SUSTAINABLE ENERGY AFRICA

AFRICAN SCHOOL OF REGULATION

GET.transform
Transforming Energy Sectors Globally

An Analytical Framework for Rate Design in the Presence of Distributed Generation in Africa

GET.transform is co-funded by

german cooperation
DEUTSCHE ZUSAMMENARBEIT

Norway

Ministry of Foreign Affairs of the Netherlands

Sweden
Sverige

Austrian Development Cooperation

An Analytical Framework for Rate Design in the Presence of Distributed Generation in Africa

September 2025

An Analytical Framework for Rate Design in the Presence of Distributed Generation in Africa[1]

Table of contents.

---

[1] This report has been prepared by the African School of Regulation (ASR) under a collaborative research project with Sustainable Energy Africa (SEA) on “An Analytical Framework for Rate Design in the Presence of Distributed Generation in Africa“. The links to access the ASR research papers and position papers can be found on the website of the African School of Regulation https://africanschoolregulation.org.

An Analytical Framework for Rate Design in the Presence of Distributed Generation in Africa

Executive summary.

Traditionally, electricity tariffs have been designed by defining a tariff structure – a fixed monthly charge ($/month) and a volumetric charge ($/kWh) – that is compatible with the existing metering capabilities – typically an electromechanical device whose number of turns is proportional to the energy consumed – so that the total estimated costs of electricity supply for any given year could be paid by the application of the tariff to the customers.

Large industrial or commercial customers – and also residential customers in some countries – usually were subject to more complex tariff structures, including a capacity component ($/kW) where kW might correspond to the maximum contracted utilisation capacity or the individual demand coincidental with the system peak, for instance. Advanced tariff designs also include time differentiation (seasonal, weekdays and weekend, day and night, even hourly). The total estimated annual supply cost had to be allocated to the three components of the tariffs. Therefore tariff design consisted of i) computing the total costs of generation, the transmission and distribution networks, retail, system operation, the regulatory authority and any other costs included in the tariff (the "regulated revenue requirement, RRR" for each activity and the total amount), and ii) efficiently allocating these costs (using cost-causality criteria) to the (two or three) components of the tariff of each customer, so that the application of the tariff to all customers over a year could recover the total estimated annual supply cost.

The presence of distributed energy resources (DERs) has changed this picture radically, because these DERs can also provide electricity services with economic value. Therefore, the tariffs must be designed now with a different perspective, in terms of the services provided or received by each agent. Each agent must be remunerated for the services that the agent provides, and it should pay for the services that the agent consumes. Again, the corresponding costs must be allocated to the (two or three) components of the tariff. Any costs that the regulatory authorities consider that must be included in the tariff and that cannot be attributed to the energy consumed (kWh) or the capacity required (kW) by the agents must be recovered by the fixed component of the tariff ($/month) as a "residual charge".

It is therefore important to think now in terms of the provision of electricity services. What services exist, and what the costs of providing them are.

Indispensable definitions.

The supply of electricity requires that various "electricity services" must be provided. Costs are incurred in providing these services, to be recovered with regulated charges or with market prices.

- "Prices" result from electricity services supplied under market conditions.
- "Regulated charges" are determined by a regulatory authority to recover the costs of a regulated activity.
- "Charge" is frequently used to designate any component of the tariff.

The electricity services of relevance for the study of DERs are energy service, network service, operating reserves and firm generation capacity. There are other services, of lesser relevance for this study.

Cost causality versus cost reflectivity in tariff design.

For a company to be financially viable, the income it receives for providing an electricity service must be cost-reflective, i.e., the regulated revenue requirement (RRR) must equal the cost to the company of efficiently providing the service, and the estimated revenue from the application of regulated tariffs must equal the RRR.

End-customer tariffs are almost never cost-reflective, due to the generalised practice of tariff cross-subsidisation, but the aggregation of the revenues obtained from application of the tariffs must equal the RRR. Otherwise, the difference between the RRR and the estimated revenue from the application of regulated tariffs must be covered by subsidies.

As affirmed above, in aggregation, the revenues from the application of tariffs must recover the costs of i) all the activities that are necessary for electricity supply: generation, transmission, distribution, retail, system operation, the regulatory authority and ii) plus other regulated costs – various categories of subsidies to fuels and technologies, support to vulnerable customers, efficiency programs, research, etc.

Note that only a few of these costs can be attributed to customers' actions as "causing" the costs: for instance, energy services, network services, operating reserves and firm capacity. All remaining costs that regulators include in the tariff cannot be allocated to customers with the criteria of cost causality and must be grouped under the label of "residual costs".

The structure of the tariff in the presence of DERs

The information required for tariff design.

It is impossible to know, meter and control all the devices and DERs that exist behind the meters of the customers. It is, however, required that the existence of DERS be reported; their authorisation, registration and compliance with quality and security standards must be mandatory.

All needed information must be obtained from the meter at the connection point. Fortunately, a correct tariff design "only" needs the value of the energy withdrawn or injected each hour (or half hour, or every 5 minutes, if very variable) at the connection point.

The structure of the tariff.

As indicated above, in the presence of DERs, electricity tariffs must be designed with the purpose of paying/being paid for the services consumed/provided, rather than on allocating the costs of the activities needed for electricity supply, although global cost reflectiveness is always a primary objective of tariffs' design.

Tariffs designed to capture cost-causality reasonably well must be structured with volumetric ($/kWh), capacity ($/kW) and fixed ($/month) components. Therefore the tariff must include explicit ($/kWh, $/kW and $/year) charges with an adequate level of time differentiation for each charge (for instance, annual for the fixed component; seasonal and day and night for the capacity component; and hourly for the energy component) for each one of the considered electricity services (i.e., those with cost causality), and a "residual cost" including all the remaining costs, i.e., those without a recognizable cost causality. In the practical implementation (the electricity bill), the several charges for each one of the three components are aggregated into a single numerical value.

It is important to state that the charges or credits of the components with cost causality must be (obviously) symmetrical.

The residual costs must be allocated to the fixed ($/month) component of the tariff according to policy, social and economic efficiency criteria, to be discussed later.

The energy component ($/kWh) must contain only the marginal cost of energy production *(in the absence of a wholesale energy market, which is the case in all African countries)* or the hourly price of a national or regional day-ahead market, when it exists and is considered suitable for the purpose. No other component must be added to this price so that demand can respond efficiently to this economic signal.

The "capacity" component ($/kWh) is a catch-all for several electricity services that are necessary to prevent power system stress situations that may be triggered by the withdrawal or injection of power at critical times:

- Peak demand or peak power injection at a distribution feeder or in a transmission line, which may require network reinforcements.
- Operating generation reserves, ready to respond to changes in total generation or demand.
- Margin of installed and set-to-operate generation capacity or demand response, ready to respond in situations when the longer-term operating generation reserves become insufficient.

Hourly meters must allow allocating the charges or credits properly in time, and identify when they coincide with stress situations of the power system.

Ideally, use "forward-looking peak-coincident" capacity charges for distribution and transmission networks. All network costs that are not recovered this way must be considered "other regulated charges", i.e., added to the "residual charge".

Remember that "network charges should not depend on commercial transactions". Network charges apply at the connection point, and they provide access to the entire network. The concept and application of "wheeling charges" must be abolished.

The fixed ($/month) component must include:

- Some costs with cost causality that are not directly related to the value of withdrawals or injections, like for instance the regulated retail costs, which only depend on the type of customer (large or small; residential, commercial or industrial; special needs) and perhaps on the kind of metering system.
- All the remaining costs, lumped together in the "residual cost" term of the fixed cost component of the tariff.

Note that, in general, **the residual costs must include generation costs** not fully recovered by the marginal generation cost, the operating service costs, and the firm generation capacity cost, **network costs** not recovered by the charges for the network-related services or nodal prices when they are used, in addition to costs of **organisations**, various **subsidies**, and other **policy charges**.

The allocation of the residual costs must be guided by various political, social & economic efficiency considerations, which may be roughly coincident. Here, the recommended approach is to follow the **Ramsey pricing criteria**[2] to maximise economic efficiency, conveniently adapted to comply with

[2] Ramsey pricing is a strategy used in regulated monopolies to allocate fixed costs across different customer groups in a way that minimises the overall distortion to demand while allowing the firm to recover its total costs. Prices are set so that the markup over marginal cost is inversely proportional to the price elasticity of

governmental guidelines, such as the protection of vulnerable customers, the safeguard of the competitiveness of local industries, or the avoidance of popular opposition to tariff increases.

Implementation recommendations.

The present situation of metering and tariff design.

The starting point for any proposal of modification is the present situation. The regulatory review described in Chapter 4 has identified the following characterisation of the typical current situation:

- End-customer tariffs typically consist of a constant volumetric component ($/kWh) that contributes a large percentage of the electricity bill; there is frequently also a small, fixed component ($/month) and rarely a capacity component ($/kW). Therefore, the volumetric component typically contains the energy term, the terms for the other electricity services and most or all of the residual charge.
- Most residential and small commercial, and industrial customers have standard meters with rotating disks that turn in either direction depending on the direction of the flow of electricity.

Key recommendations.

The recommendations focus on reducing the shortcomings of the current tariff design and metering systems gradually. The recommendations are presented in priority order, with the most relevant ones first:

First priority: Avoid that the energy produced behind the meter cancels any charges other than the energy charges.

It is assumed that the typical current situation that was described above and that there is no regulatory response.

The lack of regulatory response results in a serious problem. Why?

- The energy generated behind the meter cancels the same amount of kWh consumed and therefore the corresponding energy charge, which is correct, but also other charges not related to the energy consumed, which will be allocated to other customers. This is not correct.
- Any exported energy will be paid the entire volumetric term, instead of only the energy term. This is not correct.
- As the total payment will be smaller than it should be, the corresponding tax will also be smaller than what it should have been.

Version 1. It is assumed that it is not viable to request that customers with DERs register and install hourly bidirectional meters. Then, it is recommended that, for all customers:

- Keep the standard meters for the time being.
- Apply strictly the volumetric ($/kWh) charge or credit to the monthly net reading of the meter.

---

demand of each customer group. In the electricity tariff design being discussed here, the Ramsey pricing rule would apply to the residual costs, which lack any cost causality criterion to be efficiently allocated.

- Include in the fixed charge ($/month) the retail charge and the allocation of the residual costs as determined by the regulator. Make use of Ramsey-like prices, with a reasonable classification of customers, to allocate the residual costs.

Version 2. It is assumed that it is viable to request that customers with DERs register and install hourly bidirectional meters. Then, it is recommended that, for customers with DERs, the following measures must be taken:

- Mandatory registration, standards compliance and bidirectional hourly meters.
- Symmetrical strictly energy charges and credits ($/kWh) for the energy withdrawn and injected.
- Symmetrical charges and credits ($/kW) for any other explicitly considered electricity services. No need to define "kW", just add the charges as "capacity".
- Retail charge ($/month) adapted to each type of customer.
- Residual charge ($/month) allocated according to Ramsey-like criteria.

And for other small customers:

- Keep the standard meters for the time being. Voluntary change to hourly meters, under se rules as customers with DERs.
- Strictly energy volumetric ($/kWh) charge or credit applied to the monthly net reading of the meter.
- Fixed charge ($/month) including the retail charge and the allocation of the residual costs as determined by the regulator. Make use of Ramsey-like prices, with a reasonable classification of customers, to allocate the residual costs.

Second priority: Avoid netting energies produced and consumed at different times.

It is assumed that customers with DERs have registered and installed hourly bidirectional meters. Customers without DERs are not mandated to have hourly meters, and nothing changes for them.

The lack of regulatory response results, again in a serious problem. Why?

The energy generated behind the meter at some time during the month cancels the same amount of kWh consumed at any other time during the month. These energies have different economic values. Typically, it can be expected that the energy produced with solar panels in the middle of the day has less economic value than the energy consumed in the evening, when solar panels are not generating. An implicit subsidy to solar panel owners.

For customers with DERs, it is recommended to apply the value of energy at each hour to the energy withdrawn or injected at each hour at the connection point. This is easy to apply once the hourly bidirectional meters are installed, and this fixes the problem completely. Time-of-use meters are an inferior alternative.

Additional recommendations.

This recommendation is related to the possibility that some customers might defect without a good economic reason. Since, frequently, the electricity tariff includes costs that do not have to be necessarily part of the tariff. It is advised to reconsider which costs are included in the electricity tariff if inefficient grid defection (i.e., defection that would not happen with a better tariff design) is a serious threat.

It is also recommended to consider the possibility of improving the accuracy of cost causality application and the contribution of demand to network service provision. To this end, gradually increase the locational component of tariffs at the transmission level for large generators and demands, as well as at the distribution level in feeders with active constraints due to peak importing or exporting power flows.

Bringing out the value of DERs beyond what tariffs can reasonably achieve.

The level of communication between the system operator and individual customers (except for the large ones), regarding the demand for electricity services and their costs, is limited by technology and convenience.

- For instance, the system operator may need a temporary reduction of a specific amount of demand for 20 minutes, because of an expected ramp in wind production, but it is cumbersome to translate this information to the sufficient customers who are willing to provide this service.
- Similarly, a system frequency deviation from the target value could be damped by the joint action of many customers, but they lack this information.

The value of these potential services cannot be captured by the three accepted categories of charges in the tariffs: $/kWh, $/kW and $/year. More sophisticated tariff designs and economic signals would be needed. Once a sufficient level of digitalisation of a substantial number of customers has been reached, these customers can be invited by an "aggregator company" to join to perform tasks with economic value, such as helping to control the system frequency, or the local voltage, or to shave the peak demand in a feeder to delay the need for a reinforcement, or to smooth a ramp in demand or production.

The aggregator can receive the request for a service from the system operator, it can also know the current situation and potential response of each customer, and it can coordinate a joint response, providing the required service in exchange for economic compensation to be shared with the participating customers. This can bring out the full economic value and technical potential of the DERs. The existence and activity of aggregators must be encouraged and facilitated, which is expected to result in a more efficient and reliable provision of electricity services.

An Analytical Framework for Rate Design in the Presence of Distributed Generation in Africa

1. Motivation and objectives of the study.

1.1. Motivation.

Important changes in the provision and consumption of electricity services are underway worldwide. These changes are driven by a confluence of factors affecting the distribution side of power systems. A variety of emerging distributed technologies—including distributed generation, flexible demand, and energy storage, supported by advanced power electronics and control devices, which are typically designated under the term "distributed energy resources or DERs" —are creating new options for the provision and consumption of electricity services. At the same time, information and communications technologies are rapidly decreasing in cost and becoming ubiquitous, enabling more flexible and efficient consumption of electricity, improved visibility of network use, and enhanced control of power systems.

The African power sector is also witnessing an unprecedented surge in distributed generation (DG) adoption, particularly. Countries like South Africa, Namibia, Kenya and Eswatini are experiencing installation rates that rival developed markets, driven not by environmental concerns or government incentives, but by businesses and industries seeking reliability and cost control. South Africa's remarkable journey from 500 MW of distributed capacity in 2019 to 5 GW in 2023 exemplifies this transformation, with distributed solar now amounting to approximately 15% of peak demand. In South Africa, this significant growth of distributed solar has emerged as a crucial solution to the country's power crisis, reducing average hourly demand by nearly a gigawatt. But similar penetration levels are seen in Kenya (11%), Namibia (15%) and Eswatini (12%).

This rapid, need-driven adoption of DG poses both opportunities and challenges for African utilities. Creating a clean, efficient, and resilient electricity system will pivot, in part, on successfully integrating renewable-based DGs into the design and operation of the electricity grid and economic signals – with an adequate structure and level of granularity in location and time – can provide the incentive structure needed to achieve this integration, regardless of whether investments in and management of DGs are undertaken by customers, by utilities, or by third-party service providers.

1.2. Objectives.

This study presents a framework for proactive regulatory, policy, and market reforms designed to enable the efficient evolution of power systems, facilitating the integration of all resources, be they distributed or centralised, that contribute to the efficient provision of electricity services and other public objectives. Although the conclusions of the study can apply in a diverse set of contexts and regulatory regimes, this study focuses mainly on Africa and more specifically on sub-Saharan African (SSA) countries.

In addition, we recognise that regulatory and policy reform often proceeds incrementally and that each jurisdiction faces unique challenges and contexts. As such, we offer this framework along with guidance on the key trade-offs regulators and policy makers confront as they pursue opportunities for progressive improvements.

The need for proactive regulatory reform is clear. Consumers now face unprecedented choice regarding how they get their power and how they manage their electricity consumption. New opportunities include the ability to invest in distributed generation, smart appliances, energy storage and energy efficiency improvements. And even defecting from the main grid, becoming autonomous.

At present, the vast majority of power systems lack a comprehensive system of efficient prices and regulated charges for electricity services. As a result, investment or customer aggregated action opportunities that could deliver substantial economic value are being left untapped because of inadequate compensation. At the same time, other customers are making investments that are overcompensated for the services that they provide to the power system. Since these latter situations cannot continue indefinitely, abrupt policy and regulatory changes are inevitable, causing frustration, economic losses and stranded assets, as multiple cases in developed countries have shown. For example, the combination of simple volumetric tariffs and net metering policies has contributed to the rapid adoption of rooftop solar photovoltaics (PV) in several jurisdictions, while exposing several flaws in current ratemaking. The rapid uptake of solar PV also demonstrates how quickly consumers can react to economic signals—whether well or poorly designed—and the importance of proactive, rather than reactive, policymaking and regulation. In multiple jurisdictions, challenges that once seemed insignificant have quickly become overwhelming, and failure to act can catch policymakers and regulators flat-footed.

