Utilities Policy 101 (2026) 102221

Contents lists available at ScienceDirect

Utilities Policy

journal homepage: www.elsevier.com/locate/jup

Full-length article

From least-cost plans to implementable electrification: A regulatory–financial framework to achieve universal access

Santos J. Díaz-Pastor [a,b,*], Carlos de Abajo [b], Robert Stoner [a], Ignacio J. Pérez-Arriaga [a,b]

[a] Massachusetts Institute of Technology (MIT), Cambridge, MA, USA
[b] Institute for Research in Technology, Comillas Pontifical University, Madrid, Spain

ARTICLE INFO

Handling Editor: Janice A. Beecher

Keywords:
Universal electricity access
Infrastructure investment
Public-private partnerships
Cross-subsidization
Cost-of-service regulation

ABSTRACT

Achieving universal electricity access requires more than a least-cost electrification plan. In many low- and middle-income power sectors, affordability constraints, distressed distribution utilities, and high perceived risk prevent least-cost pathways from being implemented by raising the cost of capital. This paper develops an integrated regulatory–financial framework that completes least-cost planning by linking: (i) techno-economic analysis across grid and off-grid options; (ii) implementable business models under cost-of-service regulation; and (iii) a financing architecture that coordinates public resources, concessional instruments, and commercial capital through a centralized platform that pools and ring-fences flows and disbursement rules. The results separate two implementation constraints. The first is the "viability gap", the shortfall between realized cash revenues and the regulated cost of service when affordability and weak retail performance prevent full annual recovery. The second is "financing needs", which arise because electrification requires large upfront investment, while cost recovery occurs gradually, even when the plan is viable in the long run. The framework clarifies the policy levers: viability gaps require explicit and predictable compensation mechanisms, while financing needs require capital structures, tenors, and liquidity facilities aligned with the regulatory recovery schedule and allowed returns sufficient to cover financing costs and preserve equity value. The approach provides a transferable methodology for regulators and policymakers to move from least-cost targets to implementable electrification programs with revenue adequacy and financeable cash-flow trajectories. It is illustrated with applications in Rwanda and Uganda, showing how the same logic can be parameterized across institutional forms to support universal access.

1. Introduction and literature review

Universal electricity access remains an urgent global challenge. Despite broad consensus on its importance, current progress is far from sufficient. Projections indicate that under existing policies, 645 million people will still be without electricity by 2030, with more than 85% of them in Africa (IEA, 2025; IEA et al., 2024). Achieving Sustainable Development Goal 7 (SDG 7) of the 2030 Agenda will require a sharp acceleration in connections. In Africa, this means reaching around 90 million people every year, which is three times the historical rate (IEA, 2022).

Reaching such a scale will demand a significant increase in current capital inflows. Africa will need to mobilize around USD 25 billion annually between 2025 and 2030 to achieve electricity access targets, yet current commitments remain far below this level and have declined in real terms over the past decade (IEA, 2022).

Cost of capital constitutes a critical barrier. Risk premiums and interest rates on African power projects are commonly two to three times those prevailing in advanced economies, eroding project bankability and discouraging private participation (African Development Bank, 2025; IEA, 2023). As a consequence, private finance has concentrated on generation assets because these projects more often secure contracted revenues and explicit cost recovery, while network investment lags. Transmission and distribution—which underpin reliable service and rural expansion—continue to receive a disproportionately small share of total investment flows, exacerbating access deficits (BloombergNEF, 2024; RES4Africa Foundation, 2021).

Distribution companies (DISCOs) sit at the core of this problem. Political mandates to hold tariffs below cost recovery create quasi-fiscal deficits, weaken balance sheets, and limit the ability of utilities to

* Corresponding author. Massachusetts Institute of Technology (MIT), Institute for Research in Technology, Comillas Pontifical University, Spain.
E-mail addresses: sjdp@mit.edu, santos.diaz@iit.comillas.edu (S.J. Díaz-Pastor).

https://doi.org/10.1016/j.jup.2026.102221
Received 24 January 2026; Received in revised form 21 April 2026; Accepted 24 April 2026
0957-1787/© 2026 Elsevier Ltd. All rights are reserved, including those for text and data mining, AI training, and similar technologies.

expand service or serve as credible off-takers for new generation (Balabanyan et al., 2021; Klug et al., 2022; Kojima and Trimble, 2016). Financial distress at the retail end reverberates through the whole value chain, raising perceived risk and the cost of capital sector-wide (Foster and Rana, 2020).

Meanwhile, techno-economic electrification models have advanced rapidly, using geospatial optimization to map least-cost mixes of grid extension, mini-grids, and stand-alone systems. Yet these models typically assume uniform interest rates and ignore the financing and regulatory constraints documented above (Agutu et al., 2022; Aluko et al., 2025). The problem is therefore not only methodological. It is operational. A masterplan can be technically coherent and still remain non-executable when financing costs, remuneration rules, and subsidy settlement are left outside the analysis.

This article addresses a practical question that arises after a national least-cost electrification plan has already been prepared: under what regulatory, contractual, and financing conditions can that plan become executable, scalable, and commercially credible? The argument is that least-cost planning is necessary, but not sufficient. A national pathway becomes implementable only when it is coupled to a sustainable remuneration model, explicit treatment of affordability-driven subsidies, and a financing structure that can absorb front-loaded rollout while preserving bankability.

To respond to those limitations, this paper proposes an integrated three-step framework that begins with a design of a least-cost electrification plan, then overlays cost-reflective regulatory and business models, and finally assembles a blended-finance architecture that consolidates public resources, concessional capital, commercial debt and tariff revenues. By aligning technical planning with bankable regulation and fiscally credible financing, the framework offers a pragmatic roadmap toward universal electricity access.

2. Lessons learned to achieve universal electrification

A substantial body of empirical and theoretical work now exists to explain barriers to universal electricity access, ranging from the techno-economic limitations of network expansion to the politics of tariff reform. Section 1 showed how these barriers materialize in practice as financially distressed distribution companies, high cost of capital and chronic underinvestment in networks.

Under these conditions, it is unrealistic to expect that a public utility or the public budget can finance universal access on its own. Most studies address one barrier at a time and therefore only partly explain why technically rigorous electrification plans often fail to move into implementation, as documented in the literature that diagnoses these mechanisms and their interactions (GCEEP, 2020; Perez-Arriaga et al., 2019; Pérez-Arriaga, 2024).

To organize the discussion, the paper groups the prerequisites for lasting electrification into four mutually reinforcing pillars. Each corresponds to a distinct failure mode documented in the literature, and together they describe the conditions under which public and private actors can invest at scale along a shared electrification pathway.

2.1. Cost-effective planning: integrating grid, mini-grid, and stand-alone options

Universal access requires matching each locality to be electrified with the technology that meets demand at the lowest life-cycle cost. Rather than privileging grid expansion by default, electrification planning must consider terrain characterization, distance, population density and estimated demand, because these factors strongly affect cost structures.

Geospatial least-cost toolkits operationalize technology choice across grid extension, mini-grids, and stand-alone systems (Ciller and Lumbreras, 2020). Evidence from REM pilots suggests that automated household-scale selection can reduce required investment by about one-third (Amatya et al., 2018; Ciller et al., 2019). Indonesia's geospatial plan reports 30–50% lower average connection costs by densifying the core grid and using renewables-based mini-grids for remote island grids (World Bank et al., 2013). OnSSET applications in Ethiopia and Zambia allocate stand-alone PV to more than half of unelectrified households, saving billions (Egli et al., 2023; Sahlberg et al., 2021). Most studies still assume simplified financing and therefore do not specify who pays, at what cost of capital, and under which recovery mechanisms (Agutu et al., 2022).

Notwithstanding the distortion resulting from oversimplified assumptions about the cost of capital, cost-effective planning stands as an independent non-negotiable principle. By lowering required investment, it reduces the total cost recovery need that must be covered through a combination of end-user payments and explicit subsidies. It provides the technical and fiscal foundation for the remaining pillars: legal mandates for universal access, financially sustainable and scalable business models based on predictable revenues, and development-oriented delivery.

2.2. Scalability: universal-access commitment for last-mile electrification

Universal access requires a system-wide approach in which regulation, funding and planning converge to succeed. This principle moves beyond financing isolated projects. It embeds an enforceable duty to connect every household and channels finance through instruments that pay the total cost of providing service at scale. The aim is to make all connections financially viable, not only those in dense or affluent areas, although not necessarily identical nor equally costly. Otherwise, expansion stalls once commercially attractive segments are exhausted. Evidence from global power sector diagnostics supports this systems perspective and links durable progress to legal mandates, credible funding commitments and institutional capacity (Foster and Rana, 2020; World Bank, 2024).

A common strategy, often labelled as results-based financing (RBF), links part of the subsidy to capital expenditure (CAPEX) deployment while assuming that tariffs move toward cost recovery. It can speed up connections, but it does not ensure last-mile delivery in high-cost, low-demand areas. Providers need an enforceable service obligation (e.g., via concessions) and a predictable mechanism to cover any revenue shortfall. If the objective is universal coverage, the financing architecture must make every connection viable on a life-cycle basis. This requires a national rollout plan that combines obligations, cross-subsidies, access funds, and performance incentives (Pérez-Arriaga, 2023).

The operational expression of this political will is the universal service obligation (USO)—a legal duty imposed on utilities or concessionaires to connect all households in a defined territory. World Bank research shows that USOs, when paired with targeted subsidies, accelerate rural electrification without undermining financial viability (Estache et al., 2004, 2006). Empirical work in developing-country utilities confirms that regions with legally enforced USOs achieve higher connection rates at comparable cost levels relative to regions operating under discretionary expansion policies (Leduchowicz-Municio et al., 2022).

Country experiences show that binding USOs, backed by dedicated funding and clear utility obligations, can accelerate last-mile connections and unlock economies of scale. Brazil's *Luz para Todos* illustrates this logic, electrifying more than 17 million rural residents between 2003 and 2023 under a legal mandate and a sector funding mechanism (Câmara dos Deputados, 2003; Ministério de Minas e Energia, 2002). China's last-mile campaign reached full coverage by 2015 after binding targets and RMB 87 billion in cross-provincial transfers to provincial utilities (He, 2019). India's Saubhagya scheme, launched in 2017, leveraged statutory obligations on state utilities to connect every willing household; by March 2022 the program had declared full village electrification, with fewer than 10,000 households still unconnected (Arif, 2025; Ministry of Power, 2023).

Scalability therefore constitutes a related but independent principle. It requires a political commitment to full electrification and a comprehensive program design. Once the program is adopted and funded, and business models are in place, providers take on explicit coverage commitments, either through contracts or by mandate in publicly owned utilities. This turns electrification into a predictable multi-year program with clear accountability metrics.

2.3. Sustainability: ensuring financial viability through cost-recovery and regulatory discipline

Financial sustainability is achieved when electricity providers—whether utilities, mini-grid operators, or concessionaires—can maintain reliable service over time by recovering the full cost of delivering electricity (that includes a reasonable rate of return on the invested assets). Without financial viability, even technically optimal and politically backed plans risk collapse due to insolvency, underinvestment, or poor service quality.

A rich literature highlights the pervasive financial fragility of power sectors in low- and middle-income countries. Comparative diagnostics for more than a dozen systems show that chronic under-recovery of costs—through tariffs that are globally insufficient to recover total costs or weak collection, and technical and non-technical losses—systematically undermines the ability of utilities to invest and operate effectively (Huentele et al., 2020; Huenteler et al., 2017; Trimble et al., 2016). Cross-country studies in sub-Saharan Africa and other developing regions confirm that only a minority of utilities cover full-service costs and that persistent revenue shortfalls are a central reason for underinvestment and poor quality of service (Asantewaa et al., 2023; Eberhard and Shkaratan, 2012; Jamasb et al., 2017). These findings imply that trying to scale up access without first restoring financial balance tends to entrench an unstable utility sector.

