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TARIFFS FOR TRANSITION

REMUNERATION AND TARIFF DESIGN FOR ELECTRICITY DISTRIBUTION IN LATIN AMERICA

DSO Review No. 10 - Series: Regulation and Markets

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KEYWORDS

Distribution remuneration; Tariff design; Incentive regulation; Energy Transition; Tariff structure: Non-conventional Assets; Social Subsidies; Investment Recognition; Price signals; Latin America.

July 2026

01 INTRODUCTION

The remuneration model and the tariff scheme constitute the economic core of electricity distribution: they define how the costs of the service are recognized, how network investments are recovered and what price signals users receive. Ultimately, their design determines the adequacy of revenues to sustain reliable infrastructure, the efficiency with which resources are allocated and the fairness with which the cost of the service is distributed across consumer segments. Remuneration regulation is therefore not a merely accounting matter, but a structural element that conditions the sector's capacity to invest, modernize and respond to society's expectations.

For decades, distribution remuneration frameworks in Latin America were built on an assumption that is now under review: that of a passive network, with unidirectional flows and relatively predictable demand, whose main function was to transport energy from the transmission system to the end user. Under that assumption, efficient reference utility schemes, price caps and multi-year tariff cycles took hold and, in their time, successfully streamlined investment and contained costs. The energy transition, however, has altered the premises on which those models rested. The emergence of distributed generation, the electrification of new uses such as transport and space conditioning, the advance of digitalization and advanced metering, and the growing demand for resilience to extreme events have transformed the distribution network into an active, bidirectional system that is far more complex to plan and to remunerate.

This transformation generates tensions that current frameworks resolve only partially. On the one hand, distributors require regulatory certainty to recover growing investments in digitalization, automation, storage and the integration of distributed resources, many of which do not fit easily into traditionally recognized asset categories. On the other, tariff schemes must send more sophisticated price signals —differentiated by time of use, by capacity and by location— without compromising the affordability of the service or the protection of vulnerable users. Compounding this is the persistent challenge of properly targeting subsidies and of shielding tariff design from political pressure, so that the economic signal preserves its technical coherence over time. The adequacy and sustainability of the tariff scheme depend, increasingly, on regulation's ability to reconcile these competing objectives.

Latin America approaches these challenges from a position of considerable regulatory heterogeneity. Remuneration models, tariff cycles and incentives coexist in the region with substantial variation across countries. This diversity offers an opportunity for comparative learning: it makes it possible to identify which arrangements have worked, which tensions are shared and which international practices could be adapted to the regional context.

This document analyzes the remuneration models and tariff schemes of electricity distribution in Latin America, with the aim of characterizing the regional landscape, contrasting it with international regulatory best practice and providing concrete elements to guide the evolution of current frameworks. The analysis is based on the Benchmarking exercise developed within ADELAT's Tariff Committee, complemented by original research on international regulatory approaches. The purpose is to offer an integrated view that makes it possible to understand the current state of remuneration and tariff regulation in the region, to assess its challenges and opportunities, and to formulate recommendations that contribute to the adequacy, efficiency and sustainability of the distribution service.

The document is structured as follows. Section 2 places the remuneration of distribution in the context of the new paradigm of the energy transition. Section 3 presents the conceptual framework of remuneration models and tariff design. Section 4 characterizes the regional landscape of remuneration models and tariff schemes on the basis of the Benchmarking results. Section 5 reviews international regulatory approaches and best practices applicable to the region. Finally, Section 6 synthesises the lessons learned and presents the conclusions and regulatory recommendations.

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> For decades, distribution remuneration models in Latin America were built on a premise that is currently being re-evaluated

02

THE REMUNERATION OF DISTRIBUTION UNDER THE ENERGY TRANSITION

The remuneration schemes and tariff designs that prevail today across much of Latin America were conceived in the reforms of the 1980s and 1990s for an electricity system that operated with a clear and stable logic. In that model, generation was produced centrally in large plants, energy flowed down through transmission and distribution networks to the end user, and the distribution network played an essentially passive role: transporting electricity in a single direction to consumers whose demand grew predictably and in proportion to economic development. The entire remuneration architecture was built on that assumption. The tariff was constructed largely on energy consumed, because consumption was a good proxy for network use; the asset base was conceived around long-lived physical infrastructure —lines, transformers, substations—; and multi-year tariff cycles assumed that cost, demand and technology conditions would remain reasonably stable between reviews. As long as those premises held, the models performed their function effectively, ordering investment and containing the cost of the service.

The energy transition has eroded those founding premises. The first driver of change is the emergence of distributed energy resources. Distributed generation —particularly solar photovoltaic—, battery storage and the incipient penetration of electric vehicles have turned the network into a bidirectional system in which thousands of users cease to be passive consumers and begin to produce, store and inject energy. This transformation fundamentally alters the assumption of unidirectional flows and, above all, breaks the correlation between the energy a user buys from the network and the costs their connection imposes on the system. A household with solar panels can drastically reduce its billed consumption and therefore its contribution to network costs recovered through volumetric charges, while remaining fully dependent on the infrastructure to back up its supply when it is not generating. The result is an erosion of the revenue base which, if left uncorrected, shifts a growing burden onto users without self-generation and may compromise the adequacy of the distributor's revenues.

The second driver is the electrification of new uses. The decarbonisation of the economy is shifting to electricity consumption previously met by fossil fuels, mainly in transport and space conditioning. This process not only increases aggregate demand but also changes its shape: the simultaneous charging of electric vehicles or the intensive use of heat pumps can generate concentrated and localised demand peaks that strain network capacity at specific points, requiring reinforcement investments whose magnitude depends less on total energy consumed than on the temporal coincidence of consumption. This reality calls into question the adequacy of tariffs based almost exclusively on energy and enhances the value of price signals that reflect the capacity and the timing of consumption, capable of steering demand toward more efficient use of existing infrastructure and of deferring costly investments.

The third driver is the digitalization of the network. Advanced metering, automation of operations, data management systems and platforms for coordinating distributed resources are giving distribution unprecedented capabilities for observation and control, indispensable for integrating the system's new complexity. But these investments pose a specific challenge for traditional remuneration frameworks: they involve non-conventional assets —software, information systems, sensors, digital capabilities— whose nature, useful life and valuation logic differ from the physical infrastructure for which the classic regulatory categories were designed. When the recognition of these assets in the regulatory base is incomplete or uncertain, regulation ends up discouraging the very investments the transition requires. Added to this is the growing demand for resilience to extreme weather events, which requires investment in the robustness and recovery capability of the network whose benefit is not always captured by the cost and quality indicators on which current models operate.

These drivers converge in a set of tensions that current remuneration and tariff frameworks resolve only partially. The first is the tension between revenue adequacy and tariff structure: if the bulk of revenue collection rests on volumetric charges while billed consumption stagnates or declines as a result of self-consumption and efficiency, the financial sustainability of the service is called into question. The second is the tension between investment certainty and affordability: the distributor needs stable rules and adequate recognition of growing investments in digitalization, storage and the integration of distributed resources, while society demands that the cost of the service be contained and vulnerable users protected. The third is the tension between the sophistication of price signals and equity: tariffs differentiated by time, capacity and location are more efficient, but their introduction must ensure that households with less capacity to respond or to invest are not disproportionately penalized. Underlying all of them, the challenge persists of correctly targeting subsidies and of shielding tariff design from political pressure, so that the technical coherence of the economic signal is preserved over time.

In this context, the remuneration model is a first-order determinant of the success of the energy transition. Whether electricity distribution can modernize at the pace the transition demands depends on its capacity to adequately recognize new investments, to send efficient price signals without sacrificing equity, and to maintain revenue adequacy in a context of transformed demand. Frameworks designed for a passive network will not disappear overnight, but they need to evolve toward schemes that value flexibility, resilience and dynamic efficiency, and that support —rather than hinder— the transformation of the system. Characterizing how the region's regulatory frameworks are responding to this new paradigm, contrasting those responses with international best practice and identifying the necessary reforms is precisely the purpose of the sections that follow.

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> The remuneration systems and tariff structures that currently govern much of Latin America were devised during the reforms of the 1980s and 1990s

03

CONCEPTUAL FRAMEWORK: REMUNERATION MODELS AND TARIFF DESIGN

Electricity distribution constitutes a natural monopoly: duplicating networks would be uneconomic and, in the absence of competition, the price of the service cannot be determined in a market. Remuneration of the activity is therefore set through regulation. The regulator's task is to approximate the outcome a competitive market would produce —efficient prices, adequate quality and sufficient investment— through a set of rules that determine how much the distributor may receive and how that revenue is passed on to users. This section presents the conceptual framework underpinning those rules: remuneration models and their economic logic, the methods for determining recognized costs, the components that make up regulated revenue, the tariff structure through which that revenue is collected, and the incentive and periodic review mechanisms that give the system its dynamism. These concepts constitute the common language with which, in the following sections, the Benchmarking evidence and international practices are interpreted.

3.1. REMUNERATION MODELS

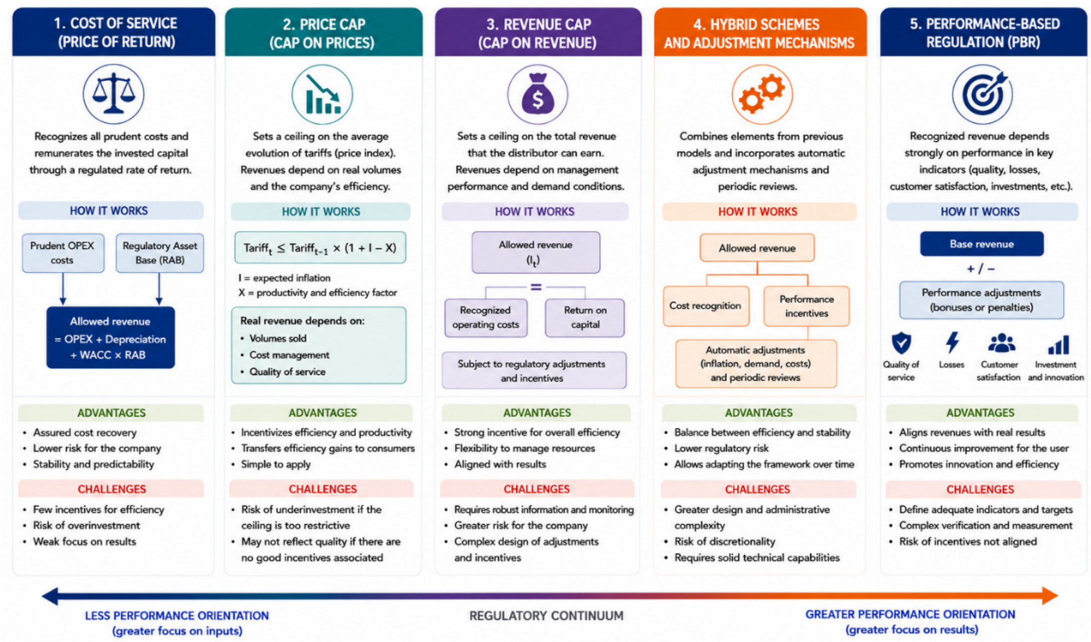

Fig. 1. Regulatory approaches to the remuneration of distribution companies

The remuneration model defines the basic rule linking the costs of the service to the revenue the distributor is entitled to receive. Although in practice regulatory frameworks combine elements of different approaches, conceptually they can be organized around four archetypes distinguished by the variable the regulator controls and by the way risk is shared between the company and users.

Rate of return regulation (also known as cost of service) is the traditional approach. The regulator recognizes the distributor's full prudent operating costs plus a reasonable return on invested capital, calculated by applying a rate of return to the asset base. Its main virtue is that it secures the recovery of investment and reduces the company's risk, which facilitates financing network expansion. Its main weakness is that it provides weak incentives for efficiency: because costs are passed through to the tariff relatively automatically, the company has little stimulus to reduce them and may even be induced to over-invest in assets, a phenomenon known in the literature as the Averch-Johnson effect. For these reasons, this model has tended to be replaced by, or complemented with, incentive schemes.

Price cap regulation inverts that logic. Instead of recognizing actual costs, the regulator sets a maximum price —or a unit value, such as the Distribution Value Added (VAD), the regulated distribution margin that prevails in the region— which the distributor may charge over a multi-year period, adjusted annually for inflation and for an efficiency factor (the familiar RPI–X scheme, whereby the price grows with inflation minus an X factor of expected productivity). By decoupling revenue from actual costs during the cycle, the price cap creates a powerful incentive for efficiency: any cost reduction below the forecast level translates into higher profit for the company until the next review. The counterpart is that it transfers more risk to the distributor —if costs turn out higher than projected, the company absorbs the difference— and requires strong technical capacity from the regulator to set the initial price and the efficiency factor correctly.

Revenue cap regulation is conceptually analogous to the price cap, but the regulator limits the distributor's total allowed revenue rather than its unit price. This approach decouples the company's revenues from the volume of energy sold, which is particularly relevant in contexts of energy efficiency, self-consumption and distributed generation, where sales may stagnate or fall without this reflecting a lesser need for infrastructure. Under a revenue cap, the distributor has no incentive to promote higher consumption in order to sustain its revenues, which aligns the model more closely with the objectives of the energy transition; in exchange, it requires adjustment mechanisms to reconcile allowed revenue with demand actually served.

In regulatory practice, the boundary between these archetypes has blurred: hybrid incentive regulation schemes (performance-based regulation) have emerged which combine control of revenue or price with risk-sharing mechanisms, quality factors and differentiated recognition of investments. Each model represents a different point on the continuum between protecting the company's profitability and applying pressure for efficiency, and the choice between them reflects a decision about how to distribute regulatory risk.

3.2. DETERMINATION OF COSTS

Whatever the remuneration model, the regulator must determine what level of costs it recognizes as the basis of the tariff. This decision is methodologically delicate, because it determines whether the tariff remunerates an efficient operation rather than the inefficiencies of a particular company. There are three main approaches.

The efficient reference utility approach —known in the region as the empresa modelo, or model company— constructs a notional company that would provide the service in the concession area at the lowest possible cost, using an optimal network configuration. It is the costs of that ideal company, and not those of the actual distributor, that are recognized in the tariff. This method, widely used in Latin America and associated with VAD schemes, transmits a strong incentive for efficiency, since any difference between actual and modelled cost is borne by the company. Its challenges lie in the complexity of modeling the efficient company correctly and in the risk that the model drifts away from real operating conditions, especially when new or non-conventional assets must be incorporated that traditional optimization logic does not contemplate.

The actual cost approach —or historical cost— recognizes the costs actually incurred by the distributor, subject to a prudence and efficiency test by the regulator. It offers greater certainty in the recovery of investments and faithfully reflects the particularities of each company, but it requires intensive regulatory oversight to prevent inefficiencies from being passed through and weakens the incentive to reduce costs. Between the two extremes lie mixed schemes, which combine modelled costs for some components —typically the network— with actual or market costs for others, or which use benchmarking techniques comparing the performance of distributors against one another to set efficiency targets. The choice of cost determination method is inseparable from the remuneration model: the efficient reference utility is the natural counterpart of price cap schemes, while the recognition of actual costs is associated with rate of return regulation.

