adelat www.adelat.com

DSO BRIEF

Distributed Generation: Towards a Sustainable Regulatory Model for Electricity Distribution

EDITORS

Alessandra Amaral, Roberto Cajamarca Gómez, Joaquín Lazo Sánchez.

CONTRIBUTORS

Daitshon Emerson Alata Ramos, Óscar Aldana, Dimitri Barros Pereira de Oliveira, Claudio Bulacio, Roman Buñay, Benjamín Dahrouge, Alfredo Gallegos, Jose Saul Guirola Argueta, Amanda Lacerda Prado, Jorge Mario Mijangos Rivas, Ednelson de Moraes, Mariano Nasarov, Edgar Armando Pérez Santos, Maria José Pérez Vanmorlegan, Aldo de Jesus Pessanha, Rodolfo Rennins, Hans Rother Salazar, Ernesto San Miguel, Donald Villegas Barrantes.

adelat

www.adelat.com

1. INTRODUCTION 5

2. NEW PARADIGM AND IMPACTS ON DISTRIBUTION SYSTEMS 7

3. REGULATORY APPROACHES TO INTEGRATING DG 9

3.1. Categorization and power thresholds for DG 10
3.2. Remuneration and market participation schemes 10
3.3. Technical connection conditions 12
3.4. Role and responsibilities of DSOs 12
3.5. Connection restrictions 13
3.6. Grid Investment Recovery Mechanisms 14

4. REGIONAL OVERVIEW OF DG 15

4.1. Penetration level 15
4.2. Regulatory Frameworks for DG integration 17
4.3. Comparative regulatory frameworks 19

5. INTERNATIONAL REGULATORY APPROACHES TO DG 32

5.1. Active role of the DSO 32
5.2. New DSO Responsibilities 33
5.3. Mechanisms for economic 35
5.4. Incentives and mandates for digitalization 37

6. CONCLUSIONS AND RECOMMENDATIONS 38

7. REFERENCES 40

01

INTRODUCTION

Distributed generation (DG), especially solar photovoltaic (PV), has become one of the most transformative phenomena in the modern electricity system. In Latin America and the Caribbean, its expansion is accelerating at the pace of falling technological costs, growing environmental awareness and the willingness of users to take an active role in the management of their energy. In countries such as Brazil, Chile and Mexico, the cost of distributed solar electricity has fallen by 40% to 70% since 2010 (IEA, 2022) , making generating power at home or in small businesses as cheap as buying from the grid. In addition, its modularity – the ability to grow through small and replicable units, adapting to different user sizes and levels of demand – has made it an accessible, flexible and expansive technology, capable of integration into residential, industrial, or community settings.

This accessibility has democratized energy production, but it has also introduced profound disruption to networks designed to operate with one-way flows. DG is transforming passive grids into active systems, where thousands of small generators, batteries, and inverters interact simultaneously, creating new planning, control, and stability challenges. Distribution companies are no longer just electricity carriers: they are becoming managers of the energy ecosystem, responsible for balancing variability, maintaining supply quality and coordinating distributed resources efficiently and safely.

Properly integrating this new reality is not automatic. It requires technological innova-

tion in areas such as smart inverters, distributed storage and digital networks, in addition to a profound regulatory transformation. Traditional frameworks, focused on energy delivered, must evolve towards schemes that value the flexibility, resilience and grid services that distributed resources provide. Markets and regulation need to learn how to manage variability, incentivize investment in flexible solutions, and allow new players to actively participate and be remunerated for their contributions to the system.

Electricity distribution in Latin America is at a challenging time. DG can become an engine of modernization and local development, strengthening energy security and reducing emissions. However, if its expansion exceeds the capacity for technical and regulatory adaptation, it can generate economic and operational imbalances in electricity distribution. The challenge is to accompany technological innovation with regulatory frameworks capable of sustaining system operation and ensuring the sustainability of the distribution service.

This paper aims to analyze the expansion of DG in Latin America and the Caribbean, and its implications for the electricity distribution model. The main technical, economic and regulatory challenges associated with its integration are addressed, considering the effects on grids operation, service sustainability and infrastructure planning. It also highlights the opportunities that DG offers to modernize the grid, improve the flexibility of the system and strengthen the relationship with users, in a context where distribution companies are taking an increasingly active role in the management of the new energy ecosystem.

02

NEW PARADIGM AND IMPACTS ON DISTRIBUTION SYSTEMS

DG emerged as an environmental response aimed at reducing emissions and accelerating the transition to cleaner and more sustainable electricity systems. Its deployment was boosted by falling technology costs and rising energy prices, also becoming an economically attractive alternative for households and small businesses. With this, DG went from being an environmental tool to a vector for the structural transformation of the electricity system, capable of providing flexibility, resilience and equity.

As a source of flexibility, DG makes it possible to manage the variability of renewable generation and electricity demand, smoothing load peaks and alleviating grid congestion thanks to its proximity to consumption. Its localized operation and its integration with technologies such as storage, digitalization and demand management make it a key resource for balancing supply and demand in real time. In terms of resilience, DG reinforces the system's response capacity in the face of failures or contingencies. By providing voltage and frequency support and even operating in island mode together with advanced storage and control systems, it allows the supply to be maintained in critical sectors and accelerates the recovery of the system during emergencies, improving service continuity in rural or isolated areas. Finally, DG can contribute to energy equity, by facilitating access to clean and affordable energy for vulnerable sectors and rural communities. Prepaid models, community ownership, and third-party schemes lower barriers to entry and encourage citizen participation in the transition, more fairly distributing economic, social, and environmental benefits.

Despite its benefits, the expansion of DG poses a series of technical, operational and regulatory challenges that redefine the role of distribution companies. The intermittency inherent in renewable sources and the increasing bidirectionality of electrical flows complicate the planning and control of low-voltage networks, where most connections are concentrated. Managing voltage, congestion, and coordination between transmission and distribution operators requires new practices and real-time monitoring capabilities. Added to this is the limited visibility of the resources behind the meter and the need to integrate thousands of small units that operate in a decentralized manner. From an economic point of view, questions arise about the use of the network, the allocation of costs and the appropriate compensation mechanisms to reflect the value that DG brings to the system.

The sum of these factors shows that the transition to more active and decentralized networks cannot be sustained with traditional methods of operation and planning. Its viability will increasingly depend on digitalization, which acts as the central enabler to manage complexity, ensure stability, and fully realize the potential of DG. In this scenario, distribution companies are consolidating themselves as the articulating axis of the energy transition, responsible for integrating these resources in a safe, efficient and economically sustainable way. Its performance will depend both on technological progress and on the existence of regulatory and investment frameworks that accompany innovation. Latin America and the Caribbean are moving in this direction with different rhythms and approaches, reflecting their technical, regulatory and socio-economic particularities. The available evidence confirms that this process is already underway: in different countries of the region, the expansion of DG is beginning to generate tangible impacts on the networks and on the distribution model. The following section discusses these effects and the implications for the technical and economic sustainability of the sector.

The available evidence confirms that this process is already underway: in different countries, the experience of distribution companies shows that the expansion of DG is not a neutral phenomenon for the grid. Its incorporation modifies electricity flows, introduces new operational requirements and stresses the traditional economic models on which the distribution service is organized. Although its penetration is still moderate, reports confirm the emergence of concrete technical and financial effects, which anticipate the challenges that will accompany its massive deployment.

On the technical level, DSOs are already observing significant alterations in voltage profiles, asset congestion and failures in protection systems. DG causes reverse power flows in transformers and feeders, local overvoltages during peak injection hours, and rapid voltage fluctuations associated with solar intermittency, requiring more sophisticated regulators and real-time voltage management. Added to this are overloads in low-voltage conductors and transformers, harmonic increases due to low-quality inverters and growing difficulties in protections coordination and safe maintenance operations. These conditions, previously marginal, are becoming recurrent and confirm that DG is not harmless for the grid: its integration implies reinforcement, monitoring and digitalization costs that must be recognized if the security and stability of the electricity system is to be maintained. Added to this is the appearance of undeclared or non-standard installations, which operate without registration or certification and aggravate technical and safety risks, by introducing unsupervised injections and making network planning difficult.

On the economic front, DSOs report three main impacts derived from the expansion of DG. The first is the reduction of billed energy, as a result of self-consumption and energy compensation schemes, which directly decreases the income available to cover the fixed costs of the network, which remain unchanged. This effect is especially visible in the migration of large customers towards self-generation, which reduces the user base on which infrastructure investments are amortized. The second impact is the increase in unrecognized operating and capital costs, associated with the need to strengthen networks, modernize metering and control, and implement bidirectional management technologies, investments that are not always reflected in the current tariff structures. Finally, the combination of lower revenues and higher costs generates a financial imbalance that puts the sustainability of the distribution business at risk, particularly in those regulatory frameworks that do not yet recognize these new roles and responsibilities. Without an adapted tariff design that clearly differentiates remuneration for the use of the grid from the sale of energy, the expansion of DG may compromise the ability of distribution companies to sustain the quality, security and modernization of the electricity system.

03

ABORDAGENS REGULATÓRIAS PARA INTEGRAÇÃO DA GERAÇÃO DISTRIBUÍDA

The expansion of DG introduces substantive changes in grids operation and planning, which makes it necessary to have a regulatory framework that organizes their integration, minimizes their adverse effects and allows their benefits to be captured without deteriorating the stability or economic sustainability of the service. The regulation thus fulfills an enabling and protective function, by establishing clear conditions for the connection, operation and valuation of these resources, and by ensuring that the modernization of the network advances safely and coherently with real distribution capacities.

The comparative analysis of the regulatory frameworks of the region shows that, despite the differences between countries, the regulation of DG is conceptually structured around six pillars that define its scope and operation. These pillars include the categorization by power, the remuneration mechanisms, the technical and administrative requirements of connection, the responsibilities of the distribution companies, the restrictions applicable when there are risks to the network and the mechanisms for recognizing investments associated with the authorization of these projects. The following subsections develop each of these pillars and describe their role within a comprehensive regulatory framework for the integration of DG. Table 1 summarizes these six regulatory pillars, highlighting their purpose, the scope of the aspects they regulate, the mechanisms that make them up, and their main implications for the network and for DSOs.

Table 1. Regulatory pillars for the integration of DG.