The financial sustainability principle thus requires that regulators define cost-reflective revenue requirements and that tariff design, subsidy models and regulatory structures be deliberately oriented toward covering operational and capital costs over time. Because universal access must scale beyond commercially viable segments, sustainability typically requires some form of regulated remuneration and end-user tariff setting, even if a limited share of connections can remain viable under purely commercial pricing.

Evidence from both developed and developing power systems shows that regulatory schemes which recover these revenue requirements and link allowed revenues to clear performance targets support higher investment and efficiency in distribution networks (Joskow, 2024; Naruc, 2022). Recent integrated regulatory–financial frameworks go further by computing cost-reflective revenue requirements for entire national electrification plans and testing their implications for tariffs, subsidies and risk allocation. (Díaz-Pastor and Pérez-Arriaga, 2025) provide such an example for Uganda.

Operationalizing this principle also has direct implications for financing. In the benchmark case, regulators first quantify the cost of providing a guaranteed level of service and then translate it into a predictable revenue stream through a stable combination of end-user tariffs and explicit subsidies. Utilities and mini-grid operators can raise long-term debt and equity against that revenue stream, because the regulatory commitment makes it credible to financiers. This benchmark fits mature systems. In many developing contexts, raising equity is more challenging and depends on country risk, regulatory credibility, business model attractiveness, and the expected shareholder return. Longer tenors and lower perceived risk reduce the weighted average cost of capital and therefore the financing component that feeds into tariffs. In those settings, balance-sheet stability reinforces this logic.

In most low- and middle-income power systems, however, current practice departs sharply from this benchmark. Revenue requirements are rarely calculated explicitly or approved *ex ante*. Subsidies arrive late or in arrears, and governments rely on *ad hoc* transfers or short-term borrowing to keep utilities solvent. During rapid electrification, the investment profile is front-loaded, and debt service may overwhelm current revenues, so refinancing based on "financing as usual" is not credible. Providers therefore face high financing costs, short maturities and recurrent liquidity crises. These conditions raise effective costs, deter private participation and lock the sector into a high cost, low investment equilibrium. Credible commitments to cover cost-reflective revenue requirements are thus not only a technical requirement of regulation but a precondition for mobilizing private capital at scale on affordable terms.

In sum, financial sustainability stands alone as a binding constraint in electrification strategy. An electrification plan without sustainable cost recovery leads to a cycle of service and failure: utilities default on maintenance, grid expansion stalls, and communities lose faith. This spirals into underperformance and drags down the broader electrification effort.

2.4. Development-focused planning: linking electricity access to productive uses and industrialization

Electrification is justified by welfare and economic gains, but these gains often require complementary measures that raise demand beyond basic lighting. Reviews and impact evaluations find modest or heterogeneous short- and medium-run effects when such complements are absent (Bonan et al., 2017; Bos et al., 2018; Lee et al., 2020; Lemanski et al., 2025).

A growing empirical and review literature shows that powering machinery, irrigation, refrigeration, and information and communication technologies can transform rural economies. This transformation can be achieved by increasing labor productivity, stabilizing agricultural output, and fostering enterprise growth. A recent systematic review of productive use in African agriculture finds that electric irrigation, agro-processing, and cold storage expand output and reduce post-harvest losses, while also increasing electricity demand and improving load factors for suppliers (ESMAP, 2023; Raji et al., 2024). Case studies of rural electrification and off-grid systems in East Africa similarly report higher profits for small firms and farms once electric equipment is adopted, although these gains materialize only when credit, market access, and technical support are in place (Bos et al., 2018; Grimm et al., 2017).

Transparency is part of the same logic. Publicly disclosed plans, targets, and subsidy rules strengthen accountability and reduce reversal risk across political cycles. The neglect of productive use, affordability, and community agency often accounts for why many apparently successful connection drives later face low consumption, revenue shortfalls, and social disappointment. Integrating this principle with cost-effective planning, a universal-access mandate, and financial sustainability completes the four-pillar framework of this paper and aligns electrification strategies with durable socio-economic progress.

These four requirements do not form an arbitrary checklist. They emerge from an implementation problem. A least-cost plan becomes an electrification program only when an implementing agent can (i) deliver the selected technology portfolio at scale, (ii) operate under a binding universal-access mandate, (iii) recover efficient costs through a transparent mix of tariffs and subsidies consistent with affordability, and (iv) stimulate demand and productive use so that revenues and welfare gains materialize over time. In fiscally constrained power sectors with financially distressed DISCOs, these conditions become mutually reinforcing. When one pillar fails, the others lose traction.

3. Methodology: an integrated three-step framework for universal electrification

This section translates the four pillars previously discussed into a three-step operational framework that links planning, regulation, and finance. The architecture is conceived to address the objective of

universal electrification within the confines of binding fiscal and financial constraints.

The framework is organized around three questions: (i) what must be built and what does it cost? (ii) who should implement and operate the investments, and under which regulatory, business and contractual arrangements? and (iii) how will the required investments be financed and their costs recovered over time?

This methodology is designed to be transferable across country contexts, with data and institutional parameters calibrated to local conditions. It has been refined through applications in Latin America and sub-Saharan Africa, where it has supported national electrification strategies and distribution sector reforms.

3.1. Step One: what must be done? – crafting the techno-economic electrification plan

The initial step within this framework is the techno-economic analysis. These plans delineate the infrastructure to be constructed, its location and the timeframe for its completion, and produce the cost streams that will subsequently inform the regulatory and financial analysis.

The techno-economic plan relies on integrated least-cost planning across on-grid and off-grid solutions. It uses georeferenced data and computer-aided modelling to characterize demand, population distribution, and existing grid infrastructure. It then evaluates, for each locality, alternative electrification modes including grid extension, minigrids, and stand-alone solar PV systems. It selects the option that minimizes life-cycle costs, subject to policy constraints such as electrification targets or technology restrictions. A critical task at this stage is generating a detailed bill of quantities and a time profile of expenditures. The plan must define the capital expenditures and the explicit operating and maintenance needs over the planning horizon.

Step One delivers a system-wide electrification pathway. The scope is national or system-wide and targets universal electricity access within a specified timeframe, such as by 2030. Outputs include, for each year, the selected technology by area, the number of new connections, required network reinforcements and extensions, and associated capital and operating expenditures. Aggregated, these outputs provide a coherent investment and connection trajectory for the whole system. As an example, Fig. 1 shows the techno-economic results and least-cost plan to achieve 100% electrification in Rwanda using REM (Ciller et al., 2019).

In the integrated framework proposed here, Step One, Step Two, and Step Three form an iterative process. Cost streams from the techno-economic plan inform the regulatory, institutional, and business model design in Step Two and the financial plan in Step Three. The resulting weighted average costs of capital for each technology can then be fed back into the techno-economic analysis. The plan is adjusted until the three steps are mutually consistent. Where this iteration does not take place, electrification plans that look optimal on paper often prove unfinanceable within realistic fiscal envelopes and are set aside in implementation.

3.2. Step Two: who should do it and how? – regulation and business models

In the complex process of developing an electrification strategy, the second step is crucial as it determines the "who" and "how" of executing a well-designed techno-economic plan. Instead of adding engineering detail, Step Two translates the blueprint from Step One into mandates, contracts, and incentives for distribution companies and off-grid providers. In a country with tight fiscal constraints that aims to combine universal access, financial sustainability, and private sector participation, the feasible design space is limited.

It is important to note that Step Two operationalizes two of the principles discussed in the previous section. The first is scalability. Universal access requires a binding commitment to serve all households, not only those in low-cost and high-demand areas. Step Two therefore embeds a universal service obligation in licenses, concessions, or equivalent instruments. It defines service areas, access targets, quality standards, and enforcement mechanisms. The second is financial

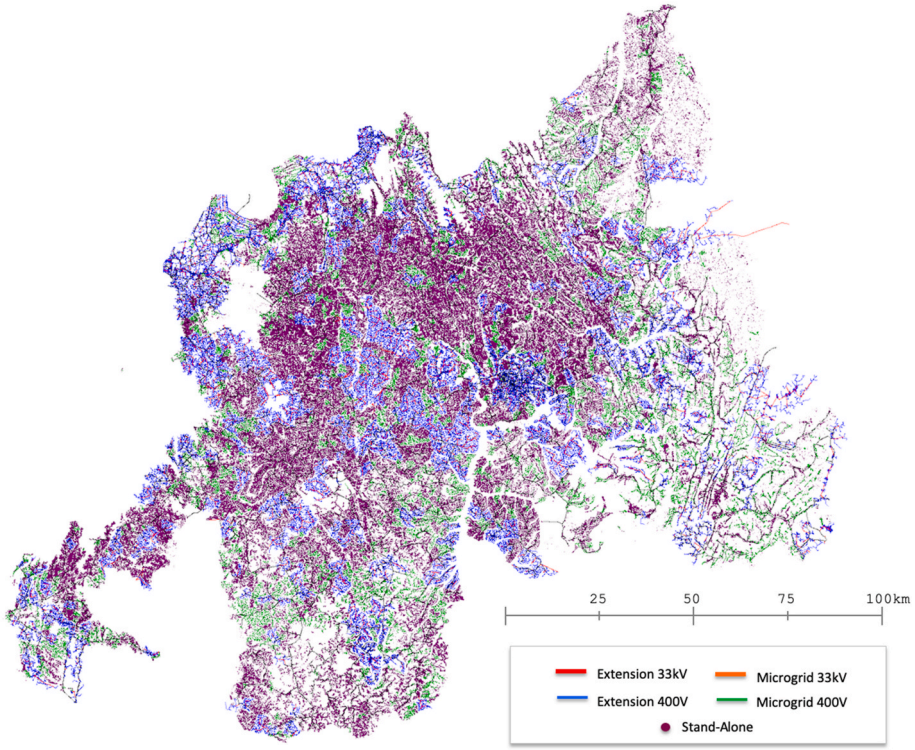

Fig. 1. Results of the national techno-economic analysis to achieve 100% electrification in Rwanda by 2024 using REM. Source: Data from (MIT/IIT-Comillas Universal Energy Access Lab, 2019).

sustainability, although at this stage the principle is only partly operationalized. Step Two establishes the regulatory and contractual basis for cost recovery by defining the cost-of-service regime and the tariff and subsidy architecture. It also specifies how cross-subsidies and external subsidies are implemented in practice. Whether these rules are sufficient to make the rollout financially sustainable is then assessed in Step Three, once they are translated into a financial plan.

3.2.1. Tariffs, subsidies, and the cost-of-service regime

Regulators influence the financial sustainability of electrification mainly through the design of end-user tariffs. A common approach is a uniform tariff for a given class of consumers across a distribution area, regardless of urban or rural location. This roughly supports progressive rates and political acceptability. In this way, rural and low consumption customers pay the same rate as urban customers even though the cost of supply is higher for the former and their demand is typically lower. Tariff design may also rely on cross-subsidies from larger customers, usually industrial and commercial or urban consumers, toward poorer, rural, and low-consumption households. Uniform tariffs therefore can create a revenue deficit during electrification, because extending service to high-cost, low-demand customers increases costs faster than revenues if tariffs remain unchanged. That deficit must then be covered through cross-subsidies, external subsidies, or tariff increases elsewhere in the system.

In practice, a combination of tariff uniformity, cross-subsidies, and budget-funded transfers is the rule rather than the exception in power sectors worldwide. They reconcile tariff uniformity, affordability, and sector solvency. They are a standard way to finance last-mile electrification in many jurisdictions (Cuenca-Enrique et al., 2024; Eberhard et al., 2011; Maphosa and Mabuza, 2017; Trimble et al., 2016).

