Brazil’s Electric Sector

Segments:

Brazil's electric sector consists of 4 segments:

	Generation	Transmission	Distribution	Sales
Role	Energy generation for the country	Transporting energy from the point of generation to the point of distribution or consumption	Conversion of energy to a lower voltage and transportation to the end consumer	Purchase and sale of electricity in the free market
Participants	Public and Private / auto producers / independent producers	Public or private companies that hold transmission blocks	Distribution concession operators	Generators, traders, free and special consumers, exporters and importers
Regulated?	Mostly not	Yes	Yes	No

Energy procurement environments:

Transactions in Brazil’s Electric Sector take place in two Energy Procurement Environments: Regulated Procurement Environment - ACR and Free Procurement Environment - ACL.

Regulated Procurement Environment (ACR):

Pursuant to Decree 5,163 issued July 2004 (“Decree 5.163/2004”), in the ACR distribution companies should guarantee they procure 100% of their sales through contracts registered at the CCEE.

Energy Auctions at the ACR

The distribution companies buy energy to supply captive consumers at public auctions regulated by ANEEL and administered by the Electricity Trading Chamber (CCEE).

Purchases at ACR auctions are made jointly, with distribution companies forming a pool of buyers, in order to force down rates, thus reducing the cost of electricity for captive consumers, regardless of the distribution company's size.

Energy auctions are defined in accordance with the type of energy on offer and the time between procurement and effective delivery of the energy by the Generator to the Distribution company.

Classification based on energy type:

- New Energy Auctions ("LEN"): energy offered from new generation ventures.

Pursuant to Decree 9.143 issued August 2017 ("Decree 9.143/2017"), the LENs can be promoted in years "A-3", "A-4", "A-5" and "A-6.

- Existing Energy Auctions ("LEE"): energy offered from existing ventures.

Pursuant to Decree 9.143/2017, for LEE bids can be submitted in years "A", "A-1", "A-2", "A-3", "A-4" and "A-5".

To illustrate, an "A-3" auction held in year "A" would see energy begin to be delivered 3 years later. For example: the product offered at an auction in 2020 would begin to be supplied in 2023.

Auction contracts, also known as Regulated-Environment Energy Procurement Agreements ("CCEARs"), can be implemented on the basis Uptime ("CCEAR-D") or Quantity ("CCEAR-Q").

In the CCEAR-Q basis, the vendor is responsible for delivering a given amount of procured energy and undertakes the risks if this supplier is affected by hydrological conditions, low reservoir levels or other such issues.

In the CCEAR-D basis, in turn, the vendor undertakes to provide a specific capacity volume to the ACR. In this case, its revenue is guaranteed and the risks, onus and benefits caused by production changes in relation to the guarantee capacity are allocated to the group of distribution companies bidding at the auction and subsequently passed through to consumers regulated through rates.

In addition to these principal auctions, the legislation also provides for specific auctions for alternative sources, generation ventures indicated by CNPE Resolution and approved by the president of the Republic and electricity from new generation ventures with joint procurements through the transmission assets necessary for transmission.

Other contracts

Contracts entered into before March 16, 2004, when Law 10.848 was published which is still effective, were in the distribution companies' portfolio. Energy can also be acquired from distributed generation through a public tender organized by the distribution company, limited to 10% of its capacity. These are known as Regulated Bilateral Contracts ("CBR").

As an alternative to bidding at the aforesaid auctions, distribution companies with their own annual market with a capacity of less than 500 GWh can opt to procure their energy volumes other ways: through distributed generators, at regulated rates of its current supplier agent; or through public procurement processes. At Energisa Group, Energisa Nova Friburgo is currently placed in this category of distribution companies, and acquires its energy through procurement contracts.

Energy quotas

The regulated environment procurement model entails the compulsory allocation of energy quotas ratified by ANEEL, from: (i) Binational Itaipu; (ii) plants classified in the Alternative Electricity Sources Incentive Program – PROINFA; (iii) Angra I and II nuclear power plants; and (iv) hydroelectric plants with concessions awarded under "Physical Capacity and Power Quotas".

(i) Binational Itaipu:

Binational Itaipu is a binational entity created under a Treaty signed by Brazil and Paraguay on April 26, 1973, in order to generate hydroelectric power on the Paraná

Rivere, jointly owned by both countries. The entity is owned by Centrais Elétricas Brasileiras S.A. – Eletrobras and Administración Nacional de Eletricidad - ANDE.

Following the publication of Law 10.438/2002, Eletrobras became responsible for purchasing and trading the energy generated by Itaipu, undertaking the role of sales agent for this energy

Normative Resolution 218 published April 11, 2006 establishes the criteria for determining the annual quota shares for energy and power purchases from Itaipu by the energy distribution companies.