Pillar	Regulatory Objective	Regulated content	Tools or mechanisms	Consequences for the grid and DSO
1. Categorization and power thresholds	Adjust requirements according to scale and impact.	Classification of the DG according to installed capacity and operational scope.	Power segmentation; thresholds.	It facilitates small-scale massification and protects stability in the face of projects with greater impact.
2. Remuneration and market participation schemes	To regulate the valuation of injections and to define the modes of economic participation.	Limits on self-consumption, sale of surpluses and access to markets.	Pure self-consumption; net metering; net billing; wholesale participation.	It avoids cross-subsidies and orders the economic interaction of the DG.
3. Technical connection conditions	Ensure that each connection is compatible with safe system operation.	Technical, administrative and contractual requirements prior to connection.	Connection procedures; electrical studies; contracts; protections and measurement.	It allows the incorporation of DG without compromising quality, safety or supply continuity.
4. Role and responsibilities of DSO	Define official and enforceable functions in relation to the DG.	Administrative, technical, operational and supervisory responsibilities.	Application management; Inspections; commissioning; measurement; Control.	It increases tasks and costs; it requires attributions, resources and tools to fulfill the role.
5. Connection restrictions	Determine if the network can support new DG under safe conditions.	Technical, safety and available capacity limits.	Evaluations of voltage, short circuit, unintentional islands, available capacity.	It avoids saturation, operational risks and instabilities; allows DSOs to condition or defer connections.
6. Cost allocation and recovery mechanisms	Regulate the allocation and financing of DG integration costs	Project-specific costs and systemic costs associated with DG.	Direct allocation; tariff recognition; Allocation according to real impact.	It prevents cross-subsidies, promotes efficient decisions and sustains the financial viability of the system.

CATEGORIZATION AND POWER THRESHOLDS FOR DG

A first regulatory component is the segmentation of DG according to its installed capacity. This principle allows installations to be divided into categories and to assign each one technical and administrative requirements according to its magnitude and potential impact. Although the specific way of applying this segmentation varies between countries, there is a basic consensus on establishing a threshold that distinguishes DG from the conventional generation regime. The subsequent differences respond to the level of detail with which each jurisdiction decides to structure its regulatory framework.

This approach reduces barriers to entry for smaller installations, which represent a limited risk to the grid and can benefit from simplified processes, and, at the same time, enables more rigorous evaluations in projects with higher capacity, where it is necessary to analyze protections, voltage profiles and possible infrastructure reinforcements before authorizing the connection. At the heart of this design is the principle of proportionality: requiring each project to have a level of analysis consistent with its potential impact on the grid. In this way, the power categorization facilitates the orderly massification of small-scale DG and protects the stability of the system against installations that can significantly influence the electricity system operation.

REMUNERATION AND MARKET PARTICIPATION SCHEMES

A second regulatory axis refers to the design of the mechanisms for economic participation of DG and, in particular, to the way in which the surpluses that these systems can inject into the grid are remunerated. In international practice, regulation tends to organize these mechanisms into three broad categories, reflecting different levels of interaction with the grid and the electricity market.

The first category corresponds to self-consumption-only projects, in which the injection of energy into the grid is prohibited. In this scheme, the facility operates in isolation from a commercial point of view, without energy exchanges with the distribution company. This approach favours administrative and technical simplicity, so that users have access to more expeditious connection procedures and with proportionally lower requirements. The regulatory logic is clear: the absence of exports eliminates operational and economic risks for the network, which makes it possible to significantly reduce barriers to entry.

> The expansion of distributed generation introduces substantial changes in the operation and planning of networks.

The second category corresponds to self-consumption projects with sale of surpluses, where the regulation authorizes the partial injection of energy into the grid under regulated compensation schemes. In this model, the sale of surpluses is carried out in a controlled manner, subject to predefined rules and prices established by the authority or by the DSO according to the applicable regulatory framework. Within this scheme, two main modalities for remunerating surpluses predominate:

- Net metering: In this scheme, the energy consumed and the energy injected are valued in the same way and the netting is carried out in units of energy. The surplus is credited to the user in kWh to be deducted from future consumption, so that each kWh produced has the same value as one kWh saved from the retail tariff. Although this model has been highly effective in accelerating the initial adoption of residential and commercial DG, it has limitations from the perspective of the economic sustainability of the system. By equating the value of the energy injected to the energy consumed, traditional net metering does not reflect the costs associated with using the grid as a backup, leading to an undervaluation of the distribution infrastructure and ancillary services needed to maintain supply. Various analyses show that, without adjustments, this scheme can generate cross-subsidies from users who do not generate to those who do, since the former end up assuming a greater proportion of the system's fixed costs (NREL, 2025).

- Net billing: In this scheme, the energy consumed and the energy injected are valued differently and the netting is done in monetary units. The user pays for their gross consumption by applying the corresponding regulated tariff and, for the energy they export, they receive a payment or credit calculated at a specific price defined by the regulation. Both values are compensated in money and not in energy: the monetary amounts derived from separately valuing consumption and injection are netted in the bill. Usually, the sale price of surpluses is determined from the avoided costs for the distribution company or the wholesale price of energy, excluding grid charges and other regulated components. In this way, an injected kWh does not have the same value as a kWh consumed, which allows the transport, backup and management costs associated with the supply to be reflected more accurately. This approach contributes to reducing cross-subsidies and safeguarding the economic sustainability of the system, even though it tends to offer somewhat lower economic incentives for the prosumer compared to net metering (NREL, 2025).

The third category corresponds to projects that participate directly in the electricity market, maintaining their DG status, but operating under an economic scheme similar to that of conventional plants. In this modality, the injected energy is valued at market prices, either on the spot market or through bilateral contracts, which requires the installation to comply with a greater set of technical and commercial obligations, such as registration as a system agent, compliance with network codes and the ability to be remotely managed or disconnected when necessary to safeguard the security of the system. Although these requirements are higher than those applied to self-consumption projects with the sale of surpluses, they are still consistent with the DG category and do not reach the complexity of a conventional generation plant.

TECHNICAL CONNECTION CONDITIONS

A third regulatory axis refers to the technical connection conditions, which define the rules under which the DG can be physically integrated into the network. Its purpose is to ensure that each project meets the necessary requirements to guarantee the safety, quality and reliability of the electrical system. In line with the principle of proportionality, these requirements are adjusted to the scale and potential impact of each installation:

- Simplified procedures for micro or small generation, based on notification, documentary review and verification of minimum equipment standards, without the need for electrical studies on a case-by-case basis.
- Standard process for medium-scale generation, which requires a formal application and, in some cases, a simplified connection study to evaluate the available capacity of the grid and eventual reinforcements.
- Comprehensive process for higher power projects, with complete load flow studies, short circuit, protection coordination, and formal interconnection requirements similar to those applied to conventional generation connected to higher voltage levels.

Within this tiered framework, the technical regulation is articulated through four central operational instruments, whose requirements are adapted to the magnitude and impact of each project. The connection procedure administratively orders the entry of new facilities, defining stages, deadlines and verifications. In small installations it is usually limited to a notification and documentary review, while in larger power projects it requires formal evaluations, inspections and detailed coordination between the distribution company and the applicant. Electrical studies are the engineering tool that allows the evaluation of technical feasibility: on a small scale they are replaced by generic capacity limits or simplified criteria, while on a medium and large scale they require complete modelling of load flow, short circuit, voltage and protections, and can condition the connection to network reinforcements. The connection contract formalises the rights and obligations of the generator once the technical assessment has been passed. In smaller projects it may be limited to an annex to the supply contract, while in larger installations it takes the form of specific agreements that assign responsibilities for metering, reinforcement works, maintenance and eventual disconnections. Finally, protection and measurement systems ensure the safe and transparent installation operation. On the small scale, certified inverters with anti-island functions and basic bidirectional meters are usually sufficient, while on the larger scale, protections adjusted to the grid scheme, remote control capability and advanced monitoring systems validated by the distribution company are required.

Procedures, studies, contracts, and metering systems make up the operational scaffolding that makes the safe expansion of DG possible. Its existence responds to the need to preserve the technical stability, operational security, commercial traceability and economic equity of the system. Strengthening these tools allows distribution companies to act not only as grid administrators, but as guarantors of an orderly, efficient and sustainable energy transition.

ROLE AND RESPONSIBILITIES OF DSOS

The fourth regulatory axis refers to the set of responsibilities that the regulations assign to distribution companies in terms of DG. Far from diminishing, these functions are expanding as the penetration of DG increases, forcing companies to manage a more decentralized, bidirectional and digitized network. This change introduces additional obligations that entail costs in personnel, control systems, technical analysis and oversight, so the regulation must explicitly recognize these tasks and provide utilities with attributions and resources proportional to their role, preventing the expansion of DG from generating gaps between the requirements and the effective capacity to meet them.

These responsibilities encompass multiple dimensions. On the administrative front, DSOs must manage connection requests, maintain up-to-date registers of distributed generators, and publish relevant technical information, which requires document management capabilities and information platforms. At the technical-operational level, they are in charge of evaluating the feasibility of each project through studies proportional to its scale, verifying regulatory compliance, inspecting facilities and, when necessary, limiting or disconnecting generators that compromise the security of the grid. In terms of commissioning and operation, they must coordinate switching operations, validate tests and ensure that the facilities meet the standards to allow the safe injection of energy. In the field of measurement and settlement, they assume the installation and operation of bidirectional metering systems, as well as the processing and valorization of consumption and injection data, functions that demand digital infrastructure and commercial traceability. Finally, at the level of regulatory supervision, they act as the agent responsible for overseeing compliance with DG standards at the local level, reporting to the regulator on the connected capacity and its performance and, in case of serious anomalies, suspending the injection of the generator until the faults are corrected. These tasks require new organizational and legal capacities, which are essential to ensure that DG is integrated into the electricity system in a safe, traceable and equitable manner.

CONNECTION RESTRICTIONS

The fifth regulatory axis refers to connection restrictions, which delimit the conditions under which a DG facility can be accepted, conditioned, or postponed according to the actual state of the grid. Although the principle of open access is present in most regulatory frameworks, its application must respect the technical and operational limits of the infrastructure, so that the incorporation of new generators does not compromise security, quality or supply continuity. These restrictions thus fulfill an essential technical management function, allowing distribution companies to assess the feasibility of each request and require corrective action when necessary.

In practice, connection restrictions are articulated around three main areas. The technical restrictions seek to preserve the electrical parameters of the network, preventing a new connection from generating instabilities, voltage distortions or problems with protections coordination. Operational safety restrictions protect the physical integrity of infrastructure, personnel, and users, preventing situations such as unintentional islands or dangerous feedback. Finally, the constraints associated with grid capacity reflect the physical limits of feeders, transformers, and low-voltage circuits, and prevent infrastructure saturation when local injection exceeds its absorption capacity. In contemporary regulatory frameworks, these assessments are increasingly supported by hosting capacity methodologies, which quantitatively estimate the margin available to integrate new generation without affecting the system operation. This approach allows distribution companies to authorize, condition or defer connections with objective and traceable criteria, and promotes transparency through the publication of capacity maps or equivalent indicators, consolidating connection restrictions as a central instrument of technical governance aimed at ensuring that the expansion of DG occurs within safe and economically sustainable margins.

GRID INVESTMENT RECOVERY MECHANISMS

The sixth regulatory axis refers to the mechanisms through which the costs associated with the integration of DG are assigned and, where appropriate, recovered . Connecting new generators requires investments in infrastructure, bidirectional metering, telecommunications, data management, and more complex operation. While DG penetration is low, these costs can be marginal; But as their online presence grows, utilities must implement additional reinforcements and systems to ensure safe and reliable service. If these costs are not properly allocated or recognized, they can go unfunded or unfairly passed on to the rest of the users, generating cross-subsidies. Therefore, this pillar seeks to ensure that the costs derived from DG are distributed equitably and efficiently.

