, showing the SAF mandate, the fossil minimum implied by the blend limit, and the flexible pool

¹⁶In the initial version of macro, only the EtJ and HEFA pathways are active.

The SAF mandate portion represents the fraction of total jet fuel demand that is required to be satisfied exclusively by SAF. MACRO will endogenously select the optimal SAF pathway to meet this demand. MACRO will also deliver a minimum fossil jet fuel amount equal to 50% of total jet fuel demand to ensure that the minimum fossil requirement is met. MACRO will endogenously determine the mix of fuel (fossil and/or SAF) that meet the flexible portion. Through this model structure, MACRO can explicitly represent policy constraints while preserving flexibility in determining the economically optimal fuel composition.

Diesel demand pool

Heavy-duty freight and agricultural transport represent the dominant end uses of diesel fuel in Brazil today, which is met through a combination of fossil diesel and biofuels. Biodiesel (FAME) blending has followed a steadily increasing mandate under the Fuel of the Future Law [183]: the mandatory blend share rose from B14 to B15 in 2025, with the law establishing a fixed schedule of a further one-percentage-point increase per year thereafter, reaching B20 by 2030. To accommodate this structure, we represent the diesel demand pool in MACRO through a demand decomposition structure that captures biodiesel blending requirements and fuel substitution options. Within the current framework, total diesel demand is divided into two primary demand categories: Biodiesel mandate demand portion and Remaining diesel demand portion (Figure 76.)

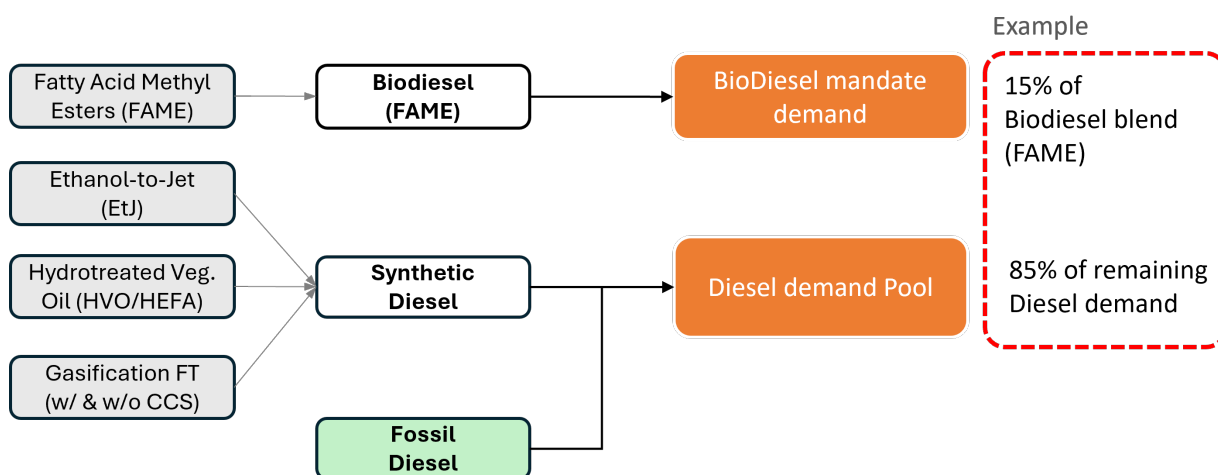


Figure 76: Demand pool structure for diesel, showing the biodiesel mandate and the flexible pool

The biodiesel mandate portion represents the required biodiesel share within total diesel consumption. This fraction is determined through scenario-specific input parameters and is satisfied exclusively using Fatty Acid Methyl Ester (FAME). The remaining diesel demand portion represents diesel consumption not covered by blending requirements. This demand category can be supplied using eligible diesel fuels excluding FAME, but including other renewable diesel pathways including EtJ and biogasification-FT,¹⁷ together with conventional fossil diesel. Accordingly, the demand pool structure enables explicit representation of biodiesel blending mandates while preserving flexibility in determining the optimal fuel mix under different scenario assumptions.

¹⁷HVO/HEFA will be added as an additional option in a future revision of MACRO.

3.2.3 Other fuel technologies and infrastructure

Hydrogen from natural gas with and without CO₂ capture

Thermal hydrogen refers to hydrogen produced by thermochemically converting a fossil-derived feedstock into hydrogen and CO₂. Without carbon capture and storage (CCS), most of the feedstock carbon is released to the atmosphere, resulting in high production emissions. Integrating CCS can substantially reduce direct plant emissions, although residual plant emissions and upstream emissions from fossil-derived feedstock production and transportation remain.

Fossil-based hydrogen production can use coal gasification or natural-gas reforming. Coal gasification converts coal into synthesis gas, while natural-gas pathways include steam methane reforming (SMR), partial oxidation, and autothermal reforming. Natural-gas SMR is represented in this study because it is the dominant existing hydrogen-production route in Brazil [185], particularly in refineries and fertilizer production, as identified by Brazil's Energy Research Office.

In a physical SMR system [186], natural gas is pretreated and reacted with steam at high temperature to produce a hydrogen-rich synthesis gas containing carbon monoxide and CO₂. A water-gas-shift reactor converts additional carbon monoxide and steam into hydrogen and CO₂. The hydrogen is then purified, conditioned, and compressed to a pressure suitable for transportation or storage. When CCS is included, CO₂ is separated from the process-gas stream and, where included within the selected plant design, from the reformer combustion flue gas. The captured CO₂ is subsequently dehydrated and compressed for transportation and storage.

MACRO represents hydrogen production with and without CCS as aggregated conversion assets rather than explicitly modeling the reformer, water-gas-shift reactors, hydrogen purification, CO₂ capture, and compression systems. Both assets have incoming natural-gas and electricity edges and outgoing hydrogen and uncaptured-CO₂ edges. The CCS version of the asset also has an outgoing captured-CO₂ edge. Electricity consumption represents hydrogen and CO₂ compression and other balance-of-plant requirements included within the adopted technology boundary.

Techno-economic parameters for SMR and SMR-CCS are derived from Case 1 and Case 2 in [186]. The reference plants produce approximately 20,126 kg H₂/h, corresponding to an Higher heating value (HHV)-based hydrogen-output capacity of approximately 794 MW_{th}. At the 90% capacity factor assumed in the report, this is equivalent to approximately 159 kt H₂/year. The capacity factor is used here to relate hourly nameplate capacity to annual production; actual utilization is determined endogenously by MACRO.

The total HHV-based natural-gas thermal input is approximately 1,031 MW_{th}-NG for SMR and 1,096 MW_{th}-NG for SMR-CCS. Dividing these inputs by the hydrogen-output capacity gives fuel-consumption coefficients of 1.30 MW-NG/MW-H₂ for SMR and 1.38 MW-NG/MW-H₂ for SMR-CCS. The higher fuel requirement in the CCS case reflects the additional energy required for CO₂ capture and solvent regeneration. The SMR-CCS configuration achieves an overall plant CO₂ capture rate of 96.2%.

NETL reports total auxiliary electricity requirements of approximately 13 MW_e for SMR and 41 MW_e for SMR-CCS, with compression accounting for a substantial share of the demand. Dividing these loads by the hydrogen-output capacity gives electricity-consumption coefficients of approximately 0.0164 MW_e/MW-H₂ for SMR and 0.0516 MW_e/MW-H₂ for SMR-CCS.

The reference SMR and SMR-CCS plants have total plant costs of approximately \$267.58 million and \$673.29 million in 2018 dollars. After escalation to 2025 dollars using the Chemical Engineering Plant Cost Index and normalization by the 794 MW-H₂ output capacity, the MACRO investment costs are approximately \$448,213 per MW-H₂ and \$1,127,801 per MW-H₂ for SMR and SMR-CCS, respectively.

Annual fixed O&M costs for SMR and SMR-CCS plants are reported as approximately \$10.63 million and \$23.33 million in 2018 dollars. Applying the same cost escalation to 2025 dollars and normalizing by capacity gives a fixed O&M cost of approximately \$17,812 per (MW-H₂)-year and \$39,084 per (MW-H₂)-year for SMR and SMR-CCS, respectively.

NETL reports total annual variable O&M costs of approximately \$13.79 million and \$38.40 million at a 90% capacity factor for SMR and SMR-CCS, respectively. These totals include approximately \$7.15 million and \$22.99 million, respectively, for purchased electricity. Because electricity consumption is represented explicitly and priced endogenously in MACRO, these electricity expenditures are excluded to avoid double counting. The remaining non-electric variable costs are approximately \$6.64 million for SMR and \$15.41 million for SMR-CCS in 2018 dollars. After CPI adjustment to 2025 dollars and normalization by annual hydrogen output, the variable O&M costs are \$1.36/MWh-H₂ for SMR and \$3.15/MWh-H₂ for SMR-CCS, respectively. A plant physical lifetime of 30 years is assumed for retirement tracking in MACRO.

For the current version of the NZB model, no cost or performance improvements are assumed for these hydrogen production technologies, regardless of the user-selected pace of energy-supply technology innovation.

Existing captive SMR facilities associated with refineries and fertilizer production are treated as outside the model boundary, while SMR-CCS has not achieved meaningful commercial-scale deployment in the modeled system. The existing capacities of both technologies are therefore set to zero in the base year. All thermal-hydrogen capacity appearing in the model results must be newly constructed.

Hydrogen from water electrolysis

Electrolytic hydrogen refers to hydrogen produced by using electricity to split water into hydrogen and oxygen. Electrolysis does not inherently produce low- or zero-emission hydrogen: its emissions intensity depends primarily on the source of the electricity consumed. In this study, electrolytic hydrogen is considered low-emissions when supplied by renewable or nuclear electricity, or by a sufficiently decarbonized electricity system.

Water-electrolysis technologies can be broadly classified as low- or high-temperature systems. High-temperature systems primarily use solid oxide electrolyzer cells (SOECs), which split steam using a solid ceramic electrolyte. They can reduce electricity consumption by supplying part of the required energy as heat. However, high-temperature electrolysis is substantially less commercially mature than low-temperature electrolysis and continues to face durability and degradation challenges [187].

Low-temperature technologies include alkaline, proton exchange membrane (PEM), and anion exchange membrane electrolyzers. Alkaline electrolysis has the longest commercial history and accounts for approximately 64% of globally installed electrolyzer capacity, compared with approximately 36% for PEM [188]. PEM electrolysis is chosen in this study because it can produce high-purity hydrogen and respond rapidly to changes in electricity supply, making it suitable for flexible operation in a power-system model.

In a physical PEM electrolysis system [187], purified water is supplied to the electrolyzer stack, where it is separated into hydrogen and oxygen. The resulting hydrogen is conditioned and, where required, compressed to a pressure suitable for storage or transportation. MACRO represents the process as an aggregated conversion asset rather than explicitly modeling the electrolyzer stacks, gas-conditioning equipment, compressors and other balance-of-plant components. The asset has an incoming electricity edge and an outgoing hydrogen edge. Electricity consumption represents the combined requirements of the electrolyzer stack and the balance-of-plant systems included within the adopted technology boundary. Water consumption and co-produced oxygen are not explicitly modeled.

Investment-cost assumptions are obtained from the EPRI Electrolysis Techno-Economic Analysis tool [189]. The largest plant-size category, representing facilities of at least 100 MW, is selected. For 2025, EPRI reports plant-capex estimates of \$721,000/MW_e at the lower end and \$1.361 million/MW_e at the higher end. These values represent the electrolyzer plant capex before installation and other project-level cost adders. To place them on a more complete total-plant-cost basis, an approximate factor of 1.59 is applied, consistent with the installation and project-level cost allowances specified in the EPRI techno-economic framework [189]. This factor reflects allowances for installation, general facilities, engineering and overhead, permitting, and contingency.

Because electrolyzer capacity in MACRO is defined by hydrogen energy output rather than electricity input, these costs are converted using the assumed conversion efficiency. A higher heating value (HHV) efficiency of 71% is assumed, corresponding to approximately 55.5 kWh/kg H₂, or 1.41 MWh of electricity per MWh of hydrogen produced. This value is broadly consistent with commercial PEM system data reported by Siemens Energy and Nel Hydrogen [190, 191]. After conversion to hydrogen output capacity, the investment costs are approximately \$1.615 million/MW-H₂ in the lower-cost case and \$3.048 million/MW-H₂ in the higher-cost case. EPRI reports the cost projections in constant 2022 dollars. No additional cost escalation is applied in this study, given the relatively small change in the CEPCI between 2022 and 2025.

Annual fixed O&M is set to 4% of investment cost in the lower-cost case and 6% in the higher-cost case. Because EPRI provides time-varying capital-cost projections, fixed O&M is calculated for each modeling year as the corresponding percentage of the projected investment cost in that year. For 2025, this corresponds to approximately \$64,600 per (MW-H₂)-year in the lower-cost case and \$182,900 per (MW-H₂)-year in the higher-cost case. These values combine a base fixed O&M assumption informed by IEA estimates [192] with an allowance for stack and component replacement. DOE assumes replacement costs equal to 11% of installed capital cost every 40,000 operating hours [193]. At an assumed 80% capacity factor, this is equivalent to approximately 1.93% of investment cost per year. The 80% capacity factor is used only for estimating replacement costs, while actual electrolyzer utilization is determined endogenously by MACRO.

A variable O&M cost of \$0.1/MWh-H₂ is adopted as a study assumption. Electricity is represented explicitly and priced endogenously. A technical lifetime of 20 years is assumed for capacity-retirement tracking in MACRO.

The slower-innovation scenario uses the higher EPRI investment cost and fixed O&M assumptions, while the faster-innovation scenario uses the corresponding lower values. The mid-range scenario is calculated as the arithmetic average of the two. Because electrolytic hydrogen has not achieved

meaningful commercial-scale deployment within the modeled energy system, its existing capacity in the base year is set to zero. All electrolyzer capacity appearing in the model results must therefore be newly constructed.

Liquid fuels synthesized from H₂ and captured CO₂

This technology converts inputs of H₂ and CO₂ by reverse water-gas-shift plus Fischer-Tropsch synthesis into liquid fuels that can meet demands for gasoline-like, diesel-like, and/or jet-like fuels. MACRO endogenously determines which source of H₂ to use. The CO₂ input is constrained to come from direct air capture plants. The inputs required per unit of liquid fuel output are from [168]. Capital and operating cost estimates given in 2023 US\$ in Cheng, et al. are escalated to 2025US\$ and used here.

Methane synthesized from H₂ and captured CO₂.

This technology converts inputs of H₂ and CO₂ by reverse water-gas-shift plus methanation into synthetic methane that can meet demands for natural gas-like fuels. MACRO endogenously determines which source of H₂ to use. The CO₂ input is constrained to come from direct air capture plants. The inputs required per unit of synthetic methane output are from [168]. Capital and operating cost estimates given in 2023 US\$ in Cheng, et al. are escalated to 2025US\$ and used here.

Direct capture of CO₂ from air

Direct air capture (DAC) refers to technologies that separate carbon dioxide (CO₂) directly from ambient air. The captured CO₂ may subsequently be transported for permanent geological storage or used in other processes. DAC does not necessarily result in negative emissions: net atmospheric CO₂ removal occurs only when the captured CO₂ is durably stored and the lifecycle emissions associated with capture, compression, transport, and storage are lower than the amount of CO₂ removed.

DAC technologies are commonly classified as liquid-solvent or solid-sorbent systems [194]. Liquid-solvent systems generally use alkaline solutions and require relatively high temperatures for solvent regeneration. Solid-sorbent systems capture CO₂ on the surface of a solid material and typically operate at lower regeneration temperatures. The electric DAC technology represented in this study is a solid-sorbent system in which electricity supplies both process equipment and an electric boiler that produces steam for sorbent regeneration.

In the physical system [195], fans move ambient air through sorbent beds, where CO₂ is adsorbed. The saturated sorbent is then regenerated using steam, releasing a concentrated CO₂ stream that is conditioned and compressed for transport and storage. MACRO represents this process as an aggregated conversion asset rather than explicitly modeling the fans, sorbent beds, boiler, steam system, and compression equipment. The asset has an incoming electricity edge, an incoming atmospheric CO₂ edge, and an outgoing captured-CO₂ edge. Electricity consumption represents the combined requirements for air movement, sorbent regeneration, CO₂ compression, and other auxiliary equipment.

Techno-economic parameters for electric DAC are derived from Case 0B-EB of the NETL *Direct Air Capture Case Studies: Sorbent System* report (DOE/NETL-2021/2865) [195]. The reference plant captures 13,430 kg CO₂/h, equivalent to approximately 100,000 tonnes of CO₂ per year at an 85% capacity factor. The modeled nameplate capacity is therefore set to 13.43 tCO₂/h. The 85%

capacity factor is used only to convert the reported hourly capacity into an annual production; MACRO determines the actual utilization of the asset endogenously.

NETL reports a total auxiliary electricity requirement of approximately 50 MW, with the DAC air fans and electric boiler accounting for most of the demand. Dividing this load by the nameplate capture capacity gives an electricity-consumption coefficient of 3.72 MWh/tCO₂.

The reference plant has a total plant cost of approximately \$140.57 million in 2019 dollars. After escalation to 2025 dollars using the Chemical Engineering Plant Cost Index and normalization by the 13.43 tCO₂/h nameplate capacity, the MACRO investment cost is approximately \$13.92 million per tCO₂/h of installed capacity.

Annual fixed O&M costs are reported as approximately \$8.53 million in 2019 dollars. Applying the same cost escalation to 2025 dollars and normalizing by nameplate capacity gives a fixed O&M cost of approximately \$844,850 per (tCO₂/h)-year.

NETL reports total annual variable O&M costs of approximately \$24.50 million at an 85% capacity factor, including approximately \$22.32 million for purchased electricity. Because electricity consumption is modeled explicitly and its cost is determined endogenously in MACRO, the purchased-electricity cost is excluded to avoid double counting. The remaining non-electric variable costs are approximately \$21.83/tCO₂ in 2019 dollars, or approximately \$27.49/tCO₂ in 2025 dollars after CPI adjustment. A plant physical lifetime of 20 years is assumed for retirement tracking in MACRO.

For the user-selected pace of energy-supply technology innovation, the slower innovation option includes no cost or performance improvements from the initial ones. For the mid-range and fast innovation options, the capital cost is assumed to decrease (linearly) by 25% and 50% by 2050, respectively.

Because electric DAC has not achieved meaningful commercial-scale deployment within the modeled energy system, its existing capacity in the base year is set to zero. All DAC capacity appearing in the model results must therefore be newly constructed.

CO₂ storage

Geological storage of CO₂ consists of injecting the fluid into subsurface formations able to receive and retain it securely over long periods. Suitability depends on the combination of a reservoir unit with sufficient porosity and permeability and one or more sealing units able to restrict vertical migration. Beyond capacity, a site must also be assessed for injectivity and containment [196, 197, 198].

The first version of NZB represents only deep saline formations: porous and permeable rocks saturated with brine and overlain by low-permeability units, which are widely distributed and globally account for the largest share of storage resources. Formations deeper than 800 m are prioritized, as keeping pressure above the critical pressure for CO₂ (73.8 bar) will ensure that CO₂ is in a dense phase. Dense-phase CO₂ results in a more efficient use of pore space, while also reducing buoyant forces on the developing CO₂ plume [196, 198, 199].

Oil and gas reservoirs, depleted or still producing, were excluded as a matter of scope rather than of merit: representing them, particularly in association with CO₂-enhanced oil recovery (EOR), would require coupling CO₂ storage to the temporal dynamics of hydrocarbon production and to economic variables, such as field maturity, production and reinjection rates, revenues from incremental oil,

market conditions and life-cycle emissions, that are not described at the necessary level of detail in this version of the energy supply optimization model [iea2015, 198].

Brazil has 72 recognized sedimentary basins, 55 onshore and 17 offshore. The *Atlas of Carbon Capture, Utilization and Storage: Exploring the Potential of Brazil* assessed eight of them for storage in saline formations (Paraná, São Francisco, Campos, Santos, Potiguar, Ceará, Sergipe-Alagoas and Recôncavo) selected on the basis of the availability, volume and quality of existing geological data and of the results of the Storage Resources Management System classification, and estimated their combined capacity at approximately 2,000 GtCO₂ [199]. Neither that selection nor that figure should be read as exhaustive: saline reservoirs are more widely distributed than depleted oil and gas reservoirs but generally less characterised, since the historical acquisition of subsurface data was directed mainly at hydrocarbon exploration and production.

NZB extends the coverage to ten basins by adding Espírito Santo and Parecis. These basins are also included in the aforementioned Atlas [199], but we have chosen to evaluate them independently because public exploratory well data are available for them. Notably, there has been geological characterisation work including seismic acquisition, and preparation of a CO₂ injection system in the region done in connection with a BECCS project associated with ethanol production in Lucas do Rio Verde [200]. A hybrid approach was adopted. For the five fully onshore basins (Paraná, Parecis, São Francisco, Espírito Santo and Recôncavo), capacity and cost were estimated in this study from public well data and a simplified spatial characterization model. For the five fully or partly offshore basins (Ceará, Sergipe-Alagoas, Potiguar, Campos and Santos), the storage potentials reported by [199] were used directly. The two sets of results were produced by different procedures and from different levels of information, which limits their comparability, but reflects inherent uncertainties in estimating potentials.

For the onshore basins, candidate intervals were identified from well logs, using the formations reported in the Atlas as an initial set of alternatives where available. Intervals were retained only if they simultaneously satisfied four exclusion criteria: (a) a lithology with reservoir potential, predominantly sandstone; (b) occurrence between 800 and 3,500m depth; (c) a shale layer immediately above the reservoir interval, with an apparent thickness of at least 10 m; and (d) sufficient information to identify the formation and determine the depths of its top and base. The lower depth limit follows the widely used reference for dense or supercritical CO₂; the upper limit of 3,500 m is a methodological boundary of this study rather than a physical limit.

Where more than one formation met the criteria in a basin, a single formation was selected as the most prospective candidate, selecting for data quality, size of the potential storage resource, and shallower depths. The exception to this rule is the São Francisco Basin, where two formations were retained because they covered largely non-overlapping parts of the basin. We note that selecting the best prospect excludes the resources associated with the remaining formations and therefore under-represents the potential storage capacity - if modeling results indicate that the best prospect is reaching its capacity limit, additional formations may be included.

The subsurface data came exclusively from the public well records made available by the Brazilian National Agency for Petroleum, Natural Gas and Biofuels (ANP) through the REATE programme [201], considering the data available up to May 2026. Wells were pre-selected in a GIS environment by overlaying the ANP drilled-well shapefile on the saline formation occurrence areas mapped by Melo

et al. [199] and retaining those whose surface coordinates fell within those areas. Sampling intensity varied with data availability: in the Parecis Basin, where public documentation is scarce, all available wells in the area of interest were examined, whereas in the Espírito Santo and Recôncavo basins, where dense well clusters occur, a spatially representative subset was selected on the assumption that closely spaced wells provide partly redundant stratigraphic information at a regional scale. Wells in operation for oil and gas production or water injection were excluded. Approximately 300 logs were examined and 134 were retained.

For each pre-selected well, the composite log and, where available, the geological monitoring log (PAG) were consulted; where both existed, the PAG prevailed. Formations and their upper and lower limits were identified by visual inspection, considering jointly the nominal formation indications, the stratigraphic sections and the lithological descriptions. Wells whose documents did not allow the formation or its limits to be determined consistently were excluded. For each retained interval, the well identification, basin, wellhead coordinates, formation, top and base depths, interpreted thickness, and the presence and apparent thickness of the overlying seal were recorded. Thickness was computed as the difference between base and top depths; where a formation appeared split by an interbed thinner than 2m, the intervals were treated as continuous, so the resulting values are interpreted gross thicknesses and may include thin non-reservoir interbeds. For directional wells, the vertical depths indicated in the logs were used, but the formation was located at the wellhead coordinates, assuming that the horizontal displacement does not significantly affect a regional-scale characterization.

Because the well data are spatially sparse and irregular, the interpreted geometry was interpolated into continuous surfaces using a workflow developed in Python. The inputs were a table with the interpreted top and base depths and thickness per well, a vector file with the wellhead locations, and two polygons representing the spatial extents assumed for the lower and higher occurrence scenarios of the formation. All data were reprojected to SIRGAS 2000 / Brazil Polyconic (EPSG:5880). Interpolation was performed on a regular grid with a horizontal resolution of 2km in both directions, built over the union of the two scenario polygons so that a single set of interpolated surfaces serves both. Top depth and thickness were interpolated separately by ordinary kriging, as implemented in the PyKriging library. Base depth was obtained as the sum of top depth and thickness rather than interpolated independently. Nodes with null or negative interpolated thickness were discarded as geometrically invalid, and only nodes satisfying both $z_{\text{top}} \geq 800 \text{ m}$ and $z_{\text{base}} \leq 3,500 \text{ m}$ were retained, which excludes outcrop areas and shallower portions even where the geological occurrence of the formation is recognized. This procedure is a simplified geostatistical model, not a dynamic reservoir simulation: it does not represent multiphase flow, pressure evolution, CO_2 saturation or well interference. Results were exported as GeoPackage and shapefile.

Porosity is one of the main parameters of the volumetric estimate, and ideally its spatial distribution would come from petrophysical and laboratory analyses of the reservoir intervals themselves. As public porosity data cover only a limited fraction of the formations considered, an empirical porosity-depth relationship was used instead, calibrated with published data for sandstones of the Rio Bonito Formation (Paraná Basin) and the Mucuri Member (onshore Espírito Santo Basin), compiled from [202] and [203]. The calibration set comprises 84 independent wells, 43 for Rio Bonito and 41 for Mucuri.

The variation of porosity with depth was represented by Athy's law (52). The equation captures the general reduction of porosity with depth but does not explicitly describe cementation, dissolution,

recrystallisation, thermal history, geological age, mineralogical composition or maximum burial depth [204, 205, 206].

$$\phi(z) = \phi_0 e^{-cz}, \quad (52)$$

where $\phi(z)$ is the porosity at depth z , ϕ_0 the porosity extrapolated to the surface and c an empirical compaction coefficient.

Each published porosity value was taken as representative of the sandstone at the mean depth of the corresponding interval, and the parameters were calibrated by non-linear least squares with physical bounds (ϕ_0 between 0.1 and 0.6; c between 10^{-5} and $3 \times 10^{-3} \text{ m}^{-1}$), producing three parameter sets: one for each calibrated basin and a global fit over the complete dataset (Figure 77). The basin-specific curves were applied to the Paraná and Espírito Santo basins and the global fit to Parecis, São Francisco and Recôncavo, which assumes that the mean compaction trend of the Rio Bonito and Mucuri sandstones is a reasonable approximation for the other formations.

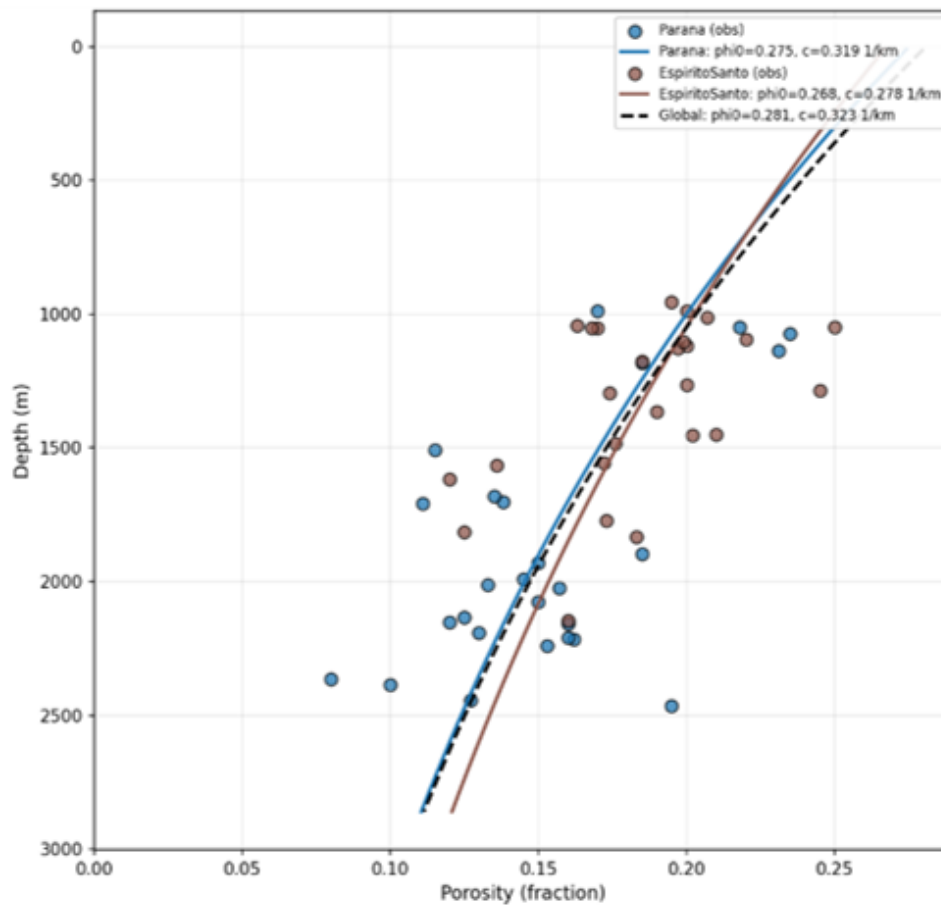


Figure 77: *Athy's law calibrated per basin (sandstones, onshore saline aquifers, Brazil).*

Storage capacity was then estimated by a regional volumetric approach based on the methodology used by the U.S. Department of Energy for saline formations [goodman2011]. For each cell i and spatial extent scenario s , the storable CO_2 mass is

$$M_{i,s} = A_{i,s} h_i \phi_i \rho_{\text{CO}_2,i} E, \quad (53)$$

where $A_{i,s}$ is the cell area within the scenario polygon [m^2], h_i the formation thickness [m], ϕ_i the

porosity, $\rho_{\text{CO}_2,i}$ the CO₂ density at reservoir conditions [kg/m³] and E the aggregate storage efficiency factor. E is the fraction of total reservoir pore volume that will be occupied by CO₂, accounting for every applicable kind of sweep ratio and displacement efficiency **goodman2011**. The total capacity of each formation is the sum over valid cells. The Lower and Higher scenarios use the same interpolated surfaces, the same porosity curves and the same efficiency factor, and differ exclusively in the area assumed for the occurrence of the formation.

CO₂ density was evaluated at the pressure and temperature corresponding to the mean depth z_m of each cell,

$$T_i = T_0 + G_T z_{m,i}, \quad P_i = P_0 + G_P z_{m,i}, \quad (54)$$

with $T_0 = 25^\circ\text{C}$, $P_0 = 0.101325\text{ MPa}$, $G_T = 25^\circ\text{C/km}$ and $G_P = 10\text{ MPa/km}$ adopted uniformly for all basins as regional approximations. Densities were computed with the **span1996** equation of state as implemented in CoolProp **[bell2014]**.

Before estimating the storage efficiency factor E , it is important to characterize the lateral boundary conditions for the system. Volumetric capacity estimates tend to either assume an aquifer of infinite lateral extent (which can be valid for individual projects in large aquifers) or posit the existence of brine production wells that extract the volumetric equivalent of the injected CO₂. Both formulations describe an 'open system', a key characteristic of which is that injection can in principle continue indefinitely as more brine is displaced from the reservoir. Storage efficiency for open systems depends largely on the geometry of the CO₂ plume and can vary substantially based on the specifics of a project: values have been reported between 0.8-6.0% (**goodman2011** and references therein).

By contrast, injection into a 'closed system' (i.e., a finite reservoir bounded by no-flow boundaries,) inevitably leads to pressure buildup, as CO₂ can only be accommodated by compression of the resident brine and corresponding expansion of the pore space. Because pressure must remain below some predetermined safe operating limit, P_{SOL} , there is a maximum allowable pressure increase $\Delta P_{\text{max}} = P_{\text{SOL}} - P_{\text{init}}$ that puts an upper bound on storage capacity for closed systems. Expressed as the storage efficiency factor, it quantifies the relative increase in pore volume that results from elastic deformation of the rock and brine under conditions of the maximum allowable increase in fluid pressure: $E = \Delta P_{\text{max}} (c_b + c_f)$, where c_b and c_f are the compressibility of brine and pore volume, respectively [207]. P_{SOL} is generally constrained by the requirement to stay below the fracture pressure, for which $P_{\text{frac}} = 1.5 \cdot P_{\text{init}}$ provides a reasonable first-order estimate. Setting $P_{\text{SOL}} = 0.9 \cdot P_{\text{frac}}$, the maximum pressure increase is $\Delta P_{\text{max}} = 0.35 \cdot P_{\text{init}}$, which increases linearly with depth. Brine compressibility c_b ranges from about $3 \cdot 10^{-10}$ to $6 \cdot 10^{-10} \text{ Pa}^{-1}$. Pore volume compressibility c_f can range from $4 \cdot 10^{-10} \text{ Pa}^{-1}$ for stiff, well-cemented rocks in deep basins up to $5 \cdot 10^{-9} \text{ Pa}^{-1}$ for shallow, unconsolidated sands [208, 209, 210]. As the trends in ΔP_{max} and c_f counteract each other, storage efficiency for pressure-constrained systems is generally between 0.1 – 1.0% [210, 207]. For the present case, where we consider deep decarbonization scenarios with full development of basin-scale CO₂ storage resources, a closed system is the more appropriate description. We estimate the storage efficiency factor $E = 0.5\%$

For the Ceará, Sergipe-Alagoas, Potiguar, Campos and Santos basins, the cell-by-cell procedure was not applied: the published P50 capacity of Melo et al. [199] was adopted as the Higher scenario and 50% of that value as the Lower scenario, a sensitivity assumption adopted in NZB to represent a smaller extent or availability of the resource, with the same 0.5% coefficient applied to both. The

same 50% reduction was applied to the Lower scenario of the Espírito Santo Basin: its small onshore area combined with a high density of wells resulted in identical spatial extents for the two scenarios, so the sensitivity had to be imposed on the capacity rather than on the polygon.

For representation in MACRO, the cumulative capacity of each formation was distributed over an assumed operational life of 50 years, giving an annualized rate consistent with full use of the cumulative capacity over that horizon. Capacity not used in a given year does not raise the annual limit of subsequent years, while the cumulative constraint prevents the total stored mass from exceeding the estimated capacity of the formation. Since MACRO performs a cost optimization, available capacity is not necessarily used: resources with relatively high costs may remain partly or entirely idle. The number of wells was estimated from a nominal rate of 0.8 MtCO₂/year per well, and where the annualized rate is below that value a single well was assumed, in which case the effective injection period may be shorter than 50 years, ending when the cumulative capacity of the formation is reached.

Storage costs were estimated from the cost curves published by Tamburini and Walter [203], which report the CO₂ break-even price (BEP), treated here as the levelized cost of storage, for seven saline aquifer reservoirs in southeastern Brazil (P1 to P7). In the original work, the BEP of each reservoir was estimated by multiple linear regression on the reservoir characteristics that most influence cost [197] (thickness, porosity and mean depth) and expressed as a function of the annual CO₂ injection rate in 2018 US dollars. Each reference curve takes the form of (55). The equation parameters and the corresponding reservoir characteristics are indicated in Table 52.

$$\text{BEP}(Q) = A + \frac{B}{Q}, \quad (55)$$

where Q is the annual injection rate [MtCO₂/year], A [US\$/tCO₂] is the asymptotic cost at high injection rates and B captures the economy-of-scale effect.

Table 52: Reference reservoirs and cost curve parameters. Costs in US\$₂₀₁₈. Source: [203]

Parameter	P1	P2	P3	P4	P5	P6	P7
Thickness [m]	42	76	86	49	44	50	25
Porosity [%]	15	18	18	11	15	16	15
Depth [m]	1,469	1,858	1,029	2,107	1,907	2,303	2,610
A [US\$/tCO ₂]	37.20	22.71	14.21	53.76	41.47	38.86	80.04
B	2.96	11.36	5.68	3.77	9.29	21.29	−3.41

Applying these curves requires associating each grid cell with one of the seven references. Given the small number of reference reservoirs, an analog approach was adopted: each cell receives the full parameter pair (A, B) of the most similar reference reservoir, similarity being measured as the Euclidean distance in the three-dimensional space of thickness, porosity and mean depth. A continuous cost surface fitted to the characteristics was tested and discarded for two reasons. First, although the asymptotic level A is well described by the three characteristics, the economy-of-scale term B is not, since it depends mainly on injectivity and on the number of wells required,

functions of permeability and capacity, which are not available in the dataset. Second, a continuous regression extrapolated beyond the calibration domain of the reference reservoirs produces non-physical estimates, including negative costs for cells of large thickness. The analog assignment, by construction, keeps the estimates within the cost range actually observed in the reference reservoirs.

The cost estimate was applied to the five onshore basins, using the same 2×2 km grid (EPSG:5880), which carries for each cell the mean reservoir depth, thickness, porosity, mean CO₂ density at reservoir conditions, pore volume and storage capacity. Both capacity scenarios were evaluated; in each, the capacity per cell was rescaled proportionally to the effective capacity obtained previously, preserving the relative spatial distribution of the storage potential. The levelized cost of each cell was represented as (56).

$$\text{BEP} = A_k + B_k/q_{\text{well}}, \quad (56)$$

where k is the analog reference reservoir and $q_{\text{well}} = 0.8 \text{ MtCO}_2/\text{year}$ is the injection rate per well, taken as the injection unit per site.

Sorting the cells by increasing BEP and accumulating their capacities yields, for each basin, a supply curve giving the marginal cost of storing the last unit injected as a function of the cumulative CO₂ stored, reflecting the preferential use of the most favorable portions of the reservoir before the more costly ones. A project life of 50 years was assumed, implying full use of the storage capacity within that horizon. Costs originally expressed in 2018 US dollars were updated to 2025 US dollars using the Chemical Engineering Plant Cost Index (CEPCI), with annual average values of 603.1 for 2018 and approximately 800 for 2025, a cumulative factor of about 1.3.

The basins and formations represented in NZB are listed in Table 53, and the resulting capacities, annualized injection rates and well counts in Table 54. The Paraná and São Francisco basins concentrate most of the estimated onshore capacity, while the onshore portion of the Espírito Santo Basin is the smallest among those assessed. The corresponding storage supply curves are shown in Figures 78 and 79 for the Lower and Higher scenarios.

Table 53: *Sedimentary basins and formations represented in NZB.*

Basin	Formation	Setting
Paraná	Rio Bonito	Onshore
Parecis	Fazenda Casa Branca	Onshore
São Francisco	Paranoá; Macaúbas	Onshore
Espírito Santo	Mucuri	Onshore
Recôncavo	Marfim	Onshore
Ceará	n/a	Offshore
Sergipe-Alagoas	n/a	Onshore/offshore
Potiguar	n/a	Onshore/offshore
Campos	n/a	Offshore
Santos	n/a	Offshore

Table 54: *Estimated storage capacity, annualized injection rate and number of wells, by scenario.*

Basin	Lower scenario			Higher scenario		
	Capacity	Annual	Wells	Capacity	Annual	Wells
	[MtCO ₂]	[MtCO ₂ /yr]		[MtCO ₂]	[MtCO ₂ /yr]	
Paraná	16,586	332	415	44,694	894	1,117
Parecis	4,464	89	111	13,789	276	344
São Francisco	5,397	108	135	29,195	584	729
Espírito Santo	104	2.1	3	208	4	5
Recôncavo	363	7	8	389	8	9
Ceará	17	0.3	1*	34	0.7	1*
Sergipe-Alagoas	35	0.7	1*	70	1.4	2*
Potiguar	22	0.4	1*	44	0.9	1
Campos	37	0.7	1	73	1.5	2*
Santos	1,878	38	47	3,755	75	93

* Total injection period shorter than 50 years.

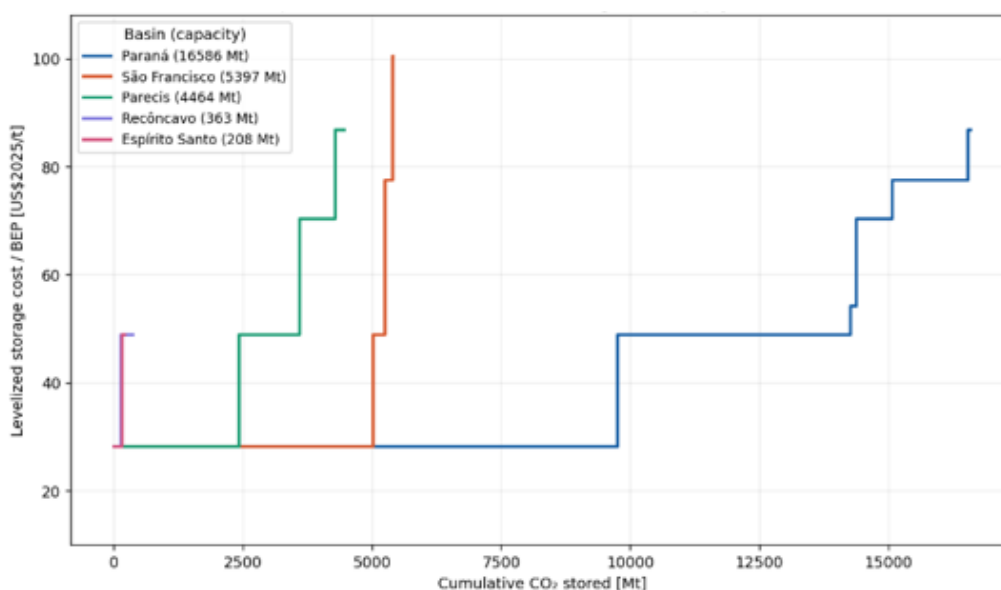


Figure 78: CO₂ storage supply curves by basin, Lower scenario.

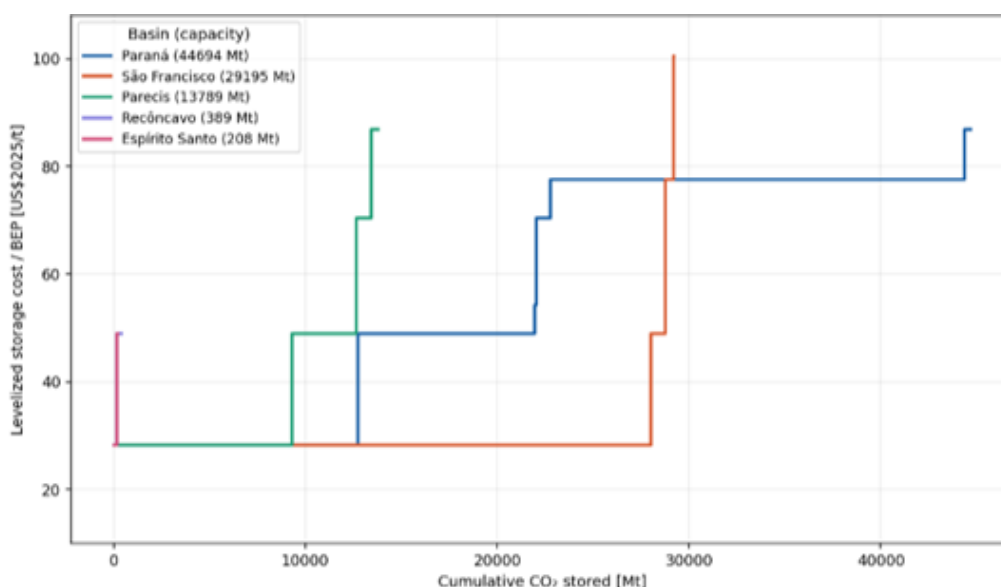


Figure 79: CO₂ storage supply curves by basin, Higher scenario.

The formations retained here should be read as candidate formations subjected to a regional screening, not as qualified or demonstrably viable injection sites. Good-practice guidance indicates that assessing a candidate formation should also cover porosity, permeability, pore pressure, salinity, reservoir continuity, seal characteristics and injectivity [211]; the NZB assessment corresponds to a stage prior to detailed site characterization, and real projects require three-dimensional geological models, dynamic flow and pressure simulations and geomechanical assessment [ieaghg2009, 116]. No optimized physical connection between emission sources and storage formations, and no pipeline routing, were carried out in this version.