The quota shares denote fractions of the power and respective bound energy, contracted by the distribution companies of the South and South-east/Midwest Subsystems in proportion to their respective markets. These are ratified by ANEEL by December 31 each year for the following year.

The distribution concession operators will assume the hydrological risks posed by ITAIPU generation, including the MRE, in proportion to the amount of electricity allocated to each of them.

(ii) Power plants qualifying for the Alternative Electricity Sources Incentive Program – PROINFA:

Law 10.438/2002 introduced the PROINFA program to scale up the supply of renewable energy (produced by SHPs, biomass and windfarms), with Eletrobras responsible for trading this energy.

The program is funded by all end consumers (free and captive) comprising the National Interconnected Grid - SIN, except for those classified as low-income. Each year ANEEL ratifies energy and funding quotas for distribution companies and other consumption agents.

(iii) Angra I and II nuclear plants:

Law 12.111/2009 determined that from January 01, 2013 payments to Eletronuclear of the revenue made on power generated by the Angra I and II powerplants will be prorated amongst all concession operators, licensees or public distribution service operators comprising the National Interconnected Grid – SIN.

Normative Resolution 530/2012 established a methodology for calculating the quota shares of the nuclear plants Angra I and II and the terms for trading these plants' energy output. The energy produced by Angra I and II is prorated based on each distribution company's quota share, which denotes the percentage of invoiced sales in relation to the group of SIN distribution companies.

Nuclear energy is sold at the CCEE through Nuclear Energy Quota Contracts - CCEN, identified as commercial relations between Eletronuclear (vendor) and each distribution agent in SIN (buyer). Angra I and II's output is attributed to the quota-holding distribution companies in the CCEE spot market. The risks, onus and benefits caused by production changes are therefore allocated to these distribution companies and subsequently passed through to consumers.

(iv) Hydroelectric plants with concessions extended under "Physical Capacity and Power Quotas".

Enacted from Provisional Law 579/2012, Law 12.783/2013 is regulated by Decree 7.805/2012, and introduced important changes to the trading model introduced by Law 10.848/2004. The hydroelectric plants whose concessions have been or will be extended should allocate their physical capacity and power guarantee to the regulated markets through "Physical Capacity and Power Quotas".

ANEEL Normative Resolution 521/2012 addressed the initial allocation of Physical Capacity Quotas, the compulsory assignment of CCEARs and the extraordinary review of distribution rates. The assignments of existing and new energy CCEARs are made to strike a balance between reducing rates and offsetting changes in the procurement level of distribution concession operators. ANEEL Ratifying Resolution 1.410/2013 determined the initial allocation of these quotas at the distribution companies (100% of the plants' physical guarantee capacity and the CCEARs assignments).

The Physical Guarantee Quota Contracts – CCGFs afford special treatment at the CCEE to plants whose concessions have been renewed under Decree 7.805/2012. The contracted amount associated with each CCGF accounts for 90% of the quota ratified by ANEEL available in the center of gravity where the plant is located. The risks, onus and benefits caused by production changes at the plants in relation to the physical guarantee are therefore allocated to these quotaholding distribution companies and subsequently passed through to consumers. The financial results in the CCEE spot market associated with the plants are therefore assumed by the distribution companies in proportion to the allocated quotas. Amongst others these results include those from the Energy Relocation Mechanism - MRE (hydrological risk).

Existing Energy MCSD

The Existing Energy CCEAR amounts on the quantity basis can be adjusted by the following applications of the Monthly Surplus and Deficit Offsetting Mechanism - MCSD:

(i) MCSD 4% or Annual, which allows the originally contracted amount to be reduced by up to 4%.

(ii) Monthly MCSD, which can be used to reduce: (i) the amounts contracted from the migration of potentially free consumers to the Free Procurement Environment – ACL, from the increase for contracts signed before March 16, 2004 and (ii) resulting from other market deviations. For CCEARs resulting from auctions in 2016 onwards, the reduction possibility was extended to the migration of special consumers - with contracted demand of between 0.5 MW and 3 MW and which upon migrating to the free market can only acquire energy from incentivized sources - windfarms, SHPs, biomass, solar and biogas. The declarations of other market deviations are prioritized in relation to the declared surpluses from the migration of free and/or special consumers in compensation against the declared deficits. However, the declared surpluses from free and/or special consumers, if not offset, are subject to contractual reduction at the respective vendors.