In practice, regulatory frameworks combine three approaches to allocate and recover the costs associated with the integration of DG. The first is the direct allocation of specific costs to the generator, in accordance with the principle of causality, so that each project finances the works and equipment that its own connection requires, such as local network reinforcements, adaptations of protections or the installation of bidirectional meters. The second approach addresses the systemic or shared costs that arise when the expansion of DG forces the modernization of general infrastructure, including telecommunications, monitoring platforms, automation or low-voltage network reinforcements; These expenses, not attributable to a single project, are recognized through the rate plans or through regulated charges for network use or backup services. Finally, some frameworks incorporate real-impact allocation mechanisms, in which remunerations or charges are adjusted according to the specific effect that each project has on the grid, rewarding installations that reduce losses or alleviate the burden on the system and requiring a greater contribution from those that generate additional costs or operational requirements.

Taken together, these six axes show that, despite the diversity of approaches and rates of progress, the countries of the region tend to converge towards the same functional framework to integrate DG. They all address, with different levels of maturity, the same structural challenges: guaranteeing the economic sustainability of the distribution companies, preserving the technical stability of the network and ensuring an equitable and safe development of the DG. The differences are expressed in depth, scope and coordination of adopted measures, but the sense of evolution is common. The following is a Latin American panorama, which examines how each country has developed these six axes and what are the main variations that define the regulatory diversity of the region.

“

Countries in the region tend to converge towards the same functional framework for integrating distributed generation.

04

REGIONAL OVERVIEW OF DG

PENETRATION LEVEL

DG has gone from being an incipient option to consolidating itself as one of the main growth vectors of the regional electricity sector. By 2024, installed capacity in the nine countries represented in ADELAT exceeds 39 GW, driven almost entirely by grid-connected solar PV systems. Brazil accounts for about 85% of the regional total, followed by Chile, Colombia and Costa Rica, where recent expansion reflects both regulatory improvements and sustained reductions in technology costs.

In general terms, the evolution is uneven. While some countries have moved towards relatively robust and stable regulatory frameworks, which provide greater predictability and incentives for investment, others still operate with incipient regulations or with limited implementation, which tends to slow down integration into distribution networks. These differences help to understand both the gap in installed capacity between countries and the asymmetry in the effective penetration of DG. The result is a heterogeneous panorama, ranging from markets with high penetration, such as Brazil, to markets in the exploratory phase, such as Peru, where DG still represents a very limited fraction of total capacity. Fig. 1 illustrates the installed DG capacity in the nine countries considered in the study, as well as their relative level of penetration within distribution networks. The representation shows the marked regional heterogeneity, both in installed magnitude and percentage participation, highlighting the concentration of development in Brazil and the diversity of trajectories among the rest of the countries.

Fig. 1. DG installed capacity and penetration in Latin America (2024).

Beyond the national panorama, the experience of the distribution companies that participated in this study allows us to observe more precisely how DG manifests itself in the real networks of Latin America. In many of these concessions, DG still represents a limited fraction of the local installed capacity, with values that do not exceed 1% in several cases. However, concessions with significantly higher levels are also identified, which exceed 20% and, in exceptional cases, reach up to 59% participation, as is the case in a Brazilian distribution company. Figure 2 illustrates this heterogeneity by showing the penetration levels recorded by the participating distribution companies, organized by country. The sample includes companies of different sizes and natures, from large operators with mixed capital to regional cooperatives, which operate under diverse regulatory frameworks and with heterogeneous degrees of digitalisation and operational maturity. This variety provides valuable empirical evidence to understand how DG is integrated into practice, revealing differences in technical management, connection processes and the relationship with users, as well as common challenges that anticipate the complexities of its deployment on a larger scale.

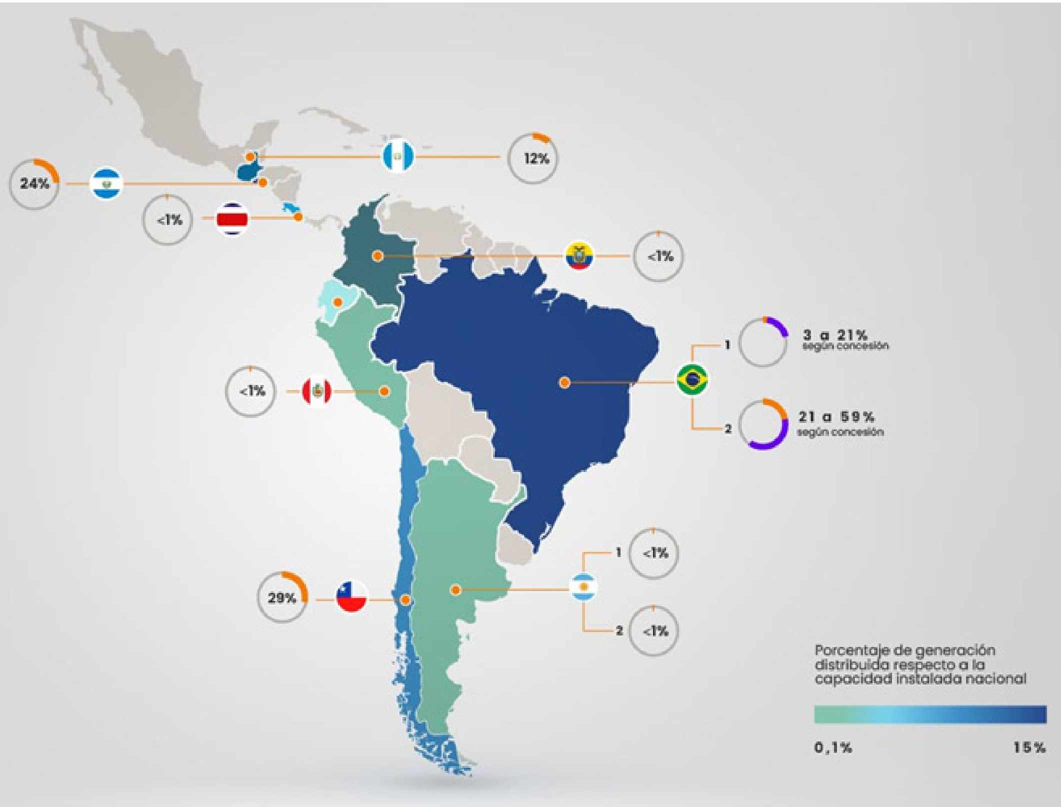


Fig. 2. Relative DG penetration in networks of participating DSOs, by country and concession.

The heterogeneity observed among distribution companies reveals the coexistence of different degrees of maturity in DG integration, closely linked to the regulatory and market conditions of each country. In general, companies operating in environments with more consolidated regulatory frameworks tend to register higher levels of DG penetration in their networks, while in other concessions the deployment remains incipient or concentrated in specific segments of users. This diversity shapes an asymmetrical regional panorama, but also valuable: it allows us to identify contrasting experiences, recognize patterns of technical and regulatory adaptation, and anticipate the challenges that accompany the different stages of development. In this context, systems with a lower presence of DGs have a time frame to strengthen their infrastructure and management capacities before reaching critical levels of saturation, while those with higher penetration can capitalize on their operational experience to refine coordination and control frameworks.

The diversity of these trajectories provides a relevant empirical basis to guide the regulatory discussion. Understanding how regulations have accompanied – or conditioned – the expansion of DG is essential to move towards more consistent and sustainable integration models. Next, it examines how this diversity manifests itself in the regulatory frameworks of the countries participating in the study, through the way in which the six pillars previously identified as structuring components of DG regulation are expressed.

REGULATORY FRAMEWORKS FOR DG INTEGRATION IN LATIN AMERICA

Regulation has been a decisive factor in the way and pace with which DG has been incorporated into Latin America's electricity systems. Beyond enabling the connection of new generators, regulatory frameworks determine the economic incentives, technical responsibilities, and degree of certainty with which distribution companies can plan and operate their networks. In this sense, a solid regulatory framework not only promotes the participation of new actors, but also establishes the necessary conditions for DSOs to exercise their operational role with security, predictability and financial balance. The regulatory trajectories observed in the region reflect both the institutional maturity of each country and its ability to design schemes that make the principle of open access compatible with grid protection, ensuring that DG expansion occurs within safe and sustainable margins for the electricity system.

In this panorama, different regulatory approaches are observed, which differ according to the degree of technical control and the attributions granted to utilities. In Brazil and Chile, regulatory frameworks combine open access mechanisms with defined prior technical evaluation schemes. Act 14300 and Module 3 of PRODIST in Brazil, together with Act 20571 and its regulations (Supreme Decree No. 57/2020) in Chile, establish detailed interconnection rules, mandatory equipment standards, and formal procedures that ensure electrical compatibility before authorizing any connection. Both countries give distribution companies the power to validate regulatory compliance and condition the connection to the effective capacity of the network, which allows for orderly, predictable and technically controlled integration.

Colombia, Ecuador, Argentina and Costa Rica represent a diversity of regulatory frameworks that have incorporated technical, administrative and commercial elements to facilitate DG integration. In Colombia, the CREG regulation and the CNO Operation Code have strengthened the traceability of processes through unified portals and protection agreements. In Ecuador, the Connection Code and Regulation ARCONEL-005/24 introduce advanced feasibility and certification procedures that seek to improve technical coordination between DSOs and system operator. Argentina, through Act 27424, has prioritized the opening and protection of the user-generator through standardized contracts and national regulations. This law invites the provinces and the Autonomous City of Buenos Aires to adhere to this law and to issue complementary regulations for its application. In Costa Rica, under the leadership of ARESEP (Public Services Regulatory Authority), the demand for quality and safety standards is maintained along with a growing technical coordination between operators and utilities. ARESEP has the function of dictating, approving and supervising compliance with all regulatory instruments required to ensure quality, reliability and safety, as well as for the efficient integration of Distributed Energy Resources (DER).

Finally, Guatemala, El Salvador and Peru have adopted regulatory frameworks that prioritize the openness and simplification of connection procedures, with the aim of facilitating DG incorporation. In Guatemala, the Technical Standard for Renewable Distributed Generation (NTGDR) guarantees mandatory access for generators to the grid and centralizes the approval of works and technical requirements in the CNEE. In El Salvador, the regulation for Renewable Producer Users (UPR) simplifies the connection of small self-consumption systems, privileging basic security and reducing the need for complex technical studies. In Peru, Act 28832 and Legislative Decree No. 1221 recognize the right of access to the network and establish economic incentives for DG, while the specific technical regulation that defines the conditions of coordination is in the process of consolidation.