The framework proposed in this study is designed to establish a level playing field for the provision and consumption of electricity services, whether via centralised or distributed resources. The goal is to remove inefficient barriers to the integration of cost-effective new sources of electricity services, rethink ill-designed incentives for certain resources, and present a system of prices and charges that can animate efficient decisions. With this framework in place, all consumers and producers of electricity services can make efficient choices based on accurate incentives that reflect the economic value of these services and their own diverse personal preferences. The recommendations must be consistent with the technical and financial capabilities of the utilities, the current situation of metering systems, and the political economy characteristics of the different African national power sectors.

2. Methodology and road map of this report.

The study is organised around three main tasks. Task 1 must provide the conceptual approach for designing electricity tariffs in the presence of DERs and for capturing the economic value of DERs. Task 2 involves taking stock of the current situation of DERs in several African countries and reviewing experiences – in Africa, but more importantly elsewhere – from which useful lessons could be learned. Task 3 – which must rely heavily on the results of Tasks 1 and 2 – must provide actionable, context-specific recommendations for tariff design, improved metering requirements, and value capture from DERs.

The structure of this report is simple because it follows the organisation of the study around the three tasks. After Chapter 1, which presents the motivation and objectives of this study, Chapter 2 briefly introduces each of the three tasks that comprise the study. Subsequent chapters 3, 4, and 5 are devoted to the development of tasks 1, 2, and 3, respectively. Chapter 6 lists the main references used in the study.

2.1. Task 1. Development of the conceptual framework.

This task provides the basis for any sound recommendation regarding tariff design in the presence of DERs and also brings out the economic value of DERs and how it can be quantified. This task consists of two components.

The first component is the understanding of the economic impact (value and/or cost) on the global power system welfare of the presence of DERs behind the connection point of each customer. This must be contemplated from a double perspective since, with DERs, the end customers can consume or produce electricity at different times during the day. These consumers can react to the economic signals provided by the regulated tariffs, which may have different structures (fixed charges, \$/kW or \$/kWh) and may vary in time and location. Conceptually (and if the metering system allows it), the tariffs should approximate a correct appraisal of the true value and cost for the system of the behaviour of the customers when observed at their connection point (the meter) to the power system. Therefore, this first component of Task 1 of the study must define an ideal tariff that can charge and/or remunerate properly the behaviour of the customer. Recommending a reasonable pragmatic implementation of this ideal tariff that is consistent with what is presently possible to achieve in African countries is the objective of Task 3.

The second component of Task 1 is to figure out what else needs to be done to showcase and capture the economic value of DERs that are not covered by the first component. Does a perfect tariff with an advanced meter compensate (charge) the customers for their value (cost) to the power system? Because, if it does, anything else that is added must be considered as double-counting, either by compensating or by charging. We can argue that i) less than perfect tariffs and meters fail to capture all the value (or the cost) of the behaviour of the customers, for instance the locational value of batteries of customers placed in congested feeders at the peak time of the day, but also that ii) in addition to what is already covered with a "perfect" tariff, there are some services with commercial value, such as frequency control, contribution to operating reserves, emergency load shedding or explicitly contributing to making some network reinforcements unnecessary, which can only be provided by aggregators, which, after being remunerated by the system operator or the distribution company for these services, will share part of these revenues with the participating customers.

2.2. Task 2. Stocktaking of the regulatory situation of DERs in African countries and elsewhere.

The purpose of this task is twofold. In the first place, it involves learning about the current status of the end customer tariffs and metering systems in a sufficiently representative sample of African countries, and particularly the existence of any specific regulation concerning the design of electricity tariffs in the presence of DERs, as well as any actions to facilitate the extraction of economic value from DERs. Since the objective of this study is to come up with actionable recommendations to be implemented in African countries, the focus in this first part of the task is to understand the present situation and to figure out what is possible in the short, medium and long term.

In the second place, a review of relevant international experiences – in Africa or elsewhere – will be carried out to extract lessons that could be useful in African countries, both on successes and failures, on regulatory measures (or the lack of them) on the same topics.

Topics of interest for the review of the current situation in tariff design in African countries and how it is being affected by the presence of DERS, are:

- Understanding the process that is presently followed to determine the tariffs for the end customers. For this study, the key topics to be examined are:
    - How the presence of DERs in the distribution network is reflected in the determination of the revenue requirement of the activity of distribution. This includes at least three subtopics: i) whether the reduction of total energy metered from all the customers is reflected or not in the revenue requirement; ii) whether the need for additional assets and controls in the distribution network is reflected or not in the revenue requirement; and iii) whether the presence of DERs distorts any existing incentive mechanism to reduce losses in the distribution network.
    - The relationship between the distribution revenue requirement and the component of the tariff associated with the distribution activity. This requires examining: i) how often the revenue requirement is updated and how deeply the update is made; and ii) how often the tariffs for the end customers are updated and how this update relates to the update of the revenue requirement.
- The structure and numerical value of the regulated tariffs for the different classes of customers, as well as understanding the rationale behind the existing tariff structure and the allocation of costs. Of particular interest is the breakdown into i) energy cost; ii) network (T and D, including retailing) costs; iii) other regulated charges; and iv) taxes. Any explicit tariff cross-subsidisation practice would also be of interest to know. Of particular interest for this study are the tariffs for residential customers, as well as for small commercial and industrial customers in the same categories.
- Any special tariffs for customers with DERs (e.g. net metering regulation, or similar) or plans to develop these special tariffs.
- The current situation of metering and any existing plans to improve it.
- Any additional initiatives to recognise or facilitate the economic value of DERs.

2.3. Task 3. Elaborate actionable context-specific recommendations.

Starting from the conceptual basis provided by Task 1, plus the current situation in African countries and the lessons learned from existing relevant experiences in Task 2, Task 3 will issue actionable context-specific recommendations for African countries on tariff design, improved metering requirements and value extraction from DERs.

Considering the current situation of African countries and the feasibility of modifying the existing tariffs and enhancing the metering capabilities of customers (or specifically those with Distributed Energy Resources, DERs), Task 3 must recommend a tariff design and metering system that is suitable for each case.

The recommendations must weigh the impacts of doing nothing or waiting too long or implementing timid measures versus the costs, disruptions and potential pushback of more radical measures that try to get closer to the ambitious objectives presented in Task 1 and the most successful experiences described in Task 2. Further investigations may be conducted following this report to engage with regulatory authorities, utilities, and other stakeholders to confirm the feasibility and effects of the suggested actions, or to review computer models that may be necessary to implement the recommendations or assess their impact.

3. Development of the conceptual framework. [3]

This conceptual framework is developed in abstract terms, supported by fundamental economic, engineering, and regulatory principles, attempting to be valid in any context. The implementation guidelines that emerge from this analysis seek to help attain maximum economic efficiency yet may require metering sophistication and the capacity to deliver and respond to economic signals that are still beyond the reach of many electricity companies and customers, in several developed markets and in African countries in particular.

This is appropriate. Task 1 clarifies the implications of the basic principles and identifies the actions that should be taken under ideal conditions. Once Task 1 is complete, and once the present situation in African countries is understood and international lessons are reviewed in Task 2, Task 3 will recommend context-specific measures for African countries that adapt the guidelines from Task 1 to the circumstances and possibilities identified in Task 2.

Let us follow the principles of economics, engineering, and regulation and see where they lead.

3.1. The impacts of DERs.

On the remuneration of the distribution activity.

The presence of DERS requires adaptations in the regulation of the distribution activity – the Distribution Revenue Requirement (DRR) determined by the regulator – where by "distribution" it is understood only the main connected grid, and not the off-grid solutions – minigrids and standalone systems – also involved in electricity supply. Two are the reasons for these regulatory modifications:

In the first place, distribution costs may increase with a significant presence of DERs – because of infrastructure reinforcements to deal with reverse flows, abnormal voltage levels, additional metering and controls – and, therefore, the method of computation of DERs must account for this impact. The country regulations that have been reviewed in Chapter 4 of this report do not consider the impact of DERs explicitly. However, a calculation of the DRR based on a correct accounting and auditing of the distribution assets will implicitly account for this impact. If the asset accounting is properly done, there is no need to modify the current procedure and regulation.

In the second place, DERs decrease the total amount of energy distributed. This presents two problems. The first one is to make sure that the adopted method of computation of the DRR does not depend explicitly on the amount of energy distributed. This does not seem to be the case in the reviewed country regulations, and therefore, as indicated before, an evaluation of the DRR based on a correct accounting of the assets can be sufficient.

The second problem is the need for a systematic tariff adjustment. As the DERs decrease the total amount of energy distributed, the revenues collected by the distribution company from the volumetric component of the tariff will also decrease, although the distribution network costs have not decreased and they have probably increased. Therefore, the tariffs must be periodically updated (which is something that has not been observed in the reviewed regulations) to make sure that, aggregated, the tariffs precisely recover the DRR established by the regulator.

---

[3] This section owes much to the MIT report "The utility of the future", Ignacio Pérez-Arriaga et al., 2016. https://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Full-Report.pdf

The presence of DERs requires a radical change of perspective in electricity tariff design.

Traditionally, electricity tariffs have been designed by defining a tariff structure – a fixed monthly charge ($/month) and a volumetric charge ($/kWh) – that is compatible with the existing metering capabilities – typically an electromechanical device whose number of turns is proportional to the energy consumed – so that the total estimated costs of electricity supply for any given year could be paid by the application of the tariff to the customers.

Large industrial or commercial customers – and also residential customers in some countries – usually were subject to more complex tariff structures, including a capacity component ($/kW) where kW might correspond to the maximum contracted utilisation capacity or the individual demand coincidental with the system peak, for instance. Advanced tariff designs also include time differentiation (seasonal, weekdays and weekend, day and night, even hourly). The total estimated annual supply cost had to be allocated to the three components of the tariffs. Therefore tariff design consisted of i) computing the total costs of generation, the transmission and distribution networks, retail, system operation, the regulatory authority and any other costs included in the tariff (the "regulated revenue requirement, RRR" for each activity and the total amount), and ii) efficiently allocating these costs (using cost-causality criteria) to the (two or three) components of the tariff of each customer, so that the application of the tariff to all customers over a year could recover the total estimated annual supply cost.

The presence of distributed energy resources (DERs) has changed this picture radically, because these DERs can also provide electricity services with economic value. Therefore, the tariffs must be designed now with a different perspective, in terms of the services provided or received by each agent. Each agent must be remunerated for the services that the agent provides, and it should pay for the services that the agent consumes. Again, the corresponding costs must be allocated to the (two or three) components of the tariff. Any costs that the regulatory authorities consider that must be included in the tariff and that cannot be attributed to the energy consumed (kWh) or the capacity required (kW) by the agents must be recovered by the fixed component of the tariff ($/month) as a "residual charge".

It is therefore important to think now in terms of the provision of electricity services. What services exist, and what the costs of providing them are.

3.2. Electricity services.

Electricity services are activities performed within a power system that have economic value for some agents, whether or not this value is monetised. These services create value by enabling the consumption of electrical energy, lowering the costs associated with consuming electrical energy, or both. DERs can provide electricity services, as can any other energy resource. Electricity services vary widely in nature.

Electrical energy.

At the core of all electricity services is electrical energy. Electrical energy is the fundamental service in the power system and the reason for its existence. Consumers value the useful work it provides, such as heating, cooling, lighting, and powering electronics and transport. That is, consuming electrical energy creates utility for consumers.

Power systems have two key physical features that are essential to understanding electricity services. First, supply and demand must always be in balance and at all locations. Second, electrical energy must be delivered from where it is produced to where it is consumed through networks that are subject to physical laws and constraints. The interaction of the power balance constraint with network constraints creates unique values of electrical energy at specific points and times in the network. These values are often termed nodal prices or locational marginal prices, LMPs. Mathematical and computational techniques exist to compute the price of electricity at a given time and location within the network. Conceptually, these prices can be extended to the entire grid, reaching every customer.

Thus, LMPs could, in theory, coordinate consumption and production at all points to respect power balance and network constraints and motivate investment decisions. Networks are a key exception since they are not fully compensated by spot prices.

Other electricity services.

In practice, regulators, system operators, or policy makers frequently place constraints on the planning and operation of the power system—above and beyond existing physical constraints—that define additional services. These constraints are intended to transform complex decision-making processes into simple formulations that can be easily implemented by power system operators and planners (e.g., “the amount of secondary operating reserves should be equal to the rated capacity of the largest generation unit in operation plus 3 percent of the expected demand,” “the power flow in a certain line cannot exceed 80 percent of its thermal rated capacity,” or “the amount of firm-installed capacity must exceed estimated peak demand by 10 percent”). These constraints are simplifications, and in some cases, they emphasise security of supply over pure economic efficiency. Such constraints take two primary forms: coordinating constraints and policy constraints. Examples include operating reserves, firm generation capacity, and electricity network capacity margins.

Locational value of electricity services.

The value of some electricity services differs substantially depending on the location where the service is provided or consumed within the power system. These differences in value emerge from physical characteristics of electricity networks, including losses, capacity limits of network components, and voltage limits at network nodes. It has been shown already that the value of electrical energy depends on location. We refer to services that exhibit this quality as having “locational value.” [4]

The value of other services is *non*-locational – that is, the value of the service does not change based on where it is delivered in the power system. For example, operating reserves[5] are deployed to contain frequency deviations that emerge as a result of imbalances between supply and demand due to forecast errors or unexpected failures of power plants or lines. Frequency is consistent across

[4] Ibid. For a precise definition of electricity services, as they directly arise by the existence of constraints to the minimisation of the overall social welfare derived from production and consumption of electricity, see Chapter 2 of this MIT report.

[5] Operating reserves are additional generating capacities that can be quickly mobilized to maintain grid stability despite the variability in supply and demand, keeping the balance between demand and supply even during unforeseen events like sudden demand surges or generator failures. Operating reserves are crucial for preventing blackouts and ensuring a reliable electricity supply.

an entire synchronised interconnected system, and, as a result, the value of frequency regulation is consistent across that entire system.

DERs can provide a range of services, including services with locational and non-locational value. Their distributed nature allows siting and operation in areas of the system where their services are most valuable. Understanding which services have locational value is, therefore, critical to understanding how DERs can create value.

The value of DERs is highly context-dependent and can decline quickly as more resources are deployed to supply a given service in a specific location and time. To value DER services accurately, prices, regulated charges, and other incentives should reflect the marginal value of these services as far as practical.

What follows is a brief description of services considered most relevant for DERs. This is not intended to be exhaustive.

Operating reserves.

Various forms of *operating reserves* are created when a constraint is placed on the amount of capacity that must be held "in reserve" to help meet power balance constraints in the case of unexpected failures of power plants or lines or of errors in forecasted demand or variable renewable energy supply. These reserves take the form of forward commitments to provide power later purchased by system operators (on behalf of electricity consumers).

Regulatory intervention has been universally adopted to ensure that sufficient reserve capacity is procured. System operators, tasked by regulators and policy makers with ensuring that the power system operates within secure limits, set constraints so that the agents in the power system are ready to respond to imbalances between electricity supply and demand with a prescribed total volume in a prespecified time range.

Many definitions of reserves exist. Nonetheless, the service emerges in the same way in these various contexts: by adding a minimum level of reserves (a constraint) and by specifying the characteristics of these reserves. Coordinated DERs in large amounts can contribute diverse kinds of operating reserves and can be compensated economically for it.

Firm capacity.

Similarly, a regulator or policy maker may decide to intervene to ensure that a level of capacity (either as available generation capacity or demand ready to disappear) will be available to meet demand at some future date, and a new service is created: *firm capacity.*

Network capacity margins.

The same types of simplifying or coordinating constraints can be applied to the functioning of networks. For example, in many systems, strict transfer capacity limits are placed on transmission or distribution lines—that is, system operators dictate that the instantaneous power transfer on a line cannot exceed a certain amount. These limits can emerge from thermal, stability, or voltage issues.

System operators may include some sort of "network capacity margin"—that is, they may impose a constraint on the minimum margin between network transfer capacity and the peak expected power flows through that network infrastructure. The possibility of this constraint becoming binding creates an opportunity to provide a service by either building more network capacity or securing commitments for future actions that can reduce peak power flows (e.g., through the installation and operation of DERs, contracting with flexible demand, etc.).

3.3. Costs, prices, regulated charges and tariffs.

DERs and price responsiveness.

DERs allow the agents in a power system to meet their own energy needs and to deliver electricity services to the system. DERs bring new options for service provision and enable demand for electricity services to become increasingly price responsive. Well-designed prices and charges become ever more important in this environment, as agents are increasingly capable of adapting their behaviours to power system conditions at specific locations, during particular times, and in relation to what specific services are being consumed or provided.