There is no restriction on declaring deficits when applying this mechanism. Energy swaps resulting from the MCSD are formally established in Assignments, between the assigning distribution companies, assignees and the selling generators. Acquired amounts are settled in a centralized fashion at the CCEE. This assignments are deducted from the amount invoiced by the vendor.

There is also the ex-post MCSD, processed annually always in the first month after the publication of energy amounts recognized by ANEEL as involuntary exposure, on the basis of a civil year of 12 months and before calculating the energy capacity insufficiency penalties. For the previous civil year, the mechanism allocates the energy CCEAR surpluses to distribution agents with deficits. Ex-post MCSD energy transfers are used for the sole purpose of determining the distribution companies' penalty, and does not change the contracted amounts.

New Energy MCSD

The New Energy MCSD introduced by Normative Resolution 693/2015 results in assignments between distribution companies based on surplus and deficit declarations.

It also enables generators to offer to reduce the sold amounts, if the amounts declared by the distribution companies result in surpluses greater than deficits.

The following applications of New Energy MCSD currently exist:

I. MCSD-EN A-0 - three times a year for assignments effective through the end of the year;

II. MCSD-EN A-1 - after auction A-1 is held, for assignments and temporary reductions effective the following year, processed in successive rounds embracing the following intervals, in order of priority: a) January to December; b) January to September; c) January to June; and d) January to March;

III. MCSD-EN AN+ – before Auction A-5 or A-6 is held, for assignments effective for 48 or 60 months, respectively, and permanent reductions of CCEARs from January the following year; and

IV. MCSD-EN A-N – before the holding of Auction A-N (A-3, A-4, A-5, A-6 and A-7), for assignments effective for 12 months from January of the N'th following year.

Unlike the Existing Energy MCSD, assignments between distribution companies are not formally established in Assignments, involving the vendor generators. This means they will only affect assignor and assignee distribution companies, preserving commercial relations with generators - i.e. the assignors retain the responsibility of paying the CCEAR to the vendor. The assignments are settled at the Electricity Trading Chamber - CCEE on a centralized basis.

Bilateral Agreements

Normative Resolution 711 issued April 19, 2016 created the possibility of bilateral agreements between CCEARs parties that permit: (i) temporary total or partial reduction in contracted energy; (ii) permanent partial reduction of this energy; or (iii) contractual termination. At the moment bilateral agreements can only be made with generating ventures that do not have generating units in commercial operation.

Surplus Sale Mechanism ("MVE")

The sale of surpluses by distribution concession operators to ACL was introduced by Law 13.360/2016, when amending Law 9.074/1995. The Surplus Sale Mechanism – MVE was regulated by Normative Resolution 824/2018.

The MVE is open to:

a) Vendors - distribution agents declaring contractual electricity surpluses; and

b) Buyers - free and special consumers, generators, traders and independent producers.

The mechanism is processed:

I. Annually, after processing MCSD-EN AN+ and MCSD-EN A-1, effective from: a) January to December; b) January to June; and c) January to March.

II. Semi-annually, effective from July to December the same year;

III. Quarterly, effective for the same year, from: a) April to June; b) July to September; and c) October to December.

The effect of selling services is reflected in the distribution company's rate review or readjustment following the recording of the respective contracts at CCEE and at the end of the accounting period for the year.

Free Contracting Environment (ACL)

At the ACL, the energy contracting takes place through electricity purchase and sale operations involving the vendors (generators or traders) and end consumers, which in this case chooses their energy supplier through bilateral contracts. free and special. Trade relations between agents in the ACL are freely agreed and regulated by bilateral electricity purchase and sale agreements which amongst other items establish the terms, volumes, flexibility and restatement indexes.

In this situation the distribution companies are only responsible for maintaining the energy transmission services, in accordance with a Distribution System Utilization Agreement (CUSD) and yielding the Distribution System Usage Charge (TUSD).

Consumers opting for the ACL can only return to the ACR after serving at least five years' notice to their local distributor, or in a shorter time frame at the distributor's discretion, pursuant to Art. 15 (9) of Law 9.074/1995.