Beyond their differences, the common challenge in the region is to align regulation with the real capacities of distribution companies. In many contexts, these companies continue to be treated as passive connecting agents, when in fact they are directly responsible for preserving the technical and economic stability of the system. Regulatory developments must move towards conditional and technically managed access schemes, which give DSOs clear powers to evaluate, prioritise and, where necessary, limit the incorporation of new generators. Only under a framework that balances openness with technical responsibility can DG expansion be carried out safely, sustainably and in a manner consistent with the real conditions of distribution networks. Table 2 summarizes the main normative elements that structure the DG regime in the nine Latin American countries that participate in this study. It includes the estimated installed capacity, the current legal framework, the prevailing surplus remuneration schemes and the upper power threshold defined by the regulations to consider a project within the DG regime. In some cases, this regime also covers installations that sell their energy on the wholesale market, without accessing regulated tariffs.

Table 2. Regulatory parameters of the DG regime in selected countries in Latin America (2024)

Country	Installed DG Capacity (2024)	% Total	Regulatory framework (year)	Upper power threshold	Predominant surplus remuneration scheme
Argentina	59 MW	0.1 %	Law 27.424 (2017)	12 MW	Net billing
Brazil	35,600 MW	15 %	Law 14.300 (2022)	5 MW	Net metering
Chile	4,300 MW	12 %	Law 20,571 (2012, amended in 2018)	9 MW*	Net billing
Colombia	487 MW	2 %	CREG 030 (2018) and CREG 174 (2021)	5 MW*	Net billing
Costa Rica	100 MW	3 %	DG ARESEP Regulation (2019–2022)	5 MW	Net billing
Ecuador	60 MW	1 %	ARCONEL 005 (2024) and Connection Code (2024)	10 MW*	Net metering
El Salvador	340 MW	12 %	UPR SIGET Regulations (2017)	Not defined	Net billing
Guatemala	210 MW	6 %	NTGDR (2014)	5 MW	Net metering
Peru	N/A	N/A	Law No. 28.832 (2006)	TBD	TBD

COMPARATIVE REGULATORY FRAMEWORKS

Power Categories and Limits

In Latin America, segmentation by power scale operates as a regulatory principle that allows technical, administrative, and economic requirements to be adjusted according to the size and potential impact of each project. More than just a nominal classification, this approach seeks to establish power thresholds that precisely define the requirements applicable to each type of installation, from connection procedures to contractual responsibilities. While most countries differentiate between micro, small, medium, and large-scale to graduate these requirements, some frameworks opt for more centralized schemes. Guatemala, for example, maintains a single category in which technical decisions are concentrated in the regulatory authority and the distribution company acts primarily as the executor of the connection process.

The implementation of the principle of segmentation varies significantly between countries. Some frameworks establish a single power threshold that delimits the DG regime compared to the conventional generation regime. Others introduce functional distinctions, such as the difference between installations intended exclusively for self-consumption and those aimed at the sale of surpluses. In some cases, segmentation is further deepened by subdividing minor categories, in order to adapt procedures and technical requirements to the level of complexity and risk of each project. These differences reflect the degree of specificity with which each regulation approaches DG, and the type of balance it seeks between access facilitation and operational control.

In microgeneration, Latin American frameworks privilege administrative simplicity, but under conditions of technical verification. In Brazil, microgeração (≤75 kW) requires the submission of standardized forms and certificates of conformity for inverters, in addition to restricting power to contracted demand. The procedure is carried out by notification, and the connection is limited to low voltage. In Argentina (≤3 kW), the protection of the user against objections operates only if the equipment is certified and the declared connection power is not exceeded. This threshold is linked to a simplified procedure and a right to connection guaranteed by law. In Colombia (≤10 kW), the simplified procedure is valid only as long as the generation does not exceed 50% of the nominal capacity of the circuit, and formal studies will be activated otherwise. In this case, the inspection is visual, and the system must respect inverter configurations and protections verified by the grid operator. In Costa Rica (≤100 kVA), the distribution company must verify that the network has sufficient capacity, and may impose physical limits such as that the power does not exceed 50% of the capacity of the conductors. These frameworks reflect a regional consensus on the need for simple, verifiable rules that are proportionate to the technical risk of minor installations.

In medium-scale DG, understood as a comparative category between extremes of power, Latin American frameworks differ in the degree of formality and in the depth of the studies required, reflecting different visions on the impact of these projects on the network. Some countries maintain procedures similar to microgeneration, prioritizing administrative agility, but with basic technical controls. In Argentina (3–300 kW), objections are raised when feasibility studies demonstrate risks to the safety of the system, after justification to the regulator. This threshold corresponds to the range where a simplified procedure is allowed, provided that the user uses certified equipment and does not exceed the declared capacity; however, the final authorization is subject to the technical evaluation of the distribution company. In Colombia (100 kW–1 MW), projects must submit a Simplified Connection Study and comply with protection coordination tests, which introduces a first level of technical analysis. If the proposed generation exceeds 50% of the nominal capacity of the circuit, an additional study is required, and the adaptation costs are borne by the applicant. In Brazil, projects between 75 kW and 5 MW (minigeração) must sign an Operating Agreement and, if they exceed 500 kW, present economic guarantees proportional to the size of the project, while the grid expanding costs also fall on the generator. Other regulations, more aware of the systemic impact of this scale, move towards schemes where the feasibility of connection depends explicitly on the capacity of the grid and the electrical compatibility of the coupling point. In Chile (10–300 kW), the DSO calculates the Permitted Installed Capacity (CIP) and the Allowable Surplus Injection (IEP), activating additional requirements if the generator exceeds the limits defined for its connection point. In Costa Rica (100 kVA–1 MVA), approval depends on available capacity, and grid reinforcements are at the expense of the generator. In Ecuador (≤100 kW), studies of power flow, short circuit and voltage imbalance are required, and distribution companies can suspend installations that do not comply with the approved parameters.

In large-scale DG, Latin American frameworks apply different models of technical and economic control that reflect their systemic impact and the need for coordination with the system operator. Although these projects are still formally part of the DG regime, they must meet requirements comparable to those of a conventional plant, both in terms of documentation and engineering. In Ecuador (>100 kW–10 MW), this implies complying with CENACE dispatch requirements and stability criteria such as the support of voltage dips, as well as fully financing the works or adaptations necessary to avoid negative impacts on the quality and reliability of the system. In Colombia (>1 MW), compliance with the CNO Agreements and the presentation of capacity guarantees and the regular reporting of technical and energy data to the regulator are required, in addition to assuming reinforcements costs if the grid does not have sufficient capacity. In Chile, this is implemented through the obligation to finance the "Additional Works" defined by the utility, and in Argentina (>300 kW–12 MW), the regulations empower the company to object to the connection when some risks are accredited. In Brazil (>75 kW–5 MW), the connection process takes place within a framework defined by ANEEL, in which the distribution company mainly plays a formal validation role. Their responsibility is focused on verifying the submission of required documents, guarantees of faithful compliance and technical compliance of the equipment, rather than on carrying out case-by-case evaluations. Once the upper DG threshold is exceeded, the facilities usually switch to the general generation regime, which implies more demanding requirements and a different contractual relationship with the electricity system.

Table 3 synthesizes the general regulatory differences between the three scales of DG, showing how Latin American frameworks grade technical, economic, and administrative requirements based on the potential impact of each project. Although the ranges and categories are not fully equivalent between countries, this classification allows us to identify common trends and recurrent regulatory approaches in the region.

Table 3. Comparison of DG scales.

Parameter	Smaller-scale DG	Medium-scale DG	Large-scale DG
General Range	Generally less than 10 kW.	Generally between 10 kW and 1 MW.	Generally between 1 MW and 10 MW.
Regulatory approach	Administrative simplicity and agile access, with a focus on standardization and basic technical verification.	A more structured process that introduces technical network analysis and requires longer deadlines.	It is assimilated to a generation plant, so it requires coordination with the System Operator.
Key Connection Criteria	Certified equipment, limit for contracted power, and verification of network capacity.	Connection studies, network analysis (flow, protections, short circuit), and calculation of network capacity.	Compliance with national grid codes, technical-economic studies, presentation of guarantees.
Liability for works and costs	No major works are planned, and the connection is approved if the predefined criteria are met.	The generator assumes the costs of grid adaptations or reinforcements.	The generator finances the additional works or systemic reinforcements defined by the DSO or regulator.

Regional experiences confirm that segmenting DG according to its impact on the network is essential to balance flexibility and control. Only through categories with proportional responsibilities can distribution companies manage the expansion of these resources safely, preserve service quality and maintain the technical and economic sustainability of the distribution system.

“

Segmentation by power scale operates as a regulatory principle.

Surplus injection and market participation

According to the degree of interaction with the grid and the way in which the energy generated is valued, Latin American regulation distinguishes three levels of DG integration: pure self-consumption, which operates without commercial exchange with the DSO; regulated remuneration schemes, which allow the controlled sale of surpluses at prices set by the authority; and participation in the electricity market, reserved for larger-scale projects that can trade energy directly in the wholesale market or through bilateral contracts. These three modalities make up the DG economic framework in the region and define the degree of technical, commercial and regulatory complexity associated with each type of connection.

At the most basic level of integration, and coexisting with other injection schemes, several Latin American countries maintain regulations for DG aimed exclusively at self-consumption. It is fundamentally a voluntary modality, where the user explicitly chooses at the time of connection not to deliver surpluses to the network, or not to receive any type of economic recognition for them. This choice is formalized in different ways. In Colombia, the self-generator can be declared “without delivery of surpluses”, installing devices that limit the injection to zero. In Costa Rica, by opting for this modality, technological mechanisms are required to prevent the reverse power flow. In Guatemala, the user may expressly state that he or she does not wish to participate as an energy seller. Precisely because it is a choice that guarantees non-injection, the connection process is simplified as much as possible, exempting the user from network impact studies. These schemes thus configure the zero level of integration, focused on self-sufficiency, and constitute the most stable and least risky modality for distribution companies, since they do not establish a commercial relationship for the purchase of energy.

Moving from this basic level of integration, Latin American regulation has also incorporated schemes that allow the injection of surpluses into the grid, integrating the user-generator into the economic structure of the electricity system. In this category, net metering and net billing mechanisms predominate. Under the net metering scheme, the Latin American countries that adopt it differ mainly in the terms and conditions for the use of energy credits accumulated by surpluses injected into the grid. In Ecuador, the monthly net balance allows credits to be kept for up to 24 months, after which they expire without economic compensation; and in Guatemala, self-producing users with surpluses maintain their credits until they are exhausted, without a predefined time limit, although without receiving any payment. In Brazil, the Electric Energy Compensation System (SCEE) allows users to accumulate credits for up to 60 months. [RC1.1]Although Law No. 14,300/2022 maintains the full energy compensation system for pre-existing systems until 2045, it establishes a methodology of credits in kWh for new connections with progressive discounts for the use of the distribution system, thus reducing the net value compensated with respect to consumption. In general, these energy offset models, while they have driven residential and commercial DG adoption, tend to undervalue the use of infrastructure and backup services that ensure supply continuity. Table 4 summarizes these differences in accumulation periods and the treatment of surpluses for the countries analyzed.