From a regulatory perspective, Step Two specifies the cost-of-service regime that governs service provision. The regulator sets an allowed revenue requirement for each regulated entity based on the cost streams defined in Step One. This includes efficient operating costs, depreciation, and a reasonable return on the regulated asset base. The allowed return is governed by the weighted average cost of capital. This parameter anchors bankability and investor participation. In this framework, "cost reflective" refers to the allowed revenue requirement in aggregate, not to the end-user tariff (as it has been just explained "cost-reflective end-user tariffs" do not exist in practice, or at most they are very rare). The regulator recalculates the revenue requirement each year to track efficient costs and an allowed rate of return on investments. The implementation condition is that the regulated entity receives the allowed amount in cash within the year. Tariffs can contribute to that cash flow, but affordability constraints can prevent tariffs from reaching the cost-reflective level. Step Two must then specify an explicit subsidy mechanism that pays the difference between revenues collected under affordable tariffs and the allowed revenue requirement.

The ultimate objective is to ensure that, on an annual basis, each company receives the stipulated revenue requirement. When rules are clear, they make each connection viable on a life-cycle basis while keeping fiscal exposure visible to government and development partners.

3.2.2. Business models by electrification mode and the "utility-like" logic

To proceed with implementation, it is essential to select business models that have the capacity to implement the techno-economic plan on a large scale. The viability of private participation is contingent upon the predictability of cash flows and the credibility of risk assessment and allocation. It is imperative that regulation and contracting be implemented to mitigate risk at the fundamental level prior to the implementation of financial de-risking instruments.

The fundamental implication is that, as with the grid, off-grid provision often needs a "utility-like" structure. This means a regulated business model that is intended to be permanent, not a time-bound project. It requires an allowed revenue model anchored in the efficient cost of service, with clear service standards and performance-based incentives. This logic applies to the main distribution grid, but also to mini-grids and stand-alone systems, where local willingness to pay often remains below full cost recovery.

For mini-grid developers, a limited number of projects have the potential to recover full costs through affordable local tariffs and anchor loads. Without a guaranteed subsidy mechanism, private capital is limited to unsustainable business models. These models include subsidies to the initial capital investment and a willing-buyer-willing-seller mechanism to set up tariffs. When more investment is needed, the tariffs must increase significantly, hitting affordability limits, and the mini-grid should be expected to collapse.

Under regulated remuneration and the guarantee of annual revenues, the regulatory authority calculates the efficient cost of providing, operating, and maintaining mini-grids, incorporating an allowed return. Regulated tariffs applied to end-users will remain at affordable levels. The discrepancy is addressed through the implementation of a regulated subsidy program. In the context of competitive procurement, bidders offer the minimum subsidy required to supply electricity in a specified territory, while adhering to predetermined access and quality standards.

The same logic applies to stand-alone systems. Under an energy-as-a-service model, customers pay a fixed, affordable monthly fee but do not own the assets. At that fee level, revenues often do not cover the full cost of providing the service. Costs include purchasing systems, deploying them, replacing or repairing equipment, billing and collection, and maintaining customer service points, including access to appliances that enable basic productive uses. A subsidy must therefore complement tariff revenues. Competitive tendering can again determine the minimum required subsidy for a specified service standard.

Grid extension requires a different treatment, because an incumbent distribution company typically exists. In most cases, the distribution segment is financially distressed (Balabanyan et al., 2021). One option is a concession for the entire on-grid distribution business, including the existing grid and the future extensions specified in Step One. This option can be structured as i) a "full concession," in which the concessionaire is responsible for investments, operations, and maintenance, or ii) a model in which major investments are publicly funded, and the operator is responsible for procurement, operations, maintenance, and minor investments. In francophone contexts, this latter model is often referred to as *affermage* or *délégation de service public* (Hosier et al., 2017; Jacquot et al., 2020). When a full concession is not feasible, separate concessions for specific extensions can later transfer to the incumbent utility, with buy-out mechanisms for residual asset value. A rural electrification agency or a public entity can also implement where public or concessional funding is sufficient.

Within this framework, concessions and related models are the vehicles through which cross-subsidies and explicit subsidies are operationalized. Their territorial scope, universal-access obligations design, incentives, and financial relations with the rest of the power sector must remain consistent with the least-cost plan and with scalability and sustainability objectives. In fiscally constrained settings, they remain one of the few viable paths to combine private participation with universal access. At this stage, however, financial sustainability is defined only at the level of regulatory and institutional design. Whether the resulting structure is actually sustainable can only be assessed in Step Three, once these rules are translated into a financial plan and tested against projected cash flows.

3.3. Step Three: how will it be financed? – the financial plan

With a robust techno-economic plan in place and implementable business models defined, the electrification program reaches its major binding constraint. It must secure financing that matches the scale and timing of investments for the entire electrification process. Step Three designs the financing architecture that supports the implementation vehicles defined in Step Two. It specifies how capital and subsidies are

mobilized, allocated, and disbursed over time. It also specifies how public resources, concessional finance, and commercial capital combine to reduce the sector's blended cost of capital and to circumscribe long-term pressures on tariffs and sovereign budgets.

Least-cost planning and financial viability require one integrated approach across grid extension, mini-grids, and stand-alone solutions. Integrated strategies can allocate resources more efficiently than fragmented programs and clarify cross-subsidy rules across consumer groups and geographies (Ankel-Peters et al., 2025; CEER, 2020; Estache et al., 2006; Falchetta et al., 2022; Maphosa and Mabuza, 2017).

3.3.1. An integrated financial approach for long-term financial sustainability

The proposed financing strategy integrates market-based capital with targeted public support. The underlying objective is to leverage private financial resources in instances where revenue security exists. To that end, the strategic employment of subsidies is instrumental in addressing scenarios where social objectives or high unit costs jeopardize the full recovery of costs. This creates a layered financing stack that matches instruments to constraints. Capital markets support bankable cash flows. Public support addresses affordability and residual risk.

Accelerated rollout creates a "viability gap" when revenues collected under affordable tariffs remain below the regulated cost of service. The shortfall must be covered through explicit subsidies or auditable cross-subsidy mechanisms. Predictability is critical. If subsidy disbursement is discretionary or delayed, the program becomes unbankable because providers cannot rely on stable cash inflows. This depends on Step Two. It requires enforceable concessions or licenses, credible tariff-setting rules and institutions, and payment security arrangements that make subsidy and cross-subsidy transfers contractually reliable (Cornieti and Nicolas, 2023; Eberhard, 2007).

Rollout also creates financing needs due to timing. Investment outlays are front-loaded, while regulatory remuneration spreads recovery over asset lives, and new rural customers consume little electricity initially. The program can therefore face early-year liquidity stress even when long-run viability holds. The plan should provide bridge finance and align repayment schedules with expected cash-flow trajectories through tenors, grace periods, sculpted debt service, and liquidity facilities.

These two constraints correspond to different policy and financing instruments. The viability gap is a recurring revenue-adequacy problem. Financing needs are a liquidity and capital-structure problem during rollout. They require distinct instruments, and they should be tracked and reported separately to avoid policy confusion.

These constraints determine instrument roles. Concessional finance is cheaper than commercial capital but rarely sufficient at scale. Its role is to de-risk and crowd in private finance and reduce the blended cost of capital. Governments can mobilize concessional loans through development finance institutions (DFIs), complemented by grants, guarantees, and results-based subsidies when cash flows are weak and investments are front-loaded.

Grants matter most when affordability constraints are structural and persistent. Guarantees provide targeted credit enhancement and can improve debt capacity, tenor, and pricing when they cover a binding priced risk. Commercial debt then provides the bulk of volume for creditworthy operators through corporate lending or project structures, including syndicated facilities and DFI participation. These instruments require predictable revenues and enforceable contracts, and lenders price residual risk through tenor, pricing, covenants, and security packages.

Instrument choice should preserve equity value under the regulated return. Excessively short tenors can front-load debt service. They can turn a financing-needs problem into a de facto viability gap. The financing plan should therefore state leverage limits, minimum tenors, and liquidity backstops for each implementing entity.

3.3.2. A coordinated financing architecture for universal access

An integrated plan needs a strong institutional focal point. Fragmented channels create inconsistent subsidy rules, unstable disbursements, and high transaction costs. They also raise policy and counterparty risk and therefore the cost of capital. Centralizing flows can improve coordination and strengthen the allocation of scarce concessional resources (Briera and Lefèvre, 2024; Fay et al., 2021; Vikas et al., 2024).

This paper therefore proposes a centralized financial strategy that integrates funding across all three electrification modes and coordinates the actions of utilities, developers, investors, and the government.

Operationalizing this strategy requires a coordinating vehicle, which this paper names "Finance-Co". Finance-Co is a government-affiliated financial intermediary dedicated to the distribution sector and universal access. It pools public resources and external support into a single platform. It then channels funds to distribution companies and off-grid developers under rules consistent with the regulatory framework.

Fig. 2 clarifies the economic flows that Finance-Co coordinates. Inflows include government-backed equity and risk support, such as guarantees where needed. Development partners provide grants and concessional loans through the same vehicle. Finance-Co then allocates resources across grid, mini-grids, and stand-alone systems to match the least-cost plan and its financing needs. For grid extension, it funds investments in new assets through the incumbent DISCO or a concessionaire. For mini-grids and stand-alone systems, it provides subsidies that close viability gaps, including capital contributions where balance sheets are constrained. The figure explicitly recognizes private provision in these segments and the possibility of unbundling investment and operations. This matters because it allows the regulator to remunerate service delivery through regulated tariffs or regulated payments, while Finance-Co finances the capital component under concessional terms.

The outflows in Fig. 2 also clarify the revenue backstop for each mode. Grid and mini-grid operators receive revenues from regulated tariffs, potentially under a common reference tariff when comparable service quality is required across modes. Stand-alone providers receive a regulated payment. These revenue streams define baseline operating cash flow. Subsidies close residual viability gaps when affordability binds.

This architecture makes cross-subsidization explicit and auditable. Fig. 2 shows a dedicated cross-subsidy channel that routes regulated tariff revenues into Finance-Co and reallocates them to fund off-grid support, including mini-grids and stand-alone systems. This makes redistribution across customer classes and geographies transparent and auditable and reduces discretionary transfers.

Commercial finance remains part of the equilibrium. Banks can lend alongside public and concessional flows when operators are creditworthy and contracts are enforceable. Finance-Co strengthens this channel by standardizing arrangements, improving payment predictability, and using transparent credit support when governments choose to provide it.

Finally, Finance-Co governance must balance national ownership with external oversight. The ministries of energy (MoE) and finance (MoF), or their equivalents, should represent the state. Development partners and other major stakeholders that provide capital and risk mitigation should participate in governance to align support with national priorities and to strengthen oversight of disbursement rules.

4. Results: cash-flow dynamics under cost-of-service regulation

This section formalizes the cash-flow feasibility conditions implied by the three-step framework under cost-of-service regulation. It distinguishes revenue adequacy (the viability gap) from rollout liquidity constraints (financing needs).

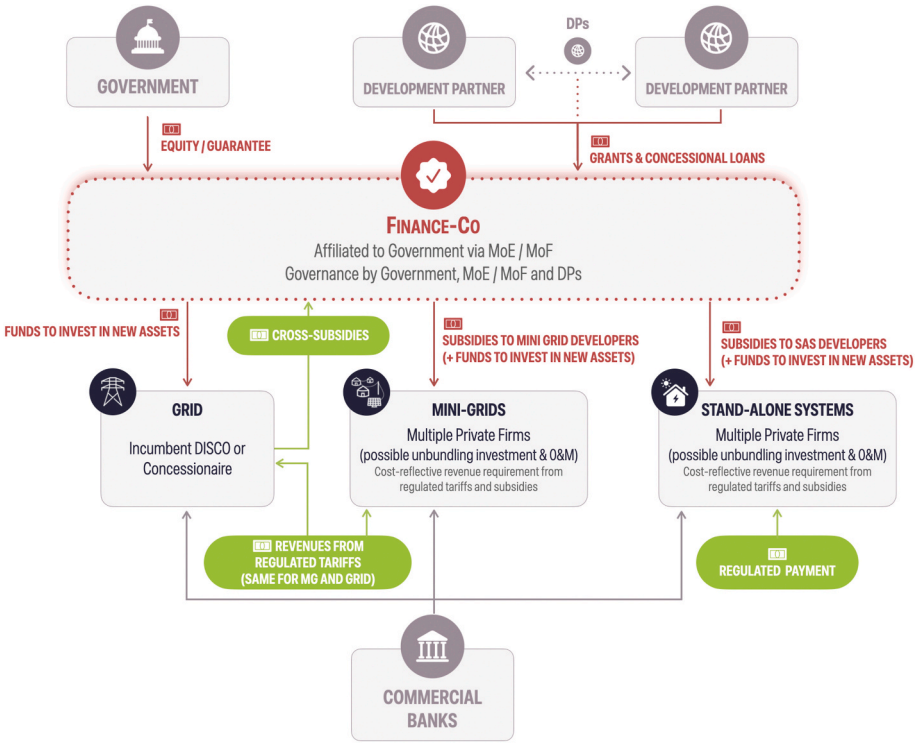

Fig. 2. Stylized cash flow structure of an integrated financing vehicle for universal electrification, showing funding sources, subsidy channels, and implementing entities across grid extension, mini-grids, and stand-alone systems.