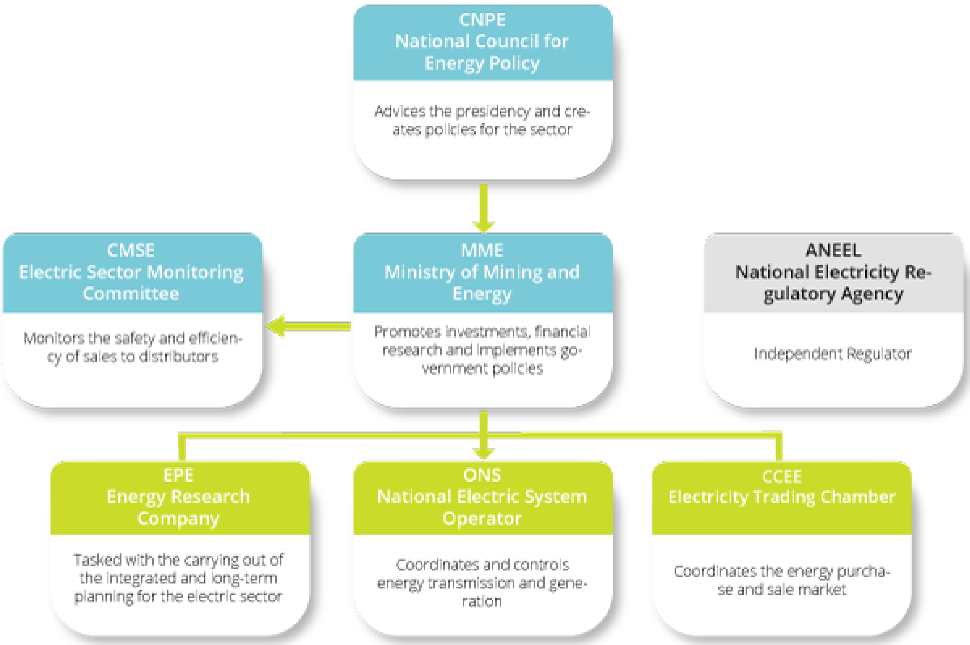
Types of Consumer:

Energy trading environments in the electric sector exist to serve two types of consumers:

- Captive: clients obliged to purchase energy from the owner of the concession they are connected to. Each consumer unit pays just one energy bill per month, which includes the energy generation distribution service, with the government regulating the rates.

- Free: clients purchasing energy directly from traders or generators under bilateral contracts with freely agreed terms. Each consumer unit will pay an invoice for the distribution service to the local concessional concession operator, i.e. for using the wire (regulated rate) and one or more invoices to the energy supplier (price negotiated contractually with the generator or trader). In order for a client to become a free client, they must consume 3,000 kW or more in any voltage level. MME Ordinance 514/2018 gradually reduced the limit on free client migration, so that from 7/1/2019 the limit changed to 2,500kW and from 01/01/2020 it changed to 2,000kW.
    - Special consumers also exist as well as free clients, the former being individual consumer units or units bound by legal or factual interests with volumes equal to or greater than 500 kW belonging to Group A. This group of consumers can only acquire electricity from renewable generation sources, such as SHPs (Small Hydroelectric Power Stations), Biomass, Wind Power and Solar.

Corporate governance in the sector:



Distribution segment regulations:

The distribution sector follows the price cap model, i.e. there is a price fixed annually and a rate for the offered product, and the company's gain derives from market growth and operational efficiency.

The sections below will address the regulations as established in the former concession agreement. The final section will address the differences between the former and the new agreements.

Rate structure

The energy rate paid to the distribution company intends to cover sector expenses on (i) consumer charges; (ii) energy transmitted by the transmission companies; (iii) the purchase of energy from generators; and (iv) the functioning of distribution companies. In short, a distribution company makes the pass-through