Table 4. Comparative analysis of the expiration of credits in net metering.

Country	Maximum accumulation period	Treatment of surplus credits
Ecuador	24 months	The accumulated balance is reset to zero (expires) and no financial compensation is granted.
Brazil	60 months	They expire without compensation and benefit the tariff system.
Guatemala	Not defined	The credit is exhausted by consumption, without specifying a fixed time limit for its expiration.

In the case of net billing, regulatory differences between countries are mainly concentrated in the method and value of remuneration applied to surpluses. In Argentina, Law No. 27,424 establishes a Net Billing Balance regime, where surpluses are remunerated at the seasonal price of the Wholesale Electricity Market (MEM), with the possibility of accumulating monetary credits for up to six months or requesting their reimbursement. This scheme also grants exemption from VAT and Income Tax for installations of up to 300 kW. In Chile, Law No. 20,571 provides that surpluses are valued at the price of the energy node, incorporating a factor of avoided losses, and are deducted from the customer's electricity bill within the same billing cycle. The remaining balances that are not discounted must be paid after five years, as established by the current regulation. This scheme applies only to installations of up to 300 kW under the DG regime. In Costa Rica, the Complete Net Metering modality allows the direct sale of surpluses to the distribution company, at a price regulated by ARESEP, calculated in accordance with the current tariff structure and the avoided system costs. The annual settlement is made by applying the price in force at the time of energy delivery. In Colombia, regulation combines both mechanisms: surpluses equivalent to monthly consumption are offset by energy, while additional surpluses are settled at the hourly stock market price, generating a hybrid compensation scheme. Table 5 summarizes these differences in remuneration mechanisms and surplus settlement deadlines for the countries analyzed.

Table 5. Comparative analysis of remuneration mechanisms in net billing.

Country	Recovery of energy surpluses	Credit and term management
Argentina	Seasonal price of the Wholesale Electricity Market (MEM).	Cumulative monetary credit. Refund available after 6 months. Exempt from VAT and Profits up to 300 kW.
Chile	Valuation at the price of the energy node, including the avoided losses factor.	Discount on the monthly bill. Remainders accumulate (adjusted for CPI) and must be paid after 5 years.
Costa Rica	Sale of surpluses at a price regulated by ARESEP (based on hourly/seasonal rates).	Monthly energy accumulation. Annual financial settlement.
Colombia	Hybrid Model: 1) Energy credit up to the monthly consumption; and 2) Sale at bag price for additional surpluses.	Monthly settlement of credits and balances.

Figure 3 shows the geographical distribution of the predominant compensation schemes in the Latin American countries analyzed, differentiating between net metering and net billing models, as well as those regulatory frameworks where a specific scheme for the remuneration of surpluses has not yet been defined.

Fig. 3.Net billing and net metering schemes in Latin America.

Connection and Measurement Requirements

Once the power limits and injection regimes have been defined, their implementation is materialized through a set of instruments that combine administrative management, technical validation and operational control. Together, these mechanisms allow distribution companies to exercise comprehensive governance over DG expansion, ensuring operational control, commercial transparency, and sustainability of the system.

In this framework, the connection procedure is the main administrative tool through which distribution companies channel applications for the incorporation of new generation. Its degree of rigor varies depending on the country and the scale of the project. In the small generation, where individual risk is limited, simplified notification and verification schemes predominate, with basic documentary reviews or visual inspection. This is the case, for example, in Colombia, where projects of less than 10 kW require the Grid Operator to carry out a visual inspection or verification of the declared parameters. On the other hand, projects between 10 and 100 kW must be verified for technical and protection parameters in accordance with the CNO Agreement. In Brazil, microgeneration (≤ 75 kW) is processed through standardized forms and certificates of conformity for inverters, without the possibility of requiring additional documentation to that required by ANEEL, and formalized with the delivery of the Operational Relationship.

At the medium scale, the procedures are formalized through standardized applications and more detailed technical reviews: in Brazil, mini-generation projects (75 kW–5 MW) must submit standardized forms defined by ANEEL and formalize an Operating Agreement with the distribution company, while in Costa Rica DSOs must issue a feasibility opinion within a maximum period of fifteen working days. In Ecuador, self-generators of up to 100 kW are exempt from paying for the connection feasibility process. However, the DSO must perform power flow analysis, voltage imbalance analysis and fault analysis, the results of which can condition the connection if they detect risks to the network. In addition, the user must cover the difference in cost of the bidirectional meter and assume any necessary adjustments in the network.

Finally, in larger projects, the process is transformed into an exhaustive technical analysis that requires feasibility opinions, capacity guarantees and coordination with the system operator. In Colombia, projects between 100 kW and 1 MW require a Simplified Connection Study with verification by the grid operator, within a period of ten business days, while for DG projects with a capacity greater than 1 MW, compliance with all the tests established in the CNO agreement is required. In Ecuador, projects over 1 MW must obtain preliminary and definitive feasibility certificates, carry out dynamic stability studies and coordinate with CENACE. In addition, the generator assumes the costs of the works or network adaptations strictly necessary to avoid negative impacts on safety or operation. Chile and Argentina apply similar approaches: in the former, the connection may involve adjustments justified by electrical studies that must be paid for by the owner of the generation facility; in the latter, distribution companies can only object to a connection if they can prove technical risks through prior studies. This progression reflects a principle of technical and administrative proportionality: the smaller the scale, the greater the agility; the larger the scale, the greater the control. In this way, connection procedures allow utilities to manage DG expansion in an orderly manner, balancing access, security, and operational predictability.

Electrical studies, on the other hand, are the main engineering tool available to distribution companies to evaluate the technical feasibility of each project, and the depth of the analysis also varies between countries and power scales. On the small scale, individual impact studies are generally non-existent; instead, the DSO applies prescriptive rules or aggregate capacity thresholds, such as the 50% limit of circuit capacity in Colombia, functioning more as a compliance check than a detailed analysis. It is at the medium scale where specific studies become mandatory, focused on evaluating the local distribution network. In Colombia, projects between 100 kW and 1 MW must submit a Simplified Connection Study. The calculation of the Permitted Installed Capacity (CIP) in Chile is a paradigmatic example of this level: a formal analysis to determine the technical headroom of the circuit. Finally, in larger projects, the scope of the analysis is extended to the electricity system in its entirety, requiring complex studies and coordination with the national system operator. In Ecuador, these studies include dynamic analysis (voltage stability, frequency stability) and coordination with CENACE is activated when the nominal power is equal to or greater than 1 MW.

At this point, the connection contract becomes the legal tool that formalizes the operational and commercial relationship between the generator and the distribution company. Its scope and complexity vary according to the scale of the project and national provisions. On a small scale, its formality is minimal In Brazil (≤ 75 kW), it is formalized through the "Operational Relationship", a standardized document. In Chile, the contract must contain the essential technical characteristics and the installed capacity of the equipment. At the medium scale, the contract evolves into a specific document, as seen in Chile or Costa Rica, clearly defining operational responsibilities. Finally, in large-scale projects, the agreement is transformed into a complex interconnection agreement, often involving the system operator. These contracts include clauses on protection, operation and maintenance schemes. In Ecuador, the Connection Contract is comprehensive and includes clauses on market participation, coordinated dispatch and penalties for non-compliance.

Finally, the measurement, control and supervision systems constitute the physical instrumentation that allows the distribution company to manage the grid operation in real time. Its level of sophistication, as in the previous instruments, varies according to the scale of the project and the regulatory framework of each country. On the small scale, the requirement is limited to bidirectional measurement and intrinsic inverter protections, designed to shut down the equipment in the event of anomalies. In microgeneration in Brazil, the redundancy of protections is unnecessary. When transitioning to the medium scale, the requirement evolves towards telemetry systems and coordinated protections, which give the distribution company remote visibility. In Brazil, generation plants with an installed capacity greater than or equal to 300 kW must have voltage and frequency control systems, and Brazilian projects over 500 kW must incorporate protections against current imbalance, voltage imbalance and directional overcurrent. In large-scale projects, control becomes active and centralized: integration with the SCADA systems of the control center becomes a requirement, empowering the distribution company, or the system operator, to perform remote switching operations, as required in Ecuador or Costa Rica.

Table 6 summarises this progression of technical, administrative and contractual requirements according to the power scale of the installation. While the table illustrates the general trends observed, it is essential to clarify that power thresholds and specific requirements vary according to each country's regulatory framework.

Table 6. Progressivity of connection requirements according to scale.

Requirement	Small scale	Medium scale	Large scale
Connection procedures	Simplified notification and verification (documentary or visual review).	Standardized application with detailed technical review. Requires a feasibility opinion.	Comprehensive technical analysis. It requires a feasibility report and guarantees. Subject to capacity and works.
Electrical studies	Non-existent or null. Prescriptive rules or aggregate capacity thresholds apply.	Mandatory specific studies, focusing on the local distribution network.	Complex system studies (dynamic stability, voltage) coordinated with the national operator.
Connection contract	Minimum formality. Usually an addendum to the supply contract or standard form.	Specific contract that assigns adaptation costs and defines operational responsibilities.	Complex interconnection agreement. It involves the system operator (dispatch, penalties).
Measurement, control and monitoring	Bidirectional measurement and intrinsic passive inverter protections (anti-island).	Telemetry systems and coordinated protections for remote visibility of the DSO.	Active and centralized control. Mandatory integration with SCADA and remote control capability.

DSO Responsibilities

In this new scenario, distribution companies assume an expanded set of administrative, technical and operational functions, aimed at ensuring a safe and transparent DG integration. The first manifestation of this new role is materialized in administrative responsibilities. In Ecuador and Guatemala, DSOs assume a growing administrative burden linked to the mass management of applications, forms and connection certificates, which must be processed under standardized deadlines and formats defined by regulators. In Colombia and Costa Rica, the administrative role is extended to transparency and operational information management, since the regulations require the publication of georeferenced maps with the available capacity of the circuits and the maintenance of unified platforms to centralize the processing and exchange of data. These tasks make the distribution company a provider of strategic information for the electricity system, a function that requires additional technical capabilities and resources, and that significantly expands its traditional mandate of operation and maintenance of the network.

Along with administrative tasks, technical responsibilities also emerge. In frameworks such as those of Chile and Ecuador, distribution companies must technically evaluate connection requests and, where appropriate, conduct or review electrical studies that analyze the impact of projects on voltage profiles, short-circuit levels, and other critical parameters. In addition, they are obliged to provide the basic information of their networks to applicants and verify the results of studies carried out by third parties, guaranteeing their technical coherence. These roles involve increasing sophistication in grid management, requiring advanced analytical capabilities, electrical modeling tools, and specialized personnel in protection, control, and simulation. In this context, the DSO assumes a central technical role in the distribution system operation, in charge of preserving its safe and reliable performance facing DG expansion.