Centralised and distributed resources are situated in different locations and have different sizes and temporal patterns for both production and consumption. The only way that these two categories of resources can jointly and efficiently operate, expand, compete, and collaborate is in the presence of a comprehensive system of economic signals—market-determined prices and regulated charges[6]—with adequate granularity to capture important variations in the value of the specific services across time and location.

Ideally, it should be established a comprehensive system of *prices* (for those services provided in markets) and regulated *charges* (for remuneration of network activities and any policy costs included in electricity rates). Such a system can act as the nervous system of the power sector, coordinating the actions of many disparate providers and consumers of electricity services by communicating prices and charges that reflect time- and location-specific conditions.

Ideally, these prices and regulated charges would reflect all the operating conditions and investment needs of the system, and the participation of all system users would be allowed. For example, to fully realise the possible benefits of distributed storage or price-responsive demand, energy prices that sufficiently reflect temporal and spatial variations in the costs of meeting electricity demand or providing electricity generation must be communicated to all customers via the distribution company, independent aggregators, and/or automated energy management systems. These economic signals would encourage the placement and operation of DERs when and where they can prove more cost-effective than centralised providers of services.

A comprehensive system of prices and charges.

A comprehensive system of prices and charges that provides economic signals and enables cost recovery consists of the following four components:

1) a price for electric *energy* (active and, in some particular cases, reactive too should be included) withdrawn or injected;
2) charges for network-related services;
3) prices or charges for other *services*, such as the provision of *operating reserves* to respond to short-term imbalances of supply and demand and to keep the frequency stable; or having

[6] Tax incentives and other policy incentives can be part of the ensemble of economic signals that the power system agents are subject to, beyond the basic system of prices and charges.

readily available *firm capacity* to respond to situations when the available installed generation capacity may be insufficient to meet the estimated demand; [7] and

4) charges to provide for *regulatory and policy costs* (such as costs incurred supporting energy efficiency or renewable targets, subsidies to vulnerable customers, the cost of organisations like the regulatory authority or the system operator, and taxes).

These four cost components differ in an important aspect that determines how they must be considered in the design of the tariff. This aspect is their "cost causality", i.e., what action of the customers causes each one of these costs. Some of these costs (1) are associated with the energy withdrawn or injected at the connection point. Network-related costs (2) are mostly caused by peak flows in distribution and transmission lines, in either direction, which require to incur in additional investments to increase the capacity of the networks or to keep the voltage within acceptable boundaries. Other costs (3) are incurred to be ready to respond to potential imbalances of supply and demand, either in the short-term or for potential imbalances of longer duration. Finally, the regulatory or policy costs (4) cannot be related to any specific action by the customers; they lack "cost causality" and here they will be denominated "residual costs".

Once this is understood, it is possible to arrive at the following practical conclusions when designing electricity tariffs.

Practical conclusions of tariff design

1. Regardless of the adopted level of time or location discrimination in the price of electric energy, the per unit value ($/kWh) applied to energy injected or to energy withdrawn at the connection point of a customer at a given time and location must be symmetrical, which is the economic value for the power system of that injection or withdrawal at that time and in this location.
2. The same symmetry principle must apply to the *services*[8] in categories (2) and (3) above, such as operating reserves, firm capacity or network-related services, because of the same reason. If there is an economic value, at the margin, it must be the same whether by providing or requiring the service.
3. Most countries do not try to use any cost causality criterion in the allocation of costs (2) and (3), which are treated the same as the regulatory and policy costs, therefore increasing the category (4) of "residual costs". If there is no "cost causality", the symmetry criterion does not apply, and these charges are allocated to generation and/or consumption with the different categories of consumers attending to considerations foreign to the power sector. Other countries may decide to charge these costs (totally or partly) according to some causality criteria, for instance charging the network-related costs in proportion to the contribution of the withdrawal (or injection) of each agent to the generation (or demand) at the time(s) of maximum network stress, whether at

[7] The activity of retail or commercialization of electricity is a necessary service, which in most power systems is regulated and considered as part of the distribution activity, while other systems have implemented retail competition and retailing costs are embedded in the energy price.

[8] It is not possible to label each of these services as "generation" or "demand", since both generation and demand may intervene in providing the services. In the same way, network reinforcements are typically needed because of peak flow conditions, but also to reduce network losses that happen at all times. The professionals who design tariffs struggle when they try to allocate the various costs to the three standard categories of charges in advanced tariffs: the volumetric charge ($/kWh), the capacity charge ($/kWh) and the fixed charge ($/month or year).

transmission, general distribution, or even feeder level. The same thing could be said of the firm generation costs, which could be charged to the contribution of the withdrawal (or injection) of each agent to the generation (or demand) at the time(s) when the power system is closest to load curtailment conditions, because supply may be insufficient to meet total demand.[9] Ideally, these charges should be separately applied in a "capacity component" of the tariff; they can also be applied as a monthly or annual lump sum, but not added to the energy component. Any fraction of the network costs not recovered in a "cost causality way" must be added to the component (4) of the residual costs.

4. Residual costs cannot be allocated in a "cost causality" way, as $/kWh or as $/kW. They must be charged as a monthly or annual lump sum, not to be added to the energy component, and be allocated to various categories of customers, considering considerations foreign to the power sector.

In summary, out of the four components of the cost of service, category (1), and – if viable (2) and (3), either party or totally– must be considered with their "cost causality" features and must be applied symmetrically to withdrawals and injections in the volumetric ($/kWh) or capacity ($/kW) component of the tariff. Category (4) and a fraction or the totality of costs (2) and (3) can be charged as a monthly or annual lump sum, separate from the energy component.

A clarification on cost-reflective remuneration, prices and charges.

Cost reflectiveness refers to the capability of the remuneration (the "revenue requirement"), the prices and the charges established by the regulatory authorities to recover the costs incurred in the supply of electricity.

The cost reflectiveness of end customer tariffs obviously depends on the level of precision in the design of the tariff, in the time and space differentiation, and the characteristics of the meter. Regarding spatial differentiation, nodal pricing (also named "locational marginal pricing") has been adopted only in a few countries, and only for large generators connected to the transmission network. Customers connected to the distribution network are universally subject to average tariffs that do not distinguish between urban and rural areas, which have very different distribution network costs, or between feeders that are close to their capacity limit and others that have lots of spare capacity. Regarding time differentiation, standard meters can only measure the total energy consumed over some period of time and therefore only a uniform tariff is possible, while hourly meters can record the consumption (or production, if this is the case) in each hour and in principle a different price or charge can be applied at each hour.

In addition to these issues in the precision of the measure, there are some important clarifications about how the tariffs can recover the incurred costs of supply that must be made here:

- The costs incurred in the supply of electricity must include the costs of the invested capital with adequate amortisations and rates of return, according to the nature of each investment.

[9] Note that these situations do not have to coincide necessarily with the moments of maximum demand. It may happen at times of moderately high demand but with very low contribution of variable generation resources, like wind, solar or even hydro. Or with a large thermal plant on maintenance.

- The regulators should make sure that the prices and charges are applied only to recover the total costs incurred in the supply of electricity *efficiently*, which may differ from the actual costs incurred.
- The remuneration (the “regulated revenue requirement”) of the supply activities of an electricity company must be cost-reflective, because this is absolutely necessary for the financial viability of the firm. However, it is not strictly necessary that the tariffs applied to the end-customers precisely recover the costs incurred in supplying electricity to each one of them. It is only needed that the *aggregation* of the revenues from the application of the tariffs to all customers must equal the regulated revenue requirement.

Strictly speaking, cost-reflective tariffs do not exist in practice. The regulatory authorities of each country in the world have accepted a radical simplification in the design of electricity tariffs, which consists in applying the same tariff to the customers in each category (classified by the volume of consumption, voltage level to which they are connected, or the type of meter and the differentiation of the tariff according to time of use) regardless of whether the customer is located in a densely populated urban area or in a small rural community far from the major load centres, where the actual cost of distributing energy can be several times higher than in an urban area. This measure greatly simplifies the billing and collection of revenues from customer payments, particularly residential ones. However, it makes all customer tariffs non-cost reflective. Cross-subsidisation among the customers belonging to a customer class (e.g. urban and rural customers with a similar consumption level) and among customer classes (e.g. between categories of customers with different levels of consumption, or between industrial and residential customers) is a universal practice.

End customer tariffs may be non-cost-reflective for a different reason. In developing countries – and sometimes also in developed ones – the regulatory authorities – typically following governmental instructions – establish tariffs that, in aggregation, do not recover the totality of the revenue requirement of the supply of electricity. This obviously impedes the normal performance of the electric utility (which may be vertically integrated or unbundled in several specialised generation, transmission and distribution companies), resulting in a lack of adequate investment and maintenance, and the associated deficient quality of service. In some cases, these governments deliver subsidies to the companies to fill this “financial viability gap”, either permanently or sporadically. It is then said that these non-cost-reflective tariffs are “subsidised”.

A well-structured system of prices and charges, grounded in economic, engineering, and regulatory principles, is essential for integrating DERs efficiently. By distinguishing cost-causal from residual costs, improving price granularity, and aligning utility incentives, power systems can capture the economic value of both centralised and distributed resources while improving efficiency, equity, and sustainability.

4. Stocktaking of DER regulatory frameworks in select African countries and beyond.

The financial sustainability of distribution utilities depends on the full and timely recovery of their costs through tariffs. This requires that the distribution revenue requirement—covering operating expenses, asset depreciation, and a regulated return—is accurately determined and periodically updated. As distributed energy resources (DERs) expand, this process becomes more complex: DERs can reduce metered sales volumes, alter load profiles, and create new system costs, such as grid reinforcement, visibility, and voltage control. Ensuring that these impacts are properly reflected in revenue requirements and tariff design is therefore central to maintaining both cost recovery and fairness.

In this context, two questions guide the analysis. First, how are the impacts of DERs on distribution costs recognised in the determination of the revenue requirement? In some cases, this may rely on forecasts and planning models, while in others it may depend on audited records of actual utility expenditures. Second, what procedures do regulators follow to translate revenue requirements into end-customer tariffs, and are systematic adjustments made when DER growth reduces revenues from volumetric charges?

The following review considers a representative set of African countries to assess current practices in distribution remuneration and tariff design, highlighting how regulators are—or are not—addressing the challenges posed by DER integration.

To complement this stocktaking exercise, the section also presents selected international experiences—including California, Germany, Italy, and Spain—to highlight both successful reforms and missteps in regulating distribution revenues, tariff design, and prosumer participation. These cases provide valuable context for identifying regulatory pathways that can help African countries integrate DERs while ensuring cost recovery, fairness, and long-term system sustainability.

4.1. A review of the existing regulations in a sample of African countries.

The financial sustainability of distribution utilities hinges on the incorporation of distribution costs into the revenue requirement, which are subsequently recovered through tariffs. This process is primarily undertaken during tariff determination and its periodic reviews, where new investments and emerging costs — including those associated with integrating distributed energy resources (DERs) — should be incorporated into the revenue requirement, leading to adjustments in the tariff structure.

It follows the review of the regulation of a subset of countries that have been selected to represent the diversity of all African countries.

Botswana

Context

The Botswana Energy Regulatory Authority Act (2016) mandates the Botswana Energy Regulatory Authority (BERA) to regulate the revenue of the Botswana Power Corporation (BPC), the sole vertically integrated utility responsible for the generation, transmission and distribution of electricity across Botswana. The Act grants BERA the authority to set revenue via Tariff Methodology using the Weighted Average Cost of Capital model, which implies the use of capital-based accounting (i.e. RAB). The calculated revenue requirement encompasses the costs of using all assets, from generation to distribution, based on a “Cost of Service/Supply of Electricity” study.

Once approved, the allowed revenue is divided by the projected sales volumes to derive the tariffs per kWh and any fixed charges, which are often segmented by customer type.[10] Each category has specific tariff structures, including fixed charges, energy charges per kWh and, for certain categories (medium/large businesses), demand charges based on peak usage.[11]

Electricity tariff reviews are conducted annually**,** with major tariff adjustments and public consultations led by BERA. This review is conducted based on tariff adjustment applications submitted each financial year by the Botswana Power Corporation (BPC). This annual major tariff allows for the inclusion of any eventual cost linked with the presence of DERs and contributes to having a tariff that considers the effect of DERs on the electricity distribution service. Furthermore, Tariffs are reviewed within the context of BPC's multi-year financial strategy (e.g. 2022–2026).

Regarding the specific tariff for prosumers, there is no dedicated tariff structure for them. However, BPC must provide electricity to prosumers at non-discriminatory rates equal to those charged to regular customers, including access to the same retail tariff options. All tariff applications and revisions follow standard regulatory procedures. Prosumers earn a 1:1 kWh credit for electricity exported to the grid during normal and off-peak hours, and a higher credit during peak hours to encourage generation when demand is high. These energy exports are not monetarily compensated except during the annual reconciliation. BPC is mandated to include the methodology of calculation and the avoided cost rate in the tariff approval process of the regulator. Based on the value of energy thus determined, export credits are applied against imported energy during the same billing period, valued at either the average avoided cost or time-of-use avoided cost, depending on the customer's tariff plan. Monthly billing reflects regular tariff charges, with energy charges adjusted for net exports, while fixed charges remain unchanged. Surplus credits are carried forward month to month but are not paid out until year-end, when they are reconciled and compensated at the avoided cost rate if unused. All bills must clearly show both the energy consumed and generated each month.

Prosumers are required to install metering equipment(s), at their own expense that accurately records both total energy consumption by the prosumer and generation from rooftop solar PV systems during a billing cycle. BPC is responsible for the installation, maintenance, and verification of meter accuracy. The meters must be bi-directional with four-quadrant capability and conform to the BPC Standards Requirements for Distribution Systems (SRDS).

Assessment

The calculated revenue requirement encompasses the costs of the use of all assets from generation to distribution. However, there is no clear explanation of whether there is an accounting separation of costs for generation, transmission and distribution. Per regulation, BERA uses the "Cost of Service/Supply of Electricity" study to identify an accurate cost for distribution; however, the last one was completed around 2019/20.

This annual major tariff allows for the inclusion of any eventual cost linked with the presence of DERs and contributes to having a tariff that considers the effect of DERs on the electricity distribution service.

---

[10] There are different customer categories, including Domestic Consumers, Small Business, Medium Business, Large Business, Government, and Water Pumping

[11] BPC, 2017, https://www.bpc.bw/media-site/news/Pages/2017-Tarrifs.aspx?utm_

Botswana is steadily advancing the integration of Distributed Energy Resources (DERs), particularly solar PV, within a supportive regulatory and policy environment shaped by the National Energy Policy and the Integrated Resource Plan. The tariff structure for domestic, small business, government, and water pumping customers includes only fixed and energy charges. [12] Tariffs in Botswana are fully bundled into a single composite rate, with no separate charges or line-items for generation, transmission, or distribution. Botswana Power Corporation, BPC's distribution costs aren't calculated separately; hence, no direct information on these costs relationship with the energy distributed was found.

Ghana

Context

Ghana's Public Utilities Regulatory Commission (PURC) uses a hybrid tariff-setting approach to determine the cost of service that combines cost-plus and performance-based principles. Regulated utilities submit financial and technical data, from which PURC determines bulk generation, transmission, and distribution charges to meet the sector's total annual revenue requirement.

Each distribution company's revenue requirement includes operating costs, depreciation, return on the regulatory asset base (RAB), taxes, and working capital. The RAB is calculated using a revalued cost approach and updated every three years. Asset registers are maintained but not standardised. The distribution service charge is based on revenue requirement divided by projected sales[13].

End-user tariffs are uniform nationwide, per PURC Act (1997) [14], with a tariff equalisation mechanism balancing cost differences among utilities[15][16]. Quarterly adjustments reflect inflation and exchange rate shifts but exclude RAB updates and DER-related impacts, such as a reduction in sales volume.

Tariffs include fixed and volumetric components.

Prosumers are subject to a dedicated tariff that distinguishes between the electricity they import from the grid and the net electricity they export. This tariff is derived by splitting the standard volumetric charge into two parts: 60 per cent for the import charge and 40 per cent for the export charge. Prosumers are billed separately for energy imported from the grid and for energy exported. If exports exceed imports over a billing cycle (typically one month), the surplus is credited at the export charge. In the case where imports and exports are equal, the prosumer still pays the import tariff.

---

[12] BPC has one billing system two tariff structures

https://www.africa-press.net/botswana/all-news/bpc-has-one-billing-system-two-tariff-structures

[13] PURC. (2022). 2022 – 2025 Electricity and water major tariff review decision. https://www.purc.com.gh/attachment/199870-20221123101102.pdf

[14] PURC (1997). ACT5 38
. https://www.purc.com.gh/attachment/382265-20201119091155.pdf

[15] PURC. (2011). Explanatory notes on revised automatic adjustment formula for setting electricity and water tariff.
https://www.purc.com.gh/attachment/459821-20210309110346.pdf

[16] PURC (2017). 2017 Rate Setting Guidelines for Electricity Distribution and Supply.
https://www.purc.com.gh/attachment/438724-20201119111122.pdf

Prosumers must install bi-directional electronic meters with separate import/export tracking and remote monitoring features, at their own cost. The utility retains ownership of the meter.

At present, DERs are not currently integrated into RAB updates or the quarterly tariff reviews, which are limited to adjustments for macroeconomic variables such as inflation and currency movements.