The capacity estimate is particularly sensitive to the spatial extent assumed for the formation, the interpolated thickness, the porosity curve, the CO₂ density and the aggregate efficiency factor.

Permeability, injectivity, compartmentalization, faults, seal continuity, hydraulic connectivity, fracture pressure and well interference are not explicitly considered, so a formation with high volumetric capacity may not be able to accept the calculated mass at the rates required by the energy system. Lithological heterogeneity remains represented only through the aggregate efficiency factor. The porosity relationship rests on a limited calibration dataset that does not cover the full range of reservoir characteristics, and is extrapolated to three basins for which no equivalent porosity data were available. Because the offshore basins take capacities directly from Melo et al. [199] while the onshore basins were estimated here, values across the two groups are not strictly comparable.

The cost estimates carry three further limitations. First, cell costs take discrete values, since the analog assignment restricts the possible parameters to the seven (A , B) pairs of the reference reservoirs. Second, the analyzed basins span characteristics beyond the calibration domain of those curves, which cover thicknesses of 25 to 86 m and depths of 1,029 to 2,610 m: cells thicker than 200 m and deeper than 3,000 m, present mainly in the Paraná and São Francisco basins, therefore receive costs obtained by analogy with substantially different reservoirs, increasing the uncertainty in those portions. Third, the estimate is sensitive to the injection rate assumed per site; at rates above 0.8 MtCO₂/year per well, costs converge towards the asymptotic values A , which are lower than those reported here.

CO₂ transport In this first version, CO₂ transport is represented as a set of fixed source-region - sink-basin connections, each characterized by a representative pipeline length and a levelized transport cost per tonne of CO₂. The representation is deliberately simplified: it is intended to give the model a first-order, spatially differentiated cost of moving captured CO₂ from where it is generated to where it can be stored, rather than to describe an actual pipeline network.

Twenty-seven state–basin pairs are defined in the current version of the model, with each state connected to one of nine sedimentary basins considered available for geological storage (Parecis, Potiguar, Ceará, Sergipe-Alagoas, Recôncavo, São Francisco, Espírito Santo, Paraná, and Campos). No connection is included to the Santos basin in this version of the model.). A storage basin can receive CO₂ from multiple states. The pairing follows the areas of influence of each basin reported in the Atlas of Carbon Capture, Utilization and Storage: Exploring the Potential of Brazil [199].

Two dimensions define the pipeline in this version: length and throughput. Because no route optimization or georeferenced trajectory was carried out at this stage, transport distances were assigned by inspection of the areas of influence mapped in [199] and rounded to representative values of 100, 200, 300 or 900 km. Four criteria were used:

- 100 km where most of the emission sources of the region already lie inside the area of influence of the basin, so that only a short connection is needed. The same value was adopted for the CW–Parecis pair, which reflects the area of influence of the ethanol plants in that region;
- approximately half the extent of the basin where the sources are distributed along it, which is the case of the connections to the Espírito Santo Basin (100 km);
- 200 and 300 km for regions whose sources are, on average, outside but adjacent to the area of influence of the basin;
- 900 km for the N–Parecis pair, corresponding to the approximate distance between Manaus, the main emission cluster of the region, and the point of greatest storage capacity in the basin.

Pipeline diameter, wall thickness and the associated capital and operating costs are computed internally by the FECM/NETL CO₂ Transport Cost Model, version 5.0 [212]. For each of the four representative distances, the model was therefore run for a range of annual throughputs, from 0.8 to 8.0 MtCO₂/year in steps of 0.8 MtCO₂/year. One pumping station every 150 km was assumed. Differences in topographic elevation along the route were not considered.

Costs were estimated with the FECM/NETL CO₂ Transport Cost Model (v5.0) [212], which builds a full capital and operating cost estimate for an onshore CO₂ pipeline from the length, the design flow rate and the number of pumping stations. The reported parameter is the levelized cost of CO₂ transport, i.e. the tariff, in constant 2025 US dollars per tonne of CO₂, that makes the net present value of the pipeline investment equal to zero over the capital recovery period. The financial parameters adopted are the same as in [203]. A technical lifetime of 50 years was assumed for the pipeline.

The resulting levelized costs are strongly dependent on the annual volume transported, as shown in Figure 80. Below roughly 2.5 MtCO₂/year the curves rise steeply for every distance, because the fixed components of the investment - rights of way, construction, and the pumping stations themselves - are spread over a small tonnage; above that threshold the curves flatten, and the remaining decline with scale is comparatively modest. The curves are not perfectly monotonic, since the FECM/NETL model selects pipeline diameters and pumping capacities from discrete commercial classes, so each transition to a larger class produces a small local increase in unit cost before economies of scale resume. This effect is visible around 4.0 and 7.2 MtCO₂/year.

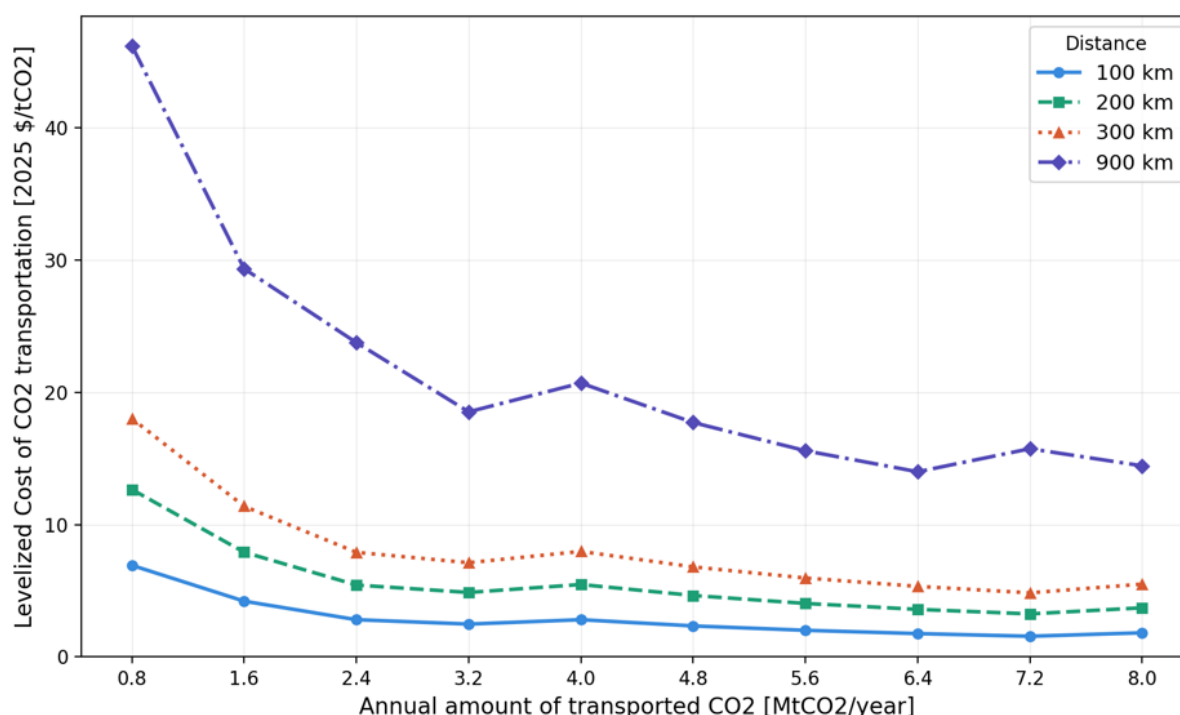


Figure 80: Levelized cost of CO₂ transport as a function of annual transported volume, for the four representative pipeline lengths adopted.

Because MACRO represents CO₂ transport as a constant cost per tonne, a single point of these curves had to be selected. A design throughput of 4 MtCO₂/year was adopted for all connections. This value lies in the flat part of the curves, beyond the steep region where the result would be highly

sensitive to the assumed volume. It is compatible with the scale of a single large capture project and with the CO₂ flows expected in the first NZB scenarios. Also, because it sits at a local maximum produced by the diameter-class transition, it is mildly conservative with respect to neighbouring throughputs. The values are applied to all six model periods (2025–2050) and to the three innovation scenarios (slower, mid-range and faster), since CO₂ pipelines are a mature technology.

3.2.4 Technology availabilities

Because the energy-supply technologies and infrastructure described in the above sections vary with respect to their stage of commercial advancement, we assign different years when each technology is first available in the model as a deployment option. All technologies and infrastructure described above are available for deployment in the initial modeling year (2025), with the following exceptions:

- Any fossil-fuel or biomass conversion technology that includes CO₂ capture cannot be deployed before 2035, except for 1G sugarcane ethanol production with CO₂ capture, which is available to be selected for deployment starting in 2030.
- No 2G ethanol capacity (without or with CO₂ capture) may be deployed before 2030.
- Ethanol-to-jet capacity may not be deployed before 2030.
- Any technology that includes biomass gasification may not be deployed before 2035.
- Electrolytic hydrogen production may not be deployed before 2030.
- Direct air capture of CO₂ and technologies for synthesizing liquid fuels or methane from inputs of H₂ and CO₂ are inactive in the current version of the NZB model. These will be included in a future version of the model.

3.3 Waste modeling

This section presents the Waste Tool in detail, specifying its modules, the equations used, and the outputs obtained. To facilitate understanding of the methods applied, the sector is initially divided into solid waste and wastewater. The former presents the routes and methods used to project emissions related to the following subsectors: (i) Solid Waste Disposal Sites (SWDS) — emissions related to the disposal of municipal solid waste in sanitary landfills, controlled landfills, and open dumps; (ii) Biological Treatment — emissions related to the organic waste treated through anaerobic digestion and composting; (iii) Thermal Treatment — emissions related to municipal solid waste and clinical waste treated through incineration.

For wastewater, the following subsectors are discussed: (i) domestic wastewater — emissions related to the treatment of wastewater, whether collected or uncollected, from households; and (ii) industrial wastewater — emissions related to the treatment of wastewater from industrial activities with high potential for organic load generation.

It should be noted that IPCC and national inventory methodologies were reproduced, using as reference the GWP values presented in the IPCC Fifth Assessment Report (AR5).

3.3.1 Solid waste

The solid waste module projects the amount of waste generated, collected, and directed to each treatment or disposal pathway (recycling, solid waste disposal sites (SWDS), biological treatment, incineration, and uncollected/open-burned waste) at the state level (Figure 81).

Solid Waste

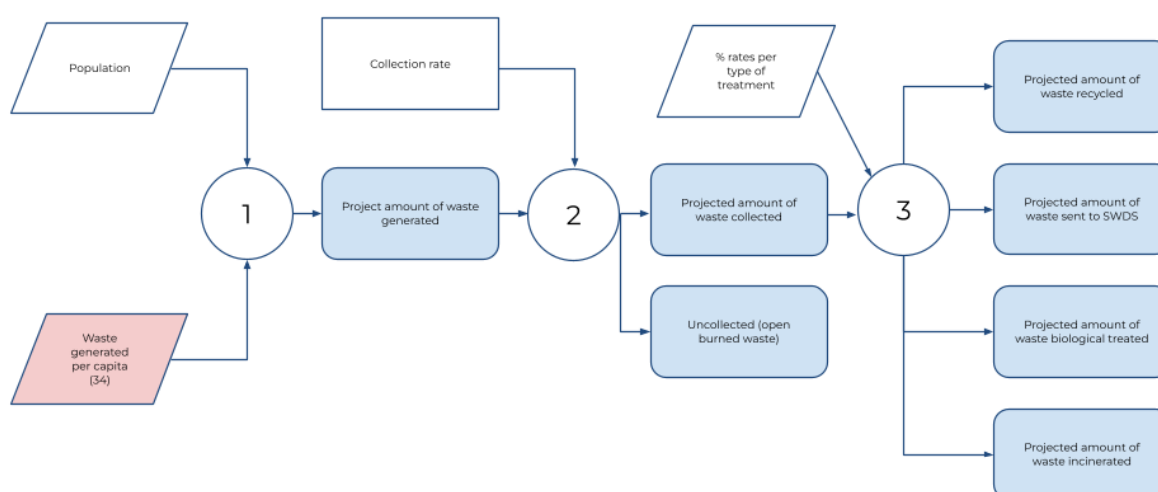


Figure 81: Solid Waste Module

Inputs

Population data are obtained from the Instituto Brasileiro de Geografia e Estatística (IBGE) [213].

Waste generated per capita is a user-defined input variable, allowing scenario-specific assumptions on generation intensity. Collection rate is a modeling parameter representing the share of generated waste that is formally collected. Shares of waste directed to each treatment type (recycling, SWDS, biological treatment, incineration) are modeling parameters derived from state-level historical data and projections based on national policies, international benchmarking and experts' opinions.

Sources

Historical waste generation, collection data, and amounts sent to managed or unmanaged disposal sites are based on the Sistema Nacional de Informações sobre Saneamento (SINISA) [214] and the Diagnóstico dos Serviços de Limpeza Urbana e Manejo de Resíduos Sólidos [215]. Waste diversion targets and treatment-type shares are informed by the Plano Nacional de Resíduos Sólidos (PLANARES) and the Plano Nacional de Redução e Reciclagem de Resíduos Orgânicos Urbanos (PLANARO), both from the Ministério do Meio Ambiente [216, 217]. International benchmarking references include the Global Waste Management Outlook 2024 [218].

Operations

The module performs three sequential calculation steps:

- Population is multiplied by the user-defined waste generation rate per capita to project the total amount of waste generated.
- The projected amount of waste generated is multiplied by the collection rate to estimate the amount of waste collected, with the remaining share assumed to be uncollected (open-burned) waste.
- The projected amount of waste collected is multiplied by waste diversion rates (recycling, composting, anaerobic digestion, and other treatment types) to allocate collected waste across treatment pathways.

Outputs

The solid waste module produces, at the state level, the projected amount of waste recycled, the projected amount of waste sent to SWDS (solid waste disposal sites), the projected amount of waste biologically treated, and the projected amount of waste incinerated. These outputs feed directly into the SWDS, biological treatment, and thermal treatment modules described in the following subsections.

3.3.1.1 Solid waste disposal sites

The disposition of the total amount of collected waste directed to final disposal presented in the previous module is determined in the Solid waste disposal site module of the waste tool (Figure 82).

Solid Waste Disposal Sites (SWDS)

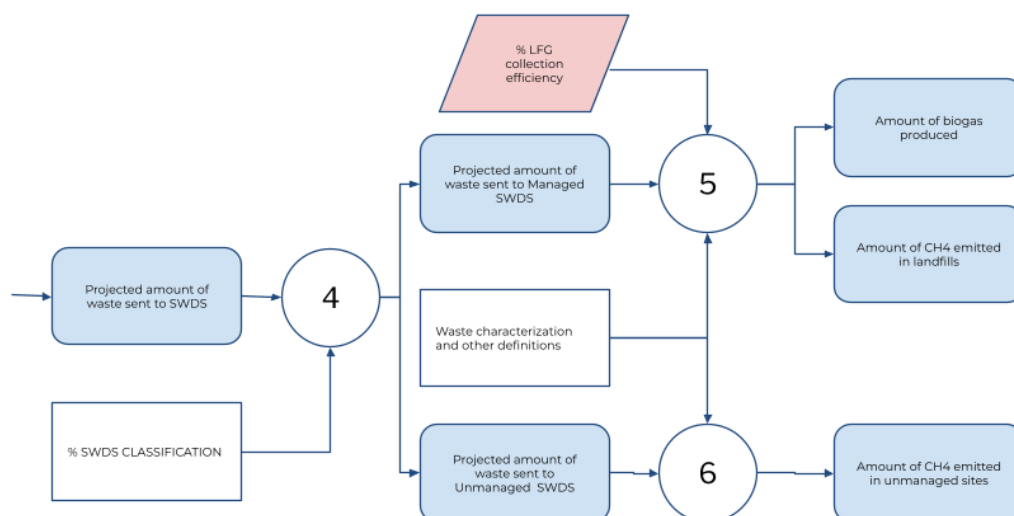


Figure 82: SWDS Module

First, the fractions of solid waste directed to sanitary landfills (managed sites), considered environmentally adequate under the Política Nacional de Resíduos Sólidos (PNRS) [219], and to controlled landfills and open dumps (unmanaged sites) are determined, since different treatment methods are associated with distinct methane correction factors and emission factors. These fractions are determined based on data obtained in IBGE census years, historical and recent series reported by SINISA [220], as well as linear interpolation for years without available information.

The second step of the process consists of applying the First Order Decay (FOD) equation, as described in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5 (Waste), Chapter 3 [221]. This method assumes that the degradable organic component of waste decomposes gradually over several decades.

CH₄ emissions from SWDS

The equations used to calculate methane (CH₄) emissions from the disposal sites sector follow the IPCC technical guidelines. The equation used to estimate methane emissions for a given year is described below:

$$CH_4 \text{ Emissions} = \left[\sum_x CH_4 \text{ generated}_{x,T} - R_T \right] \times (1 - OX_T) \quad (57)$$

Where:

- CH_4 Emissions: methane emitted in year T (tonnes);
- T : inventory year;
- x : waste category or disposal type;

- R_T : methane recovered in year T (tonnes);
- OX_T : oxidation factor in year T (fraction).

Methane generation (FOD method)

The FOD model is based on an exponential factor that describes the fraction of degradable carbon that is effectively decomposed in a given year. For this purpose, the amount of decomposable degradable organic carbon (DDOCm) deposited is quantified, along with the amount of accumulated organic matter, according to the equations below.

The mass of decomposable DOC deposited is calculated as follows:

$$DDOCm = W \times DOC \times DOCf \times MCF \quad (58)$$

Where:

- $DDOCm$: mass of decomposable degradable organic carbon deposited (tonnes);
- W : mass of waste deposited (tonnes);
- DOC : degradable organic carbon in the year of disposal (fraction);
- $DOCf$: fraction of DOC that decomposes (fraction);
- MCF : methane correction factor (fraction).

Following the definition of the waste collection rate and the amount of decomposable degradable organic carbon (DDOCm), the accumulated organic fraction for a given year is obtained by applying the equation below:

$$DDOCma_T = DDOCmd_T + (DDOCma_{T-1} \times e^{-k}) \quad (59)$$

Where:

- T : inventory year;
- $DDOCma_T$: DDOCm accumulated in the SWDS at the end of year T (tonnes);
- $DDOCma_{T-1}$: DDOCm accumulated in the SWDS at the end of year (T-1) (tonnes);
- k : reaction constant, defined as $k = \ln(2)/t_{1/2}$, where $t_{1/2}$ is the half-life (years).

Since the amount of CH₄ generated is proportional to the amount of decomposable material, the year of disposal is not relevant to methane generation; what matters is the amount of material decomposing at the end of year T, determined by the equation below:

$$DDOCm_{\text{decomp}_T} = DDOCma_{T-1} \times (1 - e^{-k}) \quad (60)$$

Where:

- $DDOCm_{\text{decomp}_T}$: DDOCm decomposed in the SWDS at the end of year T;

- $DDOCm_{aT-1}$: DDOCm accumulated in the SWDS at the end of year (T-1);
- k : reaction constant.

Finally, the amount of CH_4 generated from decomposable material is obtained by multiplying the fraction of methane found in the biogas by the stoichiometric CH_4/C ratio, as shown in the equation below:

$$CH_4 \text{ generated}_T = DDOCm \text{ decomp}_T \times F \times \frac{16}{12} \quad (61)$$

Where:

- $CH_4 \text{ generated}_T$: amount of methane generated from decomposable material (tonnes);
- $DDOCm \text{ decomp}_T$: DDOCm decomposed in the SWDS at the end of year T (tonnes);
- F : fraction of methane in the volume of biogas (fraction);
- $16/12$: stoichiometric ratio (CH_4/C).

The variables related to gravimetric composition and the reaction constant k — associated with mean annual temperature (MAT), mean annual precipitation (MAP), and potential evapotranspiration (PET) — are based on the Quarto Inventário Nacional de Emissões e Remoções Antrópicas de Gases de Efeito Estufa [222] and obtained for each Brazilian state.

Regarding methane recovery, the amount of landfill gas currently recovered for energy or flared is based on projects registered under the UNFCCC Clean Development Mechanism (CDM) platform [223], while future recovery projections are based on national policy targets and maximum recovery potentials derived from EPA studies [224].

Outputs

The outputs of this module are the emissions estimates related to managed and unmanaged disposal, and the energy generation potential derived from landfill gas recovery.

3.3.1.2 Biological treatment

In the biological treatment module, the process for estimating emissions consists of understanding the different treatment routes adopted, namely: composting and anaerobic digestion, the former being the most commonly adopted route in Brazil.

Figure 83 shows the biological treatment module of the waste tool.

Biological Treatment

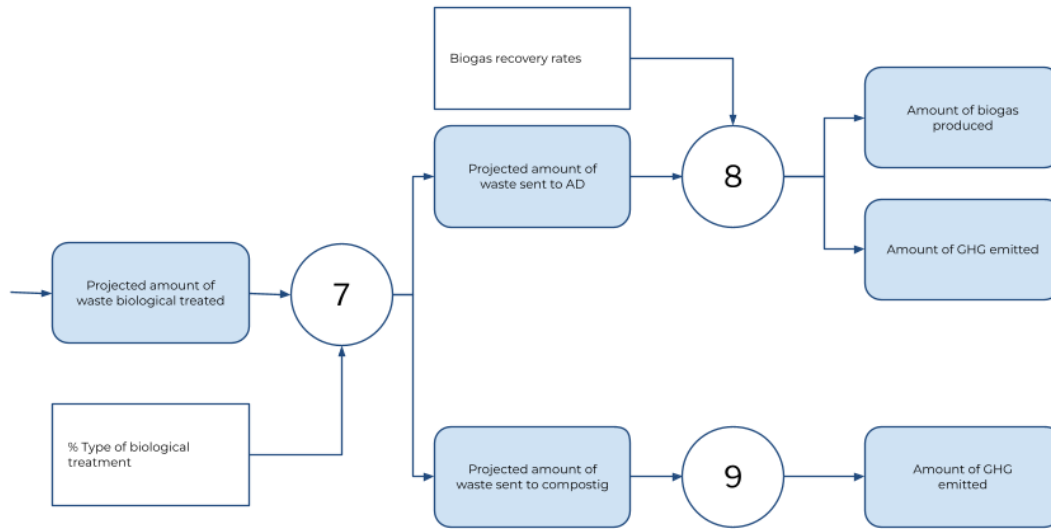


Figure 83: Biological treatment Module

From the total fraction directed to biological treatment, a share is applied to disaggregate the amount allocated to anaerobic digestion or composting. These shares are based on the targets defined in the PLANARES and PLANARO [216, 217], while historical data are based on information reported by SINISA [214].

CH_4 emissions from biological treatment are defined by the following equation:

$$CH_4 \text{ Emissions} = \left[\sum_i (M_i \times EF_i) \times 10^{-3} \right] - R \quad (62)$$

Where:

- CH_4 Emissions: amount of CH_4 generated per year (tonnes CH_4 /year);
- i : type of biological treatment (composting or anaerobic digestion);
- M_i : mass of organic waste treated by biological treatment type i (tonnes of waste);
- EF_i : emission factor for treatment type i (g CH_4 /kg waste treated);
- R : amount of methane recovered (tonnes CH_4).

N_2O emissions are estimated according to the following equation:

$$N_2O \text{ Emissions} = \sum_i M_i \times EF_i \times 10^{-3} \quad (63)$$

Where:

- N_2O Emissions: amount of nitrous oxide generated per year (t N_2O /year);

- i : type of biological treatment (composting or anaerobic digestion);
- M_i : mass of organic waste treated by biological treatment type i (tonnes of waste);
- EF_i : emission factor for treatment type i (kg N₂O/t waste treated);
- 10^{-3} : conversion factor from tonnes to kg.

Different emission factors are adopted for each treatment method, obtained both from the Quarto Inventário Nacional [222] and from the default values recommended by the IPCC 2006 Guidelines [225].

It should also be noted that anaerobic digestion presents a biogas recovery potential. This potential is estimated based on the IPCC 2006 methodology [225], which assumes that the biogas generated in anaerobic digestion facilities is recovered for energy use, with only a fraction of the methane generated being unintentionally emitted due to leakage during process disturbances or other unexpected events.

Outputs

The outputs of this module are the greenhouse gas emissions estimates by state, as well as the energy generation potential based on the use of biogas derived from anaerobic digestion.

3.3.1.3 Thermal treatment

The thermal treatment module (Figure 84) is based on three components. The first refers to the amount of domestic solid waste directed to incineration, a practice not currently adopted in Brazil; the second refers to the amount of clinical waste directed to this treatment route; and the third refers to the amount of uncollected domestic solid waste burned on-site (open burning).

Thermal Treatment

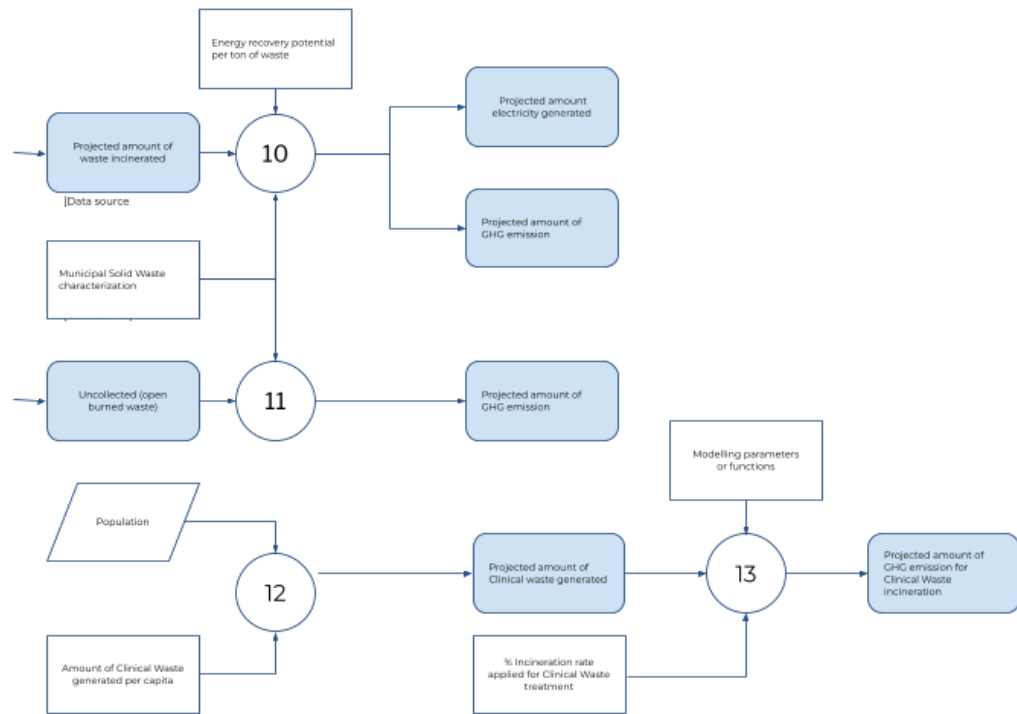


Figure 84: Thermal Treatment Module

Current data are obtained from information reported in the PNAD Contínua [226], in SINISA [214] and in the Quarto Inventário Nacional [222]. Estimates of energy recovery potential from thermal treatment routes are based on *Aproveitamento Energético de Resíduos Sólidos Urbanos no Brasil: Potencial de Descarbonização por Arranjo Tecnológico* [227] and on *Energy Recovery Technologies from Municipal Solid Waste: Enhancing Solid Waste Brazilian Policy* [228].

CO₂ emissions from the incineration and open burning are determined according to the following equation:

$$CO_2 \text{ Emissions} = \sum_i (SW_i \times dm_i \times CF_i \times FCF_i \times OF_i) \times \frac{44}{12} \quad (64)$$

Where:

- CO_2 Emissions: amount of CO₂ generated per year (tonnes CO₂/year);
- SW_i : total amount of waste of type i incinerated, on a wet weight basis (tonnes/year);
- dm_i : dry matter content in the waste incinerated (fraction);
- CF_i : fraction of carbon in the dry matter (total carbon content, fraction);
- FCF_i : fraction of fossil carbon in the total carbon (fraction);
- OF_i : oxidation factor (fraction);
- 44/12: conversion factor from C to CO₂ (dimensionless).

CH₄ and N₂O emissions from the incineration and open burning of solid waste are determined according to the following equations:

$$N_2O \text{ Emissions} = \sum_i IW_i \times EF_i \times 10^{-3} \quad (65)$$

Where:

- N_2O Emissions: amount of nitrous oxide generated per year (t N₂O/year);
- IW_i : mass of waste burned by type i (t/year);
- EF_i : emission factor for waste type i (kg N₂O/t waste);
- 10^{-3} : unit conversion factor (kg to t).

$$CH_4 \text{ Emissions} = \sum_i IW_i \times EF_i \times 10^{-3} \quad (66)$$

Where:

- CH_4 Emissions: amount of methane generated per year (t CH₄/year);
- IW_i : mass of waste burned by type i (t/year);
- EF_i : emission factor for waste type i (kg CH₄/t waste);
- 10^{-3} : unit conversion factor (kg to t).

Outputs

The outputs of this module are the greenhouse gas emissions estimates and the electricity generation potential from the incineration of domestic solid waste.

3.3.2 Wastewater treatment

Emissions from wastewater treatment are disaggregated into domestic and industrial wastewater, and are related to the degradation of organic matter and other components present in the effluent. As presented for solid waste, different treatment routes – or even the absence thereof – result in different emission factors within the calculation methods.

3.3.2.1 Domestic wastewater treatment

Figure 85 shows the domestic wastewater treatment module of the waste tool.

Domestic Wastewater Treatment

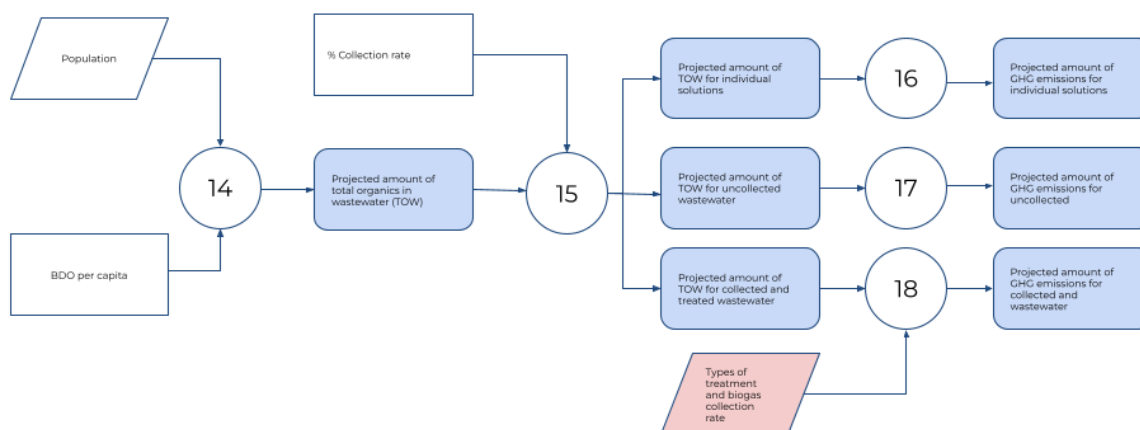


Figure 85: Domestic Wastewater Treatment Module

The first step in estimating GHG emissions from domestic wastewater treatment is to determine the total biochemical oxygen demand (BOD) present in the effluent. This is obtained by multiplying the population by the per capita BOD rate reported in the Quarto Inventário Nacional.

Based on this, the total collected BOD is estimated and allocated across the different treatment routes adopted in Brazil, disaggregating the information into individual solutions (commonly known as septic tanks), uncollected fraction, and the collected and treated fraction. For each of these routes, the equations below are applied to estimate GHG emissions.

Regarding input data, information from the Quarto Inventário Nacional [222] and IBGE population projections [213] are used, along with collection data reported in SINISA [214], national census [229], and data from the Atlas Esgotos of the Agência Nacional de Águas (ANA), used to define the treatment types most commonly adopted in Brazilian wastewater treatment plants (WWTPs) [230].

CH₄ emissions from the treatment and discharge of domestic wastewater are defined according to the following equation:

$$CH_4 \text{ Emissions} = (TOW_{dom} \times EF) - R \quad (67)$$

Where:

- CH₄ Emissions: amount of methane generated per year (kg CH₄/year);
- TOW_{dom}: total organic domestic effluent (kg BOD/year);
- EF: emission factor (kg CH₄/kg BOD);
- R: amount of CH₄ recovered per year (kg CH₄/year).

The total organic domestic effluent is estimated by the following equation:

$$TOW_{dom} = Pop \times D_{dom} - SI \quad (68)$$

Where:

- Pop : urban population (inhabitants);
- D_{dom} : degradable organic component of domestic effluent (kg BOD/ 1 inhabitants-year);
- SI : organic component removed as sludge in the inventory year (kg BOD/year).

The emission factor (EF) for domestic wastewater is determined according to the following equation:

$$EF = B_0 \times \sum (WS_{i,x} \times MCF_x) \quad (69)$$

Where:

- B_0 : maximum methane producing capacity (kg CH₄/kg BOD);
- $WS_{i,x}$: fraction of effluent of type i treated using system x (dimensionless);
- MCF_x : methane conversion factor of system x treating effluent i (dimensionless);
- $\sum (WS_{i,x} \times MCF_x)$: the sum of the product of the $WS_{i,x}$ and MCF_x coefficients corresponds to the weighted MCF.

N₂O emissions are quantified by applying the following equation:

$$N_2O \text{ Emissions} = Pop \times CP \times Frac_{NPR} \times EF_{effluent} \times \frac{44}{28} \quad (70)$$

Where:

- N_2O Emissions: annual nitrous oxide emissions (kg N₂O-N/year);
- Pop : urban population (inhabitants);
- CP : annual per capita protein consumption (kg/(inhabitant-year));
- $Frac_{NPR}$: fraction of nitrogen in protein (kg N/kg protein);
- $EF_{effluent}$: N₂O emission factor (kg N₂O-N/kg N);
- $44/28$: conversion factor from N₂O-N to N₂O.

Despite the biogas generation potential from treatment in anaerobic reactors, given the Brazilian context marked by the absence of consolidated information, this topic was not explored in the first version of the Waste Tool.

Outputs

The tool's outputs present the GHG emissions from wastewater treatment for each Brazilian state.

3.3.2.2 Industrial wastewater treatment

Figure 86 shows the industrial wastewater treatment module of the waste tool.

Industrial Wastewater Treatment

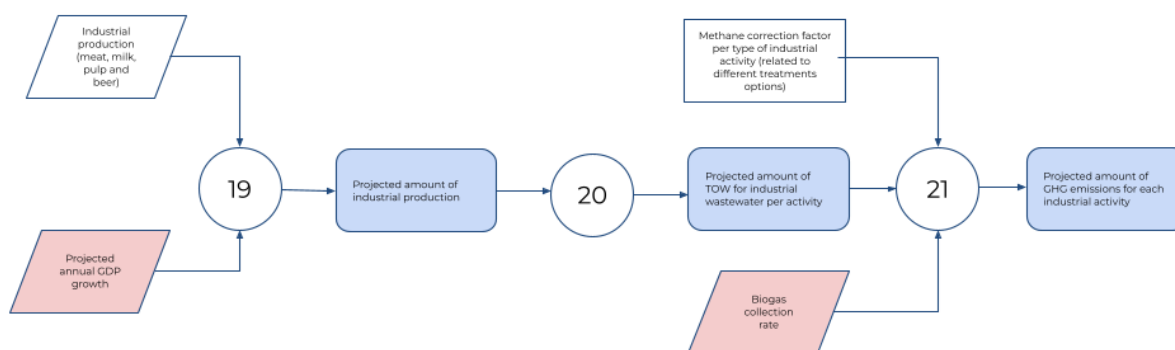


Figure 86: industrial Wastewater Treatment Module

To estimate emissions from the treatment of industrial wastewater, the same approach adopted in the Reference Report of the Waste Sector for the elaboration of the Quarto Inventário Nacional is reproduced [222]. This report identifies the following industrial activities as having the greatest potential for organic matter generation in effluents in Brazil: production of beef, pork, and poultry; production of raw and pasteurized milk; beer production; and pulp production.

Input data for these activities are obtained from industry associations, the Pesquisa Pecuária Municipal (PPM), and other IBGE surveys [231].

Emissions associated with the treatment of industrial wastewater are quantified in a manner similar to that presented in the domestic wastewater section. The difference lies in the quantification of the organic load, which for industrial wastewater is related to industrial production rates, as shown in the equation below.

$$TOW_{ind} = P_i \times D_{ind} \quad (71)$$

Where:

- P_i : industrial production (t product/year);
- D_{ind} : organic load emission rate (kg BOD/t product).

The emission factor (EF) for industrial wastewater is determined according to the following equation:

$$EF = B_0 \times \sum (WS_{i,x} \times MCF_x) \quad (72)$$

Where:

- B_0 : maximum methane producing capacity (kg CH₄/kg BOD or kg CH₄/kg COD);
- $WS_{i,x}$: fraction of effluent of type i treated using system x (dimensionless);
- MCF_x : methane correction factor of system x treating effluent i (dimensionless);
- $\sum (WS_{i,x} \times MCF_x)$: the sum of the product of the $WS_{i,x}$ and MCF_x coefficients corresponds to the weighted MCF.

The weighted MCF values for each industrial sector are taken from the Quarto Inventário Nacional for the years 1990 and 2016 [222]. Between 1990 and 2016, correction factor values were linearly interpolated; for periods without available information, MCF values were extrapolated. To estimate recovered methane (R), recovery values presented in the Quarto Inventário Nacional were adopted as a basis, from which the recovery MCF was defined for each industrial activity.

Outputs

The outputs of this module are the GHG emissions estimates from the treatment of industrial wastewater.

3.4 Land-use optimization and downscaling

This section describes and documents in more detail the methods underlying the three models used in the land-use change and agriculture sectors.

The land-use modeling workflow is organized into three complementary components. First, MAgPIE-Brazil simulates land use and agricultural production dynamics under different socioeconomic, policy, and climate assumptions, generating projections of land use, agricultural production, land use change, and associated emissions. Second, the AFOLU Accounting Tool (AAT) complements MAgPIE-Brazil by representing systems that are not explicitly simulated in the optimization model, including pasture condition dynamics, crop management systems, and carbon removals associated with protected areas. Finally, the third model, the Spatial Economic Allocation Landscape Simulator (SEALS), translates the coarse-resolution outputs of MAgPIE-Brazil into high-resolution spatially explicit land-use maps.

The following subsections describe the methodological approach, assumptions, and calculations implemented in each component of this workflow.

3.4.1 Land-use optimization (MAgPIE-Brazil)

In MAgPIE-Brazil, future food and commodity demand is driven by socioeconomic scenarios that specify population growth, income (GDP) development, and dietary transitions globally. The model calculates demand for food, feed, bioenergy, materials, and processed commodities in different world regions. Food demand evolves as populations grow and diets change, including shifts in calorie intake, consumption of animal products, fruits and vegetables, processed foods, and food waste. These demand components are integrated into the model's overall supply requirements for agricultural commodities.

MAgPIE-Brazil then estimates the agricultural production required to satisfy this demand at lowest global cost. Regional demand is translated into production requirements while accounting for international trade assumptions and existing trade patterns. Crop and livestock production are constrained by biophysical information supplied by the LPJmL vegetation model¹⁸, including potential crop yields, irrigation water availability, and land productivity. The model balances domestic production, imports, exports, processing requirements, feed demand, and other commodity uses to determine the production levels needed in each region. Livestock production is represented through production volumes and associated feed requirements, which determine the demand for pasture and feed crops within the optimization framework.

To translate production into land demand, MAgPIE-Brazil uses spatially explicit yield information. Required production quantities are divided by attainable yields to determine the cropland, pasture, and forestry area needed to meet demand and these potential yields are then calibrated to observed crop and pasture area as reported by FAOSTAT. Land-use categories represented in the model include cropland (rainfed and irrigated), pasture, forest, and other natural land. Because yields differ by location and management intensity, identical production targets can lead to different land requirements depending on local biophysical conditions and technological development.

¹⁸The model LPJmL ("Lund-Potsdam-Jena managed Land") is designed to simulate vegetation composition and distribution as well as stocks and land-atmosphere exchange flows of carbon and water, for both natural and agricultural ecosystems. The current version of LPJmL is published by [232]

The model subsequently optimizes land allocation across competing land uses using a cost-minimization framework. MAgPIE-Brazil is a global partial-equilibrium model whose objective is to satisfy regional and global demand at the lowest total cost while respecting constraints on land, water, trade, and production technologies. The optimization considers production costs, transport costs, land conversion costs, investments in technological change, agricultural intensification options, and regional competitiveness. Land is allocated among crops, livestock production, forestry, bioenergy production, and natural land according to the most cost-effective combination that fulfills demand.

Finally, MAgPIE-Brazil generates land-use change trajectories and estimates AFOLU (Agriculture, Forestry and Other Land Use) greenhouse gas emissions and removals over time. Operating recursively through time, the model projects how cropland, pasture, forests, and other land categories expand, contract, or shift geographically in response to changing economic and environmental conditions. By linking land-use dynamics with information on carbon densities, vegetation, and management practices, MAgPIE-Brazil quantifies emissions from land conversion, agricultural production, and other land-use activities, as well as carbon sequestration in forests and other ecosystems. This allows the model to assess long-term implications of alternative socioeconomic pathways, land-use policies, and climate mitigation strategies on AFOLU emissions and removals throughout the 21st century.

The NZB project uses a preliminary version of the upcoming MAgPIE-Brazil, a version of MAgPIE-Brazil calibrated to national statistics and land use patterns ([11]). As part of the MAgPIE-Brazil development, Brazil's initial land-use maps in MAgPIE-Brazil were reconstructed through a sequential, cell-level harmonization of national datasets ([14]). MapBiomass Collection 10 land-cover and secondary-vegetation classes are converted into LUH3-compatible categories¹⁹, with primary forest constrained to never increase over time and secondary forest redefined as the sum of planted forest and regrown secondary vegetation. Primary-forest carbon stocks from Brazil's 4th National Inventory ([234]) were then used to reclassify low-biomass Cerrado, Caatinga, Pantanal, and Pampa cells from primary to non-forested primary land. IBGE planted-area statistics replace LUH3 cropland estimates to correct national totals, and to allocate MapBiomass' "Mosaic of Uses" class to either pastures or cropland. Finally, irrigated and flooded areas were replaced by MapBiomass data and were capped by total cropland and distributed across the five LUH3 crop functional types. The result is a fully cell-balanced Brazilian land-use time series used to replace the default LUH3 data in MAgPIE-Brazil for Brazil [14].

Additionally, the MAgPIE-Brazil version used for this project includes a new feature that establishes a cap on emissions defined exogenously [235]. This change allows a user of the NZB modeling framework to choose a target emission level for the AFOLU sector for the year that Brazil reaches net-zero emissions in aggregate, and this then sets the target emissions that the energy/industrial sector would need to meet – same magnitude but opposite sign to the AFOLU sector target. The implementation of the emissions cap is described in detail in Section 3.4.1.2.

3.4.1.1 MAgPIE-Brazil modules and implementation in NZB

MAgPIE-Brazil is organized into a modular architecture in which individual modules represent specific components of the land-use system. This structure allows alternative process representations and model configurations to be combined within a common scenario framework.

¹⁹Land-Use Harmonization 3 (LUH3) is an upgraded global dataset designed to link historical land-use reconstructions with future projections. Built for Earth system models and climate experiments, it provides annual gridded data on land states, transitions, and management at a 0.25-degree resolution[233].

The workflow described in the previous section emerges from the interaction of these modules. Socioeconomic drivers determine future demand for food, feed, bioenergy, and other land-based commodities, which are then translated into production requirements, land demand, trade flows, technological change, land-use allocation decisions, and associated greenhouse gas emissions. Policy interventions and climate-related assumptions can be introduced through dedicated modules that modify or constrain these processes [236].