In terms of physical connection and operation, distribution companies assume a direct role in the execution, supervision and commissioning of DG facilities. In Brazil and Chile, DSOs carry out the final inspection of the facilities, install the metering system and formalize the start of commercial operation of the generator. In Guatemala, the physical connection can only be made under the coordination and direct supervision of the distribution company, while in Ecuador they must supervise the works and operational tests to ensure that the connection meets the conditions of safety and reliability of the system. In all cases, these tasks involve a significant operational burden and generate direct technical costs that are rarely explicitly recognized in regulatory schemes, despite being essential to preserve the interoperability, security and stability of the distribution network.

In terms of metering and settlement responsibilities, utilities are expanding their role to commercial and operational energy management. In Brazil and Chile, the regulation assigns the distribution company the installation, maintenance and operation of advanced metering systems, capable of accurately recording both imported and exported energy. In addition, there is an obligation to process this data and reflect the results in billing, either through energy credits or monetary compensation. The implementation of these tasks requires additional technological and operational capabilities, as well as closer coordination between the technical, commercial and regulatory areas, key elements to ensure the traceability of information and the stability of the distribution system in an increasingly decentralized environment.

In terms of regulatory oversight and compliance responsibilities, distribution companies take an active role in DG operational monitoring. In El Salvador and Ecuador, the regulations expressly provide for the power of DSOs to carry out subsequent inspections and, in the event of serious non-compliance, request or execute the temporary suspension of the operation. This task reinforces the role of the distribution company as a guarantor of the integrity of the local system and as the first level of technical control in the supervision of regulatory compliance, a role that requires adequate institutional capacities and regulatory support to maintain the security and reliability of the network.

Table 7 summarizes the main roles that DSOs assume in the DG management, illustrated with examples of application in some countries of the region.

> “Distributors take on a wider range of administrative, technical, and operational functions.

Table 7. DSOs' operational and regulatory responsibilities in DG integration.

New responsibility	Main function of the DSO	Specific tasks
Administrative Management	Channel requests and provide strategic information to the system.	Ecuador and Guatemala: mass processing of applications and forms. Colombia and Costa Rica: publication of network capacity maps and maintenance of unified platforms.
Engineering and technical analysis	Assess the feasibility and technical impact of each project.	Argentina, Chile and Ecuador: Carrying out or validating detailed electrical studies. Multiple countries: provision of network base information and verification of technical consistency of third-party studies.
Physical connection and commissioning	Supervise the correct physical installation and commissioning of the generator.	Brazil and Chile: final inspection and installation of the measurement system. Ecuador and Guatemala: direct supervision of works and operational tests before commissioning.
Commercial Measurement and Settlement	Manage the recording and clearing of energy flows.	Brazil and Chile: installation, operation and maintenance of bidirectional metering. Ecuador and Argentina: processing of energy data and reflection of credits or compensations in billing.
Regulatory Oversight and Compliance	Act as a guarantor of network security and regulatory compliance.	El Salvador and Ecuador: post-connection inspections and suspension of operation in the event of serious non-compliance. Various frameworks: first-level role of technical control of the system.

Possible connection restrictions

Although most Latin American frameworks enshrine the principle of open access to the network, this right coexists with the need for distribution companies to have clear powers to condition or limit new connections when there are well-founded risks to security or service quality. Restrictions are not a discretionary act, but an indispensable technical tool to maintain the stability of the system and safeguard the supply continuity. In practice, the causes justifying such limitations are grouped into three main areas: technical reasons, operational safety conditions and restrictions arising from the available capacity of the network. This balanced approach makes it possible to reconcile the access of new generators with the fundamental responsibility of DSOs to guarantee a safe and reliable electricity system operation.

The technical restrictions imposed by utilities vary according to the regulatory framework. In Brazil and Ecuador, the DSO defines the voltage level, the number of phases and the maximum permissible power according to the circuit configuration from the design stage. In Chile and Colombia, interconnection standards establish specific requirements for protections, anti-island schemes and electrical compatibility, which distribution companies must verify before authorizing the connection. In projects that incorporate electronic power converters, the presentation of technical documentation or certified tests that accredit compliance with international standards is required, a practice applied in Argentina, Brazil and Guatemala. Some countries have moved towards more refined quality control schemes: Costa Rica prohibits voltage variations of more than 5%, while Ecuador empowers the distribution company to revoke the qualification certificate if the generator repeatedly fails to comply with quality standards. In the most advanced frameworks, such as in Chile and Colombia, the DSO can condition the connection or adjust operational parameters to prevent disturbances, overloads or security risks.

Regarding operational safety restrictions, distribution companies have specific powers to prevent risks and safeguard the integrity of the grid during DG operation. In Argentina and Costa Rica, the regulations oblige generators to guarantee that their operation does not affect the continuity or safety of the National Electric System, and must incorporate anti-island protections and automatic disconnection in the event of failures. In Brazil, DSOs can require additional measures when there are local vulnerabilities, while in Ecuador and El Salvador they are empowered to immediately suspend the operation of facilities that pose a risk to personnel or equipment. Argentina and Colombia expressly recognize their power to disconnect generators that operate outside the norm or endanger the stability of the system.

In terms of constraints associated with network capacity, Latin American frameworks apply two complementary approaches. The first is based on predefined thresholds, such as the 50% limit of the nominal circuit capacity in Colombia, which acts as a preventive quantitative control. The second, more dynamic, delegates to the distribution company the power to calculate the effective reception capacity and condition the connection when the admissible technical margins are exceeded. In Chile, the determination of the Permitted Installed Capacity (CIP) and the Permitted Surplus Injection (IEP) makes it possible to establish precise operating limits, and if exceeded, to require the applicant to finance the necessary reinforcement works. Similar mechanisms exist in Argentina, Ecuador or Guatemala, where approval depends on technical feasibility and the real availability of the network, and the adjustments are the responsibility of the interested party. These tools are a central element of DSOs asset management, allowing them to maintain the reliability of the system, safeguard equity between users and ensure that network development costs are assumed by those who originate it.

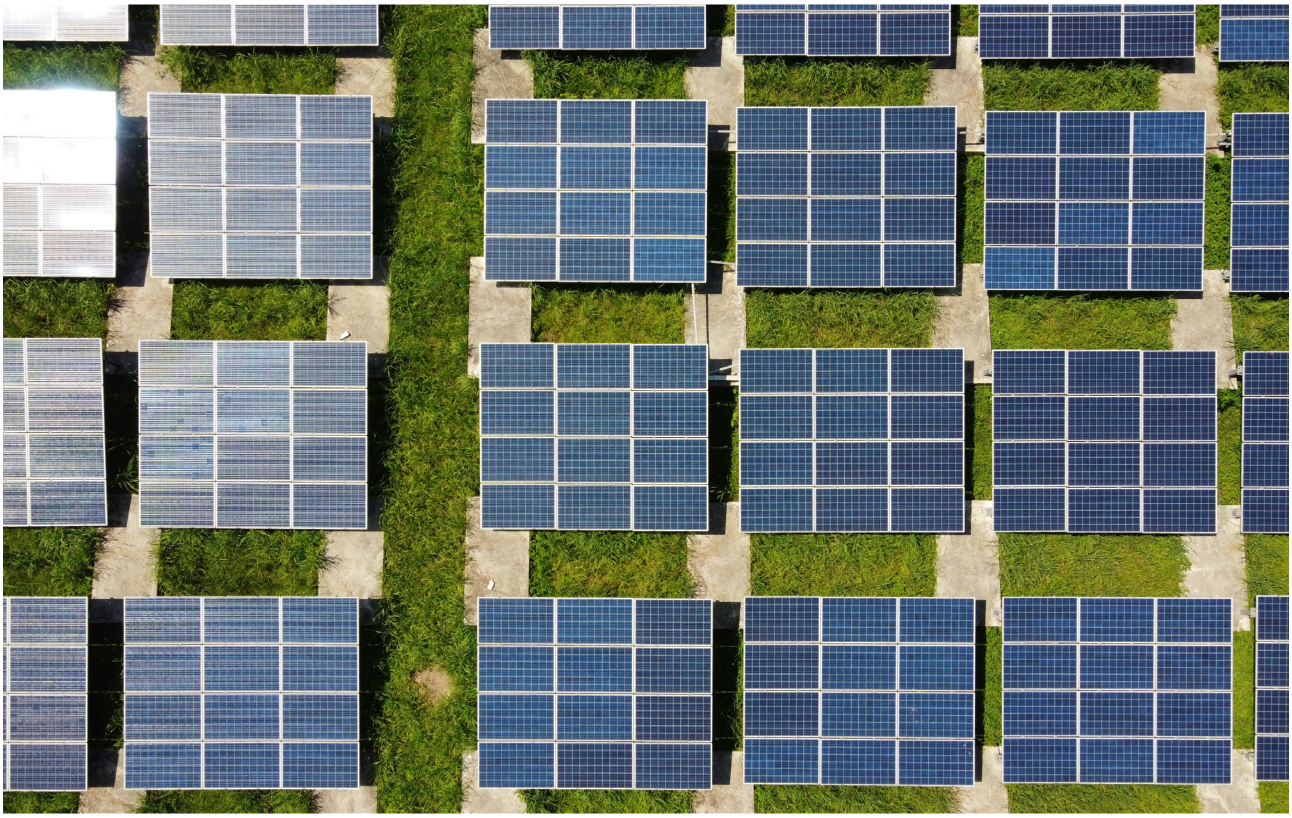
Grid Investment Recovery Mechanisms

The first mechanism to sustain DG financial integration is the direct allocation of costs to the generator, in accordance with the principle of causality. In Chile, the generator must pay for additional works when its project exceeds the technical capacity of the circuit; Ecuador and Guatemala apply the same principle, obliging the applicant to finance the necessary extensions. In Argentina, the user-generator covers the cost of the meter and the connection or it is included in the tariff through the following Five-Year Tariff Review (RQT), while in Costa Rica and Ecuador it is required to pay the difference for advanced bidirectional equipment. This scheme avoids cross-subsidies and preserves the economic sustainability of the distribution networks, ensuring that individual costs are not passed on to the rest of the users.

When direct allocation does not cover the systemic impacts of DG, regulatory frameworks resort to recovery mechanisms via tariffs or regulated charges, which allow integration shared costs to be recognized. In Costa Rica, investments in network adaptation are recognized in ARESEP’s tariff studies; in Brazil, they are remunerated through the Weighted Average Capital Cost (WACC), providing financial stability; and in Guatemala, fixed and power charges are applied that ensure the generator’s contribution to the structural costs of the system. In Ecuador, the generator can build and transfer the works to the distribution company, which then recovers the operating and maintenance expenses through its tariff structure. These mechanisms complement the principle of causality and guarantee the economic sustainability of the system in the face of a DG growing expansion.