Assessment

Ghana's regulatory framework follows a structured approach to tariff setting, with clear procedures for determining revenue requirements and mechanisms for making quarterly adjustments. However, significant gaps persist.

The quarterly tariff adjustment mechanism is designed to respond to macroeconomic changes such as inflation and exchange rate fluctuations. However, it does not account for structural shifts triggered by DERs, including declining utility sales, altered load profiles, and growing needs for more dynamic network services. These changes are not reflected in the adjustments, despite their long-term implications for cost recovery and system planning.

There is also no evidence that DERs are considered in revenue requirement assessments during the triennial major tariff reviews. Although the Annual Revenue Requirement (ARR) for distribution companies is, in principle, independent of sales volumes, this independence holds only if the distribution service charges and end-user tariff updates reflect changes in energy sales due to customer-sited generation. As prosumers consume more of their own electricity, utility sales volumes decline, necessitating upward adjustments to the network charge to ensure utilities recover their approved revenue.

Yet, there is no indication that these adjustments are made in practice. Even if they were, the framework lacks provisions for allocating the resulting higher network costs fairly between prosumers and traditional consumers. This regulatory gap, if left unaddressed, could lead to cross-subsidies from non-prosumers to prosumers. As the uptake of behind-the-meter solar PV and other DERs accelerates, this shortcoming poses risks to equity, cost recovery, and long-term financial sustainability in the distribution sector.

Failing to reflect the impacts of DERs in revenue requirement calculations and tariff adjustments risks weakening the alignment between regulatory frameworks and the evolving electricity system. In addition, it is important to use the true historical costs of assets for RAB determination. Addressing these gaps is critical to maintaining the financial health of utilities, ensuring fair and cost-reflective pricing, and positioning DERs as assets that strengthen rather than destabilise the power sector.

Kenya

Context

Kenya's distribution company—Kenya Power and Lighting Company (KPLC)—is remunerated through a cost-of-service approach under the Energy Act 2019 and the Energy (Electricity Market, Bulk supply and Open Access) Regulations, 2024.[17] For distribution, the Energy and Petroleum Regulatory Authority (EPRA) calculates the required revenue enabling KPLC to cover these costs and earn a

[17] Energy-Act-2019.pdf and https://kenyalaw.org/kenya_gazette/gazette/volume/MzA4Mg--/Vol.CXXVI-No.28/

regulated return. This return is permitted for all regulated assets used for distribution and registered in the Facilities Database (FDB). [18]

The Kenyan tariff consists of two parts. The first is a base tariff (KSh/kWh), which is determined by dividing the revenue requirement by the forecasted kWh sales across consumer categories and is fixed for at least three years. The second component is variable (per kWh) and is based on foreign exchange rates and inflation. This component, known as the 'pass-through', is adjusted monthly and added to the base tariff to calculate the end-user tariff. This tariff has three components[19]: a base tariff, a pass-through component, and taxes and levies.

EPRA conducts two tariff reviews. The first is a comprehensive review of base electricity tariffs, conducted every three years, known as the Electricity Tariff Control Period (ETCP). These reviews assess the total costs associated with electricity generation, transmission, and distribution to determine tariffs that ensure utilities can operate sustainably while providing consumers with affordable electricity. For distribution costs, EPRA conducts a detailed review of KPLC's RAB, which is updated annually to align with the regulated utility's financial year, to reassess utility revenue requirements. This update aims to modify the base tariff by updating the revenue requirement using forecasts of utility distribution costs.

The second tariff review is a monthly Pass-Through cost adjustment in which EPRA adjusts the variable component of the end-user tariff to reflect changes in variable costs, including fuel and foreign exchange fluctuations, inflation, and other taxes and levies, such as water levies. These adjustments ensure that tariffs remain aligned with actual costs, preventing under- or over-recovery of expenses by utilities.

Regarding the specific tariff for prosumers, there is no dedicated tariff structure for them; instead, they are billed using the standard retail tariff for imported electricity, while any energy they export to the grid is credited at 50% of that retail rate.

Assessment

Kenya's regulatory framework employs a structured approach to tariff setting, utilising a cost-of-service method to determine tariffs that encompass all distribution and retailing expenses. However, there are some gaps regarding the tariff setting, updating and the consideration of DER.

There is no explicit statement on how often the regulated asset database is updated, nor is there a clear indication that revenue requirement updates include additional costs due to distributed energy resources (DERs). These costs could involve upgrading the grid, managing a more complex and

---

[18] The FDB is a GIS-based platform that stores, analyses, and manages information on transmission and distribution facilities. The FDB is a live Oracle GIS system that includes about 95% of distribution network physical data—medium-voltage, low-voltage lines, transformers, meters, etc.

[19] Overall Tariff Composition by December 2024 is as follows:

- Base tariff: 67% (~19.08 KSh/kWh)
- Pass-through 17% (~4.96 KSh/kWh)
- Taxes & levies: 16% (~4.67 KSh/kWh)

Total retail tariff: ~28.7 KSh/kWh

decentralised grid, which may increase operation and maintenance (O&M) expenses, as well as any costs related to ensuring grid compliance.

Furthermore, it is unclear whether the distribution operational costs, which are audited in KPLC's annual financial and compliance audits conducted by the Auditor-General of Kenya, are used to update the revenue requirement. Usually, major changes to the base tariff are only made during this tariff review. This approach does not align with best practices, which advise that utilities' costs- including new investments, especially those related to DERs- should be reviewed regularly, considering the increasing penetration of DERs in the grid. Relying on this could lead to substantial tariff hikes every three years. Utilising a GIS-based platform to store, analyse, and manage information on distribution and transmission assets supports the process of ensuring that all distribution costs and assets, including new investments, generate a return. This is a good strategy and one recommended for other countries.

Another issue concerns the Kenya tariff component, specifically the pass-through effect. The monthly update serves to prevent utility revenue erosion caused by inflation or foreign exchange fluctuations, ensuring utilities recover the actual costs incurred. This practice is common in several African countries. However, since the pass-through accounts for 15–20% of the final tariff, including taxes and levies unrelated to the energy sector, it may lead to higher tariffs.

Malawi

Context

Malawi's electricity regulation follows a cost-of-service (rate-of-return) methodology with a revenue cap[20]. The regulatory asset base includes only long-term, operational assets directly financed by the utility, excluding subsidised or future assets. Depreciation is calculated using the straight-line method on historical cost, while asset valuation uses the depreciated replacement cost approach.

Tariff applications to the Malawi Energy Regulatory Authority (MERA) must include a four-year business plan[21]. ESCOM, the licensed distributor, submits forecasts for sales, proposed tariffs by customer category, efficiency and collection targets, as well as power procurement and capital investment plans. MERA approves investments based on alignment with load growth, reliability, and loss reduction.

Tariffs are adjusted through a two-tier system: a comprehensive review every four years (e.g., 2023–2027) and monthly updates using the Automatic Tariff Adjustment Formula (ATAF), which reflects macroeconomic changes[22]. Cost allocation to customer categories is guided by cost-causation

[20] MERA. (2017). End-user tariff determination procedures and information requirements. Link: https://mera.mw/download/mera-tariff-determination-procedures-and-information-requirements/?wpdmdl=1286&refresh=688b83b0e98751753973680

[21] Malawi. (2007). Energy Regulation Act

[22] MERA. (2023). The 2023 – 2027 electricity base tariff determination.

https://mera.mw/download/detailed-report-on-2023-2027-electricity-base-tariff-determination-1-september-23/?wpdmdl=2864&refresh=688b8459712df1753973849

principles. MERA ensures tariffs reflect the actual cost impact of each group on the system, avoiding cross-subsidies where not explicitly justified.

Customers face differentiated tariffs: single-phase domestic users are on an inclining block tariff (IBT), while three-phase users have flat tariffs. Prepaid users pay higher per-kWh rates without fixed fees, and postpaid users pay lower energy rates but incur monthly fixed charges. Commercial and industrial customers follow time-of-use (ToU) tariffs with energy, capacity, and demand charges.

Prosumers must install a single bi-directional meter that is able to measure the flow of electricity in both directions at the same rate (prepaid meters are disallowed) and cover all interconnection and metering costs. They receive credit—not monetary compensation—for exports up to the level of imports, valued at the utility's avoided energy cost (either average or ToU-based). Utilities must disclose the avoided-cost methodology in their tariff filings.

Billing is monthly and based solely on actual meter readings. Export credits apply only to the energy portion of the bill; fixed and network charges remain payable. Any surplus credits are rolled over to the next billing period.

Assessment

Malawi's cost-of-service regulatory model provides a solid foundation for utility cost recovery and financial sustainability. However, it lacks key elements needed to accommodate a power system with increasing distributed energy resources (DERs).

A major gap is the absence of clear regulatory mandates for a verified, comprehensive asset register, especially in the distribution segment. Without auditable records, it is difficult to validate depreciation claims or accurately determine the RAB.

The framework also does not account for DERs in revenue requirement calculations. Their potential to defer investments, improve reliability, or impose system costs like voltage control and losses remains unaddressed. As DER adoption grows, the reduction in utility sales volume could result in under-recovery of network costs if a corresponding adjustment to revenue structures is not made.

Tariff reviews—currently limited to multi-year adjustments and monthly macroeconomic updates—do not reflect structural changes in demand or cost drivers introduced by DERs. This limits regulatory responsiveness to evolving grid conditions.

To strengthen its approach, Malawi should institutionalise robust asset valuation practices, integrate DERs into cost and tariff calculations, and broaden tariff adjustments to include structural system changes.

Positively, Malawi's prosumer policy limits export credits to the energy component of the bill, excluding fixed and non-energy charges. This prevents cost shifting to non-prosumers while supporting distributed generation.

Overall, while the foundation is sound, adapting the framework to reflect DER impacts is essential for long-term sector resilience and fairness.

Namibia

Context

Namibia's Electricity Control Board (ECB) applies a cost-of-service methodology to set tariffs, allowing utilities to recover efficient operating costs and earn regulated returns only on self-financed assets[23].

Asset valuation is supported by NENA (Namibian Electrical Network Assets Register), a standardised and IFRS-compliant register for distribution assets up to 33 kV[24]. Utilities must submit NENA data annually to justify asset values and depreciation during tariff reviews. ECB periodically updates unit cost rates to reflect inflation and market changes[25].

Tariffs are reviewed annually and reflect actual service costs and broader economic impacts. Residential postpaid customers pay a flat energy charge, a fixed fee, and a capacity charge. Prepaid and social prepaid customers are exempt from the latter two. Commercial and industrial tariffs include energy (with ToU pricing of three periods: Peak, Standard, and Off-peak), capacity, and fixed charges. Additional charges cover losses, infrastructure, balancing, and regulatory levies. Penalties apply if actual demand exceeds Notified Maximum Demand (NMD).

Meters for embedded generation must record inflows and outflows separately; prepaid meters are not allowed. Prosumers pay the same tariff structure as regular customers and cover interconnection and shallow connection costs.

Exported energy is credited on a monthly rollover basis, aligned with the utility's financial calendar. Electricity import by the prosumer is billed based on the regular retail tariff schedule. Electricity exports up to the amount of import during the same billing period are credited based on the value of the energy exported. This value is calculated as either the time-of-use avoided energy costs of the distribution company if the prosumer is on a ToU tariff structure, or as the average avoided energy cost of the distribution company if the prosumer is not on a ToU tariff structure.

Any exported electricity exceeding imports in a billing period is carried forward as credit toward future energy charges. Fixed and non-energy charges are not offset by export credits.

If the prosumer's system demonstrably supports the utility's daily peak demand with 99% certainty, capacity compensation is permitted, based on the distribution utility's avoided capacity cost.

All billing is based on actual monthly readings, ensuring accuracy and fairness.

Assessment

Namibia's regulatory framework aligns closely with international best practices, particularly in tariff setting and asset valuation. A key strength is the requirement that capital cost claims be backed by validated asset records, which enhances transparency and reduces investor risk.

However, the ECB's practice of periodically updating unit costs for existing assets risks inflating the regulated asset base and compromising the cost-of-service model. A more appropriate approach would retain historical values for existing infrastructure while applying updated rates only to new investments[26].

[23] ECB. (2018). Distribution grid code: electricity act, 2007

[24] ECB. (2019). Operating and reporting manual – user guide and tariff rulebook

[25] ECB. (2019). National electricity tariff study for the electricity distribution industry

[26] ECB. (2016). Economic rules: Electricity Act, 2007.

While Namibia's asset data practices are robust, DERs are not yet integrated into revenue requirement calculations. Given their potential to defer network investments, enhance reliability, or introduce new system costs, DERs should be formally incorporated into regulatory models.

The framework's treatment of prosumers is a step in the right direction. Export compensation based on avoided energy cost—whether time-of-use or average—sends cost-reflective price signals, at least on a temporal basis. Requiring distributors to disclose the methodology and rates in tariff filings adds regulatory accountability. The inclusion of capacity compensation for prosumers who support peak demand is a particularly progressive measure, rewarding firm contributions that go beyond simple energy exports.

Additionally, limiting credits to the energy portion of the bill ensures fixed and network costs are recovered, preventing cost shifting to non-prosumers. This safeguards financial viability while enabling fair participation in the electricity market.

Overall, Namibia offers a technically sound and forward-leaning framework for prosumer participation. With targeted improvements to formally integrate DERs into utility remuneration, it is well-positioned to ensure both system efficiency and regulatory equity.

South Africa

Context

South Africa employs a rigorous cost-of-service (cost-to-serve - CTS) method to determine tariffs. The Revenue Requirement is calculated using a Regulatory Asset Base (RAB) that includes all assets for distribution, updated annually through the Regulatory Reporting Manual (RRM). By regulation, all licensed distributors are required to conduct a comprehensive Cost-of-Supply (COS) study at least every five years, or more frequently if significant structural changes occur. Eskom's CTS study allocates costs to each customer category using three main cost drivers: i) energy Purchase Costs based on the kWh sales volume (including distribution losses), ii) Capacity Costs based on peak demand (kVA), and iii) Retail Costs allocated per Point of Delivery (PoD): metering, billing, and customer service. The tariffs (energy, capacity, network, and retail) are then unbundled, reflecting separate cost components. This study guides the determination of distribution cost components. Utility costs attributable to DERs are incorporated into the end-user tariff based on the results of the Utilities COS studies. These studies help utilities identify and allocate costs associated with serving different customer categories, including those with Distributed Energy Resource (DER) installations.

Within a Multi-Year Price Determination (MYPD) process, NERSA calculates the end-user tariff over three years, including approved annual increases. The tariff is unbundled, which is beneficial and relevant when assessing DERs. Eskom submits a revenue application based on projected costs and investments over three to five years. NERSA evaluates the efficient cost of supply plus a reasonable return. The approved revenue is then divided by forecasted electricity sales to determine a unit price. On 17 March 2025, NERSA approved the Retail Tariff Plan (RTP), designed to align electricity tariffs with actual costs of generation, transmission, and distribution, ensuring customers pay for the services they use. The RTP introduces several tariff changes: i) Unbundling of tariff charges into distinct components to reflect specific cost drivers: Generation Capacity Charge, Time-of-Use (TOU) Charges (for peak and off-peak periods), Network Charges, and Retail Charges; ii) Elimination of

---

https://www.ecb.org.na/wp-content/uploads/2024/01/Electricity_Technical-Rules_-Revised_Draft.pdf

Inclining Block Tariffs (IBT) and adoption of flat rates per cost-reflective category; iii) Adjustments for Renewable Energy Users (metering).

A major end-user tariff review occurs every three years under the Multi-Year Price Determination (MYPD) framework, while a minor review takes place annually to account for changes in particular cost elements such as fuel prices, inflation, and exchange rates. Setting tariff adjustment rates for the next three years based on forecasts offers clarity and a positive signal to potential investors. This process is similar in several other countries. It considers the utilities' new investment forecasts for the upcoming three years, and any unforeseen or unplanned investments or costs during the tariff review cannot be included in the tariff. During each regulatory control period, the RAB is updated annually to reflect changes in asset values resulting from factors such as capital expenditure, depreciation, disposals, and inflation.

Regarding metering, Distributors are responsible for installing suitable meters for prosumers. These meters must be bi-directional, capable of recording electricity flow in both directions with separate registers, support time-of-use metering with peak supply measurement and have two-way communication capabilities. They must also meet the distributor's technical standards and relevant metering regulations. The distributor or an authorised third party will procure, install, and maintain the meters, and may charge prosumers for related costs. Spinning disc meters cannot be used to measure reverse power flow.

Once a prosumer connects to the distribution network, the distributor must apply a tariff structure comprising three key components. First are the variable charges (c/kWh), which include import tariffs (covering energy purchase and network costs linked to demand or usage on a time-of-use basis) and export tariffs (compensating the prosumer at the distributor's avoided energy cost, also time-of-use-based). Second are fixed charges (R/day or R/kVA), based on the customer's Notified Maximum Demand (NMD). These charges cover network-related capital, maintenance, fixed operating costs, as well as service and administrative expenses like billing and customer support. Finally, additional charges may apply, including one-time connection fees for metering and network setup, as well as contributions to subsidies or levies.