> The remuneration model defines the basic rule linking service costs to the revenue the distributor is entitled to receive

3.3. COMPONENTS OF REGULATED REVENUE

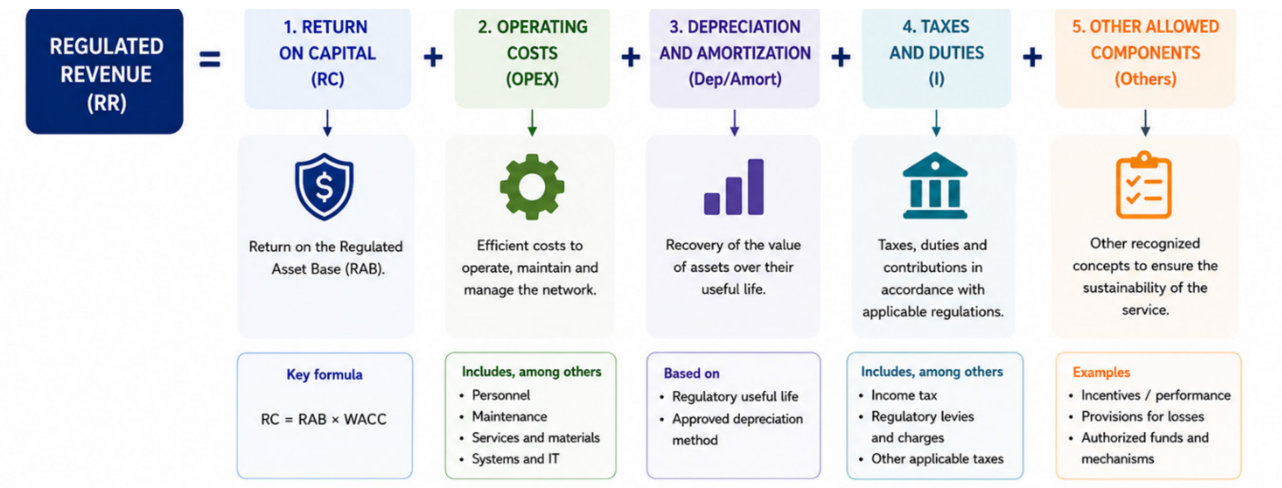

Fig. 2. Components of the distributor's regulated revenue

Regardless of the model, a distributor's regulated revenue consists essentially of three elements: the return on invested capital, the recovery of that capital through depreciation, and the coverage of operating and maintenance costs. The central piece is the Regulatory Asset Base (RAB), which represents the value of the capital invested in the network on which the company is entitled to earn a return. Determining the RAB is one of the most sensitive decisions in regulation, and it is approached through different valuation methods: historical cost records assets at their depreciated acquisition cost; replacement cost —through the New Replacement Value (VNR), the equivalent of depreciated replacement cost (DRC)— values assets according to what it would cost to replace them today with others of equivalent technology, depreciated for use. The method chosen and the frequency with which the RAB is updated have a direct impact on the level of the tariff and on the investment signals the company receives.

The costs underpinning revenue are usually classified into capital costs (CAPEX, capital expenditures), corresponding to investments in long-lived assets that are incorporated into the RAB and remunerated over time, and operating costs (OPEX, operating expenditures), corresponding to current expenditure on operation, maintenance and retail supply, recognized in the period in which they are incurred. The distinction between the two is not neutral: when the recognition of CAPEX is more favorable than that of OPEX —because it is remunerated with a return over its useful life— the company may be biased toward meeting its needs through investment in assets rather than through operational solutions, even where the latter would be more efficient (the so-called capex bias). To correct this bias, the TOTEX approach (total expenditures) has gained ground, recognizing total expenditure —capital and operating— in an integrated way and allowing the company to choose the most efficient combination of investing and operating, without regulation predetermining the answer. TOTEX is particularly pertinent in a context of digitalization, where solutions based on software, data and flexibility can advantageously substitute for the physical expansion of the network.

In most regulatory schemes, the return applied to the RAB is determined through the Weighted Average Cost of Capital (WACC), which combines the cost of debt and the cost of equity according to the financing structure of an efficient company. The WACC seeks to reflect the return investors would require to finance an activity of comparable risk, so that it is sufficient to attract capital without passing an excessive cost on to users. Its calibration is one of the most debated points of any tariff review, because small variations in the rate produce significant effects on the tariff and on the viability of investments. A recurring principle in good regulatory practice is that the recognized rate of return should be consistent with the effective regulatory risk the company faces: if the framework transfers significant risk to the distributor, the rate should reflect this; if it mitigates that risk through adjustment and pass-through mechanisms, the rate may be lower.

3.4. TARIFF STRUCTURE AND PRICE SIGNALS

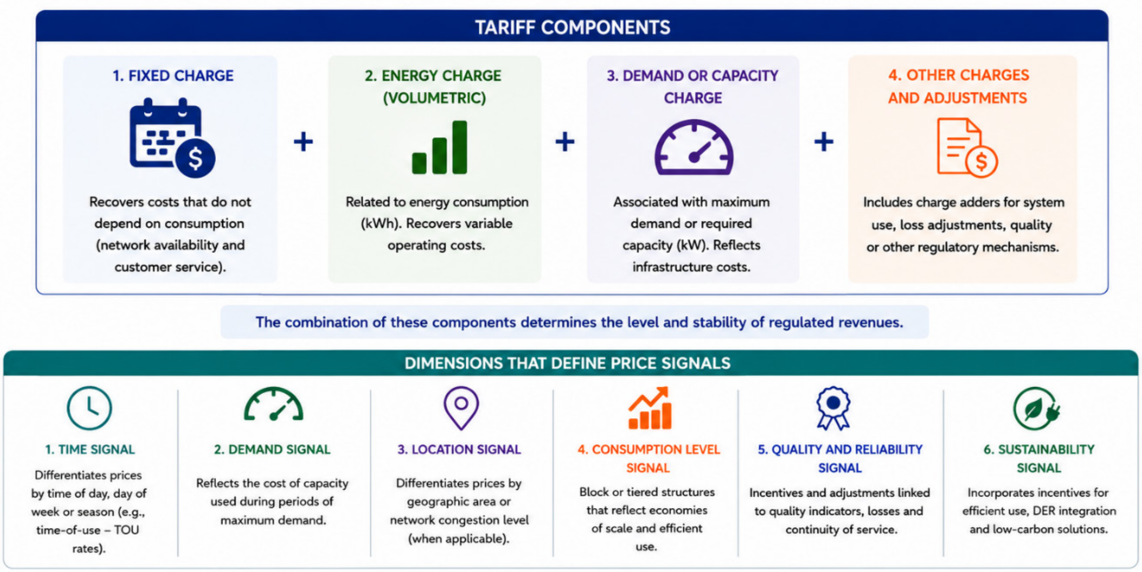

Fig. 3. Tariff design: components and dimensions

While the remuneration model determines how much the distributor receives, the tariff structure defines how that revenue is collected from users, that is, the way regulated revenue is translated into specific charges on the bill. The design of this structure performs a dual function: to collect the allowed revenue adequately and stably, and to send users price signals that reflect the cost their consumption imposes on the system. These two objectives can come into tension, and much of the debate on tariff design consists of balancing them alongside considerations of equity and simplicity.

The basic components of a tariff are the fixed charge, levied irrespective of consumption and intended to recover costs that do not vary with the energy consumed —mainly those associated with infrastructure—, and the variable or volumetric charge, proportional to the energy consumed and expressed in monetary units per kilowatt-hour. To these is added, in many designs, the capacity or maximum demand charge, which charges the user for the capacity they require from the system, measured as their maximum demand over a given period. The capacity charge is conceptually relevant because much of the network's costs are determined by the capacity that must be available at times of maximum demand, and not by total energy consumed; its application to residential users, however, requires adequate metering and is generally reserved for medium and large demands. The proportion in which revenue is collected through fixed, variable and capacity charges determines the extent to which the tariff reflects the actual cost structure and the way the cost of the service is shared among users with different consumption profiles.

A further dimension of tariff design is the temporal differentiation of prices. Time-of-use tariffs, hourly tariffs and, in their most advanced form, dynamic tariffs, vary the price of energy according to the moment of consumption, raising it in hours of higher demand and lowering it in hours of lower demand. These signals seek to induce more efficient use of the network, shift consumption toward off-peak hours and harness demand flexibility, a capability of growing value with the electrification of transport and the penetration of distributed generation. Their deployment, however, depends on the existence of advanced metering and raises challenges of user acceptance and understanding.

3.5. REGULATORY INCENTIVES AND TARIFF CYCLES

Modern regulatory frameworks do not confine themselves to setting a level of revenue; they incorporate explicit incentives designed to align the distributor's behavior with public interest objectives that cost control alone does not guarantee: service quality, loss reduction, operational efficiency and, increasingly, resilience and the integration of new technologies. These incentives may be symmetric, where the company's performance affects its revenues in both directions —so that exceeding standards generates a bonus and falling short a penalty—, or asymmetric, where only non-compliance is penalized without rewarding superior performance. The difference matters: a symmetric scheme turns quality into a profitable investment variable and encourages the company to go beyond the minimum required, whereas a penalty-only scheme tends to anchor performance around the regulatory threshold. The treatment of technical and non-technical losses follows an analogous logic: recognizing an efficient level of losses, penalizing excesses and, in the best designs, rewarding reductions, transfers to the distributor the incentive to manage them actively.

These incentives operate within tariff cycles, that is, the multi-year periods —usually of four or five years— during which the parameters set in a tariff review remain in force, before being recalculated at the following review. The duration of the cycle involves a trade-off: a longer period reinforces the incentive for efficiency, because the company retains the productivity gains it achieves for longer, but it increases the risk that parameters become outdated as costs, demand or technology change. To mitigate that risk, frameworks incorporate mid-period review mechanisms and, above all, indexation and adjustment mechanisms that periodically update remuneration in line with inflation, the exchange rate or other relevant factors, preserving the real value of revenue over the cycle.

The combination of cycle duration, the robustness of adjustment mechanisms and the predictability of the rules ultimately determines the regulatory risk perceived by the investor, closing the circle with the rate of return. In this way, the five elements —remuneration model, cost determination, revenue components, tariff structure and incentives— operate as an interdependent system whose balance defines the adequacy and sustainability of the tariff scheme.

> “Regardless of the remuneration model, the regulator must determine which level of costs it recognizes as the basis for the tariff

04

REGIONAL LANDSCAPE OF REMUNERATION MODELS AND TARIFF SCHEMES

4.1. REMUNERATION MODELS

Choosing a remuneration model is not a decision that ends in itself: all the others follow from it —how costs are determined, how assets are valued and recognized, what rate remunerates capital and what incentives apply— and all of them answer, fundamentally, the same question: who bears the risk that actual costs diverge from those recognized, the company or users. The dimensions that follow should therefore be read not as independent features, but as parts of a single system. Seen in this way, the region's frameworks show that beneath the variety of designs certain logics recur, and that the challenges of the energy transition tend to reappear at the same points.

4.1.1. Models applied in the region

The benchmarking reveals a landscape that, at first sight, suggests uniformity: most distributors report operating under a price cap regulation scheme built around the Distribution Value Added (VAD). That coincidence, however, conceals differences in the rule by which the distributor's revenue is set. What truly distinguishes the models is that rule and, with it, the sharing of risk between the company and users: how closely revenue is tied to the costs the company actually incurs. On that criterion, the regional landscape falls into three categories along a single continuum.

The first, and by far the most widespread, is the price cap: the regulator sets a maximum tariff for a multi-year period —the VAD— calculated on efficient reference costs rather than on those of the actual distributor. Chile is its purest expression; Guatemala and Peru operate under the same rule, building that standard from a notional reference utility. Brazil shares the incentive-based price cap logic —setting tariffs by cycle and allowing the company to retain efficiency gains without fully passing through its costs— but with a difference worth noting: its efficient cost derives not from a notional reference utility but from benchmarking among real distributors. El Salvador shares the paradigm from its own trajectory —its General Electricity Law values assets at New Replacement Value and remunerates them with a rate set by law— and Bolivia also belongs here, with a singular feature: it remunerates capital through a commercial rate of return benchmarked to the returns of utilities in the Dow Jones index. The Argentine federal jurisdiction, although likewise framed as a price cap, builds revenue by applying a rate of return to an asset base. What unifies the group is the consequence: because revenue is set in advance against a standard —whether a notional reference utility or an efficiency benchmark built by comparison— and not on actual expenditure, the company gains benefits by improving its efficiency, but absorbs the difference when its real costs exceed it, so that the risk of operating above the standard falls on it.

At some distance lies the revenue cap, whose regional exponent is Colombia. Here the regulator sets not a unit price but a cap on the distributor's total revenue, anchored in the assets actually installed by the operator and in an approved investment plan, under Resolution CREG 015 of 2018. The scheme retains a strong efficiency incentive but, by tying remuneration to the real asset base rather than to a theoretical company, it decouples revenue from sales volume and shares risk differently: the operator does not bear the full gap between what was planned and what was executed.

At the opposite end of the continuum is cost-of-service regulation, characteriztic of systems dominated by public companies or cooperatives. In Costa Rica, Ecuador and Paraguay, revenue closely follows the costs the company actually incurs, with the aim of recovering them and sustaining reinvestment rather than of remunerating private capital; in Paraguay, indeed, the tariff is set by the Executive by decree. Because revenue is coupled to actual expenditure, the risk that such expenditure turns out to be high falls on the user or the State, not on the company.

Beyond the variety of labels, what these three positions share is a single principle: the model sets revenue by tying it, to a greater or lesser degree, to the company's actual costs, and on that degree of coupling depends who bears the risk. But no model operates in a vacuum: all of them require a cost figure on which to set that revenue. How that figure is constructed —the level of costs the regulator recognizes as the basis of the tariff— is the subject of the following subsection.

Table 1 summarizes this landscape: the three approaches through which the region remunerates distribution, the cost base on which each builds revenue and the resulting sharing of risk, together with the countries falling under each.

Table 1. Remuneration models applied in the region

Approach	Logic	Cost base	Countries
Price cap on efficient costs	Revenue set ex ante against a standard, not on actual expenditure	Theoretical model company or benchmarking among distribution utilities based on real assets	Chile, Guatemala, Peru, Brazil, El Salvador, Bolivia
Revenue cap	Cap on total revenue anchored in the real physical network, with investment plans.	Mixed scheme: actual installed assets (CAPEX) + efficiency benchmarking (OPEX).	Colombia
Cost of service	Revenue follows the actual costs incurred to guarantee the service	Actual and accounting costs of the company (subject to prudence criteria)	Costa Rica, Ecuador, Paraguay

4.1.2. Determination of recognized costs

Whatever the model, setting revenue first requires a figure: the level of costs the regulator recognizes as the basis of the tariff. Producing that figure is not a formality but a technical decision in which the region's frameworks display their most concrete differences. The question is no longer how far the recognized cost departs from actual expenditure —that is defined by the model— but how that cost is constructed and by whom. The benchmarking groups the answers into three mechanisms, from the most to the least technically elaborate.

The most demanding is the efficient reference utility, which fully reconstructs the company that would provide the service at minimum cost through an engineering study. Chile, Guatemala and Peru share this approach, with nuances. In Chile and Peru the study groups distributors into typical areas or sectors according to load density and dimensions a reference company for each, following several rounds of observations among the company, an independent consultant and the regulator. Where they differ is in who values the costs and who settles disputes. Peru concentrates both functions in the regulator: OSINERGMIN approves a Database of Standard Distribution Costs,

mandatory for the VAD calculation, and, when observations are not resolved, sets the final values itself. Chile and Guatemala, by contrast, leave the justification of costs to the consultant carrying out the study —in Guatemala, an engineering firm pre-qualified before the National Electricity Energy Commission— and refer disagreements to an independent body: the Panel of Experts in Chile and a three-member Expert Commission —one appointed by each party and a third by mutual agreement— in Guatemala. In all three cases the cost entering the tariff is entirely modelled: the actual distributor's accounting costs play no part in the calculation.