4.1. Notation and time indexing

Let t index years and let i index regulated entities. In the simplest case, i is the incumbent distribution company. In the integrated framework, i can also represent: (i) a distribution concessionaire (grid operation and grid extension in a defined territory), (ii) a mini-grid concessionaire, or (iii) a stand-alone service provider operating under a regulated energy-as-a-service model.

4.2. Annual realized revenues

Annual realized revenues are the cash revenues collected from end-users through regulated tariffs and charges. They are the only recurrent income of the electricity business. They depend on tariff levels, delivered energy, billing, losses, and collection performance.

A general representation for each entity i at time t is:

$$\mathrm{REV}_{t,i} = \Sigma_{c\in C}\left(p_{t,i,c} \times E_{t,i,c} \times \eta_{t,i,c}\right) + R_{t,i}^{other} \quad (1)$$

Where:

- c indexes customer classes (for example residential, commercial, industrial).
- $p_{t,i,c}$ is the regulated tariff or average regulated price for class *c*.
- $E_{t,i,c}$ is billed energy or an equivalent billing base for class *c*.
- $\eta_{t,i,c}$ is the collection rate.
- $R_{t,i}^{other}$ captures other regulated income items, such as regulated connection charges, regulated service fees, or regulated transfers that are treated as revenue in accounts.

4.3. Annual regulated cost of providing the service as the revenue requirement

Under cost-of-service regulation, the regulator sets the revenue requirement that is intended to cover efficient costs and allow a reasonable return on invested capital. In a given year t, for each entity i, the cost of service is calculated using the following formula:

$$CoS_{t,i} = OPEX_{t,i} + DEP_{t,i} + RAB_{t,i} \times WACC_{t,i} \quad (2)$$

Where:

- $OPEX_{t,i}$ is efficient operating expenditure allowed by the regulator.
- $DEP_{t,i}$ is regulatory depreciation of the RAB.
- $RAB_{t,i}$ is the regulated asset base.
- $WACC_{t,i}$ is the Weighted Average Cost of Capital used to remunerate the RAB.

This representation is consistent with orthodox regulatory accounting principles, emphasizing that the allowed return is determined by the WACC. In essence, this parameter operates as the primary factor influencing the return on the RAB, consequently impacting the overall revenue requirement and the subsequent determination of tariffs (Gómez, 2013a, 2013b; Reneses et al., 2013).

4.4. Annual total expenditure as cash outflows

The revenue requirement is not a cash flow. It is a regulated accounting construct that defines the distribution of cost recovery over a period of time. On the other hand, the implementation of an electrification plan requires a cash-based perspective, as the DISCO and the other implementing entities are obligated to meet tangible cash obligations on an annual basis. These obligations encompass both investment outlays and financing payments. Consequently, the annual total expenditure is defined as the total cash outflow associated with the operation and financing of the business in year (t).

A practical decomposition is:

$$\mathrm{TOTEX}_{t,i} = \mathrm{OPEX}_{t,i} + \mathrm{CAPEX}_{t,i} + \Delta NWC_{t,i} + \mathrm{TAX}_{t,i} + \mathrm{DS}_{t,i} + \mathrm{DIV}_{t,i} \quad (3)$$

Where:

- OPEX$_{t,i}$ includes actual administration, operation, and maintenance costs.
- CAPEX$_{t,i}$ includes all growth and maintenance investments executed in that year.
- $\Delta NWC_{t,i}$ captures net working capital variations.
- TAX$_{t,i}$ captures income taxes and other cash taxes where applicable.
- DS$_{t,i}$ captures debt service, including interest and principal repayments.
- DIV$_{t,i}$ captures dividends paid to equity holders.

This definition preserves the key idea that the TOTEX includes real operating and capital expenditures plus the cash consequences of the financing structure.

4.5. Two gaps that bind implementation

The definitions above imply two distinct gaps. They have different economic meanings and require different policy and financial responses. Confusing them is a recurrent source of implementation failure.

4.5.1. The viability gap: when affordability prevents revenues from reaching cost of service

The first gap arises when tariffs are set below the cost of service. In that case, annual realized revenues fall short of the regulated revenue requirement:

$$VG_{t,i} = CoS_{t,i} - REV_{t,i} \tag{4}$$

Where $VG_{t,i}$ is the viability gap of entity i in year t.

If tariffs remain below cost of service for prolonged periods without a credible compensation mechanism, the regulated business is structurally loss-making. In that case, private participation becomes unlikely and commercial debt becomes unavailable. Even concessional lenders will hesitate when cash-flow predictability is weak (Huentele et al., 2020; Walder and Kirkman, 1999).

The policy interpretation is direct: if a government chooses to keep tariffs below the regulated revenue requirement, the deficit becomes a public responsibility. The compensation instrument can take different forms (budget transfers, an access fund, a sector levy, or ring-fenced flows through an institution such as Finance-Co), but it must be transparent and enforceable. Otherwise, the viability gap increases risk, raises WACC, and augments the long-run costs faced by consumers and taxpayers.

4.5.2. The financing needs: when total cash expenditures exceed the cost of service in a given year

The second gap persists even in instances where the activity is considered viable from a regulatory standpoint. A DISCO may incur a cost of service compatible with a viable financial plan, yet it also faces a substantial cash deficit during the initial implementation phase. The annual financing needs of a given entity are defined as follows:

$$FN_{t,i} = TOTEX_{t,i} - CoS_{t,i} \tag{5}$$

Where $FN_{t,i}$ is the financing needs of entity i in year t. During the high-investment phase, capital expenditure rises sharply, working capital often rises, and debt service begins once debt is drawn. These cash items can push (TOTEX) above (CoS) even when (CoS) is properly defined and updated.

The core driver is the intertemporal structure of cost recovery. $CoS_{t,i}$ remunerates investment through depreciation and the allowed return over the asset's economic life. It therefore converts a front-loaded cash outlay into a multi-year revenue requirement. It does not reimburse the full cash outlay in the year when the entity builds the asset. The resulting timing wedge is the "financing needs" gap. The entity must cover it through an appropriate mix of equity and debt, using instruments with tenors and repayment profiles consistent with rollout dynamics.

The economic interpretation differs from the viability gap. The financing needs gap is not, by itself, evidence of regulatory failure. It reflects timing. Investment is front-loaded, while cost recovery is spread over asset lives. As a result, a program can fail because it lacks bridge finance even if subsidy policy is sound. A program can also fail because subsidies are uncertain or poorly executed even when capital is available.

Fig. 5 makes clear that electrification binds through two channels. First, revenue adequacy under affordability constraints determines whether (REV) can cover the (CoS) in the long run. The second is cash timing, which determines whether the entity can finance (TOTEX) during periods of intensive investment, when revenues lag behind expenditures.

4.5.3. Consolidated annual cash balance: sources and uses of funds

Fig. 6 reframes the two gaps in a single sources-and-uses view. In any year t, the regulated entity must cover total cash expenditures through a combination of revenues, subsidies, and financing sources. A practical cash balance identity is:

$$\mathrm{REV}_{t,i} + \mathrm{SUB}_{t,i} + \Delta\mathrm{DEBT}_{t,i} + \Delta\mathrm{EQUITY}_{t,i} = \mathrm{TOTEX}_{t,i} + \Delta\mathrm{CASH}_{t,i} \tag{6}$$

where $SUB_{t,i}$ represents explicit subsidies/transfers paid to the entity, $\Delta DEBT_{t,i}$ is net debt raised, $\Delta EQUITY_{t,i}$ is net equity injected, and $\Delta CASH_{t,i}$ is the change in cash balances.

This identity clarifies the operational meaning of the two gaps. If (REV) < (CoS), then (SUB) must compensate for the viability gap unless an explicit subsidy mechanism exists. If (TOTEX) > (CoS), then (DEBT) and (EQUITY) must cover financing needs, subject to constraints on leverage, tenor, and risk appetite.

Equation (6) also provides a rationale for why annual subsidy calculations are not sufficient. The government must ensure that required subsidies are predictable and disbursed on schedule. Where this is not credible, payment risk increases WACC and can dominate the business case, undermining implementability (DAC Working Party on Aid Effectiveness, 2011; Foster and Rana, 2020).

4.6. Long-horizon dynamics: the asynchrony between REV, CoS, and TOTEX

Figs. 3–6 describe the annual cash-flow logic. Fig. 7 extends the logic over a multi-year rollout (stylized over a 20-year horizon) and highlights a structural asynchrony: (TOTEX) typically peaks early due to front-loaded investment, (CoS) rises and remains elevated because the revenue requirement remunerates the accumulated asset base over asset lives, and (REV) lags because newly connected customers consume little electricity initially and because tariffs remain constrained by affordability.

The difference between the (CoS) curve and the (REV) curve corresponds to the viability gap defined in equation (4). The government must reduce this gap as early as feasible by increasing tariffs to the extent allowed by affordability and political acceptability and, in years when tariffs cannot reach the revenue requirement, by guaranteeing subsidies on an annual or multi-year basis.

The asynchrony between (TOTEX) and (CoS) emphasizes the importance of capital structure and financing instrument selection. Tenors and repayment profiles should align with the recovery horizon implied by the regulatory regime and asset lives. Longer tenors reduce

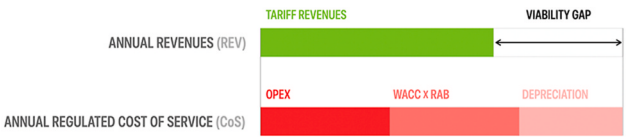

Fig. 3. Regulated revenue requirement and tariff revenue adequacy.



Fig. 4. Regulated cost of service compared with annual total expenditure.

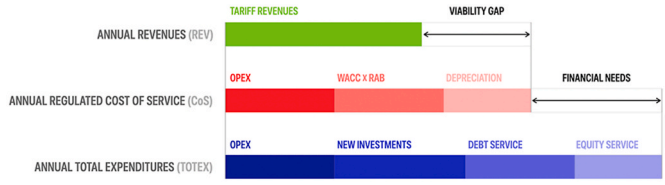

Fig. 5. Mapping tariff revenues to regulated costs and total expenditure obligations.

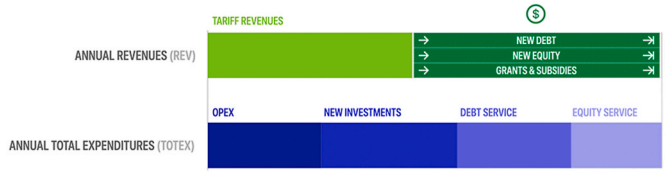

Fig. 6. Tariff revenues and complementary financing sources to meet total expenditure.

annual debt service and reduce the annual tariff and subsidy pressure required to keep the program bankable.