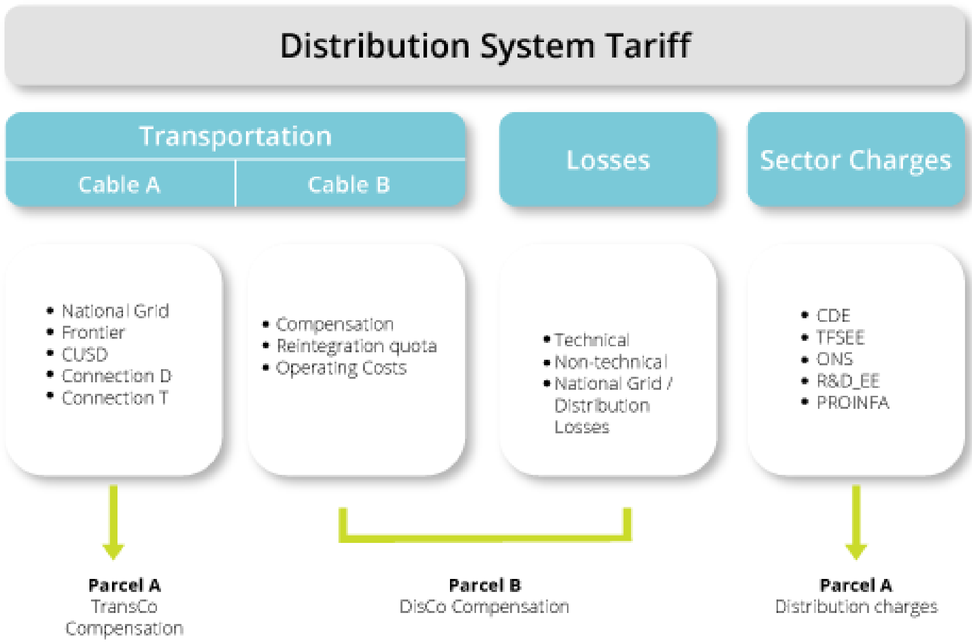
This rate is divided into

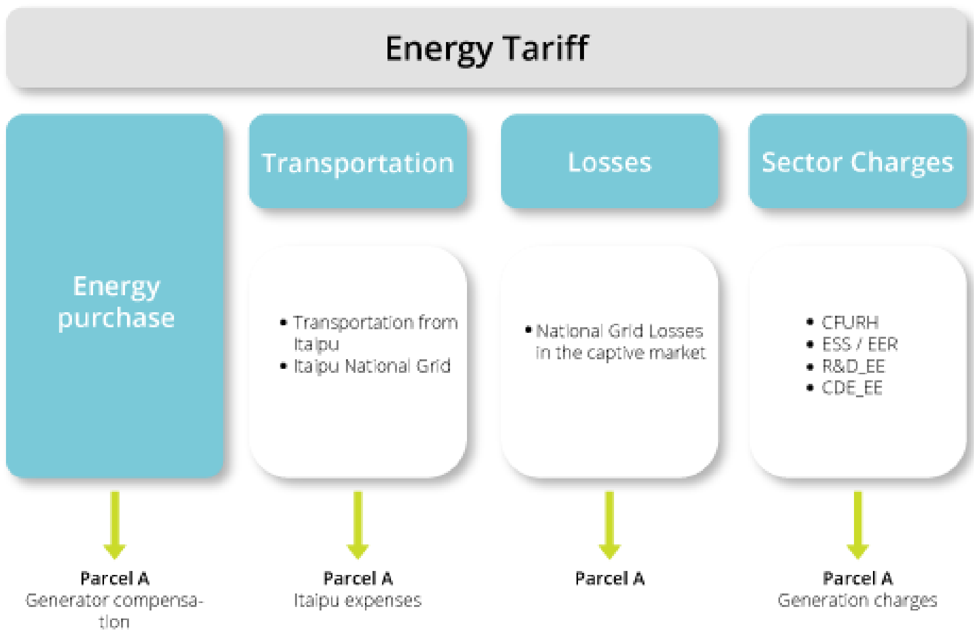
- Energy Rate (TE): rate paid by the distribution company's captive clients to cover costs of purchasing energy from generators, transporting energy from Itaipu, energy losses in the National Grid and consumer charges for generation.
- Distribution System Usage Charge (TUSD): rate paid by captive free clients for using the distribution company's cables, in order to cover costs on energy transmission, energy distribution and energy distribution charges.

We can also split the rate into the Parcel A and Parcel B concepts, which are related to the distribution companies' cost management capacity:

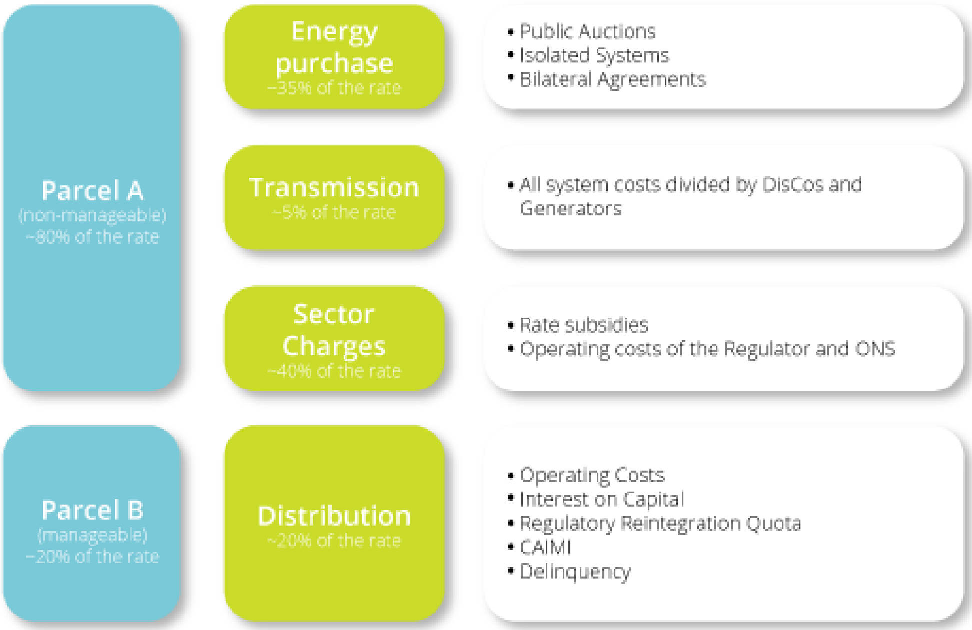
- Parcel A: non-manageable costs, i.e., outside the distribution companies' control (energy purchase, energy transportation and charges). Parcel A items are present in the TUSD and TE.
- Parcel B: manageable costs. Parcel B items are only present in the TUSD