A second procedure, the mixed scheme, forgoes modeling the entire company and treats each cost category differently. Colombia combines two techniques depending on the type of expenditure: for assets it uses catalogues of construction units valued at standard prices —under Resolution CREG 015 of 2018— and for operating costs it relies on econometric benchmarking, in particular stochastic frontier models that estimate efficient expenditure by comparing the performance of distributors with one another. In Argentina, the federal jurisdiction uses a similar method for setting the VAD, and the energy cost is a passthrough of the system's cost. Bolivia and Brazil blend differently: they separate manageable costs —network operation, maintenance and administration, subject to the efficiency standard— from non-manageable ones, such as energy purchases, which are recognized at actual value and passed through to the tariff; in Brazil that separation goes so far as to structure the tariff into two portions, one manageable and one not. The resulting cost is no longer wholly theoretical: it is anchored in part to the assets actually installed or to the expenditure the company does not control, while retaining efficiency pressure on what it can manage.

The third procedure, the recognition of actual costs, characteriztic of cost-of-service systems, starts from the expenditure the company actually incurs, subject to a prudence test that discards unnecessary outlays. Costa Rica is the best-documented case: its tariff base is built on the operator's justified costs and assets, under the cost-of-service principle. Here the determination resembles an audit of actual expenditure more than the construction of an efficient standard.

These three procedures differ in their sophistication and in who carries them out, but they share a feature worth retaining: none treats costs as a single block. All distinguish what it costs to invest in the network from what it costs to operate it —capital and operation— and tend to apply a distinct logic to each, as the mixed scheme illustrates by valuing assets with one method and operation with another. That separation between capital and operation, and the consequences it entails, is the subject of the following subsection.

4.1.3. Recognition of CAPEX and OPEX

The costs of providing the distribution service are not of a single nature. Part is capital invested in long-lived assets —lines, substations, transformers— disbursed once and used over decades; the other is current expenditure —operation, maintenance, administration— consumed and renewed year after year. That difference requires them to be recognized separately, and practically the whole region does so, without integrating them into a single pot of expenditure: this is the sharpest difference from the TOTEX approach consolidated elsewhere —which recognizes total expenditure and lets the company choose the most efficient combination of investing and operating— a contrast that distributors in Chile, Colombia and Brazil themselves make explicit in the benchmarking. The recognition of each component also follows a common pattern: CAPEX is incorporated into an asset base and remunerated over time, through depreciation that recovers the investment and a rate of return on capital not yet amortised, while OPEX is recognized in the period in which it is incurred, almost always calculated against efficiency standards —in Colombia, through the stochastic frontier models already described. What varies is the presentation: in most cases both end up merged into a single annualised charge —Chile's VAD expresses them as an equivalent annual cost that the customer pays without distinguishing how much corresponds to each— whereas Colombia keeps them separate in two distinct revenue streams.

That separation, however, is not innocuous. When it is the regulator —or the reference utility model— that determines in advance what proportion corresponds to investment and what to operation, the distributor loses the freedom to substitute one for the other: it cannot opt for an operational or contracted solution instead of building an asset, even where this would be more efficient. And because CAPEX is remunerated with a return over its useful life while OPEX is only recovered within the period, the design tilts the balance toward investment in physical assets, the bias toward capital that the regulatory literature calls capex bias. The consequence goes beyond accounting: in a context where many of the transition's solutions —flexibility, demand management, contracted services— are operational rather than physical, a framework that rewards the asset over the operation discourages precisely the most efficient responses.

Of the two components, capital poses the more complex regulatory problem, because it is not exhausted within a single period: it enters an asset base that the company carries forward and that is remunerated over years. How much that base is worth, and on what criterion it is updated, conditions much of the recognized revenue, and is the subject of the following subsection.

4.1.4. Valuation of the Regulatory Asset Base (RAB)

The capital invested in the network is remunerated not according to what appears in the company's books, but according to the value the regulator recognizes: the Regulatory Asset Base (RAB). The rate of return is applied to that figure and the depreciation that recovers the investment is calculated from it, so that the RAB acts as a direct multiplier of revenue: the larger it is, the greater the remuneration. Its valuation is therefore one of the most sensitive —and most contested— points of every tariff review. The first decision it raises is the criterion for valuing assets: their acquisition cost (historical value) or what it would cost to replace them today with equivalent ones (replacement cost, or New Replacement Value, VNR —depreciated replacement cost in international practice). In both cases the value is taken net of depreciation accumulated through use and age; what differs between them is the starting point.

Faced with that choice, the region has opted almost unanimously for replacement cost. Regulation establishes it explicitly in Chile, Guatemala, Peru and El Salvador, which value their assets at New Replacement Value. Colombia reaches the same result by its own route: it builds the base with the construction units at standard prices already mentioned and incorporates, alongside electrical assets, non-electrical ones and substation land. In Argentina, typical construction sets are defined and their market value is determined, including non-electrical assets. In Brazil the replacement criterion operates through ANEEL's tariff methodology —PRORET— even though the framework laws refer only generically to asset revaluation and depreciation. The principle they share is forward-looking: by setting value in current terms, replacement cost keeps the base at what the network is actually worth today and prevents inflation from eroding it, something especially valuable in economies with a history of volatile prices. No case of purely historical accounting appears among the frameworks reviewed: even Costa Rica, whose operator describes a historical-value valuation, is governed by a law that refers to "model productive structures" rather than to the original cost of assets.

To the valuation criterion is added a second decision, often more decisive: how often the base is updated. Here frameworks divide into two. In most —Chile, Guatemala, Argentina, Brazil— the RAB is fully revalued only at each tariff process, every four or five years; between reviews it is, in essence, a fixed snapshot. In Argentina, the federal jurisdiction represents an intermediate position, in which the review is carried out every five years, but the assets incorporated each year are added to the remuneration base without triggering a full review. Colombia represents the other extreme: it updates the base annually, incorporating the investments actually executed and brought into operation by the operator. And it is here that the valuation of the base ceases to be a technical matter and becomes an economic one: a RAB frozen for the whole cycle forces new investment to wait until the next review before it begins to be remunerated, whereas one updated frequently recognizes it almost immediately. How each framework treats that new investment —when and how it incorporates it— is the subject of the following subsection.

4.1.5. Remuneration of new assets

A distribution network is never finished. Demand grows, assets age and must be replaced, and quality requirements and the energy transition compel continuous investment. The question that defines this point is when that investment begins to be remunerated: whether the regulator recognizes it before it is executed, on the basis of what is forecast for the period —ex ante—; afterwards, once the asset is in operation —ex post—; or by combining both moments. In reference utility schemes, recognition is essentially ex ante: future investment enters the tariff through the construction of the model, which is dimensioned looking forward —Chile's General Law of Electricity Services calculates the VNR on installations adapted to demand and considers forward-looking factors such as the penetration of new technologies; Guatemala's Regulation requires costs to be projected according to forecast demand growth and expansion plans. What is remunerated, in these cases, is the efficient network the model projects; a real investment the model has not anticipated finds no recognition until the next tariff process.

Other frameworks tie recognition to actual execution. In cost-of-service systems an ex post recognition operates: the prudent asset enters the base once executed and brought into operation, as one more cost; and even in cases such as Costa Rica, the annual review means that recognition is relatively close to commissioning. Between the forward-looking model and subsequent recognition lies the mixed scheme, whose most developed exponent is Colombia: under Resolution CREG 015 of 2018, the operator submits for approval a plan setting ex ante the recognizable investments and their maximum amounts, and the base subsequently incorporates ex post the assets actually executed, with an adjustment correcting deviations between what was planned and what was carried out; its annual updating gives it an agility that schemes reviewed every four or five years cannot match.

The difference between these modes is not one of nuance, and it centers on rigidity. In the most rigid ex ante schemes, investment made by the company mid-cycle that the model had not foreseen goes unremunerated until the following review, and by then it has lost value —a cost that distributors themselves emphasize in the benchmarking: the Guatemalan distributor sums it up as the loss of the time value of money that deferred recognition fails to compensate. The effect is that the design discourages precisely the investment the transition makes most urgent, a tension that international experience addresses with specific practices for

Table 2. Recognition of new investments.

Timing of recognition	How it works	Implication for new investment	Countries
Ex ante (tied to the model)	Only what is foreseen in the model or tariff study for the 4- or 5-year cycle is recognized	Unanticipated investment waits for the next process (the company bearing the financial cost or the loss of value over time).	Chile, Guatemala, Peru, El Salvador, Bolivia
Mixed (investment plan)	Plan approved ex ante + ex post incorporation of the assets actually executed	Prompt recognition, thanks to annual updating of the regulatory asset base	Colombia, Argentina (Federal level)
Ex post (at cost)	The asset enters the calculation base once executed, in operation and recorded	Recognized promptly (with annual reviews), but lacking the strong efficiency incentive imposed by theoretical standards.	Costa Rica, Ecuador, Paraguay

recognizing investment and innovation. And if conventional, predictable investment already runs into these delays, the problem is compounded with assets that do not fit the network's traditional categories —software, automation, data management systems— whose remuneration is the subject of the following subsection.

Table 2 summarizes when each framework recognizes new investment and what that timing implies for the distributor.

4.1.6. Recognition of non-conventional assets

The energy transition has brought into the network a class of assets bearing little resemblance to the lines and transformers for which the classic regulatory categories were designed: smart meters, automation equipment, sensors, software and data management systems, often intangible and with shorter useful lives. Their recognition tests frameworks conceived for physical infrastructure, and the regional response generally comes with difficulty. In reference utility schemes recognition is the most restricted, for a structural reason: the model incorporates a technology only once it has become the most efficient alternative, that is, the standard. Chile illustrates this clearly —digitalization and automation are remunerated only if the National Energy Commission adopts them in the reference utility as the least-cost solution, or if a regulation requires them— and distributors confirm it in the benchmarking: in Guatemala they note that the model barely accommodates these assets, and in Argentina, that their recognition is left to the regulator's discretion. The effect is paradoxical: the framework rewards those who adopt the technology once it is already common and penalizes those who introduce it first.

Where a point of entry exists, it tends to be narrow and case-by-case. Colombia opened one through the special construction units and the technological renewal investments provided for in Resolution CREG 015 of 2018, although the operator must justify technically why the asset differs from the standard and demonstrate its cost-benefit ratio, in a procedure distributors describe as slow and uncertain; Peru has advanced along a similar path, allowing technological innovation projects and smart metering systems to be incorporated into the VAD, but still without clear rules for their valuation. These are partial openings: they enable specific technologies, one by one, rather than providing general scope for non-conventional investment. Only cost-of-service systems accommodate them naturally, recognizing them —tangible or intangible— as one more cost through depreciation or amortisation, as Costa Rica does, albeit in exchange for the weak efficiency incentive already described. The underlying pattern is common: most frameworks value an asset by its category —whether it fits a known construction unit— and not by the outcome it delivers, and genuinely new assets, by definition, do not fit; this is one of the gaps that international experience addresses most directly, by recognizing them according to the function they perform.

For the distributor, all of this translates into uncertainty: the investment the transition makes indispensable is recognized late, partially or at the regulator's discretion. If the framework transfers that risk to the company, it is worth asking whether the rate of return it receives compensates for it, the question addressed in the following subsection.

4.1.7. Rate of return on assets (WACC) and regulatory risk

Valuing the asset base answers how much capital is remunerated, but not at what rate. That rate —the weighted average cost of capital, or WACC— is what, applied to the regulatory base, converts invested capital into recognized profitability: without it, the base is merely a valued inventory, not revenue. Its weight is twofold. It is, first, a multiplier: a variation of a few tenths of a percentage point moves the tariff appreciably, which is why it is one of the most contested parameters of every review. And it is, moreover, the place where the risk the model allocates ultimately gets paid for. The cost the company absorbs when it is remunerated against a standard, the investment that takes time to be recognized, the new assets that find no place: all of this is risk borne by the distributor, and the principle governing the setting of the rate is that it should be consistent with that risk —if the framework transfers substantial risk to the company, the rate should reflect it; if it mitigates it, the rate may be lower. Comparing rates across countries does, however, require a caveat: they are not homogeneous —some are expressed in real terms and others in nominal terms, some pre-tax and others post-tax— so they say something only when read on a common basis.

A first group sets the WACC using the capital asset pricing model (CAPM) and updates it regularly, so that the rate follows market conditions and country risk. Brazil recalculates it annually; Argentina, Chile and Colombia, at each review. The Argentine case is the most eloquent illustration of the consistency principle: in January 2025 the ENRE reduced the distribution rate to 6.22% real post-tax —9.56% pre-tax— down from the previous 10.31%, justifying this by the improvement in macroeconomic indicators and the fall in sovereign risk. Chile abandoned in 2019, through Law 21,194, the historical fixed rate of 10% real per year that had applied since 1982 and replaced it with a band of between 6% and 8% real determined by CAPM. In these frameworks the rate is a live variable, not an inherited number.

A second group retains rates set directly by law, which remain unchanged absent legislative reform. Peru maintains the 12% real pre-tax established in the Electricity Concessions Law of 1992 —a value that also operates as the center of a sectoral control band: if the aggregate profitability of distributors departs from the range of 8% to 16%, the regulator adjusts tariffs to bring it back. El Salvador retains the 10% real of its General Electricity Law of 1996, which the 2024 reform did not modify. And Guatemala offers the limiting case: although its law provides for a band of between 7% and 13%, the National Electricity Energy Commission set the rate at the 7% floor and has kept it at that legal minimum for over a decade. The predictability of these rates is high, but they have a downside: by not following market conditions, they may become misaligned with the real cost of capital and, when they fall below it, transfer the difference to the distributor.

In a third group, systems dominated by public companies or cooperatives dispense with a commercial WACC. In Costa Rica, the law guarantees the operator recovery of its investment and a reasonable benefit without breaking financial equilibrium, a principle that ARESEP's methodology translates into a limited return, well below commercial rates in the region. Ecuador is an even more extreme case: for years it recognized a discount rate of 0% —only depreciation, with no return on public capital— and only in 2025 raised it to a positive real value, albeit still minimal. Paraguay does not set a formal rate of return: ANDE, a vertically integrated state company, recovers its capital through the costs of the service. Bolivia constitutes a singular case: it recognizes a commercial rate, but calculates it by reference to the returns of utilities in the Dow Jones index, decoupling it from local financial risk. Read on a common basis, the region's rates show less dispersion than the raw figures suggest, and the highest —those of Colombia and Peru, at around 12% real pre-tax— largely reflect greater country risk, in line with the principle that the remuneration of capital should follow risk.

Even so, a well-set rate is not sufficient on its own. What ultimately determines the investor's risk is not only the level of the rate, but the stability and predictability of the rules: a generous rate on paper is diluted if investments are recognized late, if tariffs are frozen for political reasons or if methodologies change unexpectedly. The rate of return is therefore a necessary but not sufficient condition for adequate remuneration. Nor is regulated revenue exhausted by remunerating capital and its risk: it also incorporates incentives that reward or penalize the distributor's performance, the subject of the following subsection.

Table 3. Mechanisms for setting the rate of return (WACC) in the region.