While all core MAgPIE-Brazil modules remain active in the NZB implementation, development efforts focused on a subset of modules that received Brazil-specific adaptations, NZB-specific extensions, or links to user-configurable scenario dimensions. These modules were prioritized based on their relevance for representing Brazilian land-use dynamics and evaluating AFOLU mitigation pathways towards net-zero greenhouse gas emissions, as shown in Table 55.

Table 55: *Implementation of MAgPIE-Brazil modules within the NZB modelling framework.*

MAgPIE-Brazil module	Description	Status	Related NZB scenario dimension
09_drivers	Socioeconomic drivers (population, GDP, scenarios)	NZB-specific scenario mapping (SSP proxies for population and GDP growth)	National economic growth (Section 4.1.4)
10_land	Land balance and land accounting framework	Brazil-specific land-use adaptation (MapBiomass-based initialization)	Not directly configurable
11_costs	Cost accounting and objective function components	Default MAgPIE-Brazil implementation	Not directly configurable
12_interest rate	Intertemporal discounting and investment costs	Default MAgPIE-Brazil implementation	Not directly configurable
13_tc	Technological change and agricultural intensification	Default MAgPIE-Brazil implementation	Not directly configurable
14_yields	Yield development and attainable productivity	Default MAgPIE-Brazil implementation	Not directly configurable
15_food	Food requirements based on dietary patterns and calorie intake	Default MAgPIE-Brazil implementation	Dietary patterns (Section 4.3.4)
16_demand	Food, feed, bioenergy and material demand	Coupled with MACRO bioenergy demand projections (see Section 3.2.2.2)	Dietary patterns (Section 4.3.4)
17_production	Agricultural production accounting	Default MAgPIE-Brazil implementation	Not directly configurable
18_residues	Agricultural residues and by-products	Default MAgPIE-Brazil implementation	Not directly configurable
20_processing	Processing of primary into secondary products	Default MAgPIE-Brazil implementation	Not directly configurable
21_trade	International trade flows and regional market integration	NZB-specific extension (fixed trade option)	Agriculture exports (Section 4.3.7)

MAGPIE-Brazil module	Description	Status	Related NZB scenario dimension
22_land conservation	Land conservation policies and conversion restrictions	Default MAGPIE-Brazil implementation	Protected areas (Section 4.2.2)
28_ageclass	Forest age-class structure and regrowth dynamics	Default MAGPIE-Brazil implementation	Not directly configurable
29_cropland, 30_croparea	Cropland allocation and crop area dynamics	Brazil-specific land-use adaptation (IBGE-based cropland reconstruction)	Cropland management systems (through AAT) (Section 4.3.2)
31_past	Pasture allocation and pasture productivity dynamics	Brazil-specific land-use adaptation (MapBiomass-based pasture reconstruction)	Pasture condition dynamics (through AAT) (Section 4.3.5)
32_forestry	Forestry production, managed forests and afforestation dynamics	NZB-specific scenario mapping (afforestation and forestry expansion proxies)	Forestry (Section 4.3.1)
34_urban	Urban and settlement land allocation	Default MAGPIE-Brazil implementation	Not directly configurable
35_natveg	Natural vegetation dynamics, carbon-based land classification, and land protection policies	Brazil-specific natural vegetation reconstruction (MapBiomass and MCTI carbon-stock data)	Natural vegetation (Section 4.2.1)
36_employment	Agricultural employment accounting	Default MAGPIE-Brazil implementation	Not directly configurable
37_labor prod	Labor productivity development	Default MAGPIE-Brazil implementation	Not directly configurable
38_factor costs	Production factor costs (land, labor, capital)	Default MAGPIE-Brazil implementation	Not directly configurable
39_land conversion	Land-use conversion dynamics and associated conversion costs	Default MAGPIE-Brazil implementation	Not directly configurable
40_transport	Transport costs and market accessibility affecting regional competitiveness	Default MAGPIE-Brazil implementation	Not directly configurable
41_area equipped for irrigation	Irrigated area infrastructure and irrigation allocation	Brazil-specific irrigation reconstruction using MapBiomass Irrigation data	Not directly configurable
42_water demand	Agricultural water demand for irrigated crop production	Default MAGPIE-Brazil implementation	Not directly configurable
43_water availability	Water availability constraints for irrigation	Default MAGPIE-Brazil implementation	Not directly configurable
44_biodiversity	Biodiversity impacts and habitat-conversion indicators	Default MAGPIE-Brazil implementation	Not directly configurable
45_climate	Climate-change impacts on agricultural productivity and water availability	Default MAGPIE-Brazil implementation	Not directly configurable

MAGPIE-Brazil module	Description	Status	Related NZB scenario dimension
50_nr soil budget	Nitrogen flows and soil nutrient balances supporting agricultural emissions accounting	NZB-specific scenario mapping (NUE improvement proxies)	Nitrogen use efficiency (Section 4.3.3)
51_nitrogen	Nitrogen cycling and N ₂ O emissions from agricultural systems	Default MAGPIE-Brazil implementation	Not directly configurable
52_carbon	Carbon stocks and CO ₂ emissions	Brazil-specific carbon-stock adaptation (MCTI-based carbon-stock estimates)	Not directly configurable
53_methane	CH ₄ emissions from livestock and agricultural activities	Default MAGPIE-Brazil implementation	Not directly configurable
54_phosphorus	Phosphorus cycling and nutrient accounting	Default MAGPIE-Brazil implementation	Not directly configurable
55_awms	Animal waste management systems	NZB-specific scenario mapping (Manure management improvement proxies)	Manure management systems (Section 4.3.6)
56_ghg policy	Climate policy constraints and AFOLU emissions targets	NZB-specific extension (AFOLU emissions cap implementation)	Land use and agriculture and energy, industry and waste net emissions caps (Section 4.1.2)
57_maccs	Non-CO ₂ mitigation options through marginal abatement cost curves	NZB-specific extension (AFOLU emissions cap implementation)	Land use and agriculture and energy, industry and waste net emissions caps (Section 4.1.2)
58_peatland	Peatland-related greenhouse gas emissions	Default MAGPIE-Brazil implementation	Not directly configurable
59_som	Soil organic matter emissions from land-use change and soil carbon dynamics	NZB-specific modification (excluded from emissions cap accounting)	Not directly configurable
60_bioenergy	Bioenergy demand and bioenergy crop production	Coupled with MACRO bioenergy demand projections (see Section 3.2.2.2)	Not directly configurable
62_material	Biomass demand for material uses	Default MAGPIE-Brazil implementation	Not directly configurable
70_livestock	Livestock production systems and feed demand	Default MAGPIE-Brazil implementation	Not directly configurable
71_disag lvst	Spatial distribution of livestock production systems	Default MAGPIE-Brazil implementation	Not directly configurable
73_timber	Timber production and wood-product demand	Default MAGPIE-Brazil implementation	Not directly configurable

MAgPIE-Brazil module	Description	Status	Related NZB scenario dimension
80_optimization	Cost-minimizing optimization framework	Default MAgPIE-Brazil implementation	Not directly configurable

Although all core MAgPIE-Brazil modules remain active in the NZB implementation, several assumptions and configuration were adopted in this first version:

- First, some NZB scenario dimensions are represented through proxy-based mappings rather than dedicated model parameters or processes. Rather than introducing new model structures, these scenario dimensions modify existing model inputs, parameters, or constraints to approximate the intended effect of the selected pathway. The detailed implementation of each proxy is described in the Chapter 4 of this document.
- Second, several management-level interventions, such as cropland management systems, pasture condition dynamics, and protected-area removals, are represented outside the optimization framework through the AFOLU Accounting Tool (AAT).
- Third, some model components continue to rely on default MAgPIE-Brazil parameterizations and have not yet undergone Brazil-specific calibration.

Figure 87 summarizes in five operational steps the functioning of MAgPIE-Brazil in the context of the NZB project:

1. Project food and commodity demand based on population, GDP and dietary patterns;
2. Estimate required agricultural production using yields and trade assumptions;
3. Translate production demand into land demand by type;
4. Optimize land allocation across competing land uses based on costs;
5. Generate land-use change trajectories and AFOLU GHG emissions/removals over time.

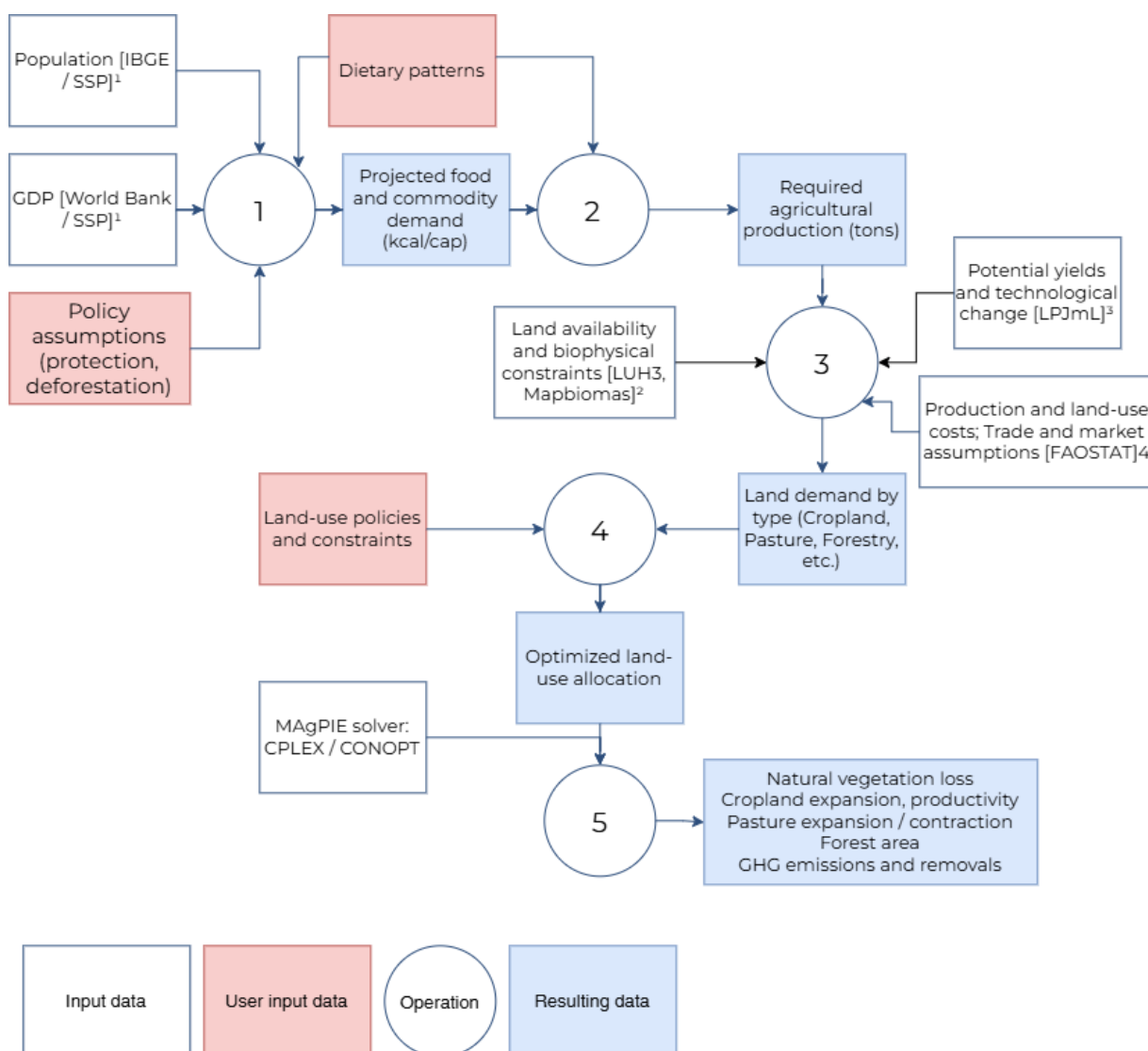


Figure 87: Operational steps describing the functioning of MAGPIE-Brazil for land-use optimization. References: 1-SSP 2-LUH3 and MapBiomias 3-LPJmL 4-FAOSTAT

3.4.1.2 The Emissions Cap implementation

A central component of the NZB implementation is the introduction of an AFOLU greenhouse gas emissions constraint. Rather than relying on an exogenously defined carbon price trajectory, MAGPIE-Brazil can be configured to operate under a *greenhouse gas emissions cap* [235]. The emissions cap is a hard upper limit placed on Brazil's total land-use and agriculture (AFOLU) greenhouse gas emissions within the model. It covers all major emission sources in that sector — carbon dioxide from deforestation and land-use change, methane from cattle and rice cultivation, and nitrous oxide from agricultural soils — converted to a single CO₂-equivalent figure using standard international accounting factors.

The current implementation adopts the *all_nosoil* accounting configuration. As a result, soil carbon stock changes represented by the land-use-specific soil carbon pools are excluded from emissions-cap accounting. This choice was motivated by the limited suitability of the default MAGPIE-Brazil soil carbon representation for the Brazilian context. To complement the processes not represented within the cap

accounting framework, the NZB modelling framework incorporates the AFOLU Accounting Tool (AAT), which provides additional estimates of emissions, removals, and land-management interventions.

The cap is defined as a trajectory: starting from Brazil's approximate 2025 emissions level, it declines linearly each five-year model timestep until it reaches the chosen target value in the target year (2040, 2045, or 2050), after which it is held constant. In each timestep, the model's optimization engine must find the least-cost combination of actions — reducing deforestation, changing land use, expanding forests, shifting livestock management, adjusting agricultural practices and trade — such that total CO₂-equivalent emissions do not exceed the trajectory value for that period. The tighter the cap, the more costly it becomes to comply, and the shadow price of the constraint (the implicit carbon price generated internally by the model) rises accordingly. This shadow price is not an explicit policy instrument — there is no carbon tax or trading scheme modelled — but it reflects how much the Brazilian economy, *as represented in the model*, would need to value a tonne of CO₂-equivalent in order to make the required level of mitigation cost-effective. Where the cap cannot be met by any available mitigation option, the model flags this through a slack variable and continues to a solution, making it possible to distinguish targets that are within the model's feasible range from those that are not. The main implementation details, assumptions, and current limitations of the emissions-cap framework are discussed below.

3.4.1.2.1 Non-CO₂ mitigation

In addition to CO₂ emissions from land-use change, the emissions cap also accounts for methane (CH₄) from enteric fermentation and manure management, and nitrous oxide (N₂O) from agricultural soils. In the model, these gases are converted to CO₂-equivalent values using AR5 GWP100 factors [237] and are therefore counted against the cap alongside CO₂ emissions. The mitigation of non-CO₂ gases is represented through the marginal abatement cost (MAC) curves implemented in MAgPIE-Brazil module 57. These curves define the costs and mitigation potentials of technical measures such as feed additives, manure management, and improvements in nitrogen-use efficiency. In the current implementation, the emissions cap forces non-CO₂ mitigation up to “step 106” of the MAC curves, corresponding approximately to the maximum technically feasible abatement under carbon prices consistent with 1.5°C pathways. As a result, both relatively lenient and highly ambitious emissions caps trigger the same level of non-CO₂ mitigation. This decoupling between cap stringency and the degree of non-CO₂ abatement should be interpreted as a limitation of the current implementation. Future developments will make non-CO₂ mitigation endogenous and responsive to the selected cap level and user-defined scenario settings.

3.4.1.2.2 Linear cap trajectory

Another important aspect of the cap is that the trajectory to the target is assumed to be linear. The model's cap trajectory for Brazil runs in a straight line from the 2025 historical emissions level down to the chosen target by the target year. This assumption was adopted as a simple and transparent approach for constructing emissions pathways within the NZB framework. Consequently, emissions levels in intermediate years are determined by the assumed cap trajectory and should be interpreted as scenario assumptions rather than independently defined mitigation targets.

3.4.1.2.3 Global context and market interactions

Also worth noting is that what happens outside Brazil is important. The cap constrains Brazilian AFOLU emissions, but global food demand does not disappear. If Brazil reduces agricultural land use to meet the cap, production may shift to other countries where land-use regulations are less strict, potentially causing emissions to rise elsewhere (carbon leakage). The current model includes the rest of the world, so some of this displacement is captured endogenously through trade. However, the degree to which global markets compensate for reduced Brazilian supply depends on assumptions about policies outside Brazil. For this reason, MAgPIE-Brazil NZB scenarios assume that Brazil is not acting alone and include a carbon price trajectory for other countries consistent with a well-below 2°C global pathway. Consequently, the costs and effectiveness of a given AFOLU emissions target depend not only on conditions within Brazil but also on assumptions regarding global climate policies and market responses.

3.4.1.2.4 Removals from primary vegetation in protected areas and feasibility check

Since MAgPIE-Brazil does not account for removals from primary vegetation in protected areas, these removals, defined from the user options (4.2.2), are added to the cap value chosen by the user. This allows the model to have an extra "credit" to reach the cap value set for the net zero year.

A methodological caveat should be noted when interpreting these results. As highlighted in applications of the IPCC managed land approach, increases in estimated removals may arise from the expansion of areas classified as protected and therefore managed, rather than from changes in vegetation growth rates themselves. Consequently, the estimated contribution of protected areas should be interpreted as an accounting-based estimate of anthropogenic removals under the adopted methodological framework.

CO₂ removals associated with primary vegetation in protected lands are estimated based on the spatial mask generated by MAgPIE-Brazil and representing the distribution of protected areas in the selected target year. These masks were disaggregated by biome and state, and carbon removals were estimated by applying biome-specific carbon increment factors to the corresponding protected area extent, according to [238]. Since carbon increment factors are defined at the biome level while NZB results are reported at the state level, estimated removals are subsequently aggregated and reported by state.

$$R = A \times C_i \times 44/12 \quad (73)$$

Where:

- R : annual CO₂ removals (tCO₂/yr);
- A : protected area extent (ha);
- C_i : annual carbon stock increment (tC ha⁻¹ yr⁻¹);
- 44/12: molecular weight ratio used to convert carbon stocks into CO₂ equivalents.

Table 56 presents the carbon increment factors adopted for each biome.

Table 56: *Biome-specific carbon increment factors adopted for protected areas according to [238].*

Biome	Carbon removal factor (tCO ₂ ha ⁻¹ yr ⁻¹)
Amazon	-1.7491
Atlantic Forest	-1.2094
Cerrado	-0.9468
Pantanal	-1.0864
Caatinga	-0.3892
Pampa	-1.5520

Resulting removals for Brazil are thus: -399 MtCO₂ for variable 6 option A (no new protected areas4.2.2), -707 MtCO₂ for option B (30x30 scenario4.2.2), and -723 MtCO₂ for option C (HalfEarth scenario4.2.2).

Feasibility for the AFOLU framework will be checked after adding emissions and removals from the AAT tool, described in Section 3.4.2.

3.4.1.2.5 Accounting framework and inventory alignment

Finally, as noted at the beginning of this section, the quantity constrained by the cap does not correspond exactly to the AFOLU emissions reported by Brazil under international climate reporting frameworks. In addition to adopting the *all_nosoil* accounting configuration, the cap is applied to the MAgPIE-Brazil variable *vm_emissions_reg*, which includes some emission sources that are not typically accounted for in Brazil's national greenhouse gas inventory. One important example is emissions from intact tropical peatlands, including methane and dissolved organic carbon emissions. Consequently, the quantity constrained by the model differs from the AFOLU emissions reported by Brazil to the UNFCCC. This difference introduces additional uncertainty when translating a model cap into an equivalent policy target. Future work may further refine this relationship through improved harmonization between model outputs and inventory-based accounting frameworks.

Taken together, these assumptions and implementation choices define how the emissions cap is represented within the NZB modelling framework and should be considered when interpreting AFOLU mitigation pathways and emissions targets generated by MAgPIE-Brazil.

3.4.1.3 Brazil-Specific Adaptations to MAgPIE

A key feature of the implementation of MAgPIE-Brazil is the incorporation of Brazilian datasets to improve the representation of land cover, agricultural production, irrigation systems, and carbon stocks [11]. While the standard MAgPIE-Brazil framework relies primarily on global datasets, the Brazilian implementation integrates national information sources that provide greater spatial detail and consistency with official statistics and monitoring systems. These datasets support both model initialization and calibration, strengthening the representation of land-use dynamics and agricultural systems in Brazil.

Four national datasets play a particularly important role in the initialization and calibration of MAgPIE-Brazil within the NZB framework:

3.4.1.3.1 MapBiomass Collection 10

MapBiomass Collection 10 was incorporated into the MAgPIE-Brazil initialization workflow to improve the representation of land cover and vegetation dynamics in Brazil [12, 11]. In particular, the dataset provides spatially explicit information on secondary vegetation, enabling the separation of natural forest areas into the primary forest and secondary forest categories used by MAgPIE-Brazil.

3.4.1.3.2 MapBiomass Irrigation

MapBiomass Irrigation was incorporated to improve the representation of irrigated agriculture in MAgPIE-Brazil. The dataset provides spatially explicit information on the distribution of irrigated areas across Brazil, including center-pivot irrigation, flood irrigation, and other irrigated areas [11, 239]. These data were harmonized with the crop classes represented in MAgPIE-Brazil and used to allocate irrigated cropland within the model initialization dataset.

To ensure consistency with the land-use representation, irrigated areas were constrained not to exceed total cropland area within each grid cell. Flood-irrigated areas were additionally restricted to crop classes compatible with irrigated rice systems. The resulting irrigation maps support a more realistic representation of agricultural production systems and improve consistency with observed irrigation patterns in Brazil.

3.4.1.3.3 MCTI Fourth National Greenhouse Gas Inventory

Carbon stock estimates from the Fourth National Greenhouse Gas Inventory, coordinated by the Ministry of Science, Technology and Innovation (MCTI), were used during the preparation of the MAgPIE-Brazil initialization dataset to support the validation of primary forest areas [234, 11]. Primary forest areas were constrained not to expand over time. Carbon stock information was additionally used to identify areas whose carbon densities were inconsistent with primary forest conditions and should therefore be assigned to other land-use classes during model initialization. The resulting land-use dataset is therefore more consistent with official Brazilian estimates of ecosystem carbon stocks.

3.4.1.3.4 IBGE Agricultural Statistics

Municipality-level harvested area statistics from the Brazilian Agricultural Municipal Survey (Pesquisa Agrícola Municipal, PAM), produced by the Brazilian Institute of Geography and Statistics (IBGE), were used to improve the spatial allocation of cropland in the MAgPIE-Brazil initialization dataset [13, 11]. The data were aggregated from municipalities to the model's 0.5° spatial resolution and used to replace the default cropland distribution adopted in the standard MAgPIE-Brazil framework. To respect land availability constraints within each grid cell, cropland totals exceeding the physical cell capacity due to double-cropping were proportionally adjusted during the spatial allocation process. Consequently, double-cropping systems are represented indirectly through harvested-area statistics rather than explicitly simulated within the current MAgPIE-Brazil implementation. The use of PAM/IBGE agricultural statistics provides a more realistic representation of cropland distribution across Brazil and improves the agreement between the initialization dataset with official national agricultural statistics.

Furthermore, the MapBiomass *Farming* class was used to harmonize cropland and pasture distributions within the MAgPIE-Brazil initialization dataset. Cropland was first allocated using PAM/IBGE statistics, and the remaining agricultural area identified by MapBiomass was subsequently assigned to the pasture and rangeland land-use class [11, 12].

Together, these datasets strengthen the national calibration of MAgPIE-Brazil and improve the representation of Brazilian land-use systems using official national data sources. These developments increase the model's relevance for land-use and climate policy analyses in Brazil.

3.4.2 Land management systems (AFOLU Accounting Tool)

This section describes the methodology used to allocate agricultural land across management categories and estimate associated emissions and removals through the AFOLU Accounting Tool (AAT). In the current version of the NZB platform, the AAT has been designed to represent land-management practices that affect soil carbon dynamics, including carbon losses from degraded systems and carbon accumulation resulting from improved agricultural management, as well as produce removal estimates in protected areas. Consequently, all emission and removal factors applied in this module are expressed as carbon dioxide (CO₂) fluxes.

The AAT workflow consists of three sequential stages (Figure 88). First, cropland and pasture areas are extracted from the MAgPIE-Brazil outputs for the selected NZB scenario. These land-use area projections constitute the activity data used by the accounting framework. Second, these are spatially allocated across Brazilian states and subsequently distributed among crop management systems and pasture vigor classes according to scenario-specific management shares. Finally, management-specific emission and removal factors are applied to each category of land-use to estimate soil-related CO₂ emissions and removals.

The methodology therefore relies on three categories of inputs: (i) land-use area projections from MAgPIE-Brazil; (ii) scenario-dependent management shares defining the distribution of cropland and pasture areas across management categories; and (iii) management-specific emission and removal factors for the land-use classes.

The resulting outputs include area allocations by management category and CO₂ emissions and removals per management category.

Operations include:

1. Disaggregate land-use into management systems (e.g., pasture condition, tillage systems);
2. Allocate area to each system using shares;
3. Apply emission/removal factors by system, calculating total soil-related CO₂ emissions and removals.

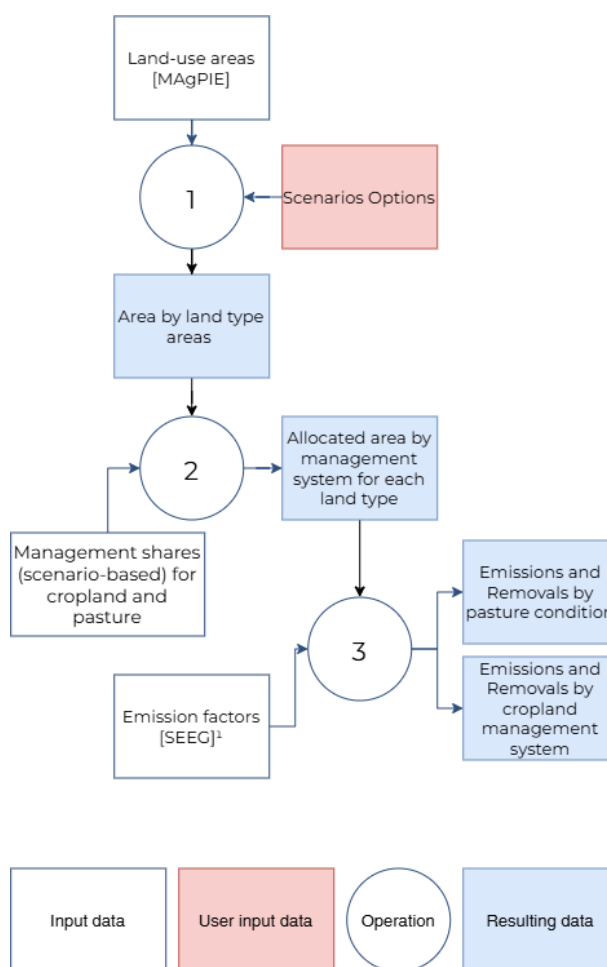


Figure 88: Operational steps describing the functioning of the AFOLU tool for the allocation of land management systems. References: 1-SEEG

3.4.2.1 Pasture-condition representation (vigor)

Pasture vigor is used in NZB as a proxy for pasture condition and management intensity. Differences in pasture vigor are associated with variations in forage productivity, livestock carrying capacity, soil condition, and greenhouse gas balances.

Within the NZB framework, transitions from degraded to better-managed pasture conditions are associated with improvements in productivity, increased soil carbon accumulation, enhanced forage quality, and higher stocking rates, leading to lower emissions intensity per unit land area. These relationships provide the conceptual basis for the pasture-vigor scenarios adopted in the AAT; however, potential effects on productivity, forage quality, carrying capacity, and livestock emissions intensity are not quantified by the AAT itself.

To represent these dynamics, the AAT disaggregates the national pasture area projected by MAgPIE-Brazil into state-level pasture areas and subsequently distributes these areas across pasture vigor classes. This procedure allows the accounting framework to capture regional differences in pasture management conditions while maintaining consistency with the national pasture trajectories generated by the land-use modelling framework.

The representation of pasture vigor is based on MapBiomass Collection 10, which provides state-

level information and classifies pasture areas as low, medium or high vigor. For AAT, these classes are mapped, respectively, as Degraded, Intermediate, and Well-managed pasture categories. This crosswalk is a modelling assumption: the MapBiomass vigor indicator primarily represents biological degradation associated with exposed soil and does not directly capture all dimensions of agronomic degradation or management quality. These data are used as the baseline distribution adopted by the AAT to allocate nationally projected pasture areas across Brazilian states and pasture vigor classes.

Because the MapBiomass Collection 10 pasture vigor dataset is only available from 2000 onwards, pasture vigor shares for 1995-1999 (MAgPIE's initialization period) were assumed to be equal to those observed in 2000.

For each modelling period, pasture areas are allocated among the three pasture vigor classes according to the assumptions associated with the selected scenario. The resulting allocation preserves the total pasture area projected by MAgPIE-Brazil after state-level disaggregation and provides the activity data used for emissions and removals accounting. Detailed assumptions regarding the evolution of pasture vigor classes under each NZB scenario are presented in section 4.3.5.

In the final step of the workflow, carbon dioxide emissions and removals are estimated by applying vigor-specific emission and removal factors to the area allocated to each pasture vigor class (Table 57).

$$CO_{2v,s,t} = A_{v,s,t} \times EF_m \quad (74)$$

Where:

- $CO_{2v,s,t}$: annual CO_2 emissions/removals associated with pasture vigor class v , state s , and period t ;
- $A_{v,s,t}$: pasture area allocated to pasture vigor class
- EF_v : CO_2 · emission/removal factor associated with pasture vigor v .

Emission and removal factors are assumed to be constant across states, modelling periods and vary only according to pasture vigor class. Consequently, differences in estimated emissions and removals across states arise from the distribution of pasture areas among the three vigor classes. Potential soil carbon saturation effects are not explicitly represented in the current version of the AAT.

Table 57: CO_2 emission and removal factors adopted for pasture vigor classes.

Pasture vigor class	Emission/removal factor (tCO ₂ ha ⁻¹ yr ⁻¹)	Reference
Degraded pasture	1.0276	[240]
Intermediate pasture	0.1101	[240]
Well-managed pasture	-2.2387	[240]

Positive values indicate net CO_2 emissions, whereas negative values indicate net carbon sequestration associated with improved pasture management conditions.

3.4.2.2 Crop management systems representation

Cropland management systems are used in NZB to represent differences in soil management practices that influence carbon dynamics and greenhouse gas balances. Within the NZB framework, transitions from conventional tillage systems towards conservation agriculture practices are associated with increased soil carbon retention and lower net greenhouse gas emissions.

To represent these dynamics, the AAT disaggregates the cropland area projected by MAgPIE-Brazil into state-level cropland areas and subsequently allocates these areas among three crop management systems:

- Conventional tillage: Soil management based on regular soil preparation and disturbance prior to planting.
- No-till practice: Conservation-oriented management with reduced soil disturbance and maintenance of crop residues on the soil surface.
- Full no-till system: Comprehensive adoption of no-tillage principles, including minimal soil disturbance, permanent soil cover, and crop diversification.

The representation of cropland management is based on historical information compiled in SEEG²⁰ (Collection 13), which combines estimates from the Brazilian Municipal Agricultural Production Survey (PAM/IBGE)²¹ and information published by the Brazilian No-Tillage Federation (FEBRAPDP)²². Between 1995 and 2016, FEBRAPDP provides national estimates of the area under no-tillage systems, reported as the combined area under No-till practice (PD) and Full no-till systems (SPD), without distinction between the two categories. For this distribution a fixed proxy was used, whereby 20% of the no-tillage area is classified as Full no-till system (SPD) and 80% as No-till practice (PD).

The 2017 Agricultural Census provides the reference year for the state-level distribution of crop management systems, and its state shares were applied to disaggregate the national FEBRAPDP estimates for the 1995-2016 period. From 2018 onwards, cropland areas were estimated using PAM/IBGE data. The area effectively available for crop management allocation was calculated as the total planted area minus areas reported under second and third crops. To estimate the adoption of no-tillage systems after 2017, the share of cropland under PD and SPD observed in the 2017 Agricultural Census was used as a reference and applied to annual cropland estimates derived from IBGE.

For each modelling period, cropland areas are allocated among these management systems according to the assumptions associated with the selected scenario, while preserving the total cropland area projected by MAgPIE-Brazil. Since MAgPIE-Brazil outputs are generated at five-year intervals, crop management allocations and associated CO₂ emissions and removals are also estimated for quin-

²⁰SEEG (Sistema de Estimativas de Emissões e Remoções de Gases de Efeito Estufa) is an initiative coordinated by the Climate Observatory that produces annual estimates of greenhouse gas emissions and removals in Brazil. The system compiles and harmonizes activity data, methodologies, and emission factors across sectors, providing a consistent database widely used for climate analysis and policy assessment.

²¹PAM (Municipal Agricultural Production Survey) is an annual survey conducted by the Brazilian Institute of Geography and Statistics (IBGE) that provides municipal-level information on harvested area, production, and yield for the main agricultural crops in Brazil.

²²FEBRAPDP (Federação Brasileira do Sistema Plantio Direto) is a Brazilian organization dedicated to promoting and monitoring conservation agriculture practices. Historical data compiled by FEBRAPDP on the adoption of no-tillage systems were used as the primary source for representing crop management systems in the NZB framework.

quennial modelling periods. The resulting allocation provides the activity data used for CO₂ emissions and removals accounting. Detailed assumptions regarding the evolution of crop management systems under each NZB scenario are presented in section 4.3.2.

This procedure allows the accounting framework to capture regional differences in management practices while maintaining consistency with the cropland trajectories generated by the land-use modelling framework.

In the final step of the workflow, carbon dioxide emissions and removals are estimated by applying management-specific emission and removal factors to the area allocated to each crop management system (Table 58).

$$CO_{2m,s,t} = A_{m,s,t} \times EF_m \quad (75)$$

Where:

- $CO_{2m,s,t}$: annual CO₂ emissions/removals associated with management system m , state s , and period t ;
- $A_{m,s,t}$: pasture area allocated to management system m , state s , and period t ;
- EF_m : CO₂ emission/removal factor associated with management system m .

Emission and removal factors are assumed to be constant across states, modeling periods, and vary only according to crop management system. Differences among states are therefore represented through the distribution of cropland areas across management categories. Potential soil carbon saturation effects are not explicitly represented in the current version of the AAT.

Table 58: CO₂ emission and removal factors adopted for crop management systems.

Crop management system	Emission/removal factor (tCO ₂ ha ⁻¹ yr ⁻¹)	Reference
Conventional tillage	1.468	[241]
Full no-till system	-1.835	[242]
No-till practices	-0.440	[241]

Positive values indicate net CO₂ emissions, whereas negative values indicate net carbon sequestration associated with conservation agriculture and no-till practice.

Feasibility for the AFOLU framework will finally be checked after adding emissions and removals from croplands and pastures for the selected scenarios.

3.4.3 High-resolution land-use spatial allocation

MAgPIE-Brazil operates at two spatial scales that include a coarse scale of world regions with similar socioeconomic characteristics and a subregional level. Both these resolutions, however, are typically too coarse to assess how global land-use dynamics could drive landscape-scale changes and associated changes in biodiversity and ecosystem services supply, which is a key sustainability challenge.

The Spatial Economic Allocation Landscape Simulator (SEALS) model [243] is therefore applied to spatially allocate projected land-use dynamics to the spatial scale that is relevant for assessing landscape and biodiversity change. SEALS uses empirically calibrated adjacency relationships, physical suitability, and conversion eligibility information at a spatial resolution of 300 x 300 meters to allocate land use activities across space. SEALS traditionally includes seven land cover classes: urban, cropland, grassland, forest, other nature, water, and other.

Adjacency rules are derived by maps that describe the strength of the spatial adjacency for each functional type on nearby land cover pixels, accounting for both distance and the agglomeration of pixels [243]. Physical suitability for land-cover allocation is determined by combining high-resolution soil organic carbon (SOC) data from [244] and topographic information. The topographic information is generated by processing data from a digital elevation model (DEM) to obtain a terrain roughness index from [245].

The first step of the SEALS calibration for NZB was to retrain its default coefficients using Brasil-specific Mapbiomas land-use change rather than the global land-cover change SEALS uses by default. A mapping was used to crosswalk from Mapbiomas land cover changes to SEALS changes. The specific coefficients for the different adjacency relationships and physical suitability were found by iteratively applying the above allocation algorithm to observed land-cover change from MapBiomas (collection 10) over 2000–2015, and selecting the coefficients that were most predictive on withheld data (2015–2020).

The coefficients on SEAL's other default predictors — soil characteristics (e.g., soil organic carbon, and the proportion of sand, silt, or clay), terrain, climate, and accessibility — were likewise refit to Brazil, using the Mapbiomas land cover time series as the training target.

With the recalibrated SEALS, the downscaling procedure for NZB takes results from MAgPIE-Brazil land-use areas at 0.5° resolution, considers spatial protection layers (WDPA, 30x30, or GSN Half Earth) as no-go areas for allocation, and spatially allocates land-cover transitions. Land-cover changes are allocated in an iterative process to the highest ranked grid cells, in order to prepare high-resolution land-cover maps for each of the modelled scenarios. Where spatial protection is imposed, part of the projected change cannot be placed.

Figure 89 summarizes the workings of the SEALS model in the context of the NZB project. A single operation includes:

1. Downscale simulated land-cover changes from MAgPIE-Brazil to a spatial resolution of 10 arc seconds (approximately 300 m), considering protection layers (WDPA, 30x30, or Half Earth) as no-go areas for allocation;

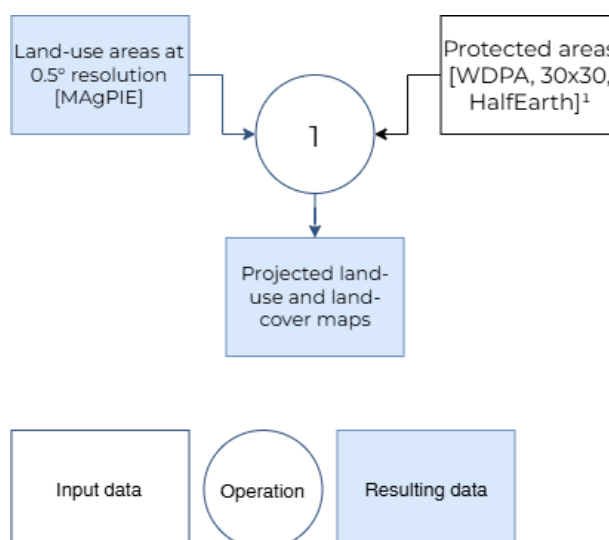


Figure 89: Operational steps describing the functioning of SEALS for downscaling and spatially allocating results from MAGPIE-Brazil. References: 1-[246] and [247]

The colours in Figure 89 distinguish inputs produced by another model in the framework (blue) from external reference data used as supplied (white), the SEALS operation itself (grey), and the resulting outputs (green). Table 90 lists each input, its source and where it can be reviewed; all paths are relative to the shared `base_data` directory.

Input data used by the SEALS downscaling, with sources and locations.

Input	Source	Location
Land-use areas, 0.5 degree	MAGPIE	<code>base_data/magpie/</code>
Base land cover, 300 m	MapBiomass Collection 10	<code>base_data/lulc/mapbiomas_300m/</code>
Protected areas	WDPA; 30x30 (Nature Sustainability, 2025); Global Safety Net (Science Advances, 2020). Supplied by PIK	<code>base_data/seals/static_regressors/</code>
Trained coefficients	Retrained for Brazil on MapBiomass (this work)	<code>base_data/seals/default_inputs/</code>
Soil covariates	MapBiomass Soil	<code>base_data/soil/mapbiomas_300m/</code>
Terrain, climate, population, accessibility, above-ground carbon	SEALS standard base data	<code>base_data/seals/static_regressors/</code>

All paths are relative to the shared `base_data` directory on the consortium drive.

Figure 90: SEALS inputs.

3.4.4 AFOLU outputs for the NZB platform

The AFOLU component of the NZB platform integrates outputs generated by MAGPIE-Brazil, the AFOLU Accounting Tool (AAT), and SEALS. Before being transferred to the platform, model outputs undergo a post-processing step that harmonizes variable names and classifications, converts units, aggregates values when necessary, and organizes results according to the platform data structure. This procedure ensures consistency across models and allows users to explore AFOLU results through a common reporting framework, including emissions and removals, agricultural and livestock production indicators, land-use areas, land management practices, and spatial land-use change

outputs.

3.4.4.1 MAgPIE-Brazil and AAT outputs

MAgPIE-Brazil provides national-scale projections of AFOLU emissions and removals, land-use areas, agricultural production, livestock production, crop yields, and nitrogen-use efficiency. The AAT complements these outputs by estimating areas and associated emissions and removals related to pasture management, cropland management systems, and protected areas.

To integrate outputs from both models, the NZB platform organizes AFOLU results into two main datasets: emissions and removals and biophysical and production indicators. Before being transferred to the platform, outputs undergo a post-processing step that harmonizes variable names and classifications, converts units, aggregates values when necessary, and structures results according to the platform reporting framework.

Crop areas reported by MAgPIE-Brazil are expressed in million hectares and converted to hectares through multiplication by 10^6 . The same conversion is applied to pasture-condition and cropland-management areas generated by the AAT, ensuring consistency among all land-use indicators presented in the platform.

MAgPIE-Brazil reports agricultural and livestock production internally in dry matter (DM) equivalents. To express production in commodity-specific physical units, commodity attributes from the MAgPIE-Brazil database are applied [236]. The conversion is based on the parameter *wm* (wet matter conversion factor), which converts dry matter into reported product weight. Conversion factors vary by commodity and are derived from values compiled from the literature in the MAgPIE-Brazil attribute database. Table 59 presents the conversion factors used in the NZB platform.

Table 59: Commodity-specific conversion factors applied to production outputs.

Commodity	wm factor	Final unit
Soybean	1.1261	t yr ⁻¹
Maize	1.1364	t yr ⁻¹
Rice	1.1494	t yr ⁻¹
Sugar cane	3.7037	t yr ⁻¹
Ruminant meat	2.4570	t yr ⁻¹
Poultry meat	2.4691	t yr ⁻¹
Pig meat	2.2026	t yr ⁻¹

For emissions, MAgPIE-Brazil outputs expressed in Mt are converted to tonnes by multiplication by 10^6 . In addition, carbon dioxide equivalent (CO₂e) values are calculated using the IPCC Fifth Assessment Report (AR5) 100-year Global Warming Potentials (GWP100), applying factors of 28 for CH₄ and 265 for N₂O [237]:

$$tCO_2e = tCO_2 + 28 \times tCH_4 + 265 \times tN_2O \quad (76)$$

In addition to the indicators directly extracted from MAgPIE-Brazil, the platform incorporates AAT outputs describing pasture condition dynamics (degraded, intermediate, and well-managed pastures), cropland management systems (conventional tillage, no-till, and full no-till systems), and their associated emissions and removals. These indicators are reported both at the state level and aggregated to the national level.

3.4.4.2 SEALS outputs

SEALS outputs are incorporated into the NZB platform as spatially explicit indicators of land-use and land-cover change. While MAgPIE-Brazil provides aggregated projections of land-use dynamics, SEALS spatially allocates these changes across the Brazilian territory, generating land-use maps for each scenario and reporting year.

To support the visualization and analysis of these spatial projections within the platform, the area occupied by each land-use class is derived from the SEALS output maps and reported in hectares. The reported classes include Urban, Cropland, Pasture and Grassland, Forest, Other Natural Vegetation, Water, and Other Areas.

SEALS outputs therefore complement the tabular indicators provided by MAgPIE-Brazil and AAT by adding a spatial dimension to AFOLU analyses, supporting visualization and interpretation of future land-use dynamics within the NZB platform.

3.5 GDP, gross output and employment estimation

Most other modules of the NZB suite of models describe the transition primarily in physical and technological terms, including energy demand, generation technologies, fuels, infrastructure, land use, and emissions. The Input-Output Model (IOM) adds the socioeconomic dimension by estimating how these changes affect the Brazilian production system.