A long-run feasibility condition can be stated in cumulative form. Over a sufficiently long horizon, cumulative sources of funds must cover cumulative uses of funds:

$$\Sigma_{t=1}^{T}\left(REV_{t,i}+SUB_{t,i}\right)+\Sigma_{t=1}^{T}\left(\Delta DEBT_{t,i}+\Delta EQUITY_{t,i}\right)\geq\Sigma_{t=1}^{T}TOTEX_{t,i} \tag{7}$$

Equation (7) is therefore a cash-flow feasibility condition. It formalizes the fact that front-loaded (TOTEX) creates a temporary funding requirement that must be bridged by a combination of subsidies and external finance.

Investment recovery is instead a present value condition. Abstracting from terminal balance-sheet adjustments, long-run viability requires that the discounted remuneration stream covers the discounted cash cost of delivery at the relevant discount rate r :

$$\Sigma_{t=1}^{T}\left[\left(REV_{t,i}+SUB_{t,i}\right)/\left(1+r\right)^{t}\right]\approx\Sigma_{t=1}^{T}\left[TOTEX_{t,i}/\left(1+r\right)^{t}\right] \tag{8}$$

Taken together, (7) and (8) separate two constraints that Fig. 7 combines visually. The first is liquidity during rollout. The second is long-run cost recovery in present value terms. Debt and equity do not substitute for revenue adequacy. They smooth the timing mismatch between early cash needs and a slower build-up of (REV + SUB). When both constraints are satisfied, least-cost electrification plans become financially implementable over the rollout horizon.

4.7. Operationalized applications from Rwanda and Uganda

This section presents two documented applications of the framework: the Rwanda electrification business-plan application of (de Abajo, 2023; de Abajo et al., 2020) and the post-Umeme National Electrification Strategy in Uganda application of (Díaz-Pastor and Pérez-Arriaga, 2025). In both cases, the purpose is not to add full case studies to the paper, but to show how the proposed approach can be organized as an implementation pathway with defined responsibilities, remuneration rules, and financing arrangements.

The case of Rwanda provides the clearest example of the transition from least-cost planning to a business- and financial-plan structure. The application is built around a sector in which tariff revenues collected by the Rwanda Energy Group (REG), the incumbent national utility, are below cost recovery and the gap is covered through budget transfers, while sector planning and development rest with REG and economic regulation rests with the Rwanda Utilities Regulatory Authority (RURA). At the same time, the scope of the application is deliberately limited. It focuses on the investments and operating assumptions required to electrify the remaining unserved population, rather than on a full restructuring of the legacy distribution business. Rwanda is therefore best read here as an *ex-ante* implementation design for the remaining electrification plan.

Within that perimeter, the Rwanda application uses a concession-oriented business-plan hypothesis to make the new rollout investable. The objective is to show how private capital and industrial capability could enter the new electrification assets under a regulated framework, not to claim that a final concession agreement had already been awarded. In the underlying proposal, the new investments are remunerated through a cost-reflective revenue requirement, while tariffs and explicit subsidies determine the cash that can actually be collected from end users. This distinction is central to the Rwanda design because it separates the remuneration needed to attract an industrial partner from the affordability constraints faced by consumers. The business-plan

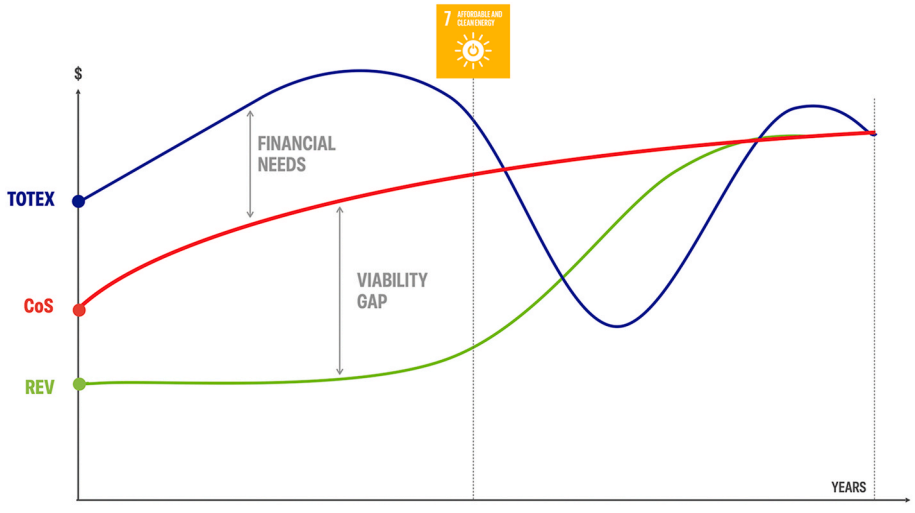

Fig. 7. Evolution of revenues, regulated costs, and total expenditure over time.

document presents this as a preliminary template to help align the government, the regulator, the incumbent utility, financing providers, and a potential industrial partner around a feasible concession agreement.

The rollout logic in Rwanda follows three distinct stages. The first stage, covering 2021–2025, mirrors the least-cost national electrification plan –as presented in Fig. 1– and deploys the least-cost technology mix to connect the remaining population and achieve universal access. In the underlying plan, this means 2.5 million new customers, 931 grid-extension projects, 1,973 mini-grid projects, and a first investment wave of about USD 1.023 billion. The second stage, covering 2026–2030, is not a second access push. Investment drops sharply and is concentrated on replacement CAPEX, maintenance, and the reinforcements needed to absorb population and demand growth while preserving service quality. The third stage, covering 2031–2040, is mainly a migration stage. Its purpose is to reduce the share of stand-alone systems from 40% in 2030 to 20% by 2040 by extending the grid to many isolated settlements, densifying already connected areas, and integrating many early mini-grids into the central network. In other words, the later wave is not a repetition of the original least-cost rollout. It is a transition in electrification mode.

The Rwanda application also specifies the changes in the regulation needed to make that rollout commercially credible. It assumes an initial 25% increase in C&I tariffs, no initial increase for non-C&I tariffs, and government subsidies equal to 10% of tariff income during 2021–2030, with a linear decline to zero by 2040. The financing stack combines USD 300 million of equity, USD 400 million of subsidized public finance, a USD 500 million first-wave commercial debt facility, a USD 500 million second-wave commercial debt facility in 2031, and an assumed USD 500 million refinancing of that commercial debt structure in 2038. Over 2021–2040, the business plan requires about USD 3.0 billion of total funding, of which about USD 2.0 billion is expected to come from operating cash flow, while net debt by 2040 is estimated at around USD 300 million. The Rwanda case makes visible both the annual revenue gap created by affordability limits and the separate financing needs created by the timing of investment.

Under these assumptions, the Rwanda business plan generates a financially sustainable implementation path. Operating cash flow reaches about USD 2.0 billion over 2021–2040. Net debt is estimated at around USD 300 million by 2040. The debt service coverage ratio (DSCR) remains above 1.4x except in 2026 and 2027. Return on equity (ROE) rises into the 10–12% range during the second rollout wave, and equity internal rate of return (IRR) is estimated at around 11–12% under alternative holding horizons.

The Rwanda case should not, however, be read as *ex-post* confirmation that the original 2024 timetable was achieved. Official REG data report cumulative household electricity access of 84.6% by end-July 2025, including 59.6% on-grid and 25.0% off-grid (REG, 2025). The value of the Rwanda application is therefore different. It shows how a least-cost national plan can be translated into a business-plan structure with explicit assumptions on service quality, remuneration, subsidies, and capital structure. Delivery speed remains sensitive to subsidy credibility, capital mobilization, and implementation capacity.

Uganda, by contrast, is the stronger benchmark for the full regulatory–financial architecture. The institutional starting point is also different. Following the 1999 unbundling, Uganda granted a 20-year distribution concession to Umeme Ltd. in 2005. Over the life of that concession, technical and commercial losses fell from almost 38% to 16.2%, the customer base grew nine-fold, and collection efficiency approached 99% (Umeme Limited, 2025). When the concession expired on 31 March 2025, the buy-out of the unrecovered regulated asset base became a major fiscal and regulatory issue (Elias Biryabarema, 2025; Njuguna, 2025). The post-Umeme application is therefore not a simple extension of the old franchise. It is a proposal for the next distribution architecture after Umeme.

According to the proposal, the business model is structured around two interconnected entities. The first, designated as Service-Co, would be a regulated and privately operated distribution service company selected through a competitive process and granted a 20-year concession by the Electricity Regulatory Authority (ERA) to operate the publicly owned Uganda National Electricity Company (UNEC) network. Service-Co bears responsibility for the operation, maintenance, billing, collection, network densification, and downstream EPC works. It also submits investment and operating proposals for regulatory approval and cost recovery.

The second entity, Finance-Co, functions as a centralized financing and settlement mechanism, aggregating grants, concessional debt, government equity, and tariff-backed surpluses. It then allocates these resources to investments in both grid and off-grid infrastructure. Private mini-grid and stand-alone providers are considered distinct entities under the approved tariffs and explicit subsidies where required. Therefore, Uganda provides a more comprehensive benchmark than Rwanda for the full Step Two architecture. Specifically, the regulatory design, the contractual form, and the financing entity are all specified in one integrated model.

The quantitative baseline is also broader. Uganda's National Electrification Strategy (NES) requires about USD 4.7 billion of investment to deliver about 10.4 million new connections. Of the currently unserved population, 53% is most cost-effectively served through stand-alone solar systems, 45% through grid extension and densification, and 2% through mini-grids. Under the base case of universal access by 2030, average annual distribution CAPEX in 2026–2030 reaches USD 809.8 million. Over the same period, Finance-Co must mobilize about USD 3.0 billion. The published financing package combines USD 2.0 billion of concessional debt, USD 600 million of grants, USD 400 million of government equity, and USD 1.12 billion of tariff-backed operational surpluses transferred from Service-Co.

The Uganda results also show how this architecture performs over time. Regulated tariff income for Umeme and, after 2025, Service-Co rises from USD 590.9 million in 2026 to USD 1.73 billion in 2030 and USD 6.80 billion by 2040. The surplus transferred from Service-Co to Finance-Co rises from USD 54.5 million in 2026 to USD 502.7 million in 2030 and USD 3.57 billion by 2040. By 2040, regulated tariffs are sufficient to cover the full revenue requirement of the distribution segment, and the concessional debt has been fully amortized. The sensitivity analysis then shows how rollout timing changes feasibility. Extending the access horizon from 2030 to 2040 reduces average annual distribution CAPEX in 2026–2030 from USD 809.8 million to USD 269.9 million and Finance-Co funding needs from USD 3.0 billion to USD 0.7 billion. Required grants fall from USD 600 million to USD 200 million, while concessional debt falls from USD 2.0 billion to USD 370 million. Uganda is consistent with the results of Section 4.6 and illustrates them in operational terms. Long-run cost recovery is necessary, but it is not sufficient. Feasibility also depends on the timing of financing needs and on the institutional capacity to mobilize and allocate capital credibly.

Together, the two applications play complementary roles, as shown in Table 1. Rwanda demonstrates how a national least-cost plan can be translated into a business plan for the remainder of the rollout process. Meanwhile, Uganda illustrates how the same logic can be embedded within a comprehensive regulatory and financial architecture centered on Finance-Co.

5. Discussion and policy implications

The results formalize two implementation constraints under affordability: revenue adequacy (closing the viability gap) and rollout liquidity (covering financing needs). They operate through different channels and therefore require different policy instruments and accountability. The relevant comparison, however, is not between least-cost planning and the framework proposed here. Least-cost planning remains the technical starting point. The added value of the proposed framework is that it forces that pathway to be tested against the revenue

Table 1
Operationalized applications of the core mechanisms of the framework.