The figures below summarize the rate composition concepts shown above:



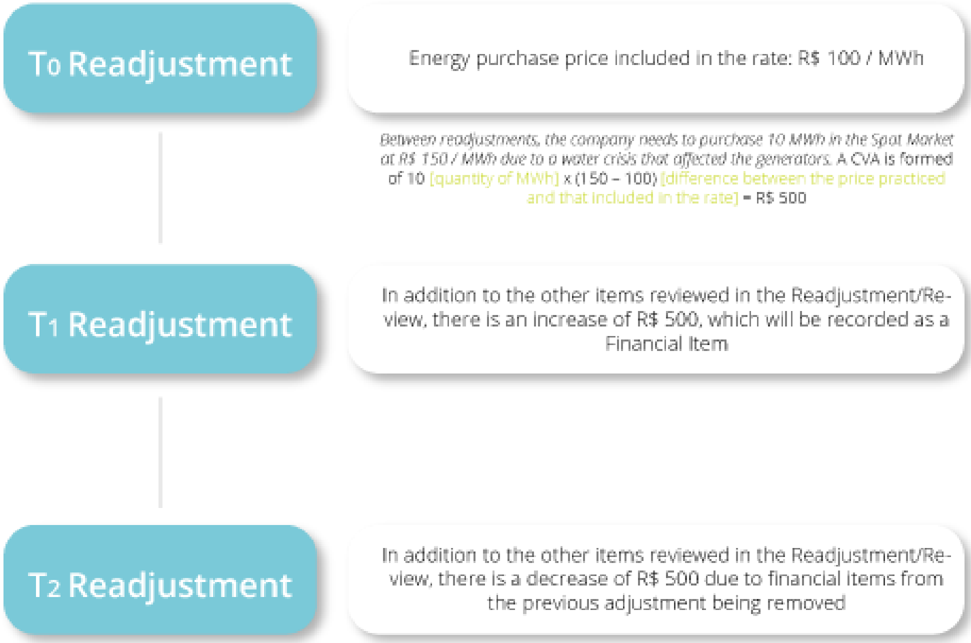


Parcel A and Parcel B in detail



Parcel A:

- Costs known as "pass through", i.e., they are simply passed through by the distribution company to the transmission companies, generation companies, government, etc
- As the companies go through just one readjustment per year, a charge could be defined after this readjustment, or the company could need to purchase energy at PLD, which could be higher/lower than the energy purchase price embedded in its rate, amongst other situations. In these cases, the distribution company will be incurring costs to be passed through that have not been received in their entirety, and this difference between the expenses and that in the rate will be recorded in an account called Compensation Account for Parcel A Variation (CVA) amongst the readjustments. At each readjustment, these amounts are embedded in the rate to offset the distribution company's expenses from the previous regulatory year, and removed from the following readjustment. See below a simplified example:



Parcel B:

- Operating Costs: The rate retention is defined by benchmarking analyses. Better performing companies are authorized to charge rates above their opportunity cost, whilst worse performing companies are forced to lower their costs.
- Interest on capital: Regulatory WACC (defined every 3 years) x BRL (Net Regulatory Remuneration Base).
- Regulatory Reintegration Quota: BRR (Gross Regulatory Remuneration Base) x Regulatory Depreciation.
- Annual Cost of Fixed and Mobile Facilities (CAIMI): Remuneration related to non-electric assets, such as rental, vehicles (not associated with the concession’s core activity) and software.
- Regulatory Losses: the regulator acknowledges that a number of clients will steal energy (non-technical losses) and understands that there are energy losses from factors outside the distribution company's control, known as Technical Losses, i.e. losses inherent in the business. Having said that, there is an amount factored into the rate to cover these factors. The loss is viewed as a factor that can be controlled by distribution companies, which are classified into complexity indexes for combating energy theft. Benchmarking comparisons are also used to regulate losses.
- Irrecoverable Revenue (delinquency): the regulator acknowledges that a number of clients will not pay their bills, including an amount for “delinquency” that the distribution company will suffer in its rates. Both irrecoverable revenue and losses are rate recognition items exclusive to distribution companies working as senior collection agents in the captive market.
- Other Revenue (services with operational synergy in the distribution sector): extra services covered by the rates, such as “sharing infrastructure and

chargable services”. Of this total revenue, a regulatory percentage is allocated to rate affordability, where the remainder constitutes extra revenue for distribution companies.