Energy exported by a prosumer must be credited in the same monthly billing cycle. Still, it can only be used to offset energy-related charges, not fixed, basic, or demand-related charges. Importantly, the distributor cannot compensate the prosumer with cash; if export credits surpass the energy consumed within a billing period, the surplus rolls over to future bills. However, any rollover must be utilised within the same financial year. Distributors should also avoid relying on estimated readings when billing prosumers. The billing setup must treat imported and exported electricity as separate transactions, ensuring that both energy flows are clearly recorded and reflected on the prosumer's bill.

Assessment

According to regulations, Eskom Distribution and licensed municipal utilities perform a Cost-of-Supply (COS) study to help determine distribution cost components included in the revenue requirement. This ensures that all distribution costs, including those related to DER presence, are taken into account. The tariff is unbundled, which is beneficial and relevant when evaluating DERs. The new Retail Tariff Plan (RTP) represents a significant restructuring of electricity tariffs aimed at improving cost reflectivity, transparency, and fairness across consumer categories. By separating charges for electricity capacity and network services, this measure aims to prevent unfair cross-subsidies and ensure customers only pay for the services they use. However, it may lead to higher costs for low-consumption households, as the previous subsidy structure is eliminated.

Setting tariff adjustment rates for the next three years based on forecasts offers clarity and provides a positive signal to potential investors. This means that utilities' new investment forecasts for those three years are considered, and any unforeseen or unplanned investments or costs during the tariff review cannot be incorporated into the tariff.

Regulatory requirements for distribution companies planning to onboard prosumers are well-designed and aligned with sound prosumer tariff development. They reflect a balanced approach that supports cost recovery, prevents cross-subsidies between prosumers and non-prosumers, and maintains fairness.

Requiring distributors to conduct a cost-of-supply study ensures tariffs are based on actual system costs. Unbundling tariffs into variable and fixed components helps prevent distortion from recovering fixed infrastructure costs through energy-only charges, especially when prosumers significantly reduce imports via self-generation.

Compensating exports based on avoided energy costs, with clear regulation stating this must be on a time-of-use basis, provides a cost-reflective signal to prosumers without overcompensation. This avoids incentives for overgeneration or unsynchronised exports that could destabilise the grid.

Using fixed charges based on Notified Maximum Demand (NMD) is also appropriate. It ensures customers pay for the capacity needed for the system to be ready, even if they import less energy due to self-generation. This helps maintain the integrity of network cost recovery and ensures fairness between full-importing and self-generating users.

Finally, including one-time and pass-through charges for metering, connection, and policy-driven levies allows utilities to recover upfront costs and ensures broader policy goals, such as electrification or low-income subsidies, are not compromised by the shift to distributed energy.

Overall, the framework outlined is coherent, practical, and defensible. It establishes a sustainable model that accommodates prosumers without undermining utility viability or distorting cost signals.

Tanzania

Context

The sector is regulated by the Energy and Water Utilities Regulatory Authority (EWURA) under the EWURA Act (Cap 414). TANESCO is the dominant vertically integrated utility (generation, transmission, distribution). EWURA calculate the Revenue Requirement on the principle that revenues of the regulated utilities have to cover their operating and maintenance expenses, depreciation, taxes and ensure a fair return on assets employed in rendering regulated services.[27] EWURA define tariff by dividing the revenue requirement by the total forecast of volume of energy. Electricity tariff structure consists of two components: a fixed charge, which is a monthly fee covering access to the grid and basic infrastructure, and a volumetric charge, which is a per-kilowatt-hour (kWh) rate based on the amount of electricity consumed. [28]

---

[27] EWURA, The Energy and Water Utilities Regulatory Act (CAp.414), https://www.ewura.go.tz/uploads/documents/en-1744291985-EWURA%20(Tariff%20Application%20and%20Rate%20Setting)%20Rules,%202017.pdf#:~:text=,determined%20by%20the%20following%20formula

[28] TANESCO, https://www.tanesco.co.tz/customer-services/tariffs

In terms of Section 24(2) of the Electricity Act, the Authority is required to make amendments to or review tariffs charged by a licensee once every 3 years. Furthermore, Under the 2017 Tariff Rules (GN 452, Rule 14), EWURA requires licensees (e.g. TANESCO) to adjust tariffs quarterly for fuel and foreign exchange rate changes, and every six months for inflation**.**

For Small Power Producers (SPPs) and mini-grid operators, EWURA prescribes standardised feed-in tariffs—based on avoided-cost or technology-cost methodology, depending on PPA dates and generation type.

Regarding meter requirement and compensation mechanism, Distribution Network Operators (DNOs) are required to allow the connection of prosumers to their networks, provided that a bi-directional meter is used. This meter must be able to record both the imported and exported energy, clearly registering and displaying the direction and volume of electricity flow.

Eligibility to be a prosumer is available on a first-come, first-served basis within a DNO's service area. However, this access is capped once the total installed capacity of net-metering customers reaches 5% of the previous year's peak load for that area. DNOs may choose to exceed this cap if they find it technically or economically feasible.

The DNO follows a monthly billing period to charge the prosumer. During this period, if the volume of electricity supplied to the prosumer by the DNO exceeds the amount exported to the grid by the prosumer, the prosumer is billed for the net kWh supplied by the DNO (and other charges such as service and demand charges depending on the customer tariff category) in accordance with the existing tariff schedule. If, on the other hand, the prosumer is a net exporter during the billing period, the DNO shall credit the prosumer for the net excess generation that rolls over to the next billing period. Any unused credits expire after three years or upon service termination. Notably, customers are not entitled to monetary compensation for excess energy.

Assessment

Tanzania, like many other African countries, adopts a cost-of-service regulation framework to determine electricity tariffs. However, as is common across the continent, the tariffs approved by the regulator often fall short of covering the full revenue requirements of utilities—particularly for TANESCO, the national utility. Furthermore, there's no indication of a centralised Regulatory Asset Base (RAB) database or any requirement to maintain such a database up to date and available for scrutiny.

Notably, the tariff structure is unbundled, comprising a fixed and a volumetric component, which is a valuable feature when assessing the integration and economic viability of distributed energy resources (DERs).

Based on publicly available documents, residential customers in Tanzania are billed using flat, volumetric tariffs with no fixed charge component. This structure risks shifting the utility's network and other non-energy costs onto non-prosumer customers when individuals in this group adopt prosumer status. As a result, relying solely on volumetric billing is not a recommended approach for charging prosumers, as it undermines cost recovery and fairness across customer categories.

Uganda

Context

The Electricity Regulatory Authority (ERA) in Uganda applies a Rate of Return (ROR) framework to determine utilities' annual revenue requirements, enabling cost recovery and a fair return on the

RAB, which is reviewed annually[29]. Licensees must submit detailed asset registers each year, including asset name, acquisition date, location, lifespan, and condition to support depreciation and return calculations.

ERA mandates the submission of additional information for the distribution segment. These are data on the number of consumers by region and metering type (including time-of-use meters), volumes exchanged with embedded generators, and consumption and billing data broken down by consumer category.

Performance-based components are integrated into the framework, with benchmarks for losses, efficiency, and bad debt to incentivise utility performance.

Tariffs are set through a hybrid process: an annual base review aligns tariffs with updated revenue requirements, while quarterly adjustments reflect macroeconomic changes like inflation, exchange rates, and fuel costs, which are capped at 2.5% compared to the previous quarter, to limit significant price volatility.

The end-user tariff is entirely volumetric across all customer groups, with no fixed or other non-volumetric charges included. To address costs related to system use—such as uncollected losses from gross supply, unrecovered network capacity charges, and the implicit use of the grid as virtual storage—the regulatory framework mandates a 20% discount on electricity exported by prosumers to the grid. Billing follows a monthly netting arrangement: the distributor offsets the prosumer's energy imports with the discounted value of their exports for the same billing period. Prosumers pay the full retail rate on net imports and receive a kilowatt-hour credit for any net exports, which is carried forward to the following billing cycle. The regulation states that this carried-over credit offsets only the energy portion of future bills but does not apply to fixed or non-energy charges, which must still be paid in full. In the absence of clear and separate fixed and non-energy charges in the end-user tariff structure, it is not clear how this is realised.

Prosumers are required to install bi-directional meters capable of recording electricity flows in both directions at equal rates. These meters must support two-way communication for real-time monitoring and be equipped to measure peak demand across different time blocks, allowing for time-of-use metering. The full cost of procuring and installing these meters is borne by the applicant.

Distribution service providers are allowed to procure power from embedded generators in addition to the bulk supplier[30]. The power supply charge would then be calculated using the weighted average cost of supply based on the proportion of electricity purchased from each source during the consumption period in question. In this way, DERs are incorporated into the energy procurement of the utility.

Assessment

Uganda's regulatory framework is grounded in a solid Rate of Return model, complemented by performance incentives and transparency measures such as detailed asset reporting. The inclusion of embedded generation in the formal supply mix reflects a forward-looking regulatory stance.

---

[29] ERA. (2006). Tariff determination in the Uganda electricity sector.

[30] Poyry Management Consulting (Norway) AS (2012). Manual for the ERA tariff model ver. 4.0.

To build on this foundation, introducing a dedicated tariff structure for prosumers with separate charges for imports and exports, along with a clearly defined non-energy component, would enhance the framework's ability to accommodate the growing role of distributed energy resources.

Zambia

Context

Electricity distribution companies in Zambia are regulated by the Energy Regulation Board (ERB). Currently, the regulated utilities include ZESCO, Copperbelt Energy Corporation, and Lunsemfwa Hydro Power Company. The ERB has published a document titled "Multi-Year Tariff Framework Rule for Determining the Revenue Requirement (RR) for Distribution Network Service Providers"[31] which clearly outlines the cost-of-service methodology used by the Board. The document explains that the Regulatory Asset Base (RAB) is the sum of all used and useful assets involved in providing regulated distribution services, regulated distribution connection services, and regulated retail services. Asset valuation is undertaken using the depreciated historic cost valuation method to determine the value of the Regulatory Asset Base. During Periodic Reviews, assets that remain in service beyond their Economic Asset Life shall continue to be part of the Regulatory Asset Base, subject to review by the ERB.

Finally, the details of the asset valuation must be reconciled with the Distribution Network Service Provider's asset register or general ledger. This reconciliation must be fully documented and submitted to the ERB along with the valuation report.

ERB employs a standard revenue requirement model, also known as a rate-of-return regulation approach, where the utility (e.g., ZESCO) is allowed to recover prudently incurred operational costs, plus depreciation, and a regulated return on its asset base (RAB × WACC). ERB excludes unreasonable or inefficient costs during review. Once ERB approves the revenue requirement, it calculates a required percentage increase over existing tariffs that will enable the utility to collect the needed revenue. These rates are then applied to different customer classes (residential, commercial, industrial), converting total revenue into per-kWh charges, demand/capacity charges, and fixed fees. Specifically, the tariff structure spans:

- Lifeline (low volume) kWh charges
- Stepped or block tariffs for residential consumption bands
- Demand/capacity charges for maximum demand (MD) and industrial customers
- Time-of-use tariffs, with peak, standard, and off-peak differentials based on half-hour intervals

There is no separate DER-specific feed-in tariff, but mini-grid tariffs are managed under a tailored Mini-grid regulatory framework, categorised by size and complexity. [32] Smaller mini grids benefit from light-handed or very light-handed regulations, reducing administrative burdens while enabling cost recovery and return on investment

---

[31] ERB, Multi-Year Tariff Framework Rule for Determining the Revenue Requirement for Distribution Network Service Providers,

https://www.erb.org.zm/wp-content/uploads/files/Final-MYTFDistribution-Pricing-Rule_200922.pdf

[32] https://efaidnbmnnnibpcajpcglclefindmkaj/https://beyondthegrid.africa/wp-content/uploads/ZAM-Energy-Regulation-Board-Mini-grid-Regulations.pdf

After each tariff period, the ERB conducts a major tariff review to set the guidelines and tariff structure for the subsequent period. Within a tariff period, automatic tariff adjustments are applied in response to changes in uncontrollable factors such as inflation, exchange rates, and hydrological conditions (including fuel costs). In April 2023, the ERB approved ZESCO's application to revise electricity tariffs for its retail customers over five years, with the first annual review scheduled for 2024. The ERB has approved distinct tariff schedules for Residential, Commercial, and Maximum-Demand customers[33], each often further broken into tariff categories with increasing tariffs for higher usage.

Regarding meter requirements and compensation mechanisms for prosumers, a postpaid or prepaid bi-directional meter is permitted. It must be capable of measuring the residual energy imported from the distribution system or the net energy exported to it. Where both active and reactive power can flow in both directions, a full four-quadrant meter must be installed. The meter remains the property of the distribution enterprise, but the prosumer is responsible for covering all associated costs, including procurement, delivery, and installation at the designated metering point.

The billing structure for prosumers (customers who both generate and consume electricity) centres on a reference tariff that serves as the baseline rate, adjusted annually based on the previous year's export-to-generation ratio: if exports are ≤ 50 % of generation, the full tariff applies; if between 50 % and 75 %, it's reduced to 75 %; and if exports exceed 75 %, the tariff drops to 50 % of the reference rate.[33] Prosumers perform an annual true-up settlement, allowing them to offset export imbalances against current or future bills or receive monetary reimbursement. Connection fees are generally waived unless network upgrades are needed or if the prosumer operates a wheeling setup (generation and load are on different sites), in which case charges may be spread over time. Distribution use-of-system fees may also apply (especially for wheeling prosumers), capped at half the reference tariff and billed per kWh. Metering data must be submitted by 15 December, covering the period from 15 December of the prior year to 30 November of the current year, to determine the next year's tariff level. Finally, exported energy is credited differently depending on meter type: prepaid accounts receive credit in their balance, while postpaid accounts see reduced import bills from export credits. Let me know if you'd like this in a chart or visual layout.

Assessment

Zambia, like many countries on the continent, uses cost-of-service regulation, but like most African countries, these tariffs are not meeting the projected revenue. The Energy Regulation Board (ERB), through its *Multi-Year Tariff Framework Rule,* confirms that tariffs are functionally unbundled into generation, transmission and distribution. Distribution costs are consolidated within ZESCO's (and other Distribution Network Service Providers') cost-of-service model, based on the Regulatory Asset Base (RAB) and operating expenditures. As regulated by the Energy Regulation Board, an asset valuation should be undertaken by the Distribution Network Service Provider using the depreciated historic cost valuation method in order to arrive at the value of the Regulatory Asset Base.

Although the draft net metering regulations in Zambia do not explicitly forbid using export credits to offset fixed or network charges, the compensation model targets exports strictly on a per kWh basis—implicitly excluding non-energy fees such as monthly connection charges or demand-based

[33] https://www.erb.org.zm/wp-content/uploads/files/standards/Draft-3-Net-Metering-Regulation-2024-Issued-for-Public-Comments.docx

kVA charges from being covered.[34] Moreover, the tiered export credit system, which increases compensation the more a prosumer exports relative to their generation, unintentionally—or perhaps intentionally—discourages self-consumption and rewards grid export. This could reflect policy intent to keep prosumers grid-connected and ensure surplus energy supports the broader system. The structure is administratively efficient but raises fairness concerns: applying a volumetric DUoS fee to wheeling prosumers based on exported kWh does not reflect actual cost causation. Since distribution costs are largely driven by peak demand and not total volume, two prosumers with the same export kWh can impose very different stresses on the network, and a simple kWh-based fee fails to capture this nuance. A more equitable model would employ a fixed monthly charge or a demand-based fee tied to the prosumer's Notified Maximum Demand (NMD). Finally, tariff design differs by customer class. For residential and small commercial customers (below 15 kVA), the structure is purely volumetric with no separate fixed or demand charges—making it unclear whether export credits can be explicitly restricted from offsetting non-energy service costs. In the absence of tariff categories that distinguish fixed components, prosumers in this category might effectively reduce or bypass contributions to network or fixed service costs, creating equity and cost recovery issues.

Zambia, like many countries on the continent, uses cost-of-service regulation, but like most African countries, these tariffs are not meeting the projected revenue. The Energy Regulation Board (ERB), through its Multi-Year Tariff Framework Rule, confirms that tariffs are functionally unbundled into generation, transmission and distribution. Distribution costs are consolidated within ZESCO's (and other Distribution Network Service Providers') cost-of-service model, based on the Regulatory Asset Base (RAB) and operating expenditures. As regulated by the Energy Regulation Board, an asset valuation should be undertaken by the Distribution Network Service Provider using the depreciated historic cost valuation method in order to arrive at the value of the Regulatory Asset Base. Zambia historically included a fixed monthly charge on some tariffs, but recent reforms have removed these for smaller customers. Consequently, lifeline residential customers now pay only volumetric energy charges. In the 2023 approved tariff schedule, a fixed monthly fee is charged only for the social services tariffs (schools, hospitals, etc) and maximum demand tariffs (purchasers of power for distribution to retail customers).