Finally, some regulatory frameworks are moving towards technical valorization schemes, which recognize the real impact of DG on losses and the operational efficiency of the grid. In Colombia, the price paid to the generator includes a component that remunerates the reduction of losses; in Chile, the surpluses are valued by incorporating the lower losses associated with local generation; and in Guatemala, if a generator increases losses, it must finance the technical solution or financially compensate for its effect. This approach seeks to align economic incentives with the technical performance of the system, promoting a more efficient and sustainable DG expansion.

> “The first mechanism to support the financial integration of distributed generation is the direct allocation of costs to the generator.



05

INTERNATIONAL REGULATORY APPROACHES TO DG

The DG global expansion has driven profound regulatory reforms in many countries, redefining the role of distribution system operators (DSOs) and the mechanisms for economic sustainability. In the most advanced systems, the distribution company no longer acts as a passive agent that guarantees supply, but as an active manager of bidirectional networks, responsible for integrating, coordinating and controlling distributed energy resources (DER) under efficiency and safety criteria. This section examines the main international approaches, with an emphasis on Europe, Australia and the United States, focusing on how regulation has evolved to balance the promotion of DG with the technical and financial stability of the DSO. It addresses the mechanisms that allow maintaining economic sustainability with high DG penetration, tariff reforms that recognize bidirectional flows, new responsibilities in planning and operational flexibility, and incentives for digitalization that underpin the DSO model as an intelligent grid manager. The analysis seeks to identify regulatory lessons that can be transferred to the Latin American context, highlighting practices that strengthen the role of distribution companies in the energy transition.

ACTIVE ROLE OF THE DSO IN DISTRIBUTED RESOURCE MANAGEMENT

In some leading countries, the distribution company is moving from being a passive operator, limited to unidirectional energy transport, to an active manager that facilitates DG integration, manages bidirectional flows and participates in the optimization of the local system. In these markets, many DSOs are already implementing pilot projects for the competitive procurement of flexibility services, contracting load reductions, reactive power injection, or temporary storage to local distributed resources (DERs) to handle congestion or voltage imbalances (CERRE, 2022). This evolution marks a structural shift in the role of the DSO from expanding physical infrastructure to managing flexibility and data as new system assets.

In Europe, recent reforms consolidate the concept of a more active DSO with explicit functions in the market. The European Union's Clean Energy Package (2019) established a legal framework that allows and obliges DSOs to use flexibility services as an alternative to grid expansions, in order to optimize investments, integrate renewables, and reduce overall system costs (Eurelectric, 2024). In this new model, the DSO is conceived as a "market-neutral enabler", in charge of orchestrating distributed third-party resources in a transparent manner, ensuring security of supply and economic efficiency (Eurelectric, 2024). Countries such as the United Kingdom and the Netherlands have positioned themselves as pioneers in this transition. In the UK, regulator Ofgem requires distribution companies to draw up proactive grid development plans, the Distribution Future Energy Scenarios (DFES), which include the incorporation of electric vehicles, solar generation and storage systems, prioritising smart solutions and local markets for flexibility rather than systematically resorting to new infrastructure works (Ofgem, 2024). In the Netherlands, the ACM regulatory authority has promoted active demand management programs and network services contracted to aggregators, consolidating the role of the DSO as the operational coordinator of the local system. An emblematic example outside Europe is the state of New York (USA), where the Reforming the Energy Vision (REV) initiative redefined the role of distribution utilities as "distributed system platforms". Under this scheme, the DSO must integrate the DERs into the daily system operation, coordinate local energy transactions, contract flexibility services and ensure transparency in information flows and prices, all under the supervision of the state regulator. This model has served as a reference for other North American states interested in aligning distribution company incentives with the integration of distributed resources, promoting investment in digitalization and advanced network management.

Thus, international reforms consolidate the expectation that the DSO will assume an active and neutral role in distributed resources management, enabled by regulatory frameworks that redefine its mission and tools. The new paradigm places the distribution company as the operational axis of the energy transition, responsible for facilitating the connection of DERs, measuring and managing their impacts on the grid, managing congestions and voltages through local flexibility and guaranteeing transparent and non-discriminatory access (Eurelectric, 2024). In this model, digitalisation, operational coordination and flexibility services become pillars of modern distribution, where intelligent management progressively replaces physical expansion as the main way to sustain safe, efficient and sustainable networks.

NEW DSO RESPONSIBILITIES: PLANNING, VISIBILITY, COORDINATION, AND FLEXIBILITY

As DG proliferates, the responsibilities of distribution operators (DSOs) have expanded significantly in the areas of planning, operational visibility, systemic coordination and flexibility management. In many countries, regulatory authorities have recognized that a secure and efficient integration of distributed resources (DER) requires the distribution company to act in an anticipatory, coordinated, and results-oriented manner, and have therefore established explicit obligations in these matters.

On the planning front, DSOs have shifted from expanding infrastructure based on projected demand to developing proactive, integrated plans that consider different scenarios for DG, EV, storage, and demand response adoption. In the United States, states such as California and New York require utilities to submit DER Integration Plans or Network Development Plans with horizons of 5 to 10 years, incorporating Hosting Capacity analysis to determine how much generation can be connected per circuit without reinforcements, and publishing this information to guide developers. In the European Union, Directive 2019/944 obliges DSOs of a certain size to submit a Distribution Development Plan every two years that includes DG forecasts and demand response, evaluating flexibility options before proposing new investments, and coordinating its planning with the transmission operator (TSO) (Eurelectric, 2024). In the UK, utilities also develop annual processes to identify Network Flexibility Needs and launch tenders for services as an alternative to strengthening the grid, transforming planning into a dynamic process where flexibility competes with physical expansion (Eurelectric, 2024).

Network visibility and monitoring have become a central axis of modern distribution management. With thousands of distributed generators in operation, DSOs need to observe in real time the behavior of their medium and low voltage networks, identify local congestion and anticipate service quality problems. In the UK, regulator Ofgem has imposed specific requirements to improve active monitoring: distribution companies must annually report LV grid visibility indicators (referring to the monitoring of low-voltage levels) to demonstrate how much monitoring has been extended in LV substations and feeders (Osborne Clarke, 2024). In addition, they are obliged to report the amount of flexible generation that has been reduced due to congestion and the degree of use of automation systems to detect and manage these congestions (Osborne Clarke, 2024). In the Nordic countries, the situation is more advanced thanks to an early deployment of smart metering. Sweden and Finland completed the installation of smart meters at virtually all customers more than a decade ago, giving DSOs access to hourly consumption and generation data at the subscriber level. This granular information allows monitoring of bidirectional flows at low voltage and detecting deviations in service quality. Currently, the region is moving towards a second generation of visibility, which includes sensors in distribution transformers, smart reclosers, and extended SCADA systems to observe in real time the state of the grid against the variability of distributed resources. This level of active monitoring is essential for the DSO to anticipate and manage surges, brownouts, or overloads, ensuring that increasing DG penetration does not compromise system stability.

Operational and market coordination has become an essential function of the DSO in the face of the entry of new players such as aggregators, energy communities and active prosumers. DSOs must coordinate vertically with transmission operators (TSOs) and horizontally with local participants, exchanging real-time information on available capacity, dispatch, and operation of DERs that may affect the global network. In Europe, the regulation establishes this data exchange obligation, while in the UK, Ofgem has appointed the electricity market operator Elexon as a facilitator of a Flexibility Market Asset Register (FMAR) (Department for Energy Security and Net Zero, 2024), a unified database of all resources (batteries, electric vehicles, generators) that participate in local flexibility markets, allowing to avoid conflicts between local and regional services (Ofgem, 2024). In the Nordics, TSO-DSO coordination is tested through pilot projects such as Finland, where the TSO (Fingrid) and several distribution companies operate a joint flexibility market: the DSO declares its load reduction needs to relieve the grid, the TSO declares theirs for system balancing, and aggregators offer services to both through coordinated auctions. These schemes, although regulatorily complex, reinforce the role of the DSO as an articulating node between local networks and wholesale markets, ensuring a coherent and efficient integration of distributed resources.

Managing distributed flexibility represents one of the most recent and transformative responsibilities of the DSO. The European Electricity Directive states that DSOs must consider the use of demand, DG, or storage resources to meet grid needs before expanding infrastructure, provided that this is cost-efficient (Florence School of Regulation, 2024). This mandate translates into transparent rules for the procurement of flexibility services. In the UK, all distribution companies hold regular tenders to purchase peak power reductions or reactive power injection from local solar plants, remunerating DERs that provide these services as an alternative to grid boosts (CERRE, 2022); Ofgem monitors that such acquisitions are made in a competitive and non-discriminatory manner. In Australia, regulators and the market operator (AEMO) promote local markets through the Distributed Energy Integration Program (DEIP), where households with solar and battery systems, through aggregators, offer consumption cuts or energy injection at critical times in exchange for financial compensation. In the Nordic countries, with a long tradition of demand response, distribution companies are experimenting with similar mechanisms: in Norway, the company Tensio has organised auctions for large customers to reduce load in winter peaks, avoiding overloading rural lines, and in Denmark, where distributed wind penetration is very high, regulated flexibility remuneration agreements have been established that compensate generators when they agree to be disconnected in situations of risk to the network. Together, these experiences show that local flexibility is consolidated as a new operational resource of the DSO, capable of replacing or complementing the traditional expansion of networks and of bringing resilience, efficiency and economic balance to modern electricity systems.

International regulatory reforms cement the new mandate of the modern DSO: to plan the network incorporating distributed resources, maintain advanced operational visibility, coordinate effectively with multiple actors, and leverage local flexibility as a management tool. These responsibilities redefine electrical distribution as a strategic and intelligent management activity, where the DSO is no longer limited to operating infrastructure to become the technical orchestrator of the distributed system. Their role is decisive for the network to evolve in a safe, efficient and resilient way, maximizing the value of distributed resources for the benefit of the system and all users.

MECHANISMS FOR ECONOMIC SUSTAINABILITY OF DSOS WITH HIGH DG PENETRATION

The growth of DG poses a financial challenge to distribution companies: as customers generate their own energy, the volume of kWh delivered decreases, eroding revenues under traditional tariff schemes based on energy sales. To address this, different countries have adjusted the economic regulation of the DSO to ensure its sustainability and encourage the integration of distributed resources without compromising service quality.

A first strategy is to decouple DSO revenues from the volume of energy distributed, using decoupling or remuneration models for allowable revenues. In Europe, including Germany and the Nordics, tariffs operate under regulated revenue caps with adjustments for efficiency, ensuring the recovery of authorized costs without relying on the flow of energy (MIT CEEPR, 2023). Similar schemes exist in many US states, which adjust tariffs periodically to cover approved fixed costs despite the fall in solar sales, removing the incentive to oppose self-consumption or energy efficiency (MIT CEEPR, 2023).