Energy-system changes can affect multiple economic activities simultaneously. Expansion of renewable electricity, for example, may change purchases of construction, equipment, transmission services, fuels, and other intermediate inputs. Changes in fuel use can affect petroleum refining, bioenergy, agriculture, transport, and industrial supply chains.

These effects are also spatially heterogeneous because production, infrastructure, natural resources, and energy technologies are unevenly distributed across Brazil. The interregional structure of the IOM makes it possible to identify both local effects and economic spillovers among states [248].

Within the integrated NZB framework, the IOM connects three complementary sources of information. Energy Pathways (EP) describes how much energy is used, by whom, and where; MACRO describes the technologies and geographical origin of energy supply; and the Model of Agricultural Production and its Impact on the Environment (MAgPIE-Brazil) provides the projected change in agricultural and livestock production. The IOM translates these physical pathways into changes in the transactions among Brazilian sectors and states. It then estimates the associated effects on gross output, GDP, employment, and the regional distribution of economic activity.

3.5.1 Input-output modeling

Input–output analysis provides a systemic representation of the economy. In this representation, productive activities use intermediate inputs from other activities together with primary factors of production, such as labor and capital, to produce goods and services. Part of this production is used again by productive activities, while the remainder supplies final demand. The resulting economic structure can be represented schematically as shown in Figure 91.

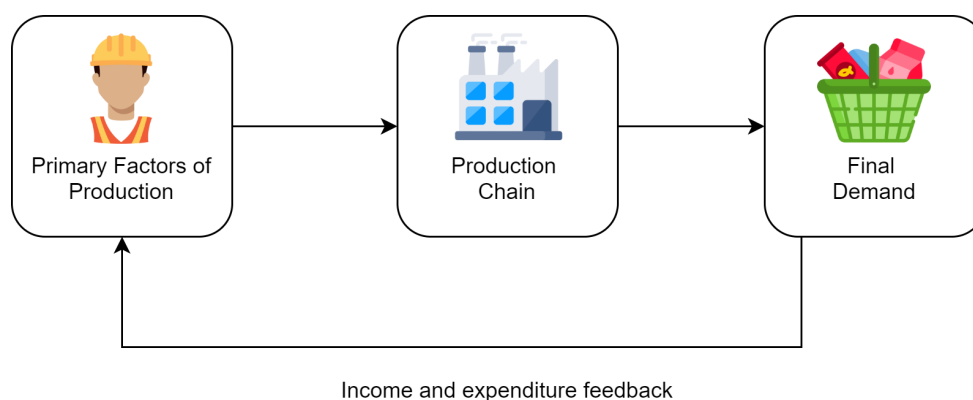


Figure 91: Simplified representation of the economic production system.

The modern input–output framework was developed by Wassily Leontief, building on earlier representations of economic flows such as Quesnay’s *Tableau Economique*. Leontief formalized the interdependence among productive activities and received the 1973 Nobel Prize in Economic Sciences

for the development and application of the input–output method [249, 250]. The principal advantage of this framework is that an activity is evaluated as part of the transaction network linking it to the rest of the economy rather than as an isolated production process [17].

3.5.2 The input–output table

An input–output table records transactions among productive activities and between production and final users. A simplified representation is shown in Figure 92.

		PRODUCERS AS CONSUMERS								FINAL DEMAND			
		Agric.	Mining	Const.	Manuf.	Trade	Transp.	Services	Other	Personal Consumption Expenditures	Gross Private Domestic Investment	Govt. Purchases of Goods & Services	Net Exports of Goods & Services
PRODUCERS	Agriculture												
	Mining												
	Construction												
	Manufacturing												
	Trade												
	Transportation												
	Services												
	Other Industry												
VALUE ADDED	Employees	Employee compensation								GROSS DOMESTIC PRODUCT			
	Business Owners and Capital	Profit-type income and capital consumption allowances											
	Government	Indirect business taxes											

Figure 92: Schematic structure of an input–output table. Source: [17].

Rows describe how the output of each supplying activity is distributed across intermediate users and final demand. Columns describe the cost structure of each consuming activity, including intermediate goods and services and primary inputs such as labor income and operating surplus.

If z_{ij} is the amount supplied by activity i to activity j , and x_j is the gross output of activity j , the technical coefficient (a_{ij}) is

$$a_{ij} = \frac{z_{ij}}{x_j}. \quad (77)$$

Collecting these coefficients yields the technical coefficient matrix **A**. Under the standard Leontief assumption, these input proportions remain fixed within each IO solution.

3.5.3 Mathematical formulation

For each activity, gross output equals intermediate demand plus final demand:

$$\mathbf{x} = \mathbf{Ax} + \mathbf{y}, \quad (78)$$

where $\mathbf{x}$ is the gross-output vector, **A** is the technical coefficient matrix, and $\mathbf{y}$ is the final-demand vector. The product $\mathbf{Ax}$ represents the intermediate demand generated by the production of all

activities. Rearranging gives

$$\mathbf{x} = (\mathbf{I} - \mathbf{A})^{-1} \mathbf{y} = \mathbf{L} \mathbf{y}, \quad (79)$$

where $\mathbf{I}$ is the identity matrix, with the same dimension as $\mathbf{A}$, and $\mathbf{L}$ is the Leontief inverse, defined as

$$\mathbf{L} = (\mathbf{I} - \mathbf{A})^{-1} \quad (80)$$

Each element l_{ij} of $\mathbf{L}$ measures the total output of activity i (including both direct and supply-chain requirements) needed to deliver one additional monetary unit of final demand for activity j . This multiplier structure can be interpreted through the expansion

$$\mathbf{x} = \mathbf{y} + \mathbf{A}\mathbf{y} + \mathbf{A}^2\mathbf{y} + \mathbf{A}^3\mathbf{y} + \dots \quad (81)$$

In this expansion, $\mathbf{y}$ is the production required to satisfy final demand directly, $\mathbf{A}\mathbf{y}$ is the first round of intermediate requirements, and $\mathbf{A}^2\mathbf{y}$, $\mathbf{A}^3\mathbf{y}$, and the subsequent terms represent progressively more distant rounds of the supply chain.

In the standard formulation, a change in final demand produces

$$\Delta \mathbf{x} = \mathbf{L} \Delta \mathbf{y}. \quad (82)$$

Here, $\Delta \mathbf{y}$ is the vector of changes in final demand and $\Delta \mathbf{x}$ is the resulting vector of changes in gross output.

Equation (82) illustrates the usual IO multiplier logic: a change in final demand generates additional production both in the sector directly affected and throughout its supply chain. The NZB transition, however, changes more than final demand. It also changes which energy sources are used, where they are produced, and which sectors purchase them. The IOM therefore introduces the energy pathway directly into the relevant transactions between suppliers and users. Because changing individual transactions can temporarily disturb the accounting balance of the IO table, the remaining entries are adjusted as little as possible until the table is balanced again. The Leontief system is then solved using this updated economic structure.

3.5.4 IOM methodology – NZB

Figure 93 summarizes the complete calculation chain. The methodological subsections below follow the six numbered operations in the figure.

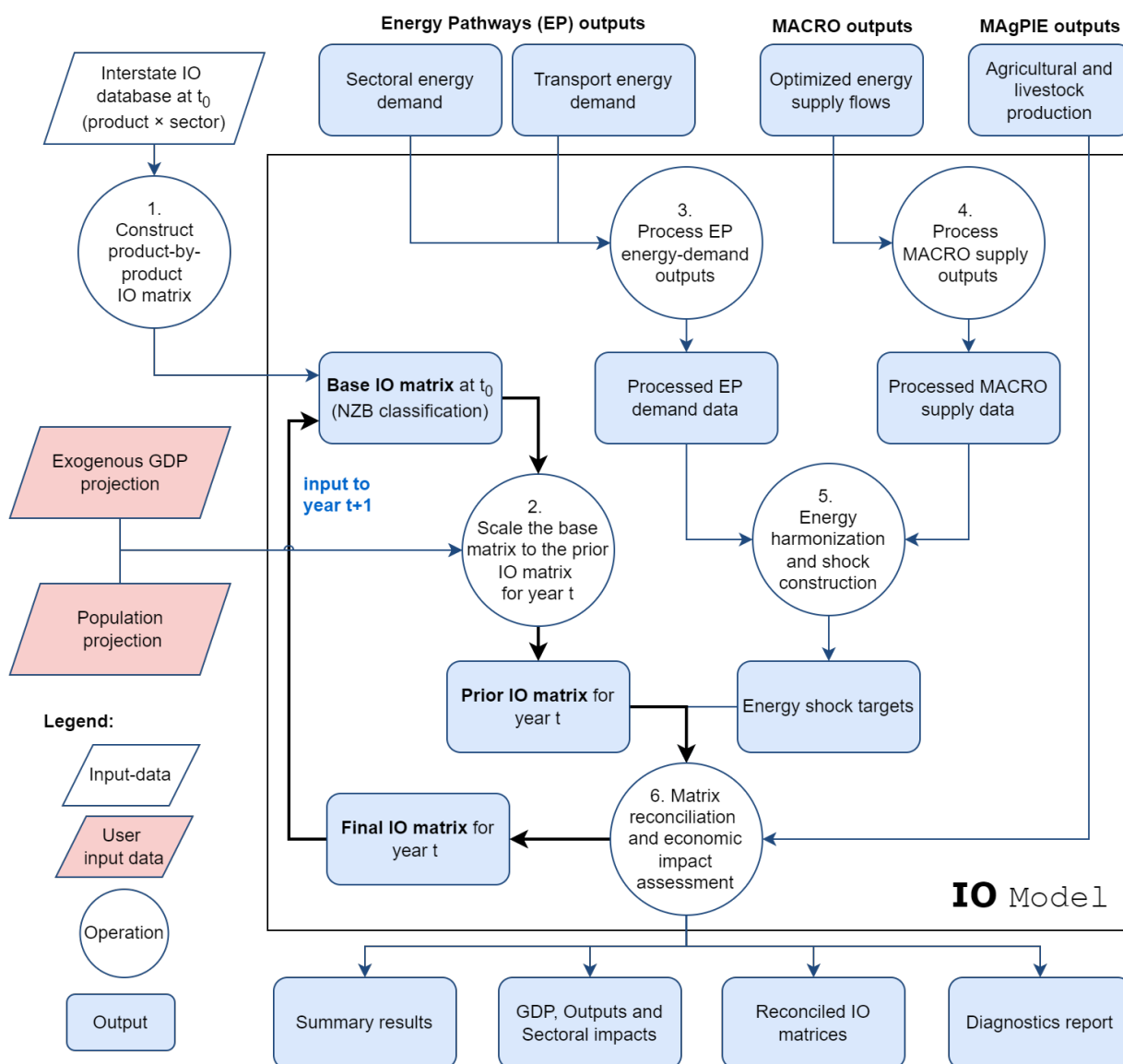


Figure 93: General workflow of the NZB Input–Output Model.

3.5.4.1 Operation 1 – Construction of the product-by-product IO matrix

The economic starting point of the IOM is the 2019 Brazilian interstate supply–use database developed by Nereus [251]. The database represents economic transactions across the 27 federative units, distinguishing 128 products and the 68 sectors responsible for their production. Its original structure is therefore not directly compatible with the symmetric IO system required by the NZB model, in which both the supplying and purchasing dimensions must follow the same classification. Operation 1 converts this supply–use structure into an interstate product-by-product matrix and subsequently aggregates it to the 29-sector NZB classification. The sectors included in this initial classification are listed in Table 60. The energy sectors are subsequently disaggregated to represent the more detailed technologies considered in the NZB pathways.

Table 60: *Sectoral classification used in the initial 29-sector NZB IO matrix.*

Sectors S1–S10	Sectors S11–S20	Sectors S21–S29
S1 – Agriculture and livestock	S11 – Ceramics, glass and other non-metallic mineral products	S21 – Aviation fuels
S2 – Forestry and logging	S12 – Food, beverages and tobacco	S22 – Gasoline and other petroleum products
S3 – Fishing and aquaculture	S13 – Textiles and apparel	S23 – Construction
S4 – Coal mining	S14 – Pulp and paper	S24 – Trade and vehicle repair
S5 – Oil and natural gas extraction	S15 – Inorganic chemicals	S25 – Land transport
S6 – Iron ore mining	S16 – Other chemicals and pharmaceuticals	S26 – Water transport
S7 – Other mining	S17 – Other manufacturing and environmental services	S27 – Air transport
S8 – Pig iron and ferroalloys	S18 – Electricity and gas utilities	S28 – Public administration, education and health
S9 – Non-ferrous metals	S19 – Ethanol and other biofuels	S29 – Other services
S10 – Cement	S20 – Diesel and biodiesel	

The conversion combines information from the supply and use tables. The supply table identifies which products are supplied by each producing sector in each state and is used to determine the composition of sectoral output. The use table records how products are purchased as intermediate inputs by these sectors, as well as how they are allocated across the different components of final demand. By combining these two sources of information, intermediate purchases originally associated with producing sectors are redistributed among the products supplied by those sectors. The resulting matrix is expressed in product terms along both dimensions while preserving the interstate origin–destination flows contained in the Nereus database.

Once the product-by-product structure has been obtained, the 128 products are mapped into the 29 sectors adopted by the NZB framework. This aggregation is performed independently within each federative unit, ensuring that the regional structure of production and trade is maintained. The resulting economic system comprises 783 productive accounts, corresponding to 29 sectors in each of the 27 federative units.

The remaining components of the source database are incorporated consistently into this new structure. Because final demand is already classified by product and destination state, its components—investment, household consumption, government consumption, consumption by non-profit institutions serving households, and exports—can be aggregated directly to the NZB sectors. Monetary accounting items, including international imports, taxes on products, and gross value added, are likewise converted and aggregated to complete the economic accounts. Employment is retained separately as a satellite indicator and is later used to construct the corresponding employment coefficients.

Throughout the transformation, the official output totals reported in the source database are preserved. Differences between these totals and the sums derived from the detailed transaction cells are recorded as preparation diagnostics rather than eliminated through ad hoc normalization. Accordingly, Operation 1 produces an internally documented interstate IO matrix that combines a common product-by-product structure with the regional and sectoral resolution required by the NZB model. This matrix provides the economic basis for the subsequent integration of the energy, macroeconomic, and

land-use pathways.

3.5.4.2 Operation 2 – Construction of the prior IO matrix

Operation 2 constructs the macroeconomic reference for each target year after the initial 2025 calibration. This reference, hereafter called the *prior*, represents how the economy would look if the structure inherited from the preceding modeled year grew at the selected GDP rate, before the new energy and agricultural conditions for the target year were introduced. Thus, *prior* refers to a growth-only reference and should not be interpreted as another term for the previous-year matrix.

Let the ordered sequence of modeled years be

$$(t_0, t_1, t_2, t_3, t_4, t_5) = (2025, 2030, 2035, 2040, 2045, 2050). \quad (83)$$

For a transition from the preceding modeled year t_{k-1} to the target year t_k , the external GDP trajectory defines the scaling factor

$$\beta_{t_{k-1}, t_k} = \frac{GDP_{t_k}^{\text{ext}}}{GDP_{t_{k-1}}^{\text{ext}}}, \quad (84)$$

where $GDP_{t_{k-1}}^{\text{ext}}$ and $GDP_{t_k}^{\text{ext}}$ are the externally projected GDP levels for the preceding and target modeled years, respectively, and β_{t_{k-1}, t_k} is the corresponding growth factor. A value greater than one indicates economic growth between the two modeled years, a value below one indicates a contraction, and a value equal to one indicates no change.

The prior IO table is then obtained by applying this factor uniformly to the table entering the current transition:

$$\mathbf{M}_{t_k}^{\text{prior}} = \beta_{t_{k-1}, t_k} \mathbf{M}_{t_k}^{\text{base}}, \quad (85)$$

where $\mathbf{M}_{t_k}^{\text{base}}$ is the complete IO table used as the starting point for the transition to year t_k , and $\mathbf{M}_{t_k}^{\text{prior}}$ is the corresponding growth-only reference. The symbol $\mathbf{M}$ denotes the complete monetary IO table, including intermediate transactions, final demand, and primary inputs.

From 2030 onward, the base of each transition is the reconciled table obtained for the preceding modeled year:

$$\mathbf{M}_{t_k}^{\text{base}} = \mathbf{M}_{t_{k-1}}^{\text{final}}, \quad (86)$$

where $\mathbf{M}_{t_{k-1}}^{\text{final}}$ is the final balanced IO table obtained for the preceding modeled year. Consequently, the economic structure produced in one modeled year is carried forward to the next transition.

The same scaling applies to each monetary component of the table. For example, the prior intermediate transaction matrix is given by

$$\mathbf{Z}_{t_k}^{\text{prior}} = \beta_{t_{k-1}, t_k} \mathbf{Z}_{t_k}^{\text{base}}, \quad (87)$$

where $Z_{t_k}^{\text{base}}$ and $Z_{t_k}^{\text{prior}}$ are the intermediate transaction matrices before and after GDP scaling, respectively. The final-demand and primary-input components are scaled by the same factor. Because intermediate transactions and sectoral output grow proportionally, this operation changes the size of the economy but preserves its production structure and technical coefficients.

The initial 2025 calibration is treated separately. The accounting-consistent 2025 matrix is updated with the 2025 information from EP, the Transport Model, MACRO, and MAgPIE-Brazil without applying additional GDP growth. The resulting final 2025 matrix then becomes the base for the transition to 2030.

The prior subsequently serves as the reference against which the energy and agricultural *shocks* are defined. In this context, a shock is an externally specified change imposed on selected elements or targets of the IO table to represent information provided by EP, MACRO, or MAgPIE-Brazil. A shock may increase or decrease a transaction or sectoral target and does not necessarily represent a sudden or adverse event. Rather, it describes how the target-year economy should differ from the growth-only reference because of the projected energy transition and changes in agricultural production.

3.5.4.3 Operation 3 – Processing of EP energy-demand outputs

EP supplies the sectoral demand side of the energy integration. Transport energy demand is provided separately by the Transport model that complements the EP results. Both sources are aligned with the selected energy scenario before being incorporated into the IOM.

The two demand sources are standardized by scenario, modeled year, destination state, consuming activity, and energy carrier. Their demand categories are mapped to the corresponding NZB activities, with residential demand assigned to household final demand and industrial, commercial, agricultural, and transport demand assigned to intermediate demand.

The processing also distinguishes known zero values from missing or unmapped information, preventing unavailable data from being interpreted as zero energy demand.

The output of Operation 3 is the **processed energy-demand dataset** shown in Figure 93.

3.5.4.4 Operation 4 – Processing of MACRO supply outputs

MACRO supplies the production and technological composition of the energy system. In the current implementation, this information is obtained from a set of energy-flow files, which are standardized and aggregated by scenario, modeled year, energy product, technology, flow direction, and available geographical identifier.

EP and MACRO have complementary roles. EP defines the level and destination of energy demand, whereas MACRO determines the technologies and producing regions that supply this demand. MACRO records may represent production, internal energy consumption, or both. These flows are retained separately so that energy used within the energy system can be distinguished from the amount available to meet final demand.

For electricity, gross production determines the technology and regional composition of supply, while consumption within the energy system is treated as an internal flow. Battery discharge is excluded

from primary generation to avoid double counting.

Physical quantities are standardized to MWh when applicable. Biomass flows reported in tonnes are converted using documented heating-value factors, while CO₂ remains in tonnes and is retained only as an environmental indicator. Conditional inputs, such as the oil-production file generated under scenario C, are read only when they are available for the selected scenario.

The output of Operation 4 is the **processed MACRO supply dataset** shown in Figure 93.

3.5.4.5 Operation 5 – Energy harmonization and shock construction

Operation 5 combines the processed EP demand and MACRO supply datasets to construct the energy targets imposed on the IO table. External mapping tables link the different sector, carrier, technology, and geographical classifications used by the two models.

Compatible EP and MACRO energy products are grouped into common harmonization pools, including electricity, ethanol, biodiesel, diesel, gasoline, aviation fuel, hydrogen, and natural gas. EP determines the quantity and destination of energy demand, while MACRO provides the corresponding production-origin and technology shares. Let $Q_{o\tau ct_k}$ denote the annual production of energy carrier c in origin state o , using technology τ , in modeled year t_k . The MACRO origin share is

$$s_{oct_k} = \frac{\sum_{\tau} Q_{o\tau ct_k}}{\sum_{o'} \sum_{\tau} Q_{o'\tau ct_k}}, \quad (88)$$

where s_{oct_k} is the share of origin state o in the national production of carrier c . When MACRO does not provide production at the state level, the available regional information is distributed using the corresponding Nereus gross-output shares. The same fallback is used when no suitable MACRO origin mix is available.

Producer prices are expressed in constant 2019 BRL per MWh, consistently with the price basis of the IO matrix. Although other NZB models may express monetary results in constant 2025 US dollars, this difference does not create a currency inconsistency because the IOM integration primarily uses their physical outputs. When an external price projection is required, only its relative change from 2025 is applied to the corresponding constant-2019-BRL reference price. Thus, only the relative price trajectory, rather than the external dollar level or a contemporary nominal exchange rate, enters the monetary conversion.

After the technology-specific prices have been expressed on this common basis, the MACRO production mix is used to calculate an origin-specific weighted average price:

$$\bar{p}_{oct_k} = \frac{\sum_{\tau} Q_{o\tau ct_k} p_{\tau t_k}}{\sum_{\tau} Q_{o\tau ct_k}}, \quad (89)$$

where $p_{\tau t_k}$ is the producer price associated with technology τ . When applicable, fuel-price and technology-innovation scenarios modify the price trajectory before this weighted price is calculated.

For carriers without a usable MACRO technology mix, the corresponding mapped producer price is used directly.

The physical EP demand is distributed across producing states and converted into a monetary origin–destination target according to

$$\hat{z}_{odjct_k} = \frac{D_{djct_k}^{MWh} s_{oct_k} \bar{p}_{oct_k}}{10^6}, \quad (90)$$

where $D_{djct_k}^{MWh}$ is the energy demand of consumer j in destination state d , and $\hat{z}_{odjct_k}$ is the corresponding monetary target in million 2019 BRL.

These monetary values define the **energy shock targets** shown in Figure 93. Only identified origin–destination energy cells are imposed as targets; the remaining cells are left to the subsequent reconciliation.

3.5.4.6 Operation 6 – Entropy-minimization reconciliation and economic impact assessment

Operation 6 combines the growth-only reference matrix from Operation 2 with the energy targets from Operation 5 and the agricultural and livestock production pathway provided by MAgPIE-Brazil.

MAgPIE-Brazil provides the projected change in total Brazilian agricultural and livestock production between consecutive modeled years. This national change is translated into a gross-output target for the Agriculture and livestock activity (S1). Because MAgPIE-Brazil does not provide state-level projections for this integration, the national target is distributed among the 27 states according to the regional S1 output shares in the matrix entering the current transition. This preserves the regional distribution already represented in the IOM. Only the gross output of S1 is imposed as a target. Its intermediate purchases, intermediate sales, and final-demand transactions remain free to adjust during reconciliation. The model can therefore reproduce the national MAgPIE-Brazil production pathway without imposing an externally unsupported state-level transaction structure.

Directly imposing the energy transaction targets and the MAgPIE-Brazil gross-output targets generally breaks the row and column identities of the IO table. Accounting consistency is therefore restored through a constrained entropy-minimization problem.

Let z_{ij} denote the intermediate transaction from supplying activity i to consuming activity j , f_i total final demand, v_j primary inputs, sd_i the statistical discrepancy, and x_i gross output. A balanced IO table satisfies

$$x_i = \sum_j z_{ij} + f_i + sd_i, \quad (91)$$

$$x_j = \sum_i z_{ij} + v_j. \quad (92)$$

Among the matrices satisfying these identities and the imposed transition targets, the model selects the one requiring the smallest change relative to the prior. The information distance for an adjustable positive cell m with prior value m^0 is

$$d(m, m^0) = m \ln \left(\frac{m}{m^0} \right) - m + m^0. \quad (93)$$

The reconciliation problem is summarized by

$$\min \left[\sum_{\ell \in \mathcal{F}} d(m_\ell, m_\ell^0) + w_x \sum_i d(x_i, x_i^0) \right], \quad (94)$$

subject to Equations (91)–(92) and the fixed transition targets. Here, $\mathcal{F}$ is the set of adjustable cells and w_x controls the penalty applied to changes in gross output. This entropy measure corresponds to the generalized Kullback–Leibler divergence, not to thermodynamic entropy. Its purpose is accounting reconciliation rather than the prediction of behavioral responses.

Cells not directly targeted by the transition remain adjustable around their prior values, while structural zeros remain zero. When a target activates an activity with negligible initial output, its initial production structure is derived from the output-weighted national structure of the same sector in states where that activity is already present.

The resulting balanced table is the final IO matrix for modeled year t_k and becomes the base matrix for the next transition. Using the reconciled transactions, the technical coefficients are recalculated according to Equation (77), and gross output is obtained from the Leontief system in Equation (79). Because each activity combines a sector and a state, the solution captures both supply-chain effects and interregional trade linkages.

GDP and employment are calculated from gross output using direct activity-level coefficients:

$$GDP_{i,t_k} = g_{i,t_k} x_{i,t_k}, \quad (95)$$

$$E_{i,t_k} = e_{i,t_k} x_{i,t_k}, \quad (96)$$

where g_{i,t_k} is the direct GDP coefficient and e_{i,t_k} is the direct employment intensity. The GDP coefficient represents gross value added and net taxes on products as a share of gross output. Its reference value is inherited from the preceding modeled year, with controlled adjustments allowed for activities directly affected by the transition. Newly activated activities use the output-weighted national coefficient of the same sector.

The 2025 employment structure is calibrated to the national employment total while preserving the regional and sectoral shares of the reference database. For subsequent years, employment intensities decline according to the labor productivity assumption associated with the selected GDP scenario.

Operation 6 produces the final reconciled IO matrix and the corresponding national, sectoral, and regional estimates of gross output, GDP, and employment. Accounting residuals, convergence, reproduction of the imposed targets, and the numerical properties of the Leontief system are retained as diagnostics.

3.5.4.7 Reported output variables

The IOM results are reported for the modeled years from 2025 to 2050 at the national and state levels. They are available for each of the 29 NZB sectors and for the aggregate category *All sectors*, which represents the total economy rather than an additional economic sector.

The reported variables are organized into three groups. Economic activity is represented by the cumulative and average annual growth of GDP and gross output. Labor-market results include employment levels, employment growth, employment as a share of the total population, and each result's share of national employment. Labor income is represented by the cumulative and average annual growth of income per job.

For GDP, gross output, employment, and income per job, cumulative changes are calculated relative to the integrated 2025 result. Let V denote any of these indicators. Its cumulative change in modeled year t_k is

$$\Delta V^{2025, t_k} (\%) = 100 \left(\frac{V_{t_k}^{\text{final}}}{V_{2025}^{\text{final}}} - 1 \right). \quad (97)$$

The corresponding average annual growth is calculated as the geometric rate

$$g_{2025, t_k}^{\text{annual}} (\%) = 100 \left[\left(\frac{V_{t_k}^{\text{final}}}{V_{2025}^{\text{final}}} \right)^{1/(t_k - 2025)} - 1 \right]. \quad (98)$$

The average annual growth rate is not calculated for 2025 because the reference interval has zero length. For the reference year, the corresponding change measures are reported as zero.

Employment is also reported in jobs. The employment-to-population indicator expresses employment as a percentage of the total population of the corresponding territory, while the share-of-national-employment indicator shows the contribution of each state and sector to total Brazilian employment. Income per job is calculated as labor income divided by employment.

Scenario building

4 Scenario building

Scenario building is the central layer between user-defined assumptions and model execution. It translates policy, technology, land-use, and behavioral assumptions into a coherent configuration that can be passed to the modeling machinery.

Scenario

A scenario is a complete set of assumptions, constraints, and parameter values used to represent one possible pathway. It is not a forecast; it is a structured experiment.

In the current version of the NZB modeling platform, there are 39 scenario variables, each of which has a range of values from which a user may choose to build the set of input assumptions that will constrain the NZB modeling machinery to follow in producing a net-zero pathway. Each scenario variable and the values for it that a user may select are described here. The NZB team plans to add additional variables in future versions of the model, and may also add additional values for a user to select from for some of the current 39 variables. All quantitative values used in the models to represent each option of each user variable can be found **here**.

The following sections describe each of the 39 variables, grouped into 8 groups:

- General variables;
- Deforestation, area protection and restoration;
- Agriculture and livestock;
- Transport;
- Industry;
- Buildings.
- Energy supply system; and
- Waste.

4.1 General variables

Four general user-definable variables are available or under development in the current version of the NZB model, as described here.

4.1.1 Net zero year

The user may choose between 2040, 2045 or 2050 as the target year for Brazil to reach net-zero GHG emissions across all sectors (energy/industry/waste/AFOLU), with CO₂e set to GWP-100 AR5 for non-CO₂ gases.

1. Net zero year

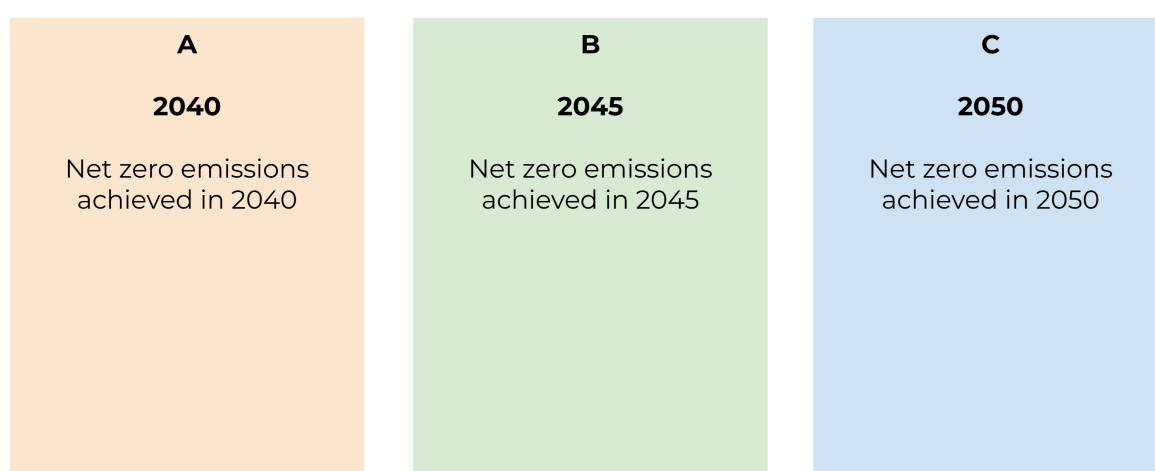


Figure 94: User options for model year for Brazil to reach net-zero GHG emissions

4.1.2 Land use and agriculture and energy, industry and waste net emissions caps

The user is requested to choose desired GHG net emissions caps for land use and agriculture (AFOLU) or for the sum of energy, industry and waste at the net-zero target year. That is done by choosing a cap value for either the AFOLU net emissions or the sum of net emissions from energy, industry and waste. If a value is chosen for the AFOLU net emissions, the same but with opposite signal value will be set for the sum of energy, industry and waste net emissions, so that they sum up net-zero. Similarly, if a value is chosen for the sum of energy, industry and waste net emissions, the same but with opposite signal value will be set for AFOLU net emissions. These values are controlled by a pair of simultaneously moving sliders.

The maximum selectable net emissions for any of those choices are set to 1,000 MtCO₂e. The potential yearly storage for underground CO₂ is -1,700 Mt; see 4.7.11) and the maximum removal for the AFOLU sector is estimated at 1,250 MtCO₂e, considering the Climate Observatory's NDC [252] plus the maximum removals from protected areas in the most ambitious scenario for variable 6 (4.2.2).

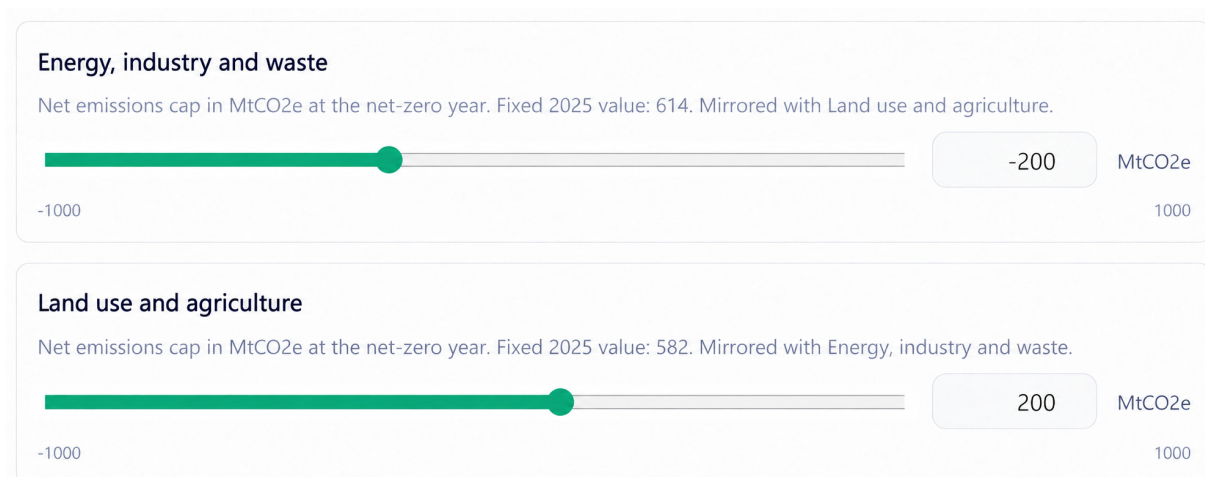


Figure 95: *Illustration of pair of sliders that sets net emissions caps for AFOLU and the sum of energy, industry and waste at the net-zero year*

Once the net emissions caps are selected for the net-zero year, NZB assumes a linear trajectory between the estimated 2025 net emissions and the net-zero year. After the net-zero target year, it is assumed that the net emissions caps are simply maintained constant. That sets the net emissions limit trajectories to be met by the optimizing models MACRO and MAgPIE-Brazil (MAgPIE reads the trajectory without taking into account the removals from protected areas since they are calculated later the AFOLU Accounting Tool).

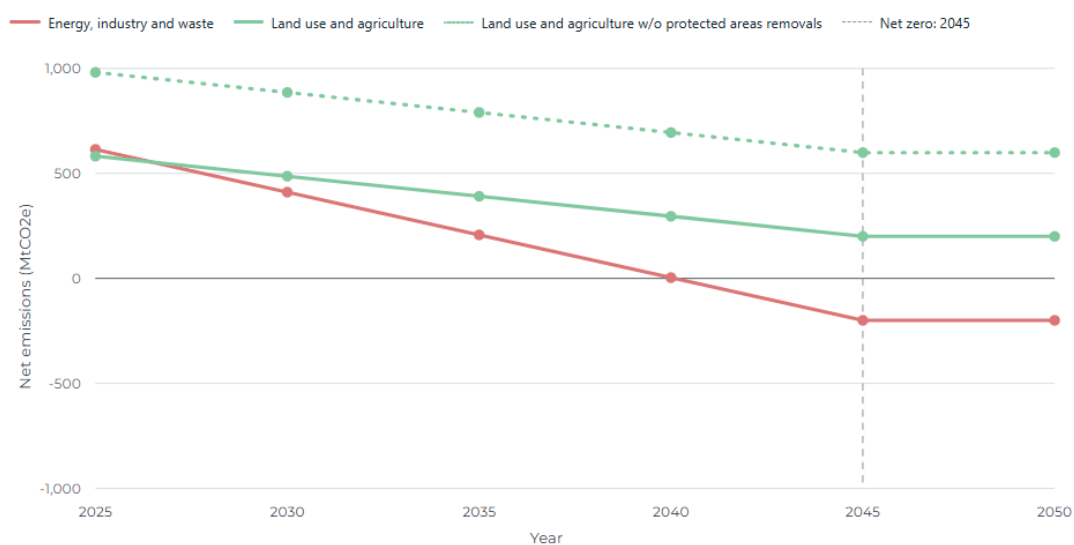
Emissions trajectoriesNet emissions (MtCO₂e)

Figure 96: Example of emissions trajectory set by the user when selecting 2045 as the net-zero year and 200 MtCO₂e as the net emissions cap for AFOLU

4.1.3 Climate change

Although not implemented in NZB v1.0, a methodology for further updates of the platform has been defined to simulate future climate change impacting the availability of hydro, wind and solar power as well as cooling needs in the buildings and industrial sectors. By simplification, all other variables are treated as independent of climate change.

Three climate change scenario options will be available in a future update of NZB:

1. 1.5°C global warming (Representative Concentration Pathway 2.6);
2. 2.0°C global warming (Representative Concentration Pathway 4.5) ; and
3. 4.0°C global warming (Representative Concentration Pathway 8.5).

Hydro, wind and solar power availability data under scenario options 2 and 3 will be obtained from [253, 254] and internal work. As no data was available for scenario option 1, average historical values will be considered instead.

4.1.4 National economic growth

NZB v1.0 considers three scenario options for projected national economic growth for 2026-2050 (Table 61). GDP is treated as an exogenous variable within the NZB modeling framework and acts as an important driver of future energy demand, transport activity, industrial production, consumption patterns, and land-use dynamics across the integrated modeling system. GDP trajectories are therefore specified externally and used as input to the sectoral models. These options are informed by energy planning documents from the Ministry of Mines and Energy (MME) and the Energy Research Office (EPE).

The source of the data for the scenario options are as follow:

- Reference case, 2026-2035: PDE 2035 official reference scenario [43];
- Reference case, 2036-2050: PNE 2050 midpoint between lower and upper scenarios [47];
- Lower case, 2026-2035: PDE 2035 official lower scenario [43];
- Lower case, 2036-2050: PNE 2050 lower scenario [47];
- Upper case, 2026-2035: PDE 2035 official upper scenario [43]; and
- Upper case, 2036-2050: PNE 2050 upper scenario [47].

Table 61: Scenario options for compound annual percentage GDP growth rates.

Scenario option	Years 2026-2035	Years 2036-2040	Years 2041-2050
Reference	2.80	2.75	2.25
Lower	1.90	2.00	1.50
Upper	3.90	3.50	3.00

Within the land-use component of NZB, implemented through MAgPIE-Brazil, GDP is also an exogenous driver and influences future demand for agricultural commodities, trade flows, and land-use change [10]. However, the GDP assumptions embedded in the current MAgPIE-Brazil configuration could not be modified within the scope of NZB v1.0. As a result, the first version of the platform adopts the closest available Shared Socioeconomic Pathways (SSPs)[255]²³ already implemented in MAgPIE-Brazil as proxies for the NZB economic growth scenarios.

To ensure consistency between the land-use module and the other components of the NZB framework, NZB v1.0 uses the closest available Shared Socioeconomic Pathways (SSPs) implemented in MAgPIE-Brazil as proxies for the selected GDP scenarios. The correspondence was established based on the similarity of the projected GDP growth trajectories between 2025 and 2050 and is summarized in Table 62.

²³ Shared Socioeconomic Pathways (SSPs) are a set of alternative socioeconomic development pathways widely used in climate, energy, and land-use modelling. They describe different trajectories of population growth, economic development, technological progress, and resource use. In this version of NZB, SSPs are used within MAgPIE-Brazil to represent alternative socioeconomic assumptions associated with each GDP scenario.

Table 62: *Correspondence between NZB GDP scenarios and MagPIE-Brazil proxy scenarios*

NZB GDP scenario	MagPIE-Brazil proxy
Lower	SSP3
Reference	SSP2
Upper	SSP5

Future versions of NZB may implement custom GDP trajectories directly within MAgPIE-Brazil, allowing full harmonization of GDP assumptions across all model components.

4.2 Deforestation, area protection and restoration

4.2.1 Natural vegetation

NZB v1.0 considers three scenario options for natural vegetation loss for the 2025-2050 period, and include options associated with the incremental strength of deforestation control, as described in Figure 97. These first version scenarios do not capture the full spectrum of Brazilian land conservation dynamics yet and are meant as a first approximation. They will be expanded and adjusted in upcoming revisions of the platform to include Brazil-specific issues such as non-compliance to Forest Code land conservation (aka the environmental deficit) and increased ecological restoration.

5. Natural vegetation



Figure 97: Scenario options for the loss and gain of native vegetation.

A. No deforestation control This scenario assumes that no additional measures are implemented to reduce deforestation or the conversion of native vegetation beyond baseline conditions. Native vegetation conversion follows the model's endogenous land-use dynamics in response to future demand for agricultural products and other land-use pressures.

B. Forest Code implementation This scenario assumes the implementation of current policies aimed at eliminating illegal deforestation and reducing the conversion of native vegetation. Compared to Option A, additional restrictions based on the Brazilian Forest Code (Law 12.651/2012)²⁴ are imposed on the conversion of native ecosystems, resulting in lower levels of native vegetation loss.

C. Reduction in deforestation This scenario assumes more stringent restrictions on deforestation and the conversion of native vegetation than those adopted in Option B. As a result, native vegetation conversion is further reduced relative to the other scenarios.

²⁴Law nº 12.651, from May 25th, 2012, also known as the Native Vegetation Protection Law: https://www.planalto.gov.br/ccivil_03/_ato2011-2014/2012/lei/112651.htm

4.2.2 Protected areas

This first version of NZB considers three scenario options for natural vegetation gain and loss for the 2025-2050 period (Figure 98). These options are used to guide the spatial allocation of transitions from native vegetation both in MagPIE-Brazil and SEALS. However, carbon removals from the vegetation within these protected areas are produced in the AFOLU Accounting Tool (AAT) and reported *a posteriori*, in such a way that the user can clearly see what the impacts of these removals on the overall net zero targets are. The reasoning behind this was described in section 3.4.2.

Scenarios options on the expansion of protected areas, in this current version, are those already implemented in MAGPIE-Brazil. In upcoming versions, these will be adjusted to include Brazil-specific and policy-driven changes in area protection, including priority areas defined by the Environmental Ministry and undesignated public forests.

6. Protected areas

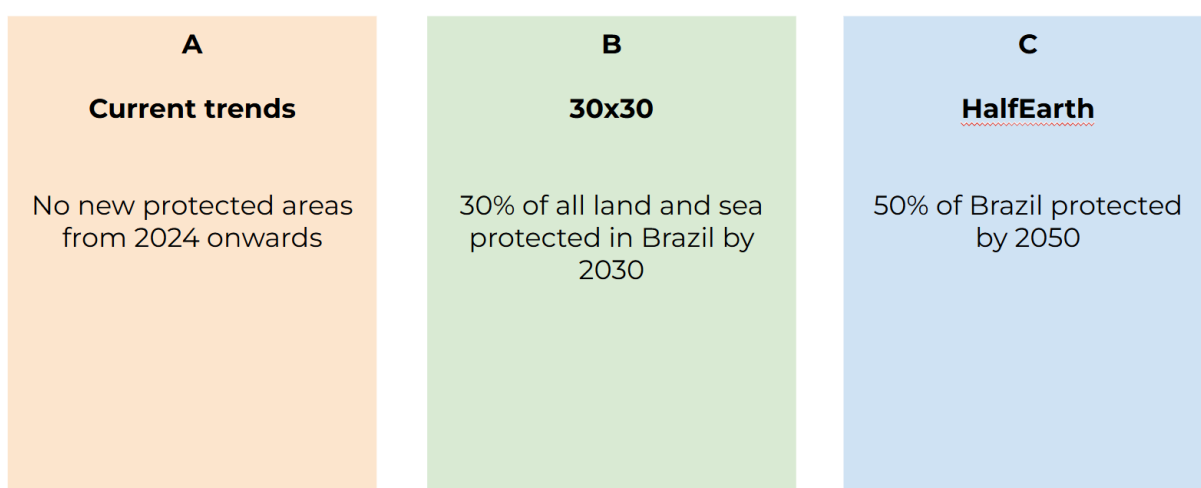


Figure 98: Scenario options related to protected areas.

A. Current trends This presents a scenario of stagnation in the creation of protected areas from the baseline of 2024. The other two scenarios are related to incremental ambitions related to the creation of new protected areas.