Mechanism	Distinctive feature	Countries
WACC by CAPM, updated periodically	Follows the market and country risk through recalculation at each tariff cycle or annually	Argentina, Brazil, Chile, Colombia
Rate or band set by law	Static: highly predictable (fixed as a number or contained within a legal band), but may become misaligned with the real cost of capital	Peru, El Salvador, Guatemala
No commercial WACC (public / cooperative logic)	Return for development or accounting cost, without remuneration of private capital	Costa Rica, Ecuador, Paraguay

Table 3 summarizes the three mechanisms by which the region sets the rate of return and the countries applying each; the specific values, given their different bases (real or nominal, pre- or post-tax), are set out in the text.

4.1.8. Incentive schemes

Setting revenue and its rate of return ensures that the distributor recovers its costs, but it does not guarantee good service: a company may operate at the recognized cost and still deliver poor quality or tolerate high losses. Frameworks therefore add explicit incentives, linking part of revenue to performance against objectives that cost control alone does not secure: quality of supply, loss reduction, efficiency and, increasingly, resilience. The decisive distinction is whether those incentives are symmetric —rewarding good performance and penalizing poor performance— or asymmetric —punishing non-compliance only—, because on this depends whether quality becomes a profitable investment or merely a threshold to be avoided.

The most widespread incentive in the region is that for quality, built around the SAIDI and SAIFI continuity indicators. But in most frameworks it operates asymmetrically: failure to meet targets entails penalties or compensation to users, without superior performance generating equivalent reward. In Argentina, for instance, quality targets form part of the sanctions regime, not of recognized remuneration. Colombia is the clearest exception: its scheme adjusts the operator's revenue upwards or downwards according to whether it performs above or below average quality targets, so that quality does move remuneration. Brazil integrates a dimension of quality and customer satisfaction into its X Factor —the component, defined in ANEEL's PRORET, that adjusts the distributor's revenues upwards or downwards.

Losses receive a two-sided treatment. On the one hand, they are a recognized component of revenue: the regulator admits an efficient level of losses —valued at the price of energy— as part of the cost of the service. On the other, and precisely because that recognized level is fixed, they operate as an incentive: if the distributor reduces its actual losses below the standard, it retains the difference as higher revenue, as operators in Chile and Argentina point out. Colombia goes further by structuring loss reduction plans that recognize the costs of the effort when targets are met and require the amounts recognized to be returned when they are not. It is one of the region's best-developed incentives.

Operational efficiency, by contrast, is rarely rewarded explicitly: in reference utility and price cap schemes it is built in from the outset, since any cost reduction below the standard accrues to the company until the next review, so that the model itself acts as the incentive. And resilience and digitalization —the objectives the transition makes most urgent— have almost no remuneration-based incentive today: distributors report that none exists or that discussion is only beginning. The overall picture is telling: the region incentivises above all by punishing, rewards the static efficiency the model already embeds, and leaves without economic signal the outcomes the new paradigm demands; it is precisely the shift toward symmetric, results-oriented incentives that international experience has developed. These incentives, moreover, do not operate at just any moment: they apply within a tariff period, and their force depends on how long that period lasts and how remuneration is updated in the meantime, the temporal dimension addressed in the following subsection.

4.1.9. Tariff cycles and indexation/adjustment mechanisms

A distributor's remuneration is not recalculated continuously: it is set at a tariff review and applies for a multi-year period, until the following review. That periodicity involves a trade-off. A long cycle reinforces the incentive for efficiency, because the company retains the productivity gains it achieves for longer; but it also increases the risk that parameters —costs, demand, technology— become outdated relative to reality. To manage that tension, frameworks combine two tools: the duration of the cycle and the indexation and adjustment mechanisms that update remuneration while it runs.

The duration of the cycle is, in the region, notably homogeneous: it almost always extends between four and five years —four in Chile and Peru, five in Guatemala, Argentina and Colombia, and four to five in Brazil. Differences appear in how the base is updated within that period: while most keep it fixed until the following review, Colombia and the Argentine federal jurisdiction allow for the update annually and Costa Rica adjusts its tariffs each year, which shortens the distance between investment and its recognition. Comprehensive mid-period review is infrequent, but several frameworks provide extraordinary safety valves: Brazil and Argentina (federal), for example, allow an out-of-cycle review where a breach of the concession's economic and financial equilibrium is demonstrated, a principle its concessions law expressly enshrines.

Indexation and adjustment mechanisms are what preserve the real value of revenue between one review and the next, and their robustness varies enormously. At one extreme lies Colombia, whose distribution remuneration is adjusted almost exclusively by the producer price index, a dependence its own distributors consider insufficient to capture the macroeconomic factors they face. At the other is Argentina which, driven by inflation, moved to monthly adjustment linked to price developments and incorporated a deferral scheme recognizing the financial cost of recovering pending increases gradually. Between these poles, the rest of the region relies on updates of intermediate frequency and on varied baskets of indices —the local consumer price index in El Salvador, or combinations adding the exchange rate and external price indices in other cases.

Duration and indexation ultimately operate as a single device: the longer the cycle, the more decisive the robustness of the adjustment becomes, and on the combination of the two depends how much risk of erosion of real revenue the distributor bears between reviews. That risk is precisely what the rate of return should recognize, so that cycle, adjustment and WACC form part of a single system. This interdependence extends to the whole scheme: the remuneration model, the determination of costs, the treatment of capital and operation, the valuation and updating of assets, incentives and cycles are not independent decisions but parts of a single system whose balance defines the adequacy and sustainability of remuneration. Having determined how much the distributor receives, there remains the other half of the tariff equation: how that revenue is collected from users, through the structure of charges addressed in the following section.

4.2. TARIFF SCHEMES AND PRICE SIGNALS

Electricity pricing in Latin America combines, to a greater or lesser degree, energy components, transmission and distribution tariffs, and sectoral charges and taxes. Although this breakdown is widely recognized in the literature, its practical application varies significantly across countries, both in how costs are allocated and in the transparency with which each component is presented to the consumer. Another central element of tariff design is the distinction between fixed and variable costs, usually translated into three components: a volumetric one, associated with energy consumption; a fixed one, aimed at recovering costs independent of use; and a capacity component, related to the sizing of infrastructure.

Understanding how each country structures these elements and how the tariff transmits economic signals to consumers and influences distributors' performance is essential in order to identify gaps, assess incentives and recognize opportunities for regulatory improvement. The differences observed in the region reflect institutional choices, regulatory maturity, public policy priorities and structural conditions of the electricity systems. Comparative analysis of Latin American tariff models therefore makes it possible to understand how costs are recovered, as well as the way each country balances efficiency, equity, financial sustainability and service quality.

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Choosing a remuneration model is not a decision that stands in isolation

4.2.1. Structure and unbundling of tariff components

Country	Fixed Charge	Energy Charge	Demand / Capacity Charge	Tariff Opening (Visible or Explicit Components)
Argentina	●	●	◐	CM, D
Bolivia	●	●	◐	G, Dep., Utility
Brazil	○	●	◐	G, D
Chile	●	●	●	G, T, D, R
Colombia	○	●	○	G, T, D, Retail, P, R
Costa Rica	●	●	◐	G, T, D, Retail, R
Ecuador	●	●	◐	G, T, D, Retail
El Salvador	●	●	◐	G, D, Retail
Guatemala	●	●	◐	G, T, D
Paraguay	●	●	◐	G, T, D, Retail
Peru	●	●	◐	G, T, D

LEGEND

●	General application
◐	Partial application (depending on voltage level or user type)
○	Not applicable

COMPONENT KEY

G	Generation (energy)
T	Transmission
D	Distribution (use of the network)
Retail	Retail
P	Losses
R	Restrictions / Other
CM	Commercialization costs
Dep.	Depreciation
Utility	Allowed utility

Fig. 4. Structure and unbundling of tariff components.

The great majority of the sample uses a basic structure of a fixed charge plus a variable charge. Only Colombia has no fixed component, and neither does Brazil in the residential segment. (there is only a minimum allowance of 30 kWh, 50 kWh, and 100 kWh). It is worth noting that a uniform fixed charge applied to all users may fulfill the function of recovering costs, but will not necessarily meet efficiency criteria.

The tariff structure in Argentina applies a fixed amount plus a variable amount for energy for small demands (≤10 kW), while medium and large demands also include charges for maximum supply capacity, for capacity demanded at peak times, for energy consumed in the different tariff periods (peak, off-peak and intermediate) and for capacity exceeded. The tariff composition in Argentina includes the Wholesale Market Purchase Cost (Energy + Capacity + Transport) and the Distribution Value Added.

In Brazil there is a fixed tariff component only for Group A consumers (high voltage), corresponding to the amount charged for contracted or metered demand, remunerating the capacity the distributor must keep available. A proposal is currently under Public Consultation to replace the present minimum-consumption model of 30, 50 and 100 kWh —under which the consumer pays a minimum amount based on a quantity of energy, even if it is not used— with a fixed monthly charge in reais. The tariff composition considers the costs of energy generated or purchase costs —which form the Energy Tariff (TE)— plus the transport of energy to consumer units, which consists of the Distribution System Use Tariff (TUSD). The TUSD is broken down into portions A —covering third-party costs—, B —corresponding to the value added of Distribution— and losses, charges and others.

Bolivia adopts a tariff structure with fixed and variable components for all demand levels. What changes is the way the variable part is charged: for small loads (≤ 10 kW) it depends solely on the energy consumed; for medium demands (11 to 50 kW) it includes energy and capacity costs; and for large consumers (> 50 kW) energy is charged by time blocks (high, medium and low), plus capacity charges and charges for exceeding capacity off-peak. Tariffs include the cost of purchasing and transporting electricity in the case of the Integrated System, or generation cost in the case of Vertically Integrated Isolated Systems; operation, maintenance and administration costs; and capital costs.

Chile's tariff structure includes a fixed component, covering customer service costs, and a variable one reflecting the remaining costs of the service. The final tariff is broken down into parts reflecting generation, transmission, distribution and other charges.

The final tariff in Colombia has no fixed component and features the most complete unbundling among the countries, corresponding to the sum of the following elements: Generation (G), variable cost associated with the energy purchased to serve regulated users; Transmission (T), variable component remunerating the use of transmission networks; Distribution (D), cost associated with the use of distribution networks; Retail supply (C), costs related to customer service; Losses (PR), variable component recognizing regulated losses in the distribution and transmission system; and Restrictions (R), costs associated with operational constraints of the electricity system. The sum of these six components produces the Unit Cost ($/kWh), which is multiplied by each user's monthly consumption to determine the amount corresponding to each tariff component.

Costa Rica adopts a fixed component in its tariff structure, applied where the consumer falls under binomial tariffs, which charge separately for energy (kWh) and demand (kW). The final tariff brings together energy —cost of generation purchased—, transmission —transport of energy to local networks—, VAD —fixed charge per user, average losses and capital, operation and maintenance costs—, capacity, regulatory charges and complementary services.

The breakdown of the tariff in El Salvador comprises a fixed component to cover retail supply costs and variable components for distribution costs and for the energy consumed, relating to generation. The distribution component reflects the amount the distributor allocates to carrying out maintenance, improvement and expansion of the network.

The tariff structures of Guatemala and Peru are quite similar, organized into three main blocks: generation, transmission and distribution. In the generation block, both include charges for energy (kWh) and capacity to meet the demand of regulated users. Transmission, in both countries, brings together connection and network use charges, incorporating costs such as losses, congestion and compensation among agents. Distribution, in turn, comprises the Distribution Value Added (VAD), which remunerates the medium- and low-voltage network, together with the connection costs associated with serving the user. In both cases, the VAD includes a fixed monthly charge, associated with the cost of keeping infrastructure available to the consumer, while the variable component is calculated on consumption (kWh) and, where applicable, on capacity demanded (kW).

Paraguay adopts a single-part tariff, comprising energy (generation and purchase cost), capacity and demand —applied mainly to large consumers at peak times— and the use of the distribution network, which incorporates infrastructure, operation and maintenance, retail costs, depreciation and remuneration of assets. In addition, there are specific arrangements for energy-intensive industrial consumers.

4.2.2. Capacity or maximum demand charge

Among the countries analyzed, only Chile has a demand charge for the residential segment. Residential consumers pay the cost related to capacity indirectly, through load factors applied to energy consumption, in both distribution and generation —there is no direct charge for contracted or metered demand. Charging is based on metered or contracted capacity, and maximum demand is measured in 15-minute blocks. Colombia has a single-part energy tariff, while Peru has a "coincident peak demand" charge, referring to the demand recorded by the customer coinciding with the national maximum demand for the month, which is included in the energy formula for residential customers (BT5), though not visibly to the user.

Most of the countries analyzed have a capacity or demand tariff for medium and large consumers (LV and HV). In Argentina, payment is for contracted capacity, with a penalty for exceeding contracted demand. In Bolivia there is also a penalty for exceeding capacity outside peak hours for large consumers. Demand tariffs are applied to medium-sized users through maximum capacity, corresponding to the highest of the capacity levels metered in the electrical period from November to October and, for large consumers, through maximum capacity in the Peak Block and Off-Peak Capacity Excess (the difference between maximum off-peak capacity and maximum peak capacity). The highest of the capacity levels metered in the electrical period from November to October is taken.

Contracting arrangements in Brazil include the green and blue tariffs for medium- and high-voltage consumers. Billing is based on the higher of metered demand in the billing cycle and contracted demand. There is also a generation tariff arrangement, applied to generating plants and to importing agents connected to distribution systems, characterized by demand tariffs irrespective of the hours of use during the day.

In Costa Rica, residential consumers and small low-voltage businesses do not pay for contracted demand. The capacity or demand tariff is paid by consumers classified as medium-sized and large Low Voltage demands, medium voltage and high voltage. These groups pay a penalty for exceeding contracted capacity and also pay for capacity acquired, linked to the wholesale cost of capacity.

El Salvador has capacity or demand charges only for medium-sized and large low- and medium-voltage consumers. In Guatemala, capacity charges generally do not apply to residential users; however, if they exceed 11 kW of consumption, they must be reclassified into a category with contracted demand, in which a contracted capacity and a maximum demand charge are payable.

4.2.3. Time differentiation and time-of-use tariffs

Country	Residential (BT) Low Voltage	Small demand (BT) Low Voltage	Medium demand (MT) Medium Voltage	Large demand (AT/MT) High/Medium Voltage	Type of time-of-use tariff	Relevant observations
Argentina	○	○	○	●	-	Applies only to Large Demands (>50 kW). Not available for residential customers.
Bolivia	○	○	○	●	3 blocks	Only Large Demands. Blocks: high / medium / low.
Brazil	●	●	●	●	White / Green / Blue Tariff	White Tariff for BT (residential). Green (A3–A4) and Blue (A3) in MT/AT.
Chile	○	○	◐	●	On-peak / Off-peak	TOU optional for customers >10 kW in BT and MT. Defined by period.
Colombia	○	○	◐	◐	– (limited option)	Not available for most regulated residential customers. Only aggregators or special options.
Costa Rica	○	○	●	●	On-peak / Mid-peak / Off-peak	TOU for BT >50 kW and MT (mandatory) for some clients. Three daily periods.
Ecuador	○	○	◐	●	On-peak / Off-peak	Applies to MT (≥13.8 kV) and large consumers. Two daily periods.
El Salvador	○	○	●	●	On-peak / Mid-peak / Off-peak	Optional for BT (residential). Mandatory for MT and large demands.
Guatemala	○	○	○	●	On-peak / Off-peak	TOU for clients >11 kW and public electric vehicle charging stations.
Paraguay	○	○	◐	●	On-peak / Mid-peak / Off-peak	Optional in MT (≥23 kV) and mandatory in AT. Three daily periods.
Peru	◐	●	●	●	On-peak / Off-peak	Residential with advanced meter (BT5D). On-peak: 18:00–23:00.