Another axis of reform has been the redesign of tariff structures to more accurately reflect the fixed and bidirectional network use costs. The case of Australia is one of the most illustrative. With more than 30% of homes equipped with solar panels, grids began to become saturated during high-generation hours. Traditionally, prosumers paid nothing to inject their surpluses, which generated congestion without mechanisms for distribution companies to manage them. In response, the Australian Energy Market Commission (AEMC) approved a comprehensive reform in 2021 that formally recognized that providing export services is a distribution function, and therefore must have adequate revenues for companies. The reform eliminated the previous prohibition that prevented DSOs from charging for exported energy, enabling new two-way tariff schemes. From 2025, distribution companies will be able to apply gradual export charges, but each customer will retain a free basic level (allowance) to inject at no additional cost (Ashurst, 2024). At the same time, AEMC prohibited DSOs from imposing zero export limits on new connections except in exceptional circumstances (Ashurst, 2024), forcing them to accept a minimum level of DG and to plan the network to manage it rather than simply reject it. In addition, the economic regulator (AER) will need to approve export tariff and curtailment value guides to protect users (Ashurst, 2024). With this structure, Australia seeks a financial and operational balance: prosumers contribute to the financing of the network they use, utilities obtain resources to strengthen and modernize their infrastructure, and the regulatory framework ensures that access to the network remains fair, predictable and sustainable.

In Europe, most countries have increased the weight of fixed or capacity charges and distributed generator tolls, reducing reliance on volumetric charges. Only a few exceptions, such as Germany, Italy or Poland, exempt small generators from paying for distribution (Eurelectric, 2018). In the United Kingdom, prosumers pay a DUoS generation component for network usage, while in Spain, since 2022, a fixed charge for contracted power has been applied. Sweden and Denmark introduce hourly rates and variable injection charges that reflect local congestion, incentivizing the storage or movement of exports at excess hours. These measures seek to avoid cross-subsidies and ensure that all users contribute equitably to the maintenance of the network. In the US, the revision of net metering schemes has been key to adapting regulation to bidirectionality. More than 47 states have migrated from traditional net metering to net billing rates or credits close to wholesale value, also introducing minimum or capacity charges (MIT CEEPR, 2023). In California, the Net Billing Tariff remunerates exported energy at market prices; Hawaii replaced net metering with plans with reduced credits and fixed payments; and in Arizona, solar customers face demand charges to contribute to fixed grid costs. These modifications seek to balance solar expansion with economic sustainability and equity among users (MIT CEEPR, 2023).

Finally, performance regulation models that align financial incentives with efficiency and innovation are consolidated. In the UK, the RIIO (Revenue = Incentives + Innovation + Outputs) scheme rewards distribution companies for achieving flexibility integration and cost savings goals. In the RIIO-ED2 period (2023-2028), Ofgem introduced a specific incentive that rewards or penalizes DSOs according to their performance in enabling flexibility and user satisfaction (Ofgem, 2024), promoting the efficient use of the network through digital solutions and alternatives to physical expansion.

In this way, many regulators are implementing innovative economic mechanisms to keep the DSO sustainable with high DG. The combination of decoupling, more fixed or capacity tariffs, performance incentives, and targeted reforms (such as charging for export) allows DSOs to avoid threatening their revenues and, in turn, focus on facilitating the energy transition rather than opposing it. The common denominator is to ensure that all users – pure consumers or prosumers – pay a fair share for the infrastructure they use, whether to extract or to inject energy, thus creating economic signals that mitigate potential cross-subsidies: prevent users without DG from bearing all the grid costs while others are partially disconnected; and efficient investments are promoted both in the network and in distributed resources (MIT CEEPR, 2023).

INCENTIVES AND MANDATES FOR DIGITALIZATION AND ADOPTION OF TECHNOLOGIES

Distribution grid digitalization has become an essential regulatory axis to enable the safe and efficient DG management. In major markets, regulators have built in incentives, funding, and even explicit mandates for DSOs to invest in smart technologies, from advanced meters and sensors to network management systems (ADMS) and distributed resource management systems (DERMS), that give them visibility, control, and operational capability over an increasingly complex network.

In the UK, Ofgem has developed a robust framework of incentives for technological innovation. Of particular note is the Strategic Innovation Fund (SIF), which co-finances smart grid, digitalisation and flexibility projects, allocating more than £4.1 million in 2024 to artificial intelligence and advanced grid forecasting initiatives (Osborne Clarke, 2024). In addition, distribution companies must present digitization and data strategies within their regulated business plans, including verifiable milestones for sensorization, automation, and data opening. The regulator assesses these advances and awards reputational and financial incentives for demonstrable achievements in digitalisation (Osborne Clarke, 2024). In Australia, digital modernization has accelerated following the 2021 reform that recognized the export of energy as a distribution service (Ashurst, 2024). The prohibition on DSOs from imposing zero export limits except in exceptional cases forces them to actively manage the network, driving the adoption of DERMS and dynamic injection control algorithms. At the same time, the ARENA agency has co-financed low-voltage control pilots with AusNet and SA Power Networks, testing the management of hundreds of solar inverters connected through cloud platforms. Overall, the Australian regulatory framework incentivizes digitalization by requiring technical capabilities to operate bidirectional networks. In Germany, the Law on the Digitalization of the Energy Transition requires the installation of smart meters and control systems in large facilities, while alternative management models such as the "energy traffic light" are explored, where the DSO defines, through monitoring infrastructure, the times when DERs can operate freely (green), with restrictions (yellow) or under direct control (red). At the European level, Regulation (EU) 2019/943 promotes the creation of the European DSO Entity, which standardises data exchange and develops common interoperability codes for future DERMS platforms. Some countries, such as the UK and France, are making strides in energy data hubs overseen by regulators, where DSOs manage secure access to consumption and generation data for authorised third parties.

Several regulators have accompanied these obligations with financing mechanisms and additional returns. In Italy, ARERA established a fund for smart grid pilot projects, granting an additional WACC on investments in automation, storage and advanced control. In the UK, the Network Innovation Competition/Allowance programmes and the current RIIO have allocated hundreds of millions of pounds to digitalisation, DERMS and microgrid projects. All these schemes seek to reduce the regulatory risk of innovating, rewarding distribution companies for adopting technological solutions that increase the efficiency of the system.

Digitalization has gone from being a technological option to a structural regulatory requirement. Through innovation funding, performance incentives, and modernization mandates, regulators are transforming the DSO into a digital electric system manager, capable of overseeing and coordinating DG, storage, and flexible demand. This global momentum ensures that the distribution network evolves as a smart platform for the energy transition (Eurelectric, 2024; Osborne Clarke, 2024).

"

Distribution grid digitalization has become an essential regulatory axis to enable the safe and efficient DG management.

06

CONCLUSIONS AND RECOMMENDATIONS

The evidence presented shows that DG expansion requires a comprehensive update of the regulatory framework to ensure its sustainable development. The decentralization of the electricity system cannot be sustained without an economic and technical structure that preserves grid stability and guarantees that the integration costs are borne by those who cause them. In this context, three priority areas of adjustment are identified: economic-tariff, technical-operational and institutional, aimed at strengthening the equity, transparency and sustainability of the distribution system.

The most urgent challenge is the modernization of the remuneration model for distribution companies. It is proposed to decouple revenues from the sale of energy and move towards a tariff structure based on the capacity and availability of the grid, recognizing that the essential function of distribution is to provide a reliable and flexible infrastructure, regardless of the volume of energy transported. This redesign requires decoupling the Distribution Value Added (VAD) from energy volumes and an update of cost allocation mechanisms, so that the investments and adjustments derived from the connection of new generators are distributed in a fair and transparent manner. At the same time, the consolidation of net billing schemes would make it possible to value the energy injected at prices that reflect the real costs of backup and use of the grid, avoiding cross-subsidies and guaranteeing the financial sustainability of the distribution system as a common infrastructure of the electricity sector.

From a technical perspective, DG sustainable development requires a comprehensive update of connection and operation standards, aimed at establishing homogeneous criteria of quality, safety and control. The regulation must provide distribution companies with the necessary maneuverability to evaluate, condition or reject projects that represent well-founded risks to the grid, based on feasibility studies and the actual capacity to host them. Likewise, minimum requirements must be incorporated for interconnection equipment and remote monitoring and control systems must be required to manage bidirectional flows in real time and maintain operational stability. These requirements must be complemented by regulatory incentives for the digitalization and automation of networks, recognizing the value of technologies such as SCADA, ADMS or DERMS in distributed resources management. Finally, the regulation must strengthen traceability and control over undeclared or non-standard installations, the proliferation of which represents a growing risk to the safety of personnel and the reliability of the system.

At the institutional and planning level, it is necessary to move towards greater regulatory coherence and systemic coordination between regulators, operators and distribution companies. The regulatory framework must clearly define the rights, obligations and attributions of each actor, including new figures such as demand aggregators or local energy managers, to avoid overlaps and liability gaps. It is also recommended to incorporate the joint planning of the reception capacity of the networks and the planned expansion trajectories, so that the incorporation of new DG projects responds to technical and sustainability criteria, and not to spontaneous growth. Institutional strengthening of distribution companies, together with explicit recognition of the new operational and administrative roles they assume in the active networks management, is essential to ensure that decentralization proceeds in a safe, orderly, and financially balanced manner.

In short, guaranteeing DG sustainable development requires strengthening the technical, operational and economic role of distribution companies. Only with regulatory frameworks that recognise their role as guarantors of the stability, equity and sustainability of the electricity system will it be possible to move towards an energy transition that is safe, inclusive and consistent with the real capacities of the grids.

> The evidence presented shows that the expansion of distributed generation requires a comprehensive update of the regulatory framework to ensure its sustainable development.

07
REFERENCES

Ashurst. (2024, July 4). AEMC announces significant changes for distributed energy resources. Ashurst Insights.

CERRE. (2022). The future of the distribution system operator (DSO): New roles and responsibilities in the energy transition. Centre on Regulation in Europe (CERRE).

Department for Energy Security and Net Zero. (2024, March 25). Improving the visibility of distributed energy assets: Call for evidence. UK Government.

Eurelectric. (2018). Charges for producers connected to distribution systems. Brussels: Eurelectric.

Eurelectric. (2024). Recommendations on the use of flexibility in distribution networks. Brussels: Eurelectric.

Florence School of Regulation. (2024). Distributed resources and flexibility. European University Institute.

IEA. (2022). Unlocking the Potential of Distributed Energy Resources Power system opportunities and best practices.

MIT CEEPR. (2023). Distributional effects of net metering policies and residential solar + storage adoption. Center for Energy and Environmental Policy Research (CEEPR), Massachusetts Institute of Technology.

NREL (2025). Energy Compensation Mechanisms for Distributed Generation.

Ofgem. (2024). DSO incentive report 2023–24. Office of Gas and Electricity Markets (Ofgem).

Ofgem. (2024, May 22). Ofgem lays the groundwork for consumer-friendly flexible energy use. Press release. Office of Gas and Electricity Markets (Ofgem).

Osborne Clarke. (2024, June 17). Energy transition: Ofgem allocates £41 million through its Strategic Innovation Fund. Osborne Clarke Insights.

Varios informes regulatorios y casos país (Ofgem UK, NY REV, ARENA Australia, NVE Noruega) como citados en el texto.

adelat