B. 30x30 The first is the 30x30 project, proposed by the Kunming-Montreal Global Biodiversity Framework (GBF)²⁵, which postulates that 30% of all land and sea should be protected worldwide by 2030. We applied this same proportion to Brazil's territory.

C. HalfEarth In the most ambitious scenario, protection grows until reaching 50% of Brazilian territory protected by 2050. This is based on the targets proposed by the HalfEarth Project²⁶.

²⁵The **30x30 project** is a global conservation target aiming to protect at least 30% of Earth's land, freshwater, and ocean areas by 2030. Formally adopted as Target 3 of the Kunming-Montreal Global Biodiversity Framework under the UN Convention on Biological Diversity, it traces back to a foundational scientific paper by [246]

²⁶The Half-Earth Project is a global conservation initiative by the E.O. Wilson Biodiversity Foundation that aims to protect 50% of the earth's land and sea to reverse the species extinction crisis and secure the long-term health of the planet. The main reference behind the project is [247]

4.3 Agriculture and livestock

4.3.1 Forestry

Planted forests in NZB are represented as a managed land-use category within MAgPIE-Brazil. Forestry scenarios define alternative assumptions regarding the expansion of planted forest area over time, influencing land allocation, biomass production, and associated greenhouse gas emissions and removals.

The forestry scenarios available in NZB are described below (Figure 99).

07. Forestry

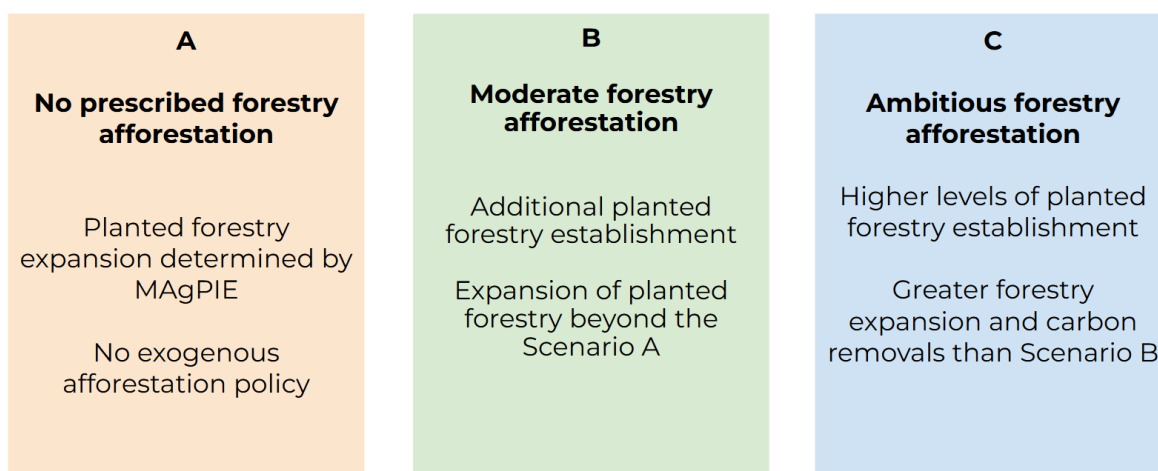


Figure 99: Scenario options related to forestry

A. No prescribed forestry afforestation This scenario does not impose any exogenous afforestation target or policy for planted forestry systems.

The establishment of new planted forest areas is determined endogenously through the model optimization process, considering land availability, production costs, biomass demand, competition among alternative land uses, and the assumptions selected for other user scenario variables.

As a result, changes in planted forest area emerge from the model and reflect the least-cost land allocation pathway consistent with the broader socioeconomic and policy assumptions adopted in each simulation.

B. Moderate forestry afforestation

Additional planted forest establishment is introduced through scenario assumptions, resulting in greater expansion of planted forest area than in Scenario A.

C. Ambitious forestry afforestation

Higher levels of planted forest establishment than with Option B result in greater expansion of planted forestry area and associated carbon removals, allowing assessment of more ambitious forestry-based mitigation pathways.

4.3.2 Cropland management systems

Crop management systems are represented through scenario-specific pathways that define the distribution of cropland areas among Conventional tillage, No-till practice, and Full no-till system over time. While total cropland area is provided by MAgPIE-Brazil, the AFOLU Accounting Tool specifies how this area is distributed across crop management systems according to alternative assumptions regarding the adoption of conservation agriculture practices. The resulting trajectories influence greenhouse gas emissions and removals through the application of the emission and removal factors described in Section 3.4.2.

The baseline distribution of crop management systems was derived from historical information compiled by FEBRAPDP and SEEG²⁷, which provide information on the adoption of no-tillage systems across Brazilian states. These data constitute the starting point for all NZB scenarios and are used to allocate national cropland projections across states and crop management systems.

Four alternative pathways were developed to represent different levels of policy implementation and adoption of conservation agriculture practices (Figure 100).

08. Cropland management systems

A	B	C	D
Historical trend	Implementation of the ABC+ and Brazil Climate Plan	High adoption of no-tillage (80% by 2035)	Constant
Continuation of historical trends (2010–2024)	Target: +4.5 Mha by 2030 for SPD (No-tillage system)	ABC+ pathway until 2030	Flat trajectory
No additional policy or structural changes	+8 Mha by 2030 for PD (No-till practice)	Accelerated expansion post-2031	No change over time, proportions are fixed at baseline (2024)
Target: none	Assumption: Stabilization after 2030	Target: 80% of cropland under PD and SPD systems by 2035	Target: none

Figure 100: Scenario options related to cropland management systems

A. Historical trend (BAU) The Historical Trend scenario assumes the continuation of observed trends in crop management systems between 2010 and 2024, corresponding to the ABC and ABC+ Plan[256] period. No additional structural changes, policies, or management interventions are assumed after 2024.

Future trajectories are derived through linear extrapolation of historical observations and extended through 2050. To maintain consistency with sectoral projections published by the Ministry of Agriculture

²⁷The NZB framework, through the AAT, uses SEEG data to represent crop management systems consistently with the methodological scope adopted by the Brazilian National GHG Inventory and the IPCC Guidelines. Represented crops include triticale, ramie, malva, flax, jute, sunflower, potato, sweet potato, broad bean, pea, onion, garlic, melon, watermelon, pineapple, tomato, castor bean, tobacco, cotton (herbaceous and tree cotton), sorghum, barley, rye, oat, groundnut, cassava, wheat, common bean, rice, maize, soybean, and sugarcane.

and Livestock (MAPA)²⁸, annual rates of change are constrained by the projected expansion of grain-crop area in Brazil, estimated at approximately 1.5% per year over the projection period. Projected management-system shares are subsequently applied to the total cropland area projected by MAgPIE-Brazil, ensuring that the sum of Conventional tillage, No-till practice, and Full no-till systems equals the total cropland area available in each modelling period.

This scenario serves as the NZB business-as-usual (BAU) pathway.

B. Implementation of the ABC+ and Brazil Climate Plan This scenario assumes the effective implementation of the targets established under the ABC+ Plan[256] and the Brazil Climate Plan[257] for the expansion of conservation agriculture practices. The following targets are considered:

1. Expansion of the Full no-till system (SPD) by 4.5 million hectares by 2030²⁹ relative to the 2019 levels;
2. Expansion of No-till practices (PD) by 8 million hectares by 2030 relative to the 2019 levels.

Since these targets are established at the national level, they are allocated across states proportionally to the area under Conventional tillage in the baseline year of the ABC+ Plan period (2019). This approach prioritizes the conversion of cropland in states with the largest potential area available for transition. All expansion of SPD and PD is assumed to originate from areas previously classified as Conventional tillage, while total cropland area remains consistent with the land-use projections generated by MAgPIE-Brazil.

Between 2025 and 2030, the expansion of SPD and PD is represented through linear interpolation towards the policy targets. Following the achievement of these targets, the distribution of cropland among management systems is held constant. Consequently, from 2030 onwards, no additional transitions among crop management systems are assumed, reflecting the full implementation of currently established sectoral policies.

C. High adoption of no-tillage This scenario follows the Implementation of the ABC+ and Brazil Climate Plan pathway until 2030. From 2031 onwards, additional transitions among crop management systems are assumed beyond current policy commitments, with the objective of allocating 80% of cropland area to conservation agriculture systems (PD + SPD) by 2035, while the remaining 20% remains under Conventional tillage. Within the conservation agriculture area, 80% is allocated to No-till practice (PD) and 20% to Full no-till systems (SPD), consistent with the allocation assumptions adopted in the AAT.

The transition between 2031 and 2035 is represented through linear interpolation, ensuring a gradual shift towards conservation agriculture practices while preserving consistency with the total cropland area projected by MAgPIE-Brazil. After 2035, the distribution of cropland among management systems remains constant throughout the remainder of the projection period.

This scenario represents an ambitious transformation pathway beyond the targets currently established

²⁸ The agricultural growth assumptions adopted in this scenario are consistent with the projections presented in *Projeções do Agronegócio: Brasil 2023/24 a 2033/34* published by the Ministry of Agriculture and Livestock (MAPA).

²⁹ The Brazil Climate Plan includes an additional target of 0.13 million hectares of SPD by 2035. However, this expansion refers to horticultural systems and is therefore not incorporated into the NZB framework. The agricultural systems represented in NZB follow the methodological scope adopted by the Brazilian National GHG Inventory, IPCC Guidelines, and SEEG.

under the ABC+ Plan and the Brazil Climate Plan, maximizing the adoption of conservation agriculture practices within the crop categories represented in the NZB framework.

D. Constant This scenario assumes that crop management practices remain unchanged after 2024. The observed distribution of cropland areas among Conventional tillage, No-till practices, and Full no-till systems is maintained throughout the entire projection period.

No transitions among crop management systems are assumed after 2024. Consequently, changes in greenhouse gas emissions and removals arise exclusively from variations in total cropland area projected by MAgPIE-Brazil rather than from changes in agricultural management practices.

Total cropland area continues to follow the corresponding MAgPIE-Brazil projections, while the proportions allocated to each crop management system remain fixed throughout the remainder of the modelling period.

4.3.3 Nitrogen use efficiency

Nitrogen use efficiency (NUE) represents the proportion of applied nitrogen that is converted into agricultural production. Improvements in NUE reduce nitrogen losses from agricultural systems and can contribute to lower nitrous oxide (N₂O) emissions while maintaining crop and livestock productivity.

In NZB, NUE scenarios are implemented through the nitrogen soil budget module of MAgPIE-Brazil and represent alternative assumptions regarding future improvements in nutrient-use efficiency across agricultural systems. These assumptions influence nitrogen requirements and associated emissions throughout the modelling period.

Because MAgPIE-Brazil is a global land-use model, NUE assumptions are implemented across all model regions rather than only in Brazil. Consequently, changes in NUE may also affect agricultural production, trade flows, land-use allocation, and associated emissions in other regions through global market interactions.

The NUE scenarios available in NZB are described in Figure 101³⁰.

³⁰The NUE trajectories shown in Figure 2 are referenced to 2050 because this is the final year of the NZB modelling horizon and corresponds to the year for which the MAgPIE-Brazil parameterisations are defined. However, NZB users may select different net-zero target years (2040, 2045, or 2050). In these cases, nitrogen use efficiency is represented according to the corresponding point along the scenario trajectory at the selected target year.

09. Nitrogen use efficiency in croplands

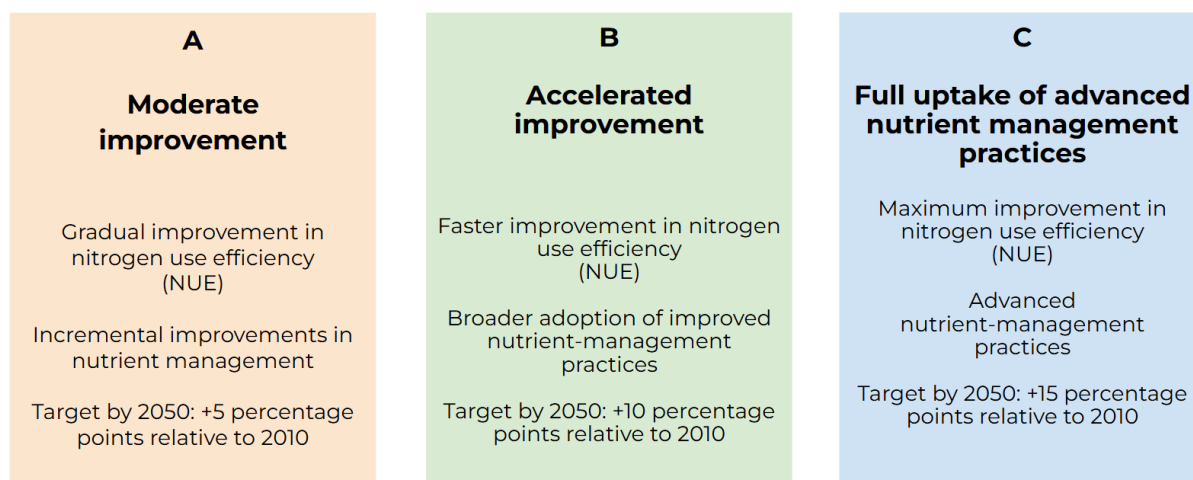


Figure 101: Scenario options related to nitrogen use efficiency

A. Moderate improvement This scenario assumes gradual improvements in nitrogen use efficiency over time.

It represents a 3 percentage-point increase in NUE by 2020 and a 5 percentage-point increase by 2050 relative to baseline values (2010), with a maximum NUE of 65%.

B. Accelerated improvement This scenario assumes faster improvements in nitrogen use efficiency than those represented in the Moderate Improvement scenario.

It corresponds to a 3 percentage-point increase in NUE by 2020 and a 10 percentage-point increase by 2050 relative to baseline values (2010), with a maximum NUE of 75%.

Compared with the Moderate Improvement scenario, this pathway assumes a more rapid adoption of improved nutrient-management practices and technologies.

C. Full uptake of advanced nutrient management practices This scenario represents an ambitious nutrient-management pathway.

It corresponds to a 3 percentage-point increase in NUE by 2020 and a 15 percentage-point increase by 2050 relative to baseline values (2010), with a maximum NUE of 75%.

This scenario assumes the widespread adoption of advanced nutrient-management practices and represents the highest level of nitrogen-use efficiency improvement considered within the NZB framework. It is intended to explore the mitigation potential associated with maximizing nitrogen-use efficiency across agricultural systems.

4.3.4 Dietary patterns

Dietary patterns in NZB are represented through the food demand module of MagPIE-Brazil [10]. Food demand is determined by interactions among population growth, income, food prices, calorie requirements, and dietary preferences. As a global land-use model, MagPIE-Brazil estimates future demand for agricultural commodities and livestock products across all world regions, which

subsequently influences agricultural production, land-use allocation, and associated greenhouse gas emissions.

In MAgPIE-Brazil, dietary scenarios combine two components:

1. alternative socioeconomic development pathways represented by the Shared Socioeconomic Pathways (SSPs, [255])³¹, and
2. optional dietary interventions that explicitly modify food consumption patterns.

The dietary scenarios available in NZB are described in Figure 102.

10. Dietary patterns

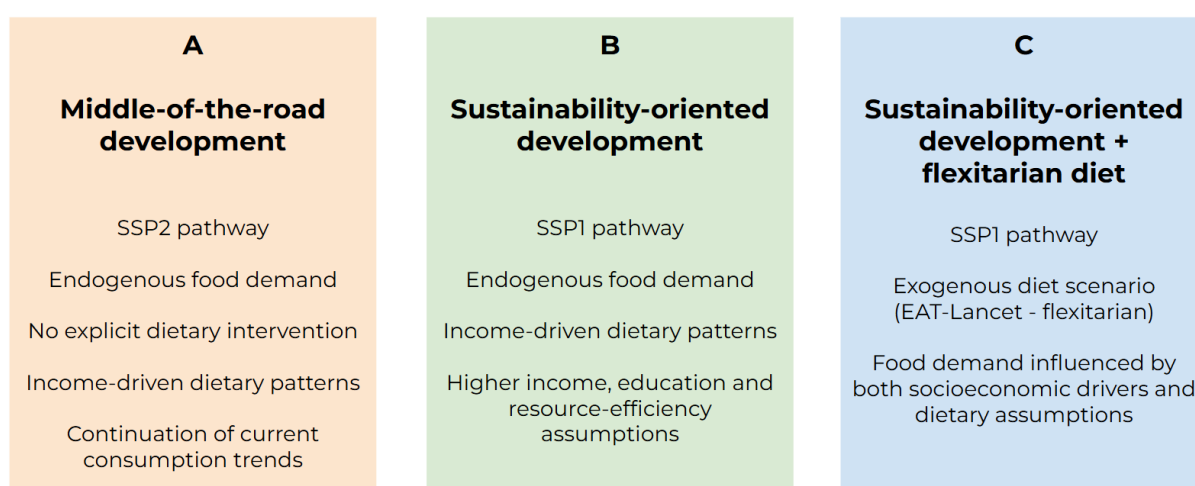


Figure 102: Scenario options related to dietary patterns

A. Middle-of-the-road development This scenario adopts the SSP2 pathway and represents a development trajectory in which social, economic, and technological trends do not shift markedly from historical patterns. Food demand is determined endogenously within MAgPIE-Brazil based on interactions among population growth, income, food prices, and model-estimated demand elasticities. No explicit dietary intervention is applied.

Dietary composition is therefore determined by the model's internal food demand relationships and responds exclusively to changes in the underlying socioeconomic drivers. No food-group consumption targets or exogenous dietary assumptions are imposed.

This scenario serves as the NZB business-as-usual (BAU) pathway for food consumption.

B. Sustainability-oriented development This scenario adopts the SSP1 pathway while maintaining endogenous food demand. As in the previous scenario, food demand is determined within the model through interactions among population, income, food prices, and demand elasticities. No explicit

³¹ Shared Socioeconomic Pathways (SSPs) are a set of alternative socioeconomic development narratives widely used in climate and land-use modelling. They describe different future trajectories of population growth, economic development, technological change, education, and resource use. In NZB, dietary scenarios are linked to SSP. SSP1 represents a sustainability-oriented development pathway, while SSP2 assumes that social, economic, and technological trends continue broadly along historical patterns.

dietary intervention or food-group consumption target is imposed.

SSP1 represents a socioeconomic pathway characterized by lower inequalities, improved human well-being, and more resource-efficient patterns of development. Within NZB, these socioeconomic assumptions influence food demand through their effects on population and income trajectories and are applied globally across all regions represented in MAgPIE-Brazil.

Consequently, food consumption patterns evolve endogenously within the model in response to socioeconomic drivers and market interactions. While SSP1 is generally associated with more sustainable development pathways, the model does not prescribe specific shifts toward either animal-based or plant-based foods. Instead, dietary composition emerges from the interaction of demographic, economic, and market factors and may vary across regions, including both Brazil and the rest of the world.

C. Sustainability-oriented development + flexitarian diet This scenario combines the SSP1 pathway with an exogenous dietary scenario based on the EAT-Lancet flexitarian diet³²[258]. As in the previous scenario, the broader socioeconomic context is defined by SSP1. However, food demand is additionally influenced by externally defined assumptions regarding the composition of food consumption.

The dietary transition is implemented through the MAgPIE-Brazil specific representation of the EAT-Lancet framework, which defines target consumption ranges for major food groups. These assumptions influence the composition of food demand while maintaining a diversified diet that includes both plant-based and animal-source foods.

The transition begins in 2025 and progresses linearly until 2050, when full convergence to the selected dietary scenario is achieved. During this period, food demand is shaped by both the socioeconomic conditions associated with SSP1 and the exogenous dietary assumptions implemented in the model.

4.3.5 Pasture condition dynamics

Pasture vigor dynamics are represented through scenario-specific pathways that define the distribution of pasture areas among the AAT categories of Degraded, Intermediate, and Well-managed pasture classes, mapped from low, medium, and high vigor Mapbiomas classes, respectively. While the total pasture area is provided by MAgPIE-Brazil, the AFOLU Accounting Tool specifies how this area is distributed across vigor classes according to alternative assumptions regarding pasture recovery and management improvement. The resulting trajectories influence greenhouse gas emissions and removals through the application of the emission and removal factors described in Section 3.4.2.

The baseline distribution of pasture vigor classes was derived from MapBiomas Collection 10, which provides state-level information on pasture condition across Brazil. These data constitute the starting point for all NZB scenarios and are used to allocate the national pasture area projected by MAgPIE-Brazil across states and pasture vigor classes.

Four alternative pathways were developed to represent different levels of policy implementation and

³²The EAT-Lancet flexitarian diet is a dietary pattern proposed by the EAT-Lancet Commission that defines reference consumption ranges for major food groups, including whole grains, fruits, vegetables, legumes, nuts, dairy products, fish, poultry, and red meat. Rather than eliminating animal-source foods, the framework specifies a balanced dietary composition intended to provide nutritional adequacy while reducing pressures on environmental systems.

pasture restoration efforts (Figure 103).

11. Pasture condition dynamics

A	B	C	D
Historical trend	Implementation of the ABC+ and Brazil Climate Plan	100% well-managed pastures by 2035	Constant
Continuation of historical trends in pasture vigor classes (2010–2024) No additional policy or structural changes Target: none	Target: +30 Mha of well-managed pastures Assumption: Reallocation from degraded to well-managed pasture; Stabilization after 2030	ABC+ pathway until 2030 Target: 100% of pasture area classified as well-managed by 2035 Assumption: Progressive conversion of degraded and intermediate pastures	Flat trajectory No change over time, proportions are fixed at baseline (2024) Target: none

Figure 103: Scenario options related to pasture condition dynamics

A. Historical trend (BAU) The Historical Trend scenario assumes the continuation of observed trends in pasture condition between 2010 and 2024, corresponding to the ABC and ABC+ Plan period. No additional structural changes, policies, or management interventions are assumed after 2024.

Future trajectories are derived through linear extrapolation of historical observations and extended through 2050. Under this scenario, the distribution of pasture area among Degraded, Intermediate, and Well-managed pasture classes evolves according to historical trends, without the introduction of additional policy-driven measures or restoration targets.

This scenario serves as the NZB business-as-usual (BAU) pathway.

B. Implementation of the ABC+ and Brazil Climate Plan This scenario assumes the full implementation of the pasture restoration target established under the ABC+ Plan and the Brazil Climate Plan, corresponding to the recovery of 30 million hectares of degraded pasture by 2030 based on 2019 levels.

Because the ABC+ Plan establishes a national target without state-level disaggregation, the restoration target is allocated across states proportionally to each state's share of the national Degraded pasture area observed in 2019, which corresponds to the baseline year adopted by the policy framework. States with larger degraded pasture areas therefore receive a larger share of the restoration effort.

To operationalize the national restoration target within the AAT, 30 million hectares are progressively reallocated from the Degraded (low-vigor) category to the Well-managed (high-vigor) category by 2030. The Intermediate pasture class is adjusted as a residual category, ensuring that the sum of Degraded, Intermediate, and Well-managed pasture areas remains equal to the total pasture area projected for each modelling period.

After 2030, no additional transitions among pasture vigor classes are assumed. This scenario represents the full implementation of the current ABC+ and Brazil Climate Plan targets, without

additional restoration or management interventions beyond those already established. As a result, the distribution of pasture areas across vigor classes remains constant throughout the remainder of the projection period.

C. 100% well-managed pastures by 2035 This scenario assumes the full implementation of the ABC+ and Brazil Climate Plan pathway until 2030, including the recovery of 30 million hectares of degraded pasture. Therefore, the distribution of pasture vigor classes follows the Implementation of the ABC+ and Brazil Climate Plan scenario during the 2025–2030 period.

From 2031 onwards, additional improvements in pasture management are assumed beyond the current policy targets. The scenario represents an accelerated transition pathway in which pasture areas continue to be progressively reallocated towards the Well-managed pasture class, with the objective of achieving 100% well-managed pasture by 2035. Areas classified as Degraded pasture and Intermediate pasture are progressively converted to Well-managed pasture between 2031 and 2035.

After 2035, no additional transitions among pasture vigor classes are assumed, as the target of full conversion to well-managed pasture has been achieved. Consequently, all pasture area remains classified as Well-managed pasture for the remainder of the projection period.

D. Constant This scenario assumes that pasture vigor conditions remain unchanged after 2024. The observed distribution of pasture areas among the Degraded pasture, Intermediate pasture, and Well-managed pasture classes is maintained throughout the entire projection period. Consequently, changes in greenhouse gas emissions and removals arise exclusively from variations in total pasture area projected by MAgPIE-Brazil rather than from changes in pasture management conditions.

4.3.6 Manure management systems

Manure management systems represent the practices and technologies used to manage livestock manure after excretion. Different systems are associated with different methane (CH₄) and nitrous oxide (N₂O) emission profiles. In NZB, scenarios represent alternative assumptions regarding the future distribution of manure among these systems, influencing greenhouse gas emissions from the livestock sector.

The manure-management scenarios available in NZB are described in Figure 104.

12. Manure management systems

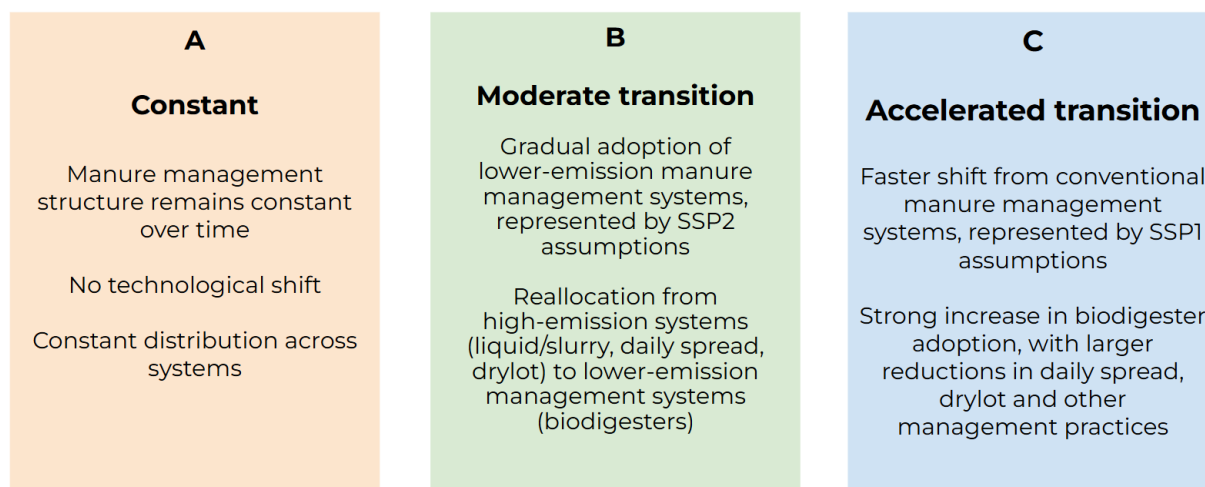


Figure 104: Scenario options related to manure management systems

A. Constant This scenario assumes that the current distribution of manure management systems remains unchanged throughout the modelling period. No transitions among manure management systems are assumed. The shares allocated to each management system are maintained for the remainder of the simulation period.

B. Moderate transition This scenario assumes a gradual transition from higher-emission manure management systems toward lower-emission treatment systems over time. In particular, it increases the share of manure treated in anaerobic digesters while reducing the share managed under systems such as liquid/slurry storage, daily spread, drylot management, and other higher-emission practices. The transition follows the SSP2 pathway, representing a gradual adoption of manure treatment technologies throughout the projection period.

C. Accelerated transition This scenario assumes a faster transition from higher-emission manure management systems toward lower-emission treatment systems than in the Moderate transition scenario. In particular, it accelerates the adoption of anaerobic digesters and increases the reallocation of manure away from liquid/slurry storage, daily spread, drylot management, and other higher-emission practices. The transition follows the SSP1 pathway and results in a larger share of manure being treated in lower-emission systems by 2050.

4.3.7 Agriculture exports

Agricultural export scenarios in NZB are implemented through the MagPIE-Brazil trade module and determine how agricultural exports evolve over time relative to domestic production.

Changes in export patterns can influence agricultural production levels, land-use allocation, and associated greenhouse gas emissions. The agriculture export scenarios available in NZB are described in Figure105.

13. Agriculture exports

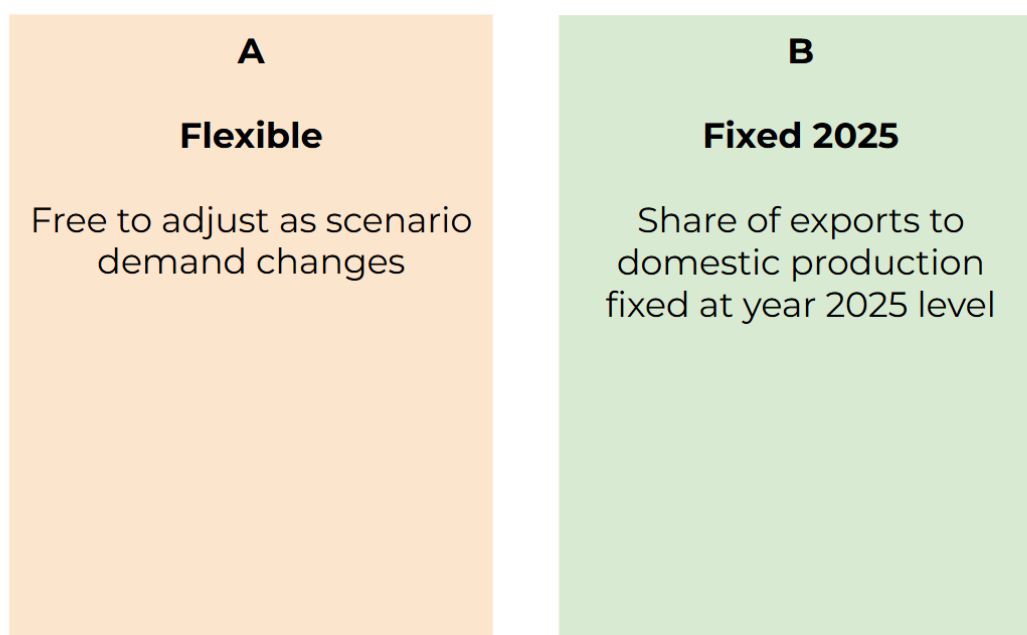


Figure 105: Scenario options for agricultural export trajectories

A. Flexible Under this scenario, agricultural exports can increase or decrease over time in response to changes in production, domestic demand, international demand, and market conditions.

This option allows trade patterns to adapt to the selected scenario assumptions and reflects a future in which agricultural exports remain responsive to economic and market developments.

Note: Because MagPIE-Brazil represents a globally connected agricultural system, changes in trade patterns may also affect production, land use, and greenhouse gas emissions in other regions. The Fixed 2025 scenario provides an alternative in which export shares remain constant over time.

B. Fixed 2025 Under this scenario, the share of agricultural production allocated to exports remains fixed at its 2025 share of total production throughout the modelling period.

Export volumes may still change as agricultural production changes. However, the proportion of production directed to export markets remains constant, preventing exports from becoming more or less important over time.

This scenario represents a future in which agricultural trade patterns remain broadly consistent with those observed in 2025. By limiting changes in export orientation over time, it allows mitigation outcomes to be driven primarily by changes within the agricultural sector itself.

4.4 Transport

Two transport specific user-definable variables are available in the current version of the NZB model: urban mobility patterns (section 4.4.1) and vehicle technology (section 4.4.2). Transport related energy demand is also affected by GDP (section 4.1.4) and biofuels mandates (section 4.7.4) as described in section 3.1.1.

4.4.1 Urban mobility

The user can choose between two options to define the level of activity of passenger transport in NZB. Both options are based on the scenarios presented in the 2024 study "Cidades Compactas Eletrificadas: Brasil", written by the Institute for Transportation and Development Policy and the University of California Davis [259].

The "business as usual" option represents the continuation of current urban transport and land-use trends, with increasing car dependency and continued expansion of road infrastructure. The "mode shift" represents the prioritization of compact urban development and a transition from private cars to walking, cycling, and high-capacity public transport. By reducing car travel demand and expanding sustainable mobility infrastructure, this path reduces infrastructure costs and improves urban accessibility. In quantitative terms for modeling passenger transport emissions, the key variable to be extracted from the study is the passenger-kilometers traveled for each category of vehicles, as described in section 3.1.1. Figures 107 and 108 show the assumed trajectories of passenger-kilometers for each variable option.

4.4.2 Vehicle technology

The user can choose between three options to define the level of vehicle technology change over time, expressed in terms of the share of each technology in new vehicle sales. The options are based on a set of published studies.

The option with lower technology change is based on the Brazilian 2035 Ten-Year Energy Plan [43].

The option with intermediate technology change is based on the Observatório do Clima's study "Futuro da Energia" [260].

The option with the fastest technology change is based on the International Council on Clean Transportation's study "Toward net-zero mobility: Evaluating scenarios for road transport decarbonization in Brazil" [21].

14. Urban mobility

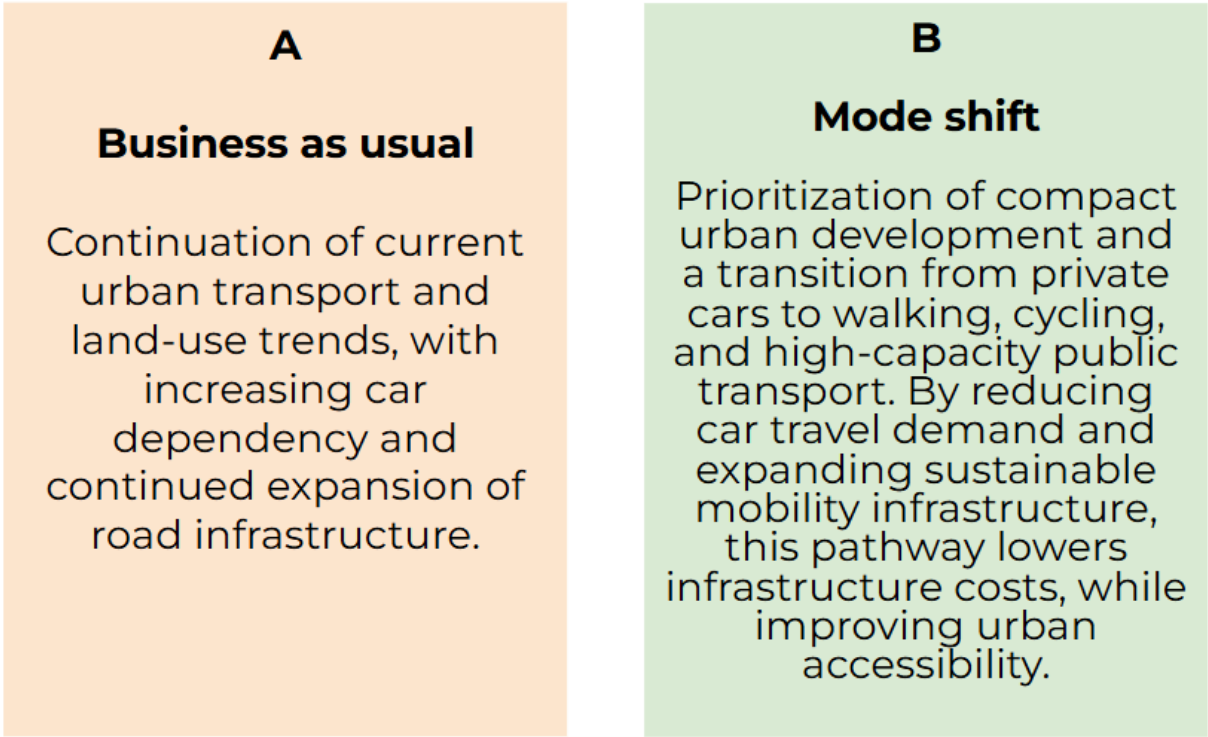


Figure 106: Scenario options for urban mobility

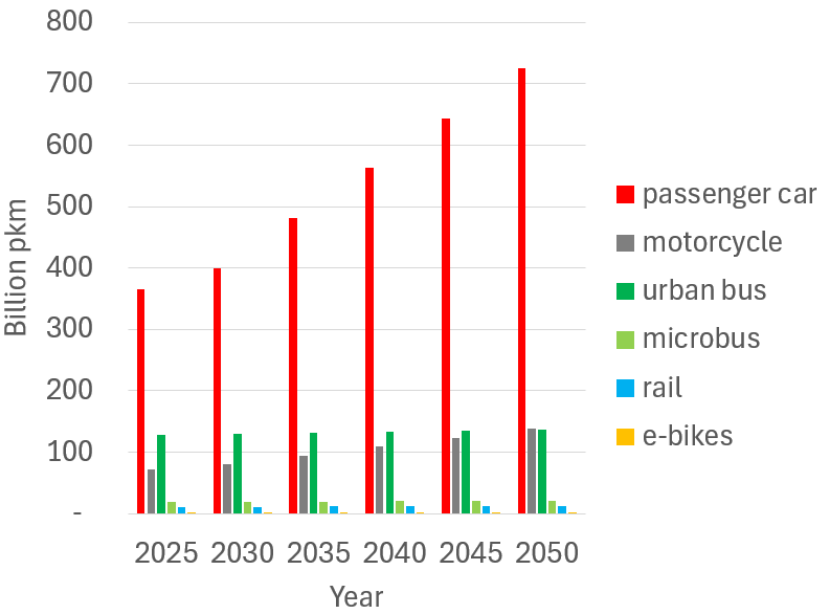


Figure 107: Passenger-kilometers travelled in the "business as usual" option

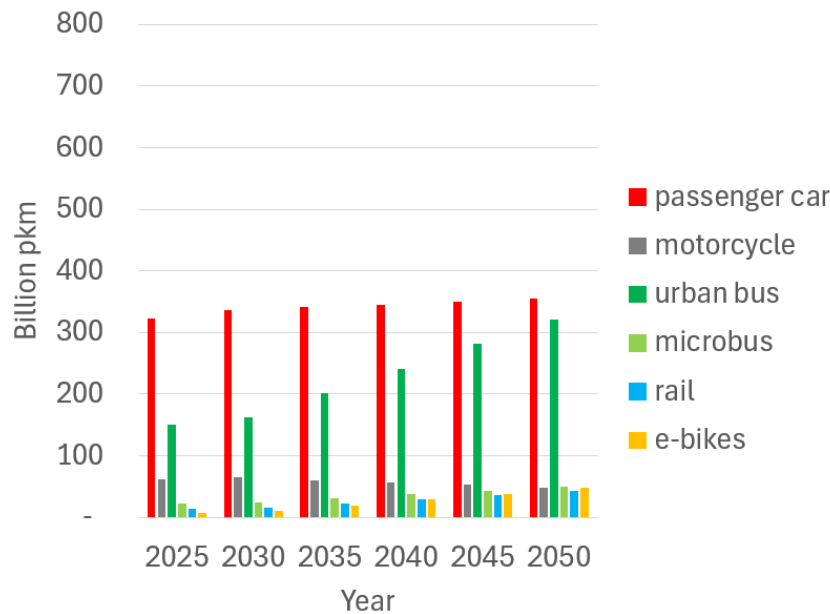


Figure 108: Passenger-kilometers travelled in the "mode shift" option

15. Vehicle technology

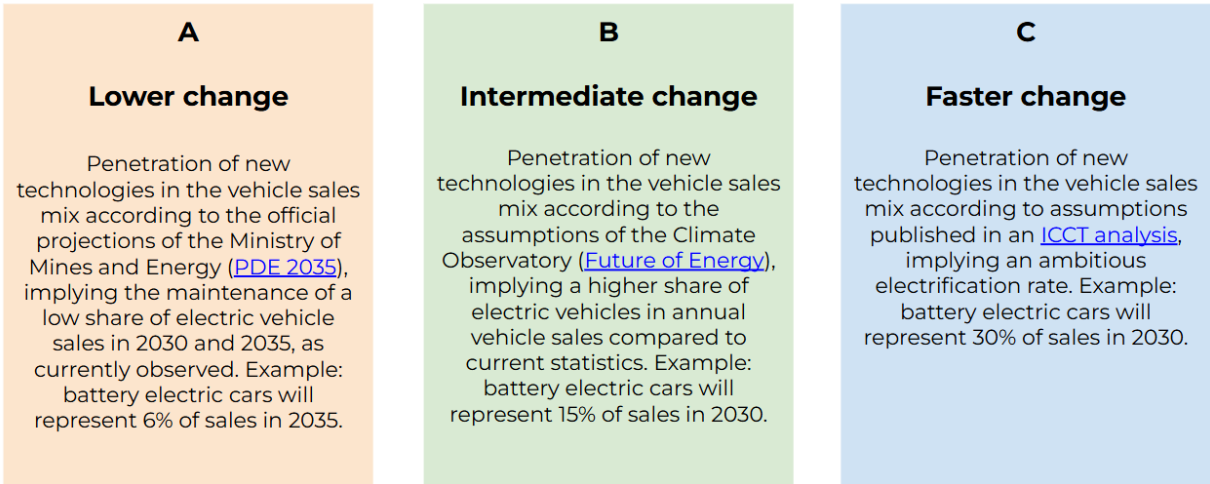


Figure 109: Scenario options for vehicle technology change

4.5 Industry

The assumptions on Industry sector were divided into three sensitivities, illustrated in Figures 110 to 112 and summarized in Tables 63, 64 and 65:

- Industrial activity;
- Industrial energy efficiency;
- Industrial energy transition.

The assumptions adopted for the energy demand forecasts in the Brazilian industrial sectors in the trend scenario were based on the trends observed in their energy consumption statistics (Figures 18 to 28) and the behavior of their decomposition equations drivers (Figures 29 to 35) during the period 1970-2025, as well as expected results, in the energy demand forecasts of (i) existing public policies promoting energy efficiency gains and modernization and (ii) industrial companies' business expansion plans.

The period between 2010 and 2025 was chosen to capture the trends for the forecasts in this scenario because of the deep structural changes that occurred in the Brazilian economy during this period. The year 2010 represents the peak of the sales of commodities by the country, resulting in a high growth in the GDP and expansion of industrial production. However, the following years were characterized by severe macroeconomic instabilities, standing out the domestic recession from 2014 to 2016 and the global shock of the COVID-19 pandemic in 2020. These events generated a high volatility in the production and value-added of the industrial sectors, affecting their energy intensity.

From a structural point of view, this period consolidates the decreasing share of the transformation industry in the Brazilian GDP. The assumption of a fall of 35% in this share for the majority of the industrial sectors in the trend scenario reflects the extension of the deindustrialization observed within this period.

On the other hand, the gains or losses of energy efficiency captured between 2010 and 2025 are the result of the organic pace of technological modernization in most of the industrial sectors in Brazil, within an environment of low investment rates and regulatory uncertainties. They form a realistic and conservative base line for the assumptions adopted in the trend scenario.

Table 63 outlines the key assumptions taken for each industrial sector in this scenario.