LEGEND

● Available / Mandatory
◐ Available / Optional
○ Not available

BT = Low Voltage
MT = Medium Voltage
AT = High Voltage

TYPES OF TIME-OF-USE TARIFFS

On-Peak: Hours of highest system demand (highest price).
Mid-Peak: Intermediate hours of demand.
Off-Peak: Hours of lowest demand (lowest price).

Fig. 5. Time differentiation and time-of-use tariffs.

Among the countries analyzed, Brazil, Costa Rica, Paraguay and Peru have hourly tariffs for residential consumers. In Brazil there is the White Tariff (tarifa branca), an arrangement characterized by differentiated electricity consumption tariffs according to the hours of use during the day, segmented into three tariff periods: peak; intermediate; and off-peak. The White Tariff applies to group B consumer units, except for the low-income and social discount subclasses of the residential class, the public lighting class, and consumer units billed under the prepayment arrangement. At present, take-up of the White Tariff is voluntary, but ANEEL's Public Consultation (Public Consultation 46/2025) is considering the possibility of automatically applying the Hourly Tariff (White Tariff) to low-voltage consumers in subgroups B1 (residential), B2 (rural) and B3 (commercial, industrial and others) with monthly consumption equal to or above 1 MWh.

In addition, there are the green and blue tariff arrangements. The green tariff is characterized by: a demand tariff, without time segmentation; an electricity consumption tariff for the peak period; and an electricity consumption tariff for the off-peak period. The blue tariff is characterized by a demand tariff for the peak period; a demand tariff for the off-peak period; an electricity consumption tariff for the peak period; and an electricity consumption tariff for the off-peak period.

In Peru, for low- and medium-voltage customers, there are various tariff arrangements; the user may choose the one that best suits their consumption profile. The option must be requested from the distributor and, in some cases, may require the meter to be capable of correctly recording the tariff components —otherwise, the customer must bear the cost of replacing the equipment. This flexibility is used particularly by consumers with time-based consumption patterns, such as agricultural activities, night-time industrial processes or operations concentrated in particular periods of the day.

Paraguay has hourly and time-of-use tariffs for residential, industrial, government and other consumers served at low and medium voltage, who pay different amounts for energy. This arrangement is optional and sets higher prices at peak times and lower prices off-peak, encouraging users to reorganize their habits and concentrate consumption in periods of lower demand.

There is an incentive for consumption outside hours of higher demand in Costa Rica for residential consumers on low voltage with consumption above 200 kWh per month. Tariffs are differentiated according to the period of the day. Three bands are used: peak, with the highest values; off-peak, with intermediate prices; and night-time, with the lowest tariffs. Values also vary according to the total volume consumed in the month, with blocks of up to 500 kWh and above 501 kWh, reflecting a structure that combines time signaling and progressivity to promote efficiency and consumption shifting.

Argentina and Bolivia have time-of-use tariff bands only for large demands, with a minimum threshold of 50 kW in Argentina. In Bolivia tariffs consider peak and off-peak, comprising three time blocks: Peak Block (18:00 to 23:00), Mid-peak Block (07:00 to 18:00 and 23:00 to 24:00) and Off-peak Block (00:00 to 07:00).

In Chile there are tariffs with time differentiation for regulated customers, structured into blocks such as peak, intermediate/flat and off-peak. These tariffs are aimed mainly at customers with greater installed capacity, generally above 10 kW, who have a smart meter capable of recording consumption by time period. Take-up of these tariffs is optional and must be requested by the user from the distributor. They are aimed at consumers who can benefit from differentiated prices by shifting part of their consumption to off-peak hours.

El Salvador has a mandatory hourly tariff for large demands, whether low or high voltage. For medium-sized customers with smart metering, hourly tariffs are available as an option.

In Guatemala there are tariffs with time differentiation by blocks. These tariffs are designed to serve users generally, encouraging efficient use of energy and stimulating consumption in periods of lower demand, including for charging electric vehicles. There are also hourly tariffs for users with demand above 11 kW, who may be metered by time blocks with the same objective, namely to promote more efficient energy consumption.

At present, in Colombia there are no tariffs with time differentiation for regulated consumers; time differentiation is provided only for certain unregulated users.

4.2.4. Unbundling and visibility of the distribution charge

The countries analyzed present different structures for identifying the distribution charge. Some, such as Argentina (federal), Brazil, Colombia, Costa Rica and El Salvador, have explicit regulated unbundling; others, such as Bolivia, Chile and Guatemala, have no clear separation for regulated users, and that separation is identifiable only for large customers in the free market; while in Peru a partial separation of the distribution charge can be observed.

Peru’s structure is distinctive: for customers without a 15-minute meter, the tariff is applied within the formula for calculating the price of energy. For customers who have such a meter or who record maximum demands, the value of maximum demand at Peak and Off-Peak Hours over the last 6 months is applied, multiplied by the VAD.

In Brazil, tariffs are segregated into the Energy Tariff (TE) and the Distribution System Use Tariff (TUSD). Regulated market consumers pay the sum of these two components, which do not appear disaggregated on the bill, although regulation is clear in defining tariff values for each of them. In the free market, consumers freely negotiate the price of energy and pay the TUSD if connected to the distribution network, or the Transmission System Use Tariff (TUST) if connected to the transmission network.

In Colombia, Costa Rica and Paraguay, regulation separates each component of the tariff and the sum of the parts constitutes the unit cost paid in energy tariffs. A similar process occurs in El Salvador, where the tariff is broken down into distribution, retail supply and energy components and, in that country's case, the bill shows this separation.

Chile and Bolivia have no differentiation for regulated market customers; explicit charge costs exist only for the free market. In Guatemala the structure is also similar, with integrated values for the regulated market, while in the free market there are categories in which the distributor performs the transport function, with a tariff for losses and another for maximum demand. In Argentina there is a distinction only from medium and large demands upwards; small residential loads have no segregation.

4.2.5. Social subsidies

There are different mechanisms and approaches to social subsidies in Latin American countries. In Argentina, El Salvador and Guatemala, subsidies are financed from the public budget. In Argentina there is a National Subsidy on a given quantity of kWh of consumption. There is also a fixed supplement relating to the Social Tariff of the federal jurisdiction (the Autonomous City of Buenos Aires, CABA, or Buenos Aires Province, PBA). These subsidies do not apply to the same customers and have different arrangements. In El Salvador, subsidies are established through a model defined by the Ministry of Economy, which pre-selects the users eligible for the benefit and sends that list to distributors, which are responsible for applying the discount directly on the bill. The entire cost is borne by the Central Government, which reimburses distributors for the subsidised amounts. This system has operated since 1999 and performs well, provided government reimbursements are made on time. In Guatemala, the Social Tariff Law objectively defines who is entitled to the subsidy and establishes how it must be applied, prioritizing low-consumption consumers. The government finances this benefit in full through a public energy company, which transfers the amount to the distributor to ensure it receives the full tariff. This process involves oversight by the regulator and the action of the government entity responsible for transferring the resources, ensuring the subsidy is applied correctly.

In Brazil, the Energy Development Account (CDE), a kind of sectoral fund, is the main mechanism through which the subsidies borne by Brazilian consumers are concentrated. Subsidies are taken to include tariff discounts and benefits, government policies such as Service Universalisation and Generation Cost Coverage in isolated systems (CCC and Coal and Fuel Oil), and the estimated impact of distributed generation on consumers' tariffs based on a consumption non-coincidence factor. For low-income residential consumers there is currently the Social Electricity Tariff, financed by other consumers through the CDE. At present, subsidies represent on average 20% of residential consumers' tariffs (ANEEL, 2026).

Bolivia, Chile and Peru have mechanisms in which subsidised users are financed by other consumers. In Bolivia there is a subsidy for residential consumers using up to 70 kWh per month, consisting of a 25% discount on the value of electricity consumption. This benefit is financed monthly by the Wholesale Electricity Market Agents, which bear the cost of the discount applied to those users' bills. In Chile, existing subsidies tend to be temporary and geared to specific situations, such as cost increases or accumulated debts, and are financed mainly by consumers themselves through tariffs, taxes or regulatory cross-subsidy mechanisms. The government usually complements only part of that financing. In some cases there are targeted subsidies for the most vulnerable households, but they depend on registration processes and periodic renewals, which limits their continuity. Overall, there is a need to structure a more permanent and stable subsidy model, capable of consistently serving those who genuinely need it, reducing dependence on provisional measures. In Peru there are two regulated subsidy mechanisms operating through different forms of financing and compensation. The FOSE (Electricity Social Compensation Fund) is a cross-subsidy created to ensure that low-income, low-consumption residential users — with a monthly average of 140 kWh or less, in line with the criteria defined by OSINERGMIN Resolution No. 206-2013-OS/C— pay less for electricity. This fund is financed by higher-consumption consumers, who contribute to reducing the tariff of the most vulnerable users. The Rural Electrification program is financed through a charge levied on all energy users, intended to sustain projects that expand access to electricity in rural areas.

Colombia presents a distinctive profile, where the subsidy system is structured by socio-economic strata and directed at residential consumers in strata 1, 2 and 3, who receive discounts limited to the basic lifeline allowance —between 130 and 173 kWh per month, depending on the municipality's altitude. These subsidies are financed through a mixed model combining National Government resources, via the General Budget of the Nation, with mandatory contributions from users in strata 5 and 6 and from the commercial and industrial sectors, which pay a 20% surcharge on their consumption. Where contributions are insufficient, the State covers the deficit. The model also provides for recognition of financial costs to retail companies until government reimbursement, although frequent delays affect their liquidity. There remains, moreover, a need to improve the targeting of subsidies, reducing reliance on the strata criterion and directing the benefit exclusively to low-income users.

In Costa Rica there is the Preferential Tariff of a social nature (T-CS) for vulnerable consumers served at low voltage. The following users fall into this category: public supply service units for pumping drinking water; public educational institutions; places of worship; care homes for older people, nurseries and shelters; centers caring for homeless people or those with substance dependence; social assistance institutions; the Red Cross and rural health centers; as well as people requiring home ventilatory support. Each category may use the special tariff only for facilities directly linked to its main purpose and, where applicable, legal and non-profit entities.

In Paraguay there is a Social Tariff for low-income residential customers and other vulnerable consumers. To access the subsidy, customers must meet requirements established by law, including monthly consumption of up to 300 kWh, belonging to the residential consumer group or forming part of officially recognized community water boards (Juntas de Saneamiento).

4.2.6. Prepayment schemes

The prepayment option has a regulatory basis in the great majority of the countries analyzed, but it is not adopted on a large scale owing mainly to economic barriers such as the cost of meters, low attractiveness for the company and operational issues.

There is no prepayment arrangement provided for in the regulation of Chile, El Salvador, Paraguay and Guatemala. Argentina and Brazil have regulation for prepaid tariffs, but with low take-up owing to factors such as costs and operational issues. Current regulation in Bolivia provides for prepayment models for services in the Low Voltage (LV) category. However, the distributor DELAPAZ has no active consumers under that model. In Costa Rica this arrangement is applied solely to residential consumers with smart meters.

In Colombia there is prepaid energy retailing; however, there are limitations on passing through, via the prepayment system, certain costs additional to the cost of the energy service. That is, costs associated with faults caused by the user, financing from the sale of the meter, connection or reconnection of the service, energy fraud proceedings or technical visits requested by users are not included in the account under the prepayment option, which does not encourage its adoption.

In Peru the prepayment arrangement is available on an optional basis in some regions. The main barrier identified is the acquisition of the meter, since not all distributors have suppliers for that equipment.

4.2.7. Medically dependent customers

Only Chile and Argentina have tariff frameworks for medically dependent consumers —households reliant on electrically powered life-support equipment— that combine economic benefit with a guarantee of service. In the remaining countries, the guarantee is limited to a prohibition on suspending supply and, in some cases, no specific regulation exists.

In Argentina, Law 27,351 guarantees free provision and continuity of service for registered medically dependent users. In Chile there is specific tariff treatment for medically dependent customers. To access the benefits, the user must present a medical certificate and register in the register of medically dependent patients, which guarantees a monthly energy allowance for the operation of essential medical equipment. The treatment includes a tariff discount —a deduction of up to 50 kWh per month— and a prohibition on disconnection for non-payment, as well as priority attention in situations of service interruption. The model also provides for the supply of emergency equipment, such as batteries or generators, whose financing is incorporated into the electricity tariff. Concession holders have no mechanisms to challenge eligibility once the medical certificate is presented.

In Brazil, medically dependent consumers must be registered with distributors in order to receive priority attention. However, there is no specific national tariff policy; any benefits are indirect, such as access to the social tariff.

In both Colombia and Peru, medically dependent users receive no differentiated tariff treatment or specific subsidies, but they have protection against suspension of supply for non-payment, provided their condition is formally recognized. In Colombia, recognition occurs upon application to the distributor accompanied by evidence and clinical history, and these users may also access the same financing arrangements available to other consumers, in addition to being protected by judicial decisions reinforcing the prohibition on disconnection. In Peru, although the logic is similar, the process requires registration with both the electricity company and Osinergmin and, once registered, users are likewise protected against disconnection and may take up installment arrangements to facilitate payment of their bills.

In Costa Rica, the Preferential Tariff of a social nature (T-CS) is applied to users on home ventilatory support owing to transitory or permanent respiratory impairment who require electrical equipment for direct assistance with the respiratory cycle. This must be prescribed by an authorised medical clinic, with a document evidencing delivery or installation of the device.

Bolivia, El Salvador, Guatemala and Paraguay have no specific regulation, so that service to these customers is provided on a case-by-case, ad hoc basis.

4.2.8. Incentives for quality and losses

Among the countries analyzed, all are found to have some form of indicators or targets for service quality and loss management, generally based on minimum performance thresholds and penalties for non-compliance. In almost all cases the model is essentially asymmetric, that is, geared to sanctions and compensation to the user, without offering positive incentives for good performance. The clear exception is Brazil and Colombia, which adopt symmetric mechanisms, allowing distributors to increase or reduce their revenues according to performance against established targets. In addition, most countries recognize losses in the tariff only up to levels considered efficient or optimal, passing the excess to the distributor as a form of economic incentive to reduce them.

In Brazil, this symmetric logic is expressed through indicators such as DEC and FEC and individual metrics assessing performance as perceived by each consumer. Meeting targets may generate revenue gains or losses, and any individual breach results in automatic compensation to the user. Losses are treated separately as technical and non-technical, with targets defined by benchmarking; only the volume within the target is recognized in the tariff. Colombia follows a similar line: in the Local Distribution System, quality is measured by SAIDI and SAIFI, and performance may raise or reduce annual revenue. The treatment of losses combines recognition for efficient companies with progressive incentives for those reducing their levels over the tariff cycle.

In the remaining countries, although quality control mechanisms and recognized loss limits exist, the predominant character is punitive. In Argentina, for example, breaching continuity limits generates automatic compensation to users, and there are additional penalties for feeders with markedly poor performance or high-impact events. Losses are recognized up to efficient levels defined by the regulator, and any amount above must be absorbed by the distributor. Bolivia likewise makes no provision for bonuses, but failure to meet quality indicators reduces the distributor's revenue. Losses are treated on the basis of an optimal level by voltage level, and deviations directly affect remuneration.