Zimbabwe

Context

ZETDC (Zimbabwe Electricity Transmission and Distribution Company) is remunerated using a cost-of-service, building-block method overseen by ZERA (Zimbabwe Electricity Regulatory Authority) under the Electricity Act[35] (Cap 13:19) and Tariff Code[36] (2019). ZERA applies the building-block model (cost-plus, COS-based), estimating the allowed revenue requirement based on the rate-of-

[34] netmetering.zesco.co.zmESI Africa

[35] https://www.veritaszim.net/sites/veritas_d/files/ELECTRICITY%20ACT%20CHAPTER%2013-19.pdf

[36] https://www.zera.co.zw/electricity-application-forms-regulations/

return (RoR) approach, which includes estimated[37] operating and maintenance costs, depreciation, return on RAB based on WACC, interest costs (on debt), and other expenses (e.g., smart metering investments, rural electrification levy). The ZERA use a RAB to determine the prices or tariffs that consumers pay for the services provided by the regulated utility. This ensures that the utility can recover its operating costs, earn a fair return on its investment, and also incentivises efficiency. A stepped/block tariff structure applies, and Tariffs are set in USD per kWh but billed in Zimbabwean dollars (ZiG) using official exchange rates. The residential/domestic tariffs in Zimbabwe have two components: A stepped energy price per kWh, depending on monthly consumption levels, and 6% REA (Rural Electrification) Levy added on top. There are no fixed monthly or capacity charges, and no peak/off-peak differentiation for domestic meters.

The tariff review period is flexible, determined on a case-by-case basis as needed, in line with the Tariff Code. It can be annual or multi-year. The recent tariff approvals and adjustments occurred in 2019, 2022, 2023, and 2024.

Zimbabwe regulations require a prosumer to have a bi-directional (four-quadrant electronic) type meter, capable of separately recording the total energy consumption by the prosumer, and the energy generated by the renewable energy source during every billing cycle. The cost of new or additional meter(s), including replacement costs, shall be borne by the prosumer. In contrast, ensuring meter accuracy compliance prior to, during, and after installation is the responsibility of the utility. The prosumer shall not pay meter rental charges.

There is no separate DER tariff for residential or small-scale users. DERs are permitted and regulated—but energy outputs and net inflows are billed at regular or wheeling rates, not via a separate DER tariff but through a compensation mechanism.

For every kWh that a residential prosumer exports to the grid, the prosumer shall receive a credit of 0.8 kWh. For a maximum demand time-of-use prosumer, the credit is 0.85 kWh. No prosumer shall receive monetary compensation from the distribution company. The licensee shall roll over the net exports from previous monthly billing periods and offset any future consumption bills of the prosumer. The reconciliation procedures and conditions for rolling over excess generation or net exports shall be determined by the regulator from time to time, with approval from the Ministry of Energy and Power Development. If the prosumer is a net importer during a monthly billing period, the prosumer shall be billed for the energy supplied by the distribution company at the standard tariff rate.

Residential prosumers receive a credit of 0.8 kWh for every kilowatt-hour of electricity they export to the grid, while maximum demand time-of-use prosumers receive a credit of 0.85 kWh per exported unit. If, during a billing period, the prosumer imports more electricity than they export, they are billed for the net energy consumed at the standard retail tariff. Credits from net exports are rolled over to offset the bill for future energy consumption. No prosumer is entitled to monetary compensation from the distribution company.

[37] The information is inconsistent, and it is not explicitly stated that the approved distribution costs are based on the Auditor-General's audit of ZETDC's financial statements or ZERA's regulatory audit. For example, the most recent financial audit by the Auditor-General of ZETDC was conducted in 2021, whereas ZERA commissioned international consultants to audit ZESA and ZETDC in 2016–17.

Assessment

Zimbabwe adopts the cost-of-service approach, similar to several African nations, to determine tariffs based on the utilities' revenue needs. The tariff is expressed in USD per kWh, but billing is conducted in Zimbabwean dollars (ZiG) at official exchange rates, introducing exchange rate risk and possible tariff volatility. Consequently, the two-part tariff—comprising a stepped energy rate per kWh and a 6% Rural Electrification Levy—lacks fixed monthly or capacity charges and does not differentiate between peak and off-peak rates for domestic meters, which diverges from best practices. This structure also prevents utilities from compensating for revenue losses caused by reduced energy consumption or DER withdrawals.

Subject to review by ZERA, adjustments are made to the RAB and, subsequently, to tariffs, considering currency, inflation, and investment needs. However, the lack of a fixed review frequency prevents ensuring that the distribution utilities' revenue requirements are accurate and cost reflective. This results in tariff unpredictability and uncertainty for stakeholders, particularly investors, due to the flexible review schedule. Nonetheless, tariff reviews have occurred annually over the past three years.

There are no specific tariffs for prosumers in Zimbabwe; instead, they pay the standard retail rate for imported electricity. For exported electricity, residential prosumers receive a credit of 0.8 kWh per exported kWh, while those on maximum demand tariffs get 0.85 kWh per kWh exported. The current residential tariff is entirely volumetric, with no fixed charges. It remains unclear whether the export credits' discount adequately covers the utility's network costs for prosumers, although this reduction seems aimed at that.

Summary

Across the sampled African countries, regulators generally apply cost-of-service or revenue-cap models anchored in a regulatory asset base. Several jurisdictions lack auditable, up-to-date asset data, weakening RAB integrity and cost allocation. Namibia's standardised asset register (NENA) is a strength.

Revenue requirements are translated into end-user tariffs, often supplemented by routine pass-through adjustments for inflation, foreign exchange, and fuel costs, as seen in Ghana, Kenya, and Malawi. These adjustments, however, do not capture the structural impacts of DERs, such as altered load profiles, deferred investments, or new operational costs related to visibility, hosting capacity, and voltage control.

Tariff structures are typically unbundled into fixed, energy (kWh), and sometimes capacity (kW) components for larger users; however, many residential tariffs remain largely—or purely—volumetric (e.g., Tanzania, parts of Zambia and Zimbabwe).

In some cases, such as Ghana, the distribution company's revenue requirement is calculated based on the value of its assets and then divided by the projected electricity volume to derive a per-unit charge. This per-unit charge is subsequently allocated to different customer categories, and in some instances, presented as a two-part tariff (comprising a fixed and an energy charge). However, the methodology for disaggregating these components is not transparent, and it remains unclear whether the fixed charge adequately reflects the underlying network costs. This ambiguity is further compounded by special regulations in some countries, which stipulate that only the energy portion is credited for exports, without a clear indication of how that portion is determined. Overall, the unbundled tariff structure for residential customers is missing. As a result, export compensation for prosumers may not transparently reflect only the energy component, as it should.

The reviewed countries require bi-directional meters for prosumers, with South Africa standing out by explicitly prohibiting spinning-disc meters for reverse power flows.

The assessments point to recurring gaps: limited, auditable asset registers; limited inclusion of DER-driven costs and benefits in revenue requirements; tariff designs that over-rely on volumetric recovery for residential customers; and prosumer crediting rules that prosumer crediting rules that address only energy while leaving non-energy cost recovery uncertain.

4.2. An overview of lessons learned in a sample of non-African jurisdictions.

Germany, Italy, and Spain provide valuable reference points for understanding tariff design and the integration of DERs. Each country has adopted distinct approaches to the distribution system operator (DSO) remuneration, tariff updates, and prosumer participation. The following sections present highlight case studies of these three jurisdictions, focusing on tariff components, update mechanisms, DER treatment, and regulatory shortcomings. Together, they offer concrete insights and lessons that can inform tariff reform efforts in African contexts. The case study of California, included at the end of this section, further demonstrates how regulatory frameworks have been progressively improved in the design and implementation of prosumer tariffs and compensation mechanisms.

California: from flat-rate incentives to a more granular, value-based compensation

The California Public Utilities Commission (CPUC) has developed a series of Net Energy Metering (NEM) programmes that have evolved through three major iterations, NEM 1.0, NEM 2.0, and NEM 3.0, to better align tariff design with the state's changing grid dynamics, cost structures, and equity considerations.[38] These programmes apply to the state's investor-owned utilities: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). These utilities are required to offer financial credits to prosumers for surplus electricity exported to the grid. The state of California has established itself as a national leader in distributed generation, with a plethora of solar projects totalling 18.75 GW of installed capacity as of 31 May 2025, reflecting the magnitude of these programmes. [39]

Introduced in 1996, NEM 1.0 credited prosumers at the full retail rate (1:1) for every kilowatt-hour (kWh) of electricity exported to the grid, regardless of when the electricity is injected. This straightforward and highly favourable structure for prosumers significantly accelerated the adoption

---

[38] Southern California Edison, *Net Energy Metering (NEM) Successor Tariff.* *https://energycenter.org/sites/default/files/docs/nav/programs/smp/NEM-ST.pdf*

[39] California Public Utilities Commission, *California DG Statistics.* Accessed July 13, 2025. https://www.californiadgstats.ca.gov/

of residential solar in California by offering short payback periods and minimal regulatory hurdles. While effective in driving early investment, the model soon drew criticism from utilities. They argued that it overcompensated solar users relative to the value of their exported energy, failed to account for grid usage patterns, and shifted fixed grid maintenance costs onto ratepayers (regular utility customers). Additionally, the absence of time-of-use pricing or fixed charges limited its ability to reflect the true cost and impact of electricity consumption and generation on the system.

In 2017, California implemented NEM 2.0 to address some of the equity and cost recovery issues raised under NEM 1.0. This version preserved the core structure of retail-rate compensation for exported energy but introduced several key reforms aimed at improving cost alignment. Notable changes included the introduction of mandatory time-of-use (ToU) rates, non-bypassable charges (NBCs) on each kilowatt-hour consumed—which fund low-income assistance and public purpose programs—and a one-time interconnection fee for new systems. [40]

These adjustments made export behaviour more reflective of grid needs and introduced limited cost contributions from prosumers. However, utilities continued to express concerns that NEM 2.0 did not adequately address the core issue of cost-shifting. Exported energy was still credited at the retail rate, which exceeded the utility's avoided cost, and the NBCs were modest in scale. Furthermore, netting of imports and exports was allowed—over hourly intervals for residential customers and 15-minute intervals for non-residential customers—enabling temporal offsetting that further muted price signals. [41] A study concluded that prosumers benefit from NEM 2.0, while ratepayers see increased rates. [42]

The latest evolution of California's net metering policy is NEM 3.0, formally known as the Net Billing Tariff. Introduced in 2023, it marks a significant shift from previous versions. While it maintains retail rates for imported electricity, along with time-of-use (ToU) pricing and non-bypassable charges, it fundamentally changes how exported energy is compensated. Instead of using the retail rate, compensation is now tied to the utility's avoided cost, calculated using the CPUC Avoided Cost Calculator (ACC). [43]

These hourly export credits, which reflect the value of electricity to the grid at specific times, are substantially lower than retail rates, by as much as 80% in some cases, resulting in longer payback

---

[40] California Public Utilities Commission, *Net Energy Metering and Net Billing.*

https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/customer-generation/net-energy-metering-and-net-billing

[41] California Public Utilities Commission, *Resolution E-5324,* CPUC, 2024. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M536/K091/536091000.PDF

[42] Verdant *Associates, LLC, Net-energy metering 2.0: lookback study.* Prepared for the California Public Utilities Commission, 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/net-energy-metering-nem/nemrevisit/nem-2_lookback_study.pdf

[43] California Public Utilities Commission, *Resolution E-5324,* CPUC, 2024. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M536/K091/536091000.PDF?

periods for new solar-only installations.[44] However, the tariff structure now encourages the adoption of solar-plus-storage systems, allowing customers to store surplus generation and export it during high-value periods.

Under this scheme, there are 576 distinct export credit values in a year, based on 12 months, 24 hours, and a weekday/weekend split. Billing for imports and exports is handled separately, with no temporal netting across intervals. [45]

From a utility's perspective, NEM 3.0 is a significant improvement. It better aligns export compensation with grid value, reduces cross-subsidies, and encourages more flexible consumption behaviours that support grid stability and reliability, and strengthens cost recovery mechanisms by helping mitigate the revenue losses that were prevalent under NEM 1.0 and 2.0.[46] For prosumers, however, the economic landscape has become more complex. Solar-only installations now yield lower returns, whereas systems with storage can still be financially viable, albeit requiring higher initial investments and a deeper understanding of system optimisation.

The progression from NEM 1.0 to NEM 2.0, and now to NEM 3.0, has been shaped by the growing need to address cost shifting and rising cross-subsidy burdens, as well as the imperative to integrate DERs more effectively into grid operations and planning. While NEM 1.0 played a pivotal role in accelerating market development by offering generous terms, it also created imbalances that placed strain on ratepayers and utility revenues. NEM 2.0 introduced modest reforms, such as ToU rates and non-bypassable charges, but these did not sufficiently address the core issues of equity and cost recovery. By contrast, NEM 3.0 marks a more decisive shift by aligning compensation with the actual value that DERs provide to the grid, while also encouraging storage integration to enhance grid responsiveness. This transition reflects California's efforts to strike a sustainable balance between promoting the adoption of DERs and preserving the financial viability of utilities.

Germany: from incentive regulation to emerging dynamic tariffs

Germany's network tariff regulation is based on incentive regulation under the Incentive Regulation Ordinance (ARegV) and the Electricity and Gas Network Charges Ordinances (StromNEV/GasNEV). The regulator, Bundesnetzagentur (BNetzA), sets the year-on-year revenue caps for each distribution system operator (DSO) during this period. The allowed revenue of each DSO is determined from audited costs and efficiency benchmarking. Operators keep any savings below the cap, creating pressure to cut costs and innovate, while still earning a regulated return on capital. This decoupling

---

[44] Wilgness, Sam, *What is NEM 3.0 and How Will it Impact California Solar Owners?* https://www.solar.com/learn/nem-3-0-proposal-and-impacts-for-california-homeowners/

[45] Wang, Sunny. *UPDATED — CPUC Releases New NEM-3 Proposed Decision: Key Changes You Need to Know.*

https://aurorasolar.com/blog/cpuc-releases-new-nem-3-proposed-decision-key-changes-you-need-to-know/

[46] California Public Utilities Commission, *Resolution E-5324,* CPUC, 2024. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M536/K091/536091000.PDF

of costs and revenues simulates competition in a monopolistic sector, sharing efficiency gains between operators and network users. [47]

Network tariffs are paid solely by final customers; feed-in suppliers are not yet charged for injecting electricity. [48]

End-user tariffs are updated regularly. Price component shares and retail bill levels are monitored and reported in the joint Monitoring Report of Bundesnetzagentur and Bundeskartellamt (the competition authority), which documents annual developments in network charges and other components. [49]

The structure of tariffs reflects both cost causation and policy layering. Larger industrial and commercial users face capacity-based charges (€/kW) determined by maximum demand or contracted capacity. Households and small businesses primarily pay energy-based volumetric charges (ct/kWh), with a small fixed monthly component covering metering, billing, and administrative costs. Levies and surcharges also appear, including the CHP levy and offshore liability levy, though the dominant EEG levy has been removed.

A typical household electricity bill in 2023 was made up of about 37 per cent energy procurement and sales, 25 per cent network charges, 24 per cent taxes (VAT and electricity tax), and 14 per cent levies and surcharges. Most costs are still recovered through volumetric charges, though there is ongoing debate about shifting more toward fixed components to reflect cost causation and to address fairness concerns across customer groups. [50]

Germany's experience with prosumer regulation has combined structural challenges with corrective reforms. For two decades, distributed renewable energy was supported through generous feed-in tariffs (FITs) funded by the EEG levy[51], which shifted costs onto consumer bills. This levy peaked at

---

[47] The principle of simulated competition.
https://www.bundesnetzagentur.de/EN/Areas/Energy/GeneralInformationRegulation/IncentiveRegulation/MainPrinciple/start.html

[48] Network charges, Bundesnetzagentur.

Link: Bundesnetzagentur - Network charges

[49] Monitoring report 2023, Bundesnetzagentur and Bundeskartellamt.
https://data.bundesnetzagentur.de/Bundesnetzagentur/SharedDocs/Downloads/EN/Areas/ElectricityGas/CollectionCompanySpecificData/Monitoring/MonitoringReport2023.pdf

[50] Ibid.

[51] Germany's EEG surcharge (levy), introduced under the Renewable Energy Sources Act in 2000, financed fixed-price feed-in tariffs for renewables by spreading the cost among electricity consumers. The levy reached over 6 cents per kWh around 2014-2021 and was about 3.72 ct/kWh in early 2022. Under a law passed in 2022, the levy was abolished effective 1 July 2022. Thereafter, funding for renewables shifted from the EEG levy to the federal budget—in particular, via the Climate and Transformation Fund.

over 6 ct/kWh between 2014 and 2021, before being abolished in July 2022 to ease the burden on households. [52]

A second challenge has been the slow and fragmented rollout of smart meters, which has limited the implementation of dynamic tariffs and fine-grained locational and temporal signals. Recognising this bottleneck, Germany adopted the Act to Relaunch the Digitalisation of the Energy Transition (2023). [53]

The Act introduces binding deadlines for smart meter deployment, beginning in 2025 with mandatory installation for defined user groups. It allows an "agile rollout," where certified devices can be installed and later updated via software, and removes the earlier "three-manufacturer rule," streamlining certification and accelerating deployment. To ease costs for households and small prosumers, the Act caps annual consumer charges for the smart meters (around €20/year for many households) and shifts the excess costs of the rollout onto the DSOs. It also standardises data communication, strengthens privacy protections. From 2025, it requires all suppliers to offer dynamic electricity tariff options, ensuring that prosumers and flexible consumers can access time-variable pricing that better reflects system costs. [54]

By lowering barriers to digitalisation and mandating access to time-variable pricing, the Act lays the groundwork for cost-reflective prosumer participation.