Other important concepts:

- Gross Regulatory Return Basis: the value of all electric assets, i.e. directly related to the distribution activity (posts, substations etc). Deducting the depreciation of the base assets produces the Net Regulatory Remuneration Base
- X Factor: indicator calculated by the regulator which measures the productivity and efficiency of a company, so that certain gains can be split with consumers over the period between the rate reviews. This indicator has 3 factors:
  - Pd: measures average productivity gains
  - Q: incentive for better service quality
  - T: defines an operating cost cutting trajectory

Rate Processes

Each distribution concession operator has its own rate anniversary, i.e. the date on which its rates are reviewed to guarantee the economic and financial equilibrium of its concession. There are 3 types of rate processes guaranteed by contract:

Periodic Rate Review: conducted every 3 / 4 / 5 years in order to guarantee the economic and financial equilibrium of its concession. At this moment parcel B is recalculated in its entirety, as is the BRR and the 3 X Factor components. The rate cycle duration is stipulated in the concession agreement. The frequency of annual rate reviews is governed by module 2 of the Rate Regulation Procedures (PRORET).

Annual Rate Readjustment: conducted annually in order to maintain the economic and financial equilibrium of the concession established in the Rate Review. At this moment, parcel B is restated for inflation (IGP-M) and the X Factor. At each readjustment the Q component of the X factor is also reviewed. The frequency of the annual rate reviews is governed by module 3 of PRORET.

RA_0 = Annual revenue including rates ratified on the Previous Reference Date (DRA)

VPA_0 = Value of Parcel A based on conditions in force in the DRA

$VPB_0 = RA_0 - VPA_0$ => Value of Parcel B based on conditions in force in the DRA

$VPB_1 = VPB_0 \times (IGP\text{-}M - Factor\ X)$ => Value of Parcel B based on conditions in force on the Processing Adjustment Date (DFP)

VPA_1 = Amount to be paid on energy purchases + Transmission + charges => Value of Parcel A based on conditions in force in the DRP

$RA_1 = VPA_1 + VPB_1$ => Annual revenue including projections for next 12 months

$IRT = RA_1 / RA_0$ => IRT: Rate Adjustment index

Extraordinary Rate Review: a distribution company can request this when the economic and financial equilibrium of its concession has been impaired by factors beyond its control. The distribution company files an application to Aneel, which analyses it and approves or rejects it. There is a contractual guarantee to request this review but acceptance of this review is not guaranteed. The frequency with which extraordinary rate reviews are accepted is governed by submodule 2.9 of PRORET.

New Concession Agreement

Following the enactment of the 1988 Federal Constitution and Laws 8.987/1995 and 9.074/1995, a new legal framework was created for the electric sector in the 1990s, especially the energy distribution sector.

The first electricity distribution concession agreements were then formally created based around the new legal framework, which regularized the exploration of the public electricity distribution service. In accordance with these Laws published in 1995, the distribution concessions under scrutiny can be extended for up to 20 years, and the aforesaid initial Concession Agreements were therefore extended until 2015.

As these Concession Agreements are coming to an end, based on the provisions of Law 12.783/2013 (Conversion of Provisional Law 579/2012 into law), the Concession Authority opted to extend them for the term of 30 years.

In light of this, following the due legal procedures to analyze the information and prepare the new Concession Agreements, interested distribution companies could accept the proposal and enter new Concession Agreements with the Concession Authority effective through 2045. From 2015 all concession renewals take place in accordance with the new contractual terms.

Main differences:

- The Irrecoverable Revenue, which under the former contract was only adjusted in reviews because it was a parcel B item, is now reviewed annually in the readjustments;
- Parcel B is now restated by the IPCA price index in the readjustments instead of by the IGP-M price index;
- Pd and Q component of the X Factor is now reviewed annually in the readjustments;
- Establishment of Continuity Indicators with rules and penalties in the event of nonperformance:

<u>Rules</u>

✓ The trajectory's start point is the highest value between the regulatory limit and value verified the year before the agreement was signed
✓ The trajectory will converge to the regulatory amounts in year 5, which will be the severest year for the performance of targets.
✓ Each distribution company has a target for DEC and FEC described in its respective contracts.