Chile follows the same corrective logic, with no positive incentives for quality or losses and with the efficient company model using distributors' actual data. Failure to meet minimum indicators results in fines that reduce revenue. In El Salvador, penalties cover not only continuity of service but also customer service and the quality of the electrical product. Recognized losses are defined in the five-yearly tariff process, with full recognition of technical losses and only partial recognition of justified non-technical losses, the excess remaining at the distributor's risk.

Guatemala sets tolerance limits for global and individual interruption indicators, distinguishing urban and rural areas. Where these are exceeded, compensation proportional to energy not supplied is payable. Recognized losses are defined in the five-yearly VAD calculation, which incorporates the efficient costs of a reference utility, with values above the limit not passed through to tariffs. In Peru, failure to meet quality limits likewise generates penalties. Improvement projects, duly approved, may be financed through the tariff. Losses are recognized on the basis of the reference utility, distinguishing technical and non-technical losses through the VAD, which reflects the distributor's performance in managing those losses.

Finally, Costa Rica and Paraguay present models that are even more restrictive in terms of incentives. In Costa Rica, distributors must meet targets for quality, quantity, timeliness, continuity and reliability, but the model is exclusively corrective and punitive, with compensation to the user where indicators are not met. Losses are treated globally, with a maximum limit, whereby values below the ceiling are recognized in full, while losses above the historical average generate a direct financial loss for the distributor. In Paraguay, although quality targets exist in concession contracts, there is no explicit, differentiated recognition of losses in the tariff, nor formal mechanisms defining recognized levels of technical or non-technical losses. Losses, including non-technical ones, are absorbed as part of the overall financial result, with no direct tariff signals to encourage their reduction.

4.2.9. Regulatory sandbox and tariff experimentation

Regulatory sandboxes are controlled environments created so that energy distributors can test innovative solutions or business models with the regulator's authorisation. They allow certain requirements of traditional regulation to be relaxed, for a limited period and under direct supervision, making it possible to experiment with new technologies and practices within specific rules previously defined by the regulatory authority.

At present there is no regulation of, or experience with, regulatory sandboxes in Bolivia, El Salvador and Peru. In Guatemala there is likewise no provision in regulation, but experiments are possible at the distributor's own risk and cost, similarly to Chile, where there is also no formal framework but innovation is permitted provided the service delivered is not affected. Colombia is undergoing a public consultation process to establish a formal framework, through draft Resolution CREG 705 012/2026, currently under analysis.

Brazil is the country in Latin America that has made most use of sandbox experience. At present there are 9 regulatory projects under way, as described below:

a) Enel São Paulo – "Tarifa flex and Economize e Ganhe" (Flexible Tariff and Save and Earn): pilot project for residential consumers.

- Tarifa flex: price variation according to the time of use.
- "Economize e Ganhe": information on specific periods and events to save energy and obtain a discount on the bill.
- Duration: 38 months, authorised in April 2023

b) EDP São Paulo – "Minha conta com meu jeito" (My Bill, My Way): demand response pilot project in low voltage.

- Tarifa hora econômica (Economy Hour Tariff): tariffs varying across the hours of the day.
- Tarifa Consumo Consciente (Conscious Consumption Tariff): demand tariff
- Tarifa Equilíbrio (Balance Tariff): demand tariff plus a fixed monthly component reflecting customer service.
- Duration: 25 months, authorised in April 2023, with the field phase beginning in July 2025.

c) Equatorial (Alagoas and Maranhão) – "Projeto minha energia" (My Energy Project): locational time-of-use and seasonal tariff

- Tariffs varying according to the hour of the day;
- Tariffs varying across the months of the year, with the aim of adjusting prices according to the volume of use of the distribution system in different periods of the year.
- Duration: 31 months, authorised in April 2023

d) Energisa (ESS, ETO and EPB) – "Conta Inteligente" (Smart Bill): hourly tariff – Time Of Use (ToU), Dynamic and Prepayment

- Best-hour tariffs, with different values for consumption across the day;
- Quarterly dynamic tariffs without the impact of tariff flags;
- Prepaid plan
- Duration: 44 months, authorised in April 2023, with the field phase beginning in November 2024

e) COPEL – "Hora certa COPEL" (COPEL Right Time): two-part tariff, multi-part tariff and digital bill for group B

- Multi-part tariffs focused on implementing more dynamic tariffs with smart meters;
- Fixed demand components and components by time band;
- Transition to the issuance of digital bills
- Duration: 26 months, authorised in June 2024.

f) COPEL – "Tarifa Mobiflex Copel" (Copel Mobiflex Tariff)

- Cheaper tariff during the early hours for those with electric vehicles
- Duration: 30 months, authorised in June 2024.

g) Energisa Mato Grosso do Sul – "Projeto Fatura Fixa" (Fixed Bill Project)

- Fixed billing for up to 12 months with periodic adjustments.
- Duration: 36 months, authorised in June 2024.

h) Permissionárias do Sul (Southern Permit Holders) – Strategies for the free energy market

- Test of market opening for low voltage
- Duration: 12 months, authorised in August 2024, with the field phase beginning in January 2025.

i) Light – "Light Controle" (Light Control): fixed billing arrangement combined with non-tariff incentive mechanisms

- Account model with fixed amounts;
- Tariff discount and cashback for residents of areas with greater economic and operational vulnerability.
- Duration: 42 months, authorised in September 2024.

Building on the Brazilian experience, through the dissemination and promotion of knowledge carried out within ADELAT, ADEERA (the Association of Electricity Distributors of the Argentine Republic) promoted a proposal for the use of sandboxes in Argentina. In the second half of 2025, Empresa Distribuidora de Electricidad de Salta S.A. (Edesa), part of the Desa group, worked together with Enresp (the Regulatory Entity for Public Services of Salta) to structure and implement the regulatory sandbox model. As a result, Salta became the first Argentine province to institutionalize this tool through a specific regulation.

On 30 December 2025, ENRESP published Resolution No. 2965/25, through which it established, among other measures, authorisation for the implementation of a regulatory sandbox, intended to test technical and tariff tools subject to prior approval by the regulator, as well as recognizing investment in networks for neighbourhoods undergoing regularisation as a priority need, allowing the sandbox to be used to explore alternative models applicable to that problem.

05

INTERNATIONAL REGULATORY APPROACHES AND BEST PRACTICES

The preceding sections established the conceptual framework of remuneration and tariff design, and characterized the state of both in Latin America on the basis of the benchmarking carried out by ADELAT. This chapter examines what international experience teaches. Its purpose is to identify, from the most advanced regulatory frameworks, the practices that have demonstrated the capacity to recognize investments adequately, send efficient price signals, protect vulnerable users and sustain innovation, so that they may serve as a reference for the evolution of Latin American schemes. These practices come mainly from markets with institutional conditions, investment levels and regulatory trajectories different from those of the region. They do not therefore constitute models to be transplanted wholesale, but points of reference whose design logic is worth understanding in order to adapt it to local realities.

5.1. PERFORMANCE-BASED REMUNERATION MODELS

The most profound transformation in the international regulation of distribution over the past two decades has been the shift from cost-of-service regulation toward performance-based regulation (PBR). The underlying change is conceptual: whereas traditional regulation controls inputs —how much the company invests and spends, and with what return those costs are recognized— performance-based regulation shifts the focus to outputs: what products and outcomes the distributor delivers to users and to the system, and it links its remuneration to the quality of that performance. The company ceases to be remunerated for accumulating assets and comes to be remunerated for meeting objectives of service, efficiency and innovation. Its most complete and mature expression is the RIIO framework of the British regulator, whose acronym summarizes the formula: revenues result from the combination of incentives, innovation and outputs (Revenue = Incentives + Innovation + Outputs).

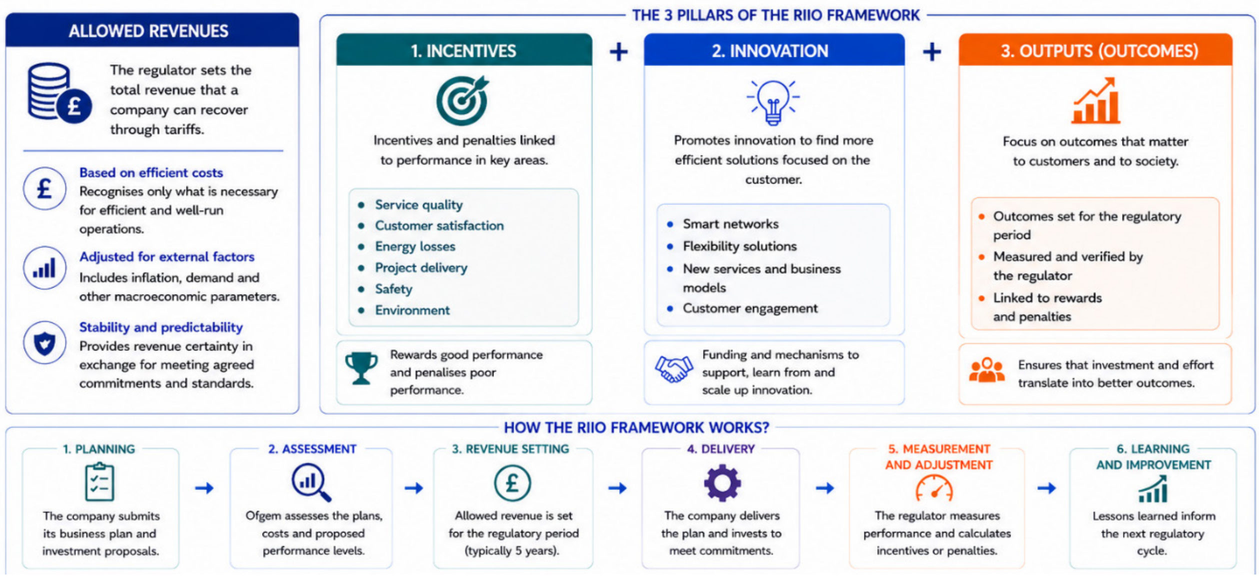

Fig. 6. How the RIIO framework works.

Rather than a single model, performance-based regulation should be understood as a set of components that may be adopted in different combinations and which, far from replacing cost-of-service regulation, complement it. The RIIO framework brings together several of these building blocks. At its core operates a multi-year revenue control that sets a path of allowed revenues for an extended period, giving the company a stable planning horizon. On that basis a set of outputs is defined which the distributor undertakes to deliver —reliability and quality of supply, customer satisfaction, connections, environmental performance, safety— compliance with which is rewarded or penalized through financial and reputational incentives. Expenditure allowances are set on a total expenditure (TOTEX) basis, so that the company may freely choose the most efficient combination of investment and operation, and deviations from that baseline —savings or overspends— are shared between the company and users through a sharing factor that preserves the efficiency incentive without transferring all risk to one party. A business plan incentive is layered on top of this, rewarding distributors whose plans represent superior value and provide information useful to the regulator in setting the price control, as well as the requirement for genuine engagement of stakeholders and consumers in preparing those plans. Finally, uncertainty mechanisms (or re-openers) allow parameters to be revised in response to cost changes or unforeseeable circumstances, preventing the multi-year nature of the control from translating into rigidity when the unexpected occurs (Ashurst, 2025).

Two parameters illustrate how the system is calibrated in practice. On the one hand, the recognized rate of return is set at levels consistent with the effective risk of the business —of the order of 5.5% to 6% for networks— reflecting the logic of aligning the remuneration of capital with regulatory risk. On the other, the system incorporates an ongoing efficiency challenge, of the order of 1% per year on the total expenditure baseline, which passes expected productivity improvements through to the tariff. The combination of these elements produces a scheme in which the company can earn higher revenues if it exceeds its performance objectives and delivers its outputs more efficiently, and loses them if it does not. This approach is not exclusive to the United Kingdom: in the United States, numerous jurisdictions have expanded the use of incentive regulation, incorporating performance metrics and indicators (performance incentive mechanisms) that reward customer satisfaction, facilitate the transformation toward a cleaner and more distributed system, and increasingly focus remuneration on outcomes rather than inputs (Joskow, 2024).

The principal virtue of performance-based regulation is that it aligns the distributor's interests with the public objectives that the energy transition has made a priority: service quality, the integration of distributed resources, resilience and innovation cease to be burdens or obligations and become sources of revenue. By focusing on outcomes, this approach also neutralizes the bias toward capital and creates space for non-conventional solutions. But its adoption requires robust regulatory capacity to define measurable outputs, set realiztic targets and process large volumes of performance information; transparent governance to lend legitimacy to the setting of objectives; and particular care in design to avoid opportunistic behavior or the manipulation of indicators. British experience shows that the calibration of sensitive parameters —in particular the rate of return— is subject to intense scrutiny and to appeals by companies, which points to the importance of the independent technical bodies analyzed in Section 5.6.

For Latin America, performance-based regulation offers a particularly pertinent frame of reference. The efficient reference utility schemes prevailing in the region already incorporate a strong incentive for cost efficiency, but they do so from an input-centered logic and, as the benchmarking showed, they coexist with quality incentive schemes that are largely asymmetric —penalizing non-compliance but not rewarding superior performance. Performance-based regulation does not require existing models to be replaced root and branch; rather, it allows its building blocks to be incorporated gradually: symmetric incentives for quality and losses, measurable outputs linked to the integration of distributed resources, sharing factors that balance risk and incentive, and user engagement in planning. Adopted selectively and adapted to each country's institutional capacity, these components offer a route for the remuneration of Latin American distribution to evolve from cost containment toward the delivery of the outcomes the energy transition demands.

5.2. RECOGNIZING INVESTMENT, INNOVATION AND NON-CONVENTIONAL ASSETS

The challenge that distributors participating in the ADELAT benchmarking identified most clearly —that current frameworks struggle to recognize investments in digitalization, storage and distributed resources, and that they tend to favor physical-asset solutions over operational ones— has been the subject of a set of regulatory responses internationally. These responses share a single purpose: to neutralize the bias toward capital, to value non-conventional solutions appropriately and to create routes for financing innovation. Their examination yields four lines of good practice relevant to the region.

The first, and the most consolidated, is the adoption of the TOTEX approach, whose most developed expression is the RIIO framework of the British regulator (Ofgem). Instead of setting separate allowances for capital and operating expenditure —each with its own treatment and incentive— RIIO establishes a single total expenditure allowance on which the company earns a return, leaving it to the distributor itself to choose the most efficient combination of investing and operating. The effect on innovation is direct: once the accounting advantage of the physical asset disappears, previously displaced solutions come to compete on equal terms. The approach is completed by a sharing mechanism (the totex incentive mechanism) which distributes deviations from forecast expenditure between the company and users, preserving the efficiency incentive. Italy offers a recent variant of interest —the ROSS approach— which combines forward-looking total expenditure targets with fixed shares between operation and capital, seeking to capture the advantages of TOTEX without wholly abandoning the predictability of the allowances (Jenkins et al., 2024). What these designs have in common is that they replace control of the input —how much is invested and in what— with control of the output —what results are delivered— leaving the company the freedom and the responsibility to choose the means.