Core mechanism	Rwanda application	Uganda application
Planning baseline	2.5 million new customers; 931 grid-extension projects; 1973 mini-grid projects; first-wave investment of about USD 1.023 billion	About 10.4 million new connections under the NES and total investment of about USD 4.7 billion; 53% of the unserved population most cost-effectively supplied by stand-alone systems, 45% by grid extension and densification, and 2% by mini-grids.
Implementation perimeter	Business-plan structure for the remaining electrification effort, not the full legacy distribution business.	Full post-Umeme architecture built around the publicly owned UNEC network, a competitively selected Service-Co, a centralized financing institution "Finance-Co", and separate off-grid private developers.
Rollout logic	2021–2025 planned least-cost rollout intended to achieve universal access; 2026–2030 stabilization with replacement and growth-related reinforcements; 2031–2040 migration from stand-alone systems to grid connections.	2021–2025 baseline calibrated on observed deployment and short-term projections; from 2026 onward, the remaining connections are distributed to meet the universal access target under the NES; the sensitivity analysis then compares a 2030 and a 2040 access path under the same regulatory and financing structure.
Revenue adequacy under affordability constraints	Tariff revenues collected by REG below cost recovery and supported by budget transfers; initial 25% increase in C&I tariffs; non-C&I tariffs initially unchanged. Government subsidies at 10% of tariff income in 2021–2030, declining to zero by 2040.	Cost-reflective revenue requirements combined with explicit cross-subsidies and tariff-backed transfers from Service-Co to Finance-Co; off-grid developers receive regulated subsidies where tariff revenues are insufficient to achieve the target return.
Financing needs and capital structure	USD 300 million equity; USD 400 million subsidized public finance; a USD 500 million first-wave commercial debt facility; a USD 500 million second-wave commercial debt facility in 2031; and an assumed USD 500 million refinancing in 2038. Net debt is around USD 300 million by 2040.	Finance-Co mobilizes about USD 2.0 billion of concessional debt, USD 600 million of grants, USD 400 million of government equity, and USD 1.12 billion of Service-Co surpluses over 2026–2030 in the 2030 base case; off-grid private firms also combine internal resources, commercial debt, equity, and regulated subsidies.
Application outputs	Revenues rise from over USD 80 million to over USD 600 million; tariff income rises from about 55% to about 90% of total revenues; operating cash flow reaches about USD 2.0 billion; net debt is around USD 300 million by 2040; DSCR remains above 1.4x except in 2026 and 2027; ROE rises into the 10–12% range; equity IRR is around 11–12%.	Regulated tariff income for Umeme and, after 2025, Service-Co rises from USD 590.9 million in 2026 to USD 1.73 billion in 2030 and USD 6.80 billion by 2040; the surplus transferred from Service-Co to Finance-Co rises from USD 54.5 million in 2026 to USD 502.7 million in 2030 and USD 3.57 billion by 2040; by 2040, regulated tariffs are sufficient to cover the full revenue requirement and concessional debt is fully amortized.
Timing sensitivity	Second rollout wave reduces stand-alone share from 40% in 2030 to 20% in 2040; financing challenge remains material beyond the first wave.	Extending access from 2030 to 2040 reduces average annual CAPEX in 2026–2030 from USD 809.8 million to USD 269.9 million and Finance-Co funding needs from USD 3.0 billion to USD 0.7 billion. Required grants fall from USD 600 million to USD 200 million, while concessional debt falls from USD 2.0 billion to USD 370 million.

model and against the timing of the financing needed to execute it.

Cost-of-service regulation becomes pivotal when electrification must accelerate while tariffs remain constrained by affordability and political economy. Unlike regulatory approaches that lock revenue trajectories for multi-year periods and only review them periodically, accelerated access requires a more responsive regime capable of frequent recalibration of the revenue requirement as execution deviates from baseline plans and financing conditions evolve. Regular reassessment reduces regulatory drift and strengthens predictability for investors, which is critical to mobilize longer-tenor capital for distribution and last-mile investments (Alexander, 2014).

In this setting, the core implementation question is not whether tariffs can be raised to cost recovery in the short run, but whether the regulated revenue requirement can be secured annually through a transparent mix of tariffs and explicit subsidies. This does not remove performance incentives. It prioritizes revenue adequacy and payment security as the first-order conditions for bankability. This is why business-model design is not secondary to planning. The contract, concession, or implementation arrangement must define who carries the service obligation, which costs are recoverable, and how any affordability gap is settled in cash.

In practice, however, affordability constraints and the commercial performance of the retail segment (losses, billing and collection) often prevent end-user payments from delivering the allowed revenue requirement in cash. The resulting shortfall is the already defined "viability gap". It must be covered through a mechanism credible to investors and lenders. Chronic under-recovery drives utility distress and quasi-fiscal deficits (Huentele et al., 2020). Three implications follow for policy design and for the financeability of network expansion and last-mile delivery.

First, make compensation explicit and rule-based. When governments choose affordability-driven tariffs, they are implicitly choosing to subsidize electricity service. Under a cost-of-service regime, this choice should be made explicit through a stable compensation instrument (for example, an access fund, a sector levy, a ring-fenced subsidy line, cross-subsidies or a standardized transfer mechanism embedded in regulation). Credible, rule-based compensation reduces discretion and payment delays, both of which increase risk premiums and WACC.

Second, improve the transparency of cross-subsidies where possible. Uniform tariffs often embed cross-subsidies from higher-consuming or higher-income segments toward low-income and rural customers.

Uniform tariffs can support progressive rates and political acceptability, but they can also obscure the magnitude and beneficiaries of redistribution. The objective is not necessarily to make the underlying regulatory mechanism explicit, which would depart from common tariff practice, but to ensure that the purpose, incidence, and financial effects of that redistribution are transparent and auditable. This can strengthen governance and reduce inconsistency across grid and off-grid modalities (CEER, 2020; Estache et al., 2006; Maphosa and Mabuza, 2017).

Third, treat subsidy predictability as a first-order bankability variable. Even when annual subsidy needs can be computed, governments often struggle to guarantee disbursements reliably through annual budget processes. In practice, subsidy payment risk can dominate the business case by raising perceived counterparty risk and, therefore, WACC. This predictability constraint is central to the political economy of access: it determines whether affordability objectives translate into durable service provision or into repeated arrears and investment stops (Pérez-Arriaga, 2024).

Closing (or explicitly funding) the viability gap is a necessary but not sufficient condition. A second constraint concerns the financing needs, which reflect the timing mismatch between front-loaded investment outlays and intertemporal cost recovery. They are not solved primarily by raising tariffs; they require financing structures consistent with rollout dynamics. Aligning debt tenor and amortization to the regulatory recovery horizon is therefore essential. When repayment profiles are too short relative to asset lives and to the speed of demand growth, debt service can generate severe early-year cash constraints even under a credible revenue requirement. Longer tenors, grace periods, and sculpted amortization profiles reduce annual cash pressure and improve implementability. In parallel, liquidity and working-capital finance must be treated as a program design variable rather than as an operator problem ex post. Expansion phases increase working capital needs (metering, billing systems, inventories) while rural consumption remains low initially. Liquidity and working capital facilities are therefore core implementation instruments during accelerated rollout.

These financing needs also clarify the complementary roles of concessional and commercial finance. Concessional instruments can lower the effective cost of capital and reduce the tariff and subsidy envelope required for feasibility. However, external concessional resources often face short commitment horizons relative to the persistence of affordability constraints (DAC Working Party on Aid Effectiveness, 2011; Gulrajani and Lundsgaarde, 2023). Results-based financing (RBF) can improve early liquidity and execution incentives within a defined program window (Vivid Economics and Savedoff, 2015), but it rarely substitutes for durable revenue adequacy when operating costs, replacement needs, and affordability-driven revenue shortfalls persist. Accordingly, the practical design challenge is not to choose between RBF and cost-of-service regulation, but to ensure their consistency: short-horizon output payments can accelerate delivery in the early stages of rollout and support operations for a limited period, while a stable revenue-adequacy mechanism is needed to sustain long-run operations and asset renewal.

The proposed integrated framework further implies that financial feasibility conditions are technology-neutral: the same revenue-adequacy and cash-timing constraints apply to grid extension, mini-grids, and stand-alone systems once they are operated as permanent service solutions. Accordingly, the key regulatory requirement is not a particular tariff design, but the existence of a coherent and credible mechanism that converts the regulated revenue requirement into timely cash receipts for each implementing agent—through a combination of user charges, explicit transfers, and/or auditable cross-subsidies consistent with affordability objectives. Without such a mechanism, private participation remains limited and service quality can deteriorate after initial rollout, independently of the chosen technology (Falchetta et al., 2022; Perez-Arriaga et al., 2019; Pérez-Arriaga, 2023).

Competitive procurement can reveal the minimum subsidy required to deliver a defined service standard in a defined territory. Concessions then enforce service obligations and performance standards. Procurement can allocate responsibilities and reveal the subsidy consistent with a required service standard, but it cannot by itself solve annual revenue inadequacy or the timing mismatch between capital expenditure and cost recovery. Experience with distribution concessions and hybrid models, including Umeme in Uganda, shows gains when obligations, remuneration, and risk allocation are clear (de Abajo, 2023; Díaz-Pastor and Pérez-Arriaga, 2025; Hosier et al., 2017; Pérez-Arriaga et al., 2022; Twesigye, 2023). Procurement complements regulation; it cannot substitute for credible cash settlement.

This logic motivates Finance-Co as a pooling and settlement platform. It reduces fragmentation, standardizes disbursement rules, and ring-fences subsidy and cross-subsidy flows. This improves payment security and supports longer-tenor finance (Fay et al., 2021). Its value is therefore not institutional complexity for its own sake. Its value is to convert dispersed public support, concessional resources, tariff-backed surpluses, and commercial capital into a predictable financing structure for a multi-technology electrification program.

International precedents support the feasibility of this institutional approach, even if mandates and legal forms differ across countries. In Bangladesh, IDCOL blended donor funding with domestic finance to scale distributed energy programs (Cabraal et al., 2021). In Tanzania, the Rural Energy Fund combined donor and government oversight to finance rural access investments and to improve coordination across programs (Danielsson and Zhou, 2011; World Bank, 2023). In Spain, the Electricity Deficit Amortization Fund helped restore sector liquidity by centralizing financial management through a dedicated legal instrument (IEA, 2021; Morningstar DBRS, 2024). In the Philippines, PSALM and the universal charge mechanism helped stabilize financial flows associated with off-grid electrification, with gains in administrative efficiency and financial transparency (CEDTyClea, 2025).

These precedents do not imply a one-size-fits-all institutional form. They support a robust functional proposition: when mandates, governance, and accountability are clear, centralizing financial management can reduce discretion and volatility in subsidy flows, improving bankability and lowering the effective cost of capital.

Finally, many national electrification strategies stop at least-cost planning and a high-level financing envelope. What they often omit is the intermediate layer between the plan and the financing envelope: the business model, the revenue requirement attached to that model, and the annual sources of cash that make execution possible. This gap helps explain why technically robust masterplans remain unimplemented (Agutu et al., 2022). The integrated framework addresses this by forcing iteration between the least-cost pathway, the implementation model, and financing. In this setting, the cost of capital is endogenous and depends on business models, enforceability, and subsidy credibility. The contribution of the framework is therefore not to replace least-cost planning, but to complete it. It turns a technical pathway into an implementable and financeable program.

If the implied financing is not feasible under fiscal and affordability constraints, the pathway must be revised in the model. This means adjusting standards, sequencing, or subsidies until planning, revenues, and cash flows align. Execution still depends on regulatory capacity, data quality, and governance safeguards in any pooled financing vehicle. This is also why the framework must remain iterative rather than prescriptive: implementation conditions can force revisions to the initial least-cost pathway without invalidating the role of least-cost planning itself. Universal access therefore requires consistency across the full chain from pathways to revenue models to financeable cash flows, which underpins the paper's conclusions.

6. Conclusion

This paper presents an integrated three-step framework that aligns least-cost electrification planning with implementable regulation and annual cash-flow feasibility. The framework bridges a persistent gap

between techno-economic roadmaps and the financing constraints faced by distribution utilities and off-grid providers. It does not argue against least-cost planning. It argues that least-cost planning becomes operational only when it is linked to an implementable business model and to a financing structure capable of absorbing affordability constraints and front-loaded rollout.