Table 63: *Adopted assumptions in the trend scenario for the Brazilian industrial sectors*

Sector	Expected trend up to 2050	Justification
Pig-iron and steel	Loses 35% in the share of GDP and gains 12.5 % in efficiency	This assumption reflects the energy efficiency gains and the loss in the GDP share observed from 2005 to 2025. The unit value of production and the share in industry's value added are assumed to remain stable
Iron-alloys	The specific energy consumption stabilizes and the sector loses 35% of its GDP share	The energy efficiency and the share in the industry's value-added were kept constant in this scenario due to their stable behavior in the last years. The loss in the GDP share follows the general deindustrialization of the country
Non-ferrous and other metals	Loses 15% in the GDP share and gains 10% in energy efficiency	These assumptions are based on the pace of this sector modernization captured between 2012 and 2021. The loss in the GDP share is smaller than that of the industry as a whole
Cement	Loses 35% of its GDP share, the unit value of production increases 31.5% and there is a gain of 17% in energy efficiency	The assumptions capture the significant optimization of the clinker furnaces and the big rise of the unit value of production during the period 2014-2023
Ceramics	The energy intensity stabilizes, while this industry loses 35% of its GDP share	It is a sector with heterogeneous products where it is assumed that its energy intensity and the share in the industry's value-added stabilizes at the 2024 values. This industry will only experience the macroeconomic impact of the decreasing share of the transformation industry in the GDP
Pulp and paper	The specific energy consumption stabilizes. The share of this sector in the industry's value-added increases 40%	This is a highly efficient industry whose value-added participation strongly increases in the whole industry's value added, as observed in the period 2012-2023
Foods and beverages	The energy intensity of this industry stabilizes with a slight fall and loses 35% in its share of GDP	The energy intensity and the share of the value-added of this industrial sector in the value-added of the industry as a whole stabilizes, while the industry's value-added share on the GDP plummet
Chemical	The share of this sector in the industry's value-added is expected to fall 11%, while its energy intensity stabilizes	The adopted assumption reflects the readjustment and the loss of participation of this sector in industry's value-added observed in the last two decades
Textiles	The energy intensity grows 12% and the sector loses 35% of its GDP share	The increase in the energy intensity mirrors the trend observed from 2016 to 2023
Mining and pelletization	The energy intensity grows 100%, while this industry loses 35% of its GDP share	The high increase of the energy intensity is related to the depletion of mines and the higher energy input required by the extraction, as observed since 2018
Other industries	The share of this sector in the industry's value-added is expected to grow 11% and its energy intensity stabilizes	The assumption about the increase of this sector share in the industry's value-added is based on the resilient growth of light manufacturing and non-energy-intensive industrial branches, as revealed by EPE's indicator ODEX between 2017 and 2024.

It is assumed that the mix of energy sources for all industrial sectors, except the pig-iron and steel industry, in this forecasting scenario remain unchanged as at 2024. The pig-iron and steel sector is an exception because there are already targets in this industry for the shares of natural gas and charcoal: 7% and 18%, respectively, of the total energy consumption; it is assumed that the energy sources making up the remaining 75% will keep the same relative shares observed in 2024.

4.5.1 Industrial activity

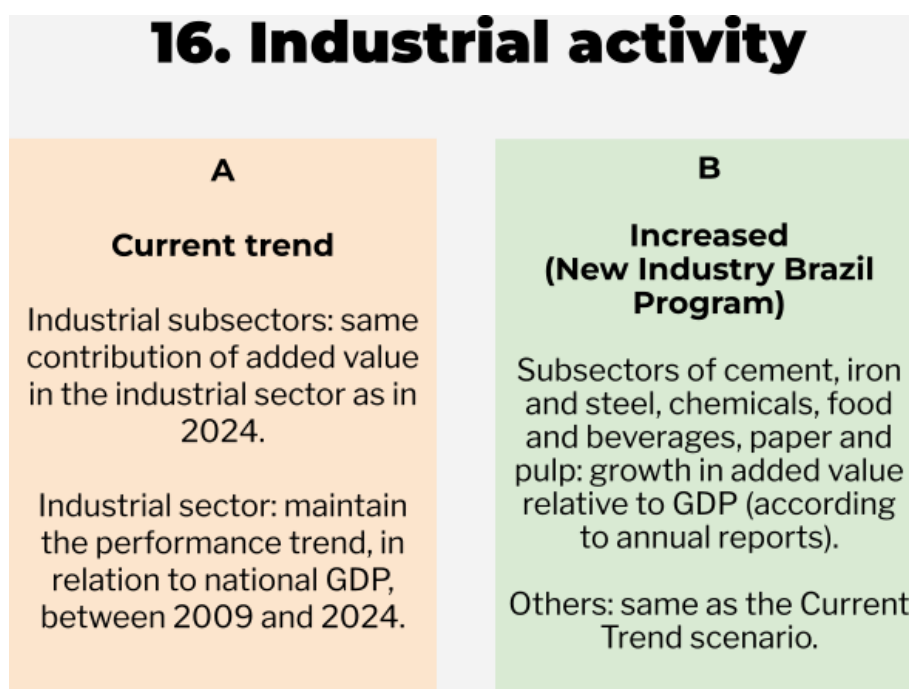


Figure 110: Industrial activity scenarios

The main objectives of the New Industry Brazil (NIB) program are the reindustrialization and modernization of the Brazilian industry in sustainable ways. A brief summary is presented in Table 64.

Table 64: Adopted assumptions of VA_{sector}/GDP in the New Industry of Brazil Scenario for the Brazilian industrial sectors

Sector	Growth of VA_{sector}/GDP (% yearly)
Cement	0.59
Pig iron and steel	0.18
Chemicals	0.18
Food and beverages	0.57
Pulp and paper	0.73
"Others"	0.0

In response to the incentives provided by the NIB program, future investment outlays have been announced for the cement, pig-iron and steel, pulp and paper, chemical, and foods and beverages

industrial sectors, together with estimates of envisaged production capacity expansion plans for the next 25 years.

The reindustrialization scenario exploits the possible impacts of these plans and past performances in improving the contributions of the industrial sectors on GDP. The following paragraphs describe how the available data can be used to estimate these changes for each of the five sectors referred to above.

There are three ways to increase the shares of the industrial sectors on GDP: (i) to expand their production capacity; (ii) to increase their capacity factor; and (iii) to improve their value-added productivity. These three possible pathways are added together in this scenario for the five types of industries evaluated here.

The Brazilian Employers' Union of the Cement Industry (SNIC) announced a total investment of R\$ 27.5 billion during the next 25 years, from which R\$ 9.62 billion should go to the expansion of production capacity. Adopting a unit cost of R\$ 0.934 billion/millions of tons, results a growth of 10.3 Mt of new capacity, which, added to the installed capacity of 109.3 Mt/year in 2026, yields a capacity of 119.6 Mt/year in 2050. Multiplying the latter by an improved capacity factor of 0.8 for this industry (it was 0.613 in 2025), results in the expected annual production of cement in Brazil in 2050. This future production can be converted to value-added multiplying it by a better value-added productivity of $0.1974 \cdot 10^3$ US\$ppp (2010)/t, achieved in 2015, 2016 and 2022 (it was $0.1803 \cdot 10^3$ US\$ppp (2010)/t in 2025). The resulting value-added can then be compared to the GDP forecast for 2050, which can assume three values in this project, in order to get the future share of this industry in the GDP.

The Institute Steel Brazil provided the information that the total investment expected for the steel industry in Brazil during the period 2026 – 2050 is R\$ 100.2 billion. From this amount, R\$ 40.08 billion is likely to be used to increase the production capacity. The assumption of a unit cost of R\$ 5.5 billion/millions of tons of steel, leads to the addition of 7.28 Mt of new capacity, which, added to the installed capacity of 51 Mt/year in 2026, results in a capacity of 58.3 Mt/year in 2050. Taking into account the obsolescence and retirement of old assets, the net capacity in 2050 will be 54.6 Mt/year. Multiplying this capacity by an improved capacity factor of 0.85% for this industry, a historical value considered ideal by the sector to optimize costs and profits (the average in the last years was 0.66) produces the expected annual production of steel in Brazil in 2050, which can be transformed into value-added multiplying it by a higher value-added productivity of $1.318 \cdot 10^3$ US\$ppp (2010)/t, achieved in 2010 (in 2025 this indicator was $1 \cdot 10^3$ US\$ppp (2010)/t). As in the case of the cement industry, the resulting value-added can then be compared to the GDP forecast for 2050.

The Brazilian Industry of Trees (Ibá) declared an investment outlay of R\$ 97.2 billions until 2029, which can assure 6 millions of tons per year of new pulp production capacity up to 2035. The pulp production in Brazil was 29.4 millions of tons in 2025 with an estimated capacity factor of 0.8, *i.e.* the installed capacity was 36.7 millions of tons per year. Adding the new pulp production capacity to the current capacity yields a capacity of 42.7 millions of tons per year in 2050. The adoption of a higher capacity factor of 0.85 for 2050 allows a production of 36.3 million tons of pulp that year. This production forecast for 2050 can be converted to value-added multiplying it by an improved value-added productivity of $0.471 \cdot 10^3$ US\$ppp (2010)/t, experienced in 2013 (it was $0.296 \cdot 10^3$ US\$ppp (2010)/t in 2025). As proposed for the two previous industrial sectors, the resulting value-added can then be compared to the GDP forecast for 2050.

The Brazilian Association of the Chemical Industry (Abiquim) announced an investment of R\$ 100 billions during the period 2026-2050, from which R\$ 30 billions should be employed for the expansion of production capacity of chemicals of industrial use. Adopting a unit investment cost of R\$ 10 billions per million tons of chemicals of industrial use results in a new production capacity of 3 Mt/year of these products. According to Abiquim, the current capacity is 65 Mt/year, which, multiplied by the current capacity factor of 0.64, yields a production of 41.6 Mt of chemicals of industrial use. The production capacity forecast for 2050, 68 Mt/year, is the sum of the current capacity with the expected new capacity. Assuming a better capacity factor of 0.80, experienced in 2009, 2011 and 2016, the production of these chemicals in 2050 is forecast at 54.4 Mt. Dividing the current value-added of the chemicals industry ($19,921 \cdot 10^6$ US\$ppp (2010)) by the current production results in a value-added productivity of $0.4789 \cdot 10^3$ US\$ppp (2010)/t. The assumption of a slightly higher value-added productivity, of $0.50 \cdot 10^3$ US\$ppp (2010)/t, in 2050 leads to a value-added of $27.2 \cdot 10^6$ US\$ppp (2010) in that year, which can be compared to the GDP forecast.

According to the Brazilian Association of the Foods Industry (ABIA), this industrial sector planned to invest R\$ 120 billions during the 2023-2026 period [261], with a perspective of continuity. From this total amount of investment, R\$ 75 billions target the expansion of production capacity, particularly in the exporting branches of animal protein and grain products, yielding an expansion of 16.1% from 2026 to 2050. ABIA declares that this industry produced 288 Mt of foods and beverages in 2025 [261]. Assuming a capacity factor of 0.8³³ results a producing capacity of 360 Mt in 2025, which is expected to increase to 418 Mt in 2050. The value-added productivity in 2025 can be calculated as the ratio between the value-added of this industrial sector in this year ($59,480 \cdot 10^6$ US\$ppp (2010)) and the production (288 Mt) in this year, resulting in $0.2065 \cdot 10^3$ US\$ppp (2010)/t. This industry production in 2050 – 355.3 Mt - can be obtained assuming, for instance, a higher capacity factor of 0.85. Assuming now an improved value-added productivity of $0.25 \cdot 10^3$ US\$ppp (2010)/t and multiplying it by the estimated production in 2050 yields a value-added of $88,825 \cdot 10^6$ US\$ppp (2010) in that year, which, divided by the forecast GDP, finally determines the share of this industry within the main indicator of the Brazilian economy performance.

³³A large amount of small and medium size companies are important players in this industry, making, however, practically impossible nowadays to measure accurately this industry's capacity factor.

4.5.2 Industrial energy efficiency

17. Industrial energy efficiency

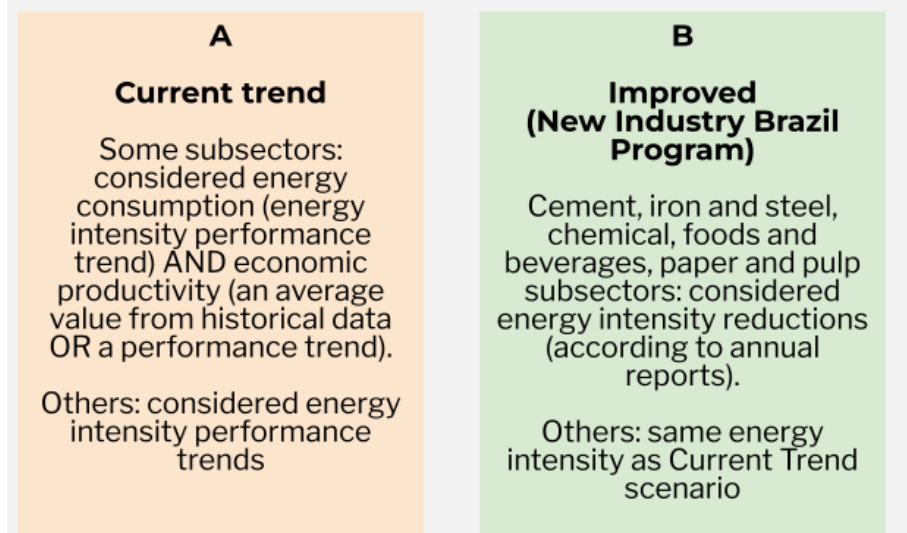


Figure 111: Industrial energy efficiency scenarios

Energy efficiency gains, reflected in reductions of the unit energy consumption, for industrial sectors with homogeneous products, or reductions in the energy intensity, for industries with heterogeneous products, can be obtained with energy efficiency actions but keeping the mix of fuels considered in the trend scenario, or the electrification of processes consuming fossil fuels can be added to the energy efficiency actions, reducing the consumption of fossil fuels.

Therefore, two scenarios are described in this section, related to the two possibilities of getting energy efficiency gains referred to above. Table 65 summarizes the changes of energy consumption in the New Industry of Brazil scenario.

Table 65: Adopted assumptions of energy consumption in the New Industry of Brazil Scenario for the Brazilian industrial sectors

Sector	Reduction in energy consumption (% yearly)
Cement	-1.63
Pig iron and steel	-1.19
Chemicals	-1.03
Food and beverages	-0.98
Pulp and paper	-0.82
"Others"	-1.19

Scenario adopting just energy efficiency measures

In this scenario, energy efficiency gains in the consumption of both thermal and electric energy are considered, taken into account measures such as the use of high-efficiency motors, optimization of

the generation, distribution and use of steam, residual heat recovery, digitalization, etc., but keeping the mix of fuels included in the trend scenario.

According to the Cement Technology Roadmap 2050 [262], published by the Brazilian Employers' Union of the Cement Industry (SNIC), there is a target of 33% reduction in the unit energy consumption of this industry up to the year 2050 through the use of calcined clay, which requires a temperature of 800 oC instead of the 1450 oC required by the clinker, and a larger waste co-processing. The goal is reducing the unit thermal energy consumption from 3,500 MJ/t (pure clinker) to 2,350 MJ/t.

It is expected a 5% reduction in the unit energy consumption of the Brazilian pig-iron and steel industry until 2050 through the recovery of gases and waste heat in the blast furnaces.

A sectors report [263] from the Brazilian Industry of Trees (Ibá) indicate a target of 18% reduction in the unit energy consumption of this industry implementing extending nip shoe presses, membrane-based drying, optimization of cogeneration with black liquor and digitalization of the forestry sector.

There is a target of reducing 6% of the energy intensity of the chemical industry through the use of digital twins and the optimization of heat recovery systems via Pinch analysis.

Improving thermal insulation, installing high-efficiency motors of the IE4 category and using advanced automation systems for the cold chain can provide a 3% reduction in the energy intensity of the foods and beverages industry.

According to studies carried out by the Energy Research Company (EPE), a large retrofit of inefficient motors by premium ones (IE4 and IE5 categories) and energy management systems following the guidelines of the ISO 50001 standard can achieve a 10% reduction in the energy intensity of the non-energy intensive "other industries" category.

Scenario considering energy efficiency measures combined with the electrification of thermal processes

This scenario simulates energy efficiency actions such as those referred above, added to the electrification of thermal processes, whenever feasible commercially, particularly when low or medium temperatures up to 400 oC are involved, using equipment such as industrial heat pumps, electric boilers, electric arc furnaces, induction furnaces, etc.

The industrial heat pumps [264] usually operate through a vapor compression cycle consuming electricity and waste heat from the environment or from industrial effluents as a source of thermal energy. Their operational temperature ranges can reach 150 oC. The unit energy consumption of an industrial heat pump often is around a quarter of the unit consumption of a boiler consuming fossil fuels, where the chimney losses can vary from 15% to 25% of the fuel heating value.

In an electric arc furnace a powerful electric arc is discharged into the melting metal, where local temperatures can reach 3,000 oC. Their operational temperature range can be above 1,500 oC. This type of furnace has a widespread use for refining direct reduced iron or iron and steel scrap during the stage of primary steelmaking.

Chemical reactors or electro-thermal systems consuming fuels can be replaced by magnetic induction systems, with reductions in the process' unit energy consumption.

The electrification of thermal processes has no room in the cement and pulp and paper industries. So,

their targets of reduction in their unit energy consumptions are 33% and 18%, respectively.

Based on the Net Zero emissions commitment in 2050 of several countries, including Brazil, the International Energy Agency [265] and the Brazilian Steel Institute [266] set a target of 25% reduction in the unit energy consumption of steel manufacturing until 2050. The average unit energy consumption of the Brazilian steel mills should decrease from 20 GJ/t to 15 GJ/t. This reduction requires, besides other complementary alternatives such as the consumption of char coal in blast-furnaces and a larger consumption of iron and steel scrap in electric arc furnaces (EAF), a transition of the blast-furnace route to the direct reduction of iron ore, using, initially, natural gas and, in the longer term, green hydrogen, and EAF.

The Special Program for the Sustainability of the Chemical Industry (PRESIQ), promoted by the Brazilian Association of the Chemical Industry (ABIQUM) [267], is a strategic initiative directed to the modernization, decarbonization and recovery of the Brazilian chemical industry. The Program has a duration from January 1st, 2027 to December 31st, 2031. It became law³⁴ in December 22nd, 2025. PRESIQ has a target of decarbonizing this industry in 30% until 2050. To achieve that, a target of 22% reduction in the energy intensity of this industry up to 2050 was proposed, based on the electrification of chemical reactors and the energy efficiency measures explained above.

In the foods and beverages industry about 45% of the thermal energy demand requires low temperatures (under 100 oC), allowing an efficient electrification to attend this demand [268]. The Brazilian Association of the Foods Industry (ABIA) set a target of 21% for the reduction of this industry's energy intensity until 2050. The technology routes to reach this target include the installation of industrial heat pumps and the energy efficiency measures.

The guidelines of the Brazilian Long-term Energy Expansion Plan (PNE 2050) [269] and the ODEX indicator used by the Energy Research Company (EPE) [270] in the Energy Efficiency Atlas [271] allow the indication of a 26% reduction target for the energy intensity of the "other industries" category until 2050. This target can be met through the energy efficiency actions aforementioned, together with the replacement of fossil fuel consuming equipment by electric systems or low-temperature industrial heat pumps.

³⁴Law No. 15,294/2025.

4.5.3 Industrial energy transition

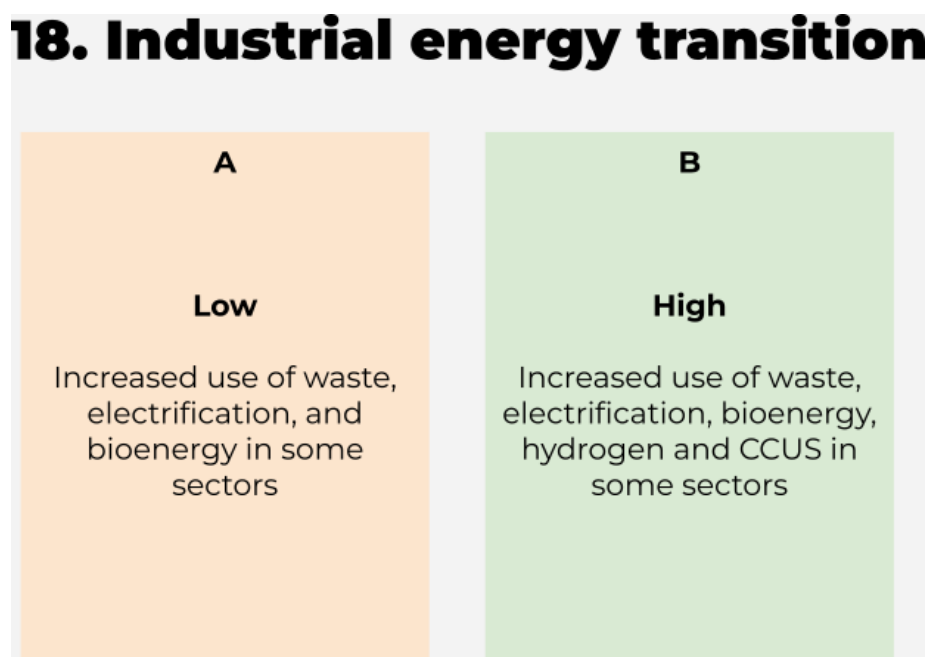


Figure 112: *Industrial energy transition scenarios*

New public policies and regulations are required to speed up the energy transition in the Brazilian industrial sectors, advancing, in time, the availability of cheaper natural gas, green hydrogen and carbon capture, utilization and storage technologies.

One of the most affected industry subsectors is the iron and steel sector. The energy transition relies on the integrated use of Electric Arc Furnaces (EAF), Direct Reduction (DR) with natural gas and the biomass in Smelting Reduction (SR) routes. Although natural gas may still depend on fossil sources, it is less carbon intensive than coke use in blast furnaces (BF). The increase of renewability in electricity generation would benefit the route EAF. Nevertheless, even with a low renewable electric mix, the EAF process still provides a gain in carbon abatement as it is a more efficient route than BF. The use of charcoal in BF is limited, but the use of biomass in SR may compensate those limitations from 2030 as innovative solutions are expected to enable the use of charcoal in SR [272]. For the current version of the model, it was assumed a trend of energy transition for substituting 40% of coal and coke in energy basis to natural gas and charcoal at the same proportion. In a fast energy transition, 95% of coal and coke would be replaced by natural gas (42%), charcoal (48%) and electricity (5%).

The data collection and analysis of energy transition for other sectors, will be further detailed in future versions of the model.

4.6 Buildings

The buildings block of the scenario space controls how the residential and commercial (services) sectors evolve to 2050. Its levers act *on top of* the bottom-up demand modules documented in Section 3.1.5 (residential), Section 3.1.6 (commercial, including public lighting) and Section 3.1.7 (data centers): the modules reconstruct present-day demand and its natural drivers, while the scenario levers described here perturb the 2026–2050 trajectory to represent alternative policy and behavioural futures. Four independent user-selected levers are provided. Two of them (Sections 4.6.1 and 4.6.3) shape the *efficiency* of energy use — through the equipment stock and through the building envelope plus occupant behaviour — and therefore reduce the useful-energy or final-energy intensity of each service. One (Section 4.6.2) shapes the *energy carrier* mix by electrifying thermal end-uses (cooking, water heating and low-temperature heat) away from LPG, natural gas and firewood. The last (Section 4.6.4) adds an exogenous *new-load* trajectory for data centers, a segment whose growth is decoupled from population and floor-area drivers.

Scenario levers — Buildings

4.6.1 Sectoral energy-efficient equipment — Minimum Energy Performance Standards (MEPS) setting an efficiency floor for the equipment placed on the market.

4.6.2 Buildings electrification — substitution of fossil and firewood thermal demand by electricity and on-site renewables.

4.6.3 Energy efficiency and behavioural change — envelope performance of new buildings plus demand reduction from occupant behaviour.

4.6.4 Data center electricity demand — exogenous growth of installed IT capacity and its power-usage effectiveness (PUE).

Except where noted, each lever ramps *linearly* from its calibration-year value (no policy effect in 2026) to the scenario target in 2050, so that intermediate years are obtained by interpolation. The levers are additive and are applied in the order efficiency → electrification, so that electrification acts on the already-efficient useful-energy demand and double counting of savings is avoided.

4.6.1 Sectoral energy-efficient equipment

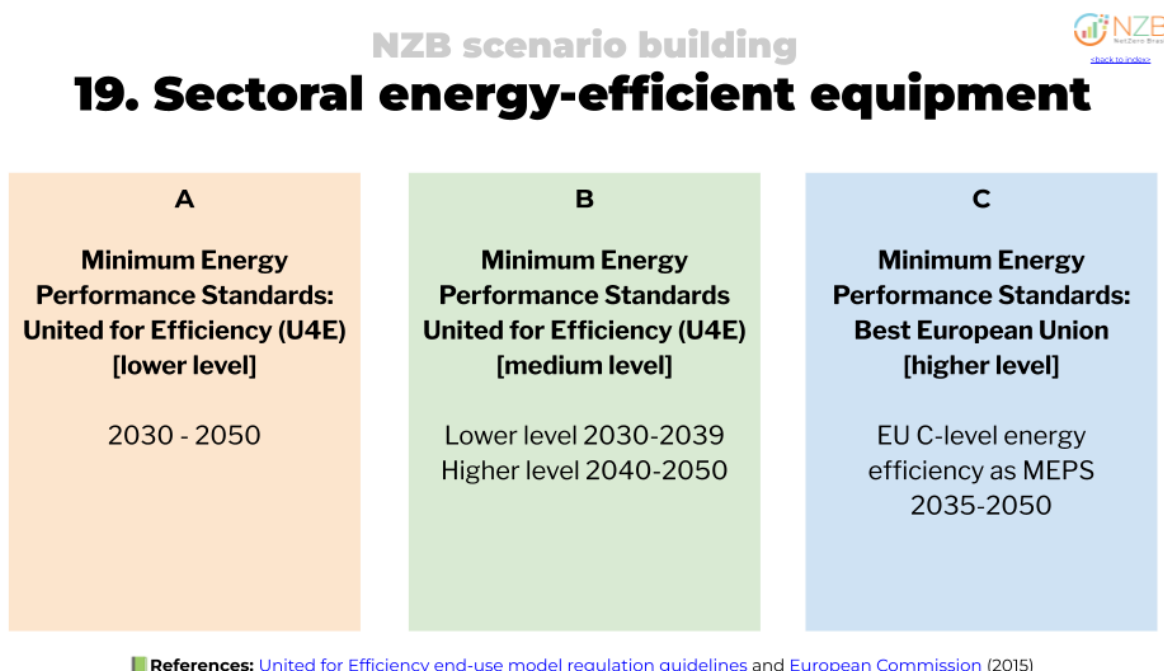


Figure 113: User Variable 19 — Sectoral energy-efficient equipment

This lever governs the efficiency of the end-use equipment placed on the Brazilian market — refrigerators, freezers, air conditioners, electric showers and water heaters, lighting, motors and office/IT loads — through Minimum Energy Performance Standards (MEPS). A MEPS is a regulatory floor rather than a market target: equipment whose efficiency falls below the stated threshold cannot be sold, so the lever acts directly on the *new* units entering the stock and reaches the stock average only as the pre-regulation vintages retire. Unlike the other buildings levers, it therefore does not ramp linearly to a 2050 value — it steps down at the year each standard enters into force. Users may choose among the three options presented in Figure 113, which differ in the stringency of the standard adopted and in the calendar of its tightening.

A. U4E minimum standards — lower level Brazil adopts the *lower* tier of the Minimum Energy Performance Standards proposed in the United for Efficiency (U4E) end-use model regulation guidelines [273], applied from 2030 and held unchanged to 2050. The U4E model regulations are the thresholds recommended for emerging economies, so this option represents alignment with international good practice at its least demanding tier, with no subsequent review of the standard over the horizon.

B. U4E minimum standards — medium level (staged tightening) The same regulatory framework as option A, but with a scheduled revision: the lower U4E tier applies from 2030 to 2039 and the *higher* U4E tier applies from 2040 to 2050 [273]. The market is given a decade to absorb the first threshold before the standard is raised, which is the pattern followed by most MEPS programmes internationally and the reason why this option delivers markedly more savings than A in the second half of the horizon without requiring a more demanding starting point.

C. European Union minimum standards — higher level The most ambitious option adopts the European energy-efficiency classes as the Brazilian minimum standard over the 2035–2050 period:

EU class C as MEPS [274]. The European thresholds are considerably more demanding than either U4E tier, so this option produces the lowest unit consumption for new equipment — at the cost of a later start date, which leaves less time for the stock to turn over by 2050, and of a stronger adaptation requirement on the domestic manufacturing base.

In the demand modules, each service s carries a unit energy consumption $UEC_s(t)$ (energy per appliance-year or per unit of activity). From the year a standard enters into force, every new unit sold complies with it, so the sales-weighted intensity of new equipment steps down to the regulated level and the stock-average intensity evolves as compliant and pre-regulation vintages turn over:

$$UEC_s(t) = [1 - \sigma_s(t)] UEC_s^{\text{base}} + \sigma_s(t) UEC_s^{\text{MEPS}}, \quad (99)$$

where $\sigma_s(t)$ is the stock share of MEPS-compliant equipment, obtained by convolving the compliant sales share with the equipment survival (stock-decay) function already defined in the residential and commercial modules, and $UEC_s^{\text{MEPS}}/UEC_s^{\text{base}}$ is the ratio between the regulated threshold and the baseline intensity of that service. Because the reduction enters the modules at the useful-energy stage, it propagates automatically to both the electricity and the thermal-fuel components of demand. Since the standard binds only new sales, the full effect of any option is reached one equipment lifetime after its start year: for appliances with a service life of 10–15 years this means that the options starting in 2030 are close to saturation by 2050, whereas option C is still working through the stock at the end of the horizon.

Note for this version — the thresholds used

It was not possible to gather the specific ratings for all equipment in the residential and commercial sectors during this stage. Furthermore, Energy Pathways model does not model the specific logic of MEPS implementation. However, the data collection is scheduled for completion in the next stages alongside the development of an external model that will generate inputs for Energy Pathways, replicating the aforementioned MEPS replacement logic.

Therefore, for the scenarios, general energy efficiency targets were applied to (sub)sectors in 2050 compared to 2024 (the efficiency gain varies linearly from 2024 to the 2050 target) as follows:

Option A – lower level equipment 10% more efficient in 2050 compared to 2024 for the residential sector and commercial subsectors schools, restaurants, supermarkets, hotels, health care, beauty salons; and 2% more efficient for the remaining commercial subsectors.

Option B – medium level equipment 15% more efficient in 2050 compared to 2024 for residential sector and for the commercial subsectors schools, restaurants, hotels and beauty salons; 20% for the commercial subsectors supermarkets and health care; and 10% for other commercial subsectors.

Option C – higher level equipment 25% more efficient in 2050 compared to 2024 for residential sector and for the commercial subsectors schools, restaurants, hotels; 30% for the commercial subsectors supermarkets and health care; 25% for the commercial subsector beauty salons; and 15% for other commercial subsectors.

4.6.2 Buildings electrification

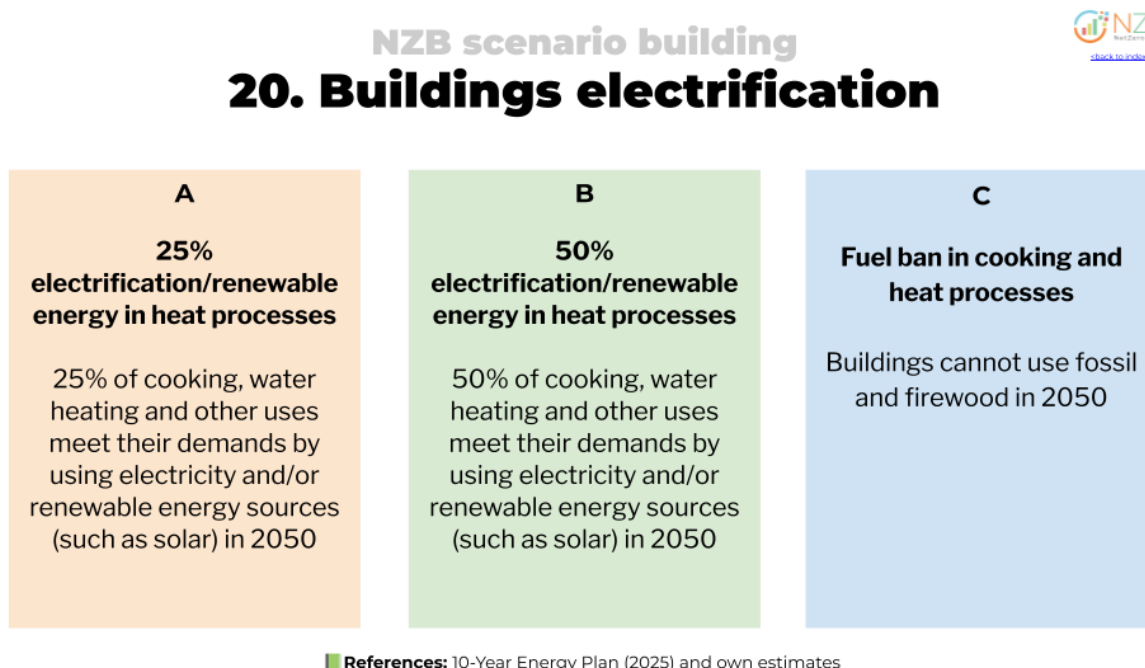


Figure 114: User Variable 20 — Buildings electrification

This lever electrifies the thermal end-uses of buildings — cooking, water heating and other low-temperature heat — displacing LPG, natural gas and firewood with electricity and on-site renewable sources such as solar thermal. It is the scenario-side counterpart of the fuel-substitution mechanism built into the residential module (Section 3.1.5), where substituted fuel energy is converted to electricity at plain energy equivalence, and of the electrifiable “thermal fraction” θ_j defined per subsector in the commercial module (Section 3.1.6), where the substituting electricity is scaled by the inverse of an efficiency gain $\eta_j > 1$. Users may choose among the three options presented in Figure 114, which differ only in the share of thermal demand that has been transferred to electricity or renewables by 2050; the residential fuel-substitution scenarios documented in Section 3.1.5 (25%, 50% and 100%) map one-to-one onto options A, B and C (with the caveat that the residential module ramps its substitution from its 2019 base year, whereas the commercial module and the lever defined here start in 2026; see Section 3.1.8).

A. 25% electrification/renewable energy in heat processes In this scenario, 25% of the energy used for cooking, water heating and other thermal end-uses is met by electricity and/or renewable energy sources (such as solar thermal) in 2050. The remaining three quarters of the thermal demand continue to be supplied by LPG, natural gas and firewood, so that fossil and biomass cooking and heating remain the dominant carriers in the residential sector throughout the horizon. This option is broadly consistent with the pace of substitution implied by the current Ten-Year Energy Expansion Plan [43] and represents the continuation of observed trends with no additional policy effort directed at building end-uses.

B. 50% electrification/renewable energy in heat processes In this scenario, half of the demand for cooking, water heating and other uses is met by electricity and/or renewable energy sources

in 2050. It represents a deliberate but partial policy effort — for instance, appliance-replacement programmes for low-income households, solar water-heating requirements in new construction, and tariff or financing instruments that make electric cooking competitive with bottled LPG.

C. Fuel ban in cooking and heat processes The most ambitious option assumes that buildings cannot use fossil fuels or firewood in 2050: the whole thermal demand of the residential and commercial sectors is met by electricity and on-site renewables. This is the buildings-sector analogue of a phase-out mandate and implies the complete retirement of the LPG, natural-gas and firewood appliance stock by the end of the horizon. This option should be read as an exploratory bounding case rather than as a forecast of a feasible policy: it establishes the upper limit of the electricity requirement of building thermal demand, against which the intermediate options can be compared.

Formally, for a building subsector j with thermal (fuel-supplied) demand D_j^{th} and an electrification share $x(t)$, the substituted electricity and the residual fuel demand in year t are

$$\Delta E_j(t) = x(t) \frac{D_j^{\text{th}}}{\eta_j}, \quad F_j(t) = [1 - x(t)] D_j^{\text{th}}, \quad (100)$$

with η_j the efficiency of the electric technology relative to the displaced thermal appliance. The substitution share $x(t)$ ramps linearly from zero in 2026 to the target of the selected option in 2050, so that intermediate years are obtained by interpolation. Because $\eta_j > 1$ for the electric technologies represented in the modules, a unit of substituted fuel energy is replaced by less than a unit of electricity, and total final energy falls as electrification rises even though the electricity series grows.

Key message

Electrification (Var. 20) changes the *carrier* of thermal demand, whereas the efficiency levers (equipment efficiency and Var. 21) change its *magnitude*. Applying efficiency before electrification ensures the electricity that substitutes for fuel is computed on the reduced, post-efficiency useful-energy demand, avoiding double counting of savings.

Refinement note — one ramp for all thermal carriers

The share $x(t)$ in Eq. (100) is a single trajectory applied to the whole thermal block — LPG, natural gas and firewood together — and η_j is defined per subsector rather than per displaced carrier. LPG and firewood differ substantially both in end-use efficiency and in how quickly they can realistically be displaced, and in the residential module no efficiency gain is applied at all. The team is aware of this and of the resulting inconsistency between the residential and commercial implementations; it is documented in the module refinement notes (Sections 3.1.5 and 3.1.6). The next model-refinement cycle will split $x(t)$ by carrier and attach carrier-specific efficiency factors, which will change the electricity requirement of the electrification options — most likely downwards for the firewood component — without changing the structure of the lever presented here.

Refinement note — transition carriers and the regional feasibility of a full fuel ban

The three options move thermal demand along a single axis — from the present LPG/natural-gas/firewood mix directly to electricity and on-site renewables — and do not represent *transition carriers* that are likely to play a role in Brazil before, or instead of, full electrification. Ethanol and other liquid biofuels for cooking, biogas from agricultural and urban residues, and sustainably managed biomass are all plausible thermal carriers, and are particularly relevant in the North region, where the electricity grid is weaker, bottled LPG is expensive and irregularly supplied, and firewood remains structurally important. For the same reasons, option C (a complete ban on fossil and firewood thermal use by 2050) is not equally attainable in every state: in the Amazon and in other remote or low-density areas the realistic end-state is a *mix* of thermal carriers — electricity where the grid allows, biofuels and efficient biomass elsewhere — rather than a single carrier. The team is aware of both limitations. The next model-refinement cycle will (i) add at least one intermediate carrier (ethanol/biofuel cooking) to the residential substitution scheme, and (ii) make the 2050 substitution target state-specific, so that the national option chosen by the user is translated into regionally differentiated ramps instead of a uniform share. Until then, option C should be interpreted as an upper bound on electrification and not as a claim that fossil-free thermal use is feasible everywhere by 2050.

4.6.3 Energy efficiency and behavioural change

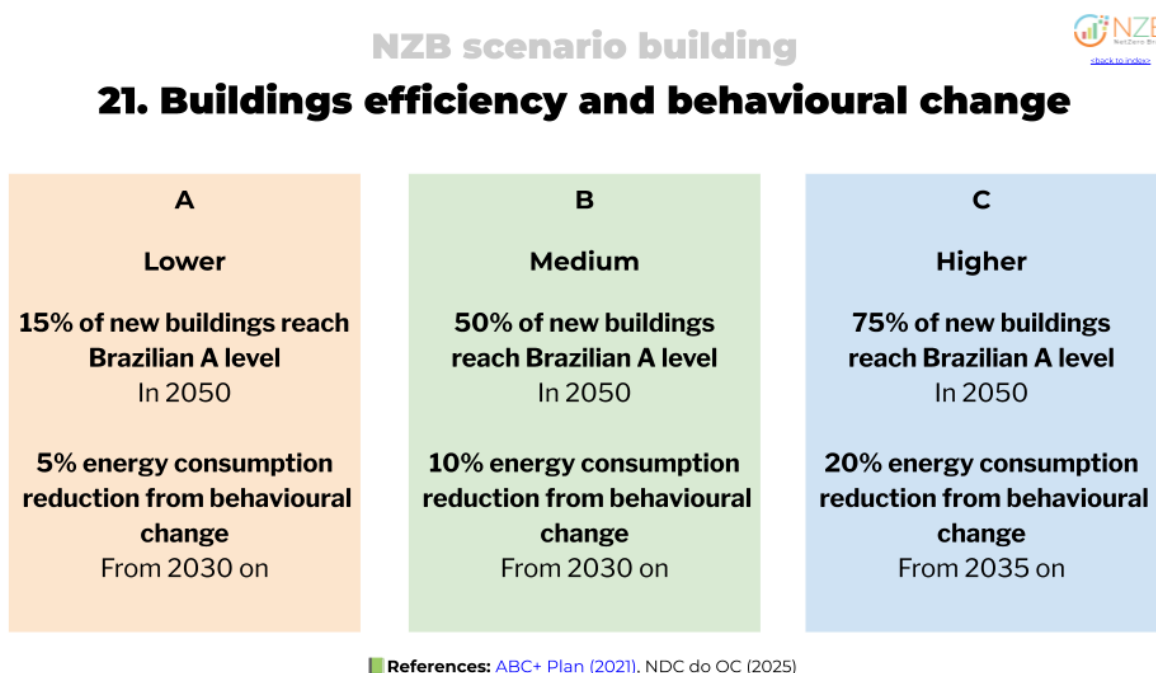


Figure 115: User Variable 21 — Buildings efficiency and behavioural change

This lever combines two mechanisms that lower building energy demand without changing the energy carrier. The first is *envelope and systems efficiency*: the share of new construction that reaches the top performance class of the Brazilian buildings-labelling scheme (PBE Edifica / PROCEL Edifica, “level A” [36]). Higher-class new buildings enter the stock with a lower specific consumption for space conditioning, water heating and lighting; the stock-average intensity therefore falls gradually, as the share of level A new buildings rises and older vintages retire, and not instantaneously in the year the target is met. The second is *behavioural change*: a direct reduction in end-use demand

from operational and occupant practices — setpoint management, load scheduling, reduced standby consumption and awareness campaigns — applied as a flat percentage cut on delivered demand from a scenario-specific start year.

Users may choose among the three ambition levels presented in Figure 115. Each option combines a 2050 target for the share of new buildings reaching Brazilian level A with a behavioural-reduction percentage and the year from which that reduction applies, so that the two mechanisms are moved together along a single ambition gradient rather than selected independently.

A. Lower Only 15% of new buildings reach Brazilian level A by 2050, and a 5% reduction in energy consumption from behavioural change is applied from 2030 onwards. This option represents the continuation of the current, largely voluntary uptake of the PBE Edifica labelling scheme, with efficiency gains driven by market renewal rather than by regulation.

B. Medium Half of the new buildings reach level A by 2050 and behavioural change delivers a 10% reduction in energy consumption from 2030 onwards. This option is consistent with the effective enforcement of the energy-performance requirements already foreseen for public and large commercial buildings, progressively extended to the residential stock.

C. Higher Three quarters of the new buildings reach level A by 2050 and behavioural change delivers a 20% reduction in energy consumption, phased in from 2035. The later start year of the behavioural component reflects the assumption that a reduction of this magnitude requires a supporting infrastructure — smart metering, dynamic tariffs and sustained information programmes — that is not expected to be in place before the mid-2030s. The ambition of this option is anchored to national decarbonisation commitments [256, 275].

Formally, for a cohort of buildings entering the stock in year τ with baseline intensity I^{base} , level A share $a(\tau)$ and level A intensity factor $\kappa < 1$, the stock-average intensity and the delivered demand are

$$I(t) = \sum_{\tau \leq t} w_{\tau}(t) [1 - a(\tau)(1 - \kappa)] I^{\text{base}}, \quad D(t) = [1 - b(t)] I(t) A(t), \quad (101)$$

where $w_{\tau}(t)$ is the surviving weight of cohort τ in year t , $A(t)$ the floor-area (or activity) driver, and $b(t)$ the behavioural reduction, equal to zero before the start year of the selected option and held at the scenario level thereafter. The envelope shares apply to *new* buildings only and enter the results through cohort turnover, whereas the behavioural reduction is a flat cut applied to the whole delivered demand from the stated start year.

Note for this version — the thresholds used

It was not possible to compile the efficiency levels of all different sectoral buildings. It will be implemented in the next version of the platform. Therefore, this version used general energy efficiency targets to residential and commercial sectors in 2050 compared to 2024 as follows:

Option A – lower level more efficient buildings and behavioural changes will decrease the energy consumption by 5% in 2050 compared to 2024.

Option B – medium level more efficient buildings and behavioural changes will decrease the energy consumption by 10% in 2050 compared to 2024.

Option C – higher level more efficient buildings and behavioural changes will decrease the energy consumption by 30% in 2050 compared to 2024.