The second line consists in valuing non-network solutions (non-wire solutions) as alternatives to physical expansion. Demand flexibility and storage can shave the peak and defer or avoid costly network reinforcements, shifting investment to a future in which capital is cheaper and uncertainty lower. For this option to materialize, advanced frameworks have enabled the contracting of flexibility services by distributors and have begun to develop local flexibility markets, a practice European institutions recommend as a cost-saving solution and a natural complement to the total expenditure approach. The regulatory key is that the framework should treat contracted flexibility and storage not as expenditure to be minimized, but as alternatives to be assessed against traditional investment, so that the distributor does not lose revenue by choosing the more efficient option.

The third line is the explicit recognition of innovation through dedicated financing mechanisms, separate from the ordinary remuneration process. British experience is again illustrative: alongside the general framework, Ofgem has maintained specific instruments for financing innovation that allow networks to trial technologies and approaches whose return is uncertain, without thereby compromising their regular allowance. This recognition may be structured as a fund, as an additional allowance conditional on results, or as a reputational and financial incentive tied to the delivery of outputs (output delivery incentives). The underlying logic is that innovation has a risk profile different from that of conventional investment and that, if subjected to the same criteria of ex post prudence and efficiency, it simply does not happen; hence the desirability of giving it a regulatory space of its own.

The fourth line addresses directly the non-conventional assets —software, data management systems, distributed energy resource management platforms (DERMS), sensors and digital capabilities— whose nature does not fit the categories of physical infrastructure. International practice resolves this tension, once again, by shifting the axis of recognition from the category of the asset to the outcome it produces: if a digital investment makes it possible to deliver the required outputs better —quality, capacity to integrate distributed resources, resilience— it is remunerated for that contribution, irrespective of whether it is a tangible or intangible asset. Distribution model transformation programs such as New York's have advanced in this direction, conceiving the distributor as a platform integrating distributed resources and recognizing investments in network intelligence and flexibility management as a central part of its function, rather than a marginal addition.

For Latin America, where efficient reference utility schemes and the strict separation between capital and operation prevail, these practices point to an agenda of gradual evolution. It is not a matter of moving to a full TOTEX, but of neutralizing the bias toward capital —so that operational and flexibility solutions are not penalized relative to physical investment—, of creating explicit routes for recognizing digital assets, storage and investments related to distributed resources that today fall into a regulatory vacuum, of enabling the contracting of flexibility as an assessable alternative to network expansion, and of giving innovation a financing space of its own.

5.3. MODERN TARIFF DESIGN: DIFFERENTIATED TARIFFS AND CAPACITY CHARGES

International practice has moved toward tariffs that more faithfully reflect the cost each user imposes on the system and that send signals capable of guiding their behavior. Two families of instruments concentrate this evolution —time-differentiated tariffs and capacity charges— and their deployment offers the region a set of lessons that go well beyond the mere existence of the signal.

> “The preceding sections established the conceptual framework of remuneration and tariff design

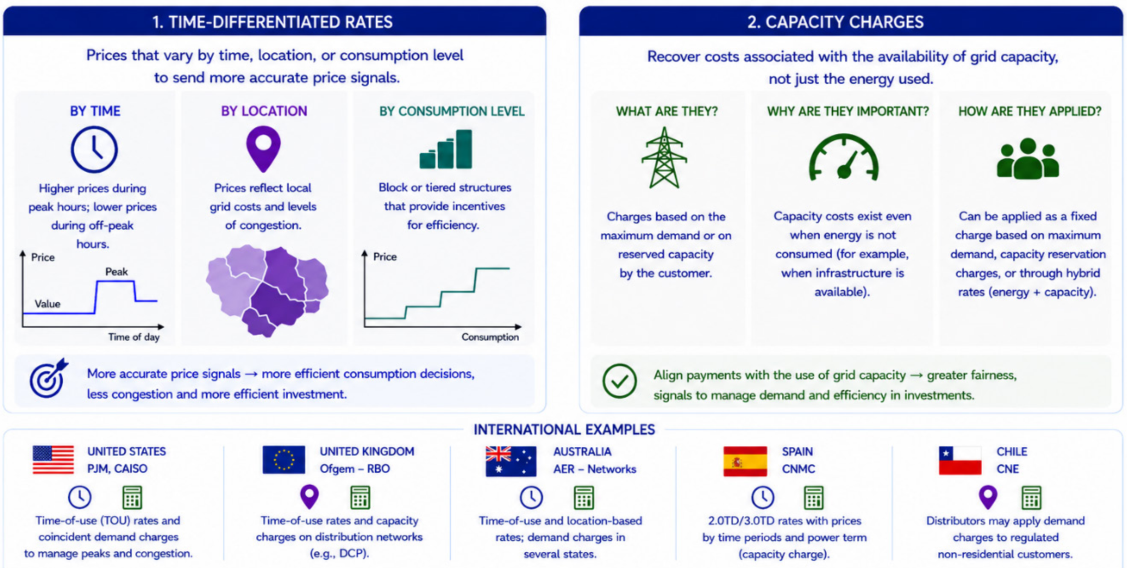

Fig. 7. Differentiated tariffs and capacity charges: international examples

The first family corresponds to a spectrum of increasing sophistication. In its simplest form, time-of-use tariffs set different prices for predefined time blocks —peak, off-peak and, sometimes, intermediate—; a step further, critical peak pricing sharply increases the price for a limited number of critical hours announced in advance; and in its most advanced form, dynamic or real-time pricing passes the actual variation in the wholesale price through to the user hour by hour. International evidence on their effectiveness is robust, with nuances. France’s Tempo tariff, a critical peak scheme in operation since the 1990s, has reduced the national peak by around 4%, with shifts of the order of 6 GW of daily load; and Hydro-Québec’s trials in Canada showed average reductions of close to 6% in critical peak events. At the same time, research warns that time-of-use and critical peak tariffs capture only a modest fraction —around 10%— of the efficiency gains that real-time pricing would achieve; but the evidence also stresses that most of the benefit is already obtained with a simple two-block scheme, which makes the time-of-use tariff the most reasonable option in terms of its balance of efficiency, simplicity and feasibility. The European Union has taken this orientation into the regulatory sphere: its Clean Energy Package enshrines the right of every final customer to contract a dynamic electricity price with their supplier.

A central lesson is that the mode of adoption conditions the outcome as much as the design of the price. Voluntary (opt-in) schemes tend to achieve low participation rates and to attract mainly users who already benefit from the change, whereas default (opt-out) schemes —in which the user is enrolled in the differentiated tariff unless they decide otherwise— achieve far greater coverage and, with it, significant systemic impact. Good practice therefore combines the default differentiated tariff with safeguards for users with less capacity to respond: transition periods, bill comparators, protection mechanisms for vulnerable households and an effective option to choose a flat tariff. The sophistication of the signal, in short, must be accompanied by careful design of the transition so as not to penalize those who cannot shift their consumption.

The second family of instruments addresses a structural limitation of purely volumetric tariffs: the cost of the network is determined largely by the capacity that must be available at times of maximum demand, not by the total energy consumed. Australia is the most developed reference point for the introduction of demand or capacity charges in the residential segment. There, the National Electricity Rules require distributors to move their tariffs gradually toward the actual cost of serving each customer, and the regulator (AER) has made network tariff reform a strategic initiative. Distributors in metropolitan Sydney —Ausgrid and Endeavour Energy— have advanced with demand charges that bill the user for their recorded maximum capacity, including ratchet-type designs that escalate the charge each time the household reaches a new maximum, with the aim of encouraging demand moderation and easing pressure on the network. The literature stresses that demand charges are the most cost-reflective way of recovering network costs, but also that their design must address considerations of equity and user understanding, and that their effectiveness depends on measuring demand coincident with the system peak rather than simply the household's individual peak.

The frontier of tariff design already points toward locational and forward-looking differentiation. Mechanisms such as distribution locational marginal pricing expose users to the real cost of delivering energy according to the state of the network at their location, anticipating a future in which congestion caused by distributed resources will require granular and even bidirectional signals charging users responsible for costs at each point. Locational differentiation of network charges is still uncommon —even in the European Union— but the European agency of regulators (ACER) has recommended assessing the incorporation of incremental or forward-looking cost models in the near term, and specialized organizations promote the concept of "smart network tariffs" combining temporal, capacity and locational signals. These developments mark the long-term direction, even though their large-scale implementation remains incipient (ACER, 2023).

Underlying this whole range is an inescapable enabling condition: none of these signals is viable without advanced metering. The slow deployment of smart meters has been one of the main brakes on the diffusion of dynamic tariffs, even in Europe. International experience therefore suggests for Latin America an ordered sequence rather than a leap: first consolidating metering infrastructure, then introducing time-of-use tariffs —preferably by default and with transition protections—, incorporating capacity charges where electrification and distributed resources make the capacity signal more valuable, and reserving dynamic and locational designs for a later phase, ideally trialled in controlled environments before being generalized. It is a roadmap that allows most of the benefits to be captured early without taking on at once the complexity and equity risks of the most advanced schemes.

5.4. TARGETING OF SUBSIDIES AND PROTECTION OF VULNERABLE USERS

International experience in targeting electricity subsidies converges on one idea: separating social protection from tariff design. In contrast to schemes that subsidise the price of the kilowatt-hour —distorting the consumption signal and shifting the burden onto non-subsidised users or onto the distributor— best practices move support outside the bill, toward targeted instruments that protect the household's ability to pay without altering the price it faces. Four concrete lessons follow from this general approach, offering a roadmap for the region.

The first is that targeting requires measurement. The most advanced jurisdictions first built a definition of energy vulnerability and the indicators to identify it. The United Kingdom evolved from a simple threshold —the household having to devote more than 10% of its income to energy— toward a combined indicator weighting simultaneously energy expenditure, the distance of income from the poverty line and the energy efficiency of the dwelling, so that only those who genuinely are vulnerable are classified as such (Office for National Statistics, 2023). The European Union developed common observatories and indicators to identify vulnerable consumers across Member States. The lesson is that targeting by the household's real condition is viable only if it rests on an objective metric of vulnerability and on the information to apply it; without this, any scheme ends up resorting to crude approximations such as stratum or consumption.

The second lesson, and the most cross-cutting, is to decouple the subsidy from the tariff through cash transfers or vouchers directed to the household. The World Bank's Energy Subsidy Reform Assessment Framework (ESRAF) summarizes the international consensus: targeted measures to protect the poor must recognize the trade-offs between coverage, generosity and fiscal savings, and should preferably build on pre-existing social programs and beneficiary registries. The virtue of this approach is twofold: it leaves the price signal intact —the household continues to face the real cost of energy and retains the incentive to consume efficiently— and it shifts financing to the targeted public budget, freeing the tariff from a redistributive function for which it is an imperfect instrument. Reform experiences accompanied by targeted cash transfers also show positive side effects on collection rates and the efficiency of spending (World Bank, 2017).

The third lesson comes from the concrete instruments already operating in Europe, which illustrate different degrees of decoupling. Spain's social bonus (Royal Decree 897/2017) defines graduated categories of vulnerability —vulnerable, severely vulnerable and at risk of social exclusion— with precise legal criteria, and applies a discount capped at a consumption limit on the energy and capacity components; it continues to operate within the bill, but with targeting verified by the household's condition. France's chèque énergie represents full decoupling: in 2017 France replaced social gas and electricity tariffs with a voucher allocated on the basis of tax and income information, independent of the energy source used, which reaches the household directly without contaminating the price signal or discriminating between fuels. The United Kingdom's Warm Home Discount targets a discount on the electricity bill through receipt of means-tested benefits, drawing on the infrastructure of the social protection system to identify beneficiaries (House of Commons Library, 2025). These three designs share a common guiding principle: eligibility is determined by the household's real condition, verified against social or tax registries.

The fourth lesson is that protection of the vulnerable user goes beyond price and extends to continuity of supply. European legislation requires Member States to protect vulnerable consumers against disconnection, and the recent Citizens' Energy Package reinforces these objectives alongside bill reduction and the fight against energy poverty. Safeguards against disconnection, enhanced protection in critical periods and priority attention configure an architecture of protection combining the economic dimension with the guarantee of service for those who depend critically upon it, and which connects with the treatment of medically dependent customers.

Taken together, these practices chart for Latin America a transition articulated in three steps: drawing on social registries to identify vulnerable households by their real condition; decoupling the subsidy from the tariff, replacing cross-subsidies and price reductions with targeted transfers or vouchers; and guaranteeing timely and predictable financing and reimbursement mechanisms that do not transfer collection risk to the distributor. This is, in essence, the direction the region's own distributors anticipated when proposing the migration toward a subsidy based on the household's real socio-economic condition.

5.5. REGULATORY EXPERIMENTATION MECHANISMS (SANDBOXES)

Amending regulation to accommodate each innovation is a slow, costly and risky process: the regulator must legislate on technologies and business models whose actual behavior it does not yet know, which creates a dilemma between holding back innovation while awaiting certainty and enabling it generally before understanding its effects. The regulatory sandbox —or controlled testing environment— has emerged as a response to this dilemma, and is today one of the most relevant international practices for experimenting with new tariff designs without compromising the stability of the general framework.

International experience offers several reference points. The United Kingdom was a pioneer in launching, through its energy regulator (Ofgem), the Innovation Link and the Energy Regulation Sandbox from 2016, a scheme allowing trials in a live energy environment —involving consumers or interacting with market rules and the physical system— through bespoke guidance and time-limited derogations from specific rules. The Netherlands advanced in a direction pertinent to tariff design: its decree on "Experiments in Decentralised, Sustainable Electricity Production", in force since 2015, enabled residents' associations and energy cooperatives to develop projects prohibited by current regulation, allowing them to organize peer-to-peer supply and to set their own tariffs within the controlled environment (Florence School of Regulation, 2020). To these cases are added the sandboxes of Singapore's Energy Market Authority, conceived to incorporate new technologies and business models with regulatory flexibility, and the schemes of Austria, France, Italy, Australia and the United States, which already form an international body of documented experience, including applications linked to dynamic distribution tariffs combined with local energy trading.

From this experience the literature has distilled a set of principles that distinguish effective sandboxes. The first is clear delimitation of scope: the trial must be bounded in time, scale and number of participants, with defined entry and exit criteria and with safeguards protecting the consumers involved, so that the experiment is reversible and its risks contained. The second is the capacity for regulatory learning: the value of the sandbox lies not in the trial itself but in the information it generates, so its design must provide for monitoring, evaluation and feedback mechanisms into the rule-making process. The third is its cross-sectoral character: many relevant energy innovations —linked to data, telecommunications or financial services— cross the boundaries of the electricity sector, and the most useful sandboxes allow for that breadth. The fourth, particularly emphasized for developing economies, is adaptation to context: the design must address the specific risks and priorities of each jurisdiction —electrification, attraction of private investment, the regulator's institutional capacity— rather than mechanically transplanting models from mature markets. Organizations such as the World Bank and ECLAC have produced practical guides on how to build regulatory sandboxes, reflecting growing interest in this tool as a route to incorporating distributed energy resources, mobilising investment and promoting innovation without destabilising the regulatory framework (World Bank, 2020) (ECLAC, 2024).

For Latin America, the sandbox represents one of the clearest gaps highlighted by the Benchmarking carried out by ADELAT. This situation is paradoxical, because it is precisely the region that faces the fullest agenda of innovations to be enabled —hourly tariffs, capacity signals, integration of distributed generation and storage, prepayment schemes— and that would benefit most from a mechanism allowing them to be tested in a bounded way before committing to large-scale reforms. The lesson from international experience is that the sandbox offers Latin American regulators a pragmatic route to reducing the risk of tariff reform: instead of choosing between paralysis and a leap in the dark, it allows learning by doing, generating local evidence on how new designs behave under the particular conditions of each system before elevating them to general rules.