The results imply that electrification fails when two distinct feasibility conditions are not met. The first condition is cash revenue adequacy under affordability limits and weak retail performance. The second condition is early-year liquidity stress when investment is front-loaded, and cost recovery arrives later. These two conditions require different instruments and different accountability. Revenue adequacy requires explicit and rules-based compensation that is settled predictably. This is where transparent subsidies and auditable cross-subsidization matter. Liquidity stress requires capital structures, financing tenors, and liquidity facilities aligned with the regulatory recovery horizon and with rollout dynamics. The operational evidence of Rwanda and Uganda shows that both conditions can be parameterized and quantified under different institutional forms.

Once stated this way, the same two feasibility conditions apply across delivery modalities. Grid extension, mini-grids, and stand-alone systems all depend on predictable cash recovery of efficient costs through a transparent mix of user payments and governed transfers. Competitive procurement and concession design can allocate responsibilities efficiently, but they cannot compensate for weak payment security or an incoherent revenue model. What changes across technologies and countries is the contractual and institutional form, not the need for credible remuneration and timely cash settlement.

The two-condition structure also clarifies why a centralized financing platform such as Finance-Co is pivotal. It can strengthen revenue adequacy by hardening settlement of subsidies and cross-subsidy transfers through standardized rules and ring-fenced flows. It can also address rollout liquidity by coordinating disbursements, reducing fragmentation, and improving the credibility of payment schedules. These functions reduce perceived risk and can lower the effective cost of capital when affordability support relies on annual budgets and short-horizon concessional commitments.

The key implication is practical. Universal access becomes financeable when planning, regulation, and financing are designed as one system with enforceable obligations and credible settlement. In this paper, credible settlement means both revenue adequacy in cash and liquidity coverage during rollout. The framework therefore completes the least-cost pathway rather than replacing it: it converts a technical roadmap into an operator-facing and financeable program. The framework provides an auditable architecture to convert electrification targets into implementable and financeable programs.

CRediT authorship contribution statement

Santos J. Díaz-Pastor: Writing – review & editing, Writing – original draft, Visualization, Validation, Resources, Methodology, Investigation, Formal analysis, Conceptualization. **Carlos de Abajo:** Writing – review & editing, Validation, Methodology, Investigation, Formal analysis, Conceptualization. **Robert Stoner:** Writing – review & editing, Validation, Supervision, Methodology, Funding acquisition, Conceptualization. **Ignacio J. Pérez-Arriaga:** Writing – review & editing, Writing – original draft, Validation, Supervision, Resources, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

We gratefully acknowledge the contributions of Pablo Dueñas, Michel Rivier, Tomás Gómez, and Paolo Mastropietro, whose insightful comments and careful reviews substantially strengthened the structure, clarity, and overall coherence of this manuscript. The research underpinning the development and early application of the Integrated Framework for Electrification across multiple countries reflects a collaborative effort led by the MIT/IIT–Comillas Universal Energy Access Laboratory. This work was initially supported by the Shell Foundation and subsequently by the Global Commission to End Energy Poverty (GCEEP), with funding provided by The Rockefeller Foundation.

Data availability

No data was used for the research described in the article.

References

African Development Bank, 2025. Africa's risk premium: a costly myth holding back a continent. Afr. Dev. Bank Group. URL. https://www.afdb.org/en/news-and-events/press-releases/africas-risk-premium-costly-myth-holding-back-continent-80966.

Agutu, C., Egli, F., Williams, N.J., Schmidt, T.S., Steffen, B., 2022. Accounting for finance in electrification models for Sub-Saharan Africa. Nat. Energy 7, 631–641. https://doi.org/10.1038/s41560-022-01041-6.

Alexander, I., 2014. Developing countries experience and outlook: getting the framework right. Util. Policy 31, 184–187. https://doi.org/10.1016/j.jup.2014.09.007.

Aluko, T.O., Ngcobo, N.C., Adebayo, A., 2025. Mini-grids and private investment in rural electrification: insights from Rwanda's emerging market. Util. Policy 95, 101948. https://doi.org/10.1016/j.jup.2025.101948.

Amatya, R., Barbar, M., Brusnahan, M., Ciller, P., Cuadra, F. de, et al., 2018. Computer-aided electrification planning in developing countries: the reference electrification model (REM). https://www.iit.comillas.edu/publicacion/workingpaper/en/347/Computer-aided_electrification_planning_in_developing_countries:_the_Reference_Electrification_Model_(REM.

Ankel-Peters, J., Bensch, G., Moull, K., Rauschenbach, M., Sievert, M., 2025. Cost-effectiveness of rural energy access strategies. Energy Policy 203, 114633. https://doi.org/10.1016/j.enpol.2025.114633.

Arif, A., 2025. Grid or gaps? Exploring the challenges of rural electrification in India post-saubhagya – SPRF. https://sprf.in/grid-or-gaps-exploring-the-challenges-of-rural-electrification-in-india-post-saubhagya/.

Asantewaa, A., Jamasb, T., Llorca, M., 2023. Electricity sector reforms and cost efficiency: the case of small electricity systems in sub-sahara Africa. Econ. Anal. Pol. 80, 880–893. https://doi.org/10.1016/j.eap.2023.09.001.

Balabanyan, A., Semikolenova, Y., Singh, A., Lee, M.A., 2021. Utility Performance and Behavior in Africa Today. World Bank. URL. https://openknowledge.worldbank.org/entities/publication/2d4ff8b8-7ed5-5a0e-96d2-e0a0bfb9e0ce.

BloombergNEF, 2024. Africa power transition factbook 2024. https://assets.bbhub.io/professional/sites/24/Africa-Power-Transition-Factbook-2024.pdf.

Bonan, J., Pareglio, S., Tavoni, M., 2017. Access to modern energy: a review of barriers, drivers and impacts. Environ. Dev. Econ. 22, 491–516. https://doi.org/10.1017/S1355770X17000201.

Bos, K., Chaplin, D., Mamun, A., 2018. Benefits and challenges of expanding grid electricity in Africa: a review of rigorous evidence on household impacts in developing countries. Energy Sustain. Dev. 44, 64–77. https://doi.org/10.1016/j.esd.2018.02.007.

Briera, T., Lefèvre, J., 2024. Reducing the cost of capital through international climate finance to accelerate the renewable energy transition in developing countries. Energy Policy 188, 114104. https://doi.org/10.1016/j.enpol.2024.114104.

Cabraal, A., Ward, W.A., Bogach, S., Jain, A., 2021. Living in the light: the Bangladesh solar home systems story. https://documents1.worldbank.org/curated/en/153291616567928411/pdf/Living-in-the-Light-The-Bangladesh-Solar-Home-Systems-Story.pdf.

Càmara dos Deputados, 2003. DECRETO Nº 4.873. https://www2.camara.leg.br/legin/fed/decret/2003/decreto-4873-11-novembro-2003-497318-publicacaooriginal-1-pe.html.

CEDTyClea, 2025. PSALM disbursements to RE developers top P455M. BusinessWorld Online. URL. https://www.bworldonline.com/economy/2025/04/08/664862/psalm-disbursements-to-re-developers-top-p455m/.

CEER, 2020. Electricity distribution tariffs supporting the energy transition. https://www.ceer.eu/publication/ceer-paper-on-electricity-distribution-tariffs-supporting-the-energy-transition/.

Ciller, P., Ellman, D., Vergara, C., González-García, A., Lee, S.J., Drouin, C., Brusnahan, M., Borofsky, Y., Mateo, C., Amatya, R., Palacios, R., Stoner, R., de Cuadra, F., Pérez-Arriaga, I., 2019. Optimal electrification planning incorporating On- and off-grid technologies: the reference electrification model (REM). Proc. IEEE 107, 1872–1905. https://doi.org/10.1109/JPROC.2019.2922543.