<u>Penalties</u>

Period	Breach of indicators	Penalty
Year 1 to 4	2x consecutive	Revoking the Concession
Year 5	Even if the Company has not previously breached any indicator, in year 5 any breach leads to the concession being revoked.	Revoking the Concession
Year 6 to 10	3x consecutive	Initiation of the Expiration Process
	1x	25% limit for dividends and interest on equity
Over the next 10 years	2x consecutive	25% limit for dividends and interest on equity
	3x in 5 years	25% limit for dividends and interest on equity

- Establishment of economic and financial sustainability indicators with penalties in the event of nonperformance

<u>Rules</u>

Indicator	Deadline.
(i) EBITDA ≥ 0	By 2018
(ii) (EBITDA – QRR) ≥ 0	By 2019
(iii) [Net Debt / (EBITDA - QRR)] ≤ [1 / (0.8 x Selic)]	By 2020
(iv) [Net Debt / (EBITDA - QRR)] ≤ [1 / (1.11 x Selic)]	By 2021

Penalties

Period	Breach of indicators	Penalty
Year 1 to 4	2x consecutive	Revoking the Concession
Year 5	Even if the Company has not previously breached any indicator, in year 5 any breach leads to the concession being revoked.	Revoking the Concession
Year 6 to 10	2x consecutive	Initiation of the Expiration Process
Over the next 10 years	1x	- 25% limit for dividends and interest on equity - Restrictive regime for contracts with related parties - Requirement on controlling shareholders to make capital contribution

- Neutrality of Parcel A: change in VPB_0 calculation in readjustments, made according to the difference between RA_0 and VPB_0:

	Former Contract		New Contract	
1	$RA_0 = \text{Effective Rate} \times M_0$	=	$RA_0 = \text{Effective Rate} \times M_0$	8
2	$VPA_0 = (MWh_{Purchase} \times Pmix_0) + (MUST_{Verified} \times TT_0) + (TE_0 \times M_0)$	=	$VPA_0 = (MWh_{Purchase} \times Pmix_0) + (MUST_{Verified} \times TT_0) + (TE_0 \times M_0)$	9
3	$VPB_0 = RA_0 - VPA_0$	≠	$VPB_0 = VTPB_0 \times M_0$	10
4	$VPB_1 = VPB_0 \times (\text{IGP-M} - \text{Factor X})$	≠	$VPB_1 = VPB_0 \times (\text{IPCA} - \text{Factor X})$	11
5	$VPA_1 = (MWh_{Purchase} \times Pmix_1) + (MUST_1 \times TT_1) + (TE_1 \times M_1)$	=	$VPA_1 = (MWh_{Purchase} \times Pmix_1) + (MUST_1 \times TT_1) + (TE_1 \times M_1)$	12
6	$RA_1 = VPA_1 + VPB_1$	=	$RA_1 = VPA_1 + VPB_1$	13
7	$IRT = RA_1 / RA_0$	=	$IRT = RA_1 / RA_0$	14

- ✓ As per (3), the VPB_0 is currently calculated as the difference between Annual Revenue and VPA in the DRA.
- ✓ As (1) RA_0 grows with the market and (2) VPA_0 grows not only with the market (due to energy purchases and charges), but also with the contracted demand, due to the MUST.
- ✓ As a result, when the VPB0 is calculated on the difference, it ends up carrying a certain margin of the Parcel A generated by the difference in the market growth and contracted demand.
    - If in the DRP the contracted demand in the last 12 months has grown less than the market, then the RA_0 is following the market, but with a VPA_0 growing less, as the MUST component is driving down the growth. Calculating the difference between the RA_0 and $VPBA_0$ therefore yields a larger VPB_0.
    - Similarly, if the contracted demand in the last 12 months had grown over and above the market, we would have a smaller VPB_0.

Key:

- RA_0: Annual revenue including rates ratified on the Previous Reference Date (DRA);
- RA_1: Annual revenue including projections for next 12 months;
- VPB_0: Value of Parcel B based on conditions in force in the DRA;
- VPB_1: Value of Parcel B based on conditions in force on the Processing Adjustment Date (DFP);
- VPA_0: Value of Parcel A based on conditions in force in the DRA;
- VPA_1: Value of Parcel A based on conditions in force in the DRP;
- IRT: Rate Adjustment Index.
- VTPB: Value of rate for parcel B items;
- M_0: Market (LTM);