Furthermore, since January 2024, Germany has required controllable consumption devices such as EV chargers and heat pumps to be "dimmable." Grid operators can no longer refuse or delay their connection but may temporarily limit their power draw to a guaranteed minimum of 4.2 kW to prevent local grid overloads. Regular household supplies are unaffected. In return, consumers with such devices benefit from reduced network charges. The measure supports the rapid integration of new electrification loads while safeguarding grid stability, pending the optimisation, digitalisation, and expansion of local networks. It also complements the ongoing *General Grid Charge System for Electricity*, AgNes, tariff reform process, which aims to introduce more dynamic and flexible network pricing. [55]

Building on this, in May 2025, BNetzA formally launched the AgNeS proceedings to overhaul Germany's network tariff system. The discussion paper identifies three central challenges: a shrinking base of full-paying users while costs keep rising, insufficient locational signals to guide cost-efficient deployment, and a lack of incentives for flexibility. Proposed reforms include broadening the financing base by charging generators for feed-in, strengthening standing or

---

[52] Elimination of EEG levy relieves electricity consumers | Federal Government

[53] Drucksache 20/5549 Gesetzentwurf der Fraktionen SPD, BÜNDNIS 90/DIE GRÜNEN und FDP Entwurf eines Gesetzes zum Neustart der Digitalisierung der Energiewende

[54] Ibid.

[55] Ibid.

capacity-based charges, and developing dynamic tariffs that reflect real-time network use. Options for storage-specific tariffs are also under review. Collectively, these measures aim to better align tariffs with cost drivers, integrate renewables and prosumers fairly, and ensure the financial sustainability of the grid. [56]

Germany's tariff system combines established incentive-based regulation with new reforms aimed at digitalisation, flexibility, and fairer cost recovery. The abolition of the EEG levy eased consumer burdens, while the 2023 Act set binding deadlines for smart meter rollout and mandated dynamic tariffs from 2025. Together with the ongoing AgNes reform process, these steps mark a shift toward fairer pricing and active integration of DERs.

Italy: reforming incentives for a fairer DER-rich future

In Italy, the regulatory authority ARERA sets the framework for transmission, distribution, and metering tariffs under multi-year regulatory periods. For the current 2024–2027 regulatory sub-period, ARERA approved the tariff framework and republished the rulebooks for distribution (TIT), metering (TIME), and connection (TIC). The framework follows a revenue-requirement model based on the regulatory asset base (RAB), recognised operating costs, and an allowed return defined by the TIWACC methodology. [57] Reconciliation, cost recognition rules, and audit provisions—typical of Italian revenue-cap practice—ensure transparency and accountability. [58]

End-user tariffs are composed of four main elements. The *energy supply* component reflects wholesale market prices plus the retailer's margin. *Network services* are regulated charges covering transmission, distribution, and metering costs. *System charges* (oneri generali di sistema) are levies used to finance policy measures such as renewable energy support and social subsidies, while *taxes*

[56] https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/EN/2025/20250512_AgNes.html

[57] TIWACC (Testo Integrato sul tasso di WACC) is ARERA's integrated methodology for calculating the weighted average cost of capital applied to regulated electricity and gas infrastructure. The framework sets the WACC for a six-year regulatory period, but with two three-year sub-periods built in, when the parameters used in the calculation of the WACC (such as risk-free rate, credit spreads, inflation, etc.) are refreshed at the start of each three-year sub-period to reflect updated market conditions.

[58] Delibera 6/6/2023
https://www.arera.it/fileadmin/allegati/docs/23/616-23.pdf

include VAT and excise duties. ARERA updates tariffs annually through resolutions that apply the approved methodology and parameter revisions. [59][60]

The weight of each tariff component varies over time with wholesale price movements, regulatory updates, and policy costs. For a typical domestic customer in the first quarter of 2024, ARERA reported a breakdown of roughly 48 per cent energy, 18 per cent network and metering, and 12.8 per cent system charges, with the remainder consisting of retailing and taxes. These shares fluctuate by quarter and are published regularly in ARERA's public notes. [61]

The 2024 to 2027 regulatory package includes output-based regulation and updated quality rules that interact with the growth of DERs by rewarding improvements in service continuity, connection performance, and related outcomes. The Integrated Text on Connections (TIC), republished under Delibera 6/16/2023, defines the rules for connection services, including cost recognition for new resources. These instruments do not place DER costs outside the revenue-requirement framework; instead, efficient DER-related network investments and operating needs are recognised within the tariff system through the distribution (TIT), metering (TIME), and connection (TIC) texts, where regulatory criteria are satisfied. [62]

Prosumer regulation has undergone significant reform. Italy is phasing out the generous legacy Scambio sul Posto (SSP) scheme in favour of the Integrated Text on Distributed Self-Consumption (TIAD). SSP, launched in 2009 and managed by the state energy services operator GSE (Gestore dei Servizi Energetici), allowed households and small renewable producers to offset annual consumption against annual generation, with surplus compensated through the Conto Scambio mechanism. By 2018, over 656,000 installations—99 per cent of them solar PV, totalling 5.6 GW—were enrolled. The scheme, combined with tax deductions of up to 50 per cent on installation costs, made rooftop PV highly profitable and accelerated uptake. However, it also created cross-subsidies and

---

[59] Arera: Guida alla letura delle voci di spesa eletricità

https://www.arera.it/fileadmin/bolletta/allegati/guidaele.pdf

[60] La bolletta dei clienti finali di energia
https://www.arera.it/fileadmin/allegati/docs/24/315-24___ti.pdf

[61] L'aggiornamento delle condizioni di tutela i trimestri 2024 nel dettaglio

https://www.arera.it/comunicati-stampa/dettaglio/elettricita-bolletta-in-tutela-108-nel-primo-trimestre-2024

[62] Delibera 6/6/2023
https://www.arera.it/fileadmin/allegati/docs/23/616-23.pdf

discouraged storage investment, since households could rely on annual netting and generous compensation. [63][64]

TIAD, by contrast, is a net-billing framework. Prosumers and energy communities pay full network tariffs and system charges on all imports, ensuring cost recovery is not eroded. Surplus exports are compensated separately at market-based values administered by GSE. TIAD also supports collective self-consumption and energy communities, enabling local optimisation of distributed resources. This reform aligns compensation more closely with system value while maintaining incentives for DER deployment and improving fairness in cost allocation. [65][66]

Italy's trajectory illustrates a broader shift from growth-driven incentives toward a balanced and sustainable model of DER integration. A mature RAB/WACC revenue-requirement framework, a clear tariff structure, performance-based quality incentives, and the transition from SSP to TIAD demonstrate how regulation can embed prosumers within the tariff system, sustain DER growth, and safeguard the financial stability of the distribution network.

Spain: capacity-heavy tariffs and a net-billing prosumer framework

In Spain, regulated portions of retail electricity bills are divided into access tariffs (peajes de acceso) and system charges (cargos). The access tariffs are regulated charges for using the transmission and distribution networks. The system charges (cargos) are regulated system charges (policy costs like RES subsidies, stranded costs, capacity payments). [67]

Comisión Nacional de los Mercados y la Competencia (CNMC) established the current methodology for the access tariffs, mandating annual updates and applying cost causality, transparency, and efficiency criteria.

The remuneration of distribution system operators (DSOs) operates under revenue-requirement logic. CNMC's Circular 6/2019 sets the remuneration methodology for the 2020–2025 period,

---

[63] Relazione tecnica modalità e condizioni tecnico economiche per l'erogazione del servizio di scambio sul posto
https://www.arera.it/fileadmin/allegati/docs/12/570-12rt.pdf

[64] The EU's 2030 Climate and Energy Policy Framework: How net metering slips through its net

https://onlinelibrary.wiley.com/doi/10.1111/reel.12339#:~:text=82%20This%20remuneration%20can%20compensate,as%20a%20net%20billing%20scheme.

[65] Testo Integrato Autoconsumo Diffuso – TIAD
https://www.arera.it/fileadmin/allegati/docs/22/727-22TIAD.pdf

[66] DECRETO CACER e TIAD – Regole operative per l'accesso al servizio per l'autoconsumo diffuso e al contributo PNRR
https://www.gse.it/documenti_site/Documenti%20GSE/Servizi%20per%20te/AUTOCONSUMO/Gruppi%20di%20autoconsumatori%20e%20comunita%20di%20energia%20rinnovabile/Regole%20e%20procedure/ALLEGATO%201%20Regole%20Operative%20CACER.pdf

[67] https://noticias.juridicas.com/base_datos/Fiscal/658354-circular-cnmc-3-2020-de-15-ene-metodologia-para-el-calculo-de-los-peajes.html

incorporating efficiency incentives, cost recognition rules, and allowed returns. CNMC publishes annual resolutions under this framework. [68][69][70]

Spain's peajes splits network cost recovery into a contracted *capacity term* (€/kW per year), which creates a predictable revenue stream for the DSOs, an *energy term* (ct/kWh consumed), to reflect usage of the grid, and a small, *fixed term*, to recover the metering fee. place strong emphasis on contracted capacity charges (€/kW per year).

A typical Spanish household bill has four components: Energy charge (the wholesale market price of electricity plus retail margin), peajes (capacity + kWh + fixed), cargos and taxes (VAT, electricity tax). [71] Capacity charges recover a significant share of network revenue, which therefore reduces reliance on volumetric charges. [72]

Spain's prosumer regulation was reformed under Royal Decree 244/2019, which repealed the earlier *impuesto al sol* ("sun tax") and created a new framework for self-consumption. [73] The decree defines administrative, technical, and economic conditions for self-consumption and allows collective self-consumption. It mandates that prosumers continue to pay full peajes and cargos on imports, while

---

[68] https://www.iea.org/policies/17795-spain-renewable-energy-communities

[69] https://www.idae.es/en/technologies/renewable-energies/self-consumption-office/self-consumption-regulations

[70] https://www.perezllorca.com/en/news/legal-briefing/autoconsumo-de-energia-electrica/

[71] La nueva factura de la luz, CNMC
https://www.cnmc.es/

[72] https://www.conecta2energia.com/wp-content/uploads/2021/07/Nuevos-PEAJES_CIRCULAR-3-2020_WEB.pdf

[73] Spain's *"sun tax"* refers to the Real Decreto 900/2015 of 9 October, which imposed a "respaldo" tariff (a charge) on self-consumed solar electricity—i.e. even when a household's solar panels covered its own use, the law required paying additional charges as if that energy had come from the grid. The tax was widely criticised for discouraging rooftop solar and creating barriers to self-consumption. It was repealed on 5 October 2018 by Real Decreto-ley 15/2018, which removed the "sun tax" and introduced measures to promote self-consumption.

Following the repeal, Royal Decree 244/2019 (5 April 2019) established a new legal framework for self-consumption, replacing full net-metering with a net-billing style scheme under which prosumers pay full grid charges on imports, and exports are remunerated separately under defined compensation regimes.

Links:

https://www.boe.es/buscar/pdf/2015/BOE-A-2015-10927-consolidado.pdf

https://climate-laws.org/documents/royal-decree-law-15-2018-on-urgent-measures-for-energy-transition-and-consumer-protection_6548

https://www.osborneclarke.com/insights/analysis-key-developments-introduced-new-royal-decree-2442019-5th-april-regulating-administrative-technical-economic-conditions-self-consumption-electrical-energy surplus exports are compensated via net billing at a wholesale-based value, rather than full retail offsetting. [74]

Spain's regulatory evolution reflects a shift from punitive rules toward an integrated and stable framework for DERs. The combination of strong capacity charges, transparent DSO remuneration, and net-billing for exports provides a foundation for accommodating growing DER penetration while preserving financial sustainability and fairness in cost allocation.

Comparative analysis

The experiences of California, Germany, Italy, and Spain illustrate different paths taken in the evolution of DER tariff design, but they converge on key lessons. Early reliance on retail net metering proved effective in accelerating adoption but unsustainable once deployment reached scale, as it created imbalances in cost recovery and shifted costs to non-prosumers. In response, each jurisdiction has moved toward models that combine fairness with financial stability: California through avoided-cost-based export credits under NEM 3.0, Germany by linking tariffs to controllable loads and exploring dynamic elements, Italy through the transition to net billing under TIAD, and Spain by embedding prosumers in a clear legal framework with strong capacity-based charges.

Across these reforms, a few lessons stand out. Net billing tied to cost causation provides a fairer and more durable basis than retail net metering. Capacity and fixed components help secure stable revenues while reducing cross-subsidies. Dynamic pricing and avoided-cost-based remuneration mark the next stage, allowing tariffs to better reflect system value and incentivise flexibility. Equally important is regulatory stability: punitive or abrupt measures, such as Spain's "sun tax," undermine trust and slow adoption, while gradual, transparent reforms, as seen in California and Italy, enable smoother adjustment. Finally, the growing role of digitalisation and storage integration signals a shift toward unlocking the full system value of DERs beyond energy exports alone.

For African regulators, these experiences underscore the importance of moving quickly beyond simple volumetric tariffs and anticipating the challenges of DER growth with tariff structures that ensure equity, efficiency, and long-term financial sustainability.

5. Recommendations in the African context.

Most power systems still rely on simplified pricing structures to allocate costs among electricity customers. The resulting tariffs, usually dominated by a single volumetric charge ($/kWh) and only marginally supported by fixed charges ($/month)-or nothing- allocated in a non-transparent manner, offer little to no temporal or spatial differentiation. As DER penetration and opportunities for flexible demand increase, such approaches are proving inadequate. They lead to inefficient investments, with some users over- or undercompensated for the services they provide, while many other potential sources of value remain unrecognised. The outcome is a power system that is unnecessarily expensive, less efficient, and incapable of revealing or rewarding the true value of DERs and price-responsive demand. A comprehensive revision of tariff design is therefore essential

[74] https://climate-laws.org/document/royal-decree-244-2019-regulating-the-administrative-technical-and-economic-conditions-of-the-self-consumption-of-electric-energy_8775

to secure cost recovery, efficiency, fairness, and effective DER integration into future power systems.

The recommendations that follow build on the principles and on the assessment of current conditions in selected African countries that are described in the preceding sections. They address the most pressing challenge in relation to DERs in the region: the rapid expansion of residential rooftop solar in the absence of adequate regulation—particularly in tariff design, but also in related areas. Although the discussion highlights rooftop solar, the recommendations apply to all forms of DERs.

5.1. General recommendations on tariff design with DERs.

The remuneration of the distribution utility: need for a new remuneration approach.

The first step in tariff design consists of determining the regulated revenue requirement that must be globally recovered with the tariffs. The revenue requirement of the distribution activity is an important component of the total amount. The first concern when designing the electricity tariffs is to make sure that each one of the components of the revenue requirement has been calculated properly. Correct end-customer tariffs require a correct computation of the distribution revenue requirement (DRR) from which they are derived.

Low penetration of distributed generation (DG) may reduce distribution flows and losses, but stronger penetration levels of solar PV will increase losses, as well as investment and operation costs. In general, higher distribution costs will be expected with a substantial presence of DG, as well as a more complex estimation of the efficient distribution cost – i.e., the regulated revenue requirement that will determine the annual remuneration to be perceived by the distribution company – because the simple extrapolation methods frequently used in the past cannot be relied upon any longer.

The actual impact of the presence of DERs on the remuneration of the distribution company will depend on the method used to calculate the revenue requirement. DG reduces the quantity of energy distributed, and therefore the distribution remuneration if both quantities are related in the calculation method, if this is the case. Thus, it will be necessary to decouple the distribution remuneration from the volume of energy distributed in the method of calculation, if this is the case.

The correct approach, which is supported by the growing trend towards digitalisation of the operation and maintenance of the distribution networks, is to keep an inventory of the existing physical assets, their investment, operation and maintenance costs, and their economic lives and amortisation status. The physical assets and the operation costs may be affected by the presence of DERs. The regulatory authorities must audit that the costs have been efficiently incurred.

The review of the practices in African countries has shown that i) all regulations broadly claim that the remuneration of distribution is based on "cost-of-service"; ii) for the most part the method that is employed does not seem to be based on the volume of energy that is distributed, which is good in the presence of DERs; iii) none of the examined cases seems to pay attention explicitly to the fact that the presence of DERs, specifically beyond a certain level, causes additional distribution costs; iv) some of the regulatory authorities update the tariffs annually or even more frequently, but none of them does it because the total energy distributed decreases or the total distribution cost increases with the growing presence of DERs.

Since distribution tariffs in African countries are mostly volumetric ($/kWh), the total revenue from tariff collection will decrease with DG unless tariffs are systematically adjusted as DG output increases so that the totality of the regulated revenue requirement is paid for. The larger the output of DG, the more the volumetric component of the tariff must increase to recover the revenue requirement.

Note that each one of the individual end-customer tariffs does not need to be cost-reflective. However, the global revenue obtained from the application of the tariffs must equal the revenue requirement.