Ciller, P., Lumbreras, S., 2020. Electricity for all: the contribution of large-scale planning tools to the energy-access problem. Renew. Sustain. Energy Rev. 120, 109624. https://doi.org/10.1016/j.rser.2019.109624.
Cornieti, S., Nicolas, C., 2023. How to unlock pipelines of bankable renewable energy projects in emerging markets and developing countries? https://www.esmap.org/Pipelines-of-Bankable-RE-Projects.
Cuenca-Enrique, C., del-Río-Carazo, L., Acquila-Natale, E., Iglesias-Pradas, S., 2024. Sustainability of rural electrification projects in developing countries: a systematic literature review. Energies 17. https://doi.org/10.3390/en17235925.
DAC Working Party on Aid Effectiveness, 2011. Aid predictability – synthesis of findings and good practices. https://mokoro.co.uk/wp-content/uploads/2015/09/Aid-predictability-synthesis-report.pdf.
Danielsson, L., Zhou, P., 2011. Mid-term review of the capacity development project of the rural energy agency, Tanzania. https://cdn.sida.se/publications/files/sida61477en-mid-term-review-of-the-capacity-development-project-of-the-rural-energy-agency-tanzania.pdf.
de Abajo, C., 2023. Adding a new analysis framework to support large scale electrification financing plans in countries lacking universal electricity access. https://repositorio.comillas.edu/xmlui/handle/11531/78664.
de Abajo, C., Diaz-Pastor, S.J., Gonzalez-Garcia, A., Perez-Arriaga, I.J., 2020. A business plan to achieve full electrification in Rwanda under the integrated distribution framework. GCEEP Work. Pap. Ser. https://www.iit.comillas.edu/publicacion/workingpaper/es/425/A_business_plan_to_achieve_full_electrification_in_Rwanda_under_the_integrated_distribution_framework_(IDF.
Díaz-Pastor, S.J., Pérez-Arriaga, I.J., 2025. An integrated regulatory–financial proposal for universal electrification in Uganda beyond the Umeme concession. Energy Econ. 152, 109033. https://doi.org/10.1016/j.eneco.2025.109033.
Eberhard, A., 2007. Infrastructure regulation in developing countries. https://www.gsb.uct.ac.za/files/hybridmirpaper.pdf.
Eberhard, A., Rosnes, O., Shkaratan, M., Vennemo, H., 2011. Africa's Power Infrastructure: Investment, Integration, Efficiency. The World Bank. https://doi.org/10.1596/978-0-8213-8455-8.
Eberhard, A., Shkaratan, M., 2012. Powering Africa: meeting the financing and reform challenges. Energy Policy 42, 9–18. https://doi.org/10.1016/j.enpol.2011.10.033.
Egli, F., Agutu, C., Steffen, B., Schmidt, T.S., 2023. The cost of electrifying all households in 40 sub-saharan African countries by 2030. Nat. Commun. 14, 5066. https://doi.org/10.1038/s41467-023-40612-3.
Elias Biryabarema, 2025. Ugandan parliament approves $190 million loan to pay power distributor umeme. Reuters. https://www.reuters.com/world/africa/ugandan-parliament-approves-190-million-loan-pay-power-distributor-umeme-2025-03-21/.
ESMAP, 2023. Accelerating the productive use of electricity : enabling energy access to power rural economic growth. https://www.esmap.org/Accelerating-the-Productive-Use-of-Electricity.
Estache, A., Laffont, J.-J., Xinzhu, Z., 2004. Universal service obligations in developing countries. Policy Res. Work. Pap. https://hdl.handle.net/10986/14227.
Estache, A., Laffont, J.-J., Zhang, X., 2006. Universal service obligations in LDCs: the effect of uniform pricing on infrastructure access. J. Publ. Econ. 90, 1155–1179. https://doi.org/10.1016/j.jpubeco.2005.07.002.
Falchetta, G., Michoud, B., Hafner, M., Rother, M., 2022. Harnessing finance for a new era of decentralised electricity access: a review of private investment patterns and emerging business models. Energy Res. Social Sci. 90, 102587. https://doi.org/10.1016/j.erss.2022.102587.
Fay, M., Martimort, D., Straub, S., 2021. Funding and financing infrastructure: the joint-use of public and private finance. J. Dev. Econ. 150, 102629. https://doi.org/10.1016/j.jdeveco.2021.102629.
Foster, V., Rana, A., 2020. Rethinking power sector reform in the developing world. Sustain. Infrastruct. Ser. URL. https://openknowledge.worldbank.org/entities/publication/1ed3a6de-0d51-5a4f-92c3-ea3bc034947b.
GCEEP, 2020. Global commission to end energy poverty: electricity access report 2020. Glob. Comm. End Energy Poverty. https://www.endenergypoverty.org/2020-report.
Gómez, T., 2013a. Monopoly regulation. In: Pérez-Arriaga, I.J. (Ed.), Regulation of the Power Sector. Springer, London, pp. 151–198. https://doi.org/10.1007/978-1-4471-5034-3_4.
Gómez, T., 2013b. Electricity distribution. In: Pérez-Arriaga, I.J. (Ed.), Regulation of the Power Sector. Springer, London, pp. 199–250. https://doi.org/10.1007/978-1-4471-5034-3_5.
Grimm, M., Munyehirwe, A., Peters, J., Sievert, M., 2017. A first step up the energy ladder? Low cost solar kits and household's welfare in rural Rwanda. World bank econ. Rev. 31, 631–649. https://doi.org/10.1093/wber/lhw052.
Gulrajani, N., Lundsgaarde, E., 2023. Navigating core funding frontiers: assessing options for mobilising flexible multilateral financing. https://odi.org/en/publications/navigating-core-funding-frontiers-assessing-options-for-mobilising-flexible-multilateral-financing/.
He, G., 2019. Financing the last mile of electricity-for-all programs: experiences from China. Econ. Energy Environ. Policy 8. https://doi.org/10.5547/2160-5890.8.1.ghe.
Hosier, R., Bazilian, M., Lemondzhava, T., Malik, K., Motohashi, M., Vilar de Ferrenbach, D., 2017. Rural electrification concessions in Africa. What does experience tell Us? World bank. https://openknowledge.worldbank.org/server/api/core/bitstreams/0bddb8be-6176-585e-a43c-50e0b10fdedf/content.
Huentele, J., Hankinson, D., Rosenthal, N., Balabanyan, A., Kochnakyan, A., Nguye, T.C., Rana, A., Foster, V., 2020. Cost recovery and financial viability of the power sector in developing countries. Insights from 15 case studies. https://openknowledge.worldbank.org/entities/publication/d866a5f0-ed0c-5cdf-ad57-ae2513f82c7e.
Huenteler, J., Dobozi, I., Balabanyan, A., Banerjee, S.G., 2017. Cost Recovery and Financial Viability of the Power Sector in Developing Countries: a Literature Review. ResearchGate. https://doi.org/10.1596/1813-9450-8287.
IEA, 2025. Access to Electricity – SDG7: Data and Projections. IEA. https://www.iea.org/reports/sdg7-data-and-projections/access-to-electricity.
IEA, 2023. Financing clean energy in Africa. https://www.iea.org/reports/financing-clean-energy-in-africa.
IEA, 2022. Africa energy outlook 2022. https://www.iea.org/reports/africa-energy-outlook-2022.
IEA, 2021. Spain 2021 – analysis. Energy Policy Rev. https://www.iea.org/reports/spain-2021.
IEA, IRENA, UNSD, World Bank, WHO, 2024. Tracking SDG7: the energy progress report, 2024. https://www.iea.org/reports/tracking-sdg7-the-energy-progress-report-2024.
Jacquot, G., Pérez-Arriaga, I., Nagpal, D., Stoner, R., 2020. Assessing the potential of electrification concessions for universal energy access: towards integrated distribution frameworks. Glob. Comm. End Energy Poverty Work. Pap. Ser. https://energy.mit.edu/wp-content/uploads/2019/09/MITEI-WP-2019-01.pdf.
Jamasb, T., Nepal, R., Tmilsina, G.R., 2017. A quarter century effort yet to come of age: a survey of electricity sector reform in developing countries. Energy J. 38, 195–234. https://doi.org/10.5547/01956574.38.3.tjam.
Joskow, P.L., 2024. The expansion of incentive (Performance-Based) regulation of electricity distribution and transmission in the United States. Rev. Ind. Organ. 65, 455–503. https://doi.org/10.1007/s11151-024-09973-x.
Klug, T.W., Beyene, A.D., Meles, T.H., Toman, M.A., Hassen, S., Hou, M., Klooss, B., Mekonnen, A., Jeuland, M., 2022. A review of impacts of electricity tariff reform in Africa. Energy Policy 170, 113226. https://doi.org/10.1016/j.enpol.2022.113226.
Kojima, M., Trimble, C., 2016. Making Power Affordable for Africa and Viable for its Utilities. World Bank. http://hdl.handle.net/10986/25091.
Leduchowicz-Municio, A., López-Gozález, A., Domenech, B., Ferrer-Martí, L., Udaeta, M. E.M., Gimenes, A.L.V., 2022. Last-mile rural electrification: lessons learned from universalization programs in Brazil and Venezuela. Energy Policy 167, 113080. https://doi.org/10.1016/j.enpol.2022.113080.
Lee, K., Miguel, E., Wolfram, C., 2020. Experimental evidence on the economics of rural electrification. J. Polit. Econ. 128, 1523–1565. https://doi.org/10.1086/705417.
Lemanski, C., Haque, A.N., de Groot, J., McAskill, N., 2025. The false optimism of electrification: why universal electricity access has not delivered urban energy transformation in South Africa. Energy Policy 198, 114506. https://doi.org/10.1016/j.enpol.2025.114506.
Maphosa, M., Mabuza, P., 2017. The trade-offs between pro-poor and cost-reflective tariffs in South Africa: a regulatory perspective. J. Econ. Behav. Stud. 8, 206–215. https://doi.org/10.22610/jebs.v8i6(J).1494.
Ministério de Minas e Energia, 2002. Lei Nº 10.438/2002. https://www.gov.br/mme/pt-br/acesso-a-informacao/legislacao/leis/lei-n-10-438-2002.pdf/view.
Ministry of Power, 2023. Press release: SAUBHAGYA ELECTRIFICATION SCHEME - a total 2.86 crore households have been electrified – Union power & NRE minister shri R. K. Singh. https://www.pib.gov.in/www.pib.gov.in/Pressreleaseshare.aspx?PRID=1907728.
MIT/IIT-Comillas Universal Energy Access Lab, 2019. Rwanda national electrification strategies and associated plans 2018-2020 (NESP 2024). http://universalaccess.mit.edu/.
Morningstar DBRS, 2024. PRESS RELEASE: Morningstar DBRS upgrades credit ratings on Fondo de Titulización del Déficit del Sistema Eléctrico, FTA. https://dbrs.morningstar.com/research/444109/morningstar-dbrs-upgrades-credit-ratings-on-fondo-de-titulizacion-del-deficit-del-sistema-electrico-fta.
Naruc, Usaid, 2022. Primer on the Impact of Electricity Tariff Reforms on Infrastructure Investment and Economic Development. https://pubs.naruc.org/pub/7F797D22-1866-DAAC-99FB-8095D77AA8A6.
Njuguna, H., 2025. Uganda vs umeme: the final bill of a 20-Year power concession. Kenyan Wall Str. - Bus. Mark. News Invest. Data AI Tools. https://kenyanwallstreet.com/uganda-vs-umeme-the-final-bill-of-a-20-year-power-concession/.
Pérez-Arriaga, I.J., 2024. Conclusions on the Policy Dialogue on “Sustainable and Scalable Minigrid Business Models.”. Afr. Sch. Regul.. https://africanschoolregulation.org/wp-content/uploads/2024/09/ASR_Kampala_Minigrids-Brief-2.pdf
Pérez-Arriaga, I.J., 2023. The integrated framework for electrification (IFE). Afr. Sch. Regul. URL. https://africanschoolregulation.org/wp-content/uploads/2025/03/ASR-POSITION-PAPER_The-Integrated-Framework-for-ElectrificationIFE-PRINCIPLES-.pdf.
Pérez-Arriaga, I.J., Diaz-Pastor, S.J., de Abajo, C., 2022. Stocktaking in the energy sector in Uganda - electricity distribution. Eur. Union Glob. Tech. Assist. Facil. Sustain. Energy. https://africanschoolregulation.org/wp-content/uploads/2023/01/GT012-Uganda-Report-Electricity-Distribution-Final-Report-FINAL-XX072022-IPA-CLEAN.pdf.
Perez-Arriaga, I.J., Stoner, R., Rahnama, R., Lee, S.J., Jacquot, G., Protzer, E., Gonzalez, A., Amatya, R., Brusnahan, M., Duenas, P., Santos, F.J., 2019. A utility approach to accelerate universal electricity access in less developed countries: a regulatory proposal. Econ. Energy Environ. Policy 8. https://doi.org/10.5547/2160-5890.8.1.iper.
Raji, T., Allee, A., Williams, N.J., 2024. Productive use of electricity in agriculture in sub-Saharan Africa: a systematic review. Prog. Energy 6, 042003. https://doi.org/10.1088/2516-1083/ad6c9e.
REG, 2025. Electricity access in Rwanda. https://www.reg.rw/what-we-do/access/.
Reneses, J., Rodríguez, M.P., Pérez-Arriaga, I.J., 2013. Electricity tariffs. In: Pérez-Arriaga, I.J. (Ed.), Regulation of the Power Sector. Springer, London, pp. 397–441. https://doi.org/10.1007/978-1-4471-5034-3_8.

RES4Africa Foundation, 2021. Private sector participation in African grid development. https://www.res4africa.org/s/PrivateSectorParticipationinAfricanGridDevelopment-RES4AfricaNovember20212.pdf.

Sahlberg, A., Khavari, B., Korkovelos, A., Fuso Nerini, F., Howells, M., 2021. A scenario discovery approach to least-cost electrification modelling in Burkina Faso. Energy Strategy Rev. 38, 100714. https://doi.org/10.1016/j.esr.2021.100714.

Trimble, C.P., Kojima, M., Perez Arroyo, I., Mohammadzadeh, F., 2016. Financial viability of electricity sectors in Sub-Saharan Africa: quasi-fiscal deficits and hidden costs. https://papers.ssrn.com/abstract=2836535.

Twesigye, P., 2023. Understanding structural, governance and regulatory incentives for improved utility performance: learning from umeme ltd in Uganda. Energy Res. Social Sci. 95, 102900. https://doi.org/10.1016/j.erss.2022.102900.

Umeme Limited, 2025. 20 years of umeme impact. https://umeme.co.ug/impact.

Vikas, N., Garg, V., Aiyer, S., Srivastava, S., 2024. Blended finance: key to bridging energy transition gap in developing countries. Inst. Energy Econ. Financ. Anal. URL. https://ieefa.org/resources/blended-finance-key-bridging-energy-transition-gap-developing-countries.

Vivid Economics, Savedoff, W., 2015. Results-Based Aid in the Energy Sector : an Analytical Guide. World Bank Group, Washington, DC. https://doi.org/10.1596/21622.

Walder, J.H., Kirkman, G., 1999. The Privatization of Light-Serviços de Eletricidade, SA: preparing the Terms of Sale. https://case.hks.harvard.edu/the-privatization-of-light-servicos-de-eletricidade-sa-preparing-the-terms-of-sale/.

World Bank, 2024. The Critical Link: Empowering Utilities for the Energy Transition. World Bank, Washington, DC. https://doi.org/10.1596/41618.

World Bank, 2023. Accelerating sustainable and clean energy access in Tanzania. https://documents1.worldbank.org/curated/en/099102523123533631/pdf/P179763105af2780a0972d0fc3654003c7e.pdf.

World Bank, ESMAP, KFW, ASTAE, 2013. Toward universal electricity access: renewable energy-based geospatial least-cost electrification planning. https://documents1.worldbank.org/curated/en/780811468267610181/pdf/843140BRI0Indo0ox0382136B00PUBLIC00.pdf.