5.6. STABILITY AND INSTITUTIONAL INDEPENDENCE OF THE TARIFF FRAMEWORK

The technical dimensions of remuneration design —the remuneration model, asset valuation, price signals or incentives— produce the expected results only if they rest on a credible and stable institutional framework. Tariff regulation ultimately operates as an implicit long-term contract among the State, the distributor and users: the company commits investments whose recovery extends over decades, trusting that the rules by which that capital will be remunerated will hold over time. When that trust is eroded —because tariffs are used as an instrument of short-term policy, because technical decisions become subordinate to the political cycle or because methodologies change unpredictably— the effect is not neutral: regulatory and political risk is incorporated directly as a premium in the cost of capital, raising the cost of financing the network and, in extreme cases, holding back the investment the energy transition requires. Institutional stability and independence are therefore not an incidental complement to tariff design, but one of its fundamental enabling conditions, and one the region itself has identified as a priority.

International practice has consolidated a body of principles on the governance of regulators that offers a clear reference. The OECD has systematized these principles around the independence of regulatory agencies, identifying five dimensions that determine a regulator's effective independence: clarity of role, transparency and accountability, financial independence, independence of leadership, and a culture of independence among its staff. Associated with these are seven best-practice principles covering the prevention of undue influence, the structure of the decision-making body, accountability, engagement with stakeholders, stable funding and performance evaluation. The underlying purpose of this framework is that regulatory decisions be perceived as objective and impartial, that politically motivated decision-making be prevented, and that a commitment be signalled to long-term objectives transcending electoral cycles. It is no coincidence that, in OECD countries, 87% of energy regulators have independent status, nor that the energy and telecommunications sectors display the most robust governance arrangements: the capital-intensive, long-horizon nature of these industries makes regulatory credibility especially valuable (OECD, 2014, 2016).

The European model offers the most demanding normative expression of these principles. Directive (EU) 2019/944 requires Member States to guarantee the independence of national regulatory authorities, which must constitute a distinct legal entity, have budgetary autonomy and adequate resources, and take no direct instructions from government or from any market interest in the exercise of their regulatory functions. This protection of methodological competence is significant, because it moves the tariff decision from the political arena to a technical body whose legitimacy rests on its competence and the transparency of its procedures, rather than on its alignment with the political moment.

Alongside independence, international experience shows that the stability of the framework depends on concrete mechanisms that lend credibility to the regulatory commitment while offering orderly routes for correcting errors. The underlying problem is time inconsistency: once investment in the network has been made, the regulator or the political authority faces the temptation to reduce tariffs below the level that induced that investment, capturing a short-term benefit at the expense of future investment. The way to neutralize that temptation is to build credible commitments. The existence of a protected regulatory asset base, with predictable remuneration methodologies and explicit indexation rules, functions as a long-term contract that reduces perceived risk and, with it, the cost of capital. In the most mature frameworks, independent appeal bodies are added to this. The British case is illustrative: the regulator's (Ofgem's) price control decisions under the RIIO framework may be appealed by companies to the competition authority (the Competition and Markets Authority). This mechanism reinforces the stability of the system: it subjects decisions to technical scrutiny, limits discretion and gives investors the assurance that an orderly and predictable remedy exists should errors occur, instead of the uncertainty of litigation or political pressure.

For Latin America, these principles hold particularly pertinent lessons, because it is precisely in the institutional dimension that the region displays its greatest gaps. International assessments of regulatory governance in the electricity sector of developing countries —such as the World Bank's Global Electricity Regulatory Index (GERI)— have documented that the lack of regulatory independence is a deficiency common to almost all countries assessed, with particularly low scores on independence from sector stakeholders and on financial independence, and with an absence of frameworks guaranteeing staggered renewal of governing bodies —a mechanism for insulating the regulator from the political cycle (World Bank, 2022). This gap translates into greater regulatory risk, a higher cost of capital and, ultimately, higher tariffs or insufficient investment. The benchmarking carried out by ADELAT captured this concern among the reform priorities expressed by the region's distributors, which pointed to the need to shield the tariff scheme from political use and even to create independent technical bodies to settle disputes between distributors and the regulator. International best practice suggests that advancing in that direction requires acting simultaneously on the five dimensions of effective independence: giving the regulator financial and managerial autonomy, establishing fixed and staggered terms that insulate it from the electoral calendar, reserving methodological competence to its technical remit, guaranteeing transparency and accountability as a counterweight to that autonomy, and providing appeal or technical arbitration bodies that offer predictability without sacrificing the possibility of correcting errors. These conditions, more than any specific refinement of tariff design, are what determine whether the remuneration framework will be able to sustain over time the investments the energy transition demands of electricity distribution.

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CONCLUSIONS AND RECOMMENDATIONS

Throughout this document it has been argued that the remuneration model and the tariff scheme constitute the economic core of electricity distribution, and that on their design depends whether the sector can invest, modernize and sustain an adequate and equitable service in the midst of the energy transition. The following conclusions identify shared patterns and the points at which the energy transition recurrently strains the frameworks in force in Latin America.

The first conclusion is that, beneath the diversity of labels, the region shares one underlying question: who bears the risk that actual costs diverge from those recognized. The price cap built around the Distribution Value Added, calculated on an efficient reference utility and with assets valued at replacement cost, is clearly the predominant paradigm, with Colombia shifted toward the revenue cap and public-company systems (Costa Rica, Ecuador, Paraguay) toward cost-of-service regulation. This convergence means that the challenges also tend to be common, and that solutions trialled in one country are, with due adaptation, relevant to the others.

The second conclusion, and the most consequential for the transition, is that current frameworks recognize investments late, partially and with bias. The strict separation between CAPEX and OPEX tilts the balance toward the physical asset and penalizes operational and flexibility solutions, precisely those the transition makes most efficient. A further problem is that, in the most rigid reference utility schemes, investment not anticipated by the model is not remunerated until the following review, with the consequent loss of the time value of money that distributors themselves emphasize; and that non-conventional assets —digitalization, automation, storage, distributed resources— find only narrow, case-by-case accommodation, because most frameworks value an asset by its category and not by the function it performs. Colombia's annual updating of the base shows that the problem of deferred recognition has a solution within the region's own paradigm.

The third conclusion is that, predominantly, regulation punishes but does not incentivise. Quality and loss schemes are largely asymmetric: they penalize non-compliance through sanctions or compensation to users, but do not reward superior performance. Only Colombia and Brazil apply symmetric schemes —the adjustment of revenue by SAIDI/SAIFI in Colombia, the quality component of Brazil's X Factor, which moves revenues between −2% and +2%— and resilience and digitalization, urgent objectives of the new paradigm, almost entirely lack an economic signal. The efficiency the model does reward is the static efficiency it already embeds, not the dynamic efficiency the transition demands.

The fourth conclusion concerns tariff design: price signals are weak and poorly differentiated. Almost the whole region uses a structure of fixed charge plus variable charge, but with a strong volumetric predominance; the capacity charge for residential users is practically non-existent —Chile applies it indirectly, through load factors; the rest reserve it for medium and large demands— and residential time differentiation is marginal, with Brazil (Tarifa Branca) and Peru as exceptions, while Colombia maintains a flat tariff for the regulated user. The transparency of the distribution charge on the bill is equally uneven: explicit in Brazil, Colombia and El Salvador, integrated and invisible in Chile, Guatemala and Argentina for the small user. The result is that the tariff rarely communicates to the user the real cost their consumption imposes on the network.

The fifth conclusion is that subsidies are poorly targeted and are channeled through the tariff. Four financing archetypes coexist —cross-subsidy, mixed, sectoral fund and state budget— but all share a common weakness: allocation is based on the property's stratum (Colombia) or the level of consumption (Peru, Bolivia, Guatemala, Brazil), rather than on the household's real socio-economic condition, generating inclusion and exclusion errors. In addition, several schemes transfer collection risk to the distributor when state reimbursements are delayed. The weight of the problem is considerable: in Brazil subsidies represent on average close to 20% of the residential tariff, a magnitude that prompted the cap on the CDE introduced in 2025.

The sixth conclusion concerns the existence of protection and innovation gaps. Protection for medically dependent customers is robust only in Chile and Argentina —which combine economic benefit, non-disconnection and technical back-up— while elsewhere it is limited to non-suspension of service or no specific regulation exists. Prepayment has a regulatory basis in most countries, but its adoption is marginal, held back by the cost of meters and low economic viability. And regulatory experimentation is almost non-existent: Brazil and Salta (Argentina) are the only places with formal, operating tariff sandboxes, Colombia is advancing with its regulation, and the rest lack a formal mechanism for testing new designs.

The seventh conclusion is cross-cutting: the adequacy of remuneration depends less on the rate of return than on the stability and predictability of the rules. The Benchmarking shows rates which, read on a common basis, are heterogeneous, and which respond to a rate-risk consistency principle that some frameworks actively apply. But a well-set rate is diluted if investments are recognized late, if tariffs are frozen for political reasons or if methodologies change unexpectedly. Institutional stability is therefore the enabling condition for everything else.

A final, propositional conclusion: Brazil emerges consistently as the regional benchmark for tariff innovation —the only country combining residential hourly tariffs, operating sandboxes, symmetric quality incentives and explicit regulatory unbundling of components— which suggests that several of the practices the region is debating already have a testing ground within Latin America, and not only in distant markets.

> “The remuneration model and the tariff regime constitute the economic core of electricity distribution

6.1. REGULATORY RECOMMENDATIONS

The recommendations that follow are organized into six lines and distinguish the structural —the remuneration model— from the tariff-related —the design of the price signal— without losing sight of the fact that both form part of a single system. They do not constitute a single model to be transplanted, but guidance that each jurisdiction may calibrate according to its legal framework, its institutional capacity and its starting point.

> Regulation punishes but does not incentivize

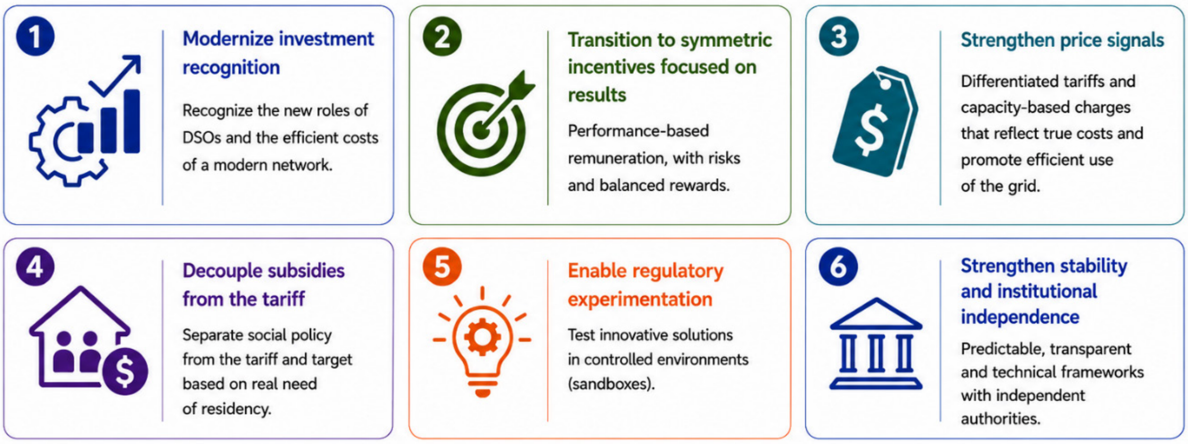

Fig. 8. Recommendations for regulators and policymakers.

- Modernize the recognition of investments and neutralize the bias toward capital. The most urgent structural priority is to ensure that the framework recognizes promptly and fully the investment the transition requires. This entails removing the penalization of operational and flexibility solutions relative to physical investment; accelerating recognition through more frequent updates of the asset base and mixed ex ante/ex post schemes such as Colombia's, which incorporate executed investment without waiting for the next cycle; and creating explicit routes for non-conventional and digital assets, recognizing them by the function they perform —quality, integration of distributed resources, resilience— and not by their accounting category. It is also advisable to give innovation a financing space of its own, with a risk profile distinct from that of ordinary investment.

- Move from asymmetric to symmetric, results-oriented incentives. The region should advance from the logic of "punishment without reward" toward schemes in which performance moves revenues in both directions, taking as a reference the models of Colombia and Brazil in quality (SAIDI/SAIFI, X Factor) and in loss management. More broadly, performance-based regulation (PBR) offers a set of building blocks —measurable outputs, sharing factors, user engagement— that may be incorporated selectively and adapted to each regulator's capacity, including economic signals for resilience and digitalization.

- Strengthen the price signals of tariff design. Move toward more cost-reflective tariffs through an ordered sequence: first consolidating advanced metering as a prerequisite; then introducing hourly tariffs —preferably by default and with transition protections for users with less capacity to respond—; incorporating capacity charges where electrification and distributed resources make the capacity signal more valuable; and reserving dynamic and locational designs for a later phase. In parallel, it is advisable to improve the transparency of the distribution charge on the bill, a condition for any price signal to be effectively perceived by the user.

- Decouple subsidies from the tariff and target them by the household's real condition. Social protection should be separated from tariff design, replacing cross-subsidies and price reductions with transfers or vouchers that preserve the price signal; targeting should be by the household's real socio-economic condition, drawing on social registries rather than on stratum or consumption; and timely financing and reimbursement mechanisms should be secured so as not to transfer collection risk to the distributor. To this agenda is added the closing of protection gaps: establishing a framework for medically dependent customers in countries that lack one, and reviewing the economic viability of prepayment as an option rather than an imposition.

- Enable regulatory experimentation through sandboxes. Given the incipient nature of many of the redesigns proposed, it is recommended that formal experimentation mechanisms be adopted allowing new tariff structures to be trialled in a bounded environment, with temporary derogations and systematic evaluation, before generalizing them. The tariff sandboxes of Brazil and Salta (Argentina) offer a direct regional reference, and the regulation under way in Colombia shows that the path is already open. This mechanism makes it possible to reduce the risk of reform: learning by doing, with local evidence, instead of choosing between paralysis and a leap in the dark.

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- Reinforce the stability and institutional independence of the regulatory framework. As a cross-cutting condition, none of the preceding recommendations will bear fruit without a credible and stable institutional framework. This implies strengthening the regulator's financial and managerial autonomy, establishing fixed and staggered terms that insulate it from the political cycle, reserving methodological competence to its technical remit, guaranteeing transparency as a counterweight to that autonomy, providing appeal or technical arbitration bodies that offer predictability, and ensuring consistency between the recognized rate of return and effective regulatory risk. The stability of the rules is, ultimately, what determines the cost of capital and the willingness to invest.

These recommendations form an articulated agenda, not a list of independent measures. The remuneration model, the determination of costs, the treatment of capital and operation, incentives, tariff design, subsidies and the institutional framework are parts of a single system, and their reform must be approached with that overall perspective: there is little point in refining the price signal if the subsidy continues to distort it, or in recognizing investments better if the rate does not reflect risk or the rules are not stable. The energy transition has made remuneration and tariff design a first-order determinant of the future of electricity distribution in Latin America. The good news is that the region does not start from scratch: it has its own reference points —Brazil and Colombia leading in several dimensions—, a shared diagnosis and a convergent reform agenda expressed by the distributors themselves. The challenge is to translate that consensus into concrete frameworks, adapted to each national reality, that support the transformation of the system.

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Current models recognize investments in a delayed, partial, and biased manner

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