DERs decrease the total amount of energy distributed. Therefore, the computation of DRR must not depend on the energy distributed (this does not seem to be the case in the reviewed regulations of African countries), and the revenues from the volumetric component of the tariff will also decrease; therefore, tariffs must be periodically updated (which is not the case for this impact in the reviewed regulations) to make sure that, aggregated, the tariffs recover the DRR.

Information that the computation of tariffs in the presence of DERs requires.

In designing tariffs for distributed energy resources (DERs), it is neither feasible nor necessary to meter or control every device behind the customer's meter. Instead, DER integration should be governed through mandatory authorisation, registration, and compliance with quality and security standards. All the information required for tariff design can be obtained from the meter at the connection point by measuring the energy withdrawn from or injected into the grid, on an hourly or, if the injection/withdrawal is very variable, on a half-hourly basis. With this data, tariffs can be designed accurately without the need to track individual devices behind the meter.

This entails that hourly meters must be mandatory for customers for DERs, and an objective for the remaining customers, whenever possible. These meters must allow allocating the charges or credits properly to the withdrawals and injections at the times when they occur. This is particularly important during those occasions when the power system is under stress, either from network limitations or from a lack of available generation capacity.

Cost causality and tariff structure

The presence of DERs demands to add the criteria of cost-causality in the design of tariffs, in addition to those of cost-reflectiveness. The charges (or credits) to any customer, in such a well-designed tariff, must be structured with volumetric ($/kWh) and fixed ($/month) components; whenever possible, a capacity ($/kW) component must be added. The charges and credits for causality-based components must be symmetrical with respect to time and location for the prosumer.

The tariff must include explicit terms for electricity services with cost causality, and a "residual cost" term for all the remaining costs. The components of the tariff with cost causality must be applied to the withdrawals (or injections) time profiles of each customer, metered at its connection point, and should be symmetrical. Terms with cost-causality and the others under the residual cost term must be allocated to one of the components (volumetric, fixed, and capacity).

In the tariff, the fixed component ($/month) must include: i) some costs with cost causality that are not related to withdrawals or injections, like the regulated retail costs, which only depend on the type of customer (large or small; residential, commercial or industrial; special needs) and perhaps of the kind of metering system, and ii) all the remaining costs, lumped together in the "residual cost" term of the fixed cost component of the tariff.

The residual costs generally include generation costs not fully recovered by the marginal generation cost, the operating service costs, and the firm generation capacity cost, network costs not recovered by the charges for the network-related services or nodal prices when they are used, in addition to costs of organisations, various subsidies, and other policy charges. The allocation of the residual costs must be guided by various political, social and economic efficiency considerations, which may roughly be coincident. Ramsey pricing criterion is recommended to maximise economic efficiency, conveniently adapted to comply with governmental guidelines, such as the protection of vulnerable customers, the safeguard of competitiveness of local industries, or the avoidance of popular opposition to tariff increases.

Ramsey pricing is a pricing strategy used in regulated monopolies to allocate fixed costs across different customer groups in a way that minimises the overall distortion to demand while allowing the firm to recover its total costs. Prices are set so that the markup over marginal cost is inversely proportional to the price elasticity of demand of each customer group. In the electricity tariff design being discussed here, the Ramsey pricing rule would apply to the residual costs, which lack any cost causality criterion to be efficiently allocated.

The energy component ($/kWh) must contain only the marginal cost of energy production (in the absence of a wholesale energy market, which is the case in all African countries) or the hourly price of a regional day-ahead market, when it exists and it is considered suitable for the purpose. No other component should be added to this so that demand can respond efficiently to this signal.

The "capacity" component ($/kW) is a catch-all for several electricity services that are necessary to prevent power system stress situations that may be triggered by the withdrawal or injection of power at critical times. The term includes i) peak demand or peak power injection at a distribution feeder or in a transmission line, which may require network reinforcements, ii) operating generation reserves, ready to respond to changes in total generation or demand, or iii) margin of installed and ready to operate firm generation capacity or demand response, ready to respond in situations when the longer-term operating generation reserves become insufficient.

The tariffs must be computed so that, when applied to the future estimated demand, as a whole, they will recover the costs of energy, the distribution and transmission networks, retail, other services, other regulated charges and taxes, minus any subsidy amount that the government may decide to apply. These costs must be allocated in the tariffs as $/kWh, $/month or (if this is the case) $/kW. *The total revenue requirement of the electricity supply must be cost-reflective. The tariffs for the various customer categories in general will not be cost-reflective* because of cross-subsidisation among the different types of customers, and also if the regulatory authorities have approved subsidies.

Make use of internal cross-subsidisation by adapting the value of the fixed component for different types of customers. In general, follow the Ramsey pricing criteria to maximise economic efficiency, although conveniently adapted to comply with governmental guidelines, such as the protection of vulnerable customers, the safeguard of the competitiveness of local industries, or the avoidance of popular opposition to tariff increases.

Charges for network services

Ideally, forward-looking peak-coincident capacity charges should be applied for both distribution and transmission networks, as these best reflect cost causality during system stress. Any network costs not recovered in this way must be incorporated into the category of residual charges. Importantly, network charges should never depend on commercial transactions but should apply at the connection point, providing users with access to the entire network. In line with this principle, wheeling charges must be abolished, since they distort cost allocation and undermine the neutrality of grid access.

5.2. The risks of inaction and partial reform

The recommendations that follow propose a gradual pathway toward more effective tariff design, considering existing limitations in metering technologies, institutional capacity, incomplete customer information, and potential resistance to change. To frame these recommendations, it is useful to first consider two counterfactual scenarios: the risks of inaction, where tariff and metering practices remain unchanged, and the risks of minimal action, where only partial reforms are introduced. Both scenarios highlight the potential inefficiencies and inequities that could undermine system sustainability, thereby reinforcing the need for a structured, step-by-step approach to tariff reform.

The consequences of doing nothing in tariff design and/or metering.

- Improper cancellation of the volumetric component of the payment.

It is assumed here that the tariff for residential users consists of a volumetric component ($/kWh), plus a small, fixed component ($/month). There is no capacity component ($/kW) for residential users, which is typically used only for medium and large commercial and industrial customers. This standard residential tariff must pay the cost of energy, the distribution and transmission networks, any other regulated costs and taxes.

It is also supposed here that the meters are of the electromechanical standard kind. Most residential and small commercial, and industrial customers have standard meters with rotating discs that turn in either direction depending on the direction of the flow of electricity and with a speed just proportional to the amount of flow, regardless of the time of day. The reading of these meters is typically checked monthly or every other month to determine the total consumption of the customer over this period.

For the sake of simplicity, it is also assumed that the tariff is constant over a year, i.e., it is the same at all times (most of the discussion below is still valid with a tariff that depends on time). Let's consider two extreme but realistic examples to help understand the implications of regulatory decisions or their absence.

In the first example, let's assume a residential customer with PV panels that produce over one month the same energy that is internally consumed at home. Therefore, the meter has the same value at the beginning and the end of the month and consequently, the component of the monthly bill corresponding to the volumetric charge of the tariff is zero. The customer only pays the small, fixed charge if there is one.

However, this customer has used the network to import *and to export* electricity, typically more than customers with no solar PV panels. Moreover, this customer does not pay other regulated charges or taxes, because they are also included in the volumetric component of the tariff.

Therefore, in this first example, the customer totally avoids paying network costs and any other residual costs and taxes applied to the total value of the bill.

In the second example, let's assume another household with a demand profile and rooftop solar panel such that – perhaps with the support of a battery – there is never energy exported to the grid, and the amount of energy that is imported is small. If nothing is done to modify the tariff, since the energy consumed as seen at the connection point is small, the total charge in the monthly bill will also be small. The internal cancellation of the energy generated and consumed not only applies to the energy cost, but also to the network costs, the other regulated costs and the taxes, since all these costs are included in the volumetric component of the tariff.

One could argue that, if the energy consumed, as seen at the connection point, is small, the bill should also be small, because what matters to the system is what is seen at the connection point, i.e., how much is injected or withdrawn at any given time. However, this customer is benefiting from the security of supply provided by the main grid in case her/his solar generation is low for several days in a row, or if her/his local generation or the battery fails. This security of supply comprises more services than energy, since it also requires operating reserves, firm generation capacity and adequate network capacity. This customer must also contribute economically, like any other, to the social and environmental initiatives of the regulatory authorities and to the taxes that correspond to all the services that are made available. These services must also be paid for by the customers with DERs that reduce their demand as seen at the connection point.

This second example has shown that some important issues still remain to be properly addressed beyond the discussion about the correct payment to any exported power (the debate of net metering versus net billing), which occupies all the attention in those countries that are trying to regulate DERs.

Improper cancellation of energies occurring at different times and with different economic value.

In addition to this tariff cross-subsidisation in the allocation of the residual costs in benefit of the owners of rooftop solar panels, there is still one more implicit subsidy for the small customers who own solar generation. Note that the economic value of the electricity produced with solar generation in the middle of the day is usually less than the economic value of the electricity consumed, which for households typically happens once the sun has set. Doing nothing means that those customers with solar panels are also implicitly compensated for their exports at the same price (typically higher) that they should pay for their imports.

The consequences of doing too little in tariff design.

The approach termed “net billing” tries to fix the problem by applying a different price (lower than the volumetric component of the tariff, for instance, the actual price of energy) to the energy injected into the grid, as metered at the connection point. This approach ignores the other implicit subsidy discussed above, which is the cancellation of production and consumption that takes place behind the meter, effectively cancelling other costs besides the energy cost, because all of them are included in the volumetric component of the tariff.

Note that “net billing” needs to meter separately the energy withdrawn from the grid at the connection point and the energy injected into the grid at the same point.

Although it is not free from complications, there is a better way of using two separate meters. First, meter the energy produced by the household solar panels separately. Then, meter the energy actually consumed in the household behind the meter separately. Then, a standard tariff could be applied to the latter, and a special "energy-only" tariff could be applied to the former. While this approach is correct, it raises concerns about intrusion behind the meter and introduces other difficulties, like verifying that there are no other generation sources, electric vehicles or batteries in the household. The objective should be to design a tariff based on the information provided by a single advanced meter (hourly and bidirectional) at a single connection point for a household, regardless of what is connected inside.

5.3. Specific recommendations to improve the current tariff design

Avoid undesired cancellation of non-energy charges

The regulatory review highlights the prevailing structure of end-customer tariffs, which are typically dominated by a constant volumetric component ($/kWh), occasionally accompanied by a small, fixed charge ($/month), and only rarely by a capacity charge ($/kW). The volumetric component not only reflects the cost of energy but also incorporates charges for other electricity services, along with most or all residual costs. For residential and small commercial or industrial customers, metering is still largely based on standard electromechanical meters with rotating disks that register consumption in either direction, depending on whether electricity is being withdrawn from or injected into the grid.

A key issue under the current tariff structure is the way energy produced behind the meter is treated. While it is appropriate that self-generated electricity offsets the corresponding energy charge, it also cancels other components embedded in the volumetric tariff—such as charges for network services or residual costs—that are unrelated to actual energy consumption. These costs are then shifted onto other customers, creating inequities. Similarly, exported energy is often credited at the full volumetric rate, rather than only the energy term, which results in overcompensation. As a consequence, total payments fall short of what is required to cover system costs, and associated tax revenues are also lower than they should be.

Two courses of action can be taken, depending on whether it is viable or not, to require DER customers to register and install hourly bidirectional meters.

If it is not viable to require customers with DERs to register and install hourly bidirectional meters, the existing standard meters should be maintained for all customers. In this case, tariffs would continue to apply a strictly energy-based volumetric charge or credit ($/kWh) on the monthly net reading of the meter, complemented by a fixed monthly charge ($/month) that includes the retail component and an allocation of residual costs determined by the regulator. The application of Ramsey-like pricing, with a reasonable classification of customers, ensures that the residual costs are distributed efficiently and fairly. This relatively simple reallocation of costs between the volumetric and fixed components would already address a large part of the problem. However, care is required in allocating residual costs to avoid social or political rejection. Because these costs are only weakly related—or often unrelated—to the net level of consumption measured at the connection point, they cannot be assigned on that basis. In the absence of hourly data on injections and withdrawals, it is not possible to calculate charges or credits for other electricity services, and the default option is to include them in the residual category. A limitation of unidirectional meters is that they record only withdrawals, ignoring injections, so exported energy is not remunerated—an outcome that is also undesirable.

If, on the other hand, it becomes viable to require customers with DERs to register and install hourly bidirectional meters, a more refined approach can be implemented. For these customers, registration, standards compliance, and hourly metering would be mandatory. Energy withdrawn and injected would be subject to symmetrical energy charges and credits ($/kWh), while other explicitly defined electricity services would also carry symmetrical charges and credits, denominated as capacity ($/kW). Retail charges would continue to be adapted to customer type, while residual charges would be allocated according to Ramsey-like principles. For smaller customers without DERs, the standard meters would be retained for the time being, with the option of voluntarily switching to hourly metering under the same rules applied to DER customers. These customers would face a volumetric energy charge based on their monthly net consumption and a fixed monthly charge covering both retail services and residual costs, again distributed according to Ramsey-like criteria.

Still, an important limitation of this approach is that energies consumed and produced at different times and with different economic values are netted out. The next proposed measure can take care of this issue.

Avoid netting energies produced and consumed at different times

This measure is meant to be applied in addition to the previous one. The objective is to avoid the cancellation (netting) of electricity that is consumed or produced at different times and which supposedly has a different economic value.

It is assumed that customers with DERs have registered and installed hourly bidirectional meters. Customers without DERs are not mandated to have hourly meters and nothing changes for them.

When customers with DERs are equipped with hourly bidirectional meters, a common problem arises if energy produced and consumed at different times is netted over the billing period. In such cases, a kilowatt-hour generated behind the meter at one point in time cancels a kilowatt-hour consumed at another, even though the two have different economic values. For instance, solar production at midday typically has a lower value than electricity consumed in the evening, when solar panels are not generating. This practice creates an implicit subsidy for solar owners at the expense of other customers.

The recommended solution in this case is to apply the hourly value of energy directly to the withdrawals and injections recorded at the connection point. With hourly bidirectional meters, this can be implemented straightforwardly and resolves the distortion completely. Time-of-use meters are a possible alternative but provide only a less precise approximation.

Try to reduce grid defection.

Often, electricity tariffs include costs that are not necessarily part of the tariff. If inefficient grid defection is a serious threat, it is advised to reconsider which costs are included in the electricity tariff.

Increase the locational component of prices and charges.

Progressively increase the *locational component of the tariffs*, both at the transmission level (for large generators and demands) and at the distribution level (in feeders with active constraints due to peak importing or exporting power flows).

5.4. Bringing out the value of DERs beyond what tariffs can reasonably achieve[75]

[75] This section applies to DERs in a broad sense, which includes all kinds of devices connected to the distribution network, such as batteries and electric vehicles, small generation, as well as residential and small commercial and industrial customers with demand response capability and DERs behind the connection point.

The objective of a comprehensive system of cost-reflective prices and charges is to ensure that the marginal cost to an agent of consuming a service, or the marginal value to an agent of providing that service, equals the marginal change in total social welfare produced by that action. In other words, the private cost or benefit of consumption or production for an agent should align with the system-wide cost or benefit. Distortions arise when the private value of an action is either lower or higher than its system value.

In principle, such a system of prices and charges would capture the full value of all agents in the power system, whether centralised or distributed. In practice, however, only large agents are able to process and act on this information. The level of communication between the system operator and individual customers (except for the large ones), regarding the demand for electricity services and their costs, is limited by technology and convenience.

For instance, the system operator may need a temporary reduction of a specific amount of demand for 20 minutes, because of an expected ramp in wind production, but it is cumbersome to translate this information to the sufficient customers who are willing to provide this service. Similarly, a system frequency deviation from the target value could be damped by the joint action of many customers, but they lack this information. The value of these potential services cannot be captured by the three accepted categories of charges in the tariffs: $/kWh, $/kW and $/year. More sophisticated tariff designs and economic signals would be needed.

Distributed energy resources (DERs) can realise their potential only when aggregated in large numbers under the coordination of an intermediary with the capability to design and manage a collective response. Once a sufficient level of digitalisation of a substantial number of customers has been reached, these customers can be invited by an "aggregator company" to join to perform tasks with economic value, such as helping to control the system frequency, or the local voltage, or to shave the peak demand in a feeder to delay the need for a reinforcement, or to smooth a ramp in demand or production.

The aggregator can receive the request for a service from the system operator, can also know the current situation and potential response of each customer, and will coordinate a joint response, providing the required service in exchange for economic compensation to be shared with the participating customers. This can bring out the full economic value and technical potential of the DERs.

The recommendations presented earlier address only two electricity services: energy and, where tariffs include an appropriate capacity component, a contribution to network capacity margins. Yet DERs, when aggregated, can provide a much wider range of services with clear economic value. These include more precise and effective contributions to local network capacity margins that reduce or defer reinforcements, the provision of operating reserves in coordination with system operator signals or direct frequency response, firm generation capacity, and potentially even services for power quality and energy security. Such opportunities are already being demonstrated in many countries, paving the way for the deeper integration of DERs into power systems worldwide.

The existence and activity of aggregators must be encouraged and facilitated, which is expected to result in a more efficient and reliable provision of electricity services.