Refinement note — envelope performance is not differentiated by climate zone

The envelope mechanism of this lever is expressed as a single national share of new buildings reaching PBE Edifica level A. That is a generic efficiency class: it is neither differentiated by Brazilian climate zone nor explicitly linked to the projected temperature/CDD path used elsewhere in the report (Section 3.1.7). The intensity factor κ in Eq. (101) is likewise a single national parameter, so the lever cannot represent the fact that the same labelling class delivers very different cooling savings in Manaus versus in Curitiba, nor the specific contribution of passive strategies (cross ventilation, shading, green roofs, solar orientation), of higher-performance materials (glazing, insulation, high-albedo coatings) and of bioclimatic design. The team is aware that quantifying these effects is difficult — it depends on adoption rates, costs and municipal building codes — and that is why this version of the NZB model keeps a single aggregate class. The next model-refinement cycle will make κ climate-zone-specific and pair it with the CDD trajectory, so that the interaction between regional warming and construction-side mitigation is represented explicitly rather than implicitly. A related effect is also absent: urbanisation itself modifies the local climate that buildings experience — urban heat islands raise night-time temperatures, and dense construction blocks the wind flow that natural ventilation relies on — so that the cooling demand of the same building class in a densifying city rises faster than the regional CDD series would suggest. Representing this requires linking the CDD path to an urban-form descriptor, which is outside the scope of the current version. Until then, the net cooling-demand growth reported for the buildings sector should be read as carrying an unresolved, regionally heterogeneous uncertainty in both directions, and not as a settled net effect.

4.6.4 Data center electricity demand

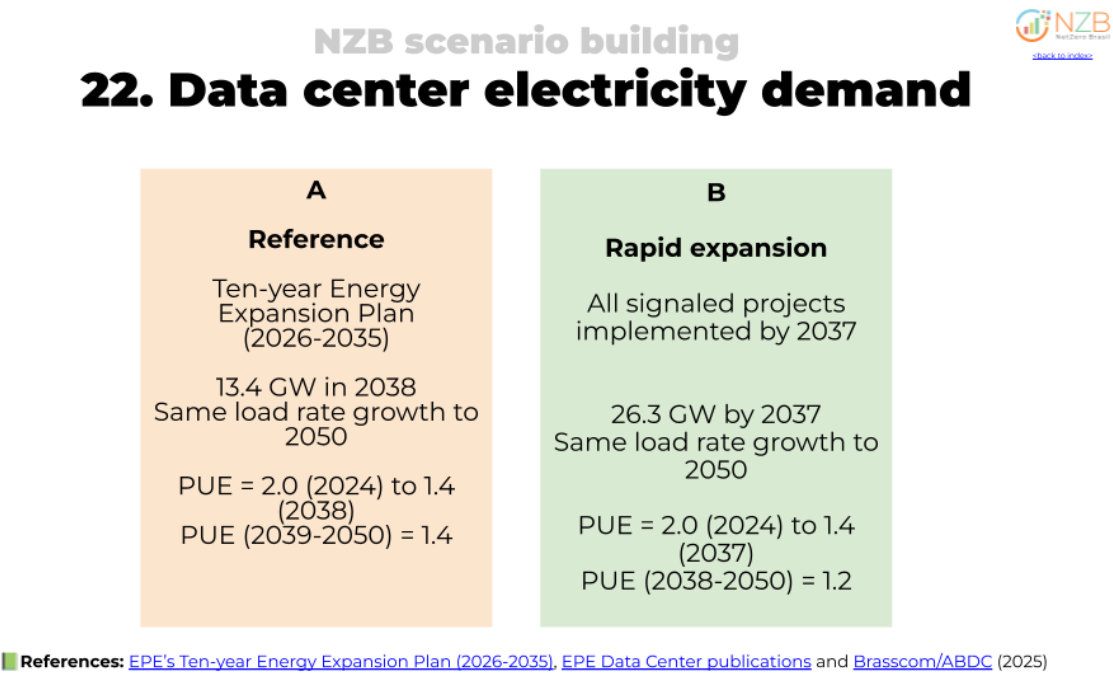


Figure 116: User Variable 22 — Data center electricity demand

Data centers are treated as an exogenous new load rather than being driven by the population and floor-area relationships used for the rest of the commercial sector. The scenario supplies a capacity build-out together with a power-usage-effectiveness (PUE) path; the logistic form of the build-out, the allocation of capacity across states, and the conversion of capacity into energy are documented in the data-center demand module (Section 3.1.7). Users may choose between the two options presented in

Figure 116, which differ both in how much capacity is built and in the efficiency floor to which the PUE converges.³⁵

A. Reference growth Capacity follows a single logistic (S-shaped) build-out fitted through the 2024 stock (0.843 GW), the expansion recognised in EPE’s Ten-year Energy Expansion Plan 2035 — 13.4 GW of installed load capacity in 2038 [43, 44] — and a 2050 anchor at which growth has decelerated to the long-run rate of the commercial sector ($\approx 2.8\%/yr$, the BEN 2011–2024 commercial-consumption trend), reaching 22.5 GW in 2050. Efficiency improves from the corrected Brazilian fleet-average PUE of 2.00 in 2024 to 1.40 in 2038, and the PUE is then held at 1.40 for the remainder of the horizon. This option represents an expansion driven by the projects already recognised in official planning, with efficiency gains obtained from the natural renewal of equipment and cooling systems rather than from regulation.

B. Rapid expansion All projects signaled to distributors and to the regulator are assumed to be implemented by 2037, bringing installed load capacity to 26.3 GW in that year — roughly twice the Reference anchor — with the same logistic accommodation towards the commercial-sector rate thereafter, reaching 59.5 GW in 2050. The PUE follows the same improvement from 2.00 in 2024 to 1.40 in 2037, but then continues to fall linearly to 1.20 in 2050, as a result of national regulations, monitoring and evaluation capacity, and local scientific and technological capacity. This option therefore diverges from the Reference growth on both terms of the demand calculation: a larger installed capacity and a lower overhead multiplier.

The facility (grid) electricity demand in year t follows from the installed load capacity $P(t)$ allocated to each state, the 50% capacity factor, the full-load specific consumption of the IT equipment ($e_{FL} = 8.8$ TWh/GW per year, i.e. the 8,760 hours of a year), and the scenario PUE path:

$$E_{DC}(t) = P(t) \times CF \times e_{FL} \times PUE(t). \quad (102)$$

The PUE multiplier captures cooling and electrical-distribution overheads: a PUE of 1.40 means 0.40 kWh of non-IT overhead per kWh of IT load, so a falling PUE represents efficiency gains in cooling and power delivery. All four factors are exported separately to EnergyPathways (Section 3.1.7).

Illustrative magnitude Applying Equation (102) to the Reference anchor of 13.4 GW at the 2038 PUE of 1.40 gives $E_{DC} \approx 13.4 \times 0.5 \times 8.8 \times 1.4 \approx 82.5$ TWh of facility electricity in 2038. The Rapid-expansion anchor of 26.3 GW in 2037, at the same PUE of 1.40, draws about 162 TWh; the same capacity at the 2050 PUE of 1.20 would draw about 139 TWh — isolating the effect of the overhead multiplier from that of the capacity build-out. By 2050 the two options deliver approximately 139 TWh (A) and 314 TWh (B). These figures are indicative national aggregates: the operative values follow the state-level capacity allocation and the PUE path of the selected option.

³⁵The card artwork still carries the Report I shorthand “same load rate growth to 2050”; the trajectory actually implemented is the logistic build-out with decelerating growth described here and in Section 3.1.7. The artwork will be aligned in the next report version.

4.7 Energy supply system

Eleven user-definable variables relating to the energy supply system are available in the current version of the NZB model, as described here.

4.7.1 Fossil fuel utilization

23. Fossil fuel utilization

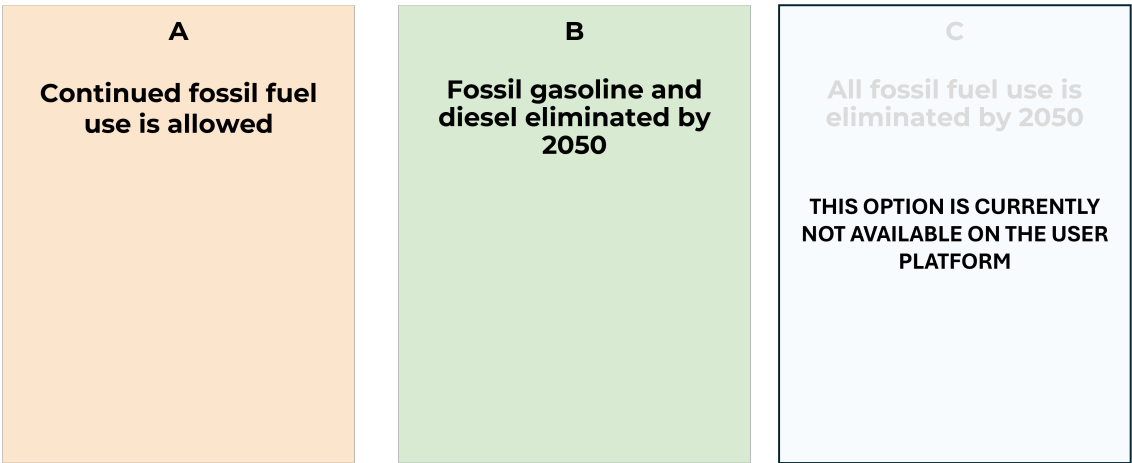


Figure 117: User Variable 23

Users may choose between two options related to future use of fossil fuels. In option A, fossil fuels continue to be an energy supply option for MACRO to choose as part of the design of the energy system transition pathway that provides the lowest total energy system cost while meeting exogenous carbon emission and other constraints. In option B, the use of fossil-gasoline and fossil-diesel fuels are constrained to fall to zero by 2050. A third option – complete elimination of fossil fuel use by 2050 – will be added in a future version of the user platform.

4.7.2 Fossil fuel prices

24. Fossil fuel wholesale prices

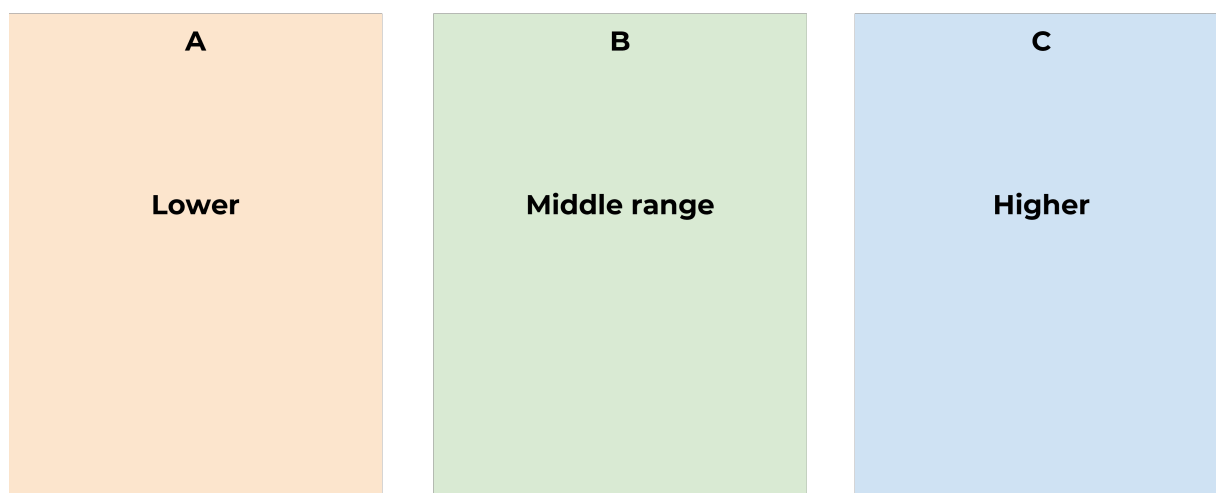


Figure 118: *User Variable 24*

Users may choose from three options for fossil fuel wholesale prices: lower, middle range, and higher. In the current version of the NZB model, relevant fossil fuels included in the energy supply model are gasoline A, Diesel A, jet fuel A, natural gas, and coal. (See Section 3.2.1.3).

In the Lower scenario, wholesale prices align with the IEA's Net Zero Emissions by 2050 (NZE) scenario [276] and the EPE's deep decarbonization scenarios [95], and describe conditions of sharp structural decline in global demand for fossil fuels (Accelerated Energy Transition – 1.5°C pathway).

Macroeconomic assumptions include a progressive decline in the price of Brent crude oil, converging to the 25 to 30 US\$₂₀₂₅ per barrel range by 2050 [276], as well as global dynamics such as the introduction of high international carbon taxes, the accelerated replacement of vehicle fleets with electric vehicles, and industrial electrification.

The forecast collapse of Brent crude prices is directly reflected in the domestic market. Gasoline A" (unblended fossil gasoline) experiences a strong downward trend in real prices.

Diesel sees a significant reduction in the price of the fossil component (Diesel A). However, the final impact on "Diesel B" (the blend sold at the pump) is mitigated by the gradual increase in the mandatory biodiesel blend, which historically has a higher production cost than oil-based diesel [277].

The effective cost of supplying jet fuel A in Brazil will face upward pressure due to mandatory targets for the inclusion of SAF under the "Fuel of the Future" program—which commands a high price premium.

Natural gas is undergoing progressive decoupling from Brent prices. With carbon taxation, gas is losing ground in baseload thermal power generation. Wellhead and "City Gate" prices are falling substantially [277].

Coal faces a scenario of economic obsolescence. The cost of domestic coal (from the Southern basin) is becoming enviable due to the removal of subsidies (specifically, for thermal plants outside the CDE sub-credit mechanism). Imported coal is seeing a sharp drop in both volume and price, remaining in use only in niche industrial applications that utilize CCUS technology.

The Middle range scenario reflects the baseline view of planning institutions, in which the demand for fossil fuels plateaus between 2030 and 2040, followed by a gradual decline through 2050.

The macroeconomic assumptions factor in the stabilization of the Brent crude price within a range of 60 to 75 US\$₂₀₂₅ per barrel throughout the projection period [43].

The scenario points to global dynamics aligned with the IEA's Stated Policies Scenario (STEPS) and the EPE's Reference Scenario, in which population and economic growth partially offset energy efficiency gains.

Gasoline A maintains real prices at levels close to recent historical averages. Domestic refining operations (by Petrobras and private players) run with stable margins.

Jet fuel A prices track Brent's stability. The Brazilian market shows organic demand growth, with distributors fully passing on costs associated with international price volatility.

Natural gas wellhead prices remain strongly indexed to Brent. According to the Ten-Year Energy Expansion Plan [43], the influx of new volumes from the pre-salt layer (Routes 3 and 4, and the Sergipe Deepwater project) exerts downward pressure on the price of the gas itself; however, transportation costs (pipeline tariffs) stabilize the final price at the city gate between 10 to 12 US\$₂₀₂₅ per million Btu (MMBtu) [95].

Coal consumption continues to depend on the maintenance of the current generation fleet until the expiration of concession contracts and the end of the term for economic subsidy laws.

The Higher scenario reflects global and domestic inertia resulting from the failure to meet global climate targets, continued reliance on fossil fuels, regulatory delays, and slow progress in electrification and the adoption of renewable substitutes (such as hydrogen and biomethane). Correlated with the IEA's "Current Policies Scenario"—or global warming trajectories exceeding 2.5°C—this outlook sees global demand for oil, gas, and coal continue to grow steadily through the mid-2040s, reaching a high, late-stage plateau near 2050.

Regarding macroeconomic assumptions, the price of a barrel of Brent crude is projected to remain high, fluctuating between 90 and 110 US\$₂₀₂₅ per barrel through 2050 [47]. This is driven not merely by physical scarcity, but by the rising marginal cost of extracting new reserves—such as those requiring deep-shale fracking or ultra-deepwater operations—needed to meet a demand that refuses to decline [276]. Although Brazil is self-sufficient in crude oil, it remains exposed to international prices due to the need to import light and medium refined products and the opportunity-cost pricing applied to domestic oil. Furthermore, the scenario factors in the easing or postponement of carbon pricing targets in both international markets and Brazil's regulated market.

As Brazil's light-vehicle fleet remains predominantly dependent on internal combustion engines—with negligible market penetration by fully electric vehicles—domestic consumption competes for "Gasoline A" (unblended gasoline), which is priced at high international levels.

Fossil diesel remains the dominant fuel for road freight transport in Brazil. The transition to electric or

hydrogen-powered trucks is stalling due to a lack of charging infrastructure. The biodiesel blend rate has stabilized at its current technical ceiling without further upward pressure, causing the final cost of "Diesel B" (blended diesel) to mirror the real cost trends of fossil fuel refining.

Faced with the failure or high cost of scaling up SAF production, global green aviation targets are being postponed. Brazilian airlines continue to burn 100% fossil-based jet fuel, passing the cost of high oil prices on to ticket fares.

Natural gas is establishing itself as the key fuel for a delayed transition; while it replaces coal abroad, it keeps global demand high. In Brazil, existing contracts remain strictly tied to an indexation formula based on high Brent crude prices. Although pre-salt gas is entering the market, the opportunity cost of exporting it as LNG prevents domestic price reductions, keeping fuel costs high.

In a slow energy transition scenario, environmental restrictions and penalties on coal are being mitigated or revoked due to energy security concerns. In Brazil, subsidies and contracts for coal-fired power plants in the Southern Basin are being extended beyond 2040, sustaining the consumption of mineral coal.

Table 66: *Scenario options for fuel prices and compound annual percentage growth rates.*

Fuel	Base price (2025)	Lower	Middle	Higher
Gasoline A (refinery)	0.45 US\$/L	-3.5%	0.1%	1.5%
Diesel A (refinery)	0.63 US\$/L	-2.8%	0.1%	1.8%
Jet fuel (refinery)	0.86 US\$/L	-2.0%	0.5%	1.6%
Natural gas (city gate)	11.00 US\$/MMBtu	-1.8%	-0.3%	2.2%
Domestic coal	72.76 US\$/t	-0.5%	0.1%	0.8%
International coal	134.28 US\$/t	-0.5%	0.1%	0.8%

4.7.3 Energy supply technology innovation

25. Energy supply technology innovation

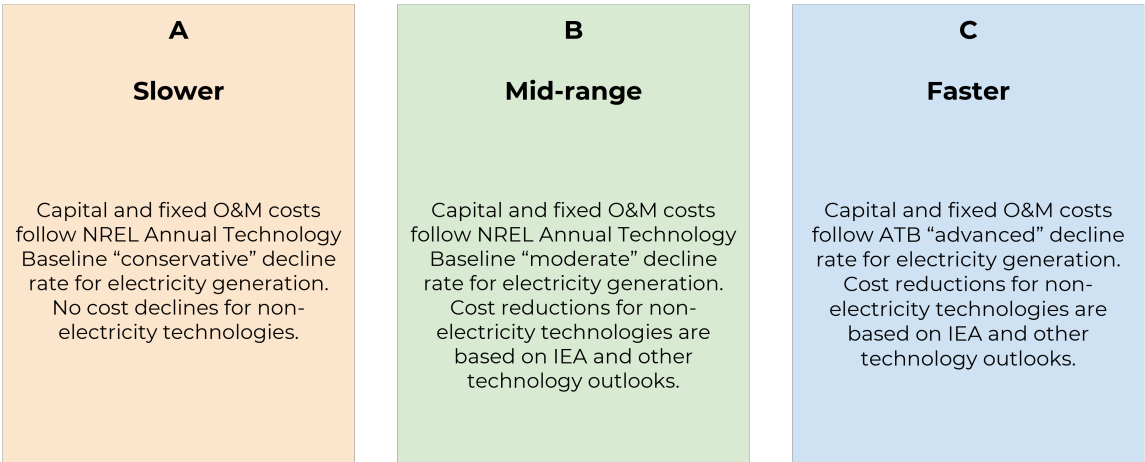


Figure 119: User Variable 25

Users may choose from three options for the pace of assumed future energy-supply technology innovations. In the model the level of innovation reflects the extent to which capital and operating costs are assumed to decrease linearly over time from the initial modeling period. Options A, B, and C correspond to slower, mid-range, and faster cost decline rates, respectively. For electricity generating technologies, the three options are based on normalized cost reduction rates for conservative, moderate, and advanced scenarios reported in [112]. Cost reductions for non-electricity energy supply technologies are based on other sources, as described in Section 3.2. The values of all relevant parameters for all technologies for each of the three user options are enumerated in [61].

4.7.4 Biofuels mandates

26. Biofuels blends

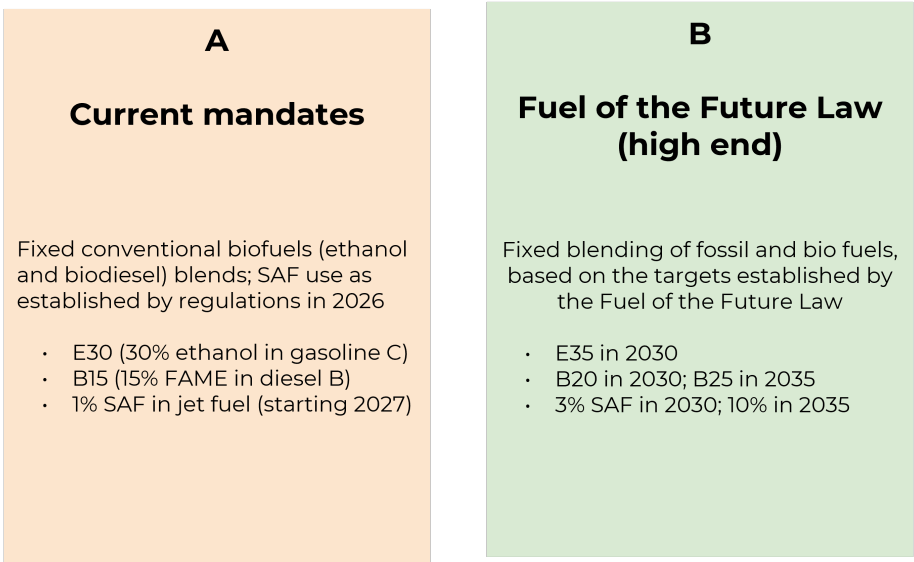


Figure 120: User Variable 26

Users may choose from two options regarding minimum non-fossil fuel content in liquid biofuels. Option A keeps minimum values currently mandated by law. Option B requires minimum non-fossil fuel content targets stipulated in the Fuel of the Future Law [183]. Note that for gasoline C and biodiesel, beyond meeting the stipulated non-fossil minima, MACRO may choose to substitute advanced drop-in biofuels for some of the remaining portion of the fuel supply. For example, drop-in diesel fuel from Fischer-Tropsh processes can be substituted for fossil diesel. In the case of jet fuel, MACRO enforces a maximum allowable SAF fraction of 50%, in line with current ASTM fuel standards.

International and national regulations concerning aviation emissions establish percentage reduction targets not simply for the volume of fossil jet fuel consumed, but rather for the amount of CO₂ emitted over the entire life cycle of the fuel used in an aircraft. It is worth noting, however, that the aviation emissions reduction percentages stipulated in the Fuel of the Future Law were, for the purposes of this analysis, simplified and considered as volumetric blending percentages of SAF in fossil jet fuel.

4.7.5 Hydropower plants

27. Hydroelectric power plants

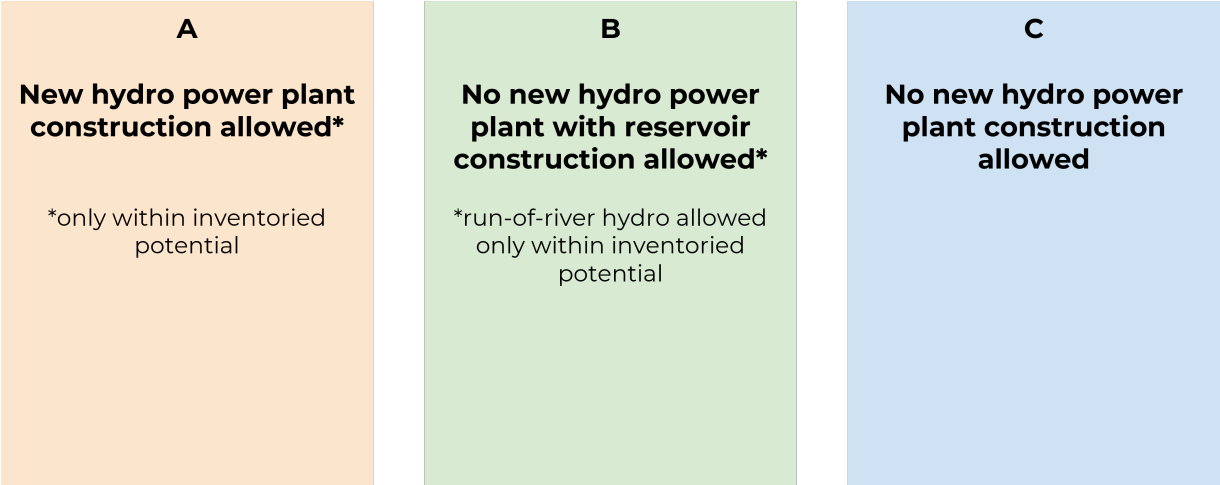


Figure 121: User Variable 27

Users can choose among three hydropower expansion options. Option A allows new reservoir and run-of-river hydropower plants within the officially inventoried potential. Option B allows only run-of-river expansion, and Option C disallows any new hydropower construction. Existing hydropower plants remain available under all three options.

We used ANEEL’s database of hydropower projects under study to estimate the expansion potential [278]. We classified reservoir projects using EPE’s assessment of potential storage reservoirs in the Brazilian Interconnected Power System [279] and complementary basin studies, including the Integrated Environmental Assessment of the Tibagi River Basin [280]. We classified small hydropower plants and projects without identified regulation capacity as run-of-river.

The dataset includes several inventoried projects with a combined potential of 55.9 GW. We do not consider projects outside the considered basins in our model. We compared these estimates with the hydropower potential reported in the Brazilian National Energy Plan 2055 [281]. Table 67 shows the expansion allowed in each scenario.

Table 67: *Maximum hydropower expansion allowed by basin and scenario.*

Type	Basin	Hydropower expansion allowed (MW)		
		Scenario A	Scenario B	Scenario C
Run-of-river	Amazonas	32,257	32,257	0
Run-of-river	Capivari	51	51	0
Run-of-river	Doce	1,506	1,506	0
Run-of-river	Grande	687	687	0
Run-of-river	Iguaçu	764	764	0
Run-of-river	Jacuí	508	508	0
Run-of-river	Jequitinhonha	140	140	0
Run-of-river	Paranapanema	453	453	0
Run-of-river	Paranaíba	1,802	1,802	0
Run-of-river	Paraná	2,029	2,029	0
Run-of-river	Paraíba do Sul	773	773	0
Run-of-river	São Francisco	1,594	1,594	0
Run-of-river	Tietê	167	167	0
Run-of-river	Tocantins	7,115	7,115	0
Run-of-river	Uruguai	3,000	3,000	0
Reservoir	Amazonas	116	0	0
Reservoir	Paranapanema	331	0	0
Reservoir	Paraná	76	0	0
Reservoir	São Francisco	762	0	0
Reservoir	Tocantins	939	0	0

Any expansion is then subjected to the basin's capacity factor (estimated using historical data). Because storage capacity data were unavailable for the potential reservoirs, we assumed that storage capacity increases in proportion to the maximum installed generation capacity.

We weighted cost assumptions by the potential installed capacity of the inventoried projects within each hydropower category, obtaining average capex values of US\$1,932/kW for run-of-river projects and US\$2,215/kW for reservoir projects (see [61]).

4.7.6 Fossil thermal power plants

28. Fossil power plants

A	B	C	D
All options unrestricted	Coal phase out	Nat gas expansion allowed, but capped	All options restricted
Coal or gas expansion allowed, no cap	No new coal-fired power plants from now and retirement of existing ones according to contracts Other options are unrestricted	No more than 15 GW of new gas-fired capacity; No new coal-fired power plants and retirement of existing ones according to contracts Other options are unrestricted	No new fossil fuel power plants from now and retirement of existing ones according to contracts

Figure 122: User Variable 28

User Variable 28 defines the set of scenarios governing the use of fossil-fuel-fired thermal power plants, namely coal, Natural Gas Simple Cycle (NGSC), Natural Gas Combined Cycle (NGCC), and Natural Gas Combined Cycle with Carbon Capture and Storage (NGCC-CCS). Four scenario options are defined.

Option A represents a scenario with no restrictions on the operation of existing thermal power plants nor on the construction of new plants of any type.

Option B represents a scenario in which no new coal-fired plants are allowed to be built, and existing coal-fired plants are retired at the end of their current concessions, with no possibility of new contracts or authorizations. Natural-gas-fired power plants, by contrast, may operate and expand freely.

In **Option C**, coal-fired power plants are subject to the same treatment as in Option B. Existing natural-gas-fired power plants may continue operating, including the possibility of lifetime extension. New natural-gas-fired power plants may expand, but are subject to a maximum installed capacity cap of 15 GW, divided equally among NGSC, NGCC, and NGCC-CCS. The cap on new natural-gas-fired power capacity was defined considering the range of expansion indicated by Brazilian energy-planning studies while intentionally adopting a more restrictive assumption for the NZB scenarios.

The National Energy Plan 2050 (PNE 2050) indicates that total installed natural-gas-fired capacity could reach approximately 28-33 GW by 2050, depending particularly on restrictions on hydropower expansion and the availability of competitively priced natural gas [47]. More recently, the Ten-Year Energy Expansion Plan 2035 (PDE 2035) projects approximately 19 GW of indicative new natural-gas-fired capacity by 2035, in addition to 2.649 GW of already contracted new gas-fired plants, resulting in an overall expansion of approximately 21.6 GW when both categories are considered [43]. As an additional near-term reference, the 2026 Capacity Reserve Auction (LRCAP) contracted approximately 15.17 GW of gas-fired capacity availability, although this amount includes both new and existing plants

and therefore should not be interpreted directly as new-build capacity [282].

Given that the purpose of this NZB scenario is to represent a more constrained pathway for fossil-fuel expansion rather than reproduce the higher levels of expansion identified in national energy-planning exercises, a cap of 15 GW of additional natural-gas-fired capacity through 2050 was adopted. This value therefore represents a deliberately restrictive assumption while remaining consistent with the order of magnitude observed across the PNE 2050, PDE 2035, and recent LRCAP results.

The representation of the capacity cap in MACRO is currently restricted to individualized generation plants. In order to avoid significantly restricting the addition of new plants in each of the model’s 27 zones, it was decided to maintain the possibility of creating one asset of each technology type (NGSC, NGCC, and NGCC-CCS) at the national level, i.e., without discretizing the plant’s zone of location. However, in order to connect the power plants to the electricity grid, it was considered to be connected to the São Paulo electricity node, corresponding to the country’s largest load center. It is anticipated that the next version of MACRO will support applying the capacity cap to a set of assets, which will allow downscaling to the state level.

Option D, finally, is the most restrictive scenario, in which no new natural-gas-fired or coal-fired power plants are permitted, and existing plants undergo phase-down, being retired according to the expiration of their current concessions, with no possibility of operational extension.

4.7.7 Nuclear power plants

29. Nuclear power plants

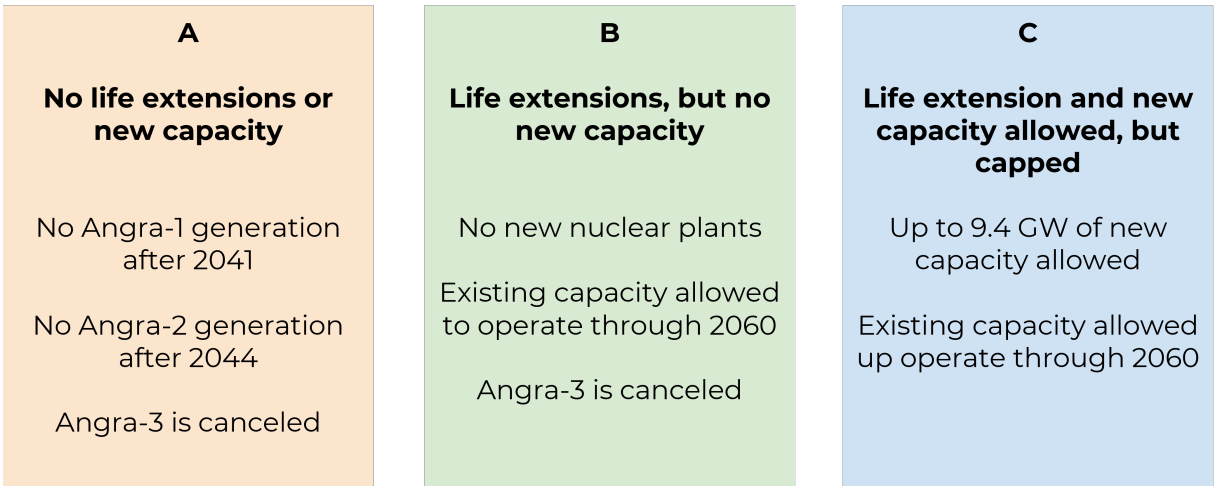


Figure 123: User Variable 29

User Variable 29 defines the set of scenarios governing the use of nuclear power plants. Three scenario options are defined:

Option A represents a scenario with no life extensions and no new nuclear capacity allowed. Angra I generation is not allowed after 2041, Angra II generation is not allowed after 2044, and Angra III is

canceled.

Option B represents a scenario in which life extensions are allowed, so the existing capacity is allowed to operate through 2060. Angra III is canceled and no new nuclear capacity may be built.

Option C represents a scenario in which both life extension (existing capacity is allowed to operate through 2060) and construction of up to 9.4 GW of new nuclear capacity are allowed. The cap was defined based on the long-term expansion range considered in the PNE 2050. It evaluated scenarios with approximately 8-10 GW of additional nuclear capacity beyond the existing Angra complex by 2050 [47]. In the NZB framework, Angra III is treated as new capacity because it is not currently operational. With a planned capacity of approximately 1.405 GW [eletronuclear_angra3], combining Angra III with the lower bound of the PNE 2050 expansion range gives 9.4 GW, the cap for new capacity through 2050 adopted for the scenario C. This might be considered a conservative interpretation of the nuclear expansion potential considered in the PNE 2050.

The representation of new nuclear power plants in MACRO follows the same approach adopted for natural-gas-fired power plants, i.e., at the national level, with the corresponding asset connected to the São Paulo electricity node.

4.7.8 Land use for solar and wind power

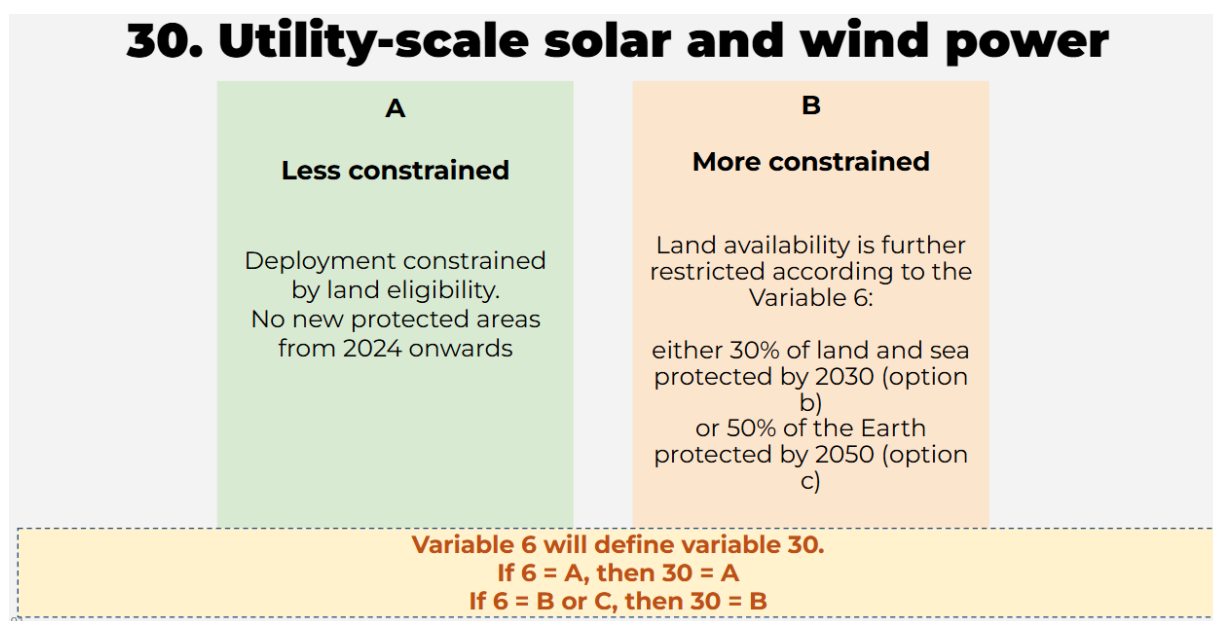


Figure 124: User Variable 30

User variable 30 defines land availability for utility-scale wind and solar expansion and is linked to the conservation assumptions of user variable 6, 4.2.2. (Note that for the current version of the NZB model, the user is not able to directly select A or B for user variable 30. They can only make a selection for user variable 6, which will then set the option specified for variable 30.) Option A for variable 30 is the less-constrained option. It uses the baseline land-eligibility criteria and assumes no further protected areas from 2024. The more constrained option (B) adds a conservation exclusion layer, whose extent depends on the scenario selected in user variable 6: either 30% of land and sea protected by 2030 or 50% protected by 2050. The linkage between variables 30 and 6 ensures that

renewable energy siting reflects the corresponding conservation ambition.

4.7.9 Rooftop solar deployment

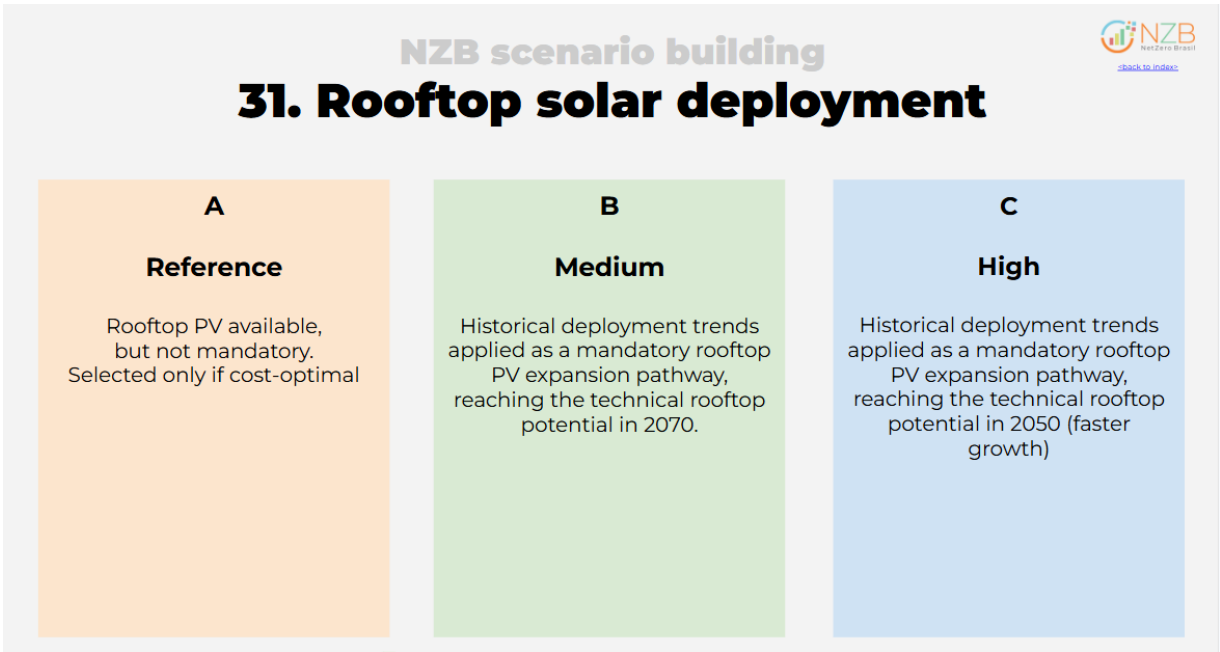


Figure 125: User Variable 31

User variable 31 presents three scenarios for the development of rooftop photovoltaic panels. We based our assumptions on the Distributed Micro and Mini Generation Data Panel (PDGD) provided by the Brazilian Energy Research Office [109]. This panel is directly fed by the database of the Brazilian National Electric Energy Agency [283]. Scenario A (Reference) considers that rooftop photovoltaic solar capacity can be deployed when it constitutes part of a least cost design of the energy supply system as determined by the MACRO model. Under this scenario, rooftop PV is available but not mandatory. Scenario B (Medium), reaches long-term rooftop PV saturation in 2070, while in Scenario C (High), the maximum capacity is reached in 2050 (faster growth). We represented rooftop PV deployment using logistic growth curves to account for the gradual acceleration in scenarios B and C, as illustrated in Figure 126. In all three scenarios, the maximum capacity of rooftop solar PV is constrained by the estimated households associated with an average rooftop area, as described in Section Scenarios.

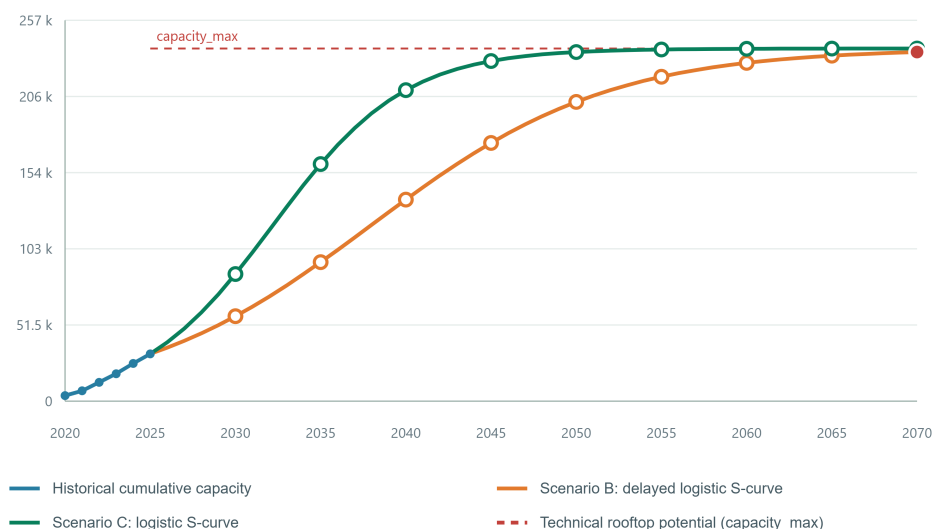


Figure 126: Scenarios of rooftop PV expansion. Historical cumulative capacity is extended using two logistic deployment pathways: a faster Scenario C and a delayed Scenario B, both converging toward the estimated technical rooftop PV potential.

4.7.10 Oil production

32. Oil production

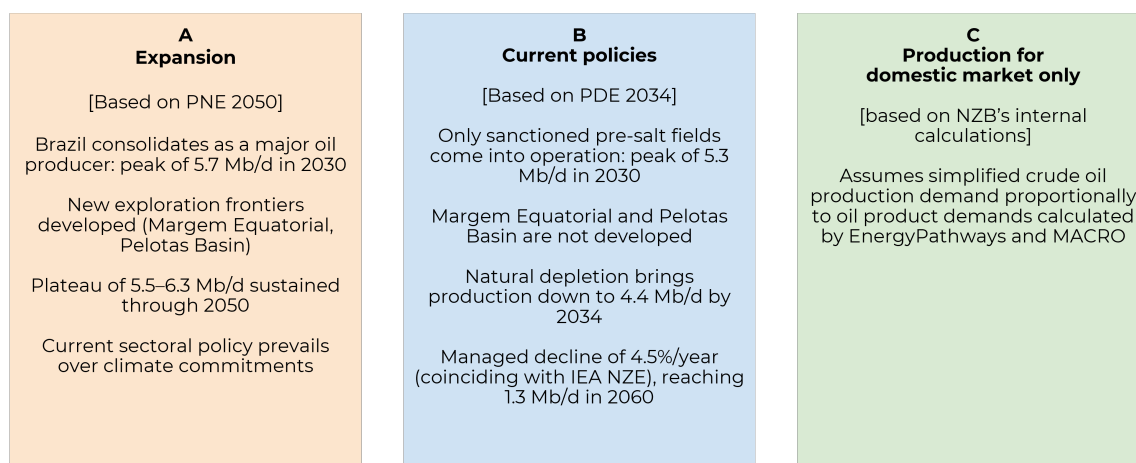


Figure 127: User Variable 32

Users may choose between three scenario options for future crude oil production in Brazil.

In all three scenarios, the domestic demand for petroleum-derived fuels is determined endogenously in MACRO. In all three cases it is assumed that the domestically-used petroleum-derived fuels are derived from crude oil produced and refined in Brazil. This oil use assumes exogenously specified CO₂ emissions of 0.0827 tCO_{2e}/t_{crudeoil} for extraction and 0.235 tCO_{2e}/t_{crudeoil} for refining (as documented in Section 3.2.1.3), in addition to fuel combustion emissions.

In scenario option A, oil production is projected based on [95], which assumes Brazil maintains the

status of a major oil producer achieving the production of 5.7 million barrels per day in 2030 and sustaining it between 5.5 and 6.3 million barrels a day through 2050. To achieve that, new exploration frontiers (Equatorial margin and Pelotas basin) are developed.

In scenario option B, oil production is projected based on the [128], which assumes only sanctioned pre-salt fields come into operation with peaking production of 5.3 million barrels a day in 2030 and natural depletion of reserves bring the production down to 4.4. million barrels a day by 2034. Beyond 2034, it was assumed a 4.5% per year decline of production, coinciding with the IEA's Net Zero Emissions by 2050 scenario [276], reaching 1.3 million barrels a day in 2060.

In scenario option C, crude oil production is assumed to be exactly the amount needed to satisfy domestic fuel demands. In scenarios A and B, oil production exceeds domestic demand, and the excess is assumed to be exported as crude oil. CO₂ emissions from refining and use of the exported portion of crude oil production are not counted here as Brazilian emissions.

4.7.11 Underground carbon storage

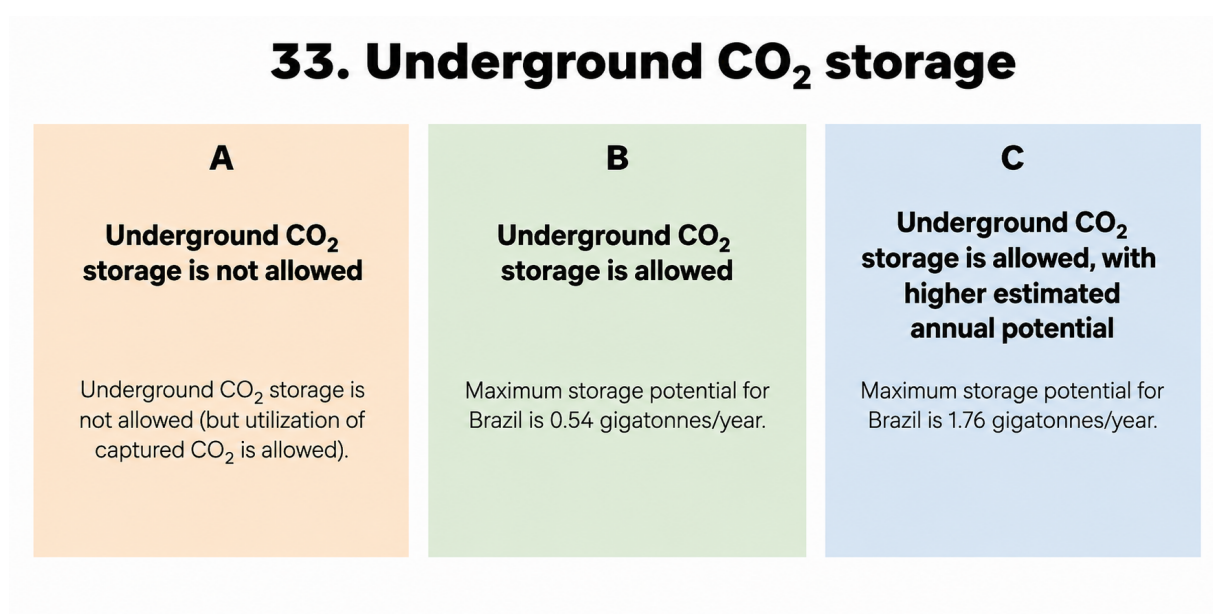


Figure 128: User Variable 33

User Variable 33 defines the set of scenarios governing the underground storage of CO₂. Underground CO₂ storage operations exist in Brazil today, currently restricted to the offshore oil and gas exploration sector for enhanced oil recovery (EOR) operations. The current version of the NZB model does not consider storage via EOR. Instead, it considers potential storage only in deep saline aquifers, as detailed under CO₂ Storage in Section 3.2.3. The scenarios for variable 33 are defined in relation to this type of storage:

Option A represents the most restrictive scenario. Underground CO₂ storage is not allowed, although the utilization of captured CO₂ remains allowed.

Option B allows underground CO₂ storage, but caps the annual storage allowed nationally at 0.54 GtCO₂/year, which is NZB's lower-end estimate of the storage potential considering the ten Brazilian

sedimentary basins analyzed.

Option C allows underground CO₂ storage with a higher cap of 1.76 GtCO₂/year, NZB's high-end estimate of annual storage potential.

4.8 Waste

The creation of scenarios for the waste sector aims to represent different possible trajectories for the management of municipal solid waste and wastewater in Brazil between 2020/2024 and 2050, allowing the assessment of the effect of different public policy and infrastructure investment hypotheses on Waste emissions. Each scenario is built from the combination of specific assumptions for a set of input parameters of the waste tool (Section 3.3), which correspond to the main stages of the waste management cycle: generation, diversion to recycling and biological treatment, final disposal, thermal treatment, gas recovery from landfill and domestic wastewater treatment.

Scenarios were defined for the following parameters: i) waste generation and prevention; ii) recycling; iii) biological treatment; iv) thermal treatment; v) landfill gas collection efficiency; and vi) domestic wastewater treatment. For each parameter, between three and four alternative trajectories were built, with scenario-specific assumptions on their evolution over the projection horizon, disaggregated at the national level and, where applicable, by state or region.

Overall, the trajectories follow a common logic across scenarios, although the nomenclature and the number of options vary by parameter: a current trend scenario, representing the continuation of observed patterns with no additional policy effort; one or more intermediate scenarios, representing the partial or full implementation of the targets established under the main sectoral policy instruments in force, such as the Plano Nacional de Resíduos Sólidos (PLANARES) and the Plano Nacional de Redução e Reciclagem de Resíduos Orgânicos Urbanos (PLANARO); and, for a subset of parameters, a Circular Economy scenario, representing more ambitious trajectories of generation reduction and diversion of waste from final disposal, going beyond the targets established in current policy instruments. It is important to highlight that not all parameters follow those categories.

The quantitative assumptions of each scenario were calibrated using historical data from the 13th Edition of SEEG [284], the targets established under PLANARES and PLANARO [216, 217], and international references, such as Global Waste Management Outlook 2024 [218]. The following sections detail the construction methodology and input data for each of these parameters.

4.8.1 Waste generation and prevention

The waste generation and prevention parameter defines the trajectory of domestic solid waste generation per capita, expressed in kg/capita/day, and determines the input values used in the subsequent calculation stages of the Waste Tool. Four alternative scenarios were built for this parameter: i) Strong growth (global as usual); ii) Implementation of prevention measures; iii) Constant; and iv) Circular Economy, each representing a distinct hypothesis about the evolution of waste generation intensity in Brazil between 2020 and 2050 (Figure 129).

34. Waste generation and prevention

A	B	C	D
Strong growth (global as usual)	Implementation of prevention measures	Constant	Circular Economy
Consider increase in generation, reaching a rate of 1.51 kg/hab.day in 2050.	Less significant increase in solid waste generation, reaching a rate of 1.27 kg/person/day.	Assumes the maintenance of current generation rates.	Assumes a reduction in waste generation starting in 2030, reaching a generation of 0.87 kg/inhabitant/day.
Growth rate of 44% compared to the year 2020 (based on global models)	Growth rate of 22% compared to the year 2020 (based on global models)	Around 1kg/hab.day	Decrease rate of -18% compared to the year 2020 (based on global models)

Figure 129: Prevention (generated waste) scenarios

All scenarios share the same national reference value of 1.05 kg/capita/day in 2020, derived from historical data of the 13th Edition of SEEG [284], and diverge from 2030 onward according to scenario-specific growth rates applied over each decade, based on the Global Waste Management Outlook 2024 [218], which presents global trajectories that were adjusted to the Brazilian context. For each state, an effort was made to preserve the relative differences in per capita generation observed across states in the base year, while following the same national growth rate in each period, so that regional disparities in waste generation intensity are maintained throughout the projection horizon.

Scenario A: Strong growth (global as usual) assumes that waste generation continues to increase in line with historical patterns observed internationally, reaching 1.51 kg/capita/day by 2050 – a 44% increase relative to 2020 – remaining constant thereafter. This trajectory is calibrated based on global models, with no additional prevention effort, although in the Brazilian context this would represent significant growth. The national and state-level values of this trajectory are presented in Table 68 and Table 69.

	2020	2030	2040	2050
Growth rate for the period (%)	0	16	13	11
Brazil (kg/capita/day)	1.05	1.21	1.36	1.51

Table 68: Strong growth (global as usual) – national growth rate and per capita generation

State	2023	2030	2040	2050
AC	1.04	1.21	1.35	1.50
AL	1.01	1.17	1.32	1.46
AM	1.22	1.42	1.51	1.51

State	2023	2030	2040	2050
AP	1.22	1.42	1.51	1.51
BA	1.07	1.24	1.39	1.51
CE	1.29	1.50	1.51	1.51
DF	0.73	0.84	0.95	1.05
ES	1.03	1.19	1.34	1.49
GO	0.96	1.11	1.25	1.39
MA	1.18	1.37	1.51	1.51
MG	0.85	0.98	1.10	1.23
MS	1.02	1.18	1.33	1.47
MT	0.95	1.10	1.24	1.37
PA	1.11	1.29	1.45	1.51
PB	1.11	1.29	1.45	1.51
PE	0.97	1.12	1.26	1.40
PI	1.33	1.51	1.51	1.51
PR	0.81	0.94	1.05	1.17
RJ	1.24	1.44	1.51	1.51
RN	1.21	1.40	1.51	1.51
RO	0.78	0.90	1.01	1.12
RR	0.86	0.99	1.12	1.24
RS	0.77	0.89	1.00	1.11
SC	0.80	0.92	1.04	1.15
SE	1.15	1.33	1.50	1.51
SP	0.94	1.09	1.22	1.36
TO	1.06	1.23	1.38	1.51
BR	1.04	1.20	1.35	1.50

Table 69: *Strong growth (global as usual) – state-level per capita generation (kg/capita/day)*

Scenario B: Implementation of prevention measures considers a less pronounced increase in generation, reflecting the partial adoption of waste prevention policies. Under this scenario, per capita generation reaches 1.27 kg/capita/day by 2050, corresponding to a 22% growth relative to 2020 – roughly half the increase observed in Scenario A – also calibrated based on global models. Table 70 and Table 71 presents the national and state-level values corresponding to this scenario.

	2020	2030	2040	2050
Growth rate for the period (%)	0	16	2	2
Brazil (kg/capita/day)	1.05	1.21	1.24	1.27

Table 70: *Implementation of prevention measures – national growth rate and per capita generation*

State	2023	2030	2040	2050
AC	1.04	1.21	1.23	1.26
AL	1.01	1.17	1.20	1.23
AM	1.22	1.42	1.45	1.49
AP	1.22	1.42	1.45	1.49
BA	1.07	1.24	1.27	1.30
CE	1.29	1.50	1.51	1.51
DF	0.73	0.84	0.86	0.88
ES	1.03	1.19	1.22	1.25
GO	0.96	1.11	1.14	1.17
MA	1.18	1.37	1.40	1.44
MG	0.85	0.98	1.01	1.03
MS	1.02	1.18	1.21	1.24
MT	0.95	1.10	1.13	1.15
PA	1.11	1.29	1.32	1.35
PB	1.11	1.29	1.32	1.35
PE	0.97	1.12	1.15	1.18
PI	1.33	1.51	1.51	1.51
PR	0.81	0.94	0.96	0.98
RJ	1.24	1.44	1.47	1.51
RN	1.21	1.40	1.44	1.47
RO	0.78	0.90	0.92	0.95
RR	0.86	0.99	1.02	1.04
RS	0.77	0.89	0.91	0.93
SC	0.80	0.92	0.95	0.97
SE	1.15	1.33	1.37	1.40
SP	0.94	1.09	1.12	1.14
TO	1.06	1.23	1.26	1.29

State	2023	2030	2040	2050
BR	1.04	1.20	1.23	1.26

Table 71: *Implementation of prevention measures – state-level per capita generation (kg/capita/day)*

Scenario C: Constant assumes that current generation rates are maintained unchanged throughout the entire projection period, at approximately 1.05 kg/capita/day (1 kg/capita/day at the national aggregate), with a 0% growth rate in every period. This scenario serves as a reference case, isolating the effect of downstream treatment and diversion assumptions from changes in waste generation itself. The corresponding values, held constant across all periods, are presented in Table 72 and Table 73.

	2020	2030	2040	2050
Growth rate for the period (%)	0	0	0	0
Brazil (kg/capita/day)	1.05	1.05	1.05	1.05

Table 72: *Constant – national growth rate and per capita generation*

State	2023	2030	2040	2050
AC	1.04	1.04	1.04	1.04
AL	1.01	1.01	1.01	1.01
AM	1.22	1.22	1.22	1.22
AP	1.22	1.22	1.22	1.22
BA	1.07	1.07	1.07	1.07
CE	1.29	1.29	1.29	1.29
DF	0.73	0.73	0.73	0.73
ES	1.03	1.03	1.03	1.03
GO	0.96	0.96	0.96	0.96
MA	1.18	1.18	1.18	1.18
MG	0.85	0.85	0.85	0.85
MS	1.02	1.02	1.02	1.02
MT	0.95	0.95	0.95	0.95
PA	1.11	1.11	1.11	1.11
PB	1.11	1.11	1.11	1.11
PE	0.97	0.97	0.97	0.97
PI	1.33	1.33	1.33	1.33
PR	0.81	0.81	0.81	0.81

State	2023	2030	2040	2050
RJ	1.24	1.24	1.24	1.24
RN	1.21	1.21	1.21	1.21
RO	0.78	0.78	0.78	0.78
RR	0.86	0.86	0.86	0.86
RS	0.77	0.77	0.77	0.77
SC	0.80	0.80	0.80	0.80
SE	1.15	1.15	1.15	1.15
SP	0.94	0.94	0.94	0.94
TO	1.06	1.06	1.06	1.06
BR	1.04	1.04	1.04	1.04

Table 73: *Constant – state-level per capita generation (kg/capita/day)*

Scenario D: Circular Economy is the only scenario that assumes an absolute reduction in waste generation, reflecting the adoption of circular economy principles. Generation continues to rise until 2030, in line with the other scenarios, but subsequently declines, reaching approximately 0.86 kg/capita/day by 2050 - an 18% reduction relative to 2020 - remaining at this reduced level through 2050. Table 74 and Table 75 presents the national and state-level values corresponding to this reduction trajectory.

	2020	2030	2040	2050
Growth rate for the period (%)	0	16	-7	-24
Brazil (kg/capita/day)	1.05	1.21	1.10	0.86

Table 74: *Circular Economy – national growth rate and per capita generation*

State	2023	2030	2040	2050
AC	1.04	1.21	1.10	0.86
AL	1.01	1.17	1.06	0.83
AM	1.22	1.42	1.29	1.01
AP	1.22	1.42	1.29	1.01
BA	1.07	1.24	1.13	0.88
CE	1.29	1.50	1.36	1.06
DF	0.73	0.84	0.77	0.60
ES	1.03	1.19	1.08	0.85

State	2023	2030	2040	2050
GO	0.96	1.11	1.01	0.79
MA	1.18	1.37	1.24	0.97
MG	0.85	0.98	0.89	0.70
MS	1.02	1.18	1.07	0.84
MT	0.95	1.10	1.00	0.78
PA	1.11	1.29	1.17	0.91
PB	1.11	1.29	1.17	0.91
PE	0.97	1.12	1.02	0.80
PI	1.33	1.51	1.40	1.10
PR	0.81	0.94	0.85	0.67
RJ	1.24	1.44	1.31	1.02
RN	1.21	1.40	1.28	1.00
RO	0.78	0.90	0.82	0.64
RR	0.86	0.99	0.90	0.71
RS	0.77	0.89	0.81	0.63
SC	0.80	0.92	0.84	0.66
SE	1.15	1.33	1.21	0.95
SP	0.94	1.09	0.99	0.77
TO	1.06	1.23	1.12	0.87
BR	1.04	1.20	1.09	0.86

Table 75: *Circular Economy – state-level per capita generation (kg/capita/day)*

4.8.2 Recycling

The recycling parameter defines the evolution of the recovery rate of recyclable materials from collected domestic solid waste, and determines part of the fraction of waste diverted from final disposal in the subsequent calculation stages of the Waste Tool. Four alternative scenarios were built for this parameter: i) Current Trend; ii) Partial PLANARES implementation; iii) PLANARES implementation; and iv) Circular Economy, each representing a distinct hypothesis about the pace of progress in recycling in Brazil between 2024 and 2050 (Figure 130).

35. Recycling

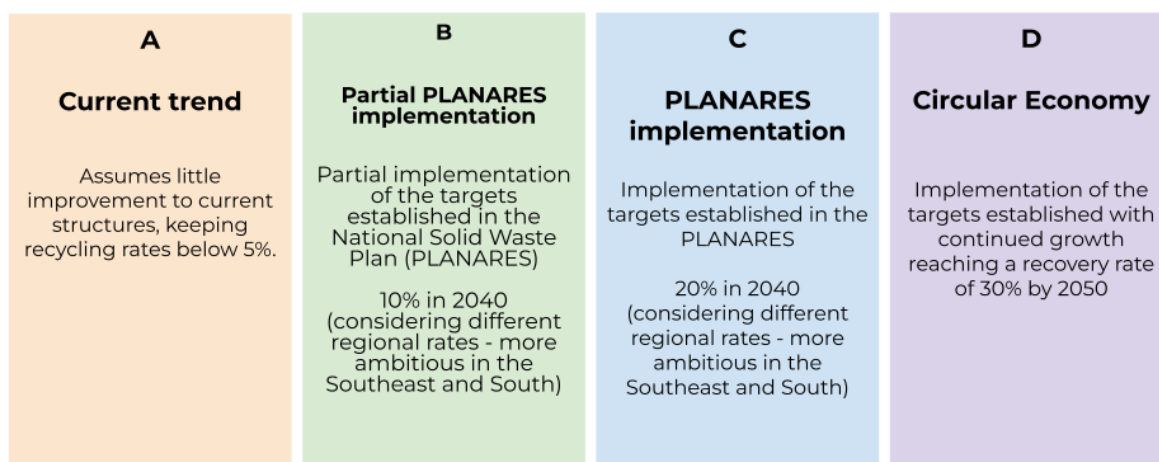


Figure 130: *Recycling scenarios*

In all scenarios, national rates were disaggregated by region (North, Northeast, Midwest, Southeast, and South), reflecting regional heterogeneity in installed waste management capacity and assigning more ambitious trajectories to the Southeast and South regions, as presented in Brazilian national policies, historically more advanced in selective collection and recycling. Historical data used as a reference for the base year are sourced from SINISA [214].

Scenario A: Current trend assumes little progress relative to current recycling structures, keeping the national rate below 5% through 2040, since recycling has shown limited progress in the Brazilian context since the implementation of the national policy [285]. Under this scenario, the South and Southeast regions reach rates of 7.2% and 6.5%, respectively, in 2040, while the North region remains around 2.8%. The national and regional values of this trajectory are presented in Table 76.

Region	2024	2028	2032	2036	2040	2050
North	1.20	1.30	1.80	2.30	2.80	2.80
Northeast	1.60	1.40	1.90	2.40	2.88	2.88
Midwest	1.90	1.13	2.40	3.03	3.68	3.68
Southeast	1.90	1.65	4.05	5.25	6.45	6.45
South	4.70	2.38	4.78	5.98	7.18	7.18
Brazil	2.20	2.30	3.20	4.10	5.00	5.00

Table 76: *Current trend – recycling rate by region (%)*

Scenario B: Partial PLANARES implementation considers the partial adoption of the targets

established under the Plano Nacional de Resíduos Sólidos (PLANARES), with the national recycling rate reaching 10% in 2040 and remaining at this level through 2050. Under this scenario, the South region reaches 14.4% and the Southeast region 12.9% in 2040, compared to 5.6% in the North region. Table 77 presents the national and regional values corresponding to this scenario.

Region	2024	2028	2032	2036	2040	2050
North	0.60	2.60	3.60	4.60	5.60	5.60
Northeast	0.80	2.80	3.80	4.80	5.75	5.75
Midwest	0.95	2.25	4.80	6.05	7.35	7.35
Southeast	0.95	3.30	8.10	10.50	12.90	12.90
South	2.35	4.75	9.55	11.95	14.35	14.35
Brazil	1.10	4.60	6.40	8.20	10.00	10.00

Table 77: *Partial PLANARES implementation – recycling rate by region (%)*

Scenario C: PLANARES implementation represents the full achievement of the target established under the plan, with the national recycling rate reaching 20% in 2040. Under this scenario, the Southeast region reaches 25.8% and the South region 28.7% in 2040, while the North region reaches 11.2%. Table 78 presents the national and regional values corresponding to this trajectory.

Region	2024	2028	2032	2036	2040	2050
North	1.20	5.20	7.20	9.20	11.20	11.20
Northeast	1.60	5.60	7.60	9.60	11.50	11.50
Midwest	1.90	4.50	9.60	12.10	14.70	14.70
Southeast	1.90	6.60	16.20	21.00	25.80	25.80
South	4.70	9.50	19.10	23.90	28.70	28.70
Brazil	2.20	9.20	12.80	16.40	20.00	20.00

Table 78: *PLANARES implementation – recycling rate by region (%)*

Scenario D: Circular Economy assumes the implementation of the PLANARES targets with continued growth of recycling rates beyond 2040, reflecting the adoption of circular economy principles. The national trajectory follows PLANARES implementation through 2040 (20%), subsequently growing to reach a recovery rate of 30% by 2050. Under this scenario, the Southeast and South regions reach 30% already by 2050, while the North, Northeast, and Midwest regions stabilize at 25% from 2050 onward. Table 79 presents the national and regional values corresponding to this trajectory.

Region	2024	2028	2032	2036	2040	2050
North	1.20	5.20	7.20	9.20	11.20	25.00
Northeast	1.60	5.60	7.60	9.60	11.50	25.00
Midwest	1.90	4.50	9.60	12.10	14.70	25.00
Southeast	1.90	6.60	16.20	21.00	25.80	30.00
South	4.70	9.50	19.10	23.90	28.70	30.00
Brazil	2.20	9.20	12.80	16.40	20.00	30.00

Table 79: *Circular Economy – recycling rate by region (%)*

4.8.3 Biological treatment

The biological treatment parameter defines the evolution of the rate of organic waste directed to composting and anaerobic digestion processes, expressed as a percentage, and determines part of the fraction of waste diverted from final disposal in the calculation tool. Four alternative scenarios were built for this parameter: i) Current trend; ii) Partial PLANARO implementation; iii) PLANARO implementation; and iv) Circular Economy, each representing a distinct hypothesis about the pace of progress in the biological treatment of organic waste in Brazil between 2024 and 2050 (Figure 131).

36. Biological treatment

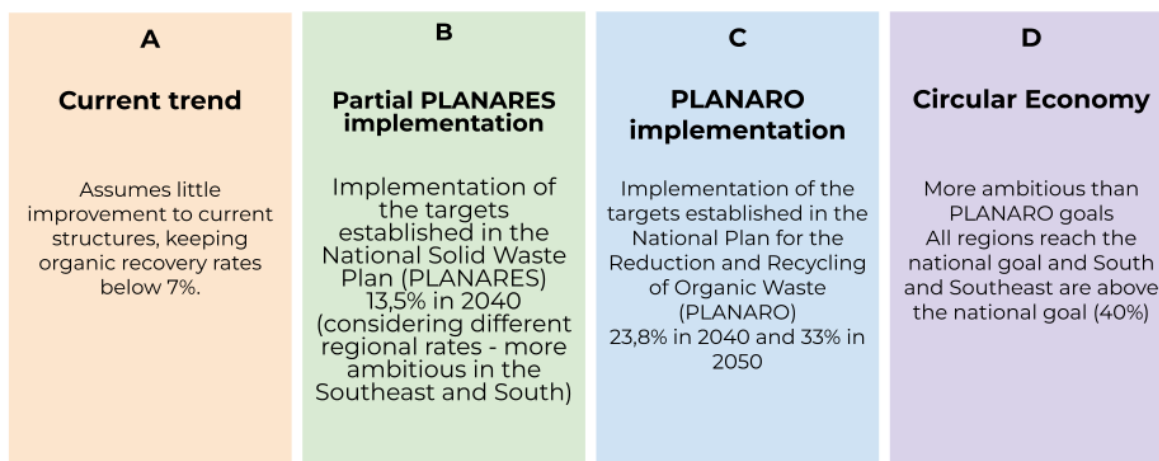


Figure 131: *Biological treatment scenarios*

In all scenarios, national rates were disaggregated by region (North, Northeast, Midwest, Southeast, and South), assigning more ambitious trajectories to the Southeast and South regions, historically more advanced in selective collection and organic waste treatment. Historical data used as a reference for the base year are sourced from the 13th Edition of SEEG [284] and SINISA [214].

Scenario A: Current trend assumes little progress relative to current biological treatment structures, keeping the organic recovery rate below 7% throughout the projection period, reaching 6.75% at the national aggregate in 2040 and remaining stable at this level through 2050. Under this scenario, the Southeast and South regions reach 9.05% in 2040, while the North and Northeast regions remain at 3.75%. The national and regional values of this trajectory are presented in Table 80.

Region	2024	2028	2032	2036	2040	2050
North	1.50	1.50	2.25	3.00	3.75	3.75
Northeast	1.50	1.50	2.25	3.00	3.75	3.75
Midwest	1.90	1.95	2.90	3.85	4.80	4.80
Southeast	3.60	3.60	5.40	7.20	9.05	9.05
South	3.60	3.60	5.40	7.20	9.05	9.05
Brazil	2.70	2.70	4.05	5.40	6.75	6.75

Table 80: *Current trend – biological treatment rate by region (%)*

Scenario B: Partial PLANARO implementation considers the partial adoption of the targets established under the Plano Nacional de Redução e Reciclagem de Resíduos Orgânicos Urbanos, with the national rate reaching 13.5% in 2040 and remaining at this level through 2050. Under this scenario, the Southeast and South regions reach 18.1% in 2040, compared to 7.5% in the North and Northeast regions. Table 81 presents the national and regional values corresponding to this scenario.

Region	2024	2028	2032	2036	2040	2050
North	1.50	3.00	4.50	6.00	7.50	7.50
Northeast	1.50	3.00	4.50	6.00	7.50	7.50
Midwest	1.90	3.90	5.80	7.70	9.60	9.60
Southeast	3.60	7.20	10.80	14.40	18.10	18.10
South	3.60	7.20	10.80	14.40	18.10	18.10
Brazil	2.70	5.40	8.10	10.80	13.50	13.50

Table 81: *Partial PLANARO implementation – biological treatment rate by region (%)*

Scenario C: PLANARO implementation represents the achievement of the target established under PLANARO, reaching 23.8% at the national aggregate in 2040 and evolving to 33% by 2050. Under this scenario, the Southeast and South regions reach 31.9% in 2040 and 33% in 2050, while the North and Northeast regions reach 13.2% in 2040. Table 82 presents the national and regional values corresponding to this trajectory.

Region	2024	2028	2032	2036	2040	2050
North	1.50	3.00	7.90	10.60	13.20	18.50
Northeast	1.50	3.00	7.90	10.60	13.20	18.50
Midwest	1.90	3.90	10.20	13.50	16.90	23.70
Southeast	3.60	7.20	19.10	25.30	31.90	33.00
South	3.60	7.20	19.10	25.30	31.90	33.00
Brazil	2.70	5.40	14.30	19.00	23.80	33.30

Table 82: *PLANARO implementation – biological treatment rate by region (%)*

Scenario D: Circular Economy is the most ambitious of the four scenarios, exceeding the PLANARO targets. All regions converge toward the national target, with the South and Southeast regions surpassing this level and reaching 40% organic recovery from 2050 onward, compared to 33% in the remaining regions. Table 83 presents the national and regional values corresponding to this trajectory.

Region	2024	2028	2032	2036	2040	2050
North	1.50	3.00	7.90	10.60	13.20	33.00
Northeast	1.50	3.00	7.90	10.60	13.20	33.00
Midwest	1.90	3.90	7.80	13.50	16.90	33.00
Southeast	3.60	7.20	14.40	25.30	31.90	40.00
South	3.60	7.20	19.10	25.30	31.90	40.00
Brazil	2.70	5.40	14.30	19.00	23.80	37.00

Table 83: *Circular Economy – biological treatment rate by region (%)*

4.8.4 LFG collection efficiency

The landfill gas collection efficiency parameter defines the evolution of the fraction of landfill gas generated at solid waste disposal sites (SWDS) that is effectively captured and directed to energy recovery or flaring, expressed as a percentage, and determines the input values used in the calculation of avoided emissions in the Waste Tool. Three alternative scenarios were built for this parameter: i) Low; ii) Medium; and iii) High, each representing a distinct hypothesis about the pace of expansion of gas capture infrastructure at Brazilian landfills between 2020 and 2050 (Figure 132).

37. Landfill gas collection efficiency



Figure 132: Landfill gas collection efficiency scenarios

Unlike the other scenario parameters, landfill gas collection efficiency is defined exclusively at the national level, with no regional disaggregation. All scenarios start from a common reference value of approximately 20% in 2020, reflecting the average efficiency observed at sanitary landfills currently in operation in the country.

Scenario A: Low assumes a limited expansion of gas capture capacity, with collection efficiency evolving gradually to reach 30% by 2050. This trajectory represents a continuation of current operating and maintenance conditions of capture systems, with no significant additional investment. The values of this trajectory are presented in Table 84.

	2020	2030	2040	2050
% collection and utilization efficiency	~20	25	27.5	30

Table 84: Low – landfill gas collection and utilization efficiency

Scenario B: Medium considers a more consistent expansion of collection infrastructure, with efficiency reaching 40% in 2040 and 50% in 2050. Table 85 presents the values corresponding to this scenario.

	2020	2030	2040	2050
% collection and utilization efficiency	~20	30	40	50

Table 85: Medium – landfill gas collection and utilization efficiency

Scenario C: High represents the implementation of the targets established under PLANARES for

landfill biogas capture, with collection efficiency reaching 63.4% in 2040 and 75% in 2050. This trajectory presupposes substantial investment in the modernization and expansion of capture systems at existing landfills, as well as the adoption of this technology at new facilities. The values of this trajectory are presented in Table 86.

	2020	2030	2040	2050
% collection and utilization efficiency	~20	38	63.4	75

Table 86: *High – landfill gas collection and utilization efficiency*

4.8.5 Thermal treatment

The thermal treatment parameter defines the evolution of the fraction of municipal solid waste directed to incineration, expressed as a percentage of the total waste mass, and determines the input values used in the subsequent calculation stages of the Waste Tool, representing a diversion from final disposal. Three alternative scenarios were built for this parameter: i) Constrained; ii) Constrained for organic waste; and iii) Unconstrained, each representing a distinct hypothesis about the role of incineration in solid waste management in Brazil between 2020 and 2050 (Figure 133).

38. Thermal treatment

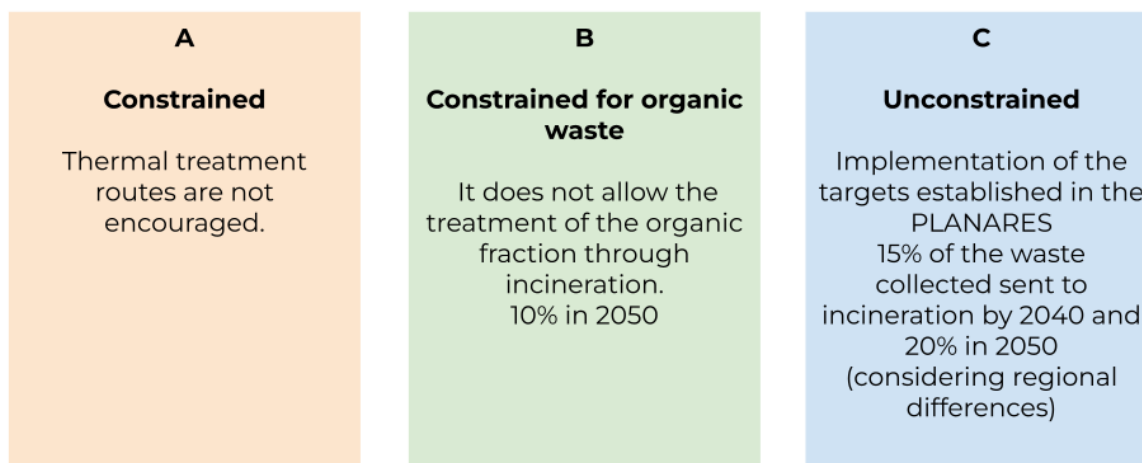


Figure 133: *Thermal treatment scenarios*

In all scenarios, national rates were disaggregated by region (North, Northeast, Midwest, Southeast, and South), reflecting regional differences in terms of local management and infrastructure capacity and in the acceptance of incineration as a treatment route, given that it may discourage investments in selective waste collection and in measures to promote a reduction in waste generation, in addition to other conflicts concerning technical and financial viability and the actual potential for energy generation [286].

Scenario A: Constrained assumes that thermal treatment routes – owing to their cost, technical implementation challenges in the southern hemisphere, and environmental impacts that are not necessarily beneficial [287] – are not encouraged, keeping the fraction of domestic waste incinerated at 0% in all regions throughout the entire period, from 2020 to 2050. This scenario represents the continuation of the current situation, in which incineration does not constitute a relevant waste treatment route in the country. The values of this trajectory are presented in Table 87.

Region	2020	2030	2040	2050
North	0.0	0.0	0.0	0.0
Northeast	0.0	0.0	0.0	0.0
Midwest	0.0	0.0	0.0	0.0
Southeast	0.0	0.0	0.0	0.0
South	0.0	0.0	0.0	0.0
% of total mass incinerated	0	0	0	0

Table 87: *Constrained – share of total mass incinerated by region (%)*

Scenario B: Constrained for organic waste does not permit the treatment of the organic fraction of waste through incineration, restricting this route to the remaining fractions of collected waste. Under this scenario, the national incinerated fraction reaches 7.5% in 2040, which represents half of the goal of the PLANARES, and 10% in 2050. In this scenario, the South region reaches 9.55% and the Southeast region 8.1% in 2040, compared to 3.6% in the North region. Table 88 presents the national and regional values corresponding to this scenario.

Region	2020	2030	2040	2050
North	0.0	2.6	3.6	3.6
Northeast	0.0	2.8	3.8	3.8
Midwest	0.0	2.25	4.8	4.8
Southeast	0.0	3.3	8.1	8.1
South	0.0	4.75	9.55	9.55
% of total mass incinerated	0	5	7.5	10

Table 88: *Constrained for organic waste – share of total mass incinerated by region (%)*

Scenario C: Unconstrained represents the implementation of the targets established under PLANARES for waste incineration, with 15% of the collected waste mass directed to incineration by 2040 and 20% by 2050, considering regional differences. Under this scenario, the South region reaches 19.1% and the Southeast region 16.2% in 2040, compared to 7.2% in the North region. The values of this trajectory are presented in Table 89.

Region	2020	2030	2040	2050
North	0.0	5.2	7.2	7.2
Northeast	0.0	5.6	7.6	7.6
Midwest	0.0	4.5	9.6	9.6
Southeast	0.0	6.6	16.2	16.2
South	0.0	9.5	19.1	19.1
% of total mass incinerated	0	10	15	20

Table 89: *Unconstrained – share of total mass incinerated by region (%)*

4.8.6 Wastewater treatment

The domestic wastewater treatment parameter comprises two components: the first refers to collection rates, and the second to the composition of technological treatment routes employed at wastewater treatment plants (WWTPs), expressed as a percentage share of each treatment type, and determines the input values used in the emissions calculation of the domestic wastewater treatment module of the Waste Tool. Three alternative scenarios were built for this parameter: i) Constant; ii) Universalization of basic sanitation services; and iii) Universalization with high investments, each representing a distinct hypothesis about the evolution of collection coverage and the technological composition of wastewater treatment in Brazil between 2025 and 2050 (Figure 134).

39. Wastewater treatment

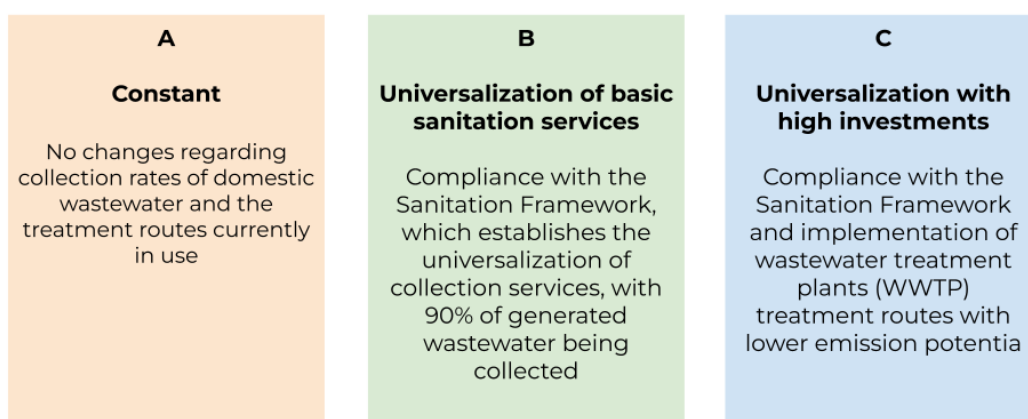


Figure 134: *Wastewater treatment scenarios*

The collection rate corresponds to the share of domestic wastewater generated that is captured by sewage collection networks, expressed as a percentage and disaggregated at the state level. The baseline reflects current state-level collection coverage, ranging from 11.7% in Amapá and Pará to 91.9% in São Paulo, with a national aggregate of 63.4%, based on municipal data presented on

SINISA [215].

Under **Scenario A: Constant**, collection rates are held at their baseline throughout the projection period, remaining at 63.4% at the national level through 2050. Under both **Universalization scenarios (B and C)**, collection rates converge to the 90%, target established by the Marco Legal do Saneamento Básico [288], by 2033, remaining at this level through 2050; the state of São Paulo, whose baseline collection rate already exceeds 90%, converges instead to 92%. At the national level, the aggregate collection rate reaches approximately 90.4% by 2033 under both Universalization scenarios. Tables 90 and 91 present the national and state-level collection rate values.

State	2025	2033	2050
AC	35.9	35.9	35.9
AL	28.1	28.1	28.1
AM	39.6	39.6	39.6
AP	11.7	11.7	11.7
BA	58.5	58.5	58.5
CE	42.9	42.9	42.9
DF	89.1	89.1	89.1
ES	77.1	77.1	77.1
GO	64.1	64.1	64.1
MA	24.1	24.1	24.1
MG	83.0	83.0	83.0
MS	58.8	58.8	58.8
MT	37.5	37.5	37.5
PA	11.7	11.7	11.7
PB	52.7	52.7	52.7
PE	54.2	54.2	54.2
PI	13.5	13.5	13.5
PR	71.2	71.2	71.2
RJ	82.5	82.5	82.5
RN	34.9	34.9	34.9
RO	13.4	13.4	13.4
RR	51.3	51.3	51.3
RS	48.1	48.1	48.1
SC	43.0	43.0	43.0
SE	48.9	48.9	48.9
SP	91.9	91.9	91.9

State	2025	2033	2050
TO	33.4	33.4	33.4
BR	63	63	63

Table 90: *Scenario A: Constant – domestic wastewater collection rate by state (%)*

State	2025	2033	2050
AC	35.9	90.0	90.0
AL	28.1	90.0	90.0
AM	39.6	90.0	90.0
AP	11.7	90.0	90.0
BA	58.5	90.0	90.0
CE	42.9	90.0	90.0
DF	89.1	90.0	90.0
ES	77.1	90.0	90.0
GO	64.1	90.0	90.0
MA	24.1	90.0	90.0
MG	83.0	90.0	90.0
MS	58.8	90.0	90.0
MT	37.5	90.0	90.0
PA	11.7	90.0	90.0
PB	52.7	90.0	90.0
PE	54.2	90.0	90.0
PI	13.5	90.0	90.0
PR	71.2	90.0	90.0
RJ	82.5	90.0	90.0
RN	34.9	90.0	90.0
RO	13.4	90.0	90.0
RR	51.3	90.0	90.0
RS	48.1	90.0	90.0
SC	43.0	90.0	90.0
SE	48.9	90.0	90.0
SP	91.9	92.0	92.0
TO	33.4	90.0	90.0

State	2025	2033	2050
BR	63.4	90.4	90.4

Table 91: *Scenarios B (Universalization of basic sanitation services) and C (Universalization with high investments) – domestic wastewater collection rate by state (%).*

In all scenarios, the technological composition is represented by five treatment routes: activated sludge, primary-level treatment (e.g., outfalls), anaerobic lagoon, anaerobic reactor, and activated sludge with extended aeration, whose shares sum to 100% of the total treated mass in each reference year, as presented in the Atlas Esgotos study by ANA [230].

Scenario A: Constant assumes the maintenance of the current domestic wastewater collection rate (Table 90) and of the treatment routes currently in use, with no changes to the technological composition throughout the projection period. Under this scenario, the share of each route remains fixed between 2025 and 2050, with activated sludge accounting for 42.5%, primary-level treatment for 20.4%, anaerobic lagoon for 14.2%, anaerobic reactor for 11.6%, and activated sludge with extended aeration for 11.3% of the treated mass. The values of this trajectory are presented in Table 92.

Scenario B: Universalization of basic sanitation services assumes compliance with the Marco Legal do Saneamento Básico [288], which establishes the universalization of collection services, with 90% of generated wastewater being collected by 2033 (Table 91). Under this scenario, the technological composition of treatment remains identical to that of the Constant scenario, reflecting the expansion of collection coverage with no change in the profile of treatment routes employed. The values corresponding to this scenario are the same as those presented for Scenario A in Table 92.

Treatment route	2025	2033	2050
Activated sludge	42.5	42.5	42.5
Primary level (e.g., outfalls)	20.4	20.4	20.4
Anaerobic lagoon	14.2	14.2	14.2
Anaerobic reactor	11.6	11.6	11.6
Activated sludge with extended aeration	11.3	11.3	11.3

Table 92: *Scenarios A (Constant) and B (Universalization of basic sanitation services) – domestic wastewater treatment route composition (%).*

Scenario C: Universalization with high investments considers, in addition to compliance with the Marco Legal do Saneamento Básico [288], the implementation of wastewater treatment plants (WWTPs) with lower-emission-potential routes. Under this scenario, the share of conventional activated sludge declines from 42.5% in 2025 to 20.3% in 2050, while the share of activated sludge with extended aeration grows from 11.3% to 33.6% over the same period, in a direct transition between these two routes. The shares of primary-level treatment, anaerobic lagoon, and anaerobic reactor remain unchanged in this scenario. The values of this trajectory are presented in Table 93.

Treatment route	2025	2033	2050
Activated sludge	42.5	35.4	20.3
Primary level (e.g., outfalls)	20.4	20.4	20.4
Anaerobic lagoon	14.2	14.2	14.2
Anaerobic reactor	11.6	11.6	11.6
Activated sludge with extended aeration	11.3	18.5	33.6

Table 93: *Universalization with high investments – domestic wastewater treatment route composition (%)*

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NetZero Brasil

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